

CRANFIELD UNIVERSITY

CHRISTOS-DIMOSTHENIS ALEXANDROPOULOS

**APPLICATION OF MACHINE LEARNING IN ASSESSMENT OF
COMBUSTION OF LIQUIFIED NATURAL GAS**

SCHOOL OF WATER, ENERGY AND ENVIRONMENT

Master of Science by Research
Academic Year: 2020 - 2021

Supervisor: Dr. Dawid Hanak
Associate Supervisor: Prof. Philip Longhurst
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the degree of Master of Science.

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ABSTRACT

This work focuses on the implementation on carbon capture on ships which run on liquified natural gas (LNG). LNG ships present a real-world example of LNG as well as a study case for carbon capture on LNG combustion. There is also special interest for that as well, since the International Maritime Organization (IMO), imposed a limit of 0.5% wt. of sulphur content in ship fuel has been imposed from 2020 to reduce pollution emissions from global shipping activities. This initiative will lead to major changes since the previous limit was set at 3.5% wt., which broadened fuel options for ships.

In addition, the IMO is developing a long-term plan to completely nullify shipping's impact on CO₂ emissions by 2030. Consequently, stricter regulations will be imposed to marine activities worldwide. LNG fuel seems to be a promising solution. The sulphur emissions are lower, in compliance with the latest IMO regulations. Additionally, it has a greater energy density in comparison to traditional fuels, like heavy fuel oil (HFO).

This paper aims to study the feasibility of a project, which equips an LNG fuelled ship with a carbon capture system. The study includes an examination of an on-board carbon capture system, by simulating the LNG engine as well as the carbon capture system in simulation software. The engine model chosen is the Wärtsilä 6L34DF.

The results of these simulations are analysed to examine the correlation between the system's variables and to evaluate the possibility of heat integration within the system. The economic feasibility of the project is then assessed, using economic data. The results show that heat integration is possible. For example, the heat provided from the flue gas is calculated at 1.323MW when the reboiler duty is 0.3353 MW. However, the project is not sustainable under current market conditions.

Keywords:

IMO, shipping, economic, feasibility, investment

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Unfortunately, my time of stay at Cranfield coincided with a period of strict lockdowns in the UK and as a result, I was deprived of the opportunity to get familiar with the environment in-depth, both scientifically and socially and to profit from the many associated opportunities. As I had to spend most of the time abroad, I did not get to meet other students working on similar objectives.

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LIST OF ABBREVIATIONS

IPCC	Intergovernmental Panel on Climate Change
SBCC	Ship Based Carbon Capture
IGCC	Integrated Gasification Combined Cycle
IEA	International Energy Agency
IMO	International Maritime Agency
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilization
EOR	Enhanced Oil Recovery
ETS	Emissions Trading System
CHP	Combined Heat and Power
THF	Tetrahydrofuran
TEC	Total Equipment Cost
TIPC	Total Indirect Plant Cost
FCI	Fixed Capital Investment
GHG	Greenhouse Gas
DFDE	Dual Fuel Diesel Engine
EEDI	Energy Efficiency Existing Ship Index
ECA	Emission Control Area
EGR	Exhaust Gas Recirculation
LCOE	Levelized Cost of Electricity
CAPEX	Capital Expenditure
OPEX	Operating Expenditure
HFO	Heavy Fuel Oil
MDO	Marine Diesel Oil
MCR	Maximum Continuous Rating
GGR	Greenhouse Gas Removal
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
MEA	Monoethanolamine
DEA	Diethylamine
PSA	Swinging Pressure Adsorption
TSA	Swinging Temperature Adsorption
OECD	Organization for Economic Cooperation and Development
PCC	Pulverized Coal Process
PFD	Process Flow Diagram
SCPP	Supercritical Pulverized Coal-Fired Power Plant
WTT	Well to Tank
WHR	Waste Heat Recovery
PTO	Power Take-off
NVP	Net Present Value
PZ	Piperazine
EF	Emissions Factor

1 Introduction

1.1 Background study

In 2018, the UN-affiliated agency of the International Maritime Organization (IMO), finalized its strategy and timeframe for controlling and eventually cutting off, completely, if possible, GHG (greenhouse gases) emissions across international shipping. Notably, IMO plans to regulate, in the immediate future, the GHG footprint of marine industry by rigorous control of pollutant emissions such as the emissions of CO₂, SO_x, NO_x and CH₄. These efforts will not only lead to a cleaner environment in compliance with the Paris agreement but will also bring about immense benefits for human and animal health and longevity.

Emissions of CO₂ arise from several sources, mainly fossil fuel combustion in power generation, industrial, residential, and transport sectors. Historically, global greenhouse gas emissions have risen from approx. 40,000 Mt CO₂eq in 1990 to almost 50,000 Mt CO₂eq in 2010, an increase of 25 % (Van Vuuren et al., 2011). Presently, greenhouse gas emissions are about 55% higher than in 1990 and 40% higher than in 2000. In 2017, the 1.3%, or 0.6 Gt CO₂ eq, increase was mainly due to a 1.2% increase in both global carbon dioxide (CO₂) emissions and methane (CH₄) emissions, which showed almost no growth in 2015 and 2016.

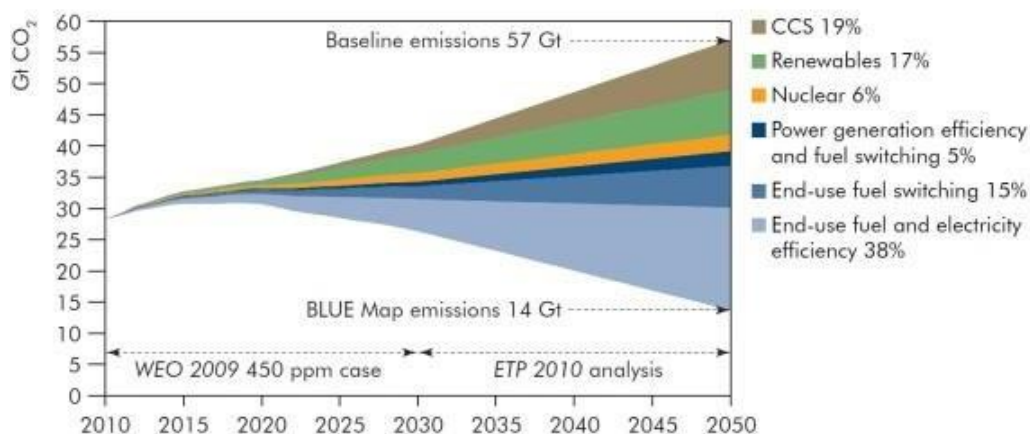


Figure1–1: Baseline scenario for 2050 emissions (IEA, 2010)

In the power generation and industrial sectors, many sources have large emission volumes that make them amenable to the addition of CO₂ capture technology. The top 25% of all large stationary CO₂ emission sources are those emitting more than 1 MtCO₂ per year and account for over 85% of the cumulative emissions from these types of sources. At the other end of the scale, the lowest 41% (in the 0.1 to 0.5 MtCO₂ range) contribute less than 10% (Finkerath, 2011).

Climate models project robust differences in regional climate characteristics between present-day and global warming of 1.5°C, and between 1.5°C and 2°C. These differences include increases in mean temperature in most land and ocean regions, hot extremes in most inhabited regions heavy precipitation in several regions and the probability of drought and precipitation deficits in some regions. Therefore, future emissions are evaluated through integrated assessment models which consider demands and provide scenarios for potential energy systems to the objective of reducing toxic emissions in a long-term basis as demonstrated in Figures 1-1 and 1-2. The Intergovernmental Panel on Climate Change (IPCC) has concluded that a significant reduction of worldwide GHG emissions is required to hold the increase in the global average temperature to well below 2 °C above pre-industrial levels while pursuing efforts for 1.5 °C. Hence, carbon capture and storage (CCS) was ranked as an important means of reducing global CO₂ levels (IPCC, 2005). Large numbers of small point sources and, as is the case of transport, mobile sources characterize other sectors, making them perhaps less amenable to capture.

Additionally, it has also been estimated that during the same period (1990-2017) emissions from international aviation and maritime transport have increased by 70%. International maritime transport, If left unregulated, is expected to be responsible for 17% of global greenhouse gas emissions in 2050 (Directorate General for Internal Policies, 2015). According to the IMO, a significant increase of 9.6% in the greenhouse gases emissions of shipping was recorded between the years 2012 -2018 (IMO, 2021)

Table 1-1: Evaluation of strategies for GHG mitigation. (Leung et al., 2014) (Hao et al., 2011) (Akdag & Yildirim, 2020) (van der Zwaan, 2013)

Method	Applications	Benefits	Drawbacks
Energy Efficiency / Energy conservation	Construction sector. Transportation sector.	Energy savings from 10% to 20%. Reduction in fuel consumption (almost at 75,7% in certain cases).	Large investment costs
Clean fuel	Transportation sector/ Energy sector	Natural gas emits 40-50% less CO ₂ than carbon due to lower carbon content and higher combustion efficiency, cleaner exhaust gas.	Higher fuel cost for natural gas. Comparable cost for conventional gas.
Clean coal technologies	Integrated gasification combined cycle (IGCC), pressurized fluidized bed combustor (PFBC), alternative combustion methods.	Coal usage with lower emissions	Significant investment is needed.
Renewable energies	Hydro, solar, thermal, wind power, and biofuels are highly developed	Use of local resources. GHG emissions may be low or nonexistent.	Applicability may depend on local resources availability and cost. Investments are too costly for developing countries.
Development of nuclear power.	Nuclear fission was adopted mainly in US, France, Russia, and Japan. Nuclear fusion in research and development phase	Average GHG emissions are almost two orders of magnitude lower for nuclear energy than for conventional coal-based power production.	Usage is controversial, due to high radiation hazards. . Infrastructure is too costly for third-world countries.
Carbon capture and storage	Applicable to large CO ₂ plant sources	It can reduce a vast amount of CO ₂ with capture efficiency > 80%	CCs full chain technologies not proven at full commercial scale.

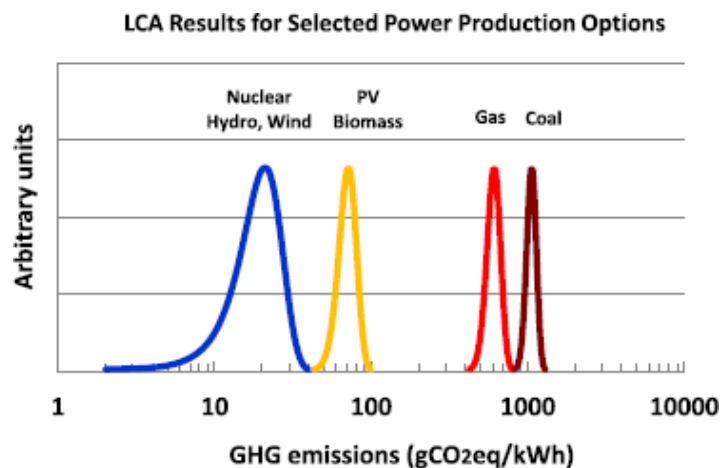


Figure 1–2. Greenhouse gas emissions of several power sources (Van der Zwaan, 2013)

Limiting CO₂ emissions from the shipping industry internationally is crucial, since maritime transport currently contributes 3% of the annual global greenhouse gas emissions, if the goals set by the IMO are to be realized. Notably, nearly all shipping-related emissions occur within 400 km of land (Awoyomi et al., 2019).

Several approaches to reduce exhaust gases from ships have been realized for a few decades. Certain technologies have theoretically the potential to minimize the CO₂ emitted: Switching to alternative fuels, i.e.: hydrogen, ammonia, or biofuel as listed in Figure 1-3, where the current and alternative fuels are demonstrated, is accompanied by many shortcomings, the cost being a major one. Implementation of 'green' technology in ship powering, such as internal combustion engines running on fuel cells of blue hydrogen or ammonia, creates new challenges. Among those are the unavailability of non-food-derived sustainable biofuels, and the lack of working prototypes along the huge cost of batteries (Feenstra et al., 2019). Both solutions, render long and medium-distance routes non-viable (OECD, 2018).

<i>Fuels of diesel quality</i>	Heavy fuel oil (HFO) Low sulphur HFO (<1 wt. % S) Low sulphur distillate fuels (<0.1 wt. % S) Vegetable oils Biodiesel Biomass-to-liquid (BTL)/synthetic biodiesel Gas-to-liquid (GTL)/synthetic diesel (Fischer-Tropsch)
<i>Gases</i>	Liquefied natural gas (LNG) Liquefied biogas (LBG) Dimethyl ether (DME) Liquefied petroleum gas (LPG) Hydrogen
<i>Alcohols</i>	Methanol Ethanol Butanol OBATE-fuel
<i>Solid fuels</i>	Uranium Coal Wood

Figure 1–3: Currently preferred and alternative marine fuel options (Al Baroudi et al., 2021).

1.1.1 IMO Greenhouse emissions reduction plan

After the implementation of the new regulation regarding sulphur content of fuel oil (namely compliance with the 0.5% sulphur limit, which entered into force on 1 January 2020) the IMO strategy focuses on further reduction of the CO₂ intensity. GHG emissions of international shipping have increased from 977 million tonnes (Mt) in 2012 to 1,076 Mt in 2018, a 9.6% rise. Even further, by 2050 emissions are projected to have increased by up to 50%, despite efficiency gains, relative to 2018, as there is expected to be continued growth of transport demand. While the impacts of the Covid-19 pandemic will probably cause a decline in emissions in 2020 - 2020, these are not expected to significantly affect projections for the coming decades. The dependence of global trade in shipping is enormous: almost 80% of global trade passes through sea routes and that number is expected to grow further. IMO aims to lower the CO₂ intensity per transport work as an average by at least 40% by 2030 and pursues efforts towards 70% by 2050(IMO, 2021). Additionally, the IMO strategy involves taxation that will be implemented for CO₂ emissions in the future. New regulations require shipowners to meet certain energy efficiency standards. For instance, the Energy Efficiency Existing Ship Index (EEXI) is currently being considered as a validation certificate by the International Convention for the Prevention of Pollution from Ships (ICPP, 2020).

Figure 1-4 shows the current distribution of fuels in the shipping industry. A combination of cleaner fuels, engine modifications, add-on retrofits, and other measures can be used to reduce exhaust gas emissions. Recirculation of a portion of exhaust gases (EGR) might also be required. Indeed, natural gas and hydrogen fuels, shown in Figure 1-2 are the most selected alternatives for marine applications. The advantages of LNG include its affordable pricing, availability, and compatibility with existing engines. However, LNG is not renewable like hydrogen fuels. (Elgohary et al., 2015).

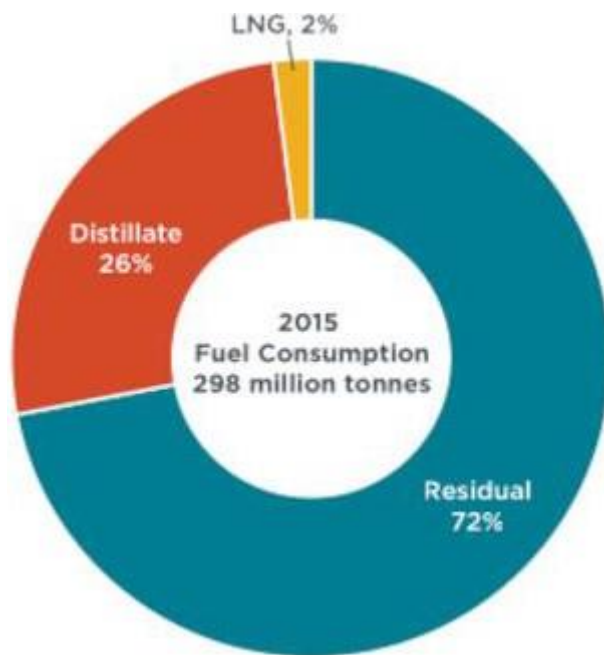


Figure 1–4: 2015 Marine fuel consumption (Al Baroudi et al., 2021)

As already mentioned, various efficiency gain processes and energy conversions have been implemented in ships worldwide. However, the lack of working prototypes and industry apprehension at the huge costs involved in developing greener boats have led climate analysts and activists to ask when and how the sector will start making the promised emission cuts. There are many issues, of course, the adjustment of the internal combustion engines and bunkering systems to the alternative fuels. Hence, improved turbines, switch to cleaner fuel, cleaning systems or scrubbers are unlikely to be sufficient, or economically feasible, to achieve deep reductions in emissions of GHGs on their own.

1.2 Motivation

The anthropogenic greenhouse effect has not only resulted in the increase of the mean earth surface temperature by 0.74°C between 1906 and 2005, but also in a substantial increase in the frequency of other weather phenomena: heavy precipitation, droughts, winds, and cyclone activity. As a result, melting of ice caps and snow covers, rise in the sea level and permanent flooding have

been observed. Therefore, a further increase in the anthropogenic GHG emission would result in the increased occurrence of hot periods and heat waves, heavy precipitation events over most land areas, as well as in a high likelihood of unusually high sea levels (Leung et al., 2014). The capture of CO₂ has been applied to large sources and recently research has been directed as to whether it could be also applied to small point sources.

