Economic feasibility of a hydrogen-fuelled marine transportation system

Case study of a bulk carrier at CMB

R. Quintana-Diaz

Master of Science Thesis

Thesis number: SDPO.18.037.M

Cover picture: Mineral Yarden, CMB Group [58]

TU Delft

Economic feasibility of a hydrogen-fuelled marine transportation system

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by

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in partial fulfilment of the requirements for the degree of

Master of Science
in Marine Technology
in the specialisation Design, Production and Operation
Faculty of Mechanical, Maritime and Materials Engineering

at the Delft University of Technology,
to be defended publicly on Wednesday September 19th, 2018 at 14:00 hours.

An electronic version of this thesis will be available on September 19, 2020 at http://repository.tudelft.nl/.

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DELIVERABLE

Date	September 19th, 2018
Document	Final
Number of pages	146

DEGREE

Master of Science (MSc)	Marine Technology
Specialisation track	Design, Production and Operation
Faculty	Mechanical, Maritime and Materials Engineering
University	Delft University of Technology
Location	Delft, The Netherlands

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Preface and Acknowledgements

The shipping industry is shifting to a more stringent emission regulation, and shipping companies are looking for economically feasible alternatives to comply with it. CMB sees on hydrogen as a game-changing technology in the medium to long-term. This thesis contributes to this hydrogen vision.
During the first period of my internship at CMB, I was involved in the naming ceremony of the "Hydroville", a hydrogen-diesel dual-fuel catamaran, which introduced me to hydrogen technologies and their future potential. As a results of this introduction, I find the topic of this thesis relevant and inspiring, since it contributes to testing alternatives that can reduce CO2 emissions, and in the long term, they could be part of the technologies involved in a hydrogen economy. Hydrogen technologies are a very dynamic field of study, and small improvements in the cost of production of energy converters or in the cost of hydrogen storage could transform the transportation sector.

The aim of this project was testing alternative fuel energy converters that could replace conventional A/Es, and to a lesser extent M/Es on board. The results did not confirm the technology of the Hydroville or fuel cells as the most promising alternative but revealed LNG-diesel dual-fuel engines as the most competitive technology. However, the know-how acquired during the analyses could accelerate the adoption of alternative energy converters in commercial ships. These technologies were tested in a case study proposed by CMB, a bulk carrier.

This project was possible with the support and knowledge provided by numerous people. I would like to thank ir. Roy Campe, R&D Manager at CMB, who gave me the opportunity to do my internship at CMB in the first place and proposed the case study of this thesis. Another important person to accomplish this project was ir. Florian Aendekerk, who made possible the acquisition of the performance data of the reference ship and was a source of inspiration on many occasions. I would like to show my special gratitude to prof.dr. Eddy Van de Voorde and ir. J.W. Frouws, since the quality of this project it is directly related to their wise advice and feedback, and also for believing in this project since the beginning.
I could not have arrived here without the support, inspiration and desire for improvement that my partner of adventures, ir. Lola Giuffré means to me. Finally, I can not miss the opportunity to mention those responsible for my being here today, my family. Thank you, Mama, Magnolia, Olivia, Gisela, Silvia, Papa, Alexis, Tino and Jorge, and also in Spanish to be understood by all: ¡Muchas gracias, les quiero!

R. Quintana-Diaz
Antwerpen, June 2018

Abstract

The crises of global warming, air pollution, acid rain and the running out of oil make the investigation into alternative fuel technologies crucial. New technologies are being investigated on a global scale in an attempt to address these problems. This thesis investigates the use of hydrogen-diesel dual-fuel engines and fuel cells. The economic feasibility includes the comparison of these energy converters with more conventional alternatives. The storage of alternative fuels, the reforming of hydrogen carriers or the inclusion of carbon capture systems are some of the aspects considered in the analysis.

The results demonstrated that due to the high emission levels of conventional diesel M/Es, according to Energy Efficiency Design Index (EEDI) regulation, the case study could not be built from 2020 onwards using the dimensions and the M/E of the reference ship, the Mineral Yarden. Even with hydrogen technologies as A/E, the EEDI is higher than the required EEDI for a bulk carrier of her characteristics. LNG-diesel dual-fuel engine technology was included to have a technically feasible design alternative after 2019. The economic analysis demonstrated that designs with LNG-diesel dual-fuel engines are significantly sensitive towards LNG price changes. An international CO2 emission taxation could accelerate the adoption of CO2 abatement systems, such as carbon capture systems. When pure hydrogen is required on board, the economic results reveal that LNG and LNH3 are the most competitive storage alternatives.

Contents

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List of Abbreviations

A/E .... Auxiliary engine

BCR .... Benefit-cost ratio

BOP .... Balance of plant

CBA .... Cost-benefit analysis

CCS .... Carbon capture system

CH3OH .... Methanol (MeOH)

CH4 .... Methane

CH2/CGH2 .... Compressed hydrogen/compressed gas hydrogen

CMB .... Compagnie Maritime Belge

CO .... Carbon monoxide

CO2 .... Carbon dioxide

DWT .... Deadweight tonnage

EEDI .... Energy efficiency design index

EEOI .... Energy efficiency operational indicator

ECA .... Emission control area

FC .... Fuel cell

FPM .... Fleet performance monitoring

GT .... Gross tonnage

H2 .... Diatomic molecule of hydrogen

H2O .... Water

HFO .... High fuel oil

HT-PEMFC .... High temperature proton exchange membrane fuel cell

ICE .... Internal combustion engine

IMO .... International maritime organization

IRR .... Internal rate of return

ISO .... International organization for standardization

LH2 .... Liquid (cryogenic) hydrogen

LHV .... Lower heating value

LNG .... Liquefied natural gas

SNG .... Synthetic natural gas

LNH3 .... Liquid anhydrous ammonia

LOHC .... Liquid organic hydrogen carrier

M/E .... Main engine

MARPOL .... International convention for the prevention of pollution from ships

MCFC .... Molten carbonate fuel cell

MGO .... Marine gas oil

MT .... Metric tonne

NH3 .... Anhydrous ammonia

NOx .... Nitrogen oxides

NPV .... Net present value

n-H2 .... Normal diatomic molecule of hydrogen

O2 .... Diatomic molecule of oxygen

o-H2 .... Ortho diatomic molecule of hydrogen

PEMFC .... Proton exchange membrane fuel cell

p-H2 .... Para diatomic molecule of hydrogen

SFOC .... Specific fuel oil consumption

SOFC .... Solid oxide fuel cell

SOLAS .... International convention for safety of life at sea

SOx .... Sulphur oxides

1 Introduction

The aim of this chapter is to explain the Plan of Approach that will allow the correct realisation of this project in shape and time. It will include the motivation of this project and some institutional information.

1.1. Research background

The crises of global warming, air pollution, acid rain and the running out of oil make the investigation into alternative fuel technologies crucial. New technologies are being investigated on a global scale in an attempt to address these problems.
Following this trend, international shipping has become more aware of its impact on local and global air emissions, even though it is not included in the Paris Agreement [110]. The Paris Agreement is a document signed by 195 countries, which limits global temperatures to a maximum of 2°C higher than pre-industrial levels.
Apart from the increasing awareness in the sector, there are more practical reasons to explore alternative fuels. New IMO regulation is expected to contribute to the CO2 emission reduction of international shipping in the next few years [112]. Thus, it is crucial not only for big shipping companies, but also medium and small ones to get ready for the regulation that will come into force.
For CMB, this project is part of the research and development activities that will ensure the meeting of future market requirements. In particular, the company desire to excell in sustainability, while remaining economically competitive.
Finally, I consider that alternative fuels are an important and challenging step to achieve a sustainable shipping industry, and that was the main reason for me to choose this topic.

CMB is a maritime group founded in 1895 as a regular shipping line between Belgium and Congo. Initially, the company name was Compagnie Belge Maritime du Congo (CBMC), but over time, the shipping lines extended to other regions, prompting the company rename to CMB. Also, over the 20th Century, the focus gradually shifted from passengers towards cargo transport.
Nowadays, CMB is a privately owned company, with its headquarters in Antwerp and with more offices in Tokyo, Hong Kong and Singapore. CMB group is active in different areas with multiple companies and holdings:

- Bocimar: Dry bulk shipping company that provides worldwide transportation of all types of dry goods. In 2016, the 60-ship fleet carried a total of 41,500,000 MT of cargo worldwide.
- Delphis: Container shipping company that specialises in mid-size container feeder ships, some of them ice-classed for the North Sea and Baltic Sea regions. In 2016, the 27-ship fleet carried a total of 11,350,000 MT of cargo.
- Bochem: Chemical tanker shipping company that controls 9 full stainless steel vessels. In 2016, Bochem´s fleet carried approximately 1,600,000 MT of cargo.
- ASL Aviation Holdings DAC: It controls a fleet of nearly 90 aircraft, providing capacity for passengers or cargo.

CMB is structured in different departments, which have concrete functions:

- Operations department: people working in this department need to be in contact with the Captain to ensure optimum performance, plan the refuelling, monitor cargo and ballast plans, prepare surveys and validate all certificates. Operators are also responsible for coordinating cleaning and maintenance jobs and communicate changes of schedule to other departments.
- Chartering department: people of this department select and evaluate chartering brokers and cargo orders. They also evaluate contracts and are responsible for negotiating chartering prices and the signature of the charter party.
- Bunkering department: this department is in continuous contact with the Operations department, since people working here are responsible for negotiating with local companies the bunkering prices. Together with the operators they decide how much to refuel in each port scale.
- Technical department: people of this department are responsible for the noon report system, and they provide key performance indicators that help other departments taking decisions. They also coordinate vessels pre-purchase, inspection, dry-dock and repairs.

CMB Technologies is the branch of the technical department that investigates the feasibility of new technologies within the shipping industry. It focuses on technology innovation, alternative ship designs, fuel consumption efficiency, and sustainability of the fleet. With the goal to acquire knowledge in mind and to acquire know-how in the design, distribution and storage of hydrogen systems, CMB built a hydrogen-diesel dual-fuel catamaran as a shuttle project. This ship was named Hydroville, and is currently serving as a taxi for CMB workers and a platform for meetings [21].
This shuttle project has proved that the hydrogen-diesel dual-fuel engine technology is a promising alternative in shipping. However, before any alternative fuel could be used in commercial vessels, technical and economic feasibility analyses need to be done on a case-by-case. CMB's initial focus is to study energy converters that could replace the function of A/Es on board. If any of these technologies prove its economic feasibility on board, it will be easier to convince all stakeholders to invest money on scaling up the technology and testing its feasibility to replace a conventional M/E on board.

In economic terms, if in the medium to long-term the hydrogen alternatives have the same NPV after the operational lifespan than conventional designs, they will become a promising solution. In addition, there are already areas where to enter it is necessary to have certain types of emission under a strict level. These are called the Emission Control Areas (ECAs).
There exist other alternative fuels and emission abatement systems that could compete with the hydrogen technologies to make the ship comply with future emission regulation, and CMB is interested in comparing hydrogen-diesel dual-fuel engines with fuel cells, LNG-diesel dual-fuel engines or carbon capture systems.
There is at least one Asian and one American shipping company also interested in hydrogen technologies. For this reason, testing the economic feasibility of the proposed case study is a required analysis before deciding which should be the next step. Depending on the results, it will be possible to evaluate the competitiveness of hydrogen or alternative fuel technologies.

1.2. Research objective

The aim of this thesis is to evaluate the technical and economic feasibility of different designs in a case study proposed by CMB.
The main focus will be to study alternative fuel technologies to replace one of the A/Es in the next generation of an existing bulk carrier design. M/E consumptions and emissions are also investigated. The current M/E of the existing bulk carrier design and an additional dual-fuel engine that can be operated in gas mode with natural gas are the two alternatives preferred by CMB.

From all the design alternatives, it is required to identify the alternatives that could comply with future emission regulation limits. The first research question is:

- *What alternative fuel and energy converter combinations on a bulk carrier doing Australia-China monthly round trips could allow the vessel to be built after 2019 while complying with the Energy Efficiency Design Index?*

The M/E and A/E consumptions of the 'reference ship'(i.e. the existing bulk carrier) in her current route will be adapted to the proposed route by CMB. The new route is part of the case study, and it consists of Australia-China monthly round trips. The existing vessel that will be taken as a reference is the Mineral Yarden, a

capesize bulk carrier part of the CMB fleet.
The fuel storage systems, the fuel processing systems, the energy converters, and in some cases the carbon capture systems that will be tested could affect the power demand and the payload of the reference ship, and this effect needs to be calculated in the technical analysis.

Furthermore, an economic analysis is carried out of the design alternatives that are technically feasible. Also, different financial scenarios are used to see which design alternative is the most competitive in each of the scenarios. To give an answer to this problem the second research question is:

- *What technically feasible design alternatives are also economically feasible? Which scenarios could affect the feasibility?*

By addressing these research questions, it will be known which design alternative is the most competitive based on different economic indicators, such as NPV, IRR, or benefit-cost ratio. Furthermore, a sensitivity analysis will contribute to understanding how different financial scenarios, fuel prices and individual components affect these economic indicators.
Finally, some recommendations and conclusions of the project will be presented.

1.3. Scope of work

The boundaries of this research will include the study of systems and components on board. Neither the production plant, nor the storage tank onshore will be considered. This means that the fuels will be considered an input with a price at the point of refuelling. If the fuel chosen is pure hydrogen, its price might not be totally exogenous at one of the refuelling ports of the case study, because CMB might have a special agreement with a local company.

The alternative fuels considered in this project are not exhaustive. Particular focus is given to pure hydrogen due to the success of the Hydroville. Additionally, natural gas, ammonia and methanol are included in the study. The reasons for choosing these fuels include refuelling availability, competitor's movements, and in-house interest.
All fuels considered in this project have two characteristics in common: a) they could be produced from renewable hydrogen, such as renewable ammonia, synthetic natural gas (SNG) or green hydrogen; and b) each fuel type requires specific storage equipment and pre-processing systems. In some cases, pure hydrogen is required and then fuel reformers are necessary to extract the hydrogen from the hydrogen carrier, e.g. SNG and PEMFC. But in other cases, the hydrogen carrier does not need to be pre-reformed, e.g. SNG and SOFC.

All alternative fuel technologies, storage systems and reformers need to be understood, since they require to be integrated on the reference ship. However, an entire engineering analysis of the new design will not be developed. Which means that neither a risk assessment nor a safety comparison with SOLAS's safety standards will be covered.
The technical analysis is used to calculate the impact on payload (tonnes) of the new technologies, and to estimate the increase on daily average electrical consumption (kW) due to the new systems on board. Also, the technical analysis will help to observe how the new technologies modify some design and operational emission indicators, to see whether or not new designs comply with future phases of the Energy Efficiency Design Index (EEDI) regulation.
The economic feasibility analysis uses the information of the technical analysis to monetise the impact on payload and average electrical consumption, which directly affect the operational expenses of the design. Also, in the economic analysis, the cost of the components of the design are taken into account and added to the initial capital investment of the ship. Additionally, the cost-benefit analysis used in the economic analysis will include limited input parameters, since it could be counterproductive to emulate the reality in too much detail.

On the other hand, to adapt the reference ship design to the new requirements, it will be required to calculate the operational profile of the existing vessel. The data required to calculate the operational profiles are extracted from the noon reports and the software tool designed in-house at CMB by F.J. Aendekerk [3] that will not be covered in this thesis.

Finally, the characteristics of hydrogen and its technologies are better represented in this document than other alternative fuel technologies. The main reason for this is because this report is intended to contribute as much as possible to the decision making at CMB, and as was explained in the research background section 1.1, the priority is to test whether the hydrogen-diesel dual-fuel technology is the correct move and which storage alternative is the most economically feasible.

1.4. Organisation

This master thesis will be carried out as a cooperation agreement between TU Delft and CMB nv. With this cooperation, I will have the role of problem solver and implementer, TU Delft will have the role of university mentor and assessor, and CMB nv will have the role of company mentor and problem owner.
The representatives of TU Delft are Prof. Dr. Eddy Van de Voorde, as Chair professor of this graduation, and Ir. J.W. Frouws, as the first supervisor. The representative of CMB nv is Ir. Roy Campe, as research and development manager and internship supervisor.
The project will have an estimated duration of nine months. It started officially on 15th December 2017, and the green light meeting is expected to occur in July.

1.5. Activities and time schedule

The activities to accomplish will include theoretical research, data collection, operational profile calculation, technical feasibility, economic feasibility, economic comparison and final discussion. This tasks will be grouped in the following parts:

- I. Literature review: deals with the regulation that affects the research, including emissions and some codes related to the use of alternative fuels on board. Also, an analysis of the characteristics of different alternative fuels and energy converters is done.
- II. Technical and economic analyses: presents the methodology, the operational profile calculation of the reference ship and her adaptation to the case study. After, the results of the analysis are carried out. Furthermore, the cost-benefit analysis is used to economically compare the alternative fuel technologies. Finally, the output of the project will present the best alternatives and the potential of these technologies in other vessel types will be discussed.
- III. Appendices: includes some calculations and information required to complete the analyses.

A Gantt chart with the content mentioned above can be seen in appendix A.

1.6. Deliverables

The deliverables that will integrate this report are a Preface and acknowledgements, a List of contents, a List of figures, a List of tables, a List of Abbreviations, a Bibliography, and the Appendices. Furthermore, the content will be organised in seven chapters:

- Chapter 1: Introduction.
- Chapter 2: Regulation.
- Chapter 3: Alternative fuels.
- Chapter 4: Methodology.
- Chapter 5: Technical feasibility.
- Chapter 6: Economic feasibility.
- Chapter 7: Conclusions.

1.7. Secrecy

The information below is part of the contract signed by all the parts.

The results of this project will be considered as confidential information. The final date of the embargo will be 31-10-2020 or 24 months after the results have been reached. Otherwise, general provision 17 will apply.

Provision 17: The Student and TU Delft undertake to keep confidential company information of which they become aware in performing the assignment for a maximum of two years as from the time at which that information comes to their attention if the Company has explicitly informed them in writing that confidentiality is

required. This duty of confidentiality does not apply to:
a. information that is clearly in the Student's or TU Delft's possession at the time when the Company provided such information;
b. information that is common knowledge on the day on which it is provided to the Student and/or TU Delft;
c. information that the Student and/or TU Delft rightfully acquired from third parties; and
d. information that has become common knowledge after the date on which it was made available to the Student and/or TU Delft, unless that information was acquired by means of a wrongful act or omission on the part of the Student and/or TU Delft.

Part I
Literature Review

The first part of this report deals with the literature research, which is the theoretical foundation required to answer the research questions proposed in Chapter 1. To test the feasibility of a new technology, firstly, it is necessary to understand the regulatory framework that affects the technology. Secondly, it is required to analyse the properties and characteristics of the alternative fuels and the energy converters, and finally, it is necessary to collect the parameters required to carry out the economic analysis.

Chapter 2 deals with the regulation relevant for this project. It starts with the emission regulation that has motivated the study of alternative fuels and continues with the technical Codes that affect the transport and use of gases or low flash point fuels on board ships. In chapter 3, relevant information on the alternative fuels and the technologies that use those fuels are discussed. It includes properties, production methods, transportation, storage and safety considerations of the alternative fuels, and the technologies that will be tested in the analyses.

2
Regulation

The shipping industry is heavily regulated and has international safety standards developed at a global scale. The main regulators are the International Maritime Organization (IMO), a United Nations agency that promotes safety and security of shipping and the prevention of pollution originated by ships, and the International Labour Organization (ILO), which develops labour rights of seafarers [67]. This chapter will focus on IMO ship emission regulation and IMO Codes important for the safety and security of ships carrying and using hydrogen as fuel.

2.1. Emission regulation

IMO ship pollution regulation is part of the International Convention for the Prevention of Pollution from Ships (MARPOL). In 1997, the MARPOL Annex VI [27] was first adopted. This annex was developed by the Marine Environment Protection Committee (MEPC), and it limited nitrous oxides (NOx) and sulphur oxides (SOx) content from ship exhaust gases. It also prohibited the deliberate emissions of ozone-depleting substances (ODS).
In 2008, a revised version of Annex VI was adopted, and it strengthened significantly the emission limits [28]. It included a progressive reduction of NOx, SOx and particulate matter, and it introduced emission control areas (ECAs). ECAs are areas with emission limits and fuel quality more stringent than the global generic requirement. Current ECAs include the North Sea, Baltic Sea, most of North America and the US Caribbean, see Figure 2.1.

After, in 2011, there were some amendments to MARPOL Annex VI, which introduced mandatory energy

Figure 2.1: Current SOx and NOx ECAs [51]

efficiency measures to reduce the amount of CO2 emissions [23]. For instance, the Energy Efficiency Design Index (EEDI), which apply to new ships, or the Ship Energy Efficiency Management Plan (SEEMP), which affect all ships.

2.1.1. NOx emissions

NOx emission standards are classified into three tiers depending on the emission limits (g/kWh) allowed. Tier I was defined in the 1997 Protocol [27], and it affects engines greater than 130 kW on ships built after 1999 or engines installed on older ships that were considerably modified after 1999. After, the amendments adopted in 2008 and enforced in 2010 [28] limited new engines to Tier II and Tier III NOx emission standards, and engines manufactured before 2000 to Tier I.

Tier III does not apply to ships with a length lower than 24 metres and used for recreational purposes. Also, it does not apply to ships with a propulsion power lower than 750 kW if demonstrated that their design cannot comply with the regulation. NOx emissions of diesel engines are controlled through the survey and certification of the engine, which is called Engine International Air Pollution Prevention (EIAPP) Certificate.

Assuming that the proposed case study is constructed in the future and operated in both ECA and Non-ECA zones, the total weighted cycle emission limits (g/kWh) that the ship should comply with will depend on the engine's rated speed (rpm) and are the following:

NOx	Total weighted cycle emission limit (g/kWh)		
Tier	rpm < 130	130 ≤ rpm ≤ 1999	rpm ≥ 2000
II	14.4	$44 \times rpm^{-0.23}$	7.7
III	3.4	$9 \times rpm^{-0.2}$	2.0

Table 2.1: NOx emission limits that could affect the case study (Tier III only NOx ECAs).

Graphically, the information of Table 2.1 can be seen in Figure 2.2.

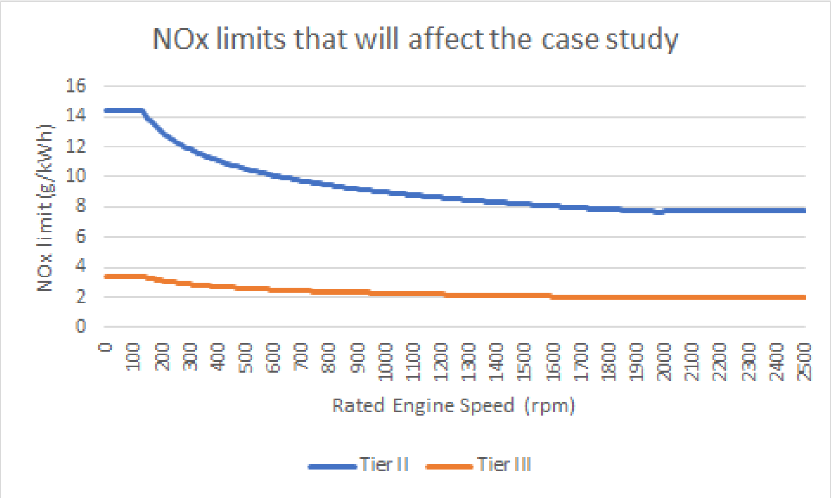

Figure 2.2: NOx emission limits that will affect the case study (Tier III only NOx ECAs)

2.1.2. SOx and particulate matter emissions

SOx and particulate matter emissions depend on the sulphur content of the fuel. This content is limited in all fuel oils used for combustion machinery on board, and its limit are expressed in terms of percentage of mass of solute (sulphur) per mass of solution (fuel). The limits that could affect the case study in both ECA and Non-ECA zones are presented in Table 2.2.

Non SOx ECA	**SOx ECA**
3.50% m/m on and after 1 January 2012	1.00% m/m on and after 1 July 2010
0.50% m/m on and after 1 January 2020	0.10% m/m on and after 1 January 2015

Table 2.2: Sulphur content that will affect the case study.

Graphically, the information of Table 2.2 can be seen in Figure 2.3.

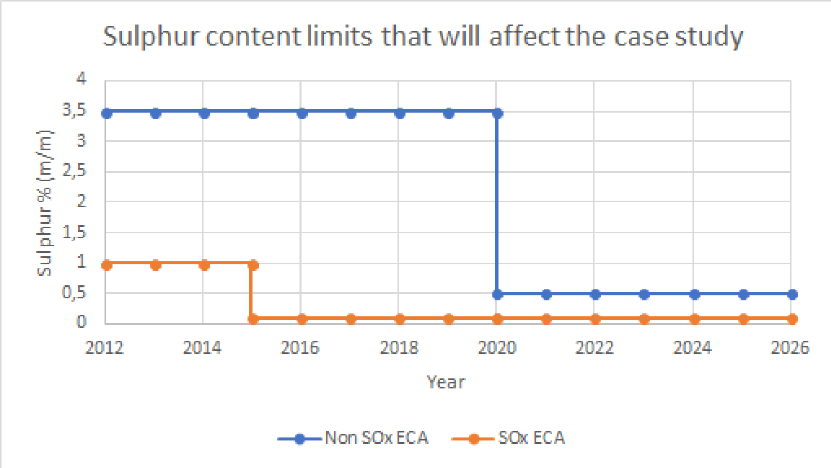

Figure 2.3: Sulphur content that will affect the case study

Ships that operate both inside and outside ECA will probably have different fuel oils in order to comply with both limitations. In this case, the shift to more stringent fuel have to be completed before entering ECAs, and the shift to less stringent fuel will start after leaving ECAs. To ensure this standard procedure at each change, the quantities of the ECA compliant fuel oils on board are recorded, together with the date, time and position of the ship [28].

2.1.3. CO2 emissions

2011 Amendments to MARPOL Annex VI [23] included two mandatory mechanisms intended to ensure the ship energy efficiency. Regulations on energy efficiency apply to all ships of 400 gross tonnage and above. But, they are not applicable to ships sailing within waters of their flag state jurisdiction. The case study proposed by CMB is subjected to this regulation, because it is higher than 400 gross tonnage and it will operate in international waters.

Energy Efficiency Design Index

The ship energy efficiency design index (EEDI) contributes to having ships with more energy efficient equipment and engines, establishing a minimum requirement for different ship types and sizes. The EEDI is a measure of a ship's energy efficiency and is expressed as grams of CO2 per vessel's capacity-mile (gCO2 / tonne·nm) [26]. In consequence, the smaller the EEDI the more energy efficient the ship design. Furthermore, the EEDI will be updated every five years, which is expected to stimulate innovation since the ship's design phase. The EEDI attained to a vessel is calculated by the Formula 2.1, which is a function of the ship's technical characteristics.

$$EEDI = \frac{\prod_{j=1}^{M} f_j \left(\sum_{i=1}^{nME} P_{ME(i)} C_{FME(i)} SFC_{ME(i)}\right)}{f_i V_{ref} f_w \, Capacity} + \frac{(P_{AE} C_{FAE} SFC_{AE}) + \left(\left(\prod_{j=1}^{M} f_j \sum_{i=1}^{nPTI} P_{PTI(i)} - \sum_{i=1}^{neff} f_{eff(i)} P_{AEeff(i)}\right) C_{FAE} SFC_{AE}\right)}{f_i V_{ref} f_w \, Capacity} - \frac{\left(\sum_{i=1}^{neff} P_{eff(i)} C_{FME} SFC_{ME}\right)}{f_i V_{ref} f_w \, Capacity} \tag{2.1}$$

where,

- C_{FAE}: carbon factor for A/E $[g_{CO2}/g_{fuel}]$,
- C_{FME}: carbon factor for M/E $[g_{CO2}/g_{fuel}]$,

- $Capacity$: ships's capacity measured in DWT or GT at the summer load line (for container ships is taken as 70% DWT) [tonnes],
- f_{eff}: correction factor due to availability of each innovative installed technology,
- f_i: correction factor in $Capacity$ for technical or regulatory limitations,
- f_j: correction factor due to design characteristics (e.g. ice breaker),
- f_w: correction factor in speed reduction due to representative sea conditions,
- M: number of propulsion shafts,
- n_{eff}: number of innovative technologies in the design,
- n_{ME}: number of M/E in the design,
- n_{PTI}: number of power take-in systems,
- P_{AE}: ship's auxiliary power requirements under normal seagoing conditions [kW],
- P_{EAeff}: ship's auxiliary power reduction due to innovative technologies [kW],
- P_{eff}: 75% of the installed power for each innovative technology that contributes to ship's propulsion [kW],
- P_{ME}: M/E installed power [kW],
- P_{PTI}: 75% of the installed power for each power take-in system (e.g. propulsion shaft motor) [kW],
- SFC_{AE}: specific fuel consumption for the A/E as given by the NOx certification [g/kWh],
- SFC_{ME}: specific fuel consumption for the M/E as given by the NOx certification [g/kWh],
- V_{ref}: ship's speed under ideal sea conditions when the propeller is absorbing 75% of the main propulsion engine(s) MCR sailing on deep water [kn],

Ship designers are encouraged to come up with new technologies to satisfy the EEDI requirements. The required EEDI varies from a reference line that depends on ship type and a progressive reduction factor function of time. The reference lines are developed by IMO using data from a large number of existing ships and analysing ship type correlations [25]. The time reduction factor is grouped in phases, from 0 to 3 [23].
Then, assuming that the proposed case study (bulk carrier, 181,218DWT as presented in Table 4.1) is built in the future, the reference line has a DWT-dependant value equal to $961.79 \times DWT^{-0.477}$ and it could be affected by Phase 1 (built before 31 December 2019), 2 (built before 31 December 2024) or 3 (built after 31 December 2024), and 10, 20 or 30% reduction factor, respectively. The EEDI of the proposed designs will be calculated in section 5.3 and compared to the EEDI limits to find out till what phase it could comply with.

Ship Energy Efficiency Management Plan & Energy Efficiency Operational Indicator

The Ship Energy Efficiency Management Plan (SEEMP) proposes a guide on best practices and a methodology for collecting ship data to improve the energy efficiency [24]. SEEMP also establish an approach for operators to improve efficiency over time, for instance, the Energy Efficiency Operational Indicator (EEOI) [22]. The EEOI is an expression of efficiency expressed as the ratio of mass of CO2 emitted per unit of transport work, and it could be used as a performance-based approach for monitoring ship efficiency. EEOI for a voyage is calculated as:

$$EEOI = \frac{\sum_j FC_j \times C_{Fj}}{m_{cargo} \times D} \tag{2.2}$$

where,

- j is the fuel type;
- FC_j is the mass of fuel j consumed;
- C_{Fj} is the fuel mass to CO2 mass conversion factor for fuel j;
- m_{cargo} is cargo carried (tonnes) or work done (number of TEU or passengers) or gross tonnes for passenger ships; and
- D is the distance in nautical miles corresponding to the cargo carried or work done.

The EEOI of the different proposed designs will be calculated in section 5.3 to compare each other in energy efficiency terms.

2.2. International code of the construction and equipment of ships carrying liquefied gases in bulk

The International Code of the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) [32] is related to the case study, because of the possibility of storing the alternative fuels in that state

on board. Even though this code was mainly developed thinking on LNG carriers, it could also provide relevant information when LNH3 or LH2 is carried. Because, it prescribes design and construction standards and equipment to minimize the risk to the ship, to her crew and to the environment.
Also, this code is a dynamic regulation that is kept under review, the last amendment [30] included modifications about ship arrangement, piping systems, electrical installations, ventilation system, and one particularly relevant for this research, the use of cargo (LNG) as fuel. In this amendment, the spaces containing boil-off gas consumers, such as boilers, inert gas generators, internal combustion engines or gas turbines are regulated, and more importantly, the point 16.9 of this amendment, "Alternative fuels and technologies" included this paraphrased basic principle:

If acceptable to the Administration, other cargo gases may be used as fuel, providing that the same level of safety as natural gas in this Code is ensured.

This opens the possibility of using hydrogen or ammonia boil-off gases when LH2 or LNH3 storage systems are integrated into the case study, providing that safety standards are kept at the same level that for natural gas.

2.3. International code for ships using gases or low flash point fuels

The International Code of Safety for Ships using Gases or other Low flash point Fuels (IGF Code) [31] regulates the machinery, equipment and systems using low flash point fuels. Initially, it focuses on natural gas, although, it also allows the use of low flash point fuels in general, such as hydrogen or methanol, using an alternative design process. Chapter 2.3 of the IGF Code clarifies that other low flash point fuels different than natural gas have to demonstrate an equivalent level of safety, and to do so, they shall be tested using the procedure specified in the International Convention for the Safety of Life at Sea (SOLAS) [111] regulation II-1/55.
The Regulation 55 was included in the amendment of 2006 [29], and it provides a methodology for alternative design analysis, evaluation and approval. The engineering analysis shall include a detailed description of the proposed design and arrangements, operational restrictions, safety justifications and risk assessments.
The engineering analysis will not be carried out in this thesis, but if the economic analysis is promising, it should be the next step.

2.4. Intermediate conclusion

This chapter has shown how the emission regulation will undergo an important reduction in global sulphur emissions after 2020. It also reveals how the progressive hardening of emission regulation has been mostly responsible for stimulating innovation since ship design phase. Furthermore, with new ECAs being considered, e.g. Hong Kong [17] and with other low flash point fuels and fuel cell regulation intended to be included in future revisions of the IGF Code [100], it is clear that new technologies will be required to comply with future regulation, such as abatement technologies, alternative energy converters or alternative fuels. Hence, shipping companies are betting on different strategies to have a competitive advantage in the future market.

The NOx and SOx regulation will affect the case study since the M/E and two A/Es will be diesel engines. In addition, if the energy converter tested is a hydrogen-diesel dual-fuel engine, the total weighted cycle NOx emissions are limited by NOx regulation, and the mixed fuel have to comply with the maximum sulphur content limit of the fuel.
Furthermore, to consider the proposed design as technically feasible, it will need to comply with the CO2 emission regulation. Since this regulation is to be updated every five years, the date when the ship is planned to be built affects the CO2 limit per tonne-mile of the case study. The EEDI is an important index to demonstrate the CO2 reduction of alternative technologies. The EEOI will help to compare alternative energy converters in the route proposed in the case study.

Moreover, in case the alternative fuel included in the design is transported liquefied, the IGC Code serves as a guideline to use boil-off gases on board. This is important, because a design in which a daily percentage of the stored fuel is lost could impact negatively to its acceptance on the shipping industry, in which idle periods are normal for ships in the spot market.
The current IGF Code redirects to SOLAS regulation II-1/55 to test low flash point fuels different than natural gas. The regulation 55 of SOLAS provides the methodology required to design the machinery and electrical

systems.
This graduation thesis will not cover an entire engineering analysis of the new design, since the determination of performance criteria, risk assessment and comparison with the safety standards of the prescriptive requirements contained in SOLAS are not in the scope of this research, as seen in section 1.3.

3
Alternative fuels

This chapter deals with the process of understanding the potential of alternative fuels to become competitive in shipping. It contains the information required to carry out the technical and economic feasibility analyses in the next part of this report. It starts with alternative fuel properties, production methods, types of storage and transportation. Energy converters that transform the chemical energy contained in fuels into electricity are then discussed. Finally, some safety considerations and the technologies included in the analyses are presented.
The alternative fuels considered in this report are hydrogen, natural gas, ammonia and methanol. In addition, the energy converters studied are internal combustion engines and different types of fuel cells. There are two hydrogen-diesel dual-fuel engine sizes, one high speed and one low speed. Also, there are two low-temperature fuel cells and two high-temperature fuel cells.

3.1. Properties

Basic thermodynamic properties of the alternative fuels will be discussed in the next subsections and some parameters, such as density, autoignition temperature, or flash point will be compared with conventional fuels at the end of this section.

3.1.1. Hydrogen

Hydrogen makes up 75% of the mass of the universe, but its molecules are so light that they escape from Earth's gravity. That is why, on the Earth's surface it is mostly found in the water molecule [55, 61]. Hydrogen is a gas at ambient conditions, so to properly transport it by truck, ship or pipeline, it is compressed or liquefied. Compressing or liquefying hydrogen produces energy losses [16].

The thermodynamic properties of hydrogen are relevant to control its storage and distribution. To explain some of this thermodynamic characteristics it is convenient to use some standard diagrams, such us the p-T or p-V diagrams.
The p-T (pressure and temperature) hydrogen phase diagram shown in Figure 3.1 [73], reveals the combinations of pressure and temperature that allow storing pure hydrogen on board. In this diagram, lines represent the change between phase regions. At standard pressure (1.013 bar) the boiling point of liquid hydrogen H2(l) is 20.38K. The point in which solid, liquid, and gaseous hydrogen coexist, called triple point, is at 0.0736bar and 13.96K. The line between liquid and gaseous phases stop at the critical point at 33.15K and 13 bar. If at the critical point the temperature and pressure are further increased, supercritical hydrogen is generated and liquid and gaseous phases are indistinguishable. The diagram also shows the four phases in which solid hydrogen exists, these phases have different lattice positions of the H2 molecules. At very high pressures, hydrogen moves to metallic phases where H2 dissociates in H atoms. Also, at very high temperatures an atomic plasma is formed.

Another important diagram to understand the thermodynamic properties of hydrogen is the p-V hydrogen phase diagram shown in Figure 3.2 [73]. In this diagram, the black lines represent isotherms, the red lines separate different phases, in the light grey area striped with red lines solid and liquid phases coexist, and in

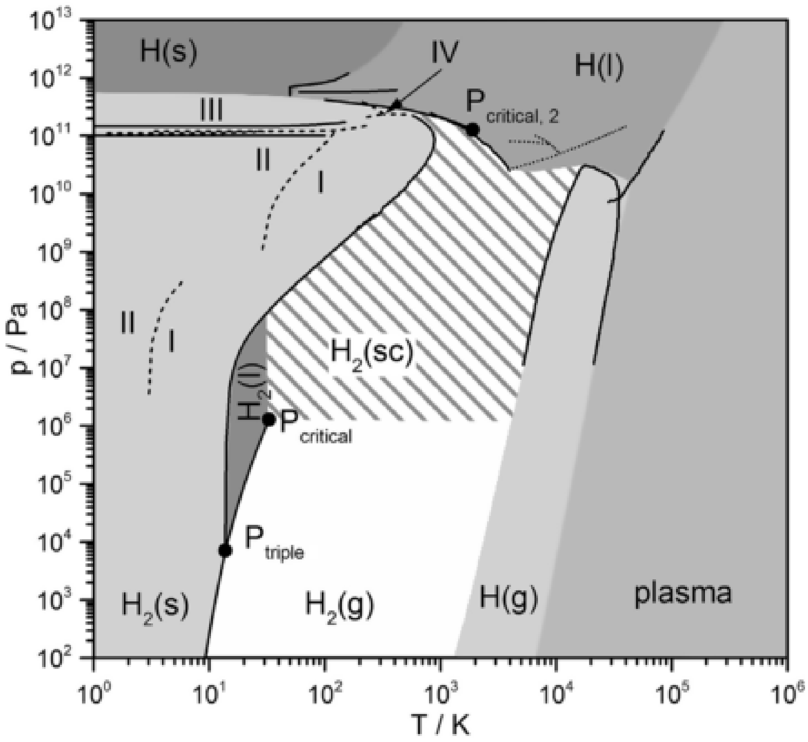

Figure 3.1: p-T hydrogen phase diagram [73].

the red hatched area liquid and gaseous phases coexist.

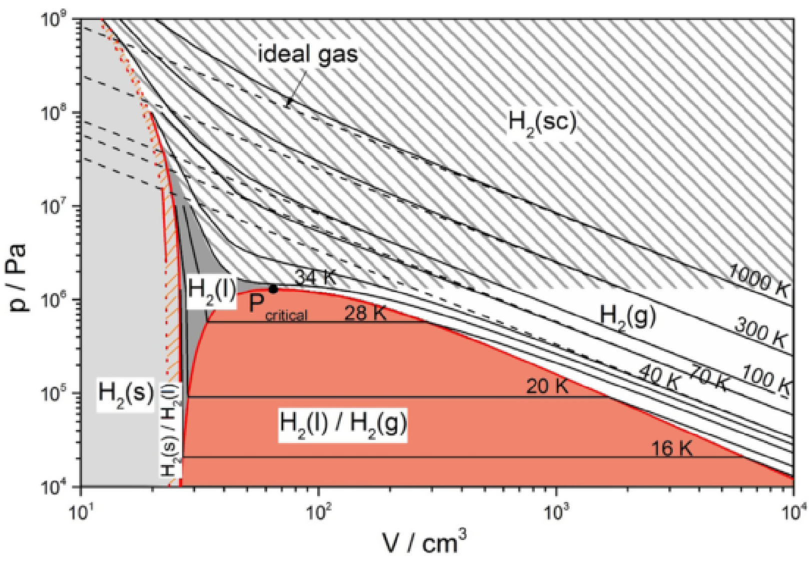

Figure 3.2: p-V hydrogen phase diagram [73].

Furthermore, in the subcritical region, which include pressures lower than the pressure of the critical point, the isotherms can be approximated with the equation of ideal gases:

$$pV = nRT \tag{3.1}$$

where,
p: pressure,
V: volume,
n: number of moles,
R: ideal gas constant (8.3144598 J/(mol·K)) [106],
T: temperature in K.

At room temperature hydrogen, helium and neon are the only gases that do not cool down when they are expanded in an isoenthalpic process [2]. This can be explained by the Joule–Thomson Effect. Gas particles can interact attractively or repulsively, and hydrogen particles at room temperature interact mostly repulsively. When repulsive interactions exist, the potential energy decreases with increasing volume. As a consequence, to preserve the total internal energy during expansion, the kinetic energy and the temperature increase [73]. A graphical representation of this phenomena is seen in Figure 3.3. Knowing that total energy is equal to internal plus kinetic plus potential energy, to keep the internal energy constant ($U_1 = U_2$), when the volume increase ($V2 > V1$) the potential energy decrease ($Ep1 > Ep2$) due to the repulsively interaction, and to compensate this decrease the kinetic energy has to increase ($Ek2 > Ek1$), which increases the temperature.

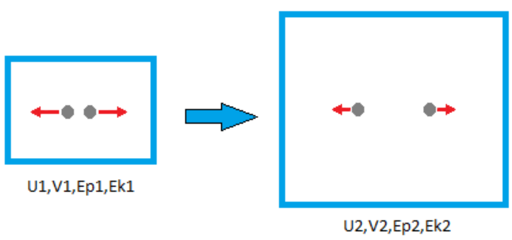

Figure 3.3: Volumetric expansion with repulsive particles. Red arrows represent the repulsive force [Own composition].

The effect on temperature and pressure in an isoenthalpic process is described by the Joule–Thomson coefficient (μ_{JT}):

$$\mu_{JT}(T,p) = \left(\frac{\partial T}{\partial p}\right)_H = \frac{V_m}{c_{vm}}(T\alpha - 1) \tag{3.2}$$

where,
$\alpha = \frac{1}{V}\left(\frac{\partial V}{\partial T}\right)_p$ is the thermal expansion coefficient,
$V_m = \frac{V}{n}$ is the molar volume, and
c_{vm} is the molar heat capacity.

The values of $\mu_{JT}(T,p)$ for the hydrogen start being positive at low temperatures, and at around 202K it becomes negative, which means that at temperatures higher than 202K the hydrogen gas heats up following an isoenthalpic expansion. That is why to liquefy hydrogen, the industry cools down the gas below 202K with conventional methods, and after use the Joule-Thompson effect to cool down it further [73], since expansions of hydrogen at temperatures below 202K cool it down further.

Furthermore, an important characteristic for hydrogen safety considerations are the explosion limits in contact with oxygen. The mixture of hydrogen and oxygen do not react below 400°C, while for higher temperatures the explosivity depends on the hydrogen and oxygen composition of the mixture, as well as on the temperature, pressure and vessel's dimensions [34]. Figure 3.4 shows the H2-O2 mixture's explosion limits, which vary due to the different collisions of free radical species (H*, HO*, O**) at temperatures higher than 750K (≈ 477°C). The three explosion limits define the two types of explosions: isothermal explosion occurs between the first and second explosion limits and consist in a chain reaction at a constant temperature, and the thermal explosion occurs at pressures above the third explosion limit, and in this case, the chain reaction produces an increase in temperature [73]. In the non-explosive region collisions among radicals also occur,

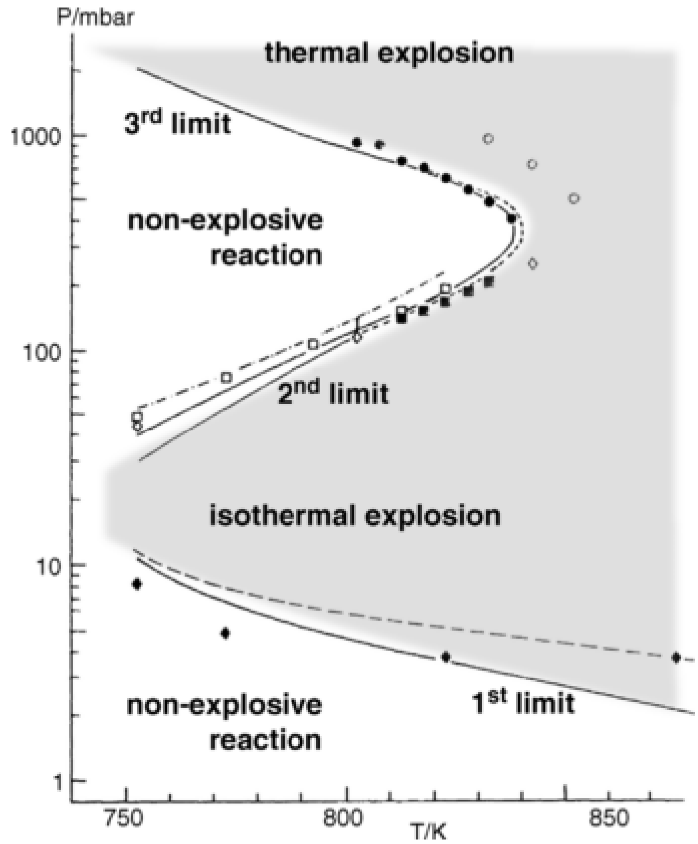

Figure 3.4: Explosion limits of H2 and O2 mixture [73]

although, at a slow phase, which produces a non-explosive reaction [73].

Moreover, some hydrogen properties such us high autoignition temperature or wide flammability range make it a promising fuel for internal combustion engines. The high autoignition temperature of H2 is a determinant factor for having higher compression ratios allowed in the engine. Also, the wide range of flammability allows hydrogen to be combusted in lean mixtures or with less fuel than the theoretical ideal for a particular ratio of air. Additionally, the low ignition energy facilitates the lean mixture, and a faster flame speed than conventional fuels allows the engine working near ideal cycle [107], in which explosion occurs instantly.

3.1.2. Natural gas

Natural gas is a gas at ambient conditions, and more than 85% of its composition is methane. Its remaining constituents are ethane (3-8%), propane (1-2%), and others [97]. The p-T diagram of a typical natural gas mixture is shown in Figure 3.5. The bubble point line separates the liquid phase from the two-phase liquid and gas area, while the dew point line separates the two-phase liquid and gas area from the gas phase. Both lines connect at the critical point, where the gas and liquid start to be indistinguishable. The P_{max}, T_{max} and Critical point are function of the composition of the natural gas [97].

