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Supply Chain of CO_2 and Techno-economical Assessment of CCS Chain

Diploma Thesis

Of

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Abstract

Decarbonization has emerged as a pivotal strategy in the global effort to combat climate change, prompting many industries to explore carbon capture technologies as a means to mitigate carbon emissions. These technologies offer the possibility of either utilizing captured carbon dioxide or safely storing it, thereby minimizing environmental impact. This thesis seeks to comprehensively analyze each facet of Carbon Capture, Utilization, and Storage (CCUS), including available carbon capture technologies, methods of CO2 utilization, and storage techniques. Furthermore, it delves into the intricacies of the CO2 supply chain, examining both its techno-economic aspects and operational considerations. Through a detailed case study of a liquefied CO2 (LCO2) supply chain, this thesis evaluates the feasibility of CCUS implementation across various scenarios, particularly in the context of carbon taxation policies. The findings of this study will provide insights into the individual impacts of each component of the carbon capture supply chain on the overall feasibility of the project. By examining various scenarios and parameters, it aims to determine the conditions under which the project becomes economically viable. Furthermore, in cases where viability is not achieved, the study will discuss potential reasons and solutions to address challenges and improve the feasibility of these carbon capture projects.

Keywords: CO2, carbon capture, CO2 storage, CO2 supply chain, net zero, techno-economical assessment

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1. Introduction

1.1. Background of the study

In recent years, the intensifying discourse surrounding climate change has underscored the critical role of CO2 in shaping environmental sustainability strategies worldwide. With the imperative to mitigate greenhouse gas emissions becoming increasingly urgent[1], industries are embracing carbon capture technologies as key solutions for both curbing CO2 emissions and fostering a circular economy that minimizes waste.

Against the backdrop of escalating climate concerns, the imperative to mitigate greenhouse gas emissions has become paramount. Recent scientific findings and global events have emphasized the urgent need for transformative action to address the root causes of climate change. Central to this discourse is the role of CO2, a primary contributor to the greenhouse effect and a focal point for efforts to reduce emissions and mitigate environmental impacts.

Carbon capture technologies represent a crucial frontier in the battle against climate change, offering innovative solutions for both capturing and repurposing CO2 emissions. These technologies encompass a diverse array of approaches, ranging from chemical absorption to direct air capture, each with its unique strengths and applications. By capturing CO2 emissions at their source, industries can prevent the release of excess CO2 into the atmosphere, thereby mitigating their environmental footprint and supporting global efforts to limit temperature rise.

Moreover, the integration of carbon capture technologies into existing industrial processes holds promise for fostering a circular economy, where waste is minimized, and resources are utilized more efficiently. However, realizing the full potential of carbon capture technologies requires a comprehensive understanding of the CO2 supply chain, from extraction and capture to transportation, storage, and utilization. In the present thesis, a detailed breakdown of each component takes place, in order to adequately understand the supply chain and effectively apply it in CCUS projects.

Additionally, while the implementation of carbon capture systems is undoubtedly a solid step in the direction of decarbonization, financial feasibility is a crucial consideration. Therefore, this thesis examines the degree to which CCS is financially viable under various conditions by conducting a detailed case study analysis of three existing factories. By assessing the economic feasibility of implementing CCS technology within these industrial contexts, this research aims to provide insights into the practical challenges and opportunities associated with scaling up carbon capture initiatives.

Through a combination of rigorous analysis and case studies, this thesis seeks to contribute to the ongoing discourse on carbon capture technologies and their role in mitigating greenhouse gas emissions.

[1] See relevant regulations in Appendix (11.1)

1.2. Project justification and structure of the thesis

The objective of this thesis is to explore the significance and methodologies of carbon capture, analyze the CO_2 supply chain, and integrate these elements into a comprehensive study of three distinct cases. The aim is to assess the potential profitability of carbon capture initiatives and provide insights into their economic viability under varying conditions. Through detailed examination and analysis, this thesis seeks to contribute to a deeper understanding of the role of carbon capture in mitigating climate change and its implications for various industries. The present thesis is structured as follows:

In Chapter 2, the significance of CCUS is examined. The chapter begins by providing a comprehensive definition of CCUS and underlines its paramount importance in the context of climate change mitigation. The techniques employed in carbon capture are then described, with a brief mention of onboard carbon capture and its challenges. This section aims to establish a foundational understanding of the pivotal role CCUS plays in addressing carbon emissions.

Chapter 3 examines the utilization of CO_2, a critical aspect in fostering a circular economy and minimizing waste. The chapter explores both converted and non-converted applications of CO_2, highlighting the diverse range of possibilities for repurposing this greenhouse gas. Through an examination of various utilization methods, the chapter underscores the importance of maximizing the value extracted from CO_2 emissions.

Chapter 4 explains the concept of geological CO_2 storage and denotes the most common formations where CO_2 is typically stored. The chapter provides a comprehensive understanding of the geological storage process, emphasizing the significance of identifying suitable formations for effective and secure storage of captured CO_2.

Chapter 5 offers a detailed breakdown of the CO_2 supply chain, delving into the primary modes of transportation and describing their construction, associated costs, and operational procedures. Through this comprehensive analysis, readers gain insights into the logistical intricacies and economic considerations involved in transporting CO_2 within the supply chain.

Chapter 6 focuses on constructing the discussed cases, compiling relevant data, and conducting comprehensive estimations and calculations pertaining to CO_2 emissions from the factories. Additionally, it delves into the cost analysis of implementing a carbon capture chain, encompassing the necessary infrastructure and the corresponding LCO_2 carrier.

In Chapter 7, following the comprehensive collection of essential information and estimations, the study applies these findings to each distinct case. It investigates how varying factors such as carbon taxation and funding scenarios influence the feasibility of carbon capture initiatives. This chapter serves as a critical analysis of the practical implications and economic dynamics surrounding carbon capture efforts within different operational context.

Chapter 8 provides an elaborate breakdown of the annual costs within the CCS chain, in order to examine the gravity of each component.

Finally, in Chapter 9, the results from each case are gathered and discussed and conclusions are extracted.

1.3. Literature review

The existing literature on carbon capture and the CO2 supply chain offers valuable insights into the technological, economic, and logistical aspects of mitigating greenhouse gas emissions. While significant progress has been made in understanding carbon capture technologies, the CO2 supply chain still faces gaps in information, particularly regarding large-scale application and transportation demands.

The IPCC Special Report on Carbon Dioxide Capture and Storage serves as a seminal resource for comprehending the fundamentals of carbon capture and storage [1]. It provides a comprehensive overview of CO2 sources, capture methods, and storage technologies, supplemented by insightful case studies of applications up to that time. Additionally, the IEA [2] offers crucial and diverse information on CO2 storage, further enriching our understanding of this critical aspect of carbon capture and storage.

Recent studies have delved into more specific and technologically advanced aspects of the CO2 supply chain. Zahid [3], for example, sheds light on the cost of transporting CO2, a critical consideration in light of evolving regulations mandating the transfer of substantial quantities. Furthermore, d'Amore et al. [4] conducted a study on the techno-economic aspects of the CO2 supply chain, offering valuable insights into the scale of associated costs and financial considerations. By examining the anticipated financial landscape of investments in carbon capture and storage, this research aids in understanding the economic viability and potential barriers to widespread adoption of these technologies. Various additional researchers, such as Becattini et al. [5], have broken down the supply chain of CO2, by delving deep into the logistics of the procedure.

While the literature reviewed provides a solid foundation for understanding carbon capture and the CO2 supply chain, there is a need for further research to address remaining gaps and uncertainties. By synthesizing findings from multiple sources and critically evaluating the existing literature, this literature review sets the stage for the present thesis to analyze and evaluate the feasibility of carbon capture from a techno-economical aspect, as well as to check what factors play the biggest role in determining the result..

2. The importance of Carbon Capture, Utilization and Storage

2.1. What is CCUS?

CCUS encompass the extraction of CO2 from significant emission sources such as power plants and industrial units fueled by either biomass or fossil fuels [2]. Additionally, CO2 extraction directly from the atmosphere is part of this process. Once collected, if not employed on-site, the captured CO2 undergoes compression and transportation via pipelines, ships, railways, or trucks to serve various purposes or is directed towards deep geological formations. These geological sites, including depleted oil and gas reservoirs, saline formations and others, serve as permanent storage locations by securely trapping the CO2.

CCUS facilities globally possess the capability to annually capture over 40 Mt of CO2. Among these facilities, several have maintained operations since the 1970s and 1980s. Notably, in the Val Verde region of Texas, natural gas processing plants initiated the supply of CO2 to nearby oil producers, marking the inception of utilizing CO2 for enhanced oil recovery procedures.

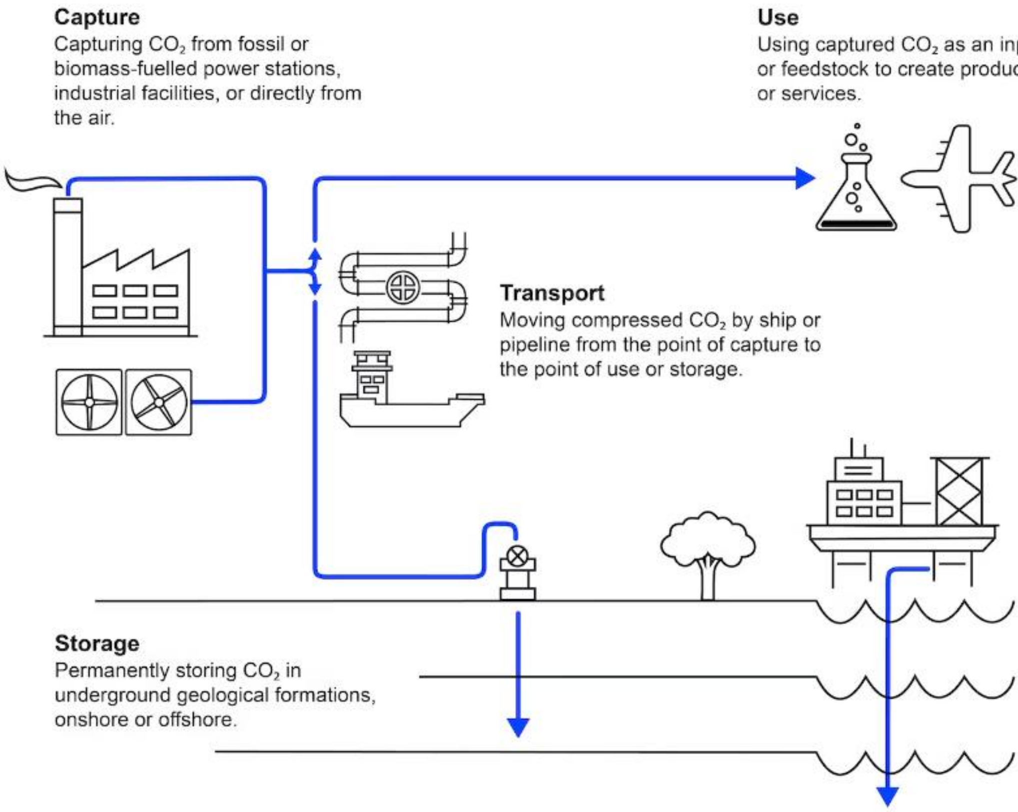

Figure 1: *Fundamentals of CCUS*

Following these initial endeavors, the implementation of CCUS has broadened its scope, reaching various regions and diversifying its applications. A significant milestone occurred in 1996 when the Sleipner offshore gas facility in Norway inaugurated the first large-scale project involving CO2 capture, injection, and dedicated storage, alongside continuous monitoring measures. This pioneering initiative has successfully stored over 20 million metric tons of CO_2 within a deep saline formation, positioned approximately 1 kilometer beneath the surface of the North Sea.

Over the next decade, CCUS's storage capacity will increase from 80 Mtpa to more than 500 Mtpa [6]. Given previous false starts, skepticism lingers. However, support and regulation have changed the dynamic and injected significant momentum into the sector. The US's Inflation Reduction Act and the EU's more recent Net Zero Industry Act continue to expedite CCUS activity.

While North America and Europe drive much of the CCUS growth, other regions, including the Middle East and Asia, will deliver material capacity over the coming decade. A diverse range of companies is leading developments in CCUS. However, the oil and gas sector is at the helm on many of these projects, given its complementary experience in sub-surface operations, managing volatile fluids at scale and working in offshore environments.

This scale of development does not come cheap, however, and to deliver the 2033 outlook, more than 70 billion USD is set to be invested in transport and sequestration infrastructure before 2030. The next 10 years will be pivotal, and delivering projects at scale and accelerating growth will be key to the technology delivering to its potential.

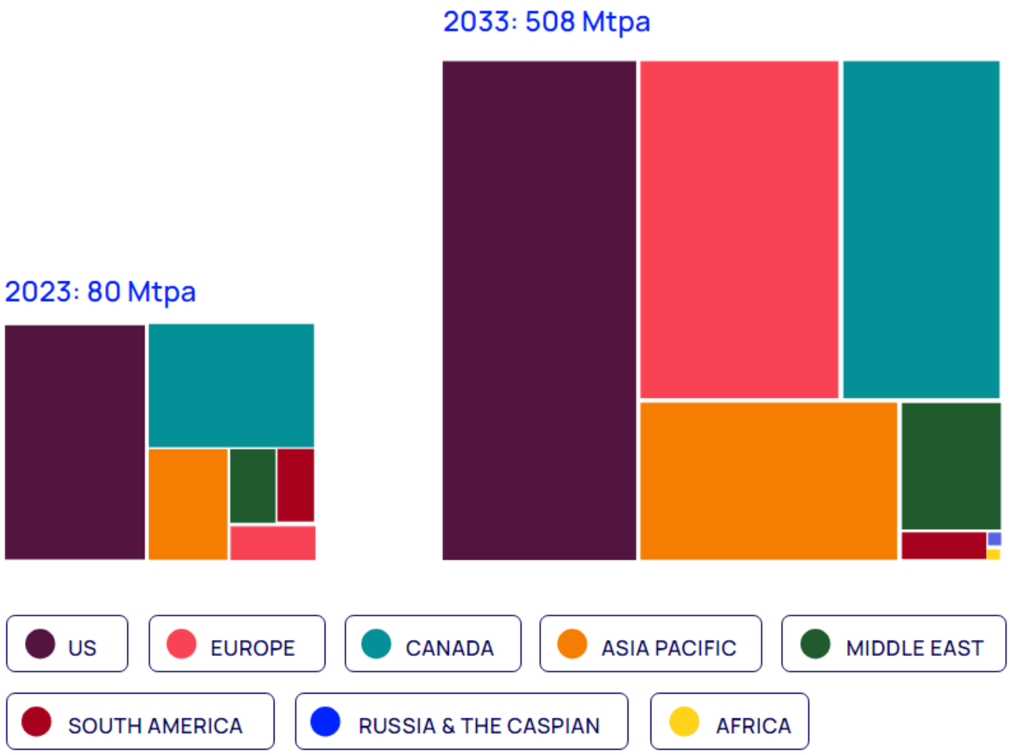

Figure 2: *CO_2 operational storage capacity 2023 to 2033 (Mtpa)*

The process of CO_2 capture holds significant importance in numerous industrial procedures. As a result, there have been commercially accessible technologies for separating or capturing CO_2 from flue gas streams for numerous years. Among the most advanced and commonly used methods are chemical absorption and physical separation. Additionally, there are alternative technologies like membranes and looping cycles such as chemical looping or calcium looping. The most relevant and widely used technologies are examined in the following chapters.

2.2. Why is CCUS important?

According to climate change experts and recognized international climate bodies, it is widely agreed that meeting global climate change objectives is unattainable without widespread adoption of CCS [75]. The IEA reports emphasize that achieving the Paris climate targets of limiting the global temperature rise to 2 ℃ by 2060 necessitates 14% of cumulative emission reductions through CCS. In the transition from the 2-degree scenario (2DS) to the beyond 2-degree scenario (B2DS), this requirement increases to 32%.

However, despite these findings, there is a significant shortage of operational facilities. To achieve the Paris Agreement's 2-degree target, more than 2,500 facilities - each with a capture capacity of 1.5 Mt per annum (Mtpa) of CO2 - need to be operational by 2040 [7].

Climate change experts, including the IPCC and the IEA, affirm that CCS stands as the sole mitigation technology capable of decarbonizing substantial industrial sectors, specifically the gigantic steel, cement, fertilizer, and petrochemical industries.

Also, the shift towards clean energy presents a chance to generate fresh job prospects and economic avenues for entire communities. These opportunities encompass diverse services such as project management, engineering, finance, legal, and environmental roles. Additionally, it entails value creation through the production of CCS components like boilers and turbines, establishment of new CCS facilities, development of low-carbon fuel supply chains, and the expansion of CO2 infrastructure, notably CO2 pipelines and associated transportation facilities. Early implementation of CCS, particularly retrofits, prevents the premature decommissioning of productive assets, thereby sustaining employment opportunities for individuals.

Utilizing ample underground storage resources remains a feasible and rational approach for mitigating CO2 emissions. The majority of critical CO2 storage sites globally have undergone thorough assessments, with numerous high-emission countries showcasing considerable storage capabilities. Extensive surveys have been conducted across various nations, such as the US, Canada, Australia, Japan, China, Norway, and the UK. These surveys have clearly defined and extensively documented potential storage locations within these countries.

CO2 utilization holds promise in fostering the creation of products and services with reduced CO2 footprints, thereby aiding in emissions reductions. It can serve as a supplementary approach to the widespread implementation of CCS, a technology consistently emphasized by the IEA as crucial within the array of technologies essential for achieving climate objectives. Specifically, CO2 utilization can facilitate investments in CO2 capture opportunities, refine technology, and, in limited instances, contribute to the initial establishment of CO2 transport infrastructure.

Nonetheless, CO2 utilization cannot supplant CO2 storage in achieving the substantial emissions reductions necessary to align with the aspirations outlined in the Paris Agreement. This limitation is attributed to the expected smaller scale of many CO2 utilization prospects, their confined capacity for negative emissions, and their early developmental stage in both technology and market realms.

2.2.1. Importance of CC in power generation

Coal and gas-powered plants continue to dominate the global electricity landscape, collectively constituting nearly two-thirds of power generation—a proportion that has remained relatively stable since 2000, despite the emergence of low-cost variable renewable energy sources. In absolute terms, electricity produced from fossil fuels has surged by 70% since 2000, reflecting the consistent upswing in worldwide power demand [8].

Coal remains the most substantial fuel source for power generation, contributing to 38% of the total, followed by gas at approximately 20%. Particularly in rapidly growing economies such as China and India, the portion of electricity generated from coal surpasses 60%. While the Covid-19 pandemic caused a temporary decline in coal generation and saw higher shares for several renewables, these trends might revert to their historical patterns as electricity demand rebounds.

The power sector stands as the largest contributor to carbon emissions within the energy domain, accounting for almost 40% of global energy-related emissions. Despite the urgent necessity to address the primary drivers of climate change, emissions from the power sector in 2022 reached 14.8 Gt of CO2.

Even with the swift growth of renewable energy production, the substantial magnitude of emissions within the current power sector and the crucial significance of electrification necessitate that nations promptly address their power-related emissions to align with global climate objectives. Essentially, the power sector must significantly diminish its carbon intensity to effectively meet these goals.

In order to achieve climate objectives, policymakers must address emissions from both existing coal-fired power plants and those currently under construction. However, as per current governmental policies, even with an expected decline of approximately 40% in CO2 emissions from the existing coal-fired power plants, annual emissions are projected to reach 6 GtCO2 by 2040. Notably, significant expansions in coal-fired capacity were still in progress at the outset of 2020, underscoring the formidable challenge ahead.

Achieving long-term climate objectives without widespread implementation of CCUS technologies in the power sector would necessitate virtually phasing out coal-fired power generation. Eventually, this approach would extend to gas-fired generation as well, demanding substantial early retirements and possibly leading to stranded assets.

The relatively young lifespan of the global fleet of fossil-fuel-powered plants implies that about a quarter of the existing fleet would be decommissioned before reaching the typical 50-year operational span. Nearly one-third of all coal-fired capacity is less than a decade old, predominantly concentrated in Asia. Those plants remaining in operation would likely experience significantly reduced operational hours.

2.2.2. EU stance on CCUS

The European Commission published ambitious plans to develop a regional carbon capture market capable of transporting up to 280 million tonnes of CO2 per year by 2040 on

February 6th 2024 [9]. The announcement was part of the EU's Industrial Carbon Management Strategy, which was unveiled alongside broader plans to set a 90% net zero reduction target by 2040. This plan introduces an interim target between the bloc's 55% reduction target by 2040 and the net zero target by 2050.

The strategy aims to expand CO_2 capture targets from 50 Mtpa to 280 Mtpa by 2040 and to 450 Mtpa by 2050. The strategy encompasses three main approaches:

1. CO_2 capture for storage (CCS): This involves capturing CO_2 emissions of fossil, biogenic, or atmospheric origin for permanent and safe geological storage (sequestration).

2. CO_2 capture for utilization (CCU): This entails using captured CO_2 to replace fossil-based carbon in synthetic products, chemicals, or fuels (e.g., conversion into e-methanol).

3. CO_2 removal from the atmosphere: This involves capturing biogenic or atmospheric CO_2 using technological means and storing it permanently.

The strategy aims to establish CO_2 as a tradable commodity for storage or utilization within the EU's single market by 2040, alongside the creation of economically viable regional value chains by the same year.

Additionally, the strategy suggests that up to one-third of captured CO_2 (over 90 mtpa) will be utilized within the EU by 2040, increasing to approximately 200 mtpa by 2050. Achieving this will necessitate the development of a CO_2 transportation network, involving the construction of new and repurposed natural gas pipelines, specialized ships, and gas transportation via road or rail.

The European Commission's Joint Research Centre (JRC) has provided preliminary estimates of the costs associated with developing CO_2 transport infrastructure. They estimate that by 2030, approximately 7,300 km of CO_2 pipelines may be required, with an estimated cost of 12.2 billion EUR, rising to around 19,000 km and 16 billion EUR by 2040.

The estimates provided do not differentiate between the costs associated with installing and operating offshore pipelines and those associated with a network of LCO_2 carriers. It is highlighted that recent advancements in LCO_2 storage technology, coupled with the potential to reduce transportation costs per tonne of CO_2 through the use of larger-capacity LCO_2 carriers, may improve total cost of ownership (TCO) comparisons against subsea CO_2 pipelines, at least until CO_2 sequestration volumes increase.

Sequestration plans will necessitate the development of a fleet of medium-sized LCO_2 carriers to transport captured CO_2 from the Mediterranean and the Baltic regions to the North Sea, where the EU plans to utilize offshore subsea storage located in EU member state and Norwegian waters.

However, the European Commission acknowledges openly that unresolved issues remain regarding market and cost structures, investment incentives for new infrastructure, tariff regulation for transportation assets, and ownership models. As a result, the Commission intends to initiate preparatory work on a future CO_2 transport regulatory package to provide investors with greater certainty.

Several regulatory challenges must be addressed before carbon capture can be effectively implemented. These challenges involve ensuring alignment with existing EU regulations, such as the ETS scheme and the EU taxonomy, as well as with future interactions with the electricity, gas, and hydrogen sectors.

International ship owners and vessel operators, who are closely monitoring the European CO2 market, may seek to minimize discrepancies among the various regulatory systems being introduced or considered in different jurisdictions.

2.3. Sources of Captured CO2

2.3.1. Burning of fossil fuels

When hydrocarbon-based substances such as wood, coal, natural gas, gasoline, and oil undergo combustion, they emit CO2. This process involves the carbon within these fossil fuels bonding with oxygen in the atmosphere to produce CO2 and water vapor.

The organic hydrocarbon fuels sourced from living organisms consist primarily of carbon and hydrogen. Upon burning, they release CO2 and water as byproducts.

2.3.2. Industrial processes

CO2, not stemming from combustion, gets released through various industrial processes involving the chemical, physical, or biological alteration of materials. These processes include:

- Utilizing fuels as raw materials in petrochemical operations.
- Employing carbon as a reducing agent during the industrial extraction of metals from ores.
- The thermal decomposition, also known as calcination, of limestone and dolomite in the production of cement or lime.
- The fermentation of biomass, such as the conversion of sugar into alcohol.

Sometimes, these emissions from industrial processes occur concurrently with emissions from fuel combustion, as seen in instances like aluminum production.

Another category of emissions emerges from natural gas processing facilities. CO2 often exists as an impurity in natural gas, necessitating its removal to enhance the gas's heating value or to comply with pipeline requirements.

2.3.3. Direct Air Capture (DAC)

DAC methods extract CO2 directly from the atmosphere, distinguishing them from carbon capture at specific emission points [10]. Currently, two technological methods are employed: solid (S-DAC) and liquid (L-DAC). S-DAC uses solid adsorbents at ambient to low pressure and moderate temperatures, while L-DAC utilizes an aqueous basic solution at high temperatures.

DAC requires more energy compared to capturing from specific sources due to the lower CO_2 concentration in the atmosphere. Operational temperatures affect the energy ratio, with S-DAC and L-DAC adaptable to heat or electricity.

S-DAC can be powered by various low-carbon energy sources, while L-DAC currently relies on natural gas for heat, though future adaptation for renewable energy is possible. Commercializing large-scale electric calcination technology is crucial for L-DAC facilities to operate solely on renewables.

DAC's adaptable siting allows for establishment in areas with low-carbon energy sources and CO_2 storage or utilization options, though considerations for climate and energy sources are vital. Establishing operational CO_2 storage sites takes years and requires intensified efforts for DAC deployment.

2.4. Carbon Capture techniques

2.4.1. On shore

Chemical absorption

The process of chemical absorption involving CO_2 is a widely used operational method where CO_2 reacts with a specific chemical solvent, such as ethanolamine compounds [11]. Typically, this process utilizes two columns: one for absorption and another operating at higher temperatures to release pure CO_2 and regenerate the chemical solvent for subsequent use. Among CO_2 separation techniques, employing amine-based solvents stands as the most sophisticated. This method has seen extensive use for many years and is presently employed in various small and large-scale projects globally across different sectors like power generation, fuel transformation, and industrial production.

Physical separation

The physical separation of CO_2 involves various methods such as adsorption, absorption, cryogenic separation, or dehydration followed by compression. Adsorption relies on a solid surface like activated carbon, alumina, metallic oxides, or zeolites, while absorption utilizes a liquid solvent such as Selexol or Rectisol. Once captured through an adsorbent, CO_2 is released by elevating temperature (temperature swing adsorption [TSA]) or pressure (pressure swing adsorption [PSA] or vacuum swing adsorption [VSA]).

Presently, physical separation is primarily applied in natural gas processing, ethanol, methanol, and hydrogen production. Nine large-scale plants employing this technique are operational, all situated in the United States. These facilities typically employ exclusive solvents, VSA, or cryogenic separation methods. The Illinois Industrial Carbon Capture and Storage Project, the largest CCUS facility applied to biofuels production, relies on dehydration and compression due to the gas stream's composition, primarily comprising CO_2 and water. Additionally, the Coffeyville Gasification Plant employs CO_2 physical separation by isolating and compressing highly concentrated CO_2 streams.

Oxy-fuel separation

Oxy-fuel separation involves burning a fuel with almost pure oxygen and then capturing the resulting CO2 emissions. As the flue gas consists primarily of CO2 and water vapor, removing the latter is easily achievable through dehydration, resulting in a high-purity CO2 stream. Typically, commercially produced oxygen is derived through energy-intensive low-temperature air separation. Hence, reducing energy consumption in this stage and throughout the entire oxy-fuel process is crucial for cutting capture costs.

Innovative approaches aiming to decrease costs include oxy-fuel gas turbines integrated into supercritical CO2 power cycles and pressurized oxy-fuel CO2 capture. These methods optimize material usage, potentially making construction and operation more cost-effective. Currently, this technology is at the stage of large prototypes or pre-demonstration. Several projects have been completed in coal-based power generation and in cement production.

Membrane separation

Membrane separation relies on polymeric or inorganic devices, specifically membranes, with high selectivity for CO2, allowing CO2 to pass while acting as barriers to retain other gases in the gas stream. The TRLs of these membranes vary depending on the fuel and application. In natural gas processing, they are primarily at the demonstration stage (TRL 6-7). The sole existing large-scale capture plant utilizing membrane separation is operated by Petrobras in Brazil. Commercially available membranes for CO2 removal from syngas and biogas already exist, while those for treating flue gas are presently in the developmental phase. Numerous membrane technologies for CO2 separation have undergone testing in the United States through collaborations involving the National Carbon Capture Center and various partners such as the Gas Technology Institute, the Department of Energy’s National Energy Technology Laboratory, Membrane Technology and Research, and Air Liquide from France.

Calcium looping

Calcium looping is a technology designed for CO2 capture at elevated temperatures, employing two primary reactors. In the initial reactor, lime (CaO) serves as a sorbent, capturing CO2 from a gas stream to generate calcium carbonate (CaCO3). This CaCO3 is then transferred to the second reactor for regeneration, yielding lime and a pure CO2 stream. The lime is subsequently cycled back to the first reactor. Calcium looping technologies, currently situated at TRL 5-6, have undergone testing primarily at the pilot plant scale, particularly for coal-fired fluidized bed combustors and cement production.

Chemical looping

Chemical looping operates similarly with a two-reactor system. In the initial reactor, tiny metal particles like iron or manganese are utilized to trap oxygen from the air, forming a metal oxide. This compound is then transported to the second reactor where it engages with fuel, generating energy and a concentrated CO2 stream while rejuvenating the reduced state of the metal. Subsequently, the metal is cycled back to the first reactor. Academic institutions, research entities, and various companies, including manufacturers in the power sector, have pioneered the development of chemical looping technologies. This has resulted in the creation and operation of approximately 35 pilot projects (TRL 4-6) with capacities up to 3 MW, specifically for coal, gas, oil, and biomass combustion (IEAGHG, 2019a).

Direct separation

Direct separation in cement production refers to capturing CO_2 emissions from the process by indirectly heating limestone using a specific calciner (TRL 6). This method extracts CO_2 directly from the limestone, excluding the mixing of CO_2 with other combustion gases. Consequently, this significantly decreases energy expenses linked to gas separation.

Supercritical CO2 power cycles

In traditional thermal power plants, turbines are typically driven by either flue gas or steam. However, in supercritical CO_2 power cycles, the turbines are powered by supercritical CO_2, which refers to CO_2 maintained above its critical temperature and pressure. Supercritical CO_2 turbines usually employ nearly pure oxygen for fuel combustion, resulting in a flue gas comprising solely CO_2 and water vapor.