The outbreak of the Covid-19 pandemic had a negative economic impact since a lot of industrial sites and plants had to cease operation in 2020. By September 2020, the GHG emissions in large metropolitan areas had dropped significantly. In New York City, it was reported that air pollution levels were cut in half, a result of the measures taken to combat the spread of the pandemic (Henriques, 2020, as cited in Rume & Islam, 2020). However, researchers are worried that emissions which were lowered in 2020, will rebound in the following years, as was seen in the wake of the financial crisis of 2009, especially in China (Q. Wang et al., 2020). As far as the ship industry is concerned, has Ship Based Carbon Capture (SBCC) the potential to contribute to emissions mitigation?

SBCC is however still an emerging technology that could be coupled ideally with cleaner fuels, i.e., LNG. Onboard those ships, CCS systems could “in theory” aid in realizing the environmental goals set by the governing bodies of marine transport. According to the Japanese Ship Technology Research Association (2020), onboard capture systems could reduce emissions by 85% and up to 90%, depending on technological advancements.

Due to certain design criteria, energy limitations, and economic issues that are different from those of a land power plant, implementing carbon capture onboard ships has plenty of room for exploration.

1.3 Aim and Objectives.

The aim of this study is to assess the feasibility of integrating the carbon capture to the LNG fueled ship. Machine learning is applied to understand the relationship between the system's variables. This is critical in specifying what the amine flow rate and the heat duty of the reboiler should be in order to

achieve a certain goal, in this case capturing 90% of carbon from the flue gas. By comparing the heat duty needed with the heat available in the flue gas, it is determined if heat integration is possible, which lessens the total cost of the operation. The objectives are:

- Validate heat integration and energy limitations.
- Discuss long term utilization of captured CO₂
- Examine the project's economic feasibility
- Evaluate those results and discuss their potential impact.

1.4 Structure of Thesis

The following chapter, namely chapter 2, comprises the literature review, providing fundamental information into various aspects related to the project. This ranges from LNG and its combustion nuances through to SBCC technology and captured CO₂ utilization trends.

Chapter 3 focuses on modelling and simulation of specified combustion and the CC process. This work evaluates the process performance of a capture system onboard an LNG-fueled ship at different engine loads. The capture system is designed using an MEA (monoethanolamine) aqueous solution with an increasing flow rate to examine its impact on capture rate and the reboiler heat duty, consequently recording the thermal energy demand. For every engine load, numerous simulations were executed with increasing MEA flow rate to investigate the correlation between the solvent flow rate, carbon capture rate, and the reboiler heat duty. Regression analysis is then performed to deduce any mathematical relationship between the examined variables.

A process simulation model is developed in Aspen Plus™ software to analyze and examine the onboard combustion and carbon capture processes. Four different simulations were developed, each one for a different engine load (50%, 75%, 85%, 100%). The engine chosen to be simulated was the Wärtsilä 6L34DF. The manufacturer's parameters for different fuel flow rates on every engine load were followed.

Then, in Chapter 4, data collected by Aspen Plus™ is utilized to examine the project's feasibility. A sensitivity analysis is performed with the design of a MATLAB algorithm to investigate which economic factor (CAPEX, OPEX, CO₂ market) has the strongest effect on the project. Finally, Chapter 5 analyzes the received results, and provides insight into the issues brought to light.

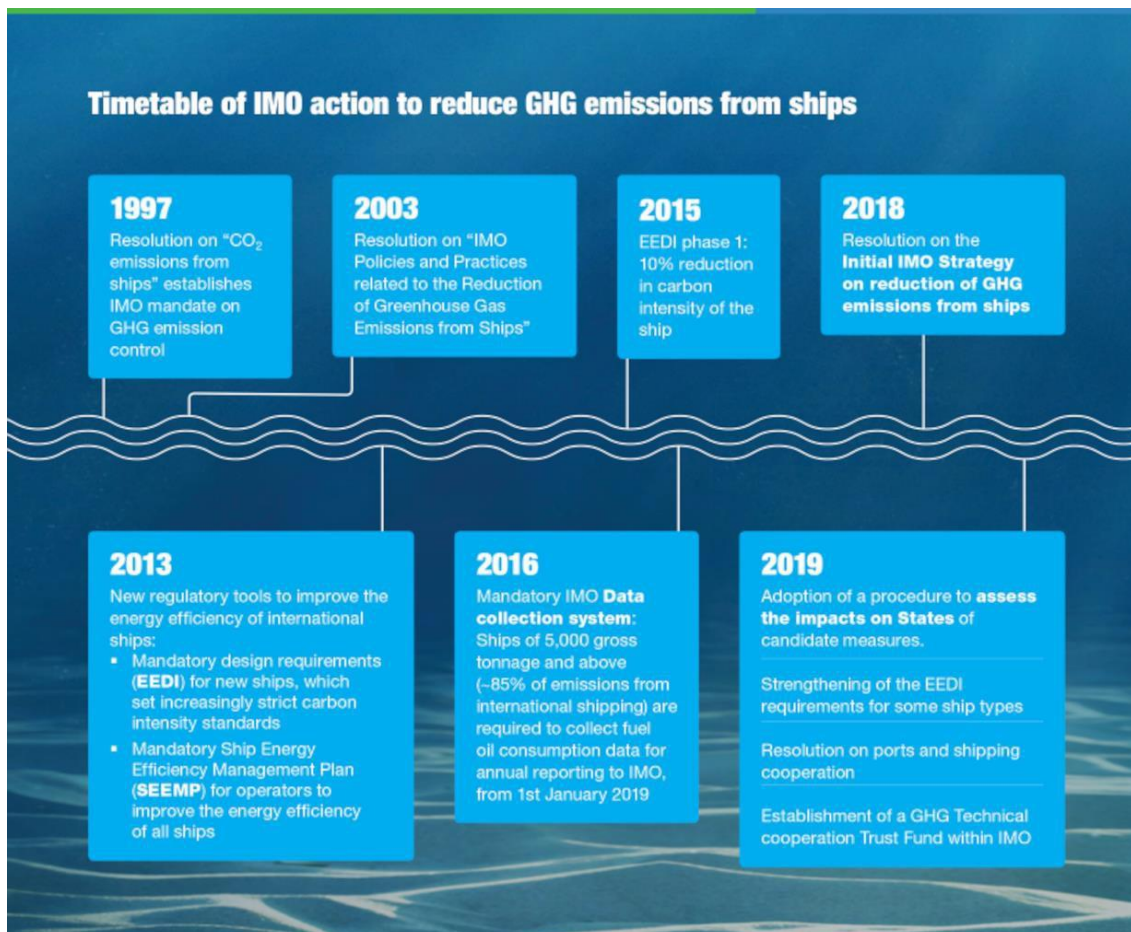


Figure 1–5: Timetable of IMO actions (IMO, 2019).

2 . LITERATURE REVIEW

2.1 The potential of LNG as a fuel

Given the aforementioned developments in the shipping industry, the potential of natural gas has gained newfound interest. LNG has the more advantageous potential over diesel fuel products, especially regarding its environmental impact, as it can be seen from the emissions factor (EF) index. EF describes the link between the quantity of an environmental pollutant and its anthropogenic source. EF is normally defined as the ratio of the weight of the pollutant to a value critical to pollution generation (mass, volume, distance, or duration of the emitting activity) (EPA, 2021). The EF for natural gas is the sum of the combustion ($0.205 \text{ kg CO}_{2\text{eq}} / \text{kWh ICV}$) and the upstream (i.e., the production and transport of the gas) ($0.0389 \text{ kg CO}_{2\text{eq}} / \text{kWh}$). The emissions factors for certain marine fuels are compared in table 2.1.

Methane contributes more to the greenhouse effect, but the methods used to calculate its impact are a subject of debate (Le Fevre, 2018). CH_4 emissions, also known as methane slips, are a significant drawback (environmentally wise) of natural gas engines, that mostly operate on the Diesel or Otto fuel cycles (Ammar & Seddiek, 2017). Models of Otto-cycle engines have indicated that methane slips rates are higher in Otto cycle engines compared to Diesel cycle ones (Thomson et al., 2015). Moreover, new dual-fuel engines with thermal efficiency ranges from 40% to 50% will greatly reduce the rates of boil- off gas release. (Watsilla, 2014, as cited in Ammar & Seddiek, 2017). However, direct methane emissions, from industries or natural seepage, have a far stronger impact in environmental pollution (Corbett et al., 2014; *Overcoming Methane Slip, Rolls Royce Marine Builds Spark-Ignited LNG-Powered Engines*, n.d.). Thomson et al., have analyzed the life cycle emissions of LNG in comparison with diesel marine fuels. The LNG environmental improvements in terms of reducing SO_x , NO_x , and particulate matter as compared to traditional heavy fuel oils (HFOs) are demonstrated in table 2-1.

Table 2-1: Emissions factor for certain marine fuels (g of pollutant/ g of fuel) including Marine Diesel Oil (MDO) and the figures for particulate matter (PM). (Le Fevre, 2018)

Emission	HFO	MDO	LNG
SO _x	0.049	0.003	trace
CO ₂	3.114	3.206	2.750
CH ₄	trace	trace	0.051
NO _x	0.093	0.087	0.008
PM	0.007	0.001	trace

Analysing the way LNG is distributed can provide useful insights regarding GHG emissions. Eight distinct pathways are identified for the production of LNG and its delivery to ships. This classification aids in studying the emissions associated with LNG transportation to the bunkering stations (Lowell et al., 2013) The pathways differ in three main characteristics: (1) the source of the gas- whether imported or local -used to generate the LNG. (2) If the LNG is being processed through an existing or a new plant. (3) The location and method of refueling ships. These are schematically depicted in Figure 2-2. Pathways 1 to 3 include imported LNG produced abroad, using large-scale liquefaction plants, and transported via a carrier to an LNG import terminal. In route 1, the inlet terminal has facilities for direct supply of ships from the LNG storage area through a special pipeline. On routes 2 and 3, LNG is loaded onto a truck at the import terminal for remote delivery to supply the vessels.

For pathway 2, the refueling area provides LNG storage, so that LNG from the inlet terminal is unloaded into a storage tank on land, and at some point, later, the vessels will pump LNG from the storage tank using a pipeline.

Pathway 3 has a remote supply point but does not have the ability to store LNG on site. In this scenario, trucks are loaded at the terminal and travel to the

remote area and the fuel is discharged directly to the boat. Routes 4 to 8 use domestic gas and liquefied natural gas. Routes 4 through 6 are equivalent to routes 1 to 3, but with LNG supplied by an existing large domestic liquefaction plant and not by a LNG input terminal. For lanes 7 and 8 there is a smaller scale liquefaction unit created specifically for the production of LNG fuel for one or more vessels. For Pathway 7, fuel loading is effectuated to the storage tanks via a special pipeline, while Pathway 8 is designed for fuel loading onto trucks for delivery on relatively nearby vessels (Lowell et al., 2013). The precise effect a delivery route has on emissions, depends on the polluting substance examined in each case. For example, extraction processes of natural gas and the distance travelled in pipelines, impact CH₄ emissions greatly (Corbett et al., 2014).

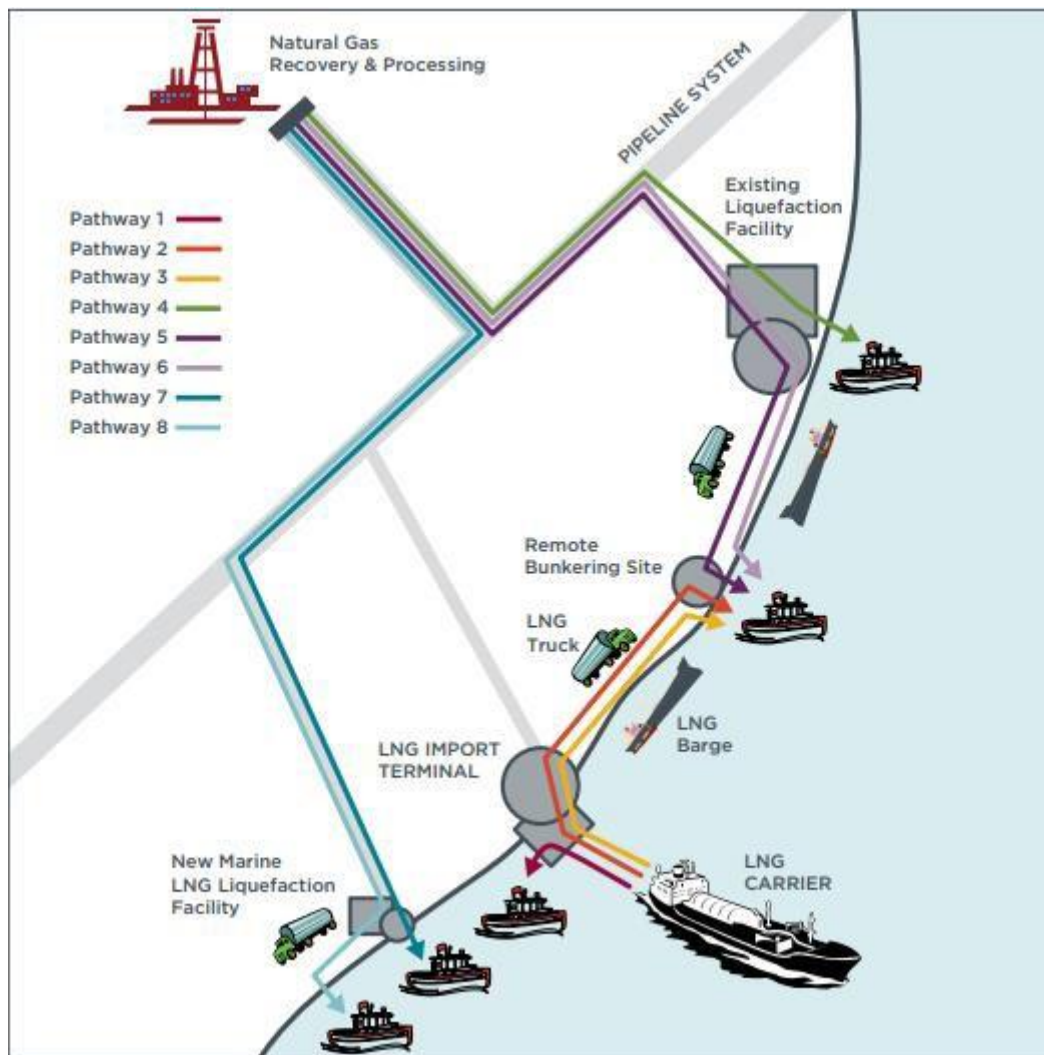


Figure 2–1: Schematic representation of LNG bunkering (Lowell et al., 2013)

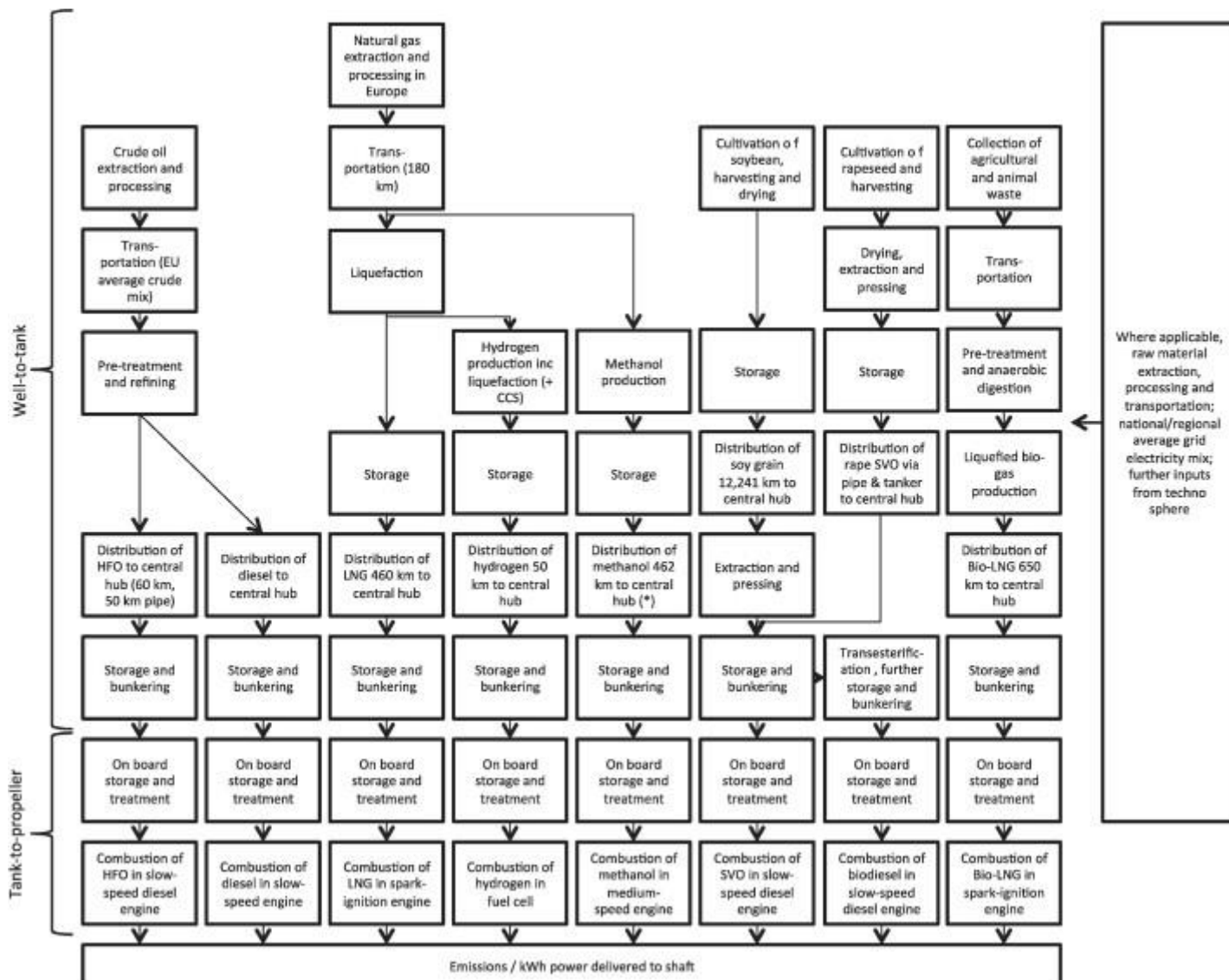


Figure 2–2: Pathway of fuels from production to combustion. (Gilbert et al., 2018)

2.1.1 Combustion of LNG

The volume of natural gas reduces almost 600 times when it is liquified to LNG. That is the property which makes LNG suitable for storage and transportation (Bortnowska, 2009). It then must be vaporized and pressurized to the pressure that is compatible with the engine requirements (Ammar & Seddiek, 2017) (2-5 bar for low-pressure dual-fuel engines, 250-300 bar for high-pressure dual-fuel engines) (Chorowski et al., 2015). The boil-off gas must be controlled to avoid the occasional gas release to the atmosphere (Chorowski et al., 2015; Stoumpos et al., 2018). The significance in properly managing boil-off gas, the natural gas steam that forms as heat is transferred to the LNG tank, will be explained in the following sections. LNG was initially used as propulsion fuel in LNG carriers where the boiled-off gas produced inside the LNG tanks was used for propulsion in traditional boilers or steam turbine systems and, at a later stage, in dual-fuel diesel engines (DFDE) (Banawan et al., 2010).