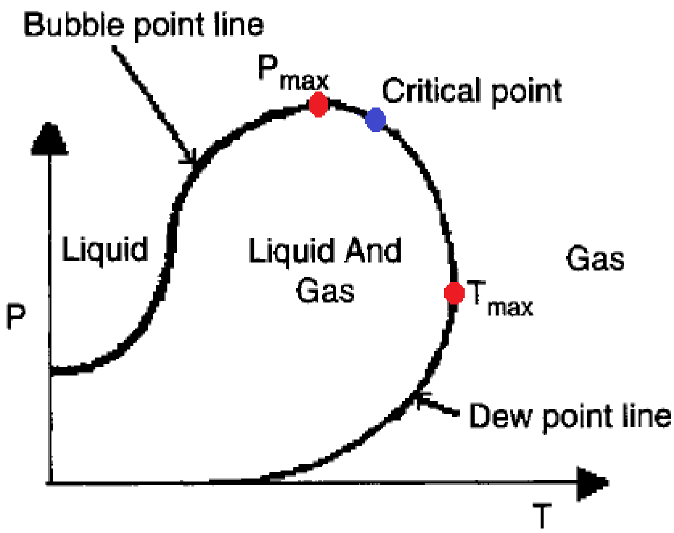

Figure 3.5: p-T natural gas phase diagram based on [97].

Figure 3.6 shows the p-T phase diagram of methane. The Critical point of methane has a temperature of $-82.59°C$ and a pressure of 45.992bar, and its Triple point has a temperature of $-182.456°C$ and a pressure of 0.117bar [151].

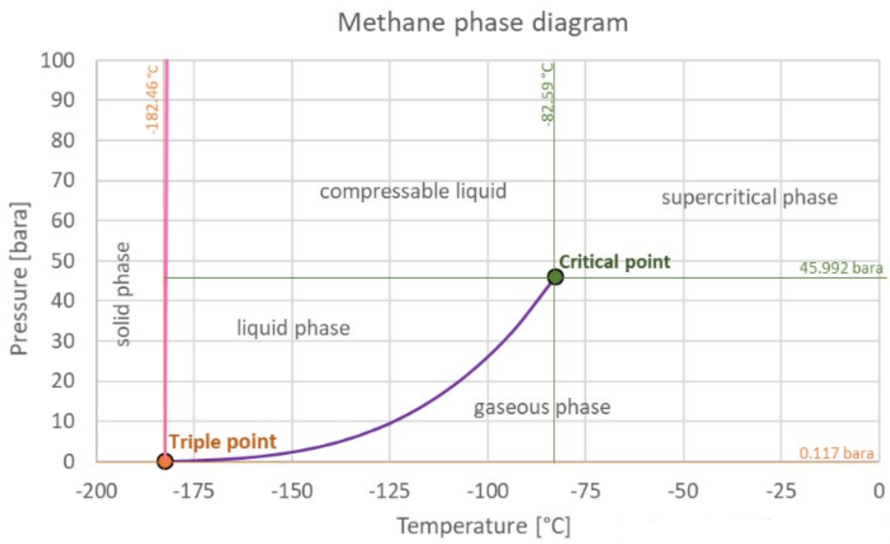

Figure 3.6: p-T methane phase diagram extracted from [151].

3.1.3. Methanol

Methanol is a liquid at ambient conditions, and a toxic alcohol that could serve as hydrogen carrier. The p-T phase diagram of methanol is shown in Figure 3.7. Methanol has the Critical point at $240.23°C$ and 82.159 bar, and the Triple point at $-97.54°C$ and 0.00000186bar [154].

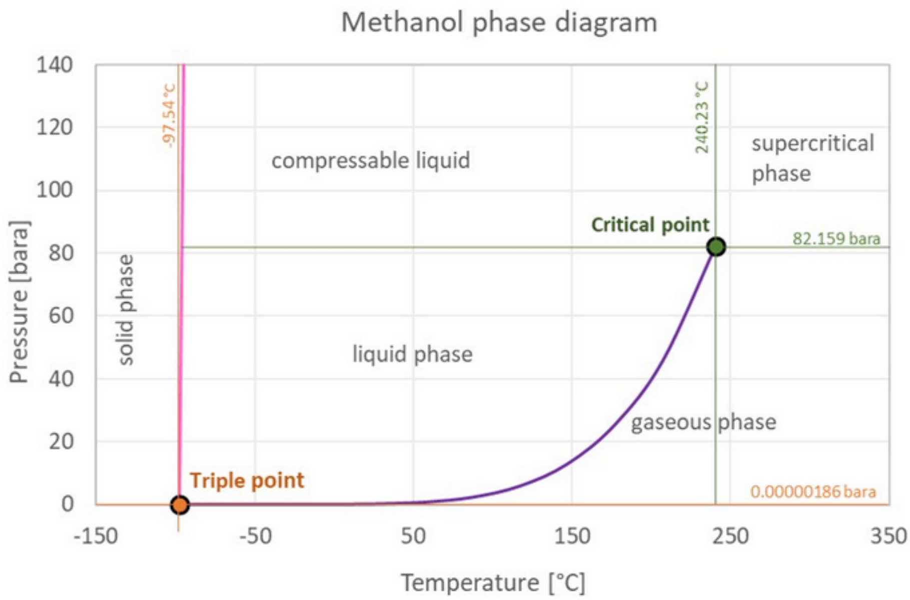

Figure 3.7: p-T methanol phase diagram extracted from [154].

3.1.4. Ammonia

Ammonia is a gas under ambient conditions and a hazardous gas that could serve as a hydrogen carrier. The p-T phase diagram of ammonia is shown in Figure 3.8. It has the Critical point at $132.25°C$ and 113.39 bar, and the Triple point at $-77.65°C$ and 0.0609bar [150].

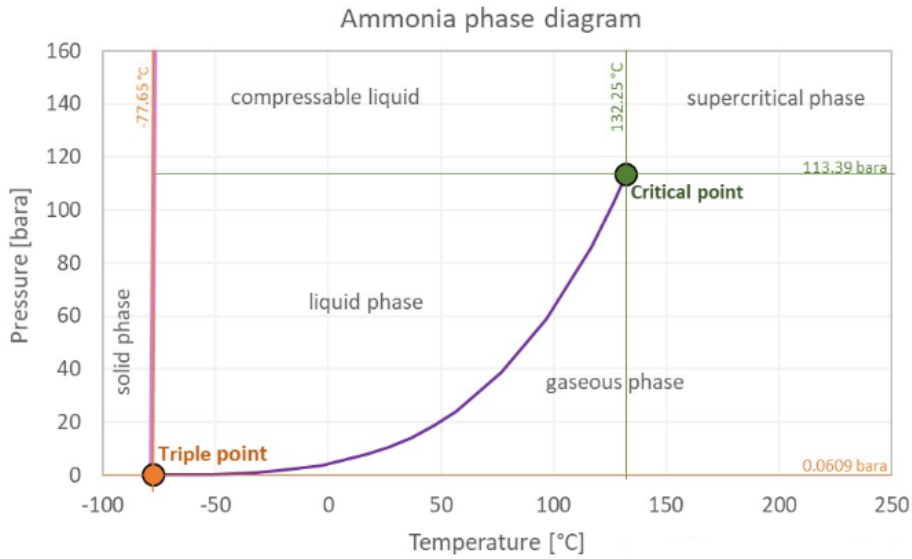

Figure 3.8: p-T ammonia phase diagram extracted from [150].

3.1.5. Liquid Organic Hydrogen Carrier

Liquid organic hydrogen carriers are organic liquids that permit a reversible hydrogenation-dehydrogenation cycle. This means that these carriers are not lost and do not release emissions during the hydrogenation or dehydrogenation processes. This is in contrast to the process when natural gas is reformed or ammonia is cracked. The advantages of this hydrogen carrier are its low toxicity and the fact that it is not classified as a hazardous material for transport. Also it can be stored in normal diesel tanks which do not need to be inerted [119].

In this project, the LOHC that will be considered is the dibenzyltoluene (hydrogen capacity of 6.2 mass %), because it has a broad liquid range ($-34°C\ to\ 390°C$) [119]. This is the LOHC carrier commercialised by Hydrogenious Technologies [146], which also commercialise the systems that allow the hydrogenation to bond hydrogen in the dibenzyltoluene and later on, the dehydrogenation of the perhydro-dibenzyltoluene to extract the hydrogen. This LOHC has an exothermic reaction during the hydrogenation that releases heat at a ratio of 65kJ per mol of H2 bonded, as can be seen in Figure 3.9. Then, in the dehydrogenation, an endothermic reaction occurs at temperatures higher than $250°C$ [119].

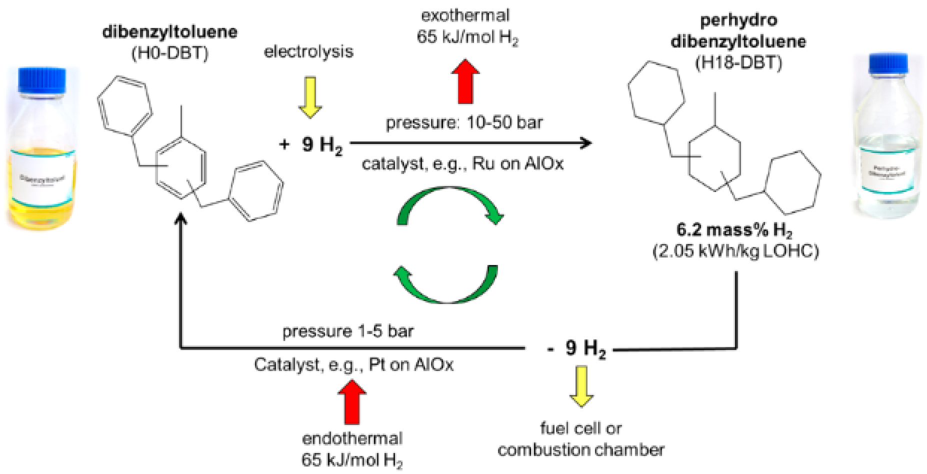

Figure 3.9: Hydrogen storage using the LOHC dibenzyltoluene/ perhydro-dibenzyltoluene [119]

3.1.6. Fuel properties comparison

The alternatives fuels discussed in this section, except the LOHC because it is only a hydrogen carrier and can not be used directly as a fuel, are compared with other conventional fuels in Table 3.1.

	Gasoline	LS Diesel	Natural Gas	Methanol	Ammonia	Hydrogen
Chemical Structure	C_4 to C_{12}	C_8 to C_{25}	CH_4(majority)	CH_3OH	NH_3	H_2
Density kg/m^3 gaseous/liquid	-/744.70	-/846.94	0.777*/456	-/794.10	0.763*/698	0.090*/70.85
Energy Content LHV	32,360kJ/l 43,448kJ/kg	36,090kJ/l 42,612kJ/kg	36,626kJ/m^3 * 47,141kJ/kg	15,957kJ/l 20,094kJ/kg	14,183kJ/m^3 * 18,577kJ/kg	10,805kJ/m^3 * 120,210kJ/kg
Autoignition tempt. °C	257	316	540	481	651	500
Flash point °C	-42.78	73.89	-187.78	11.11	<-33.34**	<-252.9**
Flammability in air vol%	1-7.6	0.6-5.5	5.3-15(CH_4)	6-36.5	15-28	4-75

Table 3.1: Fuel properties comparison based on [18], [75], [107], [104], [105], [72], [153], [152] and [121].

*: The LHV in terms of volume of the gases is considered at 0°C and 1 atm.
**: By definition, the flash point is the temperature at which enough amount of fuel vapours are produced to have an ignitable mixture with air. The flash point is always lower than the boiling point [107], that is why how the flash point is not found, the boiling point is included with the "<" symbol.

In Table 3.1, it can be seen that liquefied hydrogen and liquefied natural gas have the lower densities [kg/m^3], while low-sulphur diesel and methanol have the higher ones. Also, it can be seen that the LHV of the hydrogen is much higher than the rest of the fuel presented.
Knowing that the autoignition temperature is the temperature required to start the combustion of a fuel without a spark or other source of ignition [107], it is interesting to see how hydrogen requires a higher temperature than methanol, low-sulphur diesel or gasoline.
Furthermore, when hydrogen, natural gas, ammonia or even gasoline are mixed with air in gaseous form, they could be ignited with an external source at temperatures below zero. Finally, one of the problems with hydrogen and to a lesser extent with methanol can be appreciated in the table. Both hydrogen and methanol have a wide range of concentrations in air at which they are flammable.

3.2. Production

In this section the production methods of the different alternatives fuels are discussed. Both distinguished traditional methods and alternative methods are discussed. Traditional methods commonly use hydrogen reformed from hydrocarbons, and alternative methods could use renewable energy to produce hydrogen generated through electrolysis of water. Fuels produced with renewable energy have the potential to eliminate pollution at the point of production and, in case of pure hydrogen (or fuels whose emissions could be captured), also at the point of use. For instance, when the renewable hydrogen is used in a fuel cell there are no CO2 emissions in the entire process.

The increasing contribution of renewable energy to the energy mix has some energy absorption limitations due to daily peaks or seasonal peaks of solar and wind energy generation. If the surplus energy generated in these peaks is used to produce hydrogen, the production will generate zero emissions and the peaks could be absorbed and monetised. Once the hydrogen is produced, it could be used as fuel or to generate synthetic natural gas, ammonia or methanol.

In general, there are two ways to locate hydrogen, natural gas or ammonia production plants. On the one hand, the first approach is to centralise production in large facilities, store the production as compressed gas or cryogenic liquid and finally, distribute it through pipelines, ships or trucks to the end users [102]. On the other hand, on-site production near the end user can avoid the distribution step and when consumed just after being produced also the storage step, compared with the first approach. However, none of the approaches can fit all the situations, as for the production of electricity the preferable approach will depend on the region [94]

3.2.1. Hydrogen

Nowadays, the production of hydrogen is mostly based on fossil fuels, using steam reforming of natural gas. For instance, about 95% of the hydrogen used in the U.S. is produced with this method [101]. The main reasons for the predominance of this method are the lower price and higher efficiency compared with other alternatives [103]. But, even if the hydrogen is produced from natural gas, moving emissions from ports near large cities to industrial zones away from urban centres is promising to improve the quality of air in port areas. In addition, the price of natural gas and electricity determines whether or not this method remains the most competitive in comparison with cleaner alternatives.

Steam reforming of natural gas

The steam reforming of natural gas starts with the removal of the sulphur, continues by mixing the gas at high pressure (3-25 bar) with steam, increasing the temperature (750-900°C), and passing the mixture over a catalyst, generally nickel-based [10]. This reaction produces a synthesis gas defined by the following equation:

$$CH_4 + H_2O \Rightarrow CO + 3H_2 \tag{3.3}$$

The synthesis gas of CO and $3H_2$ is mixed with more steam to produce some more hydrogen and carbon dioxide, and this reaction is governed by the equation:

$$xCO + xH_2O \Rightarrow xCO_2 + xH_2 \tag{3.4}$$

Furthermore, the carbon dioxide also react with the methane, which produce also some hydrogen. The following equation shows this phenomenon:

$$CH_4 + CO_2 \Rightarrow 2CO + 2H_2 \tag{3.5}$$

A general overview of the steam reforming of natural gas can be shown in Figure 3.10.

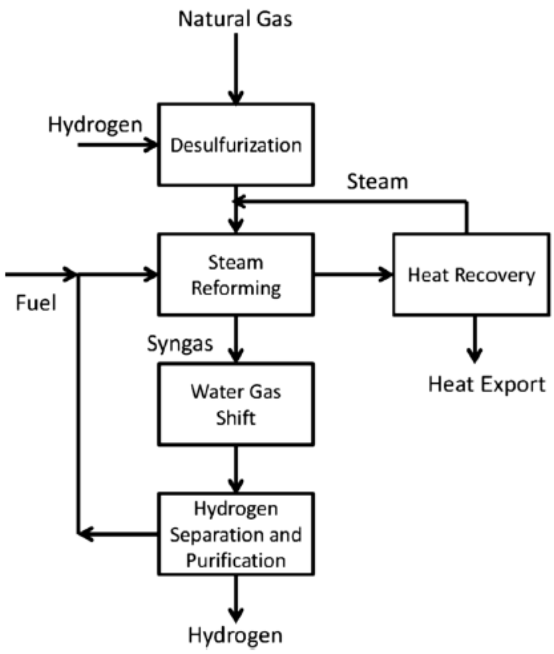

Figure 3.10: Hydrogen production via steam reforming [10]

To design a reforming plant to carry out this process on board a ship requires an extensive study that could cover an entire thesis project. As mentioned in section 1.3, this will not be covered. However, knowing the amount of LNG required to produce 1kg hydrogen is enough to estimate the LNG required on board. When hydrogen is produced from natural gas, 3.5kg of LNG are required to produce 1kg of H2 [19], which means that the reformer efficiency is approximately $\eta_{ref} = \frac{1kg\ H2\times120,210kJ/kg}{3.5kg\ NG\times47,141kJ/kg} \approx 0.73\%$.
In addition, a small scale steam methane reformer plant is used to know the weight and production of such a system. The model chosen is the "HGS-C" by Hygear, which comes containerised and has a hydrogen nominal output of 84-104 Nm^3/h, a weight of 9,500kg and maximum electric consumption of 14kW per unit [64], it can be seen in Figure 3.11.

Figure 3.11: Containerised steam methane reformer plant [64]

Electrolytic processes

Electrolytic processes represent a minor part of the total production, but when high purity hydrogen is required, they are a good alternative. Furthermore, this technology is the nexus between electricity produced with renewable energy sources and its transformation to chemical energy as hydrogen, which could provide more flexibility [10]. The produced hydrogen serves as storage mechanism that could be used when required as gas fuel for power generation, transportation or heating applications [162]. This principle is shown in Figure 3.12.

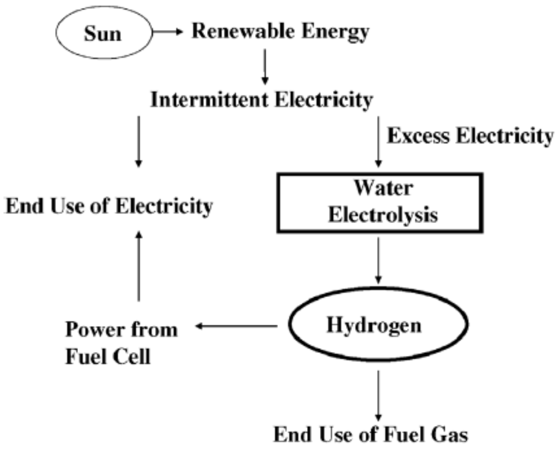

Figure 3.12: Distributed energy system using water electrolysis [162]

Hydrogen is an energy carrier that in combination with an electrolysis plant could connect the power sector with other end users. It could provide more energy flexibility: firstly, storing electricity in chemical form when surplus energy exists on the grid, and secondly, using the stored hydrogen when peak demands occur. Energy companies could sell hydrogen directly to end users or buy hydrogen from distributors when peaks in the grid are expected [78].

The basic reaction that defines the electrolysis of water is the following:

$$2H_2O \Rightarrow 2H_2 + O_2 \tag{3.6}$$

The three major electrolytic processes to generate hydrogen are:

- Alkaline electrolysis: the most important electrolytic process in the industry when pure hydrogen is required. The electrolysis occurs with a mixture of potassium hydroxide and water at a temperature of 60-90° [10].
- PEM electrolysis: this technology is based on the proton exchange membrane (PEM). It uses water and electricity as input, has a short response time, and a versatile range of action, which makes this method competitive in the renewable energy market [10].
- High-temperature electrolysis: the energy required to break chemical bonds does not need to be only electrical. This principle is used by high temperature (HT) electrolysis, by supplying heat the amount of electricity required is lower [10].

Reforming of methanol

There are three main reactions to extract hydrogen from methanol [59]:

- Decomposition of pure methanol: this method is endothermic, so heat must be provided to sustain the reaction. The carbon monoxide is harmful to low-temperature fuel cells [14], so extra processing has to be done to eliminate CO. However, high-temperature fuel cells (e.g. SOFC or MCFC) may not have this problem, because CO has even been studied as fuel for this type of fuel cell [62].

  $$CH_3OH \Rightarrow 2H_2 + CO \tag{3.7}$$

  When the CO has to be eliminated, water is mixed with the CO to produce water-gas shift reaction, which is an exothermic reaction as follows:

  $$CO + H_2O \Rightarrow H_2 + CO_2 \tag{3.8}$$

- Steam reforming of methanol: this method combines the two reactions of the first method in one only reaction:

$$CH_3OH + H_2O \Rightarrow 3H_2 + CO_2 \tag{3.9}$$

This reaction is endothermic and produces some traces of CO as the by-product.
- Partial oxidation of methanol: This reaction is exothermic and is able to provide some heat to endothermic process when more than one method is used simultaneously:

$$CH_3OH + \frac{1}{2}H_2O \Rightarrow 2H_2 + CO_2 \tag{3.10}$$

The disadvantage of this method is that the amount of hydrogen produced by the same amount of methanol is lower, because the water does not contribute to the formation of the final hydrogen.

As for the case of natural gas, a steam reforming plant of methanol on board will not be covered in this project. Although, by using the first or second method it was demonstrated in the calculations done in the Appendix B that 188.74g of hydrogen can be produced per each kilogram of methanol, while for the third method 125.83g of hydrogen can be produced per each kilogram of methanol. However, in reality, reformers do not reach those theoretical productions of hydrogen. In this case, the maximum LHV efficiency considered is 90% [157]. Then, the real production of hydrogen per kilogram of methanol is 169.87g.

In addition, a small methanol unit is used to know the weight and production of such a system. The model chosen is the "Me 150" by REB Research, which is able to generate a hydrogen nominal output of 4.77 Nm^3/h and a weight of approximately 90.72kg [33]. However, since this model did not have freely available information about electric consumption, another plant was used to do calculate the effect on average power demand, the Mahler AGS hydrogen plant with a production of 1,000 Nm^3/h has a electric power consumption of 45kW [90].

Cracking of ammonia

To extract the hydrogen from the ammonia the decomposition reaction that occurs is:

$$2NH_3 \Rightarrow 3H_2 + N_2 \tag{3.11}$$

This reaction is endothermic and with the calculation done in the Appendix B it was shown that theoretically, it is possible to obtain 177.55g of hydrogen per each kilogram of ammonia. However, as in the case of hydrogen extraction from methanol, the ammonia cracker LHV efficiency will be considered 90% [157]. Then, the real amount of hydrogen produced per kilogram of ammonia is 159.80g.
As for other reforming alternatives, the detailed design of an ammonia cracker plant on board will not be covered in this project.
In addition, a standard ammonia cracker unit is used to know the weight and production of such a system. For instance, ammonia cracker units with a hydrogen nominal output of 80.11 Nm^3/h and a weight of approximately 2,500kg are on the market [147]. On the other hand, the electric consumption of a system able to have a hydrogen nominal output of 60 Nm^3/h is 59.5kW [52].

Dehydrogenation of liquid organic hydrogen carrier

The dehydrogenation process was explained in subsection 3.1.5. Now, the dehydrogenation plant commercialised by Hydrogenious Technologies [146] is presented.
The biggest dehydrogenation plant commercialised by Hydrogenious Technologies is the "Hydrogenious ReleaseBOX Series 100" [144], and it can be seen in Figure 3.13. It has a hydrogen nominal output of 100 Nm^3/h at a pressure of 1-3 bar, it needs an electric connection of 400V, it requires a heating demand of 10kWh per kg of H2 released, and it is containerised in 20ft ISO-container.

3.2.2. Natural gas

On the one hand, conventional natural gas is a fossil fuel found in hydrocarbons reservoirs, and is originated with the degradation of organic matter during million of years [97]. On the other hand, synthetic natural gas can be produced from renewable hydrogen and CO/CO2 captured from exhaust gases or generated in other

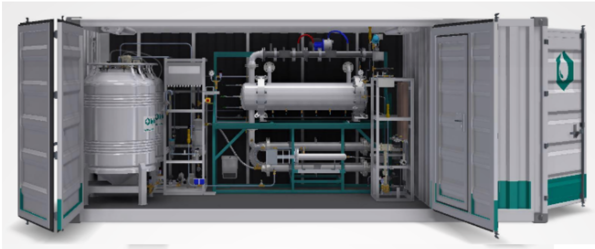

Figure 3.13: Hydrogenious ReleaseBOX for hydrogen release from LOHC [144]

chemical processes, using methanation.
Methanation is a process that uses a nickel-based catalyst to convert H2 and CO/CO2 mixtures into CH4 [164]. The main reactions in this process are:

$$CO + 3H_2 \Rightarrow CH_4 + H_2O \tag{3.12}$$

$$CO_2 + 4H_2 \Rightarrow CH_4 + 2H_2O \tag{3.13}$$

After, the resultant gas requires to be upgraded to have grid specifications, which is done removing the water and CO2 from the mixture [164].

3.2.3. Ammonia

The two major methods to produce ammonia are steam reforming of natural gas (or liquefied petroleum gas/naphtha) and partial oxidation of heavy fuel oil. For instance, in the case of using natural gas (majority is methane, CH4) and steam reforming, the overall reactions are [9]:

$$0.88CH4 + 1.26Air + 1.24H_2O \Rightarrow 0.88CO_2 + N_2 + 3H_2 \tag{3.14}$$

$$N_2 + 3H_2 \Rightarrow 2NH_3 \tag{3.15}$$

Before the first reaction occurs, the feedstock (e.g. natural gas in this case) need to be desulphurised, and before the second reaction is possible, the CO2 of the gas mixture need to be removed [9].

3.2.4. Methanol

The most important production method of methanol is from natural gas. Using steam reforming of natural gas as explained in subsection 3.2.1, it is possible to have a syngas (H2, CO, CO2) that can be converted into crude methanol. The reactions that occur to produce the crude methanol are [71]:

$$CO + 2H_2 \Leftrightarrow CH_3OH \tag{3.16}$$

$$CO_2 + 3H_2 \Leftrightarrow CH_3OH + H_2O \tag{3.17}$$

After these reactions occur it is required to distillate the crude methanol to achieve the desired purity [40].

3.2.5. Liquid organic hydrogen carrier

The dibenzyltoluene has a long tradition as oil, which ensures technical availability, industrial acceptance and low price with good quality standards [119]. Once the hydrogen carrier is acquired, it is necessary to bond the hydrogen to it. To do that, the hydrogenation plant from Hydrogenious Technologies [146] was chosen.
The biggest hydrogenation plant commercialised by Hydrogenious Technologies is the "Hydrogenious StorageBOX Series 100" [145], and can be seen in Figure 3.14. It is able to bond 160kg of hydrogen per hour, it requires a hydrogen inlet pressure of 30-50 bar, it needs an electric connection of 400V, it requires 10kWh per kg of H2 bonded for cooling systems, and it is containerised in 20ft ISO-container.

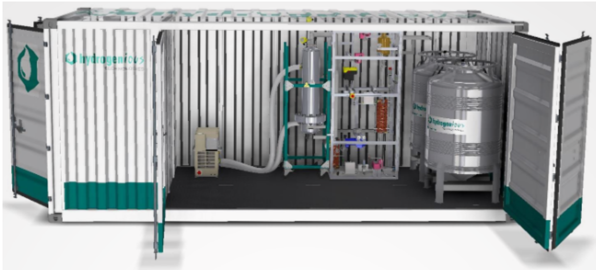

Figure 3.14: Hydrogenious StorageBOX for hydrogen storage in LOHC [145]

3.3. Transportation and storage

All alternatives fuels considered could be transported by truck to the port of refuelling using the same technology required to transport them on board. However, the natural gas distribution network could also be used to transport natural gas or even hydrogen.
It is possible to transport hydrogen pre-mixed with carbon so that the hydrogen-rich gas can be transported mixed with natural gas. Also, it is possible to blend hydrogen in natural gas to transport natural gas with a higher content of hydrogen [68, 74].
The first alternative mixes hydrogen with CO2/CO through methanation [54]. Then, this methane could be easily blended with natural gas (which is mostly methane) and injected in the normal natural gas infrastructure [109].
The second alternative reduces the carbon content of LNG when the new hydrogen-rich LNG is directly used as fuel. However, if the hydrogen want to be separated from the blend, the separation process will add some extra energy losses in the cycle [109].

In this section, the focus will be to study the effect of compressing or liquefying the alternative fuels to transport them on board, as well as the effect on weight and volume of storing them on board.

3.3.1. Hydrogen

Storage methods that reduce the volume required to store hydrogen are very important to increase the volumetric density of hydrogen storage. Three hydrogen storage alternatives of this kind are studied in this project: liquefied hydrogen, which can store 70.85kg of H2 per cubic metre of fuel, compressed hydrogen at 250 bar, which can store approximately 16.67kg of H2 per cubic metre of fuel, and compressed hydrogen at 350 bar, which can store approximately 21.00 kg of H2 per cubic metre of fuel. They are chosen because they are standard marketed solutions, so their characteristics and costs are available.

When the hydrogen is compressed to 250 bar, the required energy is less than 2kWh (<6% of H2 LHV = 33.33 kWh/kg) per kilogram, when it is compressed to 350 bar, 2-4 kWh per kilogram (6-12% of LHV), and to liquefy the hydrogen, 8-12 kWh per kilogram (30-40% LHV) [49]. It can be seen that reaching high pressures or cryogenic temperatures attain important energy losses [20].

The gravimetric specification (Empty tank mass [kg]/ H_2 stored mass [kg]) and the volumetric specification (Outer tank volume [L]/ H_2 stored mass [kg]) of the three alternatives studied are:

- 10-tube 250bar skid 40ft container [57] has a grav. spec. of 45.36 [kg/kg] and vol. spec. of 85.51 [L/kg],
- 40ft container able to carry four type IV composite 350bar cylinders [12] has a grav. spec. of 22.27 [kg/kg] and vol. spec. of 89.58 [L/kg],
- 20ft LH2 ISO-tank [117] [96] has a grav. spec. of 8.7 [kg/kg] and vol. spec. of 24.77 [L/kg].

3.3.2. Natural gas

Among the natural gas transportation methods, liquified natural gas has been selected because it allows transporting the remarkable amount of 130.29kg of H2 per cubic metre of fuel, and it is a widespread solution in the maritime industry [124]. The technology to store and transport natural gas as LNG is mature

enough [50] to consider it an interesting hydrogen carrier on board.
The selected LNG tank is a 40ft ISO tank [38], which has a gravimetric specification of 2.35 [kg/kg] (Empty tank mass / H_2 stored mass), and a volumetric specification of 14.30 [L/kg] (Outer tank volume/ H_2 stored mass).

3.3.3. Methanol

Methanol is a liquid able to transport 134.89kg of H2 per cubic metre of fuel, which is the highest amount of H2 per cubic metre of fuel from all the fuels considered. The effect of methanol transport has been done using as reference the characteristics of a gasoline/fuel oil 40ft ISO tank. The selected tank [6], has a gravimetric specification of 3.33 [kg/kg] (Empty tank mass / H_2 stored mass), and a volumetric specification of 12.69 [L/kg] (Outer tank volume/ H_2 stored mass).

3.3.4. Ammonia

The chosen ammonia transportation method is liquified, because it allows transporting the considerable amount of 111.54kg of H2 per cubic metre of fuel. The selected ammonia tank is a 40ft ISO tank to store LNH3 [5], and has a gravimetric specification of 2.61 [kg/kg] (Empty tank mass / H_2 stored mass), and a volumetric specification of 17.12 [L/kg] (Outer tank volume/ H_2 stored mass).

3.3.5. Liquid organic hydrogen carrier

The LOHC carrier commercialised by Hydrogenious Technologies [146] has a density of 920 kg/m^3, the amount of hydrogen per cubic metre of LOHC is 57kg, the electric energy required to hydrogenate the LOHC (cooling required) is 10 kWh/kgH2, which represents around 30% of the H2 LHV = 33.33 kWh/kg, and to dehydrogenate the LOHC (heating required) is also 10 kWh/kg, however this energy can also be supplied using heat recovered from exhaust gases or thermal sources.
As for the methanol transportation tank, a gasoline/fuel oil 40ft ISO tank was taken as reference. The selected tank [6], has a gravimetric specification of 7.88 [kg/kg] (Empty tank mass / H_2 stored mass), and a volumetric specification of 30.02 [L/kg] (Outer tank volume/ H_2 stored mass).

3.4. Energy converters

Energy converters in shipping need to be chosen considering the scalability of the technology, the specific requirements due to operation on the marine environment and the transferable knowledge available from onshore applications.

In this section, different energy conversion technologies that could use the alternatives fuels will be covered. The advantages and disadvantages of the different technologies will be compared. The technologies that will be mentioned are combustion engines, fuel cells and turbines.

3.4.1. Combustion engines

Internal combustion engine (ICE) technology is well known in the shipping industry, which has large experience in operating and maintaining M/Es and A/Es. There are different hydrogen combustion engine technologies that could be used in shipping. For instance, pure hydrogen combustion under homogeneous charge compression ignition (HCCI), or hydrogen diesel dual-fuel in a compression ignition (CI) engine.
The first one has knocking and self-ignition problems, which produce a drop in the engine thermal efficiency [160]. But these problems can be solved using exhaust gas recirculation (EGR) [98] or with a lean mixture of fuel [143]. The second one consists in adding small quantities of hydrogen to the diesel fuel, which increase the hydrogen to carbon ratio. In addition, when about 5% hydrogen is added to a diesel engine the diesel ignition lag is shortened which decrease the engine operational pressure and can increase the durability [142].

Furthermore, the low heating value of hydrogen based on volume could require increasing the size of the hydrogen engine to reach the same power output than a diesel engine. Another downside of the use of this technology is that the burning rates of hydrogen that cause high pressures and temperatures during combustion could make release high NOx emission rates [69], that must be abated to comply with emission regulation mentioned in subsection 2.1.1.

3.4.2. Fuel cells

Fuel cell technology does not have moving parts as combustion engine technology has, although, fuel cells require complementary machinery, such us humidifiers, pumps and fans. Fuel cell principle is based in two reactants, the most common hydrogen and oxygen, which are combined in the fuel cell to produce water, electricity and heat [113].
Some advantages of fuel cells in shipping are the following: the DC output of fuel cells could be directly used in some consumers, the reduction of noise in comparison with conventional ICE, and the no emission of CO2, NOx nor SOx when hydrogen and oxygen are used as reactants [113]. However, if other reactants, such as methanol or LNG replace the hydrogen, then CO2 is emitted.
On the other hand, the downsides of this technology are the difficulties to bunker some of the required solvents or alternative fuels in some ports, the complex storage of pure hydrogen and other alternative fuels on board, and the energy losses when some hydrogen carriers need to be reformed before entering the fuel cell.

Fuel cell systems have gas processing units and a stack of fuel cells modules that transform the chemical energy into electricity. Depending on the intended use of the fuel cell, different types exist. Generally, the working temperature of the fuel cell is a function of the required output. Small demands could be achieved with low-temperature fuel cells, while larger demands are generally achieved with high-temperature fuel cells. The advantage of high-temperature fuel cells is that they can accommodate waste heat recovery systems that improve the overall efficiency of the energy converter [156].

High temperature proton exchange membrane fuel cell

High-temperature proton exchange membrane fuel cell (HT-PEMFC) has the same principle that PEMFC and similar electrical efficiency (or slightly better), but it operates at a temperature up to 200°C. However, it has less sensitivity to impurities and a water management with only steam. This allows it to have a more simple reforming process when the hydrogen needs to be reformed from other hydrogen carriers, since a clean-up reactor after the reformer is not required.
The HT-PEMFC can operate at a higher temperature because it uses an acid electrolyte, and the heat generated can be used in heat recovery systems. The downsides of HT-PEMFC are that it can not start to operate alone in cold conditions [156], and also that no company is known to the author that commercialise systems of more than 5kW [132], which would require the installation of many systems on board to reach the 800kW required on this project. That is why this energy converter was discarded from the alternatives.

3.4.3. Turbines

Turbines are energy converters with large experience operating with natural gas and other low flash point fuels. Currently, there are studies that demonstrate the feasibility of H2-LNG dual-fuel turbines [77]. However, to achieve turbine power plants with high efficiencies at part loads it is required to have gas recirculation system and combined cycles [158]. However, these systems are mainly designed to high output gas to power turbine sizes, in which the extra capital investment can be recovered due to the efficiency increase of high output generators.

The turbine sizes required for the power demand on board a bulk carrier, which is the case study of this project, are not big enough to benefit from combined heat and power systems and gas recirculation systems. That is why the turbines are discarded as electric power supply alternative in the case study. On the other hand, the H2-LNG dual-fuel turbines are still under development phase so it was decided to not include this technology as the prime mover to be used for propulsion purposes.

3.5. Technologies included in the analyses

Shipping industry requires technology that provides continuous nominal power and operates properly under marine conditions. Ship motions can produce situations on board with heel angles of 22.5° and trim angles of 10°, and the machinery needs to continue operating under these conditions. Furthermore, in the engine room machinery has to cope with temperatures up to 45°C and relative humidity up to 60% [86].

There are some clear design principles for new ships, no matter what new technologies are tested. For instance, storing the fuel, processing the fuel and using the fuel in different rooms can avoid a domino effect, which is a critical failure to avoid. Also, for the same reason, fuel pipelines between rooms shall have mechanisms to disconnect the flow in case of fire or other emergencies. Moreover, an essential point to consider is the availability and reliability of the system, since technologies such as fuel cells have the inconvenience that crew members could not repair manually a fuel cell stack itself, with the exception of changing some filters of the stack on board [159].

Special safety considerations need to be addressed due to hydrogen low flammability limits, such us design differences in ventilation, firefighting systems and leak control systems [89]. Additionally, fuel tanks need to be located within a specific minimum distance of separation to the hull (ship side: Beam/5 or 11.5m, whichever is less; and ship bottom: Beam/15 or 2m, whichever is less [31]) and with monitoring devices.
The experience with LNG could provide valuable know-how in the design of H2 systems. Both LNG and LH2 are stored at cryogenic temperatures and they suffer a high volume increase when they shift from liquid to gas phases [124]. Also, these similarities contribute in having standardised solutions for problems that appear with both fuels. For instance, double walled pipelines for distribution, fuel systems located in dedicated spaces, or cylindrical fuel tanks that resist better high pressures or low temperatures [124].

Hydrogen requires special considerations in terms of corrosion. Mainly because hydrogen electrons pass through metals to areas where oxygen is more abundant, which originates damage to stainless steel in strained areas with an excess of oxygen. Thus, embrittlement (i.e. loss of ductility) of steel will occur at ambient temperatures when high pressures exist and the hydrogen enters the crystal structure of the metal. In addition, at high temperatures ($> 300°C$), hydrogen reacts with the carbon in the steel to produce methane and slowly reduce the steel properties. However, steel alloys with chromium, tungsten, titanium and vanadium are resistant to high temperature ($\leq 400°C$) hydrogen attack [8].
As mentioned in section 2.3 hydrogen and fuel cells are regulated by SOLAS Regulation II-1/55, which has safety levels in accordance with demonstrations projects. Moreover, the flag state of the vessel is responsible for having a vessel IMO compliant and national-rule compliant. But generally, classification societies survey ships on behalf of the flag state to obtain flag state approval. Furthermore, the basic principle that applies for low flash point fuels is that the system has to be as safe as conventional fuel systems, and in shipping, no single failure should trigger a dangerous situation [159].

An analysis of fuel cells in shipping [156] used different parameters to rank fuel cells technologies. These parameters included cost, power output, lifespan, fuel required, emissions or size. It was revealed that the fuel cells that have more potential for the use in shipping are the solid oxide fuel cell (SOFC), the proton exchange membrane fuel cell (PEMFC) and the high-temperature PEMFC (HT-PEMFC). However, due to the characteristic of the case study, in which size is less critical, the molten carbonate fuel cell (MCFC) is also considered.

Furthermore, as part of the sensitivity analysis that will be carried out, all the fuel prices and equipment cost will be modified in the different scenarios presented in section 6.3.

3.5.1. Pure hydrogen storage

The cost of pure hydrogen storage on board is influenced by the hydrogen price, the energy lost due to compression or liquefaction and the cost of tanks.

Firstly, the price of hydrogen mainly depends on the pathway to reach the end user. Hydrogen can be produced from fossil fuels or from renewable energy, and it can be compressed or liquefied to be stored and transported. In general terms, some studies priced hydrogen as 10 $/kg in the short term, and 5-8 $/kg in the long term [109]. Other studies priced hydrogen as 9 $/kg up to 2020 [93]. Furthermore, there is an important margin of reduction, since the cost of production with distributed natural gas reforming technology is 4.5 $/kg [123]. However, the estimated price of pure hydrogen in this project will be 3$/kg. This price is an input provided by CMB nv, which is achievable in 2018 due to company agreements with local companies. Also, note that the hydrogen price will be included in the sensitivity analysis, so from this analysis it will be understood whether this parameter is critical for the economic feasibility or not.

To transport hydrogen as compressed gas at 250 bar less than 6% of the energy content of hydrogen is lost [49]. To transport it at 350 bar about 8.9% of the energy content of hydrogen is lost [15], and to liquefy the hydrogen about 40 % of the hydrogen is lost [91]. Hence, considering these energy losses the price of the different hydrogen states would be 3.18$/kg for 250 bar, 3.267$/kg for 350 bar compressed hydrogen, and 4.2$/kg for liquefied hydrogen.

On the other hand, a 20ft ISO tank similar to the tanktainer show in Figure 3.15, it is able to store 1,200kg, and its cost is approximated as \$600,000 in 2016 [117]. Including the inflation rate of about 4.00% the cost is \$623,866.80 [81].

Figure 3.15: Cryogenic tank container [141]

A 10-tube 250bar skid 40ft container similar to the container shown in Figure 3.16, it is able to store 657kg of hydrogen and would have a price of approximately \$100,000, based on a quotation in 2018 [57].

Figure 3.16: Tube skid container [57]

A 40ft container able to carry four type IV composite 350bar cylinders, which is containerised similarly than the 250bar module shown in Figure 3.17, it is able to store 809 kilograms of hydrogen and its price was \$633,750 in 2013 [12]. Including the inflation rate, the cost is \$678,901.46 [82].

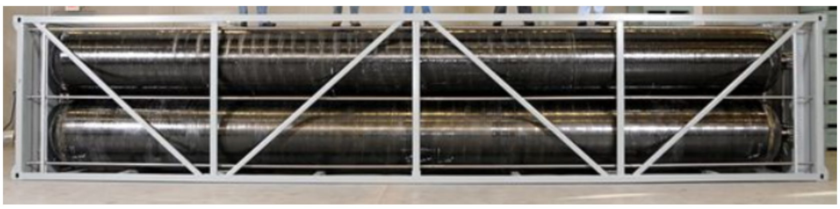

Figure 3.17: Container module with four 250bar composite tubes [56]

3.5.2. Hydrogen carriers storage

The price of natural gas is calculated considering the monthly average prices in China from November 2017 to July 2018, so the estimated price is 9.27 \$/MMBTU [126]. Knowing that one tonne of LNG has approxi-

mately 48.6 MMBTU, the price is equivalent to 450.36 $/T. However, to liquefy the natural gas approximately 2,900kJ/kg [48] are required, which is about 6.15% of the LHV of natural gas presented in Table 3.1. The LNG price that will be considered is 478.06$/T.
The price of methanol is considered 460$/T in 2018 in the Asia Pacific area, based on Methanex data [95]. The price of ammonia is estimated using data from the last 2 years (2017 and 2018) as 280 $/T [47]. Finally, the price of the selected LOHC in subsection 3.3.5 has a price 2.5$/kg based on a direct quotation from 2018. However, this LOHC can be reused in +400 loading/unloading cycles, so the operational cost of using this LOHC depends directly on the price of pure hydrogen used to hydrogenate it.

A 40ft ISO tank to store cryogenic LNG as the one shown in Figure 3.18 has a cost of $99,000 in 2018 [65].

Figure 3.18: 40ft LNG tanktainer [65]

A 40ft ISO tank to store methanol or LOHC does not require to be compressed or at low temperature, so a standard fuel oil/gasoline tank, as the one shown in Figure 3.19, it is selected. The estimated cost is $20,000 in 2018 [6].

Figure 3.19: Fuel oil/gasoline tanktainer [6]

A 40ft ISO tank to store LNH3 requires a better isolation than a standard tank, since the LNH3 requires to be stored at low temperatures. The model shown in Figure 3.20 has an estimated cost of $22,000 in 2018 [5].

Figure 3.20: 40ft liquid ammonia tanktainer [5]

Furthermore, the use of LNG, methanol, LNH3 or LOHC requires the use of reformers or crackers to produce the pure hydrogen required for some of the technologies. The price of small-scale steam methane reformer plant able to produce $400m^3/h$ of hydrogen was \$369,958 in 2002 [76]. Including the inflation rate, the cost is approximately \$518,206 [83]. The cost of a methanol reformer with the same generation capacity than the natural gas reformer was approximated with the relation of different investment costs presented in [140], which estimates steam reforming plants of small-sizes 21% more expensive than methanol plants. Then, the cost of the methanol reforming plant is considered \$409,383. The cost of an ammonia cracker unit able to produce 1-3gH2/s is estimated in \$100,000 in 2006 [147]. Assuming 12gH2/s or approximately $517.88m^3/h$ [120] of hydrogen generation capacity and using the 6/10th Rule to estimate the cost [46], the result is \$229,739. Including the inflation rate, the cost is \$287,162 [84]. Iin section 5.2 it will be explained why a higher demand of hydrogen occurs when ammonia crackers are used. Finally, in the case of the LOHC dehydrogenation plant, to have the same hydrogen generation than the natural gas reformers, four ReleaseBOX as the one shown in Figure 3.13 are required. The cost of the ReleaseBOX was not possible to find freely available and it was estimated at \$20,000 per unit, so the total cost of the system would be near to the total cost of the steam methane reformer plant. Then, the total cost of the dehydrogenation modules is \$80,0000.

3.5.3. Carbon dioxide capture systems

When LNG and methanol are used as hydrogen carriers they need to be reformed, and if the CO2 emissions produced in the reforming process want to be avoided then carbon capture systems (CCSs) are required. The same occurs when LNG is used in LNG-diesel dual-fuel engines.

This project focusses on post combustion capture systems, in particular absorption processes with solvents,since this is the technology most used in power generation applications on shore and it is more mature than pre-combustion capture systems [129]. The solvent that will be used in this project, monoethanolamine (MEA), it has already been studied on board ships[4].
These technologies are mostly developed for onshore power plants, mainly coal and gas fired stations. The use of coal requires sulphur removal before carbon capture [129], while the sulphur content can be neglected in case of natural gas [4]. That is why in the case study proposed by CMB, the carbon capture system (CCS) is only considered when natural gas is being used in dual-fuel engines operating with natural gas or when the natural gas or methanol is being reformed to use the hydrogen in other energy converters.

The operational principle of the CCS is visualised in Figure 3.21.
In Figure 3.21, it can be seen how the exhaust gases of the energy converter or "flue gas(raw)" enters the absorber. Also, the MEA (lean stream) coming at around 40° from the lean cooler is injected in the top of the absorber. After, the amine reacts with the exhaust gases, and approximately 90% of the total CO2 in the flue gas can be captured. The output fluxes of the absorber are the remaining flue gas with approximately 10% of the CO2 and a semiliquid mixture with 90% of the CO2 (rich stream)·

Then, the rich stream is passed through a heat exchanger, whose high-temperature flux is the lean stream coming from the stripper. This lean stream, after exiting the heat exchanger, will be directed towards the lean cooler mentioned above. On the other hand, once the rich stream is heated up and it exits the heat exchanger, it goes to the stripper, where more heat is provided to raise the temperature to around $120°C$. At this temperature, it is possible to "distillate" a gas that contains mainly CO2 and solvent vapours. Then, these vapours are condensed and redirected back to the stripper, while the pure CO2 stream is obtained.