2.4.2. On board

Growing demand

The 2023 IMO revised GHG Strategy, aiming for net-zero GHG emissions by approximately 2050, will bring significant changes to the maritime sector [12]. Vessels will need to transition from traditional fuels to greener alternatives. Investments in LNG, LPG, and methanol dual-fuelled vessels are rapidly increasing, sparking industry discussions on which alternative fuels can be provided at affordable prices.

In its updated Low Carbon Outlook, ABS re-evaluated supply and demand data for alternative fuels and adjusted the future fuel mix based on the latest market information. The study also assessed how the revised IMO decarbonization strategy and 2050 net-zero targets impacted the projected fuel mix.

By combining projected ship demand with forecasts for a changing fuel mix in deep-sea shipping, ABS translated scenarios for global energy consumption into global fuel consumption by ships. Overall, ABS's updated findings suggest that by 2050, demand for fossil fuels may be slightly lower than previously estimated, highlighting the necessity for onboard carbon capture technologies.

The adoption of onboard carbon capture in the shipping industry will necessitate LCO_2 reception infrastructure at ports to transport captured CO_2 for offshore storage or industrial use. This could lead to increased LCO_2 shipping from ports to offshore facilities, whether over short or long distances.

Challenges of on-board carbon capture

The initial phase of CCUS technology is the capture process, which demands careful analysis. This step directly influences the reduction in CO2 emissions and subsequently impacts the reduction of GWP associated with the technology's implementation. Indeed, despite these reductions, it's premature to incorporate them into the EEDI/EEXI or CII calculations. The integration of CC technologies into the IMO regulatory framework remains a subject of ongoing discussion and deliberation [13]. Until clear guidelines and standards are established regarding the inclusion of carbon capture initiatives in emissions calculations, it would be premature to factor them into regulatory compliance assessments. However, even by dismissing the above, selecting the appropriate technology would be no easy task. The following parameters must be considered:

- Capacity for GWP reduction: The initial constraint outlined by the IMO regulations necessitates a 40% reduction in CO2 emissions by 2030. However, beyond this immediate target, the ultimate objective aims for zero emissions by 2050. Therefore, the effectiveness of a technology in capturing CO2 becomes crucial as it indicates the potential longevity of the solution. Higher capture capacities imply a reduced likelihood of requiring further modifications to the vessel, enhancing its future-proofing.
- Capacity: What distinguishes maritime CCS applications from those in other industrial sectors like energy production is the limited available space for technology implementation, as previously highlighted. Thus, these solutions must demonstrate high space efficiency and adaptability to existing systems for successful implementation.
- CO2 Purity: The concentration of captured CO2 at the output stage is also significant when considering potential future applications in its lifecycle. Diverse strategies exist for managing the captured CO2 , ranging from storing it in depleted natural gas reservoirs to reusing it for synthetic fuel production.
- Energy Requirements: CCS systems themselves demand energy to function effectively, prompting an examination of the system's energy needs and their impact on the auxiliary motors' existing energy generation on board. It's essential to assess whether a technology's high energy consumption might offset any gains in energy by potentially increasing fuel consumption and emissions. Therefore, if the system requires excessive energy, the actual reduction in CO2 emissions might be compromised. The effective reduction is calculated as follows:

$$CO_{2\,effective\ capture} = CO_{2\,total\ capture} - CO_{2\,produced\ to\ supply\ the\ CCS\ systen}$$

The primary challenges faced in maritime applications, when compared to land-based processes employing the same system, are consistent across various technologies. Primarily, space constraints pose a critical concern in maritime settings, particularly due to the addition of these systems onto pre-existing vessels. This necessitates their integration near the engine bay, where space is already at a premium. This limitation affects not only the technologies themselves but also the storage of degraded materials and captured CO2. Contrastingly, this issue is less acute in land-based processes where storage facilities can be expanded as needed. Furthermore, the discharge of these materials presents a greater challenge in maritime cases compared to land scenarios, where transportation is simpler via piping or vehicles, although not negligible.

Moreover, numerous CCS technologies require chemicals for proper operation, which necessitate production or regeneration through a separate plant. While these systems can be coupled in land-based industries given sufficient space, this integration isn't always feasible in maritime applications. Consequently, the need for raw chemicals can be another vulnerability in onboard CCS applications. These factors pose both physical challenges due to the implementation of loading and unloading processes, and logistical hurdles as not all ports can offer such services. Hence, route planning and adjustments will be necessary to address this issue [14].

Another crucial aspect to consider pertains to safety concerns, especially regarding the storage and utilization of the chemical intermediates essential for individual processes. The significance of this issue varies among different technologies. Absorption-based processes employ solvents, requiring specific containers for these substances. However, storage itself doesn't raise concerns compared to solid chemical-based reactions, where space constraints become the primary challenge.

The application of MCFC poses more significant challenges due to its reliance on hydrogen, typically derived from reforming or cracking processes (e.g., methane or ammonia). Consequently, onboard storage and treatment of fuel are necessary, and during operation, hydrogen is utilized in its molecular form. Maintaining safety conditions is relatively simpler in land-based applications. Conversely, aboard a ship, the monitoring of the system becomes more critical due to the inherent difficulty in implementing redundant physical safety measures.

The stability of carbon capture systems exhibits distinct differences between land-based and maritime applications, carrying varying levels of criticality. In land applications, the system's stability benefits from its integration, firmly anchored to the ground. Contrastingly, in maritime applications, the CCS system is affixed to a vessel navigating waves and fluctuating atmospheric conditions, posing concerns for different system types. This dynamic environment can alter the fluid dynamics of liquid chemicals used in the system. For instance, motion in absorption processes might create uneven pathways within columns, reducing system efficiency. Similarly, in MCFC systems, it could impact the distribution of molten carbonate, although component capillarity might help mitigate these effects. Consequently, stabilizing mechanisms might be necessary in maritime applications to counteract these issues.

Additionally, operational conditions may be influenced by opportunistic constraints, such as the need to lower temperature or pressure to minimize energy consumption and risks on board.

While studying carbon capture systems in land-based setups aids in understanding fundamental principles and assessing maritime applicability, it's imperative to emphasize the necessity for further research specifically tailored to on-board use. The distinctive challenges encountered at sea demand thorough consideration and investigation to ensure effective implementation.

3. CO_2 utilization

3.1. CO_2 as part of a circular economy

The possibility to produce but to capture and avoid emitting CO_2 opens a new chapter. In a linear economy, raw materials are extracted, processed, and turned into products which are then discarded at the end of their life.

By contrast, the circular economy model is one that maximizes the sustainable use and value of resources, eliminating waste and benefiting both the economy and the environment The Carbon Circular Economy recognizes the Earth's limits in terms of GHG concentration levels and seeks to achieve a safe balance by limiting fugitive carbon entering the atmosphere and ensuring circularity in living and durable carbon flows.

Under this model, goods and services are produced in a way that minimizes waste, emissions, energy and materials. The focus is on the "4 Rs": reduce, re-use, recycle, and recover. It reflects a holistic way of thinking about the economy as an entire system, where waste is seen as a loss to the economy, and not merely a by-product or an "economic externality".

Carbon per se is not the 'enemy' but rather fugitive CO_2, which is released into the atmosphere; primarily from fossil fuel combustion. It recognizes sustainability as a source of revenue and profit, rather than as a cost to be borne. A transition towards circularity requires a paradigm shift in thinking, so that consuming and throwing away goods is not seen as a positive indication of economic growth. The circular economy is related to the concept of environmental sustainability – the ability of the environment to sustain economic activity without being irreparably damaged or destroyed by resource depletion. Environmental sustainability is one element of sustainable development –development that meets the needs of the present without compromising the ability of future generations to meet their own needs.

3.2. CO_2 as a commodity

CO_2 has the potential to serve as an ingredient for various products and services. Its applications encompass both direct utilization, where CO_2 remains unchanged chemically (non-conversion), and the conversion of CO_2 into valuable products through chemical and biological processes.

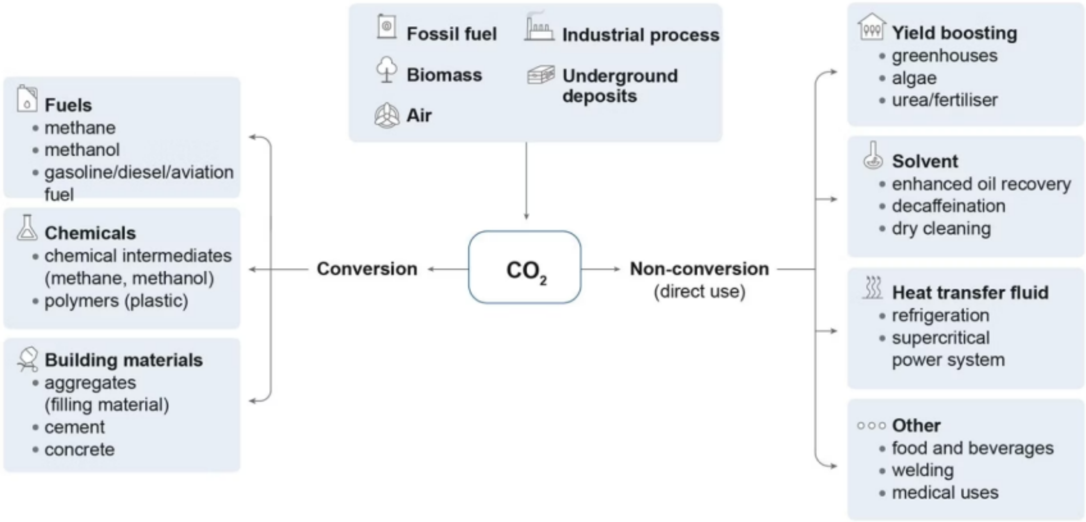

Figure 3: *Uses of CO2*

Globally, approximately 230 Mt of CO2 are utilized annually [15]. The primary consumer is the fertilizer industry, using 130 Mt of CO2 in urea production, followed by the oil and gas sector, consuming 70 to 80 Mt of CO2 for enhanced oil recovery [16]. Additional practical applications encompass food and beverage production, metal fabrication, cooling, fire suppression, and promoting plant growth in greenhouses. Most of the current commercial applications directly utilize CO2.

Novel pathways involve converting CO2 into fuels, chemicals, and construction materials. These processes, involving chemical and biological transformations, are gaining attention from governments, industries, and investors, although most are still at an early stage and encounter challenges related to commerce and regulations.

The manufacturing of CO2-based fuels and chemicals demands substantial energy and necessitates significant amounts of hydrogen. The carbon present in CO2 facilitates the conversion of hydrogen into a more manageable and usable fuel, such as for aviation purposes. Additionally, CO2 has the potential to substitute fossil fuels as a foundational material in chemicals and polymers. Less energy-intensive routes involve reacting CO2 with minerals or waste streams, like iron slag, to produce carbonates utilized in the creation of building materials.

3.3. CO2 uses

3.3.1. Converted CO2 uses

CO2 for fuel production

CO2 can be utilized to create fuels like methane, methanol, gasoline, and aviation fuels by combining it with hydrogen, yielding carbon-infused fuels more manageable than pure hydrogen. Low-carbon hydrogen can be generated through fossil fuel combining with CCS or electrolyzing water with low-carbon electricity. CO2-based fuels are promising for applications like aviation where alternatives are challenging. Pilot plants producing methane and methanol from CO_2 and hydrogen have been established. However, production costs are notably higher, primarily due to electricity costs. Feasibility depends on regions with abundant renewable energy and CO_2 resources like North Africa, Chile, or Iceland [17]. Production costs are expected to decline with reductions in capital costs and the availability of low-cost renewable energy and CO_2. CO_2-derived methanol might become competitive based on local methanol market prices. CO_2-derived methane and methanol offer climate benefits if produced with low-carbon energy, potentially reducing emissions significantly compared to conventional methods [39]. However, comprehensive testing is needed to meet existing quality standards.

CO2 for chemicals

The carbon, along with oxygen, present in CO_2, offers an alternative to fossil fuels for manufacturing chemicals such as plastics, fibers, and synthetic rubber. Similar to CO_2-derived fuels, the most well-established technological pathway involves converting CO_2 into methanol and methane. Methanol, in turn, can be transformed into other valuable carbon-based chemical intermediates like olefins, crucial for producing plastics, and aromatics, widely used across various sectors such as health, hygiene, food production, and processing.

A specific category of chemicals, known as polymers, is integral in creating plastics, foams, and resins. CO_2's carbon can substitute a portion of fossil fuel-based raw materials in the production process of polymers (as shown in Figure). Unlike the conversion of CO_2 into fuels and chemical intermediates, incorporating CO_2 in polymer processing demands minimal energy input since CO_2 is converted into a molecule with an even lower energy state, namely carbonate. Several companies are presently operating polymer plants that utilize CO_2 as a raw material.

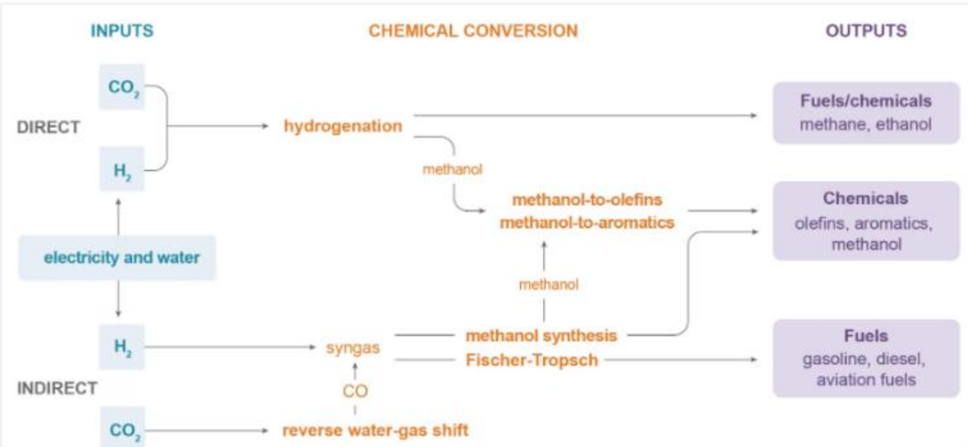

Figure 4: *CO2 for fuels and chemicals*

CO2 for polymers

Utilizing CO_2 in polymer processing holds potential competitiveness in the market due to the relatively low energy demands during production and the high value these polymers command. Some argue that specific polymers could be manufactured at 15% to 30% lower costs than their fossil-based counterparts, provided the cost of the CO_2 utilized is lower than the raw materials derived from fossil fuels that it replaces [18]. For instance, the Chimei Asai facility in Chinese Taipei, a collaboration between Asahi Kasei Chemicals and Chi Mei Corp, has been producing approximately 150,000 tonnes of polycarbonates annually using CO2 as a foundational material for over a decade [19]. While the potential market for polymers remains relatively limited, early opportunities for polymer processing with CO2 may emerge in areas where existing polymer plants can be adapted and fossil fuel prices are elevated.

The potential climate advantages in polymer production hinge on the amount of CO2 that can be absorbed within the material, which could amount to as much as 50% of the polymer's mass [20]. For instance, a polymer containing 20% CO2 by weight demonstrates a 15% reduction in life cycle CO2 emissions compared to the traditional production process [18]. Similarly to CO2-derived fuels and chemicals, comprehensive compliance testing is imperative before polymers with substantial CO2 mass percentages can enter the market.

CO2 for building materials

CO2 is utilized in building materials production through processes like CO2 curing in concrete. This involves CO2 reacting with calcium or magnesium to create low-energy carbonate molecules, enhancing concrete's performance and reducing its carbon footprint. Adoption challenges include regulatory barriers and lengthy standards updating processes. Non-structural concrete applications could be initial targets for these innovations. Additionally, CO2 can react with waste materials from power plants or industrial processes to produce construction aggregates, offering competitiveness by offsetting waste disposal costs. Companies globally consume around 75 kt of CO2 annually for this purpose. Regulatory revisions are needed to permit the use of specific waste materials, similar to approaches taken with construction materials derived from minerals. Focusing on more open market segments could aid in establishing a market presence for these innovations.

3.3.2. Non-converted CO2 uses

CO2 for crop yield boosting

CO2 finds utility in enhancing the productivity of biological processes like algae production and crop cultivation in greenhouses. Presently, the most advanced application for enhancing yields involves employing CO2 alongside low-temperature heat in industrial greenhouses, demonstrating maturity in yield improvement. This method has the potential to increase yields by approximately 25% to 30%. The Netherlands stands out as a frontrunner in utilizing CO2 in greenhouses, estimated to consume between 5 and 6.3 Mt of CO2 annually. Out of this quantity, roughly 500,000 tons per year are sourced externally, primarily from industrial facilities, while the remainder is derived from on-site gas-fired boilers or co-generation systems [20]. Transitioning from these on-site systems to alternative industrial CO2 sources or employing CO2 captured directly from the atmosphere holds the promise of delivering climate-related advantages.

CO2 as a refrigerant

CO_2 can be used as a commercial refrigerant, with its unique critical point at 31 °C and 74 bar. Despite higher pressures required compared to hydrofluorocarbons, CO_2 has a significantly lower GWP, reducing climate impacts from leaks. Its lower liquid density simplifies system design and size. CO_2's refrigeration capacity at 0 °C is notably higher than synthetic refrigerants', especially at −30 to −50 °C, enhancing system efficiencies [21]. Implementing CO_2 systems in supermarkets can reduce direct greenhouse gas emissions while maintaining energy consumption levels. Additionally, CO_2 is favored for ground source heat pumps and innovative CO_2 heat pump systems offer significant heating advantages, particularly in cold climates, outperforming conventional heating supplements in electric vehicles.

CO_2 in the food & beverage industry

CO_2 is used to prevent pest infestation in harvested grains, fruits, and vegetables, serving as a non-toxic alternative to chemical fumigation [22]. Modified Atmosphere Packaging (MAP) or Controlled Atmosphere Packaging (CAS) with CO_2 extends the shelf life of produce by inhibiting ripening and mold growth. CO_2 is also employed to immobilize animals before slaughter, improving meat quality by raising blood pressure. Cryogenic freezing with CO_2 ensures rapid processing and preserves meat taste and texture. Dry ice, made of CO_2, is preferred for transporting frozen foods as it sublimates into gas, keeping stored foods dry. CO_2 is also used to preserve fruits, baked goods, and dairy products, minimizing spoilage during storage and transportation. In the beverage industry, CO_2 is crucial for decaffeinating coffee, carbonating beer, and soft drinks, accounting for 16.4% of annual CO_2 utilization as of 2019.

CO_2 for fire suppression

Various agents are employed in suppression systems to combat fires, catering to different environments. Clean agent or inert gas suppression systems are commonly found in spaces like server rooms, where personnel work. Conversely, CO_2 fire suppression systems are prevalent in areas with few or no occupants, such as engine rooms, generator rooms, power stations, flammable liquid storage spaces, and around large industrial machinery.

Despite their effectiveness in quelling fires, CO_2 fire suppression systems pose health risks compared to other agents. Consequently, they are primarily installed in unoccupied environments. Fires require oxygen, fuel, and heat to sustain. By eliminating one of these elements, fires can be suppressed or extinguished. While some suppression agents reduce fire heat, CO_2 systems eliminate oxygen to halt the fire. Upon detecting smoke or fire, the system releases CO_2 into the protected space, rapidly increasing CO_2 levels and reducing oxygen, leading to fire suppression or extinction.

CO_2, being colorless, odorless, and electrically non-conductive, leaves no residue, safeguarding sensitive equipment within the protected area. This feature minimizes downtime and associated costs as the CO_2 does not damage equipment. Once the CO_2 disperses to safe levels, personnel can safely access the space, assess any fire or smoke damage, and resume work without requiring cleanup.

CO_2 for urea production

Urea, among the oldest fertilizers globally, is manufactured through a two-step process involving the reaction of CO_2 and ammonia at elevated temperatures and pressures [23]. The ammonia necessary for this process is generated using the Haber process, combining hydrogen and nitrogen. Producing the essential H_2 and CO_2 for urea production relies on two primary methods: steam reforming of natural gas and coal gasification. Additionally, H_2 can be derived from water electrolysis, while CO_2 can be directly extracted through carbon capture technologies. Nitrogen is obtained by directly isolating it from atmospheric air through liquefaction and fractional distillation.

CO_2 in welding

CO_2 can be used as an inert gas in MIG welding, since it enhances welding speed, penetration, and the mechanical characteristics crucial for steel, rendering it the most appropriate gas for MIG welding of steel.

Additionally, there’s a welding method called CO_2 welding in which captured CO_2 may be utilized [24]. CO_2 welding typically involves utilizing a gas cylinder to provide the active gas. Alternatively, welding with CO_2 can be achieved by using a gas-filled welding wire. In this process, a welding torch feeds the welding wire toward the weld pool of the workpiece undergoing welding. As the welding wire melts, it combines with the molten pool generated during the welding process. This molten pool represents the melted metal, partially formed by the fusion of the initial material being welded. CO_2 welding stands out as a cost-effective welding method due to the inexpensive nature of CO_2 as a shielding gas. Essentially, there exists no dissimilarity between CO_2/MAG welding and MIG welding except for the shielding gas utilized. The welding process remains identical. Moreover, the same welding machine is applicable for both welding techniques. It's important to note that CO_2 welding is not suitable for welding inert metals, commonly known as precious metals, as these materials do not react to the influence of other elements like active gases.

CO_2 in the medical sector

CO_2 serves multiple purposes in medical applications [25]:

It is employed to rapidly deepen anesthesia when combined with volatile agents, aiding in enhanced respiration and overcoming breathholding and bronchial spasm. Additionally, it facilitates blind intubation during anesthesia procedures. In medical scenarios requiring hypothermia induction, CO_2 assists in vasodilation, thereby reducing the extent of metabolic acidosis. For patients with arteriosclerosis undergoing surgery, CO_2 is used to increase cerebral blood flow. Furthermore, it stimulates respiration post a period of apnea and aids in chronic respiratory obstruction after initial relief. CO_2 is also utilized to prevent hypocapnia during hyperventilation and finds applications in various clinical and physiological investigations. In gynecological examinations, it is insufflated into fallopian tubes and abdominal cavities. Moreover, solid CO_2 (dry ice) is employed in tissue freezing techniques and for wart destruction via freezing. In order to be used in the above medical applications, a minimum purity of 99.5% v/v is required.

3.4. Future of CO_2

Predicting the future market potential for products and services derived from CO_2 presents considerable challenges. The early stage of technological advancement and the reliance on policy frameworks for most applications make estimating the future market size quite complex. In theory, certain applications of CO_2 utilization, like fuels and chemicals, could potentially scale up to billions of tonnes of CO_2 use annually. However, practically, they would encounter competition from the direct use of low-carbon hydrogen or electricity, which are likely to be more cost-effective across most applications.

Presently, the production costs for CO_2-based fuels and chemicals are several times higher than those for their conventionally produced counterparts, primarily due to the expenses linked with hydrogen production. Commercial production becomes feasible in markets where both inexpensive renewable energy and abundant CO_2 are available, such as in regions like Chile or Iceland. While CO_2-derived polymers could potentially be manufactured at a lower cost than their fossil-based counterparts, the market for these products remains relatively limited.

Building materials generated from CO_2 and minerals or waste streams exhibit competitive potential in today's market. Early markets are emerging for CO_2 utilization in concrete manufacturing, with CO_2-cured concrete demonstrating reduced costs and enhanced performance compared to conventionally produced concrete. The production of building materials from waste and CO_2 can also compete favorably by avoiding expenses associated with traditional waste disposal methods. CO_2 employed in building materials remains permanently stored in the product, offering additional climate benefits, especially with reduced cement input in the case of CO_2-cured concrete. Nevertheless, broader deployment may require trials and updates to product standards for certain concrete products.

The future outlook for CO_2 utilization will heavily rely on the backing of supportive policies. Many CO_2 utilization technologies may only be competitive against traditional processes if their potential for reducing emissions is acknowledged within climate policy frameworks or if incentives for lower-carbon products are in place. Public procurement stands as an effective strategy to establish an initial market for CO_2-derived products that demonstrate verifiable climate benefits, aiding in the development of technical standards.

Anticipations for the CO_2 utilization market in the short term suggest a relatively limited scale, yet opportunities at an early stage can be cultivated. These initial prospects encompass building materials, and in certain instances, polymers, as well as industrial CO_2 use within greenhouse settings. Industrial zones that combine low-cost raw materials, low-carbon energy, consumer bases, and leverage existing CO_2 pipelines may offer early deployment chances.

Further research, development, and demonstration (RD&D) efforts are imperative, particularly for applications that could contribute to an eventual economy with net-zero CO_2 emissions. This includes the development of chemicals and aviation fuels derived from biogenic or atmospheric CO_2. These efforts should align with RD&D initiatives focusing on low-carbon hydrogen production.

4. Storage of CO_2

4.1. What is geological storage?

Capturing and storing CO_2 underground offers a means to prevent CO_2 emissions into the atmosphere. This process involves capturing CO_2 from significant stationary sources, transporting it, and then injecting it into appropriate deep geological formations.

The Earth's subsurface functions as the largest reservoir for carbon, housing the majority of the world's carbon within coals, oil, gas, organic-rich shales, and carbonate rocks. Over hundreds of millions of years, geological storage of CO_2 has naturally occurred in the Earth's upper crust. CO_2, originating from biological activity, igneous processes, and the interactions between rocks and fluids, has accumulated in the natural subsurface environment. It exists in various forms, such as carbonate minerals, in solution, or in gaseous or supercritical states—either as a gas mixture or as pure CO_2.

The deliberate injection of CO_2 into subsurface geological formations began in Texas, USA, during the early 1970s. This practice was initiated as part of enhanced oil recovery (EOR) projects and has continued in Texas and numerous other locations ever since [26].

By the late 1990s, various research programs, both publicly and privately funded, were initiated in the United States, Canada, Japan, Europe, and Australia, focusing on CO_2 geological storage. Alongside these efforts, several oil companies started showing interest in geological storage as a viable mitigation option, particularly in gas fields abundant in natural CO_2, such as Natuna in Indonesia, In Salah in Algeria, and Gorgon in Australia. More recently, coal mining and electricity-generation companies have also begun exploring geological storage as a mitigation avenue relevant to their industries.

Since then, geological storage of CO_2 has evolved from a concept of limited interest to one recognized as a crucial mitigation strategy. This shift is attributed to several factors. Firstly, ongoing research, along with successful demonstration and commercial projects, has bolstered confidence in the technology. Secondly, there is a widespread agreement that a diverse array of mitigation strategies is necessary. Thirdly, geological storage coupled with CO_2 capture has the potential to significantly reduce atmospheric CO_2 emissions. However, for this potential to materialize, the technique must be safe, environmentally sustainable, cost-effective, and broadly applicable.

To store CO_2 in geological formations, it needs to be compressed, usually reaching a highly condensed fluid state known as 'supercritical.' The density of CO_2 increases with depth, typically until around 800 meters or more, where the injected CO_2 becomes a dense supercritical substance.

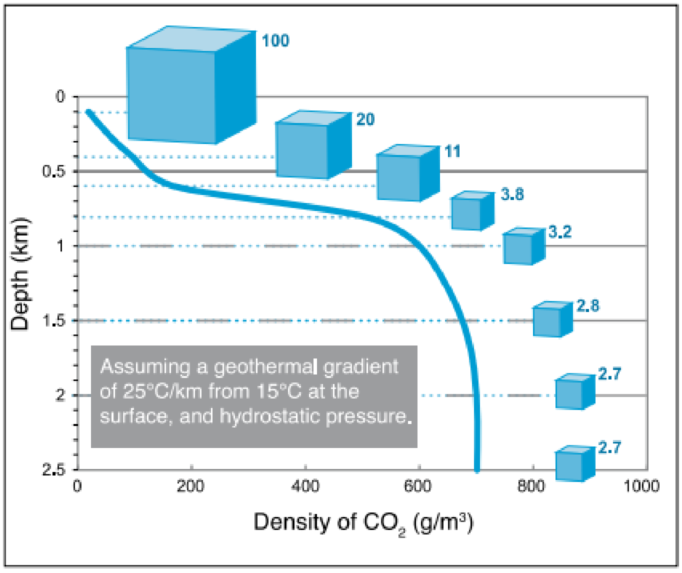

***Figure 5:** Density of CO2*

Geological storage of CO2 can be conducted across various geological settings within sedimentary basins. In these basins, potential storage formations include oil fields, depleted gas fields, deep coal seams, and saline formations [27]. Subsurface geological storage is viable both onshore and offshore, with offshore sites accessed through pipelines from the shore or offshore platforms. While offshore locations like the continental shelf and some deep-marine sedimentary basins hold potential for storage, most sediments on the abyssal deep ocean floor are often too thin and impermeable for effective geological storage. Additionally, apart from storage in sedimentary formations, some exploration has been directed towards storage in caverns, basalt, and organic-rich shales.

Large-scale injection of fluids into the deep subsurface has been a long-standing practice for disposing of unwanted chemicals, pollutants, or by-products from petroleum production. Additionally, it is used to boost oil and gas production or to replenish depleted formations. The underlying principles of these procedures are well-established, and in many countries, there are regulatory frameworks overseeing such activities.

4.2. Oil and gas fields

4.2.1. Abandoned oil and gas fields

Depleted oil and gas reservoirs represent ideal options for CO2 storage due to various compelling reasons. Initially, the fact that the original oil and gas remained trapped within these reservoirs for extended periods, sometimes spanning millions of years, underscores their structural integrity and safety. Moreover, the geological structure and physical attributes of most oil and gas fields have undergone extensive scrutiny and characterization. Additionally, the oil and gas industry has developed sophisticated computer models predicting hydrocarbon movement, displacement behavior, and trapping mechanisms. Lastly, existing infrastructure and wells within these depleted fields can potentially be repurposed for CO2 storage operations.

Depleted fields, having already contained hydrocarbons, are generally not negatively impacted by CO2. Furthermore, if hydrocarbon fields are still in production, implementing a CO2 storage strategy can be optimized to enhance oil or gas production. However, the plugging of abandoned wells in many mature fields began decades ago when they were filled with a mud-laden fluid. Subsequently, cement plugs were placed within the wellbore, but there was no anticipation that these plugs would one day be relied upon to contain a reactive and potentially buoyant fluid like CO2. Thus, evaluating the condition of wells penetrating the caprock is crucial [28]. In numerous instances, locating these wells might be challenging, and confirming caprock integrity may necessitate pressure and tracer monitoring.

Reservoir capacity must be managed carefully to avoid surpassing pressures that could damage the caprock. Reservoirs should exhibit limited sensitivity to reduced permeability, which might result from plugging in the area near the injector and fluctuations in reservoir stress. Storage in reservoirs at depths less than approximately 800 meters might be technically and economically viable, but shallow reservoirs with limited storage capacity, where CO2 could remain in the gas phase, could pose challenges.