LNG-engines might be a feasible financial option for vessels, which remain in ECA zones for the greater part of their journey, i.e., handy sized tankers and medium RO-RO (Roll on-Roll off) vessels (Leo et al., 2010, as cited in Ammar & Seddiek, 2017). Since the sulphur concentration on LNG flue gases is practically zero, there is no requirement for any pre-treatment before they enter the CC system (van den Akker, 2017). Also, the energy required for CO₂ capture and storage is reduced significantly by heat integration: the exhaust gases from the engine are used to reheat the solvent in the stripper column. Additionally, the cold required for CO₂ liquefaction is provided for by the LNG, which is stored at -162°C and must be evaporated before entering the engine. Process design and simulation performed at TNO shows that the heat available in the exhaust gases is enough to capture over 90% of the CO₂ produced. Enough cold is provided by LNG vaporization to store the CO₂ at around -22°C.

2.1.1.1 Boil-off Gas

Boil-off gas (BOG) occurs as heat transfers from the environment through insulated spaces and holding tanks, resulting in steam formation. BOG is an

issue that all vessels which carry LNG must deal with. Most of the BOG is generated from the cargo transport (Fernández et al., 2017). The main causes of this effect are:

- Heat transfer between the environment and the LNG tank
- Spraying LNG on the tank, to keep the temperature levels from rising.
- As the vessel moves, the fluid inside the tank collides with the walls. The energy from this motion releases LNG steam inside the tank. Therefore, the BOG volume is greatly increased during periods of unfavorable weather.

As the BOG levels rise within the tank, the pressure increases as well. It is very crucial for the LNG carriers to lower the BOG levels before the conditions reach critical status. Certain ships have on-board liquefaction installations which consume high amounts of energy to return the gas to its previous state and back to the tank (Fernández et al., 2017).

2.1.2 Overview of LNG marine propulsion systems

2.1.2.1 BOG propulsion

The LNG propulsion systems have a direct correlation to the BOG produced in LNG tanks. Depending on the usage of BOG generated on the tanks, there are different types of propulsion systems (Fernández et al., 2017) Figure 2-3 shows the propulsions systems for LNG carriers, meaning ships who run on a different fuel, other than LNG, but need to burn the BOG produced in order to maintain storage tank pressure.

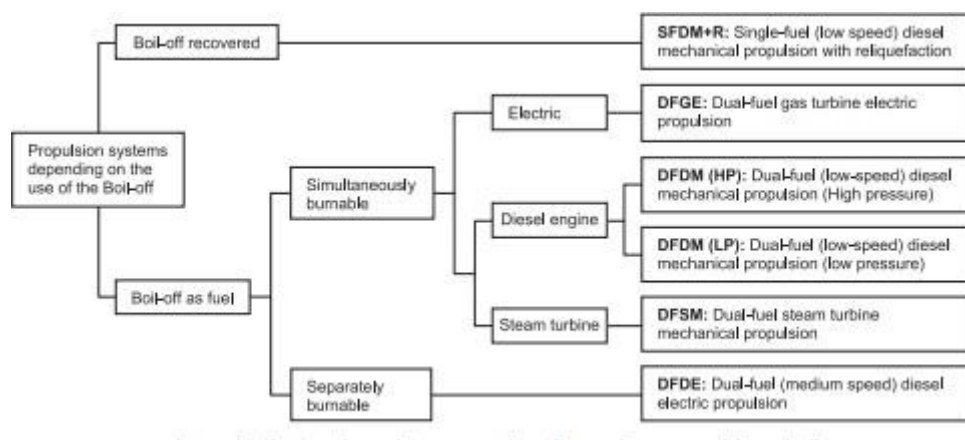


Figure 2–3: Use of Boil-off gas in propulsion (Fernández et al., 2017)

Steam turbines were the most popular technology used by LNG carriers since 1960. In that configuration, heavy diesel (Heavy fuel oil) and BOG were transferred to the boilers to generate steam. The steam would then transfer energy to the turbines or the electric turbo generators. The boilers are designed to burn two fuel types (BOG and fuel oil) at the same time. The BOG created as the ship remains idle at the port is also pumped to the boilers for burning but without any energy conversion (Fernández et al., 2017).

2.1.2.2 Dual fuel engines

Dual-fuel engines are named as such because they can be operated with two kinds of fuel. These engines operate on the lean-burn fuel model from the Otto cycle. When these engines run on gas a small amount of diesel pilot fuel (1-8 %) is used for ignition in the combustion chamber (Fernández et al., 2017). The dual-fuel engines can belong either to the 2-stroke or the 4-stroke class. 4-stroke engines can be categorized in two ways, depending on gas pressure and the gas injection mechanism (Stoumpos et al., 2018). High-pressure engines (near 350 bar), in which gas enters the cylinder at the combustion phase, and low-pressure engines (5-7 bar), in which gas enters at the intake phase and mixes with air (Stoumpos et al., 2018). As with 4-stroke engines, the 2-stroke variations are similarly classified. A high-pressure (300-350 bar), where gas injection happens at the combustion phase. In the lower-pressure variant (close to 7 bar), gas enters the engine cylinder as the compression phase is executed (Stoumpos et al., 2018).

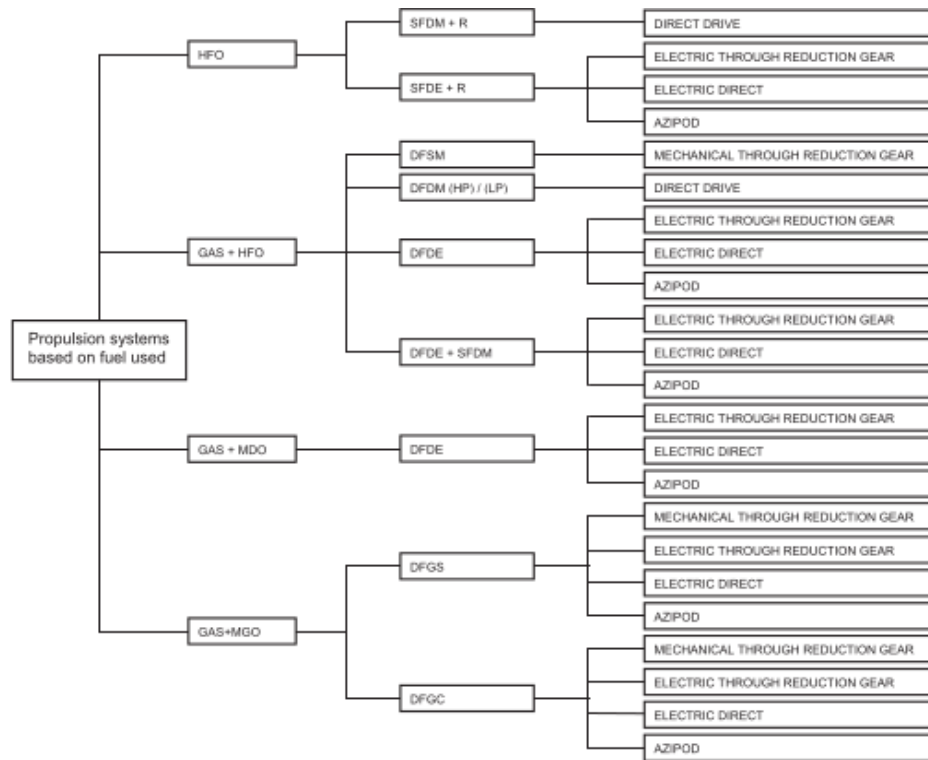


Figure 2–4: Schematic representation of propulsion systems for different fuels (Fernández et al., 2017)

2.2 Carbon Capture

CO₂ capture technologies are generally expensive, even though they are readily available in some cases. Almost 70–80% of the total cost of a full CCS system including capture, transport, and storage consists of carbon capture (Leung et al., 2014). Carbon capture is an effective strategy in the effort to reduce the concentration of carbon dioxide. The possibility of CCS becoming sought-after in the industrial sector, is affected by many variables: expenses, level of technical readiness, how well it will be adopted in the third world, regulations for

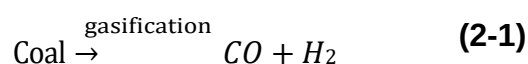
governments and other institutional bodies, and public opinion regarding environmental issues (IPCC, 2005).

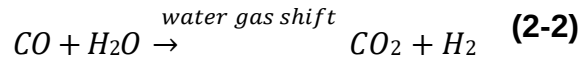
2.2.1 Types of CO₂ capture in the industry

There are 3 different basic combustion procedures, each one with its respective capture process: post-combustion, pre-combustion, and oxyfuel combustion (IPCC, 2005; Leung et al., 2014). The concentration of CO₂ in the gas stream, the pressure of the gas stream, and the fuel type (solid or gas) are the crucial factors in the making the right choice for a capture system (IPCC, 2005). The CO₂ content in the flue gas is dependent on the composition of the LNG that is combusted. LNG consists mostly of methane (CH₄). Other components are ethane (C₂H₆), propane (C₃H₈), and nitrogen (N₂). Usually, a small amount (0 to 1.5%) of other hydrocarbons is present in the LNG.

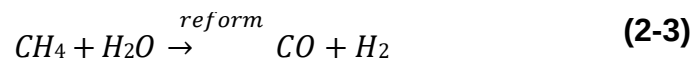
2.2.1.1 Pre-combustion capture of CO₂

The fuel, in this process, has to undergo a certain treatment before energy production. The pretreatment for coal involves a gasification process conducted in a gasifier under low oxygen level aiming to separate it from the hydrogen before combustion: Syngas is generated, a mix of gases composed mostly of CO and H₂, and is mainly free from other pollutant gases is formed (Eq 2.1). The reaction can also take place with air and (or) steam (IPCC, 2005). Syngas may include substances like CO₂, CH₄, and traces of impurities like H₂S and NH₃ (Liu et al., 2009). Consequently, the carbon is stored or used for other purposes while the hydrogen is used for combustion. The syngas will then undergo a water gas shift reaction with steam forming more H₂ while CO will be converted to CO₂ (Eq2- 2) (Leung et al., 2014).





The H₂/CO₂ fuel gas mixture contains CO₂ in high concentration (≥ 20%), which is considered advantageous for carbon sequestration. After separation, the result is a fuel, with high-hydrogen content, that can be utilized in combustion applications such as boilers and engines (IPCC, 2005).. Pre-combustion capture can be applied to Integrated Gasification Combined Cycle (IGCC) power plants using coal as fuel, but this will incur an efficiency loss of 7–8%. Natural gas, as it mainly contains CH₄, can be reformed to syngas containing H₂ and CO (Eq. 2-3)). The content of H₂ can be increased by the water gas shift reaction (Eq 2-2).



2.2.1.2 Oxyfuel combustion

In oxyfuel combustion, the fuel reacts with pure oxygen instead of an air mixture (Leung et al., 2014). Oxyfuel combustion uses the amount of nitrogen present in the exhaust gas until it is reduced greatly. Consequently, there is a substantial reduction in thermal NO_x in this process (Leung et al., 2014). When fuel combustion occurs in pure oxygen conditions, the generated flame burns at very high temperatures. To counter this, carbon dioxide and/or waste gases, which contain steam, are circulated in the reactor/combustion engine (IPCC, 2005)

As a result of the pure oxygen conditions, the composition of the flue gas consists mainly of CO₂, H₂, particulates, and SO₂. Particulates and SO₂ can be easily stripped off the mixture. The remaining flue gas, which now contains CO₂ in high concentration, can be separated, compressed, transported, and stored (Leung et al., 2014).

This results in high CO₂ concentrations in the gas stream and, hence, in the easier separation of CO₂ and increased energy requirements in the separation of oxygen from the air (Figure 2-6).

2.2.1.3 Post-combustion capture of CO₂

Post-combustion systems separate CO₂ from the flue gases produced by the combustion of the primary fuel in air. However, it is literature concerning carbon capture from natural gas-fired engines that is relevant in this study, since it is focused on natural gas combustion. CO₂ concentration in this case is much lower than what it is in the flue gas from coal-fired boilers.

Post-combustion processes are the most developed and researched upon for CO₂ capture. Post-combustion carbon capture in power plants is economically feasible under specific conditions. Post-combustion capture is compatible with currently existing plants without significant modifications (M. Wang et al., 2011). The drawback, however, is the loss of the efficiency of power generation.

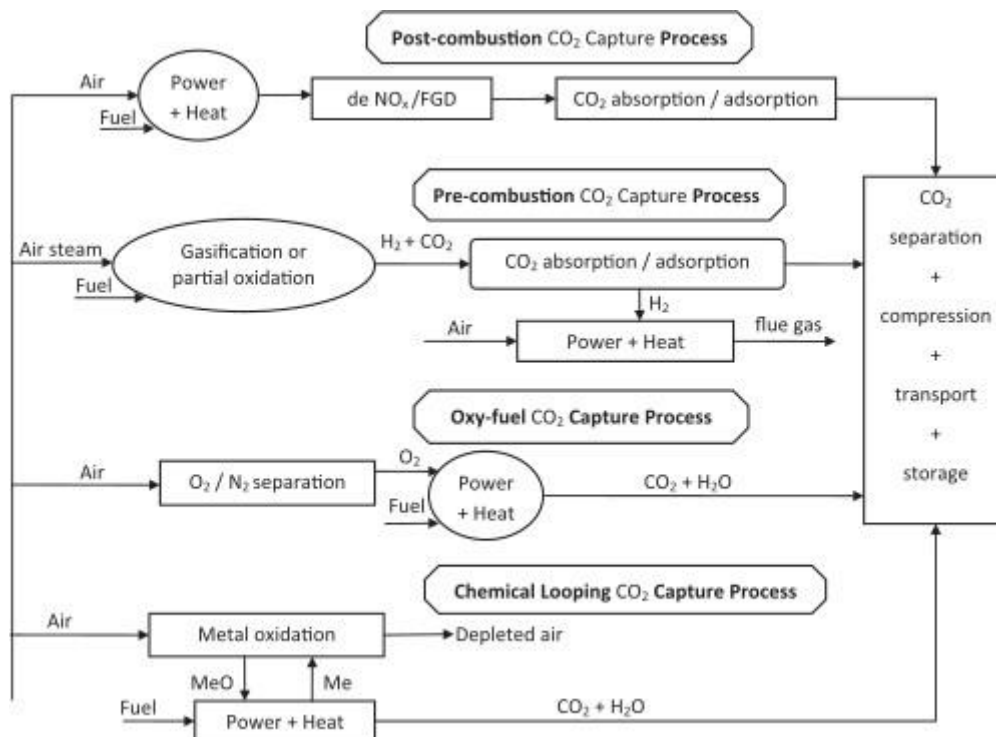


Figure 2–5: Process diagram for CO₂ capture processes (Leung et al., 2014)

2.2.2 Separation technologies

The following section provides details for the methods used to separate CO₂ from the flue gases. The main methods discussed and analyzed in this section are absorption, adsorption, chemical looping combustion, membrane separation, cryogenic distillation.