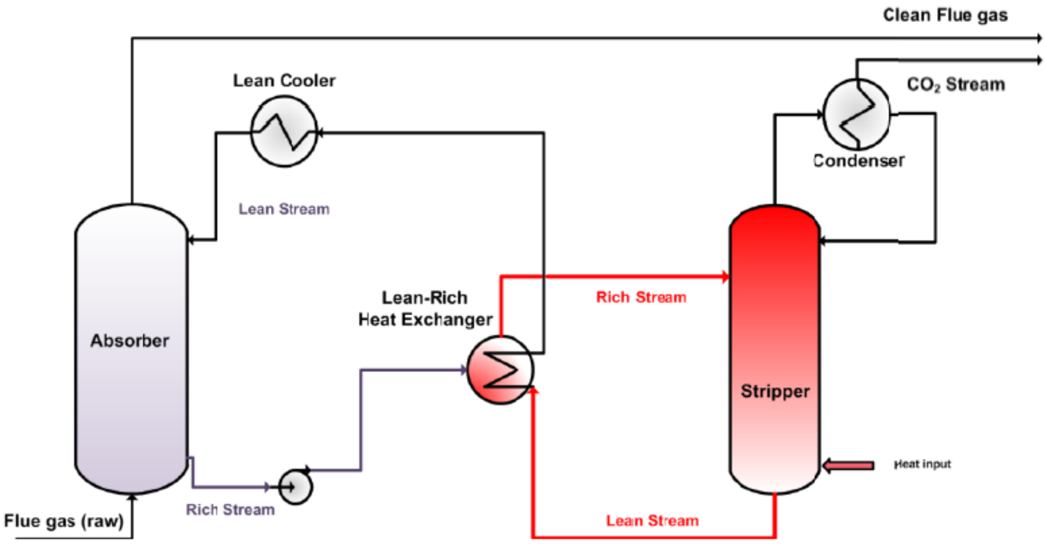

Figure 3.21: Basic scheme of a carbon capture system, E. Sanchez-Fernandez [129]

Finally, the CO2 stream that leaves the control volume in Figure 3.21 can be stored in different ways. In this project, the CO2 will be liquefied using the cooling provided by the evaporation of LNG stored at cryogenic temperatures. Concretely, it will be the two-stage compression and cooling procedure used in Appendix E to calculate the required power demand of the system.

3.5.4. Energy converters with pure hydrogen as input

In this section, only the technologies that require pure hydrogen as input are discussed.

Hydrogen-diesel dual-fuel ICE

Currently, there are no hydrogen combustion engines on the market. However, CMB Technologies collaboration with an engine manufacturer and with an engineering firm made possible the development of an engine that can operate in hydrogen-diesel dual-fuel mode. This engine is installed in the Hydroville [21], and it can be operated using compressed hydrogen gas fuel, but also using only diesel fuel.
Therefore, if ICE technology wants to be tested on the case study of this project, the knowledge and experience acquired with the Hydroville is the starting point. However, the engines installed in the Hydroville have a relative small-size (221kW of crankshaft power each) compared with the size required for this project. The A/E of the reference ship that is to be replaced generates 800kW of electrical power. Therefore, another engine is required.

For this project and to be able to compare H2-diesel dual-fuel ICE with other energy converters, a marine gen set of the same original equipment manufacturer than the one installed in the Hydroville was selected. It was the Volvo Penta D16 MG HCM534F HE shown in Figure 3.22, and its specifications are presented in Table 3.2. The price of this A/E is estimated at $100,000 per unit, based on an individual quotation from 2018.

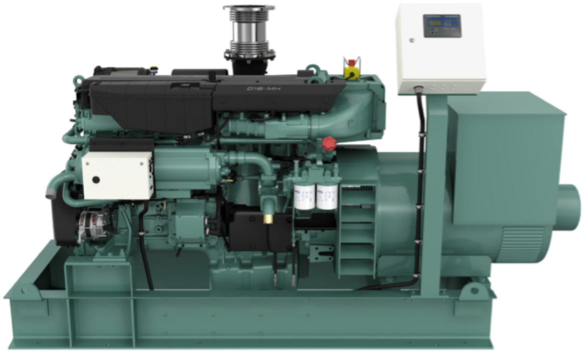

Figure 3.22: Volvo Penta D16 MG HCM534F HE [114]

ICE D16 MG HCM534F HE	
Engine output/Power generation (1500rpm/50Hz)	450/420kW
Dimensions (LxWxH)	3165x1177x1912mm
Weight	3926kg
Specific fuel consumption (Full load)	206[g/kWh]

Table 3.2: Specifications of marine gen set by Volvo Penta [114].

Furthermore, another engine that will operate with compressed hydrogen has started to be developed. It is the 6 DZD engine of Anglo Belgian Corporation (ABC) shown in Figure 3.23, which has larger size, and considerably greater weight than the D16 MG, but lower SFOC. The 6 DZD engine specifications can be seen in Table 3.3. The price of this A/E is estimated in $550,000 per unit, based on an individual quotation from 2018.

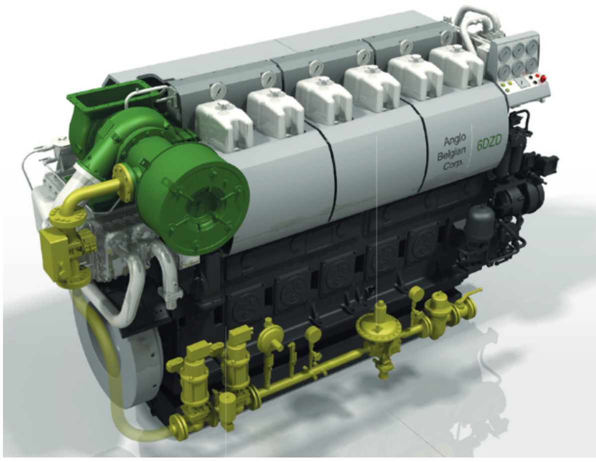

Figure 3.23: Anglo Belgian Corporation 6 DZD [1]

ICE 6 DZD	
Engine output/Power generation (1000rpm/50Hz)	1000/950kW
Dimensions (LxWxH)	6037x1535x3207mm
Weight	22,200kg
Specific fuel consumption (Full load)	≈200[g/kWh]

Table 3.3: Specifications of marine gen set by ABC [1].

Note that for having some results to compare energy converters, it was assumed that the modifications that were applied to the engines installed on the Hydroville could also be used in these generator sets. With this technology, the hydrogen/diesel ratio will vary according to captain instructions, but with a different limit for each type of engine depending on NOx emissions or knocking problems.
To facilitate the calculations of this project, it will be assumed that on average, 75% of the input energy of the ICE comes from hydrogen. The remaining 25% comes from MGO. These percentages are reachable with current technology and software.

In addition, how the maximum output of the Volvo Penta D16 MG HCM534F HE generator set is 420kW, two will be required to cover the 800kW of the A/E to be replaced. While in the case of the ABC 6 DZD gen set, only one is required.

Proton exchange membrane fuel cell

Proton exchange membrane fuel cell, or PEMFC, is fuelled by pure hydrogen and operates at low temperatures (50-100°C), knowing that the LHV of hydrogen is 33.33 [kWh/kg] [53] it has an efficiency of 50-60% (LHV) [156]. Other authors consider a wider interval for the conversion efficiency, from 40 to 60% [157]. The downsides of this technology are the high sensitivity to impurities, such as sulphur and carbon monoxide, a moderate lifetime and a difficult water management due to the existence of multi-phase (steam and liquid).
PEMFC uses platinum electrodes (catalyst) and the electrolyte is a humidified polymer that let hydrogen ions pass through. The reactants are hydrogen and oxygen and the main reactions that occur are the following [156]:

$$Anode: \quad 2H_2 \Rightarrow 4H^+ + 4e^- \tag{3.18}$$

$$Cathode: \quad O_2 + 4H^+ + 4e^- \Rightarrow 4H_2O \tag{3.19}$$

$$Total: \quad 2H_2 + O_2 \Rightarrow 2H_2O \tag{3.20}$$

The output of the reaction is water, together with heat and electricity. But, when hydrocarbons are used as fuel they need to be pre-reformed, and CO2 and in some cases NOx emissions are generated in this process.

Two heavy duty models of PEMFC that operate with pure hydrogen were selected to be compared with the other hydrogen alternatives: the HD100 of Ballard Power shown in Figure 3.24 and the HD180 of Hydrogenics shown in Figure 3.25. Both specifications are shown in Table 3.4.

Figure 3.24: Ballard Power FCveloCity HD100 [116].

Figure 3.25: Hydrogenics HD180 [63].

PEMFC	HD100	HD180
Power output	100kW (DC:400-580V/288A/Idle power: 6kW)	198kW (DC:180-360V/0-1000A)
Dimensions (LxWxH)	FC module: 1200x869x506mm Coolant subsystem: 737x529x379mm Air subsystem: 676x418x352mm	1582x1085x692mm (Coolant pump excluded, but air subsystem included)
Weight	FC module: 285kg Coolant subsystem: 44kg Air subsystem: 61kg	720kg (Coolant pump excluded, but air subsystem included)
Lifespan	+20,000 hours	+10,000 hours

Table 3.4: Specifications of PEMFCs by Ballard Power [116] and by Hydrogenics [63].

The price of fuel cells depends on the brand, but as an approximation, a report from 2018 priced PEMFCs for shipping uses in $2,200 per kW [118].

Finally, the maintenance cost is the fuel cell refurbishment after they exceeded their lifespan hours, and the maintenance of the electrical and mechanical balance of plant (converters, fans, pumps, etc.). It is assumed $1,000 per kW of fuel cell refurbished [118]. The fuel cells lifespan depend on the fuel cell model: the HD100 PEMFC of Ballard Power has 20,000 hours Table 3.5.4, the HD180 of Hydrogenics has 10,000 hours [155], a SOFC could reach 20,000 hours [130], and the MCFC could also reach 20,000 hours [163]. Also, it is assumed that 3% of the fuel cell capital cost is yearly required for the mechanical balance of plant maintenance. In addition, $830 per fuel cell power installed (kW) is yearly required to maintain the electric balance of plant of the system [118].

3.5.5. Energy converters with natural gas as input

In this chapter, it will be discussed an energy converter to be used as M/E, and three energy converters to be used to replace the function of one A/E. All can use natural gas as the input fuel.
The Wartsila 46DF (M/E) and the Wartsila 20DF (A/E) are designed for continuous operation in natural gas operating mode or diesel operating mode. The solid oxide fuel cells and molten carbonate fuel cells are able to reform internally the natural gas and generate a DC output, so they replace the function of an A/E.

Wartsila 46DF

The Wartsila 46DF is a 4-stroke, turbocharged and intercooled dual-fuel engine that can operate in two modes. In the gas mode operation, natural gas is the main fuel, but it requires a pilot fuel (e.g. MGO or MDO) to ignite the mixture. In the diesel mode operation, the engine requires a liquid fuel oil (e.g. HFO, MGO or MDO) [139].
This dual-fuel engine can be seen in Figure 3.26.

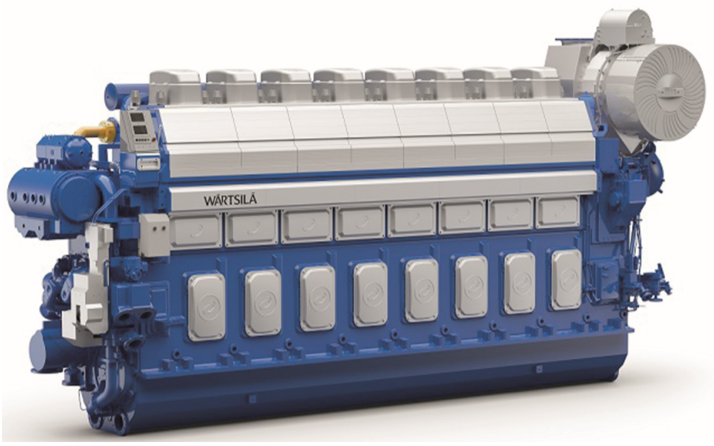

Figure 3.26: Wartsila 46DF [139]

The model selected for this project is the Wartsila 14V46DF, and its main specifiactions can be seen in Table 3.5.

Wartsila 14V46DF	
Maximum continuous output	16,030kW
Dimensions (LxWxH)	11,425x4,555x5,290mm
Weight	223,000kg

Table 3.5: Specifications of Wartsila 14V46DF [139].

More information about this engine can be found in Appendix D.

Wartsila 20DF

The Wartsila 20DF is a 4-stroke, turbocharged and intercooled dual-fuel engine with direct liquid fuel injection and indirect gas fuel injection. It can operate in the same two modes explained for the Wartsila 46DF above [138].
This dual-fuel engine can be seen in Figure 3.27.

Figure 3.27: Wartsila 20DF [137]

The model selected for this project is the Wartsila 6L20DF, and its main specifiactions can be seen in Table 3.6.

Wartsila 6L20DF	
Engine output/Power generation (1000rpm/50Hz)	960/920 kW
Dimensions (LxWxH)	3,108x1,690x2,530mm
Weight	16,900kg

Table 3.6: Specifications of Wartsila 6L20DF [138][136].

More information about this engine can be found in Appendix D.

Solid oxide fuel cell

Solid oxide fuel cell, SOFC, operates at high temperatures (500-1000°C), and it has more flexibility than PEMFC and HT-PEMFC. This greater flexibility is because the reforming can be done internally in the fuel cell, and hydrocarbons could be used as fuel. The electrolyte is a porous ceramics, and the anode is nickel-based.
When natural gas is used as fuel, it needs to be reformed, which produces CO2 and could produce some NOx when heat recovery systems are used after reforming, due to the high temperatures. The reforming follows the next reactions [156]:

$$Steam\ reforming: CH_4 + H_2O \Rightarrow CO + 3H_2 \tag{3.21}$$
$$Water-gas\ shift: \quad CO + H_2O \Rightarrow CO_2 + H_2 \tag{3.22}$$
$$Total: \quad CH_4 + 2H_2O \Rightarrow CO_2 + 4H_2 \tag{3.23}$$

Then, the reactions that use the reformed hydrogen as fuel are the following [156]:

$$Anode: \quad 2H_2 + 2O^{2-} \Rightarrow 2H_2O + 4e^- \tag{3.24}$$
$$Cathode: \quad O_2 + 4e^- \Rightarrow 2O^{2-} \tag{3.25}$$
$$Total: \quad 2H_2 + O_2 \Rightarrow 2H_2O \tag{3.26}$$

Assuming that the LHV of natural gas is the one presented in Table 3.1, the conversion efficiency of an SOFC can be considered on the range 45 to 60% (LHV) [157]. The technology can be used in large-scale power stations, reaching power outputs on the scale of megawatts.

An SOFC that operates with natural gas was selected to be compared with the other hydrogen alternatives, the ES5-YA8AAA of Bloom Energy shown in Figure 3.28, and its specifications are shown in Table 3.7.

Figure 3.28: Bloom Energy ES5-YA8AAA [43].

SOFC ES5-YA8AAA	
Power output at AC:480V/60Hz	300kW
Dimensions (LxWxH)	Alternative 1: 5588x2642x2134mm Alternative 2: 10033x1347x2261
Weight	Alternative 1: 15,800kg Alternative 2: 15,400kg

Table 3.7: Specifications of SOFC by Bloom Energy [44].

SOFC ES5-YA8AAA had an approximate cost of \$800,000 per 100kW in 2010 [115], so including the effect of the U.S. inflation rate the cost is considered \$915,559.31 per 100kW, approximately 14.44% increase [79].

Molten carbonate fuel cell

Molten carbonate fuel cell, MCFC, operates at high temperatures (600-700°C), and its electrolyte is a molten carbonate salt (no noble metal). The major difference with other fuel cell types is that this electrolyte requires CO2 as input to regenerate itself. The anode is nickel-based and the cathode is a nickel oxide with some lithium. In consequence, in the MCFC, both the catalyst and the electrolyte have a low cost. The fuel cell reactions are the following [156]:

$$Anode: \quad 2H_2 + 2CO_3^{2-} \Rightarrow 2H_2O + 2CO_2 + 4e^- \tag{3.27}$$

$$Cathode: \quad O_2 + 2CO_2 + 4e^- \Rightarrow 2CO_3^{2-} \tag{3.28}$$

$$Total: \quad 2H_2 + O_2 \Rightarrow 2H_2O \tag{3.29}$$

Assuming that the LHV of natural gas is the one presented in Table 3.1, the conversion efficiency of MCFCs can be considered from 40 to 55% (LHV) [157]. As for the SOFC, the MCFC is really flexible with fuel types because the reforming occurs inside the fuel cell. But the reforming produces CO2 and could produce some NOx when heat recovery systems are used after reforming. Other drawbacks of this technology are its slow starting and its slow adaptation to changing power demands [156].

An MCFC that operates with natural gas was selected to be compared with the other hydrogen alternatives, the SureSource 1500 of Fuel Cell Energy. The system integrated by this fuel cell and the different balance of plants are shown in Figure 3.29, and the specifications are shown in Table 3.8.

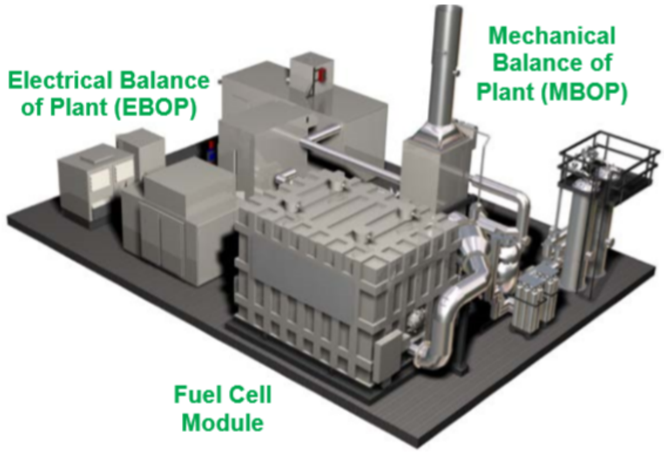

Figure 3.29: Fuel Cell Energy SureSource 1500 system [45].

MCFC SureSource 1500	
Power output at AC:480V/50 or 60Hz	1400kW
Dimensions (LxWxH)	FC module: 6046x4344x4090mm FC+BOP: 16942x11913x4090
Weight	FC module: 48535kg FC+BOP: 99110kg

Table 3.8: Specifications of MCFC by Fuel Cell Energy [45].

The MCFC SureSource 1500 costed about $4,200 per kW in 2010 [125], so including the inflation rate, the price is considered $4,806.69 per kW [80].

As for the PEMFC, the maintenance cost considered for the SOFC and MCFC it is assumed $1,000 per kW of fuel cell refurbished [118]. A SOFC could reach 20,000 hours [130], and the MCFC could also reach 20,000 hours [163]. Again, 3% of the fuel cell capital cost is assumed as yearly maintenance of the mechanical balance of plant, and $830 per fuel cell power installed (kW) is yearly required to maintain the electric balance of plant of the system [118].

3.5.6. Conversion efficiency of the energy converters

The different technologies presented in previous sections are compared in terms of conversion efficiency, which refers to the input of fuel (chemical energy) required to generate certain power output (electric energy). The diesel oil used to calculate the efficiency of ICEs has an LHV of 42,700kJ/kg and the natural gas of the dual-fuel engine is 49,620kJ/kg, the same used by the manufacturers [114] [7] [138]. The calculation of the efficiency of ICEs is presented in Appendix C, while the efficiency of fuel cells has been already mentioned in subsection 3.5.4 and subsection 3.5.5. All efficiencies are visualised in Table 3.9.

Technology	**D16 MG**	**6 DZD**	**6L20DF**	**HD100**	**HD180**	**ES5-YA8AAA**	**SureSource 1500**
Efficiency [LHV %]	40.93	42.15	44.72	40-60	40-60	45-60	40-55

Table 3.9: Conversion efficiency [Own composition based on Appendix C and [157]].

3.5.7. Specific power and power density of the energy converters

To compare different hydrogen system power specifications, it is possible to use the mass of the system (specific power) or the volume (power density). These two indicators are the following:

$$Specific\ power = \frac{Power\ output\ [kW]}{Mass\ [kg]} \tag{3.30}$$

$$Power\ density = \frac{Power\ output\ [kW]}{Volume\ [m^3]} \tag{3.31}$$

The specifications of the different technologies presented in subsection 3.5.4 and subsection 3.5.5 that are used to replace the function of an A/E are compared using these indicators in Table 3.10.

Technology	D16 MG	6 DZD	6L20DF	HD100	HD180	ES5-YA8AAA	SureSource 1500
Module s.p. [kW/kg]	0.107	0.043	0.054	0.351	0.275	-	0.029
System s.p. [kW/kg]	-	-	-	0.256	0.259	0.019/0.020	0.014
Module p.d. [kW/m^3]	58.967	31.967	72.72	189.517	166.695	-	13.033
System p.d.[kW/m^3]	-	-	-	129.052	148.253	9.522/9.818	1.696

Table 3.10: Specific power and power density of different energy converters [Own composition based on data from Tables 3.2, 3.3, 3.4, 3.6, 3.7 and 3.8].

Note that to be able to compare both PEMFC systems the coolant subsystem used in the HD100 was also used in the HD180. Even though the fuel cell module is made by different brands it serves as an approximation. Also, the two values that have the ES5-YA8AAA represent two different designing alternatives. Finally, both ES5-YA8AAA and SureSource 1500 could be undervalued in this analysis, since some of their systems are already integrated in common engine rooms, such us water treatment or subsystems of the electrical balance of plant.

3.6. Intermediate conclusion

The use of hydrogen in shipping brings new challenges to the entire fuel system, especially when the hydrogen is stored at cryogenic temperatures because LH2 have to be kept at temperatures below $-252.77°C$. Another difficulty is the hydrogen temperature increase that occurs when it is expanded, as explained in section 3.1. For instance, if PEMFCs are used in the case study, heat exchangers will require to keep the injected hydrogen at temperatures below the maximum working temperature of the fuel cell, around $80°C$.

Hydrogen and oxygen react at temperatures higher than $400°C$, which means that a conventional butane lighter, whose adiabatic flame temperature is theoretically $1970°C$ [35], could start the reaction. Currently, the regulation about smoking is stringent enough in merchant vessels, in which non-smoking areas are well defined and ships such as tankers have delimited rooms where smoking is allowed. However, a smoking ban on board could be an important restriction for leisure or business yachts. For instance, in the Hydroville is forbidden to smoke on board [21].

The alternative methods of transporting and storing hydrogen on board have remarkably differentiated characteristics. That is why these options are required to be compared economically to decide which one is the best alternative for the case study. These technologies can also be compared in terms of hydrogen mass content per cubic metre of fuel [kg of H2/m^3 of fuel] or in terms of hydrogen mass content per tonne of fuel [kg of H2/kg of fuel]. The alternatives that are going to be compared with these two indicators have already been presented in this chapter and are compress hydrogen gas (350bar), liquefied hydrogen, natural gas, methanol, liquefied ammonia and liquid organic hydrogen carrier.

To carry out the comparison of these storage methods, it is required to know the density of pure hydrogen and other hydrogen carriers, the hydrogen mass per kilogram of the hydrogen carrier and the kilograms of hydrogen per cubic metre of fuel. Firstly, the density are collected from different sources: the CH2(350bar) [131], the LH2 [36], the LOHC from a direct quotation, LNG, methanol and LNH3 from Table 3.1. Secondly, the hydrogen that can be obtained per kilogram of fuel has been mentioned in the different subsections of subsection 3.2.1, except for the LOHC, which also comes from a direct quotation. Finally, the kilograms of hydrogen per cubic metre of fuel can be calculated with the other two parameters, and all are shown in Table 3.11.

Fuel	CH2 (250bar)	CH2 (350bar)	LH2	LNG	Methanol	LNH3	LOHC
Density [kg/m^3]	16.67	21	70.85	456	794.1	698	921
H2 per kg of fuel [kg]	1	1	1	0.286	0.170	0.160	0.062
H2 per m^3 of fuel [kg]	16.67	21	70.85	130.29	134.89	111.537	57

Table 3.11: Characteristics of different hydrogen carriers [Own composition based on [131][36][149][37][152]].

With all the parameters obtained, it is possible to compare the storage alternatives. Table 3.12 shows the comparison of alternatives in terms of hydrogen mass content per cubic metre of fuel. The proper way to read this table is, for example, *there is 8.092 times more kilograms (or any mass unit) of hydrogen in one cubic metre of methanol than in one cubic metre of CH2 (250 bar).*

Fuel	CH2 (250bar)	CH2 (350bar)	LH2	LNG	Methanol	LNH3	LOHC
CH2 (250bar)	1	0.794	0.235	0.128	0.124	0.149	0.292
CH2 (350bar)	1.260	1	0.296	0.161	0.156	0.188	0.368
LH2	4.250	3.374	1	0.544	0.525	0.635	1.243
LNG	7.816	6.204	**1.839**	1	0.966	1.168	2.286
Methanol	**8.092**	6.423	**1.904**	1.035	1	1.209	2.367
LNH3	6.691	5.311	**1.574**	0.856	0.827	1	1.957
LOHC	3.419	2.714	0.805	0.438	0.423	0.511	1

Table 3.12: Comparison of hydrogen mass content per cubic metre of different fuels and states [Own composition based on Table 3.11].

In Table 3.12, it is shown that the methanol has the highest mass content of hydrogen per cubic metre, while the compressed hydrogen at 250bar has the lowest. Also, it should be emphasised that LNG contains 1.839 times more hydrogen than LH2, methanol contains 1.904 times more hydrogen than LH2 and LNH3 contains 1.574 times more hydrogen than LH2 per cubic metre of fuel.

On the other hand, Table 3.13 shows the comparison of alternatives in terms of hydrogen mass content per tonne of fuel. The proper way to read this table is for example, *there is 1.682 times more kilograms (or any mass unit) of hydrogen in one tonne of LNG than in one tonne of methanol.*

Fuel	CH2 (250bar)	CH2 (350bar)	LH2	LNG	Methanol	LNH3	LOHC
CH2 (250bar)	1	1	1	3.500	5.887	6.258	16.158
CH2 (350bar)	1	1	1	3.500	5.887	6.258	16.158
LH2	1	1	1	3.500	5.887	6.258	16.158
LNG	0.286	0.286	0.286	1	**1.682**	1.788	4.617
Methanol	0.170	0.170	0.170	0.595	1	1.063	2,745
LNH3	0.160	0.160	0.160	0.559	0.941	1	2.582
LOHC	0.062	0.062	0.062	0.217	0.364	0.387	1

Table 3.13: Comparison of hydrogen mass content per tonne of different fuels and states [Own composition based on Table 3.11].

In Table 3.13, it is shown that in terms of mass of fuel, compressed and liquefied hydrogen are pure hydrogen, therefore 100% of the fuel is hydrogen. Without considering the pure hydrogen forms, the LNG has the highest hydrogen content per fuel mass and the LOHC has the lowest.

Then, the storage of the different fuels requires different tank types to be stored, and the fuel densities also affect the total mass of fuel transported. The Table 3.14 compares gravimetric and volumetric specifications of the seven different alternatives explained in section 3.3. The LH2 storage could have a slightly better gravimetric specification and volumetric specification than the presented in Table 3.14, but a 40ft tanktainer containing LH2 was not found.

Fuel	Grav. spec [kg empty tank/kg H2 stored]	Vol. spec [L outer tank/kg H2 stored]
CH2 (250bar)	45.36	85.51
CH2 (350bar)	22.27	89.58
LH2	8.70	24.77
LNG	2.35	14.30
Methanol	3.33	12.69
LNH3	2.61	17.12
LOHC	7.88	30.02

Table 3.14: Gravimetric and volumetric specifications of different fuels and states [Own composition based on section 3.3 and table 3.11].

Finally, even though PEMFC technology had a positive result in the energy converters comparison in terms of specific power and power density shown in Table 3.10, the positive effect of affecting less of the payload of the vessel with this technology could be overcome by the negative effect of having higher capital investment or maintenance cost. Therefore, both effects will be considered for all the energy converters in chapter 6 when trying to answer the second research question presented in section 1.2.

Part II
Technical and Economic Analyses

This project try to answer technical and economic questions related to designs integrating different alternative fuels and energy converters in a case study proposed by CMB. Initially, the focus was given to study energy converters that could replace one of the A/E in the next generation of an existing bulk carrier design. Although, to study whether the alternative designs comply or not with the regulation, the emissions of the M/E also need to be considered.

Once the objective of the project is clear and the parameters required for the analyses are identified, the next step is to estimate those parameters and carry out the economic analysis. This part will cover the standard procedure adopted to do a complete feasibility analysis, the calculation of technical parameters, the development of the analyses and the outputs of the project.

Chapter 4 will present the methodology used for the analyses, including a generic standard procedure to test new technologies in a reference ship. This is important since at the end of the analysis it is required to ensure that the selected alternative is economically the best alternative (under certain scenarios), but firstly, it has to be technically feasible. After, the reference ship and the case study will be presented. Finally, it will cover how the operational profile of the reference ship is adapted to the new route and how a CBA is performed.

Furthermore, in chapter 5 the technical parameters that quantify the influence of the different storage alternatives and energy converters are calculated, and this effect will be included in the tool developed to calculate the CBA. Also, the different designs will be analysed in terms of their Energy Efficiency Design Index (EEDI). In that way, it can be seen whether some of the designs could comply with more phases than others (including the current design of the Mineral Yarden) or none of the designs reduce the CO2 emission enough to be built in later phases.

After finding the alternatives that are technically feasible and once the parameters required for the CBA are known, these parameters are included in the developed tool and the economic feasibility analysis is presented in chapter 6. This chapter covers the CBAs from different perspectives, the sensitivity analysis and the outputs of the project. Also, the optimal design under the different scenarios and the potential of the tested technologies to be used on other routes or ship types will be discussed.

Finally, the CBA tool developed in this project can be used by CMB in the future. Firstly, the CBA includes weight and cost estimations of components and systems based on information and quotations acquired during the literature research. So these estimations could not be accurate in the future. However, all the weight and cost estimations of individual components included in the tool can be updated by CMB in the future. Secondly, in case that new alternative fuels or energy converters want to be included in the CBA, they can be added in the CBA tool and their economic results could be compared with the other alternatives.

4 Methodology

This chapter will answer the first research question mentioned in section 1.2, and to do that, different alternative fuels and energy converters have to be integrated into a design based on a reference ship. Concretely, some of the new energy converters will replace one of the A/Es, and the Wartsila 46DF mentioned in subsection 3.5.5 will replace the current M/E of the Mineral Yarden. In this way, old and new combinations could be compared. The daily average consumption of the current M/E of the reference ship will be adapted to the new route and used in the technical and economic analyses as the consumption of the current M/E and to calculate the average engine output that will be required by the Wartsila 46DF.
In addition, to avoid confusion whether this project is a new building or a retrofitting, it should be seen as an iteration of a ship class, which will have similar design than the reference ship but renovated characteristics, so it will be a new building based on a previous design.

To test the alternative technologies on the reference ship a generic procedure step-by-step has been designed in section 4.1, so the technical and economic feasibility of the new designs is ensured.
Technical feasibility is defined in this project as the ability of the proposed designs to operate in the new route using the alternative fuel technologies while complying with international regulation (NOx, SOx, EEDI, EEOI, etc.). The definition does not include the constraint of transporting the same amount of cargo than the current design of the Mineral Yarden. This was decided together with CMB to be able to use the information obtained with the fleet performance tool about average consumptions. In consequence, the payload of the vessel is modified for each combination but the ship conserves her dimensions. In general terms, this definition just tries to demonstrate that the new technology does not affect the normal operation of a bulk carrier. On the other hand, the economic feasibility analysis will test the economic behaviour of the designs that comply with the technical feasibility under different scenarios.

The particulars of the Mineral Yarden, her operational profile and her consumptions are already known, so knowing the differences between the old and new routes, it is possible to calculate the changes on yearly days sailing loaded, in ballast and berthed in port. Then, with those parameters is it possible to calculate the M/E consumption in the new route, and include it in the technical and economic analyses.

The economic analysis will be done using a cost-benefit analysis from a private perspective (CMB) and from a welfare or societal perspective. The reason to consider these two perspectives is that in the private perspective, the externalities are not included as a cost.
The CBA from a private perspective is just an analysis of the income and costs that CMB would have in market conditions, which allows to find out the payback period, the IRR, the BCR and the cost per tonne-mile of the different alternative designs.
On the contrary, the welfare perspective includes the real CO2 emission cost to welfare, which is higher than the private perspective cost. Then, all economic indicators calculated in the private perspective are affected due to this extra cost. In that way, if the results of the CBA from a welfare perspective demonstrate that some of the alternatives have better economic indicators than the current design on the Mineral Yarden, there exist arguments to ask for a subsidy to the government.
Additionally, once the CBA from a private perspective is done, the different design will be ranked using the

benefit-cost ratio, which will help to discard the less promising technologies.

4.1. Standard procedure to test new technologies in old designs

This procedure was developed to have a basic structure to follow while performing the technical and economic analyses. It allows keeping the overview of the entire project at any stage of the analysis. It was devised with the intention to be really generic, so it could also work with any new technology (subsystem) that wants to be tested on previous designs (system), which means that it could also be used in cars, trains, etc.

The standard procedure to test new technologies on board previous ship designs uses the knowledge acquired during the lifetime of a ship or during a certain operation period. It helps to decide among alternative designs for the next generation of a ship.
This standard procedure was developed after reflecting on how to benefit from the high amount of data collected with a fleet performance tool, which normally record daily M/E and A/E consumptions, days in port, days sailing in ballast, etc.
Ideally, the route of both the reference ship and the new design would be the same, which could allow not having to adapt the old recorded consumption to the new route. However, the case study that CMB is interested in has a different route than the reference ship was doing when the operational profile was recorded.

The following procedure is an own composition:

1. Obtain operational profile of ship R operating in route r_0 from date i to date j.
2. Adapt operational profile to route r_n (not necessary when new ship operates in the same route, $r_n = r_0$)
3. Redesign ship R introducing technology k.
4. Test technical feasibility of ship R with technology k integrated.
5. If technology k is technically feasible move on to step 6, otherwise go back to step 3 and try technology $k+1$ or if there are not more technologies to be tested, state that there are not technically feasible solutions.
6. Test economic feasibility under different scenarios.
7. Save results and go back to step 3 if there are more alternatives to test, otherwise compare the saved results of the different alternatives.

where,

- R: reference ship,
- r_0: reference route,
- i: starting date to consider the operational profile of the reference ship,
- j: last date to consider the operational profile of the reference ship,
- r_n: new route,
- k: technology that want to be tested.

4.2. The reference ship

The main particulars of the reference ship are shown in Table 4.1.

Capesize bulk carrier Mineral Yarden	
Dimensions (LOAxBxD)	291.98x45.00x24.70m
DWT(summer load line)	181,218MT
Other weights (Fuel, fresh water, etc.)	5,744.47MT
M/E	HITACHI-MAN B&W 6S70ME-C8.2
M/E BHP	15,450kW
M/E consumption (MCR)	170.3[g/kWh]
M/E weight	555.0[ton]
A/Es	Three 4-STROKE DAIHATSU 6DE-18
A/E Power output	800kW
A/E consumption (MCR)	198.2[g/kWh]
A/E weight	13.0[ton]

Table 4.1: Main particulars of the Mineral Yarden [92] [39].

The performance of this ship was recorded for a year using the fleet performance monitoring tool developed in-house [3]. The recorded period went from 01-01-2017 to 01-01-2018, while the Mineral Yarden was operating doing round trips from South America to the eastern Mediterranean area. The transit times of those trades were 2 to 4 days loading, about 18 days sailing loaded, 2 to 4 days unloading and 18 days sailing in ballast, which means that approximately 8 rounds trips were possible yearly. The relevant data extracted during that period is shown in Table 4.2.

Parameter	Average	Median	Maximum	Minimum
M/E consumption [MT/day]	35.79	37.79	54.77	0.48
A/E consumption [MT/day]	2.37	2.25	3.85	1.69
Average A/E Load [%]	54.94	53	80	40
Combined A/E Power [kW]	498	400	1140	60

Table 4.2: Main parameters of the Mineral Yarden extracted from FPM [3].

For the same period, the annual operational profile of the Mineral Yarden was calculated using data from ship reports and collected with the fleet performance monitoring tool used at CMB. The operational profiles are shown in Figure 4.1.

4.3. The case study

The case study proposed by CMB consists in a long-term contract to transport iron ore from Port Hedland to any port in China (Dalian, Qingdao, Xiamen, etc.) with a frequency of monthly round trips. The contract does not specify a destination port in China. Although, Dalian was chosen as the destination port in the SeaRates tool [87] to visualize the entire region of operation in Figure 4.2, because it is one the most northern ports.

Now, assuming that the transit times of this route are 3 days loading, about 9 to 12 days sailing (about 3,000 nautical miles) depending on the Chinese port, 3 days unloading and 11 days sailing in ballast based on estimations done with the SeaRates platform [87]. With this estimations, there is margin to say that 12 round trips can be done yearly. Then, each one-way trip is around two weeks and the complete round trip has a monthly frequency.

4.3.1. Adaptation of the operational profile

The case study route is shorter than the reference ship did on the period recorded from 01-01-2017 to 01-01-2018, that is why to estimate the consumption is necessary to adapt the yearly consumptions to the new

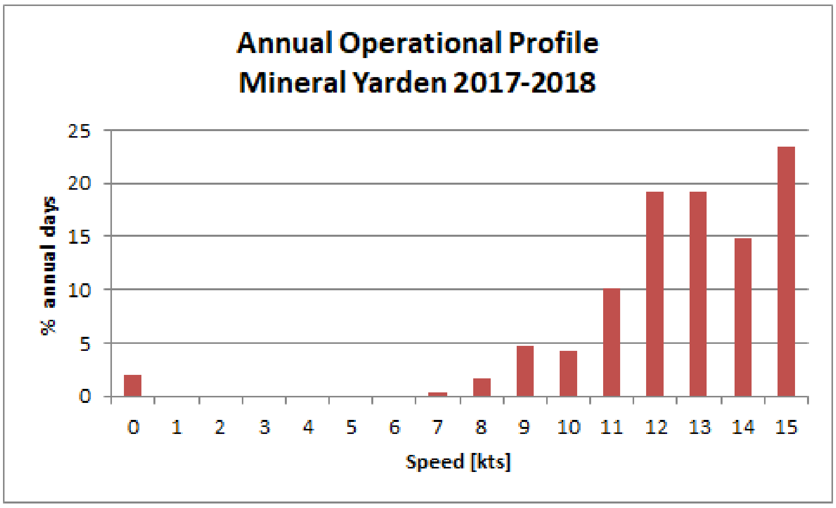

Figure 4.1: Operational profile of Mineral Yarden using data collected with the FPM tool[3]

Parameter	South America-East Mediterranean	Australia-China
Days loading per trip	3	3
Days sailing loaded per trip	18	12
Days unloading per trip	3	3
Days sailing in ballast per trip	17	11
Annual round trips	8.9 (Aprox. 8)	12.6 (Aprox. 12)
Annual days sailing loaded	160	151
Annual days sailing in ballast	151	138
Annual days in port	53	75

Table 4.3: Route differences between reference ship and case study.

route. The differences are shown in Table 4.3.

The differences in the annual number of days sailing would affect clearly the M/E annual average consumption per day, previously shown in Table 4.2, which in the new route could be slightly reduced due to thr higher number of days in port. Then, it is assumed a linear relationship between days sailing and annual average M/E daily consumption.
Knowing that in the old route 311 days in one year the ship was sailing and the M/E consumption was 35.79[MT/day], with 289 days sailing per year the new M/E consumption is 33.26 [MT/day]. On the other hand, the auxiliary engine consumption will be kept unmodified, because there is no shaft generator or cold ironing systems whose effects could be easily quantifiable.

4.4. Cost-benefit analysis

As it was explained in the introduction of this chapter the cost-benefit analysis (CBA) is chosen because it allows obtaining more information about the alternative technologies to be tested. From the point of view of a company, all decisions will be taken considering the private perspective results. But, the welfare perspective results are relevant when the government is willing to subside project with could improve the welfare of the population.
The economic analysis tries to find out the best combination of energy converter and storage method among all the alternatives that can lower the CO2 emissions of the current design in the Mineral Yarden. But to be implemented on a ship operating on the market, it also needs to be competitive with the current design of the Mineral Yarden, since this project is not intended to be a public relations project. That is why subsidies are mentioned in this project.
For instance, it could happen that the current design of the Mineral Yarden was the best NPV from a private perspective. But, from a welfare perspective, it was another design. Then, the government could go for sub-

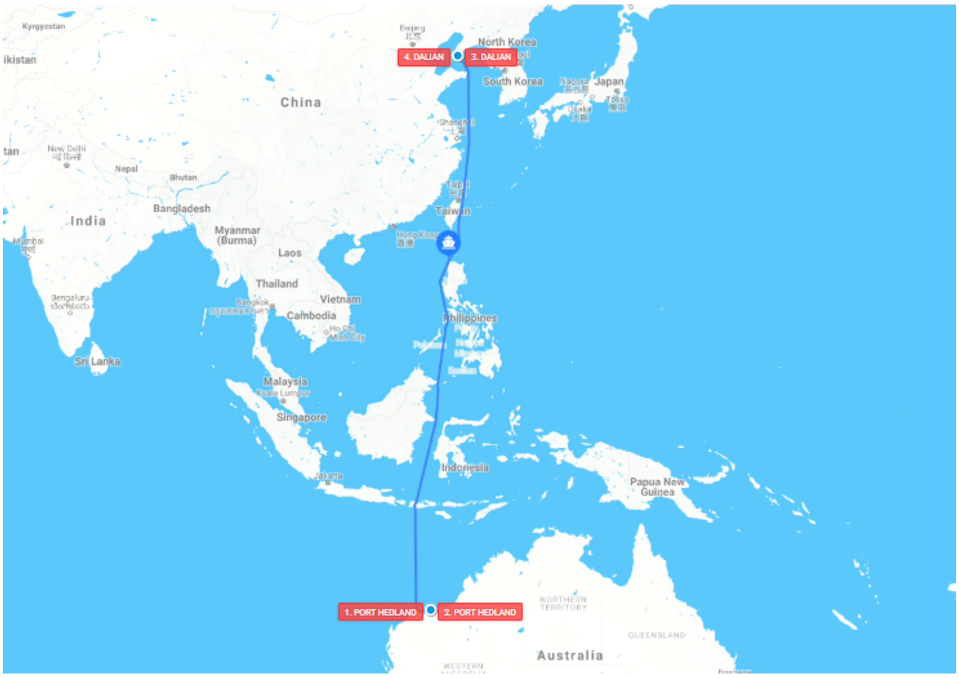

Figure 4.2: Possible route, Port Hedland - Dalian [87]

siding the latter if the subsidy required was lower than the difference in NPV between the current design in the Mineral Yarden and the best alternative from a welfare perspective. At the same time, the subsidy should be enough to make the subsided design competitive in the private perspective. So if these two conditions apply, then both parts are willing to cooperate, since the government is improving the welfare of the population and CMB is able to compete in the market while reducing the amount of emission emitted. All this information could be available because a CBA has been chosen to test the economic feasibility of the different technologies.
In this CBA the CO2 emission cost in the private perspective is undervalued in comparison to the welfare perspective, this phenomenon is known as "externalities". This difference between the price of a product and its impact on the total welfare of the population could also appear in other parameters that have not been considered, e.g. NOx, SOx, etc.
The purpose of this section is explaining how a CBA can be used in this project to ensure that the alternative with the largest positive expected net present value is chosen for the case study. Also, the remaining parameters required for the CBA will be identified in this section.
A cost-benefit exercise consist of two major steps for R. Layard and S. Glaister [41]:

- Value the costs and benefits yearly.
- Discount the benefit minus cost result every year of the project duration and add them, to obtain the net present value.

Other authors, such as A.E. Boardman et al. [13], include more steps in the CBA because they also specify intermediate steps to complete the CBA procedure, from the selection of alternatives to the sensitivity analysis. However, the way to estimate costs and benefits, and consequently the final NPV is the same using R. Layard and S. Glaister [41] or using A.E. Boardman et al. [13].
The steps used by A.E. Boardman et al. [13] to carry out the CBA are:

1. Specify the alternative projects: the alternatives that are going to be considered by the analyst.
2. Decide which perspective counts: whose benefits and costs are included, e.g. provincial or national perspective.
3. Identify the impact categories, catalogue them, and select measurement indicators: benefits and costs that will affect the present value of the project.
4. Predict the impacts quantitatively over the life of the project.
5. Monetise all impacts: attach dollar values.

6. Discount benefits and costs to obtain present values.
7. Compute the net present value of each alternative.
8. Perform sensitivity analysis.
9. Make a recommendation.

The CBA literature of A.E. Boardman et al. [13] gives a clear procedure for analysts without experience on doing CBAs, while R. Layard et al. [41] provides further information about the theory behind subsidies. Furthermore, the latter explains that the shadow price on a constraint is the increase of the objective function to be maximized when the constraint has been modified in one unit. So, to identify the shadow price is equivalent to recognise which of the constraints affect more the function to maximize. This definition inspired the idea of using the price sensitivity analysis to do recommendations of what technology should concentrate the focus to be further improved in chapter 7.

For having a more detailed guide during the CBA development, the 9-step procedure is chosen, and it will be further explained step-by-step in the following subsections.

4.4.1. Step 1: specify the set of alternative projects

The title of this step refers to the alternative designs that the ship could have varying the alternative fuel storage methods and the energy converters. There are 8 storage alternatives (including the current fuel storage method in the Mineral Yarden, HFO and MGO/MDO), 8 energy converters that could have the function of A/E (including the current A/E in the Mineral Yarden, see Table 4.1), and 2 M/E alternatives (including current M/E in the Mineral Yarden, see Table 4.1). Although, not all the energy converters can work with all the alternative fuels.

Firstly, the seven storage alternatives that have been discussed in subsection 3.5.1 and subsection 3.5.2 plus the current storage in the Mineral Yarden were selected because they are already standard alternatives. The 250bar and 350bar pressures of the compressed hydrogen alternatives are available in containerised cylinders. The other alternatives can use standard tanktainers or tanks. All these storage alternatives are available in the market and their cost has been found out or estimated. The storage alternatives are the following:

- Marine diesel oil/Marine gas oil (current Mineral Yarden design)
- Compressed hydrogen gas, CH2 (250bar).
- Compressed hydrogen gas, CH2 (350bar).
- Liquefied hydrogen, LH2.
- Liquefied natural gas, LNG.
- Methanol, CH3OH.
- Liquefied ammonia, LNH3.
- Liquid organic carrier, LOHC.

Secondly, the seven energy converters explained in subsection 3.5.5 and subsection 3.5.4 were mainly selected because they are promising technologies that could reach the 800kWe of power generation required in this project. Then, this energy converters will be compared with the current A/E in the Mineral Yarden, see Table 4.1. The two ICEs are being developed by CMB and third parties at the moment and all the fuel cells are already on the market. The energy converters are the following:

- ICE Daihatsu 6DE-18.
- ICE Volvo Penta D16 MG.
- ICE Anglo Belgian Corporation 6 DZD.
- ICE Wartsila 6L20DF.
- PEMFC Ballard Power HD100.
- PEMFC Hydrogenics HD180.
- SOFC Bloom Energy ES5-YA8AAA.
- MCFC Fuel Cell Energy SureSource 1500.

Finally, the M/E of the current design of the Mineral Yarden will be compared with the high-size LNG-diesel dual-fuel engine presented in subsection 3.5.5:

- ICE Hitachi-MAN B&W 6S70ME-C8.2.

- ICE Wartsila 14V46DF.

The main priorities to choose from all the storage methods and energy converters have been their availability in the market and their capacity to replace the current energy converters in the Mineral Yarden. This is, to have the same maximum engine output on the M/E and to generate a similar amount of electric power than the replaced A/E. Furthermore, since the beginning of the project, the author wanted to compare the hydrogen-diesel dual-fuel engine technology, installed on board the Hydroville [21], with other energy converters that could ensure the CO2 emission reduction, fuel cells. So it could be said that to find answers about the rivalry between ICEs and FCs, three new ICE models and four FC models were chosen as A/E.

Furthermore, as mentioned above, all energy converters are not compatible with some of the storage methods. For instance, the SOFC Bloom Energy ES5-YA8AAA and the MCFC Fuel Cell Energy SureSource 1500 are only commercialized with natural gas as input fuel. Also, the three energy converters that could operate with MDO/MGO are the ICE Daihatsu 6DE-18 (only operates with MDO/MGO) and the two Wartsila dual-fuel engines (can also operate with LNG and pilot fuel). Finally, the current M/E on the Mineral Yarden, ICE Hitachi-MAN B&W 6S70ME-C8.2, can only operate with HFO.
In addition, carbon capture systems are integrated when low-sulphur exhaust gases exist. In those cases, the resultant design is considered a different alternative. This occurs for designs with LNG or MeOH reformers, the SOFC Bloom Energy ES5-YA8AAA, the MCFC Fuel Cell Energy SureSource 1500 or when LNG is used in the Wartsila 14V46DF or the Wartsila 6L20DF.