4.2.2. Enhanced oil recovery (EOR)

EOR involving CO2 injection presents potential economic benefits by boosting incremental oil production. Typically, conventional primary production recovers around 5–40% of the original oil in place [29].Secondary recovery methods, like water flooding, retrieve an additional 10–20% of the oil in place. Various miscible agents, including CO2, have been employed for EOR, leading to an average incremental oil recovery of 7–23% (averaging 13.2%) of the original oil in place.

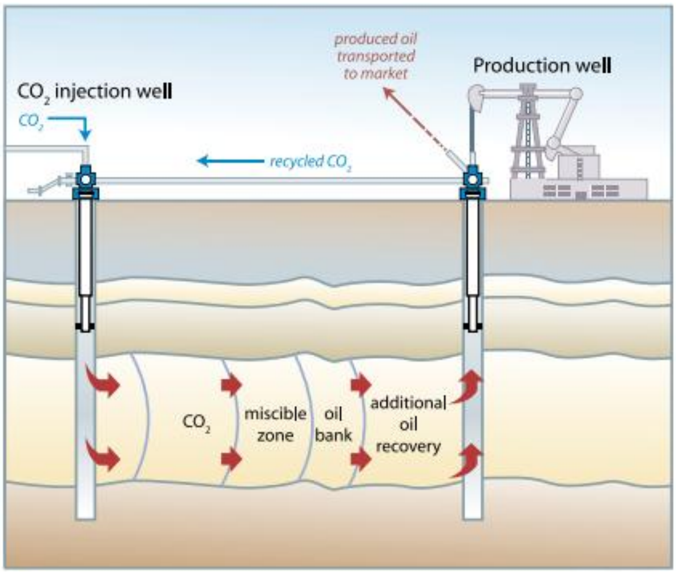

Figure 6: *Injection of CO2 for enhanced oil recovery (EOR) with some storage of retained CO2*

Several CO2 injection strategies have been proposed, such as continuous CO2 injection or alternating water and CO2 gas injection. The displacement of oil by CO2 injection relies on the phase behavior of CO2 and crude oil mixtures, heavily influenced by reservoir temperature, pressure, and crude oil composition. These mechanisms range from oil swelling and viscosity reduction when injecting immiscible fluids (at low pressures) to completely miscible displacement in high-pressure applications. In such cases, over 50% and up to 67% of the injected CO2 typically returns with the produced oil, often separated and reinjected into the reservoir to minimize operational costs [30]. The remaining CO2 becomes trapped in the oil reservoir via various means, including irreducible saturation, dissolution in reservoir oil that isn't produced, and in pore spaces disconnected from the flow path of producing wells.

For optimized CO2 storage in EOR endeavors, oil reservoirs must adhere to additional criteria [31]. Typically, reservoir depth should surpass 600 meters. In instances involving heavy-to-medium gravity oils (12–25 API oil gravity), the injection of immiscible fluids often proves sufficient. However, the more desirable miscible flooding method is suitable for lighter, low-viscosity oils (25–48 API oil gravity). For miscible floods, reservoir pressure should exceed the minimum miscibility pressure (ranging between 10–15 MPa), crucial for achieving miscibility between reservoir oil and CO2, dependent on oil composition and gravity, reservoir temperature, and CO2 purity.

To ensure effective oil removal, preferred criteria for both flooding types include relatively thin reservoirs (less than 20 meters), a high reservoir angle, homogeneous formations, and low vertical permeability. In the case of horizontal reservoirs, the absence of natural water flow, major gas caps, and significant natural fractures are preferable. Reservoir thickness and permeability are non-critical factors.

Reservoir heterogeneity significantly impacts CO2 storage efficiency. The disparity in density between lighter CO2 and reservoir oil and water often results in the movement of CO2 along the reservoir's top, particularly in relatively homogeneous and highly permeable reservoirs, detrimentally affecting CO2 storage and oil recovery. Therefore, reservoir heterogeneity might positively impact the process by impeding the upward movement of CO2, compelling lateral spread, thereby ensuring more comprehensive invasion of the formation and greater storage potential [30].

4.2.3. Saline formations

Saline formations refer to deep sedimentary rocks saturated with formation waters or brines containing high concentrations of dissolved salts. These formations are widespread and hold significant volumes of water, yet they are unsuitable for agricultural use or human consumption. Locally, saline brines find usage in the chemical industry, while formation waters of varying salinity serve purposes in health spas and the production of low-enthalpy geothermal energy. Given the probable rise in geothermal energy utilization, potential geothermal areas might not be viable for CO2 storage. Although the concept of combined geological storage and geothermal energy has been proposed, regions exhibiting strong geothermal potential are generally less favorable for CO2 geological storage due to extensive faulting, fracturing, and a sharp increase in temperature with depth. In exceptionally arid regions, deep saline formations might be considered for future water desalinization efforts.

The Sleipner Project in the North Sea stands as the most prominent demonstration of a CO2 storage initiative within a saline formation. This project marked the pioneering endeavor at a commercial scale specifically dedicated to geological CO2 storage. About 1 million tons of CO2 are annually extracted from the produced natural gas and then injected underground at Sleipner. Commencing operations in October 1996, it is anticipated that a total of 20 million tons of CO_2 will be stored over the project's lifetime. A simplified depiction of the Sleipner scheme is illustrated in Figure 7.

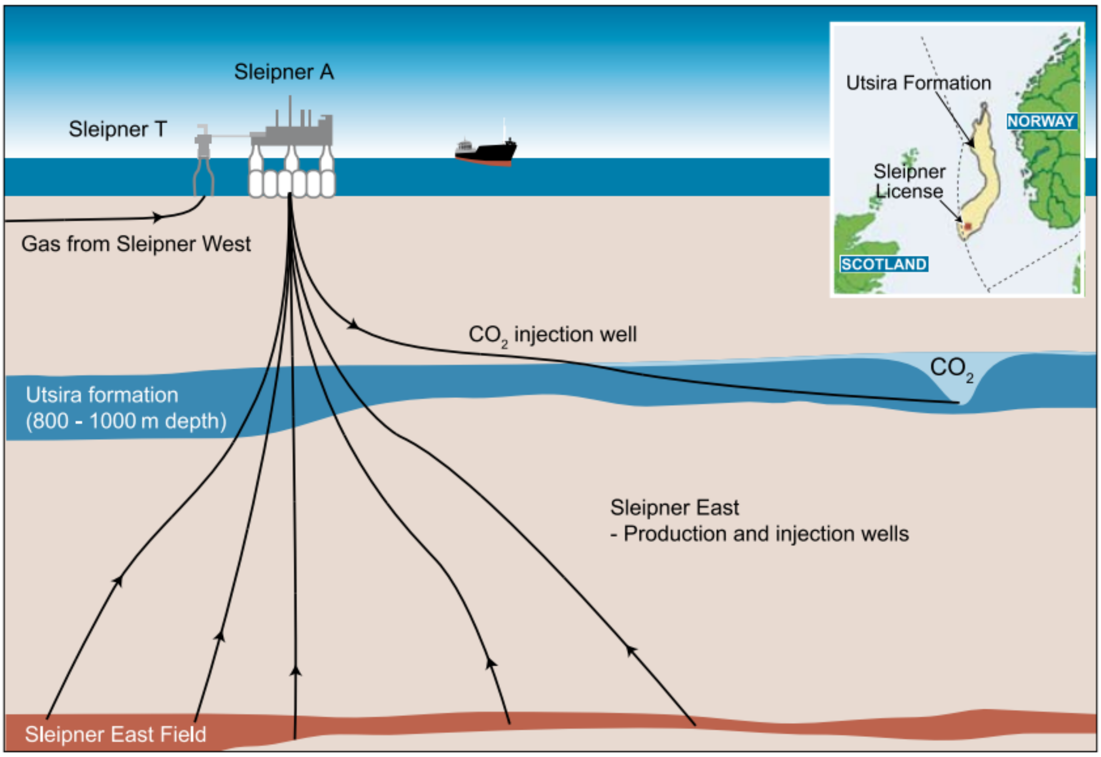

Figure 7: *Simplified diagram of the Sleipner CO_2 Storage Project. Top right: location and extent of the Utsira formation*

At Sleipner, CO_2 injection occurs into poorly cemented sands located approximately 800–1000 meters below the sea floor. These sandstones encompass secondary thin shale or clay layers that impact the internal movement of injected CO_2. A substantial, extensive shale or clay layer serves as the primary seal above the saline formation, which boasts a remarkably large storage capacity.

Monitoring of the Sleipner CO_2 plume's fate and transport has been effectively accomplished through seismic time-lapse surveys. These surveys significantly contributed to refining the conceptual model regarding the fate and movement of stored CO_2. So far, no CO_2 leakages have been reported [32].

4.2.4. Coal seams

Coal contains fractures, known as cleats, which contribute to its permeability. Inside these cleats, the solid coal comprises numerous micropores where gas molecules from the cleats can diffuse and become firmly adsorbed. Coal possesses the capability to physically adsorb various gases and may harbor as much as 25 normal m^3 of methane per tonne of coal at coal seam pressures, measured at 1 atmosphere and 0 °C. Notably, coal exhibits a greater inclination to adsorb gaseous CO_2 in comparison to methane. The ratio of adsorbable CO_2 to CH_4 can vary significantly, ranging from as low as one for mature coals like anthracite to ten or higher for younger, less mature coals like lignite. When gaseous CO_2 is injected via wells, it traverses the coal's cleat system, diffuses into the coal matrix, and attaches onto the surfaces of coal micropores, consequently releasing gases with lower affinity towards coal, such as methane.

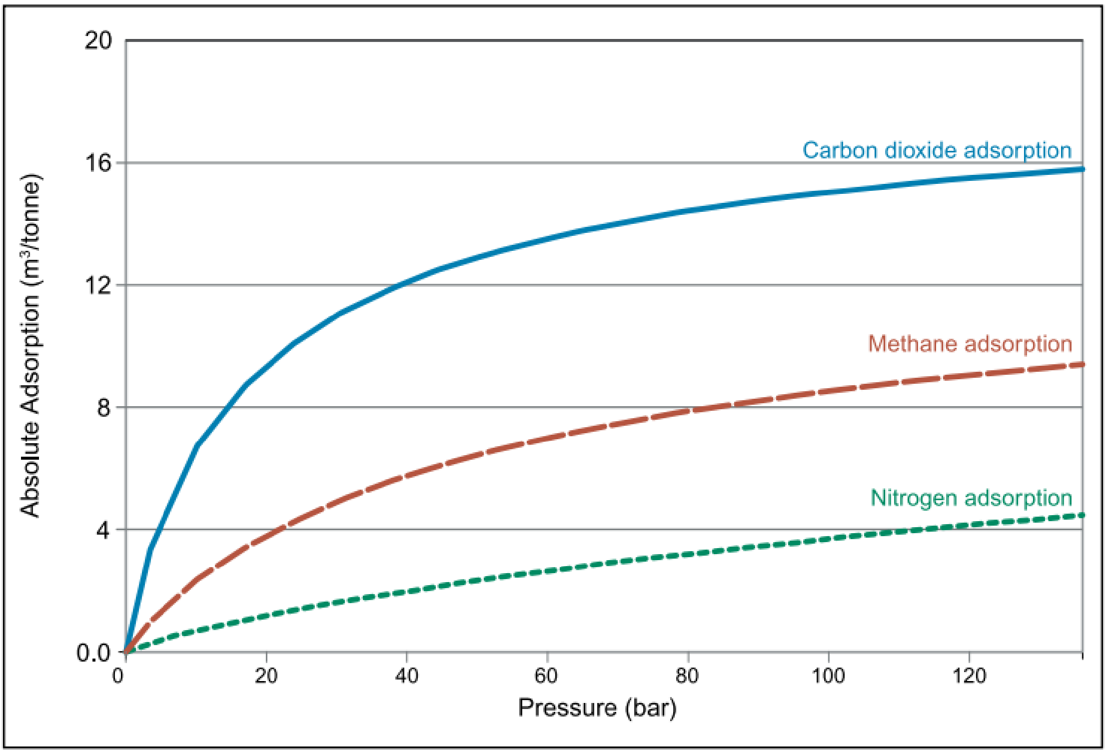

Figure 8: *Pure gas absolute adsorption in standard cubic feet per tonne on Tiffany Coals at 55°C*

It appears that gradually, adsorption gives way to absorption, causing CO_2 to diffuse or 'dissolve' within the coal [33]. Carbon dioxide acts as a 'plasticizer' for coal, reducing the temperature required to transition from a glassy, brittle structure to a rubbery, plastic state (referred to as coal softening). In a specific instance, the transition temperature was observed to decrease from approximately 400°C at 3 MPa to <30°C at 5.5 MPa CO_2 pressure [33]. However, this transition temperature heavily depends on coal maturity, maceral content, ash content, and the applied confining stress, making it challenging to extrapolate to real-world conditions.

The plasticization or softening of coal due to CO_2 can potentially adversely impact permeability, hindering CO_2 injection. Moreover, coal tends to expand as CO_2 is adsorbed and/or absorbed, leading to a substantial reduction in permeability and injectivity by several orders of magnitude or more. This decrease in permeability and injectivity might be addressed by elevating injection pressures. Some research indicates the possibility of CO_2 injected into coal undergoing reactions, further complicating the challenge of injecting CO_2 into low-permeability coal formations [34].

When CO_2 is injected into coal seams, it can displace methane, thereby improving Coal Bed Methane (CBM) recovery. Successful CO_2 injection has been demonstrated at the Allison Project and within the Alberta Basin, Canada, both at depths surpassing that corresponding to the CO_2 critical point. Utilizing CO_2 for ECBM (Enhanced Coal Bed Methane) holds the potential to significantly raise the methane yield to nearly 90% of the gas, a substantial increase compared to the conventional recovery of only 50% achieved through reservoir-pressure depletion alone.

Coal permeability stands out as one among several critical factors in determining an ideal storage site. The permeability of coal exhibits considerable variability and generally diminishes with increased depth due to cleat closure from escalating effective stress. The majority of CBM-producing wells worldwide are situated at depths less than 1000 meters.

The initial screening criteria proposed to identify favorable regions for CO2 ECBM include the following:

- Sufficient permeability (specific minimum values yet to be established).
- Favorable coal geometry, characterized by a few thick seams rather than numerous thin seams.
- Geologic simplicity with minimal faulting and folding.
- Homogeneous and enclosed coal seams that are both laterally continuous and vertically isolated.
- Appropriate depth, typically reaching down to 1500 meters, although deeper depths have not been thoroughly explored.
- Suitable gas saturation conditions, ideally featuring high gas saturation for effective ECBM.
- Capability to remove water from the formation.

The literature suggests that the rank of coal may have a more substantial influence than previously believed, mainly due to its impact on the varying adsorptive capacities of methane and CO2. However, if the coal remains unmined or without depressurization, it's probable that CO2 will be stored in the coal seam for geological periods. Nonetheless, any disturbances to the formation, as with any geological storage method, could jeopardize the effectiveness of storage. Thus, anticipating the probable future of a coal seam becomes a crucial factor in determining its suitability for storage and in the selection of storage sites. Potential conflicts between mining activities and CO2 storage might arise, particularly concerning shallow coal deposits.

5. Supply chain of CO2

A supply chain represents a cohesive manufacturing system where raw materials undergo conversion into finished goods and are subsequently delivered to customers [35]. At its core, a supply chain consists of two fundamental interlinked processes:

(1) The Production Planning and Inventory Control Process, and

(2) The Distribution and Logistics Process.

These processes serve as the foundational structure for transforming raw materials into final products and orchestrating their movement.

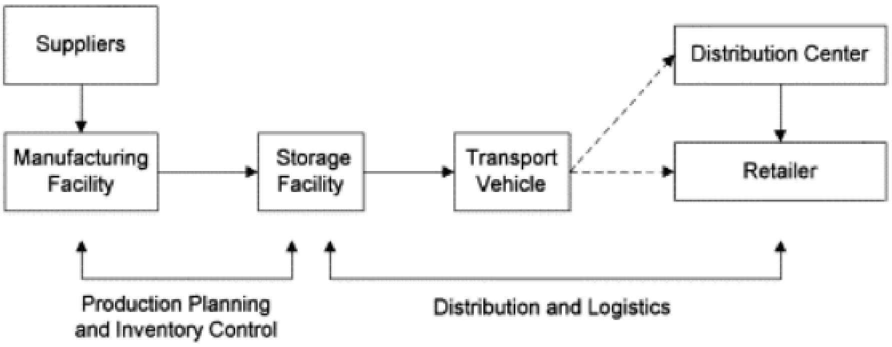

Figure 9: *Typical supply chain*

The Production Planning and Inventory Control Process encompasses the manufacturing and storage facets along with their interfaces. Specifically, production planning involves designing and overseeing the entire manufacturing process, which includes scheduling and acquiring raw materials, planning and scheduling manufacturing procedures, and managing material handling procedures. Inventory control involves creating and managing storage policies and protocols for raw materials, work-in-progress inventories, and typically, final products.

The Distribution and Logistics Process dictates the retrieval and transportation of products from storage to the determined user. These products may either be transported directly to the user or initially routed to distribution centers, which then manage the transportation to the end destination. This process encompasses the oversight of inventory retrieval, transportation logistics, and the final delivery of products.

These interlinked processes collaborate to form a unified supply chain. The design and administration of these processes determine how effectively the supply chain functions as a cohesive entity to meet the desired performance objectives.

5.1. Supply chain of industry captured CO2

Carbon capture, transportation, and storage are vital for aligning the world economy with the greenhouse gas emission reduction goals set by the Paris Agreement. The primary demand for transporting LCO2 by ship stems from the sequestration of CO2 captured from onshore power stations, petrochemical plants, and various industrial processes.

According to the latest report from the Global CCS Institute, the capacity of all CCS facilities under development has increased to 361 million tonnes per annum, marking a 48% growth since the 2022 report. The total capacity of the CCS project pipeline has grown at a compound rate exceeding 35% per annum since 2017, with a remarkable 48% annual increase in 2023, the largest surge since the upward trend began in 2018 [12].

The number of CCS facilities in the development pipeline has also reached a record high. As of July 2023, there are 392 projects, indicating a 102% year-on-year increase. Since the Institute's 2022 report, 11 new facilities have commenced operations, and 15 new projects have begun construction. Additionally, 198 new facilities have been added to the development pipeline, resulting in a total of 41 projects in operation, 26 under construction, and 325 in advanced and early development stages.

Transporting captured CO2 from power plants and industrial sources presents various options, including pipelines, ships, railways, and motor carriers. Pipelines excel in transmitting significant CO2 volumes across short distances but come with considerable initial costs and restricted adaptability. On the other hand, CO2 shipping allows for the transport of smaller quantities over longer distances, boasting lower initial expenses and greater adaptability. Illustrated in Figure 10, the CO2 shipping process presents a viable alternative to pipelines, especially for smaller and dispersed emission sources.

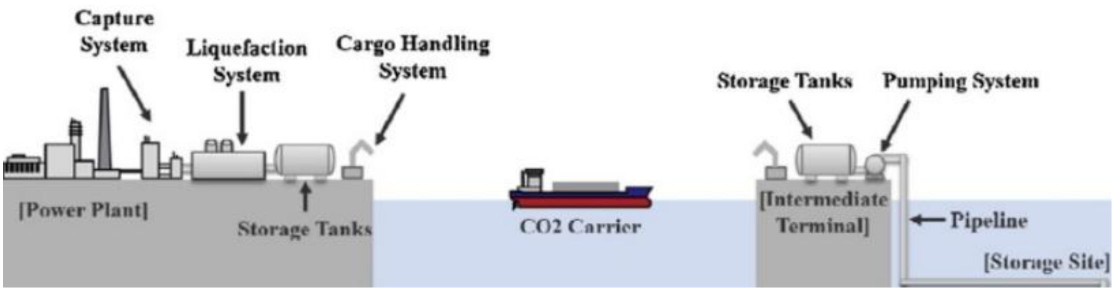

Figure 10: *CO2 supply chain*

Railway and truck transfer each have their benefits, but it is important to note that they pose problems regarding the transferable capacity, especially when compared to pipelines and ships. Therefore, as time goes on and more CCUS projects come online, which means that great quantities will need to be moved around, it is unlikely that these two means of transportation will be able to compete as main components of the supply chain. Having said that, since not every emitter has direct access to pipelines or a port (initially at least), trucks and trains will play an important role in completing the chain.

5.2. Truck transport

Although trucks belong in the CO2 supply chain, there has been no essential need to specialize in exclusively CO2 carrying vehicles. Therefore, the literature is poor regarding the transportation of CO2, as most general trucking related studies shall apply, regardless of the cargo moved.

5.2.1. Advantages of CO_2 transport by truck

Trucking poses several advantages as a means of moving cargo. The flexibility and accessibility of trucks make them well-suited for delivering CO_2 to diverse locations, even in challenging terrains. Especially valuable for last-mile delivery, trucks ensure that CO_2 can be transported directly to points of use, such as industrial facilities or locations implementing CCS technologies.

One key advantage of trucks is their ability to provide timely delivery, crucial for meeting the demands of industries like food and beverage, healthcare, and manufacturing. Additionally, the adaptability of the trucking industry allows for quick responses to changes in CO_2 demand, making it a reliable option in fluctuating scenarios or emergencies.

Trucks offer versatility in handling various load sizes, catering to different production or consumption needs. Their integration into intermodal transportation systems allows for seamless connections with other modes like rail or sea freight, contributing to a more efficient supply chain. While the truck carrying the CO_2 itself may be as simple as a regular truck, conservative in terms of technological features, the CO_2 is stored in ISO containers (in liquid form to maximize the mass moved), ready to be moved on to the next part of the supply chain. Therefore, no specialized technology is required regarding the motor, which allows for a wide spectrum of trucks to be used within the chain. It is also important to note that the trucking industry is also heavily affected by current regulations, which means that as time progresses more environmentally friendly technologies will be implemented in the motors, thus further reducing the carbon footprint of CO_2 transportation.

For regional distribution, trucks prove instrumental, supporting localized industries and reducing the need for long-distance transportation in specific cases. Cost-effectiveness comes into play, particularly for short to medium distances, making trucks economically viable for certain segments of the CO_2 supply chain.

Modern trucking operations leverage technology for dynamic routing and real-time tracking, enhancing efficiency and reducing the carbon footprint. Furthermore, the industry is progressing towards environmental sustainability, with the introduction of electric and hybrid trucks, as well as the use of alternative fuels.

5.2.2. Cost of CO_2 transport by truck

The cost of transporting cargo via trucking is influenced by several key factors. First and foremost is the distance the cargo needs to travel, as longer distances typically incur higher expenses due to increased fuel consumption, labor costs, and wear and tear on the trucks.

Additionally, the weight and volume of the cargo play a significant role in determining costs. Heavier or bulkier loads may require specialized equipment or multiple trucks, leading to higher transportation expenses.

The type of cargo being transported is another crucial consideration. Hazardous materials, perishable goods requiring temperature-controlled transport, oversized loads, or fragile items may incur additional fees due to regulatory requirements or specialized handling needs.

Fuel prices are a major determinant of transportation costs, as fuel represents a significant expense for trucking companies. Fluctuations in fuel prices directly impact shipping rates, with higher fuel prices leading to increased transportation costs.

The route taken and the terrain encountered along the way also affect costs. Routes with tolls or through congested urban areas may result in additional expenses, while difficult terrain or elevation changes could impact fuel efficiency and maintenance costs.

Labor costs, including driver wages, benefits, and other compensation, contribute significantly to overall transportation expenses. Factors such as driver shortage or high demand for experienced drivers can influence labor costs.

Trucking companies must also account for compliance with transportation regulations, including safety standards, environmental regulations, and hours-of-service rules, which may result in additional administrative or operational costs.

Insurance coverage for cargo, liability, and other risks adds to the overall cost of transportation, as do expenses associated with truck maintenance, repairs, and depreciation of equipment.

Market demand and seasonality can also influence pricing dynamics in the trucking industry, with peak shipping seasons or high demand for specific routes leading to higher rates.

Liquid CO2 can be moved in insulated tanker cars, which are similar in design for both truck and rail transport. When transported by trucks, assuming nearly full capacity of 22 tons, costs are slightly higher due to the pricier trailers and slightly higher operational and maintenance expenses. According to survey findings, the adjusted unit cost is $0.111 per ton-kilometer [36].

5.2.3. Transport time of CO2 by truck

The transport time of CO2 via trucks is influenced by several factors. Firstly, the distance to be covered is a primary consideration, as longer distances naturally require more time for transit. Additionally, the chosen route plays a significant role, with factors such as traffic congestion, road conditions, and detours affecting travel time.

Loading and unloading processes also impact transport time. Efficient loading and unloading at both the origin and destination points are essential for minimizing delays. Regulatory requirements, including driving hours restrictions and mandatory rest breaks for drivers, further affect transport time, as drivers must adhere to these regulations.

The condition and performance of the truck, as well as the experience and skill level of the driver, are crucial factors. Well-maintained trucks and experienced drivers can contribute to smoother and more efficient transport, reducing overall travel time. Finally, weather conditions, such as adverse weather or hazardous driving conditions, can also slow down transport and increase travel time.

Overall, a combination of distance, route, loading and unloading processes, regulatory requirements, vehicle condition, driver experience, weather conditions, and facility efficiency collectively influence the transport time of CO_2 when transported by trucks. Efficient planning and management are essential to optimize transport time and minimize delays.

5.3. Railway transport

5.3.1. Advantages of railway transport

Transporting CO_2 by railway presents a range of advantages that contribute to its appeal as a viable mode of transportation. Firstly, railways offer cost-effectiveness, particularly for long-distance hauls, leveraging economies of scale to provide competitive rates, especially when compared to trucking over similar distances. This affordability is complemented by the high capacity of railways, capable of efficiently accommodating large volumes of LCO_2, which is advantageous for industries requiring bulk supply.

Efficiency is another key advantage, as railways generally boast lower fuel consumption per ton-mile compared to trucks, thereby reducing greenhouse gas emissions per unit of cargo transported. This efficiency aligns with environmental sustainability goals, offering a greener transportation option. Moreover, railways are known for their reliability, providing consistent schedules and transit times crucial for industries reliant on uninterrupted CO_2 supply.

Safety is paramount in rail transport, with stringent protocols and regulations in place for transporting hazardous materials like CO_2. The infrastructure and specialized equipment contribute to enhanced safety during transit, mitigating risks associated with accidents or spills. Additionally, the well-established railway infrastructure and extensive network facilitate CO_2 transportation to various industrial centers, improving accessibility and supply chain flexibility.

By diverting CO_2 transportation away from roads and onto railways, rail transport helps alleviate road congestion and reduce wear and tear on highways. This not only benefits the environment but also contributes to overall transportation efficiency. Railways excel in long-distance transportation, providing a reliable and cost-effective solution for moving CO_2 over extended distances, thereby serving regions or industries located far from production or capture facilities.

Finally, similarly to trucking, as trains move ISO containers that are strictly regulated, there is no need to revolutionize the railway industry for CO_2 transport. The current fleet is equipped to undertake CO_2 transport without any specialized additions.

5.3.2. Cost of CO_2 transport by railway

Several factors collectively influence the transportation of CO_2 by railway, shaping the logistics and operations of this mode of transport.

Firstly, the availability and condition of railway infrastructure, encompassing tracks, terminals, and loading/unloading facilities, are pivotal. Well-maintained and accessible infrastructure facilitates efficient transportation. Regulatory compliance is another critical consideration. Adhering to safety standards, handling procedures, and documentation obligations governing the transportation of hazardous materials like CO_2 is essential for safe and legal operations. The capacity and suitability of railway cars and specialized equipment for CO_2 transport significantly impact efficiency and volume. Availability of appropriate tanker cars and infrastructure for loading/unloading CO_2 is crucial.

Distance and route selection play a significant role. Longer distances may require additional planning, while route choices affect transit times and costs. Efficient scheduling and coordination of railway operations are vital for timely and reliable CO_2 transport, necessitating collaboration among shippers, rail operators, and stakeholders. Weather conditions pose challenges, as adverse weather can disrupt railway operations, potentially leading to delays or logistical complications. Market demand and capacity utilization influence space availability and pricing for CO_2 transport services. Fluctuations in demand or capacity affect scheduling and pricing dynamics. Cost considerations, encompassing freight rates, access fees, and other charges, impact the economics of CO_2 transport by railway and inform mode and route selection decisions.

Intermodal connections between railways and other transportation modes, such as trucks or pipelines, offer additional transportation options and optimize supply chain efficiency. Environmental and safety concerns drive regulatory compliance and infrastructure development, shaping operations to align with emissions reduction goals and risk mitigation measures [37].

While specific market data on CO_2 transport by rail is scarce, costs are anticipated to align with those of other tanker-shipped commodities. Additional expenses may include staging, loading, and unloading facilities, potentially requiring infrastructure development at both origin and destination stations. Studies in various regions provide cost estimates, with staging operations contributing minimally to overall expenses. It's assumed that staging and loading operations add a nominal fee to the total cost of rail transport, while the unit cost remains comparable to similar commodities like biomass. Studies have estimated that the cost of CO_2 transport by rail is $0.044 per ton-kilometer, with an additional $2 per ton for the staging and loading operation [36]. Overall, railway transport offers a reliable and cost-effective solution for moving liquefied CO_2, contributing to efficient supply chain management.

5.4. Pipeline transport

Transporting CO_2 for sequestration necessitates an effective and well-coordinated transportation infrastructure. Typically, pipelines emerge as the primary choice, especially in cases where a consistent flow of CO_2 from capture sites is required. In order to firmly grasp the concept of pipeline transfer of CO_2, it is first necessary to understand how such a system is designed.

The physical, environmental and social factors that determine the design of a pipeline are summarized in a design basis, which then forms the input for the conceptual design [1]. This includes a system definition for the preliminary route and design aspects for cost-estimating and concept-definition purposes. It is also necessary to consider the process data defining the physical characteristics of product mixture transported, the optimal sizing and pressures for the pipeline, and the mechanical design, such as operating, valves, pumps, compressors, seals, etc. The topography of the pipeline right-of-way must be examined. Topography may include mountains, deserts, river and stream crossings, and for offshore pipelines, the differing challenges of very deep or shallow water, and uneven seabed. It is also important to include geotechnical considerations. For example, is this pipeline to be constructed on thin soil overlaying granite? The local environmental data need to be included, as well as the annual variation in temperature during operation and during construction, potentially unstable slopes, frost heave and seismic activity. Also included are water depth, sea currents, permafrost, ice gouging in Arctic seas, biological growth, aquifers, and other environmental considerations such as protected habitats. The next set of challenges is how the pipeline will accommodate existing and future infrastructure – road, rail, pipeline crossings, military/governmental restrictions and the possible impact of other activities – as well as shipping lanes, rural or urban settings, fishing restrictions, and conflicting uses such as dredging.