2.2.2.1 Absorption in a liquid solvent

CO₂ is isolated from the flue gas with the aid of a liquid solvent, which can be reused after a stripping process either by providing heat or depressurization (Leung et al., 2014). This process is considered the most developed for CO₂ separation (Bhown & Freeman, 2011). The most commonly- utilised sorbents are (MEA), diethanolamine (DEA), and potassium carbonate. From all the alkanolamines, such as MEA and DEA, MEA was found the most efficient one for CO₂ absorption over 90% (Thitakamol et al., 2009). Some different solvents, for example, piperazine and anion-functionalized ionic fluid have been considered in recent years (Gurkan et al., 2010). Piperazine has been reported to have faster reaction times than MEA, but since it is more volatile than MEA, its application in CO₂ retention is more high-priced (Bougie & Iliuta, 2011).

One significant test for this innovation is its potential amine degradation, which leads to solvent loss, damage to the equipment, and volatile compounds (Leung et al., 2014). Besides, amine emissions can react and form nitrosamines and nitramines which have detrimental effects both for the environment and human health (SEPA, 2015).

There are several commercially available process technologies which can in principle be used for CO₂ capture from flue gases. However, comparative assessment studies (Riemer & Ormerod, 1995) have shown that absorption processes based on chemical solvents are currently the preferred option for post-combustion CO₂ capture. They offer high capture efficiency and selectivity, and the lowest energy use and costs when compared with other existing post-

combustion capture processes (IPCC, 2005; M. Wang et al., 2011). Since post-combustion process and separation by absorption demonstrate relatively ideal compatabillity and absorption by liquid solvent is the chosen method in this study, the following paragraphs describe an absorption process by detail.

In a post-combustion process, after cooling, the flue gas is brought into direct contact with a CO₂ capture solvent counter-currently in the absorption column as is schematically shown in Figure (2-7). Since flue gas is usually at atmospheric pressure, the partial pressure of CO₂ will fluctuate between 3-15 .provided to the reboiler, the reaction is reverted, and the solvent is recirculated to the system. The CO₂ is isolated at the top of the stripper column in a gaseous phase. A blower is needed to counter for the pressure drop at the absorber column (IPCC, 2005). The absorber temperatures range between 40°C and 60°C. CO₂ reacts, then, reacts with the solvent. The CO₂-rich solvent is then, transferred to the stripper column, where the reverse reaction will take place. The temperature range for regeneration is set between 100°C and 140°C. Pressure, inside the column, however, is measured just a bit greater than the atmospheric pressure. Heat must be provided at a constant rate to the reboiler, to sustain the temperature for the regeneration. The thermal energy cost is generated then as a result of the heating required to separate the CO₂ from the solvent. The isolated carbon dioxide exits the stripper column while steam is recirculated. The lean solvent is transferred to the absorber after it has been cooled down.

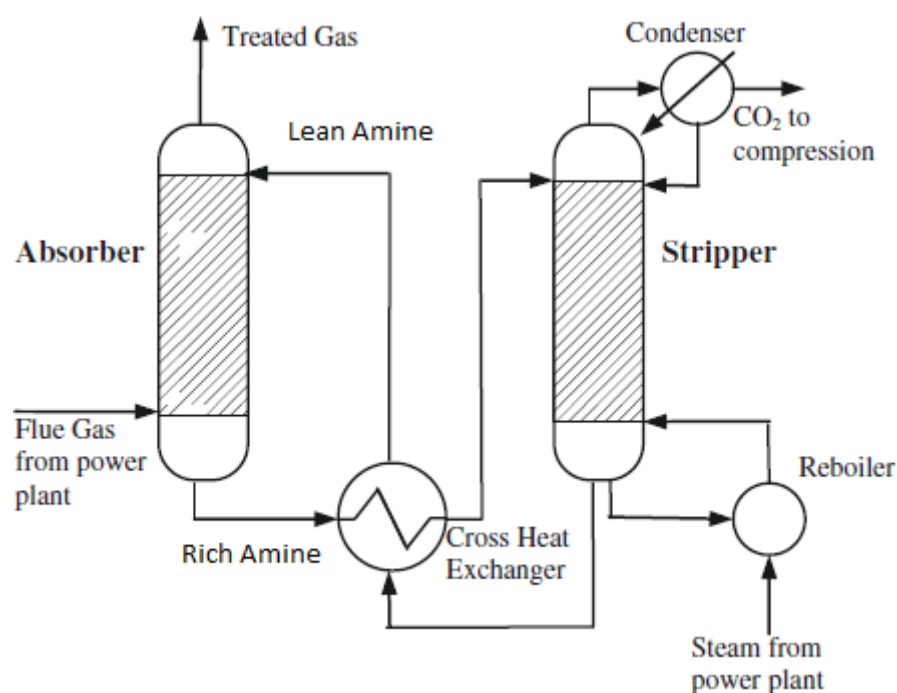


Figure 2–6: Flow diagram for CO₂ recovery from flue gas (Van den Akker, 2017)

2.2.2.2 Adsorption in a solid

As opposed to absorption processes which utilize a liquid solvent, a solid sorbent is utilized to confine the CO₂ on its surfaces. Large specific surface area, high selectivity, and high regeneration are the principal characteristics for solvent selection. Commonplace solvents incorporate sub-atomic strainers, initiated carbon, zeolites, calcium oxides, hydrotalcites, and lithium zirconate. The adsorbed CO₂ can be isolated by swinging the pressure (PSA) or temperature (TSA) of the system. PSA is a commercially developed method , with efficicnecy that can reach and even 85% (Takamura et al., 2001). In PSA, CO₂ is adsorbed in the surface of a slid material in high pressure. Afterwards, the pressure will decrease in order to release CO₂ for transport and further utilisation. In TSA, the adsorbed CO₂ is released as the system temperature is augmented with the use of hot air or steam injection. TSA has the drawback of slower regeneration but can produce purity of CO₂ higher than 95% and recovery rates greater than 80% (Clausse et al., 2011). The operating expenses of a specific TSA procedure was calcuatltd ti be near 80–150 US \$/tonne per CO₂ captured (Leung et al., 2014). Additionally, wastes form the industrial and

agricultural sectors, could be recycled as sorbents for adsorption, a practice that can reduce costs greatly if adapted.

2.2.2.3 Chemical looping combustion

A metal oxide takes the role of oxygen carrier, without having to use pure oxygen directly (Leung et al., 2014). The metal oxide is reduced to form a metal, while the fuel is oxidized to CO₂ and water. Then the metal is oxidized again and is recycled back in the process (Leung et al., 2014). Water, the by-product of this procedure, is discarded by condensation, as pure CO₂ is acquired without any energy consumption for separation. There is a plethora of metal-oxides, which are both low-cost and suitable for this process, including Fe₂O₃, NiO, CuO, and Mn₂O₃. Comparison of IGCC with pre-combustion and chemical looping combustion have shown the net plant efficiency of the latter is 2,8% higher (Erlach et al., 2011)

2.2.2.4 Membrane separation

The membrane can be used to allow only CO₂ to pass through while blocking other substances of the flue gas. The membrane, which is the most important part of the process, consists of a composite polymer. A thin layer of this material is connected to a thicker, non-selective and low-cost layer that provides mechanical support to the membrane (Rackley, 2017). This process is also used to separate other gases, such as O₂ from N₂ and CO₂ from natural gas (Leung et al., 2014). Production of ceramic and metallic membranes and polymeric membranes for membrane diffusion could lead to more efficient CO₂ separation than absorption processes based on liquid (Leung et al., 2014)

2.2.2.5 Hydrate-based separation

Hydrate-based CO₂ separation is a process in which the flue gas is treated with water under high pressure to form hydrates. The CO₂ is selectively engaged by the hydrates and is separated from other gases. The chemical mechanism behind this method is the fact that CO₂ can form hydrates easier, than other gases, such as N₂. This technology has the benefit of a low energy cost. The energy demand could be as low as 0.57 kWh/kg CO₂. Improving, the hydrate

formation rate while limiting hydrate pressure would result in greater the CO₂ capture rates. Tetrahydrofuran (THF) is a water-miscible solvent, that can form a bond with water at low temperature to form solid clathrate structures (Leung et al., 2014). As demonstrated by a study, even a small amount of THF dramatically decreases the formation pressure of hydrates allowing for CO₂ capture at medium pressures (Linga et al., 2008).

2.2.2.6 Cryogenic distillation

Cryogenic distillation is a technology that facilitates gas separation. This process has many similarities with other distillation methods, but it specializes in the separation of components of gaseous mixtures, instead of liquid (Leung et al., 2014). For CO₂ separation, the temperature of the waste gas, which contains CO₂, is lowered to desublimation area (-100°C to -135°C), and then the solidified CO₂ is separated and compressed to a high pressure of 100-200 atmospheres. The recovery rate can almost reach 90-95% of the flue gas (Leung et al., 2014). This technology, however, is very energy-demanding, calculated to be 600-660 kWh per tonne of CO₂ retrieved in liquid form (Giittlicher & Pruschek, 1997).

2.2.2.7 Comparison of carbon capture processes.

In pre-combustion carbon capture, CO₂ concentration in the gas is higher which reduces the investment cost and the required energy to capture CO₂. Pre-combustion carbon capture is a fully developed technology, already commercially developed in certain industrial sectors. However, fuel processing is more expensive and complex, compared to the post-combustion capture system (Leung et al., 2014). Post-combustion carbon capture is the most mature method compared to other methods. The procedure can be easily retrofitted in older installations and does not require a change in the combustion equipment. On the other hand, the demand for separation is high since the concentration of CO₂ in the flue gas fluctuates around 4-14%. Oxy-fuel combustion results in flue gases with high CO₂ concentrations. High CO₂ concentration leads to more efficient and cost-effective separation. CO₂ concentration exceeds 80%, when for in ambient air combustion, it is in the 14-33% range. In this case, however,

the cost of air separation is a very unattractive factor (Pocklington & Leese, 2009).

Table 2-2: Comparison of different separation technologies. (Leung et al., 2014)

Technology	Benefits	Drawbacks
Absorption	<ul style="list-style-type: none"> -High absorption efficiency (>90%) -Sorbents can be regenerated by heating and/or depressurization -Most mature for CO₂ separation 	<ul style="list-style-type: none"> - Absorption efficiency depends on CO₂ concentration - Significant amounts of heat for absorbent regeneration are required -Environmental impacts related to sorbent degradation have to be researched further.
Adsorption	<ul style="list-style-type: none"> -Process is reversible and the adsorbent can be recycled -High adsorption efficiency achievable (>85%) 	<ul style="list-style-type: none"> -Require high-temperature adsorbent - High energy required for CO₂ desorption
Chemical looping combustion	<ul style="list-style-type: none"> -CO₂ is the main combustion product, which remains unmixed with N₂, thus avoiding energy-intensive air separation -Process has been adopted for separation of other gases -High separation efficiency achievable (>80%) 	<ul style="list-style-type: none"> -Process is still under development and there is no large-scale operation experience - Operational problems include low fluxes and fouling
Hydrate-based separation	<ul style="list-style-type: none"> -Small energy penalty 	<ul style="list-style-type: none"> -New technology and more research and development are required
Cryogenic distillation	<ul style="list-style-type: none"> -Mature technology -Adopted for many years in the industry for CO₂ recovery 	<ul style="list-style-type: none"> - Only viable for very high CO₂ concentration > 90% v/v - Should be conducted at a very low temperature - Process is very energy-intensive.

2.3 Ship Based Carbon Capture (SBCC)

The equipment of carbon capture installation can be fitted onboard a ship as previous studies have shown (van den Akker, 2017). However, that requires major modifications on the ship and the logistics of fuel distribution. The present

review was based on very few studies. Namely, “Process and Economic Evaluation of an Onboard Capture System for LNG-Fueled CO₂ Carriers” by A. Awoyomi et al, “Carbon Capture onboard an LNG-fueled ship: a feasibility study” MSc Thesis of Van den Akker, and “Ship-based carbon capture onboard of diesel or LNG-fueled ships” by Feenstra et al., 2019. These studies examine in detail how such a system could work in terms of energy and ship space management. They propose the utilization of the flue gas heat to save energy costs for the carbon capture process. Van den Akker showed that is possible to fit a carbon capture installation for a ship using a general cargo vessel as an example. Feenstra et al. demonstrated that aiming for a 90% capture rate is feasible and that for higher capture rates the cost per carbon tone captured lessens. Awoyomi et al, investigate the integration of exhaust gas recirculation (EGR) system, in order to increase the efficiency of the process. The conclusion was that the cost of capture decreases when the capture rate is increased, with the added effects of an EGR system. In SBCC, the heat available is defined by the type of engine used and the perpetual load. There are plenty of particular issues critical to this application: Efficiency of the capture process, energy penalty for on-board liquefaction, as well as cost issues.

2.3.1 Efficiency of SBCC

The efficiency process depends greatly on the solvent used in the absorption process, as the thermal cost in the stripper has the most impact in the total energy penalty. Monoethanolamine, a popular solvent for this method, is connected with an energy demand around 3.5 GJ per tonne of CO captured. The energy penalty for gas-fired power station, under these conditions, would amount almost to 16%, compared to a power station with no carbon capture facilities (Sanchez-Fernandez, 2013). There has been progress regarding solvent options. In the first Post-Combustion Capture Conference, Siemens researchers presented a process with a relatively low energy cost of 2.7 GJ/tonne CO₂ (Schneider & Schramm, 2011). Modern power stations, include systems in their operational cycles which can retrieve the thermal energy of exhaust gases. At certain cases, almost 6% of the total energy of the waste gases is not recovered

(Sanchez-Fernandez, 2013). Ships, on the contrary, do not usually take advantage of the thermal energy in the waste gases, a heat source that could be proven very convenient for a capture carbon installation Van den Akker, 2017).

2.3.2 The onboard storage of CO₂

Storage CO₂ in a gaseous state is not a viable choice because of space limitations. CO₂, therefore, should be stored either in a solid or in a liquid state. Storage in the solid state can be achieved in two ways. Cooling CO₂ at solidification temperature is one of the possible strategies. At 1 atm pressure, this temperature is -78°C. At this pressure and temperature, the enthalpy of sublimation of the gas is 573 kJ/kg (NIST, 2021). The energy penalty for this cost would be quite high. Another solution is using another substance which can form chemical bonds with CO₂, as suggested by some researchers (H. Wang, 2017). However, there is the drawback of adding extra weight to the ship. A drawback of solid CO₂ storage is that a thorough system for handling the CO₂ would have to be designed, that would eliminate any possible hazard for the crew. Developing such a system, would be a very difficult task (van den Akker, 2017).

Storage in the liquid state is the most sensible approach. The triple point of carbon dioxide is at 5.18 bar and -56,6°C. The minimum required pressure to store CO₂ as a liquid is 5.18 bar. Nonetheless, storing CO₂ near triple point conditions, could cause solid CO₂ to form. Solid CO₂ presence could clog the piping infrastructure and slow down transferring from the CO₂ tank.

For maritime transfer of large quantities (over 10,000 tonnes) of CO₂ the recommended pressure is around 7 bar and -50°C (Mitsubishi Heavy Industries, 2004). Low storage pressure permits the usage of large tanks, by lowering the manufacturing costs. For lower quantities, higher temperatures (and pressure) can be also applied, reducing the total energy cost.

2.3.3 Energy penalty for onboard liquefaction

In the studies mentioned above, the CO₂ is compressed, in ambient temperature, to a supercritical state (100-110 bar) for pipeline transport (Sanchez-Fernandez, 2013; Schneider & Schramm, 2011). Another approach would be to liquify CO₂ at a lower temperature. Van den Akker, examined the case where CO₂ is stored as at -26°C. The energy consumption, however, would be greater in comparison. The necessary energy to compress CO₂ to 110 bar is almost 0.31 GJ_e/tonne CO₂ or 86 kWh per tonne of CO₂ (Sanchez-Fernandez, 2013). The energy cost to liquify CO₂ to 24°C is 130 kWh/tonne CO₂ at 18 bar. However, the energy demand for the capturing process is measured at 830 kWh/tonne (van den Akker, 2017). Hence, its impact on the total energy cost is more significant.

Energy for CO₂ compression can be supplied from either the main or the auxiliary engines. Nonetheless, the energy required for cooling is thermal. Hence, a «cold» source is needed for the heat transfer, if available on the ship. LNG is stored at -160°C but it needs to be at 0°C before entering the engine. The heat source, in that case, is the cooling water of the ship. The LNG could absorb the required heat from the CO₂, thereby cooling it. A heat transfer between the fuel and CO₂, could definitely reduce the energy costs involved in CO₂ storage (van den Akker, 2017). Finally, a cost comparison between the capture processes exclusively is given in the table (2-3). The costs of electricity generation include the cost of CO₂ compression to 11 MPa but exclude the costs of CO₂ transport and storage, which will depend strongly on location conditions. If CO₂ is used for enhanced oil recovery there may be a net revenue from CO₂ transport and storage, which reduces the net cost of electricity. A cost of \$10/tonne of CO₂ stored would be equivalent to about 0.4c/kWh for the natural gas-fired plants and 0.8c/kWh for the coal-fired plants. The cost of CO₂ emissions avoided for the gas-fired plants is relative to the gas-fired combined cycle plant without capture. The cost of CO₂ emissions avoided for the coal-fired plants is relative to the pulverized coal-fired plant without capture.