The intention of including another alternative as M/E is not to compare the two engines operating with HFO. The interesting comparison for CMB is to compare the ICE Hitachi-MAN B&W 6S70ME-C8.2 with the ICE Wartsila 14V46DF operating in gas mode, which could identify the potential of LNG as M/E fuel. In addition, exactly the same could be said for the ICE Daihatsu 6DE-18 and the ICE Wartsila 6L20DF. That is why both dual-fuel engines are only tested in gas mode operation.
In consequence, the total number of design combinations that will be studied are 57:

1. Hitachi-MAN B&W 6S70ME-C8.2 & MDO/MGO & ICE Daihatsu 6DE-18
2. Hitachi-MAN B&W 6S70ME-C8.2 & CH2 (250bar) & ICE Volvo Penta D16 MG
3. Hitachi-MAN B&W 6S70ME-C8.2 & CH2 (250bar) & ICE Anglo Belgian Corporation 6 DZD
4. Hitachi-MAN B&W 6S70ME-C8.2 & CH2 (250bar) & PEMFC Ballard Power HD100
5. Hitachi-MAN B&W 6S70ME-C8.2 & CH2 (250bar) & PEMFC Hydrogenics HD180
6. Hitachi-MAN B&W 6S70ME-C8.2 & CH2 (350bar) & ICE Volvo Penta D16 MG
7. Hitachi-MAN B&W 6S70ME-C8.2 & CH2 (350bar) & ICE Anglo Belgian Corporation 6 DZD
8. Hitachi-MAN B&W 6S70ME-C8.2 & CH2 (350bar) & PEMFC Ballard Power HD100
9. Hitachi-MAN B&W 6S70ME-C8.2 & CH2 (350bar) & PEMFC Hydrogenics HD180
10. Hitachi-MAN B&W 6S70ME-C8.2 & LH2 & ICE Volvo Penta D16 MG
11. Hitachi-MAN B&W 6S70ME-C8.2 & LH2 & ICE Anglo Belgian Corporation 6 DZD
12. Hitachi-MAN B&W 6S70ME-C8.2 & LH2 & PEMFC Ballard Power HD100
13. Hitachi-MAN B&W 6S70ME-C8.2 & LH2 & PEMFC Hydrogenics HD180
14. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & ICE Volvo Penta D16 MG
15. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & ICE Volvo Penta D16 MG & CCS
16. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & ICE Anglo Belgian Corporation 6 DZD
17. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & ICE Anglo Belgian Corporation 6 DZD & CCS
18. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & ICE Wartsila 6L20DF

19. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & ICE Wartsila 6L20DF & CCS
20. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & PEMFC Ballard Power HD100
21. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & PEMFC Ballard Power HD100 & CCS
22. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & PEMFC Hydrogenics HD180
23. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & PEMFC Hydrogenics HD180 & CCS
24. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & SOFC Bloom Energy ES5-YA8AAA
25. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & SOFC Bloom Energy ES5-YA8AAA & CCS
26. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & MCFC Fuel Cell Energy SureSource 1500
27. Hitachi-MAN B&W 6S70ME-C8.2 & LNG & MCFC Fuel Cell Energy SureSource 1500 & CCS
28. Hitachi-MAN B&W 6S70ME-C8.2 & CH3OH & ICE Volvo Penta D16 MG
29. Hitachi-MAN B&W 6S70ME-C8.2 & CH3OH & ICE Volvo Penta D16 MG & CCS
30. Hitachi-MAN B&W 6S70ME-C8.2 & CH3OH & ICE Anglo Belgian Corporation 6 DZD
31. Hitachi-MAN B&W 6S70ME-C8.2 & CH3OH & ICE Anglo Belgian Corporation 6 DZD & CCS
32. Hitachi-MAN B&W 6S70ME-C8.2 & CH3OH & PEMFC Ballard Power HD100
33. Hitachi-MAN B&W 6S70ME-C8.2 & CH3OH & PEMFC Ballard Power HD100 & CCS
34. Hitachi-MAN B&W 6S70ME-C8.2 & CH3OH & PEMFC Hydrogenics HD180
35. Hitachi-MAN B&W 6S70ME-C8.2 & CH3OH & PEMFC Hydrogenics HD180 & CCS
36. Hitachi-MAN B&W 6S70ME-C8.2 & LNH3 & ICE Volvo Penta D16 MG
37. Hitachi-MAN B&W 6S70ME-C8.2 & LNH3 & ICE Anglo Belgian Corporation 6 DZD
38. Hitachi-MAN B&W 6S70ME-C8.2 & LNH3 & PEMFC Ballard Power HD100
39. Hitachi-MAN B&W 6S70ME-C8.2 & LNH3 & PEMFC Hydrogenics HD180
40. Hitachi-MAN B&W 6S70ME-C8.2 & LOHC & ICE Volvo Penta D16 MG
41. Hitachi-MAN B&W 6S70ME-C8.2 & LOHC & ICE Anglo Belgian Corporation 6 DZD
42. Hitachi-MAN B&W 6S70ME-C8.2 & LOHC & PEMFC Ballard Power HD100
43. Hitachi-MAN B&W 6S70ME-C8.2 & LOHC & PEMFC Hydrogenics HD180
44. Wartsila 14V46DF & LNG & ICE Volvo Penta D16 MG
45. Wartsila 14V46DF & LNG & ICE Volvo Penta D16 MG & CCS
46. Wartsila 14V46DF & LNG & ICE Anglo Belgian Corporation 6 DZD
47. Wartsila 14V46DF & LNG & ICE Anglo Belgian Corporation 6 DZD & CCS
48. Wartsila 14V46DF & LNG & ICE Wartsila 6L20DF
49. Wartsila 14V46DF & LNG & ICE Wartsila 6L20DF & CCS
50. Wartsila 14V46DF & LNG & PEMFC Ballard Power HD100
51. Wartsila 14V46DF & LNG & PEMFC Ballard Power HD100 & CCS
52. Wartsila 14V46DF & LNG & PEMFC Hydrogenics HD180

53. Wartsila 14V46DF & LNG & PEMFC Hydrogenics HD180 & CCS

54. Wartsila 14V46DF & LNG & SOFC Bloom Energy ES5-YA8AAA

55. Wartsila 14V46DF & LNG & SOFC Bloom Energy ES5-YA8AAA & CCS

56. Wartsila 14V46DF & LNG & MCFC Fuel Cell Energy SureSource 1500

57. Wartsila 14V46DF & LNG & MCFC Fuel Cell Energy SureSource 1500 & CCS

4.4.2. Step 2: decide which perspective counts

As mentioned in the introduction of this chapter, the two perspectives that are considered are the CMB private perspective and the welfare or societal perspective. In the private perspective, the costs and benefits of building and operating the ship for 20 years are considered from the point of view of CMB. This means that the CO2 emission price per tonne considered is the market cost, in other words, what a company should have to pay in case a "CO2 taxation" was implemented.
In the welfare or societal perspective, again the costs and benefits of building and operating the ship for 20 years are considered, but in this case from the point of view of the population welfare. With this perspective, the benefits are assuming equal than for the private perspective, but the operational costs of technologies that emit CO2 increase.
In practice, how CO2 has been the only parameter considered, the only difference between both perspectives is the CO2 price, which in the private perspective refers to the price that CMB could have to pay, while in the societal perspective is the real cost for society.

4.4.3. Step 3: identify the impact categories

In this step, the physical impacts of the different design alternatives are identified. The most important parameters that affect positively as benefits, and negatively as costs, to the NPV of the different design alternatives are considered. Not all benefits and cost that exists are taken into account because that could be counterproductive.
After the most important parameters are recognised, they need to be catalogued as cost or benefit, which sometimes brings confusion. For instance, at the beginning of this CBA, the CO2 emission was considered a benefit for cleaner alternatives. It was seen as CO2 emission cost "saved" in the cleaner alternative compared to the current design in the Mineral Yarden. However, it is a cost for alternatives that emit CO2, so from a conceptual point of view, it makes more sense include the CO2 emission cost in all the alternative that emit CO2.
Even though in both cases the comparison among alternatives is equal in percentage terms, the NPV result of each design alternative is more realistic when CO2 emission is considered a cost.

The parameters recognised are Initial investment, Operational income, CO2 sales, Scratch value, M/E consumption, A/E consumption, Fuel cell maintenance and CO2 emission. From these parameters, the benefit impact categories are:

1. Operational income of the design alternative ("Operational income"). It takes into account the effect on the payload of the storage method, the alternative fuel reformer, the carbon capture system and the energy converter. The measurement indicator of this parameter is [$/year] and it is calculated with the following equation:

$$Operational\ income = (P - S - R - CCS - EC) \times CR \times n \tag{4.1}$$

where,

- P: standard payload calculated as DWT at summer load line minus other weights (fuel, fresh water, etc.) and also minus a security margin in case the ship is not always fully loaded (e.g. for a bulk carrier of 181,218DWT a margin of 7,000T),
- S: effect of the storage method of the alternative fuel (containerised cylinders, tanktainer or tank) on payload [T], it includes both the weight of the empty tank and the fuel on it,
- R: effect on payload [T] of alternative fuel reformers or crackers when pure hydrogen is required,

- CCS: effect on payload [T] of carbon capture systems. This effect is considered when CCS is included in the design, which could occur when LNG or MeOH are reformed, or when LNG is used in SOFCs, MCFCs, LNG-diesel dual-fuel engines and the CO2 can be extracted from their exhaust gases,
- EC: effect of energy converters on payload [T] assuming that at least 800kW are installed as A/E and 15,450kW are installed as M/E (*Note: the weight of the replaced A/E and M/E need to be subtracted from this effect*),
- CR: Charter rate of iron ore transported [$/T],
- n: number of complete trips (considering part in load and part in ballast) per year.

Note: this graduation thesis uses a reference ship whose M/E and A/E consumptions are known, which adds value to the CBA and contributes to answering the research questions presented in section 1.2. That is why the approach followed was to include the effect of replacing the storage and energy converter in the payload. But is important to mention, that from an economic point of view, a more generic approach is to modify the ship design (e.g. length) to be able to transport the same amount of cargo which all the alternatives.

2. The sale of the CO2 stored on board when carbon capture systems (CCS) are installed ("CO2 sales"). It is considered that the CO2 can be sold after each trip in every port. The measurement indicator of this parameter is [$/year], and it depends on the number of trips per year and the price of CO2.
3. Scratch value of the ship ("Scratch value"). The measurement indicator of this parameter is [$], and it only happens when the operational life of the ship has finished, after 20 years of use.

On the other hand, the cost impact categories are the following:

1. Construction cost of the ship for each design alternative ("Capital investment"). It includes the price of a standard capesize bulk carrier plus the alternative fuel storage, the M/E or energy converter (minus the current installed in the Mineral Yarden) and in some cases, also alternative fuel reformers and carbon capture systems. The measurement indicator of this parameter is [$], and it occurs in the year "zero".
2. Fuel consumption of the main engine ("M/E fuel"). For the Hitachi-MAN B&W 6S70ME-C8.2, it is calculated with the average daily M/E consumption of HFO obtained in subsection 4.3.1 and the price of HFO. For the Wartsila 14V46DF, it is calculated with the average engine output required, which is obtained with the daily M/E consumption and the SFOC of the Hitachi-MAN B&W 6S70ME-C8.2 in Table 4.1, the gas consumption presented in Appendix D for this engine, and the price of LNG and low-sulphur MGO. The measurement indicator of this parameter is [$], and it is considered every operational year of the ship.
3. Fuel consumption of the auxiliary engine ("A/E fuel"). This parameter refers to A/E consumption of the current design of the Mineral Yarden or the alternatives that replace it. There are four different cases:

   - In the current design of the Mineral Yarden, it could be calculated with the average daily A/E consumption of MGO shown in Table 4.2 and the price of low-sulphur MGO.
   - In the case of hydrogen-diesel dual-fuel A/Es, it is calculated assuming that 75% of the input energy of the ICE comes from hydrogen and that the remaining 25% comes from MGO, as explained in subsection 3.5.4. Then, it is calculated using the average daily power produced, the sfoc of the respective engines, the price of the alternative fuel and the price of MGO.
   - In the case of Wartsila 6L20DF, it is calculated using the consumptions in Appendix D for this engine, the average daily power produced and the price of LNG and low-sulphur MGO.
   - In the case of fuel cells, it is calculated using the average daily power produced, the efficiency of the fuel cells presented in Table 3.9 and the price of the alternative fuel.

   In all cases, as for the "M/E fuel" parameter, the measurement indicator of this parameter is [$], and it is considered every operational year of the ship.
4. Maintenance cost of the fuel cells ("Maintenance"). As explained in section 3.5, fuel cells require to be refurbished after their lifespan, which represents an important amount of money for high power installations. The measurement indicator of this parameter is [$], and it is considered every operational year of the ship.

5. Cost due to the emission of CO2 ("CO2 emission").
   (a) For the Hitachi-MAN B&W 6S70ME-C8.2, the CO2 emission cost is calculated with the daily consumption of HFO obtained in subsection 4.3.1, the fuel to CO2 emission factor of HFO (3.1144 tonnes of CO2 per tonne of HFO [22]), and the cost of CO2 per tonne emitted. For the Wartsila 14V46DF, the CO2 emission cost is calculated with the consumption of LNG and low-sulphur MGO, the CO2 emission factor per tonne of LNG and MGO (2.7500 and 3.2060 tonnes of CO2 per tonne of fuel respectively [22]), and the cost of CO2 per tonne emitted.
   (b) In case of the CO2 emission of the Wartsila 6L20DF, the cost is calculated with the daily average power generated, the specific consumption [g/kWh], the CO2 emission factor per tonne of MGO (3.2060 tonne of CO2 per tonne of MGO), the CO2 emission factor per tonne of LNG (2.7500 tonne of CO2 per tonne of LNG) [22], and the price of CO2 per tonne.
   (c) In case of the Bloom Energy ES5-YA8AAA and the MCFC Fuel Cell Energy SureSource 1500, they both have their specific CO2 emission per kWh factor. The ES5-YA8AAA CO2 emission factor is 377,84g of CO2 per kWh generated [44]. The SureSource 1500 CO2 emission factor is 308.44g of CO2 per kWh generated [45].
   (d) When LNG is reformed approximately 7 kg of CO2 are generated per each kg of hydrogen [135]. When MeOH is reformed approximately 7.28 kg of CO2 are generated per each kg of hydrogen [161].

   The measurement indicator of this parameter is [$], and it is considered every operational year of the ship.

4.4.4. Step 4: predict the impacts quantitatively

In this step, some predictions about the different alternatives need to be done. The data required to be estimated are:

- The standard payload considered for all design alternatives. It is calculated using the data in Table 4.2, and assuming the 7,000T margin mentioned in Step 3. Then, the cargo transported per trip in the current design of the Mineral Yarden would be 168,473.53MT, and this payload varies for each alternative design.
- The effect of the storage method on the payload. First of all, when the LNG is not required for the M/E, the LNG required for the auxiliary energy converters is transported in 40ft tanktainers. But when the M/E also uses LNG, all LNG is stored in a big-size tank.
  The HFO and low-sulphur MGO storage is already included in the reference payload, so they do not need to be considered here. The effect of storing the pure hydrogen, LNG, CH3OH, LNH3 or LOHC required by the auxiliary energy converters is calculated considering that 15 tonnes of hydrogen (or its equivalent in other alternative fuel) is stored on board. This amount is enough to complete the trip with PEMFCs and LNH3 storage, which is the design alternative with the higher hydrogen consumption. Then, with the 15 tonnes fixed, it is possible to calculate the number of tanktainers or containers required. Because the amount of hydrogen that can be transported per tanktainer or container of each alternative fuel is known:
  - Weight of the CH2(250bar) storage: to store 15T of hydrogen and using the 10-tube 250bar skid 40ft container mentioned in subsection 3.5.1, 23 containers are required. The total effect is $15T + 23 \times 29.80T = 700.40T$.
  - Weight of the CH2(350bar) storage: to store 15T of hydrogen and using the 40ft container able to carry four type IV composite 350bar cylinders mentioned in subsection 3.5.1, 19 containers are required. The total effect is $15T + 19 \times 18.019T = 357.36T$.
  - Weight of the LH2 storage: to store 15T of hydrogen and using the 20ft ISO tank mentioned in subsection 3.5.1, 13 tanktainers are required. The total effect is $15T + 13 \times 10.44T = 150.72T$.
  - Weight of the LNG storage: to store 15T of hydrogen and using the 40ft ISO tank mentioned in subsection 3.5.2, 3 tanktainers are required. The total effect is $\frac{15T}{0.286} + 3 \times 12.67T = 90.51T$.
    Note: the 0.286 is the ratio H2-LNG from Table 3.11.
  - Weight of the MeOH storage: to store 15T of hydrogen and using the 40ft ISO tank mentioned in subsection 3.5.2, 3 tanktainers are required. The total effect is $\frac{15T}{0.170} + 3 \times 20.20T = 148.90T$.

  - Weight of the LNH3 storage: to store 15T of hydrogen and using the 40ft ISO tank mentioned in subsection 3.5.2, 4 tanktainers are required. The total effect is $\frac{15T}{0.160} + 4 \times 10.50T = 135.87T$.
  - Weight of the LOHC storage: to store 15T of hydrogen and using the 40ft ISO tank mentioned in subsection 3.5.2, 6 tanktainers are required. The total effect is $\frac{15T}{0.062} + 6 \times 20.20T = 363.57T$.

  For the designs with the Wartsila 14V46DF, the LNG storage tank has a capacity of approximately 1,285.46 tonnes (2,818.98m^3 with the density of LNG in Table 3.11). This amount was calculated using the two Wartsila dual-fuel engines (consumptions in Appendix D) and it allows to operate these engines in gas mode at full load for 3 weeks. In consequence, this LNG storage tank is assumed to be big enough to cover the 2-week trip of the case study seen in section 4.3 for all the design alternatives.
  The tank weight has been approximated from a lower size tank [66] as 810.84T. On the other hand, the HFO tonnes equivalent in terms of energy to the 1,285.46 tonnes of LNG have been substracted from the other weights (fuel) in Table 4.1. Thus, $1,285.46T \times \frac{47,141\frac{kJ}{kg}}{39,000\frac{kJ}{kg}} = 1,553.79T$ using the LHV of natural gas from Table 3.1, and using 39,000(kJ/kg) as the LHV of HFO [148]. Then, the total effect is $1,285.46T + 810.84T - 1,553.79T = 542.51T$.

- The effect of reformers on the payload. It is calculated assuming that a hydrogen nominal output of $400\frac{Nm^3}{h}$ covers the highest demand of hydrogen (This assumption proved to be incorrect when ammonia reformers were used, since they demanded a high electric power demand, and consequently, the energy converter required more hydrogen nominal output. This case will be further explained below). The total effect is:
  - Natural gas reformer, taking as reference the containerised reformer plant mentioned in subsection 3.2.1, 4 units are required to supply the hydrogen nominal output assumed, then the total effect on payload is $4 \times 9,5T = 38T$.
  - Methanol reformer, taking as reference the small methanol reformer unit mentioned in subsection 3.2.1, 84 units of this model are required to supply the hydrogen nominal output assumed, then their effect on payload is $84 \times 90.72kg = 7,620.48kg$. But these units are not containerised, so it is assumed that four 20ft containers are required to fit the reformers. Then, knowing that the tare weight of a 20ft empty container is 2,300kg [42], the total effect on payload is 16.82T.
  - LOHC dehydrogenation plant, taking as reference the dehydrogenation plant presented in subsection 3.2.1, 4 units of this model are required to supply the hydrogen nominal output assumed. But how the weight of this plant is not found, it was chosen the same weight than the steam methane reformer, which also is containerised. Then, the total effect considered is 38T.
  - Ammonia cracker, at the beginning of the technical analysis and taking as reference the system mentioned in subsection 3.2.1, 5 units of this model were required to supply the hydrogen nominal output assumed. However, as explained above, after the first iteration in the technical analysis, it was observed that due to the high extra electric power consumption of the ammonia crackers, two more reformer unit was necessary to cover the approximately $520\frac{Nm^3}{h}$ demand of hydrogen. Then, 7 units are installed and the effect on payload is $7 \times 2.5T = 17.5T$. But these crackers are not containerised, so it is assumed that seven 20ft containers were required to fit the crackers. Then, the total effect on payload is 33.6T.
- The effect of carbon capture systems on the payload. CCSs are included in the design together with LNG/ MeOH reformers, SOFCs/MCFCS or Wartsila dual-fuel engines. This effect is calculated using the reference system mentioned in subsection 3.5.2 and based on J.T. Akker [4]. In that system, the LNG capacity on board was 135T, the CO2 capture rate was 1,129 kg per hour and the CCS weight including the absorber (monoethanolamine) was 79.93T. There are three cases for the CCS in this project:
  - CCS together with Hitachi-MAN B&W 6S70ME-C8.2 and LNG reformers, SOFCs/MCFCS or the Wartsila 6L20DF: the LNG capacity on board to operate in gas mode and at full load for 3 weeks the Wartsila 6L20DF is around 78.47 tonnes (consumption of $8,048\frac{kJ}{kWh} \times \frac{1}{49,620\frac{kJ}{kg}} \times 960kW = 155.7\frac{kg}{h}$, see Appendix D). This is considered the higher consumption of this case, and in consequence, the CO2 capture rate needs to be at least 385.36 kg per hour (194.22T CO2 tank for 3 weeks operation), knowing that the LNG to CO2 factor is 2.75 [22] and the CCS is able to capture 90%, as explained in subsection 3.5.3. Then, assuming that the weight of the system varies linearly with the CO2 capture rate capacity, the CCS weight including the absorber is 27.28T.

  - CCS together with methanol reformers: this CCS requires extra cooling systems, since methanol it is not transported at cryogenic temperatures as LNG, and the cooling provided in the LNG evaporator need to be generated with cooling units. Then, it is assumed an extra 10% of weight compared with the CCS required with LNG reformers. The weight of the CCS is considered 30.01T.
  - CCS together with Wartsila 14V46DF combinations: to operate these engines in gas mode at full load for 3 weeks the LNG capacity is around 1,282.85T, as calculated for the effect of the fuel storage on payload above. The combined LNG consumption of both dual-fuel engines is 2550.51 kg/h, which is calculated following the same procedure than for the Wartsila 6L20DF and with the information of Appendix D. The CO2 capture rate needs to be at least 6,312.53 kg per hour (3,181.51T CO2 tank for 3 weeks operation), knowing that the LNG to CO2 factor is 2.75 [22] and the CCS is able to capture 90%, as explained in subsection 3.5.3. Then, assuming that the weight of the system varies linearly with the CO2 capture rate capacity, the CCS weight including the absorber is 446.91T.

- The effect of the CO2 tank on the payload. It is calculated using the rule used in [4] to calculate the weight of CO2 tanks of 60T capacity. The rule approximates the weight of the empty tank as 41% of the tank capacity. Then, using the CO2 required to be stored for the 3-weeks operation calculate above the 2 main cases are:
  - CCS together with Hitachi-MAN B&W 6S70ME-C8.2 and LNG/MeOH reformers, SOFCs/MCFCS or the Wartsila 6L20DF: $CO2\ tank[T] = 194.22T \times 0.41 = 79.63T$
  - CCS together with Wartsila 14V46DF combinations: $CO2\ tank[T] = 3,181.51T \times 0.41 = 1,304.42T$

  Note that this approximation could oversize the effect of the CO2 tanks on the payload because the tank sizes are higher than the reference tank.
- The effect of the energy converters on the payload. When the Wartsila 14V46DF of Table 3.5 is installed as M/E, there is an increase on payload in comparison with the Hitachi-MAN B&W 6S70ME-C8.2 of Table 4.1. The total effect is a payload increase of $555T - 223T = 332T$.
  For the effect of the auxiliary energy converters, it is calculated assuming that 800kW need to be generated:
  - In the case of the Volvo Penta D16 MG, Table 3.2, 2 units are required, so their total effect on payload is 7.85T.
  - In the case of the ABC 6 DZD, Table 3.3, 1 unit is required, so its effect on payload is 22.2T.
  - In the case of the Wartsila 6L20DF, Table 3.3, 1 unit is required, so its effect on payload is 16.90T.
  - In the case of the Ballard HD100, Table 3.4, 8 units of the system are required, so their effect on payload is 3.12T.
  - In the case of the Hydrogenics HD180, Table 3.4, 5 units of the system are required, so their effect on payload is 3.82T.
  - In the case of the Bloom Energy ES5-YA8AAA, Table 3.7, the number of smaller modules determine the plant size, so it is assumed that an 800kW system could be built. Then assuming a linear relationship between maximum power generation and weight of the system, the effect on payload is 41.07T.
  - In the case of the FuelCell Energy SureSource 1500, Table 3.8, the size of the MCFC and the BOP vary with the required power to generate. Then assuming a linear relationship between maximum power generation and weight, the effect on payload is 56.63T.

4.4.5. Step 5: monetise the impacts

Each of the impacts described in previous steps needs to be valued in dollars. The parameters monetised are:

- Charter rate per tonne of the cargo transported (iron ore): 6$/tonne, based on Nikkei index and news from 2017 [99],
- Scratch value after 20 years: 6,200,000$ based on Clarkson from 2016 [128],
- Standard price of a capesize bulk carrier: 41,875,000$ based on Clarkson from 2017 [127].
- Price of the CCS: Its cost is calculated using the reference system mentioned in subsection 3.5.2 and based on J.T. Akker [4]. The reference system with a CO2 capture of 1,129 kg per hour has an approximate cost of €1,548,400 in 2017, or equivalently $1,749,771, using the average exchange rate of 2017, 1.130051 US$ per € [108]. The cost is different for the three CCS cases considered in this project:

- CCS together with LNG reformers, SOFCs/MCFCS or the Wartsila 6L20DF: this CCS requires a CO2 capture rate of 385.36 kg per hour and its cost is estimated using the 6/10th Rule [46], also used for reformers in subsection 3.5.2, for each of the components of the CCS (e.g. absorber, stripper, condenser, reboiler, blower, vaporizer, compressor, etc.), which means that the CCS cost estimation should be in the range of -40% to +40%. The estimated cost of this CCS is 809,678€ ($914,977).
- CCS together with methanol reformers: as explained above this CCS require extra cooling units. Then, it is assumed an extra 10% cost in comparison with the CCS required with LNG reformers. Then, the cost estimation of this CCS is 890,646€ ($1,006,475).
- CCS together with both Wartsila dual-fuel engines: this CCS requires a CO2 capture rate of 6312.53 kg per hour and its cost is estimated using also the 6/10th Rule [46]. The estimated cost of this CCS is 4,390,732€ ($4,961,751).

- Price of the CO2 tank: it is calculated using as reference a CO2 tank with a net capacity of 47.80T and a price of €40,000, which is one of the tanks used in [4]. Then, using the 6/10th Rule [46], it is possible to estimate the cost of the CO2 tanks in the two cases of this project:
  - CO2 tank with Hitachi-MAN B&W 6S70ME-C8.2 and LNG/MeOH reformers, SOFCs/MCFCS or the Wartsila 6L20DF: $€40,000 \times \left(\frac{194.22T}{47.80T}\right)^{0.6}$ =€92,760.
  - CO2 tank with Wartsila 14V46DF combinations: $€40,000 \times \left(\frac{3181.51T}{47.80T}\right)^{0.6}$ =€496,573.
- Price of the CH2(250bar) storage: to store 15T of hydrogen and using the 10-tube 250bar skid 40ft container mentioned in subsection 3.5.1, 23 containers are required. The total cost of this storage method is $2,300,000.
- Price of the CH2(350bar) storage: to store 15T of hydrogen and using the 40ft container able to carry four type IV composite 350bar cylinders mentioned in subsection 3.5.1, 19 containers are required. The total cost of this storage method is $12,899,128.
- Price of the LH2 storage: to store 15T of hydrogen and using the 20ft ISO tank mentioned in subsection 3.5.1, 13 tanktainers are required. The total cost of this storage method is $8,110,268.
- Price of the LNG storage: to store the LNG equivalent to 15T of hydrogen the 40ft ISO tanks mentioned in subsection 3.5.2 are used, 3 tanktainers are required. The total cost of this storage method is $297,000. On the other hand, to store 1,285.46T of LNG, a big-size stank is used. The price of this tank is estimated using the price of the 40ft tank as the reference, which can transport 18,844kg of LNG, and the 6/10th Rule [46]. Then, the cost of this tank is approximated as $\$99,000 \times \left(\frac{1285.46T}{18.844T}\right)^{0.6} = \$1,247,279$.
- Price of the MeOH storage: to store 15T of hydrogen and using the 40ft ISO tank mentioned in subsection 3.5.2, 3 tanktainers are required. The total cost of this storage method is $60,000.
- Price of the LNH3 storage: to store 15T of hydrogen and using the 40ft ISO tank mentioned in subsection 3.5.2, 4 tanktainers are required. The total cost of this storage method is $88,000.
- Price of the LOHC storage: to store 15T of hydrogen and using the 40ft ISO tank mentioned in subsection 3.5.2, 6 tanktainers are required. The total cost of this storage method is $120,000.
- Price of natural gas reformer: it was calculated using a generation capacity of $400m^3/h$, and as explained in subsection 3.5.2, the cost is approximated as $518,206.
- Price of methanol reformer: it was calculated using a generation capacity of $400m^3/h$, and as explained in subsection 3.5.2, the cost is approximated as $409,383.
- Price of ammonia cracker: it was calculated using a generation capacity of approximately $517.88m^3/h$, and as explained in subsection 3.5.2, the cost is approximated as $287,162.
- Price of LOHC dehydrogenation plant: it was calculated using a generation capacity of approximately $400m^3/h$, and as explained in subsection 3.5.2, the cost is approximated as $80,000.
- Price of the Daihatsu 6DE-18: this engine in combination with a generator can produce 800kW, and the generator set price is $200,000 based on CMB estimations.
- Price of the Volvo Penta D16 MG: using the price per unit mentioned in subsection 3.5.4, and how 2 units are required to generate the 800kW, the total price is $200,000.
- Price of the ABC 6 DZD: using the price per unit mentioned in subsection 3.5.4, and how 1 unit is required to generate the 800kW, the total price is $550,000.
- Price of the Wartsila 6L20DF: this engine in combination with a generator can produce 920kW. Then, its cost has been approximated from the Daihatsu 6DE-18 price with 6/10th [46] as $\$200,000 \times \left(\frac{920kW}{800kW}\right)^{0.6} = \$217,494.71$. Additionally, it is estimated that a dual-fuel engine has a 5% higher capital cost than a pure

diesel engine with the same output, based on CMB approximations. Then, the estimated price for this engine is $228,369.45.

- Price of the PMFCs: using the price per kilowatt mentioned in Table 3.5.4, and to generate 800kW, the total price is $1,760,000.
- Price of the Bloom Energy ES5-YA8AAA: using the price per 100kW mentioned in subsection 3.5.5, and to generate 800kW, the total price is $7,324,474.
- Price of the FuelCell Energy SureSource 1500: using the price per kilowatt mentioned in subsection 3.5.5, and to generate 800kW, the total price is $3,845,352.
- Price of the Hitachi-MAN B&W 6S70ME-C8.2: this engine has an output of 15,450kW, and its price is estimated in $15,000,000 based on CMB estimations.
- Price of the Wartsila 14V46DF: this engine has an output of 16,030kW. Then, its cost has been approximated from the Hitachi-MAN B&W 6S70ME-C8.2 price with 6/10th [46] as $\$15,000,000 \times \left(\frac{16{,}030kW}{15{,}450kW}\right)^{0.6} = \$15,335,371$. Additionally, it is estimated that a dual-fuel engine has a 5% higher capital cost than a pure diesel engine with the same output, based on CMB approximations. Then, the estimated price for this engine is $16,102,139.
Note: a natural gas dual-fuel engine requires extra fuel supply systems (e.g. evaporators), a rough approximation based on previous CMB quotations monetise the systems for required LNG input in $1,500,000. Then, the estimated price for the Wartsila 14V46DF and its additional fuel supply systems is $17,602,139.
- Price of HFO: 400$/tonne based on data from April 2018 [133].
- Price of LSMGO: 546.50$/tonne based on data bunkering data in Singapure from January 2017 to June 2018 (both months included) [134].
- Price of hydrogen: 3,000$/T, as mentioned in subsection 3.5.1,
- Price of LNG: 478.06$/T, as mentioned in subsection 3.5.2,
- Price of MeOH: 460$/T, as mentioned in subsection 3.5.2,
- Price of LNH3: 280$/T, as mentioned in subsection 3.5.2,
- Price of LOHC: 250$/T, as mentioned in subsection 3.5.2,
- Price per tonne of CO2 sold in the market: the CO2 price in 2020 is estimated in the low case as $15 per tonne, in the mid case as $20 per tonne, and in the high case as $25 per tonne [88].
- Price per tonne of CO2 emitted in the market: 7.57$/T CO2 emitted, based on Chinese CO2 price market in Beijing in 2018 [122].
- Value of CO2 emitted on population welfare: it is assumed 60$/MT in 1990 [70], so including the inflation rate $115.50 in 2018 [85].

4.4.6. Step 6 & 7: discounts benefits and costs and compute the NPV of each alternative

The impact of the design alternatives occur over years, that is why is required a discount rate to aggregate the benefits and costs. This is done with the same principle used to calculate the net present value of a project:

$$NPV = \sum_{t=0}^{n} \frac{B_t - C_t}{(1+s)^t} \tag{4.2}$$

where,
t: year,
n: lifespan of the project, 20 years are considered in this project, even though the operational life of a ship could reach +30 years, the regulation could get more stringent in the region that will operate (the scratch value after 20 years was included as a benefit on year 20),
s: social discount, 4.3% used by Prof. William Nordhaus (Yale University). This social discount is in accordance with current real interest rates, and it can be empirically estimated. It is based on the opportunity cost of capital by individuals, and reflect the willingness to reduce consumption today to have a higher future consumption [60],
B_t: benefit in year t,
C_t: cost in year t.

The difference between the private and the societal or welfare perspectives can also be identified in the NPV formula. Basically, the sum of costs any of the years (C_t) in the private perspective is lower than the C_t in the societal perspective. This occurs due to the fact that the market price of the tonne of CO2 emitted is lower than the welfare cost of CO2, while the B_t does not change with the perspective, as it was explained in subsection 4.4.2.

4.4.7. Step 8: perform sensitivity analysis

To avoid that the biases of the author or uncertain predictions influence too much the results of the CBA, sensitivity analyses are carried out. However, for practical reasons, only the most important parameters are studied. The parameters included in the sensitivity analyses are:

- price of HFO
- price of LSMGO.
- price of hydrogen.
- price of LNG.
- price of Methanol.
- price of Ammonia.
- price of LOHC.
- price of CO2 emission in the market.
- price of captured CO2 in the market.
- charter rate.
- price if Hitachi-MAN B&W 6S70ME-C8.2.
- price of Volvo Penta D16 MG.
- price of ABC 6 DZD.
- price of Wartsila 6L20DF.
- price of PEMFC.
- price of Bloom Energy ES5-YA8AAA.
- price of MCFC.
- price of LH2 20ft tanktainer
- price of 10-tube 250 bar 40ft container.
- price of 4-tube 350 bar 40ft container.
- price of LNG 40 ft tanktainer.
- price of LNG big-size tank (1,285.46T of LNG capacity).
- price of MeOH/LOHC 40ft tanktainer.
- price of LNH3 40ft tanktainer.
- price of LNG reformer.
- price of MeOH reformer.
- price of LNH3 cracker.
- price of LOHC reformer.
- price of CCS for LNG reformers, SOFC/MCFC or Wartsila 6L20DF.
- price of CCS for MeOH reformers.
- price of CCS for Wartsila 14V46DF in combination with other energy converters.
- price of Fuel cell refurbish.
- price of BOP annual maintenance.

The cost of the standard capesize bulk carrier and the scratch value of the ship are not included in the sensitivity analyses because all designs are affected in the same way by them. So, a change in the price of these parameters will modify the NPV of all designs in the same amount.

4.4.8. Step 9: recommend the best alternative

This step will be straightforward once all the NPV of the different design alternatives are known. To create a ranking of the different design alternative the benefit-cost ratio will be used. The following formula calculates this ratio:

$$BCR = \frac{Sum\ of\ discounted\ annual\ cash\ flows\ to\ year\ zero}{Sum\ of\ discounted\ capital\ investment\ to\ year\ zero} = \frac{\sum_{t=0}^{n} \frac{B_t - C_t}{(1+s)^t}}{\sum_{t=0}^{n} \frac{CI_t}{(1+s)^t}} \tag{4.3}$$

where the parameters are the same than the used in subsection 4.4.6.
This economic indicator can be read as the amount of dollars generated per dollar invested over the lifetime of a project. Which means that if the BCR of a design alternaitve is lower than one the initial capital investment is not recovered.

4.5. Intermediate conclusion

This chapter stresses the advantages of using a CBA in this project. Especially, why including a welfare or societal perspective in the economic analysis gives more arguments to ask for subsidies for sustainable projects.

The standard step-by-step procedure presented in section 4.1 benefits from the information collected with fleet performance monitoring tools (e.g daily average M/E consumption), and make use of it when new technologies are tested in old designs. This procedure is one of the outputs of this project, and it could be used in the future in the maritime sector or in other fields. The major advance is that it uses the knowledge acquired operating an old design to help with the selection of the best economic design alternative from a bunch of technically feasible designs.

Furthermore, the most relevant aspects of the chosen methodology are the total number of alternatives that will be studied, 57 (7 new storage alternatives, 8 new energy converters, and the current design of the Mineral Yarden), the final percentage of hydrogen considered in the hydrogen-diesel dual-fuel engines, 75% of the total energy content, and the fact that the CCS is only considered when LNG or MeOH are used as alternative fuel, because they are the only alternative fuels that emit CO2 when they are reformed.

On the other hand, the alternative fuel reformers have different power consumptions and the CCS in combination with LNG or MeOH also have different power consumptions. Then, the effect on the daily average power required of these systems will be considered in the technical feasibility chapter 5, since it directly modifies the power demanded to the energy converter.

There are many small costs that are not considered in the CBA (e.g. port and channel fees, crew salary, etc.), but most of these parameters have a minor importance or influence in the same way to all the designs. However, this could change in the future, since some ports are reducing the port tariff of clean vessels (e.g Port of Hamburg [11]).

5

Technical feasibility

The aim of this chapter is to test that the different design alternatives comply with the emission regulation presented in subsection 2.1.3, and also, to calculate some of the parameters that will be used in chapter 6. Firstly, the effect of different storage methods and energy converters in the payload of the reference design is obtained. Secondly, the effect of the alternative fuel reformers and the different CCSs on the electric power demand required on board is calculated. After these parameters are known it is possible to calculate the EEDI and EEOI of each design alternative.

At the end of this chapter, the first research question will be answered, and all the technically feasible alternatives will be used in the economic analysis.

5.1. Effect on payload

The case study is a bulk carrier, so the best way to describe the effect on payload is recognising the weights of the new components of the alternative designs. Thus, the payload of the different designs is calculated subtracting the weight of the storage system, the fuel processing system, the energy converters, and in some cases the carbon capture system, from the standard payload existent in the current design of the Mineral Yarden.

First of all, using the data of subsection 4.4.4, it is possible to present the weight of different fuel storage methods and their related systems (e.g. reformers, CCS, or CO2 tank). Table 5.1 shows the different weights. In this table, the "Fuel storage" parameter includes 15T of hydrogen of fuel or an equivalent amount of a hydrogen carrier (except for the LNG case, as will be seen below) and the empty tank weight.
When the Wartsila 14V46DF is included in the design the LNG stored on board to operate this M/E at full load for 3 weeks is around 1285.46T, and the LNG tank weights approximately 810.84T, as it was estimated in subsection 4.4.4. Then, in this case, the total fuel storage weight is 2,096.30T. Furthermore, when the CCS is integrated with the Wartsila 14V46DF the systems need to be bigger to capture the higher exhaust gases flux. Thus, the CCS weight is 446.91T and the CO2 tank weight is 1,304.42T, as calculated in subsection 4.4.4.

Parameter	**CH2(250bar)**	**CH2(350bar)**	**LH2**	**LNG**	**Methanol**	**LNH3**	**LOHC**
Fuel storage [T]	700.40	357.36	150.72	90.51/2,096.30	148.90	135.87	363.57
Reformer weight [T]	-	-	-	38.00	16.82	33.60	38.00
CCS weight [T]	-	-	-	27.28/446.91	30.01	-	-
CO2 tank weight [T]	-	-	-	79.63/1,304.42	79.63	-	-

Table 5.1: Weight of fuel storage methods and their related systems.

Also, using the data of subsection 4.4.4, it is possible to present the weights of the different energy converters in Table 5.2.

Parameter	**D16 MG**	**6 DZD**	**6L20DF**	**HD100**	**HD180**	**ES5-YA8AAA**	**SureSource 1500**
Weight (Including BOP) [T]	7.85	22.20	16.90	3.12	3.82	41.07	56.63

Table 5.2: Weight of energy converters.

The different design alternatives will now be analysed and their payload will be compared in Table 5.3. In this table, the effect of changing or adding components to the current design of the Mineral Yarden is presented. That is why the different effects (e.g. M/E, A/E or FC, Storage fuel and tank, etc.) are referenced with the current design of the Mineral Yarden.
How the current M/E in the Mineral Yarden is the Hitachi-MAN B&W 6S70ME-C8.2, the designs with this engine do not have a M/E effect on the payload. The designs with the Wartsila 14V46DF do affect the payload, and this effect was calculated in subsection 4.4.4.
The A/E or FC effect is the difference between the new energy converter and the DAIHATSU 6DE-18, which is the A/E of the Mineral Yarden Table 4.1.
Also, when the CCS is included, the payload is lower at the end of the trip, since the CO2 captured weights more than the LNG or CH3OH consumed during the trip. Then, the payload effect is calculated considering only 10% filled LNG/CH3OH tanks and 100% filled CO2 tanks, knowing that the 10% is enough to keep the cryogenic temperatures in the tank. In the LNG case, the total storage effect considering the LNG tanks filled 10% is 43.26T. In the MeOH case,the total storage effect considering the MeOH tanks filled 10% is 69.43T.

Also, note that to transport the same amount of energy as LNG requires less weight than as HFO, as seen in subsection 4.4.4. So, when only 10% of the LNG is considered in the tank, the total effect to the reference payload is $(10\%\ of\ 1,285.46T) + 810.84T - 1,553.79T = -614.40T$.

In Table 5.3, it can be seen that the designs with higher effect on payload are the combinations with the Wartsila 14V46DF together with CCS. Also, it can be stressed that from the alternatives with the Hitachi-MAN B&W 6S70ME-C8.2, the storage of pure hydrogen as compressed hydrogen at 250 bar in 40ft containers has the higher storage effect with 700.40T. Furthermore, the combined effect on payload of energy converters, storage methods, reformers, CCSs and CO2 tanks is visualised in Figure 5.1. See how none of the designs affect the payload in more than 900T.

Finally, this payload will be used in the calculation of the EEOI in section 5.3, and also adding to this payload the "Other weights" parameter from Table 4.1 it is possible to obtain the DWT at summer load line of each design, which is used in the calculation of the EEDI in section 5.3.

Design alternative	M/E[T]	A/E or FC[T]	Stor.[T]	Ref.[T]	CCS & CO2 tank[T]	Total effect[T]	Payload[T]
Current design Mineral Yarden							175,473.53
6S70ME & CH2(250b) & D16 MG		-5.15	700.40			695.25	174,778.28
6S70ME & CH2(250b) & 6DZD		9.20	700.40			709.6	174,763.93
6S70ME & CH2(250b) & HD100		-9.88	700.40			690.52	174,783.01
6S70ME & CH2(250b) & HD180		-9.18	700.40			691.22	174,782.31
6S70ME & CH2(350b) & D16 MG		-5.15	357.36			352.21	175,121.32
6S70ME & CH2(350b) & 6DZD		9.20	357.36			366.56	175,106.97
6S70ME & CH2(350b) & HD100		-9.88	357.36			347.48	175,126.05
6S70ME & CH2(350b) & HD180		-9.18	357.36			348.18	175,125.35
6S70ME & LH2 & D16 MG		-5.15	150.72			145.57	175,327.96
6S70ME & LH2 & 6DZD		9.20	150.72			159.92	175,313.61
6S70ME & LH2 & HD100		-9.88	150.72			140.84	175,332.69
6S70ME & LH2 & HD180		-9.18	150.72			141.54	175,331.99
6S70ME & LNG & D16 MG		-5.15	90.51	38.00		123.36	175,350.17
6S70ME & LNG & D16 MG & CCS		-5.15	43.26	38.00	106.91	183.02	175,290.51
6S70ME & LNG & 6DZD		9.20	90.51	38.00		137.71	175,335.82
6S70ME & LNG & 6DZD & CCS		9.20	43.26	38.00	106.91	197.37	175,276.16
6S70ME & LNG & 6L20DF		3.9	90.51			94.41	175,379.12
6S70ME & LNG & 6L20DF & CCS		3.9	43.26		106.91	154.07	175,319.46
6S70ME & LNG & HD100		-9.88	90.51	38.00		118.63	175,354.90
6S70ME & LNG & HD100 & CCS		-9.88	43.26	38.00	106.91	178.29	175,295.24
6S70ME & LNG & HD180		-9.18	90.51	38.00		119.33	175,354.20
6S70ME & LNG & HD180 & CCS		-9.18	43.26	38.00	106.91	178.99	175,294.54
6S70ME & LNG & ES5-Y.		28.07	90.51			118.58	175,354.95
6S70ME & LNG & ES5-Y. & CCS		28.07	43.26		106.91	178.24	175,295.29
6S70ME & LNG & S.S. 1500		43.63	90.51			134.14	175,339.39
6S70ME & LNG & S.S. 1500 & CCS		43.63	43.26		106.91	193.8	175,279.73
6S70ME & MeOH & D16 MG		-5.15	148.90	16.82		160.57	175,312.96
6S70ME & MeOH & D16 MG & CCS		-5.15	69.43	16.82	109.64	190.74	175,282.79
6S70ME & MeOH & 6DZD		9.20	148.90	16.82		174.92	175,298.61
6S70ME & MeOH & 6DZD & CCS		9.20	69.43	16.82	109.64	205.09	175,268.44
6S70ME & MeOH & HD100		-9.88	148.90	16.82		155.84	175,317.69
6S70ME & MeOH & HD100 & CCS		-9.88	69.43	16.82	109.64	186.01	175,287.52
6S70ME & MeOH & HD180		-9.18	148.90	16.82		156.54	175,316.99
6S70ME & MeOH & HD180 & CCS		-9.18	69.43	16.82	109.64	186.71	175,286.82
6S70ME & LNH3 & D16MG		-5.15	135.87	33.60		164.32	175,309.21
6S70ME & LNH3 & 6DZD		9.20	135.87	33.60		178.67	175,294.86
6S70ME & LNH3 & HD100		-9.88	135.87	33.60		159.59	175,313.94
6S70ME & LNH3 & HD180		-9.18	135.87	33.60		160.29	175,313.24
6S70ME & LOHC & D16MG		-5.15	363.57	38.00		396.42	175,077.11
6S70ME & LOHC & 6DZD		9.20	363.57	38.00		410.77	175,062.76
6S70ME & LOHC & HD100		-9.88	363.57	38.00		391.69	175,081.84
6S70ME & LOHC & HD180		-9.18	363.57	38.00		392.39	175,081.14
14V46DF & LNG & D16 MG	-332	-5.15	542.51	38.00		243.36	175,230.17
14V46DF & LNG & D16 MG & CCS	-332	-5.15	-614.40	38.00	1,751.33	837.78	174,635.75
14V46DF & LNG & 6DZD	-332	9.20	542.51	38.00		257.71	175,215.82
14V46DF & LNG & 6DZD & CCS	-332	9.20	-614.40	38.00	1,751.33	852.13	174,621.40
14V46DF & LNG & 6L20DF	-332	3.9	542.51			214.41	175,259.12
14V46DF & LNG & 6L20DF & CCS	-332	3.9	-614.40		1,751.33	808.83	174,664.70
14V46DF & LNG & HD100	-332	-9.88	542.51	38.00		238.63	175,234.90
14V46DF & LNG & HD100 & CCS	-332	-9.88	-614.40	38.00	1,751.33	833.05	174,640.48
14V46DF & LNG & HD180	-332	-9.18	542.51	38.00		239.33	175,234.20
14V46DF & LNG & HD180 & CCS	-332	-9.18	-614.40	38.00	1,751.33	833.75	174,639.78
14V46DF & LNG & ES5-Y.	-332	28.07	542.51			238.58	175,234.95
14V46DF & LNG & ES5-Y. & CCS	-332	28.07	-614.40		1,751.33	833.00	174,640.53
14V46DF & LNG & S.S. 1500	-332	43.63	542.51			254.14	175,219.39
14V46DF & LNG & S.S. 1500 & CCS	-332	43.63	-614.40		1751.33	848.56	174,624.97

Table 5.3: Payload of the design alternatives.