The conceptual design phase encompasses the following elements:

- Mechanical design adheres to established protocols
- Stability design employs standard techniques and software for conducting stability assessments, whether or onshore. However, there have been queries regarding offshore methodologies.
- Corrosion protection.
- Trenching and backfilling practices entail burying onshore lines to a depth of about 1 meter, while offshore lines are typically buried in shallow waters. For pipelines in deeper waters narrower than 400 mm, trenching and occasional burial are employed to safeguard against potential damage from fishing equipment.
- CO_2 pipelines are potentially more prone to longitudinal running fractures compared to pipelines carrying hydrocarbon gases. To mitigate this risk, fracture arresters are installed at approximately 500-meter intervals.

5.4.1. Construction of land pipelines

Construction planning may commence before or after rights of way are obtained, yet the decision to proceed with construction is contingent upon securing the legal authorization to construct a pipeline and ensuring compliance with all governmental regulations. The construction procedures for both onshore and underwater CO_2 pipelines mirror those of hydrocarbon pipelines, drawing from an established and comprehensively understood engineering expertise. Certain operations can be executed concurrently during the construction phase.

Seasonal considerations influenced by environmental and social factors may impact the timing of construction. The process typically involves clearing the land and excavating the trench. Priority is given to critical elements such as urban regions, river crossings, and road passages. Pipe segments, usually in double joints measuring 24 meters in length, are welded after being received at the pipe yard. Subsequently, these welded segments are transported to staging areas along the pipe route for installation, where they undergo further welding, testing, coating, wrapping, and subsequent lowering into the trench. Once in place, a hydrostatic test is conducted, followed by the drying of the line. Finally, the trench is backfilled, and the land and vegetation are restored to their original state.

5.4.2. Safety of land pipelines

The frequency of incidents is continuously decreasing, marking pipeline transfer as a safe and reliable method of transportation. According to the European Gas Pipeline Incident Group (EGIG), during the 2015-2019 period, 90 incidents were reported. This could be brought into perspective by taking into consideration the primary failure frequency per 1000 km*yr index, which stood at 0.126, compared to 0.372 for the 1970-2007 period [38].

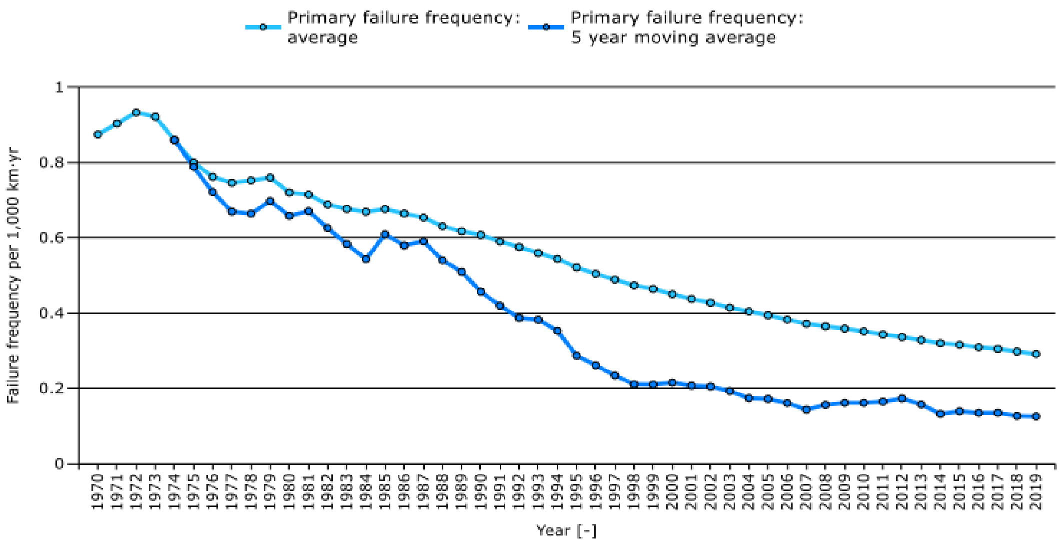

Figure 11: *Pipeline failure frequency*

5.4.3. Corrosion

As examined by [39], if the pipeline maintains conditions that ensure minimal water content and other contaminant levels, similar to current practices in EOR pipelines, the corrosion rates are expected to remain adequately low, as indicated by observed real-world data. Achieving this low corrosion rate might result from various factors such as employing cleaning technologies before CO2 capture, the impact of the capture process itself (especially the reaction of MEA with sulfur compounds and oxygen), and subsequent gas treatment following capture. However, further investigation is necessary to accurately measure the remaining contaminants that could enter the CO2 stream during transportation.

From a corrosion standpoint, iron exhibits high activity within the acidic pH spectrum. When water combines with CO2, it initiates the in-situ formation of carbonic acid, which, even at low concentrations, notably reduces the pH of the water phase.

The majority of common impurities, stemming from the nature of the CO2 source and hence unavoidable, comprise sulfur (S) and nitrogen (N) compounds. Unfortunately, these compounds are detrimental, leading to the spontaneous creation of nitric and sulfuric acids when mixed with acidified water. This intensifies the overall acid concentration, further lowering the pH significantly and subsequently accelerating corrosion rates.

It appears that the primary factor influencing corrosion rate is the presence of water, as CO2 itself, along with contaminants, can acidify water. The absence of an aqueous phase minimizes corrosion, although evidence suggests that corrosion might persist even when water content is below a critical level. Further research is imperative to comprehend corrosion in water-free conditions.

5.4.4. Cracking

The evaluation of fracture prevention should encompass three key mechanisms [40]:

1. Initiation of ductile fracture
2. Propagation of ductile fracture
3. Initiation of brittle fracture

Pipelines transporting dense phase CO2 might face various failure modes, including rupture caused by running cracks in brittle fracture mode, ductile tears, holes, pinholes, cracks, dents, gouges, or loss of wall thickness due to corrosion (internal or external).

Therefore, implementing suitable technical and managerial measures becomes essential to mitigate the risk of potential catastrophic failures.

The management of pipelines carrying dense phase CO2 relies on the pipeline steel's ability to effectively withstand both brittle and ductile failure mechanisms.

The primary goals of fracture control are to guarantee that under specified stress and temperature conditions, there will be no occurrence of brittle fracture. Additionally, in case of pipeline damage leading to a fracture, the objective is to ensure that the fracture will display ductile behavior and will be contained within a specific distance in both directions from the point where it started.

Ensuring the prevention of fracture initiation involves precise selection of pipeline materials and thorough testing during the design and procurement phases. The goal is to prevent fracture initiation under all conceivable design and operational conditions.

To prevent the propagation of ductile fractures, specific material toughness requirements are outlined to halt the progression of a running fracture. Alternatively, mechanical crack arrestors can be employed. However, employing these arrestors, thicker than the pipeline, at regular intervals isn't advised due to the associated costs and fabrication challenges it poses for the pipeline system design.

5.4.5. Cost of pipelines

The expenses associated with pipelines can be classified into three main components [3]:

- Construction Costs
  - ✓ Material and equipment expenses (including pipe, pipe coating, cathodic protection, telecommunication equipment, potential booster stations)
  - ✓ Labor costs for installation
- Operation and Maintenance Costs

- ✓ Expenses for monitoring
- ✓ Maintenance expenditures
- ✓ Possible energy-related costs

- Other Costs (such as design, project management, regulatory filing fees, insurance costs, right-of-way expenses, contingency allowances)

Pipeline material costs are contingent on factors like pipeline length, diameter, volume of CO_2 to be transported, and the quality of the carbon dioxide. Investments tend to increase when one or multiple compressor stations are needed to offset pressure loss along the pipeline, for longer pipelines, or in hilly terrains. Alternatively, compressor stations can be avoided by increasing pipeline diameter and reducing flow velocity. Reported transport velocities range from 1 to 5 m/s. The pipeline's actual design will optimize the diameter, pressure loss, and wall thickness.

Determining the pipeline diameter is critical for accurately assessing the economic viability of a transportation project. Various factors, including flow rate, inlet pressure and temperature, pressure drop, and topographical discrepancies, are essential considerations in determining the appropriate diameter size. Pipeline diameter calculations typically fall into two main categories: those based on hydraulic principles for turbulent flow in circular pipelines and those focused on optimizing design from an economic standpoint. Below are showcased Equations 1-4 [3] for pipeline diameter calculation. IEAGHG utilized Equation 1 for pipeline diameter calculation, providing a quick but rough estimate that does not account for pressure drop. Additionally, it assumes the use of average velocity for diameter calculation.

$D = \sqrt{\frac{4Qm}{\upsilon\pi\rho}}$	$D^5 = \frac{32\, f_F Qm^2}{\pi^2\rho\left(\frac{\Delta p}{L}\right)}$	$D = \left(\frac{4^{10/3}\, n^2\, Qm^2\, L}{\pi^2\rho^2\left(z_1 - z_2 + \left(\frac{p_1 - p_2}{\rho g}\right)\right)}\right)^{3/16}$	$D_{opt} = 0.363\left(\frac{Qm}{\rho}\right)^{0.45}\rho^{0.13}\mu^{0.025}$
(Equation 1)	(Equation 2)	(Equation 3)	(Equation 4)

Figure 12: *Pipeline diameter estimation formulas*

Costs can fluctuate based on terrain types. Onshore pipeline costs may surge by 50 to 100% or more in congested, heavily populated areas, mountains, nature reserves, zones with obstacles like rivers and freeways, and densely urbanized regions due to construction accessibility and additional safety measures. Offshore pipelines, usually operating at higher pressures and lower temperatures than onshore counterparts, can often be 40 to 70% more expensive, but not consistently so.

Pooling CO_2 from multiple sources into a single pipeline proves more cost-effective than transporting smaller amounts separately. Initial and smaller projects might encounter relatively higher transport costs, making them sensitive to travel distances. However, as capacities grow (with widespread application), transport costs may decrease. Developing a 'backbone' transport structure could ease access to large remote storage reservoirs but necessitates substantial upfront investment decisions. Same principles regarding the cost of pipelines apply to underwater pipelines as well.

The overall expense of a pipeline system comprises two primary elements: capital and operational costs. Capital costs are divided into pipe and compressor capital costs, while operational costs primarily encompass compressor operating expenses [41].

Pipeline capital costs are typically assessed per unit length and tend to rise proportionally with the diameter of the pipeline. However, variations in materials, technology, and labor expenses across different global regions can lead to significant fluctuations in costs. Additionally, the specific geographical location within the same region, such as sparsely or densely populated areas, or areas with challenging terrain features like rivers, can influence costs. Design factors, including the number and size of compressor stations, also impact costs.

Costs tend to escalate in mountainous regions, nature reserves, areas with obstacles such as rivers and highways, and heavily urbanized areas due to accessibility constraints during construction and the need for additional measures. Investment expenses can be calculated empirically based on existing data or through direct calculations, such as determining the amount of steel required, or a combination of both methods. Generally, offshore pipelines incur significantly higher costs compared to onshore pipelines.

5.4.6. Construction of underwater pipelines

Underwater pipelines are typically constructed using various methods. The lay-barge technique is commonly employed, involving 12 or 24-meter pipe sections brought to a dynamically positioned or anchored barge. These sections are individually welded to the pipeline's end as the barge moves forward slowly. The pipeline then exits the barge over the stern, passes over a support structure called a 'stinger,' and descends through the water as a suspended span until reaching the seabed. Alternatively, pipelines up to 450mm in diameter may be constructed using the reel method, where the pipeline is pre-welded onshore, wound onto a ship's reel, and unwound into its final position. For short lines or shore crossings in shallow waters, different tow and pull techniques are utilized, where the pipeline is welded onshore and then pulled into its designated location.

In instances where trenching is necessary for the pipeline, it is typically done after the pipeline has been laid on the seabed. Trenching methods might involve a jetting sled, plough, or a mechanical cutting device dragged along the line. However, for shore crossings and very shallow waters, trench excavation often precedes pipeline laying. Excavation methods vary, including the use of dredgers, backhoes, draglines for soft sediments, or blasting followed by clamshell excavators for rock terrain. In numerous instances, shore crossings are drilled horizontally from the shore, minimizing uncertainties in the surf zone and reducing environmental disruption during construction.

Connections underwater are facilitated by different mechanical systems or through hyperbaric welding (conducted in air under local hydrostatic pressure). Alternatively, pipe ends can be lifted above the surface, welded together, and then lowered as a connected line to the seabed. Underwater pipelines, ranging in diameter up to 1422 mm, have been successfully constructed in various environmental conditions, including depths of up to 2200 meters. Figure 13 illustrates the diameters and maximum depths of significant deepwater pipelines built up until 2004. The challenge of construction generally increases in proportion to the product of the depth and diameter, a value that has increased four times its maximum since

1980. Despite this, current technological capabilities allow for the feasibility of even larger and deeper pipelines.

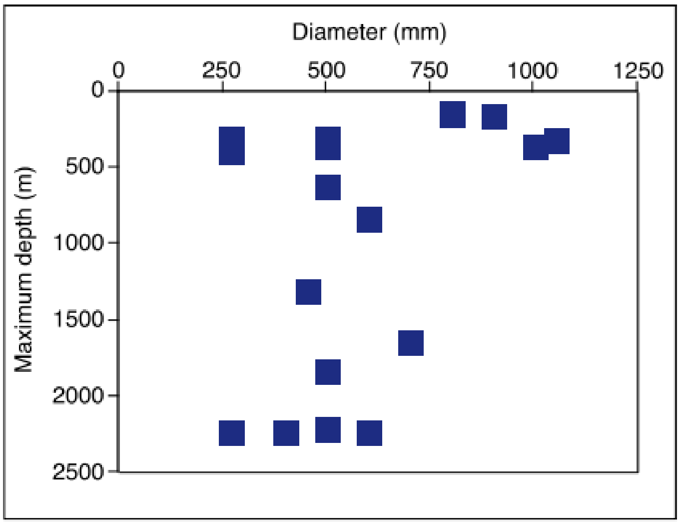

Figure 13: *Diameter of underwater pipelines*

5.4.7. Safety of underwater pipelines

The occurrence of failures during service remains infrequent. Instances of ships dragging anchors resulting in failures occur primarily in shallow waters (less than 50 meters). Incidents involving ships sinking onto pipelines or objects falling onto them are exceedingly rare. Larger pipelines, sized at 400 mm in diameter or above, have demonstrated safety from damage caused by fishing gear. However, smaller pipelines are typically trenched to shield them from potential harm.

5.4.8. Operation of pipelines

Operational aspects of pipelines are categorized into three main areas: daily operations, maintenance, and health, safety, and environmental considerations. For example, CO2 pipelines operating in the USA must adhere to federal operational guidelines. General operational considerations encompass various aspects such as training, inspections, safety protocols integration, pipeline markers, public awareness campaigns, damage prevention initiatives, communication systems, facility security measures, and leak detection protocols. Comparable regulatory operational requirements are typically found for pipelines outside the USA.

Personnel are a fundamental part of operations and are mandated to possess qualifications proportionate to their roles. Continuous training for personnel, including contractors working near the pipeline and the general public, is imperative, emphasizing safety procedures. Operational functions also involve daily maintenance, scheduled planning, and the implementation of policies to inspect, maintain, and repair all line-related equipment and the pipeline itself. This encompasses valves, compressors, pumps, tanks, rights-of-way, public signage, line markers, and regular pipeline flyovers.

Long-distance pipelines incorporate instrumentation at intervals to facilitate flow monitoring. These monitoring points, compressor stations, and block valves are interconnected with a central operations center. Automated systems control a significant portion of operations, requiring manual intervention only in uncommon disruptions or emergency situations. To ensure operational continuity, the system includes redundancies that mitigate operational capability loss in the event of component failure.

"Pigs," piston-like devices driven by gas pressure, are deployed for pipeline cleaning and inspection. These advanced devices are capable of assessing internal corrosion, mechanical deformation, external corrosion, as well as determining the precise line position and identifying spans in underwater lines. Pipeline technology is continually evolving, promising further functionalities for pigs in the future. Inspection of land pipelines occurs via aerial surveys at agreed intervals between operators and regulatory bodies, enabling the early detection of unauthorized excavation or construction before potential damage. Remotely operated vehicles used to monitor underwater pipelines, capturing video records, and autonomous underwater vehicles have replaced them, eliminating the need for a direct cable connection to a mother ship [60]. Some pipelines also integrate independent leak detection systems, employing acoustic or chemical release measurements, or detecting pressure changes or slight alterations in mass balance, representing well-established and routine technologies.

5.5. Ships for CO2 transportation

The CO2 shipping market is currently in its early stages, and the emergence of potential trading patterns for LCO2 carriers is expected once the locations of sequestration and utilization projects become clearer. Quantitatively estimating how much LCO2 will be transported by shipping is challenging, but approximately 25-30% of global CCS facilities are situated in coastal areas, with some regions reaching up to 50%. It is anticipated that around 20-30% of captured CO2 will be transported by ship [12].

Liquid CO2 has a higher density than its gaseous form, making it more economically practical to transport in this state. Alongside pipelines, shipping will be crucial for moving LCO2, especially when sources and storage locations are too distant for pipeline infrastructure. Shipping provides a versatile solution, particularly for emitters located far from geological storage options, and offers the potential for earlier project development at lower costs compared to pipeline infrastructure.

The development of dedicated vessels is essential to enable LCO2 shipping, but relevant infrastructure must be concurrently developed. The entire chain should be well-defined as it affects CO2 conditioning requirements (pressure and temperature) and offload or injection conditions, with different equipment potentially required for each application.

Understanding the sources and destinations of captured carbon is pivotal for analyzing LCO2 trading routes. By pinpointing and prioritizing key trading routes, stakeholders can concentrate their efforts and resources on project implementation. Various categorization methods can be employed to organize emitters, end users, and sequestration sites:

1. Sector-Based: Grouping emitters by sectors such as power generation, industrial processes, transportation, buildings, agriculture, and waste management enables targeted strategies tailored to each sector's unique characteristics and challenges.

2. Regional: Analyzing carbon utilization and sequestration regionally helps identify areas with high post-capture carbon processing activity. Focusing CCUS efforts on regions with high emissions can significantly contribute to overall carbon mitigation, considering factors like population density, industrial concentration, and environmental vulnerabilities.

3. Fuel Source: Categorizing emitters based on their primary fuel sources (coal, natural gas, oil, biomass) offers insights into the carbon intensity of different energy systems and carbon utilization methods.

4. CCUS Infrastructure Availability: Sorting emitters based on their proximity to CO2 storage sites, existing pipeline networks, or potential utilization opportunities informs the feasibility of project development in these locations.

5.5.1. Design of CO2 carriers

The IMO implemented the International Gas Carrier Code to regulate the hull and tank structure design for ships transporting liquid gas like LPG carriers and LNG carriers [42]. Ships dedicated to carrying CO2 follow the standards outlined in this code. Liquid gas transport vessels typically employ three tank structures: pressure type, low temperature type, and semi-refrigerated type. The pressure type prevents cargo gas from boiling under atmospheric conditions, while the low temperature type keeps the cargo gas in a liquid state at a low temperature under atmospheric pressure. Larger LPG and LNG carriers predominantly utilize the low temperature type due to its suitability for mass transport. Semi-refrigerated tankers, including existing CO2 carriers, maintain conditions necessary to keep cargo gas as a liquid, accommodating a broader range of cargo conditions [43].

In *Figure 14* is depicted the CO2 phase diagram indicating that, at atmospheric pressure, CO2 exists as gas or solid depending on the temperature [1]. To sustain CO2 in liquid form, both low temperatures and pressures significantly higher than atmospheric pressure are required. Consequently, a CO2 cargo tank must be pressure-type or semi-refrigerated, with the semi-refrigerated type being favored by ship designers. These tanks are typically designed around temperatures ranging from -54 ºC per 6 bar to -50ºC per 7 bar, which aligns closely with the CO2 point. In a standard design, semi-refrigerated LPG carriers operate at approximately -50°C and 7 bar while transporting around 22,000 m^3 [43].

During transportation, there might be carbon dioxide leakage into the atmosphere. The overall atmospheric loss from ships accounts for about 3 to 4% per 1000 km, including boil-off and exhaust from ship engines. Implementing capture, liquefaction, and onshore recapture measures could potentially reduce this loss to 1 to 2% per 1000 km [44].

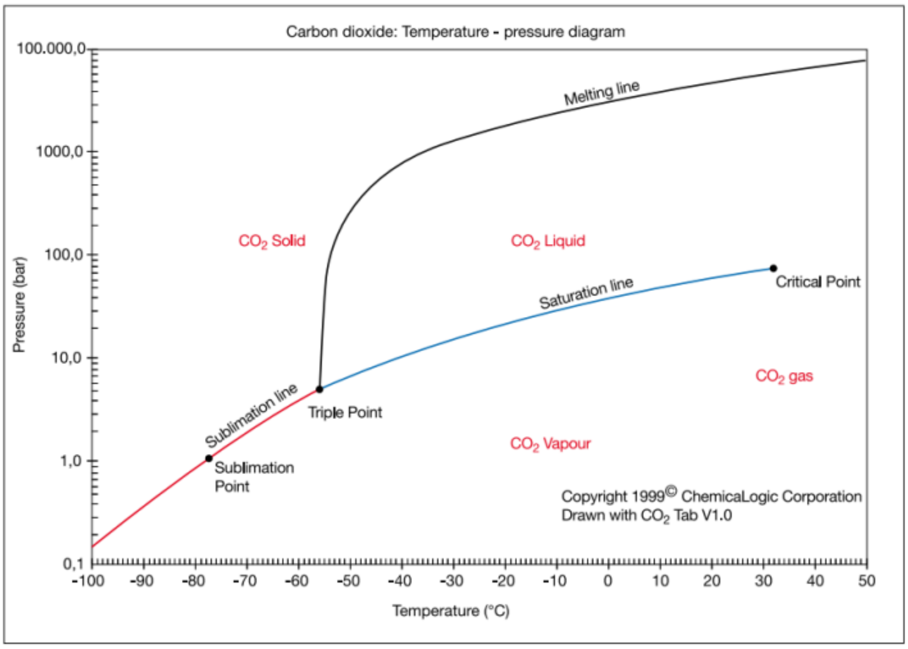

Figure 14: *CO2 phase diagram*

5.5.2. Construction and existing experience

Carbon dioxide tankers are built utilizing the identical technology employed in constructing current liquefied gas carriers. The largest LNG vessels, ranging from 120,000 m^3 to 270,000 m^3 hold potential relevance for extensive carbon dioxide shipping projects. However, shipbuilding firms underscore that repurposing LNG ships for liquid CO2 purposes entails substantial challenges and efforts, considering the limited additional value they offer, as a vessel's capital expenditure accounts for only 14% of the overall project cost [45]. Conversely, according to IEAGHG [46], converting between cargo inventories is seen as practically feasible for a singular conversion, presenting an opportunity to mitigate risks to project feasibility. Some technical limitations include the utilization of up to 60% of the tank capacity of LPG carriers for CO2 transport due to the difference in density between liquid CO2 and LPG (550–700 kg/m^3 for LPG and 1050–1200 kg/m^3 for liquid CO2). Additionally, large LPG and ethylene carriers have design pressures below 0.8 MPa, limiting their maximum storage pressures. However, smaller LPG carriers, engineered to operate between 1.1 and 1.9 MPa, might potentially accommodate 2,000–3,000 tons of CO2 at medium pressures, presenting an exception to this limitation. The IPCC [1] mentioned that carrier ships designed for carbon dioxide transportation, having a capacity of 22,000 m3 and capable of carrying up to 24,000 tons, are viable and do not present substantial new technical obstacles. Consequently, proposals have been made for larger vessels, sized at 40,000 m3 and 100,000 m3, equipped with pressurized onboard tanks . In summary, the knowledge gained from LNG and LPG shipbuilding endeavors can substantially aid in the creation of large CO2 carriers, and so far, no significant technical hurdles have been recognized. Potential designs can incorporate several concepts like close packing of vertical tanks, the X-bow design, as well as options involving insulation and double-walled cargo systems.

Various studies [1], [47], [48] have extensively examined potential configurations for carriers, aiming to identify optimal solutions. In Figure 15 is illustrated a possible carrier arrangement.

Research indicates that vessels transporting CO_2 at low pressure would resemble the designs of LPG vessels [47], [48], utilizing cylindrical tanks. These ships would transport carbon dioxide at its highest density, allowing for smaller vessel sizes. On the other hand, transportation at medium pressures would employ designs akin to carriers used in the commercial transportation of CO_2 for food and brewery industries. However, high-pressure solutions would entail small cylindrical bottles, similar to those used in natural gas pipe transport, necessitating approximately 700–900 cylinders per ship, thereby posing space-related challenges [47].

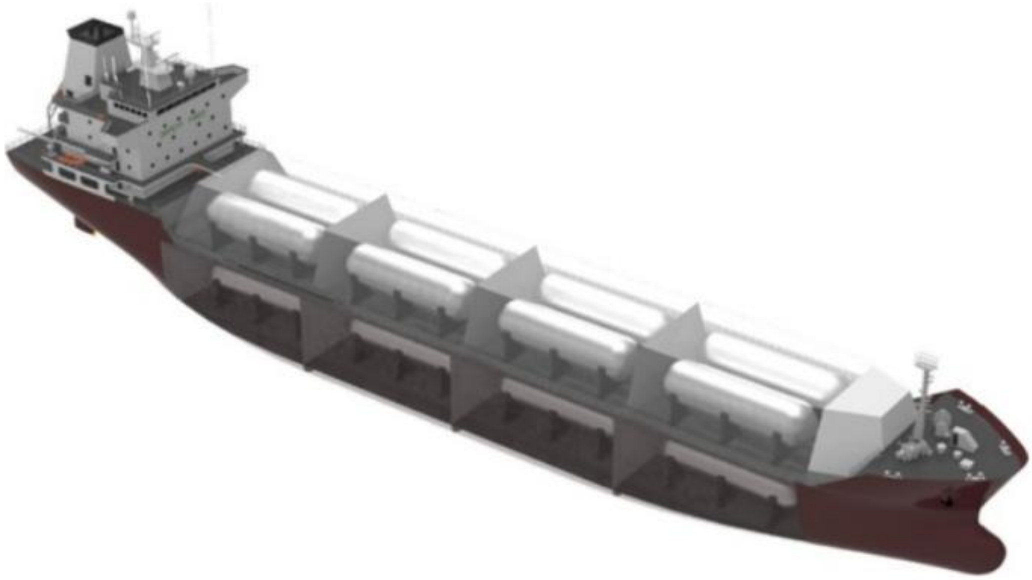

Figure 15: *Conceptual design of CO2 carrier*

It's important to highlight that CO_2 shipment has been utilized for more than three decades on a notably smaller scale within the brewery and food industries, operating under conditions of 1.4–1.7 MPa and 238–243 K. Nevertheless, the cumulative transportation volume across Europe reaches around 3 Mt of CO_2 annually [49]. These quantities, while substantial for industrial use, are notably lower compared to the volumes anticipated for CCUS projects.

5.5.3. Outlook for LCO2 carriers

The scale of the CO_2 and LCO_2 shipping markets remains uncertain. However, with a growing number of CCUS projects announced, expanding the quantity and capacity of LCO_2 carriers will be crucial to transport the substantial volumes of captured CO_2. Projections for the future fleet size are ambitious [12].

The utilization of CO_2 in industrial processes, including alternative fuel production, is still in its early stages, with wide-ranging predictions for market growth. However, the increasing demand for CO_2 utilization in industrial processes, driven by the energy transition, is expected to create additional demand and further expand the LCO_2 market.

According to a 2018 study by the European Zero Emission Technology and Innovation Platform (ETIP ZEP), approximately 600 vessels will be needed to support the growing

CCUS sector in Europe. While the study focused on the EU, LCO2 vessels will facilitate the development of the carbon value chain worldwide.

As vessel sizes increase, the required fleet size may decrease; however, the total capacity needed will follow the market trend, reflecting a greater demand for LCO2 carriers.

Estimating the size of the shipping market involves various assumptions and variables, including the total CCUS market size, project announcements and successes, economic conditions, and disruptions, making accurate predictions challenging. Nevertheless, as new projects are announced and source-to-sink matching improves, it becomes evident that a significant number of new vessels will be necessary to meet the demand for transport, storage, and utilization.

5.5.4. Operation

As per [43]:

- Loading
  Liquid CO2 is transferred from the temporary storage tank to the cargo tank using specialized pumps designed for high-pressure and low-temperature CO2 service. To prevent contamination and the formation of dry ice, the cargo tanks are initially filled and pressurized with gaseous CO2.
- Transportation to the Site
  The environmental heat affecting the cargo tank's walls results in CO2 boiling and increased tank pressure. Discharging the CO2 boil-off gas alongside the ship's engine exhaust is not hazardous, but it does release CO2 into the air. Achieving zero CO2 emissions during capture and storage can be accomplished by using a refrigeration unit to capture and liquefy the boil-off and exhaust CO2.
- Unloading
  At the destination site, liquid CO2 is unloaded from the cargo tanks. To prevent contamination, the volume previously occupied by liquid CO2 is replaced with dry gaseous CO2. This CO2 can potentially be recycled and liquefied when refilling the tank.
- Return to Port in Ballast and Dry-Docking
  Upon completion of a voyage, the CO2 tanker returns to port for the next trip. During repair or regular inspection in dock, the gas CO2 in the cargo tank is purged with air for safety. Before the first loading post-docking, cargo tanks are thoroughly dried, purged, and filled with CO2 gas.

Ships with similar construction, employing a combination of cooling and pressure, are presently utilized for transporting other industrial gases.

5.5.5. Safety

Tankers generally maintain higher standards compared to ships overall. Incidents leading to public concern primarily arise from stranding in tankers. However, this issue can be managed by meticulous navigation along specified routes and by adhering to stringent operational protocols. While LNG tankers possess potential hazards, they are meticulously designed and seem to be operated at extremely elevated standards. Notably, there have been no instances of accidental cargo loss from LNG ships. For instance, the LNG tanker El Paso Paul Kaiser encountered substantial hull damage after running aground at 17 knots in 1979. Despite this, the LNG tanks remained intact, and no cargo was lost. In contrast, carbon dioxide tankers and terminals carry significantly lower fire risks, but a risk of asphyxiation exists if a collision were to rupture a tank. However, such risks can be minimized by ensuring that the stringent construction and operational standards currently applied to LPG are similarly employed for carbon dioxide transport.

5.5.6. Cost of CO2 carriers

The expenses associated with a marine transport system encompass various cost components. Alongside investments in ships, there is a need for financial input into loading and unloading facilities, intermediate storage, and liquefaction units. Additional costs are attributed to operations, such as labor expenses, ship fuel and electricity costs, as well as harbor fees. Ensuring an optimal utilization of installations and ships within the transport cycle is vital. Extra facilities, including expanded storage requirements, must be established to proactively address potential disruptions in the transport system. Cost estimations show considerable variability due to the absence of previously constructed CO2 shipping chains at this scale. Anticipated economies of scale are expected to have a significant influence on the overall costs.