2.4 Transport

As soon as the separation of CO₂ is complete, the captured CO₂ needs to be transported to the storage site or to the industrial complex, where it will be utilized. A reliable, secure, and viable transportation is critical to any CSS system. The quantity that needs to be transported dictates the method that will be used (Leung et al., 2014). These methods include road tankers, ships, and pipelines. The separation of CO₂ in the natural gas processing industry, which uses similar technology, operates in a “Mature market” mode, meaning that the technology is now in operation with multiple replications of the commercial-scale technology worldwide.

Pipelines are generally thought to be the most feasible method for land transport of high volumes of CO₂ (Svensson et al., 2004), even for long distances when the case demands it, and are preferred for transporting large amounts of CO₂ for distances up to around 1,000 km. For amounts smaller than a few million tonnes of CO₂ per year or for larger distances overseas, the use of ships, where applicable, could be economically more attractive.

The transport costs fluctuate greatly, depending on the economic state of each region. In China, a cost analysis study concluded that for a mass flow of 4000 tCO₂/day the use of ship tankers will cost 7.48 USD/tonne CO₂ (Gao et al., 2011). In comparison, the cost for transport via railway tankers would be 12.64 USD/tonne and 7.05 USD/tonne for 300 Km pipelines. In the North Sea, CO₂ transport by ship tankers is discerned to be feasible and cost competitive (Kjärstad et al., 2016). Transportation and storage data are even more difficult to generalize compared to CO₂ capture process data, given that they are very site-specific or even unique for every single project. Because of this complexity, available storage capacities and associated costs still remain subject to significant research in many regions of the world.

2.5 CO₂ Utilization

Today, around 230 million tonnes (Mt) of CO₂ are used each year (IEA, 2019). The largest consumer is the fertilizer industry, where around 130 MtCO₂ per year is used in urea manufacturing, followed by the oil sector, with a consumption of 70 to 80 MtCO₂ for enhanced oil recovery (EOR) (IEA, 2019).

The five key categories of CO₂-derived products and services with market potential are fuels, chemicals including soaps, building materials from minerals, building materials from waste, and CO₂ use to enhance the yields of biological processes. CO₂ is also widely used in food and beverage production, the fabrication of metal, cooling, fire suppression, and greenhouses to stimulate plant growth, (Figure 2-7).

Commercial and regulatory obstacles are impeding the expansion of CO₂, rather than technological limitations. Production costs are much greater for CO₂-based fuels and chemicals in comparison to their conventionally produced counterparts. Production on a commercial large scale is possible in places with available renewable energy, such as Iceland or Chile. CO₂ derived polymers could be generated at a reduced cost to their fossil-derived counterparts, but the market size is not inviting to investors. Building materials produced from CO₂ and minerals can be competitive today, as CO₂-cured concrete has lower costs and better performance than conventional concrete. The utilization of waste and CO₂ could prove to be a viable option since it bypasses all the costs associated with conventional waste disposals. Also of great relevance is that CO₂ in building materials is permanently stored. This adds environmental benefits to the final product derived.

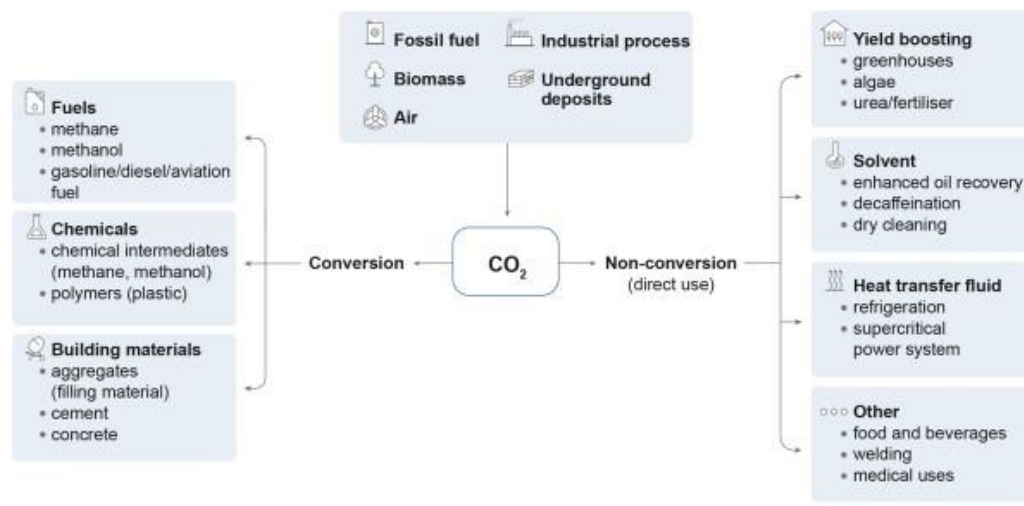


Figure 2–7: CO₂ utilization pathways (IEA, 2019)

2.5.1 CO₂ derived fuels

Fuels, that can be generated from CO₂ include methane, methanol, gasoline, and aviation fuels. The chemical process for the fuel synthesis, however, needs both hydrogen and CO₂. Hydrogen production is a very demanding procedure energy-wise. The fuel that is produced from this procedure is more stable than pure hydrogen. In cases where the application of other low carbon energy sources, such as electricity or hydrogen, has proven to be extremely challenging, like in aviation, where the utilization of CO₂-derived fuels seems to be a very promising solution. A large number of companies have invested in pilot plants, which aim to use tonnes of CO₂ to generate methanol and methane. There are also other chemical and biological conversion pathways to produce CO₂-derived fuels, which are still in the early stage of research (IEA, 2019)

2.5.2 CO₂ in agriculture

CO₂ utilization in greenhouses is a field where CO₂ can have commercial applications. CCU in an industrial greenhouse is the most developed method to increase crops production, which can result in a 25-30% production boost. Netherlands is the clear leader in CO₂ usage in greenhouses, with annual consumption between 5 and 6 MtCO₂- 500KtCO₂ per year of this amount comes from external sources, mainly industrial plants Most of it is produced by means

of combined heat and power (CHP) installations (Mikunda et al., 2015). Hence, carbon capture and utilization (CCU) has the potential to provide business cases as CO₂ waste streams are turned into feedstock for the synthesis of marketable products.

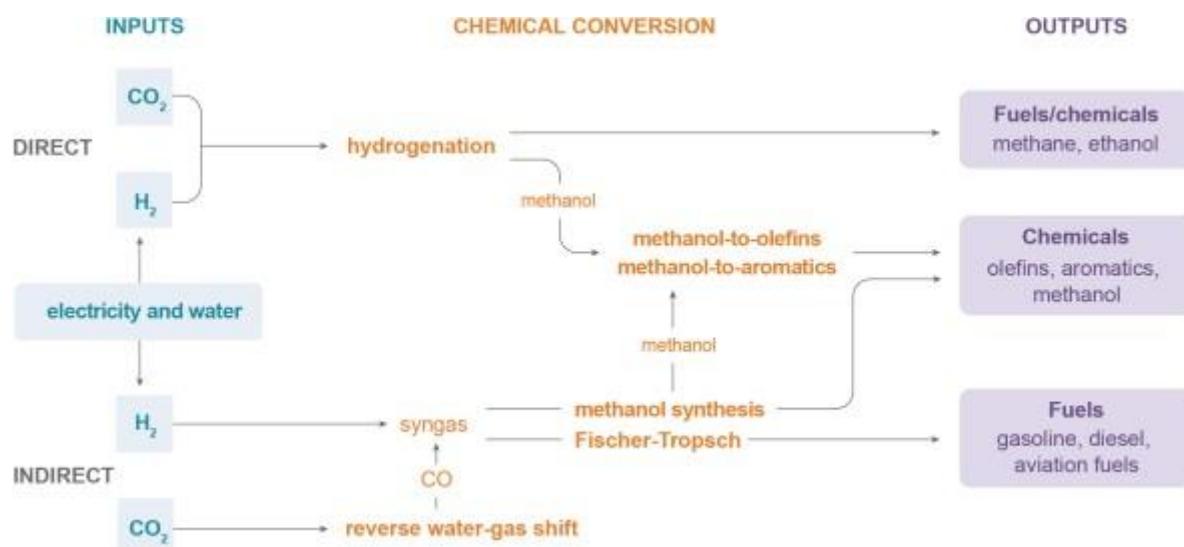


Figure 2–8: CO₂ chemical conversion scheme (IEA, 2019)

2.6 Cost evaluation parameters

Cost data are usually split into capital costs or CAPEX, related to the construction of equipment, fuel costs, and nonfuel operating and maintenance costs (related to the process and its equipment). These are used together to calculate the first-year cost of electricity (COE) or LCOE, since the first plants constructed were electricity production plants, over the lifetime of the plant. Sources of capital costs are often not clearly stated in publications. Carbon capture and storage (CCS) and carbon capture and utilization (CCU) are evaluated by the International Energy Agency (IEA) and U.S. Energy Information Administration (EIA) as two of the most cost-effective methods for climate change mitigation among various technologies (IEA, 2019). Harmonization of costing methodologies is needed to simplify technology comparisons, to increase transparency.

Financial or investment planning regarding CCS units is affected by many special conditions, i.e., national, or regional policies, emission caps and the background of the investor. Additionally, fuel quality and price will surely impact the decision-making (Finkerath, 2011). CCS economic planning utilizes LCOE, and CO₂ avoided cost, with CCS technology by integrating the energy penalty when accounting for the construction of the power generation plant. LCOE is the average income per unit of electric energy generated that would equal the expenses of construction and operation of a plant during a precise financial cycle. CO₂ captured cost is derived using a plant without a CCS unit installed as a benchmark (Lee et al., 2020). CO₂ void cost can be calculated by balancing the costs of a power plant with and without CCS technology. CO₂ avoidance cost is the CO₂ tax at which the product cost is the same for a plant without CO₂ mitigation technology (but paying the CO₂ tax) and of the same fuel plant that includes CCS technology but has to account for the added capital and the loss of efficiency. Analyzed techno-economic data and key target metrics commonly required as input for energy scenario modelling and general energy policy support are power type, capacity factor, net power output, net efficiency, fuel type, overall CO₂ capture rate, net CO₂ emissions, capital cost, operation and maintenance cost, year of cost data (Lee et al., 2020).

Published techno-economic information is reviewed and re-evaluated to compare the results of different studies. (IEA 2011). Overnight costs include pre-construction or owner's costs, and contingency costs: engineering, procurement, and construction costs. Overnight costs assume a power plant could be constructed in a single day. They reflect technological and engineering costs in a particular country and the financial infrastructure that is in place to realize construction. Contingency costs are included to reflect cost uncertainties due to the level of project definition, the risk related to technology maturity and performance, or unforeseen regulatory difficulties.

3 METHODOLOGY

3.1 Simulation models

To better understand the system of on-board CCS, process modelling is applied. Process modelling is a very useful tool since it provides the opportunity to better understand the implications of the system (properties, dimensions, utilities) while saving time, since there is no need to design and build and actual test system.

In this study, LNG combustion and CC process are simulated on ASPEN PLUS™ software V11.

The simulation examines four engine loads (load factors). Load factor of the engine is the actual power output of its engine relative to its maximum continuous rating (MCR) (Ships Business, 2015). MCR is defined as the maximum power output generated by an engine as it operates, continuously at secure conditions (Marine Insight, 2021). Under normal operating conditions, it is preferred that the engine load is maintained at a steady condition. (Ships Business, 2015)

3.1.1 Modelling the LNG combustion

The engine chosen to be modelled is the 3000 kW Wärtsilä 6L34DF, a dual fuel type engine, that runs on both LNG and diesel oil. An engine this size is broadly used in cargo ships (van den Akker, 2017). On LNG operation, a small amount of diesel (pilot fuel) is used as well, to aid in ignition (Wartsilla, 2020). For the purposes of this thesis, it is assumed that no pilot fuel is used.

The air flow is transferred through a splitter before being divided to two streams. Both streams are of the same composition and are compressed to 2.0265 bar.

Afterwards, the streams are heated to 250°C before entering the mixer. After having been through the mixer, then final stream is compressed to 12.1325 bar. The LNG fuel is stored at -160°C, to maintain its liquid stage needed for storage. To enter the Gibbs reactor, which is used to simulate the combustion process of the engine, the fuel must be vaporized. In the model, a heater has been used, but the heat transfer needed for this operation can also be realized via a heat transfer between the low temperature LNG stream and the high temperature isolated CO₂ steam (The isolated CO₂ is the product the carbon capture process.). LNG must enter the engine at a temperature range between 0°C-60°C. At this simulation it enters the engine at 10°C. Natural gas is usually very rich on CH₄, contains lesser amounts of C₂H₆ and C₃H₈ and has traces of non-organic components, i.e., N₂ and O₂. In this study, the molar composition of LNG is as shown on table 3-1

Table 3-1: LNG composition

Component	Composition
CH ₄	91.4%
C ₂ H ₆	7.2%
C ₃ H ₈	0.5%
N ₂	0.9%

Fuel flow rate is also an important parameter that must be defined as well. The product guide gives the values for the fuel consumption for each load. Knowing the lower heating value (LHV) of LNG, the fuel flow rate can be calculated.

$$Fuel\ flow\ rate\ \left(\frac{kg}{hr}\right) = \left(\frac{FC}{LHV}\right) * 3000\ (kW) \quad (3-1)$$

A schematic representation of the basic combustion process is demonstrated on figure 3.1.

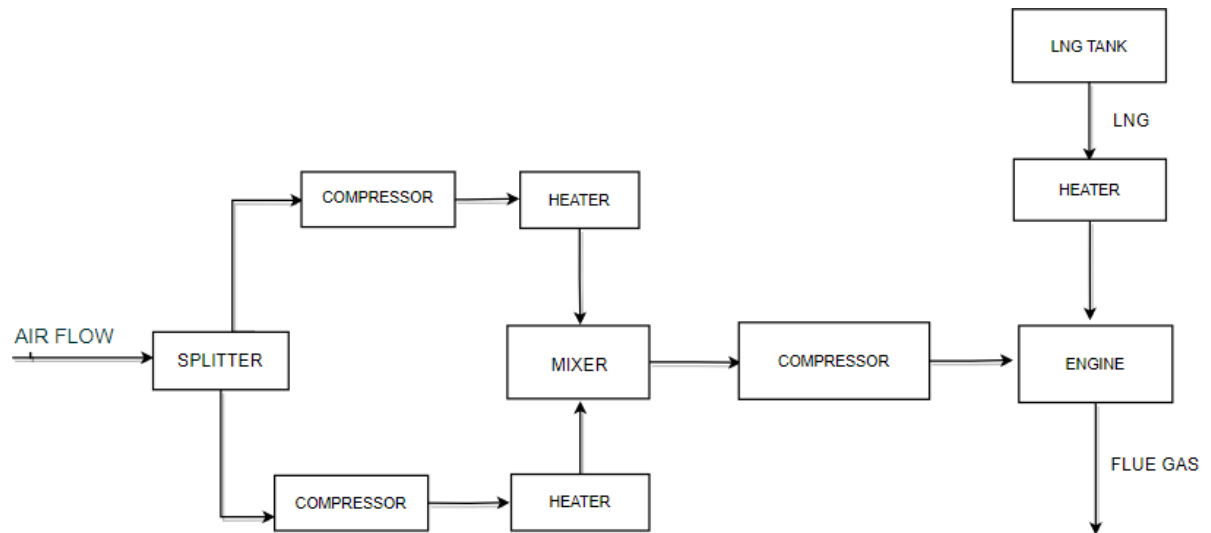


Figure 3–1: Process flowchart for the LNG combustion process.

Specific fuel consumption (figures are taken from the product guide) and flow rates for each engine load are demonstrated on table 3-2.

Table 3-2: Fuel consumption and Fuel flow rates for each engine load

Engine Load	Specific Fuel consumption (kJ/kWh)	Fuel flow rate (kg/hr)
50%	8345	252.1161
75%	7743	350.9674
85%	7527	386.971
100%	7387	446.7956

To validate the modelling of the LNG engine, the results for the flue gas flow rate generated by the simulation will be compared to the figures found on the product guide (Wartsilla, 2020)

Table 3-3: Exhaust gas flowrate, modelling-product guide comparison

Engine load	Exhaust gas flowrate (kg/s) (Product guide)	Exhaust gas flowrate (kg/s) ()
50%	3.1 kg/s	3 kg/s
75%	3.8 kg/s	3.95 kg/s
100%	4.6 kg/s	4.59 kg/s

As seen on Table 3-3 the model is validated since the resulting flue gas flow rates for each loading are very close to the numbers given by the guide.