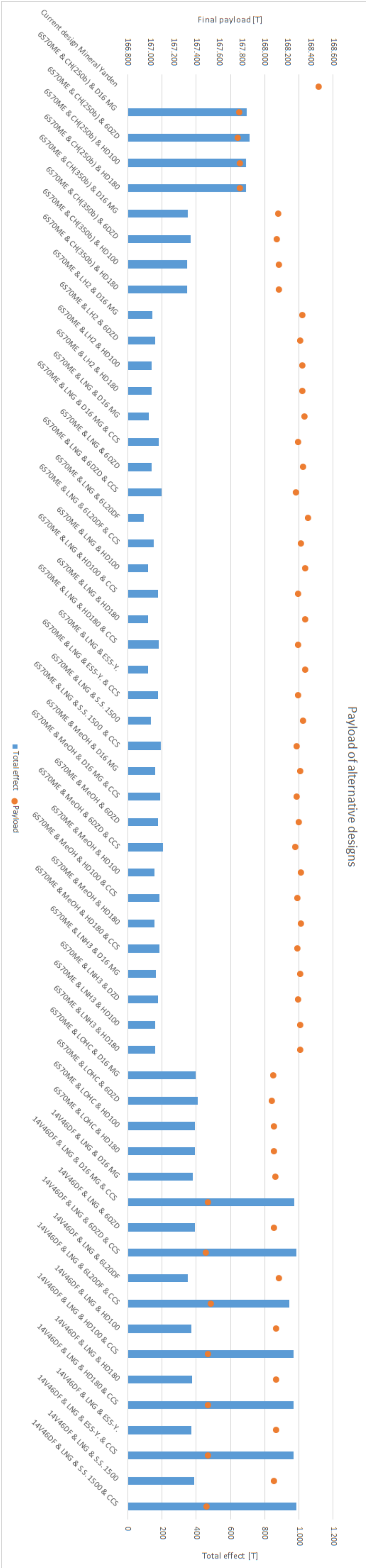

Figure 5.1: Total effect on payload of the alternatives designs

5.2. Effect on power demand

Some of the storage alternatives require specific systems to extract the hydrogen from them (e.g. steam reformers, crackers), so it can be used in energy converters that require pure hydrogen. However, the electric power demanded by these systems vary the daily average power demand of 498kW taken as reference from Table 4.2 and explained in subsection 4.3.1. This is relevant, because an increase of the daily average power demand increases the yearly auxiliary energy converter consumption cost ("A/E fuel" parameter in the CBA) mentioned in subsection 4.4.3.

The power demand is calculated using the number of units of each reformer required, as explained in subsection 4.4.4, and the electric power consumption of each reformer shown in subsection 3.2.1. Although, there are heat sources on board that could be used to increase the hydrogen carrier temperature before entering the reformer, which could reduce considerably the electric power demand. In this project, it has been assumed that the electric consumption of the reformers and crackers could be reduced 40% using these heat sources.

First, the energy converter used to calculate the minimum required hydrogen production per hour was the PEMFC (50% LHV efficieny), which has the highest hydrogen consumption from the alternatives. The hydrogen required to produce the 498kW is approximately 29.9kg/h or $358.4m^3/h$ [120]. Then, knowing the hydrogen to be produced, the hydrogen generation and the electric power demanded by the reformers, which were presented in subsection 3.2.1, it is possible to calculate the extra power required on board due to the reformers and crackers:

- Natural gas reformer extra power demand: $358.4m^3/h \times \frac{14kW}{104m^3/h} \times 60\% = 28.94kW$.
- Methanol gas reformer extra power demand: $358.4m^3/h \times \frac{45kW}{1{,}000m^3/h} \times 60\% = 9.68kW$.
- Ammonia cracker extra power demand: $358.4m^3/h \times \frac{59.5kW}{60m^3/h} \times 60\% = 213.22kW$.
- LOHC dehydrogenation plant extra power demand: $358.4m^3/h \times \frac{3600s/h}{1000g/kg} \times 10kWh/kg \times 60\% = 179.38kW$.

Note that this electric power demand is to produce the average daily consumption. But, as seen in seen in subsection 4.4.4, there are more reformer units on board to reach $400m^3/h$ (520 m^3/h, in the case of ammonia crackers)
The effect of the different reformers on the average power demand is shown in Table 5.4.

Parameter	LNG reformer	MeOH reformer	LNH3 cracker	LOHC dehydrogenation
System demand [kW]	28.94	9.68	213.22	179.38
Total average [kW]	527.18	507.91	711.45	677.62

Table 5.4: Effect of the different reformers on the yearly average power demand.

Secondly, the carbon capture systems have different electric consumption depending on the size of the system. When the CCS is installed in combination with the Hitachi-MAN B&W 6S70ME-C8.2 and LNG/MeOH reformers, SOFC ES5-YA8AA, the MCFC SureSource 1500 or the Wartsila 6L20DF, it only captures the CO2 related with the power generation on board. On the other hand, when the CCS is installed in combination with the alternative designs that include the Wartsila 14V46DF, it also captures the CO2 of the M/E. The CCS power demand has been estimated in Appendix E using the reference system mentioned in subsection 3.5.2 and based on J.T. Akker [4]. The effect on power demand of the different designs can be seen in Table 5.5.

Design alternative	Reformer[kW]	CCS[kW]	Total effect[kW]	Ave. demand[kW]
6S70ME & LNG & D16 MG & CCS	28.94	25.99	54.93	553.16
6S70ME & LNG & 6DZD & CCS	28.94	25.99	54.93	553.16
6S70ME & LNG & 6L20DF & CCS		24.49	24.49	522.72
6S70ME & LNG & HD100 & CCS	28.94	25.99	54.93	553.16
6S70ME & LNG & HD180 & CCS	28.94	25.99	54.93	553.16
6S70ME & LNG & ES5-Y. & CCS		25.99	25.99	524.22
6S70ME & LNG & S.S. 1500 & CCS		25.99	25.99	524.22
6S70ME & MeOH & D16 MG & CCS	9.68	66.57	76.25	574.48
6S70ME & MeOH & 6DZD & CCS	9.68	66.57	76.25	574.48
6S70ME & MeOH & HD100 & CCS	9.68	66.57	76.25	574.48
6S70ME & MeOH & HD180 & CCS	9.68	66.57	76.25	574.48
14V46DF & LNG & D16 MG & CCS	28.94	373.42	402.36	900.59
14V46DF & LNG & 6DZD & CCS	28.94	373.42	402.36	900.59
14V46DF & LNG & 6L20DF & CCS		371.91	371.91	870.14
14V46DF & LNG & HD100 & CCS	28.94	373.42	402.36	900.59
14V46DF & LNG & HD180 & CCS	28.94	373.42	402.36	900.59
14V46DF & LNG & ES5-Y. & CCS		373.42	373.42	871.65
14V46DF & LNG & S.S. 1500 & CCS		373.42	373.42	871.65

Table 5.5: Yearly average power demand of designs that require CCS.

5.3. Regulation feasibility

In this section, the payload and the power demand of each different design alternative presented above is used to calculate the energy efficiency design index and the energy efficiency operational indicator explained in subsection 2.1.3.

5.3.1. EEDI

Using the formula explained in subsection 2.1.3 to calculate the reference EEDI for the Mineral Yarden, with a capacity of 181,218 MT (DWT, summer load line), the result was 2.985 $\left[\frac{gCO2}{tonne\times nm}\right]$. Note that, even though the capacity changes for each design, the maximum effect is 986.77T (less than 0.6% of 181,218) as seen in Table 5.3, then the variation in the reference EEDI can be neglected.
The reduction of the reference EEDI en each phase is shown in Table 5.6.

Phase	EEDI $\left[\frac{gCO2}{tonne\times nm}\right]$
0 (2013-2014) [Reference]	2.985
1 (2015-2019) [-10%]	2.686
2 (2020-2024) [-20%]	2.388
3 (2025 and onwards) [-30%]	2.090

Table 5.6: EEDI limits of the Mineral Yarden design in the different phases.

After, the EEDI of the different alternatives was calculated using the EEDI formula also explained in subsection 2.1.3, and the Capacity of each design (Payload+Other weights) as explained in section 5.1. The results of the EEDI are shown in Table 5.7. See how the contributions of the M/E and the A/E or FC to the EEDI are presented separately, in two different columns. Then, both contributions are added and presented as "Total EEDI". In addition, the EEDI of the current design of the Mineral Yarden is also included, which allows to recognise the effect of the different technologies on the EEDI.
Note that for the dual-fuel engines that operate with 75% hydrogen in terms of energy, MGO/MGO is chosen to cover the remaining 25%. Also, the Wartsila dual-fuel engines require a pilot fuel in their gas mode operation, and it was MGO/MDO, which produces higher CO2 per tonne of fuel than HFO, as seen in subsection 4.4.3.

Alternatives	M/E	A/E or FC	Total EEDI $\left[\frac{gCO2}{tonne \times nm}\right]$
Current Mineral Yarden design	2.512	0.165	2.678
6S70ME & D16 MG with 75% H2 (CH2 250bar)	2.522	0.043	2.565
6S70ME & D16 MG with 75% H2 (CH2 350bar)	2.517	0.043	2.560
6S70ME & D16 MG with 75% H2 (LH2)	2.514	0.043	2.557
6S70ME & D16 MG with 75% H2 (LNH3)	2.515	0.043	2.558
6S70ME & D16 MG with 75% H2 (LOHC)	2,518	0.043	2,561
6S70ME & D16 MG with 75% H2 (LNG)	2.514	0.143	2.657
6S70ME & D16 MG with 75% H2 (LNG+CCS)	2.515	0.053	2.568
6S70ME & D16 MG with 75% H2 (MeOH)	2.515	0.147	2.661
6S70ME & D16 MG with 75% H2 (MeOH+CCS)	2.515	0.053	2.568
6S70ME & 6 DZD with 75% H2 (CH2 250bar)	2.522	0.042	2.564
6S70ME & 6 DZD with 75% H2 (CH2 350bar)	2.517	0.042	2.559
6S70ME & 6 DZD with 75% H2 (LH2)	2.515	0.042	2.556
6S70ME & 6 DZD with 75% H2 (LNH3)	2.515	0.042	2.556
6S70ME & 6 DZD with 75% H2 (LOHC)	2.518	0.042	2.560
6S70ME & 6 DZD with 75% H2 (LNG)	2.514	0.139	2.653
6S70ME & 6 DZD with 75% H2 (LNG+CCS)	2.515	0.051	2.566
6S70ME & 6 DZD with 75% H2 (MeOH)	2.515	0.143	2.657
6S70ME & 6 DZD with 75% H2 (MeOH+CCS)	2.515	0.052	2.567
6S70ME & 6L20DF with LNG & pilot fuel	2.514	0.120	2.634
6S70ME & 6L20DF with LNG+CCS & pilot fuel	2.514	0.012	2.527
6S70ME & HD100 with 100% H2 (CH2 250bar)	2.522	0	2.522
6S70ME & HD100 with 100% H2 (CH2 350bar)	2.517	0	2.517
6S70ME & HD100 with 100% H2 (LH2)	2.514	0	2.514
6S70ME & HD100 with 100% H2 (LNH3)	2.515	0	2.515
6S70ME & HD100 with 100% H2 (LOHC)	2.518	0	2.518
6S70ME & HD100 with 100% H2 (LNG)	2.514	0.109	2.623
6S70ME & HD100 with 100% H2 (LNG+CCS)	2.515	0.011	2.526
6S70ME & HD100 with 100% H2 (MeOH)	2.514	0.114	2.628
6S70ME & HD100 with 100% H2 (MeOH+CCS)	2.515	0.011	2.526
6S70ME & HD180 with 100% H2 (CH2 250bar)	2.522	0	2.522
6S70ME & HD180 with 100% H2 (CH2 350bar)	2.517	0	2.517
6S70ME & HD180 with 100% H2 (LH2)	2.514	0	2.514
6S70ME & HD180 with 100% H2 (LNH3)	2.515	0	2.515
6S70ME & HD180 with 100% H2 (LOHC)	2.518	0	2.518
6S70ME & HD180 with 100% H2 (LNG)	2.514	0.109	2.623
6S70ME & HD180 with 100% H2 (LNG+CCS)	2.515	0.011	2.526
6S70ME & HD180 with 100% H2 (MeOH)	2.514	0.114	2.628
6S70ME & HD180 with 100% H2 (MeOH+CCS)	2.515	0.011	2.526
6S70ME & ES5-YA8AAA with 100% LNG	2.514	0.098	2.612
6S70ME & ES5-YA8AAA with 100% LNG+CCS)	2.515	0.010	2.525
6S70ME & SureSource 1500 with 100% LNG	2.514	0.080	2.594
6S70ME & SureSource 1500 with 100% LNG+CCS	2.515	0.008	2.523
Wartsila 14V46DF & D16 MG with 75% H2 (LNG)	2.057	0.143	2.200
Wartsila 14V46DF & D16 MG with 75% H2 (LNG) & CCS	0.207	0.053	0.260
Wartsila 14V46DF & 6 DZD with 75% H2 (LNG)	2.057	0.139	2.196
Wartsila 14V46DF & 6 DZD with 75% H2 (LNG) & CCS	0.207	0,052	0.258
Wartsila 14V46DF & 6L20DF with LNG & pilot fuel	2.057	0.120	2.177
Wartsila 14V46DF & 6L20DF with LNG & pilot fuel & CCS	0.207	0.012	0.219
Wartsila 14V46DF & HD100 with 100% H2 (LNG)	2.057	0.109	2.166
Wartsila 14V46DF & HD100 with 100% H2 (LNG) & CCS	0.207	0.011	0.218
Wartsila 14V46DF & HD180 with 100% H2 (LNG)	2.057	0.109	2.166
Wartsila 14V46DF & HD180 with 100% H2 (LNG) & CCS	0.207	0.011	0.218
Wartsila 14V46DF & ES5-YA8AAA with LNG	2.057	0.098	2.155
Wartsila 14V46DF & ES5-YA8AAA with LNG & CCS	0.207	0.010	0.217
Wartsila 14V46DF & SureSource 1500 with LNG	2.057	0.080	2.138
Wartsila 14V46DF & SureSource 1500 with LNG & CCS	0.207	0.008	0.215

Table 5.7: EEDI of the alternative designs.

Alternatives	**EEOI** $[\frac{tonneCO2}{tonne \times nm}]$
Current Mineral Yarden design	3.212×10^{-6}
6S70ME & D16 MG with 75% H2 (CH2 250bar)	3.062×10^{-6}
6S70ME & D16 MG with 75% H2 (CH2 350bar)	3.056×10^{-6}
6S70ME & D16 MG with 75% H2 (LH2)	3.052×10^{-6}
6S70ME & D16 MG with 75% H2 (LNH3)	3.077×10^{-6}
6S70ME & D16 MG with 75% H2 (LOHC)	3.077×10^{-6}
6S70ME & D16 MG with 75% H2 (LNG)	3.196×10^{-6}
6S70ME & D16 MG with 75% H2 (LNG+CCS)	3.074×10^{-6}
6S70ME & D16 MG with 75% H2 (MeOH)	3.194×10^{-6}
6S70ME & D16 MG with 75% H2 (MeOH+CCS)	3.078×10^{-6}
6S70ME & 6 DZD with 75% H2 (CH2 250bar)	3.060×10^{-6}
6S70ME & 6 DZD with 75% H2 (CH2 350bar)	3.054×10^{-6}
6S70ME & 6 DZD with 75% H2 (LH2)	3.051×10^{-6}
6S70ME & 6 DZD with 75% H2 (LNH3)	3.075×10^{-6}
6S70ME & 6 DZD with 75% H2 (LOHC)	3.075×10^{-6}
6S70ME & 6 DZD with 75% H2 (LNG)	3.190×10^{-6}
6S70ME & 6 DZD with 75% H2 (LNG+CCS)	3.072×10^{-6}
6S70ME & 6 DZD with 75% H2 (MeOH)	3.189×10^{-6}
6S70ME & 6 DZD with 75% H2 (MeOH+CCS)	3.075×10^{-6}
6S70ME & 6L20DF with LNG & pilot fuel	3.154×10^{-6}
6S70ME & 6L20DF with LNG+CCS & pilot fuel	3.012×10^{-6}
6S70ME & HD100 with 100% H2 (CH2 250bar)	3.004×10^{-6}
6S70ME & HD100 with 100% H2 (CH2 350bar)	2.999×10^{-6}
6S70ME & HD100 with 100% H2 (LH2)	2.995×10^{-6}
6S70ME & HD100 with 100% H2 (LNH3)	2.995×10^{-6}
6S70ME & HD100 with 100% H2 (LOHC)	2.999×10^{-6}
6S70ME & HD100 with 100% H2 (LNG)	3.148×10^{-6}
6S70ME & HD100 with 100% H2 (LNG+CCS)	3.012×10^{-6}
6S70ME & HD100 with 100% H2 (MeOH)	3.149×10^{-6}
6S70ME & HD100 with 100% H2 (MeOH+CCS)	3.013×10^{-6}
6S70ME & HD180 with 100% H2 (CH2 250bar)	3.004×10^{-6}
6S70ME & HD180 with 100% H2 (CH2 350bar)	2.999×10^{-6}
6S70ME & HD180 with 100% H2 (LH2)	2.995×10^{-6}
6S70ME & HD180 with 100% H2 (LNH3)	2.995×10^{-6}
6S70ME & HD180 with 100% H2 (LOHC)	2.999×10^{-6}
6S70ME & HD180 with 100% H2 (LNG)	3.148×10^{-6}
6S70ME & HD180 with 100% H2 (LNG+CCS)	3.012×10^{-6}
6S70ME & HD180 with 100% H2 (MeOH)	3.149×10^{-6}
6S70ME & HD180 with 100% H2 (MeOH+CCS)	3.013×10^{-6}
6S70ME & ES5-YA8AAA with 100% LNG	3.125×10^{-6}
6S70ME & ES5-YA8AAA with 100% LNG+CCS)	3.009×10^{-6}
6S70ME & SureSource 1500 with 100% LNG	3.102×10^{-6}
6S70ME & SureSource 1500 with 100% LNG+CCS	3.007×10^{-6}
Wartsila 14V46DF & D16 MG with 75% H2 (LNG)	2.749×10^{-6}
Wartsila 14V46DF & D16 MG with 75% H2 (LNG) & CCS	4.391×10^{-7}
Wartsila 14V46DF & 6 DZD with 75% H2 (LNG)	$2{,}744 \times 10^{-6}$
Wartsila 14V46DF & 6 DZD with 75% H2 (LNG) & CCS	4.354×10^{-7}
Wartsila 14V46DF & 6L20DF with LNG & pilot fuel	2.707×10^{-6}
Wartsila 14V46DF & 6L20DF with LNG & pilot fuel & CCS	3.395×10^{-7}
Wartsila 14V46DF & HD100 with 100% H2 (LNG)	2.702×10^{-6}
Wartsila 14V46DF & HD100 with 100% H2 (LNG) & CCS	3.377×10^{-7}
Wartsila 14V46DF & HD180 with 100% H2 (LNG)	2.702×10^{-6}
Wartsila 14V46DF & HD180 with 100% H2 (LNG) & CCS	3.377×10^{-7}
Wartsila 14V46DF & ES5-YA8AAA with LNG	2.679×10^{-6}
Wartsila 14V46DF & ES5-YA8AAA with LNG & CCS	3.343×10^{-7}
Wartsila 14V46DF & SureSource 1500 with LNG	2.655×10^{-6}
Wartsila 14V46DF & SureSource 1500 with LNG & CCS	3.301×10^{-7}

Table 5.8: EEOI of the alternative designs.

In Table 5.7, it can be seen how the M/E is responsible for most of the CO2 emissions, in consequence, the selection of the M/E mostly determine the phase in which the design is valid to be built. All designs with the Hitachi-MAN B&W 6S70ME-C8.2 as M/E are only valid to be built till phase 1. Because the EEDI of all these designs only considering the M/E is 2.512 $\left[\frac{gCO2}{tonne \times nm}\right]$, which is higher than the 2.388 $\left[\frac{gCO2}{tonne \times nm}\right]$ of phase 2. On the other hand, all designs with the Wartsila 14V46DF and without CCS are valid to be built in phase 2. Finally, the only design alternatives that can be built in phase 3 are the combinations with the Wartsila 14V46DF and CCS.

5.3.2. EEOI

The formula explained in subsection 2.1.3 was used to calculate the current EEOI of the current design of the Mineral Yarden, and the EEOI of the alternative designs. To do so, it was used the payload calculated in section 5.1 and the power demands presented in Table 5.4 and Table 5.5. The results are shown in Table 5.8. The results shown in Table 5.8 demonstrate that all design alternatives have a positive effect on the EEOI, since all values decrease compared with the current design of the Mineral Yarden. In addition, it can be observed that all alternatives with the Wartsila 14V46DF have lower emission per tonne-mile than any of the designs with the Hitachi-MAN B&W 6S70ME-C8.2. Also, when CCSs are installed together with the Wartsila 14V46DF the EEDI decreases in one order of magnitude compared with the rest of the alternatives.

5.4. Intermediate conclusion

First of all, the energy converters proposed to replace one of the auxiliary engines do not reduce the EEDI enough to be under the limit of Phase 2 (2020-2024) when the Hitachi-MAN B&W 6S70ME-C8.2 is kept in the design. Even with PEMFC systems and pure hydrogen storage, an EEDI of 2.514-2.628 (see Table 5.7)is far from the 2.388 limit of Phase 2 (see Table 5.6). Which means that the current design of the Mineral Yarden and the proposed designs could only be built till 2019. On the other hand, the designs with the Wartsila 14V46DF are all valid for Phase 2 and in combination with CCS also for Phase 3.

In second place, the Anglo Belgian Corporation 6 DZD engine outperforms in term of EEDI and EEOI the Volvo Penta D16 MG engine with all storage alternatives. Also, the the Ballard HD100 slightly outperform the Hydrogenics HD180 because of the fact that for the same output the Hydrogenics HD180 is heavier than the Ballard HD100.
Then, if we focus in the designs without CCS, some conclusion can be extracted. The design with the Wartsila 6L20DF as A/E has a lower EEDI and EEOI than the other ICEs operating with 75% hydrogen when this hydrogen is reformed from LNG or MeOH. Also, it can be seen that the design with the MCFC SureSource 1500 has a lower EEDI and EEOI than the SOFC ES-YA8AA.

After the technical feasibility analysis, the first research question mentioned in section 1.2:

- *What alternative fuel and energy converter combinations on a bulk carrier doing Australia-China monthly round trips could allow the vessel to be built after 2019 while complying with the Energy Efficiency Design Index?*

Initially, the energy converters considered as alternatives in section 3.4 were ICEs, FCs and H2-LNG dual-fuel turbines. However, turbines were already discarded in the literature research subsection 3.4.3 because of the size of the generator required for this case study, and due to the lack of field experience using that technology as prime mover for propulsion purposes. Then, all the energy converters tested in this chapter were ICEs and FCs.

Two were the alternatives tested in this chapter as M/E, and the results shown in Table 5.7 demonstrated that only the designs with the Wartsila 14V46DF could be built from 2020 onwards. Then the design alternatives that are considered technically feasible to be built after 2019 while complying with the Energy Efficiency Design Index are:

1. Wartsila 14V46DF and Volvo Penta D16 MG: the Wartsila engine operating in gas mode with LNG and pilot fuel MGO/MDO, the Volvo engine operating with 25% MGO/MDO of the energy input and with 75% H2 reformed from LNG.

2. Wartsila 14V46DF and Volvo PentaD16 MG with CCS: this design is similar than the alternative 1, but it also include a carbon capture system which is able to capture 90% of the CO2 produced by the Wartsila engine and 90% of the CO2 produced in the LNG reformers.

3. Wartsila 14V46DF and Anglo Belgian Corporation 6 DZD: the Wartsila engine operating in gas mode with LNG and pilot fuel MGO/MDO, the ABC engine operating with 25% MGO/MDO of the energy input and with 75% H2 reformed from LNG.

4. Wartsila 14V46DF and Anglo Belgian Corporation 6 DZD with CCS: this design is similar than the alternative 3, but it also include a carbon capture system which is able to capture 90% of the CO2 produced by the Wartsila engine and 90% of the CO2 produced in the LNG reformers.

5. Wartsila 14V46DF and Wartsila 6L20DF: both Wartsila engines operating in gas mode with LNG and pilot fuel MGO/MDO.

6. Wartsila 14V46DF and Wartsila 6L20DF with CCS: this design is similar than the alternative 5, but it also include a carbon capture system which is able to capture 90% of the CO2 produced by the Wartsila engines.

7. Wartsila 14V46DF and Ballard Power HD100: the Wartsila engine operating in gas mode with LNG and pilot fuel MGO/MDO, the Ballard Power proton-exchange membrane fuel cell operating with 100% hydrogen reformed from LNG.

8. Wartsila 14V46DF and Ballard Power HD100 with CCS: this design is similar than the alternative 7, but it also include a carbon capture system which is able to capture 90% of the CO2 produced by the Wartsila engine and 90% of the CO2 produced in the LNG reformers.

9. Wartsila 14V46DF and Hydrogenics HD180: the Wartsila engine operating in gas mode with LNG and pilot fuel MGO/MDO, the Hydrogenics proton-exchange membrane fuel cell operating with 100% hydrogen reformed from LNG.

10. Wartsila 14V46DF and Hydrogenics HD180 with CCS: this design is similar than the alternative 9, but it also include a carbon capture system which is able to capture 90% of the CO2 produced by the Wartsila engine and 90% of the CO2 produced in the LNG reformers.

11. Wartsila 14V46DF and Bloom Energy ES5-YA8AAA: the Wartsila engine operating in gas mode with LNG and pilot fuel MGO/MDO, the Bloom Energy solid oxide fuel cell operating with 100% LNG.

12. Wartsila 14V46DF and Bloom Energy ES5-YA8AAA with CCS: this design is similar than the alternative 9, but it also include a carbon capture system which is able to capture 90% of the CO2 produced by the Wartsila engine and 90% of the CO2 produced by the SOFC.

13. Wartsila 14V46DF and Fuel Cell Energy SureSource 1500: the Wartsila engine operating in gas mode with LNG and pilot fuel MGO/MDO, the Fuel Cell Energy molten carbonate fuel cell operating with 100% LNG.

14. Wartsila 14V46DF and Fuel Cell Energy SureSource 1500 with CCS: this design is similar than the alternative 11, but it also include a carbon capture system which is able to capture 90% of the CO2 produced by the Wartsila engine and 90% of the CO2 produced by the MCFC.

All these alternatives will be included in the economic feasibiity analysis in chapter 6, however, it is decided to also include the remaining design alternativies studied in this chapter. Because, their analysis could provide valuable information about the power generation alternatives in combination with storage alternatives different than LNG.

6 Economic Feasibility

The aim of this chapter is to formulate an advise to CMB about which of the technical feasible design alternatives performs better in the proposed route, and about which storage alternative to transport hydrogen is economically the best.
For the first advise, it is necessary to recognise which of the 14 design alternatives that could be built after 2019 complying with the EEDI regulation has the highest benefit-cost ratio [i.e. (Benefits-Costs)/Investment]. For the second advise, from the design alternatives that have the Hitachi-MAN B&W 6S70ME-C8.2 as M/E and that require pure hydrogen for their A/E or F/C, it will be recognised the design with the best BCR.

In this chapter the results of the cost-benefit analysis explained in section 4.4 will be presented. First, the private perspective analysis will be carried out, so the designs with a BCR lower than one are discarded because they do not recover the investment, and also the remaining alternatives are ranked with the BCR. Secondly, the welfare perspective analysis will be carried out. This will allow to see if there are differences in the top BCR ranked designs between perspectives. Also, the welfare perspective will allow to observe if a subsidy to a design with a CCS could make it competitive with its homologue without CCS in the private perspective and at the same time, it could benefit the population welfare. This benefit can be quantified in dollars, since the improvement between the alternative with and without CCS in the societal perspective should be at least equal, but preferably higher than the value of the subsidy. Also, the private perspective results will be compared with the welfare or societal perspective results, so the externalities due to CO2 emission emitted are identified.

Furthermore, the sensitivity analysis will have two parts. First part, it will include some scenarios, in which all the parameters are aligned in favour of cleaner alternatives, the "Pro-zero emission scenario", or all the parameters are aligned against cleaner alternatives, the "Pro-hydrocarbon scenario". Second part, it will include sensitivity analysis of specific fuel and system prices.

6.1. Economic private perspective

The economic analysis from a private perspective includes a market price for the CO2 emitted, even though, currently this market does not exist on an international level (in the sensitivity analysis it will be studied how this assumption affects the results obtained). The fact is that if it is included as a real cost for the private company and no as an externality, then probably it should not be called CBA from a private perspective and just economic analysis from a private perspective. Because, although the procedure of calculation is similar, a real CBA includes externalities.

The analysis from a private perspective helps to decide among the different design alternatives from the point of view of a private company, and in this perspective, the cost per tonne of CO2 emitted is assumed to be 7.57$/T, as explained in subsection 4.4.5. The approach of the analysis consist on adding the benefits minus cost yearly, discounting them and after using them to calculate the different indicators: NPV after 20 years, Payback period, IRR, BCR, Cost per tonne-mile.

The duration of the project is 20 years, but for practical reasons, the tables used to present the economic results will only show from Year 0 to Year 2 and from Year 19 to Year 20. The alternative designs studied in the economic analysis were already presented in subsection 4.4.1, and they are 57. However, only the 14 designs described in section 5.4 were proven technically feasible to be build after 2019. That is why, these 14 designs will be studied separately from the remaining designs. In this way, it is possible to answer the second research question presented in section 1.2, but also reach some conclusions about alternative electric power supplies and other alternative fuels different than LNG (all 14 designs use LNG).

In addition, to have a reference of how the current design of the Mineral Yarden (first design combination of the 57 showed in subsection 4.4.1) would perform under the same conditions than the case study, Table 6.1 shows its economic analysis and other indicators.

Year	**0**	**1**	**2**	**...**	**19**	**20**
BENEFITS						
Operational income		12,130,094	12,130,094	...	12,130,094	12,130,094
Scratch value				...		6,200,000
COSTS						
Capital investment	41,875,000			...		
M/E fuel		4,855,960	4,855,960	...	4,855,960	4,855,960
A/E fuel		472,784	472,784	...	472,784	472,784
CO2 emission		307,204	307,204	...	307,204	307,204
BENEFIT-COST	-41,875,000	6,494,145	6,494,145	...	6,494,145	12,694,145
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-41,875,000	6,226,409	5,969,711	...	2,918,234	5,469,117
NPV till that year	-41,875,000	-35,648,590	-29,678,878	...	41,285,720	46,754,838
Payback period	8 years					
IRR	9.91%					
BCR	1.117					
Cost per tonne-mile	0.000637					

Table 6.1: Economic analysis and indicators that the current design of the Mineral Yarden (A/E: DAIHATSU 6DE-18) would have from a private perspective

From a private perspective, Table 6.1 shows that the current design on the Mineral Yarden has a NPV after 20 years of $46,754,838, a payback period of 8 years, an IRR of 9.91%, a BCR of 1.117, which means that per each dollar invested 1.117 dollars are obtained over the lifetime of the project, and a cost per tonne-mile of $0.000637. These indicators will be used as reference to compare the remaining designs.

6.1.1. Technically feasible design alternatives

Once the current design of the Mineral Yarden is economically analysed, the 14 design alternatives that are technically feasible are tested with the same indicators.

The results shown that none of them have a benefit-cost ratio higher than one, which means that they do not recover the initial investment. The design alternative with the highest BCR from a private perspective is the combination with the Wartsila 14V46DF and the Wartsila 6L20DF and without CCS, and the second highest is the same design but with CCS. Then, it is interesting to explain in detail both alternatives, because after analysing the welfare perspective it could be decided that a subsidy to the design with the CCS could benefit the population welfare by reducing the CO2 emissions.

First, the economic analysis of the design without CCS and other indicators are shown in Table 6.2.

In Table 6.2 it can be seen that after 20 years the NPV is $35,336,104 , the payback period is 10 years, the IRR is 7.10%, the BCR is 0.772, which means that per each dollar invested only 0.772 dollars are obtained over the lifetime of the project, and the cost per tonne-mile is $0.000700. These results compared with the results of Table 6.1 are the following:

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,114,657	12,114,657	...	12,114,657	12,114,657
Scratch value				...		6,200,000
COSTS						
Capital investment	45,752,788			...		
M/E fuel		5,581,451	5,581,451	...	5,581,451	5,581,451
A/E fuel		350,355	350,355	...	350,355	350,355
CO2 emission		258,421	258,421	...	258,421	258,421
BENEFIT-COST	-45,752,788	5,924,429	5,924,429	...	5,924,429	12,124,429
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-45,752,788	5,680,181	5,446,003	...	2,662,224	5,223,663
NPV till that year	-45,752,788	-40,072,606	-34,626,603	...	30,112,441	35,336,104
Payback period	10 years					
IRR	7.10%					
BCR	0.772					
Cost per tonne-mile	0.000700					

Table 6.2: Economic analysis from a private perspective of the design with Wartsila 14V46DF, Wartsila 6L20DF and without CCS.

- NPV after 20 years decreases $11,418,735 or a 24.42% compared with current design of the Mineral Yarden.
- Payback period increases 2 years.
- IRR decreases from 9.91% to 7.10%.
- BCR decreases from 1.117 to 0.772.
- Cost per tonne mile increases from $0.000637 to $0.000700.

Secondly, the economic analysis of the design combination with the Wartsila 14V46DF, the Wartsila 6L20DF and CCS and other indicators are shown in Table 6.3.

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,071,859	12,071,859	...	12,071,859	12,071,859
CO2 sales		627,522	627,522	...	627,522	627,522
Scratch value				...		6,200,000
COSTS						
Capital investment	51,211,112			...		
M/E fuel		5,581,451	5,581,451	...	5,581,451	5,581,451
A/E fuel		611,880	611,880	...	611,880	611,880
CO2 emission		32,292	32,292	...	32,292	32,292
BENEFIT-COST	-51,211,112	6,473,756	6,473,756	...	6,473,756	12,673,756
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-51,211,112	6,206,861	5,950,970	...	2,909,072	5,460,334
NPV till that year	-51,211,112	-45,004,251	-39,053,281	...	31,688,520	37,148,854
Payback period	10 years					
IRR	6.73%					
BCR	0.725					
Cost per tonne-mile	0.000728					

Table 6.3: Economic analysis from a private perspective of the design with Wartsila 14V46DF, Wartsila 6L20DF and with CCS.

In Table 6.3 it can be seen that after 20 years the NPV is $37,148,854, the payback period is 10 years, the IRR is 6.73%, the BCR is 0.725, which means that per each dollar invested only 0.725 dollars are recovered over the lifetime of the project, and the cost per tonne-mile is $0.000728. These results compared with the results of Table 6.1 are the following:

- NPV after 20 years decreases $9,605,985 or a 20.55% compared with current design of the Mineral Yarden.
- Payback period increases 2 years.
- IRR decreases from 9.91% to 6.73%.
- BCR decreases from 1.117 to 0.725.
- Cost per tonne mile increases from $0.000637 to $0.000728.

Thirdly, the design alternative with the third highest BCR from a private perspective is the combination with the Wartsila 14V46DF and the Volvo Penta D16 MG and without CCS. Its economic analysis and other indicators are shown in Table 6.4.

Year	**0**	**1**	**2**	**...**	**19**	**20**
BENEFITS						
Operational income		12,112,572	12,112,572	...	12,112,572	12,112,572
Scratch value				...		6,200,000
COSTS						
Capital investment	46,242,625			...		
M/E fuel		5,581,451	5,581,451	...	5,581,451	5,581,451
A/E fuel		596,448	596,448	...	596,448	596,448
CO2 emission		263,709	263,709	...	263,709	263,709
BENEFIT-COST	-46,242,625	5,670,964	5,670,964	...	5,670,964	11,870,964
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-46,242,625	5,437,166	5,213,007	...	2,548,326	5,114,461
NPV till that year	-46,242,625	-40,805,459	-35,592,452	...	26,376,861	31,491,321
Payback period	11 years					
IRR	6.33%					
BCR	0.681					
Cost per tonne-mile	0.000723					

Table 6.4: Economic analysis from a private perspective of the design with Wartsila 14V46DF, Volvo Penta D16 MG, LNG as hydrogen carrier and without CCS.

In Table 6.4 it can be seen that after 20 years the NPV is $31,491,321, the payback period is 11 years, the IRR is 6.33%, the BCR is 0.681, which means that per each dollar invested only 0.681 dollars are recovered over the lifetime of the project, and the cost per tonne-mile is $0.000723. These results compared with the results of Table 6.1 are the following:

- NPV after 20 years decreases $15,263,517 or a 32.65% compared with current design of the Mineral Yarden.
- Payback period increases three years.
- IRR decreases from 9.91% to 6.33%.
- BCR decreases from 1.117 to 0.681.
- Cost per tonne mile increases from $0.000637 to $0.000723.

Finally, the design alternative with the fourth highest BCR from a private perspective is the combination with the Wartsila 14V46DF and the Anglo Belgian Corporation 6 DZD and without CCS. Its economic analysis and other indicators are shown in Table 6.5.
In Table 6.5 it can be seen that after 20 years the NPV is $31,365,513, the payback period is 11 years, the IRR is 6.26%, the BCR is 0.673, which means that per each dollar invested only 0.673 dollars are recovered over the

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,111,539	12,111,539	...	12,111,539	12,111,539
Scratch value				...		6,200,000
COSTS						
Capital investment	46,592,625			...		
M/E fuel		5,581,451	5,581,451	...	5,581,451	5,581,451
A/E fuel		579,075	579,075	...	579,075	579,075
CO2 emission		263,110	263,110	...	263,110	263,110
BENEFIT-COST	-46,592,625	5,687,902	5,687,902	...	5,687,902	11,887,902
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-46,592,625	5,453,405	5,228,577	...	2,555,938	5,121,758
NPV till that year	-46,592,625	-41,139,219	-35,910,643	...	26,243,755	31,365,513
Payback period	11 years					
IRR	6.26%					
BCR	0.673					
Cost per tonne-mile	0.000723					

Table 6.5: Economic analysis from a private perspective of the design with Wartsila 14V46DF, Anglo Belgian Corporation 6 DZD, LNG as hydrogen carrier and without CCS.

lifetime of the project, and the cost per tonne-mile is $0.000723. These results compared with the results of Table 6.1 are the following:

- NPV after 20 years decreases $15,389,326 or a 32.91% compared with current design of the Mineral Yarden.
- Payback period increases three years.
- IRR decreases from 9.91% to 6.26%.
- BCR decreases from 1.117 to 0.673.
- Cost per tonne mile increases from $0.000637 to $0.000723.

6.1.2. Non-technically feasible design alternatives

The remaining 42 design alternatives are not technically feasible, but they will also be compared with the current design of the Mineral Yarden.
The results obtained shown that six of them have a benefit-cost ratio higher than one, which means that in these designs each dollar invested produces more than one dollar over the lifetime of the project. The design alternative with the highest BCR from a private perspective is the combination with the Hitachi-MAN B&W 6S70ME-C8.2, the Wartsila 6L20DF and without CCS, and the second highest is the same combination but with CCS. Then, the only alternative that will be presented in detail is the combination without CCS. The economic analysis and other indicators are shown in Table 6.6.
In Table 6.6 it can be seen that after 20 years the NPV is $48,035,950, the payback period is 8 years, the IRR is 10.09%, the BCR is 1.138, which means that per each dollar invested 1.138 dollars are obtained over the lifetime of the project, and the cost per tonne-mile is $0.000628. These results compared with the results of Table 6.1 are the following:

- NPV after 20 years increases $1,281,111 or a 2.74% compared with current design of the Mineral Yarden.
- Payback period is 8 years in both cases.
- IRR increases from 9.91% to 10.09%.
- BCR increases from 1.117 to 1.138.
- Cost per tonne mile decreases from $0.000637 to $0.000628.

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,123,297	12,123,297	...	12,123,297	12,123,297
Scratch value				...		6,200,000
COSTS						
Capital investment	42,200,369			...		
M/E fuel		4,855,960	4,855,960	...	4,855,960	4,855,960
A/E fuel		350,355	350,355	...	350,355	350,355
CO2 emission		301,467	301,467	...	301,467	301,467
BENEFIT-COST	-42,200,369	6,615,514	6,615,514	...	6,615,514	12,815,514
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-42,200,369	6,342,775	6,081,280	...	2,972,773	5,521,408
NPV till that year	-42,200,369	-35,857,595	-29,776,315	...	42,514,541	48,035,950
Payback period	8 years					
IRR	10.09%					
BCR	1.138					
Cost per tonne-mile	0.000628					

Table 6.6: Economic analysis from a private perspective of the design with Hitachi-MAN B&W 6S70ME-C8.2, Wartsila 6L20DF and without CCS.

Secondly, the design alternative with the third highest BCR from a private perspective is the combination with the Hitachi-MAN B&W 6S70ME-C8.2, the Volvo Penta D16 MG and without CCS, and the fifth highest is the same combination but with CCS. Then, the only alternative that will be presented in detail is the combination without CCS. The economic analysis and other indicators are shown in Table 6.7.

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,121,212	12,121,212	...	12,121,212	12,121,212
Scratch value				...		6,200,000
COSTS						
Capital investment	42,690,206			...		
M/E fuel		4,855,960	4,855,960	...	4,855,960	4,855,960
A/E fuel		554,042	554,042	...	554,042	554,042
CO2 emission		305,412	305,412	...	305,412	305,412
BENEFIT-COST	-42,690,206	6,405,798	6,405,798	...	6,405,798	12,605,798
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-42,690,206	6,141,705	5,888,499	...	2,878,534	5,431,055
NPV till that year	-42,690,206	-36,548,502	-30,660,003	...	39,339,185	44,770,240
Payback period	9 years					
IRR	9.37%					
BCR	1.049					
Cost per tonne-mile	0.000648					

Table 6.7: Economic analysis from a private perspective of the design with Hitachi-MAN B&W 6S70ME-C8.2, Volvo Penta D16 MG, LNG as hydrogen carrier and without CCS.

In Table 6.7 it can be seen that after 20 years the NPV is $44,770,240, the payback period is 9 years, the IRR is 9.37%, the BCR is 1.049, which means that per each dollar invested 1.049 dollars are obtained over the lifetime of the project, and the cost per tonne-mile is $0.000648. These results compared with the results of Table 6.1 are the following:

- NPV after 20 years decreases $1,984,599 or a 4.24% compared with current design of the Mineral Yarden.
- Payback period increases one year.
- IRR decreases from 9.91% to 9.37%.
- BCR decreases from 1.117 to 1.049.
- Cost per tonne mile increases from $0.000637 to $0.000648.

Thirdly, the design alternative with the fourth highest BCR from a private perspective is the combination with the Hitachi-MAN B&W 6S70ME-C8.2, the Anglo Belgian Corporation 6 DZD and without CCS. The economic analysis and other indicators of this design are shown in Table 6.8.

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,120,179	12,120,179	...	12,120,179	12,120,179
Scratch value				...		6,200,000
COSTS						
Capital investment	43,040,206			...		
M/E fuel		4,855,960	4,855,960	...	4,855,960	4,855,960
A/E fuel		537,905	537,905	...	537,905	537,905
CO2 emission		304,853	304,853	...	304,853	304,853
BENEFIT-COST	-43,040,206	6,421,461	6,421,461	...	6,421,461	12,621,461
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-43,040,206	6,156,722	5,902,898	...	2,885,573	5,437,803
NPV till that year	-43,040,206	-36,883,484	-30,980,587	...	39,189,762	44,627,565
Payback period	9 years					
IRR	9.28%					
BCR	1.037					
Cost per tonne-mile	0.000648					

Table 6.8: Economic analysis from a private perspective of the design with Hitachi-MAN B&W 6S70ME-C8.2, Anglo Belgian Corporation 6 DZD, LNG as hydrogen carrier and without CCS.

In Table 6.8 it can be seen that after 20 years the NPV is $44,627,565, the payback period is 9 years, the IRR is 9.28%, the BCR is 1.037, which means that per each dollar invested 1.037 dollars are obtained over the lifetime of the project, and the cost per tonne-mile is $0.000648. These results compared with the results of Table 6.1 are the following:

- NPV after 20 years decreases $2,127,274 or a 4.55% compared with current design of the Mineral Yarden.
- Payback period increases one year.
- IRR decreases from 9.91% to 9.28%.
- BCR decreases from 1.117 to 1.037.
- Cost per tonne mile decreases from $0.000637 to $0.000648.

Finally, the design alternative with the sixth highest BCR from a private perspective does not use LNG as hydrogen carrier, it uses LNH3, and it is the combination with the Hitachi-MAN B&W 6S70ME-C8.2 and the Volvo Penta D16 MG. The economic analysis and other indicators of this design are shown in Table 6.9.
In Table 6.9 it can be seen that after 20 years the NPV is $42,418,934, the payback period is 9 years, the IRR is 9.00%, the BCR is 1.004, which means that per each dollar invested 1.004 dollars are obtained over the lifetime of the project, and the cost per tonne-mile is $0.000663. These results compared with the results of Table 6.1 are the following:

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,118,263	12,118,263	...	12,118,263	12,118,263
Scratch value				...		6,200,000
COSTS						
Capital investment	42,250,162			...		
M/E fuel		4,855,960	4,855,960	...	4,855,960	4,855,960
A/E fuel		774,744	774,744	...	774,744	774,744
CO2 emission		292,646	292,646	...	292,646	292,646
BENEFIT-COST	-42,250,162	6,194,912	6,194,912	...	6,194,912	12,394,912
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-42,250,162	5,939,513	5,694,644	...	2,783,770	5,340,197
NPV till that year	-42,250,162	-36,310,649	-30,616,005	...	37,078,737	42,418,934
Payback period	9 years					
IRR	9.00%					
BCR	1.004					
Cost per tonne-mile	0.000663					

Table 6.9: Economic analysis from a private perspective of the design with Hitachi-MAN B&W 6S70ME-C8.2, Volvo Penta D16 MG and LNH3 as hydrogen carrier.

- NPV after 20 years decreases $4,335,905 or a 9.27% compared with current design of the Mineral Yarden.
- Payback period increases one year.
- IRR decreases from 9.91% to 9.00%.
- BCR decreases from 1.117 to 1.004.
- Cost per tonne mile decreases from $0.000637 to $0.000663.

6.1.3. Private perspective conclusion

The use of the Wartsila 6L20DF in combination with the Wartsila 14V46DF was the design alternative with the highest BCR of the technically feasible alternatives, and also the Wartsila 6L20DF in combination with the Hitachi-MAN B&W 6S70ME-C8.2 was the design alternative with the highest BCR of the non-technically feasible alternatives. Which means, that no matter the M/E installed the Wartsila 6L20DF operating in gas mode outperforms from a private perspective the other electric energy supply alternatives. The second best A/E with both M/E is the Volvo Penta D16 MG, and the third best is the Anglo Belgian Corporation 6 DZD.