5.5.7. Components of the shipping chain

Dehydration

Drying the CO2 stream is essential to maintain the system's integrity, which involves preparing pipelines and vessels to minimize the risk of corrosion, hydrate formation, and freezing. However, there isn't a consensus on defining the acceptable moisture level, although the primary goal is to minimize or remove free water. It's important to note that water solubility varies based on stream conditions and impurity presence, requiring a comprehensive understanding of CO2 phase behavior during shipping conditions. Typically, the maximum acceptable water content in the system is considered to be between 10 to 50 ppmv or less than 60% of the dew point to prevent operational issues while handling liquid, cryogenic CO [48].

Illustrated in Figure 16, various dehydration techniques exist, contingent upon the desired stream specifications. However, vendors provide restricted information due to commercial sensitivity, thereby limiting available technical and economic data in literature, which also carries a certain level of uncertainty. Certain methods like refrigerant drying and compression with cooling fall short in attaining the necessary moisture levels for CO2 shipping. Nevertheless, they can serve as an initial step to diminish the workload demanded from the primary dehydration unit, consequently resulting in more cost-effective dehydration procedures.

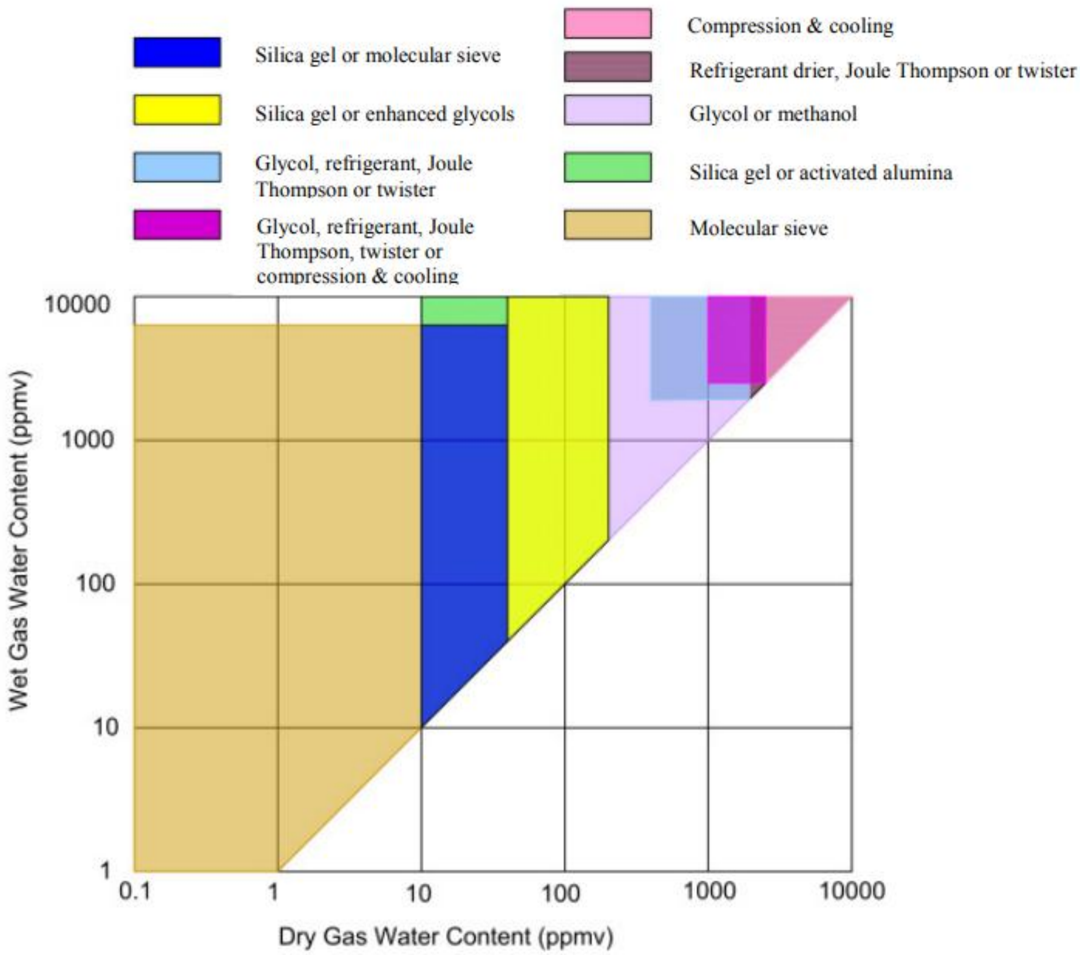

Figure 16: *Comparison of different dehydration technologies***[50]**

Under certain conditions, the existence of particular impurities poses an intolerable risk as they have the potential to damage the system or compromise the strict dehydration standards associated with their presence. In such instances, it becomes necessary to eliminate these impurities through an alternative process. Substances like amines, glycols, SOx, and NOx can significantly affect both the triethylene glycol (TEG) system and molecular sieve dehydration. However, their exact influences are not yet comprehensively understood, necessitating further research to evaluate their impact on these processes.

TEG absorption followed by desorption stands as a well-established method for gas dehydration, capable of achieving moisture levels in CO2 systems ranging from 30 to 150 parts per million by volume (ppmv). This outcome is contingent upon the process intensity and the concentrations of glycol [50]. However, when extremely low water content (around 1 ppmv) is necessary, employing solid adsorbents emerges as the most suitable option [51]. A comparison between these two technologies revealed that the capital expenditure for molecular sieve is 20% higher, while its energy consumption is 80% higher compared to TEG [48]. An ongoing limitation pertains to the absence of experimental validations concerning the impact of impurities on water solubility under conditions of liquid cryogenic environments.

Liquefaction

According to [52], liquefaction constitutes 77% of the energy demand in the transmission chain or 10% of total consumption in CCUS chains. Compressor energy demands and costs are significant, with capital expenditure influencing expenses. Liquefaction consumes 11–14% more energy compared to similar processes. Liquefaction methods include open- or closed-cycle refrigeration, as illustrated in Figure 17, chosen based on factors like cooling water temperature and refrigerant types [53]. Open-cycles involve pressurizing the stream and single or multi-stage expansion, while closed-cycles use external cooling agents like ammonia, propane, or R134a.

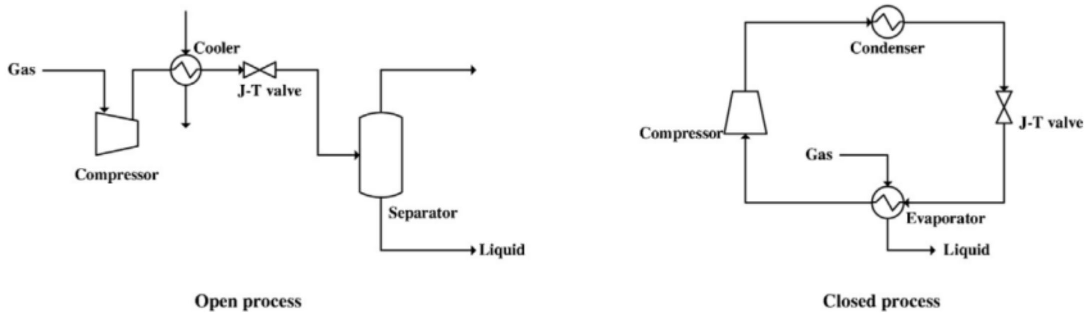

Figure 17: *CO2 open and closed liquefaction process* **[54]**

Propane and ethane are recommended for closed systems at 0.6 MPa, while propane and ammonia are suggested for higher pressures [55]. Optimal liquefaction occurs at 6 MPa and 295 K, although transportation near the triple point is favored for reduced costs and improved density [52], [56]. However, Nam et al. [57] and Seo et al. [55] found optimal liquefaction at different conditions, emphasizing the need to consider broader chain factors and project-specific variables. The energy demand of liquefaction varies based on disposal amount, desired conditions, and process type.

Internal CO2 systems are preferred for handling large volumes due to high expenses associated with heat exchanger installation and external refrigerants [56]. External refrigeration methods are economically beneficial at lower pressures, while higher pressures favor internal systems. Life cycle costs (LCCs) show similar patterns with liquefaction pressures. Changes in seawater temperatures (278 K to 303 K) significantly impact plant layout and energy consumption, with total compressor power varying between 90 and 140 kWh per ton of CO2 [58]. Zahid et al. [42] suggest operational expenses increase with liquefied pressures, while Seo et al. [55] found liquefaction power decreases with higher pressures (0.6–6.5 MPa) due to decreased refrigeration power outweighing increased compression power. Optimal liquefaction conditions are identified as 6.5 MPa and 298 K in terms of energy intensity.

However, the researchers determined that 4.5 MPa and 283 K represented the most Researchers found 4.5 MPa and 283 K to be the most economically efficient liquefaction condition, considering life-cycle costs, due to lower capital expenses compared to higher pressures (5.5–6.5 MPa) [55]. Despite the liquefaction process's significant impact on chain economics, optimal project conditions were identified as 1.5 MPa and 245 K , highlighting liquefaction process optimization's secondary role.

Energy efficiency within external refrigeration systems can be improved by incorporating multiple refrigeration stages with different temperatures. Propene, ammonia-propane, and ammonia are identified as the most energy-efficient refrigerants in 1-stage, 2-stage, and 3-stage closed cycles, respectively [59]. The impact of the working fluid is crucial in 1-stage systems but less so in 2-stage and 3-stage cycles.

Engel and Kather [60] proposed process optimization strategies, including energy recuperation using liquid expanders and phase separators instead of cascade heat exchangers, reducing energy intensity by 30–40%.

While valuable for comparing energy consumption, these studies lack cost analyses and consideration of discharge volume's influence on cycle selection. Increasing inlet pressure reduces energy demands and expenses for both types of liquefaction systems, particularly significant at higher pressures. For example, an inlet pressure of 1 MPa incurs approximately five times greater total costs compared to 10 MPa [52], [59].

Geographical placement of liquefaction facilities aims to minimize transmission expenses. Nam et al. [57]suggest locating plants near emission clusters and connecting them via pipelines to lower-emission areas. Impurities significantly affect CO_2-rich stream phase boundaries, influencing liquefaction conditions.

Deng et al. [61] found impurities can increase liquefaction costs by up to 34%, notably in external refrigeration systems using ammonia. Pre-combustion Rectisol streams with methanol, hydrogen, carbon monoxide, hydrogen sulfide, nitrogen, and water showed the highest cost increase. Post-combustion streams from cement plants with water and minimal nitrogen content saw slight cost increases, especially at delivery pressures below 3 MPa. Purity standards impact process costs due to safety considerations.

Engel and Kather [60] noted increased energy demand in external refrigeration systems with high-pressure pipelines, especially in oxy-fuel scenarios, even with additional refrigeration stages. This highlights the impact of impurities on liquefaction expenses.

Storage

After liquefaction, liquid carbon dioxide needs to be temporarily stored at its bubble point before being loaded onto batch shipping. Inside the tank, both liquid and gaseous phases coexist under identical pressure and temperature conditions. The storage tanks are typically filled to a maximum loading capacity ranging from 72% to 98%, determined by the chosen pressure. This intentional allowance leaves a portion of the tank volume for the gaseous phase, serving to prevent operational problems stemming from heat entry and sudden pressure fluctuations, which could potentially lead to catastrophic ship failure [7].

Developing suitable intermediate storage is crucial for enabling an efficient shipping schedule and ensuring a continuous discharge of liquid CO_2 from the liquefaction plant. Lower-pressure conditions necessitate more energy-intensive processes at the onshore liquefaction plant. However, they offer advantages in storage due to the higher density of liquid CO_2 near the triple point and reduced vessel thickness.

The observations of Nam et al. [57], regarding overall expenses related to storage tanks in proportion to storage pressure are illustrated in *Figure 18*.

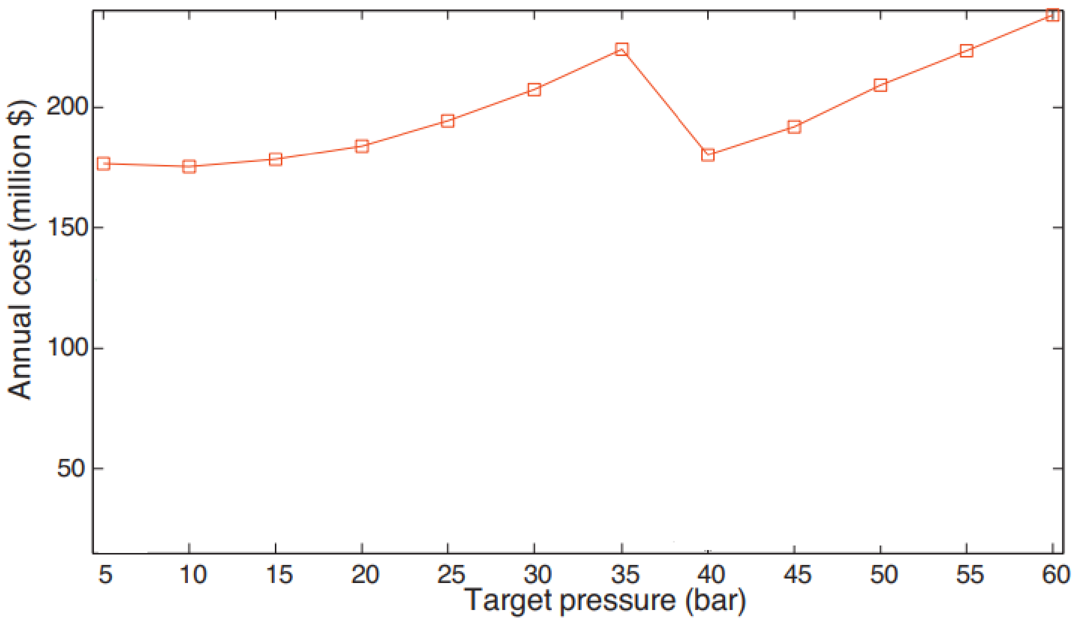

Figure 18: *Capital expenditure costs for onshore storage segment for 150,000 m^3*

Various designs such as cylindrical, bi-lobate, or semi-pressurized spherical tanks have been explored in existing literature, considering their use in other industrial applications [52],[62]. Manufacturers have indicated that spherical tanks, albeit more complex to construct, exhibit slightly lower overall installation costs. Additionally, suitable construction materials for these tanks include carbon steel, aluminum 1050, or 304L/316L stainless steel [62]. The maximum dimensions and thickness of walls in cylindrical storage tanks vary according to the chosen pressure levels. Larger ships typically demand thinner walls because of reduced dynamic pressure, stemming from the lesser acceleration of smaller ships. Also, Yoo et al. [63] have found that for smaller capacities up to 28,000 m^3, storage tanks can be positioned horizontally on the barge, while larger volumes would be better suited for a vertical orientation.

Loading

By utilizing expertise from the LNG and LPG industries, the technical execution of loading operations benefits significantly. Storage tanks are loaded continuously with liquefied CO2 from the liquefaction plant through a loading system employing high-pressure, low-temperature pumps. Liu et al. [64] proposed that pressurized gas phase carbon dioxide should fill cargo tanks to prevent air contamination and the formation of dry ice. They also recommended the use of articulated rigid loading arms, specifically designed for cryogenic liquids, over flexible cryogenic hoses due to their lower susceptibility to mechanical failure and leakage [65]. Nevertheless, both systems are currently employed for the loading of liquid CO2 [66]. During the loading process, the level inside the vessel gradually rises. To avoid excessive vessel pressure, it's necessary to constantly remove this vapor stream and redirect it back to the liquefaction unit throughout the operation. This is accomplished by employing a second parallel arm known as the CO2 vapor 'return line' [64].

Minimizing loading duration enhances delivery efficiency, reducing the need for a higher number of ships to unload a specific quantity and necessitating elevated flow rates. Nonetheless, it's crucial to consider the resulting pressure decrease [67]. Flow rates ranging between 2870 and 3530 metric tons per hour [42] are deemed suitable and would facilitate the loading of a 30,000 cubic meter ship within a 12-hour timeframe [68]. However, such flow rates would require a reliable Emergency Release System (ERS) to prevent CO_2 discharge in case of failure or unplanned disconnection of the loading arm from the ship [45].

Throughout this process, the tank's internal pressure decreases. To prevent freezing, it's essential to recycle the vapor created during the voyage in the cargo ship back to the storage tank. This action also helps control pressure escalation within the cargo tank. To prevent the formation of dry ice due to rapid depressurization of the system, maintaining suitable safety margins is imperative, although there is no universal agreement on their precise specifications. Standard measures for mitigating boil-off gas, such as insulating the entire loading system, must be executed, considering a greater amount of boil-off gas is produced during loading than during storage [42].

Offloading and injection

Following sea transport, CO_2 can be discharged either onshore at a port, particularly in port-to-port scenarios, or offshore before being directed to its final storage location. The former, pertaining to port-to-port shipping, is a well-established method with extensive expertise gained from the large-scale shipping of similar gases like LNG and LPG. It's presently employed in the food, beverage, and ammonia industries. Conversely, offshore unloading is yet to be validated and presents technical challenges in its implementation [46]. The selection of the appropriate unloading solution and associated infrastructure remains an unresolved matter and is anticipated to significantly impact vessel design, process equipment, and overall costing.

Transfer systems to the wellhead encompass auxiliary platforms facilitating equipment installation or direct injection from the ship. The former choice permits the creation of a consistent flow into the reservoir, providing temporary storage to counter adverse weather conditions. The continuous operation nature minimizes the risk of cyclic thermal and pressure loads on casings and non-metallic materials [67]. However, these systems come with the drawback of necessitating higher capital expenditure for their setup [46].

On the other hand, offloading via a flexible riser using a buoy for direct injection into the well implies the need for carbon dioxide conditioning, pressurization, and heating onboard the ship. To achieve this, the stream must be pumped to the appropriate pipeline pressure, ranging from 5 to 40 MPa [55], [46], and then heated to temperatures between 258 K and 293 K, contingent upon the specific site. This heating process can be accomplished using pre-warmed seawater or by utilizing waste heat available from the ship. Fluctuations in seawater temperature due to varying weather conditions may pose operational safety concerns, considering the requisite temperature and pressure conditions necessary to prevent hydrate formation. However, direct injection from the ship can be accomplished for several wells by integrating compression and heating equipment onboard. Offshore discharge is regarded as a new process within the CO_2 shipping chain, necessitating advanced technology to prevent the formation of dry ice during unloading and to establish agreement on the preferred system [69].

Before offloading, pre-conditioning involves raising the temperature of carbon dioxide to 273 K and compressing it to approximately 20–30 MPa, necessitating the installation of suitable heating and compression equipment on the vessel. The required thermal and electrical power for this operation can be obtained from seawater and the ship's engines [69]. In situations involving the transportation of substantial volumes over long distances using multiple vessels, employing a seabed pipeline as a heat exchanger might emerge as a favorable solution.

5.6. Intermediate CO2 storage

Regardless of the mode of transportation, intermediate storage plays a crucial role in the CO2 supply chain. Intermediate storage becomes particularly crucial when CO2 from multiple sources is being transported to either a single storage site or multiple sites [3]. There are two key advantages to having an intermediate storage tank. Firstly, it ensures a consistent flow of CO2 to the storage site, which is essential for safe transmission and uninterrupted operation of the storage facility. Secondly, in the event of routine or unexpected maintenance at the storage site, an intermediate tank serves as a buffer between the CO2 capture and storage processes. This buffer is especially critical when the downtime for injection at the storage site is short, typically less than 24 hours.

Liquid CO2 and its vapor coexist in equilibrium within the tank, with the tank's pressure determined solely by temperature. At the triple point of CO2, occurring at -56.6°C and 5.2 bar pressure, the liquid form can coexist with its vapor and solid phases. Below this point, equilibrium between vapor and solid dry ice is possible, but liquid CO2 cannot exist at atmospheric pressure. Venting the tank to atmospheric pressure in case of malfunction would result in a temperature drop to that of dry ice (-78.3°C), posing a risk of extreme stresses and potential fracture failure. This same phase change occurs in portable CO2 fire extinguishers, where high-pressure liquid CO2 expands adiabatically, converting to dry ice at -78.3°C. To ensure safe operation, tanks are designed to operate at a pressure of 6.5 bar, corresponding to a design temperature of -52°C.

A well-defined operational strategy is crucial for ensuring the safe operation of the tank throughout various stages. Tank operation typically involves three modes: loading, filled idle, and unloading.

During the loading mode, a continuous stream of liquefied CO2 from the liquefaction section enters the storage tank. As the liquid fills the tank, the level within the storage vessel increases, compressing the vapor phase above the liquid. To prevent excessive pressure buildup, this vapor must be removed from the tank. A continuous vapor stream is extracted from the storage tank and returned to the liquefaction plant while the tanks are being filled. Once the tank is filled with liquid CO2, it enters the filled idle mode until the unloading process begins.

The safe retention of liquid CO2 during the filled idle mode relies on several factors, including ambient temperature, tank insulation material, insulation thickness, and the level of filling in the tank. Depending on the shipping schedule, the tank transitions to the unloading mode when liquid CO2 is transferred from the storage tank to the ship. As liquid CO2 is removed from the storage tank, the pressure decreases, potentially leading to the solidification of the tank contents. To counteract this pressure reduction, CO_2 vapor is introduced to the tank to maintain pressure equilibrium. This vapor, generated during CO_2 loading onto the ship, is returned from the ship to the storage tanks. This process prevents pressure reduction in the tank and pressure buildup in the ship.

6. Case study data collection

In order to comply with the current regulations and to follow the trend towards decarbonization, industries are turning their attention to CCUS. Depending on the scale of the application, the CCUS chain can prove to be very expensive. Therefore the inquiry arises, whether so large an investment is worth it or if industries would be better off paying the carbon tax. Therefore, this segment of the thesis aims to construct a comprehensive argument, drawing upon published data and scholarly literature, to ascertain the optimal course of action from a techno-economic standpoint.

6.1. Methodology

This study will assess industries with significant CO2 emissions, focusing on a cement plant, a power plant, and a steel plant. Specifically, the study will analyze TITAN cement plant in Kamari, Greece; the PPC power plant in Aliveri, Greece; and the Hellenic Halyvourgia steel plant in Velestino, Greece. By gathering data on their 2022 CO2 emissions and considering each company's scope and relevant regulations, projections for their annual emissions from 2025 to 2050 were formulated.

The required size of the LCO2 carrier needed to transport accumulated daily captured CO2 to the Prinos injection point[2] in the North Aegean will be determined. By considering current new building prices, estimates will be made regarding the cost of the ship, including operational expenses. Subsequently, calculations will be conducted to ascertain the shipping company's necessary charges to transport CO2 from the plants.

Following the above assessment, the study will proceed to compute both fixed and variable costs for the plants, which include:

- The capital and operational expenses associated with implementing a CC system.
- The expenditure involved in constructing, operating, and maintaining a compressor and its accompanying pipeline for transporting captured CO2 to the nearest port.
- The building, operational, and maintenance costs linked to the liquefaction plant compressor.
- The expenses associated with liquefaction and storage of the LCO2.

After gathering data on the total cost of CCS, the final step involves calculating the cost for each plant due to carbon tax in a business-as-usual scenario, without the integration of any emission reduction systems.

This process will enable us to draw conclusions regarding the feasibility of carbon capture and identify the key factors influencing its viability.

[2] See relevant info in Appendix (11.2)

6.2. CO2 emissions estimation

6.2.1. TITAN Kamari cement plant

The data extracted from TITAN's annual report for 2022 reveals that the plant currently emits 619 kg of CO2 per tonne of cementitious product, with a target of reducing this figure to 50 kg CO2 per tonne by 2050 [70]. This reduction is projected to occur linearly, commencing in 2026, allowing time for the implementation of the CC system. Additionally, the annual clinker production is reported as 2.5 mtpa with a linear increase considered, reaching an estimated 110% of the 2022 capacity. The annual clinker production is assumed to remain constant until 2025. Finally, it is assumed that the reduction in CO2 emissions each year is due to the capture of the produced CO2. The CO2 production data is presented in Table 1.

Table 1: *TITAN Kamari CO2 production data*

TITAN cement Kamari								
Year	kg CO2/ t product	Annual t clinker	CO2 emitted			CO2 captured		
			t/yr	t/day	kg/s	t/yr	t/day	kg/s
2025	619	2500000	1547500	4239.7	49.1	0	0	0
2026	595.2	2510000	1493952	4093.0	47.4	53548	146.7	1.7
2027	571.4	2520000	1439928	3945.0	45.7	107572	294.7	3.4
2028	547.6	2530000	1385428	3795.7	43.9	162072	444.0	5.1
2029	523.8	2540000	1330452	3645.1	42.2	217048	594.7	6.9
2030	500	2550000	1275000	3493.2	40.4	272500	746.6	8.6
2031	477.5	2560000	1222400	3349.0	38.8	325100	890.7	10.3
2032	455	2570000	1169350	3203.7	37.1	378150	1036.0	12.0
2033	432.5	2580000	1115850	3057.1	35.4	431650	1182.6	13.7
2034	410	2590000	1061900	2909.3	33.7	485600	1330.4	15.4
2035	387.5	2600000	1007500	2760.3	31.9	540000	1479.5	17.1
2036	365	2610000	952650	2610.0	30.2	594850	1629.7	18.9
2037	342.5	2620000	897350	2458.5	28.5	650150	1781.2	20.6
2038	320	2630000	841600	2305.8	26.7	705900	1934.0	22.4
2039	297.5	2640000	785400	2151.8	24.9	762100	2087.9	24.2
2040	275	2650000	728750	1996.6	23.1	818750	2243.2	26.0
2041	252.5	2660000	671650	1840.1	21.3	875850	2399.6	27.8
2042	230	2670000	614100	1682.5	19.5	933400	2557.3	29.6
2043	207.5	2680000	556100	1523.6	17.6	991400	2716.2	31.4
2044	185	2690000	497650	1363.4	15.8	1049850	2876.3	33.3
2045	162.5	2700000	438750	1202.1	13.9	1108750	3037.7	35.2
2046	140	2710000	379400	1039.5	12.0	1168100	3200.3	37.0
2047	117.5	2720000	319600	875.6	10.1	1227900	3364.1	38.9
2048	95	2730000	259350	710.5	8.2	1288150	3529.2	40.8
2049	72.5	2740000	198650	544.2	6.3	1348850	3695.5	42.8
2050	50	2750000	137500	376.7	4.4	1410000	3863.0	44.7

6.2.2. PPC Aliveri power plant

The emissions data extracted from PPC's published reports indicates that the Aliveri power station generated an average of 50.4 kt of CO_2 per month, equivalent to 604.8 kt CO_2 annually [71]. It is noteworthy that PPC has already surpassed its 2030 emissions goals, and it is presumed that emissions will begin to decline from 2031 onwards. For the period 2025-2030, emissions are assumed to remain constant. By 2050, Net Zero emissions are anticipated, representing 10% of the initial value, adjusted to 11% to accommodate an increase in power output. All reductions are assumed to occur linearly, and the data is outlined in Table 2.

Table 2: *PPC Aliveri CO2 production data*

PPC power Aliveri						
Year	CO2 emitted			CO2 captured		
	t/yr	t/day	kg/s	t/yr	t/day	kg/s
2025	604800	1680	19.4	0	0	0
2026	604800	1680	19.4	0	0	0
2027	604800	1680	19.4	0	0	0
2028	604800	1680	19.4	0	0	0
2029	604800	1680	19.4	0	0	0
2030	604800	1680	19.4	0	0	0
2031	577886.4	1583.3	18.3	26913.6	96.7	1.12
2032	550972.8	1509.5	17.5	53827.2	170.5	1.97
2033	524059.2	1435.8	16.6	80740.8	244.2	2.83
2034	497145.6	1362.0	15.8	107654.4	318.0	3.68
2035	470232	1288.3	14.9	134568.0	391.7	4.53
2036	443318.4	1214.6	14.1	161481.6	465.4	5.39
2037	416404.8	1140.8	13.2	188395.2	539.2	6.24
2038	389491.2	1067.1	12.4	215308.8	612.9	7.09
2039	362577.6	993.4	11.5	242222.4	686.6	7.95
2040	335664	919.6	10.6	269136.0	760.4	8.80
2041	308750.4	845.9	9.8	296049.6	834.1	9.65
2042	281836.8	772.2	8.9	322963.2	907.8	10.51
2043	254923.2	698.4	8.1	349876.8	981.6	11.36
2044	228009.6	624.7	7.2	376790.4	1055.3	12.21
2045	201096	550.9	6.4	403704.0	1129.1	13.07
2046	174182.4	477.2	5.5	430617.6	1202.8	13.92
2047	147268.8	403.5	4.7	457531.2	1276.5	14.77
2048	120355.2	329.7	3.8	484444.8	1350.3	15.63
2049	93441.6	256.0	3.0	511358.4	1424.0	16.48
2050	66528	182.3	2.1	538272.0	1497.7	17.33

6.2.3. Hellenic Halyvourgia Velestino steel plant

According to the published report of Hellenic Halyvourgia, the manufacturing process of the Velestino plant generates 222.852 kg of CO_2 equivalent per tonne of steel product [72]. While no further public data is available, it is known that their furnaces utilize natural gas as fuel. By calculating the amount of fuel burned to produce one tonne of steel product, the CO_2 emissions per tonne were determined to be 147.67 kg. A linear reduction of 90% in CO_2 emissions by 2050 is assumed, alongside a 10% increase in annual steel production, initially at 700 ktpa. The CO_2 production data is presented in Table 3.