Unfortunately, the product guide did not contain the flue gas flow rate for 85% load. It must be mentioned that the guide is updated regularly by Wärtsilä, and the figures presented here are subject to change.

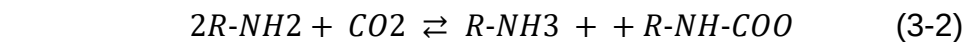
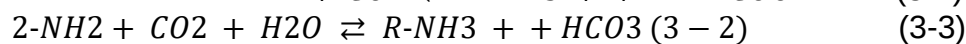
3.1.2 Modelling the Carbon Capture procedure

The SBCC procedure simulated, is a post-combustion procedure with MEA similar in concept to on land procedure. Again, the parameters and the assumption of the model will be discussed. For the main processes of the onboard carbon capture plant, in which the MEA is involved (absorption, stripping, heat-exchanger), the Electrolyte-NRTL model and Redlich-Kwong equation of state (EOS) was chosen. Precise modelling of the thermodynamic properties of CO₂ absorption in aqueous alkanolamine solutions is crucial for the accuracy and the validity of the results. Vapour-Liquid equilibrium, heat capacity and speciation of a system consisting of MEA-CO₂-H₂O can be determined accurately enough with the Electrolyte-NRTL EOS ((Zhang & Chen, 2011) Processes which only involve the flue gas (cooling, heating), the utilized equation of state was Peng- Robinson-Boston-Mathews (PRBM). Peng- Robinson is amongst the most frequently selected equations states for natural gas procedures in the petroleum industry. (Adewumi, 2021)

The solvent solution chosen was 30 wt.% MEA and the packing material used in the absorption column is Sulzer Mellapack X125.

3.1.2.1 SBCC Process description

The flue gas is treated with an amine solvent, monoethanolamine (MEA) (30% wt.) in the absorber. The CO₂ in the flue gas reacts with the amine to form carbamates. The reactions that take place are the following.



In the next stage of the procedure, the rich amine stream is transferred to the stripping column, where the reverse reaction occurs. As a result, the captured CO₂ is isolated and can be collected. Additionally, the amine is regenerated and is circulated back into the system.

The energy demands, however, for the reboiler of the stripping column can be met from the heat provided by the flue gas stream itself. In that way, the system does not require any external heat source for the intensive amine stripping process.

The flue gas is directed through a cooler and heat exchanger (which uses sea water as a coolant) to be cooled down before it enters the absorption column, in which it will be treated with MEA solution.

The packing material used in the absorption column is Sulzer Mellapack X125. After the absorption process has ended, the flue gas which now contains less CO₂ is freed to the atmosphere while the rich amine (the solution has now captured CO₂ as reactions (3.1) and (3.2) have taken place inside the absorption column) is pumped through a heat exchanger to the stripping column. In the stripping column, the reverse reactions are favored. As a result, CO₂ is separated and subsequently is directed to a flash separator to rid it off any possible impurities. The amine is regenerated and recirculated back to the system. All the columns are modelled after the rate-based approach. The design of the system was based on the carbon capture Aspen plus model presented in the paper by Feenstra et al.

Figure 3-2 demonstrates the flowchart for the Carbon capture process.

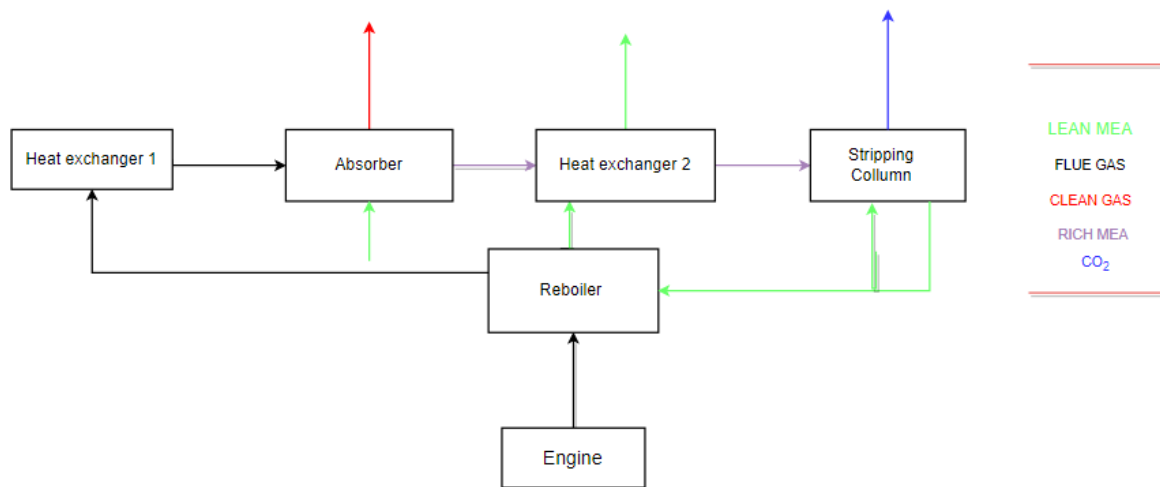


Figure 3–2: Schematic representation of the on-board carbon capture process.

3.1.2.2 Heat and cold side integration

The possibility of waste heat recovery (WHR) is a very critical feature of SBCC. WHR is a by-product of processing plants, for which no application is designed. Instead of taking advantage of this heat surplus, it is discarded to the environment (Jouhara et al., 2018)

In SBCC, excess heat carried by the exhaust gas can be put to use by supplying the reboiler with the necessary heat for its operation. The proposed heat transfer occurs between the flue gas and the amine on the reboiler. Is however the heat sufficient for the needs of the system?

Akker (2017) and Feenstra et al. (2019), have shown that heat integration is feasible for 100% engine load. While Van den Akker discusses the possibility for lower loads as well and concludes that it should be feasible, there is no comparison with reboiler duty.

Cold side integration is achievable since the isolated CO₂ exits the top of the reboiler at a very high temperature. The thermal energy can be transferred to

LNG to vaporize it and cool down CO₂ as well. Cooling down and liquefying CO₂ is necessary for its storage. Conclusions about energy management will be discussed on the results section.

3.2 Implementing machine learning- Collecting and analysing data.

Machine learning analysis into this project is focused on regression analysis for the collected data. Examining the relation between certain critical variables of the system, namely, amine flow rate, carbon capture rate and reboiler heat duty was selected. Studying these variables can lead to important conclusions, i.e., choosing the right solvent flow for a certain carbon capture target.

The same number of simulations were executed in the Aspen Plus modelling environment for each engine load. The controlling variable was the flow rate of the amine stream. Analysing the results from these simulations gave insight on the correlation between the amine flow rate and the percentage of carbon captured as well as the necessary heat duty of the reboiler for each case.

Regression analysis is a necessary data-processing technique, which aids in the understanding of the mathematical relations connecting these two variables. The importance of knowing how these variables affect each other is critical, since the goal of the operation is to capture 90% of the available carbon on the flue gas.

Performing this regression analysis is essential for the study on heat integration, since it will provide the data needed to calculate the heat duty and amine flow for the 90% target of carbon capture.

3.3 Economic analysis

Aspen offers a tool of economic analysis, which can be applied to calculate both the equipment expenditure and the operating costs of the installation. Using this information, an analysis can be performed, which would determine the conditions under which this project would be a profitable investment for any shipowners.

Capital expenditures (CAPEX) and operating expenditures (OPEX) are among the most important parameters of the analysis. CAPEX covers all the costs related to equipment and equipment installation while operating costs (OPEX), include all the costs that are accompanied with the continuing usage of the equipment.

3.3.1 CAPEX analysis

Equations 3-4 to 3-7 show the formula which is used to calculate CAPEX. These equations were originally designed for the Octavius project to evaluate large CO₂ capture installations. This method has proven to be very accurate with CAPEX estimations (Feenstra et al., 2019). The following parameters of this formula have to be defined first. Total equipment cost (TEC) is derived through ASPEN PLUS. After having calculated TEC, the following parameters are derived as well, TDPC Total Direct Plant Cost (TDPC), total indirect plant cost (TIPC) and fixed capital Investment (FCI).

$$\text{TDPC} = 2.01 * \text{TEC} \quad (3-4)$$

$$\text{TIPC} = 0.14 * \text{TDPC} \quad (3-5)$$

$$\text{TFCI} = \text{TDPC} + \text{TIPC} \quad (3-6)$$

$$\text{CAPEX} = \text{FCI} \div 0.8 \quad (3-7)$$

It is important to note that the system will be designed for 100% engine load, which is the safest scenario since. Sizing that equipment for 100% load also ensures that it will be operational for all lower loads as well. Therefore, the resulting CAPEX for 100% will be used in the economic analysis for all other loads.

3.3.2 OPEX

As mentioned before, operational costs cover all the costs tied with the continuing usage of the equipment (For example, maintenance costs and power demand costs). Maintenance costs are generated with the aid of APSEN economic analysis but for power demand costs, it is crucial to have information on fuel prices. Mean LNG price for March 2020 was 398€ per metric tonne (TITAN LNG, 2020). With the current conversion rate of \$/€ at 1.18 that price translates to 716.4 USD. Additionally, it is safe to assume that the ship engine is operational for 57% of the time. With all the above information, the power cost can be calculated, for each loading with the following formula (van den Akker, 2017)).

$$\text{Cost} = 0.57 * \text{Power demand} * \text{Fuel consumption} * \text{Operating hours} * \text{Fuel cost} \quad (3-8)$$

To perform these calculations, the specific fuel consumption value is taken from the product guide.

Table 3-4: Fuel consumption rates for each load (Wartsilla, 2020)

Engine load	Specific Fuel consumption (Kg/kw)
50%	0.1501
75%	0.1530
85%	0.1574
100%	0.1714

Table 3-5: Power demand costs for each loading

Engine Load	Cost of power demand (USD)
50%	77898.20
75%	71507.51
85%	68219.81
100%	69512.72

3.3.3 Sensitivity analysis

Decisions regarding investment opportunities, often have long lasting effects. Not only it is difficult to predict these outcomes, any attempt at changing the original decision will be tied to severe financial consequences. Financial decisions should be made by taking into account future conditions, specifically how certain variables, which greatly affect the profitability of an investment, will

vary in the future. The economic factors that are examined in this research are: CAPEX, LNG price and CO₂ price.

On table 3, it becomes evident that CAPEX has a lot more impact on total cost, than OPEX. It is expected then that it would be the most impactful economic input on the sensitivity analysis. LNG price is tied to power demand on the system and therefore it will affect the operational cost. CO₂ price varies with the available market for captured CO₂. In this study, we consider a price of 40\$ per tonne of CO₂ to be sold in a EOR facility, without taking account any transport costs (through pipes or other infrastructure). There are also other industries which utilize CO₂, like the agricultural sector which uses CO₂ to enhance production. For example, in the agricultural sector of the Netherlands, carbon sales have a sales range of 50-80€ per tonne of CO₂ with transport costs of 10€ per tonne (van den Akker, 2017). In the analysis of this research, the index that shows whether the investment is attractive or not is the NPV.

4 Results and Discussion

4.1 Results of carbon capture simulations

From the carbon capture simulation, a data set for each engine load was generated. Each set records the value that the simulation produces for the molar flow rate CO_2 in the flue gas and the clean gas that leaves the absorber. Knowing this information, the carbon capture rate for each MEA flow rate is calculated as shown in the following equation 4-1.

$$\text{Capture rate} = (1 - \text{CO}_{2\text{in}}/\text{CO}_{2\text{out}}) * 100\% \quad (4-1)$$

Where $\text{CO}_{2\text{in}}$ and $\text{CO}_{2\text{out}}$ correspond to the molar flows of CO_2 in the flue gas and the clean gas, respectively.

Before progressing to further analysis, it is best to draw an initial conclusion about the correlation of the examined variables by plotting them in a graph. Figures 4-1 and 4-2 demonstrate the graph for MEA flow and Carbon capture

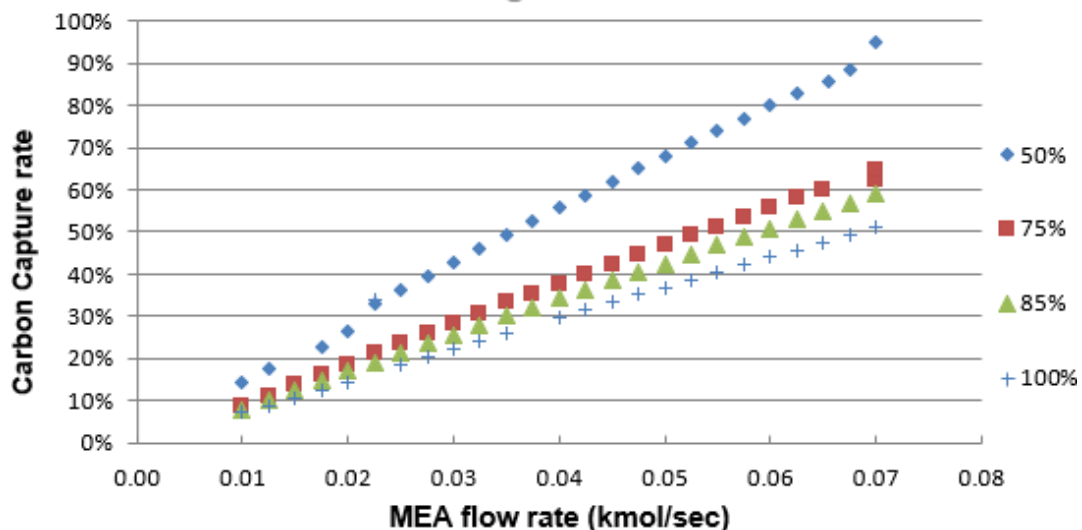


Figure 4–1: MEA flow rate-Carbon capture rate graph for each load

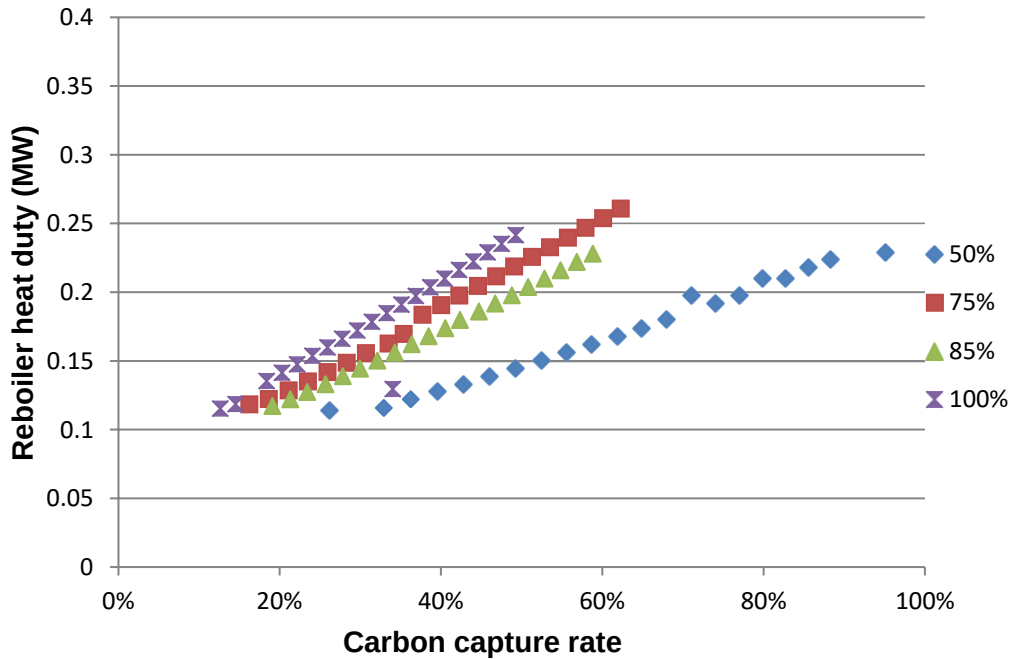


Figure 4–2: Capture rate -Reboiler Heat duty graph.

The graphs seem to reinforce the initial conception that the correlation would be linear and of course positive. The positive correlation was expected since the capture rate would, theoretically, increase when the amine flow was greater but whether that correlation would be linear or of any other nature, was a matter to be examined. The very few datapoints that are out of the general trend represent outliers that came as result of a simulation error.

4.1.1 Regression analysis results.

Regression analysis is a data-processing technique, which aids in the understanding of the mathematical relations connecting the variables. The importance of knowing how these variables affect each other is critical, since a certain target about the capture plant has been set (90% capture rate). Performing this regression analysis is essential for the study on heat integration, since it will provide with the data needed to calculate the heat duty and amine flow for the 90% target of carbon capture. The results of the regression analysis are for each pair of variables, namely MEA flow rate-Carbon capture rate and capture rate- Heat duty, are presented on tables 4.1.