On the other hand, from the non-technically feasible design alternatives, the top BCR ranking is occupied by LNG as hydrogen carrier, it is in the 6th position where the first hydrogen carrier different than LNG appears, LNH3 in combination with the Volvo Penta D16 MG.

The top six BCR and technically feasible design alternatives (e.g. with Wartsila 14V46DF) and the top six BCR and non-technically feasible design alternatives (e.g. with Hitachi-MAN B&W 6S70ME-C8.2) with their differences in NPV after 20 years, payback period, IRR, BCR and cost per tonne-mile can be seen in Table 6.10. In this table, it can be seen that all the designs with a CCS have a higher Cost per tonne-mile than their homologues without CCS. This occurs because the extra power demand required for the systems that capture and liquefy the captured CO2 increases this parameter.

Design	NPV	Payback period	IRR	BCR	Cost per tonne-mile
Current design of the Mineral Yarden	$46,754,838	8 years	9.91%	1.117	0.000637$/t-mile
Wartsila 14V46DF & 6L20DF	$35,336,104	10 years	7.10%	0.772	0.000700$/t-mile
Wartsila 14V46DF & 6L20DF & CCS	$37,148,854	10 years	6.73%	0.725	0.000728$/t-mile
Wartsila 14V46DF & D16 MG	$31,491,321	11 years	6.33%	0.681	0.000723$/t-mile
Wartsila 14V46DF & D16 MG & CCS	$31,071,393	11 years	5.66%	0.601	0.000765$/t-mile
Wartsila 14V46DF & 6 DZD	$31,365,513	11 years	6.26%	0.673	0.000723$/t-mile
Wartsila 14V46DF & 6 DZD & CCS	$31,082,183	11 years	5.63%	0.597	0.000764$/t-mile
6S70ME-C8.2 & 6L20DF & LNG	$48,035,950	8 years	10.09%	1.138	0.000628$/t-mile
6S70ME-C8.2 & 6L20DF & LNG+CCS	$47,484,303	8 years	9.78%	1.099	0.000633$/t-mile
6S70ME-C8.2 & D16 MG & LNG	$44,770,240	9 years	9.37%	1.049	0.000648$/t-mile
6S70ME-C8.2 & D16 MG & LNG+CCS	$43,987,320	9 years	9.04%	1.007	0.000653$/t-mile
6S70ME-C8.2 & 6 DZD & LNG	$44,627,565	9 years	9.28%	1.037	0.000648$/t-mile
6S70ME-C8.2 & D16 MG & LNH3	$42,418,934	9 years	9.00%	1.004	0.000663$/t-mile

Table 6.10: Economic indicators of the design alternatives with the highest BCR from a private perspective.

6.2. CBA welfare or societal perspective

The approach followed in the CBA from a welfare perspective includes the CO2 emitted as an externality, so its cost represents the price to the population welfare. There are more emissions that could have been considered as externalities, such as, NOx or SOx. But they have not been included in this project because it is not straightforward to quantify these emissions in each design. Then, the only difference between the economic analysis from a private perspective and the CBA from a welfare perspective is the price per tonne of CO2 emitted, which is higher in the welfare perspective.

The CBA from a welfare perspective helps to decide among the different design alternatives from the point of view of the welfare of the population, and in this perspective, the cost per tonne of CO2 emitted is assumed to be 115.50$/T, as explained in subsection 4.4.5.

The alternatives studied in the private perspective will now be analysed from a welfare perspective.

Firstly, to have a reference of how the current design of the Mineral Yarden would perform under the same conditions than the case study, Table 6.11 shows its CBA and other indicators.

Year	**0**	**1**	**2**	**...**	**19**	**20**
BENEFITS						
Operational income		12,130,094	12,130,094	...	12,130,094	12,130,094
Scratch value				...		6,200,000
COSTS						
Capital investment	41,875,000			...		
M/E fuel		4,855,960	4,855,960	...	4,855,960	4,855,960
A/E fuel		472,784	472,784	...	472,784	472,784
CO2 emission		4,687,204	4,687,204	...	4,687,204	4,687,204
BENEFIT-COST	-41,875,000	2,114,145	2,114,145	...	2,114,145	8,314,145
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-41,875,000	2,026,985	1,943,418	...	950,021	3,582,048
NPV till that year	-41,875,000	-39,848,015	-37,904,597	...	-14,802,328	-11,220,279
Payback period	+20 years					
IRR	-2.89%					
BCR	-0.268					
Cost per tonne-mile	0.000998					

Table 6.11: CBA and indicators that the current design of the Mineral Yarden (A/E: DAIHATSU 6DE-18) would have from a societal perspective

From a societal perspective, Table 6.11 shows that the current design on the Mineral Yarden has a NPV after 20 years of -$11,220,279, a payback period of more than 20 years, an IRR of -2.89%, a BCR of -0.268, which means that per each dollar invested 0.268 dollars are lost over the lifetime of the project, and a cost per tonne-mile of $0.000998. These results reveal that the impact of the CO2 emission cost increase is too high to be overcome by the current design of the Mineral Yarden.
Also, these results compared with the results of the current design of the Mineral Yarden from a private perspective seen in Table 6.1 are the following:

- NPV after 20 years decreases from $46,754,838 to -$11,220,279.
- Payback period increases from 8 years to more than 20 years.
- IRR decreases from 9.91% to -2.89%.
- BCR decreases from 1.117 to -0.268.
- Cost per tonne mile decreases from $0.000637 to $0.000998.

Then, the remaining design alternatives were studied and none of them had a BCR higher than one. However, some of the designs had better BCR than the current design of the Mineral Yarden.

6.2.1. Technically feasible design alternatives

From all technically feasible design alternatives, the design alternative with the highest BCR from a welfare perspective is the combination with the Wartsila 14V46DF, the Wartsila 6L20DF and with CCS. Its CBA and other indicators are shown in Table 6.12.

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,071,859	12,071,859	...	12,071,859	12,071,859
CO2 sales		627,522	627,522	...	627,522	627,522
Scratch value				...		6,200,000
COSTS						
Capital investment	51,211,112			...		
M/E fuel		5,581,451	5,581,451	...	5,581,451	5,581,451
A/E fuel		611,880	611,880	...	611,880	611,880
CO2 emission		492,705	492,705	...	492,705	492,705
BENEFIT-COST	-51,211,112	6,013,344	6,013,344	...	6,013,344	12,213,344
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-51,211,112	5,765,430	5,527,737	...	2,702,179	5,261,970
NPV till that year	-51,211,112	-45,445,682	-39,917,944	...	25,792,709	31,054,679
Payback period	11 years					
IRR	5.71%					
BCR	0.606					
Cost per tonne-mile	0.000766					

Table 6.12: CBA from a societal perspective of the design with Wartsila 14V46DF, Wartsila 6L20DF and with CCS.

In Table 6.12 it can be seen that after 20 years the NPV is $31,054,679, the payback period is 11 years, the IRR is 5.71%, the BCR is 0.606, which means that per each dollar invested only 0.606 dollars are recovered over the lifetime of the project, and the cost per tonne-mile is $0.000766. These results compared with the results of Table 6.11 are the following:

- NPV after 20 years increases from $-11,220,279 to $31,054,679.
- The current design of the Mineral Yarden was not paid back in 20 years, while this design is paid back in 11 years.
- IRR increases from -2.89% to 5.71%.
- BCR increases from -0.268 to 0.606.
- Cost per tonne mile decreases from $0.000998 to $0.000766.

Additionally, it will also be presented the CBA of the same design (Wartsila 14V46DF & Wartsila 6L20DF) but without CCS, which is the 4th highest BCR. This information could be interesting to decide if a subsidy to the design with CCS could improve the population welfare. Then, the CBA and other indicators of the design without CCS are shown in Table 6.13.
In Table 6.13 it can be seen that after 20 years the NPV is -$13,432,616, the payback period is more than 20 years, the IRR is -3.21%, the BCR is -0.294, which means that per each dollar invested 0.294 dollars are lost over the lifetime of the project, and the cost per tonne-mile is $0.001003. These results compared with the results of Table 6.11 are the following:

- NPV after 20 years decreases from -$11,220,279 to -$13,432,616.
- The payback period is more than 20 years in both cases.
- IRR increases from -2.89% to -3.21%.
- BCR increases from -0.268 to -0.294.
- Cost per tonne mile decreases from $0.000998 to $0.001003.

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,114,657	12,114,657	...	12,114,657	12,114,657
Scratch value				...		6,200,000
COSTS						
Capital investment	45,752,788			...		
M/E fuel		5,581,451	5,581,451	...	5,581,451	5,581,451
A/E fuel		350,355	350,355	...	350,355	350,355
CO2 emission		3,942,880	3,942,880	...	3,942,880	3,942,880
BENEFIT-COST	-45,752,788	2,239,970	2,239,970	...	2,239,970	8,439,970
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-45,752,788	2,147,622	2,059,081	...	1,006,561	3,636,258
NPV till that year	-45,752,788	-43,605,166	-41,546,084	...	-17,068,875	-13,432,616
Payback period	+20 years					
IRR	-3.21%					
BCR	-0.294					
Cost per tonne-mile	0.001003					

Table 6.13: CBA from a societal perspective of the design with Wartsila 14V46DF, Wartsila 6L20DF and without CCS.

Secondly, the design alternative with the second highest BCR from a societal perspective is the combination with the Wartsila 14V46DF, the Volvo Penta D16 MG and with CCS. Its CBA and other indicators are shown in Table 6.14.

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,069,774	12,069,774	...	12,069,774	12,069,774
CO2 sales		624,219	624,219	...	624,219	624,219
Scratch value				...		6,200,000
COSTS						
Capital investment	51,700,949			...		
M/E fuel		5,581,451	5,581,451	...	5,581,451	5,581,451
A/E fuel		1,018,934	1,018,934	...	1,018,934	1,018,934
CO2 emission		640,737	640,737	...	640,737	640,737
BENEFIT-COST	-51,700,949	5,452,871	5,452,871	...	5,452,871	11,652,871
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-51,700,949	5,228,064	5,012,525	...	2,450,323	5,020,498
NPV till that year	-51,700,949	-46,472,885	-41,460,359	...	18,125,743	23,146,241
Payback period	13 years					
IRR	4.30%					
BCR	0.448					
Cost per tonne-mile	0.000814					

Table 6.14: CBA from a societal perspective of the design with Wartsila 14V46DF, Volvo Penta D16 MG and with CCS.

In Table 6.14 it can be seen that after 20 years the NPV is $23,146,241, the payback period is 13 years, the IRR is 4.30%, the BCR is 0.448, which means that per each dollar invested only 0.448 dollars are recovered over the lifetime of the project, and the cost per tonne-mile is $0.000814. These results compared with the results of Table 6.11 are the following:

- NPV after 20 years increases from $-11,220,279 to $23,146,241.
- The current design of the Mineral Yarden was not paid back in 20 years, while this design is paid back in 13 years.
- IRR increases from -2.89% to 4.30%.

- BCR increases from -0.268 to 0.448.
- Cost per tonne mile decreases from $0.000998 to $0.000814.

Finally, the design alternative with the third highest BCR from a societal perspective is the combination with the Wartsila 14V46DF, the Anglo Belgian Corporation 6 DZD and with CCS. Its CBA and other indicators are shown in Table 6.15.

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,068,741	12,068,741	...	12,068,741	12,068,741
CO2 sales		622,471	622,471	...	622,471	622,471
Scratch value				...		6,200,000
COSTS						
Capital investment	52,050,949			...		
M/E fuel		5,581,451	5,581,451	...	5,581,451	5,581,451
A/E fuel		989,256	989,256	...	989,256	989,256
CO2 emission		635,234	635,234	...	635,234	635,234
BENEFIT-COST	-52,050,949	5,485,271	5,485,271	...	5,485,271	11,685,271
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-52,050,949	5,259,129	5,042,309	...	2,464,883	5,034,457
NPV till that year	-52,050,949	-46,791,820	-41,749,511	...	18,190,645	23,225,102
Payback period	13 years					
IRR	4.29%					
BCR	0.446					
Cost per tonne-mile	0.000813					

Table 6.15: CBA from a societal perspective of the design with Wartsila 14V46DF, Anglo Belgian Corporation 6 DZD and with CCS.

In Table 6.15 it can be seen that after 20 years the NPV is $23,225,102, the payback period is 13 years, the IRR is 4.29%, the BCR is 0.446, which means that per each dollar invested only 0.446 dollars are recovered over the lifetime of the project, and the cost per tonne-mile is $0.000813. These results compared with the results of Table 6.11 are the following:

- NPV after 20 years increases from $-11,220,279 to $23,225,102.
- The current design on the Mineral Yarden was not paid back in 20 years, while this design is paid back in 13 years.
- IRR increases from -2.89% to 4.29%.
- BCR increases from -0.268 to 0.446.
- Cost per tonne mile decreases from $0.000998 to $0.000813.

6.2.2. Non-technically feasible design alternatives

From all non-technically feasible design alternatives, the design alternative with the highest BCR from a welfare perspective is the combination with the Hitachi-MAN B&W 6S70ME-C8.2, the Wartsila 6L20DF and with CCS, and the second highest BCR is the same design but without CCS. Then, only the design with CCS will be presented in detail. The CBA and other indicators of the design with the CCS are shown in Table 6.16.
In Table 6.16 it can be seen that after 20 years the NPV is -$6,832,880, the payback period is more than 20 years, the IRR is -1.67%, the BCR is -0.158, which means that per each dollar invested 0.158 dollars are lost over the lifetime of the project, and the cost per tonne-mile is $0.000971. These results compared with the results of Table 6.11 are the following:

- NPV after 20 years increases from -$11,220,279 to -$6,832,880.
- Both designs are not paid back in 20 years.
- IRR increases from -2.89% to -1.67%.

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,123,297	12,123,297	...	12,123,297	12,123,297
CO2 sales		38,033	38,033	...	38,033	38,033
Scratch value				...		6,200,000
COSTS						
Capital investment	43,208,106			...		
M/E fuel		4,855,960	4,855,960	...	4,855,960	4,855,960
A/E fuel		367,577	367,577	...	367,577	367,577
CO2 emission		4,391,466	4,391,466	...	4,391,466	4,391,466
BENEFIT-COST	-43,208,106	2,546,328	2,546,328	...	2,546,328	8,746,328
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-43,208,106	2,441,350	2,340,700	...	1,144,228	3,768,249
NPV till that year	-43,208,106	-40,766,757	-38,426,057	...	-10,601,129	-6,832,880
Payback period	+20 years					
IRR	-1.67%					
BCR	-0.158					
Cost per tonne-mile	0.000971					

Table 6.16: CBA from a societal perspective of the design with Hitachi-MAN B&W 6S70ME-C8.2, Wartsila 6L20DF and with CCS.

- BCR increases from -0.268 to -0.158.
- Cost per tonne mile decreases from \$0.000998 to \$0.000971.

Secondly, the design alternative with the third highest BCR from a societal perspective is the combination with the Hitachi-MAN B&W 6S70ME-C8.2, the Volvo Penta D16 MG and with CCS. The CBA and other indicators are shown in Table 6.17.

Year	0	1	2	...	19	20
BENEFITS						
Operational income		12,116,917	12,116,917	...	12,116,917	12,116,917
CO2 sales		36,859	36,859	...	36,859	36,859
Scratch value				...		6,200,000
COSTS						
Capital investment	43,697,944			...		
M/E fuel		4,855,960	4,855,960	...	4,855,960	4,855,960
A/E fuel		581,356	581,356	...	581,356	581,356
CO2 emission		4,480,792	4,480,792	...	4,480,792	4,480,792
BENEFIT-COST	-43,697,943	2,235,667	2,235,667	...	2,235,667	8,435,667
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-43,697,943	2,143,496	2,055,126	...	1,004,628	3,634,404
NPV till that year	-43,697,943	-41,554,447	-39,499,321	...	-15,069,131	-11,434,726
Payback period	+20 years					
IRR	-2.83%					
BCR	-0.262					
Cost per tonne-mile	0.000999					

Table 6.17: CBA from a societal perspective of the design with Hitachi-MAN B&W 6S70ME-C8.2, Volvo Penta D16 MG and with CCS.

In Table 6.17 it can be seen that after 20 years the NPV is -\$11,434,726, the payback period is more than 20 years, the IRR is -2.83%, the BCR is -0.262, which means that per each dollar invested 0.262 dollars are lost over the lifetime of the project and the cost per tonne-mile is \$0.000999. These results compared with the results of Table 6.11 are the following:

- NPV after 20 years decreases from -\$11,220,279 to -\$11,434,726.

- Both designs are not paid back in 20 years.
- IRR increases from -2.89% to -2.83%.
- BCR increases from -0.268 to -0.262.
- Cost per tonne mile increases from \$0.000998 to \$0.000999.

Finally, the design alternative with the fourth highest BCR from a societal perspective is the combination with the Hitachi-MAN B&W 6S70ME-C8.2, the Anglo Belgian Corporation 6 DZD and with CCS. Its CBA and other indicators are shown in Table 6.18.

Year	**0**	**1**	**2**	**...**	**19**	**20**
BENEFITS						
Operational income		12,115,884	12,115,884	...	12,115,884	12,115,884
CO2 sales		35,785	35,785	...	35,785	35,785
Scratch value				...		6,200,000
COSTS						
Capital investment	44,047,944			...		
M/E fuel		4,855,960	4,855,960	...	4,855,960	4,855,960
A/E fuel		564,424	564,424	...	564,424	564,424
CO2 emission		4,477,474	4,477,474	...	4,477,474	4,477,474
BENEFIT-COST	-44,047,943	2,253,811	2,253,811	...	2,253,811	8,453,811
Discount factor	1	1.043	1.0878	...	2.2254	2.3211
Discounted annual B-C	-44,047,943	2,160,892	2,071,805	...	1,012,781	3,642,221
NPV till that year	-44,047,943	-41,887,051	-39,815,246	...	-15,186,789	-11,544,568
Payback period	+20 years					
IRR	-2.83%					
BCR	-0.262					
Cost per tonne-mile	0.000999					

Table 6.18: CBA from a societal perspective of the design with Hitachi-MAN B&W 6S70ME-C8.2, Anglo Belgian Corporation 6 DZD and with CCS.

In Table 6.18 it can be seen that after 20 years the NPV is -\$11,544,568, the payback period is more than 20 years, the IRR is -2.83%, the BCR is -0.262, which means that per each dollar invested 0.262 dollars are lost over the lifetime of the project and the cost per tonne-mile is \$0.000999. These results compared with the results of Table 6.11 are the following:

- NPV after 20 years decreases from -\$11,220,279 to -\$11,544,568.
- Both designs are not paid back in 20 years.
- IRR increases from -2.89% to -2.83%.
- BCR increases from -0.268 to -0.262.
- Cost per tonne mile increases from \$0.000998 to \$0.000999.

6.2.3. Welfare perspective conclusion

With this perspective, the designs with carbon capture systems start to perform economically better than the same designs without carbon capture systems. The reason to that is that the high capital investment required for the big-size CCS required to capture 90% of the carbon dioxide emitted by the Wartsila 14V46DF starts to pay off when the price per tonne of CO2 emitted is high, as occurs in the welfare perspective.

The top six BCR and technically feasible design alternatives (e.g. with Wartsila 14V46DF) and the top six BCR and non-technically feasible design alternatives (e.g. with Hitachi-MAN B&W 6S70ME-C8.2) with their differences in NPV after 20 years, payback period, IRR, BCR and cost per tonne-mile can be seen in Table 6.19.

Design	NPV	Payback period	IRR	BCR	Cost per tonne-mile
Current design of the Mineral Yarden	-$11,220,279	+20 years	-2.89%	-0.268	0.000998$/t-mile
Wartsila 14V46DF & 6L20DF	-$13,432,616	+20 years	-3.21%	-0.294	0.001003$/t-mile
Wartsila 14V46DF & 6L20DF & CCS	$31,054,679	11 years	5.71%	0.606	0.000766$/t-mile
Wartsila 14V46DF & D16 MG	-$18,275,350	+20 years	-4.45%	-0.395	0.001033$/t-mile
Wartsila 14V46DF & D16 MG & CCS	$23,146,241	13 years	4.30%	0.448	0.000814$/t-mile
Wartsila 14V46DF & 6 DZD	-$18,288,231	+20 years	-4.42%	-0.393	0.001032$/t-mile
Wartsila 14V46DF & 6 DZD & CCS	$23,225,102	13 years	4.29%	0.446	0.000813$/t-mile
6S70ME-C8.2 & 6L20DF & LNG	-$8,856,406	+20 years	-2.23%	-0.210	0.000983$/t-mile
6S70ME-C8.2 & 6L20DF & LNG+CCS	-$6,832,880	+20 years	-1.67%	-0.158	0.000971$/t-mile
6S70ME-C8.2 & D16 MG & LNG+CCS	-$11,434,726	+20 years	-2.83%	-0.262	0.000999$/t-mile
6S70ME-C8.2 & 6 DZD & LNG	-$12,903,750	+20 years	-3.27%	-0.300	0.001006$/t-mile
6S70ME-C8.2 & 6 DZD & LNG+CCS	-$11,544,568	+20 years	-2.83%	-0.262	0.000999$/t-mile
6S70ME-C8.2 & 6 DZD & LNH3	-$12,835,873	+20 years	-3.28%	-0.301	0.001007$/t-mile

Table 6.19: Economic indicators of the design alternatives with the top six highest BCR (technically and non-technically feasible designs) from a welfare perspective.

In Table 6.19, all the designs with a CCS have a lower cost per tonne-mile than their homologues without CCS, the opposite phenomena than in the private perspective. This occurs because the CCS is able to reduce 90% of the CO2 emissions, so even though, this systems require a higher capital investment and a higher electric power demand to operate, the high CO2 emission cost of the designs without CCS makes it better. The high CO2 emission cost in the design without CCS is produced by the increase in the cost per tonne of CO2 emitted of this perspective.

The use of the Wartsila 6L20DF in combination with the Wartsila 14V46DF and CCS is the design alternative with the highest BCR of the technically feasible alternatives, and also the Wartsila 6L20DF in combination with the Hitachi-MAN B&W 6S70ME-C8.2 and CCS was the design alternative with the highest BCR of the non-technically feasible alternatives. Which means, that no matter the M/E installed the Wartsila 6L20DF operating in gas mode outperforms also from a welfare perspective the other energy supply alternatives.
When CCSs are included the Volvo Penta D16 MG slightly outperforms Anglo Belgian Corporation 6 DZD. However, in this perspective, when CCSs are not included, the Anglo Belgian Corporation 6 DZD outperforms the Volvo Penta D16 MG.

6.2.4. NPV private vs welfare perpective

Now, the NPV of the different technically feasible alternatives will be compared with both perspectives. This can be seen in Table 6.20.
The major highlight of Table 6.20 is the fact that in terms of NPV all designs with CCS outperform their homologue without CCS, especially there is a huge difference in the Welfare perspective, which could be an indication that a subsidy could make sense in this project.

6.2.5. Subsidy

A subsidy is interesting for CMB because it allows the new design to reduce the emissions but at the same time remain competitive in the market. For a government, give a subsidy to a project like this makes sense if the population welfare will benefit from it. However, there are many factors that influence the decision of a government, since the amount of money destinated to subsidies is limited and only the projects which a higher impact are chosen. The characteritics of this project, makes it diffucult to ask for a subsidy, since the ship is sailing most of the time in international waters. The probability to receive a subsidy by a government is higher when the ship is intended to operate in the national waters of a country. In consequence, in this case study, the highest probability that a subsidy is given would require an agreement between Australia and China, the supplier and recipient countries.

The requirement of a subsidy will be studied for the two designs with the two highest BCR from a private perspective. They are the design combinations with the Wartsila 14V46DF, the Wartsila 6L20DF and with/with-

Design alternative	Private perspective	Welfare perspective
Current design Mineral Yarden [$]	46,754,839	-11,220,279
Wartsila 14V46DF & Volvo Penta D16 MG [$]	31,491,321	-18,275,350
Wartsila 14V46DF & Volvo Penta D16 MG & CCS [$]	31,071,393	23,146,241
Wartsila 14V46DF & ABC 6DZD [$]	31,365,513	-18,288,231
Wartsila 14V46DF & ABC 6DZD & CCS [$]	31,082,183	23,225,102
Wartsila 14V46DF & Wartsila 6L20DF [$]	35,336,104	-13,432,616
Wartsila 14V46DF & Wartsila 6L20DF & CCS [$]	37,148,854	31,054,679
Wartsila 14V46DF & Ballard Power HD100 [$]	17,939,599	-30,998,176
Wartsila 14V46DF & Ballard Power HD100 & CCS [$]	18,473,343	12,364,575
Wartsila 14V46DF & Hydrogenics HD180 [$]	14,228,524	-34,709,251
Wartsila 14V46DF & Hydrogenics HD180 & CCS [$]	14,762,268	8,653,500
Wartsila 14V46DF & Bloom Energy ES5-YA8AAA [$]	11,959,227	-36,286,160
Wartsila 14V46DF & Bloom Energy ES5-YA8AAA & CCS [$]	12,912,659	6,912,480
Wartsila 14V46DF & Fuel Cell Energy SureSource 1500 [$]	16,253,908	-31,558,762
Wartsila 14V46DF & Fuel Cell Energy SureSource 1500 & CCS [$]	16,620,233	10,695,758

Table 6.20: NPV after 20 years of the different technically feasible designs under the two perspectives.

out CCS. Their economic indicators from a private perspective were presented in Table 6.2 and Table 6.3, and from a welfare perspective were presented in Table 6.12 and Table 6.13. Now, they are presented together in Table 6.21.

Parameter	Private w/o CCS	Private w/ CCS	Welfare wo/ CCS	Welfare w/ CCS
NPV	$35,336,104	$37,148,854	-$13,432,616	$31,054,679
Payback period	10 years	10 years	+20 years	11 years
IRR	7.10%	6.73%	-3.21%	5.71%
BCR	0.772	0.725	-0.294	0.606
Cost[$] per tonne mile	0.000700	0.000728	0.001003	0.000766

Table 6.21: Economic indicators of the design combinations with the Wartsila 14V46DF and the Wartsila 6L20DF from both perspectives.

Then, some conclusion can be extracted from Table 6.21:

- In terms of NPV, a subsidy is not required to make competitive the design with CCS in the private perspective, since its NPV after 20 years of operation is higher than the design without CCS.
- In terms of payback period, a subsidy is not required because they have the same payback period in the private perspective.
- In terms of IRR, a subsidy of $1,260,000 is required so that the design with CCS has an IRR of 7.10% in the private perspective. In the welfare perspective, the IRR of the design with CCS is much higher, then also the subsidy could have a positive impact.
- In terms of BCR, the design with CCS will require a subsidy of approximately $1,350,000 to have a BCR of 0.772 in the private perspective. In the welfare perspective, the design without CCS losses 0.294 dollars per each dollar invested while the design with CCS recovers 0.606 per each dollar invested. Then, supporting the design with CCS would reduce the cost to the population welfare.
- The cost per tonne-mile of the design with CCS is higher than the design without CCS in the private perspective because of the higher A/E consumption due to the higher electric power demanded by the CCS and the relatively low price per CO2 tonne emitted. On the other hand, in the welfare perspective, the relatively high price of the price per CO2 tonne emitted makes the cost per tonne-mile of the design with CCS lower. Then, to have a cost per tonne-mile of $0.000700 the design with CCS would require a subsidy of $6.600.000. This quantity is relatively high compared with the above mentioned because the initial subsidy has to compensate the fact that this design has a higher electric power demand, and in consequence A/E consummption cost, over the whole lifetime of the project.

6.3. Sensitivity analysis

The sensitivity analysis is the tool used to show how the cost estimations affect the economic feasibility of the technical feasible designs, and also to reach more conclusions about all alternative fuels and energy converters.

Now, to determine in what range should the sensitivity analysis be studied, it is pointed out that some system prices were estimated using the 6/10th Rule [46], which means that the accuracy of the order of magnitude estimation of these systems should be in the range -40% to +40%. That is why in the two types of sensitivity analysis that will be carried out (e.g. scenario based and price), -40% to +40% will be the range of study.

6.3.1. Scenario based

To carry out the scenario based sensitivity analysis the scenarios need to be described. There are three major scenarios that will be used as best case scenario, normal scenario and worst case scenario. First, the pro-zero emission scenario (-40 % change on parameters that contribute to the adoption of cleaner alternatives), second, the as-is scenario (parameters do not change from the values considered in section 6.1 and section 6.2), and third, the pro-hydrocarbon scenario (+40 % change on parameters that contribute to the adoption of cleaner alternatives). Table 6.22 shows the characteristics of each scenario.
Note that LNG, MeOH or LNH3 are considered hydrogen carriers, so a -40% cost reduction of any of them is integrated in the pro-zero emission scenario.

The NPV results from a private perspective of the alternative designs under the three scenarios described above are presented in Table 6.23. This table shows the NPV after 20 years of the different storage and alternative fuel technologies.

Parameter Scenario	Pro-zero emission	As-is	Pro-hydrocarbon
HFO price [$/kg]	0.560	0.400	0.240
LSMGO price [$/kg]	0.7651	0.5465	0.3279
Hydrogen price [$/kg]	1.800	3.000	4.200
LNG price [$/kg]	0.287	0.478	0.669
Methanol price [$/kg]	0.276	0.460	0.644
Ammonia price [$/kg]	0.168	0.280	0.392
LOHC price [$/kg]	1.500	2.500	3.500
CO2 emission [$/tonne]	10.598	7.570	4.542
CO2 sales [$/tonne]	25.000	20.000	15.000
CCS for LNG reforming/FCs [$]	548,986	914,977	1,280,968
CCS for M/E and LNG reforming/FCs [$]	2,977,051	4,961,751	6,946,451
CCS for MeOH reforming [$]	603,885	1,006,475	1,409,065
CO2 tank for CCS (reforming/FCs) [$]	55,656	92,760	129,864
CO2 tank for CCS (M/E + reforming/FCs) [$]	297,944	496,573	695,202
Hitachi-MAN B&W 6S70ME-C8.2 [$]	9,000,000	15,000,000	21,000,000
Wartsila 14V46DF [$]	9,661,284	17,602,139	22,542,995
ICE D16 MG [$]	60,000	100,000	140,000
ICE 6 DZD [$]	330,000	550,000	770,000
ICE 6L20DF [$]	137,022	228,369	319,717
PEMFCs [$/kW]	1,320	2,200	3,080
SOFC ES5-YA8AAA [$/kW]	5,493.4	9,156	12,817.8
MCFCs [$/kW]	2,884.0	4,807	6,729.4
LH2 20ft tanktainer [$]	311,933	623,867	935,800
10-tube 250 bar 40ft container [$]	50,000	100,000	150,000
4-tube 350 bar 40ft container [$]	339,451	678,902	1,018,353
LNG 40ft tanktainer [$]	49,500	99,000	148,500
LNG (1,285.46T capacity) [$]	748,367	1,247,279	1,746,191
Methanol/LOHC 40ft tanktainer [$]	10,000	20,000	30,000
LNH3 40ft tanktainer [$]	11,000	22,000	33,000
LNG reformer [$]	310,924	518,206	725,489
Methanol reformer [$]	245,630	409,383	573,136
Ammonia cracker [$]	172,297	287,162	402,027
LOHC reformer [$]	48,000	80,000	112,000
Fuel cell refurbish [$/kW]	500	1,000	1,500
BOP annual maintenance [$/kW]	415	830	1,245

Table 6.22: Parameters of the three scenarios considered.

Design / Scenario	As-is	Pro-zero emission	Pro-hydrocarbon
Current Mineral Yarden design [$]	46,754,839	19,418,299 (-58,47%)	74,091,378 (58,47%)
6S70ME & D16 MG with 75% H2 (CH2 250bar) [$]	38,271,953	16,000,830 (-58,19%)	60,543,076 (58,19%)
6S70ME & D16 MG with 75% H2 (CH2 350bar) [$]	27,999,747	9,968,275 (-64,4%)	46,031,219 (64,4%)
6S70ME & D16 MG with 75% H2 (LH2) [$]	30,027,509	11,263,705 (-62,49%)	48,791,312 (62,49%)
6S70ME & D16 MG with 75% H2 (LNH3) [$]	42,418,934	18,402,679 (-56,62%)	66,435,189 (56,62%)
6S70ME & D16 MG with 75% H2 (LOHC) [$]	32,980,738	12,685,045 (-61,54%)	53,276,430 (61,54%)
6S70ME & D16 MG with 75% H2 (LNG) [$]	44,770,240	19,934,460 (-55,47%)	69,606,019 (55,47%)
6S70ME & D16 MG with 75% H2 (LNG+CCS) [$]	43,987,320	19,849,429 (-54,87%)	68,125,211 (54,87%)
6S70ME & D16 MG with 75% H2 (MeOH) [$]	42,006,595	18,289,246 (-56,46%)	65,723,943 (56,46%)
6S70ME & D16 MG with 75% H2 (MeOH+CCS) [$]	40,189,208	17,561,398 (-56,3%)	62,817,017 (56,3%)
6S70ME & 6 DZD with 75% H2 (CH2 250bar) [$]	38,259,428	16,168,472 (-57,74%)	60,350,384 (57,74%)
6S70ME & 6 DZD with 75% H2 (CH2 350bar) [$]	27,987,222	10,135,917 (-63,78%)	45,838,527 (63,78%)
6S70ME & 6 DZD with 75% H2 (LH2) [$]	30,101,140	11,483,041 (-61,85%)	48,719,239 (61,85%)
6S70ME & 6 DZD with 75% H2 (LNH3) [$]	42,356,424	18,548,740 (-56,21%)	66,164,108 (56,21%)
6S70ME & 6 DZD with 75% H2 (LOHC) [$]	33,174,138	12,983,669 (-60,86%)	53,364,607 (60,86%)
6S70ME & 6 DZD with 75% H2 (LNG) [$]	44,627,565	20,029,353 (-55,12%)	69,225,778 (55,12%)
6S70ME & 6 DZD with 75% H2 (LNG+CCS) [$]	43,836,442	19,927,532 (-54,54%)	67,745,352 (54,54%)
6S70ME & 6 DZD with 75% H2 (MeOH) [$]	41,953,454	18,437,068 (-56,05%)	65,469,840 (56,05%)
6S70ME & 6 DZD with 75% H2 (MeOH+CCS) [$]	40,156,147	17,710,372 (-55,9%)	62,601,921 (55,9%)
6S70ME & 6L20DF with LNG & pilot fuel [$]	48,035,950	22,793,572 (-52,55%)	73,278,328 (52,55%)
6S70ME & 6L20DF with LNG+CCS & pilot fuel [$]	47,484,303	22,934,234 (-51,7%)	72,034,371 (51,7%)
6S70ME & HD100 with 100% H2 (CH2 250bar) [$]	24,249,091	8,457,102 (-65,12%)	40,041,080 (65,12%)
6S70ME & HD100 with 100% H2 (CH2 350bar) [$]	13,976,885	2,424,547 (-82,65%)	25,529,223 (82,65%)
6S70ME & HD100 with 100% H2 (LH2) [$]	15,728,368	3,554,209 (-77,4%)	27,902,526 (77,4%)
6S70ME & HD100 with 100% H2 (LNH3) [$]	29,331,419	11,708,892 (-60,08%)	46,953,946 (60,08%)
6S70ME & HD100 with 100% H2 (LOHC) [$]	18,966,074	5,401,208 (-71,52%)	32,530,940 (71,52%)
6S70ME & HD100 with 100% H2 (LNG) [$]	31,272,603	12,733,725 (-59,28%)	49,811,480 (59,28%)
6S70ME & HD100 with 100% H2 (LNG+CCS) [$]	30,612,854	12,801,046 (-58,18%)	48,424,662 (58,18%)
6S70ME & HD100 with 100% H2 (MeOH)[$]	28,150,036	10,845,749 (-61,47%)	45,454,322 (61,47%)
6S70ME & HD100 with 100% H2 (MeOH+CCS) [$]	26,516,359	10,366,526 (-60,91%)	42,666,191 (60,91%)
6S70ME & HD180 with 100% H2 (CH2 250bar) [$]	20,538,016	6,230,190 (-69,67%)	34,845,842 (69,67%)
6S70ME & HD180 with 100% H2 (CH2 350bar) [$]	10,265,810	197,635 (-98,07%)	20,333,985 (98,07%)
6S70ME & HD180 with 100% H2 (LH2) [$]	12,017,293	1,327,298 (-88,96%)	22,707,288 (88,96%)
6S70ME & HD180 with 100% H2 (LNH3) [$]	25,620,344	9,481,981 (-62,99%)	41,758,707 (62,99%)
6S70ME & HD180 with 100% H2 (LOHC) [$]	15,254,999	3,174,296 (-79,19%)	27,335,702 (79,19%)
6S70ME & HD180 with 100% H2 (LNG) [$]	27,561,528	10,506,813 (-61,88%)	44,616,242 (61,88%)
6S70ME & HD180 with 100% H2 (LNG+CCS) [$]	26,901,779	10,574,134 (-60,69%)	43,229,424 (60,69%)
6S70ME & HD180 with 100% H2 (MeOH) [$]	24,438,961	8,618,837 (-64,73%)	40,259,084 (64,73%)
6S70ME & HD180 with 100% H2 (MeOH+CCS) [$]	22,805,284	8,139,614 (-64,31%)	37,470,953 (64,31%)
6S70ME & ES5-YA8AAA with 100% LNG [$]	24,659,073	8,788,928 (-64,36%)	40,529,217 (64,36%)
6S70ME & ES5-YA8AAA with 100% LNG+CCS) [$]	23,867,574	8,678,279 (-63,64%)	39,056,869 (63,64%)
6S70ME & SureSource 1500 with 100% LNG [$]	28,953,753	11,384,082 (-60,68%)	46,523,424 (60,68%)
6S70ME & SureSource 1500 with 100% LNG+CCS [$]	28,028,835	11,122,301 (-60,32%)	44,935,369 (60,32%)
14V46DF & D16 MG with 75% H2 (LNG) [$]	31,491,321	62,582,781 (98,73%)	399,861 (-98,73%)
14V46DF & D16 MG with 75% H2 (LNG) & CCS [$]	31,071,393	69,335,034 (123,15%)	-7,192,247 (-123,15%)
14V46DF & 6 DZD with 75% H2 (LNG) [$]	31,365,513	62,688,208 (99,86%)	42,818 (-99,86%)
14V46DF & 6 DZD with 75% H2 (LNG) & CCS [$]	31,082,183	69,519,063 (123,66%)	-7,354,698 (-123,66%)
14V46DF & 6L20DF with LNG & pilot fuel [$]	35,336,104	65,803,558 (86,22%)	4,868,651 (-86,22%)
14V46DF & 6L20DF with LNG & pilot fuel & CCS [$]	37,148,854	74,457,060 (100,43%)	-159,353 (-100,43%)
14V46DF & HD100 with 100% H2 (LNG) [$]	17,939,599	55,348,267 (208,53%)	-19,469,069 (-208,53%)
14V46DF & HD100 with 100% H2 (LNG) & CCS [$]	18,473,343	63,263,834 (242,46%)	-26,317,149 (-242,46%)
14V46DF & HD180 with 100% H2 (LNG) [$]	14,228,524	53,121,355 (273,34%)	-24,664,307 (-273,34%)
14V46DF & HD180 with 100% H2 (LNG) & CCS [$]	14,762,268	61,036,923 (313,47%)	-31,512,387 (-313,47%)
14V46DF & ES5-YA8AAA with LNG [$]	11,959,227	51,798,914 (333,13%)	-27,880,460 (-333,13%)
14V46DF & ES5-YA8AAA with LNG & CCS [$]	12,912,659	59,815,823 (363,23%)	-33,990,506 (-363,23%)
14V46DF & SureSource 1500 with LNG [$]	16,253,908	54,394,068 (234,65%)	-21,886,253 (-234,65%)
14V46DF & SureSource 1500 with LNG & CCS [$]	16,620,233	61,956,616 (272,78%)	-28,716,149 (-272,78%)

Table 6.23: NPV after 20 years of the different technology combination and under the three scenarios.

Table 6.23 shows some interesting effects that will now be further explained. First of all, as it was expected, considering the As-is scenario as the reference value, in all design cases the percentage of change in the NPV after 20 years between the Pro-hydrocarbon and Pro-zero emission scenarios is quantitatively equal, but with opposite sign.
On the other hand, varying the range from -40% to +40% it has been seen how the NPV of some design cases are affected in a small percentage (e.g. 50-60%), which means that the NPV of these designs are under a low uncertainty, and the cost estimated could affect slightly the final NPV. By the contrary, the NPV after 20 years of operation of other designs which are affected with high percentages (e.g. +100%) are much less certain. Which means that some of the cost estimation done for these design could affect dramatically the final NPV of these designs.

Secondly, the highest NPV in the Pro-zero emission scenario is the alternative with the Wartsila 14V46DF, the Wartsila 6L20DF and with CCS. On the other hand, in the Pro-hydrocarbon scenario, the highest NPV is the current design of the Mineral Yarden, followed by the alternative with the Hitachi-MAN B&W 6S70ME-C8.2, the Wartsila 6L20DF and without CCS.

Finally, the design combination with/without CCS which was studied to be subsided in subsection 6.2.5 showed in Table 6.23 a relatively high percentage of change, 86,22% the alternative without CCS and 100,43% the alternative with CCS. Then, it can be said that the uncertainty in the calculation of the NPV of these design is rather high, but compared with the remaining technically feasible designs they are the lowest.

6.3.2. Price based

In this sensitivity analysis the effect on NPV after 20 years of varying individual prices of alternative fuels and technologies will be studied. The different price-effect of alternarnative fuels that will be studied are the following:

1. **HFO price:** to study this effect the A/E is kept constant (e.g. the Volvo Penta D16 MG) and the different storage alternatives with the Hitachi-MAN B&W 6S70ME-C8.2 are compared with the design with the highest NPV and technically feasible (e.g. Wartsila 14V46DF & 6L20DF with LNG & pilot fuel). The results of changing the price are shown in Figure 6.1. It can be seen that the HFO price affects drastically

Figure 6.1: HFO price study

the NPV after 20 years, and that the current design in the Mineral Yarden starts having worse NPV after 20 years than the Wartsila 14V46DF & 6L20DF combination at HFO prices higher than 470$/T.

2. **MGO price:** to study this effect the technically feasible designs alternatives (e.g. Wartsila 14V46DF) are compared with the current design in the Mineral Yarden in Figure 6.2. It can be seen that the MGO price

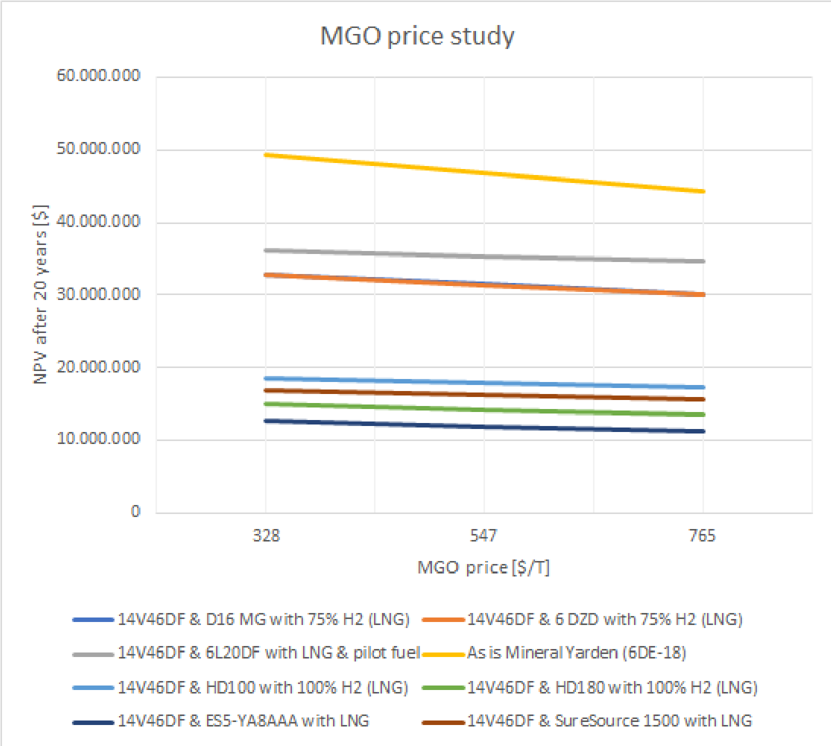

Figure 6.2: MGO price study

affects also the NPV after 20 years of the current design of the Mineral Yarden, and how its A/E operates 100% on this fuel the effect is higher than in the technically feasible designs.

3. **H2 price:** to study this effect the A/E is kept constant (e.g. the Volvo Penta D16 MG) and the different storage alternatives that require pure hydrogen are tested CH2 (250bar), CH2 (350bar), LH2 and LOHC. The results of changing the price are shown in Figure 6.3. It can be seen that the H2 price affects considerably the NPV after 20 years, but reducing its price 40% is not enough to make the design competitive with current design in the Mineral Yarden.

4. **LNG price:** to study this effect the technically feasible design alternative without CCS are included (e.g. with Wartsila 14V46DF). The results of changing the price are shown in Figure 6.4. It can be seen that the LNG price has a huge impact on the NPV after 20 years, and at a prices lower of approximately 405$/T of LNG some of the design alternatives start having a higher NPV after 20 years than the current design of the Mineral Yarden.

5. **MeOH price:** to study this effect the design alternatives with include MeOH as hydrogen carrier and without CCS are shown in Figure 6.5. It can be seen that the MeOH price affects considerably the NPV after 20 years, but reducing its price 40% is not enough to make the design competitive with current design of the Mineral Yarden.

6. **LNH3 price:** to study this effect the designs that use LNH3 as hydrogen carrier alternatives are shown in Figure 6.6. It can be seen that the LNH3 price affects considerably the NPV after 20 years, but even with low prices it can not compete with current design of the Mineral Yarden.

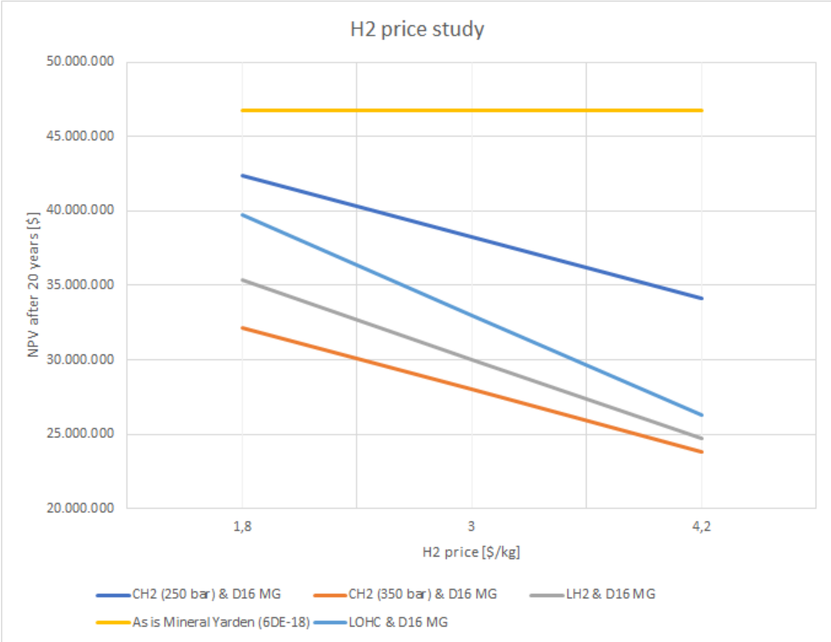

Figure 6.3: H2 price study

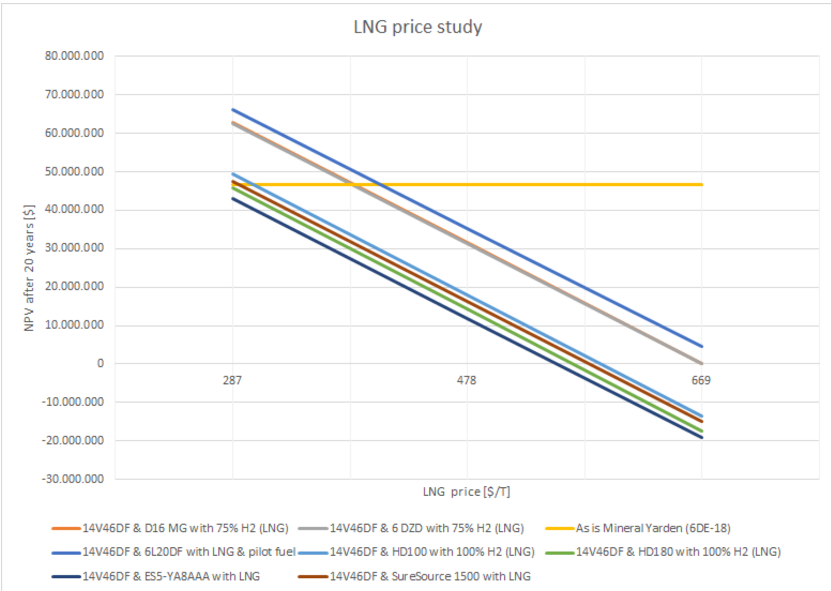

Figure 6.4: LNG price study

Now, the different price-effect of technologies that will be studied are the following:

1. **LOHC cost:** the LOHC is considered a storage technology to transport hydrogen and not a fuel, because it is a hydrogen carrier that can be reused (hydrogenated and dehydrogenated hundred of times). Thus, it is a capital expenditure considered in the initial investment. On the other hand, the operational expenditure of this technology depend on the hydrogen price, and that is why it was also considered in Figure 6.3. The alternatives that are affected by a change on the LOHC cost are shown in Figure 6.7.

