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Utilization of innovative generation systems onboard cruise ships

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Abstract

Shipping sector was responsible for nearly 3% of global carbon dioxide equivalent emissions in 2018, increasing its total emissions of almost 10% from 2012. These emissions are dangerous for climate change effects, but they can particularly harm people because they are concentrated in ports. Even if almost 85% of the global fleet in 2017 was represented by oil tankers, bulk carriers, and container ships when deadweight tons are accounted, more than 10% of the global fleet value was represented by cruise ships. National and international regulators in past years issued mandatory regulations about sulphur oxides and nitrogen oxides emissions. These requirements were observed by switching to low-sulphur content fuels and using exhaust gas cleaning systems. The focus of current regulations under development and future emission targets is tackling carbon dioxide emissions. Possibly, cruise ships could also face stricter emissions in particular areas of the planet, since they travel worldwide and in some of the most fragile environments of the planet, like fjords and coral bays.

Different operative and design measures to reduce carbon dioxide emissions are still under evaluation but switching to carbon-neutral fuels is one of the most promising ones. Different fuels would also enable to install different power generation systems onboard vessels, like fuel cells and gas turbines. All those innovative solutions will indeed influence payload capacity and increase design and maintenance complexity. In recent years, fuel cells are gaining momentum because they can operate with different fuels, both fossil and renewable ones, and can bring emissions reduction while also decreasing noise and vibration onboard.

The scope of this work is to assess all potential fuels and power generation systems that can be employed now or shortly onboard cruise ships. This analysis is outlined with a holistic approach, considering emissions for fuels production, thermal power generation emissions and the impact of those new solutions on a cruise ship. The economics of each alternative design solution is also considered ensuring that alternative systems can be employed with current costs.

This work has been structured focusing first on a detailed literature review about all potential fuels, onboard storage and treatment systems, power generation systems and exhaust gas treatment systems suitable for maritime applications. Data analysis and literature review are fundamental to knowing all technical and economical characteristics of equipment related to power generation onboard ships. These data are inputs for the development of the simulation tool able to simulate one year of operation of a cruise ship, as described the in following paragraphs.

In this work, the production process of every fuel considered is modelled and emissions related to its production, its cost and its environmental impact when oxidised inside power generation systems are calculated. This modelling activity is crucial to assess the overall lifecycle of the vessel's impact and economics. Fuel handling and storage systems onboard are modelled by a parametrisation of their main characteristics: volume and mass required onboard for their installation, electrical and thermal power required, and capital and maintenance cost. Power generation systems' cost and impact onboard are modelled as described for fuel storage and handling system, except for their emissions and the possible heat recovery by their exhaust gases. These characteristics' variation with generators' load percentage is modelled, and they are used to estimating for each power requirement the emissions related to its production. Electrical and thermal power request is modelled considering cruise ships which sail in four different scenarios which represent four typical itineraries followed by real vessels.

Using the described simulation tool, two different reference cruise ships are analysed to assess which fuel, storage system and power generation system is best suited for carbon dioxide emission reduction or the lowest greenhouse gas emission reduction cost. This tool calculates total emissions produced by a given vessel for each combination of fuel, storage system, power generation system and emission abatement technology. Also, the impact on onboard payload both in terms of mass and volume is assessed. From this data, the simulation tool can calculate total capital costs and the cost for one year of operations and the Carbon Intensity Indicator attained value, which is a measure of the emissions related to shipping operations. The combination of these data is also important because it allows calculating best-performing technologies considering different criteria like the lowest Tank-To-Wake (TTW) carbon dioxide equivalent reduction cost, lowest Well-To-Wake (WTW) carbon dioxide equivalent reduction cost and lowest total cost.

This thesis provides a deep understanding of the complexity of carbon dioxide emission reduction topics for all vessels and particularly for cruise ships. The holistic approach applied to this analysis shows that technical solutions that can effectively reduce carbon dioxide emissions can bring unsustainable economics unless future technical developments in the future will bring more sustainable costs. The need to pursue the lowest possible cost and the highest quantity of payload is bringing shipowners to consider systems that move carbon dioxide emissions in other moments of the ship's life-cycle or that cause emissions currently not addressed by regulators, like methane slip from internal combustion engines. For this reason, a continuous and sincere dialogue between all stakeholders involved in shipping is necessary to identify the best solutions both from environmental and economic perspectives: this work and the proposed simulation tool can be considered a strong base for this discussion.

Sommario

Il settore del trasporto via mare è stato responsabile di circa il 3% delle emissioni globali di anidride carbonica nel 2018, aumentando il totale delle sue emissioni del 10% rispetto al 2012. Queste emissioni sono pericolose a cause della loro influenza sui cambiamenti climatici, ma sono considerate particolarmente pericolose anche per le persone, dato che sono concentrate prevalentemente nelle zone portuali. Nonostante nel 2017 l'85% di tutte le navi esistenti al mondo considerando la stazza lorda fosse costituito da petroliere, portarinfuse e navi porta container, le navi da crociera rappresentavano in più del 10% del valore della flotta globale. Negli ultimi anni gli enti di regolamentazione nazionali e internazionali hanno emesso regolamenti obbligatori per limitare le emissioni di ossidi di zolfo e ossidi di azoto. Questi regolamenti sono stati rispettati utilizzando combustibili a basso tenore di zolfo o implementando a bordo sistemi di trattamento dei gas di scarico. Ad oggi la diminuzione delle emissioni di anidride carbonica è il principale obiettivo dei regolamenti attualmente in fase di sviluppo. Le navi da crociera inoltre potranno dover sottostare a limiti ancora più stringenti in alcune aree del pianeta: queste navi operano in tutto il mondo e navigano in alcune degli ecosistemi più fragili, come i fiordi e le barriere coralline.

Attualmente sono in fase di valutazione metodologie tecniche o operative per ridurre le emissioni di anidride carbonica, ma una di quelle considerate più promettenti è utilizzare combustibili a neutralità climatica o senza contenuto di carbonio. L'utilizzo di combustibili diversi dagli attuali permette anche di installare a bordo nuove tipologie di generatori di energia a bordo, come le celle a combustibile o le turbine a gas. Queste soluzioni innovative avrebbero però sicuramente un'influenza sul carico pagante e incrementerebbero la complessità della progettazione e della manutenzione della nave. Negli ultimi anni le celle a combustibile hanno ottenuto sempre maggior attenzione soprattutto per la loro capacità di utilizzare più combustibili diversi, sia di origine fossile che rinnovabili, e perché possono ridurre le emissioni diminuendo nel frattempo anche vibrazioni e rumore a bordo della nave.

Lo scopo di questo lavoro è illustrare tutti i possibili combustibili e tutti i sistemi di generazione di energia che possono essere installati ad oggi o nell'immediato futuro a bordo delle navi da crociera. L'analisi è stata sviluppata utilizzando un approccio olistico, considerando le emissioni relative alla produzione del combustibile, alla generazione di energia termica e all'impatto che questi sistemi innovativi avrebbero sul carico pagante. Inoltre, i sistemi alternativi per la generazione di energia a bordo sono analizzati anche dal punto di vista economico per assicurarne la loro fattibilità anche secondo questa tipologia di requisiti.

Questo elaborato è strutturato analizzando in prima battuta la letteratura scientifica esistente riguardante tutti i possibili combustibili, i sistemi di stoccaggio e trattamento, i

sistemi di generazione di energia e i sistemi di trattamento dei gas di scarico. L'analisi della letteratura scientifica è fondamentale per ricavare tutti i parametri tecnici ed economici di ogni sottosistema relativo alla generazione di energia a bordo delle navi da crociera. I dati ottenuti sono stati utilizzati come input per lo sviluppo di uno strumento di calcolo capace di simulare un anno di operatività di una nave da crociera come descritto nei paragrafi successivi.

Nello studio proposto è stato modellato il processo di produzione di ogni combustibile e sono calcolati le emissioni direttamente correlate al suo processo produttivo, il suo costo e le emissioni dovute alla trasformazione del combustibile in energia elettrica. L'attività di modellazione è essenziale per valutare l'impatto dei nuovi sistemi di generazione sull'intero ciclo di vita della nave. I sistemi di stoccaggio e trattamento del combustibile a bordo sono stati parametrizzati in base alle loro caratteristiche principali: peso e volume occupato a bordo, potenza termica ed elettrica richiesta durante il funzionamento, costo iniziale e di manutenzione. I sistemi di generazione di energia sono stati modellati in maniera analoga a quelli di stoccaggio e trattamento del combustibile, ad eccezione delle loro emissioni e del possibile recupero termico dai gas di scarico. La variazione di questi dati è stata modellata in funzione della percentuale di carico dei generatori e questi dati sono stati utilizzati per stimare la richiesta di energia termica e le emissioni istantanee della nave in ogni condizione di carico. La richiesta elettrica e termica è stata elaborata considerando una nave da crociera che naviga in quattro scenari operativi diversi che rappresentano quattro tipici itinerari seguiti normalmente dalle rotte più seguite.

Utilizzando lo strumento di calcolo qui descritto, sono state analizzate due navi da crociera diverse per determinare quale combustibile, sistema di stoccaggio e generatore di energia siano più indicati per diminuire le emissioni di anidride carbonica o per ottenere il minor costo di riduzione di tali emissioni. Inoltre, è stato determinato l'impatto sul carico pagante in termini di volumi e peso a bordo. Da questi dati lo strumento di calcolo determina il costo di acquisto totale e il costo operativo per ogni anno di utilizzo, oltre al valore di *Carbon Intensity Indicator* ottenuto. Questo indice è una misura delle emissioni di anidride carbonica ed è direttamente correlato al tipo di servizio della nave e alla quantità di carico pagante trasportata. Lo strumento di calcolo permette di definire quale soluzione tecnologica ottiene i migliori risultati utilizzando diverse metriche come; minori emissioni di anidride carbonica equivalente considerando il ciclo TTW (dovute alla sola operatività della nave), minori emissioni di anidride carbonica equivalente considerando il ciclo WTW (dovute all'intero ciclo di vita) e il minor costo totale del sistema di generazione.

Questo lavoro è destinato a fornire una profonda comprensione della complessità delle tematiche relative alla riduzione delle emissioni di anidride carbonica causate dalle navi e in particolare dalle crociere. L'approccio olistico adottato in questa analisi dimostra che molte soluzioni che possono garantire una sostanziale riduzione delle emissioni inquinanti richiedono un aumento dei costi attualmente non sostenibile. La necessità di garantire i costi operativi più bassi possibile e la massima quantità di carico pagante infatti sta facendo considerare agli armatori soluzioni che spostano solamente la fonte delle emissioni inquinanti o che causano emissioni non ancora considerate, come quelle di metano da parte dei motori a combustione interna. Proprio per questo motivo è necessario un continuo dialogo tra i vari soggetti interessati dal problema che permetta di trovare soluzioni sostenibili sia dal punto di vista ambientale che da quello economico: questo elaborato e lo strumento di calcolo possono essere considerate una solida base di partenza per questa importante discussione.

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List of papers

Peer reviewed Journal Articles

Pietra, M. Gianni, N. Zuliani, S. Malabotti e R. Taccani, «Experimental Characterisation of an Alkaline Electrolyser and a Compression System for Hydrogen Production and Storage» Energies (https://doi.org/10.3390/en14175347), vol. 14, 2021.

M. Gianni, A. Pietra, and R. Taccani: "Impact of SOFC power generation plant on Carbon Intensity Index (CII) calculation for cruise ships" for Journal of Marine Science and Engineering - Special Issue "Advanced Research in Innovative Ship Energy Systems ".

A. Pietra, M. Gianni, N. Zuliani, S. Malabotti, R. Taccani, "Experimental characterisation of a PEM fuel cell for marine power generation" for International Journal of Hydrogen Energy - Special Issue dedicated to EFC21, 2021

Conference Proceedings

A. Pietra, M. Gianni, N. Zuliani, S. Malabotti, «Experimental characterisation of a PEM fuel cell for marine power generation» in ES3 Web Conf. Volume 334 EFC21-European Fuel Cells and Hydrogen Piero Lunghi Conference, DOI: 10.1051/e3sconf/202233405002, 2022

M. Gianni, V. Bucci, A. Marinò, "System simulation as decision support tool in ship design" in Procedia Computer Science 180:754-763, DOI:10.1016/j.procs.2021.01.323, 2021

M. Gianni, A. Pietra and R. Taccani, «Outlook of future implementation of PEMFC and SOFC onboard cruise ships» in E3S Web of Conference 238, DOI: 10.1051/e3sconf/202123804004, 2021

List of acronyms

ABS	American Bureau of Shipping
AFC	Alkaline Fuel Cells
AEM	Anion Exchange Membranes
bbl	Oil barrel
BMDF	Blended Marine Diesel Fuel Oil
BOP	Balance Of Plant
CAPEX	CAPital Expenditure
CCS	Carbon Capture and Storage
CIMAC	Conseil International des Machines à Combustion
CNG	Compressed Natural Gas
DMFC	Direct Methanol Fuel Cells
DNV-GL	Det Norske Veritas - Germanischer Lloyd
ECA	Emission Control Areas
EEDI	Energy Efficiency Design Index
EGB	Exhaust Gas Boiler
EIA	U.S. Energy Information Administration
ESD	Emergency Shut Down
EU	European Union
FAME	Fatty Acid Methyl Esters
FP	Fast Pyrolysis
F-T	Fischer-Tropsch
FVT	Fuel Valve Train
GHG	Green House Gases
GWP	Global Warming Potential
HAZID	HAZard IDentification
HAZOP	HAZard and OPerability
HFO	Heavy Fuel Oil
HRSG	Heat Recovery Steam Generator
HTL	Hydro-Thermal Liquefaction
HT-PEMFC	High Temperature Proton Exchange Membrane Fuel Cells
HVO	Hydrotreated Vegetable Oil
IFO	Intermediate Fuel Oil
IMO	International Maritime Organisations
IRC	Intercooled Regenerative Cycle

LCOE	Levelised Cost Of Electricity
LDF or LDO	Light Diesel Fuel Oil
LEL	Lower Explosive Limit
LFL	Lower Flammable Limit
LFSS	Low-flashpoint Fuel Supply System
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LPG	Liquefied Petroleum Gas
MCFC	Molten Carbonate Fuel Cells
MCR	Maximum Continuous Rating
MDF or MDO	Marine Diesel Fuel Oil
MEPC	Maritime Environmental Protection Committee
MGO	Marine Gas Oil
O&M	Operating and Maintenance
OPEX	Operating Expenditure
PAFC	Phosphoric Acid Fuel Cells
PEM	Proton Exchange membrane
PEMFC	Proton Exchange Membrane Fuel Cells
PFSA	Perfluorosulfonic Acid
PM	Particulate Matter
PTW	Pump-To-Wheel
RACER	Rankine Cycle Energy Recovery
ROK	Republic Of Korea
rpm	revolutions per minute
SCR	Selective Catalyst Reduction
SECA	Sulphur Emission Control Areas
SFOC	Specific Fuel Oil Consumption
SMR	Steam Methane Reforming
SOECs	Solid Oxide Electrolysis Cells
SOFC	Solid Oxide Fuel Cells
SOLAS	Safety of Life at Sea
STS	Ship To Ship
SVO	Straight Vegetable Oil
TPS	Shore Tank to Ship
TTP	Tank-To-Propeller
TTS	Tank To Ship

ULSFO	Ultra Low-sulphur Fuel Oil
USCG	United States Coast Guard
UK MCA	United Kingdom Maritime and Coastguard Agency
VLSFO	Very Low-sulphur Fuel Oil
WTP	Well-To-Pump
WTT	Well-To-Tank
WTW	Wtll-To-Wake

Introduction

Climate change and global warming awareness is growing, and national and international organisations are issuing regulations or outlining goals to address this urgent need. The transport sector is one of the various sources of global pollution: International Maritime Organisations (IMO) estimates that shipping was responsible for nearly 3% of the global carbon dioxide equivalent emissions in 2018, with a total of 1076 million tons, which represents a 9.6% increase over the 977 million tons accounted for in 2012 [1]. IMO has also outlined a strategy to further reduce the future GHG (Green House Gases) emissions by the shipping sector. The goal is to reduce carbon dioxide emissions per transport work by at least 40% by 2030 and try to achieve a reduction of 70% by 2050 compared to 2008. Furthermore, global annual GHG emissions from shipping are expected to be reduced by at least 50% by 2050 compared to 2008, reaching carbon-neutrality as soon as possible by the end of this century [2].

This study is focused on cruise ships because their market is growing in the last few years. Cruise ships represent almost 10% of the global fleet value, even if they represent only 0.3% of the global fleet when considering deadweight tonnes [3]. Twenty-eight cruise ships were delivered in 2021 with passenger capacity ranging from 120 passengers to more than 5000 [4]. For cruise ships, it is not important only for electric power generation for propulsion, ship services, and payload services, but also for thermal power generation needed to produce hot water and steam. Lower GHG emissions can be reached by employing different kinds of measures. Different technical solutions bring different effects on ship design, construction, and behaviour during its operations: for this reason, when evaluating different measures for emissions reduction it is required a holistic approach [5]. One of the possible solutions for emission reduction is switching from traditional residual oil-based fuels to gaseous fuels, like natural gas, or washing exhaust gases with abatement technologies. Low-sulphur fuel oils, scrubbers, and selective catalytic reduction systems are the most popular technical solutions to comply with emission limits for nitrogen oxides and sulphur oxides which came into force during the last few years [6]. More refined fuels and emission abatement technologies could not be enough to comply with future potential carbon dioxide emission limits. Different fuels, possibly with a neutral or zero-carbon content, are another possible solution to reduce carbon dioxide emissions. A change of fuel could also bring to consider the installation of different power generators, such as fuel cells and gas turbines [7].

For these reasons, carbon dioxide emissions reduction is considered one of the main topics of future ship design. The complexity of this challenge can be faced only with a holistic approach that must account for the fact that ships are probably the most complex mean of transportation to be decarbonised. This challenge can be considered an opportunity to bring in this traditional and slow-innovating world a revolution that would involve not only cruise ships but also other types of vessels and related infrastructures onshore.

Research question

Ships play a crucial role in world economy because they are dedicated to moving goods or people, and they are also employed for other specific purposes like military defence, fishing and research. Maritime contribution to global world carbon dioxide emissions is comparable to some of the most emitting countries, and this issue is addressed by national and international bodies. In this context, the cruise ship sector is constantly growing. Their environmental impact is addressed both by regulators, which aim to cut global maritime sector's carbon dioxide emissions, but also by shipowners to become more environmentally aware when selling their cruises to customers. Switching to new fuels and different power generators, like gaseous fuels and fuel cells, is considered one of the most promising solutions for reducing the environmental impact of cruise ships. Fuel cells differ in their internal technologies, their operating temperatures and the type of fuels that can be converted into electrical energy. These differences bring ship designers to face difficult choices when deciding which power generation system should be employed onboard. This thesis is focused on describing all potential solutions for reducing carbon dioxide emissions from cruise ships, highlighting the strong potential that fuel cells have in this process. This thesis employs a holistic approach because it considers not only emissions related to cruise ship voyages, but also all emissions related to fuel production. The holistic approach of this work brought also to consider the impact that different power generation systems and new fuels would have onboard a ship in terms of lost payload capacity and thus to the economic difference introduced by these new systems not only in terms of capital and operating expenditures for innovative systems but also in terms of lost revenues.

Given all the above context, the research question of the proposed PhD thesis is the following:

Can a simulation tool based on a holistic approach be useful to assess fuel cells and innovative fuels' impact on cruise' ships electrical and thermal power generation systems?

The answer to this research question has been investigated by developing a simulation tool able to assess the impact on two different sizes of cruise ships of all potential combinations of fuels and power generation systems already employed or that can potentially be employed shortly, as introduced in the next section.

Methodology

This section is dedicated to the description of the methodology applied to reply to the research question.

A simulation tool able to assess both economic and technical aspects related not only to ship operation but to the whole life-cycle of the vessel and of the fuel used onboard has been developed to answer the proposed research question. First, a database regarding both technical and economic characteristics of fuel production systems (see chapter 1.1), fuel storage systems for shipping, fuel treatment and handling systems (see chapter 1.2), power generators (see chapters 2.1, 2.2 and 2.3) and exhaust gas treatment (see chapter 2.4) was obtained by a rigorous and extensive literature review. This activity brought also to model power generators and heat recovery systems efficiencies variation with generators' load request. Another model was developed as shown in chapter 5.1 and it describes four different operative profiles of a general cruise ship which operates in different scenarios around the world. These operative profiles describe how much electrical and thermal power is required and for how much time in every operative condition. Variation of electrical power is related to power request for propulsion and onboard services. Thermal power request is related to onboard services too and is higher when the ship sails where ambient conditions are cooler, like in the North Sea. Knowing electrical and thermal power request and generator characteristics simulation tool defines instantaneous fuel consumption, from which total fuel consumption is obtained by knowing the operative profile. Total fuel consumption and total emissions related to fuel oxidation are fundamental data to calculate costs for fuel storage, handling and for its supply, but also carbon intensity indicator and emission reduction costs.

Structure of this work

This section is dedicated to the description of this thesis' contents.

The first section is dedicated to a detailed technical review of all potential marine fuels, their production pathways and the required storage and treatment system onboard. Carbon dioxide equivalent emissions and cost of fuel production has been analysed thanks to an extensive literature review and has been validated through the calculation of those same figures. Calculated values are compared to the ones found in literature, highlighting cost and emissions related to infrastructures, feedstock, and electricity for each fuel's production pathways. Fuel storage and treatment systems have been analysed and described thanks to a literature review. The volume and mass variations introduced when different fuels and storage systems are employed onboard are also explained in this section.

The second section gives a detailed technical review of all potential power generators for cruise ships, describing their main characteristics and modelling their behaviour on different load conditions. Waste heat recovery options to be coupled with these power generators are also analysed in this chapter. Emphasis has been placed on modelling Proton Exchange Membrane (PEM) fuel cells and Solid Oxide Fuel Cells (SOFC) since this PhD activity has been focused on this topic and has been supported by an experimental activity on real maritime power generators. In the same section, there is a description of emission abatement technology currently employed onboard and that can potentially be deployed in the future, and the impact that these systems have onboard is highlighted. Emission abatement systems have an impact on electrical and thermal balance, while also requiring space and bringing additional mass onboard. For this reason, their characterisation is fundamental for the holistic approach that characterises this thesis. After these analyses and modelling, a calculation of Tank-To-Wake (TTW) emissions is performed, and key results are shown.

The third section is a review of all real application onboard ships of innovative fuels, power generators and emission abatement technologies considered in this thesis. This analysis is important because it gives a benchmark for following results, but also because it highlights which technologies are already available for onboard applications, which are only at a demonstration phase and finally the ones that today are just at a research level.

The fourth section is dedicated to a brief analysis of applicable rules and regulations from national and international bodies which have been specifically written for alternative fuels and power generation systems. This section has been included to highlight that while international regulations, in particular IMO, are prescribing limits and outlining goals for emission reductions, specific requirements for new systems that can help to match these goals are still not developed.

The final section details all results obtained during the PhD activity. Reference case cruise ships are characterised, and their operative profiles are defined. Electrical and thermal power requirements for both considered cruise vessels are described for all different operative scenarios. At the end of this modelling activity, the ship's power generation systems are simulated during one year of operation. The thesis gives total fuel consumption knowing the load required by each generating system and its the electrical efficiency variation with the percentage of its maximum continuous rating. Seventy-eight different system configurations have been analysed with a holistic approach to find out carbon dioxide equivalent emissions related to ship operations and to the whole life-cycle of the fuel and power generation system. These options have been analysed also in terms of volume and mass introduced onboard and considering economics of these alternatives, both considering and ignoring contribution of lost payload capacity. All alternatives have been compared to one of the most recent international standards about carbon dioxide emissions, highlighting which technology guarantees compliance with this regulation and highlighting some potential flaws of this law. The thesis also identifies best-performing technologies in terms of carbon dioxide equivalent emissions' reduction cost and total installation cost, but only for power generation systems able to guarantee an emission reduction.

Main upsides and downsides of each one of the best-performing power generation systems are finally analysed considering with a holistic approach all aspects involved in this analysis, which are sometimes not completely considered in literature available.

1. Analysis of possible marine fuels

Power onboard cruise ships can be generated through various technical solutions. As other means of transport, ships generate power (both electrical, thermal and mechanical) converting chemical power stored inside one or more fuels onboard. Different systems for power generation can be applied to ships, and different systems imply the possible employment of different fuels onboard. Fuels have an impact on the ship, first because it influences the design of the ship in terms of volume occupied, weight, auxiliary systems and bunkering appliances. Some of the fuels that are described in following paragraphs have already been applied onboard ships and are well known, like Heavy Fuel Oil (HFO) and Marine Gas Oil (MGO). Other fuels are starting to gain momentum in the marine market, like Low-sulphur Fuel Oil (LSFO) and Liquefied Natural Gas (LNG), because they can reduce emissions of carbon dioxide and sulphur oxides. Other alternatives, like methanol and ammonia, are transported by chemical carriers, but are not applied as fuels, except for some first test ships in these years. These chemical products, which can be used also as fuels, have the slight advantage that there is already some infrastructure in some ports to handle and to bunker them onboard. Then, there are some potential new fuels, like hydrogen, which would require new infrastructures in ports and onboard ships. Then, biofuels or synthetic fuels are another possible solution, which would benefit from the fact of having similar properties to non-renewable fuels. Most of the fuels have been analysed considering aspects useful to assess the whole life-cycle of the system, starting from their production process: Capital Expenditure (CAPEX), Operating Expenditure (annual OPEX), lifetime, emissions, specific weights and volumes, efficiencies are just some of the characteristics that have been collected or calculated thanks to deep research of literature regarding these topics. Other more established fuels, like fossil fuels, have been analysed only with a literature review and their cost and the emissions related to their production are not considered in this thesis.

1.1. Fuels

Different type of fuels that have played or are playing a role in maritime world and some of the possible alternative prime energy sources are being evaluated and tried for future wide application onboard ships, especially in the cruise ship sector. Many different aspects must be considered when assessing maritime fuels: some of them are listed in Figure 1. There are technical aspects that must be considered: first, fuel properties, strictly related to storage equipment and the maintenance required by them (assessed in paragraph 1.2). Some fuels could require treatments before being used in power generators (paragraph 1.2) and can be employed only with some type of generators (paragraph 2). Obviously, environmental impact of different fuels and generator must be assessed, especially considering all national and international regulations about emissions. In this thesis, a life-cycle environmental performance of most of innovative fuel has been considered performed to guarantee a holistic approach. Consequences of a fuel spill should be considered important among environmental aspects. Initial and operating costs of different fuels should be assessed alongside with fuel price to fully understand economical aspects. There are other characteristics that play a role in fuel choice, like safety, security, fuel availability in ship's route, logistics, public opinion about solution adopted and all external regulations.

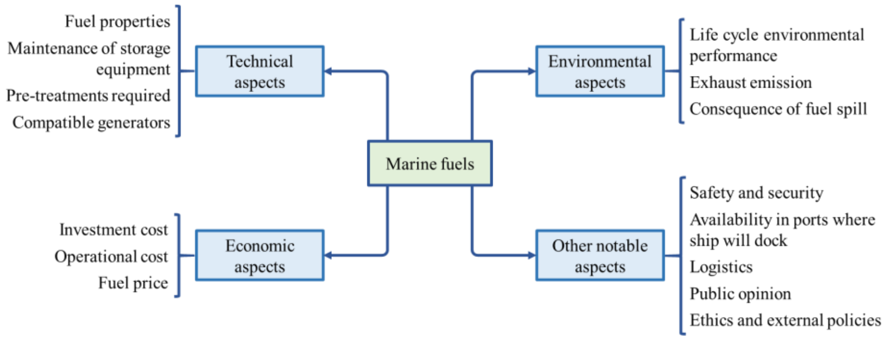

Figure 1 - Aspects to be considered when assessing different marine fuels

Emissions and fuel characteristics will be analysed dividing the whole fuel's life-cycle in two different parts. The succession of phases that can transform raw materials or various feedstocks into a fuel that is stored inside the ship (or in a vehicle) is defined as Well-To-Tank (WTT) pathway [8]. This process includes:

- Production or extraction of primary energy source.
- Its treatments or transformations to be performed just before the first stage.
- Transportation to processing sites.
- Transformation or conditioning to obtain market-quality fuel.
- Transportation to bunkering sites.
- Bunkering to the ship.

Tank-To-Propeller (TTP) or Tank-To-Wake (TTW) emissions are related to the generation of electric power from generators inside the ship. Each ship has in each moment of its operative life a power request that is given by the sum of all the power requests that let the vessel fulfil the scope for which it has been built. Total power required is different from the total power generated because and from the heating value of a substance there are some losses related to various factors, like generator's efficiencies and electrical auxiliaries. Emissions are related to the quantity of fuel produced, so to the heating value of it, when accounting for WTT emissions. Alternative WTT pathways included in this work are related to the possibility of producing carbon-neutral fuels, or at least reducing their life-cycle GHG emission. Some fuels that are normally non-renewable can be produced from renewable feedstock, like natural gas produced by CO_2 captured from the air and hydrogen obtained by electrolysis of water. To be 100% renewable, all electric energy involved in the process must come from renewable energy sources, and all transportation modes associated to those fuels should not emit GHG. Each WTT process can assure benefits in terms of emissions, but also final fuel cost must be accounted [9].

1.1.1. Methodology used for calculations

The thesis assessed all different phases, grouping some of them is macro categories to calculate production cost and emissions related to some renewable or fossil fuels. These categories are:

- Infrastructures (in terms of CAPEX and OPEX) needed for fuel treatment or production. These infrastructures have feedstock as inputs, and the output is the fuel considered. The most common feedstock will be hydrogen, with different production methods under consideration, and carbon dioxide.
- Feedstock needed for fuel production, which are related for their production or extraction to certain costs and emissions.
- Electricity needed to perform treatment, transformation, or processing of the fuel under analysis.
- Transportation will not be accounted in this thesis since it is not considered useful to establish a single transportation pathway for the quantity of fuels analysed.

To properly address uncertainty related to these calculations, two different values for production costs and emissions have been calculated. These values are related to different scenarios of CAPEX, OPEX, electricity needed, feedstock required and emissions. One case, in which is taken the lower values for these variables, is called optimistic scenario, and can be related also to a long-term future near 2050. The second one is a more pessimistic scenario, in which higher values are taken for each variable, and can be considered a short-term future, like 2030. Lifetime in years, annual full load hours and an interest rate are needed to assess how much CAPEX and OPEX influence the cost of different fuels or feedstocks. With this data is it possible to calculate the annual constant payment required for a loan taken to cover CAPEX at a constant interest. It has been assumed for each calculation that interest is equal to 4% and the future value of each plant is equal to zero. The formula used in the calculation is the following:

$$annual\ CAPEX\ \left[\frac{€}{plant\ capac.per\ year}\right] = \frac{CAPEX \cdot i}{1 - \frac{1}{(1+i)^n}} \tag{1.1.1}$$

Then, CAPEX quantity that must be assigned to a unit of feedstock or fuel produced is obtained thanks to the following calculation:

$$CAPEX\ \left[\frac{€}{unit\ of\ product}\right] = annual\ CAPEX \cdot annual\ full\ load\ hours \tag{1.1.2}$$

Annual OPEX is given as a percentage of annual CAPEX, and the share that is assigned to a unit of product is calculated in the same way shown for CAPEX in equation 1.1.2. To assess the impact of different feedstock on production cost and emissions, input data must be the quantity of feedstock required for a unit of fuel produced and the production cost and emission factor per unit of feedstock, which are combined as shown in the equation 1.1.3, which can be used also for electricity.

$$Product\ cost\ rel.to\ feedst.\left[\frac{€}{unit\ of\ prod.}\right] = Feedst.req.\ \cdot Feedst.cost \tag{1.1.3}$$

Values obtained via calculations are compared to the ones find in literature, that in following paragraph are shown as mean values and error bars related to minimum and maximum values.

The most basic feedstock that are considered in the following paragraphs are nitrogen, distilled water, and carbon dioxide. Its production cost and the total carbon dioxide emission related to their production process is shown in Table 1 and Table 2, which are optimistic and pessimistic scenarios respectively.

Table 1 – Nitrogen, water and carbon dioxide production cost and emission (optimistic value)

Characteristic	Unit	Nitrogen	Water	CO2
CAPEX	€/(kg/d)/a	€ 3.679	€ 0.0474	€ 20.14
	€/kg	€ 0.001	€ 0.0000	€ 0.00
OPEX	€/(kg/d)/a	€ 0.147	€ 0.0019	€ 3.02
	€/kg	€ 0.000	€ 0.0000	€ 0.00
Electricity	€/kg	€ 0.008	€ 0.0002	€ 0.08
Total cost	€/kg	€ 0.008	€ 0.0002	€ 0.09
CO_{2eq} emission	g_{CO2eq}/kg	0.90	24.87	9.95

Table 2 – Nitrogen, water and carbon dioxide production cost and emission (pessimistic value)

Characteristic	Unit	Nitrogen	Water	CO2
CAPEX	€/(kg/d)/a	€ 4.783	€ 0.0474	€ 34.38
	€/kg	€ 0.001	€ 0.0000	€ 0.01
OPEX	€/(kg/d)/a	€ 0.191	€ 0.0019	€ 6.88
	€/kg	€ 0.000	€ 0.0000	€ 0.00
Electricity	€/kg	€ 0.008	€ 0.0002	€ 0.11
Total cost	€/kg	€ 0.009	€ 0.0002	€ 0.11
CO_{2eq} emission	g_{CO2eq}/kg	0.90	24.87	12.44

A justification of the parameters that are used is given in the following paragraphs. It can be noted that total production cost is related primary to electricity to produce these feedstocks. For this reason, the following paragraph is dedicated to this topic. Calculations of all fuels' production cost and emissions have been developed thanks to an automatic tool developed during the PhD activity.

1.1.2. Electric grid energy price and emissions

All fuel's production processes require energy for all the different phases of fuel extraction, treatment, or synthesis. For this reason, electricity price and emissions related to it are data of primary importance when accounting WTT emissions of different fuels. It is necessary to find reference values in literature to have an estimation of emissions and price of electric energy under different boundary conditions. According to a study about renewable methanol it is stated that in the European Union (EU) the amount of renewable energy sources used to generate electricity varies from country to country and for example the carbon dioxide equivalent emission is almost 20 g_{CO2eq}/kWh_e in Sweden, 90 g_{CO2eq}/kWh_e in Finland and 250

g_{CO2eq}/kWh_e in Russia [10]. Emission factors of electric energy have a lot of importance in almost every study about renewable fuels because they influence the WTT performances of these alternatives. In a report about blue hydrogen emission factor for Norway is set at 17 g_{CO2eq}/kWh_e, while for the Netherlands this data was between 290 g_{CO2eq}/kWh_e and 530 g_{CO2eq}/kWh_e in 2017 [11]. The analysis of a case study in the Republic Of Korea (ROK) brought to definition of emission factors for different electric energy sources as shown in Table 3 [12]. According to a public database, emissions from electricity generation were widely variable across Europe in 2019 as it is shown in Figure 2. Emission factors vary from 8 g_{CO2eq}/kWh_e in Sweden to 891 g_{CO2eq}/kWh_e in Estonia, with an average of 275 g_{CO2eq}/kWh_e across EU countries [13].

Table 3 – Emission factors for different electricity source in kg/kWh_{fuel} [13]

Electricity source	**CO_2**	**SO_x**	**NO_x**	**N_2O**	**CH_4**
Hard Coal	$9.14*10^{-1}$	$5.98*10^{-4}$	$1.11*10^{-3}$	$2.71*10^{-5}$	$2.26*10^{-3}$
Nuclear energy	$4.42*10^{-3}$	$1.57*10^{-5}$	$1.87*10^{-5}$	$1.28*10^{-7}$	$7.37*10^{-6}$
Renewable energy	$1.04*10^{-2}$	$1.55*10^{-5}$	$1.45*10^{-5}$	$2.53*10^{-7}$	$1.47*10^{-5}$
Energy generated in ROK	$5.35*10^{-1}$	$2.57*10^{-4}$	$6.08*10^{-4}$	$1.36*10^{-5}$	$9.54*10^{-4}$

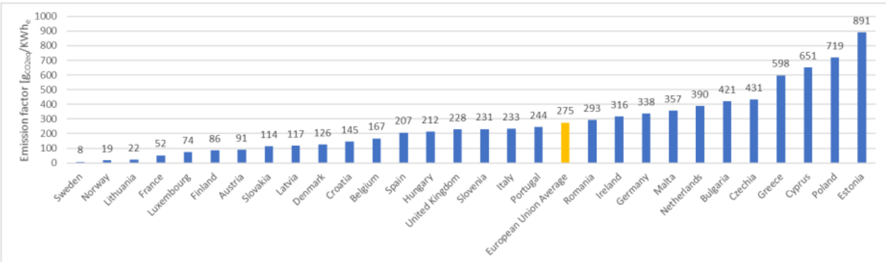

Figure 2 - Emission factors for EU countries in 2019 [13]

In a case study based in Germany, electricity cost from renewables is pointed out for wind onshore, offshore and photovoltaic technologies. Cost of electricity from these sources is variable and in 2020 it was between 0.075 €/kWh_e and 0.108 €/kWh_e, while decreasing in 2030 between 0.07 €/kWh_e and 0.085 €/kWh_e and in 2050 between 0.061 €/kWh_e and 0.069 €/kWh_e [14]. In another report, electricity price of renewable energy is assumed to be almost 0.05 €/kWh_e and the prices of synthetic fuels are calculated with this data variable between 0.02 €/kWh_e and 0.08 €/kWh_e [15]. In another study about carbon-neutral fuel options, the price of renewable energy is taken between 0.05 €/kWh_e and 0.1 €/kWh_e in 2020, between 0.04 €/kWh_e and 0.083 €/kWh_e in 2030 and between 0.02 €/kWh_e and 0.05 €/kWh_e in 2050 [16]. According to another study about power-to-liquid technologies that can be coupled with a hybrid photovoltaic and wind electrical power generation plant, renewable electricity cost is almost 0.023 €/kWh$_e$ [17]. According to another report focused on evaluating future cost of electric energy, levelised cost of energy for fossil fuel technologies can vary between 0.05 \$/kWh$_e$ and 0.10 \$/kWh$_e$ (which shift between 0.08 \$/kWh$_e$ and 0.12 \$/kWh$_e$ if CCS is implemented), for nuclear power plants this data is between 0.04 \$/kWh$_e$ and 0.07 \$/kWh$_e$, for wind powered generation systems between 0.04 \$/kWh$_e$ and 0.11 \$/kWh$_e$, for solar panels between 0.05 \$/kWh$_e$ and 0.08 \$/kWh$_e$ and for hydro power plants between 0.05 \$/kWh$_e$ and 0.10 \$/kWh$_e$ [18].

From this literature review, it has been decided to choose the electricity factors shown in Table 4 as cases to be implemented in the automatic tool used to calculate production cost and emissions of different fuels. It is important to highlight that there is not a case in which energy is 100% renewable and with zero emissions of each kind. Unless differently specified in all calculations, even in Table 1 and Table 2, "Sweden Mix" emission factors and electricity cost are taken as reference case for every calculation, while minimum electricity price is assumed for the optimistic scenarios and maximum electricity price is taken for pessimistic scenarios.

Table 4 - Emission factors and price of electricity used in the study [18]

	Emission factors					**Price**	
	CO_2	SO_x	NO_x	N_2O	CH_4	Min	Max
	g/kWh	g/kWh	g/kWh	g/kWh	g/kWh	€/kWh	€/kWh
Coal	914	0.5980	1.1100	0.0271	2.2600	0.050	0.100
EU average	275	0.1373	0.3139	0.0070	0.4885	0.070	0.085
Finland Mix	86	0.0503	0.1000	0.0022	0.1501	0.070	0.085
Sweden Mix	8	0.0144	0.0118	0.0002	0.0104	0.070	0.085
Nuclear	0.442	0.0157	0.0187	0.0001	0.0074	0.070	0.085

1.1.3. Oil-based fuels

Since the 1960s, the marine fuels market has been dominated by residual fuel oil, widely known as Heavy Fuel Oil (HFO). This fuel is the residual part of distillation and cracking process of crude oil: it has elevated levels of sulphur and metallic compounds, aromatics and carbon residues. Residual fuels need treatments, like filtration and heating, before their utilization inside diesel engines. Residual fuels can be classified according to CIMAC (Conseil International des Machines à Combustion) as shown in Table 5 and in Table 6 [19]. The correspondence between residual fuel name according to CIMAC and their marine fuel's name is the following:

- Heavy Fuel Oil (HFO): RMH 380 to RMK 700.

- Intermediate Fuel Oil (IFO): RMA 30 to RMG 380.

Intermediate fuel oil is obtained blending heavy fuel oil with up to 40% distillate oil to obtain the best compromise between price and characteristics of the fuel.

A block diagram that represents the production of marine oil-based fuels, both distillate and residual products, is shown in Figure 3.

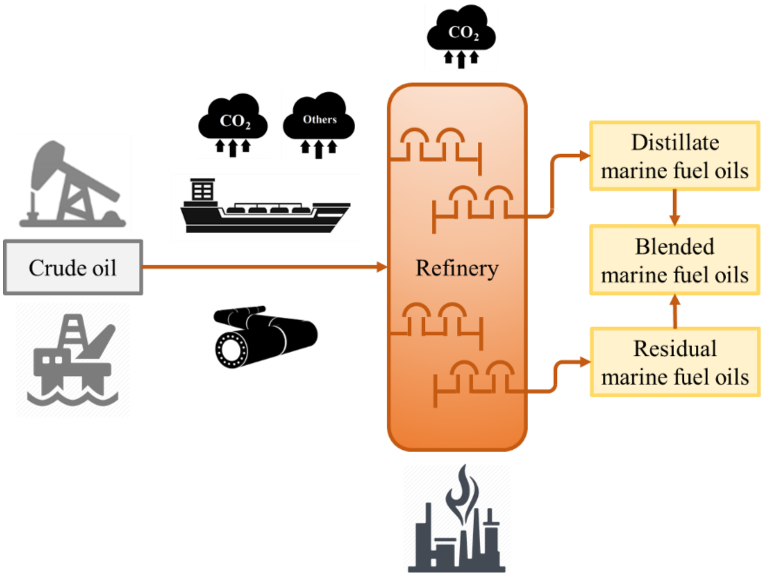

Figure 3 - Block diagram of marine oil-based fuels production

Table 5 - Residual fuels characteristics part 1 (as bunkered) [19]

<table>
<tr><th>Characteristics</th><th>Unit</th><th>RMA
30</th><th>RMB
30</th><th>RMD
80</th><th>RME
180</th><th>RMF
180</th></tr>
<tr><td>Max density at 15 °C</td><td>kg/m^3</td><td>960</td><td>975</td><td>980</td><td colspan="2">991</td></tr>
<tr><td>Max kinematic viscosity at 50 °C</td><td>cSt</td><td colspan="2">30.0</td><td>80.0</td><td colspan="2">180.0</td></tr>
<tr><td>Min kinematic viscosity at 50 °C</td><td>cSt</td><td>22</td><td>-</td><td>-</td><td colspan="2">-</td></tr>
<tr><td>Flash point (min)</td><td>°C</td><td colspan="2">60</td><td>60</td><td colspan="2">60</td></tr>
<tr><td>Pour point:
- Winter quality (max)
- Summer quality (max)</td><td>°C</td><td>
0
6</td><td>
24
24</td><td>
30
30</td><td colspan="2">
30
30</td></tr>
<tr><td>Carbon residue (max)</td><td>% (m/m)</td><td colspan="2">10</td><td>14</td><td>15</td><td>20</td></tr>
<tr><td>Ash (max)</td><td>% (m/m)</td><td colspan="2">0.10</td><td>0.10</td><td>0.10</td><td>0.15</td></tr>
<tr><td>Water (max)</td><td>% (V/V)</td><td colspan="2">0.5</td><td>0.5</td><td colspan="2">0.5</td></tr>
<tr><td>Sulphur (max)</td><td>% (m/m)</td><td colspan="2">3.50</td><td>4.00</td><td colspan="2">4.50</td></tr>
<tr><td>Vanadium (max)</td><td>mg/kg</td><td colspan="2">150</td><td>350</td><td>200</td><td>500</td></tr>
<tr><td>Total sediment potential (max)</td><td>% (m/m)</td><td colspan="2">0.10</td><td>0.10</td><td colspan="2">0.10</td></tr>
<tr><td>Aluminium plus silicon (max)</td><td>mg/kg</td><td colspan="2">80</td><td>80</td><td colspan="2">80</td></tr>
</table>

Table 6 - Residual fuels characteristics part 2 (as bunkered) [19]

<table>
<tr><th>Characteristics</th><th>Unit</th><th>RMG
380</th><th>RMH
380</th><th>RMK
380</th><th>RMH
700</th><th>RMK
700</th></tr>
<tr><td>Max density at 15 °C</td><td>kg/m^3</td><td colspan="2">991</td><td>1010</td><td>991</td><td>1010</td></tr>
<tr><td>Max kinematic viscosity at 50 °C</td><td>cSt</td><td colspan="3">380</td><td colspan="2">700</td></tr>
<tr><td>Min kinematic viscosity at 50 °C</td><td>cSt</td><td colspan="3">-</td><td colspan="2">-</td></tr>
<tr><td>Flash point (min)</td><td>°C</td><td colspan="3">60</td><td colspan="2">60</td></tr>
<tr><td>Pour point:
- Winter quality (max)
- Summer quality (max)</td><td>°C</td><td colspan="3">
30
30</td><td colspan="2">
30
30</td></tr>
<tr><td>Carbon residue (max)</td><td>% (m/m)</td><td>18</td><td colspan="2">22</td><td colspan="2">22</td></tr>
<tr><td>Ash (max)</td><td>% (m/m)</td><td colspan="3">0.15</td><td colspan="2">0.15</td></tr>
<tr><td>Water (max)</td><td>% (V/V)</td><td colspan="3">0.5</td><td colspan="2">0.5</td></tr>
<tr><td>Sulphur (max)</td><td>% (m/m)</td><td colspan="3">4.50</td><td colspan="2">4.50</td></tr>
<tr><td>Vanadium (max)</td><td>mg/kg</td><td>300</td><td colspan="2">600</td><td colspan="2">600</td></tr>
<tr><td>Total sediment potential (max)</td><td>% (m/m)</td><td colspan="3">0.10</td><td colspan="2">0.10</td></tr>
<tr><td>Aluminium plus silicon (max)</td><td>mg/kg</td><td colspan="3">80</td><td colspan="2">80</td></tr>
</table>

Table 7 – Distillate fuels characteristics (as bunkered) [19]

Characteristics	Unit	CIMAC DMX	CIMAC DMA	CIMAC DMB	CIMAC DMC
Max density at 15 °C	kg/m^3	-	890	900	920
Max kinematic viscosity at 50 °C	cSt	5.50	6.00	11.0	14.0
Min kinematic viscosity at 50 °C	cSt	1.40	1.50	2.50	4.00
Flash point (min)	°C	43	60	60	60
Pour point: - Winter quality (max) - Summer quality (max)	°C	- -	-6 0	0 6	0 6
Carbon residue 10% (V/V) distillation bottoms (max)	% (m/m)	0.30	0.30	-	-
Carbon residue (max)	% (m/m)	-	-	0.30	2.5
Ash (max)	% (m/m)	0.01	0.01	0.01	0.03
Appearance		Clear & bright			
Total sediment existent (max)	% (m/m)	-	-	0.10	0.10
Water (max)	% (V/V)	-	-	0.3	0.3
Cetane Index (min)		45	40	35	35
Sulphur (max)	% (m/m)	1.00	1.50	2.00	2.00
Vanadium (max)	mg/kg	-	-	-	100
Aluminium plus silicon (max)	mg/kg	-	-	-	25

During the last twenty years, IMO has taken some measures to encourage the utilization of different types of fuels, especially low-sulphur ones. Among oil-based fuels, there are some fuel oils that have a smaller sulphur content, like Low-sulphur Fuel Oil, Marine Diesel Oil and Marine Gas Oil. These fuels are totally or partially composed by distillate fuel oil. These fuels are classified by CIMAC as shown in

Table 7 and the correspondence among them and their marine fuel's name is the following:

- Marine Gas Oil (MGO): DMX;
- Light Diesel Fuel Oil (LDF or LDO): DMA;
- Marine Diesel Fuel Oil (MDF or MDO): DMB;
- Blended Marine Diesel Fuel Oil (BMDF): DMC.

Prices for IFO 380, MGO and Very Low-sulphur Fuel Oil (VLSFO, obtained by blending up to 40% of residual fuel with distillate) are shown in Figure 4, Figure 5 and Figure 6. Among these fuels, just VLSFO allows complying with IMO Annex VI regulations 14.1 and 14.4 about fuel's maximum allowed sulphur content outside ECA (Emission Control Areas), since it has a maximum 0.5% (m/m) sulphur content. Other fuels will necessarily need an emission abatement system to reduce sulphur oxide emissions, like open or closed loop scrubbers. A recently published report about zero-carbon fuels gives a traditional oil-based fuel production cost estimation: for HFO 0.045 $\$/kWh_{fuel}$ in 2020 and 0.055 $\$/kWh_{fuel}$ in 2050, for VLSFO 0.055 $\$/kWh_{fuel}$ in 2020 and 0.07 $\$/kWh_{fuel}$ in 2050 and for MDO 0.06 $\$/kWh_{fuel}$ in 2020 and 0.08 $\$/kWh_{fuel}$ in 2050 [20].

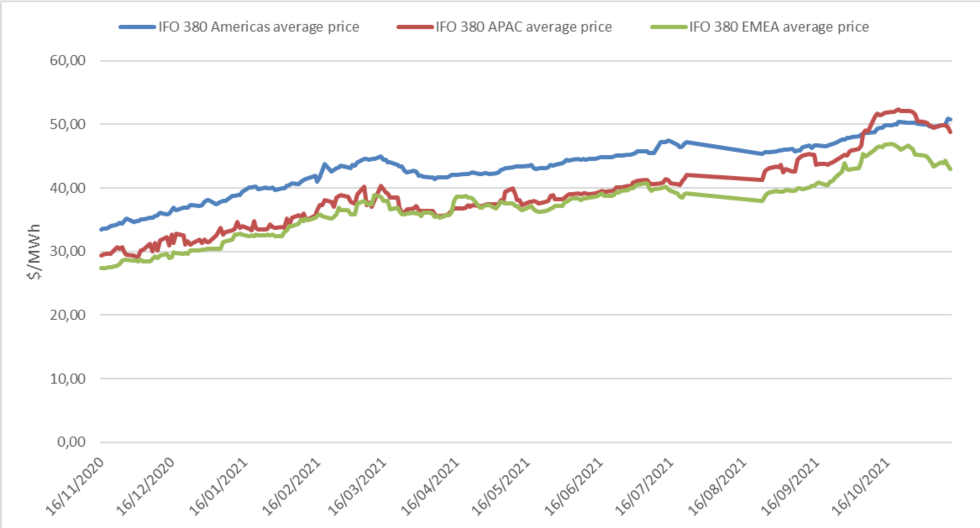

Figure 4 – HFO price between November 2020 and November 2021

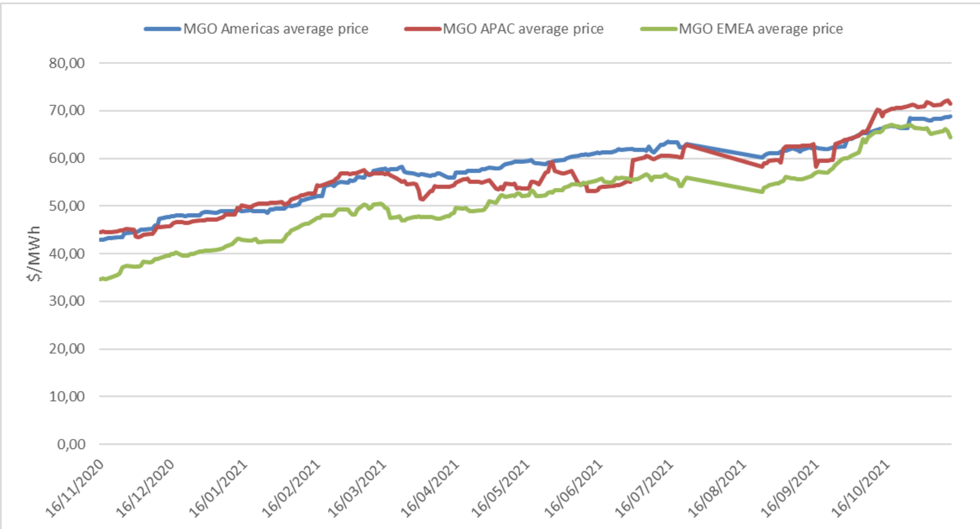

Figure 5 – MGO price between November 2020 and November 2021

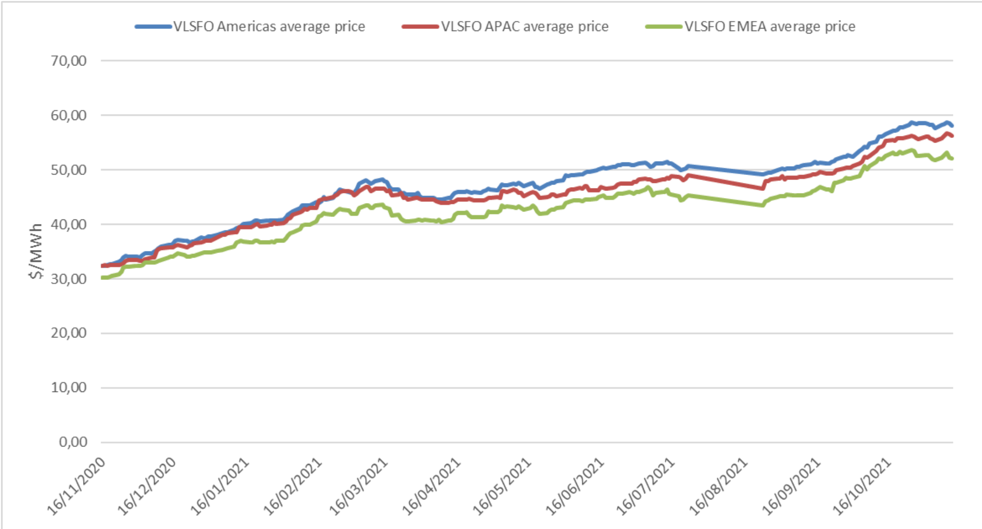

Figure 6 – VLSFO price between November 2020 and November 2021

An option to comply with sulphur's emission regulations inside ECAs is Ultra Low-sulphur Fuel Oil (ULSFO), with a sulphur content lower than 0.1% m/m [21]. As it is shown in Figure 18, HFO production is also a source of GHG emission according to a source its contribution is between 54 g_{CO2}/ kWh_{fuel} and 47 g_{CO2}/ kWh_{fuel}. Also, energy is required during the production and treatment of marine heavy fuels, as shown in Figure 19, and according to the same source, this data has a value between 0.17 kWh_{el}/kWh_{fuel} and 0.14 kWh_{el}/kWh_{fuel} [22]. According to another study, emissions for extraction and production in Europe of conventional fuels can be estimated as 31 g_{CO2}/kWh_{fuel} for HFO and 35 g_{CO2}/ kWh_{fuel} for MGO [23]. According to another research, the energy requirement for the WTT process of oil-based fuels is between 0.25 kWh_{el}/kWh_{fuel} and 0.30 kWh_{el}/kWh_{fuel}, while GHG emissions related to these processes can vary between 13 g_{CO2}/ kWh_{fuel} and 19 g_{CO2}/ kWh_{fuel} [9]. Values above this range have been found in another study, in which ULSFO and MGO emissions for the production process are indicated between 42 g_{CO2}/kWh_{fuel} and 75 g_{CO2}/kWh_{fuel} [24]. As explained in paragraph 1.1.6, methane slip caused by carbon-based fuel extraction and production must be accounted for because it has a high Global Warming Potential (GWP). For oil-based fuels, the share of mass of methane freed in the atmosphere on the total mass of oil-based fuel produced, about 0.38% to 0.57% of methane slip is caused by processes onshore and about 0.17% for production offshore [25]. Total GHG emission has been estimated in a study that considers both WTT and TTW process related to oil-based fuels and LNG. This research states for HFO a WTT carbon dioxide equivalent emission at 100 years between 35 g_{CO2eq}/kWh_{fuel} and 52 g_{CO2eq}/kWh_{fuel}, for VLSFO between 47 g_{CO2eq}/kWh_{fuel} and

60 g_{CO2eq}/kWh_{fuel} and for MGO between 67 g_{CO2eq}/kWh_{fuel} and 77 g_{CO2eq}/kWh_{fuel} [26]. Similar values have been found in a work about conversion factors for GHG emissions, in which residual oil emissions' level is almost 35 g_{CO2eq}/kWh_{fuel} and MGO emissions' level is almost 63 g_{CO2eq}/kWh_{fuel} [27]. Further confirmation of MGO's WTT emission is given in another study about the possible employment of renewable energy in transport, in which it accounts for almost 68 g_{CO2eq}/kWh_{fuel}, with an electric energy consumption of about 0.20 kWh_{el}/kWh_{fuel} [14]. WTT emissions related to the MGO production process are higher and equal to 187 g_{CO2eq}/kWh_{fuel} according to another study about the life-cycle assessment of alternative ship fuels for a coastal ferry, which uses for its calculation the parameters shown in Table 8 [12].

Table 8 – Emission factors of MGO in the Well-to-Tank phase [12]

Phase of WTT process	Unit	CO_2	SO_x	NO_x	N_2O
Production and pipeline transport	kg/kg_{crude}	$2.00*10^{-1}$	$2.51*10^{-6}$	$2.94*10^{-4}$	$2.33*10^{-4}$
Transport (Saudi to ROK)	kg/kg_{crude}	$3.36*10^{-1}$	$2.65*10^{-4}$	$9.16*10^{-3}$	-
Refinery	kg/kg_{MGO}	$3.00*10^{-1}$	$1.72*10^{-3}$	$6.99*10^{-4}$	
Terminal storage	kg/kg_{MGO}	$1.80*10^{-4}$	$4.10*10^{-7}$	$2.60*10^{-9}$	
Bunkering	kg/kg_{MGO}	$1.80*10^{-4}$	$4.10*10^{-7}$	$2.60*10^{-9}$	

Some works found in literature has also estimated synthetic hydrocarbon fuel price, which is produced starting from hydrogen, obtained via electrolysis, and carbon dioxide. These works are focused especially on finding less polluting fuels for airborne transportation, for example combining carbon dioxide and hydrogen extracted from seawater at a cost of approximately 3$ to 6$ per gallon (0.66€ to 1.31€ per litre, or 0.07 €/kWh_{fuel} and 0.14 €/kWh_{fuel}), compared to a jet fuel price of 1.24$ per gallon [28] [29]. Obviously, in order to zero CO_2 emission from the overall process of fuel production and utilization, electricity used in the fuel production process must come from CO_2-neutral sources. The work reviewed different processes and different electrical energy sources. Most processes involve Fischer-Tropsch reaction with CO coming from water-gas shift reaction. This process comprises a polymerisation that takes hydrogen and carbon monoxide as reagents and produces various quantities of synthetic hydrocarbons (alkanes, alkenes, alcohols and others), depending on the conditions of the reaction and of the catalytic bed in which synthesis is conducted [30]. A block diagram of these processes is represented in Figure 7. Three main energy components to be considered are:

- Energy needed to extract CO_2 from air (250 kWh for 3.2 tonnes of CO_2, required to produce 1 tonne of diesel fuel);
- Energy to produce H_2 from water (1.74 kWh_{el}/kWh_{H2}, giving a total of 17044 kWh);

- Thermal energy for conversion process (1750 kWh per tonne of CO_2), since the reaction is exothermal.

Electrolysis represents 73% of the total energy required in the process and using Levelised Cost Of Electricity (LCOE) published by the U.S. Energy Information Administration (EIA) for hydrogen produced by this technology that can range from 30 to 50 \$/MWh it arrives at a cost of 100 to 164 \$/bbl (\$ for an oil barrel) [31]. In specific works dedicated to that topic, Direct Air Capture (DAC) of carbon dioxide can account for a CAPEX between 750 €/(ton_{CO2}/y) and 1280 €/(ton_{CO2}/y), an OPEX between 15% and 20%, almost due to a demanding heating system, and requires between 1.2 kWh_{el}/kg_{CO2} and 1.5 kWh_{el}/kg_{CO2} [32] [33]. These data have been used for the calculations shown in Table 1 and Table 2.

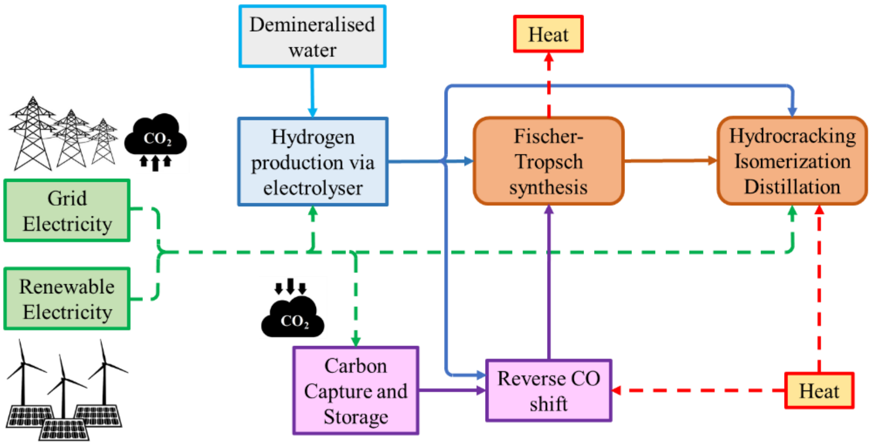

Figure 7 - Block diagram of Fischer-Tropsch fuels production

In another publication, two conditions are presented as most important for the economical viability of synthetic fuels: high annual full load hours of power-to-liquid or power-to-gas facility and a competitive price for renewable energy. Excess renewable energy is not sufficient to meet the price targets that can allow synthetic fuels to play a role in the decarbonisation strategies around the world. Also, this work states that synthetic fuel production will begin when the cost of the final product will drop between 20 and 30 c€ per kWh (so approximately 2 to 3 € per litre of fuel). This study also highlighted that cost can drop to 15 c€ per kWh in 2030 and to almost 10 c€ per kWh by 2050. Production cost for CO_2 is 145 €/t_{CO2} today and is projected to be 100 €/t_{CO2} after 2030. In these years, CO_2 obtained from the industry as a by-product via carbon capture can cost between 33 €/t_{CO2} and 17 €/t_{CO2} [34]. Calculations performed during the PhD activity and shown in Table 1 and Table 2 have indicated a cost between 90 €/t_{CO2} and 110 €/t_{CO2}, which is confirmed by this literature review. Another publication illustrates simulation and evaluation of a synthetic fuel's generation process thanks to an Aspen Plus tool. It found a power-to-liquid efficiency of 43.3% and a fuel price of 460 $/bbl when a renewable electricity cost of offshore wind power equal to 160 $/MWh is used in calculations [35]. According to a study previously mentioned, Fischer-Tropsch synthesis plant implicates an investment cost of up to 900 €/kW of liquid fuel produced in 2020, 550 €/kW in 2030 and possibly a further drop to 300 €/kW in 2050. For carbon dioxide capture plant a CAPEX of 2230 €/kW is assumed for 2020 and a drop to 1635 €/kW in 2050 is foreseen. For these processes, annual OPEX has been estimated as 3% to 4% of CAPEX and also a load factor of 8000 hours per each year [34]. Also, electricity consumption of the carbon dioxide capture plant can vary from 0.7 to 1.1 MJ/kg_{CO2}, more than double of values assumed in the first study mentioned in this paragraph [14]. F-T Diesel production can require up to 0.06 kWh_{el}/kWh_{fuel} for its production from forest residue (with a negative GHG emission of 245 g_{CO2}/kWh) and can require up to 0.66 kWh_{el}/kWh_{fuel} for its production from natural gas. Total cost of F-T diesel can vary between 0.28 €/kWh_{fuel} and 0.48 €/kWh_{fuel} [14]. Another useful source for data about electrofuels production gives a CAPEX varying between 400 €/kW_{fuel} and 8000 €/kW_{fuel} and an annual OPEX between 5% and 10% of CAPEX for each year. Lifetime of the plant can be estimated to vary between 20 and 30 years and the resulting production cost of the fuel is stated from 0.2 €/kWh_{fuel} to 0.3 €/kWh_{fuel}. CAPEX for F.T synthesis according to another study can vary between 400 €/kW_{fuel} and 1000 €/kW_{fuel} [36]. CAPEX according to another report for a F-T synthesis plant is equal to almost 880 €/kW_{fuel} with annual OPEX about 3% of CAPEX, an efficiency equal to 57.5% and an electric energy requirement of about 0.02 kWh_{el}/kWh_{fuel}. The whole WTT process implicates the emission of about -277 g_{CO2}/kWh_{fuel}, 0.11 g_{NOx}/kWh_{fuel}, 0.012 g_{SOx}/kWh_{fuel}, 0.001 g_{N2O}/kWh_{fuel} and $3.2*10^{-4}$ g_{CH4}/kWh_{fuel}. Resulting production cost is 0.14 €/kWh_{fuel} in 2018, 0.09 €/kWh_{fuel} in 2030 and 0.04 €/kWh_{fuel} in 2050 [17]. Carbon capture from the air has a CAPEX of 228 €/ton_{CO2} and an annual OPEX equal to 4% of CAPEX, requiring 225 kWh/ton_{CO2} [37].

According to data presented, it can be calculated that the amount of carbon dioxide captured and so removed by the atmosphere is around 260 g_{CO2}/kWh_{fuel}. Excluding electricity demand for hydrogen production, that will be treated in paragraph 1.1.8, the consumption of electrical energy can be estimated as 0.5 kWh_e/kWh_{fuel} and the hydrogen input per fuel output is taken as 1.74 kWh_{H2}/kWh_{fuel}. In a study currently under development, F-T diesel WTT process implicates a carbon dioxide emission of almost 25 g_{CO2}/ kWh_{fuel} [24].

In Figure 8 and Figure 9 are shown Oil-based fuels production costs and WTT carbon dioxide equivalent emissions calculated in this thesis and the range found from the literature review. HFO, MGO and LSFO have a comparable price range, but the most costly among them is MGO, since it is more refined. Synthetic FTD obtained via renewable hydrogen produced via Solid Oxide Electrolisers (SOEC-H2 FTD) has an estimated cost equal to more than three times the one of MGO. Synthetic FTD obtained from hydrogen produced by natural gas via steam reforming and carbon capture (CCS-H2 FTD) has an estimated cost slightly lower than SOEC-H2 FTD. The main price difference between these two options is related to feedstock cost, thus on hydrogen cost, which is higher for renewable hydrogen. Electricity and infrastructure cost are almost the same for these two cases. As shown in paragraph 1.1.2, electricity price is considered equal to 0.070 €/kWh, so its optimistic value.

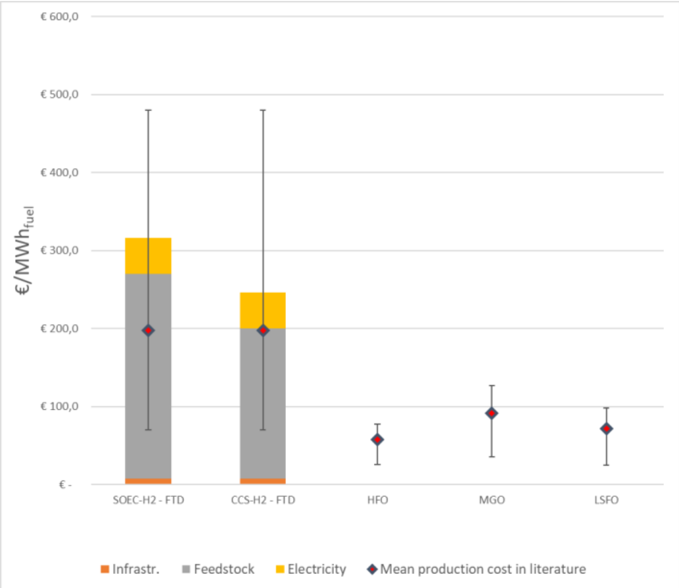

Figure 8 – Oil-based fuels production cost (optimistic case)

WTT carbon dioxide equivalent emission values from HFO and LSFO can be considered comparable and equal to almost 50 kg_{CO2}/MWh. WTT carbon dioxide equivalent emission values from MGO are slightly higher because a more elaborated refining process requires more energy and thus more emissions. Calculated value for WTT emissions for SOEC-H2 FTD are negative and equal to almost -210 kg_{CO2}/MWh, a figure inside literature range and near the mean literature value equal to almost -170 kg_{CO2}/MWh (without specifying hydrogen type). This negative value is related to the fact that carbon dioxide used in the FTD production process is captured directly from air, while emissions related to hydrogen production are neglectable. For FTD produced from hydrogen obtained by natural gas, the calculated WTT emission is almost zero (2 kg_{CO2}/MWh): this figure is the result of the balance between emissions related to hydrogen production and FTD synthesis and the carbon dioxide capture process.

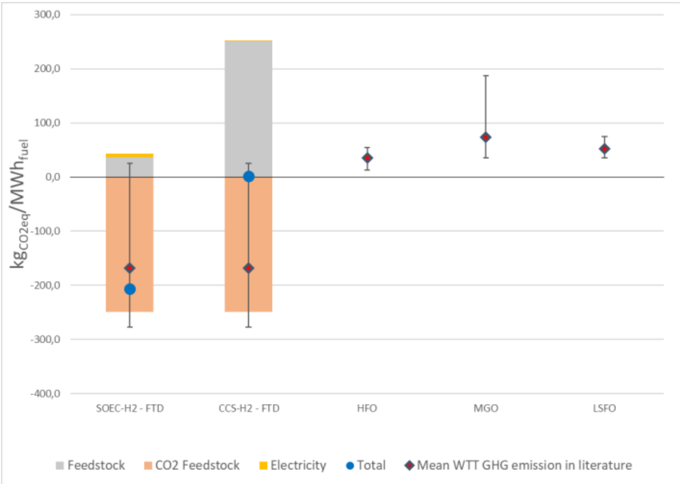

Figure 9 - Oil-based fuels WTT emissions (optimistic case)

1.1.4. Biofuels

Biofuels are characterized by low-sulphur content, and they can assure a reduction of CO_2 that depends on the type of product analysed. Currently, there is no availability of large volumes of biofuels, so this cannot be considered an easy solution to reduce emissions from shipping. Also, the maritime sector has a reduced knowledge about handling biofuels onboard and compatibility with prime diesel engine suppliers' needs to be verified. There are various types of biofuels obtained through different feedstocks, but current types produced at a sufficient volume rate are:

- Biodiesel derived from oil or pulping of various plants.
- Bioethanol obtained from waste and lignocellulosic feedstock.

Among these options, we can consider HVO (Hydrotreated Vegetable Oil), FAME (Fatty Acid Methyl Esters) and two generations of bioethanol, with characteristics shown in

Table 7. Other options, like Straight Vegetable Oils (SVOs) do not need a lot of treatments, but are pure oil extracted from plants. They can be used as an alternative for oil-based fuels into marine internal combustion engine, but it is not suggested to use them for long periods. SVOs are characterized by a high viscosity and tend to build up carbon deposits inside engines [38]. Usually, FAME is identified as biodiesel and thanks to lower viscosity and boiling point than SVO can assure lower engine degradation and maintenance. By now it is commonly used as "drop-in" fuel, so it can be added directly in MDO or MGO and resulting mixture can be directly used in traditional diesel engines with minor modifications. Biodiesel can reduce smoke, soot, sulphur oxides, carbo monoxide and particulate matter. As downside, it must be properly heated because its properties for fuel transfer operations

degrade at temperatures lower than 32°C and it tends to degrade pumps, injectors, and piston rings quicker than traditional oil-based fuels. Biodiesel also should comply with requirements given in standard EN ISO 14214. This fuel can improve lubricating efficiency of some traditional marine fuels, reducing wear of components [39]. HVO is produced from vegetable oils or animal fats chemically treated and needs hydrogen during its production. This is also a "drop in" fuel that can be blended with conventional ones to be used inside conventional diesel engines. For this reason, HVO is also known as renewable diesel. They do not need a high-quality feedstock as biodiesel to be produced and are characterized by higher cetane number and energy density. There are still some questions about sustainability of these fuels since their price and their overall production process emissions are related to their feedstock, that implies high land usage and so high water consumption [40]. Due to its more complicated production process, this fuel is considered a high-quality product and it has an easier fuel logistics and integration onboard ships. HVO has a higher heating value than FAME. Currently, algae are under evaluation to become a possible feedstock for these products [41]. A basic block diagram of some biofuels is shown in Figure 10, in which unlike other block diagrams it is not shown the need of electricity or heat, because they are needed in almost each production process. Also, hydrogen is needed in the production process of HVO and bioethanol [42].