Table 3: *HH Velestino CO2 production data*

Hellenic Halyvourgia (HH) steel Velestino								
Year	kg CO2/ t product	Annual t steel	CO2 emitted			CO2 captured		
			t/yr	t/day	kg/s	t/yr	t/day	kg/s
2025	147.67	700000	103371.11	283.2	3.28	0	0	0
2026	142.36	702800	100048.35	274.1	3.17	3322.8	9.10	0.11
2027	137.04	705600	96695.82	264.9	3.07	6675.3	18.29	0.21
2028	131.72	708400	93313.51	255.7	2.96	10057.6	27.56	0.32
2029	126.41	711200	89901.44	246.3	2.85	13469.7	36.90	0.43
2030	121.09	714000	86459.60	236.9	2.74	16911.5	46.33	0.54
2031	115.78	716800	82987.98	227.4	2.63	20383.1	55.84	0.65
2032	110.46	719600	79486.59	217.8	2.52	23884.5	65.44	0.76
2033	105.14	722400	75955.44	208.1	2.41	27415.7	75.11	0.87
2034	99.83	725200	72394.51	198.3	2.30	30976.6	84.87	0.98
2035	94.51	728000	68803.81	188.5	2.18	34567.3	94.70	1.10
2036	89.19	730800	65183.34	178.6	2.07	38187.8	104.62	1.21
2037	83.88	733600	61533.10	168.6	1.95	41838.0	114.62	1.33
2038	78.56	736400	57853.09	158.5	1.83	45518.0	124.71	1.44
2039	73.25	739200	54143.31	148.3	1.72	49227.8	134.87	1.56
2040	67.93	742000	50403.75	138.1	1.60	52967.4	145.12	1.68
2041	62.61	744800	46634.43	127.8	1.48	56736.7	155.44	1.80
2042	57.30	747600	42835.33	117.4	1.36	60535.8	165.85	1.92
2043	51.98	750400	39006.47	106.9	1.24	64364.6	176.34	2.04
2044	46.66	753200	35147.83	96.3	1.11	68223.3	186.91	2.16
2045	41.35	756000	31259.42	85.6	0.99	72111.7	197.57	2.29
2046	36.03	758800	27341.24	74.9	0.87	76029.9	208.30	2.41
2047	30.72	761600	23393.30	64.1	0.74	79977.8	219.12	2.54
2048	25.40	764400	19415.58	53.2	0.62	83955.5	230.02	2.66
2049	20.08	767200	15408.08	42.2	0.49	87963.0	240.99	2.79
2050	14.77	770000	11370.82	31.2	0.36	92000.3	252.06	2.92

6.3. LCO2 carrier: Estimation of fixed and variable costs

6.3.1. Voyage calculation

To accurately estimate the required capacity of the LCO2 carrier, it is essential to define its intended route. The vessel will embark from the Elefsina port, where the gaseous CO2 from the cement plant will be transported via pipeline and liquefied. It will then proceed to Aliveri, where it will load LCO2 from the power plant, which is built by the water. Subsequently, the vessel will navigate through the Euboean Gulf to reach the Volos port, where the gaseous phase CO2 from the steel plant will be transported via pipeline and liquefied. Notably, the route through the Euboean Gulf is shorter than going around Euboea, although the ship must be appropriately sized to traverse the Evripos channel, which is 39 meters wide and 8.5 meters deep. Upon reaching its maximum capacity after loading the LCO2, the vessel will proceed to the Prinos injection point for unloading, before returning directly to Elefsina. The corresponding distances are shown in Table 4.

Table 4: *Route distances*

Section	km	nm
Elefsina-Aliveri	156	84.2
Aliveri-Volos	208	112.3
Volos-Prinos	286	154.4
Prinos-Elefsina	446	240.8
1 way	650	350.9
Round trip	1096	591.7

Assuming a moderate speed of 13 knots, the vessel requires approximately 46 hours to complete a round trip. Considering the loading and unloading phases, the total duration for a round trip is estimated to be 6 days. To ascertain the capacity and total number of vessels required, it is essential to understand the daily and annual quantity of LCO2 that will be captured, as well as the volume accumulated in the storage tanks during the 6-day period of a round trip. By consolidating the data from the preceding section for each plant and considering the density of LCO2 as 1150 kg/m^3, the necessary calculations are performed and presented in Table 5.

Table 5: *Total LCO2 in the tanks*

Total CO2 captured					
Year	**t/yr**	**m^3/yr**	**M m^3/yr**	**m^3/d**	**m^3 gathered in 6 days**
2025	0	0	0	0.0	0.0
2026	56871	49453	0.04945	135.5	812.9
2027	114247	99345	0.09935	272.2	1633.1
2028	172130	149678	0.14968	410.1	2460.5
2029	230518	200450	0.20045	549.2	3295.1
2030	289412	251662	0.25166	689.5	4136.9
2031	372397	323823	0.32382	887.2	5323.1

2032	455862	396401	0.39640	1086.0	6516.2
2033	539806	469397	0.46940	1286.0	7716.1
2034	624231	542810	0.54281	1487.1	8922.9
2035	709135	616639	0.61664	1689.4	10136.5
2036	794519	690886	0.69089	1892.8	11357.0
2037	880383	765551	0.76555	2097.4	12584.4
2038	966727	840632	0.84063	2303.1	13818.6
2039	1053550	916131	0.91613	2509.9	15059.7
2040	1140853	992046	0.99205	2717.9	16307.6
2041	1228636	1068379	1.06838	2927.1	17562.4
2042	1316899	1145130	1.14513	3137.3	18824.0
2043	1405641	1222297	1.22230	3348.8	20092.6
2044	1494864	1299881	1.29988	3561.3	21367.9
2045	1584566	1377883	1.37788	3775.0	22650.1
2046	1674747	1456302	1.45630	3989.9	23939.2
2047	1765409	1535138	1.53514	4205.9	25235.1
2048	1856550	1614392	1.61439	4423.0	26537.9
2049	1948171	1694062	1.69406	4641.3	27847.6
2050	2040272	1774150	1.77415	4860.7	29164.1

Initially, it is observed that even in 2050, when the captured CO2 reaches its maximum, the annual stored LCO2 (1.771 Mt p.a.) is within the 3 Mt p.a. limit set by the Prinos storage site [73].

It is presumed that the ship owner initiates the first order in 2023 with a delivery period of 3 years, enabling the ship to commence operations in 2026. An analysis of the data indicates that a vessel capacity of 6,000 m^3 is sufficient for transporting the accumulated LCO2 during the initial 5 years of its operation. Subsequently, a new vessel must be operational by 2032, followed by an addition every 5 years thereafter. An operational life of 25 years is assumed, and thus the first ship remains in operation for the entirety of 2050 and is scrapped in 2051.

All relevant data for voyage calculation is compiled in Table 6, where:

- "Days until cap of new ship is reached" indicates the number of days required for the newest ship to reach its maximum capacity, while the rest of the fleet undertakes continuous full-load trips.
- "Full ship #" denotes the count of ships conducting continuous full-load trips.
- "Left CO2 every 6 days" represents the volume of LCO2 in cubic meters accumulated every 6 days, determining the trip frequency of the newest ship.
- "Days at port before first departure" signifies the duration needed for the newest ship to initiate its first full-load route. After that, the ship remains at port for N-6 days before departing, as LCO2 accumulates while it is at sea.

Considering it's impossible for ships to operate routes continuously throughout the year, the newest ship, rather than staying at port, is presumed to undertake necessary routes while other vessels undergo maintenance. Ultimately, what's crucial is achieving the total number of trips each year, a goal easily met with this arrangement.

Table 6: *Voyage calculation*

Voyage calculation																	
Year	m^3/d	m^3 gathered in 6 days	# of operational ships	Full ship #	Left CO2 every 6 days	Days until cap of 1st ship's reached	Days at port before first departure					Number of trips /yr					Total trips/yr
							Ship 1	Ship 2	Ship 3	Ship 4	Ship 5	Ship 1	Ship 2	Ship 3	Ship 4	Ship 5	
2025	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	135.5	812.9	1	1	0	44	44	0	0	0	0	9	0	0	0	0	9
2027	272.2	1633.1	1	1	0	22	22	0	0	0	0	16	0	0	0	0	16
2028	410.1	2460.5	1	1	0	14	14	0	0	0	0	26	0	0	0	0	26
2029	549.2	3295.1	1	1	0	10	10	0	0	0	0	36	0	0	0	0	36
2030	689.5	4136.9	1	1	0	8	8	0	0	0	0	45	0	0	0	0	45
2031	887.2	5323.1	1	1	0	6	6	0	0	0	0	60	0	0	0	0	60
2032	1086.0	6516.2	2	1	516.2	69	0	69	0	0	0	60	5	0	0	0	65
2033	1286.0	7716.1	2	1	1716.1	20	0	20	0	0	0	60	18	0	0	0	78
2034	1487.1	8922.9	2	1	2922.9	12	0	12	0	0	0	60	30	0	0	0	90
2035	1689.4	10136.5	2	1	4136.5	8	0	8	0	0	0	60	45	0	0	0	105
2036	1892.8	11357.0	2	1	5357.0	6	0	6	0	0	0	60	60	0	0	0	120
2037	2097.4	12584.4	3	2	584.4	61	0	0	61	0	0	60	60	6	0	0	126
2038	2303.1	13818.6	3	2	1818.6	19	0	0	19	0	0	60	60	19	0	0	139
2039	2509.9	15059.7	3	2	3059.7	11	0	0	11	0	0	60	60	33	0	0	153
2040	2717.9	16307.6	3	2	4307.6	8	0	0	8	0	0	60	60	45	0	0	165
2041	2927.1	17562.4	3	2	5562.4	6	0	0	6	0	0	60	60	60	0	0	180
2042	3137.3	18824.0	4	3	824.0	43	0	0	0	43	0	60	60	60	9	0	189
2043	3348.8	20092.6	4	3	2092.6	17	0	0	0	17	0	60	60	60	21	0	201
2044	3561.3	21367.9	4	3	3367.9	10	0	0	0	10	0	60	60	60	36	0	216
2045	3775.0	22650.1	4	3	4650.1	7	0	0	0	7	0	60	60	60	52	0	232
2046	3989.9	23939.2	4	3	5939.2	6	0	0	0	6	0	60	60	60	60	0	240
2047	4205.9	25235.1	5	4	1235.1	29	0	0	0	0	29	60	60	60	60	15	255
2048	4423.0	26537.9	5	4	2537.9	14	0	0	0	0	14	60	60	60	60	26	266

2049	4641.3	27847.6	5	4	3847.6	9	0	0	0	0	9	60	60	60	60	40	280
2050	4860.7	29164.1	5	4	5164.1	6	0	0	0	0	6	60	60	60	60	60	300

6.4. CapEx estimation

To estimate the Capital Expenditure (CapEx) of the aforementioned ship, data was sourced from Clarkson's Ship Intelligence Weekly (Issue 1,588, 01-Sep-2023) [74]. Specifically, new building prices for tankers of different sizes were collected and are detailed in Table 7.

Table 7: *New building prices*

Tanker size	DWT	Price M USD
VLCC	320,000	126
Suez	157,000	85
Afra	115,000	68
MR	51,000	47

Additionally, data regarding the price of LCO2 carriers was extracted from the latest order of Capital Gas. An order for two LCO2 carriers was placed in 2024, valued at 76,250,000 USD each [75].

The trend line representing tanker prices, extracted from the data in Table x, is illustrated in Figure 19.

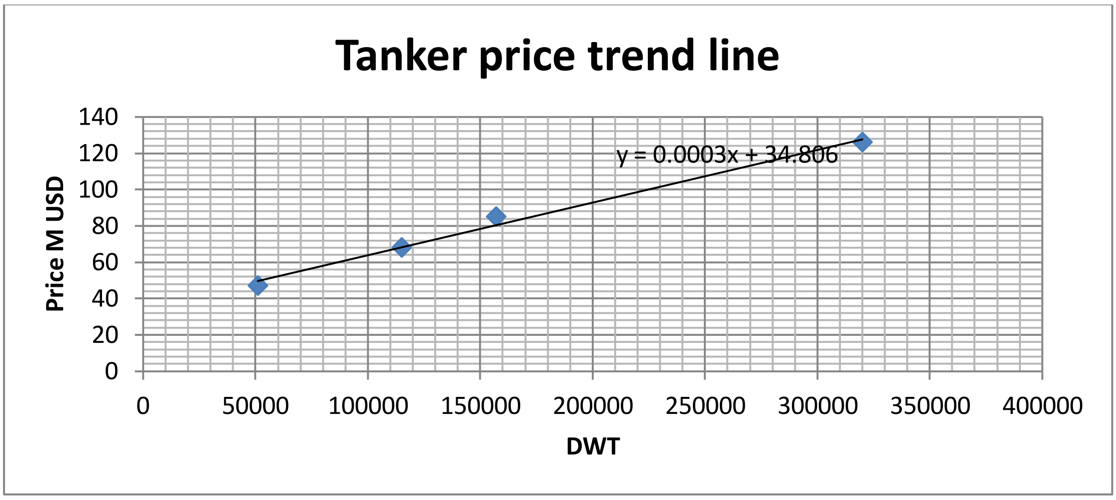

Figure 19: *Tanker price trend line*

Based on the trend line, a tanker valued at 76.25 million USD corresponds to a 138,147 DWT tanker. The capacity ratio between the studied LCO2 carrier and the Capital Gas LCO2 carrier, in terms of cubic meters, is 0.2728. Multiplying the corresponding tanker's DWT by the calculated ratio yields a DWT of 37,676. By inserting this value into the trend line, a rough estimation of the studied LCO2 carrier price is obtained. The actual price is estimated at 46.109 M USD (2023).

Taking into account a yearly inflation rate of 3%, the estimated prices for the subsequent orders are provided in Table 8. It's important to acknowledge that this estimation is inherently uncertain, as the price of ships in the upcoming years is determined by the market and remains unpredictable. Nonetheless, employing the inflation rate serves as the most suitable available method. To address the high costs calculated in the CapEx section, a balance will be sought in the maintenance, repair, and insurance cost estimation. Specifically, the price of only the first ordered ship will be used as a reference for all vessels.

Table 8: *CapEx of each ordered ship*

CapEx			
Ship #	**Year**	**M USD**	**M EUR**
1	2023	46.11	42.88
2	2029	55.06	51.20
3	2034	63.83	59.36
4	2039	73.99	68.81
5	2044	85.78	79.77

6.5. OpEx estimation

As mentioned in the literature review, LCO2 carriers are deemed similar to LPG carriers due to shared characteristics in cargo conditions. To acquire data on the principal dimensions and installed power of the specific LCO2 carrier under consideration, an LPG carrier with comparable capacity, namely Stealth Maritime's Gas Flawless, was examined. Relevant data from its specifications is compiled in Table 9.

Table 9: *Gas Flawless spec* **[76]**,**[77]**

Gas Flawless	
LBP (m)	95
B (m)	20
D (m)	8
T (m)	6
M/E MCR (kW)	3,900
Power per gen-set, 2 total (kW)	400
Capacity (m3)	6,400
GT (mt)	4779
Crew	14

In order to estimate the characteristics of the studied LCO2 carrier, considering its slightly smaller capacity, the following assumptions were made:

- A slight reduction in principal dimensions and Main Engine MCR and GT.
- Total crew and Genset numbers remain unchanged.

The estimated data is compiled in Table 10.

Table 10: *Studied LCO2 data*

Studied LCO2 carrier	
LBP (m)	92
B (m)	19
D (m)	8

T (m)	6
M/E nominal power (kW)	2775
Power per gen-set, 2 total (kW)	400
Vs (kn)	13
GT (mt)	4500
Crew	14
SFOC ME LSMGO g/kWh	178.0
SOC ME LO g/kWh	0.84
SOC ME CO g/kWh	0.1
SFOC DG LSMGO g/kWh	193.9
SOC DGLO g/kWh	0.70

Where,

- $SFOC_{ME/LSMGO}$ is the Specific Fuel Oil Consumption of the Main Engine while burning LMSGO,
- $SOC_{ME/LO}$ is the Specific Oil Consumption of the Main Engine's lube oil.
- $SOC_{ME/CO}$ is the Specific Oil Consumption of the Main Engine's cylinder oil.
- $SFOC_{DG/LSMGO}$ is the Specific Fuel Oil Consumption of the Genset while burning LMSGO,
- $SOC_{DG/LO}$ is the Specific Oil Consumption of the Genset's lube oil.

The selected Main Engine (M/E) for this ship is MAN B&W's 5S35MC7.1, with an MCR of 3,700 kW @ 173 rpm . The vessel's nominal power is calculated as 75% of the engine's MCR. Regarding the Gensets, 2 sets of Yanmar's 6NY16LSN were chosen, each capable of producing 400 kW.

All data concerning fuel and oil consumption was obtained from the respective project guides. It's essential to highlight that because the vessel's route falls within an Emission Control Area (ECA), the use of Low Sulfur Marine Gas Oil (LSMGO) is mandated for both the M/E and the Gensets. Consequently, SFOCs for each engine were adjusted to accommodate the use of LSMGO, as outlined below:

$$SFOC_{LSMGO} = SFOC \times \frac{CV_{SF}}{CV_{LSMGO}}$$

Where,

- $SFOC_{LSMGO}$ is the corrected SFOC while using LSMGO,
- $SFOC$ is the specific fuel oil consumption retrieved from the project manuals,
- CV_{SF} is the calorific value of the standard fuel, valued at 42,700 MJ/kg,
- CV_{LSMG} is the calorific value of LSMGO, valued at 42,800 MJ/kg.

The calculated consumptions are gathered in *Table 11*.

Table 11: *Daily consumptions*

Fuel & oil consumptions	
M/E fuel t/day	11.7739

M/E LO t/day	0.0559
M/E CO t/day	0.0067
Genset fuel t/day per engine	1.8485
Genset LO t/day per engine	0.0067
(200L of FW per person per day)	

Prices for the consumables were collected from [78] and [79], reflecting the latest available data, and are detailed in Table 12. It's important to mention that the salary is presented as a daily expense for ease of calculation.

Table 12: *Consumable prices*

Consumables prices	
LSMGO $/mt	860
LO $/mt	1500
CO $/mt	2000
FW $/T	0.5
Food USD/person per day	10
Mean Salary USD/person/day	100

With all the provided data, we can now estimate the cost per trip. However, it's essential to first describe the trip in detail.

The voyage commences from Elefsina port, where the vessel loads the LCO2 from TITAN cement. It then proceeds to Aliveri to load the LCO2 from the Aliveri power plant, followed by a journey to Volos to load the LCO2 from HH steel. Subsequently, the vessel heads north to the Prinos injection point to unload before returning to Elefsina. The vessel is at sea for 2 days, with the Main Engine running at 75% MCR and one Genset operational. The loading phase is estimated to last 2 days, during which the Main Engine is offline and one Genset is running. Similarly, the unloading phase is expected to last 2 days, with the Main Engine offline and both Gensets operational.

The total cost per trip is ***42,492.18 USD.***

Regarding the estimation of annual maintenance, repairs, insurance, and port charges costs, the literature provides the following information [79]:

- Maintenance & repair cost: 0.5% $CapEx$ (USD)
- Insurance: 1% $CapEx$ (USD)
- Port charges: $(\# \; of \; ports/trip) \cdot 0.86 \cdot GT * (\# \; of \; trips/year)$ (USD)

With all of the above data, the OpEx of each ship is easily calculated and gathered in Table 13. It is noted that each round trip includes two port charges, one in Elefsina and one in Volos. The PPC power plant is by the water and is equipped with its own dock.

***Table 13:** Annual OpEx of each ship*

Year	Ship 1	Ship 2	Ship 3	Ship 4	Ship 5
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	947760	0	0	0	0
2027	1326283	0	0	0	0
2028	1867028	0	0	0	0
2029	2407774	0	0	0	0
2030	2894446	0	0	0	0
2031	3705564	0	0	0	0
2032	3705564	731462	0	0	0
2033	3705564	1434432	0	0	0
2034	3705564	2083327	0	0	0
2035	3705564	2894446	0	0	0
2036	3705564	3705564	0	0	0
2037	3705564	3705564	785537	0	0
2038	3705564	3705564	1488506	0	0
2039	3705564	3705564	2245551	0	0
2040	3705564	3705564	2894446	0	0
2041	3705564	3705564	3705564	0	0
2042	3705564	3705564	3705564	947760	0
2043	3705564	3705564	3705564	1596655	0
2044	3705564	3705564	3705564	2407774	0
2045	3705564	3705564	3705564	3272968	0
2046	3705564	3705564	3705564	3705564	0
2047	3705564	3705564	3705564	3705564	1272208
2048	3705564	3705564	3705564	3705564	1867028
2049	3705564	3705564	3705564	3705564	2624073
2050	3705564	3705564	3705564	3705564	3705564

At this point, it is noted that for the ships that remain in operation beyond 2050, the OpEx are considered fixed until the end of their lifetime.

6.6. Freight rate estimation

To determine the freight rate for each ship, it's crucial to establish parameters regarding the loan that the ship owner obtains, and also describe the economic lifetime of the ship.

The ship owner initiates the order for the vessel, scheduled for delivery in 3 years' time. They allocate 25% of their own capital, while securing the remaining 75% through a loan carrying an 8% interest rate. This loan is amortized annually, commencing at the end of the first year and extending over a repayment period of 17 years. OpEx are detailed above. A return of 10% is anticipated, and the economic lifespan of the ship is estimated at 25 years (with an overall lifespan of 28 years), factoring in a scrap value equivalent to 2.5% of the initial purchase price. A tax rate of 25% is assumed. Each vessel is chartered on a per-trip basis, with six total dry dockings scheduled; every 5 years for the first 3 and then in a “per 3-2-3 years” pattern, with incurring expenses equating to 1.4%, 1.6%, 1.8%, for the first three and 2% of the vessel's price for the rest [80]. Notably, no dry docking occurs in the final year, as the vessel is scrapped. Income and outflow sources are collected below.

Income sources:

- The scrap value influx occurs singularly, during the final year of the ship's operational lifespan.
- The vessel begins generating income upon delivery, in this study the total necessary annual income is referred to as R.

Outflow sources:

- The equity capital outflow occurs once at the inception of the ship's economic life.
- The loan installments completed over a 17-year period and disbursed annually.
- Annual OpEx
- Annual tax payments.
- Dry docking expenses.

For reference, the aforementioned financial factors are gathered in Table 14.

Table 14: *Financial factors*

Interest rate % (r)	8
Return % (i)	10
Equity %	25
Loan %	75
Tax %	25

The calculation of the minimum required freight rate is done by zeroing the net present value (NPV) for the expected lifespan of the vessel. The general formula is:

$$NPV = \sum_{n=1}^{28} \frac{INCOME_n - CHARGES_n}{(1+r)^n}$$

The above formula in the present problem took the following form:

$$\begin{aligned} NPV = \sum_{n=4}^{28} \frac{R}{(1+r)^n} + \frac{A_{28}}{(1+r)^{28}} \\ - \sum_{n=1}^{17} \frac{D}{(1+r)^n} \\ - \sum_{n=4}^{28} \frac{OpEx}{(1+r)^n} - I_{equity} - \sum_{n=4}^{28} 0.25 \cdot \frac{R - OpEx - D_p}{(1+r)^n} - \frac{Dock_9}{(1+r)^9} \\ - \frac{Dock_{14}}{(1+r)^{14}} - \frac{Dock_{19}}{(1+r)^{19}} \frac{Dock_{22}}{-(1+r)^{22}} - \frac{Dock_{24}}{(1+r)^{24}} - \frac{Dock_{27}}{(1+r)^{27}} \end{aligned}$$

Where:

- R ($): Annual revenue from transportation
- A_{28} in $: The value of the vessel after 28 years
- D ($): Loan installment from financing
- OpEx ($): Operational expenses of the vessel
- $Dock_9$ ($): Dry docking cost after 9 years (5 years after commence of operation)
- $Dock_{14}$ ($): Dry docking after 14 years
- $Dock_{19}$ ($): Dry docking after 19 years
- $Dock_{22}$ ($): Dry docking after 22 years
- $Dock_{24}$ ($): Dry docking after 24 years
- $Dock_{27}$ ($): Dry docking after 27 years
- $D_p = (C - A_{28})/24$ ($): Linear annual depreciation
- I_{equity} ($): Equity capital

The annual loan installment for each vessel was determined using the subsequent formula:

$$D_i = \frac{r \cdot (1+r)^{17}}{(1+r)^{17} - 1} \; (USD)$$

The requisite data for computing the NPV of each vessel was compiled in Table 15.

Table 15: *: Ship financial data*

(USD)	Ship 1	Ship 2	Ship 3	Ship 4	Ship 5
CapEx	46108909	55056449	63825514	73991263	85776153
Equity	11527227	13764112	15956378	18497816	21444038
Loan	34581682	41292337	47869135	55493447	64332115
Loan payment	3791170	4526855	5247866	6083715	7052693
Scrap value	1152723	1376411	1595638	1849782	2144404
D_P	1873174	2236668	2592911	3005895	3484656
DD_1	645525	770790	893557	1035878	1200866
DD_2	737743	880903	1021208	1183860	1372418
DD_3	829960	991016	1148859	1331843	1543971
$DD_{4/5/6}$	922178	1101129	1276510	1479825	1715523

The annual required revenue for each ship is presented in Table 16.

Table 16: *Annual revenue per ship*

(USD)	Ship 1	Ship 2	Ship 3	Ship 4	Ship 5
R	12228309.3	10218803	13467501.6	15229980	17296958.3

Finally, by combining the annual calculated revenue of the shipping company with the captured CO2 quantity, we are able to extract a price for the shipping of LCO2. The final cost data of shipping LCO2 is gathered in Table 17.

Table 17: *LCO2 shipping cost*

Year	Total R USD	m3 CO2 moved	USD/m3 CO2	EUR/m3	USD/t CO2	EUR/t CO2
2025	0	0	0	0	0	0
2026	12228309	49453	247.272	229.963	215.019	199.968
2027	12228309	99345	123.089	114.473	107.034	99.541
2028	12228309	149678	81.697	75.979	71.041	66.068
2029	12228309	200450	61.004	56.734	53.047	49.334
2030	12228309	251662	48.590	45.189	42.252	39.295
2031	12228309	323823	37.762	35.119	32.837	30.538
2032	22447112	396401	56.627	52.663	49.241	45.794
2033	22447112	469397	47.821	44.474	41.584	38.673
2034	22447112	542810	41.354	38.459	35.960	33.442
2035	22447112	616639	36.402	33.854	31.654	29.438
2036	22447112	690886	32.490	30.216	28.252	26.275
2037	35914614	765551	46.913	43.630	40.794	37.939
2038	35914614	840632	42.723	39.733	37.151	34.550
2039	35914614	916131	39.203	36.458	34.089	31.703
2040	35914614	992046	36.203	33.668	31.480	29.277
2041	35914614	1068379	33.616	31.263	29.231	27.185
2042	51144594	1145130	44.663	41.536	38.837	36.119
2043	51144594	1222297	41.843	38.914	36.385	33.838
2044	51144594	1299881	39.346	36.591	34.214	31.819
2045	51144594	1377883	37.118	34.520	32.277	30.017
2046	51144594	1456302	35.119	32.661	30.539	28.401
2047	68441552	1535138	44.583	41.462	38.768	36.054
2048	68441552	1614392	42.395	39.427	36.865	34.284
2049	68441552	1694062	40.401	37.573	35.131	32.672
2050	68441552	1774150	38.577	35.877	33.545	31.197

6.7. Carbon capture ashore: Estimation of fixed and variable costs for each factory

In this section, we will estimate the total cost of carbon capture for each plant. To accomplish this, we will begin by detailing the entire carbon capture process and outlining the associated equipment.

The initial component is the carbon capture plant, where a conventional monoethanolamine (MEA) plant is considered for each facility. Subsequently, the captured CO2 is pressurized for transportation via pipeline to the nearest port. Upon arrival, it undergoes further pressurization and processing in the liquefaction plant. Finally, the liquefied LCO2 is stored in appropriate storage tanks. All costs are provided in EUR, consistent with the corresponding literature. Final prices can and will be readily converted to USD for the purpose of integration with shipping costs.

6.7.1. Carbon capture plant

Due to limited literature on carbon capture plant prices, projections were made using available data. For estimating the cost of the carbon capture plant at each examined facility, insights were drawn from a study analyzing an MEA CC plant in Norway [81]. The reported CapEx for the plant amounted to 119 million EUR. Although detailed capacity data was lacking, the study provided information on the flue gas flow rate (257,100 m3/hr) and the use of natural gas. Considering that natural gas flue gas typically contains around 10% CO2 by volume, the estimated CO2 flow rate was derived as 25,710 m^3/hr [82]. Additionally, the report specified flue gas conditions at 1 bar pressure and 80°C, leading to a calculated gas density of 1.52 kg/m^3.

Next, the "0.6 rule" is applied, which estimates the cost C_1 of an installation of a given capacity V_1, using a known installation's cost C_2 and capacity V_2 as a reference. This rule is often used in engineering projects [83]. The formula is expressed as:

$$C_1 = C_2 \cdot \left(\frac{V_1}{V_2}\right)^{0.6}$$

At this point, it's crucial to clarify that all the necessary equipment in the carbon capture chain is designed and constructed to handle the maximum capacity of captured CO2 projected for 2050.

The data regarding the installation cost of the plant for each factory is compiled in *Table 18*.

Table 18: *Carbon capture plant cost estimation*

	Capacity (kg/s)	Plant cost (M EUR)
Literature	10.86	119
TITAN	44.7	278.233
PPC	17.33	157.584
HH	2.92	54.094

6.7.2. Capture cost

Based on the literature [4], the average variable costs for cement, power, and steel plants, powered by natural gas, are calculated and gathered in Table 19:

Table 19: *Variable costs of carbon capture for each factory*

	TITAN	PPC	HH
EUR/t CO2 captured	7.548	21.030	40.128

By considering the annual tons of CO2 captured by each factory, the variable cost of the capture plant can be readily computed and presented in Table 20:

Table 20: *Annual variable capture cost for each plant (EUR/yr)*

Year	TITAN	PPC	HH
2025	0	0	0

2026	404180	0	133336
2027	811953	0	267866
2028	1223319	0	403591
2029	1638278	0	540511
2030	2056830	0	678625
2031	2453855	565993	817934
2032	2854276	1131986	958438
2033	3258094	1697979	1100136
2034	3665309	2263972	1243029
2035	4075920	2829965	1387117
2036	4489928	3395958	1532399
2037	4907332	3961951	1678876
2038	5328133	4527944	1826547
2039	5752331	5093937	1975413
2040	6179925	5659930	2125474
2041	6610916	6225923	2276729
2042	7045303	6791916	2429180
2043	7483087	7357909	2582824
2044	7924268	7923902	2737664
2045	8368845	8489895	2893698
2046	8816819	9055888	3050926
2047	9268189	9621881	3209350
2048	9722956	10187874	3368968
2049	10181120	10753867	3529780
2050	10642680	11319860	3691787

6.7.3. Gas compressor

As per the literature [84], the captured CO2 leaves the carbon capture plant at ambient pressure and a temperature of 313K. However, to traverse the pipeline, it must be pressurized to a final pressure of 2MPa. Employing a 3-stage compression cycle, the total power and cost of the compressor were determined as per below.