   This hydrogen carrier technology even at low prices does not have the potential to be competitive with the current design of the Mineral Yarden. It would also require a hydrogen price reduction in combination with the LOHC capital investment reduction to have a chance to compete with current design of the Mineral Yarden.

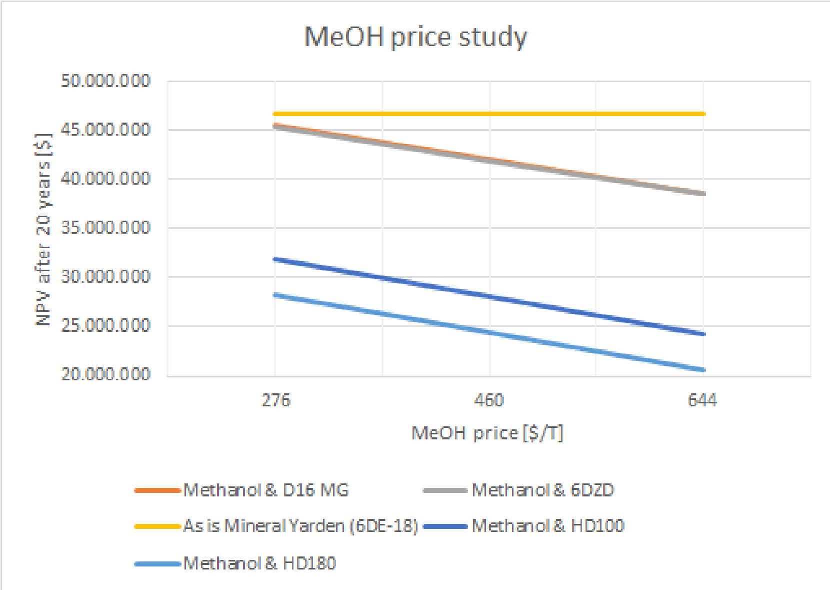

Figure 6.5: MeOH price study

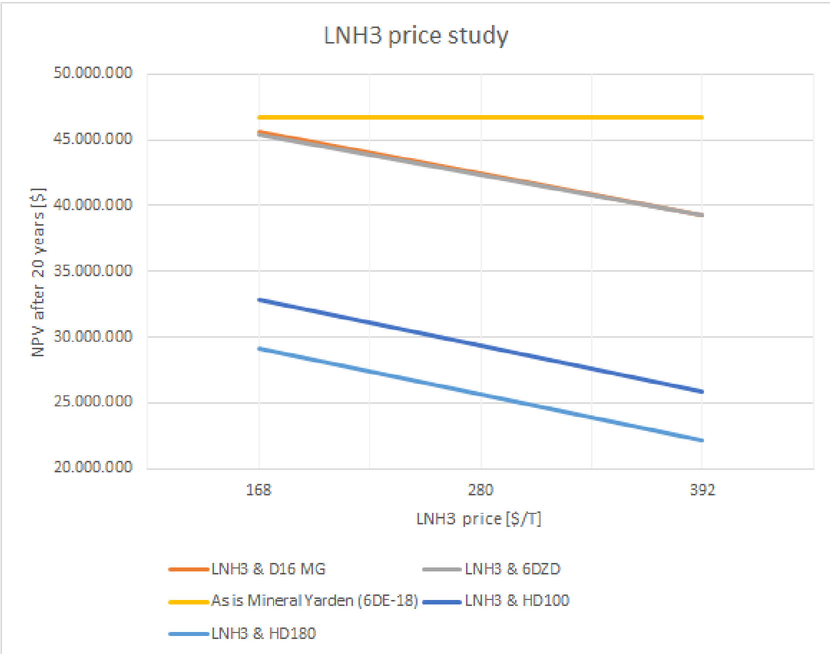

Figure 6.6: LNH3 price study

2. **CCS for LNG reformers or A/Es effect:** to study this effect the designs that include a CCS to capture the CO2 from LNG reformers, the Bloom Energy ES5-YA8AAA, the Fuel Cell Energy SureSource 1500 or the Wartsila 6L20DF are shown in Figure 6.8. It can be seen that the price of CCS for LNG reformers or A/Es marginally affects the NPV after 20 years, and even at 40% higher price the design with the Wartsila 6L20DF remains competitive with the current design of the Mineral Yarden.

3. **CCS for MeOH reformers effect:** to study this effect the designs that include a CCS to capture the CO2 from MeOH reformers are shown in Figure 6.9. It can be seen that the price of CCS for MeOH reformers slightly affects the NPV after 20 years and the alternatives can not compite with the current design of the Mineral Yarden.

4. **CCS for Wartsila 14V46DF and reformers or FCs effect:** to study this effect the designs that include a

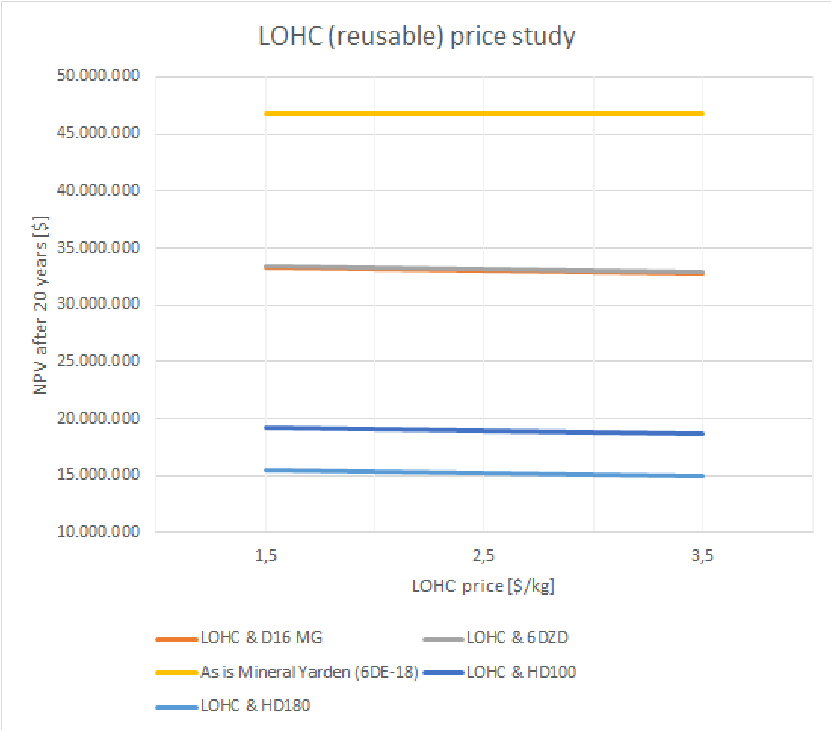

Figure 6.7: LOHC price study

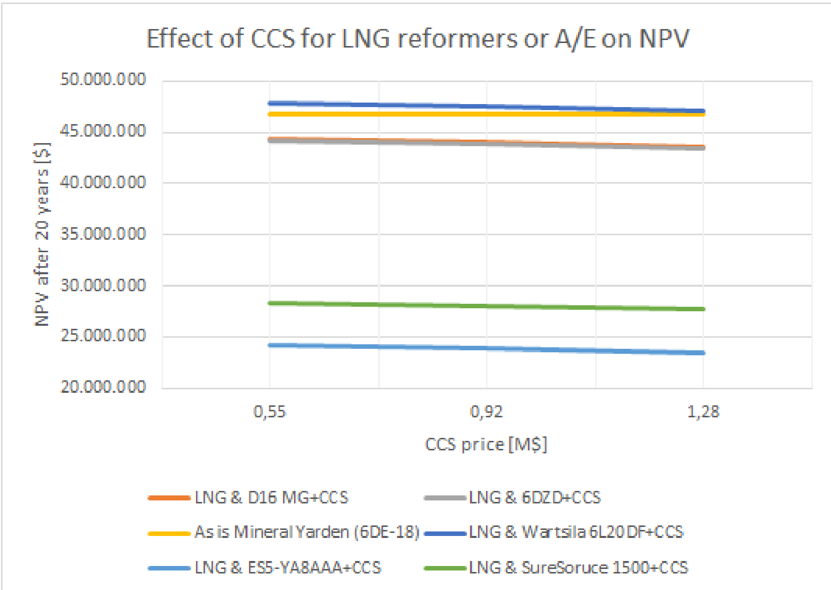

Figure 6.8: CCS for LNG reformers or A/Es price study

CCS to capture the CO2 from Wartsila 14V46DF and reformers or FCs are shown in Figure 6.10. It can be seen that the price of CCS for Wartsila 14V46DF and reformers or FCs significantly affects the NPV after 20 years, but even with a 40% price reduction any of the alternatives could compite with the current design of the Mineral Yarden.

5. **Wartsila 14V46DF effect:** to study this effect the designs that include this engine and without CCS are shown in Figure 6.11. It can be seen that the price of the Wartsila 14V46DF considerably affects the NPV after 20 years, but even with a 40% price reduction any of the alternatives could compite with the current design of the Mineral Yarden.

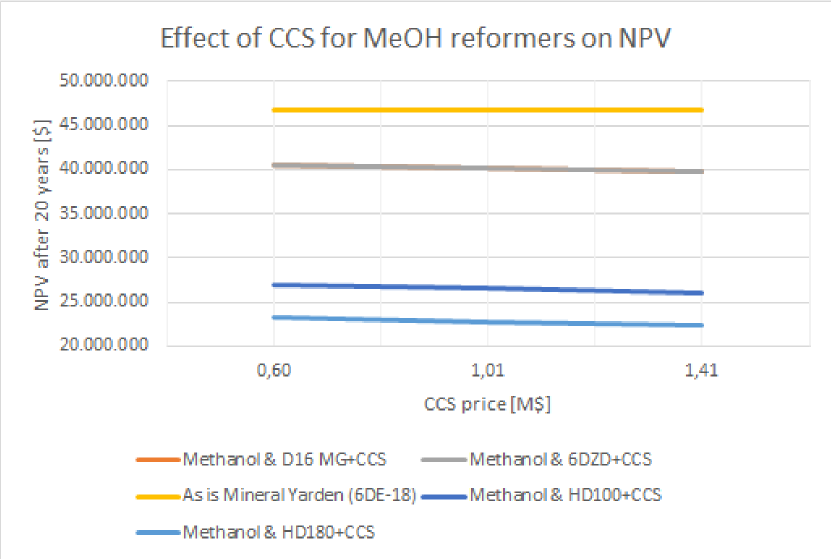

Figure 6.9: CCS for MeOH reformers price study

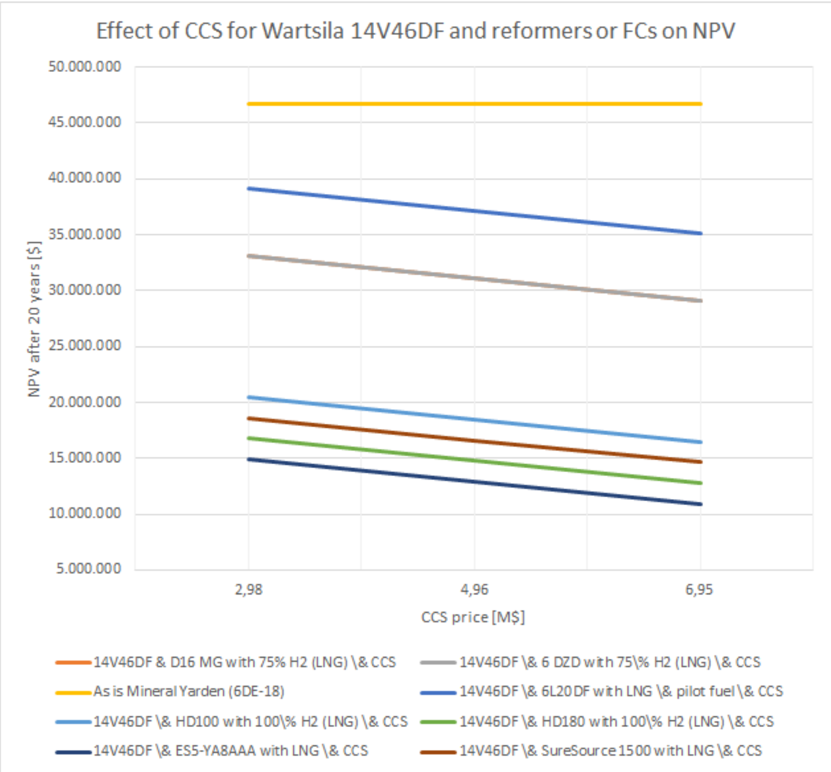

Figure 6.10: CCS for Wartsila 14V46DF and reformers or FCs price study

6. **Volvo Penta D16 MG:** two units of this energy converter are required on board to produce 800kWe. The alternative designs that include this A/E are shown in Figure 6.12.

   Price changes in the Volvo Penta D16 MG do not affect the NPV enough to make the design competitive with the current design of the Mineral Yarden.

7. **ABC 6DZD effect:** only one unit of this technology is required on board to produce 800kWe. The alternative designs that include this A/E are shown in Figure 6.13. Price changes in the ABC 6DZD do not affect the NPV enough to make the design competitive with the current design of the Mineral Yarden.

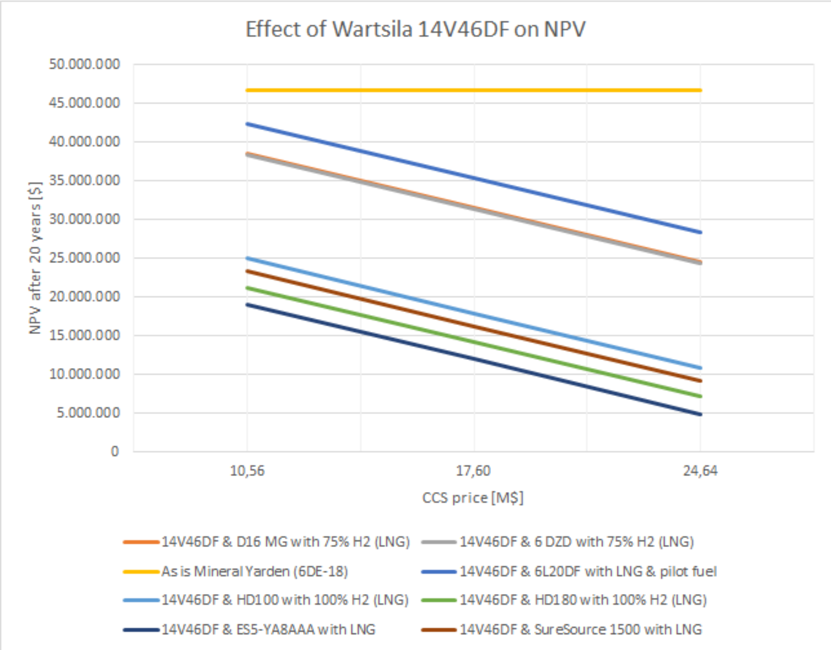

Figure 6.11: Wartsila 14V46DF price study

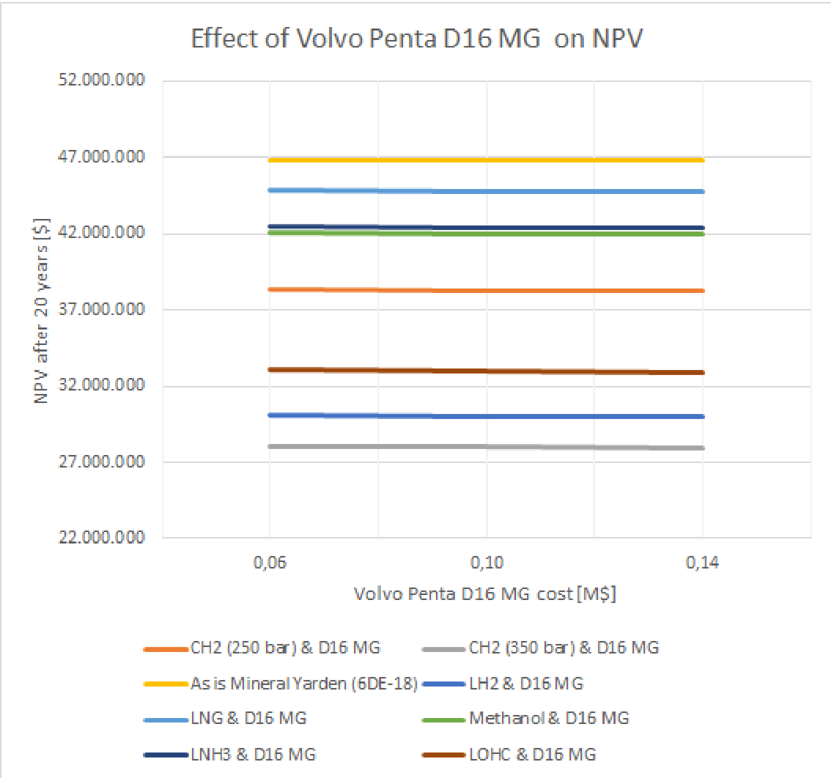

Figure 6.12: Volvo Penta D16 MG price study

8. **Wartsila 6L20DF effect:** only one unit of this technology is required on board to produce 800kWe. The alternative designs that include this A/E are shown in Figure 6.14. Price changes in the Wartsila 6L20DF do not affect the NPV enough to make the design with this A/E and the Hitachi-MAN B&W 6S70ME-C8.2 worst than the current design of the Mineral Yarden.

9. **LH2 20ft tanktainer effect:** the designs that include this storage alternative are presented in Figure 6.15.

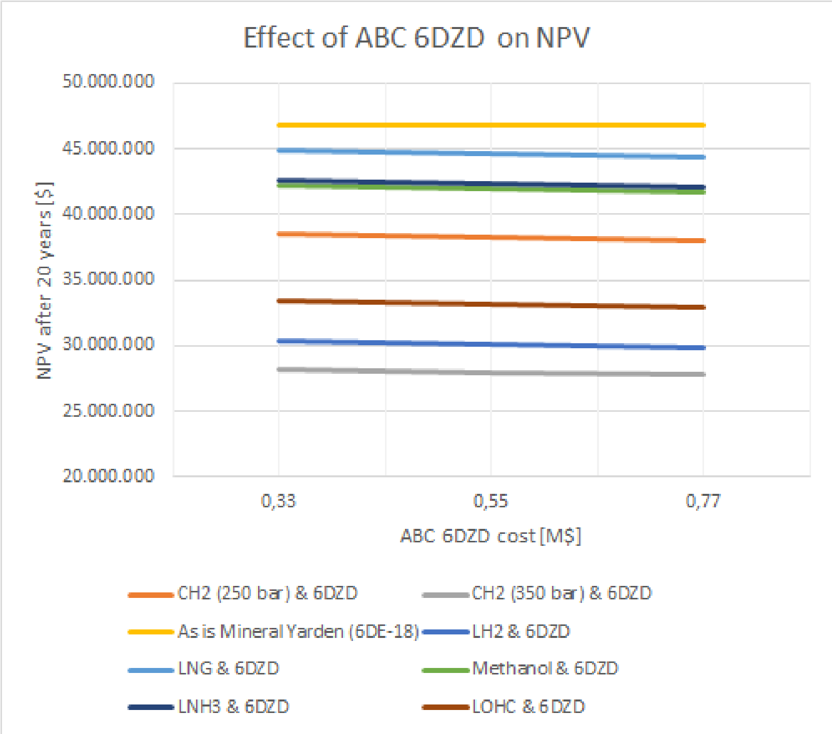

Figure 6.13: ABC 6DZD price study

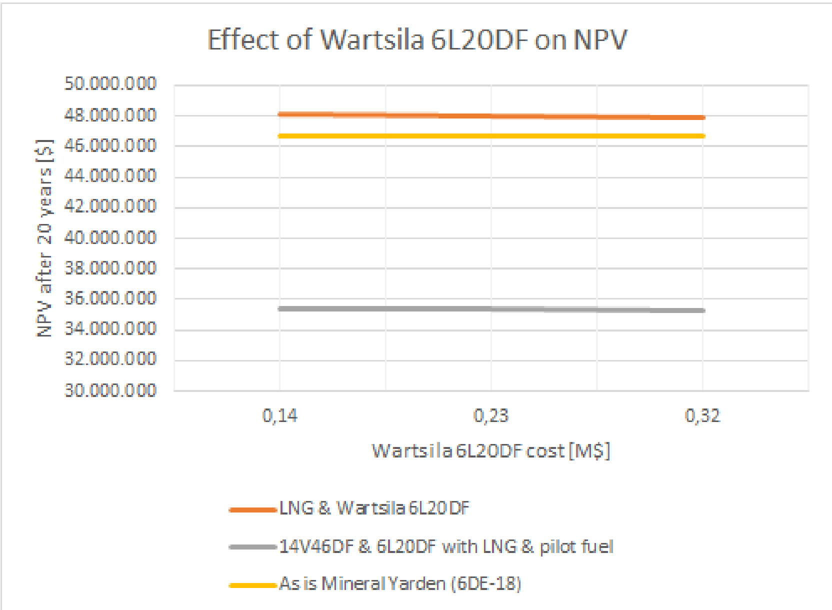

Figure 6.14: Wartsila 6L20DF price study

It can be seen that changes on the cost of the LH2 tank affect drastically the NPV after 20 years of the designs. This is due to the high cost per tank, and the fact that at least 13 tanks are required to carry 15 tonnes of hydrogen on board. Even though there is an important improvement in the NPV when the cost of the tank is reduced, much more is required to be competitive with current Mineral Yarden design. The complexity and high cost of LH2 storage make it difficult to compete with other pure hydrogen alternatives, such as the 10-tube 250bar tanktainer.

10. **10-tube 250bar 40ft container:** the alternatives that are affected by a change on the cost of this storage

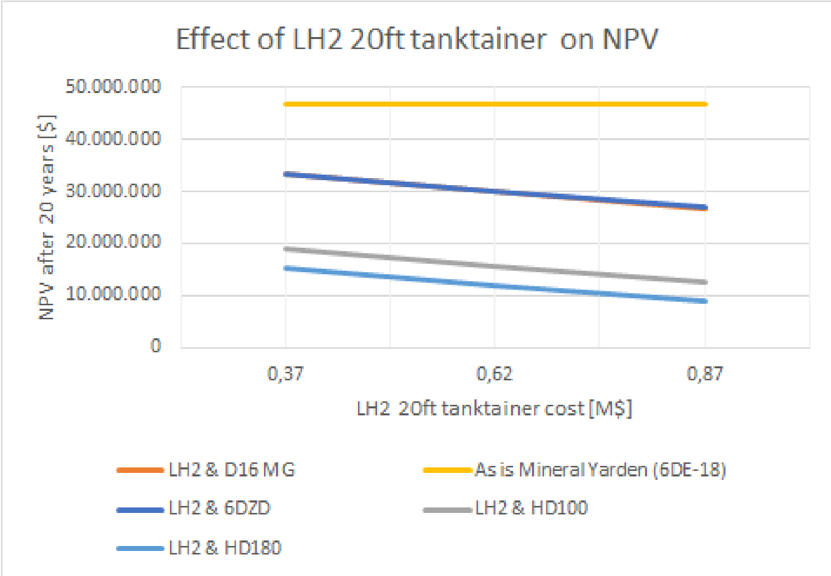

Figure 6.15: Effect of LH2 20ft tanktainer on NPV

technology are shown in Figure 6.16.

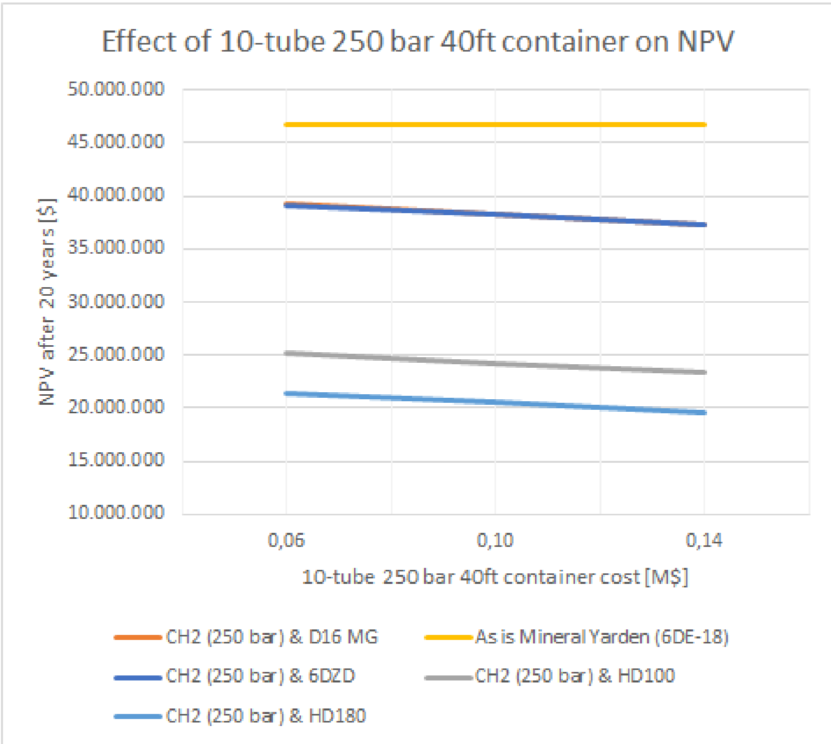

Figure 6.16: 10-tube 250 bar 40ft container price study

It can be seen that changes on the cost of the 10-tube 250 bar 40ft container slightly affect the NPV after 20 years, mainly due to the many units installed on board, since at least 23 containers are required to carry 15 tonnes of hydrogen on board. Additionally, a cost improvement of this storage alternative it is not enough to compete with current Mineral Yarden design.

11. **4-tube 350bar 40ft container:** the alternatives that are affected by a change on the cost of this storage technology are shown in Figure 6.17.

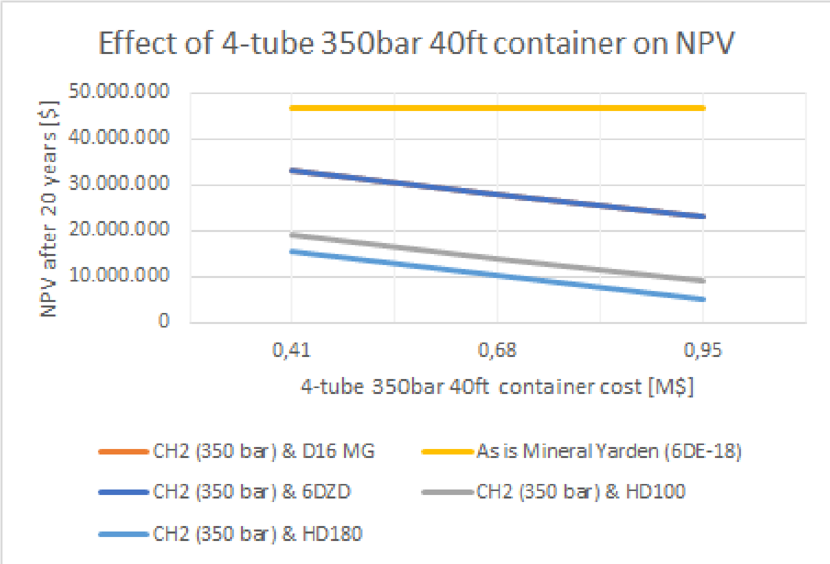

Figure 6.17: 4-tube 350bar 40ft container price study

It can be seen that changes on the cost of the 4-tube 350bar 40ft container significantly affect the NPV after 20 years, mainly due to the many units installed on board, since at least 19 containers are required to carry 15 tonnes of hydrogen on board. Additionally, a cost improvement of this storage alternative it is not enough to compete with current Mineral Yarden design.

12. **LNG 40ft tanktainer:** the alternatives that are affected by a change on the price of this storage technology are shown in Figure 6.18. It can be seen that changes on the price of the LNG 40ft tanktainer

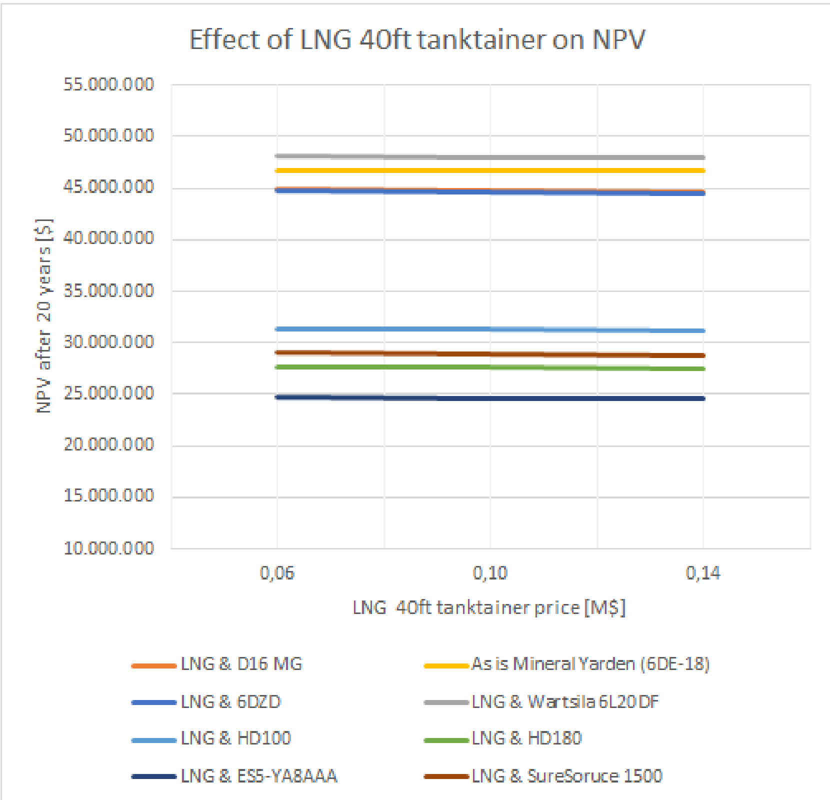

Figure 6.18: Effect of LNG 40ft tanktainer on NPV

slightly affects the NPV after 20 years, and that the design with the Wartsila 6L20Df outperforms the current Mineral Yarden design at all prices presented.

13. **LNG tank (1,285.46T capacity):** the alternatives that are affected by a change on the price of this storage tank are shown in Figure 6.19. It can be seen that changes on the price of the LNG (1,285.46T capacity)

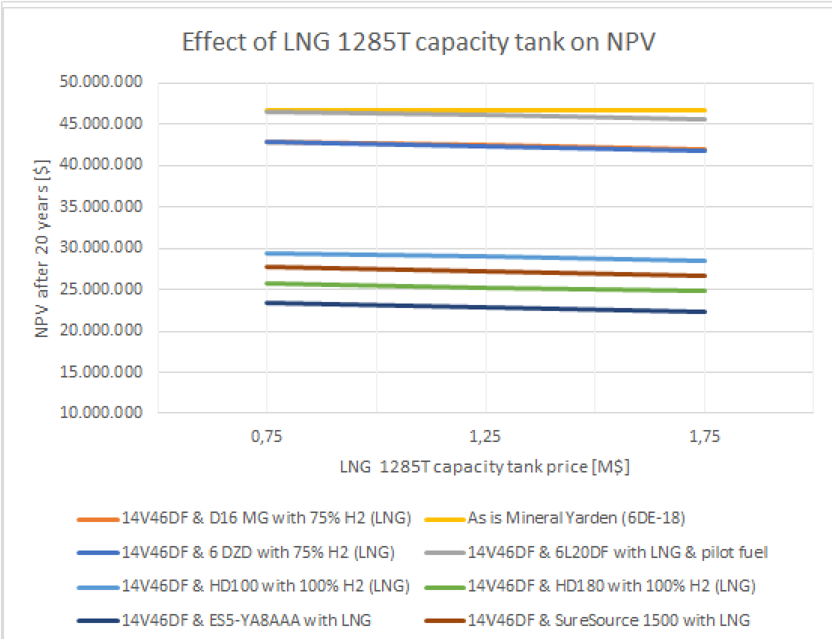

Figure 6.19: Effect of LNG 40ft tanktainer on NPV

tank slightly affects the NPV after 20 years, and that the design with the Wartsila 6L20Df is close in terms of NPV after 20 years to the current Mineral Yarden design when a 40% price reduction of the LNG tank exists.

14. **MeOH/LOHC 40ft tanktainer:** this storage alternative need to be used in combination with the proper reformers to extract the hydrogen. The alternatives that are affected by a change on the cost of the tank are shown in Figure 6.20.

    It can be seen that changes on the cost of the MeOH/LOHC 40ft tanktainer hardly affects the NPV after 20 years, and that a cost improvement of this storage alternative it is not enough to compete with current Mineral Yarden design.

15. **LNH3 40ft tanktainer:** this storage alternative need to be used in combination with ammonia crackers to extract the hydrogen. The alternatives that are affected by a change on the price of this storage alternative are shown in Figure 6.21.

    It can be seen that changes on the price of the LNH3 40ft tanktainer barely affects the NPV after 20 years, and that a price improvement of this storage alternative it is not enough to compete with current Mineral Yarden design.

16. **LNG reformer:** the alternatives that are affected by a change on the price of the natural gas reformer are shown in Figure 6.22. The changes on the price of the LNG reformer slightly affects the NPV after 20 years, and a price reduction of it is not enough to compete with current Mineral Yarden design.

17. **MeOH reformer:** the alternatives that are affected by a change on the price of the methanol reformer are shown in Figure 6.23. The changes on the price of the LNG reformer slightly affects the NPV after 20 years, and a price reduction of it is not enough to compete with current Mineral Yarden design.

18. **LNH3 cracker:** the alternatives that are affected by a change on the price of the ammonia cracker are shown in Figure 6.24. The changes on the price of the LNH3 cracker barely modify the NPV after 20 years, and a price reduction of it is not enough to compete with current Mineral Yarden design.

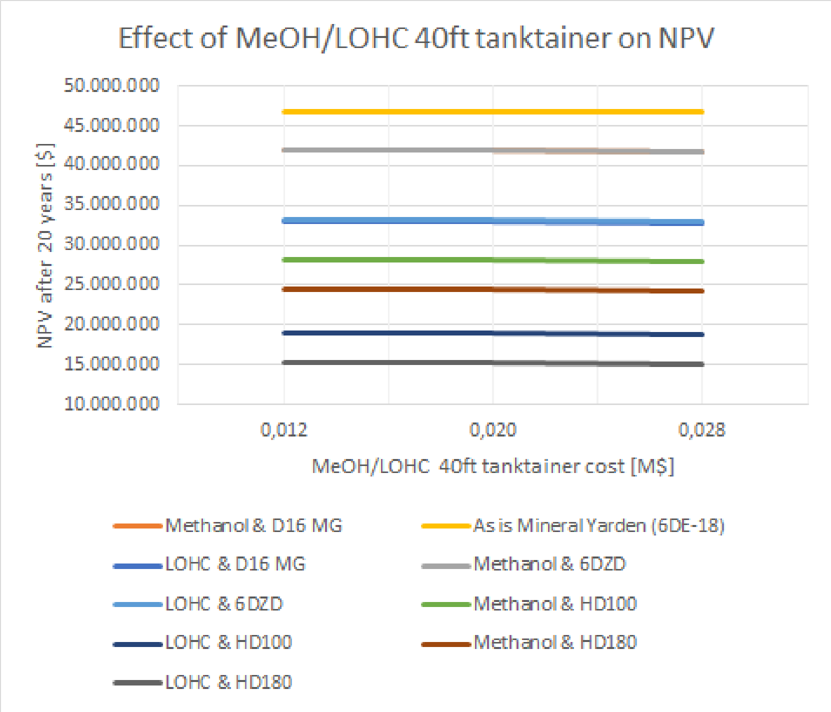

Figure 6.20: Effect of MeOH/LOHC 40ft tanktainer on NPV

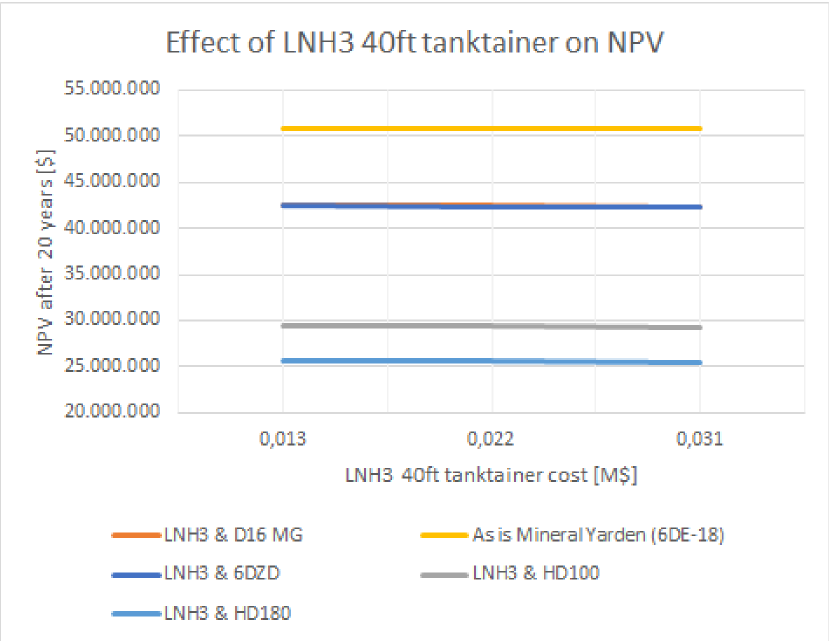

Figure 6.21: Effect of LNH3 40ft tanktainer on NPV

19. **LOHC reformer:** the alternatives that are affected by a change on the price of the liquid organic hydrogen carrier reformer are shown in Figure 6.25. The changes on the price of the LOHC reformer slightly modify the NPV after 20 years, and a price reduction of it is not enough to compete with current Mineral Yarden design.

Finally, the effect on NPV of changing the cost per tonne of CO2 emitted can be understand in Figure 6.26.
It can be seen that the design combinations with CCS do not vary much with changes in the price of CO2 emitted, but the designs without CCS vary considerably. This makes that the designs with the Volvo Penta

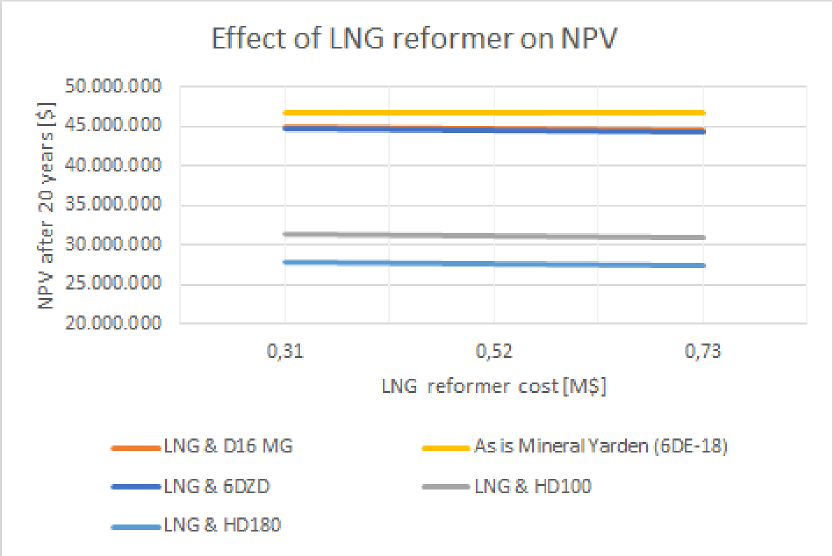

Figure 6.22: Effect of LNG reformer on NPV

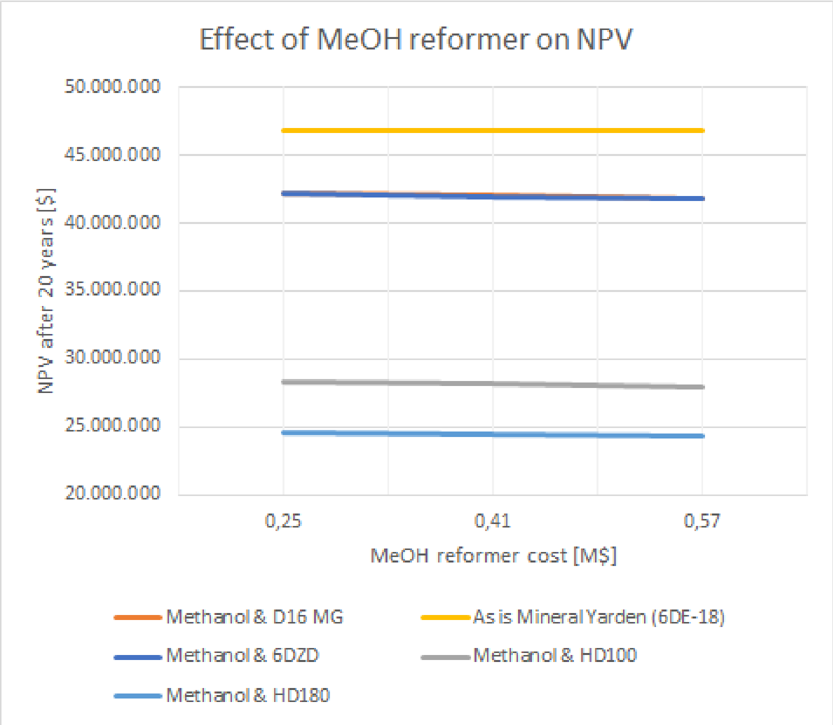

Figure 6.23: Effect of MeOH reformer on NPV

D16 MG/ABC 6 DZD and without CCS have worse NPV after 20 years than their homologues with CCS at CO2 emission cost per tonne higher than 9$. In the design with the Wartsila 6L20DF occurs the same phenomena but at a cost per tonne higher than 4$.

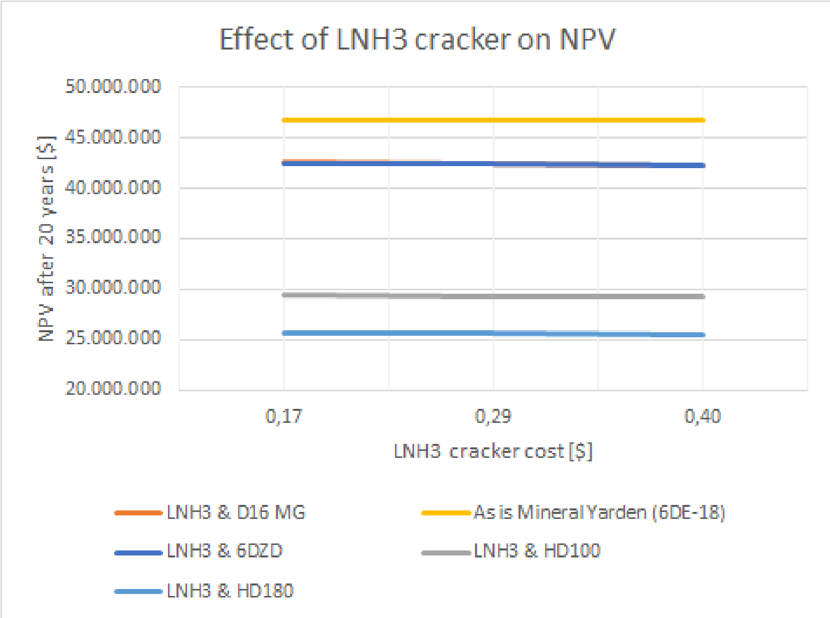

Figure 6.24: Effect of LNH3 cracker on NPV

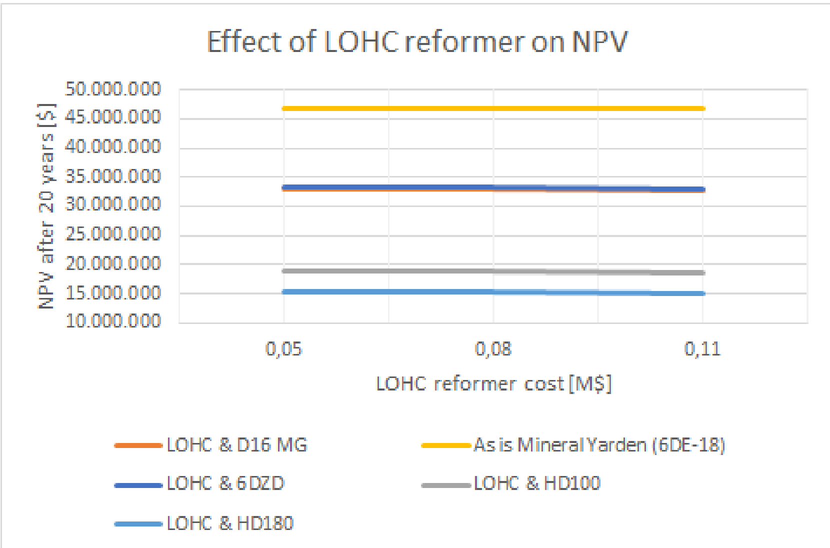

Figure 6.25: Effect of LOHC reformer on NPV

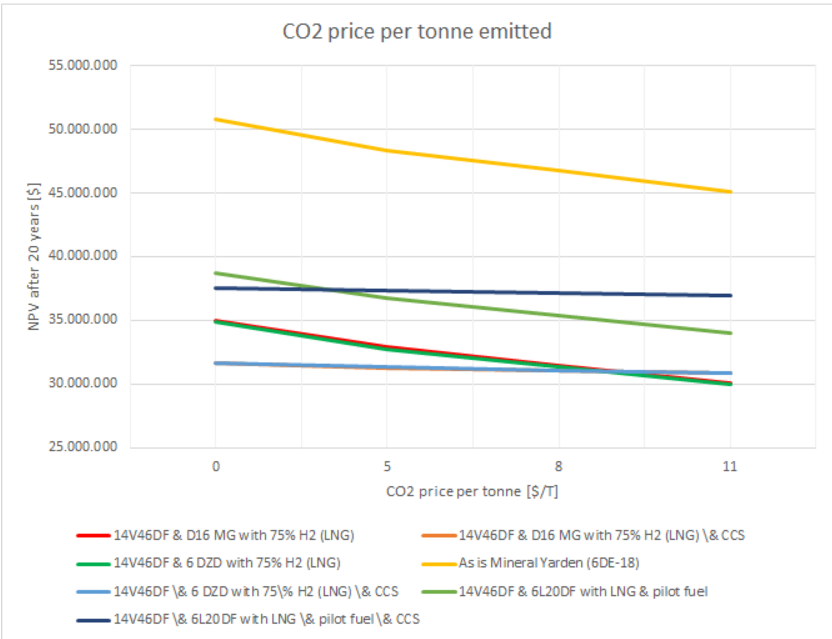

Figure 6.26: CO2 price per tonne emitted study

6.4. Intermediate conclusion

The energy converters with better economic performance as A/E are the ICEs, such as the Wartsila 6L20DF or the Volvo Penta D16 MG. Because none of the designs with FCs is in the top six BCR of the technically or non-technically feasible designs, neither in the private perspective nor the welfare perspective.