Table 9 - Characteristics of biofuels [42]

Characteristics	Unit	HVO	FAME	Bioethanol 1st gen.	Bioethanol 2nd gen.
Lower Heating Value	MJ/kg	43	38	27	27
Density	kg/m^3	0.779	0.888	0.789	0.789
Carbon content	%	77	77	52	52
CO_2 emission on combustion	g/kWh	270	270	292	292
Life-cycle GHG equivalent	g/kWh	29 90	270 400	123	87

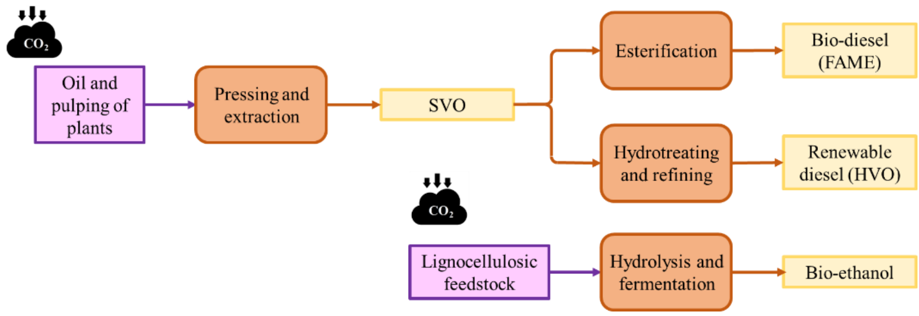

Figure 10 - Block diagram of biofuels production

Another work classifies main advantages, disadvantages and characteristics of biofuels option for the marine sector, that are listed in Table 10 and in Table 11 [43]. Also, it is important to highlight the fact that not every biofuel can be blended directly with marine fuels, for example bio-oils. These products could be blended with HFO to reduce PM and sulphur emission, even if more extensive studies would be needed to consider this a real possibility. Also, price is an important factor that must be assessed for all these options. FAME price is estimated around 3.5 $/gal (almost 0.93 $/l), renewable diesel from 3 $/gal (0.79 $/l) to 4.3 $/l (1.14 $/l), F-T diesel from 1.2 $/gal (almost 0.32 $/l) to 3.1 $/gal (almost 0.82 $/l) and FP bio-oil at less than 0.94 $/gal (almost 0.25 $/l). These fuels can provide a reduction of PM emission, also with blend level lower than 10%, and are beneficial both for SO_x and NO_x emissions. Low-sulphur oxides emissions are related to sulphur content inside biofuels, shown in Table 11, that is even lower than low-sulphur marine distillates. Biofuel cost is indicated in another study as variable between 0.12 $/kWh$_{fuel}$ and 0.28 $/kWh$_{fuel}$ [44].

Table 10 - Biofuels for marine use key properties [44]

Fuel type	Availability	Advantages	Disadvantages.
FAME	Commercial	1. Miscible with MGO 2. Mature technology 3. Approved for use with MGO (7% blend level)	Oxidation stability and shelf life
SVO (Straight Vegetable Oil)	Commercial (not for marine)	Relatively inexpensive	Oxidation stability and shelf life
Renewable diesel	Commercial	1. Miscible with MGO 2. Mature technology 3. Excellent combustion properties 4. Neat zero O_2	High production cost
Fischer-Tropsch (F-T) diesel	Commercial	1. Miscible with MGO 2. Excellent combustion properties	Complex processing and expansive
Fast-pyrolysis (FP) bio-oil	Commercial	1. Possible low PM formation 2. Miscible with butanol	1. Incompatibilities with infrastructure 2. Not miscible with neat MGO
Hydrothermal liquefaction (HTL) biocrude	Research stage	Improved heating value compared with FP bio-oil	Demonstration scale only
Upgraded FP bio-oil	Research stage	1. Miscible with MGO 2.Good heating value	Bench scale only

A great advantage for biofuels implementation is the fact that carbon emitted during combustion is pulled from the atmosphere during the life of biomass part of these products' feedstock. Biodiesel, renewable diesel, and F-T diesel have an estimated emission of about 270 g_{CO2}/kWh_{fuel} of fuel combusted, while the carbon uptake of their production process is almost 162 g_{CO2}/kWh_{fuel}, 180 g_{CO2}/kWh_{fuel} and 252 g_{CO2}/kWh_{fuel} respectively [43]. Also, as stated in paragraph 1.1.2, F-T diesel can also be produced directly from hydrogen and carbon dioxide captured from atmosphere. From another source, the whole production process of bioethanol can determine a global emission between 25 g_{CO2}/kWh_{fuel} and 108 g_{CO2}/kWh_{fuel} [42]. A value confirming this emission range from bioethanol WTT emissions has been found in another public report, that also indicates a biodiesel WTT emission oh about 41 g_{CO2eq}/kWh_{fuel} [27]. According to another study currently under development, WTT carbon dioxide emission is influenced by raw materials used for biofuels production. If crop residues are used, WTT emission of carbon dioxide is -272 g_{CO2}/kWh_{fuel}, while for example if palm oil or soybean oil represent raw materials WTT emission is between -223 g_{CO2}/kWh_{fuel} and -300 g_{CO2}/kWh_{fuel} [24]. Same conclusions are drowned for bioethanol production, that if obtained via hydrolysis of sugar or starch can account WTT emissions for almost -38 g_{CO2}/kWh_{fuel}, else if obtained by sugarcane this data is almost -17 g_{CO2}/kWh_{fuel}. According to another source, biofuel production cost can improve from 0.08 $/kWh_{fuel}$ to 0.12 $/kWh_{fuel}$ in 2020 to a range between 0.06 $/kWh_{fuel}$ and 0.08 $/kWh_{fuel}$ in 2050 [45]. A database of WTT emissions for different fuel production processes states a renewable diesel carbon uptake between -205 g_{CO2}/kWh_{fuel} and -187 g_{CO2}/kWh_{fuel} [22].

Table 11 - Biofuel properties [22]

Characteristics	Unit	Biodiesel	Renewable diesel	F-T diesel	FP bio-oil	Upgraded FP oil	HTL biocrude
Density	kg/m^3	880	780	765	1200	840	1100
Kinem. viscosity (40°C)	cSt	4 - 6	2 - 4	2	40 - 100		
Cetane number	-	47 - 65	>70	>70			
Lubricity	µm		650	371			
Lower heating value	kWh/kg	10.3	12.2	11.9	4.4		8.9
Cloud point	°C	-3 – 15	-5 - -34	-18			
Pour point	°C	-5 – 10			-9 -36		
Water content	% (m/m)	0	0	0	20 - 35	0.1	8
Oxygen content	% (m/m)	11	0	0	34-45	0.5	10-13
Sulphur content	% (m/m)	<0.0015	<0.0005	<0.1	<0.05	<0.005	0

A recent report states that the cost of biofuels is now and will be in the medium term higher than fossil fuels [46], and the main drivers for their implementation onboard ships are:

- A general interest in reducing emission levels from ships, both from national and international agencies, but also from costumers.
- The desire of shipowners to be less dependent on crude oil pricing.
- The possibility of integrating biofuels into existing infrastructure both on-shore and off-shore as pure fuel or blending it with traditional ones.

Producing a biofuel for marine use can be advantageous both for producer and for consumer because quality required for these users is not very high, especially when compared to road transport or aviation. For economic considerations, some useful information has been found, especially regarding both fixed and operating and maintenance (O&M) costs [47]. The plant's configuration in this work can synthesize HVO from waste vegetable oil, and hydrogen is obtained via high temperature Solid Oxide Electrolysis Cells (SOECs). Plant production is 40000 t/y and works for 8000 h/y. Estimated quantity of hydrogen required in the process is 0.15 kWh_{H2}/kWh_{fuel}, while electricity consumption of the whole plant is 0.1 kWh_{el}/kWh_{fuel}. Total plant cost is calculated as 51.39 million dollars (M$), of which 5.93 M$ are accounted for SOECs. Operating and maintenance cost are 6.87 M$/y (13.4% of CAPEX), assuming 0.04 $/kWh of electricity and a price of 260 $/t for waste vegetable oil. According to sensitivity analysis performed, waste vegetable oil price has the largest impact on HVO price, more than fuel oil price or SOECs lifetime. Final levelised cost of product obtained is 0.68 $/l. According to other sources, energy consumption for biodiesel production from soybean is almost 0.5 kWh_{el}/kWh_{fuel} [46].

In Figure 11 and Figure 12 are shown production cost and WTT carbon dioxide equivalent emission ranges and mean values found in literature. Production cost is more variable and slightly higher for biodiesel than for renewable diesel, but this data is also more uncertain. These tendencies are very similar for WTT carbon dioxide equivalent emission: this figure for biodiesel production has more uncertainty than the one for renewable diesel, and the mean WTT emission level is higher for biodiesel production. The difference between WTT emission levels is pronounced, and renewable diesel production mean value is almost equal to -110 kg_{CO2}/MWh.

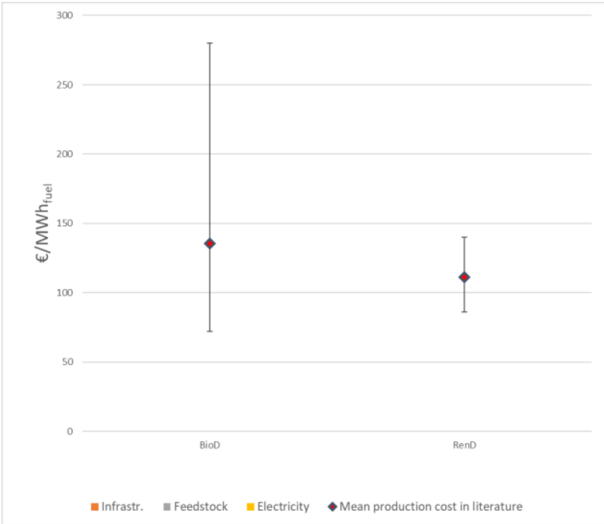

Figure 11 – Biofuels' production cost

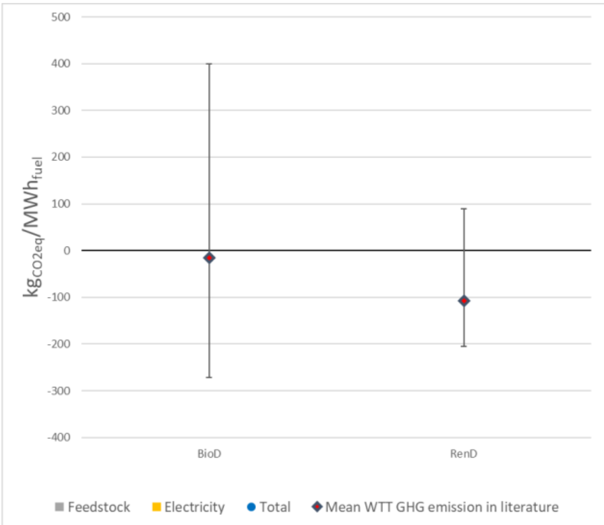

Figure 12 – Biofuels WTT emissions

1.1.5. Liquefied Petroleum Gas (LPG)

Despite being a common alternative fuel for engines, Liquefied Petroleum Gas (LPG) has not been considered for a long time as a possible marine fuel. LPG is a mixture of light hydrocarbons (normally propane and butane) that is gaseous at ambient temperature and pressure but can be easily liquefied when pressurised or refrigerated. LPG is a by-product of some processes involving other hydrocarbons, mainly oil refining and natural gas purification. Global LPG production in 2016 was, on an energy basis, equal to average fuel consumption of the whole maritime sector from 2010 to 2012. Thanks to new requirements about emissions, LPG is owning consideration among alternative fuels for shipping because it can lower all noxious exhaust gases, especially sulphur oxides and particulate matter. LPG is relatively easier to install onboard ships than Liquefied Natural Gas (LNG), and in some ports there are already dedicated infrastructures for storage and bunkering. LPG quality can vary among ports, and this can cause some problems that can be overcome installing a fuel treatment system onboard the ship. It is worth to highlight the fact that LPG can be used as fuel for Diesel engines, Otto cycle engines and gas turbines. Cruise vessels are considered among the type of ships that could benefit more from a conversion to LPG, and its payback period is estimated to be the same as LNG [48]. As a lot of alternative fuels for the marine sector, a wider LPG adoption will require investments from shipowners and ship designers, development of new engines and the definition of new rules and regulation by IMO, classification societies and national authorities. LPG price during 2015 has dropped at less than 5 \$/GJ (18 $\$/MWh_{fuel}$) on a Lower Heating Value (LHV) basis, as shown in Figure 14 [49]. Estimations of the price from 2016 to 2022 found an LPG price between 5 and 15 \$/GJ (54 $\$/MWh_{fuel}$), almost the same rage attributed to LNG in a study about cost and benefits of different alternative fuels for a product tanker [50]. In another study about alternative fuels for shipping, LPG cost is estimated to be between 0.03 $\$/kWh_{fuel}$ and 0.10 $\$/kWh_{fuel}$ [44]. Historical price of US LPG is shown in Figure 13 [51].

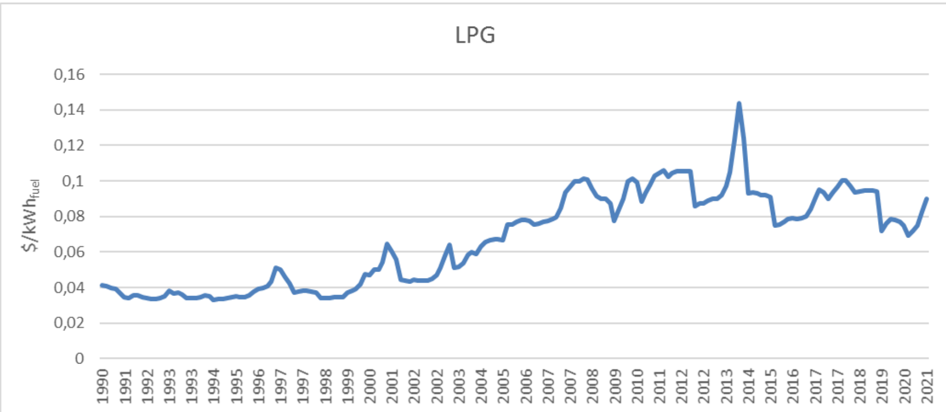

Figure 13 – US LPG residential historical price [51]

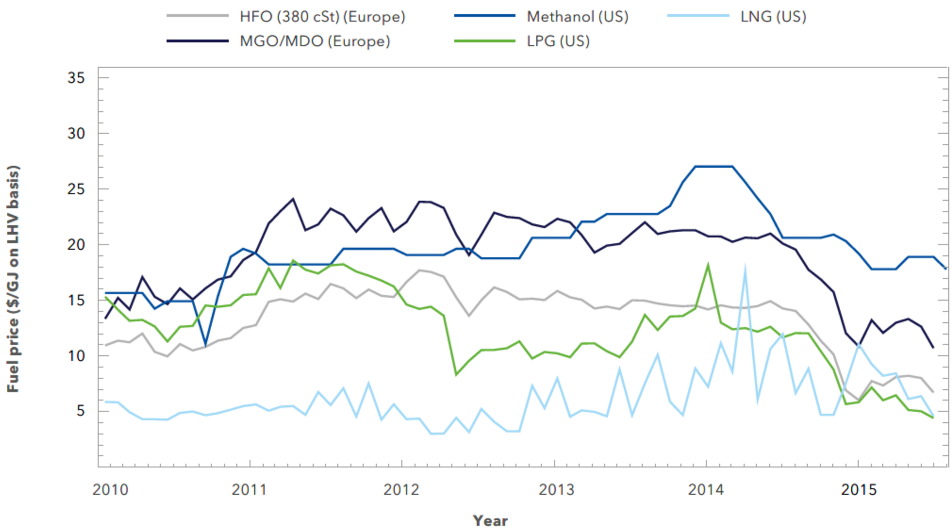

Figure 14 - Historic price of HFO, MGO, methanol, LPG, and LNG between 2010 and 2015 [51]

Specific CO_2 emission has been assumed based on its carbon content (3.01 kg_{CO2}/kg_{MeOH}) as 220 g_{CO2}/kWh_{fuel} and is also confirmed by other sources about fuel's specific carbon dioxide emissions [52]. Another source for emission data from LPG combustion is shown in Figure 18: this work considers almost 50 g_{CO2}/kWh_{fuel} of Well-To-Pump (WTP) emission and 234 g_{CO2}/kWh_{fuel} for Pump-To-Wheel (PTW) emission [53]. LPG production process requires 0.14 kWh_{el}/kWh_{fuel} [22]. In some studies, about life-cycle assessment of fuels, WTT emissions of carbon dioxide accountable for LPG are almost 28 g_{CO2}/kWh_{fuel} [24] [27]. Fuel price range was determined from this literature review and not considering the whole production process because of the lack of literature sources. This range will be considered an input data for next analysis and for a comparison with other possible marine fuels.

Renewable LPG, also known as bioLPG, is gaining momentum during recent years. Right now is considered bioLPG the waste of bio-diesel's production process that implies hydrogenation of animal and plant oils, that has been briefly described in paragraph 1.1.4. Whole world's production of bioLPG is currently performed by these processes. Technically, there are other processes that could be used to produce bioLPG, but these are currently at a validation stage. Overall, bioLPG can assure a CO_2 emission reduction on its whole lifecycle that can vary between 60% and 90% [54]. Cost of bioLPG in literature has been indicated as 128 €/MWh [53]. Another reference project for a bioLPG production process of almost 262 million of liters each year requires 3000 tons per day of wood and states that production cost, is almost 90 $/MWh [55]. Since both LPG and bioLPG are mainly by-products of the production processes shown in Figure 3 and Figure 10, no block diagram of fuel production is shown in this paragraph. Essentially, a dedicated process for LPG production would be very similar to the one shown in Figure 7 and Figure 10 because it can be produced by atmospheric carbon dioxide or cellulosic feedstock [54].

In Figure 15 and Figure 16 are shown production cost and WTT carbon dioxide equivalent emission ranges and mean values for LPG and bio-LPG found in literature. Production cost is higher for bio-LPG than for LPG. This tendency is the opposite of the one valid for WTT carbon dioxide equivalent emission: this figure for bio-LPG production is lower than the one of LPG production process. Also, uncertainty for WTT carbon dioxide equivalent emission is higher than uncertainty for production cost.

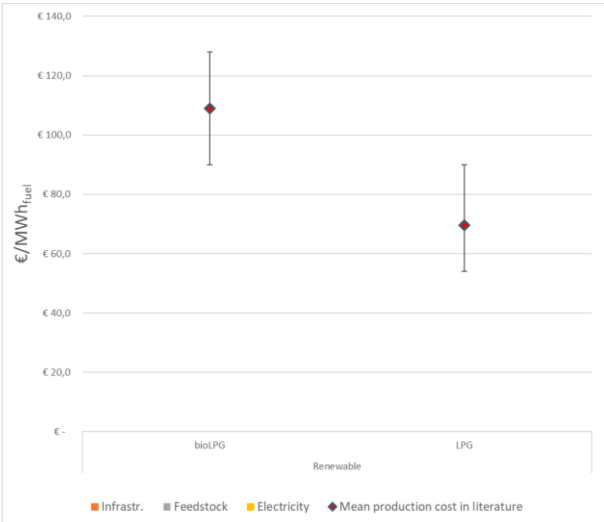

Figure 15 – LPG and bio-LPG production cost

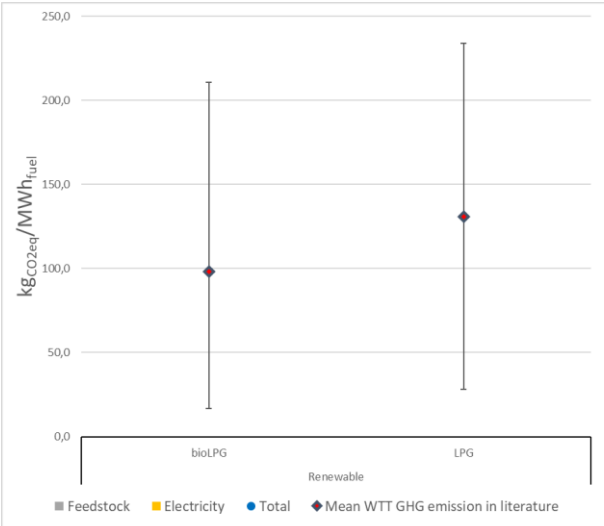

Figure 16 - LPG and bio-LPG WTT emissions

1.1.6. Liquefied Natural Gas (LNG)

Natural gas is a hydrocarbon mixture that can be found under earth's surface or that can be synthesized artificially. As a fossil fuel is mainly composed by methane (CH_4), which can represent a mass concentration between 70% and 99 %, and other hydrocarbons like ethane (C_2H_6), propane (C_3H_8) and butane (C_4H_{10}) with variable percentages. Some non-combustible gases like nitrogen, helium and carbon dioxide are part of natural gas mixture. Its composition and so its lower and higher heating value varies according to place of extraction across the world. Variation of natural gas composition that comes from different fossil sites around the world can be found in Table 12 [56]. LNG has been considered for many years as the main solution for noxious emission reduction in shipping because, when compared to HFO, it has the advantage of an 85% NO_x emission reduction, almost no SO_x and particulate matter emission and a 20% to 30% CO_2 emission reduction [57] [58]. These important results are obtained without emission reduction systems, now widely installed in oil fuelled ships. LNG is now seen by some ship designers as a transitional solution for shipping sector between current fuels and possible net-zero emission fuels in the future, like the ones described in this chapter [59]. For this reason, different ship types, including cruise ships, are adopting LNG as fuel is constantly growing. This fuel option bring also concern is growing about methane emission related both to the production process of natural gas and to the conversion from fuel to energy by power generators [60]. This aspect must be carefully considered because methane has a great impact on global warming, since its Global Warming Potential (GWP) over 100 years can range from 27 to 47 [61]. Another source states that

GWP for methane is equal almost to 84-87 over a 20-year lifetime, and it equal almost to 28-36 over a 100 years' timeframe [62]. GWP is the quantity of heat that can be absorbed by a gas in the atmosphere, expressed as a multiple of the heat that would be absorbed by the same mass of carbon dioxide.

Table 12 - Typical composition of LNG by country [56]

Origin	Methane (C1) %	Ethane (C2) %	Propane (C3) %	Butane (C4+) %	Nitrogen (N2) %
Algeria	87.6	9.0	2.2	0.6	0.6
Australia	89.3	7.1	2.5	1.0	0.1
Malaysia	89.8	5.2	3.3	1.4	0.3
Nigeria	91.6	4.6	2.4	1.3	0.1
Oman	87.7	7.5	3.0	1.6	0.2
Qatar	89.9	6.0	2.2	1.5	0.4
Trinidad & Tobago	96.9	2.7	0.3	0.1	0.0

Natural gas has a specific weight of 0.777 kg/m^3 at 0 °C and 1 bar. This gas needs to become liquid at -162 °C at 1 bar to be stored with a sufficient high density oh ships. Under these conditions, LNG has a specific weight equal to almost 728 kg/m^3. It can be assumed that its LHV is equal to 13.5 kWh/kg (48.6 GJ/kg). Natural gas in its vapour phase is flammable when volume concentration in air is between 5% to 15%. Unlikely other potential new fuels for maritime sector, LNG installation onboard is supported by IMO's International Code of Safety for Ship Using Gases or Other Low-flashpoint Fuels (IGF Code) and by various classification society's rules and regulations. Also, flag administrations, such as United States Coast Guard (USCG) or United Kingdom Maritime and Coastguard Agency (UK MCA) have developed national regulations [63]. This fuel is seen as an alternative, especially for ships which sale most of their routes inside Emission Control Areas (ECAs). Natural gas has a very little sulphur content, so it can cut sulphur oxides emissions and when used in internal combustion engines it can reduce nitrogen oxides emissions. Natural gas, as previously stated, is mainly composed by methane and on a twenty-year period, and methane can trap up to 86 times more heat than the same amount of carbon dioxide in a 20 years' timeframe [64]. So, if prime generator does not use whole fuel stream input, methane can be freed in atmosphere, causing an important GHG impact. LNG is also able to cut carbon dioxide emission due to its lower carbon content per LHV of the fuel: specific CO_2 emission from LNG is equal to 2.75 kg_{CO2}/kg_{fuel}, while this data for HFO is equal to 3.11 kg_{CO2}/kg_{fuel}. LNG price is also very competitive with other oil-based alternatives, as can be seen from Figure 14, because its price has been lowered since 2010 than MGO and can be considered comparable to HFO. In other documents, like a European Union (EU) study about natural gas as a fuel or a publication about the cost of innovative energy systems onboard ships, LNG price in 2015 and in the future is set between 0.030 $\$/kWh_{fuel}$ (with multiple confirmations on this cost) and 0.060 $\$/kWh_{fuel}$, with a price that increases with time [65] [14] [66]. In a study about alternative marine fuels by DNV-GL for LNG price states that this data falls in the range from 0.05 $\$/kWh_{fuel}$ and 0.18 $\$/kWh_{fuel}$ [44]. Historical price of natural gas at Henry Hub is shown in Figure 17 [67].

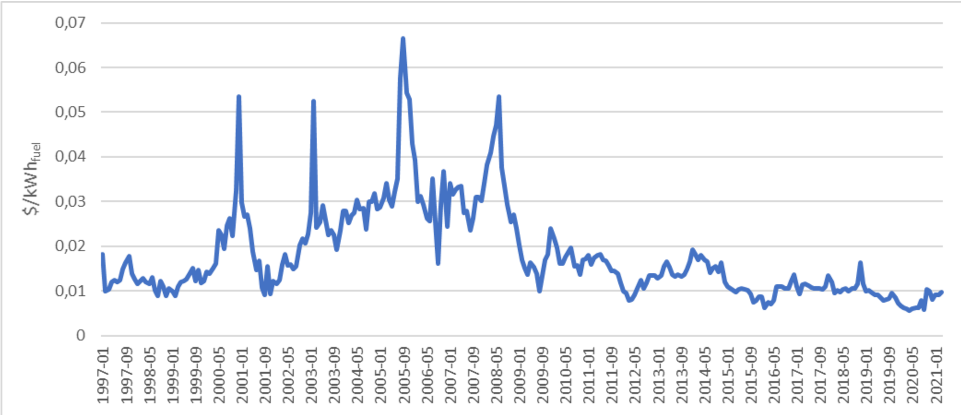

Figure 17 - Henry Hub historical natural gas price [67]

Green House Gases (GHG) emissions caused by LNG and other hydrocarbon fuels already treated in this document are showed in Figure 18, with data found in a reliable database of the US Department of Energy [22]. In this figure, Well-To-Pump (WTP) emissions and Pump-To-Wheel (PTW) emissions of the road vehicles are the same as WTT and TTW of the marine cases. From the same sources in Figure 19 is shown electric energy consumption for production of different fuels. In this case is indicated that LNG processing requires 0.19 kWh_{el}/kWh_{fuel}, a little higher than Compressed Natural Gas (CNG) electric energy required because liquefaction process is different from compression, and obviously more energy demanding. Also, in that publication it is stated that 70 g_{CO2}/kWh_{fuel} are emitted from LNG production process. In a study about methanol that compares this fuel with alternatives, like natural gas, it is stated that natural gas extraction implies an emission of GHG between 7 g_{CO2}/kWh_{fuel} and 29 g_{CO2}/kWh_{fuel}: these values are confirmed by a publication about cost of sustainable fuels [68] [66]. According to an online database about emissions related to marine fuels' production process, WTT emission for natural gas extraction and processing are between 47 g_{CO2}/kWh_{fuel} and 83 g_{CO2}/kWh_{fuel} [24]. Values of almost 40 g_{CO2}/kWh_{fuel} for CNG and 70 g_{CO2}/kWh_{fuel} for LNG are stated in research about conversion factors for companies that report GHG emissions [27]. Without compression or liquefaction, natural gas production process can account for almost 25 g_{CO2}/kWh_{fuel} according to a study about the methane slip emission issue [69]. A study about possible alternative fuels in transport sector highlights a WTT emission of almost 62 g_{CO2eq}/kWh_{fuel} for CNG and 73 g_{CO2eq}/kWh_{fuel} for LNG, with an electric energy required for the production process equal to 0.21 kWh_{el}/kWh_{fuel} and 0.22 kWh_{el}/kWh_{fuel} respectively [14]. A WTT emission equal to almost 110 g_{CO2eq}/kWh_{fuel} for natural gas production and treatment is indicated in a document about life-cycle assessment of alternative ship's fuels [12].

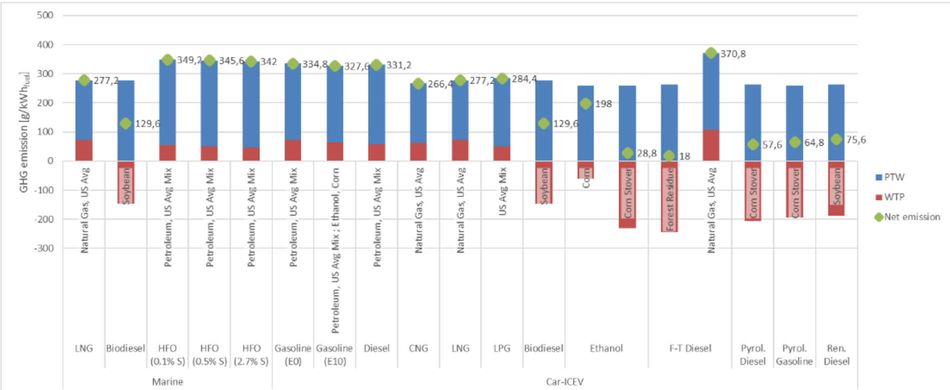

Figure 18 - GHG emissions from hydrocarbon fuels [12]

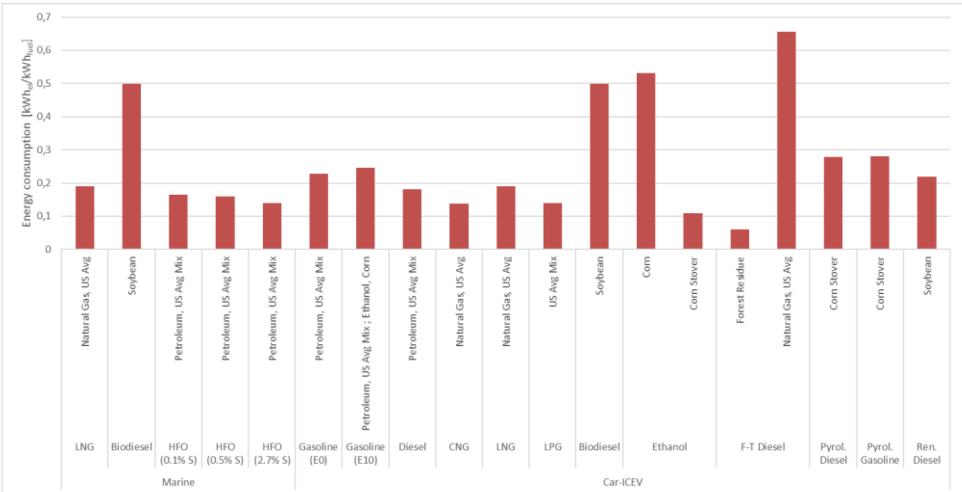

Figure 19 – Electric energy consumption for fuel production and management [12]

Table 13 – Emission factors of natural gas in the Well-to-Tank phase [12]

Phase of WTT process	Unit	CO_2	SO_x	NO_x	N_2O	CH_4
Production and pipeline transport	kg/kg_{NG}	$6.76*10^{-2}$	-	$4.28*10^{-4}$	$1.5*10^{-4}$	$9.50*10^{-5}$
Purification and liquefaction	kg/kg_{LNG}	$2.28*10^{-1}$	$1.27*10^{-6}$	$1.87*10^{-4}$	$7.47*10^{-6}$	$1.94*10^{-3}$
Transport (Qatar to ROK)	kg/kg_{LNG}	$3.08*10^{-1}$	-	$2.00*10^{-4}$	$5.64*10^{-6}$	$5.64*10^{-6}$
Terminal storage	kg/kg_{LNG}	$1.80*10^{-4}$	$4.10*10^{-7}$	$2.60*10^{-9}$	-	-
Bunker truck (108 km)	kg/kg_{LNG}	$5.72*10^{-3}$	$3.6*10^{-8}$	$7.48*10^{-6}$	$3.43*10^{-7}$	$4.59*10^{-9}$
Bunkering operations	kg/kg_{LNG}	$1.80*10^{-4}$	$4.10*10^{-7}$	$2.60*10^{-9}$	$2.60*10^{-9}$	$8.86*10^{-6}$

Natural gas is extracted by wells both onshore or offshore and, normally, is treated to remove hydrocarbons with a high molecular weight and impurities, like water, sulphur, and residual carbon dioxide [56]. Then, natural gas is transported to its liquefaction sites via pipelines or ships able to transport Compressed Natural Gas (CNG). A block diagram of this process is shown in Figure 20. WTT emissions related to these processes are caused by three possible events:

- Venting from production and processing sites, that can be deliberate or accidental.
- Flaring.
- Fugitive methane emission from operations like transmission and distribution, both for transports to the liquefaction plant and in the liquefaction site [70].

Accounting the share of methane mass freed in atmosphere on the total mass of natural gas produced, about 0.55% to 0.94% of methane slip is caused by WTT processes onshore and about 0.19% for production offshore (equal respectively to 0.41 g_{CH4}/kWh_{fuel}, 0.70 g_{CH4}/kWh_{fuel} and 0.14 g_{CH4}/kWh_{fuel}) [25]. Other estimations of methane slip emission states that for WTT processes can account up to 1.1 g_{CH4}/kWh_{fuel} for LNG [64] or almost 0.6 g_{CH4}/kWh_{fuel} [24]. Other more accurate methods for methane slip calculations can be found in a study about an emissions' estimation methodology for oil and natural gas industry [71]. Global GHG emission for LNG production process, which accounts both carbon dioxide and methane, has been indicated between 67 g_{CO2eq}/kWh_{fuel} and 77 g_{CO2eq}/kWh_{fuel} [26]. A publication about potential approaches to decarbonise energy for heating indicates a WTT GHG emission between 25 g_{CO2eq}/kWh_{fuel} and 210 g_{CO2eq}/kWh_{fuel}, depending on how gas is produced, transport mode and distance [72].

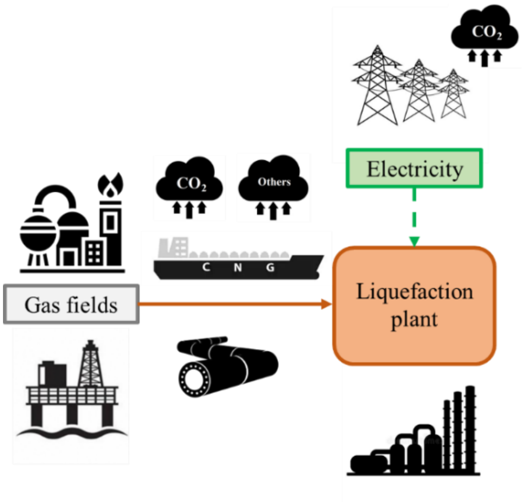

Figure 20 - Block diagram of LNG production

Synthetic methane can be produced by various feedstock, but in this paragraph only power-to-gas solution will be considered. This method includes a methanation process that receives as inputs hydrogen, carbon dioxide and electricity and produces methane. Carbon capture cost has already been analysed in paragraph 1.1.2, while a methanation system can cost from 600 €/kW$_{NG}$ to 300 €/kW$_{NG}$ in 2030 and 350 €/kW$_{NG}$ to 200 €/kW$_{NG}$ [73]. In the same work, also carbon dioxide storage and compression stages are considered as CAPEX components, as shown in Table 14. The resulting price in the same publication is a synthetic methane price from 300 €/MWh$_{fuel}$ to 250 €/MWh$_{fuel}$. In another publication about electricity-based fuels, synthetic methane cost is set between 200 €/MWh$_{fuel}$ and 300 €/MWh$_{fuel}$ in 2030, with the possibility to reach 100 €/MWh$_{fuel}$ in 2050 (using renewable energy sources) [34]. In the same document, the assumed cost for the methanation plant is between 800 €/kW$_{NG}$ to 200 €/kW$_{NG}$. A case study about GWP of hydrogen and methane production from renewable electricity, with details incorporated in next paragraphs, points out the fact that production of synthetic fuels needs to be conducted with surplus of electricity from renewable sources, since if using electricity from fossil fuel the environmental impact would be negative [74]. Also, transportation of synthetic fuel must be carried out without implying GHG emission. A block diagram representing the LNG synthesis via methanation is shown in Figure 21. This production process, if carried out with renewables, can bring to a negative WTT carbon dioxide emission, equal to almost -180 g$_{CO2}$/kWh$_{fuel}$ [24], but in some cases even -200 g$_{CO2}$/kWh$_{fuel}$ [66]. Research about renewable fuels for transport sector states a CAPEX for a methanation plant equal to 7000 €/kW$_{NG}$ in 2020, decreasing to almost 700 €/kW$_{NG}$ from 2030, and declaring a cost of synthetic methane in the following ranges: 360 €/MWh$_{fuel}$ to

425 €/MWh$_{fuel}$ in 2020, 252 €/MWh$_{fuel}$ to 306 €/MWh$_{fuel}$ in 2030 and 219 €/MWh$_{fuel}$ to 252 €/MWh$_{fuel}$ in 2050 [14]. In a study about sustainable marine fuels, price of synthetic LNG coming from renewable electricity is indicated even at a lower value, equal to 0.10 €/kWh$_{fuel}$ [66]. Market price of synthetic natural gas is estimated to be between 0.06 $/kWh$_{fuel}$ and 0.13 /kWh$_{fuel}$ [75]. One research compares different fuels for the marine transport sector, both traditional and synthetic, and it states that carbon dioxide required for synthetic methane production is almost 194 g$_{CO2}$/kWh$_{fuel}$ and that energy required for CO_2 separation from the air is about 1.83 kWh/kg$_{CO2}$ (0.36 kWh$_e$/kWh$_{fuel}$). Also, hydrogen required for methane synthesis is 36.4 g$_{H2}$/kWh$_{fuel}$ and the energy required for the process is 0.02 kWh$_e$/kWh$_{fuel}$ [76]. CAPEX for a methanation plant in a paper about electrofuels is supposed to be in the range from 30 €/kW$_{fuel}$ to 300 €/kW$_{fuel}$ [36]. A natural gas liquefaction plant is characterised by a CAPEX between 500 $/kW$_{fuel}$ and 900 $/kW$_{fuel}$, while annual OPEX can vary between 5% and 10% according to research about this way of storing natural gas [77].

Table 14 – CAPEX and ANNUAL OPEX assumptions for LNG synthesis [73]

Sub-system	**Unit**	**CAPEX**		**Unit**	**ANNUAL OPEX**	
		2030	2050		2030	2050
Methanation	[€/kW$_{NG\dot{e}}$]	600 - 300	350 - 200	[% of CAPEX]	10 - 5	3
CO_2 storage	[€/m^3]	100 - 50	50	[% of CAPEX]	3.5 – 1.5	1
CO_2 compression	[€/kg]	2500 - 1000	1000 - 750	[% of CAPEX]	3.5	3.5
SNG storage	[€/m^3]	100 - 10	50 - 10	[% of CAPEX]	1	1
Installation and design	[% of CAPEX]	28 - 10	10	[% of CAPEX]	-	-

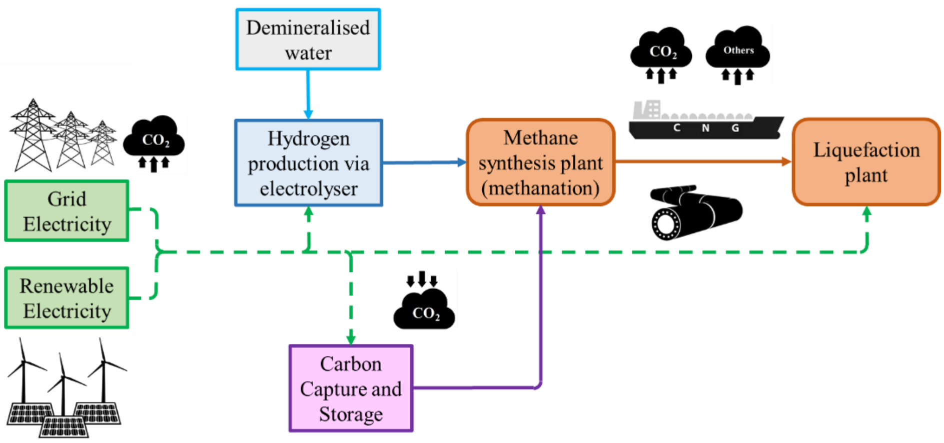

Figure 21 - Block diagram of synthetic LNG production

Natural gas and synthetic natural gas (S-NG) production cost and WTT carbon dioxide equivalent emissions are shown in Figure 22 and in Figure 23. Synthetic natural gas production cost has been calculated for two cases: one with renewable hydrogen produced via Solid Oxide Electrolysers and (SOEC-H2 S-NG) and one from renewable hydrogen produced via PEM electrolysers (PEM-H2 S-NG). SOEC-H2 S-NG has a calculated production cost almost four times higher than fossil natural gas: its production cost is mainly related to hydrogen production cost, with minor contributions from infrastructures and electricity cost. These facts are valid also for PEM-H2 S-NG, because its production cost is between four and five times higher than fossil natural gas and the main component of its production cost is feedstock cost. Also, uncertainty for S-NG is very high from the literature review, but the mean value is similar to the calculated production cost, equal respectively to 250 €/MWh and 210 €/MWh.

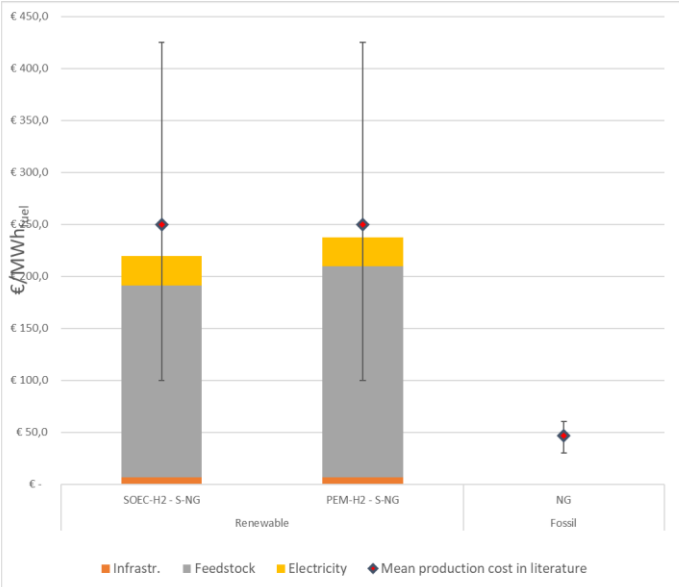

Figure 22 – Fossil and synthetic natural gas production cost (optimistic case)

Emission related to fuel processing, in case of fossil natural gas, or fuel synthesis, in case of synthetic natural gas, are extremely different. For SOEC-H2 S-NG and PEM-H2 S-NG these figures are negative because carbon dioxide is captured from air or from other processes and used for fuel production, avoiding its emission. Fossil natural gas processing is a carbon dioxide emitting process, and its emissions are also related to methane slip and flaring. Also, considering this optimistic scenario for both emissions and prices, the Swedish energy mix provides almost zero emissions from electricity. If Finland electricity data are considered (see Table 3 for data), the results obtained are shown in Figure 24: synthetic natural gas production are characterised by WTT carbon dioxide equivalent emissions higher than fossil natural gas. Obviously, if a more emitting energy mix was considered (like the EU average), these results would be worsened in terms of WTT emissions.

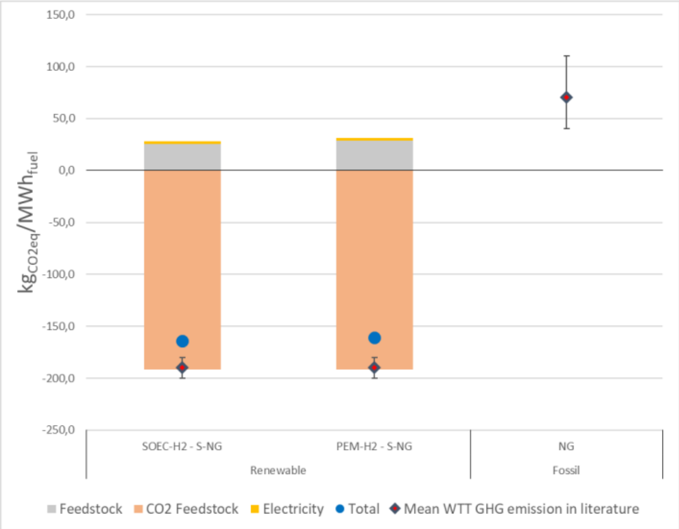

Figure 23 – Natural gas WTT emissions (optimistic case)

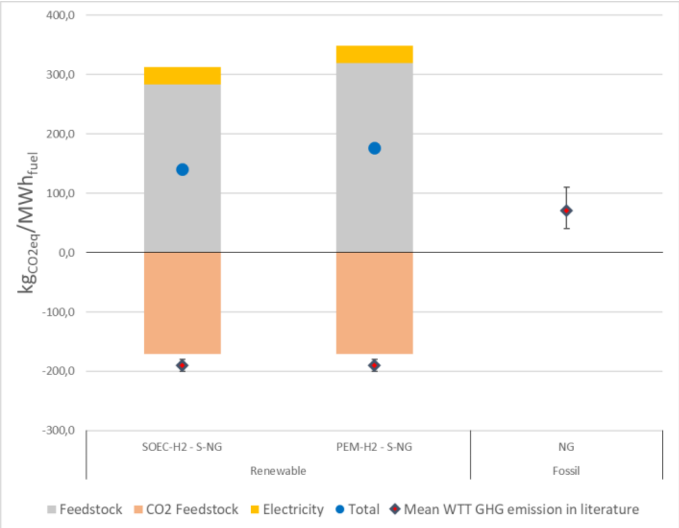

Figure 24 - Natural gas WTT emissions (optimistic scenario – Finland electricity)

1.1.7. Methanol

Methanol is a chemical composed by four hydrogen atoms, one oxygen atom and one carbon atom (CH_3OH) that is today used especially in the petrochemical industry as a feedstock for other chemicals, for example acetic acid and formaldehyde [78]. It is also named sometimes as methyl alcohol or wood alcohol. Methanol has a density of about 791 kg/m^3 and a lower heating value of almost 5.54 kWh/kg. Methanol can be produced from non-renewable feedstock as coal, causing high GHG emissions, or from natural gas. During the last years this chemical has also gained attention as low-carbon fuel for transportation because it can be produced from renewable feedstock like wastes, biomass, or carbon dioxide. Also, since this is a liquid fuel, existing distribution, storage, and bunkering facilities can handle methanol with minor modifications, reducing infrastructures cost and investments [79]. Methanol is considered overall less hazardous to human health than, for example, gasoline and is significantly less toxic to marine life than crude oil, since most of the effects related to short term exposure are temporary and reversible [73].

Methanol production by natural gas synthesis has an energy efficiency of about 70% and involves chemical processes like steam reforming and partial oxidation [74]. Emissions of its production process come from natural gas combustion and, since chemical reactions are exothermic, excess heat can be recovered. Emissions from extraction and transportation processes of natural gas to methanol's production plant can be estimated in 90 g_{CO2}/kWh_{fuel} when considering this feedstock extracted from Norway [75]. Other natural gas extraction sites can lead to different emissions, that can rise up to 28.8 g_{CO2}/kWh_{fuel}. Methanol production from natural gas is responsible for an emission of almost 108 g_{CO2}/kWh_{fuel} [3]. Studies about innovative fuels and their GHG emission during the whole life-cycle estimate a WTT carbon dioxide emission for methanol production from natural gas between 76 g_{CO2}/kWh_{fuel} and 116 g_{CO2}/kWh_{fuel} with also a methane emission of about 0.6 g_{CH4}/kWh_{fuel} [17]. For a methanol synthesis plant from natural gas can be assumed the same economic considerations that are given in the following about a synthesis plant from hydrogen and carbon dioxide. It should be also noted that in this case the only input is natural gas, between 2 kWh_{NG}/kWh_{fuel} and 2.2 kWh_{NG}/kWh_{fuel} and almost 0.6 kWh_e/kWh_{fuel}. A block diagram of methanol production process is shown in Figure 25 [59].

Methanol production from coal is characterised by an emission due to its production that can be estimated as almost 414 g_{CO2}/kWh_{fuel}. This production process is surely cheaper because it relies on a feedstock widely available but very carbon intensive and obviously non-renewable [17].

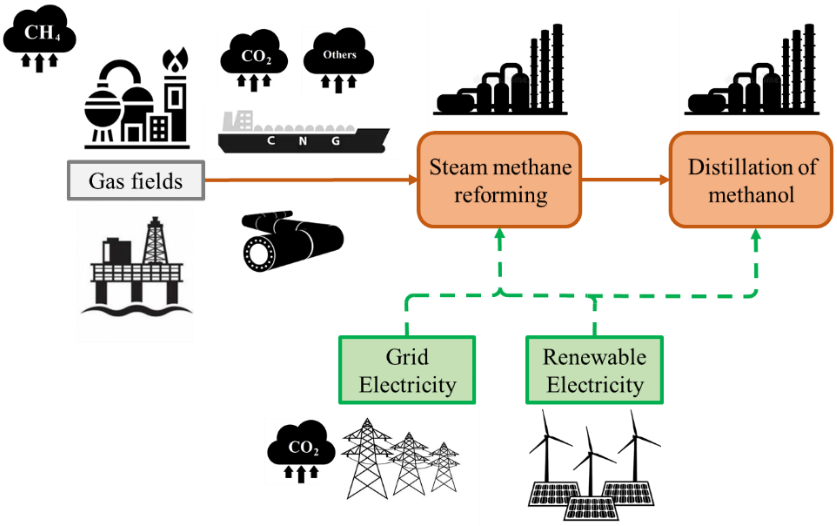

Figure 25 - Block diagram of methanol production

It is worth to highlight that methanol, but also LNG, produced from natural gas do not have potential for a substantial GHG emission reduction when assessing the whole life-cycle [76]. For this reason, different feedstock and production methods must be assessed. Methanol can also be produced from biomass, and in this case it is called bio-methanol. Residues from forestry are transformed to black liquor and then gassified in an oxygen-rich atmosphere in order to produce syngas. This process needs electricity, so its source is important for GHG total emission. Electric energy need for this process is almost 2.1 MWh/ton of methanol, so almost 0.4 kWh_{el}/kWh_{fuel} [77]. According to the same study, different energy sources can bring to an almost neutral GHG emission (CO_2 captured via carbon capture and storage or woods and plants that then become methanol's feedstock). Emissions are equal almost to 234 g_{CO2}/kWh_{fuel} when renewable energy is used. The smallest part of emissions is related to biomass and bio-methanol transportation. A block diagram of this production process is shown in Figure 26. An alternative pathway to methanol production is similar to the one shown in Figure 21 and comprises carbon capture and hydrogen production via electrolysis. Methanol production from natural gas implies a methane slip of 0.040 g_{CH4}/kWh_{fuel} and when it is produced from biomass this data reaches almost 0.151 g_{CH4}/kWh_{fuel} [76]. From the same source, an emission of almost 72 g_{CO2}/kWh_{fuel} is given for methanol production from natural gas and a total emission of almost 493 g_{CO2}/kWh_{fuel} is indicated for methanol produced from biomass feedstock.

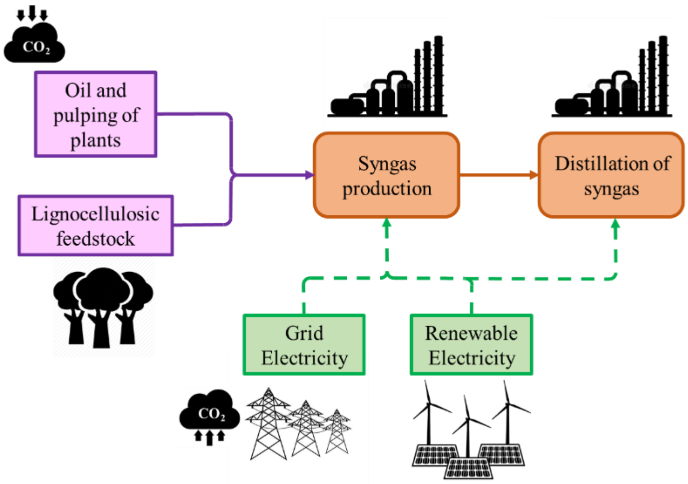

Figure 26 - Block diagram of bio-methanol production

Methanol historical pricing as a worldwide mean value is given in Figure 27 [78]. Another reference baseline for methanol price, obtained by a study about LPG, is shown in Figure 14, where this data fluctuate between 0.036 $/kWh$_{fuel}$ and 0.100 $/kWh$_{fuel}$ [42]. A confirmation of this price range is given in other studies about alternative marine fuels, in which methanol price coming from US or China is variable between 0.020 $/kWh$_{fuel}$ and 0.120 $/kWh$_{fuel}$ [72] [61] [59]. The cost of methanol is between 0.09 $/kWh$_{fuel}$ and 0.15 $/kWh$_{fuel}$ according to a study that compares different primary energy sources for waterborne transport [37].

Synthetic methanol produced exclusively with renewable energy sources a cost of 0.1 $/kWh$_{fuel}$ and an emission of -250 g_{CO2}/kWh$_{fuel}$ [59]. Methanol produced from hydrogen and carbon dioxide has in 2020 a production, transport, and logistic cost of about 0.25 $/kWh$_{fuel}$ that can decrease down to 0.09 $/kWh$_{fuel}$ in 2050 [38]. In another publication by Mitsubishi about low emission fuels for shipping, synthetic methanol market price is estimated to vary between 0.09 $/kWh$_{fuel}$ and 0.15 $/kWh$_{fuel}$ [68].

Figure 27 - Methanol price during last 15 years [78]

Carbon Recycling International plant is a company founded in Iceland that recycle carbon dioxide to produce chemicals, such as methanol. Annally it captures arount 5600 tons of CO_2 from the atmosphere and is able to produce 4000 tons of methanol, giving a carbon uptake for the production process of about 252 g_{CO2}/kWh_{fuel} [79] [80]. Performing a stoichiometric calculation, minimum hydrogen input in this production process is 22.6 g_{H2}/kWh_{fuel}. A paper about fuels obtained from green hydrogen indicates an input of this gas of about 33.8 g_{H2}/kWh_{fuel}, an electric energy requirement of almost 0.06 kWh_e/ kWh_{fuel} (just for methanol synthesis, not for carbon dioxide captur or hydrogen production) and the need of 248 g_{CO2}/kWh_{fuel}. Resulting price for synthetic methanol is indicated as almost 0.144 $/$kWh_{fuel}$ [81]. Investment cost for a methanol synthesis production plant can be assumed to be between 600 €/kW_{fuel} and 1000 €/kW_{fuel} in 2030 and decrease between 300 €/kW_{fuel} and 550 €/kW_{fuel}, with annual operating cost equal to 3% of CAPEX [27]. Investment cost in another study about a small scale methanol plant is assumed to vary between 700 $/tons/year and 1100 $/tons/year, that are equal respectively to 440 €/kW_{fuel} and 700 €/kW_{fuel} [82]. Another source of information states that total capital investment can vary between 470 €/kW_{fuel} and 1100 €/kW_{fuel}, depending on the annual production capacity of the plant, while annual OPEX can be assumed to be 5% of CAPEX [83]. According to a work that regards alternative fuels for transportation, methanol synthesis from carbon dioxide and hydrogen had a cost of about 0.128 €/kW_{fuel} in 2015 and this will decline down to 0.086 €/kW_{fuel} in 2050 [7]. One research compares different traditional and new fuels and it states that carbon dioxide required for methanol production is equal to almost 345 g_{CO2}/kWh_{fuel}, while hydrogen input is equal to 34.2 g_{H2}/kWh_{fuel} and energy requirement for synthesis is equal to 0.24 kWh_e/kWh_{fuel} and to almost 0.63 kWh_e/kWh_{fuel} for carbon dioxide separation from the air [69]. CAPEX for a methanol synthesis plant is indicated between 200 €/kW and 400 €/kW in a paper that reviews production cost of different electro-fuels [29]. A report about renewable marine fuels production cost and emissions highlights a CAPEX for a methanol synthesis plant of almost 730 €/kW, an annual OPEX equal to 4% of CAPEX, an efficiency equal to 80% and an energy requirement of about 0.04 kWh_e/kWh_{fuel}. The whole WTT process brings to the emission of about -226 g_{CO2}/kWh_{fuel}, 0.23 g_{NOx}/kWh_{fuel}, 0.025 g_{SOx}/kWh_{fuel}, 0.002 g_{N2O}/kWh_{fuel} and $6.8*10^{-4}$ g_{CH4}/kWh_{fuel}. Resulting production cost is 0.13 €/kWh_{fuel} in 2018, 0.08 €/kWh_{fuel} in 2030 and 0.04 €/kWh_{fuel} in 2050 [13]. Methanol produced from biomass had in 2011 an estimated production cost between 0.065 €/kWh_{fuel} and 0.073 €/kWh_{fuel} [84], and this estimation was confirmed also in 2019 by another source, that indicated a price range of 0.065 €/kWh_{fuel} – 0.079 €/kWh_{fuel} [85].

Figure 28 and Figure 29 show renewable methanol (R-MeOH) and fossil methanol, produced from natural gas, production costs and WTT carbon dioxide equivalent emissions. Calculated production cost is higher for methanol produced from renewable hydrogen, almost 50% higher than methanol produced from fossil natural gas. Calculated production cost is largely influenced by feedstock price. Electricity influence on the price is also higher for fossil methanol than for methanol produced by hydrogen. For this reason, it cannot be considered from an economic point of view the production of methanol from non-renewable hydrogen.

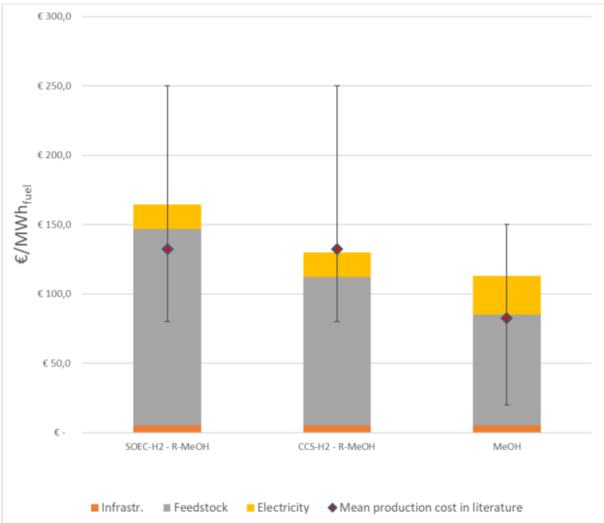

Figure 28 – Various methanol pathways production cost (optimistic case)

WTT carbon dioxide equivalent emissions have been calculated, and they are higher for fossil methanol, probably because natural gas production emissions from flaring and methane slip are not considered. WTT carbon dioxide equivalent emissions are negative for methanol produced from renewable hydrogen thanks to an almost neutral feedstock. For methanol production from non-renewable hydrogen, WTT carbon dioxide equivalent emission is still negative, but higher than renewable hydrogen case.

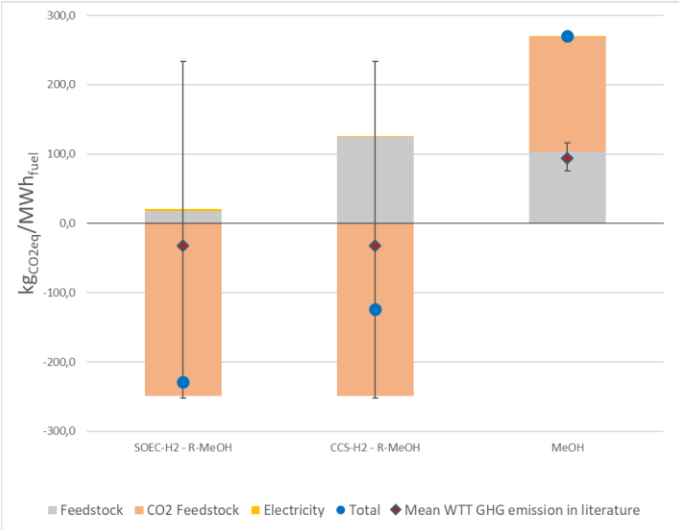

Figure 29 - Various methanol pathways WTT emissions (optimistic case)

1.1.8. Hydrogen

Hydrogen is the lightest element in the periodic table and thus the lightest among gases, with a density of almost 84 g/m^3 at 15 °C and 1 bar but is also characterised by the highest Lower Heating Value among possible future fuels for transportation, equal to 33.3 kWh/kg. Hydrogen is not naturally found in its elemental state on earth, like for example natural gas, but can be produced in various ways and in recent years is gaining momentum as an energy carrier [86]. This element is considered an important part of the transition to a carbon-free economy because when it is used as a fuel into internal combustion engines, turbines, or fuel cells, it doesn't produce carbon dioxide or other carbon-related emissions. Increased contribution of renewable energy sources for electrical generation requires alternative energy storage systems [87]. Industrial scale hydrogen production methods are three as explained in the following.

- Production from fossil fuels: steam methane reforming is the main method for hydrogen production via fossil fuels. Hydrogen and carbon oxides are produced by the catalytic conversion of hydrocarbons and steam. Main steps of this process are synthesis gas (syngas) generation, water-gas shift reaction and gas purification. This method is not carbon-free, since it implicates carbon dioxide emission, that can be strongly reduced by CO_2 capture and storage [88] (see Figure 30).

- Production from biomass: crops and wood residues, animal and municipal waste and other materials can be used as feedstock for hydrogen production via thermochemical and biological process [89]. These methods can be considered for a totally renewable hydrogen production only if renewable energy sources are used to provide the energy required for these processes.
- Production via water splitting: electrolysis, thermolysis and photo-electrolysis are methods that can be used to produce hydrogen from water. Among these possibilities, electrolysis is the most established and effective technique for water splitting [90]. This method can be considered to produce renewable hydrogen only if renewable energy sources are used (see Figure 30).

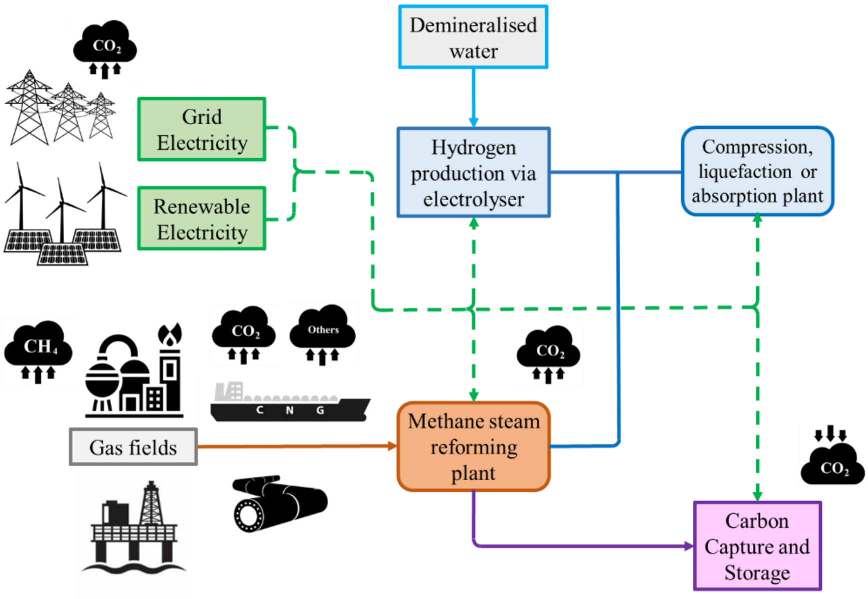

Figure 30 - Block diagram of hydrogen production

This energy vector can be classified according to carbon dioxide emissions related to hydrogen production, as the following paragraphs are going to explain.

Brown and black hydrogen is produced by transforming lignite (brown) or bituminous (black) coal in syngas and then in hydrogen. This production process results in high carbon dioxide and monoxide emissions (almost 250 g_{CO2}/kWh_{fuel} for the reaction and almost 145 g_{CO2}/kWh_{fuel} for all other emission sources, like energy generation and coal extraction [91]).

Grey hydrogen is produced via Steam Methane Reforming (SMR) process of natural gas without carbon capture and storage. Emissions related to this process are almost 260 g_{CO2}/kWh_{fuel}, as confirmed by various works about different hydrogen production processes

[88] [92], but can reach even 290 g_{CO2}/kWh$_{fuel}$ [93]. The stoichiometric calculation for the steam methane reforming process, including water-gas shift reaction, indicates a CO_2 production of 165 g_{CO2}/kWh$_{fuel}$, a natural gas requirement of about 60 g_{CH4}/kWh$_{fuel}$ and the need of 270 g_{H2O}/kWh$_{fuel}$. Efficiency of this process is typical between 65% and 75%, bringing to emissions previously stated and to a natural gas requirement of about 90 g_{CH4}/kWh$_{fuel}$ [94]. In a document about emission potential of hydrogen, carbon dioxide equivalent emission coming from steam methane reforming process without carbon capture is between 222 g_{CO2eq}/kWh$_{fuel}$ and 325 g_{CO2eq}/kWh$_{fuel}$ [65]. Value that falls in this range (270 to 300 g_{CO2eq}/kWh$_{fuel}$) are indicated in other researches and studies about various hydrogen production projects for its utilization in different sectors [62] [95] [88]. A paper regarding innovative fuels states even higher emissions from hydrogen production via SMR, with almost 500 g_{CO2eq}/kWh$_{fuel}$ [59]. The whole WTT SMR hydrogen production process energy requirement can vary between 0.03 kWh$_e$/kWh$_{fuel}$ and almost 1.1 kWh$_{NG}$/kWh$_{fuel}$, while water required is equal to 140 g_{H2O}/kWh$_{fuel}$ according to a study about blue hydrogen [4]. A paper about fuels obtained by biomass indicates a natural gas consumption for SMR process of about 91 g_{CH4}/kWh$_{fuel}$ and a GHG emission of almost 276 g_{CO2eq}/kWh$_{fuel}$ [35], while a study about renewable fuels in transport sector states a natural gas consumption of about 100 g_{CH4}/kWh$_{fuel}$, an electricity consumption of almost 0.1 kWh$_e$/kWh$_{fuel}$, a CAPEX of 2000 €/kW$_{fuel}$, a lifetime of 15 years, a full load period of 6000 h/year and an annual OPEX corresponding to 5% of CAPEX [7]. Also, for this plant the capital cost for installation is about 555 \$/kW$_{fuel}$. A similar result of almost 500 €/kW$_{fuel}$ is indicated in a database of conversion factors to report ship emissions [20], while a higher CAPEX of about 800 €/kW$_{fuel}$ is indicated in a report that describes the installation of a big SMR plant in England. This work also states an annual OPEX equal to 4% of capital investment cost [96]. A report about hydrogen and fuel cells estimates a total GHG emissions due to hydrogen SMR production process between 360 g_{CO2eq}/kWh$_{fuel}$ and 504 g_{CO2eq}/kWh$_{fuel}$, with influence on natural gas transportation mode [97]. Depending on natural gas price, cost of hydrogen produced without carbon capture can vary from 0.040 \$/kWh$_{fuel}$ (natural gas price of 0.017 \$/kWh$_{NG}$) to 0.075 \$/kWh$_{fuel}$ (natural gas price of 0.041 \$/kWh$_{NG}$). Operating and maintenance costs are about 8% to 10% of CAPEX [93] [20]. Research about blue hydrogen indicates a range for production costs equal to almost 0.045-0.050 \$/kWh$_{fuel}$ [4], while other papers state a production cost of about 0.06 \$/kWh$_{fuel}$ to 0.07 \$/kWh$_{fuel}$ [88] [59]. A publication about life-cycle assessment of alternative ships' fuels states a WTT emission for brown hydrogen between 710 g_{CO2eq}/kWh$_{fuel}$ (of which almost 135 g_{CO2eq}/kWh$_{fuel}$ for natural gas production, transport and purification and 575 g_{CO2eq}/kWh$_{fuel}$ for steam reforming) when renewable energy is employed and 1100 g_{CO2eq}/kWh$_{fuel}$ when energy generated by a coal-fired plant is used (390 g_{CO2eq}/kWh$_{fuel}$ of emissions are related to hydrogen liquefaction). Also, WTT

emission factors for SMR are reported in this work and are: 296 g_{CO2}/kWh$_{fuel}$, 0.13 g_{NOx}/kWh$_{fuel}$, 0.05 g_{SOx}/kWh$_{fuel}$, 1.06*10^{-4} g_{N2O}/kWh$_{fuel}$ and 0.07 g_{CH4}/kWh$_{fuel}$ [5]. Grey hydrogen production cost is estimated as 0.060 \$/kWh$_{fuel}$ in 2018, 0.055 \$/kWh$_{fuel}$ in 2030 and 0.050 \$/kWh$_{fuel}$ in 2050 in another study [13].

Blue hydrogen is produced by steam reforming process, but with carbon capture and storage. Since carbon dioxide is captured, emissions are reduced and the final result depends on the strategy used and on the emission reduction needed by the specific installation. In one study, emissions are lowered by 74% and are equal to 77 g_{CO2}/kWh$_{fuel}$, with an energy needed by carbon capture equal to 0.018 kWh$_e$/kWh$_{fuel}$, accounting for a total of almost 0.031 kWh$_e$/kWh$_{fuel}$. Depending on natural gas price, cost of hydrogen produced with carbon capture can vary from 0.050 \$/kWh$_{fuel}$ (natural gas price of 0.017 \$/kWh$_{NG}$) to 0.080 \$/kWh$_{fuel}$ natural gas price of 0.041 \$/kWh$_{NG}$). [93]. Also, capital investiment cost for carbon capture and storage is between 10% and 20% of a SMR plant without SMR and this processing rises the plant annual OPEX to about 15% of CAPEX [98]. In a study dedicated to blue hydrogen, maximum capture level has been set between 85% and 90%; emissions level is almost 30 g_{CO2}/kWh$_{fuel}$. and an electrical energy requirement of about 0.035 kWh$_e$/kWh$_{fuel}$, arriving at a hydrogen cost between 0.052 \$/kWh$_{fuel}$ and 0.055 \$/kWh$_{fuel}$ [4]. In a publication about potential emissions related to hydrogen production, steam reforming with carbon capture can account for an emission of carbon dioxide between 37 g_{CO2eq}/kWh$_{fuel}$ and 45 g_{CO2eq}/kWh$_{fuel}$ [65]. Lower emissions, almost 27 g_{CO2eq}/kWh$_{fuel}$, can be obtained with a CCS system efficiency around 90% [62]. In this case, electrical needs has not been directly expressed, but emissions from power required for CCS (19 g_{CO2eq}/kWh$_{fuel}$) and for SMR (27 g_{CO2eq}/kWh$_{fuel}$) are given. Knowing the emissions' factors used in this report, in particular an electricity to emissions conversion factor of 462 g_{CO2eq}/kWh$_{el}$, energy required for CCS and SMR can be calculated, and their value is equal to 0.040 kWh$_e$/kWh$_{fuel}$ and 0.060 kWh$_e$/kWh$_{fuel}$ respectively [20]. In a comparative overview about hydrogen production process, blue hydrogen cost is indicated as almost 0.068 \$/kWh$_{fuel}$ [88]. A report about a blue hydrogen production project assumes a carbon dioxide capture rate of about 94.2% and thus a GHG emission by the SMR process of 14 g_{CO2eq}/kWh$_{fuel}$ [96]. A partial confirmation of previously stated values can be found in another report about blue hydrogen production process, in which emissions vary between 40 g_{CO2eq}/kWh$_{fuel}$ and 60 g_{CO2eq}/kWh$_{fuel}$, depending on the capture technology [62]. A research that considers the whole WTT hydrogen production process via SMR with CCS estimates an emission of about 150 g_{CO2eq}/kWh$_{fuel}$ [97]. Grey hydrogen production cost is estimated as 0.080 \$/kWh$_{fuel}$ in 2018, 0.068 \$/kWh$_{fuel}$ in 2030 and 0.055 \$/kWh$_{fuel}$ in 2050 [13].

Green hydrogen is produced by water splitting using only renewable energy sources. Right now, vast majority of green hydrogen produced worldwide comes from different type of electrolyser [99]. According to CertifHy scheme, green hydrogen is defined as produced from renewable energy [100]. Energy from renewable sources, according to article 2 of the directive 2018/2001 of the European Parliament and of the council, is defined as "*energy from renewable non-fossil sources, namely wind, solar (solar thermal and solar photovoltaic) and geothermal energy, ambient energy, tide, wave and other ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas, and biogas*" [101]. In the same classification scheme is also defined CertifHy Low Carbon Hydrogen when this energy vector comes from a production batch or sub-batch having a GHG footprint equal or lower to a limit that, at the time this work is being written, is set at 36.4 g_{CO2eq}/kWh_{fuel}. With all this hypothesis, hydrogen WTT production process does not implicate any emission. Power requirement for this production method is by the way important in order to assess its cost or, eventually, emissions related to an electrical energy generation not completely renewable. There are essentially three electrolyser's technologies:

- Alkaline electrolyser: this technology is characterised by the fact that anode and cathode are separated by a permeable membrane and all these equipments are placed into a potassium hydroxide or sodium hydroxide solution and by an operative temperature below 90 °C [102] [103];
- Proton Exchange Membrane (PEM) electrolyser: in this type of reactor there is no electrolyte because ions are exchanged between electrodes via the particular membrane (perfluorosulfonic acid PFSA, commercial name Nafion) placed between them and the presence of noble-metal catalysts. For this reason, this technology is currently more expansive than alkaline electrolysers. This type of electrolyser is characterised by an operative temperature below 80 °C [81]. A similar technology, still at a research and development level, is Anion Exchange Membrane (AEM) electrolyser, that combines beneficial aspects of Alkaline and PEM electrolysers [104];
- Solide Oxide Electroliser Cells (SOEC): these electrolysers are based, as the ones indicated in previous point, on a polymeric membrane and are characterised by high operative temperatures, between 700 °C and 850 °C. This characteristic allows a potential higher efficiency, but also a faster degradation. Also, this technology is still at a demonstration level [104].

A comparison of the main characteristics of different type of electrolysers are shown in Table 15 and Table 16, from which it is also clear that future efficiency better performances will also originate from a higher operative pressure. This is also because hydrogen to be transported, stored or even liquefied must be compressed, with a requirement of electric power that can account between 6% and 16% of hydrogen LHV. Water consumption from these processes is between 540 g_{H2O}/kWh_{fuel} and 720 g_{H2O}/kWh_{fuel} [104].