Initially, the Compression ratio (CR) was calculated with the following formula:

$$CR = \left(\frac{P_{final}}{P_{initial}}\right)^{\frac{1}{N_{stage}}} = \left(\frac{2}{0.1}\right)^{\frac{1}{3}} = 2.714$$

The power required for each compression stage was calculated as per below:

$$W_{s,i} = \left(\frac{Q_i \cdot Z_s \cdot R \cdot T_{in}}{M \cdot \eta_{is}}\right) \cdot \left(\frac{k_s}{k_s - 1}\right) \cdot \left[(CR)^{\frac{k_s - 1}{k_s}} - 1\right]$$

For all stages [84]:

- $R = 8.314 \frac{kJ}{mol \cdot K}$

- $M = 44.01 \frac{kg}{kmol}$
- $T_{in} = 313\ K$
- $\eta_{is} = 0.75$
- Q_i is the CO2 flow rate for plant i, in kg/s

For stage 1:

- $Z_s = 0.995$
- $k_s = 1.277$

For stage 2:

- $Z_s = 0.985$
- $k_s = 1.286$

For stage 3:

- $Z_s = 0.970$
- $k_s = 1.309$

Regarding the CapEx of each compressor, the following formula was used:

$$C_{comp,i} = m_i \cdot \left[(0.13 \cdot 10^6) \cdot (m_i)^{-0.71} + (1.4 \cdot 10^6) \cdot (m_i)^{-0.6} \cdot \ln\left(\frac{P_{final}}{P_{initial}}\right)\right] \cdot 0.93\ [EUR]$$

Data regarding the cost of the compressors are gathered in *Table 21*.

Table 21: *Total power and capital cost of the gas compressors*

	TITAN	PPC	HH
W1 (kW)	3912	1517	255
W2 (kW)	3884	1506	253
W3 (kW)	3805	1493	240
Wt (kW)	11647	4516	749
EUR	18199195	12485567	6150510

As for the operational and maintenance costs of each compressor, the literature suggests the following formula:

$$OpEx_i \left(\frac{EUR}{yr}\right) = 0.04 \cdot C_{comp,i}$$

Since the above formula corresponds to the full capacity of the pipeline in 2050, a reduction in O&M costs was proposed, starting at 1% of the compressor's cost with a linear increase leading to the aforementioned 4%.

All relevant data is gathered in Table 22.

Table 22: *Operational & Maintenance costs of the gas compressors*

Year	EUR/yr		
	TITAN	PPC	HH
2025	195690	134253	66135
2026	216981	148860	73330
2027	238272	163467	80525
2028	259564	178074	87721
2029	280855	192680	94916
2030	302146	207287	102112
2031	323437	221894	109307
2032	344728	236501	116503
2033	366019	251108	123698
2034	387310	265714	130893
2035	408601	280321	138089
2036	429892	294928	145284
2037	451183	309535	152480
2038	472475	324141	159675
2039	493766	338748	166871
2040	515057	353355	174066
2041	536348	367962	181261
2042	557639	382569	188457
2043	578930	397175	195652
2044	600221	411782	202848
2045	621512	426389	210043
2046	642803	440996	217239
2047	664094	455602	224434
2048	685386	470209	231630
2049	706677	484816	238825
2050	727968	499423	246020

6.7.4. Pipeline cost

To calculate the cost of each pipeline, the required length of each pipeline must be determined. It's worth noting that for the PPC plant, which is situated by the water, using literature to compute pipeline costs isn't feasible due to its very short length. Consequently, a fixed price will be assumed for PPC's pipeline to facilitate gas transfer to the liquefaction plant.

Analyzing the geographic location of each plant provides essential data on the pipeline's length and the plant's altitude, both crucial for subsequent calculations. It was found:

- $L_{TITAN} = 10\ km$
- $L_{HH} = 12\ km$

Where L_i is the distance of the plant I from the nearest port, and

- $\Delta z_{TITAN} = 200\ m$
- $\Delta z_{HH} = 50\ m$

Where Δz_i is the altitude of plant i.

Additionally, after reviewing [85], a gas speed of 5 m/s was assumed within the pipeline. The velocity value should fall within the range 5-20 m/s.

In terms of the final pressure, literature suggests an expected value of 1.5 MPa. Without boosters, the specific pressure loss for the TITAN and the HH pipelines was calculated to be 57.620 Pa/m and 43.254 Pa/m, respectively. These values fall within the expected limit set by the literature. Therefore, no boosters are required for the installation.

Having the assumed speed and the flow rate of the gas, we are able to calculate the diameter of the pipeline through the formula:

$$D_i = \sqrt{\frac{4 \cdot Q_i}{\pi \cdot u}}$$

Where:

- Q_i is the flow rate of the gas in m^3/s
- υ is the velocity of the gas, which was assumed to be 5 m/s

The conversion from mass to volume regarding the flow rate was achieved by dividing the mass value by the density of the gas, which is 38.84 kg/m3 under conditions of 2 MPa pressure and 80°C.

It is important to note that the chosen nominal diameters of the pipes are the adjacent smaller values from the list of nominal diameters [86]. This decision was made to prevent an increase in diameter, which would cause the speed to drop and fall out of the recommended range. Conversely, a slight decrease in diameter ensures that the velocity remains safely within the specified range.[1]

The results are gathered in Table 23:

Table 23: *Diameter of pipelines*

	TITAN	PPC	HH
D_{calc} (m)	0.5381	0.3387	0.1352
D_{final} (m)	0.508	0.32385	0.127
υ (m/s)	5.61	5.47	5.66

The cost estimation for the materials of the pipeline denoted as I, is calculated as per the following formula [87]:

$$I_i = C \cdot D_i \cdot L_i / 1000$$

Where,

- C is a constant value used in the linear cost model, which is evaluated at 1200 EUR/m^2 in Greek terrain,
- D_i is the final outer diameter of the pipeline in m,
- L_i is the length of the pipeline in km.

According to the literature, the breakdown of costs is as follows: 35% for materials as estimated above, 38% for labor, 7% for acquiring rights of way (ROW), and 20% for miscellaneous expenses. The cost breakdown for the cement and steel plants is provided in Table 24, along with the fixed price assumption for the power plant's pipeline.

Table 24: *Pipeline fixed costs*

(EUR)			
Plant	**TITAN**	**PPC**	**HH**
Materials	6096000		1828800
Labor	6618514		1985554
Miscellaneous	3483429		1045029
ROW	1219200		365760
Total	17417143	200000	5225143

The literature also specifies that the operational and maintenance costs are calculated using the following formula:

$$O\&M_i = 7000 \cdot L_i$$

Given that all estimates have been based on the 2050 gas flow rate, it is prudent to adjust the operational and maintenance costs for previous years. For the cement and steel plants, a slight reduction is assumed initially, followed by a linear increase in costs until 2050. Conversely, for the power plant, where the pipeline length is negligible, a small fixed cost is assumed. The variable costs of the pipeline are gathered in Table 25.

Table 25: *Pipeline annual variable costs*

Year	O&M (EUR/yr)		
2025	50000	5000	55000
2026	50800	5000	56160
2027	51600	5000	57320
2028	52400	5000	58480
2029	53200	5000	59640
2030	54000	5000	60800
2031	54800	5000	61960
2032	55600	5000	63120
2033	56400	5000	64280
2034	57200	5000	65440
2035	58000	5000	66600
2036	58800	5000	67760
2037	59600	5000	68920

2038	60400	5000	70080
2039	61200	5000	71240
2040	62000	5000	72400
2041	62800	5000	73560
2042	63600	5000	74720
2043	64400	5000	75880
2044	65200	5000	77040
2045	66000	5000	78200
2046	66800	5000	79360
2047	67600	5000	80520
2048	68400	5000	81680
2049	69200	5000	82840
2050	70000	5000	84000

6.7.5. Liquefaction system

The proposed liquefaction system is an open cycle with a valve and a turbine [88]. In this design, the process begins with the captured CO2 gas being cooled using cooling water to lower its temperature. The cooled gas then undergoes compression in two stages. The first stage compressor increases the pressure of the gas to the transport pressure, followed by the removal of impurities like H_2S.

Subsequently, the gas is further compressed in the second compressor stage to raise the pressure to 85 bar. In the cooler of the second compressor stage, the gas is liquefied using cooling water. The liquefied CO2 is then further cooled through heat exchange with a cold recycle stream to enhance liquefaction efficiency.

The high-pressure liquefied CO2 is depressurized to the transport pressure through a valve, adjusting the pressure for transportation. The liquid and vapor CO2 are separated in a flash column, with the vapor CO2 recycled back into the system. The liquid CO2 is directed to a CO stripper where CO is removed from the liquid.

In this design, the expansion of the CO2 gas is achieved using a turbine instead of a compressor. The whole liquefaction process is shown in Figure 20.

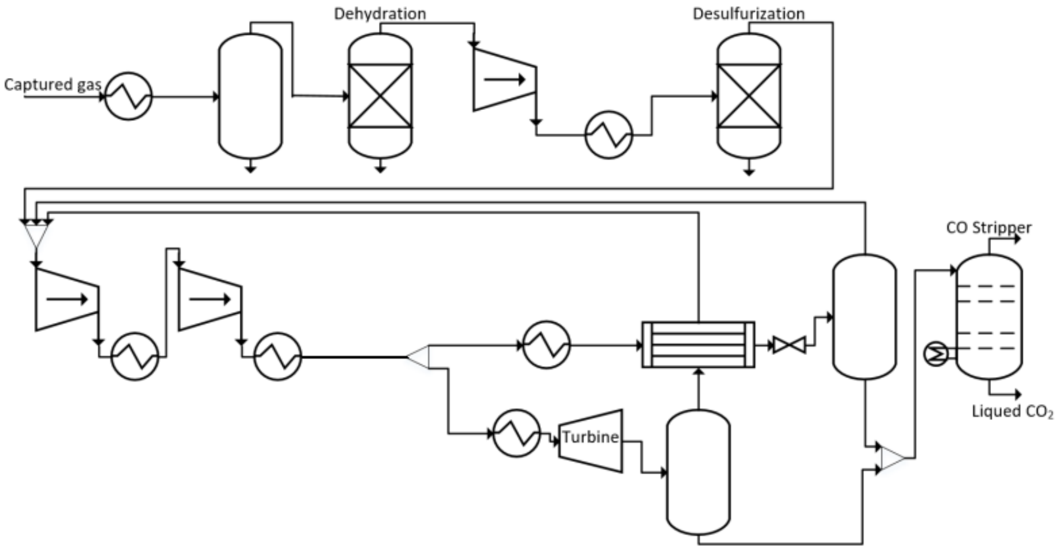

Figure 20: *Chosen liquefaction process*

The means to estimate the compressor cost were described in the gas compressor section. For the liquefaction system, we assume an initial pressure of 1.5 MPa for the cement and the steel plant and 2 MPa for the power plant, since there is no pressure drop due to the short length of the pipeline. So, collectively for the compressor [88]:

- $P_f = 8.5\ Mpa$
- $CR_{TITAN,HH} = 2.3804$
- $CR_{PPC} = 2.062$
- $Z_1 = 0.935$
- $Z_2 = 0.845$
- $k_1 = 1.379$
- $k_2 = 1.704$

The calculations as previously described yielded the results presented in Table 26.

Table 26: *Fixed liquefaction compressor costs*

	TITAN	PPC	HH
W1 (kW)	3229.0	1023.1	210.7
W2 (kW)	3107.9	974.1	202.8
Wt (kW)	6336.9	1997.2	413.5
M USD	11495685	6638070	3904000
M EUR	10690987	6173405	3630720

Similar to the approach taken for the gas compressor, the operational and maintenance costs were estimated accordingly. The results are compiled in Table 27.

Table 27: *Annual operational & maintenance costs for the liquefaction system compressor*

Year	EUR/yr		
2025	106910	61734	36307
2026	119739	69142	40664
2027	132568	76550	45021
2028	145397	83958	49378
2029	158227	91366	53735
2030	171056	98774	58092
2031	183885	106183	62448
2032	196714	113591	66805
2033	209543	120999	71162
2034	222373	128407	75519
2035	235202	135815	79876
2036	248031	143223	84233
2037	260860	150631	88590
2038	273689	158039	92946
2039	286518	165447	97303
2040	299348	172855	101660
2041	312177	180263	106017
2042	325006	187672	110374
2043	337835	195080	114731
2044	350664	202488	119088
2045	363494	209896	123444
2046	376323	217304	127801
2047	389152	224712	132158
2048	401981	232120	136515
2049	414810	239528	140872
2050	427639	246936	145229

For the liquefaction unit equipment, we employ the "0.6 rule," previously utilized in another section. The plant examined in the literature had an inlet stream flow rate of 123.125 t CO_2/hr, translating to a flow rate of 34.2 kg CO_2/s. Table 28 presents the fixed costs of the equipment for the reference unit, along with the adjusted costs for all plants following the application of the rule.

Table 28: *Costs of liquefaction unit*

(EUR)	Reference unit	TITAN	PPC	HH
Heat exchanger	6045000	7099333	4020890	1380256
VLE separators	372000	436882	247439	84939
CO stripper	232500	273051	154650	53087
Turbine	930000	1092205	618598	212347
Total	7579500	8901472	5041577	1730629

Regarding operational costs, literature indicates a figure of 6.65 EUR /t CO_2 liquefied for similar post-combustion systems [3]. The annual liquefaction costs are detailed in Table 29.

Table 29: *Annual liquefaction costs*

Year	TITAN	PPC	HH
2025	0	0	0
2026	356067	0	22095
2027	715300	0	44387
2028	1077698	0	66878
2029	1443261	0	89567
2030	1811989	0	112453
2031	2161752	178962	135538
2032	2514508	357924	158820
2033	2870257	536886	182301
2034	3228997	715848	205979
2035	3590730	894810	229855
2036	3955455	1073772	253930
2037	4323172	1252734	278202
2038	4693882	1431696	302672
2039	5067584	1610658	327340
2040	5444278	1789620	352206
2041	5823965	1968582	377271
2042	6206643	2147544	402533
2043	6592314	2326506	427993
2044	6980978	2505468	453651
2045	7372633	2684430	479507
2046	7767281	2863392	505561
2047	8164921	3042354	531812
2048	8565553	3221316	558262
2049	8969178	3400278	584910
2050	9375795	3579240	611756

6.7.6. Intermediate storage and injection

Following liquefaction, the LCO2 necessitates intermediate storage tanks before loading onto the vessel. Considering the maximum daily LCO2 output of each factory, it was determined that storage tanks of 4000 m^3, 1500 m^3, and 250 m^3, respectively, are necessary for the cement, power, and steel plants.

Since data on industrial-sized LCO2 tanks was unavailable, LPG storage tanks were deemed a reliable reference due to similarities in storage conditions. However, information on the cost of tanks of this size was scarce, necessitating certain assumptions. After reviewing various suppliers, it was determined that the larger tank of 4000 m3 has an estimated cost of 4 million USD, the 2500 m^3 tank has an estimated cost of 2 million USD, and the smaller tank of 250 m3 has an estimated cost of 300k USD.

At present, the public is not privy to the specific pricing details concerning the Prinos injection point. However, existing literature indicates that for storage facilities of comparable capacity (3 Mt/yr), the estimated cost stands at approximately 8 USD per ton of CO2 [89].

For a comprehensive overview of the annual storage expenses associated with each factory, refer to Table 30.

Table 30: *Annual injection cost for each factory (EUR)*

Year	TITAN	PPC	HH
2025	0	0	0
2026	398397	0	24721
2027	800336	0	49664
2028	1205816	0	74829
2029	1614837	0	100214
2030	2027400	0	125822
2031	2418744	200237	151650
2032	2813436	400474	177701
2033	3211476	600712	203973
2034	3612864	800949	230466
2035	4017600	1001186	257181
2036	4425684	1201423	284117
2037	4837116	1401660	311275
2038	5251896	1601897	338654
2039	5670024	1802135	366255
2040	6091500	2002372	394077
2041	6516324	2202609	422121
2042	6944496	2402846	450386
2043	7376016	2603083	478873
2044	7810884	2803321	507581
2045	8249100	3003558	536511
2046	8690664	3203795	565662
2047	9135576	3404032	595035
2048	9583836	3604269	624629
2049	10035444	3804506	654445
2050	10490400	4004744	684482

6.8. Total variable cost of Carbon Capture

All the above estimations have been gathered to compile the total annual cost of all variable components in Table 31.

Table 31: *Annual cost of carbon capture*

	Annual cost in M EUR		
Year	**TITAN**	**PPC**	**HH**
2025	0.353	0.201	0.157
2026	12.254	0.223	1.015
2027	13.458	0.245	1.209
2028	14.672	0.267	1.405
2029	15.896	0.289	1.603

2030	17.131	0.311	1.802
2031	17.524	2.100	1.961
2032	26.096	4.710	2.635
2033	26.665	6.335	2.806
2034	27.414	7.780	2.987
2035	28.283	9.109	3.176
2036	29.237	10.357	3.371
2037	39.505	14.229	4.166
2038	40.469	15.488	4.363
2039	41.492	16.695	4.565
2040	42.563	17.863	4.771
2041	43.673	18.998	4.979
2042	54.856	23.583	5.842
2043	55.980	24.724	6.054
2044	57.137	25.841	6.269
2045	58.323	26.937	6.486
2046	59.536	28.016	6.706
2047	71.961	33.250	7.657
2048	73.192	34.330	7.880
2049	74.446	35.395	8.106
2050	75.722	36.448	8.333

6.9. Total fixed cost of Carbon Capture

All estimations concerning the fixed costs of the case are compiled in Table 32 for each plant.

Table 32: *Total fixed cost*

EUR	TITAN	PPC	HH
Carbon capture plant	278232954	157584391	54094188
Gas compressor	18199195	12485567	6150510
Pipeline	17417143	200000	5225143
Liquefaction plant compressor	10690987	6173405	3630720
Liquefaction plant	8901472	5041577	1730629
LCO2 tanks	4000000	2000000	300000
Total	337441750	183484940	71131190

7. Running the cases

7.1. Cases description

Having collected all necessary data regarding the fixed and variable costs for each plant concerning carbon capture, it is crucial to assess whether this significant investment will prove beneficial. Three key factors define the financial feasibility of the process:

- The CapEx financing parameters

- The price of the carbon tax

- The EU funding

Three different cases will be examined, in order to draw conclusions:

<u>Case 1</u>

The price of the carbon tax will be considered fixed at 60 EUR/t CO_2 throughout the period of 2025-2050, which is the carbon price as of February 17th, 2024 [90]. Regarding the CapEx, two scenarios will be examined: in the first, the entire cost of the CapEx will burden the factories. In the second, EU funding will be secured. It's worth noting that the carbon price assumption does not reflect reality, as it is expected to rise over time, a topic to be explored further in this thesis. Nonetheless, this worst-case scenario will be studied to provide a preliminary estimate of the cost difference between the installation and a business-as-usual scenario.

<u>Case 2</u>

The price of the carbon tax will follow the expected price that the literature suggests. As for the CapEx, two scenarios will be examined, as described in case 1.

<u>Case 3</u>

In order to examine in what degree CCS is the most viable solution, halved emissions will be assumed for each factory. This assumption is made considering the factories have implemented other means of reducing emissions as well, like green fuels. Both the worst case (low fixed carbon price, no EU funding) and the realistic (expected carbon price, EU funding) scenario will be run.

7.2. Case 1

First and foremost, it is imperative to calculate the cost that burdens each factory due to the carbon tax in a business-as-usual scenario. The aforementioned increase in factory productivity was taken into account, with no implemented means of reducing emissions. Also, the carbon price was considered fixed at 60 EUR/t CO_2. The results are shown in Table 33.

Table 33: *Business-as-usual cost due to carbon tax*

Year	Annual cost (EUR)			Carbon price
	TITAN	PPC	HH	
2025	92850000	36288000	6202267	60
2026	93221400	36288000	6227076	60
2027	93592800	36288000	6251885	60
2028	93964200	36288000	6276694	60
2029	94335600	36288000	6301503	60
2030	94707000	36288000	6326312	60
2031	95078400	36469440	6351121	60
2032	95449800	36650880	6375930	60
2033	95821200	36832320	6400739	60
2034	96192600	37013760	6425548	60
2035	96564000	37195200	6450357	60
2036	96935400	37376640	6475166	60
2037	97306800	37558080	6499975	60
2038	97678200	37739520	6524784	60
2039	98049600	37920960	6549593	60
2040	98421000	38102400	6574402	60
2041	98792400	38283840	6599212	60
2042	99163800	38465280	6624021	60
2043	99535200	38646720	6648830	60
2044	99906600	38828160	6673639	60
2045	100278000	39009600	6698448	60
2046	100649400	39191040	6723257	60
2047	101020800	39372480	6748066	60
2048	101392200	39553920	6772875	60
2049	101763600	39735360	6797684	60
2050	102135000	39916800	6822493	60

Next, a financing plan was established to manage the CapEx of each factory in the CC scenario. An equity capital of 25% is assumed, with the remainder financed through a loan at an 8% interest rate, repaid annually over a period of 15 years. The relevant numbers are shown in Table 34.

Table 34: *Financing plan for each factory*

(EUR)	TITAN	PPC	HH
Total CapEx	337441750	183484940	71131190
EU Funding	0	0	0
Equity capital	84360438	45871235	17782797
Loan	253081313	137613705	53348392
Loan installments	29567375	16077347	6232668

By combining the OpEx with the financing of the CapEx and the taxed emissions of each factory, the total annual cost for each component was calculated and displayed in Table 35.

Table 35: *Annual cost of Carbon Capture for each factory (EUR)*

Year	TITAN	PPC	HH
2025	207130412	98437569	30375174
2026	131458542	52588349	13250321
2027	129420945	52610364	13243669
2028	127365087	52632379	13236845
2029	125290969	52654393	13229848
2030	123198590	52676408	13222679
2031	120435818	52850692	13173249
2032	125824707	53846163	13637022
2033	123183267	53856052	13595784
2034	120695081	53686199	13563599
2035	118300168	53399831	13537220
2036	115963712	53033647	13514766
2037	122913482	55290614	14090275
2038	120532826	54934496	14067085
2039	118183573	54527079	14046353
2040	86287527	38002426	7794826
2041	83971592	37523499	7777417
2042	91701736	40492714	8412233
2043	89345842	40019370	8394329
2044	86995974	39521480	8377510
2045	84648328	39003054	8361571
2046	82299877	38467281	8346347
2047	91136648	42085691	9060454
2048	88752513	41550981	9044980
2049	86365047	41001590	9030085
2050	83972438	40439425	9015669

By subtracting the cost of the CCS scenario from the cost of the business-as-usual scenario, the annual gain for each factory was returned in Table 36.

Table 36: *Annual gain with CCS implementation (EUR)*

Year	TITAN	PPC	HH
2025	-114280412	-62149569	-24172907
2026	-38237142	-16300349	-7023245
2027	-35828145	-16322364	-6991784
2028	-33400887	-16344379	-6960151
2029	-30955369	-16366393	-6928345
2030	-28491590	-16388408	-6896368
2031	-25357418	-16381252	-6822128
2032	-30374907	-17195283	-7261092
2033	-27362067	-17023732	-7195045
2034	-24502481	-16672439	-7138050
2035	-21736168	-16204631	-7086863

2036	-19028312	-15657007	-7039600
2037	-25606682	-17732534	-7590300
2038	-22854626	-17194976	-7542300
2039	-20133973	-16606119	-7496759
2040	12133473	99974	-1220424
2041	14820808	760341	-1178205
2042	7462064	-2027434	-1788213
2043	10189358	-1372650	-1745499
2044	12910626	-693320	-1703871
2045	15629672	6546	-1663123
2046	18349523	723759	-1623090
2047	9884152	-2713211	-2312388
2048	12639687	-1997061	-2272105
2049	15398553	-1266230	-2232400
2050	18162562	-522625	-2193176
	Total gain by 2050 (M EUR)		
	-350.570	**-303.541**	**-144.077**

To determine the portion of the total CapEx covered by the EU in funded projects, an analysis of the ET) funded projects list was conducted. Specifically, it was discovered that the TITAN cement plant in Kamari is slated to receive 234 million EUR in funding for the installation of a carbon capture plant. This funding constitutes 84% of the total CapEx. Assuming a similar funding arrangement, which is described in Table 37 and a financing strategy for the remaining portion as described earlier, the annual gain was computed and is outlined in Table 38.

Table 37: *Financing plant for each factory with EU funding*

(EUR)	TITAN	PPC	HH
Total CapEx	337441750	183484940	71131190
EU Funding	283451070	154127350	59750199
Equity capital	13497670	7339398	2845248
Loan	40493010	22018193	8535743
Loan installments	4730780	2572375	997227

Table 38: *Annual gain with CCS implementation and EU funding (EUR)*

Year	TITAN	PPC	HH
2025	-18581050	-10112761	-3999916
2026	-13400547	-2795378	-1787804
2027	-10991550	-2817393	-1756343
2028	-8564292	-2839407	-1724710
2029	-6118774	-2861422	-1692904
2030	-3654996	-2883437	-1660926
2031	-520823	-2876281	-1586687
2032	-5538313	-3690312	-2025651
2033	-2525473	-3518761	-1959604

2034	334113	-3167468	-1902609
2035	3100427	-2699660	-1851422
2036	5808282	-2152035	-1804158
2037	-770087	-4227563	-2354859
2038	1981969	-3690004	-2306859
2039	4702621	-3101148	-2261318
2040	12133473	99974	-1220424
2041	14820808	760341	-1178205
2042	7462064	-2027434	-1788213
2043	10189358	-1372650	-1745499
2044	12910626	-693320	-1703871
2045	15629672	6546	-1663123
2046	18349523	723759	-1623090
2047	9884152	-2713211	-2312388
2048	12639687	-1997061	-2272105
2049	15398553	-1266230	-2232400
2050	18162562	-522625	-2193176
	Total gain by 2050 (M EUR)		
	92.842	**-62.435**	**-50.608**

7.3. Case 2

The literature outlines that the predicted trajectory of the carbon tax price under the EU ETS until 2050 follows a pattern of stability, increase, and potential challenges [91], [92]. By 2030, the carbon price is expected to remain relatively stable at around 70-75 EUR /t CO2, supported by other decarbonization policies alongside the EU ETS. This period of stability is crucial for maintaining a consistent price signal and ensuring investments in clean technologies continue.

However, in the 2030s, the carbon price is projected to increase, reaching approximately 130 EUR/t CO2 by 2040. This rise is driven by a growing decarbonization context and the need for stronger abatement efforts from power generators and industry players. The Market Stability Reserve (MSR) plays a significant role in maintaining price stability up to 2035 by absorbing permits and preventing an oversupply that could lead to price drops.

Beyond 2030, as the cap on emissions continues to decrease, significant decarbonization efforts are required. The market becomes tense, and without action by the MSR, the carbon price is forecasted to surge to over 500 EUR/t CO2 in 2044 if the current market design is not updated. This highlights the importance of revising the EU ETS system to align with very low greenhouse gas emissions in the 2040-2050 period. For the purposes of this study, a cap of 400 EUR /t CO2 will be established in 2044, maintaining this fixed limit until 2050. Furthermore, linear progression will be presumed between the specified milestones. The cost in the business-as-usual scenario is presented in Table 39.

Table 39: *Business-as-usual cost due to carbon tax*

Year	Annual cost (EUR)			Carbon price
	TITAN	PPC	HH	
2025	92850000	36288000	6202267	60
2026	97882470	38102400	6538429	63
2027	102952080	39916800	6877073	66
2028	108058830	41731200	7218198	69
2029	113202720	43545600	7561803	72
2030	118383750	45360000	7907890	75
2031	127563520	48929832	8521087	80.5
2032	136811380	52532928	9138833	86
2033	146127330	56169288	9761127	91.5
2034	155511370	59838912	10387969	97
2035	164963500	63541800	11019360	102.5
2036	174483720	67277952	11655299	108
2037	184072030	71047368	12295787	113.5
2038	193728430	74850048	12940822	119
2039	203452920	78685992	13590406	124.5
2040	213245500	82555200	14244539	130
2041	325191650	126017640	21722405	197.5
2042	437973450	169888320	29256091	265
2043	551590900	214167240	36845598	332.5
2044	666044000	258854400	44490925	400
2045	668520000	260064000	44656319	400
2046	670996000	261273600	44821713	400
2047	673472000	262483200	44987106	400
2048	675948000	263692800	45152500	400
2049	678424000	264902400	45317894	400
2050	680900000	266112000	45483288	400

If the CapEx of the CCS systems is financed without any funding from the EU, following the same approach outlined in *Case 1* (25% equity, 75% loan, 8% interest, 15-year payoff period), the annual gain was computed and is presented in Table 40.

Table 40: *Annual gain with CCS implementation (EUR)*

Year	TITAN	PPC	HH
2025	-114280412	-62149569	-24172907
2026	-38057928	-16300349	-7012036
2027	-35108433	-16322364	-6946771
2028	-31775109	-16344379	-6858469
2029	-28053673	-16366393	-6746862
2030	-23939840	-16388408	-6611684
2031	-17931498	-15767532	-6353415
2032	-19416427	-15638528	-6564841
2033	-12205212	-14194629	-6227253

2034	-4474011	-12241675	-5854226
2035	3844582	-9842891	-5442022
2036	12792808	-7034978	-4988267
2037	13150323	-6520903	-5086510
2038	23541204	-3064428	-4539594
2039	34611047	772658	-3948190
2040	75945473	21056294	2921450
2041	148868183	46040961	7532754
2042	220381214	71619062	12062615
2043	310707808	104681298	17822006
2044	409847026	141809656	24163152
2045	434696672	152688306	25666544
2046	459700123	163584303	27179343
2047	473671352	170326117	27972932
2048	499016487	181221051	29506225
2049	524517953	192130666	31049061
2050	550177562	203053055	32601539
	Total gain by 2050 M EUR		
	3870.227	**1220.806**	**131.125**

For an EU funding scenario, similar to Case 1, the results are gathered in Table 41.

Table 41: *Annual gain with CCS implementation and EU funding (EUR)*

Year	TITAN	PPC	HH
2025	-18581050	-10112761	-3999916
2026	-13221333	-2795378	-1776595
2027	-10271838	-2817393	-1711329
2028	-6938514	-2839407	-1623027
2029	-3217078	-2861422	-1511421
2030	896754	-2883437	-1376242
2031	6905097	-2262560	-1117974
2032	5420167	-2133557	-1329399
2033	12631382	-689658	-991812
2034	20362583	1263297	-618784
2035	28681177	3662080	-206581
2036	37629402	6469993	247174
2037	37986918	6984069	148932
2038	48377799	10440543	695847
2039	59447641	14277629	1287252
2040	75945473	21056294	2921450
2041	148868183	46040961	7532754
2042	220381214	71619062	12062615
2043	310707808	104681298	17822006
2044	409847026	141809656	24163152
2045	434696672	152688306	25666544

2046	459700123	163584303	27179343
2047	473671352	170326117	27972932
2048	499016487	181221051	29506225
2049	524517953	192130666	31049061
2050	550177562	203053055	32601539
	Total gain by 2050 M EUR		
	4313.639	**1461.913**	**224.594**

7.4. Case 3

In the worst case scenario, with the fixed low carbon price and no EU funding, the business-as-usual cost is shown in Table 42.