Table 4-1: Regression analysis results

Engine Load	MEA-CC rate equation	CC rate -Reboiler duty Equation
50%	$y=1327.9x+0.11$	$y=0.00340x+0.07$
75%	$y=917.9x+0.01$	$y=0.00323x+0.06$
85%	$y=847.61x$	$y=0.00281x+0.07$
100%	$y=729.32+0.16$	$y=0.00337x+0.08$

As expected in all cases the correlation between the variables is linear. However, to properly evaluate this relation of dependence between all the variables studied, it is important to take into consideration the coefficient of determination (r^2 value) (Renaud & Victoria-Feser, 2010). The closer the value of r^2 is to 1, the more accurate the linear regression is. The r^2 values for each case are presented on tables 3.3 and 3.4.

Table 4-2: r^2 values for amine flow rate -carbon captured linear regression.

Engine Load	MEA flow rate-Carbon capture rate, r^2 value.
50%	0.9918
75%	0.9985
85%	0.9997
100%	0.9997

Table 4-3: r^2 values for carbon captured-heat duty linear regression.

Engine Load	Percentage of Carbon captured- Heat duty, r^2 value.
50%	0.8933
75%	0.9971
85%	0.9991
100%	0.9886

It is evident from these values, that linear regression is the accurate model which describes the correlation between all the variables examined. A test hypothesis was examined on a subset of the dataset.

4.2 . Heat Integration

The possibility of heat integration is an advantage for the onboard carbon capture system, since it provides the opportunity for energy savings, thus making the process more economically viable.

In this case, thermal energy must be provided from the exhaust gas to the reboiler of the stripping column. The heat transfer occurs between the amine at the reboiler and the flue gas, at the temperature it exits the turbocharger. The temperatures for the flue gas for each loading are cited at the Wärtsilä product guide. It also assumed that any excess heat is lost, as the flue gas exits the engine to proceed to the reboiler.

As mentioned in the previous chapter, heat is transferred from the flue gas to the amine in the reboiler. The target temperature is close to 120°C, which mean a ΔT (difference in temperature) of 10°C is a safe assumption.

For the heat specific capacity of the flue gas, the values are generated from ASPEN PLUS and are presented on the following table for each load, except

85% load since the guide did not include other important parameters (flue gas flow rate, temperature as it exits the engine) for this analysis.

Table 4-3: Flue gas heat capacity for each load examined.

Engine Load	Heat Capacity (kJ/kgK)
50%	1.253
75%	1.252
100%	1.130

ASPEN PLUS results can be validated with the following figure which represents the heat capacity for flue gases of natural gas fuel.

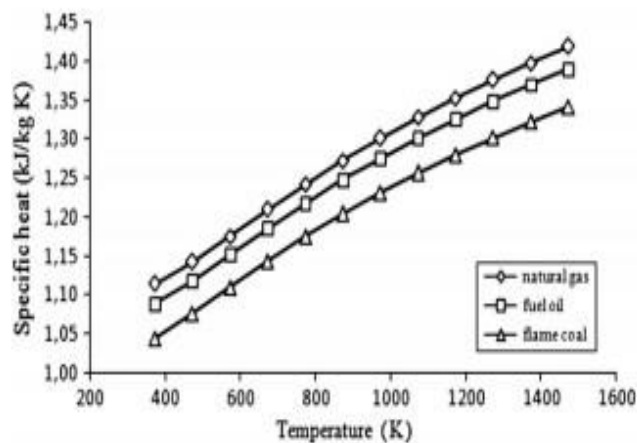


Figure 4-3: Heat capacity for different fuels at different temperatures. (Coskun et al., 2009)

To understand if the heat available in the flue gas leaving the engine is sufficient to meet the energy requirement of the carbon capture process, the heat duty of the reboiler was compared to the heat available in the flue gas. It was assumed that the flue gas is cooled to 130°. As seen in Table 4-5, the available heat duty is sufficient to cover the energy demand of the reboiler at all considered loads. The product guide does not include the turbocharger temperature for 85% load. However, since there is surplus heat in every other engine load, it is safe to assume that heat integration would also be possible for 85% load. This implies that retrofit of the carbon capture process to the LNG-fuelled engine is technically viable and no onboard steam generation will be required.

Table 4-4: Specifications requirements for 90% carbon capture.

Engine load	Flue gas temperature (°C)	Amine flow rate (kmol/sec)	Heat duty (MW)	Available heat duty (MW)
50 %	402	0.0698	0.244	1.083
75%	401	0.097	0.3353	1.323
100%	381	0.112	0.3617	1.336

4.3 Economic Analysis Results

4.3.1 Total cost

A timeframe for the project needs to be decided before any economic analysis. In most cases of available research which studies on-board carbon capture, a period of 25 years was chosen, as it seems a reasonable timeframe for evaluating the investment (Feenstra et al., 2019; Van den Akker, 2017).

Table 4-5 depicts all the assumption made for this hypothetical investment. In Figure 4.4, the cost per carbon tonne capture for each loading is shown. The cost is higher for low loads since it was designed for 100% engine load and the amount of carbon available for capture is fewer in lower engine loads.

Table 4-5: Assumptions and parameters for baseline economic evaluation.

Project time frame	25 years
CAPEX	30% grant for the equipment is considered. A logical scenario since a lot of institutions will want to give incentives for limiting GHG emissions (Awoyomi et al., 2019; Broutin et al., 2014)
Discount rate	0.08
Carbon Sales	40\$ per tonne to EOR facilities
LNG price	716.4 USD
Depreciation	Straight-Line Depreciation. Salvage Value is equal to 0.

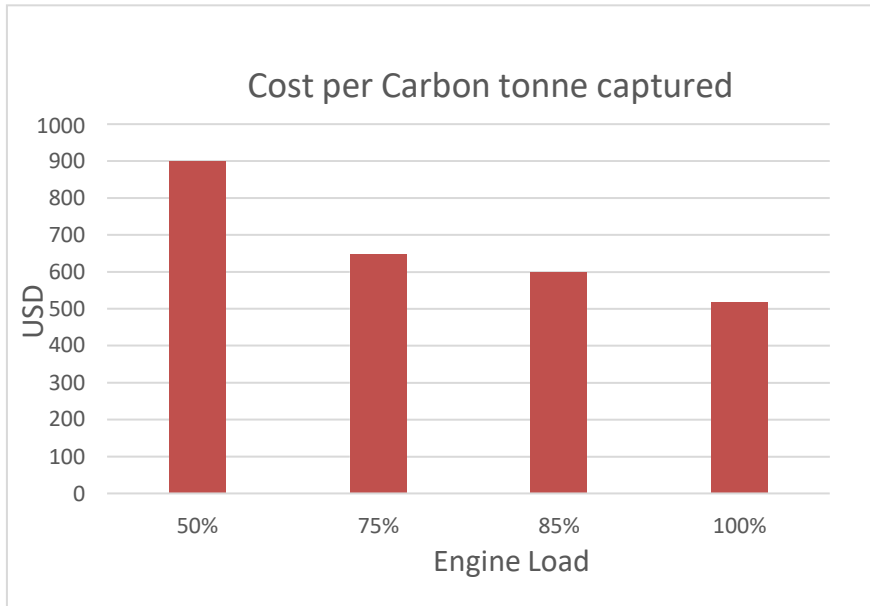


Figure 4–4: Cost per tonne of carbon captured.

4.3.2 Economic incentives for capturing carbon.

The main incentive for ship-owner considering installing a carbon capture unit is the probable financial benefits they might receive from institutions like the European Union and the IMO, who have set goals for combatting carbon emissions. The European Union has set up the ETS (emissions trading system) which provides financial support for innovative carbon capture projects. It is safe to assume that on-board carbon capture will be encouraged since its contribution to a cleaner environment is evident (Awoyomi et al., 2019).

There is a precedent for granting a percentage of the initial investment by governmental and international organizations of CCS projects. For example, the OCTAVIUS project received almost 65% of its total budget from the European

union (an amount 5.1M€ were funded out of a total budget of 7.8M€) (Broutin et al., 2014)

In table 4-7, the economic input for each engine load is shown in full detail, including Capital costs, operating costs, and annual depreciation. Annual cash flow is measured by subtracting all costs from the profit made by selling CO₂.

Table 4-6: Economic input for project baseline evaluation.

Engine load	CAPEX(USD)	Annual Depreciation (USD)	Maintenance cost (USD)	Operating cost (USD)	Profit (USD)	Annual cash flow (USD)
50%	1786193.33	71447.77	40357.54	118255,747	123680	-66023.47
75%	1786193.33	71447.77	59680.3	131187,807	172188,24	-26537.57
85%	1786193.33	71447.77	109390	160670,722	189874,13	-11332.53
100%	1786193.33	71447.77	91158	177609,805	219493,01	-60476.33

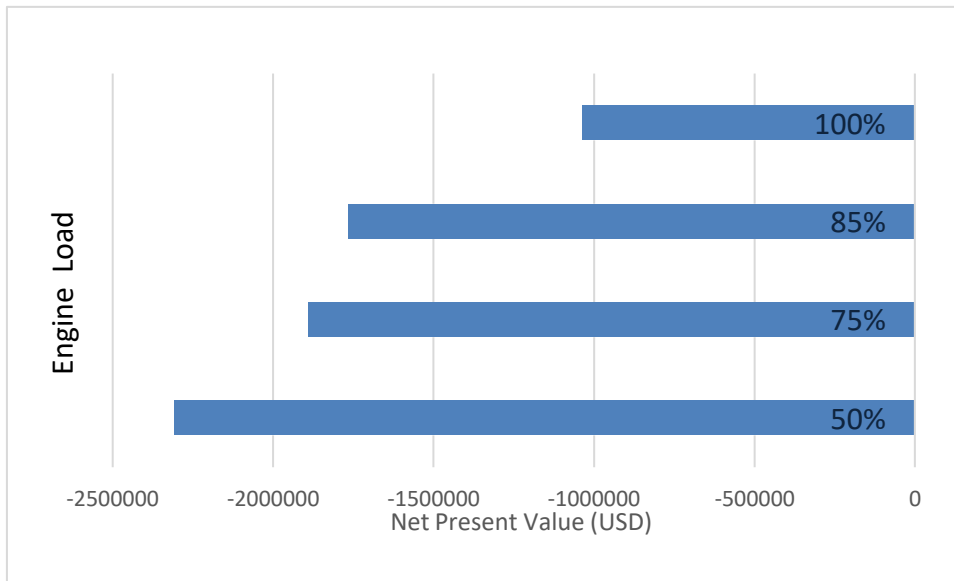


Figure 4–5: Resulting NPVs for the baseline conditions presented on Table 3.

The resulting NPVs in figure 3 indicate that in this baseline scenario, the investment is not a feasible decision since the annual cash flow is negative. There are many reasons behind this unfavourable result.

First, the design of the system has been realized with the specifications for 100% engine load in mind. Hence, the equipment and installation costs for this onboard CSS plant would be too high for lower engine loads. As seen on figure 3, the NPV for 50% load is the lowest, meaning the least cost-effective.

In addition to high capex, there is also the issue of low profits from the baseline scenario. This can be attributed to two reasons. The tonnes of carbon captured and the price per tonne of carbon on the market. The amount of carbon sold to the market, even though it is sufficient to provide an annual profit, in the long run does not outweigh the initial capital. Therefore, the total outcome, after a twenty-five-year timeframe is negative.

The market prices limit the cost effectiveness of the process, especially on low engine loads where the available CO₂ to capture is considerably less. As discussed before, the market for carbon is still uncertain and anticipating relevant policies. At this state of the market, it is not an easy task to find a profit-producing outlet, especially when the amount captured is so low as in on-board carbon capture. On the following sensitivity analysis, the market price, along with the other economic inputs will examine how much effect they have on the investment.

Besides selling carbon, this project can be feasible through other means. There is the example of the emissions trading systems (ETS), where highly pollutant industrial plants acquire permits to emit CO₂ at a certain limit, and have the option to sell these permits, if the emission limit has not been exceeded, to other installations which will produce more pollutants than the amount set by the supervising authorities, such as local governments, European Union.

4.3.3 . Parameters for Sensitivity analysis

A Monte Carlo simulation was developed on MATLAB software to examine the effects of the inputs for each load. Each economic input will be studied separately from the others and a final model will examine the variance on all variables of the system. Each input will vary from a 50% to a 150% range of the figure given on the 4.1 section (baseline scenario). On the following table, the value range for each variable is given. The simulation generates 10000 values for the studied input each time and gives the resulting NPV.

Table 4-7: Range of values of the inputs for the sensitivity analysis

Economic input	Lowest value	Baseline value	Highest value
CAPEX	1275852.375	2551704.75	3827557.125
LNG price	358.2	716.4	1074.6
CO ₂ price	20	40	60

The following histograms show the variance of NPV per factor examined. Because the system was designed for 100% engine load and the CO₂ tonnes captured for 50% are considerably fewer for those captured on higher loads, the profitability index is expected to be negative in every case and only in very favourable cases the loss will be minimum. As the engine load increases along with the number of tonnes captured, NPV will increase as well. The highest engine loads (85% and 100%) will have the most favourable NPVs. Only, the multifactorial analysis will be presented and discussed here.

4.3.4 Results of Multivariate analysis

The following histograms (Figures 4.6-4.9) show that the vast majority of the resulting NPVs are negative. There are very few cases of positive outcomes, which occur only in engine loads that are over 50%.

The main cause for the unfavourable NPV distribution is that the system was designed for 100% engine load, meaning that the CAPEX is disproportional to the system's requirements for lower engine loads. Additionally, the amount of carbon captured cannot be profitable, even at the higher end of CO₂ market price range, when the capital expenditures are so expensive for lower engine loads.

The very few positive cases of NPVs signify that, under those conditions examined the option to install an on-board carbon capture plant is generally unfavourable. Only in very few cases, where the cost-factors (CAPEX, LNG price) are very low and the price for CO₂ sale is very high is the investment profitable.

As expected, as engine load increases, so do the few cases when the investment is favourable. This is, of course, connected with the available CO₂ that there is to capture in higher loads. In this analysis, the only profit from carbon capture is generated from sales. No other form of financial gain is considered. For example, an ETS scheme or savings on corporate taxes as a reward for lowering GHG emissions. However, to the extent of the author's knowledge, there is no ETS plan that covers shipping emissions.

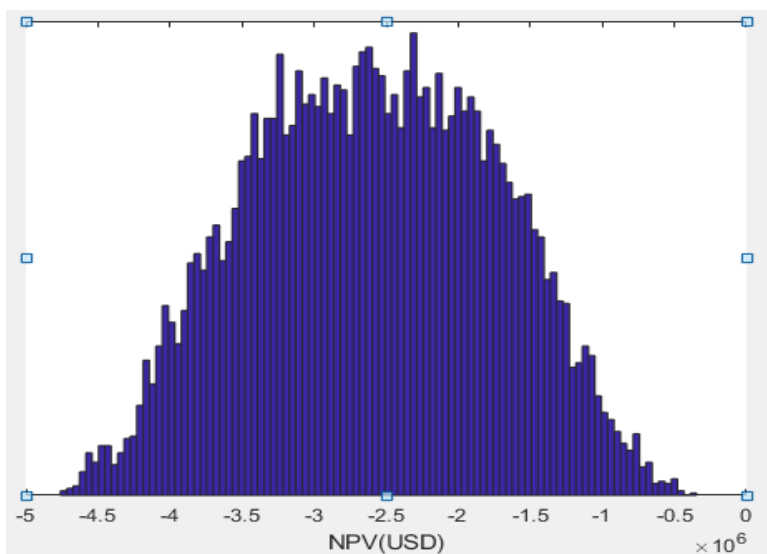


Figure 4–6: Histogram of NPV variance as all factors change within the set limits, for 50% load.

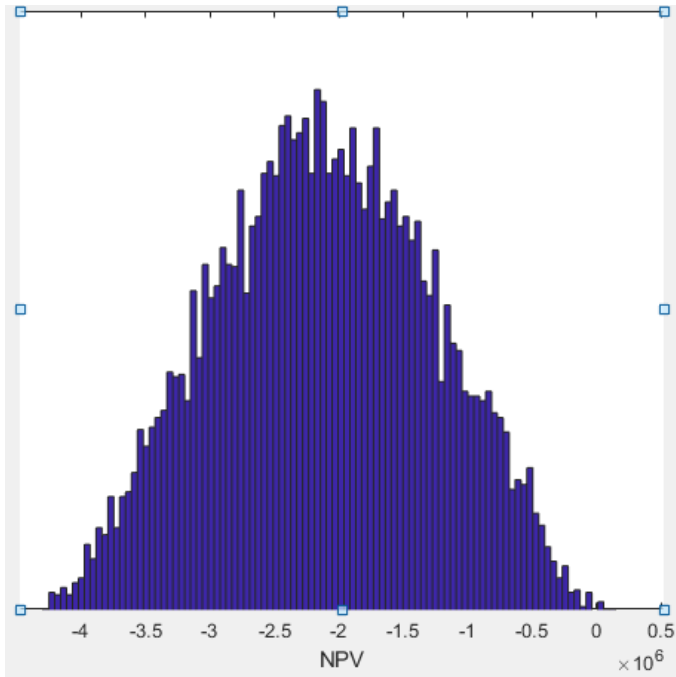


Figure 4–7: Histogram of NPV variance as all factors change within the set limits, for 75% load

In the first histogram (figure 4.6) which represents the results for 50% engine load, it becomes evident that there are no conditions which can render the project feasible when running on this engine specification. The same conclusion can be attributed to the second and third histogram of the NPVs for 75% and 85% (figures 4.7 and 4.8) engine load respectively, with a minor difference being that there is a slight number of cases which are near zero, meaning that there is no net loss or net gain if the investment was made under these conditions.