Table 15 - Main Characteristics of electrolysers in 2020 [104]

	Unit	**Alkal.**	**PEM**	**AEM**	**SOEC**
Cell pressure	[bar]	< 30	< 70	< 35	< 10
Efficiency	[kWh_e/kWh_{fuel}]	1.5 – 2.3	1.5 – 2.5	1.7 – 2.1	1.4 – 1.7
Efficiency	[%]	43 - 67	40 - 67	47 - 58	58 - 70
Lifetime	[thousend h]	60	50 - 80	> 5	> 20
CAPEX stack	[$\$/kW_e$]	270	400	-	> 2000
CAPEX system	[$\$/kW_e$]	500-1000	700-1400	-	-

Table 16 - Main Characteristics of electrolysers in 2050 [104]

	Unit	**Alkal.**	**PEM**	**AEM**	**SOEC**
Cell pressure	[bar]	> 70	> 70	> 70	> 20
Efficiency	[kWh_e/kWh_{fuel}]	< 1.4	< 1.4	< 1.4	< 1.4
Efficiency	[%]	> 70	> 70	> 70	> 70
Lifetime	[thousend h]	100	100 - 120	100	80
CAPEX stack	[$\$/kW_e$]	< 100	< 100	< 100	< 200
CAPEX system	[$\$/kW_e$]	< 200	< 200	< 200	< 300

According to a study which compares different Power-To-Gas solutions, efficiency of alkaline electrolyser is about 71%, the one of PEM electrolyser is around 63% and for SOEC this data is about 82%. Also, CAPEX for these technologies has been set between 370 €/kW and 925 €/kW for alkaline electrolyser, 250 €/kW for PEM electrolyser and 500 €/kW for SOEC technology. Final hydrogen production cost in the study resulted between 0.15 €/kWh_{fuel} (alkaline electrolyser) and 0.50 €/kWh_{fuel} (SOEC) in 2013, while in 2030 for every technology this data value vary between 0.03 €/kWh_{fuel} and 0.07 €/kWh_{fuel} [105]. According to researches about different power-to-gas technologies, green hydrogen cost can vary in 2020 between 0.06 $\$/kWh_{fuel}$ to 0.15 $\$/kWh_{fuel}$ and in 2050 between 0.03 $\$/kWh_{fuel}$ to 0.1 $\$/kWh_{fuel}$, being influenced especially by CAPEX of electrolysers' plant and by electricity's price [104] [99]. Hydrogen cost from alkaline electrolysers (CAPEX indicated around 500 $/kW) and different zero GHG emissions can vary between 0.13 $\$/kWh_{fuel}$ (with nuclear electric energy) and 0.19 $\$/kWh_{fuel}$ (with eolic energy) [88]. A study about innovative fuels for ships takes as reference a green hydrogen cost of 0.08 €/kWh_{fuel} [59]. Electricity consumption for a general electrolysis systems are indicated in another study as variable between 1.6 kWh_e/kWh_{fuel} and 2.4 kWh_e/kWh_{fuel}, while water consumption is almost 270 g_{H2O}/kWh_{fuel} [4]. Another research regarding Power-To-Gas solutions states that electricity consumption for a PEM or alkaline electrolyser is almost 1.73 kWh_e/kWh_{fuel} and water consumption is around 290 g_{H2O}/kWh_{fuel}. This document also indicates a 10 to 20 years lifetime for an alkaline electrolyser and a 6 to 15 years lifetime for a PEM electrolyser [67]. A project database states for each electrolyser technology the electric power consumption: 1.5 kWh_e/kWh_{fuel} for alkaline electrolysers, 1.6 kWh_e/kWh_{fuel} for PEM technology and 1.3 kWh_e/kWh_{fuel} for SOEC [95]. A study about different zero emission fuels highlights for alkaline and PEM fuel cells an efficiency equal to 58% and an electric power consumption of about 1.7 kWh_e/kWh_{fuel} for current technology and a decrease to almost 1.4 kWh_e/kWh_{fuel} in 2030. Also, CAPEX for an electrolysis plant is estimated between 1100 €/kW_{fuel} and 1800 €/kW_{fuel} in 2020 and between 370 €/kW_{fuel} and 440 €/kW_{fuel} in 2050 [7]. A study regarding a Power-To-Gas technical and economic analysis that embodies PEM electrolysers gives an energy utilization factor between 1.7 kWh_e/kWh_{fuel} and 1.9 kWh_e/kWh_{fuel} with a hydrogen production cost between 0.06 €/kWh_{fuel} and 0.18 €/kWh_{fuel} [106]. A research that comprehends data from different sources also states a hydrogen production cost via electrolysis between 0.07 €/kWh_{fuel} and 0.24 €/kWh_{fuel}, but also a retail price that today is almost 0.36 €/kWh_{fuel} and in 2030 can reach 0.15 €/kWh_{fuel}. This source also states a CAPEX for alkaline electrolysers between 750 €/kWh_{fuel} in 2017 and 480 €/kWh_{fuel} in 2050 and for PEM electrolysers between 1200 €/kWh_{fuel} and 700 €/kWh_{fuel} [107]. According to another source, CAPEX and lifetime for different electrolysers technologies are the ones shown in Table 17 [108]. A publication about renewable energy conversion to green fuels highlights a CAPEX for an electrolyser (technology unknown) of 400 €/kW and an energy requirement of 1.37 kWh_e/kWh_{fuel}, with a lifetime of 20 years [109]. CAPEX for differen electrolyser technologies is indicated in this range according to a research: 600-2600 €/kW for alkaline technology in 2015 and 400-900 €/kW in 2030, 1900-3700 €/kW for PEM electrolyser in 2015 and 300-1300 €/kW in 2030, 400-1000 €/kW for SOFC in 2030 [29]. Green hydrogen production in a publication focused on solutions to decarbonise shipping has in 2020 a production, transport, and logistic cost between 0.11 \$/kWh_{fuel} and 0.28 \$/kWh_{fuel} that can decrease to reach a cost range between 0.04 \$/kWh_{fuel} and 0.09 \$/kWh_{fuel} in 2050 [38]. An article that explains a techno-economical assessment of different fuel production processes highlights a CAPEX for water desalinisation unit equal to 2.23 €/(m^3/year), an annual OPEX equal to 4% of CAPEX, a lifetime of 30 years and an electricity consumption of about 3 kWh_e/m^3. Also, CAPEX for alkaline electrolyser is set to 320 \$/kWh_e, for PEM ones between 250 \$/kWh_e and 1300 \$/kWh_e and for SOEC between 625 \$/kWh_e and 1000 \$/kWh_e, while annual OPEX is given as 2%, 4% and 5% of CAPEX respectively. Lifetime is equal to 30 years for alkaline electrolysers and 20 years for PEM technology and SOEC [10]. The whole WTT process of green hydrogen production implicates the emission of about 0.006 g_{CO2}/kWh_{fuel}, 0.04 g_{NOx}/kWh_{fuel}, 0.004 g_{SOx}/kWh_{fuel}, $3.6*10^{-4}$ g_{N2O}/kWh_{fuel} and $1.1*10^{-4}$

g_{CH4}/kWh_{fuel} according to a publication about different solutions for net zero-emission fuel production processes [13].

Table 17 – CAPEX and stack lifetime of different electrolyser's technologies [108]

	Year	Alkal.	PEM	SOEC
CAPEX [€/kW]	2020	761 - 2146	1684 - 2770	4315 – 8608
	2030	623 - 1315	992 – 2308	1223 - 4315
	Long term	300 - 1084	300 - 1385	760 - 1546
Stack lifetime [kh]	2020	60 – 90	30 - 90	10 – 30
	2030	90 – 100	60 – 90	40 – 60
	Long term	100 - 150	100 – 150	75 - 100

Hydrogen can be stored in various ways to be transported and used as ship fuel, or to be used to produce other fuels. To assess the final cost of hydrogen production, a brief review of the main economic parameters of its different storage options is required. CAPEX for a liquefaction plant can be assumed between 1700 €/kW_{fuel} and 4000 €/kW_{fuel}, while electric energy requirement can be taken between 0.20 kWh_e/kWh_{fuel} and 0.36 kWh_e/kWh_{fuel} and 8000 operating hours each year [107]. CAPEX for a compression plant to 850 bar, used to refuel storage tanks at 700 bar, is between 500 €/kW_{fuel} and 1000 €/kW_{fuel}, and it has a 30 years lifetime [110]. Annual OPEX for liquefaction plant can be assumed equal to 5% of CAPEX, while for compression it can be taken as 1% of CAPEX. Also, energy requirement for compression can vary between 0.07 kWh_e/kWh_{fuel} and 0.14 kWh_e/kWh_{fuel} [9].

Figure 31 and Figure 32 show hydrogen's production pathways calculated production costs and WTT carbon dioxide equivalent emissions. Green hydrogen production cost is uncertain from what has been found in this literature review, but calculated value are very similar to mean values found in literature. Also, calculated production costs are greatly influenced by electricity price, since feedstock is reduced to water. Compression electrical consumption is lower than liquefaction power demand, and thus compressed hydrogen price is lower than liquefied one. Uncertainty is lower for hydrogen produced by steam methane reforming, both with or without carbon capture and storage, and calculated values are almost equal to mean values found in literature. In this case, electricity cost has a lower influence on hydrogen cost because in this case natural gas cost has a significant impact.

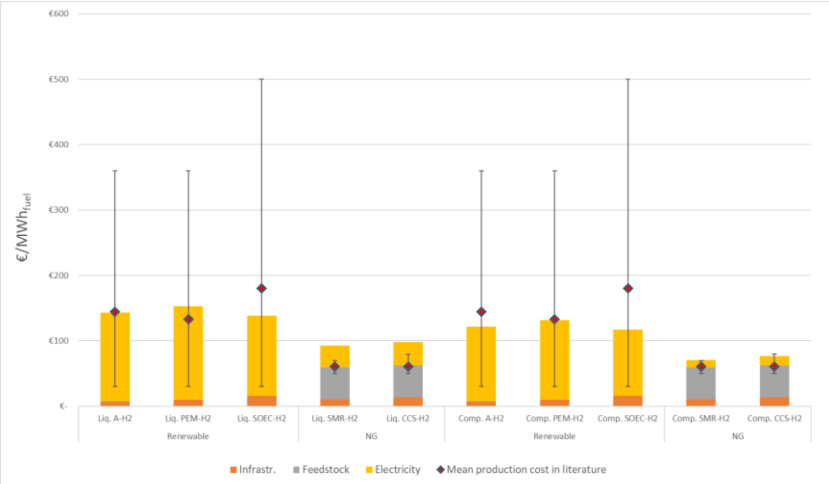

Figure 31 – Hydrogen production cost (optimistic case)

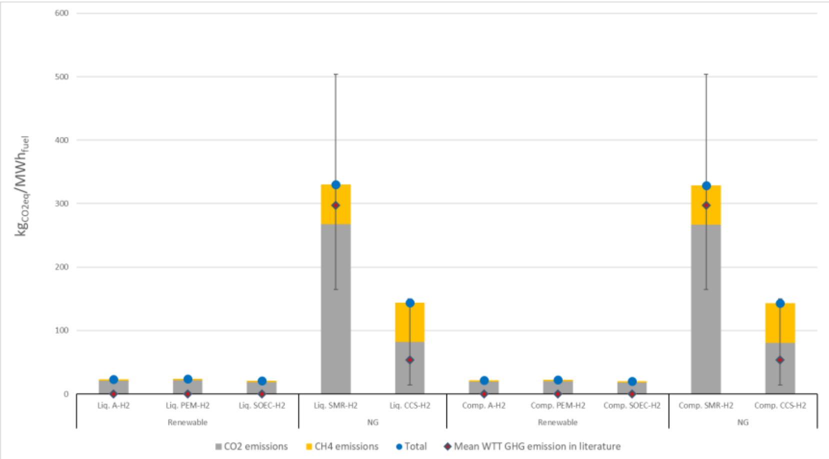

Figure 32 - Hydrogen WTT emissions (optimistic case)

1.1.9. Ammonia

Ammonia is gaining interest to reach a significant reduction in GHG emissions since it has zero-carbon content and can be used both as a fuel and as hydrogen carrier. Ammonia is today already widely available in ports since it is used mainly as fertilizer and as a precursor to nitrogen compounds, but it is produced almost entirely from hydrocarbons [11]. So, ammonia can be seen like hydrogen more as an energy carrier than a real fuel, and since its production process starts with hydrogen it shares its colours definitions. Brown ammonia is obtained by hydrogen produced from natural gas without CCS, blue ammonia comes from hydrogen produced via SMR with CCS and green ammonia is obtained by green hydrogen. Its lower heating value is equal to 5.2 kWh/kg, and it can be stored at low temperatures (-34 °C) and 1 bar or at ambient temperature and 10 bar to reach a density of about 682 kg/m^3. A block diagram of its production process is shown in Figure 33. It is gaseous at ambient conditions and has a density of about 0.73 kg/m^3 at 1.013 bar and 15 °C, while it can be also liquefied when pressurised at 8.6 bar at 20 °C, reaching a density of almost 610 kg/m^3. Ammonia is mostly produced by the Haber-Bosch process, that makes hydrogen and nitrogen react at high pressures (about 300 bar) and temperatures (400-500 °C). In the reaction chamber there is an iron-based catalyst and a complete conversion from precursors to ammonia can be reached via several passes through this process [113] [114]. The efficiency accounting the lower heating value as basis is between 48% and 66%. Nitrogen for the process is obtained from an air separation unit. Ammonia price has reached a peak between 2011 and 2013 of almost 0.135 \$/kWh_{fuel}, and it has lowered to almost 0.040 \$/kWh_{fuel} in 2019, with an average price between 2008 and 2017 of about 0.08 \$/kWh_{fuel}. Real production cost depends on natural gas or hydrogen price and on electricity price. Brown ammonia can account for a total WTT emission of about 307 g_{CO2eq}/kWh_{fuel} and green ammonia can require up to 1.92 kWh_e/kWh_{fuel} [11]. Almost 160 g_{N2}/kWh_{fuel} and 34 g_{H2}/kWh_{fuel} are required for ammonia production, and air separation requires about 0.056 kWh/kg_{N2}, so almost 0.01 kWh_e/kWh_{fuel}. For fuel synthesis, energy requirement is about 0.09 kWh_e/kWh_{fuel} [71]. Total energy requirement for brown ammonia produced from SMR requires almost 1.38 kWh_e/kWh_{fuel} for the whole WTT process, while this value for blue ammonia is equal to almost 1.76 kWh_e/kWh_{fuel} with the best available technology and can reach 1.44 kWh_e/kWh_{fuel} in 2050. Green ammonia synthesis requires almost the same energy as blue ammonia WTT production process. Carbon footprint is estimated in 307 g_{CO2eq}/kWh_{fuel} for brown ammonia and 77 g_{CO2eq}/kWh_{fuel} for blue ammonia [110]. The whole WTT ammonia production process is reviewed and analysed in a publication and total emission is declared equal to almost 365 g_{CO2eq}/kWh_{fuel}. Also, in this research, it is stated that hydrogen required during the process is equal to almost 34 g_{H2}/kWh_{fuel} [115]. An article about cost of innovative and sustainable future ship energy systems states for brown ammonia a cost of 0.03 €/kWh_{fuel} and an emission level of 290 g_{CO2eq}/kWh_{fuel}, while for green ammonia a cost equal to almost 0.1 €/kWh_{fuel} [61].

In research about green ammonia production, an air filtration systems for nitrogen production require between 0.02 kWh_e/kWh_{fuel} and 0.12 kWh_e/kWh_{fuel}, with an investment cost of about 8 €/(kg_{N2}/day). Ammonia synthesis in that case requires up to 0.75 kWh_e/kWh_{fuel} [110].

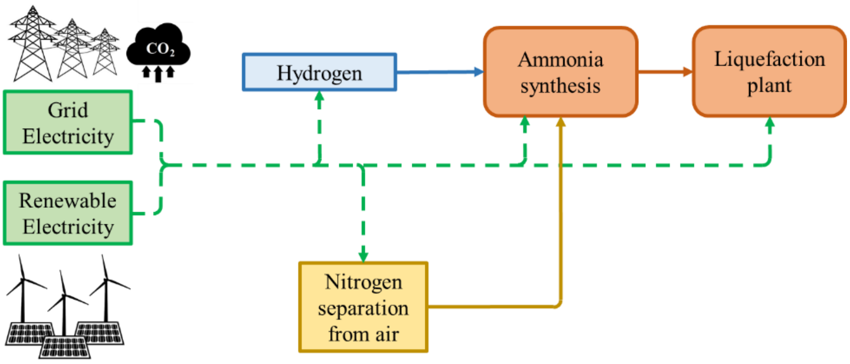

Figure 33 - Block diagram of ammonia production

A publication about fuel synthesis highlights an ammonia synthesis process efficiency of about 95%, a nitrogen cost equal to 10 €/ton$_{N2}$, an annual OPEX equal to 2% of CAPEX (estimated via an exponential function of the production capacity), a nitrogen requirement equal to 158 g_{N2}/kWh$_{fuel}$, a hydrogen input of 34 g_{H2}/kWh$_{fuel}$ and also an energy requirement of almost 0.1 kWh$_e$/kWh$_{fuel}$ [83]. A document describing possible uses of green hydrogen states that producing a tonne of ammonia via SMR requires about 10 MWh, accounting both feedstock and energy, thus a total requirement of 1.92 kWh$_e$/kWh$_{fuel}$. Almost the same amount of energy is required for green hydrogen production. Also, this process implies a GHG emission of 365 g_{CO2eq}/kWh$_{fuel}$ [115]. A research that outline possible future scenarios for ship propulsion systems states a price of green ammonia between 0.077 \$/kWh$_{fuel}$ to 0.165 \$/kWh$_{fuel}$ in 2025 and between 0.045 \$/kWh$_{fuel}$ to 0.054 \$/kWh$_{fuel}$ in 2050 [116]. Ammonia from renewable energy cost in 2020 almost 0.22 – 0.28 \$/kWh$_{fuel}$, but its cost for production, transport and logistics can decrease down to 0.08 - 0.22 \$/kWh$_{fuel}$ according to a study [40]. CAPEX for a ammonia synthesis plant is indicated in a paper about electrofuels between 200 €/kW$_{fuel}$ and 400 €/kW$_{fuel}$ [32]. A report about synthetic fuel production cost highlights that the whole WTT process implicates the emission of about 0.04 g_{CO2}/kWh$_{fuel}$, 0.24 g_{NOx}/kWh$_{fuel}$, 0.026 g_{SOx}/kWh$_{fuel}$, 0.002 g_{N2O}/kWh$_{fuel}$ and $7.2 \cdot 10^{-4}$ g_{CH4}/kWh$_{fuel}$. Resulting production cost is 0.09 €/kWh$_{fuel}$ in 2018, 0.06 €/kWh$_{fuel}$ in 2030 and 0.03 €/kWh$_{fuel}$ in 2050 [16]. Nitrogen generation has a CAPEX between 50 €/(kg day) and 65 €/(kg day), an annual OPEX equal to 4%, a lifetime of 20 years and annual full load hours up to 6000, while ammonia synthesis plant has an estimated CAPEX between 600 €/kW$_{fuel}$ and 800 €/kW$_{fuel}$ and an annual OPEX of about 4% [117].

Figure 34 shows calculated ammonia production cost and literature cost range and mean value. As shown in this chart, calculated production cost is inside literature range but is significantly higher than the mean value, in particular when ammonia is produced with renewable hydrogen. Production cost is mainly related to feedstock cost, in this case hydrogen and nitrogen, and since SOEC-H2 has a higher production cost than CCS-H2, SOEC-H2 NH3 has a higher cost than CCS-H2 NH3.

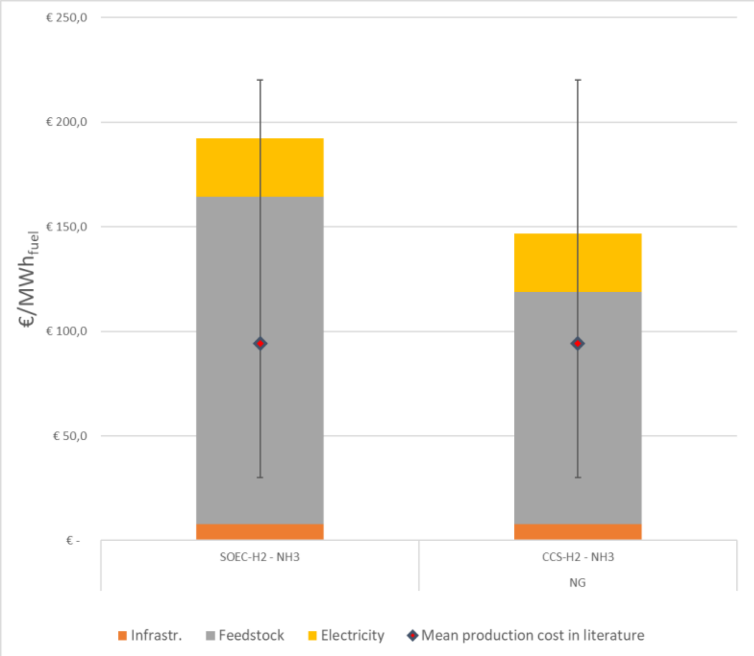

Figure 34 – Ammonia production cost (optimistic case)

Figure 35 shown ammonia WTT carbon dioxide equivalent emissions calculated during the PhD activity and the range of values that can be found in literature. Almost all emissions related to ammonia production are associated to carbon dioxide emissions linked to hydrogen production. Unlikely ammonia production cost, in this case since SOEC-H2 is characteised by a lower carbon dioxide equivalent emission than CCS-H2, SOEC-H2 NH3 has a lower carbon dioxide equivalent emission than CCS-H2 NH3. SOEC-H2 NH3 carbon dioxide equivalent emissions value calculated is lower than literature's range. This finding can be explained by the fact that today ammonia is produced by grey hydrogen and thus emissions related to its renewable production are insufficient. It is also possible that in this thesis there has been an underestimation of emissions related to nitrogen production.

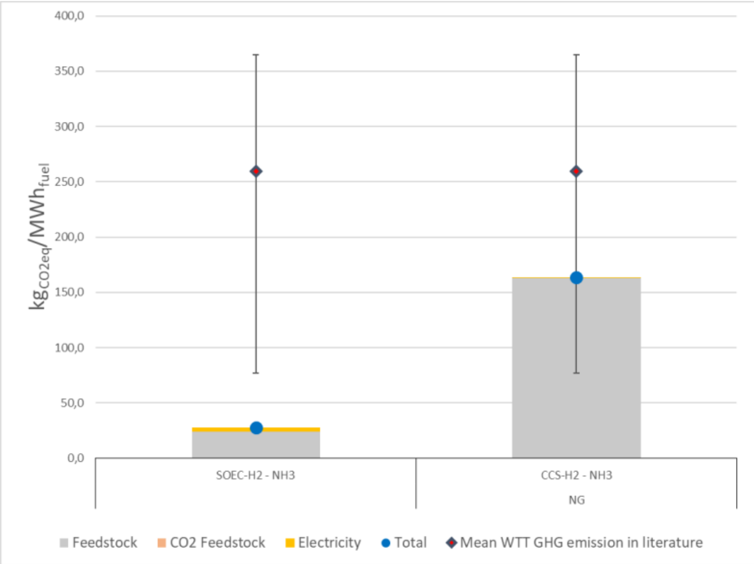

Figure 35 - Ammonia WTT emissions (optimistic case)

1.1.10. Overview about calculated data regarding marine fuels

This paragraph summarise all findings related to marine fuels previously described, adding some more specific data to better understand these results.

First, all calculated production costs are indicated in Figure 36 when optimistic input data are considered, while also showing the range and mean value of data which have been found in literature. Traditional oil-based fuels alongside fossil LNG and LPG are the cheapest options as maritime fuels. Compressed and liquefied brown and blue hydrogen are strictly linked to natural gas price and thus their price is higher than this gas, but their calculated production cost is comparable with the one of traditional maritime fuels. All these fuels have a calculated production cost included between 50 €/MWh and 100 €/MWh. Methanol produced from fossil natural gas, biofuels and green hydrogen are the potential options with a calculated production cost between 100 €/MWh and 150 €/MWh. Near the upper limit of this range, there are also production costs of ammonia and methanol produced starting from blue hydrogen. For renewable hydrogen, production cost is extremely influenced by electricity cost: cheap green hydrogen will be obtained by enhancing electrolyser's efficiency and having cheap renewable electrical energy. Methanol and ammonia production costs are mainly affected by natural gas price. The graph shows also that synthetic natural gas, ammonia, and methanol produced from green hydrogen (SOEC-H2, its cheapest green production technology) have a production cost in the range between 150 €/MWh and 200 €/MWh. These fuel options are obviously more expensive than their feedstock, and their cost is directly related to the same parameters which affects green hydrogen production. Another possibility to decrease production cost would be to enhance fuel synthesis' efficiency and thus the needed input of hydrogen. PEM electrolysers can surely play an important role in future hydrogen production scenarios but considering their efficiency hydrogen produced by this technology is more expensive than the one produced via SOEC. FTD, both produced from green or brown hydrogen, is characterised by the highest production cost and this figure is linked both to feedstock cost and to electricity cost.

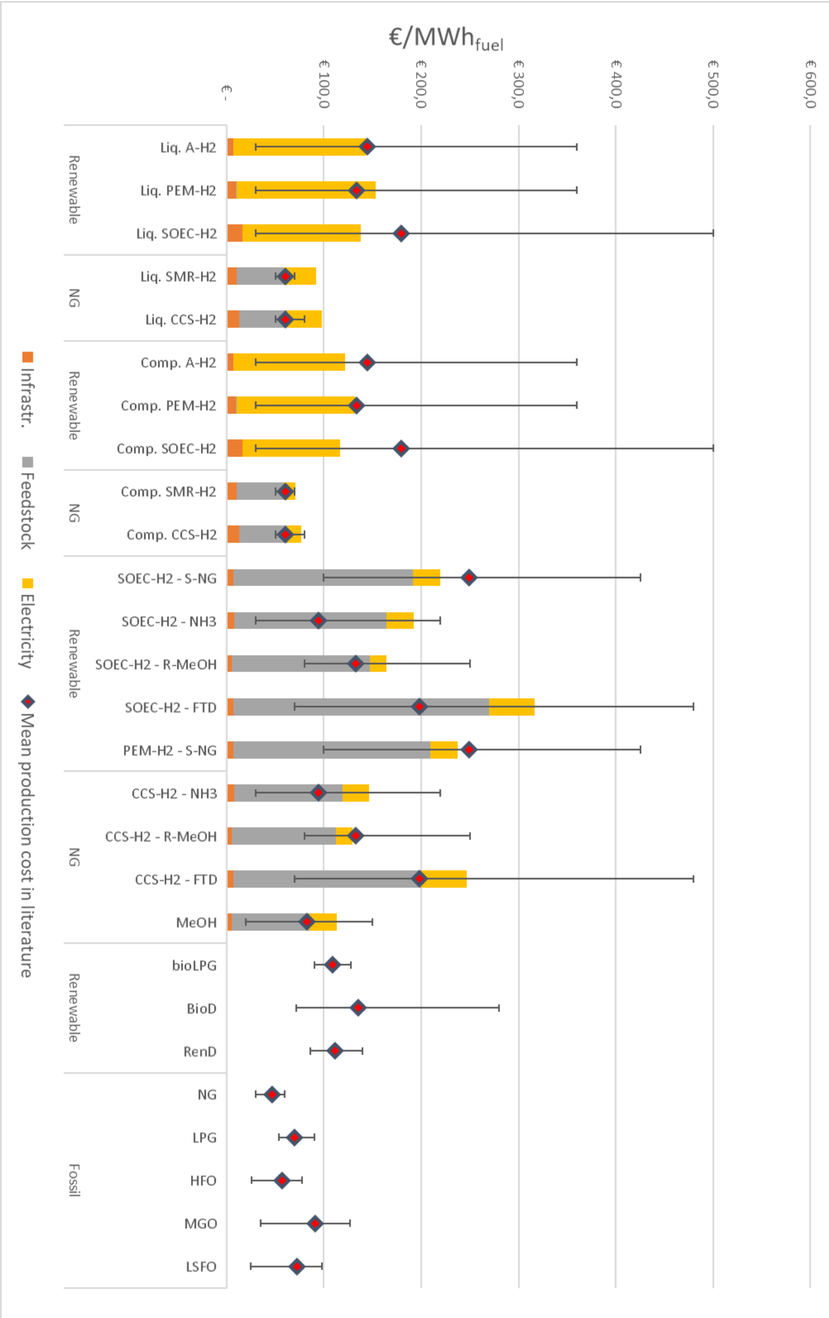

Figure 36 – Overview of marine fuels production cost (optimistic case)

When considering the pessimistic case, thus assuming higher feedstock inputs needed for synthetic fuels or higher electricity consumption for production processes and a higher electricity cost at 85 €/MWh, calculated marine fuels production costs are shown in Figure 37. These more demanding conditions bring to a higher brown hydrogen cost, which now is more affected by electric energy cost since its production efficiency is lower. Green hydrogen production cost is also increased over 200 €/MWh for the same reason. Higher hydrogen production cost is then directly linked to higher production costs for synthetic fuels, both when produced from green hydrogen and when produced from grey hydrogen. Synthetic fuels based on green hydrogen have a calculated production cost over 300 €/MWh, except for synthetic natural gas produced with hydrogen obtained via PEM electrolysers. The main reason behind this finding is the fact that SOEC technology is less mature than PEM, and thus the uncertainty about the electrical efficiency that will be archived with a future commercial product is less certain than PEM's one.

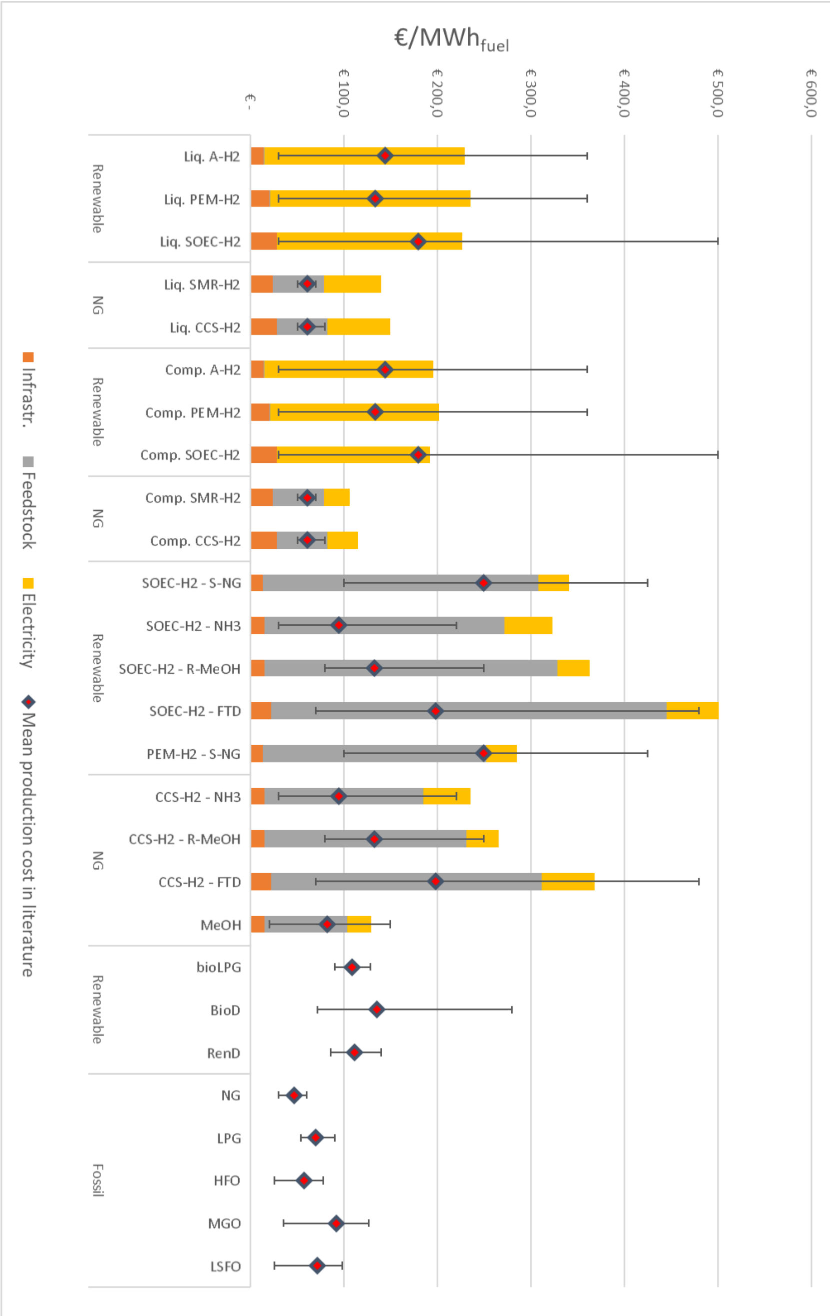

Figure 37 - Overview of marine fuels production cost (pessimistic case)

Figure 38 shows an overview of WTT carbon dioxide equivalent emissions calculated during the PhD activity. The less emitting fuels are synthetic methanol, natural gas and FTD produced from green hydrogen, because their WTT emissions are overall negative due to the carbon dioxide feedstock required for their production and obtained by capturing this chemical from air or from exhaust gases of other processes. Synthetic methanol produced from grey hydrogen has a calculated WTT carbon dioxide equivalent emission below zero because the carbon dioxide required for the production process is more than the emission related to hydrogen production from natural gas. Also, according to literature, the mean WTT carbon dioxide equivalent emission of renewable diesel is negative, but higher than synthetic fuels already cited. Green hydrogen, ammonia produced from green hydrogen, FTD produced with blue hydrogen WTT calculated emissions are near to zero, so almost carbon-neutral for their production process. In case of green hydrogen and ammonia, emissions are related only to the electricity used during the production process, while the neutrality for FTD produced from blue hydrogen is given by the balance between carbon dioxide emitted by the hydrogen production process and carbon dioxide captured for FTD synthesis. Emission values for blue hydrogen (both liquefied and compressed) and for ammonia produced from blue hydrogen are included in the range between 100 kg_{CO2eq}/MWh and 200 kg_{CO2eq}/MWh: these emissions are influenced by both feedstock (fossil natural gas production process) and hydrogen steam methane reforming. Without carbon capture and storage, the calculated WTT carbon dioxide equivalent emission is over 300 kg_{CO2eq}/MWh. Ammonia WTT emissions are only related to the type of hydrogen used for its production and are obviously slightly higher because electrical power generation emissions are accounted in its WTT carbon dioxide emissions. Methanol production from fossil natural gas has been calculated and is equal to almost 270 kg_{CO2eq}/MWh: these emissions are related to its feedstock, but especially to its production process, which still suffers from methane slip. The share of carbon dioxide and methane emitted in the atmosphere for these fuels is shown in Figure 39. As shown in this graph, negative emissions are only related to carbon dioxide, while methane slip and flaring always increase emissions and are particularly significant for WTT carbon dioxide equivalent emissions of methane and FTD produced by blue hydrogen.

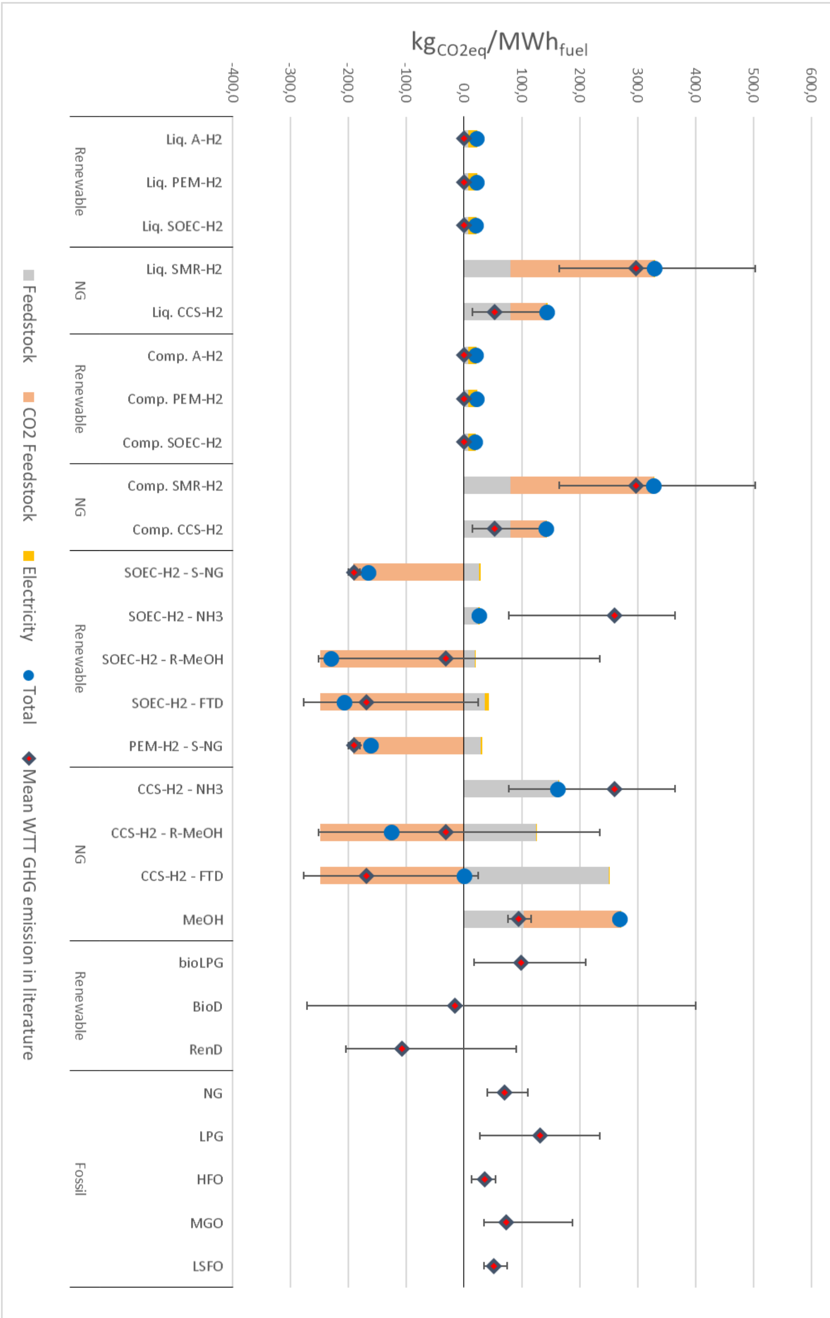

Figure 38 – Overview of marine fuels WTT emissions (optimistic case)

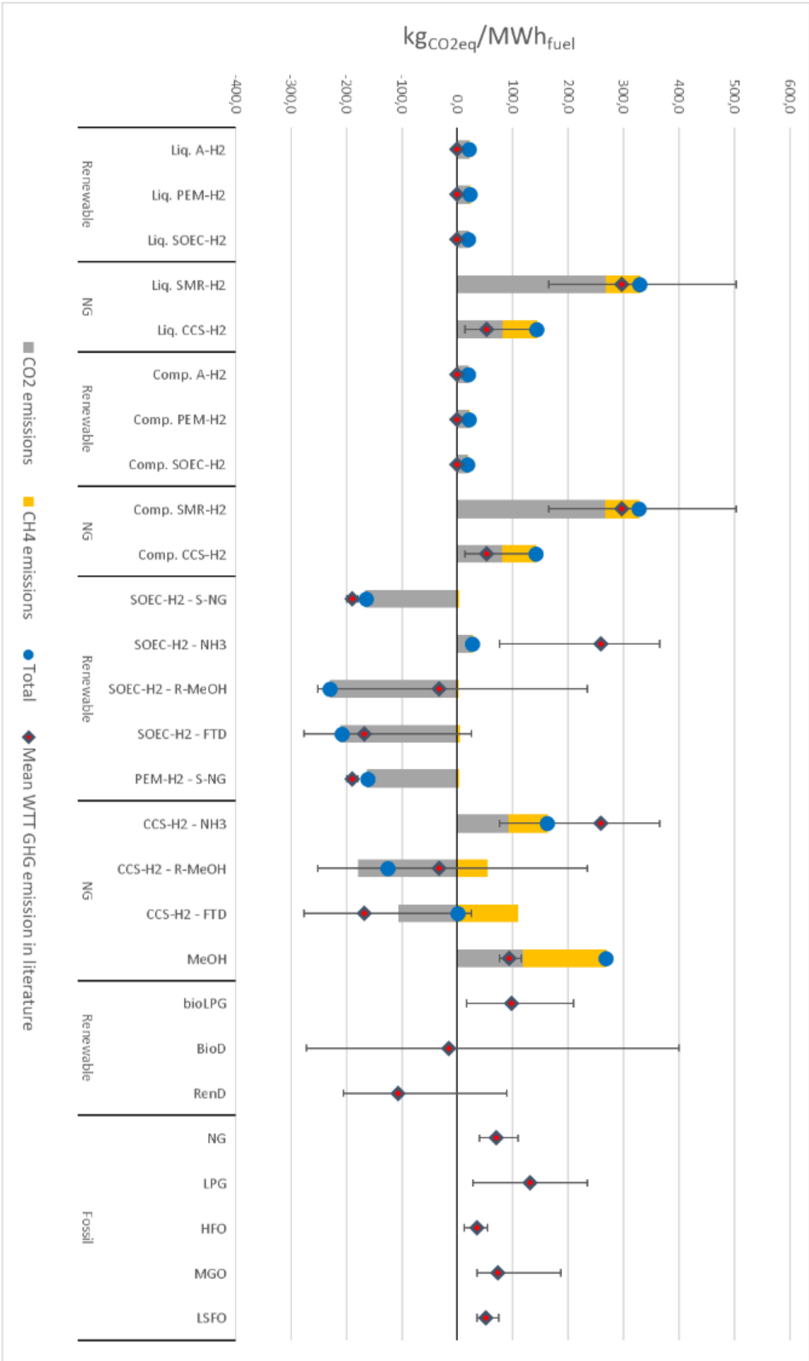

Figure 39 - Overview of marine fuels WTT emissions as CO_2 or CH_4 (optimistic case)

Figure 40 and Figure 41 show calculated WTT carbon dioxide emissions distinguished according to source of the emission and according to type of emission in the pessimistic case already described. In this case, fuels characterised by the calculated lower emissions do not change their emissions, because carbon dioxide required is almost the same and the electrical power required does not increase significantly. More significant variations are registered for grey and blue hydrogen, where steam methane reforming's efficiency and electric energy required play an important role on the overall emissions. For this reason, methanol produced from blue hydrogen calculated WTT emissions in this case are higher than zero and equal to almost 30 kg_{CO2eq}/MWh. Figure 41 is particularly significant because it highlights the fact that for grey and blue hydrogen are particularly influenced in this pessimistic case by values of methane slip and flaring. All scenarios which involve fossil methane shall be carefully considered because methane emissions are an issue for today's technology and the GWP of this gas shall be urgently addressed.

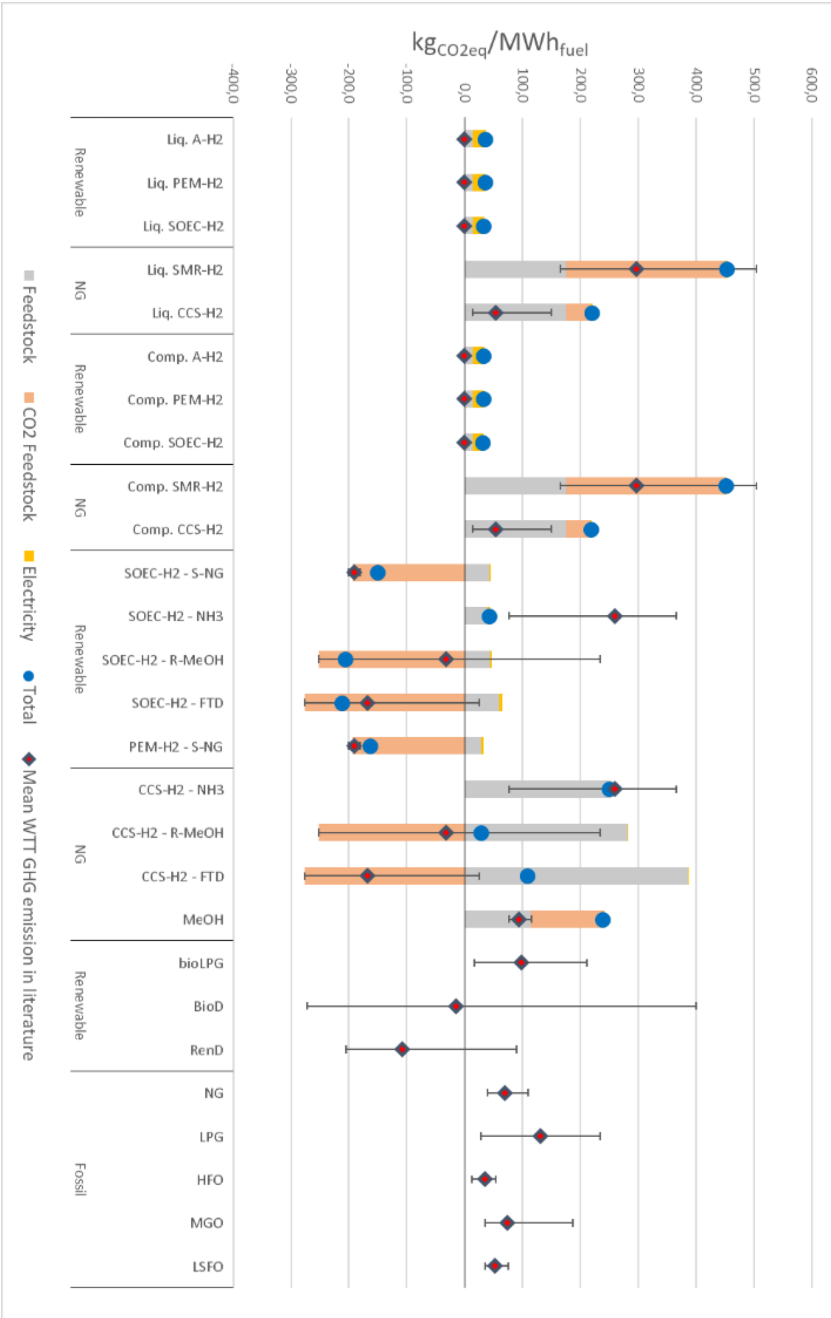

Figure 40 – Overview of marine fuels WTT emissions (pessimistic case)

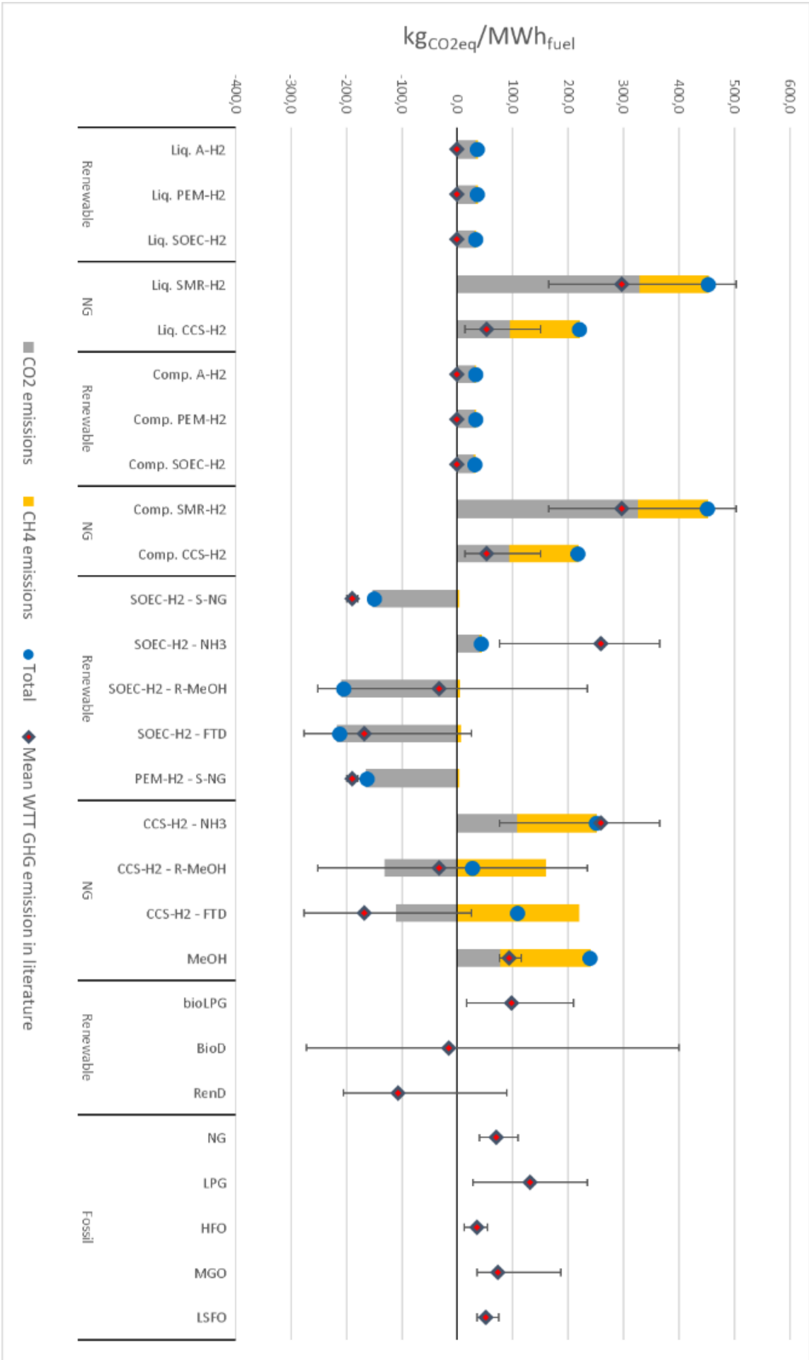

Figure 41 – Overview of marine fuels WTT CO_2 and CH_4 emissions (pessimistic case)

Figure 42 gives an overview of how much energy, as electric energy or LHV of natural gas feedstock, is required for potential marine fuels production. For biofuels and fossil fuels obtained by oil refining, it is only indicated the electrical energy required for fuel processing and production, thus ignoring the LHV of the raw material used for their production. For other potential marine fuels, energy input for the obtained output is an index of the overall efficiency of the process. Hydrogen, both green, blue, and brown, is the most efficient fuel on a WTT analysis, because for almost every option in the optimistic case the energy requirement is about 1.5 kWh_e/kWh_{fuel}. Synthetic renewable fuels are less efficient than pure hydrogen because they are produced from it, and thus their production requires additional electrical power. Also, production process has an efficiency lower than one and thus hydrogen input on an LHV basis has always a higher value than fuel output energy content. The same concepts can be applied to synthetic fuels produced by blue hydrogen. The most efficient option among synthetic fuels is renewable methanol, followed by renewable ammonia and by the same fuels obtained by blue hydrogen.

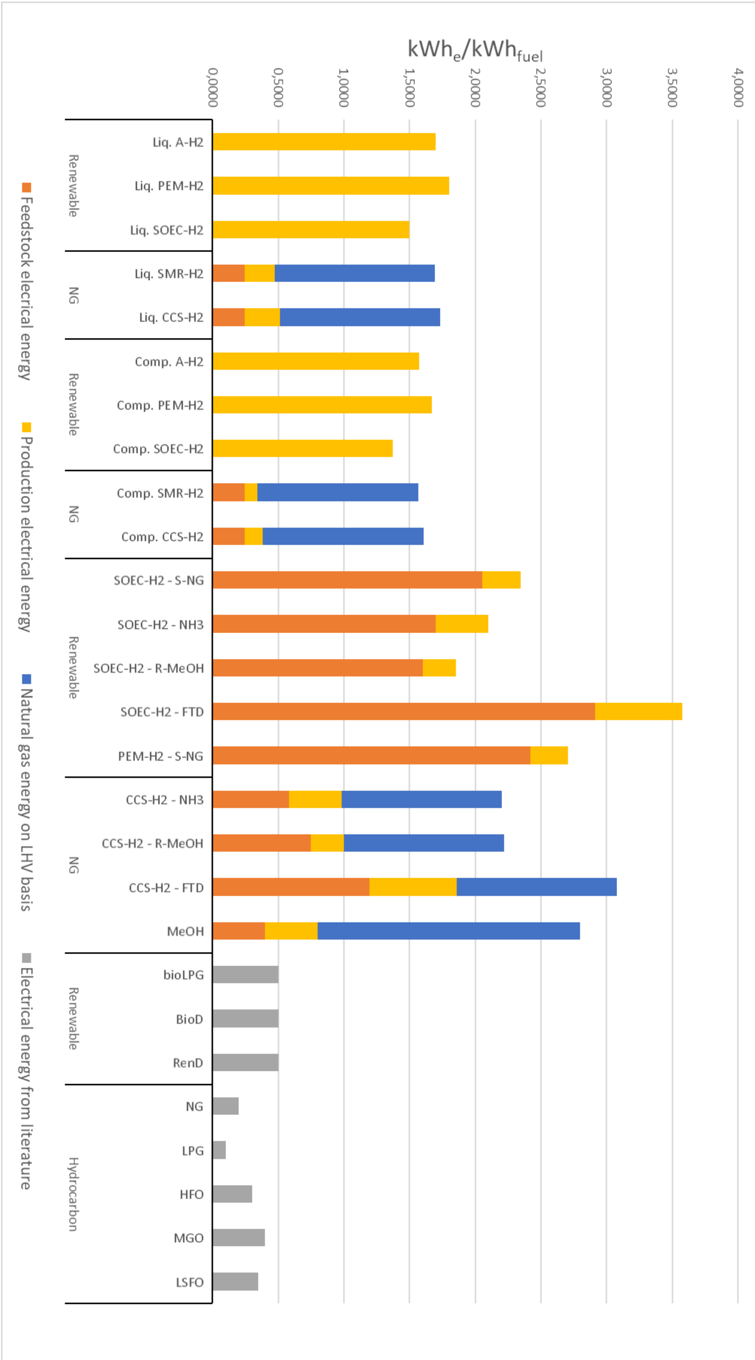

Figure 42 – Overview of marine fuels electrical energy required for production (optimistic case)

The pessimistic case of energy requirement for marine fuels production is shown in Figure 43. All hydrogen options are still the most efficient fuels that can be produced, but the difference between compressed and liquefied hydrogen is more pronounced than the difference in the optimistic case. When considering synthetic fuels, natural gas produced from green hydrogen becomes the most efficient option, followed by ammonia produced from green hydrogen and then produced from blue hydrogen. In this case, the lowest energy requirement values are around 2 kWh_e/kWh_{fuel}, and the highest energy requirement is renewable FTD's one, which is equal to almost 4.5 kWh_e/kWh_{fuel}.

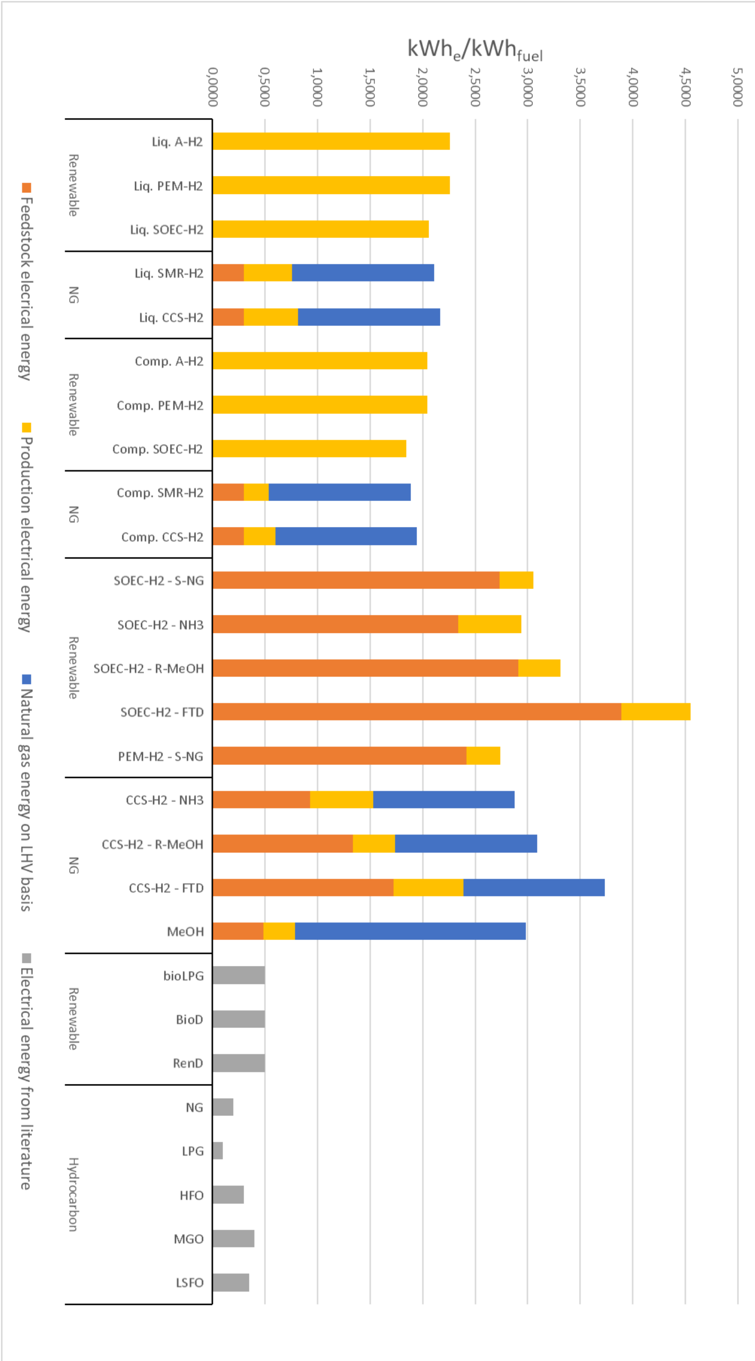

Figure 43 - Overview of marine fuels electrical energy required for production (pessimistic case)

1.2. Fuel storage, treatment, and potential reforming

Different fuels require different energy storage systems onboard the ship and different bunkering processes once the vessel is docked in port and needs to perform a refuelling. It is not obvious also to find each type of fuel in each port, especially when considering novel fuels like many of the types that are described in the previous section. In the following paragraphs, an overview about different fuel storage systems is described, giving their installation and maintenance cost in terms of CAPEX and OPEX, fuel's main data like energy density by volume and weight, fuel density, tanks volumetric storage density and specific weight of fuel contained. These data are particularly important because, as will be shown, some fuels have very good properties when considered without their storage systems, but when this is accounted, these characteristics change drastically. Room storage density is calculated to assess the real space required for the storage system with also its associated ship's structures, like bulkheads, decks, openings. An overview about fuel's safety and consequences of a spill in the sea is described, alongside with considerations about fuel availability in ports and bunkering procedures.

Different fuels require dedicated treatment systems to serve their purpose inside prime generators, especially when the prime energy source is a very contaminated product, like HFO, or when the generator requires only a product that can be obtained from the fuel, like PEM fuel cells fuelled by hydrogen stored as ammonia inside the ship. For this equipment an estimation of CAPEX, OPEX, lifetime, emissions and of parameters related to efficiency are shown in the following paragraphs. Specific volumes and weights are analysed in each paragraph to assess the impact on volumes and weights onboard the ship.

1.2.1. Oil-based fuels and Fischer-Tropsch diesel storage

Oil-based fuels that have been analysed in the last section are HFO, LSFO and MGO. These fuels are stored in tanks that can vary in some characteristics like shape, size, and capacity and that can be independent or part of the ship's structure. For these fuels, the characteristics showed in Table 18 can be identified.

Table 18 – Main characteristics of oil-based fuels and F-T diesel [118]

	Unit	HFO	MDO	LSFO	F-T diesel
Fuel density	kg/m^3	980	890	855	765
Fuel energy density	MWh/ton	10.8	11.3	11.9	11.9
Fuel energy density	MWh/m^3	10.6	10.1	10.2	9.1

The typical HFO fill, transfer, storage, and purification system is shown in Figure 44, but almost every part of this system is similar when storing and treating MGO, LSFO and F-T diesel [118]. During bunkering operations, liquid fuel can be stored from two different flanges, one for each side of the ship, that are linked to storage tanks. HFO tanks are heated with coils placed near their lower side, in which steam or hot water circulates to keep the fuel at the right viscosity and temperature to pump it when needed. The maximum filling capacity of a bunker tank varies, but it is normally in the range between 85 % to 90%, to allow fuel expansion due to heating. HFO is then moved with transfer pumps and filtered in centrifugal separators to separate heavy sludge, that is sent to a dedicated tank, and solid particulate or other impurities. After this treatment, fuel is transferred to settling tanks to be further heated and purified, especially because it needs water and solids separation and a de-aeration treatment. Settling tanks are designed to accept fuel oils with a 60 °C minimum flash point, so for F-T diesel this data must be checked case by case. Each tank must also be properly isolated to minimise heat losses. Then, fuel is pumped to service tanks where it is mixed with the liquid fraction that is coming back directly from the engine because it has not been burnt. SOLAS requires two separate fuel oil service tanks on ship built on or after 1 July 1998, one for higher sulphur content fuel oil and one with a low-sulphur content that allows the ship to comply with MARPOL annex VI emission regulations [119]. Finally, fuel is brought to the right temperature and viscosity thanks to a steam circuit. MGO, LSFO and F-T diesel treatment process depends on the fuel quality and on the specific characteristics of the internal combustion engine. These systems, and internal combustion engines, can accept different kinds of liquid fuels and so some of this equipment can be used for more than one fuel, if present onboard. According to a study about renewable liquid fuels produced from biomass and F-T diesel, these chemicals can be theoretically used neat with no treatment system modification, even if there has not been any test of ships running 100% on F-T diesel [120]. An important advantage bring by HFO is the fact that it works also as lubricant for ship engine, allowing them to run smoothly.

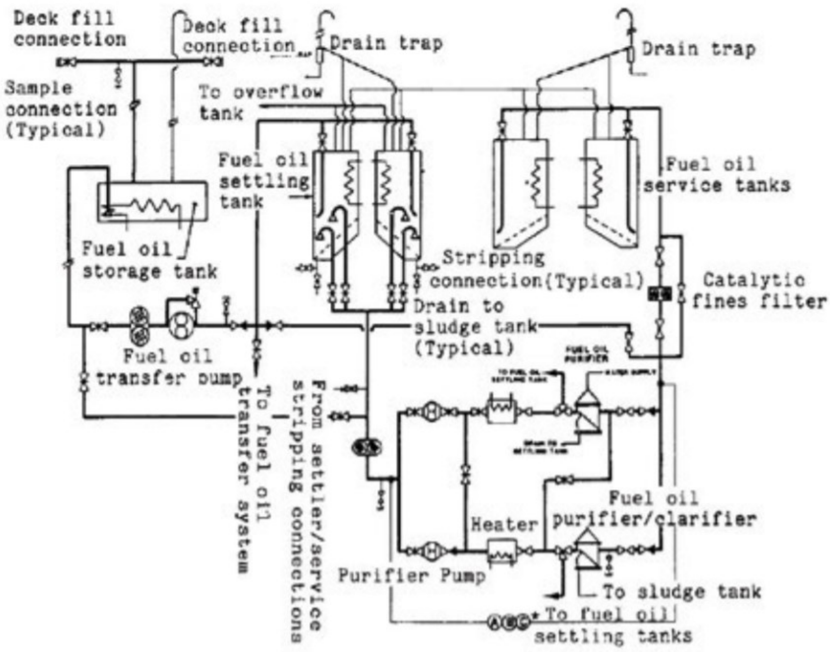

Figure 44 - Typical HFO fill, transfer, storage, and purification system [120]

It is important to highlight that the build-up of sediment inside the tanks can cause contamination of new fuels that are stored inside the tank. It is suggested to regularly clean storage and settling/service tanks and drain settling/service tanks to remove water and sludge to avoid this phenomenon [121]. Also, different storage tanks should be dedicated to different fuels, or, before bunkering, a stripping and cleaning of the tank should be performed. Another important aspect is the fact that FT diesel is theoretically directly usable today as “drop in” fuel, but its commercialisation at a global scale seems difficult. Blending can be performed at the refinery, at port or directly onboard. If blending occurs onboard, separate tanks should be arranged for F-T diesel and conventional oil-based fuel to maintain better fuel properties. This operation requires additional skills and training for crew members and a sampling activity for demonstrating compliance of the ship with emissions’ regulations. The most logical place for blending is directly on the bunker storage site in ports, to bunker inside the ship fuels already blended [3].

According to a database of technical and economic data about different fuels for shipping, CAPEX for liquid fuel tanks, both Oil-based and F-T diesel, can vary between 0.11 €/kWh$_{fuel}$ and 0.6 €/kWh$_{fuel}$ stored, while annual OPEX can be estimated around 8% of CAPEX for traditional oil-based fuels and around 15% of CAPEX for F-T diesel. Lifetime of all this equipment can be estimated in 30 years [20]. It can be assumed a filling coefficient equal to

90%, a 5% loss of fuel for purification and filtering and another 2% loss to account unpumpable sediment to estimate tank volumetric storage density. Multiplying this coefficient gives a volume efficiency for storage tanks equal to 84%. The same value can be used as mass efficiency for these storage tanks, and it is confirmed by another project where contained energy density of various fuels is given [20]. Storage tanks can be placed in dedicated rooms or in rooms in which also fuel treatment systems are arranged. So, the real volume occupied by the tank onboard can be increased by 10%. According to an analysis of possible suppliers, the fuel treatment system CAPEX can account between 50 €/kW_{fuel} and 80 €/kW_{fuel} and annual OPEX can be estimated as 10% of CAPEX. The lifetime of this equipment is assumed to be between 10 and 15 years, and its processing of different fuels does not imply emissions of any kind. Energy as electricity and heat is required for fuel processing, and this data can vary between 0.003 kWh/kWh_{fuel} and 0.005 kWh/kWh_{fuel}. Also, this type of equipment needed for fuel treatment has a specific weight variable between 15 kg/kW_{fuel} and 22 kg/kW_{fuel} and a specific volume between 0.08 m^3/kW_{fuel} and 0.1 m^3/kW_{fuel}.

1.2.2. Biofuel storage

In the paragraph dedicated to biofuels, renewable diesel (HVO) and biodiesel (FAME) have been considered as alternative fuels to be further analysed as marine fuels. Both these alternatives can substantially reduce sulphur content and thus sulphur oxide emissions, but they have lower densities than traditional oil-based fuels and comparable specific energy content. Density of renewable diesel is equal to 780 kg/m^3 and its LHV is equal to 12.2 kWh/kg, while this data for biodiesel is equal to 880 kg/m^3 and its LHV is equal to 10.3 kWh/kg, as indicated in Table 11. Currently, only biodiesel is approved as marine fuel when blended with MGO at a concentration up to 7% in a volume basis, bringing to a substantial reduction of PM emissions [38]. The main challenges for biofuels adoption at a large scale are the availability of an abundant feedstock supply and a reliable processing technology. The whole biofuels' production worldwide in 2016 was around 26 million tons of oil equivalent, while the total worldwide marine fuels consumption of oil in 2020 was almost 330 million tons [122] [1]. One of the main concerns about biofuels is its regular supply in ports all around the world, alongside its price and its safety onboard, especially regarding topics like chemical stability during transport and long-term storage. Also, since government subsidies and policies have encouraged investments on biofuels for road transport and even air sector has become a possible market for these energy sources, marine biofuels are not receiving the highest share of interest. Simultaneous production of jet or road refined biofuels and marine residual products can be a solution for producers to sell a biofuel more economically feasible [41]. It's still not completely understood if biofuels will have compatibility issues with fuel handling and storage system, especially regarding steel corrosion, but essentially an onboard treatment plant has the same structure as a traditional oil-based fuel's handling and storage system. In this thesis, it was assumed that all economic data are the same that has been exposed in paragraph 1.2.1 for Fischer-Tropsch diesel. It was assumed that annual OPEX for biofuel treatment system is equal to 15% of CAPEX to consider the higher maintenance requirement for this kind of plant, like more recurring filter substitutions. Among proven benefits related to biofuels utilisation onboard ships, it is worth to note that biodiesel can be blended up to 100% to traditional oil-based fuels. Biodiesel also significantly decrease soot emissions, their higher cetane number enable to start engines faster, and they do not bring to bacterial formation in storage tanks even after six months. Among downsides, availability of biodiesel, higher attention to housekeeping and extra training of ship staff are the most important downsides highlighted. Also, biodiesel acts as solvents and can degrade some type of rubber compounds, so hoses and seals must be replaced with more resistant materials. Special attention should be given to materials used in its systems, since some metallic materials like copper and brass are susceptible to biodiesel chemical properties. When considering renewable diesel and thus vegetable oils, blending is not an option because it could result in emulsions rather than blends. In this case, as for residual oil fuels, temperature must be monitored to keep the right viscosity [3]. Another downside of biofuels is the fact that no international marine market specification is available for these products. Currently, there are only standards for vehicle fuel or for land-based combustion equipment related to biofuels, among which are worth to mention EN ISO 14214 for European Union and ASTM D6751 for the United States of America. There are also different standards for fuel blends. Another aspect to be considered is low temperature properties of biofuels, especially when compared with fuel oils. Since biofuels are characterised by high cloud points and pour points near 0 °C, if the ship sails for long times in cold climates, operative problems can arise. In the event of a spill, biofuels degrade from two to four times faster than oil-based fuels [123]. It should be noted that renewable diesel has lower operability issues in cold climate conditions than biodiesel, but it is less available worldwide [34]. For biofuels containment systems, some references can be found into IMO's International Code for the Construction and Equipment of Ships carrying Dangerous Chemicals in Bulk (IBC Code), chapter 17. Most tanks designed to store diesel fuels can store pure biodiesel without troubles, since steel, aluminium and most fibreglass are suited to store this fuel, but special attention should be placed to temperature to not let it drop below cloud point [124].

1.2.3. LPG storage

LPG is a fuel already traded in ships and is transported in three different ways:

- Refrigerated at almost -50 °C and at ambient pressure.
- Semi-refrigerated at almost -10 °C and at a pressure between 4 and 8 bar.
- Under pressure, at almost 17 bar.

An overview of a possible LPG storage and handling system onboard a ship is shown in Figure 45. In this thesis, a pressurised tank that works at ambient temperature was taken as reference case for ship systems. LPG has almost a density equal to 540 kg/m^3 at 17 bar and ambient temperature. Fuel goes from the service tank into a Low-flashpoint Fuel Supply System, which regulates pressure to the level required by the engine, and it ensures that fuel remains in its liquid phase. Also, this equipment must avoid the occurrence of cavitation and brings LPG to fuel booster injection valve. A heat exchanger is placed inside the LFSS to regulate fuel temperature. Inside this Fuel Valve Train (FVT) there is a master fuel valve that allows LPG flow towards the internal combustion engine and a connection to a nitrogen supply system for purging purposes. All these systems can be placed either inside or outside the ship if this is possible. When inside the ship, special safety measures should be employed, like double walled pipes, redundant and dedicated ventilation systems, and segregation from other non-hazardous spaces, similarly to what already occurs with LNG and that is described into paragraph 1.2.4. All these systems should be protected by mean of gas and fire detectors, properly interconnected with the automation system to eventually trigger Emergency Shut Down (ESD), if necessary. It must be also highlighted that LPG is composed mainly by butane and propane, which are heavier than air, and so they cause different risk from other low-flashpoint fuels like natural gas and hydrogen that are lighter than air. A concentration range between 2% and 9% in air causes an explosive atmosphere, and this occurs in lower spaces, thus requiring leak detectors to be placed in low spots [44].

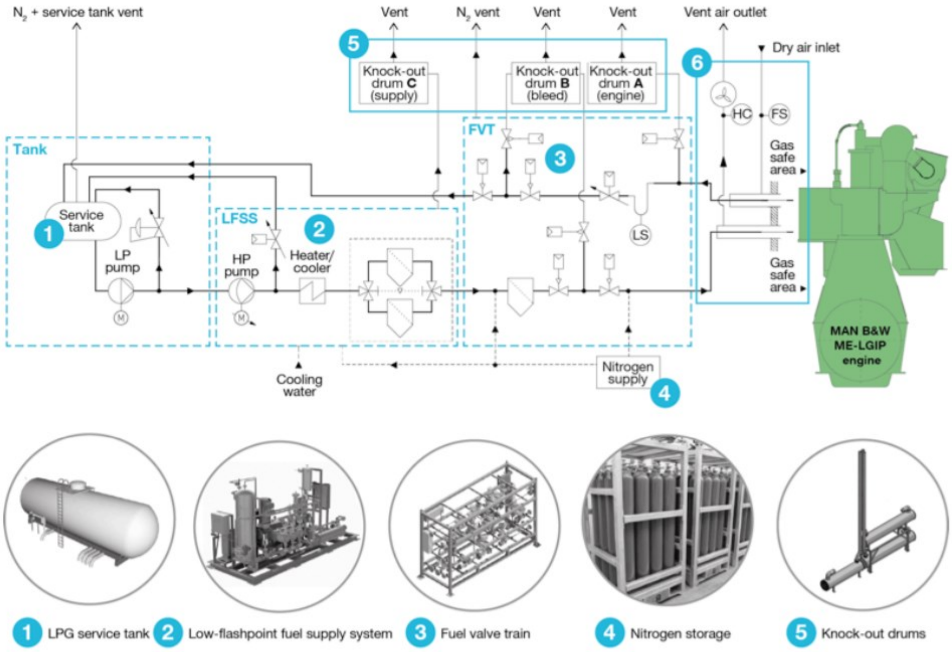

Figure 45 - LPG transfer, storage, and treatment system [44]

LPG bunkering can occur from terminals, from trucks onshore or from another ship, which is considered specially the safest bunkering operation mode. Since there are mainly three methods for LPG storage onboard a chip, bunkering can be difficult or even impossible if the fuel is not available in conditions compatible with the storage tank onboard. Among possibilities, and referring just at a compressed system onboard, we can have on the bunkering vessel:

- Pressurised LPG: in this case, LPG is transferred by a pump of the bunker vessel. For safety purposes, LPG tank onboard the ship must have a connection with the bunkering vessel that act as vapour return system by mean of a safety valve.
- Semi-refrigerated tanks: for bunkering, in addition to the pump, a heat exchanger must be installed on the bunker vessel. LPG temperature must be higher than the minimum required by the ship's storage tank. Vapour return in this case should be handled by dedicated systems installed inside the bunkering ship.

So, whichever system is available in the port facility, the ship's fuel handling and bunkering systems can be the same and adaptability is required only to bunkering ships [44]. LPG can theoretically be supplied using existing facilities, allowing a reduction of initial costs for infrastructures, since there are more than 1000 LPG storage facilities in ports around the world. LPG bunkering can also benefit from standards already established by bulk LPG shipping, which is characterised by an excellent safety record for the marine transportation sector. In 2017 globally there was a surplus of LPG production, so its use as fuel for some vessels can be a viable option in the short to medium term, at least when considering its availability [125].