Now, it is possible to answer the second research question mentioned in section 1.2:

- *What technically feasible design alternatives are also economically feasible? Which scenarios could affect the feasibility?*

To consider a design alternative economically feasible it has to have a BCR higher than one from the private perspective. Then, none of the technically feasible alternative is economically feasible, as it was shown in Table 6.10. However, the sensitivity analysis demonstrated that some price changes could make some of the technically feasible design alternatives economically feasible. For instance, the design with Wartsila 14V46DF and Wartsila 6L20DF would have a BCR higher than one with a LNG price lower than \$412 per tonne, and the same design would outperform the current design of the Mineral Yarden in terms of NPV with a LNG price lower than \$405 per tonne. Another circunstance that could make more technically feasible alternatives economically feasible is the improvement of different technologies used by the technically feasible design. For example, a slightly LNG price reduction together with a small reduction of the LNG tank price, the Wartsila 14V46Df price or the LNG reformer, could make more technically feasible alternatives also economically feasible.

Additionally, from the analysis carried out to the non-technically feasible designs, it has been seen that the LNG is the most appealing alternative fuel, followed by LNH3 with a sixth position in the highest BCR from a private perspective in Table 6.10. However, during the estimation of the natural price, it was observed that the LNG price has been strongly increasing in the last 6 months. Then, if this trend continues, the LNG could stop being the dominant alternative.

Furthermore, the Wartsila 6L20DF outperformed the Volvo Penta D16 MG, and both outperformed the ABC 6 DZD in the private perspective. The lower consumption of the Wartsila 6L20DF is the reason to that, but even though the ABC 6 DZD also has a lower consumption than the Volvo Penta D16 MG, its high initial capital investment ranked it the last. Although, in the welfare perspective, how the ABC 6 DZD has a lower consumption also emit less CO2 per kWe produced, which makes that when CCS are not included in the designs, the ABC 6 DZD outperforms the Volvo Penta D16 MG. Also, the Ballard Power HD100 had better economic results than the Hydrogenics HD180, mainly due to a lower maintenance cost.

7 Conclusions

In this chapter, the outputs of the project, some recommendations and future potential of the alternative energy converters and storage fuel technologies will be discussed.

In this thesis, the properties of different alternative fuels have been calculated, the specific power and power density of different energy converters that could use some of the hydrogen carriers have been obtained. Different complementary technologies, such as fuel reformers or carbon capture systems (CCS) have been explained and tested, and their effect have been included in the payload and in the power demanded. After, all technologies have been integrated in the economic analysis. The tool that have been developed is able to give the economic indicators of the different design combinations.

The recommendations to CMB are that to make the Anglo Belgian Corporation (ABC) 6 DZD engine ($550,000) competitive with the Volvo Penta D16 MG, the price difference with the latter need to be further reduced. Even though, two units of the Volvo Penta D16 MG are required to generate the 800kWe and the ABC 6 DZD has a lower consumption, the capital difference is not recovered after 20 years of operation. Another important consideration is the storage of pure hydrogen, the results show that the 10-tube 250 bar in a 40ft container (85.51L outer tank/kg H2, volumetric speficiation, see Table 3.14) at a price of $100,000 per tank can not compete with alternative fuels with much higher volumetric specifcations. For instance, the LNG 40ft tanktainer (14.30L/kg H2) could fit the 15T of hydrogen required in this project in 3 tanks, while the 250bar alternative would require 23 40ft containers, and the same occurs when the 250bar storage is compared with ammonia or methanol. Then, the price of the 250bar storage is reduced or the LNG alternative, even requiring LNG reformers for some of the energy converters will continue outperforming the pure hydrogen alternatives.

Future research should be done in the post-combustion CCS technology used in this project, especially if a CO2 taxation enters into force and there are no further alternatives for M/E than LNG or HFO. The existence of prime movers and electric power suppliers that could operate in gas mode with LNG and low-sulfur pilot fuel together with CCS could be an alternative with high potential in the future. If the CCS technology gets more developed it could also become an interesting alternative for feeders that operate most of the time close to port areas. In addition, there exists a high demand for pure CO2 for the agri-food industry, which could ensure the CO2 sales in ports. In addition, if the LNG is obtained from conventional hydrocarbons the process is not CO2 neutral, but if synthetic natural gas from renewable electrical energy is used, it could be CO2 neutral.

Finally, during this thesis some contacts with original equipment manufacturers proved that the industry is working in solid oxide fuel cells (SOFC) and molten carbonate fuel cells (MCFC) for marine applications and power demands of more than 1MW, which could make fuel cells interesting as A/E replacement, since these high-temperature fuel cells do not require pure hydrogen and the alternative fuel could be reformed internally. Then, future research should follow the evolution of SOFCs and MCFCs because these energy converters have a high efficiency, but their capital investment is still too high compared with internal combusiton engines.

Part III
Appendices

A

Gantt chart

ID	Task Name	Start	Finish	Duration
1	Thesis Project Definition	15-12-2017	31-1-2018	34d
2	Graduation Internship at CMB	15-12-2017	4-7-2018	144d
3	PROBLEM DEFINITION	15-12-2017	29-12-2017	11d
4	1. Introduction	20-12-2017	29-12-2017	8d
5	1.1. Research background	20-12-2017	22-12-2017	3d
6	1.2. Research objective	22-12-2017	25-12-2017	2d
7	1.3. Scope of work	25-12-2017	26-12-2017	2d
8	1.4. Organization	25-12-2017	26-12-2017	2d
9	1.5. Activities and time schedule	27-12-2017	29-12-2017	3d
10	1.6. Deliverables	27-12-2017	29-12-2017	3d
11	1.7. Secrecy	27-12-2017	29-12-2017	3d
12	PART I: LITERATURE REVIEW	3-1-2018	14-3-2018	51d
13	2. Regulation	3-1-2018	24-1-2018	16d
14	2.1. Emission regulation	3-1-2018	10-1-2018	6d
15	2.2. IGC Code and amendments	11-1-2018	16-1-2018	4d
16	2.3. IGF Code	17-1-2018	24-1-2018	6d
17	3. Alternative fuels	25-1-2018	14-3-2018	35d
18	3.1. Properties	25-1-2018	6-2-2018	9d
19	3.2. Production	7-2-2018	13-2-2018	5d
20	3.3. Transportation and storage	14-2-2018	20-2-2018	5d

Figure A.1: Project schedule part one

21	3.4. Energy conversion processes	21-2-2018	5-3-2018	9d
22	3.5. Safety considerations	6-3-2018	6-3-2018	1d
23	3.6. Technologies included in the analyses	7-3-2018	14-3-2018	6d
24	PART II: TECHNICAL AND ECONOMIC ANALYSES	15-3-2018	15-6-2018	67d
25	4. Methodology	15-3-2018	3-4-2018	14d
26	4.1. Standard procedure to test new technologies in old designs	16-3-2018	19-3-2018	2d
27	4.2. Reference ship	20-3-2018	21-3-2018	2d
28	4.3. Case study	22-3-2018	26-3-2018	3d
29	4.4. Cost-benefit analysis	27-3-2018	3-4-2018	6d
30	5. Technical feasibility	4-4-2018	17-4-2018	10d
31	5.1. Effect on payload	4-4-2018	6-4-2018	3d
32	5.2. Effect on power consumption	9-4-2018	10-4-2018	2d
33	5.3. Regulation	11-4-2018	17-4-2018	5d
34	6. Economic feasibility	18-4-2018	7-6-2018	37d
35	6.1. Assumptions	18-4-2018	23-4-2018	4d
36	6.2. Private vs societal perspectives	24-4-2018	31-5-2018	28d
37	6.3. Sensitivity analysis	1-6-2018	7-6-2018	5d
38	7. Output of the project	8-6-2018	15-6-2018	6d
39	Report last version	22-6-2018	22-6-2018	0d
40	Green light meeting	4-7-2018	4-7-2018	0d

Figure A.2: Project schedule part two

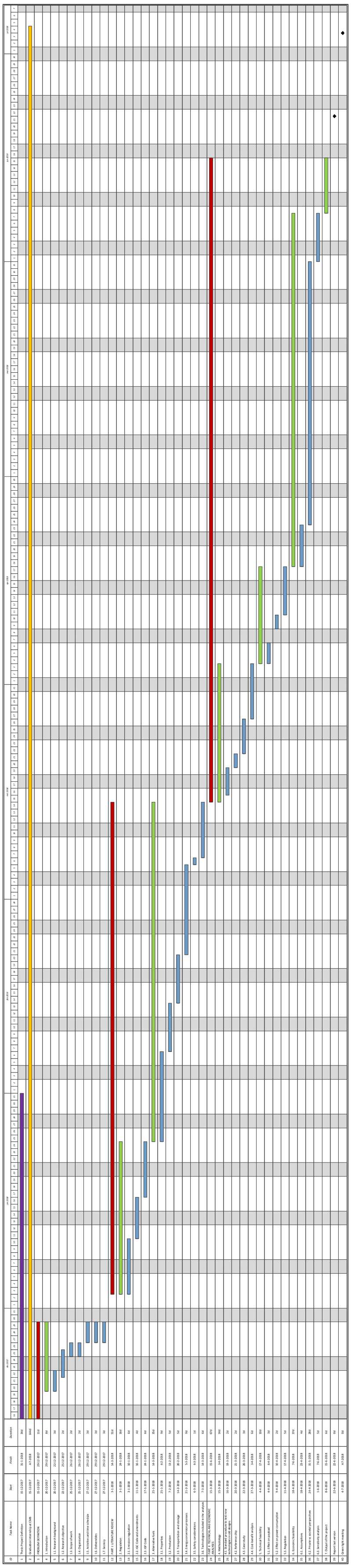

Figure A.3: Project Gantt chart.

B

Production of hydrogen from alternative carriers

B.1. Decomposition of pure methanol

The main reaction is the following:

$$CH_3OH \Rightarrow 2H_2 + CO \tag{B.1}$$

$M_M(CH_3OH) = 12.0107[g/mol] + 3 \times 1.00794[g/mol] + 15.9994[g/mol] + 1.00794[g/mol] = 32.04186[g/mol]$
$M_M(H_2) = 2 \times 1.00794[g/mol] = 2.01588[g/mol]$
Then:
$1\ mol\ of\ CH_3OH \longleftrightarrow 32.04186g$
$n\ moles\ of\ CH_3OH \longleftrightarrow 1000g$
So $n\ moles\ of\ CH_3OH = 31.20917\ moles$, and how the relation between CH_3OH and H_2 in the main reaction is 1 to 2, the moles of H_2 produced are 62.41834 moles.

The second reaction is:

$$CO + H_2O \Rightarrow H_2 + CO_2 \tag{B.2}$$

How the relation between CH_3OH and CO in the main reaction is 1 to 1, the moles available of CO are 31.20917. This CO moles in the second reaction produce 31.20917 H_2 moles, due to the relation 1 to 1 of CO and H_2 in the second reaction.
Adding the moles generated on the first and second reactions results in 93.6275 H_2 moles, and knowing the molecular mass of H_2, the grams of H_2 produced are approximately 188.74g.

B.2. Steam reforming of methanol

The reaction is the following:

$$CH_3OH + H_2O \Rightarrow 3H_2 + CO_2 \tag{B.3}$$

Similarly than in the first production method, a kilogram of methanol is equivalent to 31.20917 $moles$, but in this case the relation between CH_3OH and H_2 in the main equation is 1 to 3, so the moles of H_2 produced are 93.6275 moles.
Knowing the molecular mass of H_2, the grams of H_2 produced are approximately 188.74g, exactly the same that the amount produced with previous method.

B.3. Partial oxidation of methanol

The reaction is the following:

$$CH_3OH + \frac{1}{2}H_2O \Rightarrow 2H_2 + CO_2 \tag{B.4}$$

Here the relation between CH_3OH and H_2 in the main equation is 1 to 2, so the moles of H_2 produced are 62.41834 moles.
Knowing the molecular mass of H_2, the grams of H_2 produced are approximately 125.83g, less amount than with previous methods.

B.4. Decomposition of pure ammonia

The main reaction is the following:

$$2NH_3 \Rightarrow 3H_2 + N_2 \tag{B.5}$$

$M_M(NH_3) = 14.007[g/mol] + 3 \times 1.00794[g/mol] = 17.03082[g/mol]$
$M_M(H_2) = 2 \times 1.00794[g/mol] = 2.01588[g/mol]$
$M_M(N_2) = 2 \times 14.007[g/mol] = 28.014[g/mol]$
Then:
$1\ mol\ of\ NH_3 \longleftrightarrow 17.03082g$
$n\ moles\ of\ NH_3 \longleftrightarrow 1000g$
So $n\ moles\ of\ NH_3 = 58.71708\ moles$, and how the relation between NH_3 and H_2 in the main reaction is 2 to 3, the moles of H_2 produced are 88.0756 moles.
Knowing the molecular mass of H_2, the grams of H_2 produced are approximately 177.5499g.

C Efficiency calculations

C.1. ICE Volvo Penta D16 MG

First, assuming a fuel with a LHV of 42,700 kJ/kg as explained in subsection 3.5.6, and with the power output presented in Table 3.2, it is possible to calculate the ideal consumption of the engine assuming one hour and 100% efficiency:

$Power\ output = 420kW \times \frac{1000W}{1kW} \times \frac{1\frac{kg\times m^2}{s^3}}{1W} = 420,000\frac{kg\times m^2}{s^3}$

$LHV = 42,700\frac{kJ}{kg} \times \frac{1000J}{1kJ} \times \frac{\frac{kg\times m^2}{s^2}}{1J} = 42,700,000\frac{m^2}{s^2}$

$$Consumption = \frac{420,000\frac{kg\times m^2}{s^3}}{42,700,000\frac{m^2}{s^2}} \times 3600s = 35.41kg \tag{C.1}$$

Now with the SFOC shown in Table 3.2, and also assuming one hour we can calculate the real consumption at full load:

$$Consumption = 206\frac{g}{kWh} \times \frac{1kg}{1000g} \times 420kW \times 1h = 86.52kg \tag{C.2}$$

Now it is possible to compare both results to calculate the conversion energy efficiency (it includes the generator lost of efficiency):

$$Efficiency = \frac{35.41kg}{86.52kg} \times 100 = 40.93\% \tag{C.3}$$

C.2. ICE Anglo Belgian Corporation 6 DZD

First, assuming a fuel with a LHV of 42,700 kJ/kg as explained in subsection 3.5.6, and with the power output presented in Table 3.3, it is possible to calculate the ideal consumption of the engine assuming one hour and 100% efficiency:

$Power\ output = 950kW \times \frac{1000W}{1kW} \times \frac{1\frac{kg\times m^2}{s^3}}{1W} = 950,000\frac{kg\times m^2}{s^3}$

$LHV = 42,700\frac{kJ}{kg} \times \frac{1000J}{1kJ} \times \frac{\frac{kg\times m^2}{s^2}}{1J} = 42,700,000\frac{m^2}{s^2}$

$$Consumption = \frac{950,000\frac{kg\times m^2}{s^3}}{42,700,000\frac{m^2}{s^2}} \times 3600s = 80.09kg \tag{C.4}$$

Now with the SFOC shown in Table 3.3, and also assuming one hour we can calculate the real consumption at full load:

$$Consumption = 200\frac{g}{kWh} \times \frac{1kg}{1000g} \times 950kW \times 1h = 190.00kg \tag{C.5}$$

Now it is possible to compare both results to calculate the conversion energy efficiency (it includes the generator lost of efficiency):

$$Efficiency = \frac{80.09kg}{190.00kg} \times 100 = 42.15\% \tag{C.6}$$

C.3. ICE Wartsila 6L20DF

First, assuming a natural gas with a LHV of 49,620 kJ/kg and a pilot fuel with 42,700 kJ/kg, and that the total energy consumption at 100% load is 8,180kJ/kWh (8,048kJ/kWh from gas) as presented in Appendix D for this engine, and with the power output presented in Table 3.6, it is possible to calculate the ideal consumption of the engine assuming one hour and 100% efficiency:

$$Power\ output = 920kW \times \frac{1000W}{1kW} \times \frac{1\frac{kg\times m^2}{s^3}}{1W} = 920,000\frac{kg\times m^2}{s^3}$$

$$LHV_{gas} = 49,620\frac{kJ}{kg} \times \frac{1000J}{1kJ} \times \frac{\frac{kg\times m^2}{s^2}}{1J} = 49,620,000\frac{m^2}{s^2}$$

$$LHV_{pilotfuel} = 42,700\frac{kJ}{kg} \times \frac{1000J}{1kJ} \times \frac{\frac{kg\times m^2}{s^2}}{1J} = 42,700,000\frac{m^2}{s^2}$$

$$Consumption_{gas} = \frac{920,000\frac{kg\times m^2}{s^3}}{49,620,000\frac{m^2}{s^2}} \times \frac{8,048\frac{kJ}{kWh}}{8,180\frac{kJ}{kWh}} \times 3600s = 65.67kg \tag{C.7}$$

$$Consumption_{pilot\ fuel} = \frac{920,000\frac{kg\times m^2}{s^3}}{42,700,000\frac{m^2}{s^2}} \times \frac{(8,180-8,048)\frac{kJ}{kWh}}{8,180\frac{kJ}{kWh}} \times 3600s = 1.25kg \tag{C.8}$$

Now with the fuel gas consumption at 100% load in gas mode shown in Appendix D for this engine and the same LHV:

$$Specific\ gas\ consumption = \frac{8,048\frac{kJ}{kWh}}{49,620\frac{kJ}{kg}} = 0.162\frac{kg}{kWh} \tag{C.9}$$

After, knowing that the fuel oil consumption at 100% load in gas mode is 3.1g/kWh as seen in Appendix D, and also assuming one hour of operation it can be calculated the real consumption at full load:

$$Gas\ consumption = 0.162\frac{kg}{kWh} \times 920kW \times 1h = 149.22kg \tag{C.10}$$

$$Pilot\ fuel\ consumption = 0.0031\frac{kg}{kWh} \times 920kW \times 1h = 2.852kg \tag{C.11}$$

Now it is possible to compare both results to calculate the conversion energy efficiency (it includes the generator lost of efficiency):

$$Efficiency = \left(\frac{65.67kg}{149.22kg} \times \frac{8,048\frac{kJ}{kWh}}{8,180\frac{kJ}{kWh}} + \frac{1.25kg}{2.852kg} \times \frac{(8,048-8,180)\frac{kJ}{kWh}}{8,180\frac{kJ}{kWh}}\right) \times 100 = 44.72\% \tag{C.12}$$

D

Technical data of Wartsila dual-fuel engines

D.1. Wartsila 14V46DF

Wärtsilä 14V46DF		ME		DE	
		Gas mode	Diesel mode	Gas mode	Diesel mode
Cylinder output	**kW**	**1145**		**1145**	
Engine speed	**rpm**	**600**		**600**	
Engine output	kW	16030		16030	
Mean effective pressure	MPa	2.38		2.38	
Combustion air system (Note 1)					
Flow at 100% load	kg/s	25.8	28.7	25.8	28.7
Temperature at turbocharger intake, max.	°C	45		45	
Temperature after air cooler, nom. (TE 601)	°C	45	50	45	50
Exhaust gas system (Note 2)					
Flow at 100% load	kg/s	26.5	29.5	26.5	29.5
Flow at 75% load	kg/s	20.3	23.1	20.0	24.1
Temperature after turbocharger at 100% load (TE 517)	°C	354	354	354	354
Temperature after turbocharger at 75% load (TE 517)	°C	373	399	405	377
Backpressure, max.	kPa	4		4	
Calculated exhaust diameter for 35 m/s	mm	1304	1378	1304	1378
Heat balance at 100% load (Note 3)					
Jacket water, HT-circuit	kW	1624	2576	1610	2576
Charge air, HT-circuit	kW	3514	4284	3514	4284
Charge air, LT-circuit	kW	1414	1610	1414	1610
Lubricating oil, LT-circuit	kW	1092	1932	1092	1932
Radiation	kW	462	476	462	476
Fuel consumption (Note 4)					
Total energy consumption at 100% load	kJ/kWh	7460	-	7440	-
Total energy consumption at 85% load	kJ/kWh	7490	-	7540	-
Total energy consumption at 75% load	kJ/kWh	7590	-	7640	-
Total energy consumption at 50% load	kJ/kWh	8080	-	8220	-
Fuel gas consumption at 100% load	kJ/kWh	7413	-	7397	-
Fuel gas consumption at 85% load	kJ/kWh	7441	-	7487	-
Fuel gas consumption at 75% load	kJ/kWh	7535	-	7585	-
Fuel gas consumption at 50% load	kJ/kWh	7934	-	8070	-
Fuel oil consumption at 100% load	g/kWh	1.0	186	1.0	185
Fuel oil consumption at 85% load	g/kWh	1.2	178	1.2	182
Fuel oil consumption at 75% load	g/kWh	1.3	184	1.3	187
Fuel oil consumption 50% load	g/kWh	3.4	185	3.4	192
Fuel gas system (Note 5)					
Gas pressure at engine inlet, min (PT901)	kPa (a)	517	-	517	-
Gas pressure to Gas Valve unit, min	kPa (a)	517	-	517	-
Gas temperature before Gas Valve Unit	°C	0...60	-	0...60	-

Wärtsilä 14V46DF		ME		DE	
		Gas mode	Diesel mode	Gas mode	Diesel mode
Cylinder output	**kW**	**1145**		**1145**	
Engine speed	**rpm**	**600**		**600**	
Fuel oil system					
Pressure before injection pumps (PT 101)	kPa	800±0		800±0	
Fuel oil flow to engine, approx	m³/h	16.8		16.7	
HFO viscosity before the engine	cSt	-	16...24	-	16...24
Max. HFO temperature before engine (TE 101)	°C	-	140	-	140
MDF viscosity, min.	cSt	2.0		2.0	
Max. MDF temperature before engine (TE 101)	°C	45		45	
Leak fuel quantity (HFO), clean fuel at 100% load	kg/h	-	10.5	-	10.5
Leak fuel quantity (MDF), clean fuel at 100% load	kg/h	27.2	53.0	28.0	53.0
Pilot fuel (MDF) viscosity before the engine	cSt	2...11		2...11	
Pilot fuel pressure at engine inlet (PT 112)	kPa	400...800		400...800	
Pilot fuel outlet pressure, max	kPa	150		150	
Pilot fuel return flow at 100% load	kg/h	670		670	
Lubricating oil system					
Pressure before bearings, nom. (PT 201)	kPa	500		500	
Pressure after pump, max.	kPa	800		800	
Suction ability, including pipe loss, max.	kPa	40		40	
Priming pressure, nom. (PT 201)	kPa	80		80	
Temperature before bearings, nom. (TE 201)	°C	56		56	
Temperature after engine, approx.	°C	75		75	
Pump capacity (main), engine driven	m³/h	335		306	
Pump capacity (main), electrically driven	m³/h	297		297	
Oil flow through engine	m³/h	230		230	
Priming pump capacity (50/60Hz)	m³/h	70.0 / 70.0		70.0 / 70.0	
Oil volume in separate system oil tank	m³	26		26	
Oil consumption at 100% load, approx.	g/kWh	0.5		0.5	
Crankcase ventilation flow rate at full load	l/min	4180		4180	
Crankcase volume	m³	4.2		4.2	
Crankcase ventilation backpressure, max.	Pa	300		300	
Oil volume in turning device	l	68.0...70.0		68.0...70.0	
Oil volume in speed governor	l	7.1		7.1	
HT cooling water system					
Pressure at engine, after pump, nom. (PT 401)	kPa	250 + static		250 + static	
Pressure at engine, after pump, max. (PT 401)	kPa	530		530	
Temperature before cylinders, approx. (TE 401)	°C	74		74	
Temperature after charge air cooler, nom.	°C	91		91	
Capacity of engine driven pump, nom.	m³/h	280		280	
Pressure drop over engine, total	kPa	100		100	
Pressure drop in external system, max.	kPa	150		150	
Pressure from expansion tank	kPa	70...150		70...150	

Wärtsilä 14V46DF		ME		DE	
		Gas mode	Diesel mode	Gas mode	Diesel mode
Cylinder output	**kW**	**1145**		**1145**	
Engine speed	**rpm**	**600**		**600**	
Water volume in engine	m³	2.3		2.3	
LT cooling water system					
Pressure at engine, after pump, nom. (PT 471)	kPa	250+ static		250+ static	
Pressure at engine, after pump, max. (PT 471)	kPa	530		530	
Temperature before engine, max. (TE 471)	°C	38		38	
Temperature before engine, min. (TE 471)	°C	25		25	
Capacity of engine driven pump, nom.	m³/h	280		280	
Pressure drop over charge air cooler	kPa	50		50	
Pressure drop in external system, max.	kPa	200		200	
Pressure from expansion tank	kPa	70...150		70...150	
Starting air system (Note 6)					
Pressure, nom. (PT 301)	kPa	3000		3000	
Pressure at engine during start, min. (20 °C)	kPa	1500		1500	
Pressure, max. (PT 301)	kPa	3000		3000	
Low pressure limit in starting air vessel	kPa	1800		1800	
Consumption per start at 20 °C (successful start)	Nm³	14.0		14.0	
Consumption per start at 20 °C (with slowturn)	Nm³	17.0		17.0	

Notes:

Note 1 At ISO 15550 conditions (ambient air temperature 25°C, LT-water 25°C) and 100% load. Flow tolerance 5%.

Note 2 At ISO 15550 conditions (ambient air temperature 25°C, LT-water 25°C). Flow tolerance 5% and temperature tolerance 15°C.

Note 3 At ISO 15550 conditions (ambient air temperature 25°C, LT-water 25°C) and 100% load. Tolerance for cooling water heat 10%, tolerance for radiation heat 30%. Fouling factors and a margin to be taken into account when dimensioning heat exchangers.

Note 4 According to ISO 15550, lower calorific value 42700 kJ/kg, with engine driven pumps (two cooling water + one lubricating oil pumps). Tolerance 5%. The fuel consumption at 85 % load is guaranteed and the values at other loads are given for indication only.

Note 5 Fuel gas pressure given at LHV ≥ 36MJ/m³N. Required fuel gas pressure depends on fuel gas LHV and need to be increased for lower LHV's. Pressure drop in external fuel gas system to be considered. See chapter Fuel system for further information.

Note 6 At manual starting the consumption may be 2...3 times lower.

ME = Engine driving propeller, variable speed

DE = Diesel-Electric engine driving generator

Subject to revision without notice.

D.2. Wartsila 6L20DF

Wärtsilä 6L20DF		AE/DE		AE/DE		ME	
		Gas mode	Diesel mode	Gas mode	Diesel mode	Gas mode	Diesel mode
Cylinder output	**kW**	**160**		**185**		**185**	
Engine speed	rpm	1000		1200		1200	
Engine output	kW	960		1110		1110	
Mean effective pressure	MPa	2.18		2.1		2.1	
IMO compliance		Tier 3	Tier 2	Tier 3	Tier 2	Tier 3	Tier 2
Combustion air system (Note 1)							
Flow at 100% load	kg/s	1.5	2.0	1.8	2.2	1.8	2.3
Temperature at turbocharger intake, max.	°C	45		45		45	
Temperature after air cooler (TE 601)	°C	45	50	45	50	45	50
Exhaust gas system (Note 2)							
Flow at 100% load	kg/s	1.5	1.9	1.8	2.2	1.8	2.3
Flow at 75% load	kg/s	1.2	1.5	1.4	1.7	1.4	1.7
Flow at 50% load	kg/s	1.0	1.0	1.1	1.2	1.1	1.2
Temperature after turbocharger at 100% load (TE 517)	°C	350	325	370	330	370	315
Temperature after turbocharger at 75% load (TE 517)	°C	400	330	405	325	400	325
Temperature after turbocharger at 50% load (TE 517)	°C	420	360	415	360	365	325
Backpressure, max.	kPa	4		4		4	
Calculated exhaust diameter for 35 m/s	mm	309	343	344	370	344	371
Heat balance at 100% load (Note 3)							
Jacket water, HT-circuit	kW	200	210	235	250	230	245
Charge air, LT-circuit	kW	260	330	300	410	320	430
Lubricating oil, LT-circuit	kW	145	140	165	175	165	175
Radiation	kW	45	45	50	50	50	50
Fuel consumption (Note 4)							
Total energy consumption at 100% load	kJ/kWh	8180	-	8340	-	8370	-
Total energy consumption at 75% load	kJ/kWh	8520	-	8720	-	8550	-
Total energy consumption at 50% load	kJ/kWh	9140	-	9500	-	9090	-
Fuel gas consumption at 100% load	kJ/kWh	8048	-	8189	-	8222	-
Fuel gas consumption at 75% load	kJ/kWh	8326	-	8494	-	8360	-
Fuel gas consumption at 50% load	kJ/kWh	8862	-	9212	-	8860	-
Fuel oil consumption at 100% load	g/kWh	3.1	195	3.4	198	3.5	197
Fuel oil consumption at 75% load	g/kWh	4.5	196	5.3	198	4.4	196
Fuel oil consumption 50% load	g/kWh	6.4	207	6.7	208	5.4	198
Fuel gas system (Note 5)							
Gas pressure at engine inlet, min (PT901)	kPa (a)	520	-	550	-	550	-

Wärtsilä 6L20DF		AE/DE		AE/DE		ME	
		Gas mode	Diesel mode	Gas mode	Diesel mode	Gas mode	Diesel mode
Cylinder output	**kW**	**160**		**185**		**185**	
Gas pressure to Gas Valve unit, min	kPa (a)	640	-	670	-	670	-
Gas temperature before Gas Valve Unit	°C	0...60	-	0...60	-	0...60	-
Fuel oil system							
Pressure before injection pumps (PT 101)	kPa	700±50		700±50		700±50	
Fuel oil flow to engine, approx	m³/h	1.1		1.2		1.2	
HFO viscosity before the engine	cSt	-	16...24	-	16...24	-	16...24
MDF viscosity, min.	cSt	1.8		1.8		1.8	
Max. HFO temperature before engine (TE 101)	°C	-	140	-	140	-	140
Leak fuel quantity (HFO), clean fuel at 100% load	kg/h	-	0.8	-	0.9	-	0.9
Leak fuel quantity (MDF), clean fuel at 100% load	kg/h	2.0	3.9	2.3	4.6	2.3	4.6
Pilot fuel (MDF) viscosity before the engine	cSt	1.8...11.0		1.8...11.0		1.8...11.0	
Pilot fuel pressure at engine inlet (112)	kPa	10...40		10...40		10...40	
Pilot fuel pressure drop after engine, max	kPa	13		13		13	
Lubricating oil system							
Pressure before bearings, nom. (PT 201)	kPa	450		450		450	
Suction ability, including pipe loss, max.	kPa	20		20		20	
Priming pressure, nom. (PT 201)	kPa	80		80		80	
Temperature before bearings, nom. (TE 201)	°C	66		66		66	
Temperature after engine, approx.	°C	78		78		78	
Pump capacity (main), engine driven	m³/h	34		34		48	
Pump capacity (main), electrically driven	m³/h	21		21		21	
Priming pump capacity (50/60Hz)	m³/h	8.6 / 10.5		8.6 / 10.5		8.6 / 10.5	
Oil volume, wet sump, nom.	m³	0.38		0.38		0.38	
Oil volume in separate system oil tank	m³	2		2		2	
Oil consumption at 100% load, approx.	g/kWh	0.5		0.5		0.5	
Crankcase ventilation flow rate at full load	l/min	726		726		726	
Crankcase ventilation backpressure, max.	Pa	300		300		300	
Oil volume in speed governor	l	1.4...2.2		1.4...2.2		1.4...2.2	
HT cooling water system							
Pressure at engine, after pump, nom. (PT 401)	kPa	200 + static		200 + static		200 + static	
Pressure at engine, after pump, max. (PT 401)	kPa	500		500		350	
Temperature before cylinders, approx. (TE 401)	°C	83		83		83	
Temperature after engine, nom.	°C	91		91		91	
Capacity of engine driven pump, nom.	m³/h	30		30		30	
Pressure drop over engine, total	kPa	90		90		90	
Pressure drop in external system, max.	kPa	150 (1.5)		150 (1.5)		150 (1.5)	
Pressure from expansion tank	kPa	70...150		70...150		70...150	
Water volume in engine	m³	0.12		0.12		0.12	
Delivery head of stand-by pump	kPa	200		200		200	
LT cooling water system							
Pressure at engine, after pump, nom. (PT 471)	kPa	200+ static		200+ static		200+ static	
Pressure at engine, after pump, max. (PT 471)	kPa	500		500		350	

Wärtsilä 6L20DF		AE/DE		AE/DE		ME	
		Gas mode	Diesel mode	Gas mode	Diesel mode	Gas mode	Diesel mode
Cylinder output	**kW**	**160**		**185**		**185**	
Temperature before engine, max. (TE 471)	°C	38		38		38	
Temperature before engine, min. (TE 471)	°C	25		25		25	
Capacity of engine driven pump, nom.	m^3/h	36		39		39	
Pressure drop over charge air cooler	kPa	30		30		30	
Pressure drop in external system, max.	kPa	120 (1.2)		120 (1.2)		120 (1.2)	
Pressure from expansion tank	kPa	70...150		70...150		70...150	
Delivery head of stand-by pump	kPa	200		200		200	
Starting air system							
Pressure, nom.	kPa	3000		3000		3000	
Pressure, max.	kPa	3000		3000		3000	
Low pressure limit in air vessels	kPa	1800		1800		1800	
Starting air consumption, start (successful)	Nm^3	1.2		1.2		1.2	

Notes:

Note 1 At ISO 15550 conditions (ambient air temperature 25°C, LT-water 25°C) and 100% load. Flow tolerance 5%.

Note 2 At ISO 15550 conditions (ambient air temperature 25°C, LT-water 25°C). Flow tolerance 5% and temperature tolerance 15°C.

Note 3 At ISO 15550 conditions (ambient air temperature 25°C, LT-water 25°C) and 100% load. Tolerance for cooling water heat 10%, tolerance for radiation heat 30%. Fouling factors and a margin to be taken into account when dimensioning heat exchangers.

Note 4 At ambient conditions according to ISO 15550 and receiver temperature 45 °C. Lower calorific value 42 700 kJ/kg for pilot fuel and 49 620 kJ/kg for gas fuel. With engine driven pumps (two cooling water pumps, one lubricating oil pump and pilot fuel pump). Tolerance 5%.

Note 5 Fuel gas pressure given at LHV = 36MJ/m³N. Required fuel gas pressure depends on fuel gas LHV and need to be increased for lower LHV's. Pressure drop in external fuel gas system to be considered. See chapter Fuel system for further information.

ME = Engine driving propeller, variable speed

AE = Auxiliary engine driving generator

DE = Diesel-Electric engine driving generator

Subject to revision without notice.

E

Electric power carbon capture systems

The power demand required by the CCS of this project is estimated using the system presented in J.T. Akker [4]. In Figure E.1, it is possible to see the two-stage compression procedure required to liquefy the CO2.

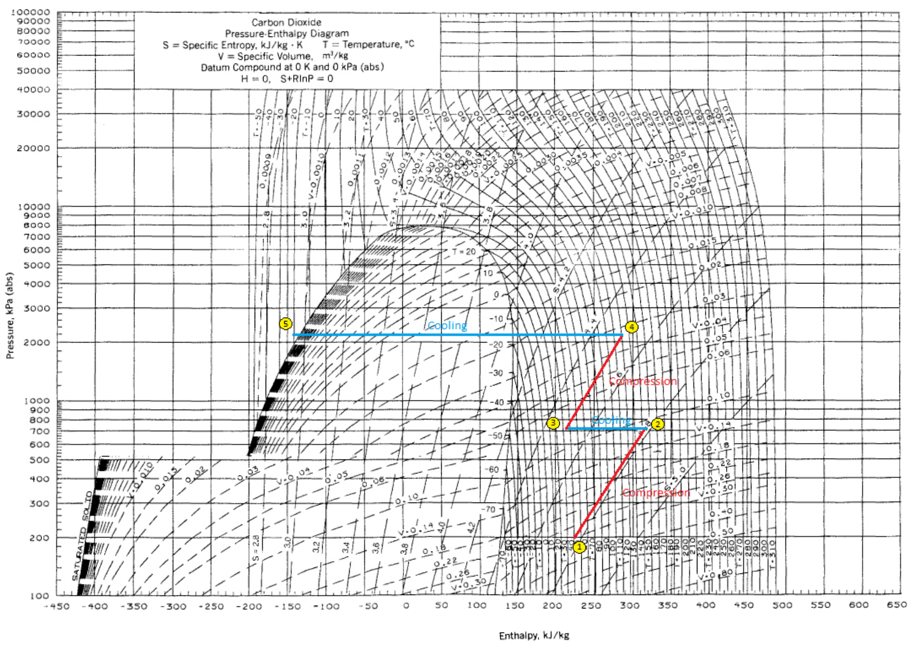

Figure E.1: Liquefaction of CO2 in the pressure-enthalpy diagram [based on [4]]

E.1. Hitachi-MAN B&W 6S70ME-C8.2 & LNG reformer & CCS

This system does not require external systems for cooling, since it uses the cooling of the LNG evaporation. Then, the electric power required is:

- Exhaust blower: the reference system liquefied 1,129kg CO2 per hour and its exhaust blower required 26.6kW. But, when LNG reformers are used, the average amount of CO2 to liquefy is 249.61kg per hour, which occurs in combination with the PEMFCs as energy converters. Then, assuming a linear relationship betwen the CO2 to liquefy per our and the size and power demand of the blower, the required electric power is 5.88kW.

- Compressors: one needs to compress the CO2 from point 1 to point 2, and a second one needs to compress from point 3 to point 4, as visualised in Figure E.1. So, assuming that they have 90% efficiency, and the 249.61kg of CO2 per hour requirement explained above:

$$Pcomp = \frac{1}{\eta} \times \dot{m}_{CO2} \times \Delta_{enthalpy} = \frac{1}{0.90} \times \frac{249.61[\frac{kg}{h}]}{3,600[\frac{s}{h}]} \times \Delta_{enthalpy}[\frac{kJ}{kg}] \tag{E.1}$$

  Then, observing Figure E.1 it is possible to recognise $\Delta_{12} = 320 - 225 = 95 kJ/kg$ (40°C to 145°C) and $\Delta_{34} = 290 - 210 = 80 kJ/kg$ (30°C to 125°C). So $\Delta_{enthalpy}$ over the two compressors is approximately 175kJ/kg. Finally, $P_{comp} = 13.48 kW$.

- Other consumers (e.g. pumps): the reference system liquefied 1,129kg CO2 per hour and this term was estimated in 30kW. Then, with the 249.61kg of CO2 per hour of this case and assumming a linear relationship betwen the CO2 to liquefy per our and the size and the power demadn of this term, the required electric power is 6.63kW.

The total electric power demanded by the CCS in combination with the LNG reformer is 5.88+13.48+6.63= 25.99kW.

E.2. Hitachi-MAN B&W 6S70ME-C8.2 & MeOH reformer & CCS

This system requires external systems for cooling. Then, the electric power required is:

- Exhaust blower: the reference system liquefied 1,129kg CO2 per hour and its exhaust blower required 26.6kW. But, in this project, the average amount of CO2 to liquefy is 245.82kg per hour, which is given by the storage alternative of MeOH and the PEMFCs as energy converters. Then, assuming a linear relationship betwen the CO2 to liquefy per our and the size and consumption of the blower, the required electric power is 5.79kW.

- Compressors: one needs to compress the CO2 from point 1 to point 2, and a second one needs to compress from point 3 to point 4, as visualised in Figure E.1. So, assuming that they have 90% efficiency, and the 245.82 kg of CO2 per hour requirement explained above:

$$Pcomp = \frac{1}{\eta} \times \dot{m}_{CO2} \times \Delta_{enthalpy} = \frac{1}{0.90} \times \frac{245.82[\frac{kg}{h}]}{3,600[\frac{s}{h}]} \times \Delta_{enthalpy}[\frac{kJ}{kg}] \tag{E.2}$$

  Again, as the process is the same that for the LNG reformer, the $\Delta_{enthalpy}$ over the two compressors is approximately 175kJ/kg. Finally, $P_{comp} = 13.28 kW$.

- Cooling systems: one needs to cool the CO2 from point 2 to point 3, and a second one needs to cool from point 4 to point 5, as visualised in Figure E.1. So, assuming that they have 90% efficiency, and the 245.82 kg of CO2 per hour requirement explained above:

$$Pcool = \frac{1}{\eta} \times \dot{m}_{CO2} \times \Delta_{enthalpy} = \frac{1}{0.90} \times \frac{245.82[\frac{kg}{h}]}{3,600[\frac{s}{h}]} \times \Delta_{enthalpy}[\frac{kJ}{kg}] \tag{E.3}$$

  Then, observing Figure E.1 it is possible to recognise $\Delta_{23} = |210 - 320| = 110 kJ/kg$ (145°C to 30°C) and $\Delta_{34} = |290 - (-140)| = 430 kJ/kg$ (125°C to −16°C). So $\Delta_{enthalpy}$ over the two coolers is approximately 540kJ/kg. Finally, $P_{cool} = 40.97 kW$.

- Other consumers (e.g. pumps): the reference system liquefied 1,129kg CO2 per hour and this term was estimated in 30kW. Then, with the 245.82kg of CO2 per hour of this case and assumming a linear relationship betwen the CO2 to liquefy per our and the size and the power demadn of this term, the required electric power is 6.53kW.

The total electric power demanded by the CCS in combination with the MeOH reformer is 5.79+13.28+40.97+6.53= 66.57kW.

E.3. Hitachi-MAN B&W 6S70ME-C8.2 & Wartsila 6L20DF & CCS

This system does not require external systems for cooling, since it uses the cooling of the LNG evaporation. Then, the electric power required is:

- Exhaust blower: the reference system liquefied 1,129kg CO2 per hour and its exhaust blower required 26.6kW. But, when the Wartsila 6L20DF is used, the average amount of CO2 to liquefy is 235.05kg per hour. Then, assuming a linear relationship betwen the CO2 to liquefy per our and the size and power demand of the blower, the required electric power is 5.54kW.

- Compressors: one needs to compress the CO2 from point 1 to point 2, and a second one needs to compress from point 3 to point 4, as visualised in Figure E.1. So, assuming that they have 90% efficiency, and the 235.05kg of CO2 per hour requirement explained above:

$$Pcomp = \frac{1}{\eta} \times \dot{m}_{CO2} \times \Delta_{enthalpy} = \frac{1}{0.90} \times \frac{235.05[\frac{kg}{h}]}{3,600[\frac{s}{h}]} \times \Delta_{enthalpy}[\frac{kJ}{kg}] \tag{E.4}$$

  Then, observing Figure E.1 it is possible to recognise $\Delta_{12} = 320 - 225 = 95kJ/kg$ (40°C to 145°C) and $\Delta_{34} = 290 - 210 = 80kJ/kg$ (30°C to 125°C). So $\Delta_{enthalpy}$ over the two compressors is approximately 175kJ/kg. Finally, $P_{comp} = 12.70kW$.

- Other consumers (e.g. pumps): the reference system liquefied 1,129kg CO2 per hour and this term was estimated in 30kW. Then, with the 235.05kg of CO2 per hour of this case and assumming a linear relationship betwen the CO2 to liquefy per our and the size and the power demadn of this term, the required electric power is 6.25kW.

The total electric power demanded by the CCS in combination with the LNG reformer is 5.54+12.70+6.25= 24.49kW.

E.4. Wartsila 14V46DF & LNG reformer & CCS

This system captures 90% of the CO2 of the Wartsila 14V46DF and the natural gas reformer, and it uses the cooling of the LNG evaporation. Then, the electric power required is:

- Exhaust blower: the reference system liquefied 1,129kg CO2 per hour and its exhaust blower required 26.6kW. But, when Wartsila 14V46DF and LNG reformers are used, the average amount of CO2 to liquefy is 3,335.95+249.61= 3,585.56kg per hour. Then, assuming a linear relationship betwen the CO2 to liquefy per our and the size and power demand of the blower, the required electric power is 84.48kW.

- Compressors: one needs to compress the CO2 from point 1 to point 2, and a second one needs to compress from point 3 to point 4, as visualised in Figure E.1. So, assuming that they have 90% efficiency, and the 3,585.56kg of CO2 per hour requirement explained above:

$$Pcomp = \frac{1}{\eta} \times \dot{m}_{CO2} \times \Delta_{enthalpy} = \frac{1}{0.90} \times \frac{3,585.56[\frac{kg}{h}]}{3,600[\frac{s}{h}]} \times \Delta_{enthalpy}[\frac{kJ}{kg}] \tag{E.5}$$

  Then, observing Figure E.1 it is possible to recognise $\Delta_{12} = 320 - 225 = 95kJ/kg$ (40°C to 145°C) and $\Delta_{34} = 290 - 210 = 80kJ/kg$ (30°C to 125°C). So $\Delta_{enthalpy}$ over the two compressors is approximately 175kJ/kg. Finally, $P_{comp} = 193.66kW$.

- Other consumers (e.g. pumps): the reference system liquefied 1,129kg CO2 per hour and this term was estimated in 30kW. Then, with the 3,585.56kg of CO2 per hour of this case and assumming a linear relationship betwen the CO2 to liquefy per our and the size and the power demadn of this term, the required electric power is 95.28kW.

The total electric power demanded by the CCS in combination with the LNG reformer is 84.48+193.66+95.28= 373.42kW.

E.5. Wartsila 14V46DF & Wartsila 6L20DF & CCS

This system captures 90% of the CO2 of the Wartsila 14V46DF and the Wartsila 6L20DF, and it uses the cooling of the LNG evaporation. Then, the electric power required is:

- Exhaust blower: the reference system liquefied 1,129kg CO2 per hour and its exhaust blower required 26.6kW. But, when Wartsila 14V46DF and Wartsila 6L20DF are used, the average amount of CO2 to liquefy is 3,335.95+235.05= 3571.00kg per hour. Then, assuming a linear relationship betwen the CO2 to liquefy per our and the size and power demand of the blower, the required electric power is 84.14kW.
- Compressors: one needs to compress the CO2 from point 1 to point 2, and a second one needs to compress from point 3 to point 4, as visualised in Figure E.1. So, assuming that they have 90% efficiency, and the 3571.00kg of CO2 per hour requirement explained above:

$$Pcomp = \frac{1}{\eta} \times \dot{m}_{CO2} \times \Delta_{enthalpy} = \frac{1}{0.90} \times \frac{3571.00[\frac{kg}{h}]}{3,600[\frac{s}{h}]} \times \Delta_{enthalpy}[\frac{kJ}{kg}] \tag{E.6}$$

  Then, observing Figure E.1 it is possible to recognise $\Delta_{12} = 320 - 225 = 95kJ/kg$ (40°C to 145°C) and $\Delta_{34} = 290 - 210 = 80kJ/kg$ (30°C to 125°C). So $\Delta_{enthalpy}$ over the two compressors is approximately 175kJ/kg. Finally, $P_{comp} = 192.88kW$.

- Other consumers (e.g. pumps): the reference system liquefied 1,129kg CO2 per hour and this term was estimated in 30kW. Then, with the 3571.00kg of CO2 per hour of this case and assumming a linear relationship betwen the CO2 to liquefy per our and the size and the power demadn of this term, the required electric power is 94.89kW.

The total electric power demanded by the CCS in combination with the LNG reformer is 84.14+192.88+94.89= 371.91kW.

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