Table 42: *Business-as-usual annual cost*

Year	Annual cost (EUR)			Carbon price
	TITAN	PPC	HH	
2025	92850000	36288000	6202267	60
2026	93221400	36288000	6227076	60
2027	93592800	36288000	6251885	60
2028	93964200	36288000	6276694	60
2029	94335600	36288000	6301503	60
2030	94707000	36288000	6326312	60
2031	95078400	36469440	6351121	60
2032	95449800	36650880	6375930	60
2033	95821200	36832320	6400739	60
2034	96192600	37013760	6425548	60
2035	96564000	37195200	6450357	60
2036	96935400	37376640	6475166	60
2037	97306800	37558080	6499975	60
2038	97678200	37739520	6524784	60
2039	98049600	37920960	6549593	60
2040	98421000	38102400	6574402	60
2041	98792400	38283840	6599212	60
2042	99163800	38465280	6624021	60
2043	99535200	38646720	6648830	60
2044	99906600	38828160	6673639	60
2045	100278000	39009600	6698448	60
2046	100649400	39191040	6723257	60
2047	101020800	39372480	6748066	60
2048	101392200	39553920	6772875	60
2049	101763600	39735360	6797684	60
2050	102135000	39916800	6822493	60

The annual gain of this scenario is shown in Table 43. A financing plan similar to the previous cases was considered.

Table 43: *Annual gain with CCS implementation, no EU funding and halved emissions*

Year	TITAN	PPC	HH
2025	-32451054	-23397453	-13841368
2026	16411267	7232973	-2034242
2027	17792227	7216352	-2009700
2028	19182317	7199731	-1985072
2029	20581537	7183110	-1960358
2030	21989886	7166489	-1935557
2031	24123335	6844226	-1868582
2032	18096491	5700778	-2314895
2033	20091344	5542910	-2256283
2034	21924312	5564785	-2206811
2035	23655375	5703175	-2163231
2036	25319350	5921381	-2123662
2037	17688467	3516436	-2682142
2038	19379379	3724576	-2642008
2039	21030255	3984014	-2604419
2040	43049795	15024784	1793775
2041	44650091	15355733	1827869
2042	36195677	12238539	1209652
2043	37818668	12563905	1244068
2044	39427002	12913818	1277314
2045	41024483	13284265	1309594
2046	42614137	13672060	1341072
2047	33009937	9905672	643134
2048	34618012	10292404	674690
2049	36220786	10693817	705581
2050	37820072	11108003	735907
	Total gain by 2050 M EUR		
	681.263	**196.156**	**-31.866**

In the more realistic scenario, with the expected trajectory of the carbon tax and with EU funding, the results are gathered in Table 44.

Table 44: *Annual gain with CCS implementation, EU funding and halved emissions*

Year	TITAN	PPC	HH	Carbon price
2025	33569815	11368878	278746	60
2026	35965626	17162984	1791594	63
2027	39965939	18053563	1989956	66
2028	44176737	18944142	2201076	69
2029	48600161	19834721	2425089	72
2030	53238353	20725300	2662128	75

2031	61213071	22404094	3115313	80.5
2032	61390737	23442990	3079237	86
2033	69957053	25648757	3572361	91.5
2034	78732148	28215554	4080867	97
2035	87779716	31080156	4608245	102.5
2036	97138286	34205863	5156626	108
2037	97583801	34889707	5132214	113.5
2038	107736625	38367925	5731919	119
2039	118238641	42078730	6354827	124.5
2040	132368045	47729344	7699780	130
2041	224873403	81862943	13744945	197.5
2042	312060077	114773307	19451100	265
2043	414105743	153351139	26126205	332.5
2044	520963902	194178426	33119469	400
2045	534678983	200152345	33953363	400
2046	548462737	206143612	34791517	400
2047	551129137	207980696	34905314	400
2048	565084312	213970900	35753667	400
2049	579110686	219975785	36606417	400
2050	593210072	225993443	37463662	400
	Total gain by 2050 M EUR			
	6011.334	2252.535	365.796	

8. Variable costs for each factory per case

In this section, each variable cost impacting the total annual expense of carbon capture is broken down into a EUR/t CO2 cost. Subsequently, it is compared to the total annual expense of that year, yielding a percentage for each component. Cases 1 and 2 vary solely based on the carbon price and the financing and funding of CapEx. Consequently, as the initial emissions data remains unchanged, the cost percentages remain constant. However, in Case 3, a notable shift is observed due to the assumption of halved emissions.

8.1 TITAN Cement

8.1.1 Cases 1 & 2

Table 45: *Percentage of annual variable costs with reference to the total CCS price for TITAN – cases 1&2*

	Capture	Pipe O&M	Gas comp	Liq. compressor	Liq. unit	Storage	Shipping
2025	0	0	0	0	0	0	0
2026	3.30	0.41	1.77	0.98	2.91	3.25	87.38
2027	6.03	0.38	1.77	0.99	5.32	5.95	79.57
2028	8.34	0.35	1.77	0.99	7.35	8.22	72.98
2029	10.31	0.33	1.77	1.00	9.08	10.16	67.36
2030	12.01	0.31	1.76	1.00	10.58	11.83	62.50
2031	14.00	0.31	1.85	1.05	12.34	13.80	56.65
2032	10.94	0.21	1.32	0.75	9.64	10.78	66.36
2033	12.22	0.21	1.37	0.79	10.76	12.04	62.60
2034	13.37	0.21	1.41	0.81	11.78	13.18	59.24
2035	14.41	0.20	1.44	0.83	12.70	14.21	56.21
2036	15.36	0.20	1.47	0.85	13.53	15.14	53.46
2037	12.42	0.15	1.14	0.66	10.94	12.24	62.44
2038	13.17	0.15	1.17	0.68	11.60	12.98	60.27
2039	13.86	0.15	1.19	0.69	12.21	13.67	58.23
2040	14.52	0.14	1.21	0.70	12.79	14.31	56.32
2041	15.14	0.14	1.23	0.71	13.34	14.92	54.52
2042	12.84	0.11	1.02	0.59	11.31	12.66	61.46
2043	13.37	0.11	1.03	0.60	11.78	13.18	59.93
2044	13.87	0.11	1.05	0.61	12.22	13.67	58.46
2045	14.35	0.11	1.07	0.62	12.64	14.14	57.06
2046	14.81	0.11	1.08	0.63	13.05	14.60	55.72
2047	12.88	0.09	0.92	0.54	11.35	12.70	61.52
2048	13.28	0.09	0.94	0.55	11.70	13.09	60.34
2049	13.68	0.09	0.95	0.56	12.05	13.48	59.20
2050	14.05	0.09	0.96	0.56	12.38	13.85	58.09

8.1.2. Case 3

Table 46: *Percentage of annual variable costs with reference to the total CCS price for TITAN- case 3*

	Capture	Pipe O&M	Gas comp	Liq. compressor	Liq. unit	Storage	Shipping
2025	0	0	0	0	0	0	0
2026	1.74	0.44	1.42	0.78	1.54	1.72	92.36
2027	3.33	0.42	1.48	0.83	2.93	3.28	87.73
2028	4.77	0.41	1.54	0.86	4.20	4.70	83.52
2029	6.09	0.40	1.59	0.89	5.37	6.01	79.66
2030	7.31	0.38	1.63	0.92	6.44	7.21	76.11
2031	8.84	0.39	1.77	1.01	7.78	8.71	71.50
2032	6.52	0.25	1.20	0.68	5.75	6.43	79.16
2033	7.45	0.26	1.27	0.73	6.57	7.35	76.38
2034	8.33	0.26	1.34	0.77	7.33	8.21	73.77
2035	9.14	0.26	1.39	0.80	8.06	9.01	71.33
2036	9.92	0.26	1.44	0.83	8.74	9.77	69.04
2037	7.60	0.18	1.06	0.61	6.69	7.49	76.36
2038	8.16	0.18	1.10	0.64	7.19	8.04	74.69
2039	8.70	0.19	1.13	0.66	7.66	8.58	73.08
2040	9.22	0.19	1.17	0.68	8.12	9.09	71.53
2041	9.72	0.18	1.20	0.70	8.57	9.58	70.04
2042	7.91	0.14	0.95	0.55	6.97	7.79	75.68
2043	8.31	0.14	0.98	0.57	7.32	8.19	74.49
2044	8.70	0.14	1.00	0.59	7.66	8.57	73.34
2045	9.08	0.14	1.02	0.60	8.00	8.95	72.21
2046	9.45	0.14	1.05	0.61	8.32	9.31	71.11
2047	7.93	0.12	0.86	0.51	6.99	7.82	75.78
2048	8.24	0.12	0.88	0.52	7.26	8.12	74.86
2049	8.54	0.12	0.90	0.53	7.53	8.42	73.96
2050	8.84	0.12	0.92	0.54	7.79	8.71	73.08

8.2. PPC

8.2.1 Cases 1 & 2

Table 47: *Percentage of annual variable costs with reference to the total CCS price for PPC – cases 1&2*

	Capture	Pipe O&M	Gas comp	Liq. compressor	Liq. unit	Storage	Shipping
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0
2031	26.95	0.24	10.57	5.06	8.52	9.53	39.13

2032	24.03	0.11	5.02	2.41	7.60	8.50	52.33
2033	26.80	0.08	3.96	1.91	8.47	9.48	49.29
2034	29.10	0.06	3.42	1.65	9.20	10.29	46.27
2035	31.07	0.05	3.08	1.49	9.82	10.99	43.49
2036	32.79	0.05	2.85	1.38	10.37	11.60	40.97
2037	27.84	0.04	2.18	1.06	8.80	9.85	50.23
2038	29.24	0.03	2.09	1.02	9.24	10.34	48.03
2039	30.51	0.03	2.03	0.99	9.65	10.79	46.00
2040	31.69	0.03	1.98	0.97	10.02	11.21	44.11
2041	32.77	0.03	1.94	0.95	10.36	11.59	42.36
2042	28.80	0.02	1.62	0.80	9.11	10.19	49.46
2043	29.76	0.02	1.61	0.79	9.41	10.53	47.89
2044	30.66	0.02	1.59	0.78	9.70	10.85	46.40
2045	31.52	0.02	1.58	0.78	9.97	11.15	44.99
2046	32.32	0.02	1.57	0.78	10.22	11.44	43.65
2047	28.94	0.02	1.37	0.68	9.15	10.24	49.61
2048	29.68	0.01	1.37	0.68	9.38	10.50	48.38
2049	30.38	0.01	1.37	0.68	9.61	10.75	47.20
2050	31.06	0.01	1.37	0.68	9.82	10.99	46.07

8.2.2. Case 3

Table 48: *Percentage of annual variable costs with reference to the total CCS price for PPC- case 3*

	Capture	Pipe O&M	Gas comp	Liq. compressor	Liq. unit	Storage	Shipping
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0
2031	18.29	0.32	10.82	5.19	5.78	6.47	53.12
2032	15.38	0.14	4.85	2.33	4.86	5.44	66.99
2033	17.59	0.10	3.93	1.90	5.56	6.22	64.70
2034	19.54	0.09	3.46	1.68	6.18	6.91	62.15
2035	21.30	0.08	3.18	1.55	6.73	7.53	59.63
2036	22.90	0.07	3.00	1.46	7.24	8.10	57.23
2037	18.33	0.05	2.16	1.05	5.80	6.48	66.13
2038	19.54	0.04	2.11	1.03	6.18	6.91	64.19
2039	20.68	0.04	2.07	1.02	6.54	7.31	62.34
2040	21.76	0.04	2.05	1.00	6.88	7.70	60.58
2041	22.78	0.04	2.03	1.00	7.20	8.06	58.89
2042	19.11	0.03	1.62	0.80	6.04	6.76	65.64
2043	19.96	0.03	1.63	0.80	6.31	7.06	64.22
2044	20.77	0.03	1.63	0.80	6.57	7.35	62.85
2045	21.56	0.03	1.63	0.81	6.82	7.63	61.54

2046	22.31	0.02	1.64	0.81	7.05	7.89	60.27
2047	19.21	0.02	1.37	0.68	6.07	6.79	65.86
2048	19.86	0.02	1.38	0.68	6.28	7.03	64.75
2049	20.49	0.02	1.39	0.69	6.48	7.25	63.67
2050	21.11	0.02	1.41	0.70	6.67	7.47	62.63

8.3. Hellenic Halyvourgia

8.3.1. Cases 1 & 2

Table 49: *Percentage of annual variable costs with reference to the total CCS price for HH – cases 1&2*

	Capture	Pipe O&M	Gas comp	Liq. compressor	Liq. unit	Storage	Shipping
2025	0	0	0	0	0	0	0
2026	13.14	5.53	7.23	4.01	2.18	2.44	65.48
2027	22.15	4.74	6.66	3.72	3.67	4.11	54.95
2028	28.72	4.16	6.24	3.51	4.76	5.32	47.28
2029	33.72	3.72	5.92	3.35	5.59	6.25	41.45
2030	37.65	3.37	5.67	3.22	6.24	6.98	36.87
2031	41.70	3.16	5.57	3.18	6.91	7.73	31.74
2032	36.37	2.40	4.42	2.54	6.03	6.74	41.51
2033	39.21	2.29	4.41	2.54	6.50	7.27	37.79
2034	41.61	2.19	4.38	2.53	6.90	7.71	34.68
2035	43.67	2.10	4.35	2.51	7.24	8.10	32.04
2036	45.46	2.01	4.31	2.50	7.53	8.43	29.76
2037	40.30	1.65	3.66	2.13	6.68	7.47	38.10
2038	41.86	1.61	3.66	2.13	6.94	7.76	36.04
2039	43.27	1.56	3.66	2.13	7.17	8.02	34.19
2040	44.55	1.52	3.65	2.13	7.38	8.26	32.51
2041	45.72	1.48	3.64	2.13	7.58	8.48	30.98
2042	41.58	1.28	3.23	1.89	6.89	7.71	37.43
2043	42.66	1.25	3.23	1.90	7.07	7.91	35.98
2044	43.67	1.23	3.24	1.90	7.24	8.10	34.63
2045	44.61	1.21	3.24	1.90	7.39	8.27	33.37
2046	45.50	1.18	3.24	1.91	7.54	8.44	32.20
2047	41.91	1.05	2.93	1.73	6.95	7.77	37.66
2048	42.75	1.04	2.94	1.73	7.08	7.93	36.53
2049	43.55	1.02	2.95	1.74	7.22	8.07	35.46
2050	44.30	1.01	2.95	1.74	7.34	8.21	34.44

8.3.2. Case 3

Table 50: *Percentage of annual variable costs with reference to the total CCS price for HH- case 3*

	Capture	Pipe O&M	Gas comp	Liq. compressor	Liq. unit	Storage	Shipping
2025	0	0	0	0	0	0	0
2026	7.43	6.26	6.21	3.45	1.23	1.38	74.05
2027	13.42	5.74	6.13	3.43	2.22	2.49	66.57
2028	18.35	5.32	6.06	3.41	3.04	3.40	60.42
2029	22.48	4.96	6.00	3.40	3.72	4.17	55.27
2030	25.99	4.66	5.94	3.38	4.31	4.82	50.90
2031	29.91	4.53	6.07	3.47	4.96	5.54	45.52
2032	24.66	3.25	4.55	2.61	4.09	4.57	56.27
2033	27.29	3.19	4.66	2.69	4.52	5.06	52.60
2034	29.62	3.12	4.74	2.74	4.91	5.49	49.38
2035	31.71	3.05	4.80	2.78	5.26	5.88	46.53
2036	33.59	2.97	4.84	2.81	5.57	6.23	43.99
2037	28.23	2.32	3.89	2.27	4.68	5.23	53.38
2038	29.76	2.28	3.95	2.30	4.93	5.52	51.25
2039	31.19	2.25	4.00	2.34	5.17	5.78	49.28
2040	32.51	2.22	4.04	2.37	5.39	6.03	47.44
2041	33.76	2.18	4.08	2.39	5.59	6.26	45.74
2042	29.41	1.81	3.47	2.03	4.87	5.45	52.95
2043	30.50	1.79	3.51	2.06	5.05	5.65	51.43
2044	31.53	1.77	3.55	2.09	5.22	5.85	50.00
2045	32.51	1.76	3.58	2.11	5.39	6.03	48.63
2046	33.44	1.74	3.62	2.13	5.54	6.20	47.33
2047	29.70	1.49	3.15	1.86	4.92	5.51	53.37
2048	30.54	1.48	3.19	1.88	5.06	5.66	52.18
2049	31.35	1.47	3.22	1.90	5.19	5.81	51.05
2050	32.13	1.46	3.25	1.92	5.32	5.96	49.95

9. Results, conclusions and suggestions for future research

Upon examining case 1, it becomes evident that with the assumed carbon price, the Carbon Capture projects are not financially viable. Over the course of 25 years, they impose significant financial burdens on each factory, ranging in the order of 10^9. However, it becomes apparent that even with highly unrealistic carbon prices but with the inclusion of EU funding, the implementation of a CC system with its associated costs, approaches breakeven for the two smaller factories. Specifically, the power and steel plants face financial setbacks of 62.4 and 50.6 million EUR, respectively, over the 25-year period. While these amounts are considerable, they remain within the expected order of magnitude given the duration of the analysis. Notably, the cement plant appears to benefit from the implementation, realizing a gain of 92.8 million EUR compared to the business-as-usual scenario. These findings suggest that carbon capture holds promise for both environmental and industrial benefits.

Case 2 demonstrates that even in the absence of EU funding, and particularly with its inclusion, the adoption of a carbon capture system presents substantial advantages for each factory. This is especially notable for the cement factory, the largest emitter among the three plants, indicating that larger-scale projects yield greater long-term benefits. Additionally, the conclusion underscores the current trend of hastening the implementation of CC systems, given the considerable financial gains they offer.

Case 3 illustrates that even under the worst-case scenario of halved emissions and a fixed carbon price of 60 EUR/t CO2, the implementation of carbon capture systems proves highly advantageous for the cement and power plants. In the steel plant's case, the setback over 25 years is modest, amounting to just 31.9 million EUR. Remarkably, in a more realistic scenario with EU funding and anticipated carbon price trends, the profits compared to the business-as-usual scenario soar. Specifically, the cement, power, and steel plants witness substantial relative gains of over 6 billion EUR, 2.25 billion EUR, and 366 million EUR, respectively. These findings indicate that while carbon capture presents a profitable and promising avenue, it should not stand alone as the sole focus of industrial investment. Rather, the results emphasize the benefits of incorporating green energy usage in the production process of the cement and steel plant, and of a power drop for the power plant, with green energy used in the grid.

The results were largely as anticipated, underscoring the prevalent discourse and implementation of carbon capture systems across various industries. It's crucial to highlight that the analysis conducted in this thesis provides an overview of the broader context. For a more comprehensive understanding of the discussed topics, a detailed and separate analysis is necessary for each individual component.

Furthermore, it is imperative to explore how the integration of carbon capture systems may impact existing green energy infrastructure and initiatives, particularly in terms of efficiency, cost-effectiveness, and overall sustainability.

Finally, the cost breakdown demonstrated that capture and shipping costs represent the most significant expenses within the CCS chain. Future research endeavors should prioritize exploring ways to advance capture technologies to mitigate costs and delve deeper into the realm of LCO2 carriers. These carriers represent a flourishing technology expected to play a pivotal role in the years ahead, yet they remain largely unexplored. As demand for CO_2 transfer grows over time, there's potential for the construction of larger vessels to meet this demand. While ship prices remain unpredictable due to market dynamics, scaling up vessel capacity could lead to economies of scale, potentially reducing costs significantly.

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11. Appendix

11.1 The need to reduce GHG emissions

Greenhouse gases (GHGs) are gases in Earth's atmosphere that trap heat [93]. They contribute to the greenhouse effect, a natural process that keeps our planet warm enough to support life. However, an excess of these gases leads to an enhanced greenhouse effect, causing global warming and climate change. The primary GHGs include:

- Carbon Dioxide (CO_2): Generated from burning fossil fuels (coal, oil, natural gas), deforestation, and certain industrial processes.
- Methane (CH_4): Emitted during the production and transport of coal, oil, and natural gas, as well as livestock digestion and decomposition of organic waste in landfills.
- Nitrous Oxide (N_2O): Produced by agricultural and industrial activities, including the use of synthetic fertilizers, fossil fuel combustion, and certain industrial processes.
- Fluorinated Gases: These include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and nitrogen trifluoride (NF_3), primarily used in industrial applications like refrigeration, air conditioning, electronics manufacturing, and as substitutes for ozone-depleting substances.
- Water Vapor: Though not directly emitted in significant quantities by human activities, water vapor acts as a powerful greenhouse gas, amplifying the effects of other greenhouse gases.

11.1.1 Regulatory framework

In order to fight climate change, the Paris Agreement that was established in 2015 and was adopted by 196 parties, states that all parties included are to work towards limiting the increase in global temperature to below 2 ℃ above pre-industrial levels [94]. While the Paris Agreement encourages countries to develop and communicate their nationally determined contributions (NDCs) to reduce GHG emissions, it doesn't prescribe specific measures for individual sectors like shipping. Instead, the IMO, the UN agency responsible for regulating shipping, has been working on addressing emissions from the maritime sector.

In April 2018, the organization adopted the "Initial IMO Strategy on Reduction of GHG Emissions from Ships," setting a vision to reduce the total annual GHG emissions from international shipping by at least 50% by 2050 compared to 2008 levels. The strategy emphasizes efforts to ultimately phase out GHG emissions from the sector.

It is crucial to note, that in response to current data and since the need for freight transport is constantly rising, new indicative checkpoints to reach net-zero GHG emissions from international shipping were set in July 2023, in the “2023 IMO Strategy on Reduction of GHG Emissions from Ships” (Annex 15). Specifically, the industry is aiming to reduce the total annual GHG emissions by at least 20% (striving for 30%) by 2030 and by at least 70% (striving for 80%) by 2040, both compared to 2008. Also, according to the new framework, the new goal is to reach net zero by or around 2050, contrary to the 50% reduction declared in the initial strategy. As for the CO_2 emissions, the current checkpoint calls for a minimum of 40% reduction by 2030 compared to 2008 [95].

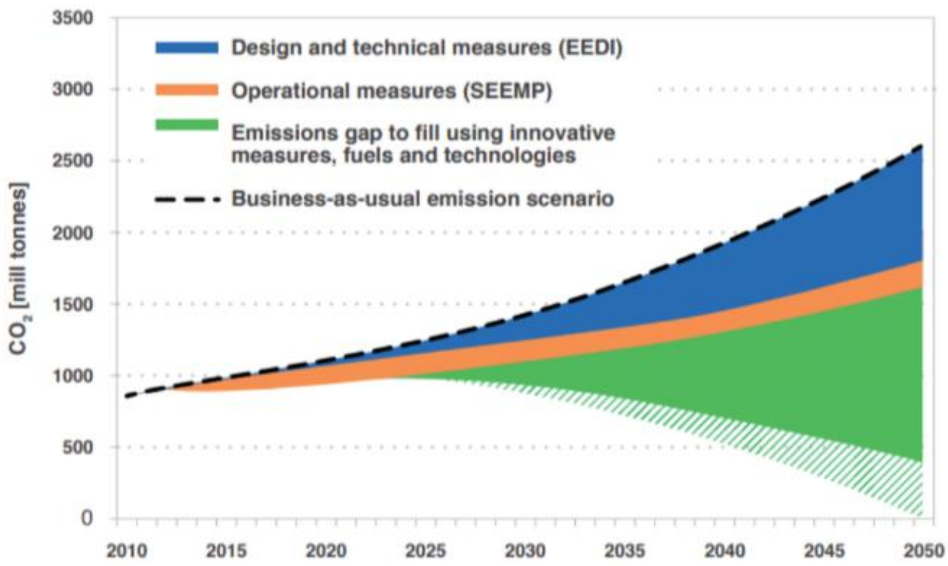

Figure 21: *GHG emissions reduction pathway*

Monitoring of emissions

The imperative to decrease air emissions from ships has led to the implementation of data collection regulations, offering significant utility in tracking emissions and shaping forthcoming strategies. Both the IMO and the EU have devised their distinct systems for monitoring emissions. The IMO initiated the DCS (Data Collection System), whereas the European Union introduced the EU MRV (Monitoring, Reporting and Verification) regulation. The EU MRV and IMO DCS have been obligatory since 2017 and 2018, respectively.

EU MRV

The EU's MRV Regulation (Regulation (EU) 2015/757), implemented on July 1, 2015, mandates the monitoring, reporting, and verification (MRV) of CO2 emissions from ships in EU or EEA ports exceeding 5000 gross tonnage (GT) [96]. This regulation encompasses six key steps: developing a monitoring plan, monitoring and reporting CO2 emissions, transparently compiling data, submitting emissions reports via the THETIS-MRV system, independent verification, and receiving a document of compliance [97]. The Commission discloses emissions annually by June 30.

IMO DCS

The IMO's Fuel Oil DCS was introduced to address fuel consumption and emissions from ships over 5000 GT [98]. It mandates annual reporting of fuel consumption, distance covered, and operational hours. Ships compile standardized fuel oil data reports, including technical specifications and consumption data, submitted to flag States for verification. Verified data is then transmitted to the IMO Ship Fuel Oil Consumption Database, ensuring transparency and accountability in maritime fuel usage and emissions management [99].

Comparing MRV-DCS

Although both the IMO and EU systems share fundamental principles such as the 5000 GT threshold, a standard monitoring duration of 12 months, the objective of curbing air pollution caused by greenhouse gases, and the mandated monitoring approach, they diverge notably in various aspects. For instance, the IMO DCS necessitates the submission of ships' fuel consumption data, whereas the EU MRV mandates reporting on CO2 emissions, cargo mass, and energy efficiency. The critical distinctions between the two systems are outlined in *Table 51*, as indicated in [100].

Table 51: *Comparing MRV and DCS*

	EU MRV	**IMO DCS**
Entry into force	1st July 2015	1st March 2018
Scope	Ships 5000 GT or above Voyages to/from EEA ports of call	Ships 5000 GT or above international voyages
1st monitoring period	2018	2019
Procedures	Monitoring plan (37 sections)	Data Collection Plan (SEEMP Part II) (9 sections)
Compliance (procedures)	Assessment Report (no need to be on board)	Confirmation of Compliance (must be on board)
Reporting	-Fuel consumption -Carbon emissions -Transport work (actual cargo carried) -Distance sailed -Time at sea excluding anchorage	-Total fuel consumption -Distance travelled -Hours underway -Design DWT used as a proxy
Verification	Independently accredited verifiers (ISO 14064)	Flag administrations or Authorized Organizations
Compliance (reporting)	Document of compliance (June 2019)	Statement of compliance (May 2020)
Publication/ Disclosure	Annual reporting data including the individual ship information made publicly available	Anonymized data will be made available to IMO member states
A centralized database of fuel consumption	THETIS, MRV, operated by EMSA	IMO management Database of Fuel Consumption, (GISIS)
Data range for monitoring	Per voyage	Not specified
Data on cargo carried	The actual amount of cargo	Deadweight (design)

Fit for 55

The European Commission introduced the Fit for 55 package on July 14, 2021, aiming to decrease the EU's overall GHG emissions by a minimum of 55% by 2030 compared to the levels observed in 1990, ultimately striving for climate neutrality by 2050. Consequently, the shipping sector will face new and stricter regulations within the EU. This section of the chapter briefly describes two key initiatives: the EU ETS and the Fuel EU regulation.

EU ETS

As stated earlier, the Commission's proposal involves broadening the reach of the EU's ETS to encompass CO_2 emissions from large ships, surpassing the 5000 GT threshold, irrespective of their flag status. This expansion aims to ensure that the maritime transport sector contributes to the heightened climate goals of the EU. The extension would cover specific emissions from ships, including:

- 100% of CO_2 emissions for voyages between EU ports.
- 100% of CO_2 emissions while at berth in ports under a Member State's jurisdiction.
- 50% of CO_2 emissions for voyages outside the EU (commencing or concluding at EU ports).

The incorporation of the EU ETS into maritime shipping would occur through a gradual phase-in period. During this transitional phase, the volume of emissions to be surrendered will incrementally increase to attain 100% by the reported period in 2026, ensuring a smooth transition. Shipping companies will need to surrender allowances according to the following schedule:

- 20% of verified emissions reported for 2023.
- 45% of verified emissions reported for 2024.
- 70% of verified emissions reported for 2025.
- 100% of verified emissions reported for 2026 and subsequent years.

Fuel EU

The Fuel EU Maritime regulation, among the suite of measures proposed in the "Fit for 55" package, is geared towards steering the EU maritime sector toward decarbonization. According to [101], this forthcoming regulation, slated to take effect in 2025, will impose life cycle GHG footprint criteria on the energy utilized aboard ships. It will encompass CO_2, CH_4, and N_2O from a well-to-wake perspective and will be applicable to the same ships covered by the EU MRV regulation.

The regulation mandates a reduction in the GHG intensity of energy consumption, measured in grams of CO_2 equivalent per MJ. It requires a 2% reduction in 2025 compared to the levels recorded in 2020, escalating to a 75% reduction by 2050. Furthermore, the regulation establishes standardized guidelines promoting the consistent adoption of renewable, low-carbon fuels, and alternative energy sources across the Union. It mandates the use of on-shore power supply or zero-emission technology in ports under the jurisdiction of a Member State, aiming for widespread utilization of environmentally friendly options.

Similar to the ETS, failure to comply with these regulations can lead to penalties and potential exclusion from EU waters [102].

11.2 Prinos LCO_2 storage

Greece's first CCUS initiative, spearheaded by the National Natural Gas System (DESFA) and Energean, anticipates finalizing pivotal regulatory and financial matters by the conclusion of 2024, with aspirations to commence its initial operational phase in 2025.

Termed the Prinos CO_2 Storage project, this collaborative endeavor between the two entities represents the sole project within the eastern Mediterranean region possessing an exploration permit. Presently, its focus lies on securing a storage permit by the close of the second quarter of 2024, followed by a licensing for operation by the culmination of 2025. The designated storage areas, situated near Kavala in northeastern Greece, have been chosen for their favorable geological attributes.

With an estimated budget exceeding 1.5 billion EUR, Energean and DESFA will respectively contribute 900 million EUR and 600 million EUR to the project. Energean's role encompasses the construction of CO_2 storage facilities, projected to accommodate between 2.5 to 3 million tons of CO_2 annually upon reaching full operational capacity.

Structured across two phases, the initiative aims to achieve a storage capacity of 1 million tons per year by the conclusion of phase one in 2025, with phase two slated to attain full operational capacity by the close of 2027.