Global LPG production is the same on an energy basis as the global oil consumption of the marine sector, and similar to global production of LNG. Since LPG is traded globally, a network of import and export terminals are spread around the world: for this reason, the possibility of developing bunkering infrastructures in ports is much higher than other fuels considered in this work. Right now, this fuel is used in most countries for retail market, so for domestic use, in chemical industries, refineries and just 9% of global production is used in transport sector.

According to a database of technical and economic data about different fuels for shipping, CAPEX for LPG tanks, can vary between 1.1 €/kWh$_{fuel}$ and 2.2 €/kWh$_{fuel}$, while annual OPEX can be estimated around 5% of CAPEX. Lifetime of all this equipment can be estimated in 30 years. It can be assumed a share of available volume on storage system's bulk between 80% and 90% to estimate tank volumetric storage density. Mass efficiency for these storage tanks can be estimated between 55% and 65%. Storage tanks should be placed in dedicated rooms and so to estimate the real volume occupied onboard by the tank onboard it has been assumed that the room volumetric efficiency can vary between 55% and 65%. This data is the ratio between storage system's volume and room volume. Fuel treatment system's CAPEX has been assumed in this thesis to vary between 150 €/kW$_{fuel}$ and 250 €/kW$_{fuel}$ and annual OPEX can be estimated as 10% of CAPEX. This data is justified by the fact that the treatment system is relatively new, and it is more complex than oil-based fuel's one: for example, double walled pipes and a nitrogen generating and distribution system are needed. The lifetime of this equipment is assumed to be 20 years, and it is assumed that onboard processing of LPG does not imply emissions of any kind. Electric energy required for fuel processing is assumed to be 50% higher than oil-based fuels' one. The same percentage increase has been applied to system's specific weight and volume because no precise data have been found [20].

1.2.4. LNG storage

Natural gas is a fuel already applied onboard vessels, and first applications onboard cruise ships are currently under development, with some already in operation, like the "Costa Smeralda" [126]. When natural gas is liquefied at -163 °C, its density is equal to 428 kg/m^3, while its energy density is almost 13.3 kWh/kg, equal to almost 5.7 kWh/m^3. An overview of a possible LNG storage and handling system onboard a ship is shown in Figure 46. First, fuel must be bunkered from a facility onshore (Shore Tank to Ship, TPS), from a truck (Truck To Ship transfer, TTS) or from another ship (Ship To Ship, STS). Tanks considered for a cruise ship installation are type C independent tanks according to IGC Code (The International Code of the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk). These tanks have often a cylindrical or bilobed shape and are designed to sustain a vapour pressure greater than 2 bar. Also, these tanks are normally vacuum insulated and pressurised. LNG in thus transferred onboard, passing from the bunker station to tank connection space that is in communication with tank's enclosed space. Since during bunkering there is formation of vapour due to heat losses and expansion of LNG, if the ship is not equipped with a re-liquefaction system a vapour return line with the bunkering facility or ship is needed. During bunkering, maximum attention must be dedicated to safety aspects. Among primary hazards of this type of operation there are: personnel's injury due to contact with cryogenic liquid, brittle fracture damage to steel structures, formation of a flammable vapour cloud that can result in a fire or explosion, both inside or outside the ship, and asphyxiation. A risk assessment activity with a classification society, comprehending also a HAZID and HAZOP activity, must be carried to certify that the whole LNG bunkering, storage, transferring and treatment system is safe for onboard utilization [58] [127].

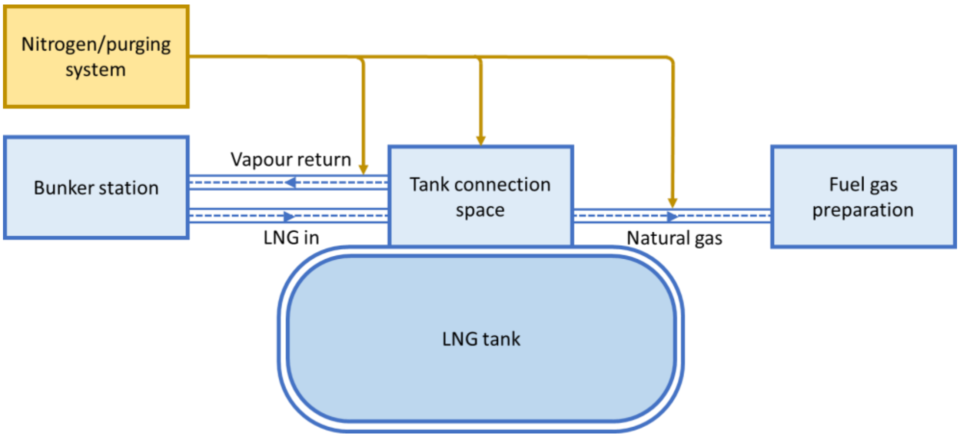

Figure 46 - LNG transfer, storage, and treatment system

When natural gas needs to be transferred from its storage tanks to diesel engines or other generators, at least a part of the system is common for each possible application. First, liquefied natural gas is pumped out of its storage tank and is brought to its gaseous phase by an evaporator inside the tank connection space. Then, a compressor transfers the fuel to a fuel gas preparation room, in which thanks to other heat exchangers and to compressors the gaseous fuel is brought to the right temperature and pressure for its next utilisation phases [128]. Double walled pipes are needed if pipes in which natural gas is carried must be double walled in accordance with IGF Code prescriptions. An LNG fuelled ship benefits from having this strong reference as a basis for the design of the system, since it is dedicated to gaseous fuels or in general low flash point fuels (fuels which have a flash point lower than 60 °C).

According to a database of technical and economic data about different fuels for shipping, CAPEX for LNG tanks, can vary between 1.5 €/kWh_{fuel} and 3.0 €/kWh_{fuel}, while annual OPEX can be estimated between 10% and 15% of CAPEX. Lifetime of all this equipment can be estimated in 30 years. It can be assumed a share of available volume on storage system's bulk between 70% and 80% to estimate tank volumetric storage density, and it was considered a filling limit of about 90%. Mass efficiency for these storage tanks can be estimated between 55% and 65%. This data is the same as LPG storage tanks even if these storage devices are different: LPG's ones are composed by a single barrier able to withstand pressures of about 20 bar, so they are characterised by a sufficient thickness, while LNG's ones are composed by two vacuum insulated layers. Storage tanks should be placed in dedicated rooms, and so it was assumed that the room volumetric efficiency can vary between 55% and 65%to estimate the real volume occupied onboard by the tank. This data is the ratio between storage system's volume and room's real volume. Fuel treatment system's CAPEX has been assumed in this thesis to vary between 200 €/kW_{fuel} and 350 €/kW_{fuel} and annual OPEX can be estimated as 10% of CAPEX. This data is justified by the fact that the treatment system is relatively new, and it is more complex than oil-based fuel's one: for example, double walled pipes and a nitrogen generating, and distribution system are needed. The lifetime of this equipment is assumed to be 20 years, and it was assumed that regassification and distribution of LNG does not imply emissions of any kind. Electric energy required for fuel processing is assumed to be 50% higher than LPG's one, since more systems are needed for its operations. The system's specific volume can be estimated between 0.15 m^3/kW_{fuel} and 0.20 m^3/kW_{fuel}, while its specific weight can be assumed to vary between 33 kg/kW_{fuel} and 44 kg/kW_{fuel} [20] [129].

If LNG is used in dual fuel engines or gas turbines, this system is sufficient for fuel treatment before it is used inside the generator. If SOFC are employed as power generators, a desulphurisation system is needed to match fuel characteristics with SOFC system's requirement. Further details about this topic are given in paragraph 2.2. The reference process that is considered is a liquid redox system that uses a chelated iron solution to convert hydrogen sulphide into elemental sulphur. Advantages of this process are reliability, flexibility, absence of hazardous waste product, low temperatures, low operating cost and a reduction of sulphur content greater than 99.9%. CAPEX for a desulphurisation system can be assumed between 15 €/kW_{fuel} and 25 €/kW_{fuel} and annual OPEX can be estimated as 15%

of CAPEX. Lifetime can be taken as 20 years, while electricity needed, plant's specific weight and volume are assumed to be the same as LNG treatment data [130].

If natural gas is used as hydrogen vector, a reformer is needed onboard to separate hydrogen from carbon. Same techno-economic data indicated in paragraph 1.1.8 can be taken to determine CAPEX, annual OPEX, lifetime, electricity needed and efficiency of the process. System's specific volume can be estimated between 0.25 m^3/kW_{fuel} and 0.35 m^3/kW_{fuel}, while its specific weight can be assumed to vary between 25 kg/kW_{fuel} and 35 kg/kW_{fuel} according to a possible supplier of reforming systems and to a database [131] [20].

1.2.5. Methanol storage

Methanol is gaining interest as possible marine fuel, and some ships are already testing its utilisation onboard. Methanol at ambient temperature and pressure has a density equal to 791 kg/m^3, while its energy density is almost 5.54 kWh/kg, equal to almost 3.55 kWh/m^3. Since it does not require pressurised or cryogenic storage, methanol is particularly suitable for retrofitting or for chemical carriers that are already transporting this fuel [79]. Comparing methanol storage to other marine fuels, fuel separators are not needed. A cooling system for safety reasons could be required, since methanol like natural gas is a low-flashpoint fuel. For this fuel, piping must be double walled when passing inside enclosed spaces and thus a nitrogen system for purging must be installed. From bunker station, methanol is transferred to tanks that can be built exactly like oil-based fuels' ones, but for methanol particular coating should be applied on the internal surface of the tanks. No heating system must be installed inside those tanks, but a cooling system should be available because methanol's flashpoint is equal to 11 °C. These tanks should also be equipped with an inerting system like LNG systems for inerting operations that can be needed. Methanol from storage tanks is pumped to generators, both fuel cells and dual-fuel engines, thanks to a fuel preparation system. This is essentially composed by pumps that must regulate pressure to the level required by following equipment. This pressure can be particularly high for internal combustion engine, as explained in 2.2. The fuel valve train must be installed inside fuel preparation room or near generators which use methanol as fuel to manage safety manual and automatic actions [74].

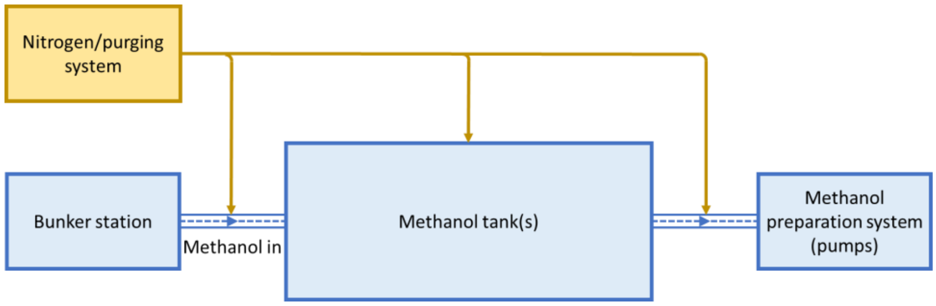

Figure 47 - Methanol transfer, storage, and treatment system

Methanol bunkering right now is performed especially by other ships or by trucks when this chemical is loaded in tankers. In this case there is no need for a vapour return line since its boiling point is around 65 °C. If methanol is accidentally released in water, it mixes rapidly with water and evaporates quickly in the atmosphere and so at short distances from the spill its concentration allows biodegradation. It disperses in water to a non-toxic level at a rate faster than a parallel petrol release, especially thanks to the effect of waves and wind. Half-life of methanol in surface water bodies has been reported to be almost 24 hours.

According to a database of technical and economic data about different fuels for shipping, CAPEX for methanol tanks, can vary between 0.7 €/kWh_{fuel} and 0.9 €/kWh_{fuel}, while annual OPEX can be estimated between 8% and 12% of CAPEX. CAPEX is slightly higher than oil-based fuels' one because of the coating and the refrigerating system. Lifetime of all this equipment can be estimated in 30 years. Tank volumetric storage density, mass efficiency and room volumetric efficiency can be assumed to be the same of oil-based fuels' one. CAPEX for fuel transfer and treatment system can be assumed to be the same for oil-based fuels: the system is overall simpler because it requires less equipment, adding just the inerting equipment and double walled pipes [20].

Methanol, as LNG, can be used as a hydrogen carrier. A reforming system to obtain hydrogen from methanol has a CAPEX between 1000 €/kW_{fuel} and 2500 €/kW_{fuel} and annual OPEX can be estimated the same share indicated for an LNG reformer. Lifetime of this system can be estimated as almost 20 years. Emissions from methanol reforming is equal to a minimum of 250 g_{CO2}/kWh_{fuel} but considering an efficiency between 74% and 82% (as for LNG reforming), carbon dioxide emission can vary from 300 g_{CO2}/kWh_{fuel} to 335 g_{CO2}/kWh_{fuel}. Electricity consumption, specific weight and specific volume are estimated to be the same of an LNG reformer.

1.2.6. Hydrogen storage

Hydrogen is the lightest element on the periodic table (0.09 kg/m^3 at ambient temperature and pressure), and it has also the highest LHV among the possible marine fuels considered, equal to 33.3 kWh/kg. These properties combined give to hydrogen a disadvantageous energy content on a volume basis, equal to almost 3 kWh/m^3, almost 1900 times lower than LNG or 3500 times lower than HFO. For this reason, hydrogen cannot conveniently be transported at ambient temperature and pressure, but it must be compressed, liquefied, or bonded with other element like nitrogen, to become ammonia (described in paragraph 1.2.7), or other elements to become a Liquid Organic Hydrogen Carrier (LOHC).

The most common storage system for both stationery and transport sectors is compressed hydrogen. Hydrogen can be stored in steel cylinders at maximum 200 bar or inside composite cylinders to reach pressures up to 800 bar [132]. Hydrogen densities in kg/m^3 are shown in Figure 48 at different temperatures and pressures: bubble's sizes stand for density and hydrogen's different states are indicated and separated by phase boundaries [133].

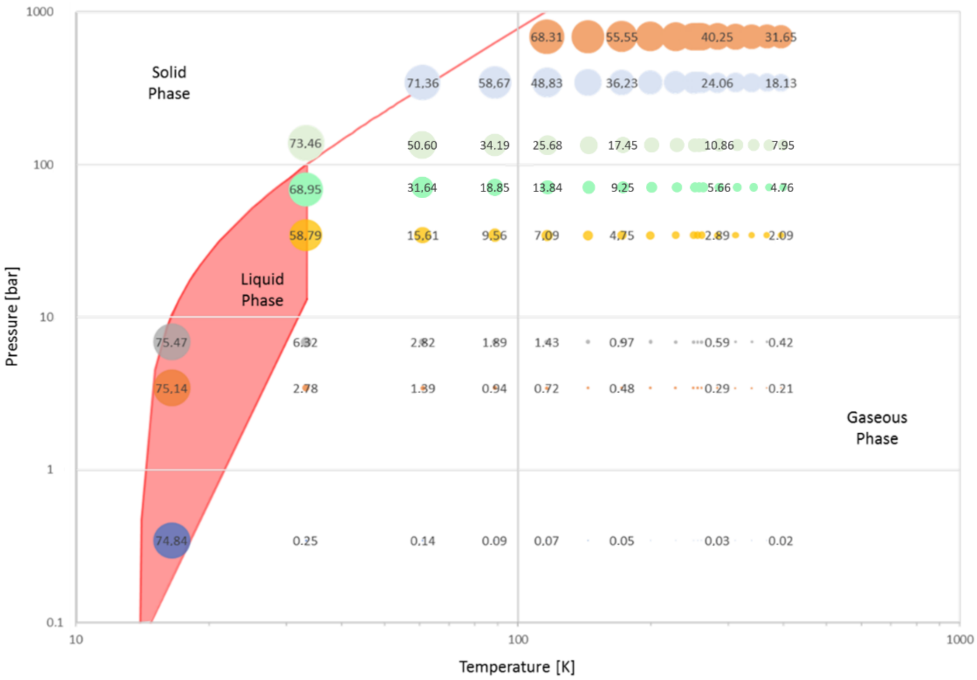

Figure 48 - Hydrogen density in kg/m3 at different pressures and temperatures [133]

Density equal to almost 42 kg/m^3 can be considered for compressed hydrogen at 700 bars, which is equal to an energy content on a volume basis of almost 1.4 MWh/m^3. Current state-of-the-art composite cylinder tanks have not a capacity sufficient for an onboard storage system of a cruise ship. For this reason, this storage system is considered just as a reference case. CAPEX for compressed hydrogen tanks at 700 bar can be estimated between 9.4 €/kWh$_{fuel}$ and 11.9 €/kWh$_{fuel}$, while annual OPEX equal at almost 5% of CAPEX. Lifetime of all this equipment can be estimated in 20 years, lower than other storage systems to account possible hydrogen embrittlement and fatigue due to charge and discharge cycles. It can be assumed a share of available volume on storage system's bulk of 90% to estimate tank volumetric storage density, and it must be considered an emptying limit of about 90%. Mass efficiency for these storage tanks can be estimated between 6% and 8%. Storage tanks should be placed in dedicated rooms, and they should be arranged on some racks if their diameter is lower than the one of today's LNG tanks. It has been assumed that the room volumetric efficiency can vary between 55% and 65% to estimate the real volume occupied onboard by the storage system onboard [20]. This data is the ratio between storage system's volume and room volume. For this storage system, distance between tanks and generators must be reduced to a minimum to lower safety requirement that will surely be employed for hydrogen utilisation onboard ships, as high rates of ventilation and purging systems. A diagram showing the basic configuration of a bunkering, transfer, storage, and treatment system for compressed hydrogen onboard a ship is shown in Figure 49. Hydrogen must be available in ports or on a bunker ship at a pressure equal or higher to the one of the storage systems onboard, that in this case is taken ad reference at 700 bar. Thanks to a compressor system outside the ship, bunkering should proceed with a flow variable with the quantity of hydrogen already in the tanks (and thus their internal pressure). Safety relief valve should be installed to avoid pipe ruptures due to over-pressurisation of the system or for safety reasons like a hydrogen detection inside the ship. Hydrogen can be freed in atmosphere since it is not a GHG. When hydrogen is available onboard, only a depressurisation system must be installed to bring this characteristic to the level required by prime generators. CAPEX for a compressed hydrogen bunkering, transfer and fuel preparation system is assumed in this thesis to be the same as an LNG treatment plant. This assumption has been made because no supplier is available today for a complete marine system of this kind. Surely this system requires less equipment than an LNG treatment system, but materials must be capable to sustain hydrogen embrittlement, purging system is always needed, and some more equipment would be required for safety reasons. Annual OPEX and lifetime are estimated the same of an LNG treatment system. At least in principle, no electricity is needed because there is no need for compressors or other devices moved by electric motors. The plant's specific weight and volume are assumed in this work to be equal to 60% of an LNG treatment system.

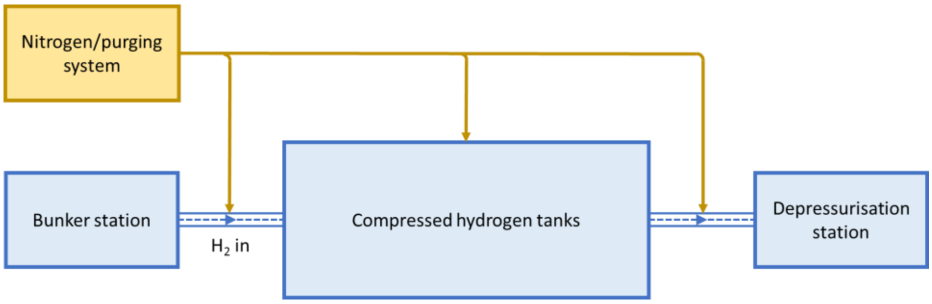

Figure 49 – Compressed hydrogen transfer, storage, and treatment system

Hydrogen can be liquefied at ambient pressure when temperature is decreased below almost -252 °C (21 K) and stored in cryogenic tanks. Density in this case is increased when compared to compressed hydrogen and is almost 72 kg/m^3, bringing to an energy content on a volume basis equal to 2.4 MWh/m^3. Liquid phase can exist only below low critical temperature of hydrogen, equal to almost -240 °C (33 K), as shown in Figure 48 [132]. CAPEX for liquefied hydrogen tanks at almost ambient pressure can be estimated between 4 €/kWh$_{fuel}$ and 8 €/kWh$_{fuel}$, while annual OPEX can be estimated between 10% and 15% of CAPEX. Lifetime of all this equipment can be estimated in 20 years, lower than other storage systems to account possible hydrogen embrittlement and thermal stresses due to extremely low temperatures. It can be assumed a share of available volume on storage system's bulk between 75% and 85% to estimate tank volumetric storage density, and it must be considered an emptying limit of about 70% [134]. Mass efficiency for these storage tanks can be estimated between 8% and 12%. Storage tanks should be placed in dedicated rooms and maybe on some racks if their diameter is lower than what is currently possible for LNG tanks [134]. It has been assumed that the room volumetric efficiency can vary between 55% and 65% as for LNG tanks to estimate the real volume occupied onboard by the storage system [135] [20]. Hydrogen must be available in ports or on a bunker ship at a pressure equal or higher to the one of the storage systems onboard, that in this case is taken as reference at 700 bar. Thanks to a compressor system outside the ship, bunkering should proceed with a flow variable with the quantity of hydrogen already in the tanks (and thus their internal pressure). Safety relief valve should be installed to avoid pipe ruptures due to over-pressurisation of the system or for safety reasons like a hydrogen detection inside the ship. When carrying on bunkering operations, liquid hydrogen must be available in ports when the ship is docked. Liquid hydrogen in the future will possibly be available for bunkering, as LNG, in three ways: from facilities installed in ports, like big liquid hydrogen storage systems, from trucks and from other ships. Refuelling system would probably be like LNG bunkering one: one line for liquid transfer and one for gaseous returns should be available to avoid pressure build-up inside hydrogen storage tanks installed in the ship. Even in this case a tank connection system, installed in a dedicated space, should be available. As for compressed hydrogen system, a purging system and emergency valves to avoid over-pressurisations should be installed. When hydrogen needs to be transferred to the generators, it is pumped out of its storage tank and is brought to its gaseous phase by an evaporator inside the tank connection space. Then, a compressor transfers the fuel to a hydrogen gas preparation room in which thanks to other heat exchangers and compressors the gaseous fuel is taken to the right temperature and pressure, as happens for natural gas in its system. CAPEX for a liquefied hydrogen bunkering, transfer and fuel preparation system is assumed in this thesis to be the double of an LNG treatment system. This assumption has been made because this system requires at least the same equipment as an LNG treatment system, but materials must be capable to sustain hydrogen embrittlement and surely more sophisticated equipment should be installed for safety reasons. Annual OPEX, lifetime and electric energy requirement are estimated as the same of an LNG treatment system. The plant's specific weight and volume are assumed in this PhD thesis to be 50% higher than an LNG treatment system.

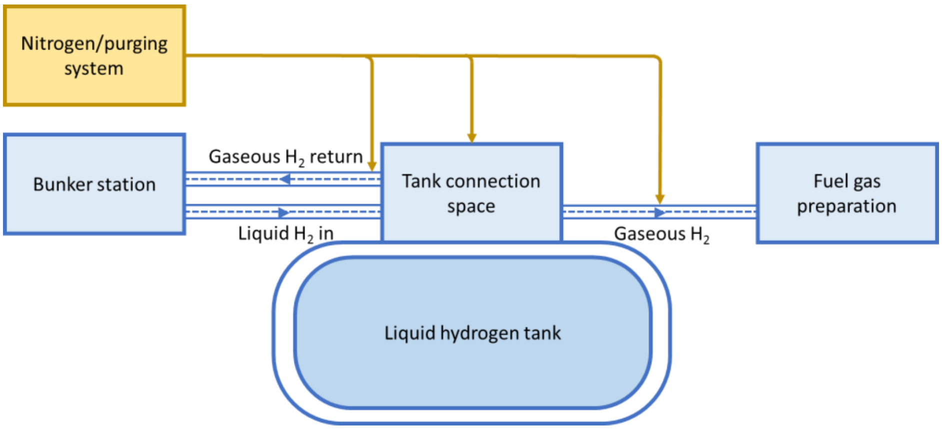

Figure 50 – Liquid hydrogen transfer, storage, and treatment system

Today, almost 50% of global hydrogen's production is dedicated to ammonia synthesis as a feedstock for fertilisers, while another 30% is destined to refineries' processes and 10% is used for methanol production. Total hydrogen produced is equal to about 67 million tons, equivalent to 2200 TWh of energy, while annual fuel oil consumption is equal to almost 3600 TWh (330 million tons) [109]. According to a report that describes hydrogen pathways for transport sector, demand for this energy vector in all its storage and transportation forms will rise in 2050 to about 20000 TWh, with a demand from transport sector of about 6200 TWh (186 million tons of hydrogen) [136]. According to European Union, hydrogen demand from transport sector can increase in 2050 between 780 TWh and 2250 TWh [137]. Over 95% of this production is fossil fuel based and uses natural gas, coal, or oil as an energy source. A report also highlights that today liquid hydrogen's refuelling stations for land-based transportation systems are operative for some niche applications, commercially viable solutions for marine bunkering are yet to be developed. A bunkering facility must have an inert gas supply and a flexible hose assembly in addition to a liquid hydrogen storage tank, permanent or mounted on a trailer or another ship. Two hoses must be connected between the bunkering site and the ship: one for hydrogen or inert gas fill and one for cooldown gas return. Inert gas must be used for removing air and moisture before bunkering and sometimes also pre-cooling. It must be installed a pressure build loop or a liquid hydrogen pump on bunkering site to perform fuel's transfer [109]. It is estimated on a feasibility study about a small ferry powered by hydrogen that bunkering operations for a refill of 1 ton of hydrogen takes almost 1 hour and 40 minutes. Forty minutes are needed for cooldown, thirty for liquid hydrogen transfer and thirty for purging and warm-up of hoses prior to disconnection [138].

1.2.7. Ammonia storage

Ammonia is a colourless gas at ambient temperature and pressure used mainly as precursor to food, fertilisers, and medicines. Ammonia can be stored in its liquid form when pressurised, since vapour pressure at 37.8 °C is 14.6 bar, and according to IMO IGF Code it is classified as a gaseous fuel. Liquid ammonia has a density of almost 680 kg/m^3 and an LHV equal to about 5.2 kWh/kg, giving an energy content on a volume basis of about 3.6 kWh/m^3. Storage can occur in pressurised tank at about 17 bars, or at temperatures below -34 °C (vaporisation temperature at ambient pressure). If a pressure tank suffers a rupture, ammonia is released as vapour that can be detected and diluted with a ventilation system. Also, when released in air, ammonia has little explosive properties. Ammonia is known to be a more stable liquid than LPG and to have similar stability to oil-based fuels. Also, handling procedures and safety measures are widely known and accepted, even in the maritime sector, since millions of tonnes of ammonia are transported worldwide in this way. Ammonia on the other hand is highly toxic and can cause death by asphyxiation. Ammonia carriers also have tanks that are built to withstand low temperatures and high pressures, and they are built with materials capable of sustaining corrosion or other reactions by this chemical.

A diagram showing the basic configuration of a bunkering, transfer, storage, and treatment system for liquid ammonia onboard a ship is shown in Figure 51. This system is in principle very similar to diagrams related to LNG or liquid hydrogen and the only differences are related to the higher operative temperatures, almost equal to ambient one, and higher pressures for ammonia liquefaction. Bunkering can be performed by other ships or by storage facilities located in ports. Bunkering lines may have a vapour return line to excessive pressure build-up inside the tank and a possible loss of ammonia due to safety valves opening. Some sort of tank connection space, or a liquid fuel supply system like what is shown in Figure 45 for LPG, must be installed near the tanks for fuel distribution onboard. These auxiliaries can include pumps, compressors, heat exchangers and filters. Then ammonia is brought to the right temperature and pressure required by the generator or the next treatment step in a fuel gas preparation system and thanks to a fuel valve train like the one shown in Figure 45 for LPG. Also, all lines must be equipped with proper auxiliary equipment for safety like a purging system, vent valves, sensors, and emergency discharge valves. Furthermore, pipes must be double walled to prevent leakage in the room in which they are installed [139].

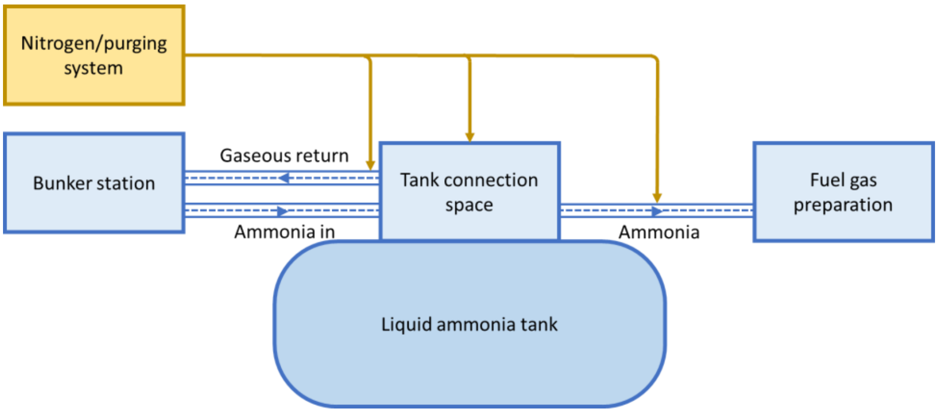

Figure 51 – Liquid ammonia transfer, storage, and treatment system

According to a database of technical and economic data about different fuels for shipping, CAPEX for LNG tanks, can vary between 3 €/kWh$_{fuel}$ and 4 €/kWh$_{fuel}$, while annual OPEX can be assumed about 5% of CAPEX. Lifetime of all this equipment can be estimated in 30 years. It can be assumed a share of available volume on storage system's bulk of about 90% to estimate tank volumetric storage density, and it must be considered a filling limit of about 90%. For each storage tank must be set a maximum filling limit because liquid should not encounter safety valves. Mass efficiency for these storage tanks can be estimated between 65% and 75%. Storage tanks should be placed in dedicated rooms and to estimate the real volume occupied onboard by the tank onboard it has been assumed that the room volumetric efficiency can vary between 55% and 65%. This data is the ratio between storage system's volume and room volume. Ammonia treatment system's CAPEX has been assumed in this study to vary between 200 €/kW$_{fuel}$ and 350 €/kW$_{fuel}$ and annual OPEX can be estimated as 10% of CAPEX, the same estimation used for an LNG treatment system. The lifetime of this equipment is assumed to be 20 years, and it is assumed that regassification and distribution of ammonia does not imply emissions of any kind. Electric energy required for fuel processing is assumed to be the same as an LNG treatment system. The system's specific volume can be estimated between 0.15 m^3/kW_{fuel} and 0.20 m^3/kW_{fuel}, while its specific weight can be assumed to vary between 33 kg/kW_{fuel} and 44 kg/kW_{fuel} [20].

Ammonia can also be used as a liquid hydrogen carrier. Due to hydrogen content in ammonia, which is equal to a mass content of about 17.5 % on a weight basis, resulting hydrogen density is almost 120 kg/m^3. To convert ammonia to hydrogen, an ammonia cracker is needed. The reaction requires heat to be performed, almost 400 kJ/mol of ammonia, thus almost 1.7 kWh_{heat}/kWh_{H2} [140]. Ammonia treatment system's CAPEX has been assumed in this study to vary between 500 €/kW_{fuel} and 700 €/kW_{fuel} and annual OPEX can be estimated as 5% of CAPEX, the same estimation used for an LNG treatment system. The lifetime of this equipment is assumed to be 20 years. Electric energy required for fuel processing is assumed to vary between 0.07 kWh/kWh_{fuel} and 0.10 kWh/kWh_{fuel}, with a process efficiency of almost 85%. The system's specific volume can be estimated between 0.10 m^3/kW_{fuel} and 0.15 m^3/kW_{fuel}, while its specific weight can be assumed to vary between 20 kg/kW_{fuel} and 30 kg/kW_{fuel} [20] [141] [71].

Global production of ammonia in 2018 was equal to almost 170 million tonnes (890 TWh) and 97% of its production increase in the next years is planned to be based on natural gas feedstock. To satisfy the whole maritime shipping sector energy demand, almost 680 million tonnes of ammonia should be produced every year [11].

1.2.8. Overview about storage option and impact onboard

Potential marine fuels are characterised by their phase at ambient temperature and pressure and by their various options for onboard storage. Characteristics of the fuel itself can be sensibly different from the one of the fuels inside its storage system, and characteristics of its storage systems can differ from its characteristics when this system is placed onboard a ship. Figure 52 aims to address these issues showing volume densities (in kWh/l, equivalent to MWh/m^3) and mass densities (in kWh/kg, equivalent to MWh/ton) for fuels, fuels and their storage devices, or tanks, and for fuels and storage technologies when integrated onboard a ship. Weights and volumes of fuels have the highest importance onboard because the highest possible quantity of weight and volume shall be dedicated to payload, which are passenger's cabins and public spaces when cruise ship are analysed. If only fuels are considered, Figure 52 shows that hydrogen has the highest mass density, more than two times all the other options considered. Traditional oil-based fuels are the best option when considering only volume density. When considering storage systems and its installation onboard a ship, volume and mass energy densities changes decreasing for every fuel. These changes are more evident for some options. The most significant change happens for compressed and liquefied hydrogen: energy density on mass basis falls from 33.3 kWh/kg to almost 4 kWh/kg. Mass efficiency for liquefied hydrogen tanks is equal to 12%, as reported in section 1.2.6. Energy density on a volume basis remains the worst among potential marine fuels, equal to almost 0.9 kWh/l. LNG and LPG as pure fuels have a higher energy density on mass bases than traditional oil-based fuels., Their energy densities on a mass basis is reduced below traditional oil-based fuels values when onboard fuel storage systems are considered, as reported in sections 1.2.3 and 1.2.4. The real problem with these fuels is volume because the actual space required of their storage system installed onboard is 2.7 kWh/l for LNG and 4 kWh/l for LPG. Methanol and ammonia as fuels have already energy densities lower than other potential maritime fuels, but even with their storage system they have an energy density on a mass basis comparable to liquefied hydrogen and better energy density on a volume basis than this gas.

These values highlight that 100 MWh of fuel bulk in case of liquefied hydrogen almost 42 m^3, when LNG is considered, it bulks almost 18 m^3 and 100 MWh of MGO bulk almost 10 m^3. This 100 MWh of fuel weights respectively 3 ton, 7.5 ton and 8.9 ton. Tanks able to store this volume of fuel should have a capacity equal to almost 70 m^3 when considering a liquefied hydrogen tank, 25 m^3 when considering an LNG storage tanks and 12 m^3 when considering a MGO storage tank. The additional weight introduced by the considered tanks is respectively equal to almost 22 ton, 4 ton and 1.7 ton. This difference is related first to the different level of insulation required by different types of tanks and fuels, and secondly to different materials and auxiliary systems like heat exchangers and compressors directly connected to fuel storage systems. Even if both liquefied hydrogen and LNG require cryogenic storage tanks, LNG technology is better established, and their design is already optimised for large storage volumes. Liquefied hydrogen tanks, as already pointed out in paragraph 1.2.6, do not have right now a technical reference for storage tanks able to satisfy cruise ship needs, and they already need further research and development to become competitive in terms of added weight with LNG storage tanks.

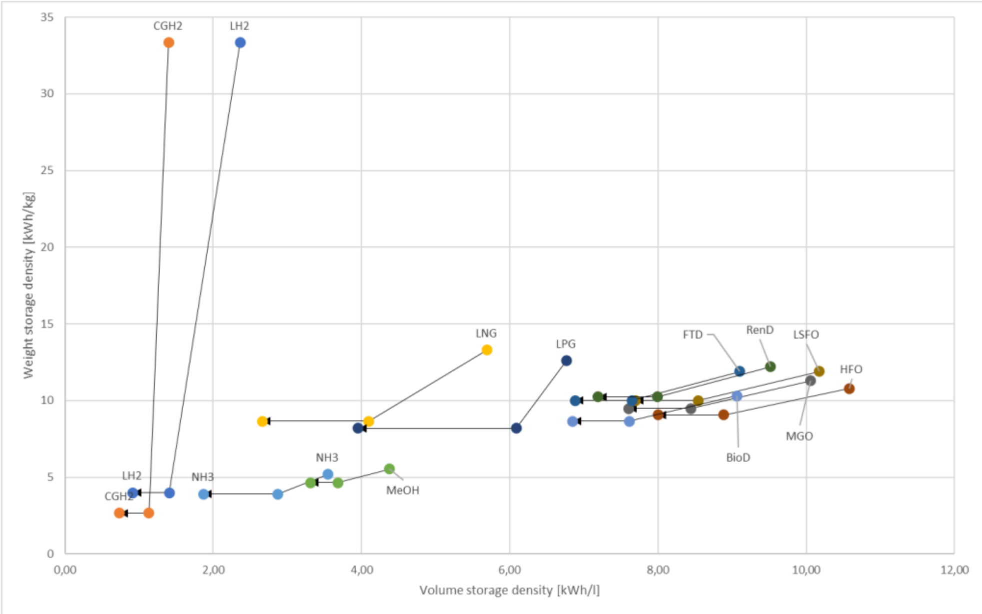

Figure 52 – Fuel densities, tank densities and tank room densities

Another possible representation of this data is shown in Figure 53, where it is highlighted space required for each MWh of fuel. Blue lines are referred only to the fuel itself; orange lines represent fuels when contained in their storage system, and grey bars indicate space required by each storage systems when installed onboard a ship. Numbers on each bar are the ratio between the space required by the fuel and volume of current most used fuel: HFO. Liquid hydrogen as a standalone fuel is 4.5 times bulkier than HFO, but when both are stored in their tanks liquid hydrogen is 6.3 times bulkier than HFO and when they are installed onboard, this liquefied gas requires 8.7 times more volume than HFO for the same energy content. Following the same procedure, the graph shows that when storage systems are installed onboard, LNG requires 3 times more space than HFO, ammonia requires 4.3 times more volume than that of oil-based fuel and so on. Methanol and LPG require respectively 2.4 and 2 times more volume than HFO. All other options require a maximum additional 20% space for onboard installation.

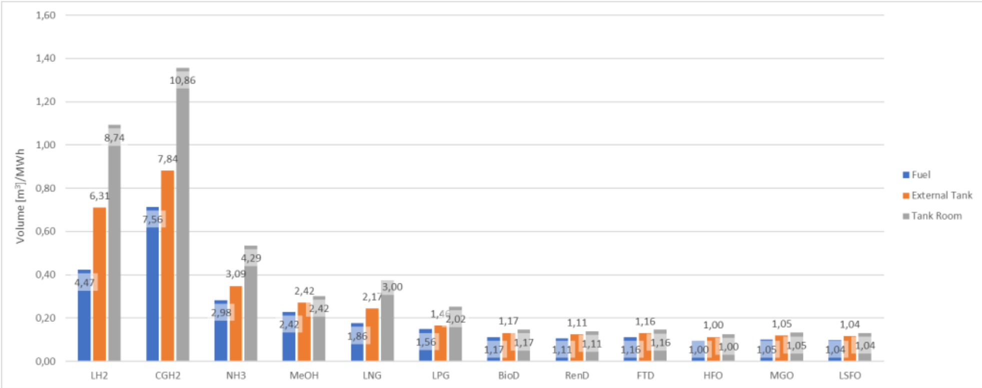

Figure 53 – Space required for each MWh of fuel onboard

Figure 54 shows the mass for 1 MWh of potential marine fuels and of their storage option. When only fuel is considered, 1 MWh of hydrogen is 70% lighter than 1 MWh of HFO, but when storage system is considered, liquefied hydrogen storage system is 2.3 times heavier than HFO tanks, and compressed hydrogen is 3.4 times heavier. LNG storage tanks have a weight comparable to HFO tanks, even though the fuel itself is 20% lighter than HFO. Ammonia and methanol both are almost two times heavier than HFO considering the storage system, and then all other liquid fuels can be considered comparable to HFO.

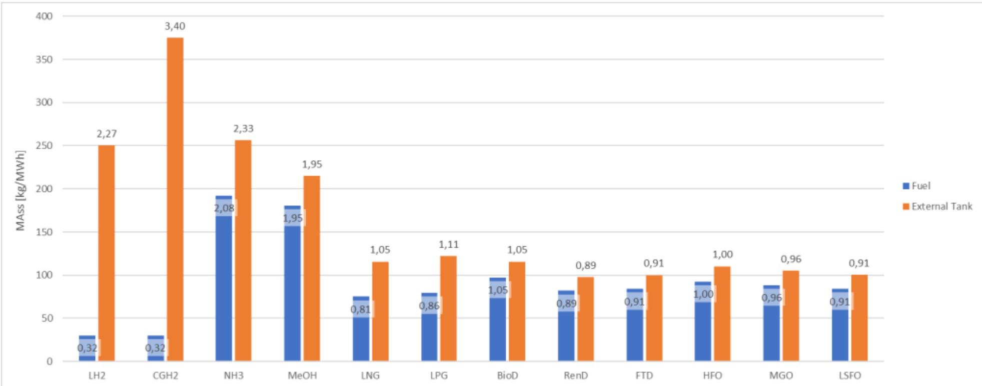

Figure 54 – Mass required for each MWh of fuel onboard

More weight or more volume occupied by a fuel’s storage system onboard a ship is a limit to the maximum payload capacity of the vessel considered. Since this research is focused on cruise ships, payload is represented by passenger’s cabins and public spaces. On average, tickets sales account for 62% of total revenue while onboard purchase of food, drinks, excursions, and all other possible expanses account for the remaining 38% of revenues. The profit obtained from these revenues is between 16% and 19%. A contemporary class cruise ship revenue for a 7-days cruise is an average of 1475$ per passenger and its profit per passenger is equal to 250$, while for a luxury class cruise ship these figures are equal respectively to 2069$ and 329$ [142]. In this PhD thesis, payload value for ton or for cubic meter has been estimated starting from these profit and revenue values. Values obtained are shown in Table 19. As previously stated, contemporary class cruise ships are less expansive and can accommodate more people onboard, so the revenue per passenger (pax) per day is lower than luxury class cruise ships. A lower revenue brings to a lower profit.

Table 19 – Revenue and profit for two different classes of cruise ships

Reference ship	**Revenue**	**Profit**		
	[€/pax/day]	**[€/pax/day]**	**[€/day/m3]**	**[€/day/t]**
Contemporary class	214 €	36 €	0.51 €	14 €
Luxury class	268 €	49 €	0.69 €	18 €

Figure 55 shows the cost of onboard storage of different fuels for a contemporary class cruise ship. Total cost is composed by cost of the storage system itself (tanks and auxiliary equipment CAPEX and OPEX) and the cost of lost payload capacity in its worst-case scenario. The worst-case scenario is represented by the maximum value of lost payload considering the whole volume and deadweight lost when comparing the new solution with a traditional HFO storage system. Compressed hydrogen is characterised by the highest storage system cost among considered options, almost 1350 €/a/MWh. The second-highest storage system cost is liquefied hydrogen, equal to more than 750 €/a/MWh. Traditional oil-based fuel tanks have an estimated cost of about 20 €/a/MWh. Compressed hydrogen is again characterised by the highest lost payload capacity cost, which is equal to almost 1600 €/a/MWh. The overall cost for onboard storage is thus equal to almost 3000 €/a/MWh for compressed hydrogen, so 168 times higher than HFO total storage system cost. Liquefied hydrogen storage system has a total cost equal to almost 1800 €/a/MWh, which is the second-highest figure for this characteristic of alternative fuel technologies. Ammonia is the third most expensive storage option for onboard fuel: for this liquid the onboard storage cost is equal to almost 600 €/a/MWh, so almost one third of liquid hydrogen cost and one fifth of compressed hydrogen storage.

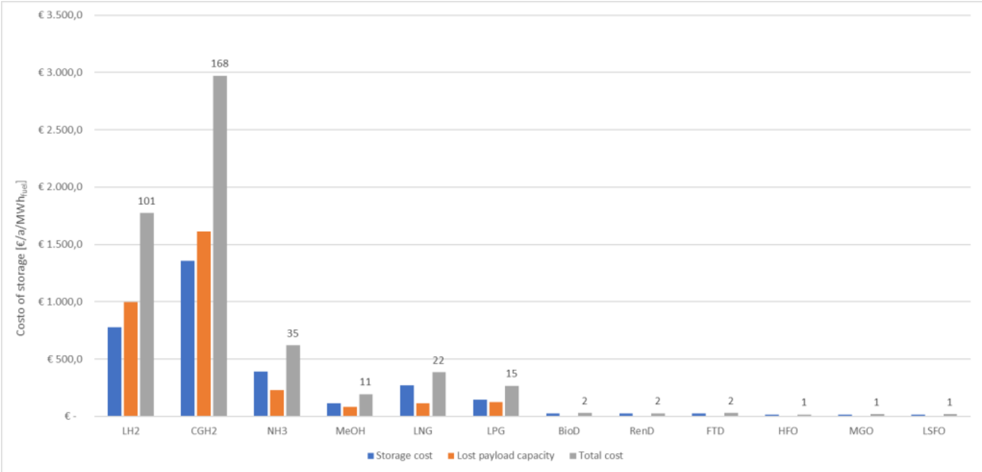

Figure 55 – Cost of onboard storage for contemporary class cruise ship

Figure 56 shows the cost of onboard storage of different fuels for a luxury class cruise ship. Storage system costs are the same of Figure 55, but the lost payload capacity cost is different because the class of cruise ship is changed. Since luxury cruise ship are characterised by a higher value for each cubic meter or ton of lost payload, the cost of onboard storage is higher for a luxury class cruise ship than the cost for a contemporary class cruise ship. Obviously, the more the storage system is heavier or bigger than HFO tanks, the more the impact on payload is sensible and thus the impact on the total cost of the storage system. Also, it can be identified the fact that hydrogen would require a big sacrifice in terms of payload or in terms of ship's autonomy, i.e., the period between ship's refuelling operations. Reducing the period between refuelling would have a beneficial impact on the quantity of fuel onboard because this operation is able to decrease the size of these storage systems and thus the impact on lost payload cost.

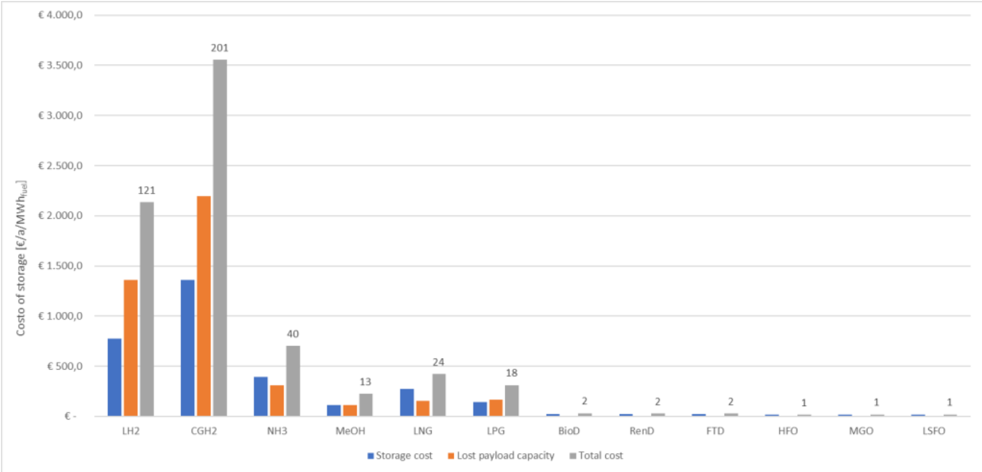

Figure 56 - Cost of onboard storage for a luxury class cruise ship

2. Power generators

Ships require power for propulsion and for all non-propulsive loads, mainly related to payload (both goods or people) and to all the systems required to let them sail and operate safely (energy distribution system, heating, ventilation and air conditioning system, telecommunications, navigation systems, ecc…). Propulsive power is in most cases the biggest part of total power required onboard a ship, while other equipment requires a smaller part of it: in some cases, like cruise ships or ro-ro/pax ships, this share can come close to propulsion power. The first forms of marine propulsion systems were sails and paddles: the most common propulsion system today is propeller, with less frequent application of pump jets and other more niche alternatives. Propellers were moved by steam engines in their first applications, now are moved by two-stroke or four-stroke diesel engines, gas turbines, steam turbines and electric motors, depending on the type of ship. Almost every rotating machine must transfer power to propellers via a reduction gear because its rotation speed is too high for that propulsion system. Only two-stroke engines have a rotation speed between 100 and 200 rpm that is close to the propeller's maximum speed. All these statements are related to displacement hulls and not for high-speed boats [143].

Non-propulsive loads are powered by electricity generated onboard from dedicated diesel generators coupled with alternators, sometimes called "auxiliary diesel generators". If electric motors are used for propulsion, four-stroke diesel generators coupled with alternators constitute the ship's power plant and this must be capable of generating all the energy required by propulsive and non-propulsive loads. This is currently the most common layout for cruise ship power generation [144].

New fuels and the need of improved efficiency and lower emissions from ships are causing other power generation system to be considered for ships, like fuel cells and batteries. In other cases, existing power generators are sustaining changes to work with different fuels. An overview about current machinery employed onboard cruise ships and possible new power generators is given in the following paragraphs.

2.1. Internal combustion engines

Even if internal combustion engines used onboard ships can be four-stroke engines or two-stroke engines, the vast majority of cruise ships today use reciprocating four-stroke internal combustion diesel engines as prime generators. This type of engine is used directly coupled to an alternator: a vessel which employs this solution is commonly known as "all electric ship" because all mechanical power generated onboard by engines' rotation is transformed in electrical power by alternators and then distributed to various users with electrical equipment such as switchboards and transformers. A diesel-electric power generation plant allows ship designers to install gensets and all their related components in sections of the ship not directly related to the propeller's shaft. These engines are characterised by a medium rotation speed, so with a maximum operating speed between 300 and 1000 rpm and use HFO or MGO as fuel, after a proper treatment described in paragraph 1.2.1. Four-stroke internal combustion engine can benefit from high ratios between power/weight and power/volume, the possibility of sustaining full load for long periods and an attractive operating cost. Also, in past decades, medium speed diesel engines' reliability and durability have been improved thanks to advanced monitoring and diagnostic systems and a better design. These engines are constituted by several cylinders, in most cases an even number, in which piston thanks to combustion of air-fuel mixture transform chemical energy into kinetic rotational energy of the crankshaft. Cylinders can be placed in-line or in a V-shaped configuration: the first one brings to engines taller, longer, and thinner than the second one when considering the same number of cylinders. Engines' Specific Fuel Oil Consumption (SFOC) and emissions have also been optimised regulating injection pressures, via a mechanical or electronically controlled common rail system, archiving higher compression ratios and stroke/bore ratios [145].

Cylinders are cooled with water that exchange heat with an intermediate water circuit that is cooled by seawater. In most recent ships, part of this heat is recovered to produce hot water for selected users onboard. Noise and vibrations are reduced by a resilient mounting system, on which also the alternator is mounted.

Choosing the right engines for a power plant is a decision that must be taken carefully, considering the options available and the operating profile of the ship. Ship designers and shipowners often favour a flexible "father-and-son" configuration, in which similar four-stroke engine models are chosen, but with different cylinder numbers. In this configuration, these gensets provide power to electric motors dedicated to propulsion and to all other machineries onboard. Among advantages of this configuration, first one is flexibility of power plant's layout: engines can be installed in locations that are not close to propellers, thus not on the stern part of the ship. Secondly, since non-propulsive loads for cruise ships and ro-ro/pax ships can require up to 40% of total installed power, a genset power plant helps to meet these high demands without increasing power installed onboard. There are two main engine rooms for a safety redundancy imposed by international rules, and each one is constituted by two or three diesel gensets. These configurations allow a load share between gensets and can help to run these engines near their best SFOC conditions to reduce fuel consumption and emissions, leaving also one or more genset hot and ready to turn on if a failure or a higher demand occurs. Electric transmission also allows prime movers, so electric motors coupled with propellers, to be mounted on double resilient basements or directly outboard with special pod configurations which help minimising noise and vibrations transmitted to the ship. This characteristic is particularly important for cruise ships because they have a special focus on comfort onboard. Since podded propulsion systems embody an electric motor directly coupled with a propeller in a submerged housing outside the ship (see Figure 57), they guarantee also a space saving inside the ship. These devices also enhance ship's manoeuvrability without installing stern thrusters. Also, propulsion units can be installed later during the ship building process, reducing "dead time" investment cost [145].

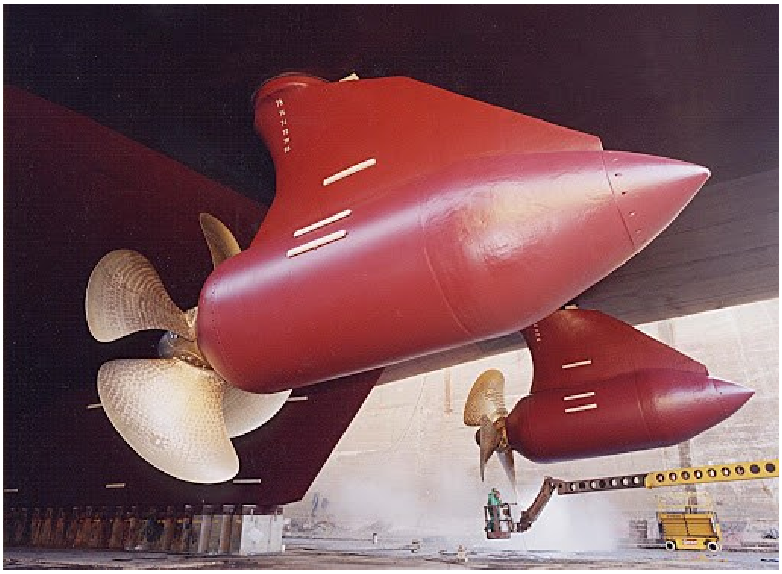

Figure 57 - Podded propulsors [145].

Four stroke rotation speed requires mounting diesel engines and alternators on heavy basements via elastomeric vibration dumpers. This basement is placed on the lowest deck of the ship, right above double bottom, via another system of elastomeric vibration dumpers.

Four-stroke engines have various interfaces with systems onboard the ship: they need both fuel and air intake to sustain the combustion reaction, they must release exhaust gases outside cylinders volume, and they need to be properly lubricated and cooled down by a water-cooling system. Air intake and exhaust release systems are a crucial part of the generation power plant: air is the essential mean to provide oxygen for the combustion process and a dedicated system which comprises ducts, grids and fans are installed onboard to route fresh air to gensets. Engine water cooling system normally consists of two separate glycol-water cooling circuits. These glycol-water cooling circuits differ for their operative temperature: one at a higher operative temperature, almost 90 °C to 65 °C, which cools down hotter parts of the engines, one at a lower operative temperature, almost 65 °C to 30 °C. These cooling liquids exchange heat with seawater.

Four stroke internal combustion engines are fuelled by HFO, LSFO or MGO in most ships. Their technology is well established by almost 40 years of experience and onboard cruise ships some of the reference models currently installed are described in Table 20 and in Table 21. While Table 20 shows some of the main data given by the engine manufacturer, Table 21 shows data calculated for this PhD activity that have been used for the parametrisation of this type of generator [146] [147]. From data of current four-stroke diesel engines fuelled by oil-based fuels analysed, it was assumed a footprint of 4.2 m^2/MW, a volume ratio of 22 m^3/MW and a weight ratio of 28 ton/MW. These values are higher than the ones shown in Table 21 because weight and volume of alternator were accounted: this equipment, alongside the engine's basement, are the main parts of the genset.

Table 20 - HFO/LSFO/MGO fuelled engines main data [146] [147]

Model	**L**	**B**	**H**	**P gen**	**Weight**
	[m]	[m]	[m]	[kW]	[ton]
Wartsila 6L46F	8.6	2.9	5.0	7200	97
Wartsila 7L46F	9.4	3.0	5.3	8400	113
Wartsila 8L46F	10.3	3.0	5.3	9600	124
Wartsila 9L46F	11.1	3.0	5.3	10800	140
Wartsila 12V46F	10.2	4.1	5.6	14400	173
Wartsila 14V46F	11.7	4.7	6.1	16800	216
Wartsila 16V46F	12.8	4.7	6.1	19200	233
MAN 12V48/60CR	10.8	4.7	5.5	14400	189
MAN 14V48/60CR	11.8	4.7	5.5	16800	213
MAN 16V48/60CR	13.1	4.7	5.5	19200	240
MAN 18V48/60CR	14.1	4.7	5.5	21600	265
MAN 6L48/60CR	8.8	3.2	5.3	7200	106
MAN 7L48/60CR	9.6	3.2	5.3	8400	119
MAN 8L48/60CR	10.5	3.3	5.3	9600	135
MAN 9L48/60CR	11.4	3.3	5.3	10800	148

Table 21 - HFO/LSFO/MGO fuelled engines calculated parameters

Model	Footprint	Volume Ratio	Weight Ratio
	[m^2/MW]	[m^3/MW]	[ton/MW]
Wartsila 6L46F	3.5	17.5	13.5
Wartsila 7L46F	3.3	17.5	13.5
Wartsila 8L46F	3.2	16.6	12.9
Wartsila 9L46F	3.0	16.0	13.0
Wartsila 12V46F	2.9	16.0	12.0
Wartsila 14V46F	3.3	19.8	12.9
Wartsila 16V46F	3.1	18.9	12.1
MAN 12V48/60CR	3.5	19.5	13.1
MAN 14V48/60CR	3.3	18.3	12.7
MAN 16V48/60CR	3.2	17.8	12.5
MAN 18V48/60CR	3.1	17.0	12.3
MAN 6L48/60CR	3.9	20.4	14.7
MAN 7L48/60CR	3.6	19.1	14.2
MAN 8L48/60CR	3.6	19.1	14.1
MAN 9L48/60CR	3.5	18.3	13.7

These power generators have been modelled in an essential but effective way in Figure 58 where it is shown the relationship between the four-stroke diesel engine's load, its electrical efficiency, and the efficiency gains through two heat recovery systems [148] [149] [150]. This analysis assumes that, like in almost every new cruise ship, an Exhaust Gas Boilers (EGB) is used for steam generation via exhaust gases' heat recovery and heat is recovered by a heat exchanger installed in the high temperature engines cooling circuit. CAPEX for four-stroke diesel engines fuelled by oil-based fuels like MGO, LSFO, HFO has been assumed to be equal to 300 €/kW, OPEX has been assumed equal to 1% of CAPEX and lifetime has been estimated in 15 years in accordance with data publicly available [20].

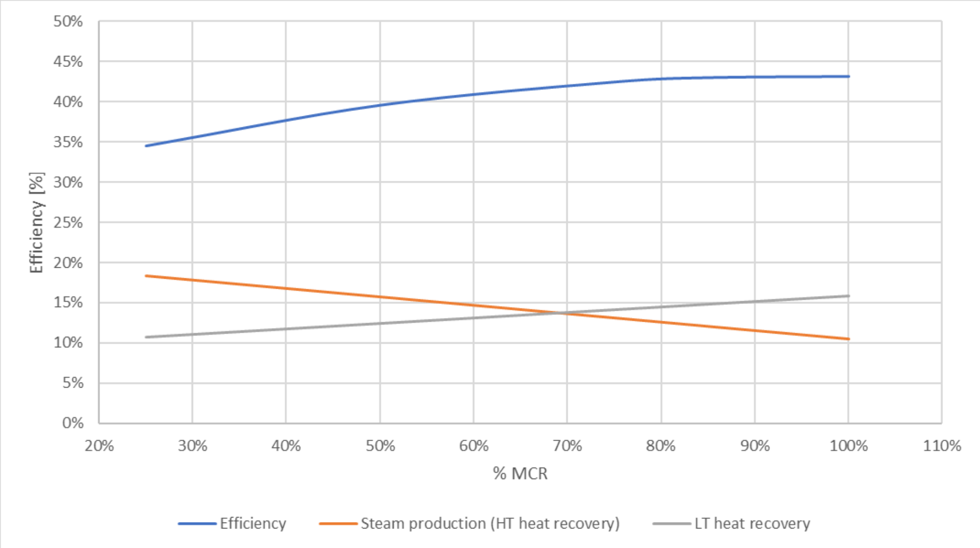

Figure 58 - Efficiency of electrical power generation and of heat recovery systems for four-stroke diesel engines fuelled by oil-based fuels

In this thesis was assumed that four stroke internal combustion engines fuelled by biodiesel, renewable diesel or Fischer-Tropsch diesel have the same electrical efficiency and heat recovery capability of a traditional four-stroke diesel engines, even if this type of power generator has not yet been commercialised. CAPEX has also been assumed to be equal to the one of traditional four-stroke engines since renewable liquid fuels in principle can be used in today's engines. It was increased OPEX for this type of match between engine and fuel at 3% of CAPEX, while assuming the same lifetime of 15 years.

Dual Fuel four stroke Internal Combustion Engines (DF-ICE) burning natural gas and MGO as pilot fuel are installed on-board ships from at least ten years, especially on LNG carriers, roll-on roll-off vessels, and cruise ships. This technology provides elimination of sulphur emission and a significant decrease in NOx and PM emission, while cutting by almost 30% the amount of CO_2 produced by the engine [129]. According to two dual fuel four stroke internal combustion engines technical datasheets, the electrical efficiency of these power generators is slightly higher than oil-based fuels' one four stroke internal combustion engines, so the electrical efficiency shown in Figure 59 was considered as reference value [151]. It was also assumed that heat recovery efficiency gains are equal to what already shown in Figure 58. Dual-fuel four stroke internal combustion engines suffer from a problem: combustion of the mixture of air and fuel is not always complete and thus a part of fuel is released in the air. This phenomenon is called methane slip and is needs to be considered carefully in this study because methane is a greenhouse gas which, as already stated in 1.1.6

has a GWP equal almost to 84 over a 20 year lifetime and to 32 over a 100 years' timeframe [59]. In this study was considered a GWP for methane slip equal to 84 to better assess cruise ship's emissions impact during the next decades. Methane slip is related to engine load and is increases at lower loads. A study states for this type of engine an emission of almost 5.5 g_{CH4}/kWh measured at test beds at ideal conditions [152], while another research states a manufacturer mean measured methane slip of 2.8 g_{CH4}/kWh and a calculated value of 4.4 g_{CH4}/kWh [55]. In this study a best-case value of methane slip equal to 5 g_{CH4}/kWh at 85% MCR was assumed, and it was also assumed that methane slip is inversely proportional to the engine's electrical efficiency.

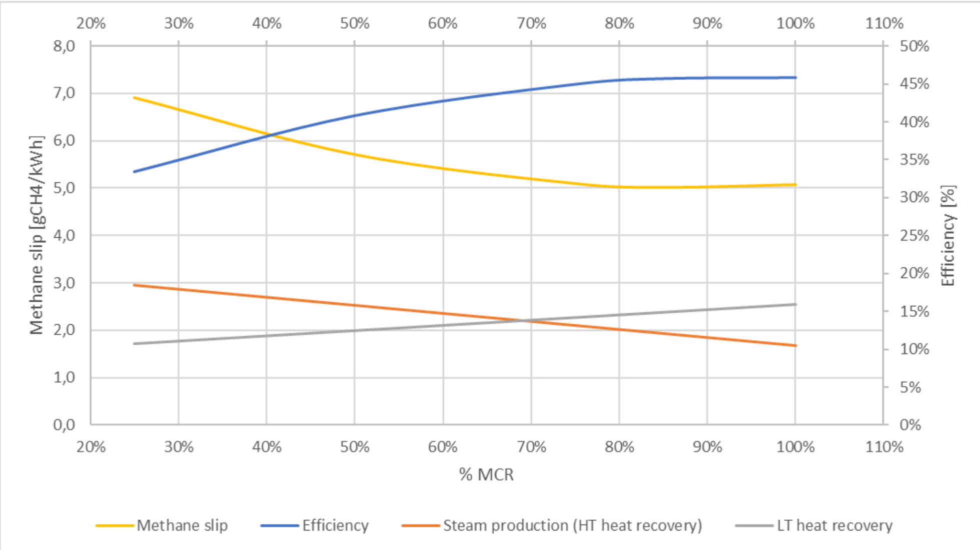

Figure 59 - Efficiency of electrical power generation and of heat recovery systems for an MGO or LNG fuelled diesel engine

Main data of dual fuel four stroke marine diesel engines are shown in Table 22, while footprint, volume ratio and weight ratio have been calculated and are shown in Table 23. From this data, in this thesis was assumed a footprint equal to 6 m^2/MW, a volume ratio of 28 m^3/MW and a weight ratio of 36 ton/MW. These values are higher than the ones shown in Table 23 because during the described PhD study weight and volume of alternator were also considered: this equipment, alongside the engine's basement, are the main parts of the genset.

Table 22 - LNG fuelled engines main data [152]

Model	L	B	H	P gen	Weight
	[m]	[m]	[m]	[kW]	[ton]
Wartsila 8V31DF	9.1	3.2	4.9	4240	90
Wartsila 10V31DF	9.8	3.2	4.9	5300	101
Wartsila 12V31DF	10.2	3.5	4.4	6360	115
Wartsila 14V31DF	10.8	3.5	4.4	7420	121
Wartsila 16V31DF	11.4	3.5	4.4	8480	131
Wartsila 6L34DF	8.7	2.3	4	2770	57
Wartsila 8L34DF	10.5	2.7	4.2	3490	76
Wartsila 9L34DF	10.5	2.9	4.2	4150	87
Wartsila 12V34DF	10.1	3.1	4.4	5530	96
Wartsila 16V34DF	11.2	3.1	4.6	7370	121
Wartsila 6L46DF	9	3.2	4.7	6870	102
Wartsila 7L46DF	9.8	3.2	4.7	8015	118
Wartsila 8L46DF	10.6	3.2	4.9	9160	130
Wartsila 9L46DF	11.5	3.2	4.9	10305	146
Wartsila 12V46DF	10.4	4.6	5.3	13740	184
Wartsila 14V46DF	11.4	4.6	5.3	16030	223
Wartsila 16V46DF	12.7	5.2	5.5	18320	235
MAN 12V51/60DF	9.9	4.7	6.6	12400	276
MAN 14V51/60DF	10.9	4.7	6.6	14480	318
MAN 18V51/60DF	13.2	4.7	6.6	18654	381
MAN 6L51/60DF	8.5	3.2	5.4	6300	106
MAN 7L51/60DF	9.4	3.2	5.4	7350	119
MAN 8L51/60DF	10.2	3.2	5.4	8400	135

Table 23 - LNG fuelled engines calculated parameters

Model	Footprint	Volume Ratio	Weight Ratio
	[m^2/MW]	[m^3/MW]	[ton/MW]
Wartsila 8V31DF	6.7	32.6	21.3
Wartsila 10V31DF	5.8	28.0	19.1
Wartsila 12V31DF	5.6	24.3	18.1
Wartsila 14V31DF	5.1	22.2	16.3
Wartsila 16V31DF	4.8	20.5	15.5
Wartsila 6L34DF	7.2	28.8	20.6
Wartsila 8L34DF	8.1	33.6	21.8
Wartsila 9L34DF	7.3	30.5	21.0
Wartsila 12V34DF	5.6	24.4	17.4
Wartsila 16V34DF	4.7	21.0	16.5
Wartsila 6L46DF	4.2	19.5	14.9
Wartsila 7L46DF	3.9	18.2	14.8
Wartsila 8L46DF	3.7	18.0	14.2
Wartsila 9L46DF	3.6	17.2	14.2
Wartsila 12V46DF	3.5	18.2	13.4
Wartsila 14V46DF	3.3	17.2	14.0
Wartsila 16V46DF	3.6	19.7	12.9
MAN 12V51/60DF	3.8	24.4	22.3
MAN 14V51/60DF	3.6	23.0	22.0
MAN 18V51/60DF	3.4	21.7	20.5
MAN 6L51/60DF	4.3	22.8	16.9
MAN 7L51/60DF	4.1	21.5	16.2
MAN 8L51/60DF	3.9	20.4	16.1

CAPEX for dual fuel four-stroke diesel engines has been assumed in a study to be equal to 470 €/kW [61], while in another database various CAPEX for this type of medium speed engines are indicated: 260 €/kW, 350 €/kW, 425 €/kW, 700 €/kW and 250 €/kW [20]. It was assumed in this thesis a CAPEX of 400 €/kW. OPEX has been assumed to be the same of a four stroke internal combustion engine fuelled by renewable fuels, thus equal to 3% of CAPEX. Lifetime has also been estimated to be the same of other four stroke diesel internal combustion engines: 15 years.

Wärtsilä has commercialised some medium speed internal combustion engine fuelled by LPG, while MAN has in its portfolio only two-stroke internal combustion engines able to be fuelled by LPG. Data referred to this technology are shown in Table 24 and in Table 25. This specific type of engine can be fuelled by both LPG and natural gas and, as other dual fuel engines, they need a small amount of pilot fuel to start combustion. The peak efficiency of these engines is almost the same of dual fuel four-stroke engines, and thus it was decided to consider electrical efficiency and heat recovery efficiency to be the same of dual fuel internal combustion engines [153]. It was also assumed that LPG-fuelled internal combustion engine would cause a lower emission of non-combusted fuel and has assumed a 60% reduction of methane slip from a dual fuel internal combustion engine. In this thesis a footprint equal to 8.4 m^2/MW, a volume ratio of 38 m^3/MW and a weight ratio of 46 ton/MW was considered analysing data shown in Table 25 and increasing those values considering weight and volume of alternator and basement that with the engine are the main parts of the genset.

Table 24 - LPG fuelled gensets main data [152]

Model	**L**	**B**	**H**	**P gen**	**Weight**
	[m]	[m]	[m]	[kW]	[ton]
Wartsila 12V34SG	10.5	3.4	4.5	4185	102
Wartsila 16V34SG	11.5	3.4	4.5	5618	125
Wartsila 20V34SG	13.1	3.4	4.6	7042	136

Table 25 - LPG fuelled gensets calculated data

Model	**Footprint**	**Volume Ratio**	**Weight Ratio**
	[m^2/MW]	[m^3/MW]	[ton/MW]
Wartsila 12V34SG	8.4	37.8	24.4
Wartsila 16V34SG	6.8	30.8	22.3
Wartsila 20V34SG	6.3	28.6	19.3

It was also assumed that LPG fuelled four stroke internal combustion engines have a CAPEX and OPEX equal to dual fuel internal combustion engines and equal respectively to 400 €/kW and 3% of CAPEX. Lifetime has also been estimated to be the same of other four stroke diesel internal combustion engines: 15 years.

Methanol fuelled four stroke internal combustion engines have a slightly longer marine experience than LPG fuelled engines. Methanol can be used as fuel by blending it with various other fuels, as MGO, natural gas or LPG [154] [155]. As for LPG, Wartsila already has in its portfolio four stroke marine internal combustion engines capable of burning methanol, and their characteristics are shown in Table 26 and in Table 27. MAN states that is developing a four stroke solution ready for mid-2022 and will start retrofitting its four-stroke engines to run on methanol from 2024, especially planning to modify series MAN 51/60DF and MAN 48/60CR [156] [157].

Table 26 - Methanol fuelled engines main data [154] [155]

Model	L	B	H	P gen	Weight
	[m]	[m]	[m]	[kW]	[ton]
Wartsila 6L32	5.6	2.4	3.6	3480	38
Wartsila 7L32	5.7	2.4	3.6	4060	44
Wartsila 8L32	6.4	2.6	3.6	4640	49
Wartsila 9L32	6.9	2.6	3.6	5220	57
Wartsila 12V32	7.1	2.9	3.6	6960	71
Wartsila 16V32	8.0	3.3	3.8	9280	35

Table 27 - Methanol fuelled engines calculated data

Model	Footprint	Volume Ratio	Weight Ratio
	[m^2/MW]	[m^3/MW]	[ton/MW]
Wartsila 6L32	3.8	13.7	10.9
Wartsila 7L32	3.4	12.1	10.8
Wartsila 8L32	3.6	12.9	10.6
Wartsila 9L32	3.4	12.4	10.9
Wartsila 12V32	3.0	10.8	10.2
Wartsila 16V32	2.9	11.0	3.8

It was assumed that methanol fuelled four stroke internal combustion engines have the same electrical and heat recovery efficiency as traditional four stroke internal combustion engines, since these characteristics are slightly lower than dual fuel engines' ones. From data shown in Table 27, Table 23 and Table 21 it was assumed a footprint of 4 m^2/MW, a volume ratio of 22 m^3/MW and a weight ratio of 28 ton/MW. In this study, it was considered that methanol fuelled four stroke internal combustion engines have a CAPEX and OPEX equal to dual fuel internal combustion engines and equal respectively to 400 €/kW and 3% of CAPEX. Lifetime has also been estimated to be the same of other four stroke diesel internal combustion engines: 15 years.

Ammonia fuelled four stroke internal combustion engines are currently under development by main manufacturer around the world, and there are only some niche applications of retrofits for two-stroke internal combustion engines. Studies analysed in this PhD thesis point out that two-stroke engines using this fuel would be very similar to dual fuel ones, thus for four-stroke engines volume ratio, weight ratio and efficiencies has been considered the same of dual fuel ones [158] [159]. It was assumed a CAPEX equal to 450 €/MW and an OPEX equal to 4% of CAPEX to reflect the novelty of this technological solution. Lifetime has been estimated to be the same as other four stroke diesel internal combustion engines: 15 years.

Hydrogen fuelled engined are, as ammonia fuelled ones, currently under development both for stationary and marine applications. Main challenges of developing the technology for a hydrogen fuelled four stroke internal combustion engines are its low methane number, its low ignition energy and a high flame speed, which results in a high pressure increase inside the combustion chamber [160]. For this reason, data like volume ratio, weight ratio and efficiencies has been considered the same of dual fuel ones. It was also assumed that CAPEX, OPEX and lifetime are the same of ammonia fuelled internal combustion engines.