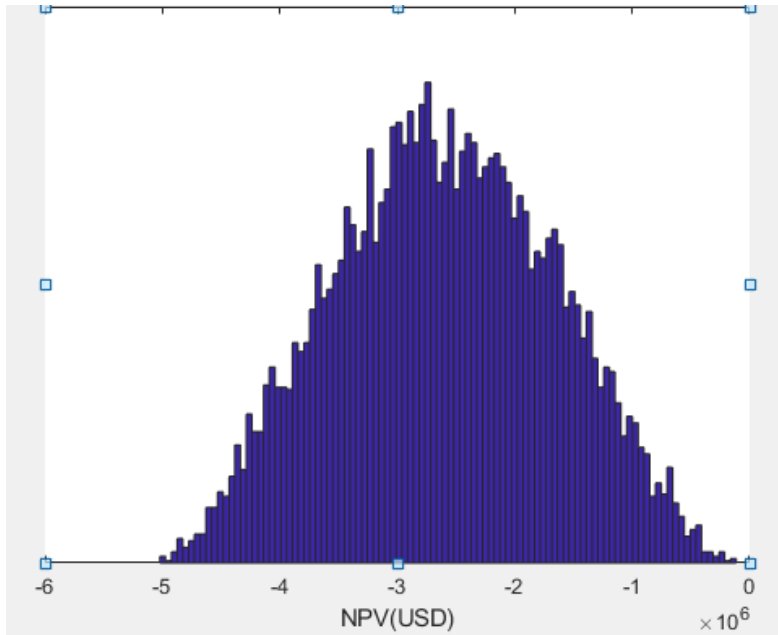


Figure 4–8: Histogram of NPV variance as all factors change within the set limits, for 85% load.

The following histogram (figure 4.9) depicts the resulting NPVs for 100% engine load. Only at this rating, there are a few cases that are positive and can provide financial gain for any investor. The reason for this, as mentioned earlier, is that only a high amount of carbon captured can be sold at the price range selected and be profitable.

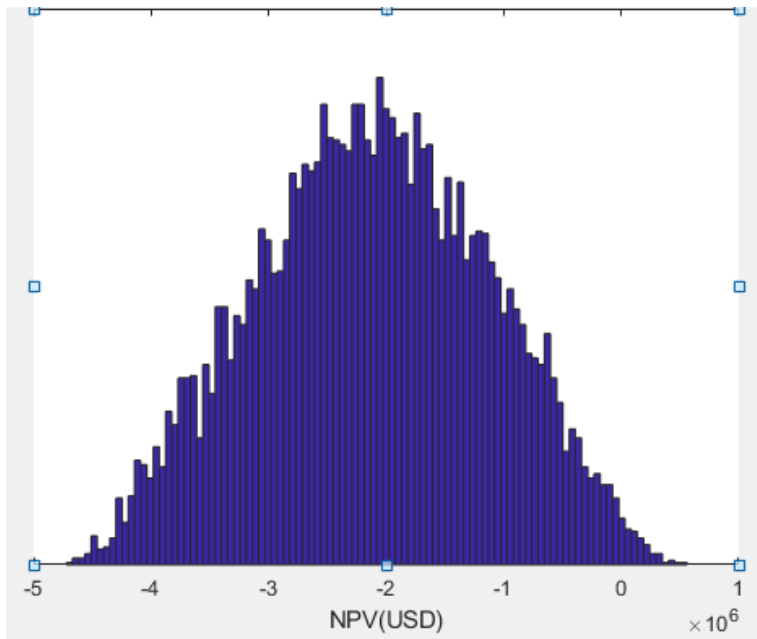


Figure 4–9: Histogram of NPV variance as all factors change within the set limits, for 100% load

4.3.4.1 Cases of favourable NPVs

In the next tables, a few select cases of favourable NPVs for all loads except 50% are presented, along with the economic factors that generated those positive outcomes.

Table 4-8: Favourable cases for 100% load.

100% Load	CAPEX (USD)	LNG price (USD)	CO₂ price (USD)	NPV (USD)
	1375594.094	589.339	56.835	116875.293
	1446428.664	501.592	56.686	127174.827
	1305750.969	627.420	57.527	185290.715
	1572442.677	527.930	59.7113	137504.365
	1324175.136	438.269	58.020	385696.607

Table 4-9: Favourable cases for 85% load.

85% Load	CAPEX (USD)	LNG price (USD)	CO₂ price (USD)	NPV (USD)
	1375594.094	589.339	56.835	116875.293
	1446428.664	501.592	56.690	127174.827
	1305750.969	627.420	57.527	185290.715
	137504.365	527.930	59.711	137504.365
	1324175.136	438.269	58.020	385696.607

Table 4-10: Favourable cases for 75% load

75% Load	CAPEX (USD)	LNG price (USD)	CO ₂ price (USD)	NPV (USD)
	1310531.689	390.091	58.995	347197.623
	1358045.096	580.602	59.181	105183.085
	1434336.512	384.445	54.669	30619.059
	1541182.337	475.979	59.960	69320.3641
	1369489.175	505.631	56.786	63623.945

As observed in the above tables, the outcome is favourable only in cases where CAPEX is close to the lower limit (1275852.375\$) and when the price for captured CO₂ approaches the upper value used in the sensitivity analysis. The LNG price however, while lower than the baseline price, which was set at 716,6\$, only approaches the lower limit of 358,2\$ in a few cases. However, the question of these favourable conditions being attainable in the future is still unsure. While there is a general motive from high profile institutions to fund environmental projects (Awoyomi et al., 2019), the carbon market remains underdeveloped for the short term future (IEA, 2019)

4.4 General discussion

SBCC is a novel concept that has yet to be implemented. However, the IMO's plan to reduce GHG emission from the shipping sector, might make the shipping industry consider it as an option for the future. Combined with LNG fuel would also comply to IMO's newer stricter regulations about sulphur emissions.

This work served as validation for the installation of an on-board carbon capture system on LNG fueled ships. Since the available literature is limited and there is no actual implementation of SBCC, it is crucial to examine all the proposed designs, energy management systems and economic scenarios.

Most of the economic analysis, however, focuses on vessels that operate on high engine load (85% and 100%), at least to the extent of the author's knowledge. In this paper, the study on feasibility includes lower engine loads as well.

The approach to the economic feasibility is centered on acquiring profit from the captured carbon. Unfortunately, the amount captured at lower loads is insufficient to produce profit under the market conditions considered on this analysis. Even at higher loads, the cases which are favorable, occur only at very advantageous market conditions (high market prices, low CAPEX and low OPEX).

The carbon market is still developing as discussed on chapter 2. Therefore, the options for profiting from carbon capture are limited. There are developed applications like EOR, but ultimately the amount of carbon captured, controls the profit.

Besides selling carbon, this project can be feasible through other means. There is the example of the emissions trading systems (ETS), where highly pollutant industrial plants acquire permits to emit CO₂ at a certain limit, and have the option to sell these permits, if the emission limit has not been exceeded, to other installations which will produce more pollutants than the amount set by the supervising authorities, such as local governments, European Union.

5 Conclusions and Recommendations for future work

5.1 Conclusions

While literature covering carbon capture on LNG fueled vessels is limited, at least to the author's knowledge, it provides enough insights on the process and certain very important aspects of it. There are many important factors which affect the performance of SBCC, namely type of solvent, concentration of solvent, flue gas flow rate, CO₂ concentration of the flue gas.

Implementing regression analysis as a machine learning feature on the study may seem excessive, since the correlation between the solvent flow rate and the amount of carbon captured appears to be positive, as the one between the carbon captured and reboiler duty. The results of the analysis confirm this hypothesis, since the association between the variables is linear (with the generated r^2 values being very close to 1 for each load). Knowing this information, facilitates choosing the correct solvent flow rate for a certain capture target.

The result of heat integration, validate those of previous studies, those of Van den Akker et Feenstra et al (Van den Akker contributed to the second one as well). Heat integration is possible at 50%, 75%, and 100% load (probably at 85% as well). As mentioned before, heat integration is crucial for energy savings and lesser costs.

Results in the economic analysis suggest that any type of this installation at the current market landscape is unfeasible. The cost is too high and if there is any profit to be made that can be achieved only under very favourable conditions (low fuel price, high price for captured CO₂). CAPEX is very high and if the vessel operates on low loads, the amount of carbon captured is not sufficient for any financial gain, under the parameters set for this analysis.

However, the current situation will not remain unchallenged for long. Carbon taxes will be implemented on the near future for ships. This development, along

with a possible cap on tax emissions, will probably influence the shipping industry's attitude on carbon capture.

5.2 Recommendations for future work

The scope of this study was to provide more information about the feasibility of SBCC in terms of specific sets of operation conditions and their consequent cost effect. In this manner it is hoped to enrich the actual investigation on the issue. Regarding machine learning implementation, it should be interesting to examine what impact a multivariate analysis would have on carbon capture rate. Examining solvent type, solvent composition, absorption, and stripping parameters would result in more detailed conclusions about the system's effectiveness. Additionally, looking into other CCS operations, not only PCC, and examine their feasibility on-board a vessel could lead to interesting conclusions. As for the economic part, further analysis should focus on cap-trading systems and carbon taxes, since such a measure could render SBCC very attractive. It also known that high profile economic organizations have expressed their public support towards environmental projects.

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APPENDICES

Appendix A

A.1 Tables of simulation Aspen simulation results.

The following tables contain the results of the Aspen simulation environment for each loading. The tables show the amine flow, the CO₂ in the flue gas entering the absorber, the CO₂ in the clean gas and the heat duty of the Reboiler.

Table Apx Σφάλμα! Χρησιμοποιήστε την καρτέλα "Κεντρική σελίδα", για να εφαρμόσετε το 0 στο κείμενο που θέλετε να εμφανίζεται εδώ.-1: **Results for 50% loading**

Amine solvent flow(kmol/sec)	CO ₂ in flue gas (kmol/sec)	CO ₂ in clean gas (kmol/sec)	Percentage of carbon captured (%)	Reboiler heat duty (MW)
0.0100	0.0043	0.0037	14.4110	3.3343
0.0125	0.0043	0.0036	17.8060	0.3123
0.0150	0.0043	0.0038	12.6490	0.1582
0.0175	0.0043	0.0034	22.8730	0.1192
0.0200	0.0043	0.0032	26.2490	0.1138
0.0225	0.0043	0.0036	32.9410	0.1156
0.0250	0.0043	0.0030	36.2540	0.1220

0.0275	0.0043	0.0028	39.5430	0.1274
0.0300	0.0043	0.0026	42.8070	0.1329
0.0325	0.0043	0.0025	46.0460	0.1386
0.0350	0.0043	0.0023	49.2590	0.1444
0.0375	0.0043	0.0022	52.4460	0.1502
0.0400	0.0043	0.0021	55.6060	0.1561
0.0425	0.0043	0.0020	58.7420	0.1619
0.0450	0.0043	0.0018	61.8520	0.1678
0.0475	0.0043	0.0017	64.9350	0.1738
0.0500	0.0043	0.0015	67.9930	0.1797
0.0525	0.0043	0.0014	71.0230	0.1972
0.0550	0.0043	0.0013	74.0220	0.1917
0.0575	0.0043	0.0011	76.9860	0.1977
0.0600	0.0043	0.0010	79.9090	0.2097
0.0625	0.0043	0.0009	82.7850	0.2097
0.0650	0.0043	0.0008	85.5990	0.2180
0.0675	0.0043	0.0006	88.3300	0.2235
0.0700	0.0043	0.0005	95.0700	0.2290

Table Apx 1-2: Results for 75% loading

Amine flow rate (kmol/sec)	CO ₂ in flue gas (kmol/sec)	CO ₂ in clean gas (kmol/sec)	Percentage of carbon captured (%)	Reboiler heat duty (MW)
0.0100	0.0061	0.0055	8.7240	11015
0.0125	0.0061	0.0054	11.3106	0.2153
0.0150	0.0061	0.0051	13.7754	0.1302
0.0175	0.0061	0.0051	16.2345	0.1183
0.0200	0.0061	0.0049	18.6815	0.1223
0.0225	0.0061	0.0048	21.1146	0.1284
0.0250	0.0061	0.0046	23.5331	0.1350
0.0275	0.0061	0.0045	25.9358	0.1418
0.0300	0.0061	0.0043	28.3227	0.1486
0.0325	0.0061	0.0042	30.6932	0.1556
0.0350	0.0061	0.0040	33.5161	0.1625
0.0375	0.0061	0.0039	35.3850	0.1694
0.0400	0.0061	0.0038	37.7066	0.1834
0.0425	0.0061	0.0036	40.0122	0.1904
0.0450	0.0061	0.0035	42.3024	0.1974

0.0475	0.0061	0.0033	44.5776	0.2255
0.0500	0.0061	0.0032	46.8384	0.2048
0.0525	0.0061	0.0031	49.0854	0.2115
0.0550	0.0061	0.0029	51.3191	0.2185
0.0575	0.0061	0.0028	53.5310	0.2255
0.0600	0.0061	0.0027	55.7486	0.2326
0.0625	0.0061	0.0025	57.9452	0.2397
0.0650	0.0061	0.0024	60.1302	0.2467
0.0675	0.0061	0.0023	62.3039	0.2538
0.0700	0.0061	0.0022	64.4653	0.2609

Table Apx 1-3. Results for 85% loading

Amine flow rate (kmol/sec)	CO ₂ in gas in (kmol/sec)	CO ₂ in gas out (kmol/sec)	Percentage of carbon captured (%)	Reboiler heat duty (MW)
0.0100	0.0067	0.0061	8.0332	1.1078
0.0125	0.0067	0.0060	10.1358	0.2132
0.0150	0.0067	0.0058	12.4661	0.1284
0.0175	0.0067	0.0057	14.6142	0.1168
0.0200	0.0067	0.0055	16.9137	0.1206
0.0225	0.0067	0.0054	19.1230	0.1170
0.0250	0.0067	0.0053	21.3214	0.1220
0.0275	0.0067	0.0051	23.4485	0.1274

0.0300	0.0067	0.0050	25.6840	0.1329
0.0325	0.0067	0.0048	27.8465	0.1386
0.0350	0.0067	0.0047	29.9966	0.1444
0.0375	0.0067	0.0045	32.1340	0.1502
0.0400	0.0067	0.0044	34.2585	0.1560
0.0425	0.0067	0.0042	36.3702	0.1619
0.0450	0.0067	0.0041	38.4693	0.1678
0.0475	0.0067	0.0040	40.5560	0.1738
0.0500	0.0067	0.0038	42.3806	0.1797
0.0525	0.0067	0.0037	44.6932	0.1857
0.0550	0.0067	0.0036	46.7443	0.1917
0.0575	0.0067	0.0034	48.7844	0.1977
0.0600	0.0067	0.0033	50.8137	0.2037
0.0625	0.0067	0.0031	52.8326	0.2097
0.0650	0.0067	0.0030	54.8415	0.2158
0.0675	0.0067	0.0029	56.8405	0.2218
0.0700	0.0067	0.0027	58.8299	0.2279

Table Apx 1-4:Results for 100% loading

Amine flow rate (kmol/sec)	CO ₂ in flue gas (kmol/sec)	CO ₂ in clean gas (kmol/sec)	Percentage of carbon captured (%)	Reboiler heat duty (MW)
0.0100	0.0077	0.0071	7.3254	1.1518
0.0125	0.0077	0.0070	8.7578	0.2136
0.0150	0.0077	0.0069	10.6842	0.1275
0.0175	0.0077	0.0067	12.6195	0.1153
0.0200	0.0077	0.0066	14.5496	0.1185
0.0225	0.0077	0.0051	34.0515	0.1238
0.0250	0.0077	0.0063	18.3824	0.1295
0.0275	0.0077	0.0061	20.2838	0.1353
0.0300	0.0077	0.0060	22.1747	0.1413
0.0325	0.0077	0.0059	24.0543	0.1474
0.0350	0.0077	0.0057	25.9229	0.1536
0.0375	0.0077	0.0056	27.7803	0.1597
0.0400	0.0077	0.0054	29.6266	0.1659
0.0425	0.0077	0.0053	31.4619	0.1722
0.0450	0.0077	0.0051	33.2865	0.1784

0.0475	0.0077	0.0050	35.1004	0.1846
0.0500	0.0077	0.0049	36.9041	0.1909
0.0525	0.0077	0.0047	38.6980	0.1972
0.0550	0.0077	0.0046	40.4823	0.2035
0.0575	0.0077	0.0045	42.2575	0.2098
0.0600	0.0077	0.0043	44.0238	0.2162
0.0625	0.0077	0.0042	45.7816	0.2225
0.0650	0.0077	0.0040	47.5314	0.2288
0.0675	0.0077	0.0039	49.2733	0.2352
0.0700	0.0077	0.0038	51.0081	0.2415