2.2. Fuel cells

Fuel cells are electrochemical devices capable of converting chemical energy directly into electrical energy by producing various by-products depending on the fuel used for the reaction. The principle of operation of this technology was discovered in 1839 by the English physicist William Groove, who thought of reversing the electrolysis process to generate current [161]. Fuel cells share some characteristics both with batteries, due to the electrochemical nature of the power generation process, and with engines which, unlike batteries, work continuously when fed with a certain amount of fuel and air. However, unlike technologies above mentioned, they do not have the limit of recharging, typical of batteries, nor that of the Carnot cycle efficiency, typical of internal combustion engines. Internal combustion engines convert chemical energy into mechanical energy, which by mean of an alternator becomes electrical energy. Fuel cells directly convert chemical energy into electricity and so it is obtained an overall higher efficiency thanks to fewer power conversions. All fuel cells work in the same way. The oxidation reaction of the fuel takes place at the anode: this fuel can be pure hydrogen or another fuel from which hydrogen can be obtained, like natural gas, methanol, or ammonia. Oxidation reaction separates hydrogen in H + ions and electrons. Oxygen normally obtained from ambient is reduced at the cathode. Fuel cell technologies differ for the type of electrolyte used: electrolytes only allow one type of positively charged ions to pass through them. These electrolytes are impervious to the passage of electrons which, to complete the reaction, must pass through an external circuit, generating electricity. Table 28 shows a brief description of the main types of fuel cells, reporting the type of electrolyte used, the chemical formula of the ion that crosses the electrolyte membrane, operating temperatures, type of fuel and mean electrical efficiency obtained [161] [162].

Alkaline fuel cells (AFC) are one of the first fuel cells technologies to be developed, and AFC were used for the Apollo missions that brought the first people to the moon. The alkaline electrolyte used easily adsorbs carbon dioxide: this contamination reduces conductivity. For this reason, the main problem with this type of fuel cells is to prevent any possible contamination of carbon dioxide at both the anode and cathode. Furthermore, the power obtainable from these cells reaches a maximum of 5 kW. For this reason, the Phosphoric Acid Fuel Cells (PAFC) have been developed from the AFC to obtain higher powers, around 200 kW, but this technology cannot reach high current densities. Both these technologies are not considered for marine applications.

Proton Exchange Membrane Fuel Cells (PEMFC) are named after the membrane that is used as an electrolyte. This membrane is usually composed of Nafion, which is a fluoropolymer consisting of tetrafluoroethylene sulfonate, which has ionic properties and is therefore considered an ionomer. The membrane allows the passage of protons and at the same time thanks to its low conductivity prevents the passage of electrons. Nafion membrane needs water to be an effective protons' conductor: this limits its operating temperature to a maximum of about 100 °C.

Table 28 – Overview of the main fuel cell technologies [162]

Technology	Electrolyte	Ion	Fuel	Operative temperature	Efficiency
Alkaline Fuel Cells (AFC)	Potassium hydroxide	OH^-	Pure hydrogen	60-120°C	50-60% (electric)
Phosphoric Acid Fuel Cells (PAFC)	Phosphoric Acid	H^+	LNG, Methanol, MDO, Hydrogen	~220°C	40% (electric) 80% (with heat recovery)
Molten Carbonate Fuel Cells (MCFC)	Sodium and/or potassium carbonate	CO_3^{2-}	LNG, Methanol, MDO, Hydrogen	~650°C	50% (electric) 85% (with heat recovery)
Solid Oxide Fuel Cells (SOFC)	Yttria-stabilized zirconia	O^{2-}	LNG, Methanol, MDO, Hydrogen	~1000°C	60% (electric) 85% (with heat recovery)
Proton Exchange Membrane Fuel Cells (PEMFC)	Nafion	H^+	Pure hydrogen	50-100°C	50-60% (electric)
High Temperature PEMFC (HT-PEMFC)	sPEEK	H^+	LNG, Methanol, MDO, Hydrogen	130-200°C	50-60% (electric)
Direct Methanol Fuel Cells (DMFC)	Polymeric membrane	H^+	Methanol	50-110°C	20% (electric)

Solid Oxide Fuel Cells (SOFC) and Molten Carbonate Fuel Cell (MCFC) are the two main types of high temperature fuel cells and can reach a power of the order of magnitude of

Megawatts. The great advantages of these technologies are the high energy efficiency that can be obtained thanks to the possible heat recovery from exhaust gases. Also, high temperature allows them to use different fuels, like natural gas or methanol, because these fuels are reformed into carbon dioxide or monoxide and hydrogen, simplifying the system, and reducing the volumes occupied by the combination of reformer and fuel cell generator.

Direct Methanol Fuel Cells (DMFC) use a solution of methanol and water as a fuel. This technology has the great advantage of directly using a liquid fuel as an internal combustion engine. However, the efficiency is very low since they suffer from the cross-over phenomenon of methanol through the membrane that separates the cathode and anode: this causes a direct reaction and obviously decreases the efficiency of the cell. This technology is currently not considered for marine applications.

The two main technologies considered for marine applications are PEMFC fuelled by hydrogen (pure or obtained onboard via natural gas reforming or ammonia cracking) and SOFC powered by natural gas, ammonia, or hydrogen [162]. Their combination of cost, power density, lifetime, fuel tolerance, fuel flexibility, technology readiness level, safety and efficiency have been considered and evaluated in various studies that confirm the fact that PEMFC and SOFC are the most promising technologies for marine applications [163].

2.2.1. Proton Exchange Membrane Fuel Cells

PEM fuel cell technology has been successfully applied for many years, even for maritime power generation. For example, they are used in the automotive sector and onboard the German-designed U-212 and U-212A submarines. These vessels are equipped with modules from 30 kW to 50 kW produced by Siemens. A detail of this application is explained in paragraph 3.2.1. These fuel cells are composed by platinum electrodes, which act as catalysts, separated by a humidified polymer membrane that acts as an electrolyte since it is permeable to hydrogen ions (H^+) but not to electrons. The operating temperature is in the range between 50 °C and 100 °C, since if it exceeded this limit, it would not allow the membrane to remain wet. PEMFC use pure hydrogen as fuel and oxygen, producing only water and low temperature heat as waste. The only way to use a non-hydrogen fuel is to use a steam reforming reaction which, starting from a hydrocarbon such as methane, produces syngas, which is a mixture of carbon monoxide and hydrogen.

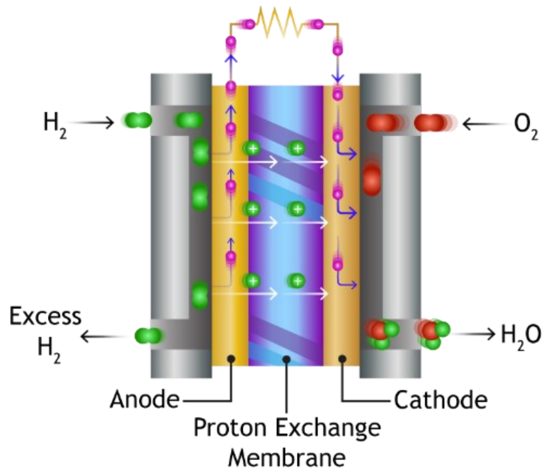

Figure 60 – PEMFC illustrated working principle [162]

The porous membrane is usually made up of Nafion, which is a DuPont patented ionomer. This is a fluoropolymer-copolymer composed by sulfonated tetrafluoroethylene, so it is a synthetic polymer having ionic properties. It is obtained from Teflon (tetrafluoroethylene) by adding sulphonic groups (SO^{3-}). Protons bind gradually to the acid sites located along the molecule and are transported, while the membrane has a low conductivity and prevents the passage of electrons if it is suitably wet. Membrane is composed by:

- Substratum: electrode with a light and porous structure, usually in carbon.
- Diffusion layer: allows the diffusion of the reactants in the active area and is usually made of carbon.
- Active layer: it is like the diffusion layer, but it is constituted of a catalyst, usually platinum, which favours the reaction.
- Nafion: semipermeable membrane located at the middle of the cell, which allows only the passage of positively charged ions.

PEM fuel cells have a high power to weight ratio (between 100 and 1000 W/kg), a relatively low operating temperature and a relatively low material cost, which makes them suitable for road or marine vehicles applications. A block diagram for a possible system configuration of PEM fuel cell technology on a marine vessel is shown in Figure 61.

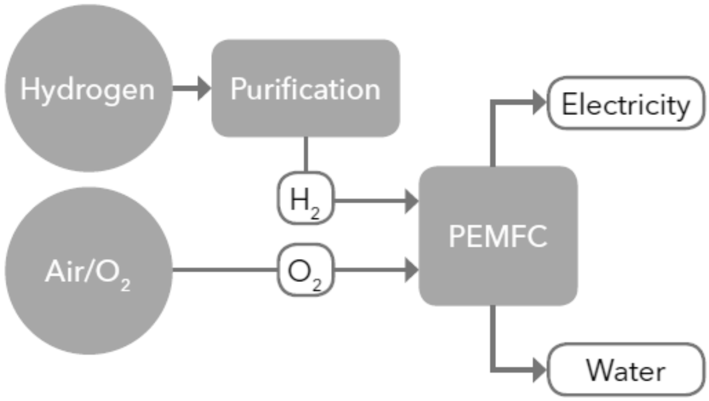

Figure 61 - Block diagram of a PEM fuel cell system [162]

The growing interest for zero-emission shipping and hydrogen has brought various fuel cell manufacturer to launch on the market PEM fuel cell modules suitable for marine applications. A collection of the main data associated with PEM fuel cell modules for marine applications currently available on the market is given in Table 29 and Table 30. From these data, it was assumed that footprint of fuel cell system is 20.0 m^2/MW, volume ratio is considered almost 40 m^3/MW and a weight ratio of 15 ton/MW. One research about new possible solutions for power generation onboard ships gives a volume ratio of almost 4 m^3/MW and a weight ratio of 4 ton/MW only for fuel cell stacks also considering a small margin for a part of the auxiliary components [164].

Table 29 – Maritime PEM fuel cells main data [164]

Model	L	B	H	P gen	Weight
	[m]	[m]	[m]	[kW]	[ton]
Nedstack MTFCPP100 [165]	2.0	1.0	2.0	100	1.50
Nedstack MTFCPP500 [166]	6.1	2.4	2.6	500	15.00
Ballard Marine [167]	1.2	0.7	2.2	200	0.88
Plug Power P60 [168]	1.0	0.6	0.5	60	0.24
Plug Power P85 [168]	1.0	0.8	0.5	85	0.30
Plug Power P100 [168]	1.0	0.9	0.5	100	0.34
Hydrogenics HD8 [169]	0.4	0.4	0.3	8.5	0.05
Hydrogenics HD10 [169]	0.4	0.4	0.3	10.5	0.05
Hydrogenics HD15 [169]	0.5	0.4	0.3	16.5	0.06
Hydrogenics HD30 [169]	0.7	0.4	0.3	31	0.07
Hydrogenics HD50 [169]	1.0	0.4	0.3	51	0.11
Hydrogenics HD90 [169]	1.6	1.1	0.3	93	0.36
Hydrogenics Celerity [169]	0.8	0.4	1.0	60	0.28
TECO FCC 1600TM [170]	3.0	2.4	2.6	1600	-
TECO FCC 3200TM [170]	6.1	2.4	2.6	3200	-
TECO FCC 6400TM [170]	12.2	2.4	2.6	6400	-
Powercell S3-49 [171]	0.4	0.3	0.2	49	0.02
Powercell S3-63 [171]	0.4	0.3	0.2	63	0.03
Powercell S3-81 [171]	0.4	0.4	0.2	81	0.03
Powercell S3-98 [171]	0.4	0.4	0.2	98	0.03
Powercell S3-125 [171]	0.4	0.6	0.2	125	0.04

Table 30 - Maritime PEM fuel cells calculated data

Model	Footprint	Volume Ratio	Weight Ratio
	[m^2/MW]	[m^3/MW]	[ton/MW]
Nedstack MTFCPP100	20.0	40.0	15.0
Nedstack MTFCPP500	29.6	76.6	30.0
Ballard Marine	4.5	9.9	4.4
Plug Power P60	10.5	4.9	4.1
Plug Power P85	9.5	4.5	3.5
Plug Power P100	8.5	4.3	3.4
Hydrogenics HD8	18.1	4.7	6.1
Hydrogenics HD10	15.8	4.1	4.5
Hydrogenics HD15	12.2	3.2	3.3
Hydrogenics HD30	9.4	2.5	2.3
Hydrogenics HD50	7.7	2.0	2.2
Hydrogenics HD90	18.5	6.4	3.9
Hydrogenics Celerity	5.0	4.9	4.6
TECO FCC 1600TM	4.6	11.8	-
TECO FCC 3200TM	4.6	12.0	-
TECO FCC 6400TM	4.7	12.0	-
Powercell S3-49	2.3	0.4	0.4
Powercell S3-63	2.1	0.3	0.4
Powercell S3-81	2.0	0.3	0.4
Powercell S3-98	1.9	0.3	0.3
Powercell S3-125	1.9	0.3	0.3

During the PhD activity, a modular and scalable PEM fuel cells power plant suitable for marine application was designed, built, and experimentally characterised. The test plant, as shown in Figure 63, consisted of:

- a 200 bar g storage system for hydrogen.
- a 100 kW PEM fuel cell generator.
- a DC/AC power converter including a supercapacitor-based energy storage.
- an electronic load bank.
- a fuel cell dry cooler.
- an electric board and a control system.

The PEM fuel cell used for these tests is one of the generators described in Table 29 and Table 30. Process air entering the stacks is provided by means of an internal centrifugal blower.

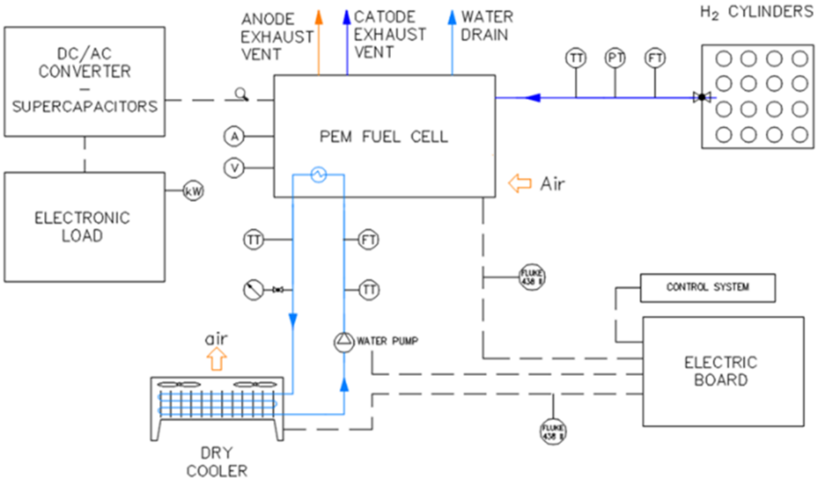

Figure 62 - P&ID of the investigated test plant [172]

Among other characteristics of these generators, PEMFC and system electrical efficiencies have been calculated at 100% and 50% nominal power (100 kW_{el} DC) referring to hydrogen LHV. Table 31 shows gross and net PEMFC and system electrical efficiency at 100% and 50% nominal power.

Fuel cell gross electrical efficiency has been defined as:

$$\eta_{FC\_gross} = \frac{P_{elFC}}{P_{in}} \cdot 100 = [\%] \tag{2.2.1}$$

Fuel cell net electrical efficiency has been calculated according to the formula indicated in IEC 62282-3-200:

$$\eta_{FC\_net} = \frac{P_{elFC} - P_{elin}}{P_{in}} \cdot 100 = [\%] \tag{2.2.2}$$

Similarly, the system gross and net electrical efficiencies have been defined as:

$$\eta_{el\_gross} = \frac{P_{elSYS}}{P_{in}} \cdot 100 = [\%] \tag{2.2.3}$$

$$\eta_{el\_net} = \frac{P_{elSYS} - P_{elin}}{P_{in}} \cdot 100 = [\%] \tag{2.2.4}$$

The difference between the FC gross and net electrical efficiency is higher at 50% nominal power output. This is due to the Balance Of Plant (BOP) and ancillaries power consumption, which increases less than linearly with respect to the FC power output. Figure 63 shows this behaviour of PEMFC and system gross and net electrical efficiencies' variation at different power outputs. The experimental gross system efficiency curve has been considered in this PhD thesis for following calculations, estimating a mean efficiency of the system equal to 52% [172].

Table 31 - System efficiency test: gross and net fuel cell and system electrical efficiency at 100% and 50% fuel cell nominal power [172]

FC power	FC gross electrical efficiency	FC net electrical efficiency	System gross electrical efficiency	System net electrical efficiency
100%	54.5 %	47.8 %	52.2 %	45.3 %
50%	58.5 %	47.5 %	56.6 %	45.6 %

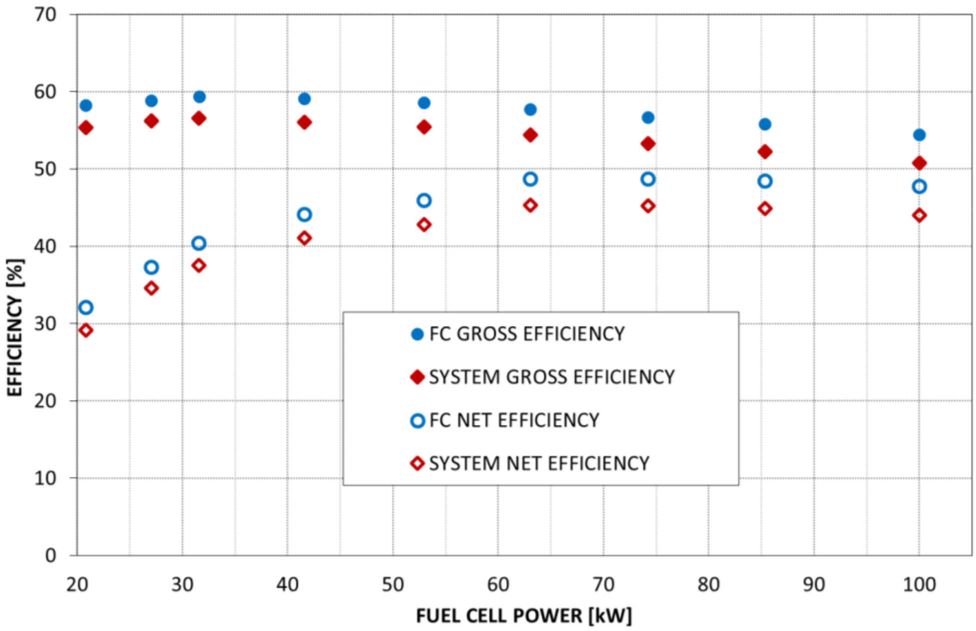

Figure 63 – PEM Fuel cell and system gross and net electrical efficiency [172]

According to a study, PEM fuel cell CAPEX can be somewhere between 500 €/kW and 2000 €/kW, depending on the serial production of marine ready products, while annual OPEX can vary between 3% to 10% of CAPEX [173]. Another research points out a CAPEX of almost 1500 €/kW for PEM fuel cells [174]. Investment cost for PEMFC system is considered equal to 730 €/kW by other studies, which also consider a system lifetime of 20 years. On the other hand, stack CAPEX and stack lifetime are considered equal respectively to 275

€/kW and 8 years [61]. An international study estimates CAPEX for PEM fuel cells for maritime applications as a value between 1000 €/kW and 2000 €/kW [175]. In this thesis has been assumed a CAPEX for PEM fuel cells equal to 1000 €/kW and an OPEX equal to 8% of CAPEX. This relatively high operative cost assumed in this thesis is related to the estimated lifetime, equal to 20 years. This lifetime is related to the system, and so in OPEX the cost of stacks replacement has been included.

2.2.2. Solid Oxide Fuel Cells

Solid Oxide Fuel Cells are characterised by high operative temperatures, normally in the range from 500 °C and 1000 °C. This operative characteristic has an influence on materials that must be used inside these devices: for this reason, the electrolyte is a porous ceramic material, normally yttrium-stabilised zirconia. SOFC's anode is made of a nickel alloy, while the cathode is made of lanthanum strontium manganite, a porous material suitable to work alongside the electrolyte used inside these devices. Unlikely PEM fuel cells, the electrolyte conduces negative oxygen ions [176]. A visual representation of this reaction is shown in Figure 64.

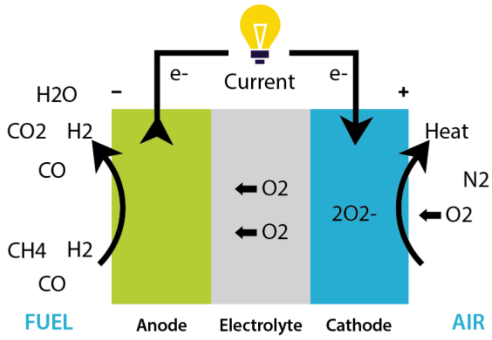

Figure 64 - SOFC illustrated working principle [162]

SOFC are characterised by a proven capacity to adapt to different types of fuel: pure hydrogen, ammonia, liquefied natural gas, biofuels, methanol, or other hydrocarbons. The reforming process takes place inside the cell thanks to high operative temperature or Catalytic-Partial-Oxidisers during the reaction starting process. Emissions include carbon dioxide or nitrogen oxides if pure hydrogen is not used as fuel [177]. Even with carbon fuels, production of nitrogen oxides is negligible, as for the emission of carbon monoxide. A block diagram for possible system configuration of SOFC technology on a marine vessel is shown in Figure 65. One of the main advantages of this technology is given by the high operating temperature, which allows heat recovery that onboard cruise ships represent a significant share of the whole power requirement from onboard users. In both stationery and cruise ship applications, SOFC systems in the range of megawatts can combine heat and power generation effectively, increasing the overall efficiency [178].

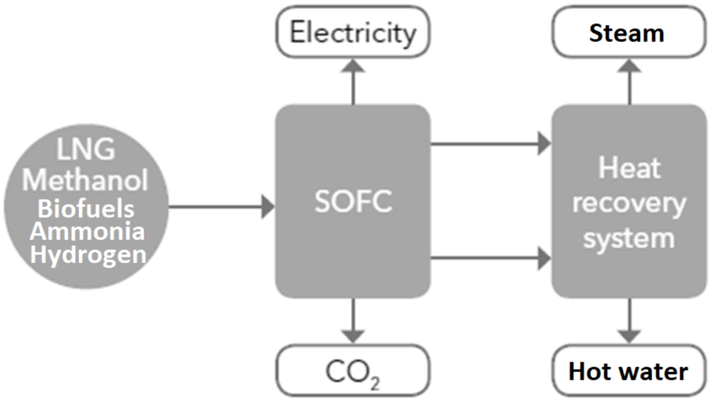

Figure 65 - Block diagram of a SOFC system [162]

There are currently no manufacturers which have in their portfolio SOFC modules or systems certified for maritime applications, but at least two manufacturers are working towards this goal: Bloomenergy and SOLIDpower [179] [180]. Main data of the commercially available products by these two companies and by another one are shown in Table 32 and in Table 33: these products are designed for land-based applications and not for onboard power generation.

Table 32 – SOFC for land-based applications main data [179] [180]

Model	L	B	H	P gen	Weight
	[m]	[m]	[m]	[kW]	[ton]
Bloomenergy	4.86	1.14	2.13	300	14
Convion C60	2.33	2.78	2.09	60	-
SOLIDpower Bluegen BG-15	0.55	0.8	1.2	1.3	0.25

Table 33 – SOFC for land-based applications calculated data

Model	Footprint	Volume Ratio	Weight Ratio
	[m^2/MW]	[m^3/MW]	[ton/MW]
Bloomenergy	18.5	39.3	46.7
Convion C60	108.0	225.6	-
SOLIDpower Bluegen BG-15	338.5	406.2	192.3

During PhD activities, it was further analysed data from a SOFC manufacturer to define possible application, benefits, and downsides of the application of this technology onboard cruise ships. This experience has brought to the calculation of an electrical efficiency curve at different power loads for a SOFC system. Theoretically, SOFC should be used at their MCR or should be shot off, because this technology has some difficulties to work at partial loads due to the high temperature that needs to be sustained to let the reaction happen. Real systems are composed in a modular way, so for example if the desired output is over 300 kW (taking as reference modules described in Table 32), two or more SOFC generators need to work in parallel to ensure the desired power output. When this system works in parallel with another power source (for example internal combustion engines, gas turbines or an energy storage system), it can work at a constant power output near its theoretical maximum to take advantage of its peak efficiency and can let the other power source provide all power variations required. This mode could be employed for example during the navigation of a cruise ship, when power required varies continuously due to different requirement by various users onboard, but when there is a minimum required power for essential services. When a SOFC system works as a unique source of power, so in an island mode, all power variations should be sustained by the SOFC system itself. The main way to provide this power variation is by putting in a “stand-by” mode and by turning on its modules. Stand-by doesn’t mean a total shut-off of the chemical reaction inside the SOFC module, but the minimum reaction required to sustain the reaction temperature inside the cell without generating an electrical output. For this reason, at partial load, the global electrical efficiency of a SOFC system drops below 50%. Also, a literature analysis shows higher peak efficiencies or mean efficiencies, but these values are referred to a condition at the beginning of the operative life, while the mean electrical efficiency at the MCR obtained during the operative life of a modular SOFC system has been considered equal to 55% [61] [20] [176] [181].

It was assumed that footprint and volume ratio of a SOFC system slightly higher than the data assumed for a PEM fuel cell system: 50.0 m^2/MW and 100 m^3/MW respectively. Similar values have been found also in literature: an article states a volume ratio between 40 m^3/MW and 200 m^3/MW, while another one puts this value in the range between 100 m^3/MW and 200 m^3/MW [20] [181]. Weight ratio is indicated in the same studies between 30 ton/MW and 70 ton/MW: for this reason, it was considered a weight ratio equal to 50 ton/MW.

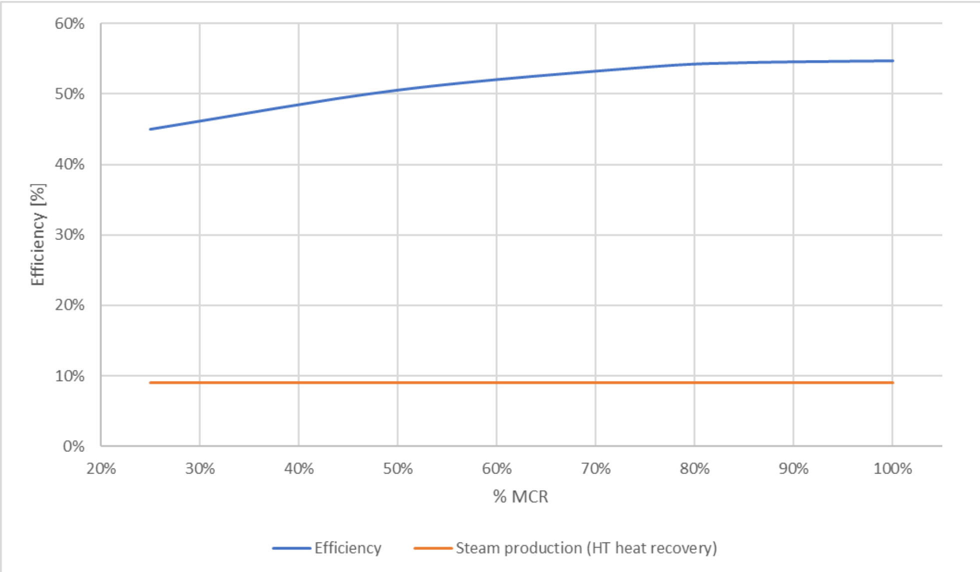

Figure 66 - Efficiency of electrical power generation and of heat recovery systems for a SOFC system

According to a study, SOFC CAPEX can be somewhere between 800 €/kW and 2000 €/kW, depending on the serial production of marine ready products, while annual OPEX can vary between 10% to 25% of CAPEX [173]. Another research confirms a CAPEX of 2000 €/kW for SOFC [182]. A database sets CAPEX between 800 €/kW and 1500 €/kW [20]. An article takes as reference values for SOFC system a CAPEX of almost 900 €/kW (in the range between 600 €/kW and 1300 €/kW) and for SOFC stacks of about 400 €/kW (in the range between 250 €/kW and 600 €/kW), while considering a lifetime equal to 20 years for the whole system and of 6 years for the stack [181]. In this study it was assumed that CAPEX for SOFC is equal to 1300 €/kW, OPEX is equal to 10% of CAPEX and lifetime of the whole system is 20 years.

2.3. Gas turbines

Gas turbines are an internal combustion engine that work with a continuous flow of exhaust gases produced by a combustor. Before entering in the combustor with fuel, air passes through a rotating gas compressor, which is driven by the turbine itself. Its working principle is based on the well-known Brayton cycle. Marine gas turbines have been historically used on naval ships, and their design has been derived from aviation gas turbines. Their employment onboard naval ships is justified by some qualities for onboard applications, like high reliability, relatively long lifetime, quick start-up operations, easy management and maintenance, noise reduction and high power ratio. Maintenance is mainly limited to preventive controls, and gas turbines can be easily supported by a high level of automation, needing less specialised personnel onboard and thus reducing operative costs. Also, these machines can run with various fuels while needing only potential modification to some materials or components to sustain degradation phenomenon. The adaptation of aviation gas turbines to the marine sector has brought manufacturers to modify materials, which should be suitable for marine environment, and the additional power conversion stage to transform thrust to rotatory motion that must be transmitted to an alternator [183]. Among various manufacturer of gas turbines for stationary applications, Rolls-Royce and General Electric have developed some gas turbines specifically suitable for the marine sector. Table 34 shows some of the main data given by the engine manufacturer [184] [185] [186]. Table 35 shows data calculated during PhD activity that have been used for the parametrisation of this type of generator. From these data, it was assumed a footprint equal to 6 m^2/MW, a volume ratio of 22 m^3/MW and a weight ratio of 10 ton/MW.

Table 34 – Marine gas turbines main data [184] [185] [186]

Model	L	B	H	P gen	Weight
	[m]	[m]	[m]	[kW]	[ton]
Rolls-Royce AG9140	8.7	2.4	3.4	3000	29
Rolls-Royce AG9160RF	9.9	2.7	3.8	4000	45
Rolls-Royce MT7	2.0	1.0	1.0	4600	1
Rolls-Royce MT30	8.7	2.7	3.5	36000	32
Rolls-Royce Spey SM1C	7.5	2.3	3.4	19500	26
Rolls-Royce Spey SM1A	7.5	2.3	3.4	12750	26
GE LM 2500	6.5	2.0	2.0	25060	5
GE LM 2500+	6.7	2.0	2.0	30200	5
GE LM 2500 +G4	6.7	2.0	2.0	35320	5

Table 35 - Marine gas turbines calculated parameters

Model	Footprint	Volume Ratio	Weight Ratio
	[m^2/MW]	[m^3/MW]	[ton/MW]
Rolls-Royce AG9140	6.89	23.28	9.75
Rolls-Royce AG9160RF	6.71	25.58	11.16
Rolls-Royce MT7	0.43	0.43	0.22
Rolls-Royce MT30	0.65	2.28	0.89
Rolls-Royce Spey SM1C	0.88	2.98	1.32
Rolls-Royce Spey SM1A	1.34	4.56	2.02
GE LM 2500	0.53	1.08	0.19
GE LM 2500+	0.45	0.92	0.17
GE LM 2500 +G4	0.39	0.79	0.15

The main downside of gas turbines is their lower electrical efficiency when compared to internal combustion engines or fuel cells: their peak electrical efficiency is almost 37%, and it can be reached near their Maximum Continuous Rating (MCR). This downside is evident near MCR, and it is even more pronounced at partial loads, where electrical efficiency drops even below 30%. For this reason, there have been a lot of research about integrated or combined cycle to increase overall efficiency of gas turbine generators, both for stationary application and marine power generation. Since the first naval applications, three concepts were developed to increase the overall efficiency using gas turbine exhaust gases, which have a temperature in the range between 600 °C and 500 °C. The first one is a simple heat recovery system, commonly known as Heat Recovery Steam Generator (HRSG), where steam is produced by a fuelled by exhaust gases coming from the turbine. The second one is the Rankine Cycle Energy Recovery (RACER), where first steam is generated by a HRSG and then this fluid is used into a steam turbine coupled with an alternator to generate more electric power. A third option is the Intercooled Regenerative Cycle (IRC), where intercoolers are used to reduce the work needed for air compression and to increase compression ratio. Then, air output from the compressor is heated by a heat exchanger interfaced with the exhaust gas ducts [187]. The main system considered for heat recovery and overall efficiency increase in literature is the HSRG. A publication focuses on which partial loads' control mode is best suited for heat recovery: constant air flow or variable air flow. This study finds out that both these systems are valid, but the real improvement is given by a variable control of coolant fraction for turbine blades. Low and high temperature heat recovery systems can increase the overall efficiency by almost 22% [188]. Research about the possible application of a RACER efficiency increasing system onboard an LNG tanker points out a 10% efficiency increase almost at any power load of the gas turbine [189].

Power to weight ratio for gas turbines brought some researchers to study how new generation turbines could replace some older models on naval ships. This study is mainly focused on electronic controls and solutions, but also gives some important data about efficiency, exhaust gas temperature and flow. From this analysis, it was assumed the electrical efficiency and the efficiency gains by high temperature and low temperature heat recovery as shown in Figure 67. [190].

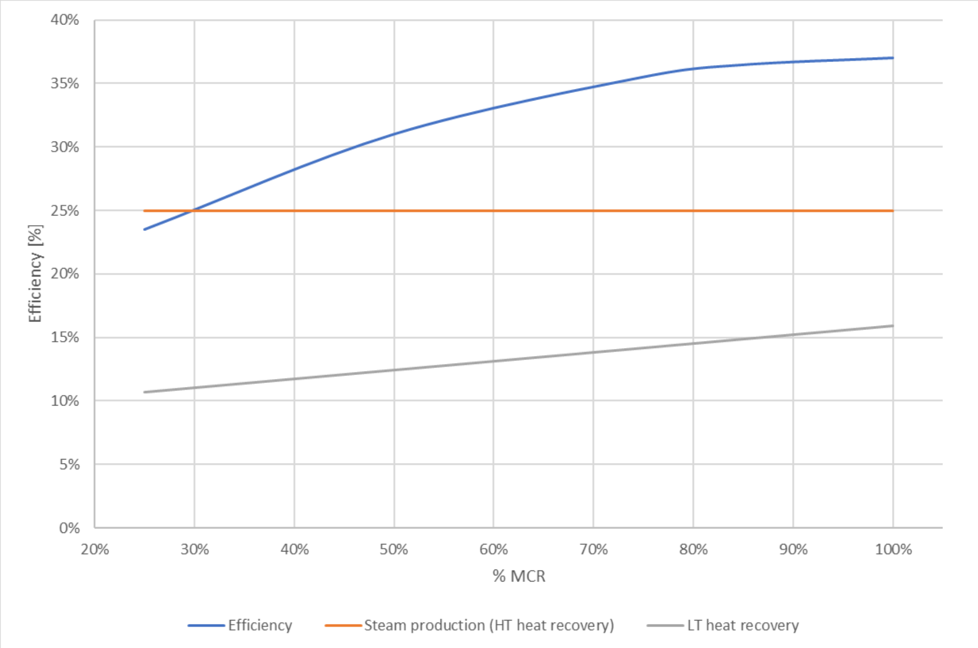

Figure 67 - Efficiency of electrical power generation and of heat recovery systems for gas turbines

In a public report about marine gas turbines, and about General Electric machines, price for a LM2500 gas turbine for marine application is indicated in the range between 6.3 million euros and 6.9 million euros (between 250 €/kW and 275 €/kW) [191]. A database which includes a big amount of data and parameters about different generators states a CAPEX for gas turbines equal to 1800 €/kW and a lifetime equal to 25 years [20]. In this study it was assumed a CAPEX equal to 800 €/kW for every possible gas turbine marine technology, an OPEX equal to 0.5% of CAPEX and a lifetime equal to 25 years.

2.4. Emission reduction systems

IMO’ MARPOL Protocol, in particular its Annex VI, from 1997 has been dedicated to cut emissions from shipping. Regulations entered into force in 2005 and limited sulphur oxides, nitrogen oxides and volatile organic compounds emissions. Complying with sulphur oxides emission is possible with two main strategies. The first one is switching to low-sulphur fuels, like oil-based MGO or LSFO or other non-oil-based fuels like LNG, cutting the sulphur inside combustion chamber and thus reducing the possible sulphur oxides emission. The other solution is installing post-combustion treatments on exhaust gases, capturing sulphur oxides emissions by mean of specifically designed machineries. Post-combustion treatment is also the main solution that can be adopted to cut nitrogen oxides emissions as required by

IMO: unlike sulphur, nitrogen does not come from the fuel (except for some possible novel fuels, like ammonia), but it is part of the ambient air and thus is always present inside power generators. Nitrogen and oxygen react only at high temperatures to produce nitrogen oxides, so they are produced from internal combustion engines and boilers. The main solution to cut these emissions is a post-combustion treatment of exhaust gases with a Selective Catalyst Reduction system (SCR). Thanks to IMO's MARPOL Annex VI sulphur oxides and nitrogen oxides emissions have been reduced: Right now, there is a limit on sulphur content in the fuel equal to 0.50% m/m, which becomes stricter inside Sulphur Emission Control Areas (SECAs) and equal to 0.10% m/m. Nitrogen oxides emissions right now should be less than 14 g/kWh (3.5 g/kWh in ECAs) for all type of engines and for high rotation speed engines (over 2500 rpm) their emission should be less than 8 g/kWh (2 g/kWh in ECAs).

IMO in 2018 has also established an initial strategy to reduce greenhouse gas emissions from ships with a resolution by its Maritime Environmental Protection Committee (MEPC). This strategy has three main goals:

1. Reduce carbon intensity of ships, implementing other phases of their Energy Efficiency Design Index (EEDI) for new ships.
2. Decline carbon intensity of international shipping by reducing carbon dioxide emissions per transport work, as an average for international shipping, by at least 40% by 2030 and trying to reach a 70 % reduction by 2050, comparing future values to 2008 emissions.
3. Peak greenhouse gas emissions from international shipping as soon as possible, and reduce total annual GHG emissions by at least 50% by 2050 compared to 2008.

Scrubbers and SCR are already widely employed onboard ships and are a proven solution to tackle sulphur oxides and nitrogen oxides from exhaust gases, but none of them can tackle carbon dioxide emissions. The amount of carbon dioxide emission per energy generated surely depends on the efficiency of the prime generator, because if a generator is more efficient, it needs less fuel to generate the same amount of power, and thus it produces less carbon dioxide. The other main variable that affects carbon dioxide emission is the type of fuel used onboard. Each fuel, as shown in chapter 1.1, is characterised by a carbon content and the amount of carbon in the fuel is one of the key factors that influences the potential carbon dioxide emission, alongside its LHV.

For this reason, ships will need to switch to fuels which are carbon-neutral like biofuels, hydrogen, or ammonia to cut emissions by the amount required by IMO in next years. The other possibility to significantly cut carbon dioxide emission could be to capture this chemical with some device like a scrubber or an SCR. These Carbon Capture and Storage (CCS) devices should be able to "wash" exhaust gases and therefore absorb carbon dioxide into a liquid, which should be stored onboard and then discharged in port facilities.

Theoretically, this captured carbon dioxide could even be used to produce synthetic fuels as described in paragraphs 1.1.3, 1.1.6 and 1.1.7.

2.4.1. Exhaust gas scrubbers

A possible alternative to low-sulphur content fuels already adopted on numerous ships is the installation of exhaust gas scrubbers in combination with internal combustion engines fuelled by HFO. This solution has been accepted by IMO and by classification society as an alternative to lower sulphur emissions, and is considered in this work to account the economic and technical impact of their installation on a ship equipped with HFO-fuelled internal combustion engines. There are essentially three types of scrubbers:

1. Seawater scrubber (open loop) which takes advantage of the alkalinity of the seawater to neutralise sulphur oxides from exhaust gases.
2. Fresh water scrubbers (closed loop) use a solution of fresh water and sodium hydroxide (NaOH) to neutralise sulphur oxides from exhaust gases.
3. Hybrid scrubber, who can operate both as a closed loop or an open loop scrubber.

Scrubbers can reduce sulphur oxides emissions by more than 90% and Particulate Matter (PM) emissions by 60 % to 90%. During their first implementations, most of the installations were open loop scrubbers. Due to the lack of requirements for a discharge water cleaning system, most of the sulphur oxides and pollutants captured by these systems were discharged directly in seawater, bringing to possible negative impacts on marine ecosystems because of acidification, eutrophication, hydrocarbons, and heavy metals discharge [192].

A hybrid scrubber system has an open loop using seawater and a closed loop using fresh water for sulphur oxides emission control. This wet scrubber system has the possibility for continuous operation in either closed loop or open loop mode without time limits. Switching between these modes depends on the seawater characteristics, prevailing water emission restrictions and operator's decisions. The sulphur oxides are captured and neutralized by washing water injected to the scrubber. The scrubber system can be started with the engines already running and loaded: in this transition phase, exhaust gases flow through a bypass. It is possible to change over from open to close loop with engines running and loaded. In the open loop process, pure seawater is extracted from the vessel's sea bay or sea chest and pumped with a seawater pump to the scrubber tower. A booster pump is used in addition to the seawater pump for lower nozzles to cool the exhaust gases before the packing bed. In open loop mode, chlorides and carbonates in the seawater neutralize the sulphur dioxides. The wash water is discharged from the lower part of the scrubber tower and led to the overboard valves. All water pumped overboard shall meet the MARPOL Resolution MEPC 259 (68) limits without any water dilution. The solvent or alkali used in the closed loop process is sodium hydroxide (NaOH) which is mixed with fresh water for a suitable concentration. The closed loop process water, also called effluent, is circulated by means of a process circulation pump. The effluent exits the scrubber in the lower part of the tower and enters the system tank, where flow is stabilized and most of the dissolved gases are separated. After the system tank, flow is directed to the process circulation pump. The effluent is pumped through a heat exchanger and back to the scrubber tower. In the heat exchanger, seawater is used for cooling. Caustic soda is fed to the system before the heat exchanger. A small bleed off is continuously led from the closed loop circulation to the water treatment process to remove accumulated impurities from the SOx scrubber process water. Water treatment has different stages, including process tanks and filtration. Sludge that is separated from the effluent is highly concentrated at the end of the treatment process and has a solid composition. The sludge is stored on-board which are exchanged to new empty ones when needed.

Electrical consumption from this type of scrubber can be estimated to be equal to 0.01 kWh_{el}/kWh_{gen}. Main and calculated data about these scrubbers are shown in Table 36 and in Table 37, similarly to what has already been done for internal combustion engines, fuel cells and gas turbines [193].

Table 36 – Hybrid scrubbers' main data [192]

Model	L	B	H	P engine	Weight
	[m]	[m]	[m]	[kW]	[ton]
D850	1.0	1.0	8.1	1200	1.8
D1050	1.2	1.2	8.3	1900	2.1
D1250	1.4	1.4	8.5	2700	2.5
D1450	1.6	1.6	8.8	3600	2.9
D1650	1.8	1.8	9.2	4700	3.6
D1850	2.0	2.0	10.0	5900	5.1
D2050	2.2	2.2	10.0	7200	5.6
D2250	2.4	2.4	10.5	8700	6.2
D2450	2.6	2.6	11.0	10300	7.9
D2650	2.8	2.8	11.5	12000	9.7
D2850	3.0	3.0	11.5	13900	10.6
D3050	3.2	3.2	12.5	15900	11.7
D3250	3.4	3.4	13.5	18100	13.8

Table 37 - Hybrid scrubbers calculated parameters

Model	Footprint	Volume Ratio	Weight Ratio
	[m^2/MW]	[m^3/MW]	[ton/MW]
D850	0.8	6.4	1.5
D1050	0.7	6.0	1.1
D1250	0.7	6.0	0.9
D1450	0.7	6.1	0.8
D1650	0.7	6.2	0.8
D1850	0.7	6.6	0.9
D2050	0.7	6.6	0.8
D2250	0.6	6.8	0.7
D2450	0.6	7.1	0.8
D2650	0.6	7.4	0.8
D2850	0.6	7.3	0.8
D3050	0.6	7.9	0.7
D3250	0.6	8.5	0.8

In a study already cited, CAPEX for a scrubber system is in the range between 200 €/kW and 400 €/kW, and it also stated that open loop scrubbers have lower OPEX than closed loop ones due to sodium hydroxide price, respectively 1% and 3% of CAPEX. This study also states an increased fuel consumption of about 3% for seawater scrubber and of 1% for freshwater scrubber [192]. Another publication already cited points out that for typical total power installed onboard cruise ships, CAPEX for a scrubber system is between 150 €/kW and 200 €/kW [79]. A study about potential application of scrubbers in a car and passenger ferry states a CAPEX of 160 €/kW and a lifetime of 15 years [194].

From this review and from its working experience, it was assumed for a generic scrubber system a CAPEX equal to 200 €/kW, an annual OPEX equal to 2% of CAPEX, a lifetime of 15 years, an electrical energy requirement equal to 0.01 kWh_{el}/ kWh_{gen}, a volume ratio for the scrubber unit equal to 0.06 m^3/kW and finally a weight ratio for all equipment equal to 10 kg/kW.

2.4.2. Selective Catalyst Reduction

Nitrogen oxide is part of exhaust gases coming from internal combustion engines because nitrogen represents 78% of the atmosphere and at very high temperature it reacts with oxygen. Diesel engines are characterised by a low fuel-air ratio to perform a complete fuel combustion, but with these conditions nitrogen oxides formation is inevitable. The more the combustion phase is quick and the more the heat increase is rapid but intense, the more nitrogen oxide will be produced. Also, the quick temperature decrease at the end of the combustion phase gives chemical stability to nitrogen oxides molecules and makes it possible its presence inside exhaust gases. Selective Catalyst Reduction (SCR) systems are a possible solution to cut emission of nitrogen oxides thanks to catalyst elements and to a reducing agent. Exhaust gases are treated by a water solution with a 40% ratio of urea by weight. This process, thanks to exhaust gases temperature, decompose urea in ammonia and carbon dioxide, which reacting with nitrogen oxides decompose them in nitrogen and water [195]. SCR is the most widespread marine application for nitrogen oxides abatement and has been adopted in almost every new build ship which burns oil-based fuels. This technology can cut up to 95% of nitrogen oxides emission [196].

A database about various fuels and solutions for ship's emission abatement gives a CAPEX between 150 €/kW and 400 €/kW, an electrical energy requirement equal to 0.01 kWh_{el}/ kWh_{gen}, a volume ratio for the SCR equal to 0.06 m^3/kW and finally a weight ratio for all equipment equal to 2 kg/kW [20].

From this review and from PhD activities it was assumed for a generic scrubber system a CAPEX equal to 200 €/kW, an annual OPEX equal to 2% of CAPEX, a lifetime of 15 years, an electrical energy requirement equal to 0.01 kWh_{el}/ kWh_{gen}, a volume ratio for the SCR unit equal to 0.06 m^3/kW and finally a weight ratio for all equipment equal to 5 kg/kW.

2.4.3. Carbon Capture and Storage

There are different possible technologies that are currently studies for CCS, for example, one of the most promising uses a liquid solvent. A possible solution as solvent are amines because they are one of the most promising capture options for exhaust gases with a low carbon dioxide partial pressure [197]. Post-combustion treatment for carbon dioxide is also promising because theoretically can be added to existing ships slightly altering current ship design, as is already happening with scrubbers and SCR [198].

In a study focused on carbon capture technologies onboard ships, chemical absorption is considered the most promising carbon capture technology for onboard application, with a potential capture rate up to 90%. It also states that the design and sizing of a carbon capture device requires an iterative process since this device requires both electrical power and thermal power, which shall be generated directly onboard by ship's systems. There is the risk that more carbon capture requirement brings to additional fuel consumption and thus to more emissions that need to be abated. Chemical absorption needs an exhaust gas temperature of about 40 °C, because at these conditions, carbon dioxide can be easily absorbed by monoethanolamine (MEA). Then, the carbon dioxide rich amine solution is sent to a heat exchanger to be heated to almost 120 °C to extract carbon dioxide. This chemical then should be compressed, liquefied, and stored inside the ship in suitable storage devices. In the study, total power installed onboard the ship is equal to 18.7 MW, and the system for carbon capture has an estimated volume of 1500 m^3 and an estimated weight of 2500 tonnes (0.08 m^3/kW and 133 kg/kW). For a 50% capture rate, CAPEX is equal to 20 million euros, while for a 90% capture rate, CAPEX is equal to 28 million euros (1070 €/kW and 1500 €/kW respectively). Annual OPEX is estimated to be equal to 2.5 % of CAPEX [199].

Another study takes as reference an LNG fuelled car and truck carrier and a hybrid diesel electric ferry for different carbon capture rates. Increased electrical consumption required for carbon capture is equal to 0.45 kWh_{el}/kg_{CO2}. In this case, CAPEX is considered in the range between 500 €/kW and 700 €/kW [200]. These values are confirmed by another study about the potential use of a carbon capture and storage device onboard an LNG powered vessel [201].

In a publication, electrical consumption for a carbon capture amine scrubbing system is assumed equal to 0.06 $kWh_{el}/kgCO_2$ and thermal power needed is equal to 1.05 $kWh_{th}/kgCO_2$, while lifetime is assumed to be between 15 and 20 years [69]. These values for electrical and thermal power required by a carbon capture system are confirmed also by a study regarding the integration of this technology onboard a LSFO powered vessel, which also gives a CAPEX of about 2000 €/kW and an annual OPEX equal to almost 3% of CAPEX [202].

Detailed research about whole lifecycle of a Carbon Capture, Storage and Transportation facility states a heat requirement for a amines-based technology between 1.2 $kWh_{th}/kgCO_2$ and 0.6 $kWh_{th}/kgCO_2$, while for an ammonia separation system the heat requires is equal to almost 0.43 $kWh_{th}/kgCO_2$. Also, power consumed by the CCS plant has been calculated and, for a land-based system, is equal to almost 16% of the power generated for a coal-fired electrical power generation plant [203].

From this literature analysis, in this thesis was assumed for a 90% carbon capture reduction system based on chemical absorption technology a CAPEX equal to 1000 €/kW, an annual OPEX equal to 3% of CAPEX, a lifetime of 15 years, an electrical energy requirement equal to 0.2 $kWh_{el}/kgCO_2$, a thermal energy requirement equal to 0.6 $kWh_{th}/kgCO_2$, a volume ratio for the scrubber unit equal to 0.06 m^3/kW and a volume ratio for the carbon dioxide storage system of 0.35 m^3/ton_{CO2} and finally a weight ratio for all equipment equal to 130 kg/kW.

2.5. Boilers for steam generation

Since cruise ships can be considered as floating cities, they do require not only electrical power but also thermal power. This power is used for various services onboard cruise ships, mainly for galleys and laundries, which operate almost 24 hours every day. Other services that require heat are tanks heating system, fuel purifiers (only for oil-based fuels), freshwater heaters, swimming pool water heaters, and heating and ventilation air conditioning system. Heat is generated onboard via heat recovery systems associated with prime generators and via steam generators fuelled by the same fuel used for power generation on the vessel. Certain users require heat at high temperatures, so high-pressure steam is required. Thermal power requirement is covered first by the heat generated by the recovery systems and then, if this figure is not enough, by the steam generated by dedicated generators installed onboard. Boiler consumption as a function of the required power is known thanks to manufacturer's data available and to estimate fuel consumption for these initial calculators' efficiency has been considered equal to 75%. Considering the need to install in every cruise ship one or more boiler and thus all economic needs for their installation and maintenance and their space and weight impact is ignored. Dual fuel boilers are currently fuelled by fossil fuels derived by oil (HFO, LSFO and MGO) or natural gas. There are currently no marine boilers that can be fed with hydrogen, methanol or ammonia and their possible use in these devices shall be discussed carefully with boilers suppliers and with burners suppliers.

2.6. TTW emission calculation

In this PhD thesis it was first assumed different technologies characterised by a unique combination of fuel's storage and treatment system, power generation technology and emission abatement technology to first assess the impact of innovative power generation systems onboard. The considered combinations are the following:

- PEM fuel cells:
    - Liquefied hydrogen (LH_2).
    - 700 bar compressed hydrogen (CH_2).
    - Liquefied natural gas (with reformer) (LNG-REF).
    - Ammonia (with reformer) (NH_3-REF).
    - Methanol (with reformer) (MeOH-REF).
- Solid Oxide Fuel Cells:
    - Liquefied hydrogen (LH_2).
    - 700 bar compressed hydrogen (CH_2).
    - Fossil liquefied natural gas (with desulphurisation) (LNG-DES).
    - Synthetic liquefied natural gas (LNG).
    - Ammonia (NH_3).
    - Methanol (with reformer) (MeOH).
- Internal combustion engine fuelled by hydrogen (ICE-H_2):
    - Liquefied hydrogen (LH_2).
    - 700 bar compressed hydrogen (CH_2).
- Internal combustion engine fuelled by natural gas (ICE-LNG).
- Internal combustion engine fuelled by ammonia (ICE-NH_3) and with an exhaust gas treatment consisting in a Selective Catalyst Reduction (SCR) system.
- Internal combustion engine fuelled by methanol (ICE-MeOH).
- Internal combustion engine fuelled by liquefied petroleum gas (ICE-LPG):
- Internal combustion engine fuelled by synthetic fuels (ICE-FTD) and with an exhaust gas treatment consisting in a Selective Catalyst Reduction (SCR) system:
    - Biodiesel (BioD).
    - Renewable diesel (RenD).
    - Fischer-Tropsch diesel (FTD).
- Internal combustion engine fuelled by HFO (ICE-HFO) and with an exhaust gas treatment consisting in a Selective Catalyst Reduction (SCR) system and a sulphur oxides scrubber (SO_xSc).
- Internal combustion engine fuelled by oil-based fuels (ICE-MGO) and with an exhaust gas treatment consisting in a Selective Catalyst Reduction (SCR) system:

    - MGO.
    - MGO and a Carbon Capture and Storage (CCS) system able to capture 50% of carbon dioxide emissions.
    - LSFO.
- Gas turbines (GT):
    - Liquefied hydrogen (LH_2).
    - 700 bar compressed hydrogen (CH_2).
    - Liquefied natural gas (LNG).
    - Ammonia (NH_3).
    - Methanol (with reformer) (MeOH).

Figure 68 shows the volume occupied by each one of the combinations described. PEM fuel cells occupy almost two times the volume required for internal combustion engines for liquid fuels per each MW of power installed (40 m^3/MW and 22 m^3/MW respectively). The bulkiest power generators are SOFC, which occupy almost 100 m^3/MW. When the analysis considers fuel treatment and exhaust gas treatment systems, values of volume occupied change. Accounting all these factors, the power generation system which occupies the lowest volume among the considered alternatives is internal combustion engines fuelled by methanol, followed by internal combustion engines fuelled by compressed hydrogen, PEM fuel cells fuelled by compressed hydrogen and PEM fuel cells fuelled by ammonia. These options occupy a volume that has been estimated to be from 46% to 63% of the space required by the reference solution, namely internal combustion engines fuelled by HFO, with exhaust gas treatment composed by both a scrubber and an SCR system (222 m^3/MW). The bulkiest option among the considered ones is SOFC power generators fuelled by liquefied hydrogen: this solution takes up to 46% more volume than the reference case system. Other bulky alternatives are gas turbines fuelled by liquefied hydrogen (+ 38%), and PEM fuel cells fuelled by LNG or methanol (+ 31%). It should be highlighted also the fact that fuel reforming onboard introduces a high volume requirement for each MW of installed power, and thus PEM fuel cells should be used only when hydrogen is stored in its pure form onboard. Also, liquefied hydrogen requires a lot of space for its treatment system, more than what LNG requires right now, partly because this fuel is already used onboard ships. Furthermore, it must be noted that contribution to volume occupied by exhaust gas treatment system is not negligible and that there are already some power generation systems that are less bulky than internal combustion engines fuelled by traditional oil-based fuels.

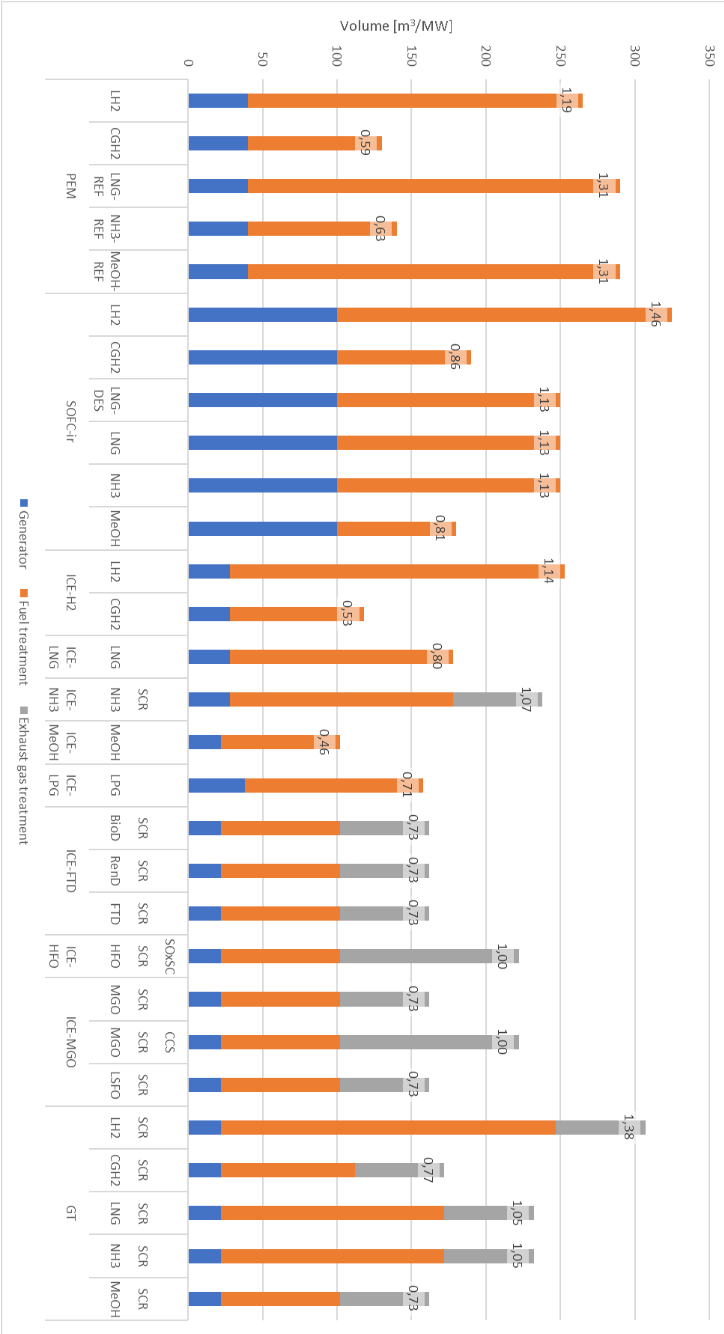

Figure 68 – Power generator, fuel treatment and exhaust gas treatment space requirements

Figure 69 shows the mass required by each one of the combinations of power generator, fuel treatment and exhaust gas treatment previously described. The weight per MW of installed power is equal to almost 60 t/MW. Majority of the considered options are less heavy than the reference case: gas turbines power generators have always a lower weight, except when fuelled by liquefied hydrogen. Gas turbines coupled with methanol are the lightest option, and their weight per MW of installed power is equal to almost 52% of reference value. Other light options are PEM fuel cells fuelled by compressed hydrogen, LNG, methanol, and ammonia: even if they require a reformer for the last three named fuels, the mass of these systems is between 60% and 70% the reference one. SOFC power generation systems are heavier than both PEM fuel cell ones and internal combustion engine ones, mainly because those power generators are heavier. Sulphur oxides scrubbers and SCR systems give a weight contribution that can be considered negligible, but a CCS system able to reduce of 50% the total carbon dioxide emission of the power generation system brings the considered option to be three times heavier than the reference case. These systems are still under a development phase for land-based applications, but they could be seriously considered for ship power generation systems in the future. However, their weight, as described in paragraph 2.4.3, would have a big impact on its potential onboard installation not only for the reaction tower, but for all the other appliances that this system will require.

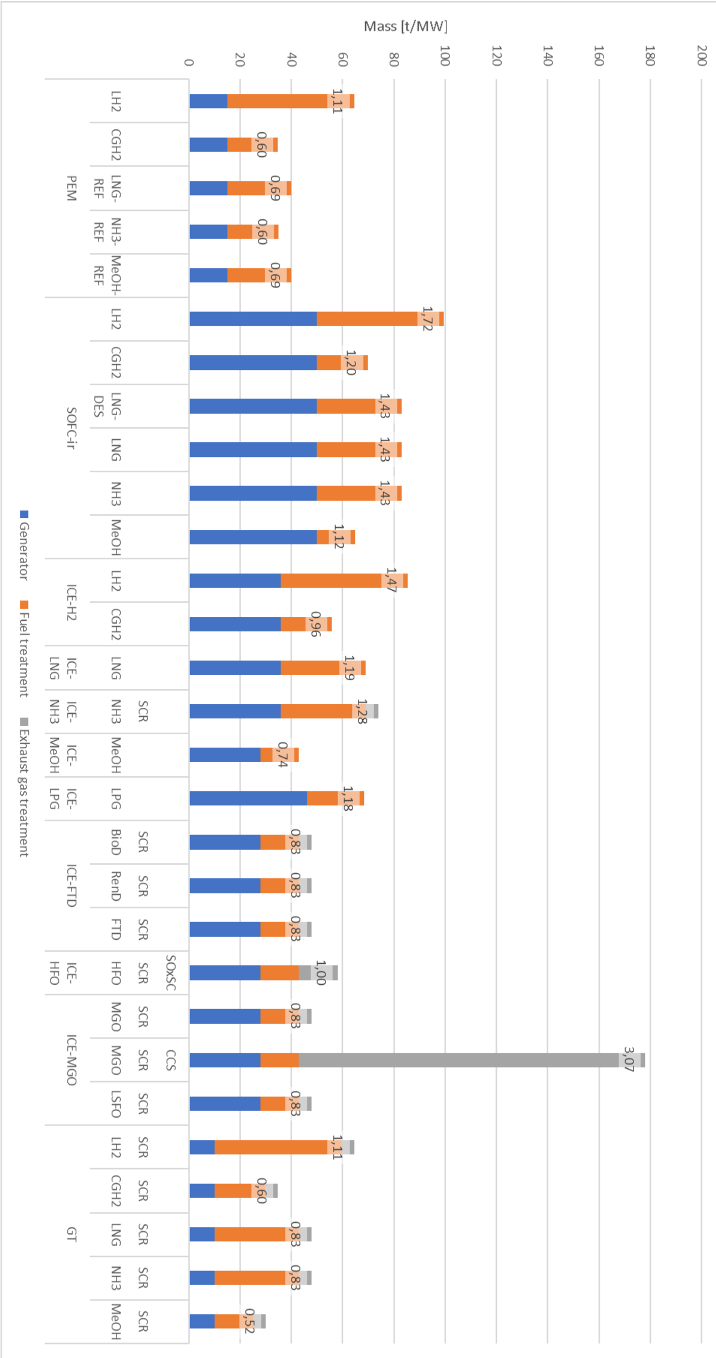

Figure 69 - Power generator, fuel treatment and exhaust gas treatment mass requirements

Figure 70 shows the Tank-To-Wake (TTW) emissions of all the different alternatives considered in this paragraph. TTW emissions right now correspond to emissions that are considered by IMO and all other regulations, even if they consider only part of the fuel's life-cycle. As an example, Figure 70 shown that PEM fuel cells, SOFC, internal combustion engines and gas turbines when fuelled by hydrogen or ammonia archive zero TTW carbon dioxide equivalent emissions. This hydrogen on the other hand can be green, blue or grey hydrogen, and its WTT emissions are very different (see Figure 35 page 57 and Figure 32 page 53). PEM fuel cells can archive a reduction of carbon dioxide equivalent emissions with natural gas reforming (67% of reference case value) or an increase in the overall emissions when coupled with methanol reforming (+9% of reference case value). SOFC always bring a reduction to the overall carbon dioxide equivalent emissions: they do not suffer from methane slip and their superior efficiency allows for a reduction equal to almost 50% of the emissions related to the reference case value (when fuelled with LNG). Internal combustion engines fuelled by LNG do not decrease emissions because they suffer from methane slip and this problem causes a 21% increase of the carbon dioxide equivalent emissions. Small benefits for internal combustion engines can be found when they are fuelled by methanol and LPG, while in this study it was calculated a more significant TTW emission reduction (almost equal to 20%) for internal combustion engines fuelled by renewable diesel and FTD. Almost the same reduction has been calculated for a power generation system composed by gas turbines fuelled by LNG. Internal combustion engines can archive a significant reduction of TTW carbon dioxide equivalent emissions only when carbon capture and storage system are installed onboard. In this case the CCS system has been dimensioned to reduce emission by 50% when compared to the reference case: this assumption has been made to reduce the overall impact on volumes, mass, heat, and electric balance.

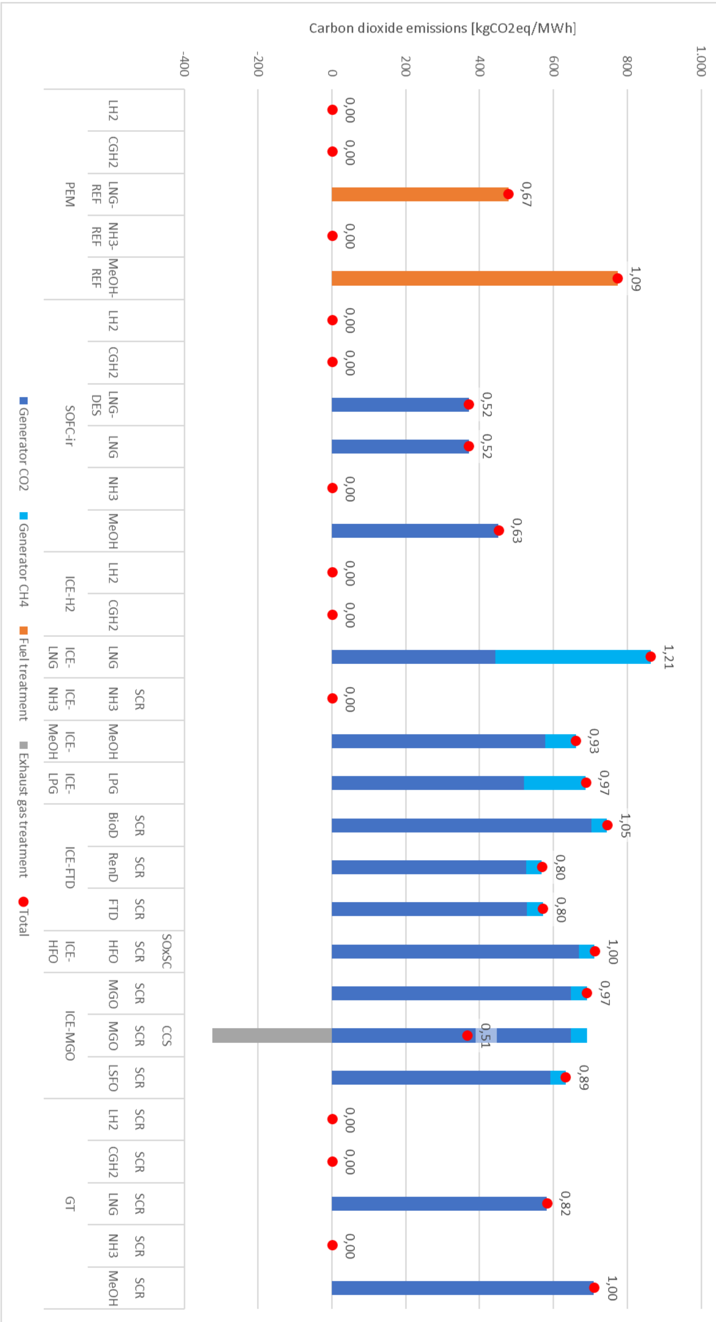

Figure 70 – TTW emissions for different power generator, fuel treatment and exhaust gas treatment

The need to better understand which solution can bring the highest carbon dioxide equivalent emission reduction brought to assess the life-cycle emissions related to different combinations of fuels and power generation systems.

Figure 71 shows the calculated Well-To-Wake (WTW) carbon dioxide equivalent emissions for PEM and Solid Oxide fuel cell technologies power systems for each MWH of electric energy generated onboard. This graph distinguishes different fuel production pathways and their emissions when related to the reference case, which is a ship powered by internal combustion engines fuelled by HFO and equipped with sulphur oxides scrubbers and an SCR system. PEM fuel cells and SOFC can reduce carbon dioxide equivalent emissions of almost 95% when fuelled by green hydrogen or by ammonia obtained by green hydrogen: residual emissions are related to fuel production process. Also, this chart does not consider the amount of carbon dioxide emission for fuel transport from its production plant to the bunkering station, but surely the benefit introduced by green hydrogen in terms of WTW carbon dioxide equivalent emissions is notable. When PEM fuel cells are fuelled by hydrogen produced by SMR (grey hydrogen) there is a WTW emission reduction equal to almost -20%. When hydrogen is produced via SMR with CCS (blue hydrogen), WTW emission reduction is more significant and equal to almost 65%. This chart also highlights the fact that PEM fuel cells associated with a methanol reforming system does not make sense from a WTW emissions point of view, because there is an increase on the overall emissions of almost 40%. PEM fuel cells associated with a natural gas reforming system would reduce WTW carbon dioxide equivalent emissions to almost 77% of the reference case. Methanol does not bring to a significant WTW emission variation when is used as fuels for a SOFC power generation system. Benefits of using green, brown, and blue hydrogen are the same as the ones already stated for PEM fuel cells when this gas is used in a SOFC system. It was calculated also that SOFC fuelled by natural gas can reduce WTW carbon dioxide equivalent emissions to 63% of the reference case power system emissions: this reduction is even more significant for synthetic natural gas produced from green hydrogen (9% for SOEC-H2 and 10% for PEM-H2). Methanol produced from green hydrogen can contribute to reduce WTW emissions to almost 4% of reference case scenario, while methanol produced from blue hydrogen gives a -72% reduction.

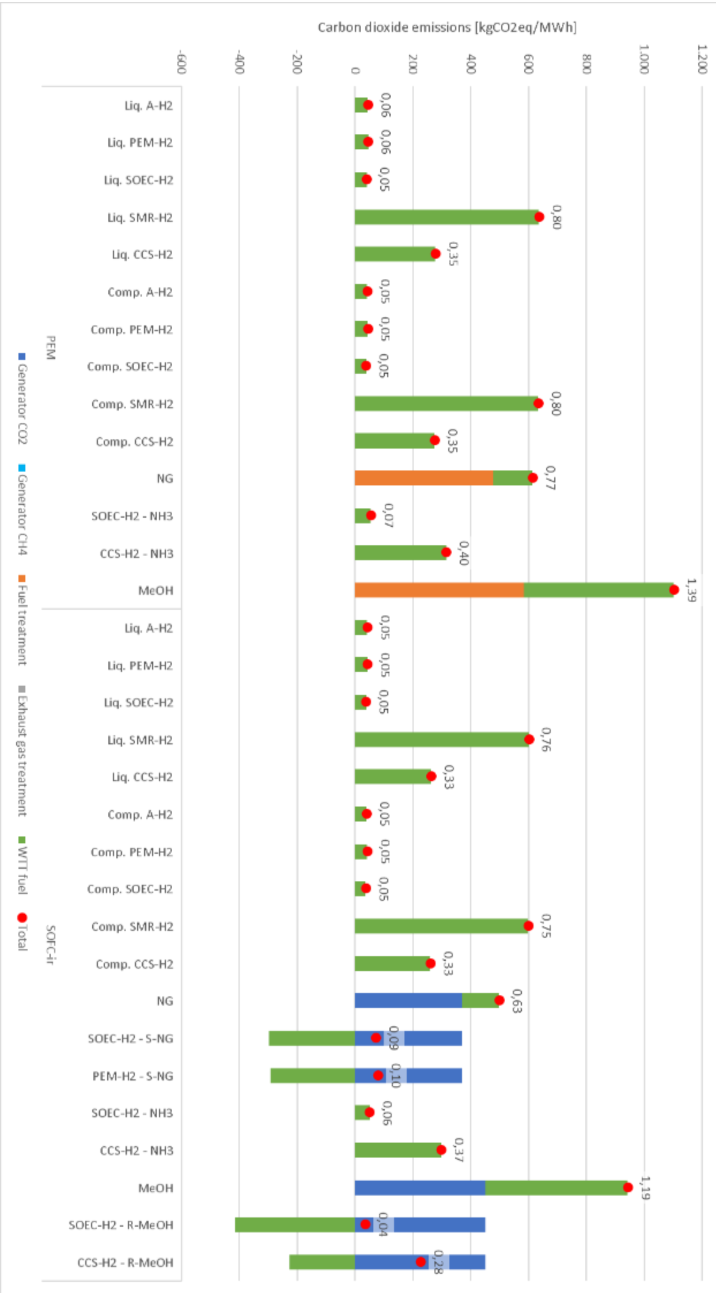

Figure 71 – WTW carbon dioxide equivalent emissions for fuel cells power generation systems

Figure 72 shows the calculated Well-To-Wake (WTW) carbon dioxide equivalent emissions for internal combustion engines power systems for each MWh of electric energy generated onboard. In this graph, it is also present the reference case scenario. Figure 72 highlights the fact that power systems fuelled by fossil fuels emit most greenhouse gases during their utilisation, while Figure 71 showed that carbon dioxide equivalent emissions related to synthetic fuels combined with fuel cells are related to fuel production processes. Internal combustion engines fuelled by green hydrogen can bring emissions' reduction, like PEM fuel cells fed by the same gas. Internal combustion engines fuelled by blue hydrogen archive a 68% reduction. A more complete analysis should also account nitrogen oxides contribution to ship's emissions, but in that case an SCR system would be installed alongside internal combustion engines, thus reducing up to 99% nitrogen oxides emissions. Internal combustion engines fuelled by natural gas are the main technology adopted today, but Figure 72 shows that its WTW carbon dioxide equivalent emissions are 28% higher than the reference case, mainly because methane slip accounts for almost 45% of their total emissions. There is a significant difference in the emissions related to this fuel when used inside SOFC power generators: in these devices fuel oxidation is complete and thus there is no methane slip. When internal combustion engines are fuelled with synthetic methane, the issue of unburnt fuel slip remains, but the renewable feedstock brings to an overall WTW emissions reduction of about 45%. Fossil methanol, LPG and MGO used with internal combustion engines bring higher emissions per MWh of energy generated when compared to HFO, mainly because of carbon dioxide equivalent emissions related to their feedstock. Internal combustion engines fuelled by ammonia produced from green or blue hydrogen significantly reduce WTW emissions, and they deliver a benefit comparable to PEM fuel cells. In this case it is certain an increased production of nitrogen oxides and thus an SCR system should be installed. Internal combustion engines fuelled by renewable methanol can significantly reduce WTW carbon dioxide emissions, especially when this fuel is produced from green hydrogen (-84%). Biodiesel brings a lower percentage reduction (-11%), while the variation introduced by renewable diesel is more pronounced (almost -60%) and by FTD. WTW emissions variation is equal to -89% of reference case emissions when FTD is produced from green hydrogen, and this figure is equal to -28% when FTD is produced from blue hydrogen. Internal combustion engines fuelled by MGO and equipped with a CCS system bring a reduction of about 32% to WTW carbon dioxide equivalent emissions.

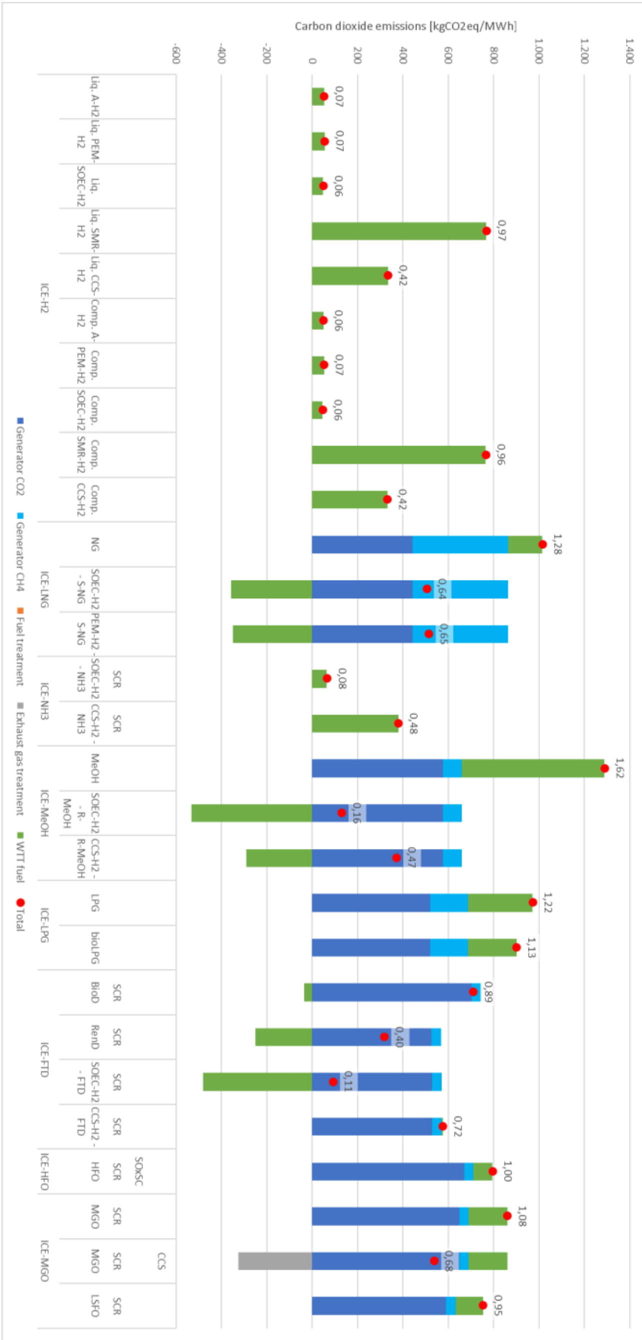

Figure 72 – WTW carbon dioxide equivalent emissions for internal combustion engines power generation systems

Figure 73 shows the calculated Well-To-Wake (WTW) carbon dioxide equivalent emissions for gas turbines power systems for each MWh of electric energy generated onboard. Emissions related to hydrogen fuelled gas turbines are low when compared to reference case, and they all are related to fuel production process. GT fuelled by green hydrogen emit 8% to 9% of reference case's WTW carbon dioxide equivalent emissions, while GT fuelled by blue hydrogen cut almost half of these pollutants. If gas turbines are fuelled by grey hydrogen, WTW emissions are increase by almost 20% when compared to reference case. Gas turbines fuelled directly by natural gas emissions are aligned with reference case scenario. Fossil methanol brings a significant increase of WTW carbon dioxide emissions also with this power generation technology, proving to be a solution for emission reduction only if produced by a sustainable feedstock. Synthetic natural gas can also provide significant emission reduction when used in gas turbines, bringing to almost an 85% reduction. These power generators can provide similar emissions reductions even with green ammonia, while ammonia produced from blue hydrogen provides only a 40% reduction.

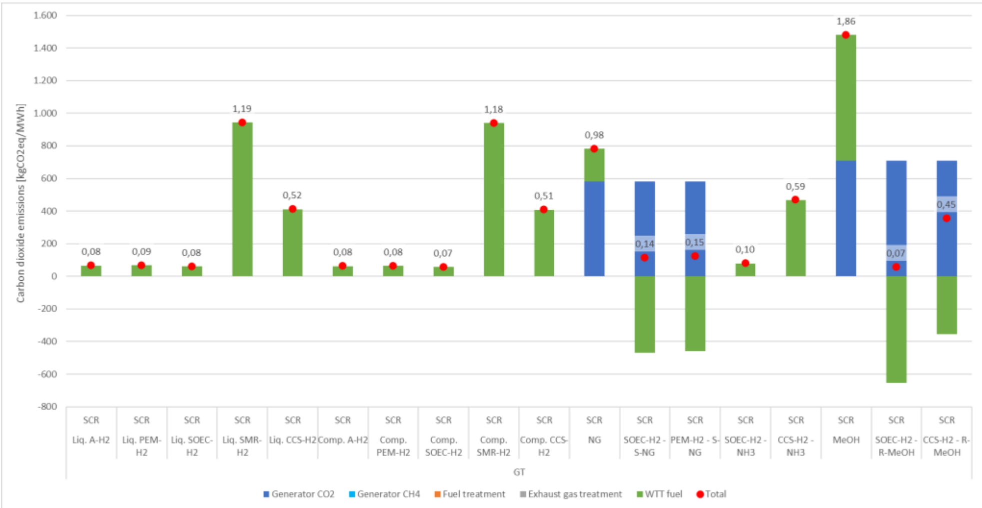

Figure 73 – WTW carbon dioxide equivalent emissions for gas turbines power generation systems

Alongside WTW and TTW carbon dioxide equivalent emissions, it is fundamental to analyse how much a different combination of power generation, fuel treatment and exhaust gas treatment systems cost, also highlighting the impact on the lost or gained payload volume and weight. Figure 74 shows the cost of alternative configuration and how much each sub-system impacts on the overall cost. Reference case is still the same described for previous figures: an internal combustion engine fuelled by HFO costs almost 100,000 €/a/MW, and almost half of this cost is related to the exhaust gas treatment system. PEM fuel cell-based power generation systems are 2 to 3.4 times more expansive than the reference case: the cheapest is with a compressed hydrogen treatment system, while the most expensive is the solution which embodies a methanol reforming. PEM fuel cells cost alone is almost 80% higher than the overall cost of the reference case cost. SOFC power generation systems are even more expansive than PEM fuel cell ones: their cost is between 3 and 5.4 times higher than the reference case. SOFC coupled with a liquefied hydrogen treatment system are the overall second most expensive power generation system. Each one of these alternatives is penalised particularly by the cost for lost payload related almost entirely to the high volume and mass of SOFC systems and by the cost of the power generation system itself. Internal combustion engines fuelled by hydrogen have a cost comparable to the reference case only when they are associated with a compressed hydrogen treatment system. Also, methanol fuelled ICE has a cost equal to almost half of the reference case, mainly because they do not need any exhaust gas treatment device. Internal combustion engines fuelled by LNG bring almost to a 50% increase for the power generation system's cost: the main cost difference with the reference case scenario is given by the lost payload capacity. Internal combustion engines fuelled by ammonia have almost two times the cost of the reference case scenario. Biofuels and MGO all bring to a decrease of the power generation system cost, but when MGO fuelled ICE are associated with a CCS system, its cost becomes almost 8 times the reference case, mainly because these systems bring to a significant decrease in the payload capacity. Gas turbines bring to increased costs for almost each fuel treatment system, except methanol, which brings almost to a 16% reduction of the power generation system cost.

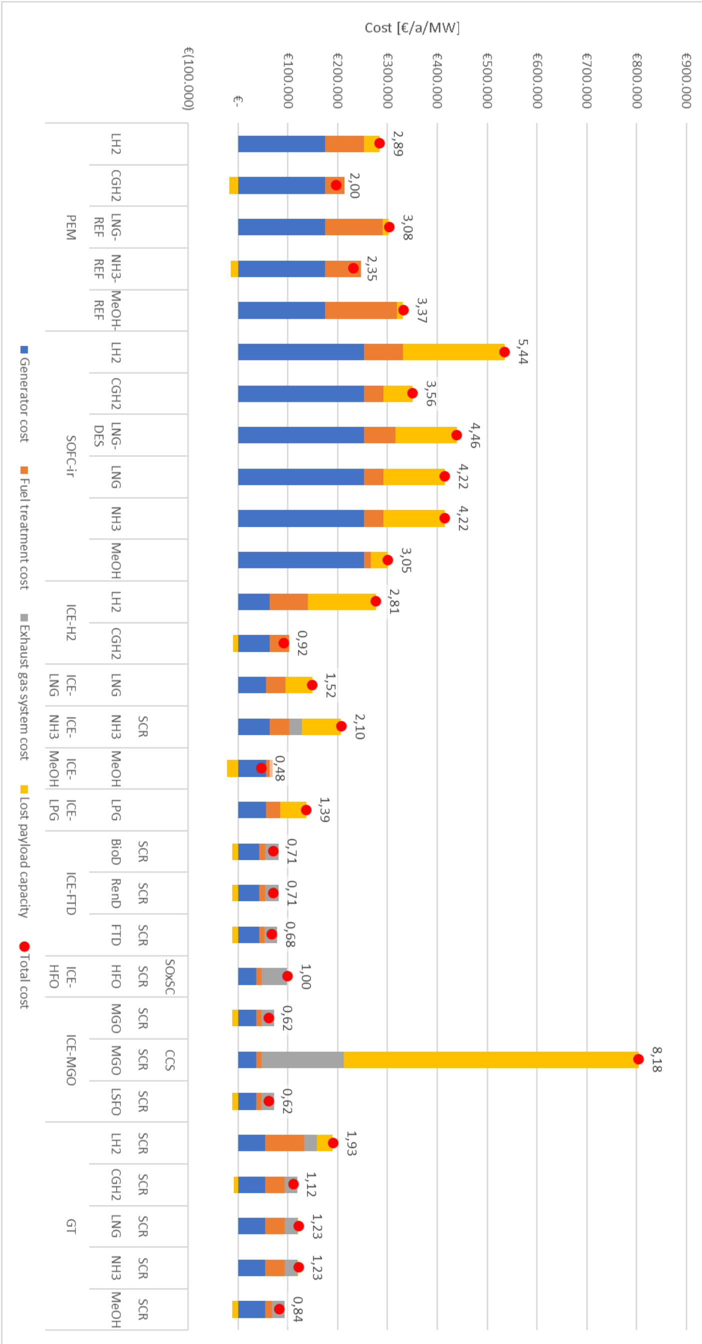

Figure 74 – Cost of engine, fuel treatment and exhaust gas treatment systems

3. Overview of existent marine application of innovative power generation systems

In this chapter, some of the past and current onboard application of innovative power generation systems onboard ships, considering utilisation of fuel cells onboard cruise ships, are described and analysed to better understand and define which can be the most promising technologies. Right now, most of the research is focused on small demonstrative applications, but recently interest is growing, and larger installations are being considered. As an example, MSC has signed a memorandum of agreement with the Italian shipbuilder Fincantieri to build two cruise ships equipped with 6 MW of hydrogen-fuelled fuel cells that shall be used for power generation when the vessel is docked in port [204]. This chapter presents an overview about some of the most important past and currently ongoing research project with real onboard tests or real application of innovative power generation systems.

3.1. Internal combustion engines with innovative fuels

Internal combustion engines are the most widespread power generation technology onboard ships, and, in most recent applications onboard cruise ships, they are directly coupled with alternators to allow an "all-electric ship" configuration. This paragraph describes some applications of alternative fuels use in onboard internal combustion engines to identify characteristics or data that in following analysis can be useful for comparison with other options and technologies.

3.1.1. Biofuels applications

AIDAprima was the first cruise ship to bunker a blend of traditional oil-based fuel and biofuel onboard a: during summer 2022. AIDAprima bunkered a blended biofuel made from waste cooking oil and MGO in Rotterdam, Netherlands (see Figure 75). This fuel has been supplied by a Dutch company named GoodFuels and AIDA, which is a brand of Carnival Corporations, wants to establish a long-term partnership. AIDAprima, built by Japanese shipbuilder Mitsubishi, is equipped with dual fuel engines which can also be fuelled with natural gas [205]. GoodFuels claim that their "drop-in" product can be used even on existing vessels without any retrofitting operation. If these claims are true, it means that biofuels can overcome an important initial barrier to become part of the solution to decarbonise the maritime sector. GoodFuels claims also that their products are not in competition with feedstocks that could be used for food production, thus claiming to have only ethical sources. The company thinks that biofuels on the long term could satisfy a share between 5% and 10% of the marine fuel mix, requiring in this case the use of more feedstocks, like by-products of paper and pulp industry [206]. In 2015, Dutch dredging and heavy lift company Royal Boskalis Westminster N.V. started exploring the employment of a drop-in biofuel for its fleet. Thus, they started working with GoodFuels and Wärtsilä testing for two years the use of a blended biofuel onboard. Results showed a substantial decrease of PM emissions, a zero sulphur oxides emission and a 90% reduction of carbon dioxide emission. Biofuels were produced from various by-products like grass, algae, tires, or paper residue [207].

Figure 75 - Blended biofuels bunkering operations in Rotterdam [207]

Blended biofuels have been bunkered on another ship, in this case on the container vessel "Kota Megah", in Singapore. The test has been carried to verify the feasibility of biofuels use onboard ships and to obtain data of the attained noxious emission reduction. The owner of this vessel stated that biofuels are among possible emission reduction solutions that are applicable to actual ships without the need of long or expensive retrofitting operations. Tests have been carried out with a blend of FAME (produced from cooking oils) and VLSFO [208]. Other research and development projects about biofuels applications onboard ships were carried out by Steeper Energy in 2013 testing a wood-based biofuel and by both Maersk and US Navy using algal oil as drop-in fuel [209].

3.1.2. LPG applications

LPG fuelled vessels have been ordered and then operated from 2021. Astomos Energy Corporation has ordered a Very Large Crude Carrier (VLCC) fuelled by LPG from Japanese shipbuilder Kawasaki Heavy Industries. The ship will be almost 300 meters long and 37 meters wide and will be equipped with MAN dual-fuel engines capable to run on LPG and traditional oil-based fuels. The owner expects with this solution a 90% reduction for PM emission and sulphur oxides emissions, but also a 20% reduction of carbon dioxide emissions. They also have signed an agreement to purchase in the future bioLPG from Shell, which claims that this fuel is carbon-neutral. The vessel is named Crystal Asteria, and it complies with EEDI Phase 3 regulation [210] [211].

The same shipbuilder in summer 2022 has also built an LPG and ammonia carrier for shipowner Kumiai Navigation Ltd. with a total tank capacity of about 87000 m^3. The shipbuilder claims that this is the 14^{th} LPG fuelled LPG carrier built by them [212]. Another ship fuelled by LPG has been built in winter 2022 by the same shipbuilder [213].

3.1.3. LNG applications

In 2021 DNV estimated that there were 251 LNG-fuelled vessels already operating and almost 400 on order by various shipbuilders, among which 26 are cruise ships [214]. LNG is the most widespread marine fuel, which is not based on oil, because it is considered a good option to zero sulphur oxides emissions while reducing nitrogen oxides and carbon dioxide emission. The diffusion of this technology has also touched the cruise industry, which is considered a great source of noxious emissions, particularly during port stays. The first cruise ship powered by natural gas fuelled engines only during port stays was AIDAsol by Carnival Corporation thanks to an external hybrid barge. AIDAperla and AIDAprima were the first cruise ships to have onboard dual fuel engines fuelled by LNG supplied by trucks during port stays. Finally, in 2018 AIDAnova was the first cruise ship equipped with LNG tanks and dual fuel engines, followed by the second cruise ship named Costa Smeralda. Also, half of Carnival Corporations orders up to 2025 are for LNG fuelled cruise ships. MSC in 2022 has announced the first construction of its first LNG fuelled cruise ship: MSC World Europa, which will also be equipped with a 50 kW SOFC generator for research and development purposes [126] [215]. AIDAnova has a length equal to 337 meters and a width equal to 42 meters, it has the capacity to transport almost 1500 crew members and 5200 passengers [216]. MSC World Europa, on the other hand, will be equipped with SOFC manufactured by Bloomenergy, which claims to be 20% to 50% more efficient than internal combustion engines [217].

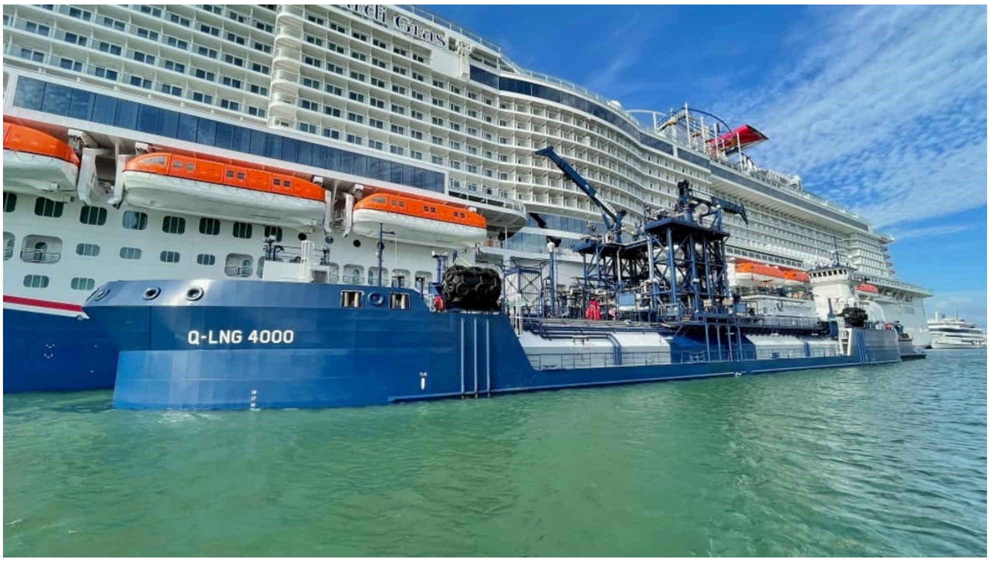

Figure 76 - Refuelling operations at LNG fuelled Carnival Mardi Gras [126]

Figure 77 - LNG storage system installation onboard Costa Smeralda [218]

3.1.4. Methanol applications

Methanol as a fuel for marine shipping is still at an early stage of development. There are some initial applications, mainly focused on methanol carriers. Methanol is a good already transported onboard chemical tankers, and thus technology and regulations to store and transport it onboard are yet developed. IINO Kaiun Kaisha is operating a 49000 DWT methanol carrier equipped with two-stroke internal combustion engines fuelled with methanol. This ship was built by South Korean shipbuilder Hyundai and engines have been supplied by MAN Energy solution and are capable to run also on VLSFO [219]. Probably the most notable application of methanol as shipping fuel was the conversion in 2015 of Stena Germanica RoPax ferry. Onboard this vessel, four dual fuel internal combustion engines able to run both on methanol and VLSFO have been installed. With this conversion, the company claims that sulphur oxides and PM emissions are reduced almost by 90% and nitrogen oxides emissions almost by 60%. During 2021, Stena has also refuelled this ship with methanol obtained from residual steel gases, thus a by-product of an industrial process [220]. Korea Shipbuilding & Offshore Engineering, one of the most important shipbuilding companies in the world, indicates that methanol-powered ships orders will increase sharply for the next 10 years, but LNG will remain the most widespread option as alternative marine fuel. By the end of 2022 they expect worldwide 50 orders for methanol fuelled ships only for container transport vessels: in 2021 there were globally 19 orders [221].

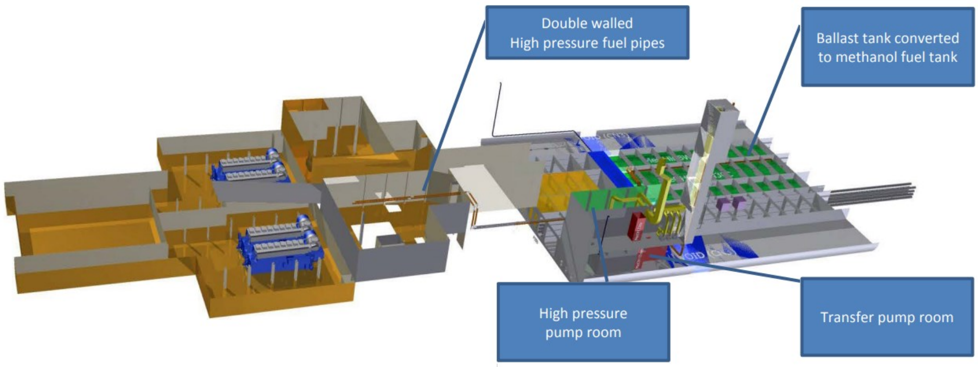

Figure 78 - 3D configuration of methanol dual fuel power generation plant onboard STENA Germanica [220]

3.1.5. Hydrogen applications

Hydrogen is currently employed as fuel is some research projects and onboard some small vessels. It is considered among one of the most promising zero-carbon fuels for ships: during 2022 MSC Group signed a Memorandum of Agreement (MoA) with Italian shipbuilder

Fincantieri to include in two future cruise ships a storage system for liquid hydrogen and 6 MW of PEM fuel cells to allow the ship to zero emissions during port stays. These cruises are scheduled to come into service from 2027 [222].

During 2022 the first liquid hydrogen carrier has been delivered and is now operating between Japan and Australia. This ship, named Suiso Frontier, can transport 1250 m^3 of liquid hydrogen at -253 °C from port of Victoria, Australia, to port of Kobe, Japan and is the first vessel able to transport such cargo over long distance and international voyages. The trip takes approximately two weeks and the ship, built by shipbuilder Kawasaki Heavy Industries, can also accommodate 25 crew members. Liquid hydrogen tanks are manufactured by JAXA Tanegashima Space Centre and are composed by a double shell structure with vacuum insulation [223] [224].

In 2022 a hydrogen-powered crew transfer vessel, equipped with dual-fuel engines supplied by MAN Engines retrofitted by CMB.TECH with a hydrogen injection system, has been delivered to its shipowner. Internal combustion engines work with a not specified share of hydrogen as fuel, but these companies are working to increase this percentage. All working characteristics of internal combustion engines like fuel consumption are the same as an equivalent MAN engine [225]. CMB.TECH have a proven track record of this type of installation, for example retrofitting a tug with hydrogen dual fuel engines. A storage system with a maximum capacity of 400 kg of hydrogen has been installed below the main deck [226]. In 2021, the same company was part of the design and construction of the first hydrogen powered ferry named HydroBingo. The vessel can transport 80 passengers and is equipped with two hydrogen dual-fuel internal combustion engines, and this solution is able to cut carbon dioxide emissions by 50%. Hydrogen is stored into a mobile trailer connected to internal combustion engines via double walled pipes. Trailer can be unloaded for bunkering operations [227].

3.1.6. Ammonia applications

Ammonia applications are very limited, although various studies about potential applications of ammonia as shipping fuel have been developed. The first vessel ready to burn ammonia is a tanker ship and has been delivered in January 2022 to shipowner Avin International. It has a deadweight tonnage equal to almost 160000 tons and is fuelled by traditional oil-based fuels but complies with ABS Ammonia Ready Level 1 requirement and with ABS LNG Fuel Ready Level 1 requirements [228]. Some timelines have been declared by various stakeholders in shipping industry: MAN Energy Solutions has declared that ammonia-fuelled internal combustion engines will be available by 2024 and that nitrogen oxides emission shall be considered a critical problem for this technology [229]. Another study has brought to the development of a conceptual design for an ammonia ready LNG fuelled vessel. The study was conducted by Nippon Yusen Kabushiki Kaisha, MTI Co. and Elomatic Oy on a post-panamax bulker and on a pure car carrier [230].

3.2. PEM fuel cells applications

Proton Exchange Membrane (PEM) fuel cells are considered a novel technology even if they have been employed since 1960s especially for aerospace applications. This type of generator requires high purity hydrogen as fuel, and therefore it can be considered a key enabling technology for carbon-free fuels. There have been some niche applications of PEM fuel cells in the maritime sector during last years, and the most notable ones are described in the following sub-paragraphs.

3.2.1. Submarines class U-212A

One of the first application of more than 100 kW of PEM fuel cells onboard has been as German-Italian designed submarine U212-A class Air Independent Propulsion (AIP) system. Starting from 1980s, PEM fuel cell-based AIP fuelled by hydrogen and pure oxygen has been tested and then installed on board submarines. The nominal power installed has progressively increased during the years, reaching a maximum of 300 kW on board class U-212A submarines developed for German and Italian Navies since 2002. This system is suitable for submarines installation because it enables them to travel underwater’s surface without the need of air which characterise internal combustion engines: at slow speeds the quantity of hydrogen and oxygen onboard enables submarines to sail almost a week without any interruption. Also, since PEM fuel cells does not have rotating parts and operate at low temperatures, they are ideal to reduce noise, vibration, and thermal signature, giving extra stealth capability to the submarine. Hydrogen is stored onboard via metal hydrides, iron-titanium alloys where hydrogen is stored as a solid solution. This system is safe and does not require extreme low temperatures like liquefied hydrogen or very high pressure. Iron-titanium alloy must be heated to extract hydrogen from its storage system, but since the amount of heat required is low, it is used the one recovered from the PEM fuel cell system itself. Oxygen is stored in its liquid form via cryogenic tanks at -183 °C [231].

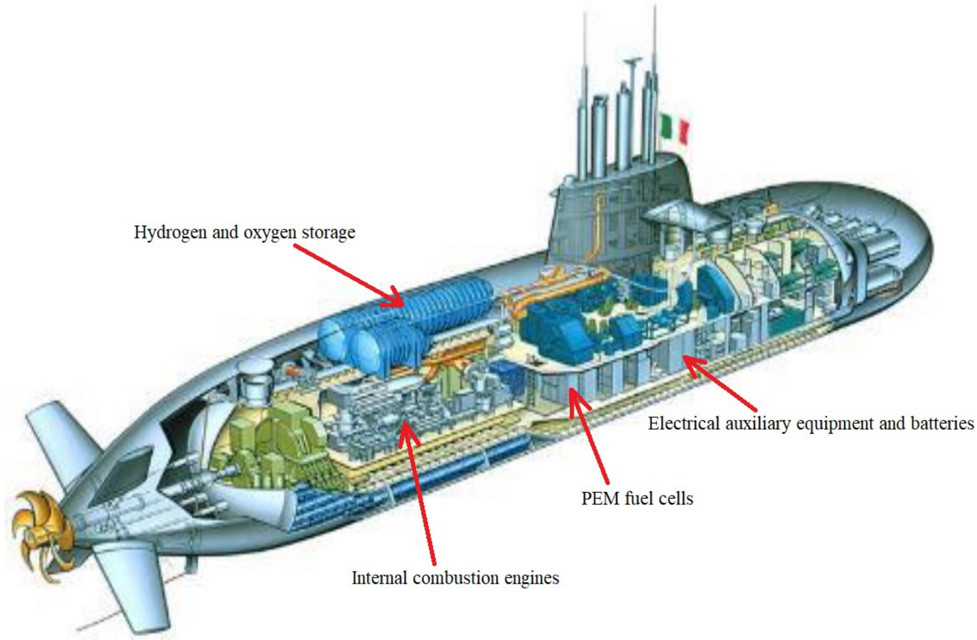

Figure 79 - Internal configuration of a class U212A submarine [231]

3.2.2. Urashima

In 2003 a system based on PEM fuel cells has been installed on the Autonomous Underwater Vehicle (AUV) Urashima by the Japan Agency for Marine Earth Science and Technology. The PEM fuel cell power installed as main source of power on Urashima was limited to 4 kW and integrated with a lithium-ion rechargeable battery storage system. As shown in Figure 80, since Urashima is an underwater vehicle, it included hydrogen tanks, but also a hydrogen storage system composed by metal hydrides, just like U212-A submarines. The small vessel is 10 meters long, 1.3 meters wide and has a height equal to 1.5 meters. Its maximum operating depth is 3500 meters, and its autonomy is 300 km. Since the goal of this project was to have an underwater vehicle with the highest possible autonomy, batteries were not the ideal power generation device for their limited autonomy in relation to their weight and volume. PEM fuel cells were considered more suitable for this application because they have higher energy density and efficiency [232] [233].

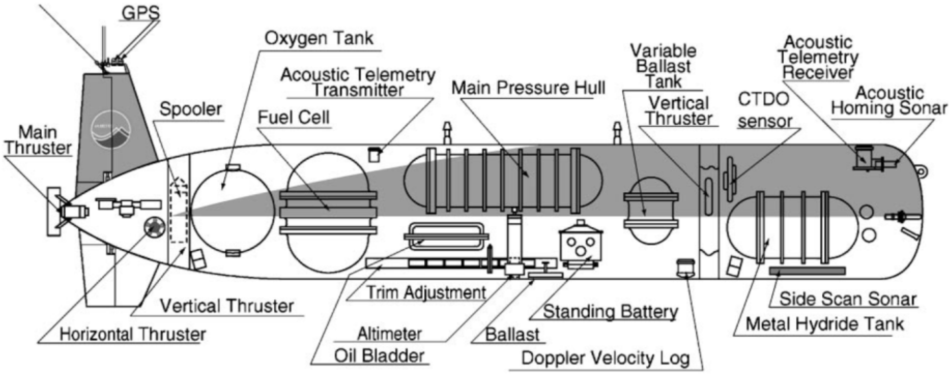

Figure 80 - Urashima internal arrangement [233]

3.2.3. Zemship

Zemship project started in 2006 with the design of a hybrid passenger ship, which brought in 2008 to the construction and trials of "FCS Alsterwasser", a passenger boat for inland navigation without any noxious emission in the city of Hamburg. In this vessel, PEM fuel cells and an energy storage system were the only power generators of the hybrid passenger boat. Goals of the project were to test the efficiency of this technology, its performances over lifetime and the infrastructure needed for its refuelling operations. In 2010 the ship was damaged by a fire caused by the energy storage system, but this event was "beneficial" for fuel cells and hydrogen reputation. First, neither PEM fuel cells nor hydrogen caused the fire onboard, and second safety systems installed onboard didn't let the fire spread to these systems without even damaging them, giving a proof of the safety of this technology [234]. The vessel was repaired to lengthen its operative life, but from 2013 the vessel was dismissed for economic reasons, mainly due to hydrogen refuelling cost. PEM fuel cells generation system was based on two 48 kW modules and seven batteries with a total capacity of 560 V and 360 Ah. is Batteries store power generated by fuel cells and then they use it for propulsion, manoeuvring and other services. Hydrogen was stored in cylinders at 350 bar and the total capacity was equal to 50 kg. This project has brought to a risk assessment with the Germanischer Lloyd to demonstrate that additional risks from a traditional internal combustion engine are minimised [235]. ZemShip project have also tested different energy management systems to evaluate the best possible operative solutions to minimise hydrogen fuel consumption and fuel cells degradation [236].

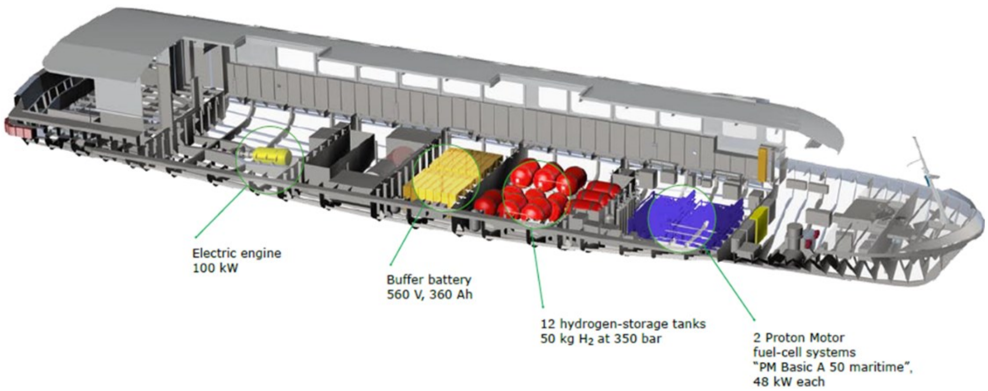

Figure 81 - Hybrid power generation system onboard FCS Alsterwasser [236]

3.2.4. Maranda

Maranda project has been funded by European Union and begin in 2017 to conclude in 2021, but currently (in 2022) the project has not brought to any result or at a real application. In this research, hydrogen fuelled PEM fuel cells should have been validated both on test benches and on board the research vessel Aranda, a research vessel which works also in harsh Arctic environment. Aranda is 60 meters long, 13.8 meters wide and has a draught equal to 5 meters and currently is equipped with four Wärtsilä-Vasa 8R22 and one W-V 12V22 engines for a combined 3000 kW. The system was intended to act as a powertrain for the vessel when working in combination with an energy storage system. It has a MCR equal to 165 kW to satisfy both load requirements by dynamic positioning motors and by all other's ship services. Potential application of fuel cells onboard these vessels is very interesting because they have requirements about vibrations, noise, and air pollution. The declared test time onshore is equal to six months. The aim of the project is to develop a hybrid PEM-battery fuel cell module that should ensure a broad spectrum of applications onboard vessels. The goal is also to demonstrate that hydrogen and PEM fuel cells are economically a viable alternative to traditional powertrains [237] [238].

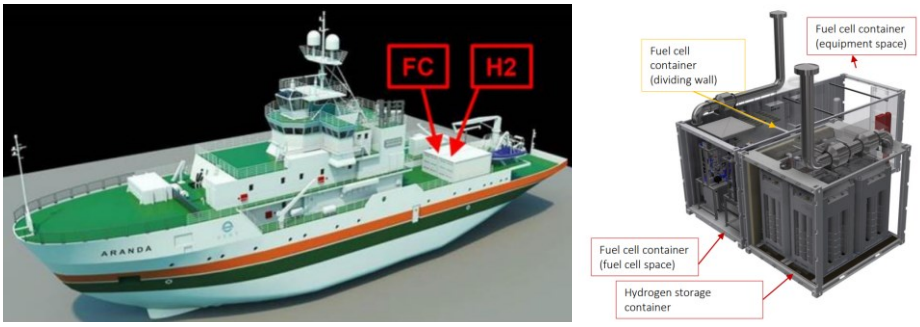

Figure 82 - Render of the PEM fuel cell module, of hydrogen storage system and of their position in project MARANDA [237] [238]

3.2.5. FLAGSHIPS

Flagships project has the aim to deploy two vessels fuelled entirely by hydrogen and powered by PEM fuel cells by 2023. The demo vessel, which has been built in Romania in 2022 and has been transported to France, should operate on river Seine in Paris. This vessel, named Zulu 06, is a cargo transport vessel and hydrogen used onboard will be produced via electrolysis, so potentially enabling zero emission transport. Fuel cells' total power installed is equal to 200 kW and hydrogen onboard will be stored in pressure vessels at 300 bar. The second vessel equipped with a hydrogen powered PEM fuel cell ship powertrain will be a retrofit: a 110 meters long container cargo vessel named FPS Waal which operates on the route between Rotterdam (Netherlands) and Duisburg (Germany). Total amount of PEM fuel cell generation capability should be equal to 1.2 MW, and it is scheduled its retrofit and conversion for summer 2023 [239] [240].

Figure 83 - Zulu 06 vessel while transport operation in France [239]

3.2.6. Nemo H_2

A PEM fuel cell power generation system was installed onboard the passenger vessel "Nemo H_2" in 2009. This ship for canal navigation was about 22 m long and designed to accommodate about 88 passengers at a maximum speed of 8.6 knots and operated in Amsterdam, Netherlands. The power generation system was composed by two 30 kW PEM fuel cell modules, six storage tanks containing 24 kilograms of hydrogen at a pressure equal to 350 bar and 55 an energy storage system with a total capacity equal to 70 kWh. Nemo H_2 was equipped with a 75 kW propulsion electric motor and an 11 kW bow thruster. The PEM fuel cells system was used to directly power the propulsion motor or to charge the energy storage system. The battery packs were used to improve the performance of transient operation of PEM fuel cells and as a back-up option for power generation. An energy management system was used to determine the operation of the battery packs. In this case, a hydrogen refuelling infrastructure was built and studied [241].

Figure 84 - Nemo H2 passenger boat while operating in Amsterdam, Netherlands [241]

3.3. SOFC and high temperature fuel cells applications

There are fewer projects for maritime application of SOFC and HT-fuel cells since their technology is less developed and optimised for mobility applications. The most notable application of these technologies onboard ships are described in the following sub-paragraphs.

3.3.1. e4ships

German shipbuilding industry, fuel cells manufacturers the Federal Ministry of Transport and Digital Infrastructure developed the idea of this project to identify and study innovative systems to be prepared for a future without heavy fuels for seagoing vessels. e4ships has two subordinate projects: SchIBZ and Pa-X-ell, both with real-life application of fuel cells onboard ships. These experiences have helped all stakeholders to contribute to the definition of rules and standards for fuel cells certification and installation onboard ships. SchIBZ has been managed by ThyssenKrupp Marine Systems and aimed to develop a modular hybrid system based on SOFC (manufactured by Sunfire) and lithium-ion batteries to help with load variations. This system was integrated inside a container, it was characterised by a power which could arrive up to 500 kW: the system was intended to work as an Auxiliary Power Unit (APU). SOFC system was fuelled by LSFO with the goal to adapt the system to be fuelled with natural gas. The system proved to be feasible to obtain an emission reduction and a key enabling technology for high overall efficiencies, since it is a Combined Heat and Power (CHP) generator (50% electrical efficiency and 90% overall efficiency). Measurements onboard also highlighted the fact that noise and exhaust gas emissions were lowered compared to a conventional internal combustion engine fuelled with MDO or HFO. Modularity is another added value of this technology, since it allows a high level of redundancy. At the end of 2016, this system has been installed onboard the cargo ship “MS Forester” to cover a share between 25% and 50% of the auxiliary power demand of the ship. Project stakeholders highlighted the fact that hydrogen will not be employed onboard until a high-density storage mode will be developed and mass production of SOFC [242] [243].

Figure 85 - MS Forester and a render of the SchIBZ module onboard [242]

Pa-X-ell project was dedicated to the potential application of HT-PEM fuel cells fuelled by methanol, equipped with a liquid cooling system that enable exhaust gas utilisation in an absorption refrigeration system. Total electrical output of the engineered system was 30 kW, and this system was tested in different climatic conditions to test how it performed. These tests indicated that the system is suitable for the marine environment. Study found out that a fuel cell system can reach higher electrical efficiencies than internal combustion engines, particularly at partial loads. This project also led to build two systems: one was tested on the land alongside an absorption refrigerator to test their interaction and the other one was installed onboard the MS Mariella, a ferry which operates on the North Sea. This second installation had a power output equal to 60 kW and was installed on the higher deck of the ship. The goal of this project was the demonstration that this technology can be installed as a decentralised generation system onboard cruise ships to increase efficiency, safety, and redundancy. Cost of these systems and power generated per each module were considered on the other hand not competitive for cruise market at the time [244].

Figure 86 - Prefabricated HT-PEM fuel cell module onboard MS Mariella [244]

These two subprojects were part of the first phase of e4ships, which began in 2009 and ended in 2016. In 2018 the second phase of e4ships project began, and its conclusion is set in 2022. This phase is characterised by further development of SchIBZ and Pa-X-ell, but also by new projects named Rivercell and ELEKTRA, both dedicated to the application of the same type of fuel cells, but for inland vessels.

In the Pa-X-ell2 demonstration project, led by Meyer Werft, a new generation of fuel cell systems (PEM) is being developed as part of a decentralized energy network and a hybrid power generator, based on the results of the previous Pa-X-ell project. These innovative energy systems are optimised to be used onboard ocean-going passenger ships, and they shall promote their market development. This project includes the creation of a concept for a decentralized energy network, the development and design of subsystems and their test operation under conditions that simulate later use in the decentralized network. Furthermore, the basic functionality of the hybrid energy system with an energy storage device is tested and verified in a test facility. For the optimal use of the fuel cell systems, developments are taking place in the field of energy management. These energy generation concepts have been developed for their good performances, their service redundancy and for the peculiar safety requirements on passenger ships. The fuel cell system is fuelled with hydrogen, which is obtained from methanol using an internal reformer. Testing of the system will be developed on land and on board.

Under the direction of ThyssenKrupp Marine Systems, the previously developed and built hybrid and diesel-powered fuel cell system is being tested on land and at sea on the MS Forester in the SchIBZ2 project, as a continuation of the SchIBZ project, to provide complete proof of the seaworthiness of the individual components and the to validate the overall system.

In the MultiSchIBZ project, ThyssenKrupp Marine Systems controls the process optimization and further development of the design of the fuel cell system from the SchIBZ2 project for introduction into commercial applications. The main measures are the optimization of the reforming processes to be able to use other fuels such as natural gas in the future, as well as the planning and development of the power electronics for a decentralized DC voltage network with components made of innovative components [245].

3.3.2. Felicitas

Felicitas project was born from research and development studies of companies like Rolls-Royce Marine Electrical Systems, shipbuilder Lürssen and Universities of Genoa, Eindhoven, and Hamburg. The project was based on a 1 MW pressurised SOFC module manufactured by Rolls-Royce Marine Electrical Systems for land-based applications and brought to the construction and testing of a 250 kW module for marine applications. The main goal of this project was to adapt the existing product to maritime environment, in particular studying how a salty air, continuous vibrations, variable loads, and different fuels could affect design and performances of this power generator. They planned to install this system onboard a yacht studying how this power generator interacts with other ship's systems, like water treatment, fuel storage, energy storage system, exhaust gas ducting and power management system. The private yacht market segment was considered promising because clients could accept to pay a higher initial price to get innovative technologies with a low environmental impact. The result of Felicitas project was given by tests of both single components and materials for the SOFC module, but also of the overall power generation system. The test showed a global efficiency of almost 60%, which has been obtained with a heat recovery system implementation. Among all fuels tested, natural gas has been identified as the most suitable option for SOFC. Also, possible combination of SOFC and PEM fuel cells can be beneficial for both technologies, and it can increase overall efficiency. The project has also brought to the development of a diesel reformer suitable for marine operations and of a micro-reactor to purify SOFC exhaust gases to fuel a PEM power generation system. SOFC have been considered a potential good power generator for the baseload of a ship, but not as the ideal solution to sustain rapid load variations. On land, a test rig with a 250 kW SOFC module and a 100 kW micro gas turbine has been developed and tested [246].

Figure 87 - 1 MW SOFC module for land application (left) and 250 kW SOFC module for marine application (right) [246]

3.3.3. FellowSHIP

FellowSHIP started in 2003 and brought to the installation of a fuel cell prototype in 2010 onboard the "Viking Lady", an offshore supply vessel. This ship is 32.2 meters long and 21 meters wide and was already equipped with dual fuel internal combustion engines with a total MCR of about 8 MW. Molten Carbonate Fuel Cells were installed to generate a maximum output equal to 320 kW. The system during project development have been changed to become a hybrid power generator with the installation of an energy storage system able to support slow response time of fuel cells. Batteries have also gained a lot of interest because they enabled peak-shaving and thus a better internal combustion engines' efficiency. Project result claimed a 100% reduction of sulphur oxides emission, an 85% reduction of nitrogen oxides emission and a 20% reduction of carbon dioxide emissions [247].

Figure 88 - MCFC module onboard the Viking Lady [247].

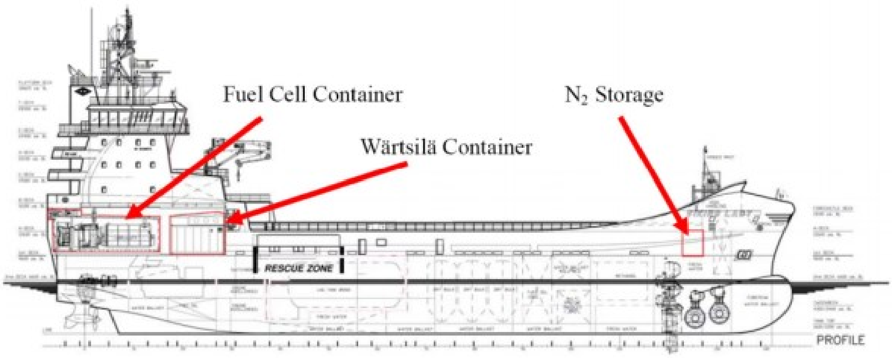

Figure 89 - MCFC module in a general arrangement onboard Viking Lady [247].

3.4. Gas turbines applications

Gas turbines have been considered particularly during the 1990s and 2000s as a possible alternative to internal combustion engines for power generation onboard merchant ships. They have been used onboard naval ships to take advantage of their high power density and ease of maintenance. Since gaseous fuels are now considered as possible fuels for future low emission shipping, gas turbines are gaining again momentum as a possible power generator onboard merchant vessel. In the last 20 years, there have been some application of gas turbines onboard fast ferries and cruise ships: the transatlantic ocean liner Queen Mary 2 which entered in service in 2004, cruise ship Celebrity Millennium which operates from 2000 and Francisco ferry built in 2013. All past applications have highlighted the fact that gas turbine power output is sensitive to ambient air temperature, thus this parameter must be seriously considered, and measures should be taken to optimise this input. Also, part load efficiency is a key factor that must be considered; thus, turbines should work near their maximum efficiency load for most of the time. When fuelled by natural gas, turbines have demonstrated to significantly lower methane slip when compared with dual-fuel internal combustion engines [248]. Potential application of gas turbines onboard cruise ships has been studied for a 66000 DWT vessel with a capacity of about 2000 passengers. The study focuses not only on the electrical power demand by the ship, but also on thermal power demand. Two extreme conditions are considered in the paper: winter and summer, which differ for external air temperature, humidity, and water temperature. The study highlights the fact that cruise ships have a low baseload which corresponds to power requirement during port stays: this type of vessel requires a unique power generator with a high modulation capability maintaining a high overall efficiency or the installation of multiple smaller power generators which shall be capable of a relatively quick start-up time. This study confirms that the overall efficiency of the power generation plant is lower when gas turbines are installed onboard, but also the decrease of about 50% of volume occupied and of about 70% of the weight required by the power generation system [249]. In a recent study it is pointed out that gas turbines are already applied in other maritime environments, like on offshore platforms and floating production, storage, and offloading vessels. These power generators offer a great flexibility because they can be integrated in combined cycles or combined heat and power system. Lifecycle cost of gas turbines are now comparable to the one of internal combustion engines, and thus in following years this technology will probably be more applied on merchant ship [250]. Celebrity Millennium is the most interesting application for this study. Electric power onboard is generated by a Combined Gas turbine and Steam turbine cycle (COGES). Two main alternators (25 MW each) are driven by two General Electric gas turbines (type LM2500+). Each gas turbine is equipped with an exhaust gas boiler which recovers heat to produce steam which drives one steam turbine equipped with a 9MW alternator. The overall efficiency obtained is equal to 43% instead of an efficiency of about 39% that would be obtained without the heat recovery system. These turbines have almost an operative life equal to 48,800 hours, which represent 10 years of life for the reference vessel. In case of non-resolvable failure, a gas turbine can be replaced in almost 8 hours, because onboard this cruise ship there is stored onboard a spare turbine. If internal combustion engines have been installed, they would have been heavier, bigger, with higher maintenance costs and higher noise and vibrations. Onboard this ship, four internal combustion engines have been installed for electric power production in very demanding operating conditions and sometimes for very low speed or mooring conditions. In Figure 90 is shown the arrangement of one of the gas turbine onboard Celebrity Millennium and the size of its related equipment, like air intake and exhaust gas ducts.

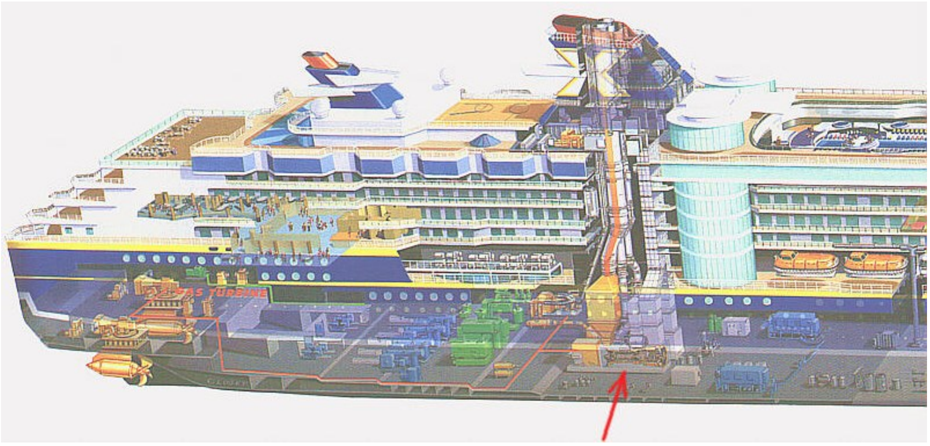

Figure 90 - Gas turbines onboard Celebrity Millennium [250]

4. Applicable rules and regulations

Ship design and shipbuilding are activities characterised by a high level of complexity, mainly because cruise ships are almost unique products where a prototype is built and repeated one or a few times. It is essential to deeply understand each phase of the intellectual process behind ship basic design and to remind all the relations with stakeholders involved in this process. All initial discussion and ideas with the client, namely a shipowner, when are defined as an initial ship design, must be compared and evaluated with various requirements given by different stakeholders. National and international regulators are some of the main actors in this process because all type of ships must meet some of these requirements. Ship contracts define which regulations must be met by ships, and these can be distinguished in four types:

1. International regulations by IMO and its technical committees: these regulations are needed by shipowners to travel worldwide.
2. Classification's society regulations, which are needed to buy an insurance on the newbuilt or retrofitted ship.
3. Flag requirements, that shipowners must have to register the ship in the fleet of a particular country, possibly obtaining a taxation reduction (especially by countries known as "flags of convenience").
4. Requirements to transit in particular waterways, like Suez or Panama Canal.

In following paragraphs, most important regulations regarding greenhouse gas emissions and new technologies are listed and described to identify main restrictions for ship design, but also to highlight possible areas with more freedom of interpretation and thus more possible technical ways to comply with these requirements.

4.1. International rules - IMO

Shipping is regulated at the international level by the International Maritime Organisation (IMO), a body part of the United Nations (UN). The IMO was founded in 1948 as an organisation able to promote international cooperation for the increase of maritime safety and for easier international trade. IMO role has been modified during its history to include all topics related to ship safety, security, and environmental impact. In recent years, IMO has considered one of its priorities the promotion of sustainable shipping and some challenging emission reduction goals from. IMO regulations cover different topics, like ship design, ship construction, equipment required onboard, vessel's manning and its final disposal [251]. IMO has also a forum where member states, shipping industry and representative of other parts of society can work together to develop and implement global standards about various topics, like maritime training, security, energy efficiency, traffic management, innovative technologies, and maritime infrastructures. This process has brought to the issue of over sixty binding international treaties [252]. The most notable convention about energy efficiency and maritime pollution is the 1973 International Convention for the Prevention of Pollution from Ships, commonly known as MARPOL [41]. The treaty is divided into six annexes according to the type of pollution, not only gaseous, but from water discharge, payload losses, sewage, and rubbish. This convention has become more comprehensive over time through the adoption of various amendments. Annex VI deals with the prevention of air pollution from ships [253]. MARPOL Annex VI covers the topic of GHG emissions. Among its most recent policies there are Energy Efficiency and Design Index, the Ship Energy Efficiency and Management Plan and the implementation of Emission Control Areas [254].

4.1.1. Energy Efficiency Design Index (EEDI)

The Energy Efficiency and Design Index was adopted at the 62nd Marine Environment Protection Committee in 2011 (MEPC 62) and is mandatory for new built ships from 2013 onwards. It has been adopted to promote overall efficiency by propulsion engines and auxiliary power generators. According to IMO, the EEDI is intended to promote a continuous innovation an incremental technical development of all the components influencing the fuel efficiency of a ship starting from its design phase [255]. The EEDI sets a mandatory limit on the allowable carbon dioxide emissions per capacity mile. It is measured in grams of carbon dioxide per tonne-mile of cargo transported. It prescribes a different upper bound for each ship type, and the required emission level is to be tightened incrementally every five years to better stimulate continuous innovation. Furthermore, it is not prescriptive on the type of solution that must be used, leaving ship designers the goal to identify the most cost-efficient solution. For this reason, it is called a performance-based index. For each type of vessel, it is set an upper limit: this reference value is equal to the average of that ships' type built between 2000 and 2010 during the period 2013-2015. The limit is to be tightened every five years from then onwards, starting with a 10% reduction with respect to the reference value for the period 2015-2020. Limits have been established until 2030, when a 30% reduction relative to the reference value will be required [256].

4.1.2. Ship Energy Efficiency and Management Plan (SEEMP)

While EEDI must be applied to ships built after 2013, the Ship Energy Efficiency and Management Plan (SEEMP) is related to all ships with a gross tonnage equal or above 400 GRT [41]. This regulation sets a mechanism which brings maritime industry to review its best practices to enable fuel-efficient ship operations. It is mainly focused on possible operational best practices like slow steaming, which is an overall speed reduction which in post cases brings to a reduced fuel consumption, or more frequent maintenance, for example for hull and propeller cleaning. It also includes design-related features, like the implementation of new technologies onboard ships like waste heat recovery systems or new propeller designs. Implementing SEEMP means to monitor ship overall efficiency through mechanical tools and indexes such as the Energy Efficiency Operational Indicator (EEOI) and to analyse their variation over time, to possibly find an increase of efficiency. The EEOI allows ship operators to quantify the effect of any changes made to improve the energy efficiency of ships. The SEEMP requires all ships of 5000 gross tones to submit fuel consumption data, along with cargo and transport work information, for each type of fuel used aboard the vessel. This data collection is aimed to provide the basis for future GHG reduction measures, as well as to track the progress and relative success of adopted measures [254] [255].

4.1.3. Emissions Control Areas (ECAs)

MARPOL Annex VI introduced global limits on the emission of sulphur oxides, nitrogen oxides and particulate matter and established the creation of Emissions control Areas (ECA). In ECAs apply lower limits on the emission of sulphur oxides (currently all ECAs) and NOx (all ECAs from January 2019 onwards) than outside ECAs. There are currently four ECAs under MARPOL Annex VI: the Baltic Sea ECA, the North Sea ECA, the North American ECA and the United States Caribbean ECA. The global limit on fuel sulphur content has been set to 0.5% from January 2020. The sulphur limit inside ECAs is set to 0.1%. The sulphur limit inside and outside ECAs do not permit the use of HFO, unless post-combustion treatments are installed onboard the ship [257].

The regulation about nitrogen oxides emissions follows a similar structure to SOx emissions, with a global limit and a lower limit inside ECAs. There are currently three tiers of NOx limits that are tied to the rated engine speed. Tier I applies to engines in ships built between 2000 and 2010. Tier II came into force in January 2011 and applies to marine diesel engines on ships built in or after 2011. Both the tier I and tier II limits are global limits. Tier III came into effect in January 2016 and applies to marine diesel engines of more than 130 kW on ships built in or after 2016 when operating inside an ECA.

There have been some critics about this regulation: sulphur oxides scrubbers reduce fuel economy onboard a ship, and these measures have brought to a higher demand of more refined fuels. Distilled fuels are surely "cleaner", but the increased processing at refineries is associated with increased energy consumption for their production and a higher hydrogen demand for their processing operations. Thus, the regulation to reduce sulphur oxides emissions can possibly lead to an increase in carbon dioxide emissions from a system perspective [41] [258].

4.1.4. Carbon Intensity Indicator (CII)

IMO has outlined a strategy to further reduce GHG emissions from the maritime sector and carbon intensity, defined as the emission of carbon dioxide per transport work. The goal is to reduce this figure by at least 40% by 2030 and try to achieve a reduction of 70% by 2050 compared to 2008. Furthermore, global annual GHG emissions from shipping are expected to be reduced by at least 50% by 2050 compared to 2008, reaching carbon-neutrality as soon as possible by the end of this century. In the latest IMO's Marine Environment Protection Committee (MEPC 76), which was held in June 2021, a new index was proposed for discussion: Carbon Intensity Indicator (CII). This factor is a measure of the total carbon dioxide emissions divided by the amount of cargo carried and by the distance travelled on an annual basis. Several options are proposed for calculating the CII, but none have been taken as the final formula. The CII measuring is linked to a rating system for ships, from A to E, where A is best. If a ship achieves a D or E rating for three consecutive years, it should outline a strategy for achieving a C or better rating the following year [259]. As this proposed regulation is recent and still under development, there are not many publications available. Some criticisms have already appeared, pointing out that there are four potential formulas of CII defined as "supply-based", "demand-based", "distance-based" and "sailing time-based". Theoretically, to comply with the "supply-based" CII, the "distance-based" CII or "time-based" CII limits, a shipowner may sail for a certain distance its ship empty, thus enhancing emissions only to comply with regulations and not to let the ship fulfil its purpose. Also, "demand-based" CII can be achieved by detouring over long distances. This new regulation can bring certain ships to increase overall emissions to comply with CII regulations [260]. The formula proposed in the CII guidelines following IMO's MPEC 76, as already reported in the introduction. First, for each type of ship the reference value for the CII must be calculated using the following formula:

$$CII_{ref} = a \cdot Capacity^{-c}$$

The values for a and c and the measure of capacity are given in Table 38, where DWT stands for deadweight, which is the weight that a ship can carry as cargo, fuel, crew, passengers, food, and water. This deadweight is referred as the maximum summer load draft.

Table 38 – Factors for reference CII calculation [259]

Ship Type	Ship size	Capacity	a	c
Bulk Carrier	DWT ≥ 279,000	279,000	4745	0.622
	DWT < 279,000	DWT	4745	0.622
Gas Carrier	DWT ≥ 65,000	DWT	$14405 \cdot 10^7$	2.071
	DWT < 65,000	DWT	8104	0.639
Tanker		DWT	5247	0.610
Container Ship		DWT	1984	0.489
General Cargo Ship	DWT ≥ 20,000	DWT	31948	0.792
	DWT < 20,000	DWT	588	0.389
Refrigerated Cargo Carrier		DWT	4600	0.557
Combination Carrier		DWT	40853	0.812
LNG Carrier	DWT ≥ 100,000	DWT	9.827	0
	100,000 > DWT ≥ 65,000	DWT	$14479 \cdot 10^{10}$	2.673
	DWT < 65,000	65,000	$14479 \cdot 10^{10}$	2.673
Ro-ro Cargo Ship (VC)		GT	5739	0.631
Ro-ro Cargo Ship		DWT	10952	0.637
Ro-ro Passenger Ship		GT	7540	0.587
Cruise Passenger Ship		GT	930	0.383

The attained value of CII for cruise passenger ships, ro-ro passenger ships, and ro-ro cargo ships is given in the following formula (4.1.1):

$$CII_{att} = \frac{CO_2\ emissions\ [g]}{GRT \cdot Distance\ sailed\ [nm]} \tag{4.1.1}$$

$$CII_{att} = \frac{CO_2\ emissions\ [g]}{GRT \cdot Distance\ sailed\ [nm]}$$The

$$CII_{att} = \frac{CO_2\ emissions\ [g]}{DWT \cdot Distance\ sailed\ [nm]} \tag{4.1.2}$$

$$CII_{att} = \frac{CO_2\ emissions\ [g]}{DWT \cdot Distance\ sailed\ [nm]}$$The

$$CII_{req} = \frac{100 - Z}{100} \cdot CII_{ref} \tag{4.1.3}$$

$$CII_{req} = \frac{100 - Z}{100} \cdot CII_{ref} Table$$

Year	Reduction Factor (Z)
2023	5
2024	7
2025	9
2026	11
2027 to 2030	To be defined

CII measurement is linked to a rating system for ships, from A to E, where A is best. If a ship obtains a rating of a D or E for three consecutive years, it should outline a strategy for achieving a C or higher rating the following year. The rating is assigned based on the ratio between the attained CII and the required CII: the higher this ratio is, the worse the rating. The threshold values for ratings from B to E are shown in Table 40: if the ratio is lower than the value in column B, rating is equal to A.

Table 40 – CII rating scheme for different type of ships [259]

Ship Type	Ship size	B	C	D	E
Bulk Carrier		0.86	0.94	1.06	1.18
Gas Carrier	DWT ≥ 65,000	0.81	0.91	1.12	1.44
	DWT < 65,000	0.85	0.95	1.06	1.25
Tanker		0.82	0.93	1.08	1.28
Container Ship		0.83	0.94	1.07	1.19
General Cargo Ship		0.83	0.94	1.06	1.19
Refrigerated Cargo Carrier		0.78	0.91	1.07	1.20
Combination Carrier		0.87	0.96	1.06	1.14
Gas Carrier	DWT ≥ 100,000	0.89	0.98	1.06	1.13
	DWT < 100,000	0.78	0.92	1.10	1.37
Ro-ro Cargo Ship (VC)		0.86	0.94	1.06	1.16
Ro-ro Cargo Ship		0.66	0.90	1.11	1.37
Ro-ro Passenger Ship		0.72	0.90	1.12	1.41
Cruise Passenger Ship		0.87	0.95	1.06	1.16

Figure 91 shows the variation of threshold values between different rating for two different reference years (2022 and 2026). As already shown in Table 39, each year, the requirement for ships would be more demanding for ships with this proposed regulation, and therefore a cruise ship that has a *C* in 2022 would reach a *D* rating in 2026, or possibly even earlier. For this reason, it is important to address this problem now, especially for new building cruise ships: these vessels must be ready to obtain a good rating and should be able to maintain or even improve it over time.

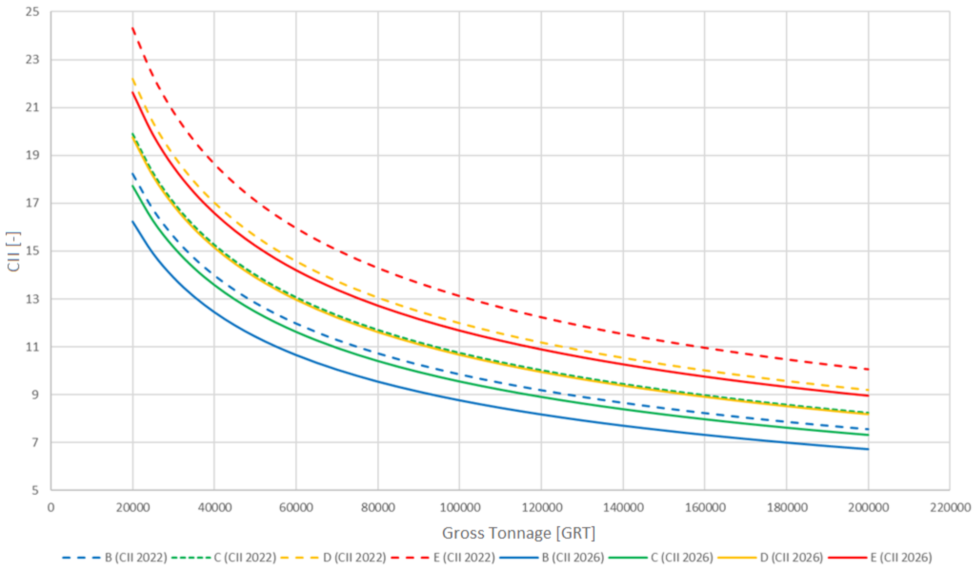

Figure 91 - Variation of threshold values of CII between different ratings for cruise ships (2022 and 2026 values)

4.1.5. International Code of Safety for Ships using Gases or Other Low-flashpoint Fuels (IGF Code)

New fuels onboard can be particularly dangerous to bunker, store, handle, and use. These fuels have different characteristics from classic oil-based fuels: they can be liquid at ambient temperature or gaseous, they could need specific materials for their chemical properties, and they could need specific temperatures or pressures to be efficiently stored. From the first ideas of using natural gas as fuel onboard ship, IMO has developed the International Code of Safety for Ships using Gases or Other Low-flashpoint Fuels (IGF Code), which came into force in January 2017. This international standard provides criteria for design and construction of ships which employ gas or a low-flashpoint fuel (flashpoint lower than 60 °C). Right now, this standard covers only detailed requirements for natural gas, both in its compressed and liquid storage options, when used in internal combustion engines, boilers, and gas turbines. For other fuels, Part A of IGF code requires an *alternative design* procedure which complies with regulation II-1/55 of SOLAS rules to demonstrate an equivalent level of safety. Carriage of Cargoes and Containers (CCC) subcommittee of the Maritime Safety Committee (MSC) is currently discussing rules for using methyl and ethyl alcohols as fuels and fuel cells. This new part of the standard should be focused on fuel cells, without specifying the fuel used. Among potential requirements for these systems, exhaust gas system and ventilation system should not be combined and should be independent by the systems related to other ship's room and equipment.

4.2. Class requirements

Each ship needs two essential certificates before starting its operations. These are the classification certification, which is released from a classification society which is part of the International Association of Classification Societies (IACS) and the safety certificate. IACS members includes American Bureau of Shipping (ABS, from the USA), Bureau Veritas (BV from France), China Classification Society (CCS), Det Norske Veritas - Germanischer Lloyd (DNV GL from Germany), Indian Register of Shipping (IRS), Korean Register (KR, from South Korea), Lloyd's Register (LR, from UK), Registro Italiano Navale (RINA, from Italy) and Nippon Kaiji Kyokai (ClassNK, from Japan). Class certification establishes laws and technical specifications to design and build a particular type of vessel, it certificates that construction phases have followed these rules and that the required characteristics have been sustained during the ship's operations, especially before and after restorations and refitting. Safety certificate is released by technical bodies part of flag administrations for merchant ships and passenger ships. Classification societies develop and update general rules and regulations which are applicable to almost all type of ships and specialised rules and regulation for various type of ships that can be applied basing on ship's service, payload or technologies employed onboard. During the last years, classification societies have been developing rules for alternative fuels, with a particular focus on gaseous fuels, and on new power generation technologies, particularly fuel cells and gas turbines, but also batteries. In the following paragraphs there is an overview of all the most recent rules and regulations issued by each classification society and with an interest for the topic of this thesis.

4.2.1. American Bureau of Shipping

American Bureau of Shipping (ABS) provides some rules for the classification of ships and guides and whitepapers for the potential use of innovative technologies and fuels onboard ships.

Table 41 – ABS rules and guidelines applicable to this research's topic [261]

Title	Publication date	Last update
Risk Assessment Applications for the Marine and Offshore Industries	April 2020	April 2020
Review and Approval of Novel Concepts	April 2017	April 2017
Guide for Gas and Other Low-flashpoint Fuel Ready Vessels	March 2022	March 2022
Gas and Other Low-flashpoint Fuel Ready Vessels	January 2017	March 2018
LNG bunkering	January 2017	March 2018
Ammonia fuelled vessels	September 2021	September 2021
Methanol and Ethanol fuelled vessels	January 2022	January 2022
SOx Scrubber Ready Vessels	October 2015	October 2015
Exhaust Emission Abatement	June 2022	June 2022
Guide for Fuel Cell Power Systems for Marine and Offshore Applications	November 2019	November 2019
Guidance Notes on Thermal Analysis of Vessels with Tanks for Liquefied Gas	September 2019	September 2019
Guidance Notes on Gas Dispersion Studies of Gas Fuelled Vessels	November 2019	November 2019
Guidance Notes on Strength Assessment of Independent Type C Tanks	January 2022	January 2022
Sustainability Whitepaper: LNG as Marine Fuel	July 2022	July 2022
Sustainability Whitepaper: Ammonia as Marine Fuel	October 2020	October 2020
Sustainability Whitepaper: Methanol as Marine Fuel	February 2021	February 2021
Sustainability Whitepaper: Hydrogen as Marine Fuel	June 2021	June 2021
Sustainability Whitepaper: Biofuels as Marine Fuel	May 2021	May 2021

4.2.2. Bureau Veritas

Bureau Veritas provides some rules for the classification of ships and guidance notes for the potential use of innovative technologies and fuels onboard ships.

Table 42 – Bureau Veritas rules and guidelines applicable to this research's topic [262]

Title	Last update
Gas-fuelled ships	July 2022
Ships using Fuel Cells	January 2022
High-voltage shore connection system	January 2010
Methanol & ethanol fuelled ships	August 2022
Ammonia-fuelled ships - Tentative Rules	July 2022
Safety of ro-ro passenger and cruise ships	January 2018
Risk-based qualification of new technology - Methodological guidelines	April 2020
Guidelines for the use of low-sulphur fuel oils (IMO 2020 compliance)	May 2019
Guidelines on LNG bunkering	July 2014
Index on applicable risk analysis for Marine and Offshore	December 2017
Guidance notes for structural assessment of passenger ships and ro-ro ships	August 2022
LPG-fuelled ships (tentative rules)	January 2018
Guidelines on conversion to LNG as fuel	February 2019

4.2.3. China Classification Society

China Classification Society provides some rules for the classification of ships and guidance notes for the potential use of innovative technologies and fuels onboard ships.

Table 43 - China Classification Society rules and guidelines applicable to this research's topic [263]

Title	**Last update**
Rules for Green Ships	April 2022
Rules for Natural Gas Fuelled Ships	January 2021
Guidelines for local strength assessment of cruise ships	August 2021
Guidelines for complete ship model calculation of cruise ships	July 2021
Guidelines for Application of Selective Catalytic Reduction (SCR) System Onboard Ship	May 2022
Guidelines on verification of the energy efficiency design index (EEDI) of ships	December 2020
Guidelines for survey of dc distribution electrical propulsion systems	May 2020
Guidelines for surveys of pure battery powered ships	March 2020
Guidelines for application of alternative design and arrangements of ships	December 2019
Guidelines for surveys of intelligent energy efficiency management of ships	April 2022
Guideline for the Monitoring, Reporting and Verification of CO2 Emissions	September 2018
Guidelines for use of low-sulphur distillate fuels in ships	September 2018
Guidelines for testing and survey of emission of nitrogen oxides from marine diesel engines	June 2020
Rules for cruise ships	October 2016
Guidelines for testing and survey of exhaust gas cleaning systems	February 2019
Guidelines related to Selective Catalytic Reduction System	May 2016
Guidelines for Application of fuel cell system	May 2016
Guidance for the development of ship energy efficiency management plan (SEEMP)	April 2016
Guidelines for Use of Low-sulphur Fuel Oils in Ships	April 2016
Guidelines related to Exhaust Gas Cleaning System	September 2019
Guidelines for Design and Installation of Dual Fuel Engine System	April 2016
Rules for Certification of Ship Energy Efficiency Management	March 2016

4.2.4. Det Norske Veritas - Germanischer Lloyd

Det Norske Veritas - Germanischer Lloyd provides a big set of rules for the classification of the ships, named RU-SHIP, where there are some general regulations, about materials, welding, hull, systems, and components. Then there is a specific part of the rules related to each ship type and then additional class notations about a lot of different topics, among which for this research are notable the ones related to propulsion, power generation, auxiliary systems, environmental protection, and pollution control. Inside these big set of rules, there are specific requirements for almost all topics covered by other classification societies [264].

4.2.5. Indian Register of Shipping

Among various classification rules for ships classified by the Indian Register of Shipping, there are only two guidelines of particular interest for the topic of this research, which are showed in the following table [265].

Table 44 – Indian Register of Shipping guidelines applicable to this research's topic [265]

Title	Last update
Guidelines on Vessels with Fuel Cell Power Installations (Provisional) – Revision 01	September 2022
Guidelines on Battery Powered Vessels	2019
Guidelines on Methanol Fuelled Vessels - Revision 03	December 2021

4.2.6. Korean Register

The Korean Register provides a general set of rules and regulation for the classification of ships and then some guidelines for specific topics, among which the most interesting for this research are given in the following table.

Table 45 – Korean Register guidelines applicable to this research's topic [266]

Title	Last update
Guidelines for Ships Using Ammonia as Fuels	June 2021
Guidelines for Wind Assisted Propulsion Systems	March 2021
Guidelines for Ships carrying Liquefied Hydrogen in Bulk	February 2021
Guidelines for Ships Using Low-flashpoint Fuels (LPG & Methyl/Ethyl Alcohol)	July 2020
Electric propulsion motor for eco-friendly vessel guidelines	July 2020
Guidelines of Heat Transfer Analysis for Ships Carrying Liquefied Gases in Bulk/Ships Using Liquefied Gases as Fuels	July 2020

4.2.7. Lloyd's Register

Lloyd's Register, as other classification societies, has its own set of general rules and regulations for the classification of the ships. Additionally, among its rules, there is a specific set of regulations for the classification of ships using gases or other low-flashpoint fuels, which can be applicable to natural gas, but also at list in this transition phase to hydrogen. There are also some guidance notes which can be analysed when assessing the ship's sustainability: these are shown in the following table.

Table 46 – Lloyd's Register rules and guidelines applicable to this research's topic [267]

Title	Last update
Rules and Regulations for the Classification of Ships using Gases or other Low-flashpoint Fuels	July 2022
Guidance notes for Collision Assessment for Low-flashpoint Fuel Tanks.	July 2016
Guidance Notes for Risk Based Analysis: Cryogenic Spill.	August 2015

4.2.8. Registro Navale Italiano

There are only a few RINA rules and guidelines specifically applicable to the topic of this research, which are listed in the following table.

Table 47 – RINA rules and guidelines applicable to this research's topic [268]

Title	**Last update**
Guide for the Ship Environmental Rating Assessment - Green Rating (ERA)	-
Guide for approval in principle of novel technologies	-
Guide on complete ship model calculation of Passenger Ships	-

4.2.9. Nippon Kaiji Kyokai

There are only a few Nippon Kaiji Kyokai rules and guidelines specifically applicable to the topic of this research, which are listed in the following table. Guidelines for liquefied hydrogen carriers have been included in this list because they can be useful to identify key requirements and ship's characteristics that could be considered useful for the potential use of hydrogen as ship's fuel.

Table 48 – Nippon Kaiji Kyokai rules and guidelines applicable to this research's topic [269]

Title	**Last update**
Rules and Guidance for the Survey and Construction of Steel Ships	2022
Guidelines for Liquefied Hydrogen Carriers	March 2017
Guidelines for Gas fuelled ships	April 2016

5. Parametrisation of the design of a ship comprising innovative power generation systems

This chapter analyses two reference ships: one contemporary class cruise ship and one luxury class cruise ship. All data about fuels, storage tanks, fuel treatment systems, power generators and exhaust gas treatment systems have been considered to analyse each possible technology combination onboard. All values will be considered in the optimistic case and the electricity emissions and cost used in the calculation are the one of the Swedish energy mix, as described in Table 4. Emissions considered, as previously stated, are carbon dioxide and methane slip: a more accurate analysis should account at least also nitrogen oxides emissions, but today's wide availability of SCR systems onboard ships enables to ignore the contribution to emissions of these systems, highlighting cost, masses and volumes introduced by these devices where they are needed. This chapter describes the methods employed for this PhD analysis and the results obtained. The overall impact on weights, volumes, costs, and carbon dioxide equivalent emissions is evaluated. Emissions evaluation is also particularly focused about the upcoming CII that is still under evaluation from IMO, as described in paragraph 4.1.4. This proposed index of ship emissions is calculated for one year of operation. It was assumed a plausible year of operation, which is composed of different typical cruise routes all over the world, spanning from the Mediterranean to Northern Europe and the Caribbean. Once characteristics of the ship have been defined, the amount of power loads related to propulsion and to all other services required onboard cruise ships are described. This power is required both as electrical power and thermal power, requiring different types of generators and of energy recovery systems. Once operative profiles and power requirements are outlined, it was performed a steady state condition simulation process to evaluate emissions and calculate CII during one year of operations.

5.1. Reference case scenario

5.1.1. Ship's main characteristics and operative profile

The first phase of the analysis performed was the definition of two reference cruise ships. This type of vessel can have different sizes, which are represented by their main characteristics like gross tonnage and deadweight. Gross tonnage is a number related to the internal volume of the ship and is defined according to the IMO's International Convention on Tonnage Measurement of Ships with Equation (5.1.1), where V is the ship's total volume in cubic meters.

$$GRT = V \cdot (0.2 + 0.02 \cdot \log_{10} V) \quad (5.1.1)$$

For this study, a ship with a gross tonnage of about 180,000 GRT and another vessel with a gross tonnage of about 50,000 GRT are taken as reference vessels. Characteristics of these cruise ships are described in Table 49.

Table 49 – Main data of reference vessels used for this study

Description	Unit	Contemporary class	Luxury class
Gross Tonnage	GRT	180,000	50,000
Length	m	350	230
Beam	m	40	30
Draft	m	9	6.5
Service speed	kn	18	17
Total installed power	kW	70000	33000
Maximum number of people onboard	-	7000	1400

Normally, for cruise ships, gross tonnage identifies cruises' market segments, with different technical and commercial characteristics. A cruise ship with 180,000 GRT can embark about 7000 people and is considered a contemporary-class cruise ship. This type of vessel is dedicated to standard routes and to almost all types of passengers, for which onboard features can represent the main attraction of the holiday. Luxury class cruise ships are smaller vessels which can embark almost 1400 people and are dedicated to more exclusive routes where other bigger ships do not normally serve. This data is important because, by knowing the class of the cruise ship, it is possible to better estimate its operative profile.

Cruise ships can travel in different locations during different seasons; thus, establishing an accurate operating profile is not easy. In this study, it was assumed that both cruise ships sail in four different scenarios. These scenarios differ in air temperature, relative humidity, and water temperature and can resemble cruises in their most popular destinations, such as East and West Mediterranean Sea, the Caribbean and North Europe (EU). A typical cruise ship would travel worldwide during the year, and thus these four scenarios can be a good model of its operative conditions. The characteristics taken as reference are shown in Table 50.

Table 50 – Main characteristics of operative profiles considered

Characteristic	Unit	East Med.	West Med.	North EU	Caribbean
Air temperature	°C	19	17	6	23
Relative humidity	%	61	73	81	77
Sea temperature	°C	21	18	10	28
Cruise days	-	7	10	14	7

These scenarios also have different durations and different ship's speed, port stays, and manoeuvre times. A normalised representation of these variations is given in Figure 92. Each step of the x-axis identifies an operating mode of the ship as a percentage of the maximum design speed. These values were chosen by analysing the actual operational profiles of cruise ships: the ship sails at a particular speed during different operative profiles. The first value, for example, is "18%". Supposing that the maximum design speed of the reference vessel is 22 knots, the operating mode identified by this value is one in which the ship sails at about 4 knots, like manoeuvring operations. For each operative mode of the x-axis, a vertical bar illustrates the percentage of the total time spent by the ship in that operating mode. The pink bars refer to the operational profile of the East Mediterranean Sea, the green bars to the West Mediterranean Sea, the grey bars to North Europe cruises, and the red bars to the Caribbean Sea. The reference cruise ship and its operating profile over one year of operation will remain the same for each ship's power plant configuration to better compare carbon dioxide emissions. It can be highlighted from that for a cruise ship, a significant share of the operational time is passed inside ports: for cruises in the East Mediterranean Sea, West Mediterranean Sea, and the Caribbean, 40% to 45% of the time is passed inside the port. For a cruise in North EU, this share is reduced to almost 20% because it is assumed that for these cruises, the ports involved in the voyage are more distant from each other. If we assume that a cruise lasts 10 days, for "East Med." port stays last almost 4 days, "West Med." and "Caribbean" port time is almost 4 days and a half and for "North EU" the time spent in this operating mode is slightly more than 2 days.

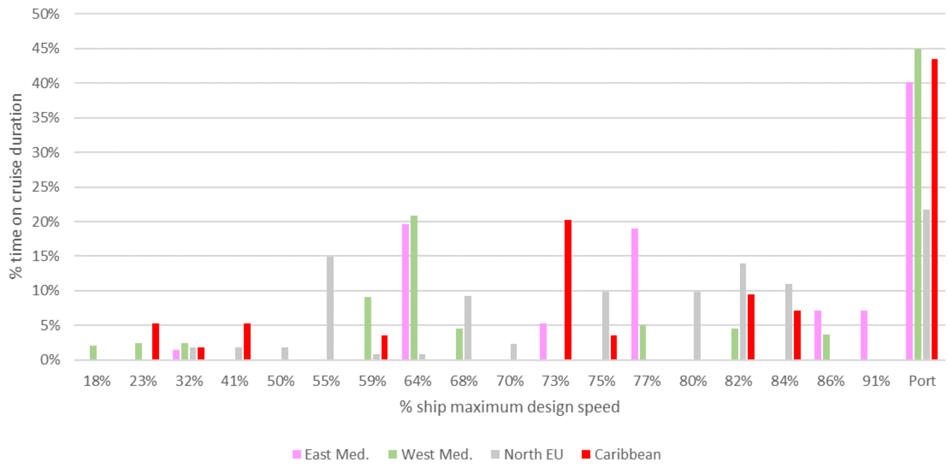

Figure 92 - Visual representation of reference vessel's operative profiles

5.1.2. Electrical power requirement estimation

Cruise ships were among the first type of vessels to implement electric propulsion on board. With this philosophy, system configuration is based on a power plant where electrical generators moved by internal combustion engines work in parallel on main switchboards, feeding two big classes of users. The first one is related to propulsion, steering and all equipment related to ship safety, like:

- Propulsion electric motors and auxiliaries.
- Engine service equipment.
- Manoeuvring thrusters and auxiliaries.
- Navigation and safety systems.

The second purpose of power generation is offering to crew and passengers everything they need, like:

- Comfort: air conditioning, accommodations with private and public services, laundries to wash linen, lighting, etc.
- Nourishment: different type of restaurants, big galleys to prepare and cook food, big refrigerated rooms to store it, etc.
- Entertainment: theatres, pools, casinos, cinemas, SPAs etc.

Electric loads related to propulsion can be estimated starting from propulsion curve. The ship's propulsion curve is obtained for most ships from in-house data coming from similar ships that have already been designed, tested in tanks, and then built, at least during the first design phases. Alternative methods are based on empirical models [264] [265] or computer-based simulation tools [266] [267]. A design power propulsion curve is taken as a reference for the reference vessel. The propulsion curve is based on the resistance of the hull at different speeds and the interaction between the propulsion system and the hull. In most cases, the propulsion curve is like a cubic function where the dependent variable is the power required for propulsion, and the independent variable is the ship's speed. Normalised reference ship's propulsion curve is shown in Figure 93. Both axes have been normalised to their maximum values, which are maximum ship's speed and maximum propulsion power, which is near to the total power of the propulsion motor.

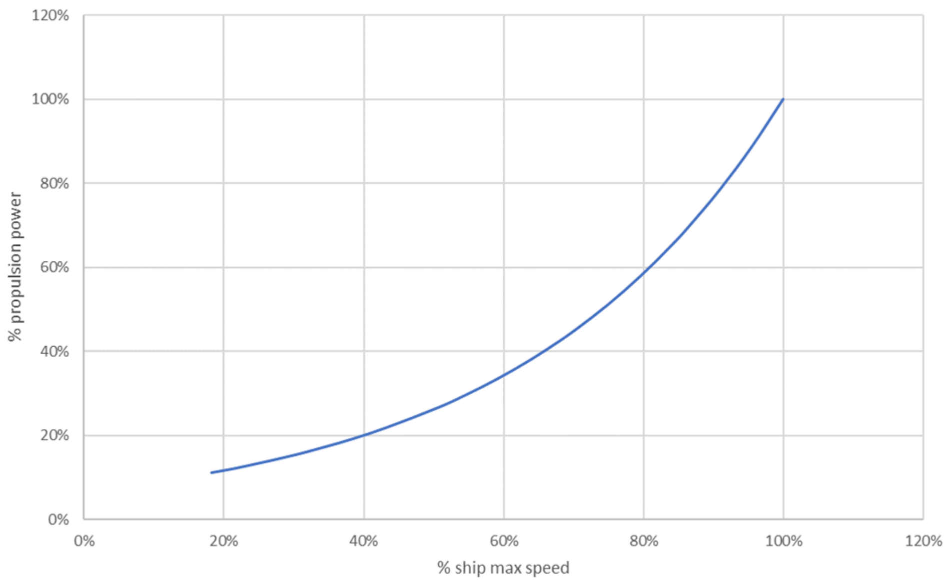

Figure 93 - Example of ship's propulsion curve

The main power requirement of merchant ships comes from propulsion, but this characteristic is not true for all types of vessels. Some types of ships require an amount of power for their payload comparable to that required for their propulsion. Cruise ships are one of these types of vessels. Cruise ships can be considered as small floating cities where all kinds of possible services and entertainment are available. These services are related to lighting, accommodation, pools, and common areas, but also private cabins, galleys, ventilation of spaces, and air conditioning. In addition, there are other loads not related directly to propulsion. Hull and deck services, such as mooring equipment, safety services, and all the auxiliaries related to propulsion services, for example, heat exchangers and ventilation for machinery spaces. It was estimated the maximum power required by all these services to be equal to:

- 15 MW for a cruise ship of about 180,000 GRT
- 6 MW for a cruise ship of about 50,000 GRT.

By adding up the required propulsion power and all loads not related to this service, the power demand for each operational scenario as a percentage of the total installed power onboard the reference vessel is shown in Figure 94. Each step of the x-axis identifies a ship operating mode as a percentage of the maximum design speed, as already explained for Figure 92. For each operating mode of the x-axis, a vertical bar illustrates the power demand in that condition as a percentage of total installed power onboard the reference vessel. The pink bars refer to the operational profile of the east Mediterranean Sea, the green bars to the west Mediterranean Sea, the grey bars to Northern Europe cruises, and the red bars to the Caribbean Sea. Since for the contemporary class cruise ship total installed power onboard the reference vessel is equal to almost 60 MW, the required power when the reference vessel sails at 77% of its design speed is almost equal to 30 MW for "East Med." and "West Med." operating profiles. The other two operating profiles are not represented by this speed (see Figure 92), and thus there is no corresponding vertical bar.

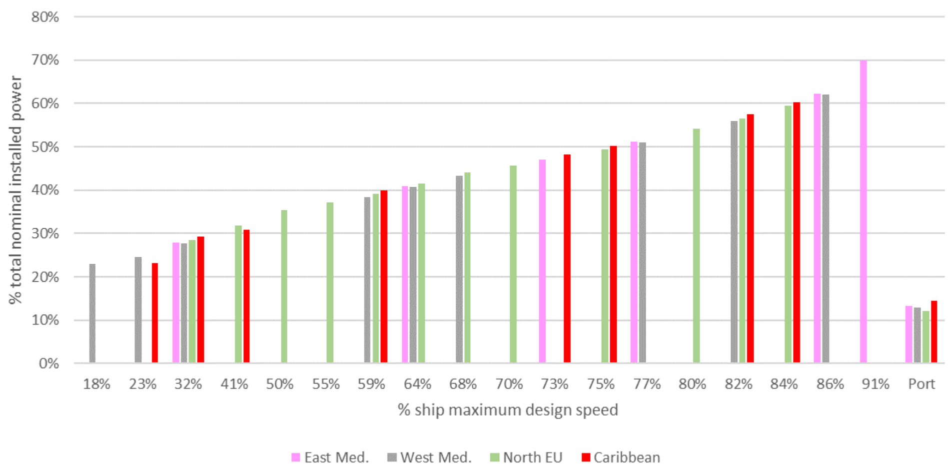

Figure 94 - Required power for each operative scenario as percentage of total nominal installed power.

As shown in Figure 94, the total power required in port is approximately 12% of the total rated power installed onboard the ship. These loads are those not related to propulsion and can be considered almost constant in each operating condition. Furthermore, the power required in the four different scenarios is similar for each operating condition: there is no great difference between the green, grey, and red bars for the "82%" operating mode. Differences are related to different environmental conditions as indicated in Table 50, which considers the different loads required, for example, for air conditioning and other services. The values chosen on the x-axis were obtained from an analysis of actual cruise ships operational data collected during this PhD activity, which are also available in literature [268].

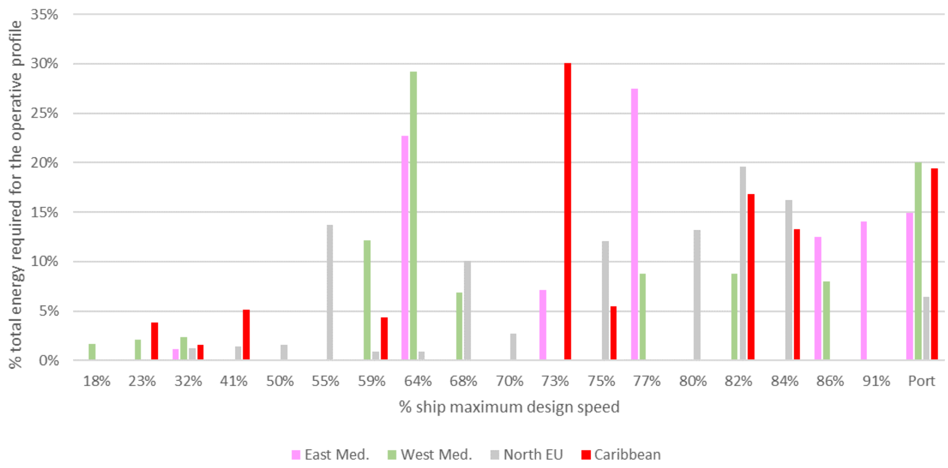

Figure 95 - Required energy for each operative scenario as percentage of the total energy required for the operative profile considered.

When steady state conditions are considered, i.e., the required power shown in Figure 94 is constantly required for the time indicated in Figure 92, the energy required for each operating condition can be calculated as the product of these two figures. The result is shown in Figure 95. Each step of the x-axis identifies an operating mode of the ship as a percentage of the maximum design speed, as already shown in Figure 92 and Figure 94. For each operating mode of the x-axis, a vertical bar illustrates the energy required in that condition as a percentage of total energy required during the entire operating profile for the reference vessel. The pink bars refer to the operational profile of the east Mediterranean Sea, the green bars to the west Mediterranean Sea, the grey bars to Northern Europe cruises and the red bars to the Caribbean Sea. If total energy demand for the "East Med." operative profile is 4000 MWh, almost 23% of this energy is required by the ship when the reference vessel is sailing at 64% of its design speed, while almost 28% of the total energy demand is requested when the ship sails at 77% of its design speed. As highlighted, for the east Mediterranean Sea operational profile, energy is required above all during navigation at medium speeds (64% and 77% of maximum design speed), while the energy required during port stays represents almost 15% of the total energy required during this type of cruise. A similar condition is presented for the west Mediterranean Sea operational profile, although the energy is required when the ship sails at a lower speed, and the energy required for port stays represents a more significant share than that of “East Med.”, reaching almost 20%. The Northern Europe operational profile is very balanced for the power demand, and does not have large peaks, but as reported in Figure 2, it is the one in which the ship sails the most, and therefore the energy required in port by the ship represents only 7% of the total energy required. For the Caribbean operational profile, the situation is like the one of the Mediterranean Sea operational profiles.

5.1.3. Thermal power requirement estimation

Since cruise ships can be considered as floating cities, they require not only electrical power but also thermal power. This power is used for various services onboard cruise ships, mainly for galleys and laundries, which operate almost twenty-four hours every day. Other services that require heat are tanks heating system, fuel purifiers (only for oil-based fuels), freshwater heaters, swimming pool water heaters, and heating and ventilation air conditioning system. Heat is generated onboard via heat recovery systems associated with prime generators and via steam generators fuelled by the same fuel used for power generation on the vessel. Certain users require heat at high temperatures, so high-pressure steam is required. Steam needed onboard reference cruise ships is shown in Figure 96. Similarly, in other figures, each step of the x-axis identifies an operating mode of the ship as a percentage of the design maximum speed. For each operating mode of the x-axis, a vertical bar illustrates the thermal power required in that operating condition as a percentage of the total thermal power generation capacity of the steam boilers installed on the reference vessel. The pink bars refer to the operational profile of the east Mediterranean Sea; the green bars to the west Mediterranean Sea; the grey bars to Northern Europe cruises; the red bars to the Caribbean Sea. If the total thermal power generation capacity of the steam boilers installed on the reference vessel is 10 MW, during “West Med.” operating mode almost 8.5 MW of thermal power is required by ship users when the reference vessel sails at 59%, 64%, 68%, 77%, and 86% of the design speed. The need for steam is particularly high in the Northern Europe operational profile since sea and air temperatures are lower, so there is a greater demand for heating by the various users. Other users only need hot water, and the power required at this lower temperature is shown in Figure 97 in the same way explained in Figure 96. The picture highlights how heat required at low temperature is lower than that required at high temperature, and the demand is also more stable in different operating conditions. In following simulations, thermal power requirement is covered first by the heat generated by the recovery systems and then, if this figure is not enough, by the steam generated by dedicated generators installed onboard. Figure 97 indicates a heat requirement higher than

100%. This relative value is given by the ratio between the thermal power required and the thermal power generation capacity of oil-fired steam boilers installed onboard. In some conditions, heat demand is higher than the thermal power generation capacity of the steam boilers: In these cases, the value is higher than 100%. When the ship is in this condition, however, the total heat demand is satisfied because thermal power is generated partially by heat recovery systems and partially by steam generators installed onboard.

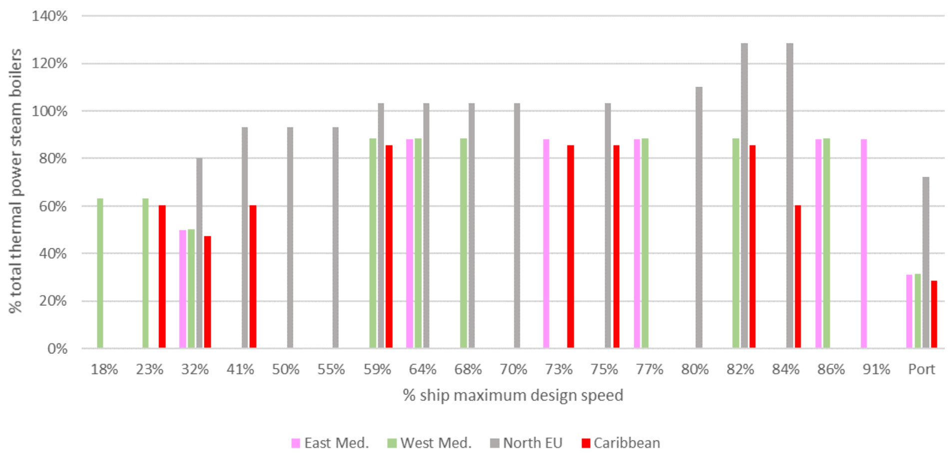

Figure 96 - Required thermal power for each operative scenario as percentage of the total thermal power generation capacity of steam boilers.

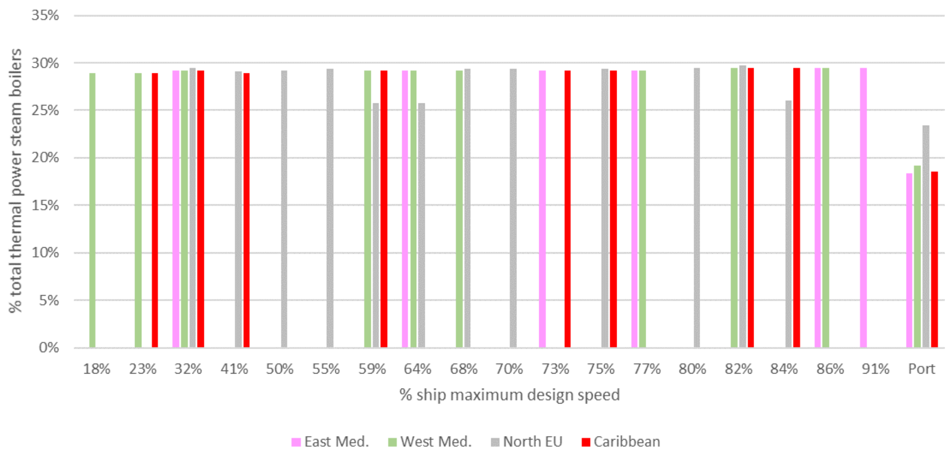

Figure 97 - Required thermal power for each operative scenario as percentage of the total thermal power generation capacity of steam boilers.

5.1.4. System Simulation

After modelling the ship's operational profiles in terms of electrical and thermal energy needs and different generating systems, the ship's power generation is modelled during one year of operation. For each condition in each operational scenario, the electrical and thermal energy required by the ship is known. Knowing the composition of the power generation plant in each configuration considered in this study, it was assumed for each condition which generators are in operation and connected to the grid, establishing the percentage of MCR for each system using formula (5.1.2), where i is the index of the generation systems available onboard.

$$\%_{MCR} = \frac{Electric\ power\ required}{\sum_i MCR_i} \tag{5.1.2}$$

Table 51 – Example of simulation system for a contemporary class cruise ship.

	Operative Profile			Generating System		
	Electric Power	**Thermal Power**	**MCR**	**Fuel Consumption**	**EGB Heat Recovery**	**HW Heat Recovery**
	kW	**kW**	**%**	**kg/h**	**kW**	**kW**
Scenario East Mediterranean	18,764	9,764	80%	3,807	6,420	5,707
	27,522	14,424	73%	5,766	9,404	9,190
	31,552	14,590	84%	6,245	10,742	8,998
	34,416	14,716	82%	6,919	11,755	10,221
	41,828	15,013	81%	8,433	14,294	12,512
	46,963	15,401	91%	9,315	16,561	12,501
	8,873	8,161	63%	1,881	2,906	3,273

Knowing the load required by each generating system and its electrical efficiency variation with the percentage of MCR, it is possible to calculate the fuel consumption. Furthermore, from the load requirement for each generating system, it is possible to evaluate the efficiency gained from the heat recovery systems. The situation for each configuration and each operational scenario is comparable to the example shown in Table 51. Since the thermal power requirement and all possible heat recovery sources are known, it is possible to calculate the resulting heat balance, which can be positive if the sum of EGB and Hot Water (HW) heat recovered is bigger than the thermal power required. If this figure is negative, the ship needs heat. Boiler consumption as a function of the required power is known (see paragraph 2.5) and therefore, knowing the required heat, the calculation of the fuel consumption becomes straightforward. The fuel consumption obtained by this calculation is instantaneous. To assess the total consumption of the ship, instantaneous fuel consumption must be multiplied by the time spent in each condition of each operative profile. Total fuel consumed for one trip of one operative profile can then be calculated by adding the values resulting from each condition that composes the operational profile in question. Emissions are directly related to fuel consumption through conversion factors related to the carbon content of fuels: by multiplying these two figures, carbon dioxide emissions are obtained.

5.2. Definition of most promising innovative technologies for onboard power generation

In this thesis, simulation tool is used to assess performances of a cruise ships where it is possible to choose just one fuel, one power generation layout and one exhaust gas treatment system. In other works, it is not possible to study a ship where two types of fuels are stored onboard. Seventy-eight different system configurations have been considered: thirty-two powered by fuel cells, twenty-eight powered by internal combustion engines, and eighteen powered by gas turbines.

Calculation starts knowing electric and thermal energy requirement for each operative scenario and for one year of operations. Annual and single scenario fuel requirement are calculated knowing electrical energy required and the specific consumption of each power generator. Thermal energy needed from steam boilers is obtained by subtracting thermal energy required by the ship and thermal energy recovered by power generators. Knowing this figure, fuel used for steam generation can be calculated in the same way described before, and overall fuel requirement is calculated by adding it to the fuel required for electric energy. Storage volume and weight is then calculated by knowing the overall fuel required for the worst-case operative scenario. Total power installed onboard is another given data (see Table 49) from which volume and weight of engine were calculated, reforming or fuel treatment and exhaust gas treatment system.

The difference between available volume and weight for payload is then calculated by subtracting the total space or weight required by the system and the space or weight used by the reference case scenario. The worst case between these two figures in terms of lost value is taken as value of lost payload. Total cost of fuel, storage system, fuel treatment system (reformer), power generation system and exhaust gas treatment system are then calculated knowing the quantity of fuel needed for one year of operation, fuel consumption for a single cruise and total power generation capacity installed onboard the ship. Knowing all these data, cost difference between each technological solution and the reference case was calculated, both considering and excluding value of lost payload to highlight its importance for this research.

Similarly, emissions coming from fuel production (WTT carbon dioxide equivalent emission), fuel processing or reforming, electrical power generation and thermal power generation are calculated for each considered cruise ship system. With these calculations it can be shown the real carbon dioxide equivalent emissions for both fuel production (WTT) and fuel utilisation onboard (TTW) not only for electrical power generation, but also for thermal power generation.

In this study, other significant values have been calculated. Break-even electricity cost was calculated knowing the cost of the whole fuel needed and the cost difference for each year of operation. The difference between these two values divided for the whole electrical energy needed gives as result break-even electricity cost. Similarly, break-even natural gas price was calculated for those fuels which require natural gas for their production process. Carbon dioxide equivalent reduction cost was also calculated, both considering only TTW and WTW emissions. To evaluate these data, total cost both considering and avoiding lost payload contribution is divided for carbon dioxide equivalent emission difference between considered solution and reference case scenario.

Finally, CII was calculated following the procedure shown in paragraph 4.1.4 and considering three carbon dioxide emission cases:

- Carbon dioxide emissions from fuel processing, reforming, and electrical power generation.
- TTW carbon dioxide equivalent emissions.
- WTW carbon dioxide equivalent emissions.

5.3. System overall costs and carbon dioxide equivalent emissions

First results shown in this research are overall costs for all alternatives.

Figure 98 shows results about system overall cost, without considering lost payload, and carbon dioxide equivalent emissions, both TTW and WTT, for fuel cells. Each generation system costs more than eighty million euros per year, except PEM fuel cells fuelled by fossil natural gas via steam reforming onboard, SOFC fuelled by fossil natural gas and SOFC fuelled by fossil methanol. Overall cost of these alternatives is highly dependent on natural gas price and thus since this variable is crucial for these analyses, it should be stated again that reference cost considered in these calculations is equal to 40 €/MWh. It is important to also highlight the fact that PEM fuel cells fuelled by fossil natural gas have the second-highest carbon dioxide equivalent emission from both a TTW and a WTW perspective. The combination with the highest emissions is PEM fuel cells, fuelled by fossil methanol. When these same fuels are used for SOFC, the system costs less because there is no need for a reforming equipment and space requirement is reduced because the fuel can directly be used for power generation. This efficiency increase brings to lower TTW and WTW emissions. For all these reasons, PEM fuel cells should only be employed when hydrogen, particularly green or blue one, is available onboard because emissions can be highly reduced, even if the overall cost, without considering lost payload, is slightly higher than the cost of SOFC fuelled by hydrogen. When considering fossil or synthetic hydrocarbons, like natural gas and methanol, SOFC become very competitive both from a cost point of view and a carbon dioxide equivalent emission point of view. SOFC fuelled by renewable methanol or from ammonia produced by blue hydrogen have an overall cost lower than both types of PEM fuel cells fuelled by hydrogen.

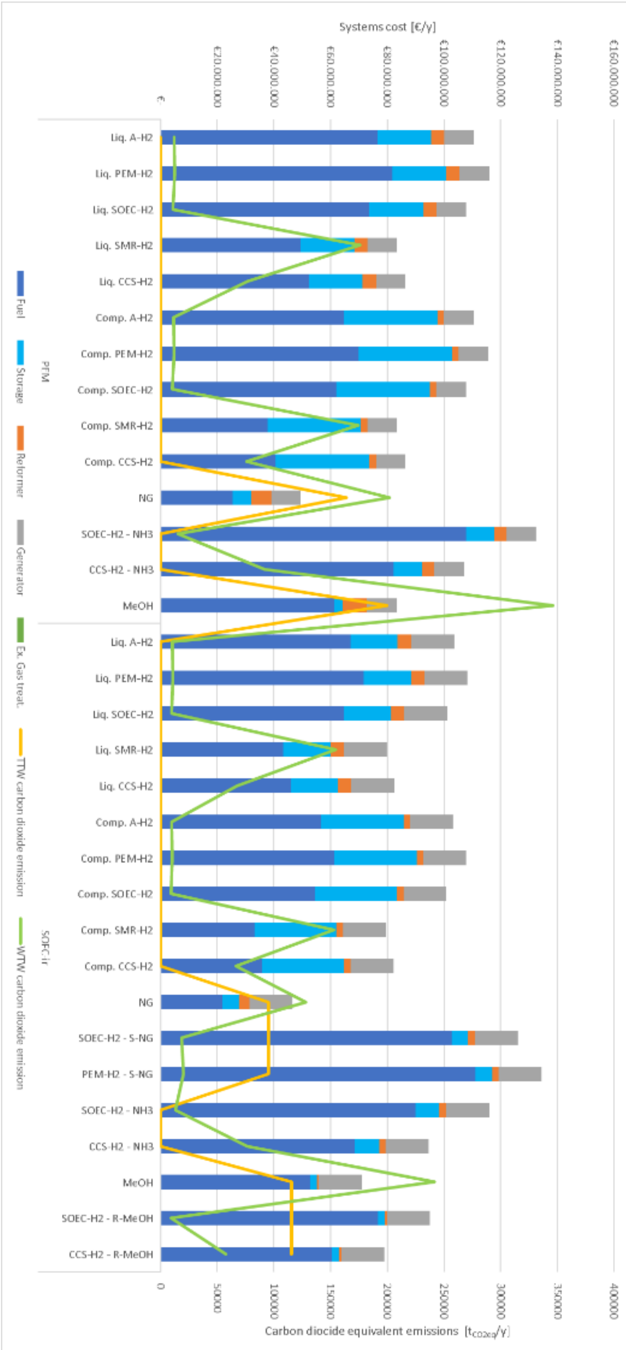

Figure 98 – System overall cost and carbon dioxide equivalent emissions for fuel cells

Figure 99 shows the same analysis of Figure 98, but the value of lost payload is accounted when the alternative design is compared with reference case scenario. All alternatives fuelled by hydrogen lose more than 20 million euros per year of lost payload, both when this fuel is liquefied or compressed at 700 bar. Obviously, these high values are influenced by the fact that hydrogen in these cases is the only fuel available onboard and that it was assumed that onboard storage should grant two weeks without refuelling. Assuming that the space for a hydrogen storage system is the same of HFO, the considered contemporary class cruise ship would be capable to operate only almost one day and a half when hydrogen is liquefied and a little bit more than one day when hydrogen is compressed. A potential ship equipped only with fuel cells and hydrogen as fuel would surely have less autonomy than a traditional cruise vessel, possibly between five and seven days, because with this solution it would be possible to sacrifice less payload onboard while also lowering CAPEX and OPEX for fuel storage and treatment system. Natural gas and methanol gain more economic benefits when lost payload is accounted because for the same amount of energy stored, they require less space and weight onboard when they are compared with hydrogen. Power generation systems fuelled by ammonia are more expensive than ships fuelled by hydrogen, but the difference is lower because its storage system is less bulky and heavy than hydrogen's one. SOFC coupled with fossil natural gas have the lower total cost between fuel cell options, and their TTW emissions are the lowest of all alternatives fuelled by hydrocarbons. When considering WTW emissions, this alternative has a lower carbon dioxide equivalent emission than cruise ships fuelled by brown hydrogen or fossil methanol, but higher than a vessel fuelled by blue hydrogen.

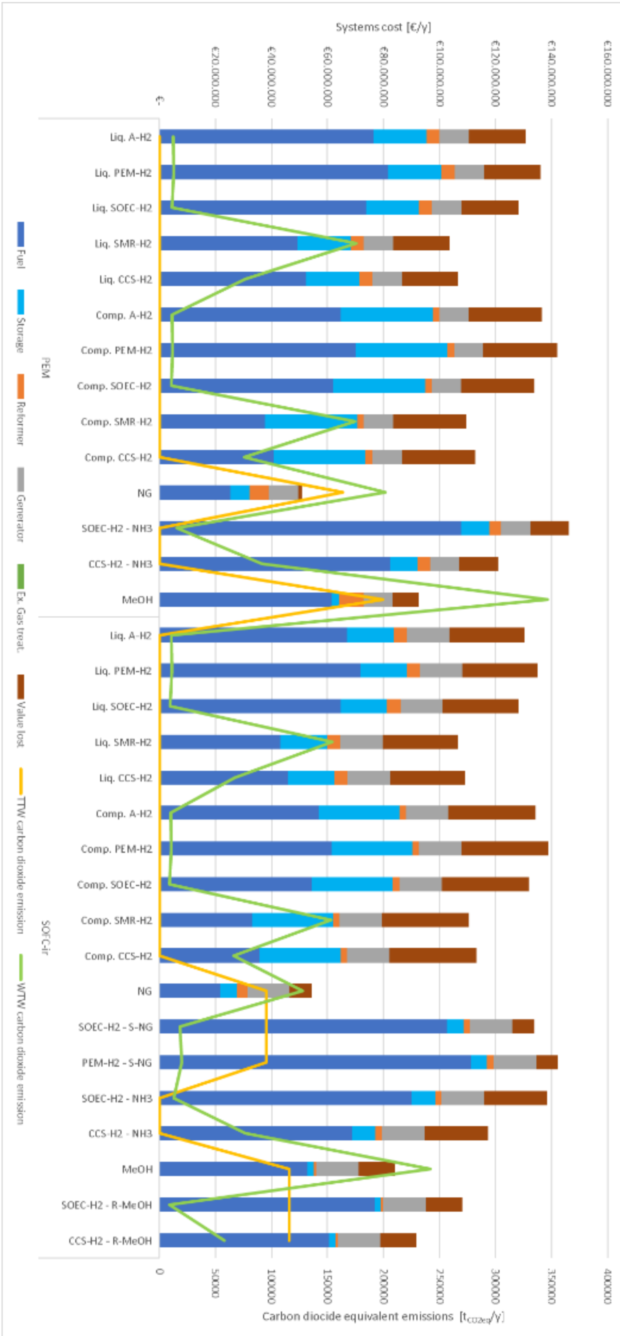

Figure 99 – System overall cost (with lost payload) and carbon dioxide equivalent emissions for fuel cells

Figure 100 shows results about system overall cost without considering lost payload, and TTW and WTT carbon dioxide equivalent emissions for internal combustion engines. Engines fuelled by hydrogen have a lower overall cost than fuel cell systems, because they require lower fuel for thermal generation (particularly when compared with PEM fuel cell systems) and lower CAPEX for the power generator itself. Emissions are the same of a PEM fuel cell system, and they are equal to almost zero when considering only TTW contribution. WTW emissions given by internal combustion engines fuelled by hydrogen are comparable to PEM fuel cell ones. Dual fuel engines fuelled by natural gas as main fuel have the lowest total cost among alternative configurations considered, even slightly lower than reference case scenario. This difference is mainly related to the lower capital cost for exhaust gas treatment system and a fuel cost lower than traditional oil-based fuels, which with most recent fluctuation in the international market should be carefully considered. It is worth to highlight that TTW and WTW emissions are among the highest, even higher than the reference case. As previously stated, even if carbon dioxide emission reduction is proven, there is still methane slip which greatly influences ship's carbon dioxide equivalent emissions. Internal combustion engines fuelled by synthetic methane have almost three times the overall cost of the same configuration fuelled by fossil natural gas. While TTW emissions are the same of the fossil alternative, WTW emissions are lower because carbon dioxide used in the fuel production process is captured from air. Internal combustion engines fuelled by ammonia have an overall cost higher than alternatives fuelled by hydrogen and comparable to the ones fuelled by synthetic natural gas, except for ammonia produced from blue hydrogen. Emission of these alternatives are low, and they are related only to fuel production process. Internal combustion engines fuelled by fossil methanol produced from natural gas have a total cost of around sixty million euros per year, almost entirely related to fuel cost. This configuration brings to a small decrease in WTT emissions when compared to reference case: total carbon dioxide equivalent emissions in a year is equal to almost 134000 t_{CO2eq}/y, which represents a 9% reduction. This design brings alto to an increase in WTW emissions, equal to almost 260000 t_{CO2eq}/y, which represents a 59% increase when compared to a traditional power generation system. Renewable methanol increases the overall cost, but it is lower than the overall cost of internal combustion engines fuelled by hydrogen, while WTT emissions in this case are extremely lower than the reference case. LPG and bio-LPG can be considered a feasible option for their low overall cost, but WTW emissions are higher than reference case and TTW emissions can be considered comparable to that system configuration. Renewable diesel has a total cost lower than biodiesel and comparable to bio-LPG, but both WTT and WTW emissions are lower than reference case scenario. FTD produced by green hydrogen surely contributes to a high WTW emission reduction, but TTW emissions are almost comparable to renewable diesel. Its cost is the highest among internal combustion engine options and is equal to almost 150 million euros per year, almost 4.5 times higher than reference case scenario. Reference case cost is equal to almost 34 million euros per year, its TTW emissions are equal to almost 147000 t_{CO2eq}/y and WTW emissions are equal to almost 165000 t_{CO2eq}/y. Internal combustion engines fuelled by MGO have an overall cost higher than reference case, equal to almost 48 million euros (+42%). This configuration's TTW emissions are slightly lower than reference cost, and they are equal to almost 141000 t_{CO2eq}/y, while WTW emissions are higher than reference case, and they are equal to almost 197000 t_{CO2eq}/y. When a CCS system capable to capture almost 50% of carbon dioxide produced by internal combustion engines is installed, system overall cost is higher, mainly because of higher fuel consumption for thermal generation. The real TTW emissions difference is almost 42%, because an additional heat requirement brings to a higher fuel consumption, while WTW carbon dioxide equivalent emissions decrease of almost 25%. Finally, a LSFO fuelled vessel has a higher cost than the reference case scenario, while emissions are slightly lower.

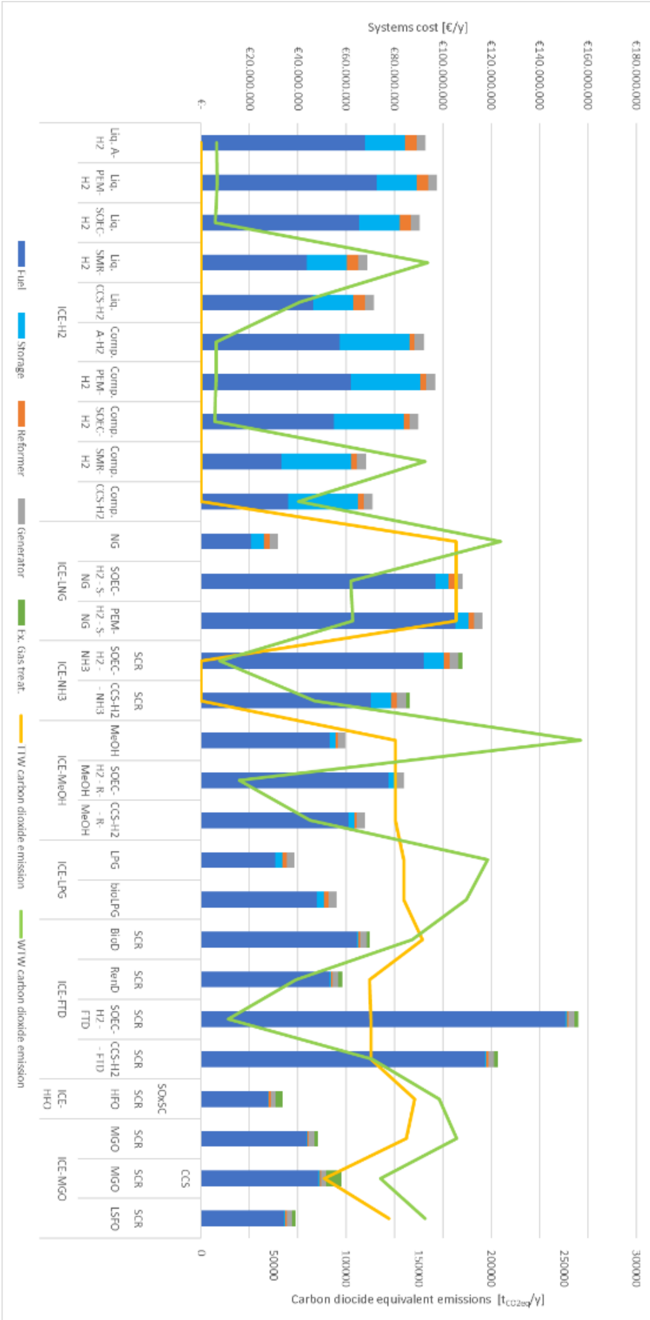

Figure 100 – System overall cost and carbon dioxide equivalent emissions for internal combustion engines

Figure 101 shows the same analysis of Figure 100, but it accounts the value of lost payload when comparing each alternative design with reference case scenario. Hydrogen storage, both in its liquefied or compressed form, brings to a total cost increase, almost equal to 26 million euros and 20 million euros respectively. Ammonia-fuelled vessels and MGO fuelled cruise ship which embodies a CCS system are penalised when accounting lost payload value. Green ammonia fuelled vessels have a total cost higher than the option fuelled by synthetic methane, while MGO fuelled cruise ship which embodies a CCS system has a cost comparable with renewable methanol. All systems which use natural gas and liquid fuels like methanol or liquid hydrocarbons do not suffer lost payload capacity. Renewable diesel, biodiesel, FTD, MGO and LSFO bring to small increases in overall payload capacity due to higher energy density of these fuels and of their auxiliaries when compared to reference case. Most alternative systems powered by fuel cells have a system overall cost higher than 100 million euros per year, while ICE-based systems have an overall cost lower than that figure for more fuel options (see Figure 101 and Figure 99).

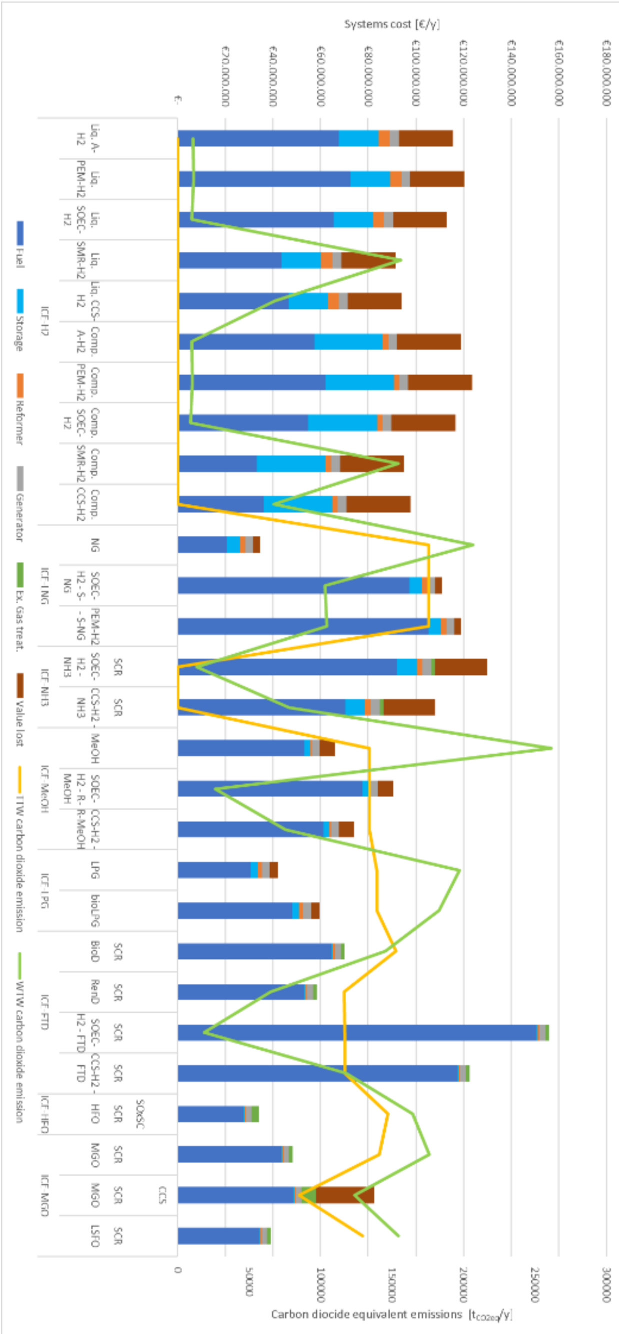

Figure 101 – System overall cost (with lost payload) and carbon dioxide equivalent emissions for internal combustion engines

Figure 102 shows results about system overall cost, without considering lost payload, and TTW and WTT carbon dioxide equivalent emissions for gas turbines. Gas turbines fuelled by hydrogen have a high cost, mainly related to fuel supply and storage systems, since gas turbines electrical efficiency is lower than internal combustion engines or fuel cell ones. Systems fuelled by green hydrogen have higher costs than the ones based on blue or brown hydrogen, but their WTW emissions are significantly higher than green hydrogen and for brown hydrogen emissions are comparable to reference case scenario. Gas turbines fuelled by natural gas have the lowest cost among these options, but this cost is higher than the cost of fuel cells or internal combustion engine systems fuelled by natural gas. Synthetic natural gas brings the highest cost among alternatives considered. Ammonia from green and blue hydrogen have a lower overall cost than synthetic natural gas. When ammonia is produced from blue hydrogen, its WTW emissions are higher than the ones of synthetic methane. Gas turbines fuelled by fossil methanol have the second-lowest cost among options considered, but TTW emissions related to the process are the highest among gas turbines systems. WTW carbon dioxide equivalent emissions are the highest for gas turbines fuelled by fossil methanol. When this liquid is produced by hydrogen, WTW emissions are lower and comparable to the ones of green and blue hydrogen, and so it is their overall cost. In this case, fuel cost is higher (since it is produced from that gas), but storage cost is significantly lower because storage systems for methanol are almost the same used for traditional oil-based fuels.

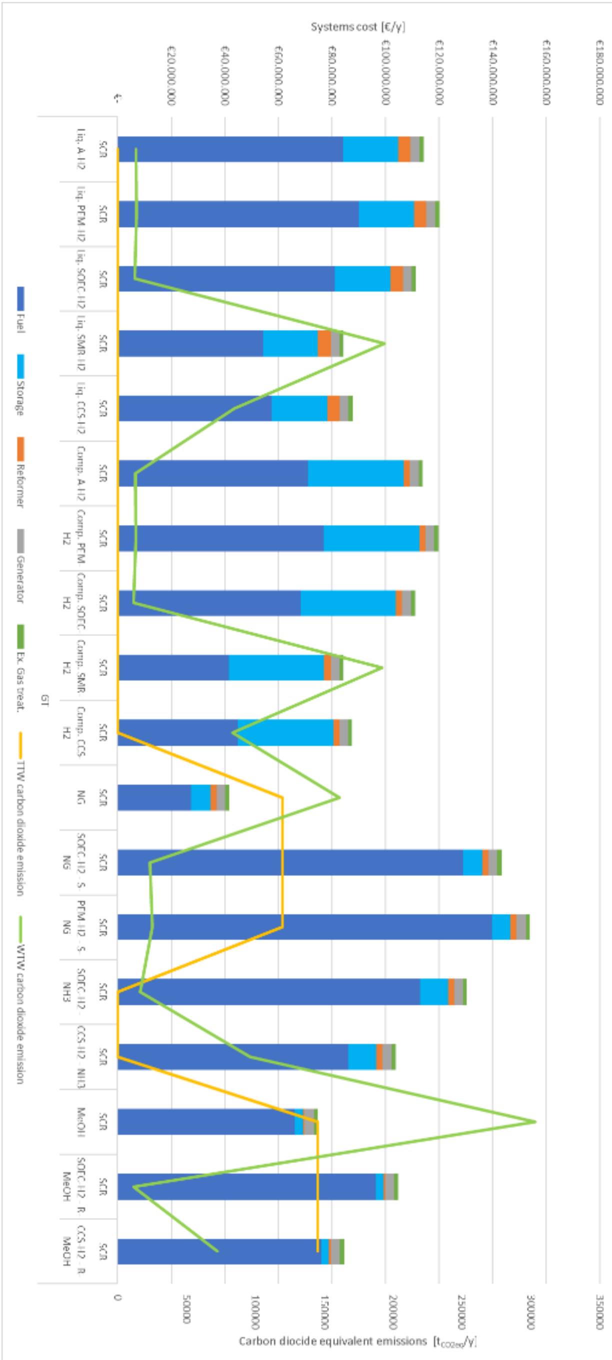

Figure 102 – System overall cost and carbon dioxide equivalent emissions for gas turbines

Figure 103 shows the same analysis of Figure 102, when accounting value of lost payload, and compares alternative designs with reference case scenario. Lost payload for hydrogen storage system represents almost a 15% increase on the previously stated cost, bringing the cost of gas turbines fuelled by green hydrogen like the one of gas turbines fuelled by synthetic natural gas. Ammonia fuelled gas turbines bring to a significant lost payload value. This value is lower than brown hydrogen fuelled alternatives and like the ones fuelled green and blue hydrogen. Methanol-fuelled gas turbines' overall cost is increased by lost payload, but it is confirmed that this fuel is the second-cheapest alternative for this power generator. Cost of renewable methanol fuelled gas turbines is comparable to the one of ammonia produced by fossil hydrogen (brown or blue).

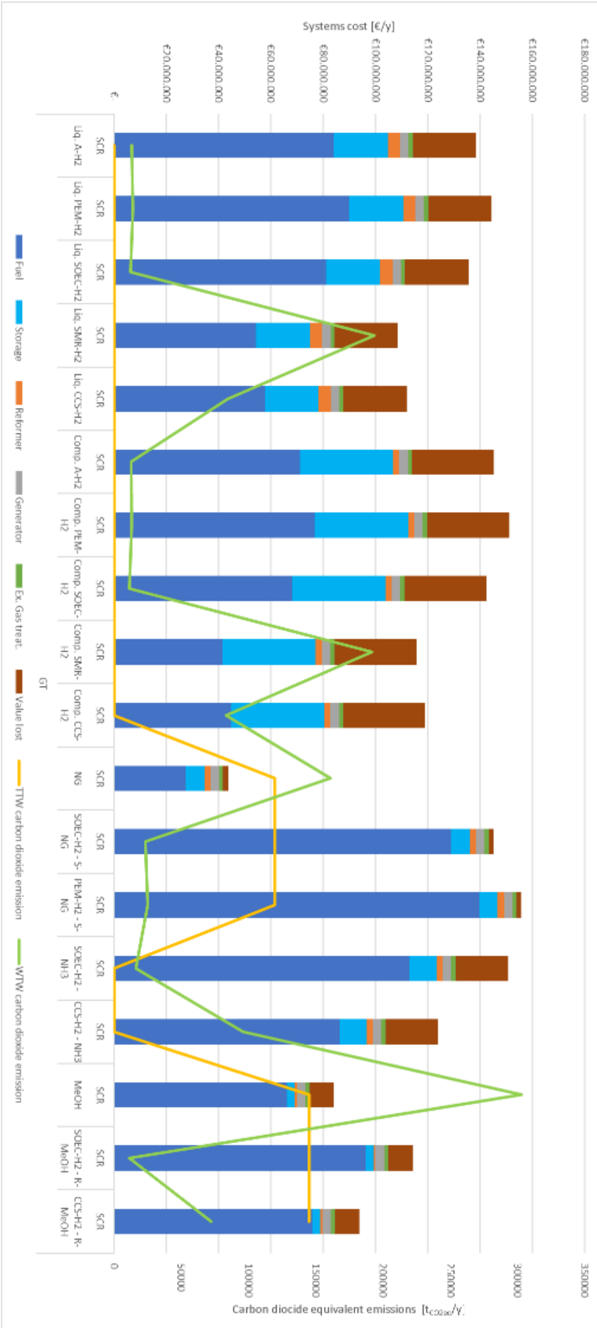

Figure 103 – System overall cost (with lost payload) and carbon dioxide equivalent emissions for gas turbines

Figure 104 shows TTW and WTW carbon dioxide equivalent reduction cost and cost difference between each power generation system and the reference case, both considering and ignoring lost payload, for fuel cells. PEM fuel cells fuelled by green hydrogen have a relatively low carbon dioxide equivalent reduction cost, both accounting TTW and WTW emissions. Reduction cost is between 480 €/ton$_{CO2eq}$ and 600 €/ton$_{CO2eq}$ without considering lost payload and between 610 €/ton$_{CO2eq}$ and 690 €/ton$_{CO2eq}$ when accounting this lost value. Price is lower when SOEC-produced hydrogen is accounted, requiring a cost premium of almost 73 million euros per year without accounting value lost and of almost 94 million euros per year considering lost payload capacity (100 million euros per year for compressed hydrogen). PEM fuel cells fuelled by brown hydrogen have a lower TTW GHG reduction cost than green hydrogen and a negative WTW GHG reduction cost because WTW emissions are higher than reference case. For this reason, this option can't be considered a feasible alternative to cut emissions coming from marine sector, particularly cruise shipping. Blue hydrogen surely makes more sense because from a TTW and WTW emission reduction cost is comparable to green hydrogen. Also, blue hydrogen's cost premium is lower than green hydrogen, and it is equal to almost 73 million euros per year (52 million euros per year without considering value lost). PEM fuel cells fuelled with fossil natural gas and fossil methanol via reformers can't be considered feasible options for future applications because they bring to an increase of both a TTW and WTW GHG emissions. Ammonia, produced from green or blue hydrogen, surely makes sense from an emission point of view, but particularly when it is renewable, its economics does not make much sense, requiring a higher cost premium than green hydrogen itself. SOFC fuelled by green hydrogen can be considered slightly better than PEM fuel cells from an economic point of view, because TTW GHG emission reduction cost is between 450 €/ton$_{CO2eq}$ and 500 €/ton$_{CO2eq}$ (between 640 €/ton$_{CO2eq}$ and 690 €/ton$_{CO2eq}$ considering lost payload) and WTW carbon dioxide equivalent emission reduction cost is between 430 €/ton$_{CO2eq}$ and 480 €/ton$_{CO2eq}$ (between 610 €/ton$_{CO2eq}$ and 660 €/ton$_{CO2eq}$ considering lost payload). Cost premium is between 94 million euros and 100 million euros per year, and it is almost the same of PEM fuel cells fuelled by green hydrogen. Those alternatives have a similar cost premium because total fuel consumption is lower for SOFC thanks to heat recovery by exhaust gases, but these generators penalise payload because they are bulkier and heavier than PEM fuel cells. Brown hydrogen has a lower cost premium than green and blue hydrogen, but WTW GHG reduction cost is very high because WTW emission reduction is lower than other alternatives (at least more than 4000 €/ton$_{CO2eq}$). SOFC fuelled by fossil natural gas have low TTW and WTW carbon dioxide equivalent reduction cost equal respectively to 243 €/ton$_{CO2eq}$ and 348 €/ton$_{CO2eq}$ (390 €/ton$_{CO2eq}$ and 560 €/ton$_{CO2eq}$ considering lost payload). Cost premium is the lowest among fuel cells options and is equal to almost 13 million euros per year without considering lost payload and almost

21 million euros accounting this figure. Synthetic natural gas has a high TTW carbon dioxide equivalent reduction cost, between 1500 €/ton$_{CO2eq}$ and 1700 €/ton$_{CO2eq}$ (1700 €/ton$_{CO2eq}$ and 1850 €/ton$_{CO2eq}$ considering lost payload) and WTW reduction costs comparable to the ones previously given, between 550 €/ton$_{CO2eq}$ and 610 €/ton$_{CO2eq}$ (600 €/ton$_{CO2eq}$ and 660 €/ton$_{CO2eq}$ considering lost payload). Cost premium for this synthetic hydrocarbon is among highest for these generators and even not accounting lost payload it is always higher than 80 million euros. Ammonia produced from green and blue hydrogen has a TTW GHG emission reduction cost between 330 €/ton$_{CO2eq}$ and 480 €/ton$_{CO2eq}$ (between 490 €/ton$_{CO2eq}$ and 630 €/ton$_{CO2eq}$ considering lost payload) and a WTW carbon dioxide equivalent emission reduction cost is between 460 €/ton$_{CO2eq}$ and 560 €/ton$_{CO2eq}$ (between 610 €/ton$_{CO2eq}$ and 810 €/ton$_{CO2eq}$ considering lost payload). Cost premium is between 50 and 70 million euros per year (72 and 93 million euros per year, considering lost payload). Fossil methanol fuelled SOFC have a high TTW GHG reduction cost, while WTW emission reduction cost is negative because WTW emissions are higher than reference case scenario. Methanol produced from green or blue hydrogen has a very high TTW GHG reduction cost, but WTW carbon dioxide equivalent emission reduction cost is almost 340 €/ton$_{CO2eq}$ without considering lost payload and between 420 €/ton$_{CO2eq}$ and 460 €/ton$_{CO2eq}$ considering this further cost. Cost premium for this combination of generator and fuel is between 36 and 52 million euros per year (49 and 65 million euros per year considering lost payload).

It is also evident that almost every alternative power generation system brings to a cost premium which is higher than reference cruise ship's annual revenue. Only alternatives which use fossil fuels bring to cost premiums lower than that figure.

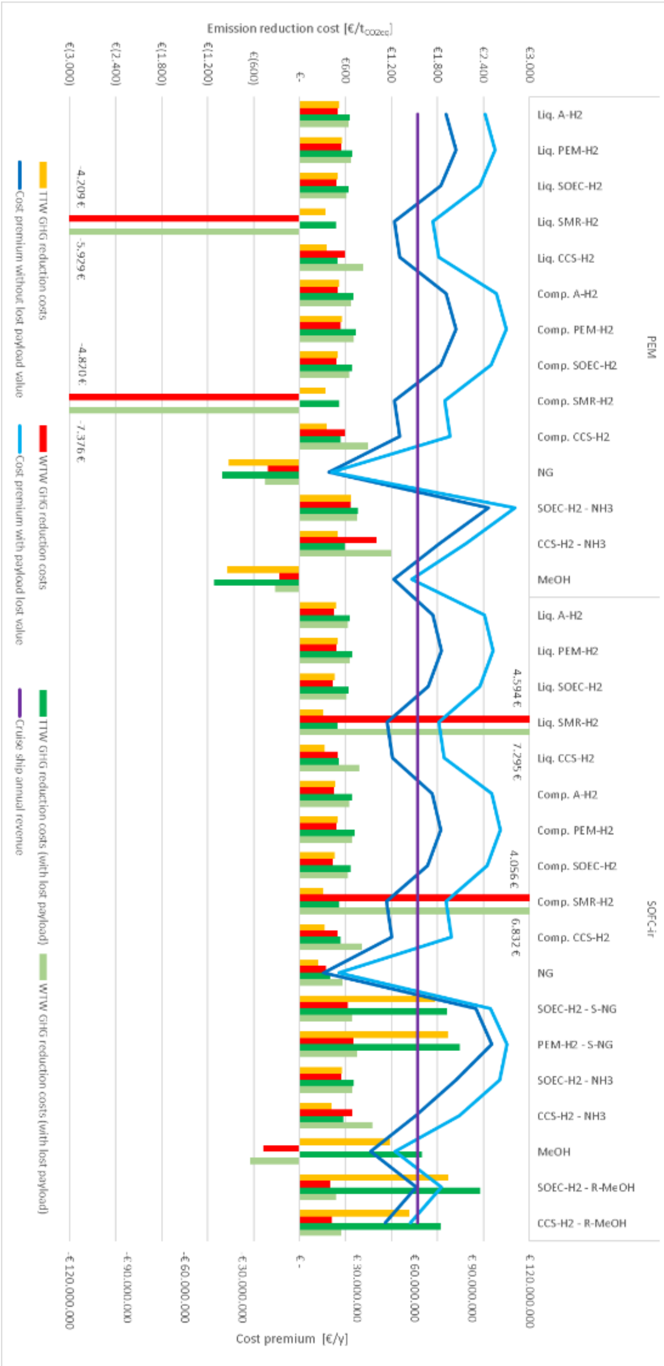

Figure 104 – TTW and WTW GHG reduction cost and differential cost for fuel cells

Figure 105 shows TTW and WTW carbon dioxide equivalent reduction cost and cost difference between each power generation system and the reference case, both considering and ignoring lost payload, for internal combustion engines. Green and blue hydrogen as internal combustion engines fuel are all characterized by low TTW and WTW GHG emission reduction costs between 250 €/ton$_{CO2eq}$ and 430 €/ton$_{CO2eq}$, which considering lost payload become 390 €/ton$_{CO2eq}$ and 600 €/ton$_{CO2eq}$. Cost premium for green hydrogen is between 56 and 64 million euros per year (79 and 89 million euros considering lost payload value), while for blue hydrogen is almost 37 million euros per year (between 60 and 64 million euros per year considering lost payload). Even in this case, brown hydrogen does not make much sense, particularly because WTW emission reduction cost is over 6000 €/ton$_{CO2eq}$ due to a low WTW GHG emission reduction. Internal combustion engines fuelled by natural gas have a positive TTW and WTW GHG reduction cost because both cost premium and emission reduction are negative figures. As already stated, carbon dioxide emissions when fossil natural gas is used onboard ships brings are slightly increased and costs are decreased. Synthetic natural gas can be considered a feasible option only considering WTW emissions, and WTW GHG reduction cost is between 1000 €/ton$_{CO2eq}$ and 1200 €/ton$_{CO2eq}$ accounting lost payload capacity (it was obtained almost the same range without considering this figure). TTW emission reduction cost is negative because TTW emissions are increased by using synthetic methane, mainly because internal combustion engines suffer from methane slip. Internal combustion engines fuelled by ammonia have a higher TTW and WTW reduction cost than other hydrogen fuelled options, between 277 €/ton$_{CO2eq}$ and 470 €/ ton$_{CO2eq}$ (423 €/ton$_{CO2eq}$ and 720 €/ton$_{CO2eq}$ accounting value lost). An ammonia fuelled powertrain has a cost premium ranging between 40 and 62 million euros per year, but accounting lost payload value its cost premium is between 62 and 84 million euros. Methanol fuelled engines have all very high TTW GHG reduction costs because emission reduction is limited when comparing this value to HFO fuelled internal combustion engines. When accounting WTW emissions, reduction cost is lower than zero for fossil methanol because its WTW emissions are higher than reference case. For synthetic methanol, WTW carbon dioxide equivalent emission reduction costs are comparable to other alternatives considered, between 280 €/ton$_{CO2eq}$ and 300 €/ton$_{CO2eq}$ (340 €/ton$_{CO2eq}$ and 350 €/ton$_{CO2eq}$ accounting lost payload value). Cost premium for this synthetic hydrocarbon is also moderate, spanning from 24 to 41 million euros without lost payload value and between 31 and 47 million euros per year accounting this figure. LPG has relatively high TTW emission reduction costs and negative WTW emission reduction costs, while also having a low-cost premium. Biodiesel has a negative TTW reduction cost because its TTW emissions are higher than reference case, but WTW emission reduction cost is high, mainly because emission reduction is low compared to the cost premium introduced. Renewable diesel has some interesting results: its TTW GHG reduction cost is equal to almost 790

€/ton_{CO2eq} (770 €/ton_{CO2eq} considering lost payload), WTW carbon dioxide equivalent emission reduction cost is equal to almost 250 €/ton_{CO2eq} (240 €/ton_{CO2eq} considering lost payload value) and cost premium is equal to almost 24 million euros per year regardless of lost payload value. FTD from green or blue hydrogen has the highest cost premium among alternatives considered and some of the highest TTW reduction costs. The only acceptable value is WTW GHG reduction cost of FTD produced from green hydrogen, which is equal to almost 710 €/ton_{CO2eq}.

MGO alone gives a small TTW emission benefit, but when this fuel is coupled with a CCS system, TTW emission reduction cost is equal to almost 390 €/ton_{CO2eq} (780 €/ton_{CO2eq} considering lost payload value) and WTW GHG reduction cost is equal to almost 593 €/ton_{CO2eq} (almost 1200 €/ton_{CO2eq} accounting lost payload value). Cost premium is equal to 48 million euros per year, and half of this figure is given by lost payload value. LSFO has relatively low TTW and WTW reduction costs and low cost premium when compared to reference case but gives also small benefits to emission reduction.

Internal combustion engine's cost premium is generally lower than previous cases and lower than reference cruise ship's annual revenue. Green hydrogen, synthetic natural gas, ammonia and FTD have cost premiums higher than annual revenue limit, but all other alternatives are economically feasible. Renewable methanol and MGO with a CCS system are close to the limit, and thus their economic feasibility should be analysed with more detail.

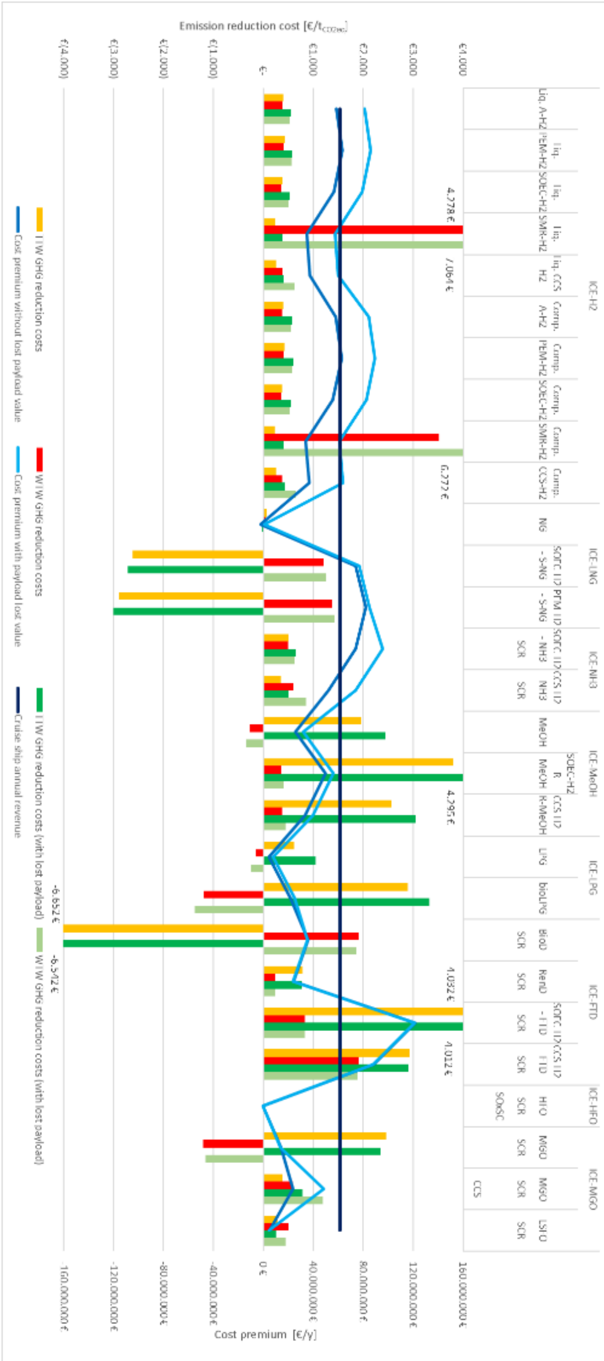

Figure 105 – TTW and WTW GHG reduction cost for internal combustion engines

Figure 106 shows TTW and WTW carbon dioxide equivalent reduction cost and cost difference between each power generation system and the reference case, both considering and ignoring lost payload, for gas turbines. Green and blue hydrogen as gas turbines fuel are all characterized by low TTW and WTW GHG emission reduction costs between 340 €/ton$_{CO2eq}$ and 660 €/ton$_{CO2eq}$, which considering lost payload become 530 €/ton$_{CO2eq}$ and 1000 €/ton$_{CO2eq}$. Cost premium for green hydrogen is between 77 and 86 million euros per year (101 and 117 million euros considering lost payload value), while for blue hydrogen is almost 53 million euros per year (between 78 and 85 million euros per year considering lost payload). These cost premiums are not sustainable and too high when compared to other options already described. Brown hydrogen has higher WTW GHG emissions and cannot be considered a feasible option for future developments. Fossil natural gas fuelled gas turbines have low TTW emission reduction costs equal to almost 280 €/tonCO2eq (450 €/ton$_{CO2eq}$ considering lost payload), but a high WTW emission reduction cost equal to almost 2200 €/ton$_{CO2eq}$ (2700 €/ton$_{CO2eq}$ considering lost payload), while cost premium is equal to almost 10 million euros per year considering 2.5 million euros of lost payload value. Synthetic natural gas has very high TTW GHG emission reduction cost and cost premiums, but WTW carbon dioxide equivalent emission reduction cost is between 660 €/ton$_{CO2eq}$ and 750 €/ton$_{CO2eq}$ (680 €/ton$_{CO2eq}$ and 760 €/ton$_{CO2eq}$ considering lost payload). Gas turbines fuelled by ammonia have a TTW reduction cost between 380 €/ton$_{CO2eq}$ and 560 €/ton$_{CO2eq}$ (510 €/ton$_{CO2eq}$ and 700 €/ton$_{CO2eq}$ accounting value lost), while WTW reduction cost spans between 550 €/ton$_{CO2eq}$ and 800 €/ton$_{CO2eq}$ (690 €/ton$_{CO2eq}$ and 1100 €/ton$_{CO2eq}$ accounting value lost). An ammonia fuelled powertrain has a cost premium ranging between 55 and 82 million euros per year, but accounting lost payload value cost premium is between 76 and 100 million euros. Methanol fuelled gas turbines have all very high TTW GHG reduction costs because emission reduction is limited when comparing this value to HFO fuelled internal combustion engines. When accounting WTW emissions, reduction cost is lower than zero for fossil methanol because its WTW emissions are higher than reference case. For synthetic methanol, WTW carbon dioxide equivalent emission reduction costs are comparable to other alternatives considered, between 390 €/ton$_{CO2eq}$ and 430 €/ton$_{CO2eq}$ (450 €/ton$_{CO2eq}$ and 530 €/ton$_{CO2eq}$ accounting lost payload value). Cost premium for this synthetic hydrocarbon spans from 40 to 60 million euros without lost payload value and between 49 and 69 million euros per year accounting this figure.

Cost premium for gas turbines is surely over reference vessel’s revenues, except when these power generators are fuelled by natural gas turbines. In this case, cost premium is well below revenues, and thus it can be considered economically feasible.

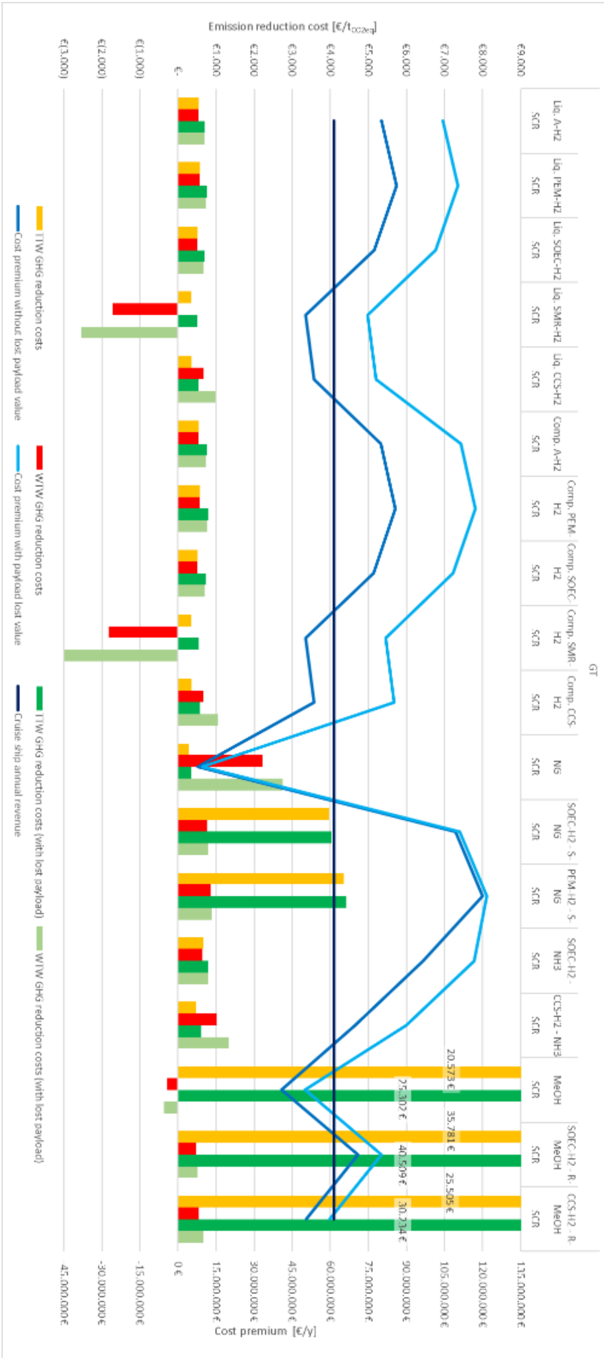

Figure 106 – TTW and WTW GHG reduction cost for gas turbines

5.4. Best-performing technologies

Three different metrics have been used to highlight best-performing technologies, and these are explained in the following paragraph. In this analysis, only alternatives which can really bring to a carbon dioxide equivalent emission reduction have been considered. Seven designs have TTW emissions higher than reference case:

- PEM fuel cells fuelled by:
    - Fossil natural gas.
    - Fossil methanol.
- Internal combustion engines fuelled by:
    - Fossil natural gas.
    - Synthetic natural gas produced from SOEC-H2.
    - Synthetic natural gas produced from PEM-H2.
    - Biodiesel.

Fourteen power generation options have WTW GHG emissions higher than reference case:

- PEM fuel cells fuelled by:
    - Brown hydrogen stored in liquid state.
    - Brown hydrogen stored in compressed state.
    - Fossil natural gas.
    - Fossil methanol.
- SOFC fuelled by fossil methanol.
- Internal combustion engines fuelled by:
    - Fossil natural gas.
    - Fossil methanol.
    - Fossil LPG.
    - Bio-LPG.
    - MGO.
- Gas turbines fuelled by:
    - Brown hydrogen stored in liquid state.
    - Brown hydrogen stored in compressed state.
    - Fossil methanol.

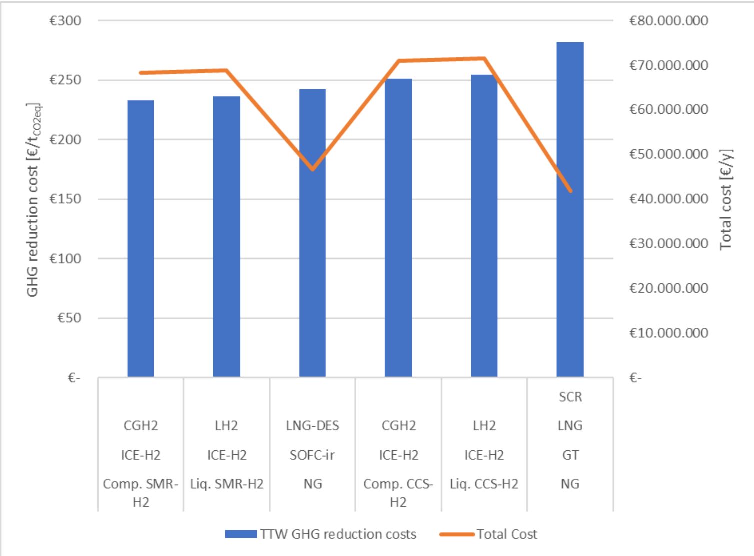

Figure 107 – Six alternatives with lowest TTW GHG reduction cost

Figure 107 shows the six alternatives with lowest TTW carbon dioxide equivalent reduction costs and their total cost. Hydrogen seems the most promising fuel for an economically feasible TTW GHG reduction. The two most cheap TTW GHG reduction cost use brown hydrogen inside internal combustion engines, one which stores this gas in its compressed state at 700 bar (233 €/ton$_{CO2eq}$), the other one with a liquid storage (237 €/ton$_{CO2eq}$). Total cost for these options is high and equal to almost 70 million dollars for each year of operations. SOFC fuelled by fossil natural gas have the third lowest TTW GHG emission reduction cost, almost equal to 243 €/ton$_{CO2eq}$. A cruise ship equipped with SOFC fuelled by fossil natural gas have a total cost equal to almost 47 million euros. Internal combustion engines fuelled by blue hydrogen take also fourth and fifth place for more economic TTW carbon dioxide equivalent reduction cost, reaching almost 251 €/ton$_{CO2eq}$ and 255 €/ton$_{CO2eq}$. These alterative designs have a total cost for their implementation equal to almost 71 and 72 million euros per year respectively. Gas turbines fuelled by fossil natural gas have the sixth lowest TTW GHG reduction cost which is equal to almost 282 €/ton$_{CO2eq}$, and this potential solution has also the lowest total cost among the first six spots equal to almost 42 million euros per year.

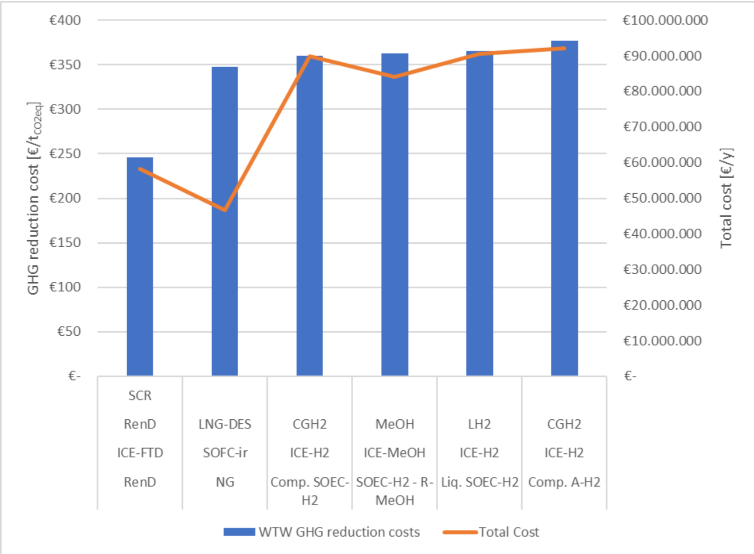

Figure 108 – Six alternatives with lowest WTW GHG reduction cost

Figure 108 shows the six alternatives with lowest WTW carbon dioxide equivalent reduction costs and their total cost. Internal combustion engines fuelled by renewable diesel have the lowest WTW GHG reduction cost equal to almost 246 €/ton$_{CO2eq}$ and a total cost equal to almost 58 million euros per year of operation. SOFC fuelled by fossil natural gas have the second cheapest WTW GHG reduction cost, which is equal to almost 348 €/ton$_{CO2eq}$, an increase of almost 41% from the cheapest WTW GHG reduction cost. Total cost for this system is equal to almost 47 million dollars for each year of operations, which is also the lowest total cost among the first six WTW GHG reduction cost alternatives. Internal combustion engines fuelled by renewable hydrogen produced from SOEC and stored in its compressed state at 700 bar have the third lowest WTW GHG emission reduction cost, almost equal to 360 €/ton$_{CO2eq}$. A cruise ship equipped with this technical system has a total cost equal to almost 90 million euros. Internal combustion engines are power generators used in all other spots of this standing. When these generators are fuelled by methanol produced from green hydrogen, WTW carbon dioxide equivalent reduction cost reaches almost 363 €/ton$_{CO2eq}$ and so it takes the fourth spot. The total cost of this system is equal to almost 84 million euros per year. Internal combustion engines fuelled by renewable hydrogen produced from SOEC and stored in its liquid state have a WTW GHG reduction cost equal to almost 366 €/ton$_{CO2eq}$. This design has a total cost for its implementation onboard equal to almost 90 million euros per year. Internal combustion engines fuelled by compressed hydrogen produced by alkaline electrolysers have the sixth lowest WTW GHG reduction cost which is equal to almost 377 €/ton$_{CO2eq}$, and this potential solution has a total cost equal to almost 92 million euros per year.

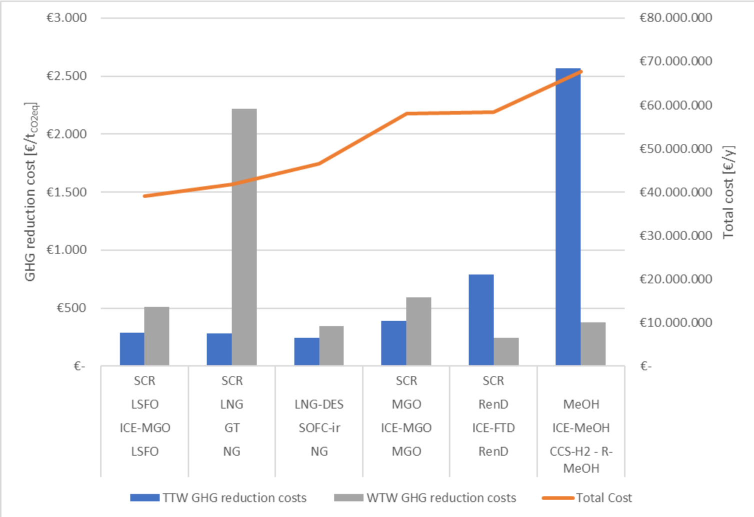

Figure 109 – Six alternatives with lowest total cost

Figure 109 shows the six alternatives with the lowest total cost and their associated TTW and WTW carbon dioxide equivalent emissions' reduction costs. Internal combustion engines fuelled by LSFO take the first place, with a total cost equal to almost 39 million euros per year. TTW and WTW GHG reduction cost are equal to almost 291 €/ton$_{CO2eq}$ and 507 €/ton$_{CO2eq}$ respectively. Gas turbines fuelled by fossil natural gas have the second-cheapest total cost, equal to almost 42 million euros per year. TTW and WTW carbon dioxide emission reduction costs for this system are equal to almost 282 €/ton$_{CO2eq}$ and 2220 €/ton$_{CO2eq}$ respectively. SOFC fuelled by fossil natural gas have the third-lowest total cost, which is almost equal to 47 million euros per year. A cruise ship equipped with this technical system has TTW and WTW GHG reduction cost equal to almost 243 €/ton$_{CO2eq}$ and 348 €/ton$_{CO2eq}$ respectively. Internal combustion engines are power generators used in all other spots of this standing. When these generators are fuelled by MGO and are coupled with a CCS system capable of reducing to a half TTW carbon dioxide emission from prime generators, their total cost is equal to almost 58 million euros per year, which is the fourth-lowest value. TTW and WTW GHG reduction cost for this solution are equal to almost 387 €/ton$_{CO2eq}$ and 593 €/ton$_{CO2eq}$ respectively. Internal combustion engines fuelled by renewable diesel have a total cost equal to almost 58 million euros per year and are in fifth place. This design's TTW and WTW GHG reduction cost are equal to almost 790 €/ton$_{CO2eq}$ and 247 €/ton$_{CO2eq}$ respectively. Internal combustion engines fuelled by methanol produced by blue hydrogen have the sixth-lowest total cost equal to almost 68 million euros per year, and its TTW and WTW GHG reduction cost are equal to almost 2570 €/ton$_{CO2eq}$ and 380 €/ton$_{CO2eq}$ respectively.

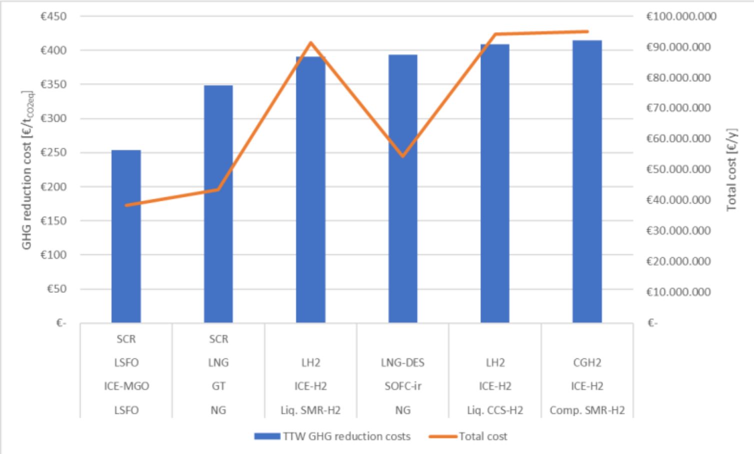

Figure 110 – Six alternatives with lowest TTW GHG reduction cost (with value lost)

The analysis shown in previous paragraphs does not account lost payload value. For this reason, all calculations were performed, accounting also the value of lost payload and selecting the six best alternatives for each metric used in previous graphs. Figure 110 shows the six alternatives with lowest TTW carbon dioxide equivalent reduction costs and their total cost. The cheapest TTW GHG reduction cost use LSFO inside internal combustion engines and has a reduction cost equal to almost 254 €/ton$_{CO2eq}$. Total cost for this option is equal to almost 38 million dollars for each year of operations, which is also the lowest total cost among the first six places. Gas turbines fuelled by fossil natural gas is the second-cheapest alternative design because its TTW carbon dioxide equivalent reduction cost is equal to almost 349 €/ton$_{CO2eq}$. Total cost for this option is equal to almost 44 million dollars for each year of operations. Internal combustion engines fuelled by brown hydrogen take third place for most economic TTW carbon dioxide equivalent reduction cost, reaching almost 390 €/ton$_{CO2eq}$. This power generation system has a total cost for its implementation equal to almost 91 million euros per year. SOFC fuelled by fossil natural gas have the fourth lowest TTW GHG emission reduction cost, almost equal to 394 €/ton$_{CO2eq}$: this technical solution has a total cost of almost 54 million euros per year for its implementation. A cruise ship equipped with internal combustion engines fuelled by blue hydrogen stored in its liquid phase have a TTW GHG emission reduction cost almost equal to 409 €/ton$_{CO2eq}$ and a total cost equal to almost 94 million euros. The same configuration with a compressed storage of brown hydrogen solution has the sixth lowest TTW GHG reduction cost, equal to almost 415 €/ton$_{CO2eq}$. This potential solution has a total cost equal to almost 95 million euros per year.

The comparison between Figure 110 and Figure 107 shows that the alternative which had the first spot (ICE with compressed SMR-H2) becomes the sixth-cheapest option when lost payload value is accounted, while the second option (ICE with liquefied SMR-H2) goes down to third place. SOFC fuelled by natural gas move from third to fourth place, while internal combustion engines fuelled by blue hydrogen stored in its liquid phase goes up from fifth to third place. Gas turbines fuelled by natural gas also rise from sixth place to second best TTW GHG reduction cost.

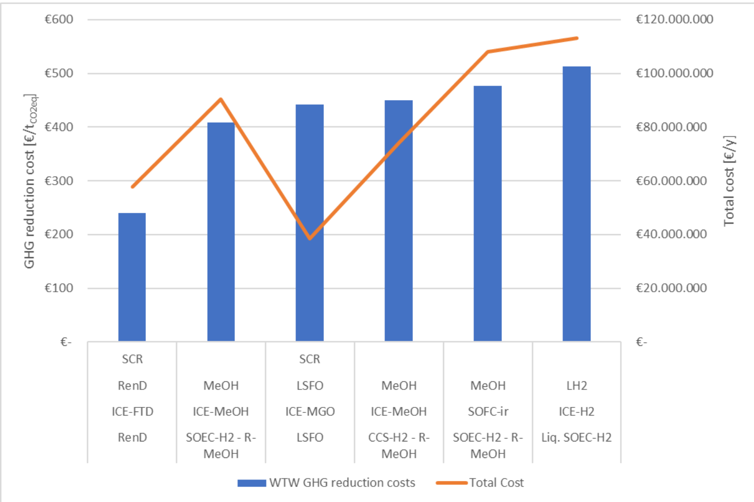

Figure 111 – Six alternatives with lowest WTW GHG reduction cost (with value lost)

Figure 111 shows the six alternatives with lowest WTW carbon dioxide equivalent reduction costs and their total cost. Renewable methanol seems the most promising fuel for an economically feasible WTW GHG reduction when lost payload value is accounted. The cheapest WTW GHG reduction cost use renewable diesel inside internal combustion engines and has a reduction cost equal to almost 240 €/ton$_{CO2eq}$. Total cost for this option is equal to almost 58 million dollars for each year of operations. Internal combustion engines fuelled by renewable methanol produced from green hydrogen is the second-cheapest alternative design because its WTW carbon dioxide equivalent reduction cost is equal to almost 408 €/ton$_{CO2eq}$. Total cost for this option is equal to almost 90 million dollars for each year of operations. Internal combustion engines fuelled by LSFO and by renewable methanol produced from blue hydrogen take also third and fourth place for more economic TTW carbon dioxide equivalent reduction cost, reaching almost 443 €/ton$_{CO2eq}$ and 450 €/ton$_{CO2eq}$ respectively. LSFO-fuelled power generation system has a total cost for its implementation equal to almost 38 million euros per year, which is the lowest total cost among the first six places. Methanol produced from blue hydrogen reaches a total cost of almost 74 million euros per year. SOFC fuelled by renewable methanol produced from green hydrogen have the fifth lowest WTW GHG emission reduction cost, almost equal to 477 €/ton$_{CO2eq}$. A cruise ship equipped with technical solution has a total cost equal to almost 108 million euros. Internal combustion engines fuelled by green hydrogen have the sixth lowest WTW GHG reduction cost, which is equal to almost 513 €/ton$_{CO2eq}$, and this potential solution has a total cost equal to almost 113 million euros per year.

Comparison between Figure 111 and Figure 108 shows that renewable diesel-fuelled cruise ships have the lowest WTW carbon dioxide equivalent reduction cost, both accounting and ignoring lost payload cost. Internal combustion engines fuelled by renewable methanol produced from green hydrogen rise from fourth to second place, but their WTW GHG reduction cost also rises from 363 €/ton$_{CO2eq}$ 408 €/ton$_{CO2eq}$. Internal combustion engines fuelled by green hydrogen go down from fifth to sixth place, also peaking their reduction cost from 366 €/ton$_{CO2eq}$ to 513 €/ton$_{CO2eq}$. All other alternatives which were present in Figure 108 are not represented in Figure 111, mainly because hydrogen and LNG onboard bring to a serious increase of lost payload value. Methanol and LSFO can thus be considered options for a cost-effective emission reduction because they do not require bulky or heavy storage systems onboard.

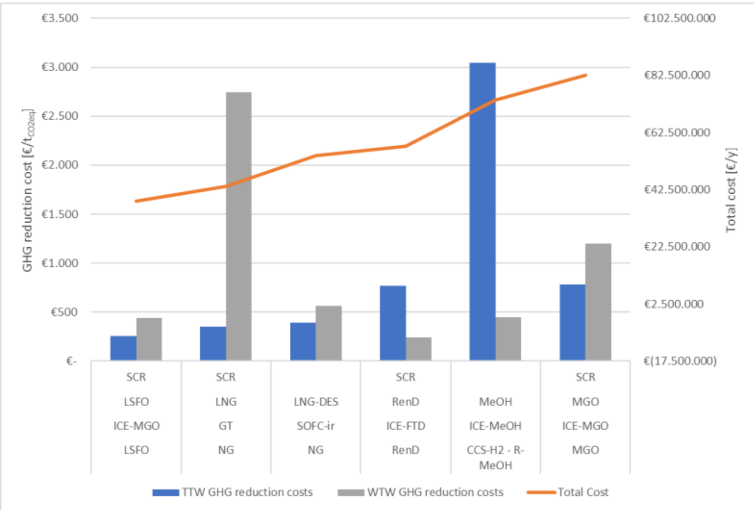

Figure 112 – Six alternatives with lowest total cost (with value lost)

Figure 112 shows the six alternatives with the lowest total cost and their associated TTW and WTW carbon dioxide equivalent emissions' reduction costs when lost payload value is accounted. Internal combustion engines fuelled by LSFO take the first place, with a total cost equal to almost 38 million euros per year. TTW and WTW GHG reduction cost are equal to almost 253 €/ton_{CO2eq} and 442 €/ton_{CO2eq} respectively. Gas turbines fuelled by fossil natural gas have the second-cheapest total cost, equal to almost 44 million euros per year. TTW and WTW carbon dioxide emission reduction costs for this system are equal to almost 348 €/ton_{CO2eq} and 2740 €/ton_{CO2eq} respectively. SOFC fuelled by fossil natural gas have the third-lowest total cost, which is almost equal to 54 million euros per year. A cruise ship equipped with this technical system has TTW and WTW GHG reduction cost equal to almost 393 €/ton_{CO2eq} and 563 €/ton_{CO2eq} respectively. Internal combustion engines are power generators used in all other spots of this standing. When these generators are fuelled by renewable diesel their total cost is equal to almost 58 million euros per year, which is the fourth-lowest value. TTW and WTW GHG reduction cost for this solution are equal to almost 770 €/ton_{CO2eq} and 240 €/ton_{CO2eq} respectively. Internal combustion engines fuelled by renewable methanol produced from blue hydrogen have a total cost equal to almost 74 million euros per year and are in fifth place. This design's TTW and WTW GHG reduction cost are equal to almost 3050 €/ton_{CO2eq} and 450 €/ton_{CO2eq} respectively. Internal combustion engines fuelled by MGO and are coupled with a CCS system capable of reducing to a half TTW carbon dioxide emission from prime generators have the sixth-lowest total cost equal to almost 83 million euros per year, and its TTW and WTW GHG reduction cost are equal to almost 780 €/ton_{CO2eq} and 1200 €/ton_{CO2eq} respectively.

Comparing Figure 112 and Figure 109, it is evident that the first three places stay the same, mainly because their impact on lost payload does not affect significantly total cost. MGO-fuelled internal combustion engines coupled with a CCS system go down from fourth to sixth place, while renewable diesel rises from fifth to fourth place. Also, renewable methanol rises from sixth to fifth place, but it is important to highlight that all related costs, TTW and WTW carbon dioxide emission reduction costs, rise above previous level, except for the first two places.

5.5. Break-even electricity and natural gas price

Most power generation systems for cruise ships considered in this analysis need a fuel produced from natural gas or from renewable electricity. We have already pointed out the cost for carbon dioxide reduction, which can be considered also as the lower limit of a carbon tax, which would make that alternative economically feasible. This analysis is focused on highlighting which would be electricity and natural gas price which would make the alternative design considered economically feasible. For alternatives which do not require electricity or natural gas for fuel production, the price considered is the same stated in paragraph 1.1.2, so an electricity price equal to 70 €/MWh, and natural gas price equal to 40 €/MWh.

Figure 113 shows electricity and natural gas break-even price for all different fuel cells-based power generation systems onboard cruise ships. Break-even electricity price is always negative for these options, because each one requires a cost premium, which could be overcome only with a negative price for electricity used for fuel production. Highest peaks are for blue and brown hydrogen because these alternatives require lower electricity for fuel production. Natural gas break-even price has been calculated for all alternatives which require fossil natural gas for their production and is considered equal to 40 €/MWh as specified in the introduction. For PEM fuel cells fuelled by fossil natural gas via steam reforming, natural gas break-even price is positive but lower than reference value (9€/MWh). For all other alternatives, natural gas price should be negative to balance cost premium required from the different power generation system considered, for SOFC fuelled by fossil natural gas, which have emerged from previous analysis as one of the most serious potential solutions for a sustainable cruising.

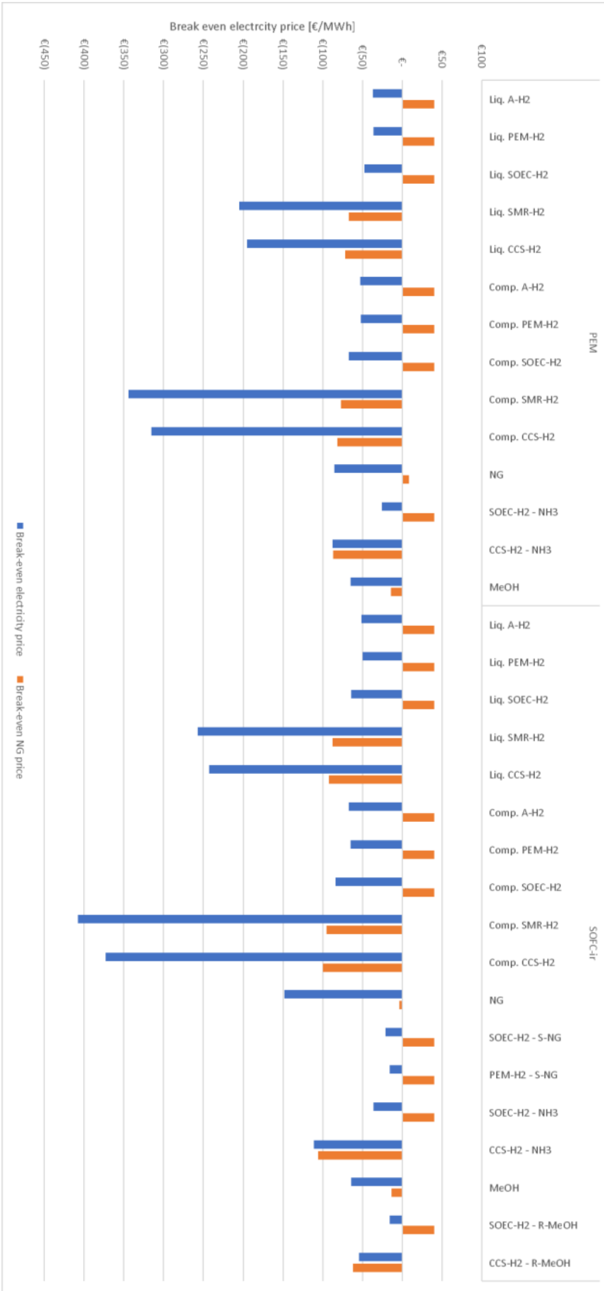

Figure 113 – Break-even electricity price and natural gas price for fuel cells-based systems

Figure 114 shows electricity and natural gas break-even price for all different internal combustion engines-based power generation systems onboard cruise ships. There are only four scenarios in which break-even electricity price is higher than zero: fossil natural gas, renewable methanol from green hydrogen, HFO and LSFO. The most interesting data is about internal combustion engines fuelled by renewable methanol produced from green hydrogen, which has a break-even electricity price equal to almost 5 €/MWh. Natural gas break-even price for alternatives in which is used directly as fuel or for fuel production is higher than zero for internal combustion engines fuelled by fossil natural gas and fossil methanol. Break-even natural gas price for these alternatives is equal to almost 39 €/MWh and 6 €/MWh respectively.

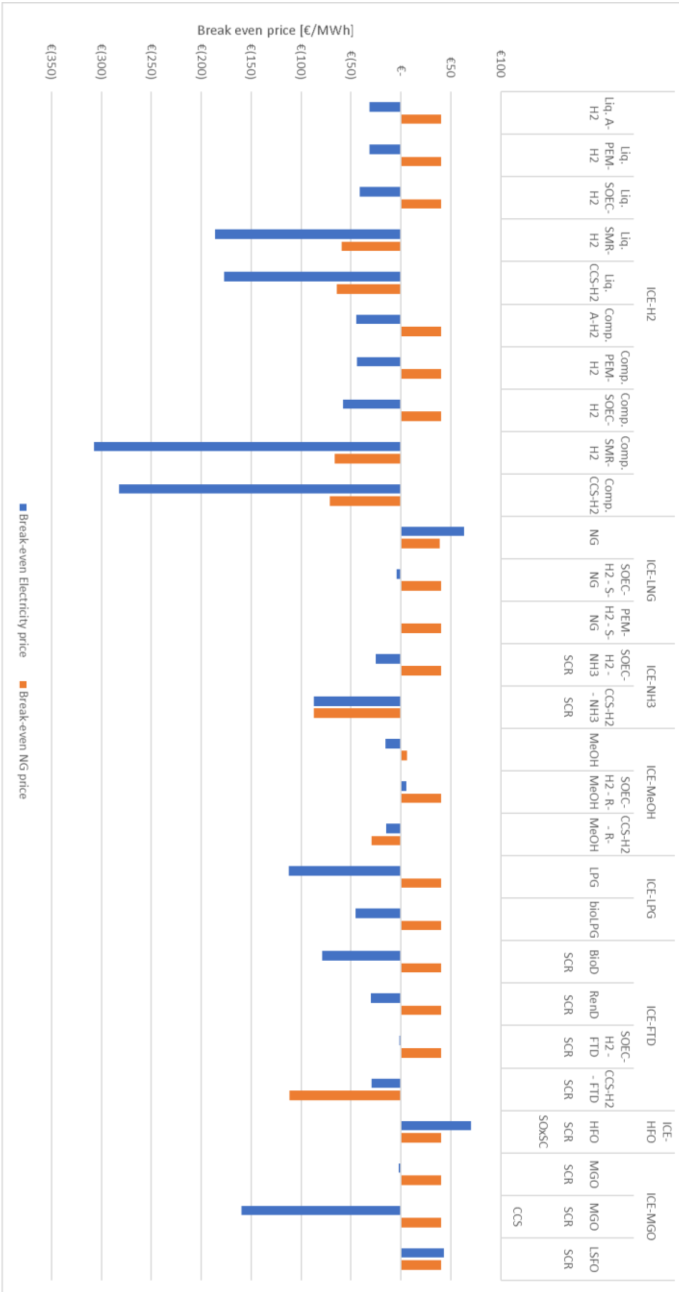

Figure 114 – Break-even electricity price and natural gas price for internal combustion engines-based systems

Figure 115 shows electricity and natural gas break-even price for all different gas turbines-based power generation systems onboard cruise ships. Break-even electricity price is always negative for these options, because each one requires a cost premium, which could be overcome only with a negative price for electricity used for fuel production. Highest peaks are for blue and brown hydrogen because these alternatives require lower electricity for fuel production. Natural gas break-even price is positive only for gas turbines fuelled by fossil natural gas and equal to almost 24 €/MWh. All other alternatives which require natural gas for fuel production need a negative price for this fuel.

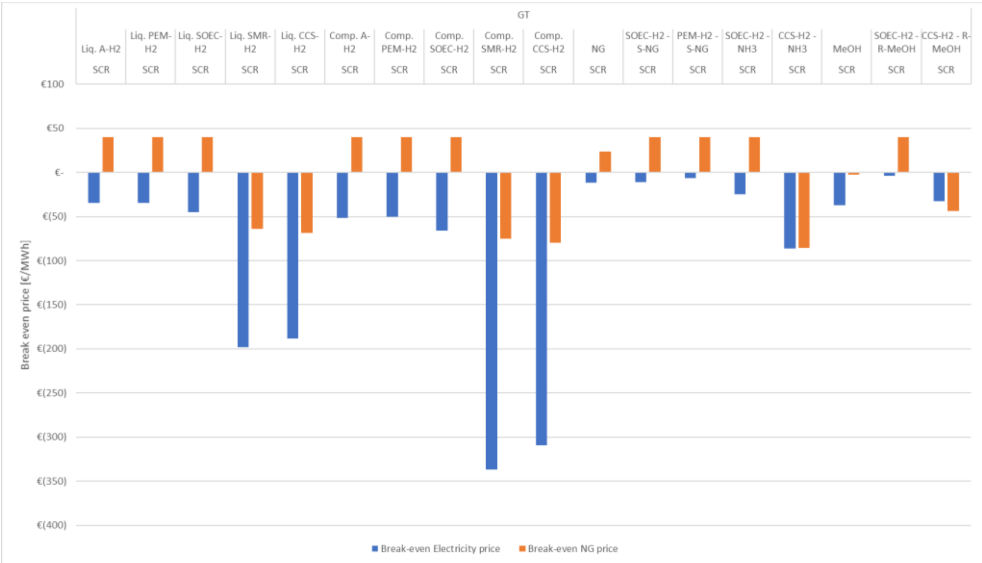

Figure 115 – Break-even electricity price and natural gas price for gas turbines-based systems

This brief analysis highlights the fact that all alternative power generation systems configuration would bring to cost premiums which cannot be absorbed only with an electricity or natural gas price potential future reduction. The inevitable cost rise for carbon dioxide equivalent emission reduction from shipping will surely benefit from possible future reduction of renewable electricity price, but cost premium should be cut also considering other alternative measures.

5.6. Attained CII

In this PhD, activity was given a special importance to the upcoming regulation about a new index regarding carbon dioxide emission by IMO, named CII. This regulation can seriously influence how today's ships are designed and how they will be designed in next years because it prescribes a progressively decreasing emission limit for each vessel. All alternative power generation systems proposed in previous chapters have been analysed from this potential new regulation's perspective to assess which alternative design can fulfil these requirements and particularly highlighting that some designs behave differently considering only TTW emissions or the whole WTW cycle.

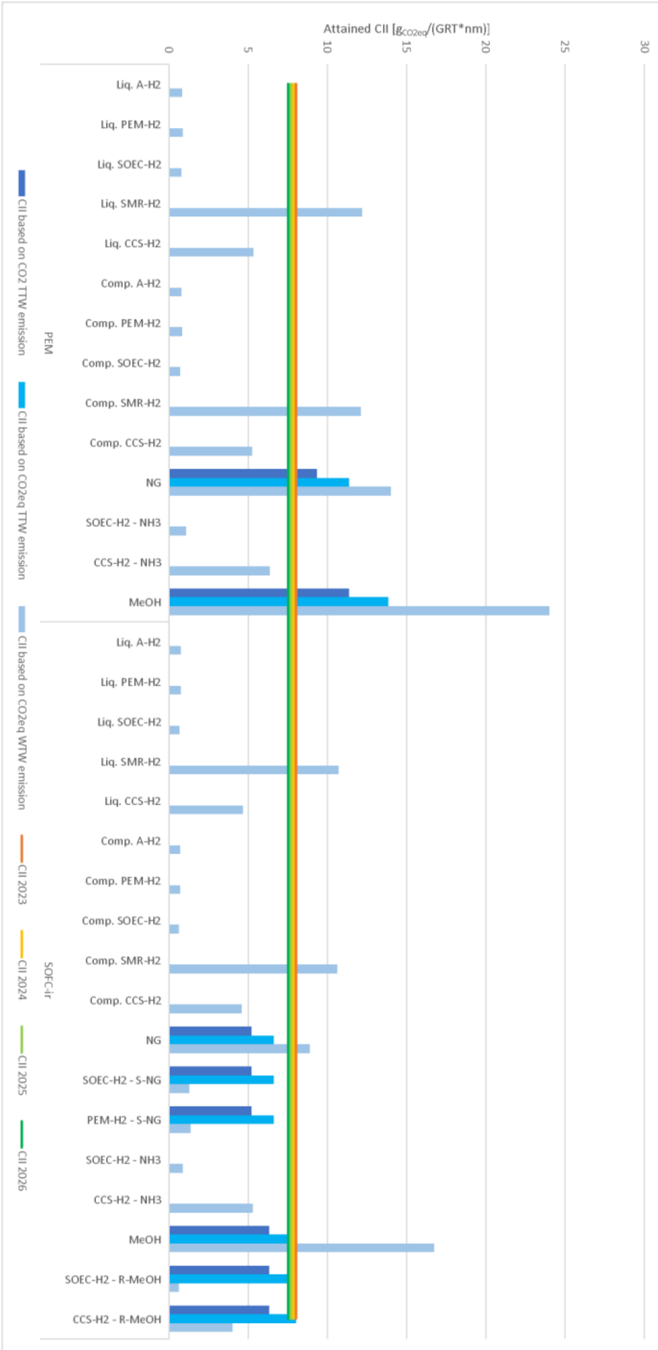

Figure 116 – CII for fuel cells-based systems

Figure 116 shows CII attained value for all different power generation system configurations based on fuel cells. CII threshold values have been calculated for 4 different values using the gross tonnage of the reference vessel that is equal to almost 180,000 GRT. Every CII threshold value is corrected and thus decreased as outlined by IMO. Blue and green hydrogen are surely the alternative which brings to an attained CII below 2026 threshold value accounting only TTW emissions or the whole life-cycle. Brown hydrogen can surely contribute to lower TTW emissions but attained CII value considering WTW carbon dioxide emissions is over threshold values. Fossil natural gas and methanol used with a reforming system to power PEM fuel cells onboard cruise ships cannot be considered a feasible option because their emission bring to an attained CII which is well over all presented threshold values. Ammonia produced from green or blue hydrogen can be considered a feasible option even when coupled with PEM fuel cells because the attained CII is below threshold values. SOFC fuelled by fossil natural gas have an attained CII below threshold values when only TTW carbon dioxide emission and TTW carbon dioxide equivalent emissions. When WTW carbon dioxide emissions are accounted in attained CII calculation, this value is over threshold and thus this option must be considered carefully for future applications. Synthetic natural gas helps to cut WTW carbon dioxide equivalent emissions well below CII threshold values. SOFC can thus be considered a good technology which can help to comply with regulations using fossil natural gas for the next years and then can be converted for the use with hydrogen, ammonia, or synthetic natural gas when regulation will become stricter and consider the whole WTW cycle. Fossil methanol complies with CII regulation when only TTW carbon dioxide emissions are considered. Its renewable option does not comply with CII regulation when only TTW carbon dioxide equivalent emissions are considered (the attained value is 8 and threshold value for 2024 is equal to 7.85). If WTW emissions are accounted, renewable methanol is a feasible option to comply with CII regulation.

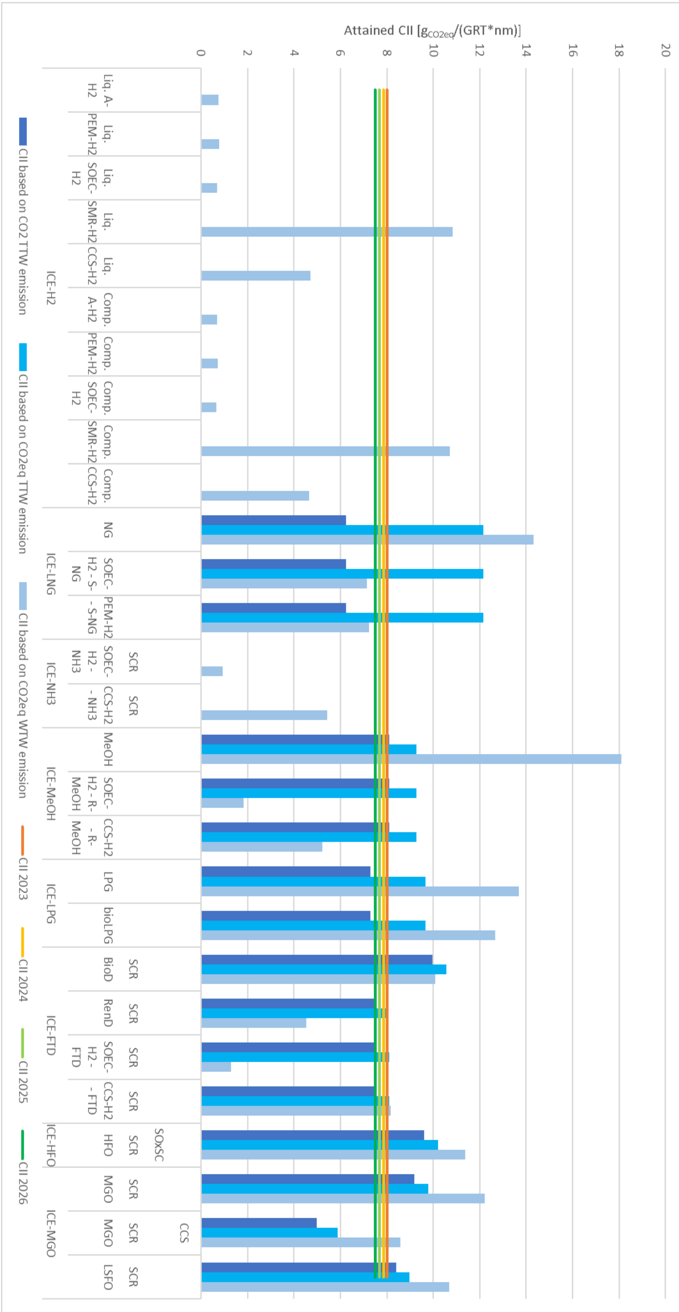

Figure 117 – CII for internal combustion engines-based systems

Figure 117 shows CII attained value for all different power generation system configurations based on internal combustion engines. For these power generators, green and blue hydrogen are the key fuel to cut emissions and to comply with CII regulation accounting only TTW emissions or the whole WTW cycle. Even in this case, brown hydrogen is not a feasible option when WTW carbon dioxide emissions are accounted during attained CII calculations. Internal combustion engines fuelled by natural gas have a particular behaviour because of methane slip. They comply with the proposed CII regulation when only TTW carbon dioxide emissions are considered, but when methane slip is accounted as carbon dioxide equivalent emission, their attained CII is almost 50% higher than threshold values. Also, attained CII calculated by considering the whole WTW cycle is over threshold values. When synthetic natural gas is used as internal combustion engine fuel, attained CII calculated using WTW carbon dioxide equivalent emissions is slightly below threshold value. Ammonia, as hydrogen, allows the cruise ship to comply with all CII required values. Fossil methanol and internal combustion engines does not comply with proposed CII regulation, but when renewable methanol is considered, attained CII calculated using WTW carbon dioxide equivalent emissions is lower than threshold value. LPG and bio-LPG can enable the ship to comply with threshold value when only TTW carbon dioxide emissions are considered. Renewable diesel and FTD produced from renewable hydrogen have attained CII values calculated using TTW emissions almost equal to threshold values, but well below these limits when WTW GHG emissions are accounted. FTD produced from blue hydrogen has higher WTW emissions, and it does not comply with CII requirements. It is also highlighted the fact that an HFO fuelled contemporary class cruise ship would not comply with proposed CII regulation for each set of emissions considered. This result is valid also for MGO and LSFO, so it is important to highlight that with current oil-based fuel options, a cruise ship like this would not comply with CII regulation. If a CCS system capable of cutting of almost a half carbon dioxide emissions of internal combustion engines is installed, attained CII for the reference vessel is below threshold limit when TTW carbon dioxide equivalent emissions are accounted. When WTW emissions are considered, this technical option does not comply with current CII regulation and would not be considered a feasible option.

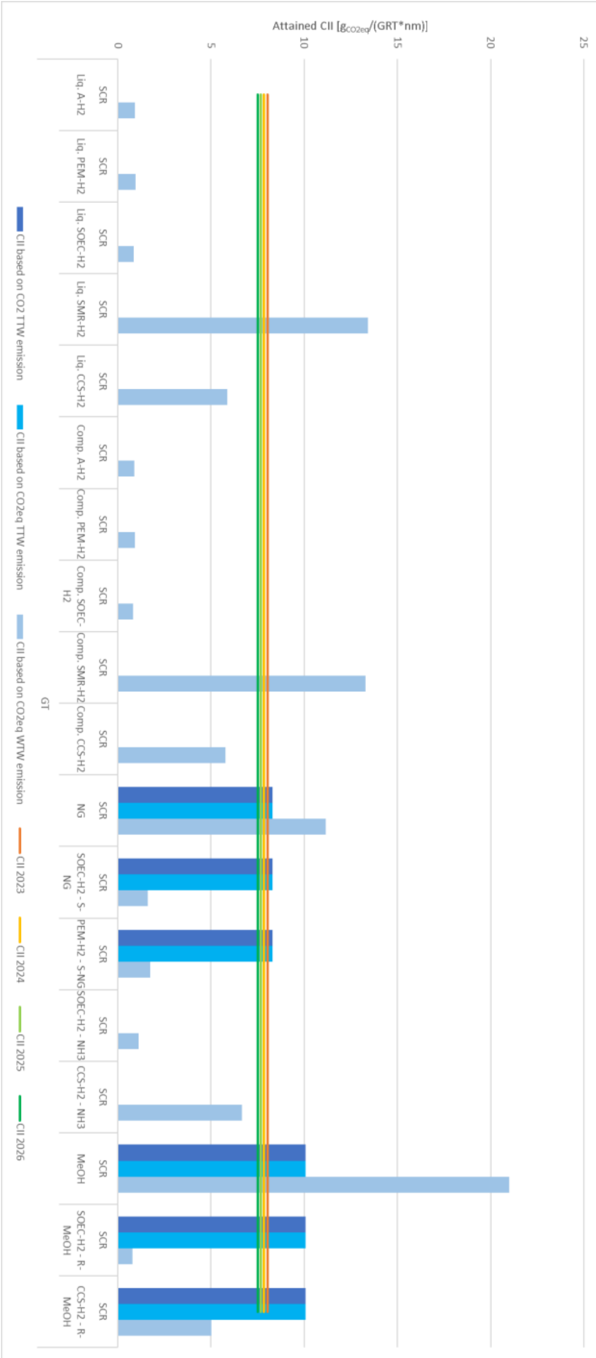

Figure 118 – CII for gas turbines-based systems

Figure 118 shows CII attained value for all different power generation system configurations based on gas turbines. For these power generators, green and blue hydrogen are the key fuel to cut emissions and to comply with CII regulation accounting only TTW emissions or the whole WTW cycle. Even in this case, brown hydrogen is not a feasible option when WTW carbon dioxide emissions are accounted during attained CII calculations. Fossil natural gas fuelled gas turbines have an attained CII higher than threshold value when only TTW or WTW carbon dioxide equivalent emissions are accounted. If synthetic natural gas is used as fuel, attained CII calculated considering WTW carbon dioxide equivalent emissions is lower than regulation's limits. Ammonia is another potential fuel which guarantees a CII value below threshold, even if this fuel is produced from blue hydrogen. Methanol case is like natural gas's one: its fossil feedstock gives attained CII over the threshold, but synthetic fuel complies with CII regulations when WTW carbon dioxide emissions are considered.

5.7. Main results for a luxury class cruise ship

The same analysis and calculations shown in previous paragraphs were performed for a smaller luxury class cruise ship with characteristics already shown in Table 49.

System overall cost and carbon dioxide equivalent emissions for different power generation system produced results are directly comparable to evidence obtained from a contemporary class cruise ship. Influence of lost payload is also similar in terms of additional percentage of overall cost to the previous case. Lost payload capacity is particularly relevant for ships equipped with a hydrogen storage system, an ammonia storage system, a fuel cell power generation system, or a CCS system.

TTW, WTW carbon dioxide emission reduction cost and differential cost for different power generation systems have some important differences between a contemporary class cruise ship and a luxury class cruise ship. These results are deeply analysed in the following paragraphs.

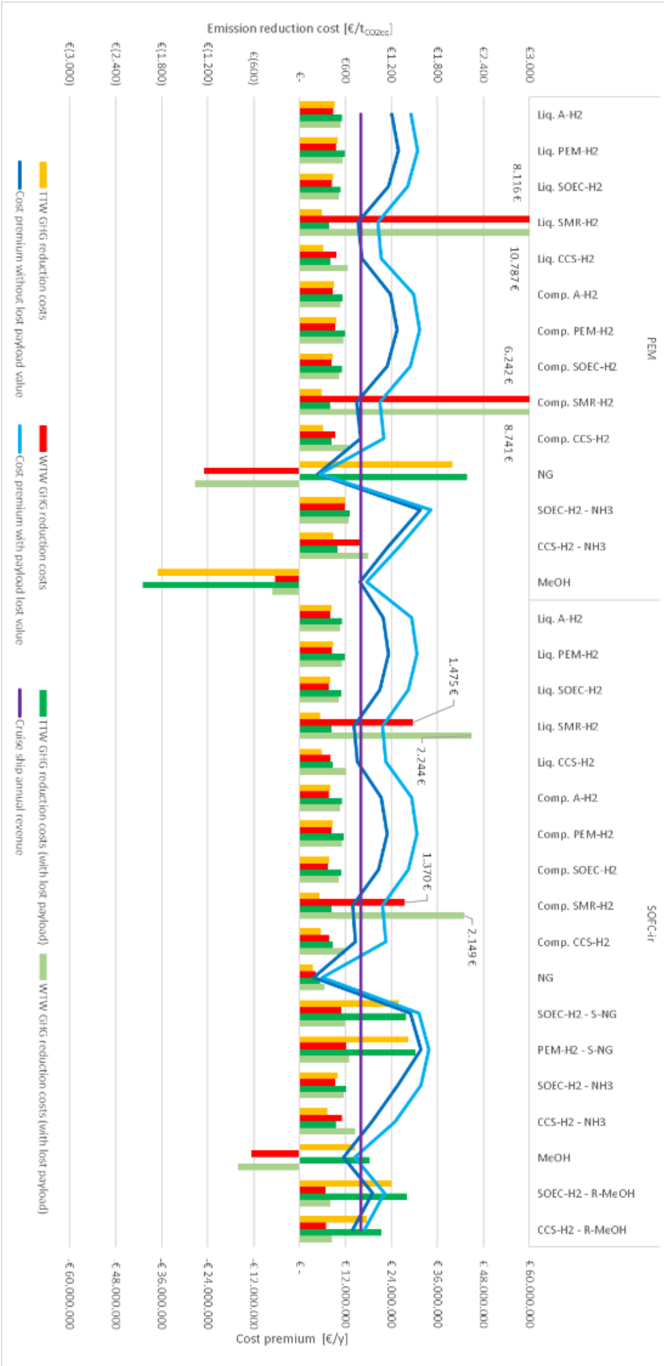

Figure 119 – TTW and WTW GHG reduction cost and differential cost for fuel cells (luxury class)

Figure 119 shows TTW and WTW carbon dioxide equivalent reduction cost and cost difference between each power generation system and the reference case, both considering and ignoring lost payload, for fuel cells. PEM fuel cells fuelled by green hydrogen have a relatively low carbon dioxide equivalent reduction cost, both accounting TTW and WTW emissions. Reduction cost is between 440 €/ton$_{CO2eq}$ and 490 €/ton$_{CO2eq}$ without considering lost payload and between 510 €/ton$_{CO2eq}$ and 600 €/ton$_{CO2eq}$ when accounting this lost value. Price is lower when SOEC-produced hydrogen is considered, requiring a cost premium of almost 24 million euros per year without accounting value lost and of almost 29 million euros per year considering lost payload capacity (100 million per year for compressed hydrogen). PEM fuel cells fuelled by brown hydrogen have a lower TTW GHG reduction cost than green hydrogen and a high WTW GHG reduction cost because WTW emissions decrease of almost 4% of reference case scenario while cost premium is more than two times reference cruise ship. For this reason, this option can't be considered a feasible alternative to cut emissions coming from marine sector, particularly cruise shipping. Blue hydrogen surely makes more sense because from a TTW and WTW emission reduction cost is comparable to green hydrogen and because its cost premium is lower than the one of green hydrogen alternatives and equal to almost 23 million euros per year (17 million euros per year without considering value lost). PEM fuel cells fuelled with fossil natural gas and fossil methanol via reformers can't be considered a feasible option for future applications because they bring to an unacceptable increase of TTW GHG emission reduction cost and to a negative WTW GHG emission reduction cost because its WTW emissions are higher than reference case scenario. Ammonia produced from green or blue hydrogen makes sense from an emission point of view because emission decrease is proven. When ammonia is considered, the economics of this power generation system does not make much sense, requiring a higher cost premium than green hydrogen itself. SOFC fuelled by green hydrogen can be considered slightly better than PEM fuel cells from an economic point of view, because TTW GHG emission reduction cost is between 400 €/ton$_{CO2eq}$ and 440 €/ton$_{CO2eq}$ (between 540 €/ton$_{CO2eq}$ and 580 €/ton$_{CO2eq}$ considering lost payload) WTW carbon dioxide equivalent emission reduction cost is between 380 €/ton$_{CO2eq}$ and 420 €/ton$_{CO2eq}$ (between 510 €/ton$_{CO2eq}$ and 560 €/ton$_{CO2eq}$ considering lost payload) and cost premium is equal to 21 million euros and 30 million euros per year. Cost premium is almost the same as PEM fuel cells fuelled by green hydrogen because, while total fuel consumption is lower due to a higher heat recovery by exhaust gases, but SOFC are bulkier and heavier than PEM fuel cells. Brown hydrogen has a lower cost premium than green and blue hydrogen, but WTW GHG reduction cost is very high because WTW emission reduction is lower than other alternatives (at least more than 4000 €/ton$_{CO2eq}$). SOFC fuelled by fossil natural gas have low TTW and WTW carbon dioxide equivalent reduction cost equal respectively to 170 €/ton$_{CO2eq}$ and 210 €/ton$_{CO2eq}$ (270 €/ton$_{CO2eq}$ and 330

€/ton$_{CO2eq}$ considering lost payload). Cost premium is the lowest among fuel cells options and is equal to almost 4 million euros per year without considering lost payload and almost 6 million euros accounting this figure. Synthetic natural gas has high TTW carbon dioxide equivalent reduction costs, between 1300 €/ton$_{CO2eq}$ and 1400 €/ton$_{CO2eq}$ (1400 €/ton$_{CO2eq}$ and 1500 €/ton$_{CO2eq}$ considering lost payload) and WTW reduction costs comparable to the ones previously given, between 550 €/ton$_{CO2eq}$ and 600 €/ton$_{CO2eq}$ (590 €/ton$_{CO2eq}$ and 650 €/ton$_{CO2eq}$ considering lost payload). Cost premium for this synthetic hydrocarbon is among highest for these generators and even not accounting lost payload it is always higher than 29 million euros.

Ammonia produced from green and blue hydrogen has a TTW GHG emission reduction cost between 360 €/ton$_{CO2eq}$ and 490 €/ton$_{CO2eq}$ (between 470 €/ton$_{CO2eq}$ and 600 €/ton$_{CO2eq}$ considering lost payload) WTW carbon dioxide equivalent emission reduction cost is between 470 €/ton$_{CO2eq}$ and 550 €/ton$_{CO2eq}$ (between 580 €/ton$_{CO2eq}$ and 720 €/ton$_{CO2eq}$ considering lost payload) and cost premium is between to 19 million euros and 26 million euros per year (25 and 32 million euros per year considering lost payload). Fossil methanol fuelled SOFC have a high TTW GHG reduction cost because TTW GHG emission reduction is lower than other alternatives. WTW emission reduction cost is negative because WTW emissions are higher than reference case scenario. Methanol produced from green hydrogen or blue hydrogen still has a very high TTW GHG reduction cost, but WTW carbon dioxide equivalent emission reduction cost is almost 340 €/ton$_{CO2eq}$ without considering lost payload and between 400 €/ton$_{CO2eq}$ and 420 €/ton$_{CO2eq}$ considering this further cost. Cost premium for this combination of generator and fuel is between 14 and 19 million euros per year (17 and 22 million euros per year considering lost payload).

It is also evident that almost every alternative power generation system brings to a cost premium which is higher than reference cruise ship's annual revenue. Only alternatives which use fossil fuels bring to cost premiums lower than that figure. Also, renewable methanol produced from blue hydrogen has a cost premium almost equal to annual revenue. Some alternatives have a cost premium which is almost two times annual revenues of the considered cruise ship.

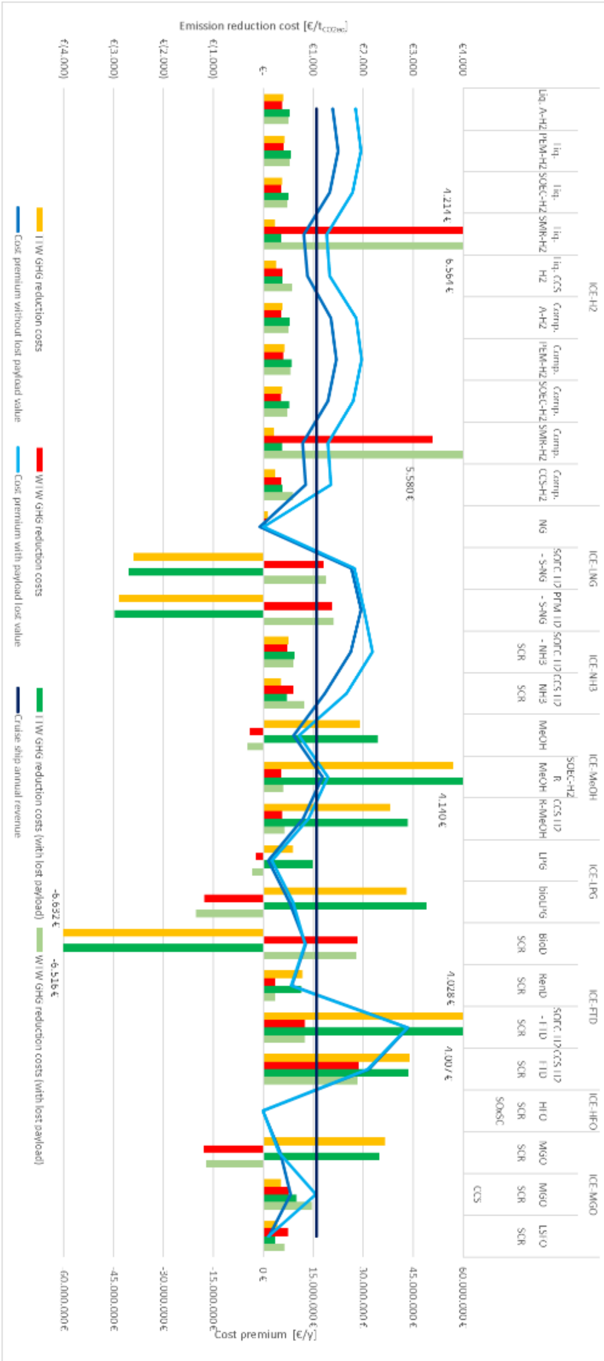

Figure 120 – TTW and WTW GHG reduction cost for internal combustion engines (luxury class)

Figure 120 shows TTW and WTW carbon dioxide equivalent reduction cost and cost difference between each power generation system and the reference case, both considering and ignoring lost payload, for internal combustion engines. Green and blue hydrogen as internal combustion engines fuel are all characterized by low TTW and WTW GHG emission reduction costs between 250 €/ton$_{CO2eq}$ and 430 €/ton$_{CO2eq}$, which considering lost payload become 380 €/ton$_{CO2eq}$ and 560 €/ton$_{CO2eq}$. Cost premium for green hydrogen is between 20 and 23 million euros per year (27 and 30 million euros considering lost payload value), while for blue hydrogen is almost 13 million euros per year (20 million euros per year considering lost payload). Even in this case, brown hydrogen does not make much sense, particularly because WTW emission reduction cost is over 3400 €/ton$_{CO2eq}$ due to a low WTW GHG emission reduction. Internal combustion engines fuelled by natural gas have a very low TTW GHG reduction cost: in this case both cost premium and emission reduction are negative figures and thus the result is a positive figure. WTW GHG emission reduction cost is negative because, while emissions are increased, differential cost becomes positive. Synthetic natural gas can be considered a feasible option only considering WTW emissions, and WTW GHG reduction cost is between 1200 €/ton$_{CO2eq}$ and 1400 €/ton$_{CO2eq}$ accounting lost payload capacity (it was obtained almost the same range ignoring this figure). TTW emission reduction cost is negative because TTW emissions are increased by using synthetic methane, mainly because internal combustion engines suffer from methane slip. Internal combustion engines fuelled by ammonia have a higher TTW and WTW reduction cost than other hydrogen fuelled options, between 350 €/ton$_{CO2eq}$ and 600 €/ ton$_{CO2eq}$ (480 €/ton$_{CO2eq}$ and 800 €/ton$_{CO2eq}$ accounting value lost). An ammonia fuelled powertrain has a cost premium ranging between 19 and 26 million euros per year, but accounting lost payload value its cost premium is between 25 and 33 million euros. Methanol fuelled engines have all very high TTW GHG reduction costs because emission reduction is limited when comparing this value to HFO fuelled internal combustion engines. When accounting WTW emissions, reduction cost is lower than zero for fossil methanol because its WTW emissions are higher than reference case. For synthetic methanol, WTW carbon dioxide equivalent emission reduction costs are comparable to other alternatives considered, between 360 €/ton$_{CO2eq}$ and 380 €/ton$_{CO2eq}$ (400 €/ton$_{CO2eq}$ and 430 €/ton$_{CO2eq}$ accounting lost payload value). Cost premium for this synthetic hydrocarbon is also moderate, spanning from 12 to 18 million euros without lost payload value and between 14 and 20 million euros per year accounting this figure. LPG has relatively high TTW emission reduction costs and negative WTW emission reduction costs, while also having a low-cost premium. Biodiesel has a negative TTW reduction cost because its TTW emissions are higher than reference case, but WTW emission reduction cost is high, mainly because emission reduction is low compared to the cost premium introduced. Renewable diesel has some interesting results: its TTW GHG reduction cost is equal to almost 790

€/ton$_{CO2eq}$ (770 €/ton$_{CO2eq}$ considering lost payload), WTW carbon dioxide equivalent emission reduction cost is equal to almost 250 €/ton$_{CO2eq}$ (240 €/ton$_{CO2eq}$ considering lost payload value) and cost premium is equal to almost 9 million euros per year regardless of lost payload value. FTD from green or blue hydrogen has the highest cost premium among alternatives considered, and some of the highest TTW and WTW GHG reduction costs.

MGO alone gives a small TTW emission benefit, but when this fuel is coupled with a CCS system, TTW emission reduction cost is equal to almost 350 €/ton$_{CO2eq}$ (670 €/ton$_{CO2eq}$ considering lost payload value) and WTW GHG reduction cost is equal to almost 510 €/ton$_{CO2eq}$ (almost 970 €/ton$_{CO2eq}$ accounting lost payload value). Cost premium is equal to 16 million euros per year, and half of this figure is given by lost payload value. LSFO has relatively low TTW and WTW reduction costs and low cost premium when compared to reference case but gives also small benefits to emission reduction.

Internal combustion engine's cost premium is generally lower than previous cases and lower than reference luxury class cruise ship's annual revenue. Green hydrogen, synthetic natural gas, ammonia and FTD have cost premiums higher than annual revenue limit, but all other alternatives are economically feasible. Renewable methanol and MGO with a CCS system are close to the limit, and thus their economic feasibility should be analysed with more detail.

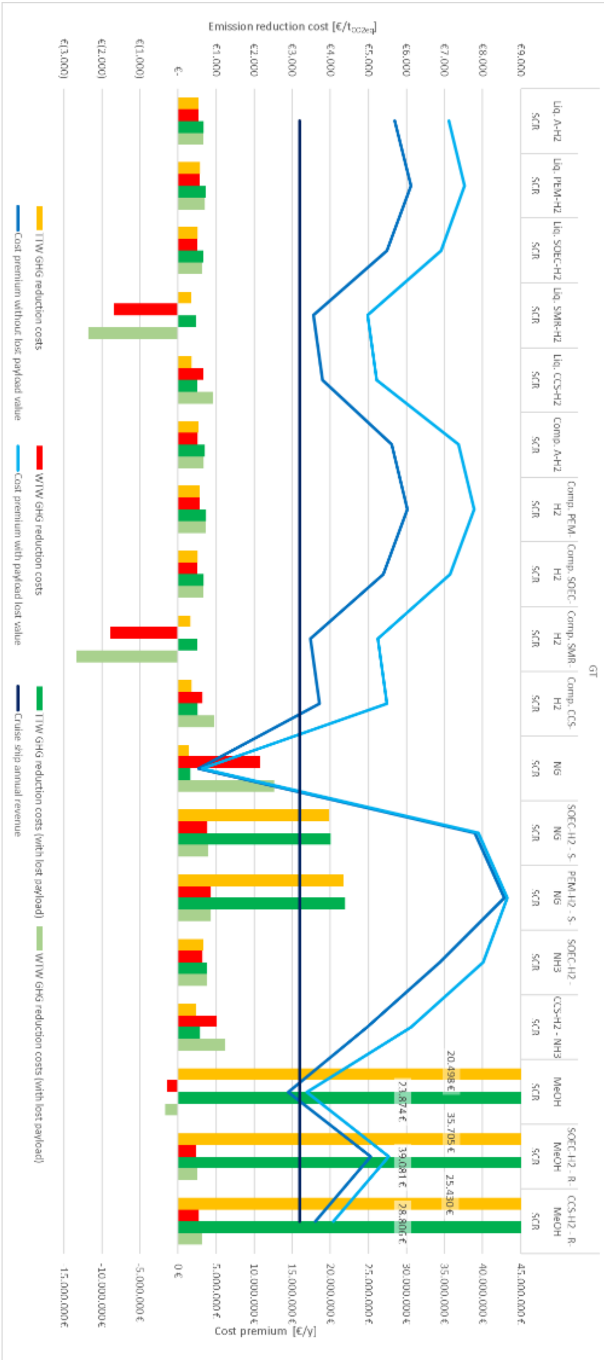

Figure 121 – TTW and WTW GHG reduction cost for gas turbines (luxury class)

Figure 121 shows TTW and WTW carbon dioxide equivalent reduction cost and cost difference between each power generation system and the reference case, both considering and ignoring lost payload, for gas turbines. Green and blue hydrogen as gas turbines fuels are all characterized by low TTW and WTW GHG emission reduction costs between 360 €/ton$_{CO2eq}$ and 580 €/ton$_{CO2eq}$, which considering lost payload become 500 €/ton$_{CO2eq}$ and 710 €/ton$_{CO2eq}$. Cost premium for green hydrogen is between 27 and 31 million euros per year (34 and 38 million euros considering lost payload value), while for blue hydrogen is almost 19 million euros per year (26 million euros per year considering lost payload). These cost premiums are not sustainable and too high when compared to other options already described. Brown hydrogen has higher WTW GHG emissions and cannot be considered a feasible option for future developments. Fossil natural gas fuelled gas turbines have low TTW emission reduction costs equal to almost 275 €/tonCO2eq (320 €/ton$_{CO2eq}$ considering lost payload), but a high WTW emission reduction cost equal to almost 2200 €/ton$_{CO2eq}$ (2500 €/ton$_{CO2eq}$ considering lost payload), while cost premium is equal to almost 3 million euros per year considering lost payload value. Synthetic natural gas has very high TTW GHG emission reduction cost and cost premiums, but WTW carbon dioxide equivalent emission reduction cost is between 770 €/ton$_{CO2eq}$ and 860 €/ ton$_{CO2eq}$ (880 €/ton$_{CO2eq}$ and 870 €/ton$_{CO2eq}$ considering lost payload). Gas turbines fuelled by ammonia have a TTW reduction cost between 470 €/ton$_{CO2eq}$ and 650 €/ton$_{CO2eq}$ (580 €/ton$_{CO2eq}$ and 760 €/ton$_{CO2eq}$ accounting value lost), while WTW reduction cost spans between 650 €/ton$_{CO2eq}$ and 1000 €/ton$_{CO2eq}$ (760 €/ton$_{CO2eq}$ and 1250 €/ton$_{CO2eq}$ accounting value lost). An ammonia fuelled powertrain has a cost premium ranging between 25 and 35 million euros per year, but accounting lost payload value cost premium is between 30 and 40 million euros. Methanol fuelled gas turbines have all very high TTW GHG reduction costs because emission reduction is limited when comparing this value to HFO fuelled internal combustion engines. When accounting WTW emissions, reduction cost is lower than zero for fossil methanol because its WTW emissions are higher than reference case. For synthetic methanol, WTW carbon dioxide equivalent emission reduction costs are comparable to other alternatives considered, between 460 €/ton$_{CO2eq}$ and 550 €/ton$_{CO2eq}$ (500 €/ton$_{CO2eq}$ and 620 €/ton$_{CO2eq}$ accounting lost payload value). Cost premium for this synthetic hydrocarbon spans from 18 to 25 million euros without lost payload value and between 29 and 39 million euros per year accounting this figure.

Cost premium for gas turbines is surely over reference vessel's revenues, except when these power generators are fuelled by natural gas turbines. In this case, cost premium is well below revenues and thus it can be considered economically feasible.

When these results are compared with the ones of a contemporary class cruise ship, it is found out that while TTW and WTW carbon dioxide equivalent reduction costs are similar between these two sizes of cruise ships. Cost premiums are higher when compared with luxury cruise ship annual revenues, so it can be stated that for smaller cruise ships, implementing less emitting power generation systems is more difficult from an economic point of view.

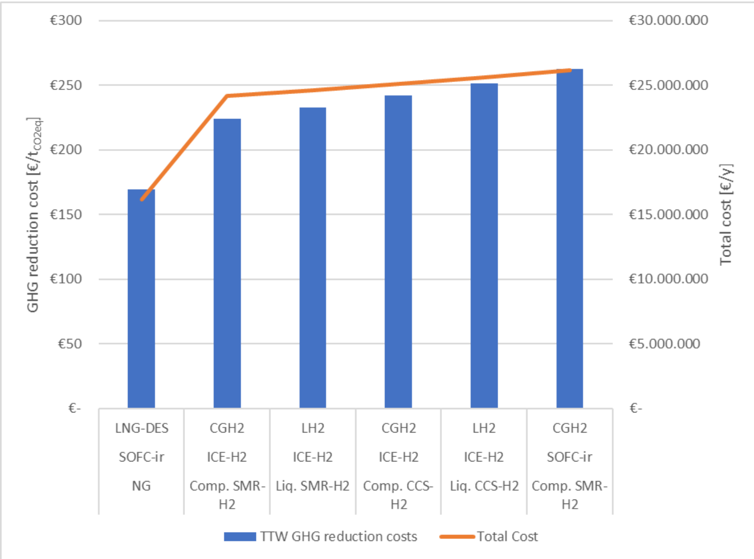

Figure 122 – Six alternatives with lowest TTW GHG reduction cost (luxury class)

Figure 122 shows the six alternatives with lowest TTW carbon dioxide equivalent reduction costs and their total cost for the luxury class cruise ship. Hydrogen seems the most promising fuel for an economically feasible TTW GHG reduction, even if for this smaller ship the lowest TTW GHG reduction cost is obtained with SOFC fuelled by fossil natural gas. This power system has a TTW GHG emission reduction cost almost equal to almost 170 €/ton$_{CO2eq}$. A luxury class cruise ship equipped with SOFC fuelled by fossil natural gas have a total cost equal to almost 16 million euros, which corresponds to a cost premium equal to almost 3 million euros and thus to almost 24% of annual revenues. The second and third most cheap TTW GHG reduction cost use brown hydrogen inside internal combustion engines, one which stores this gas in its compressed state at 700 bar (224 €/ton$_{CO2eq}$), the other one with a liquid storage (233 €/ton$_{CO2eq}$). Total cost for these options is high and equal to almost 24 million dollars for each year of operations. Internal combustion engines fuelled by blue hydrogen take also fourth and fifth place for more economic TTW carbon dioxide equivalent reduction cost, reaching almost 242 €/ton$_{CO2eq}$ and 251 €/ton$_{CO2eq}$. These alterative designs have a total cost for their implementation equal to almost 25 and 26 million euros per year respectively. SOFC fuelled by compressed brown hydrogen have the sixth lowest TTW GHG reduction cost which is equal to almost 263 €/ton$_{CO2eq}$, and this potential solution has a total cost equal to almost 26 million euros per year.

Comparing these results with what has been found out for contemporary class cruises, it must be acknowledged the fact that SOFC can be considered more feasible for luxury class cruise ship than for contemporary class vessels, while gas turbines can find some applications for bigger vessels. It is confirmed that brown and blue hydrogen are some of the most promising fuels for a TTW carbon dioxide equivalent emission reduction.

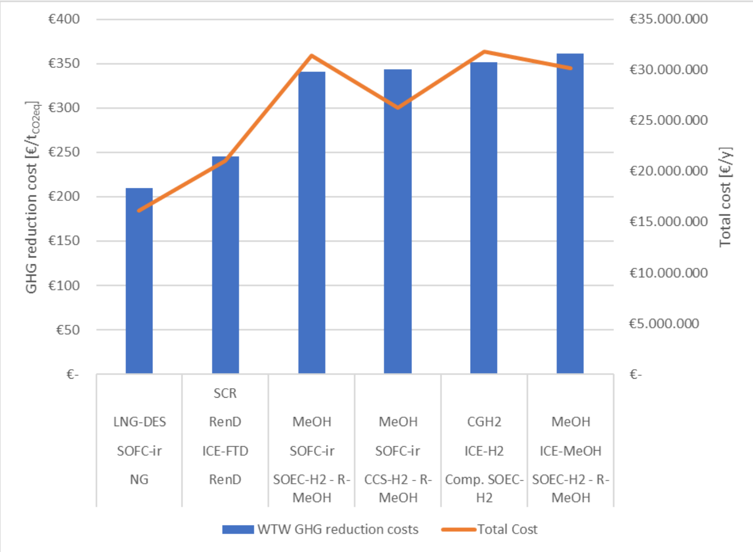

Figure 123 – Six alternatives with lowest WTW GHG reduction cost (luxury class)

Figure 123 shows the six alternatives with lowest WTW carbon dioxide equivalent reduction costs and their total cost. SOFC fuelled by fossil natural gas have the lowest WTW GHG reduction cost equal to almost 210 €/ton$_{CO2eq}$ and a total cost equal to almost 16 million euros per year of operation, which is also the lowest total cost among the first six lowest WTW GHG reduction cost alternatives. Internal combustion engines fuelled by renewable diesel have the second cheapest WTW GHG reduction cost, which is equal to almost 245 €/ton$_{CO2eq}$. Total cost for this system is equal to almost 21 million dollars for each year of operations. SOFC fuelled by renewable methanol produced from green hydrogen have the third lowest WTW GHG emission reduction cost almost equal to almost 340 €/ton$_{CO2eq}$, almost a 39% increase from the second cheapest WTW GHG reduction cost. A cruise ship equipped with this technical system has a total cost equal to almost 32 million euros. When SOFC are fuelled by methanol produced from blue hydrogen, WTW carbon dioxide equivalent reduction cost reaches almost 344 €/ton$_{CO2eq}$ and so it takes the fourth spot. The total cost of this system is equal to almost 26 million euros per year. Internal combustion engines fuelled by renewable hydrogen produced from SOEC and stored in its compressed state have a WTW GHG reduction cost equal to almost 352 €/ton$_{CO2eq}$. This design has a total cost for its implementation onboard equal to almost 32 million euros per year. Internal combustion engines fuelled by methanol produced from green hydrogen have the sixth lowest WTW GHG reduction cost, which is equal to almost 361 €/ton$_{CO2eq}$, and this potential solution has a total cost equal to almost 30 million euros per year.

Comparing these results with what has been found out for contemporary class cruises, it was found out that SOFC confirmed their potential for small luxury class cruise ships, because they are the generator in three of the six first alternatives. Renewable methanol is also a fuel that must be seriously considered as a potential solution for luxury class cruises. It should also be highlighted the fact that WTW carbon dioxide equivalent reduction cost is generally lower for luxury class cruises, which could bring to more orders for these types of cruise ships.

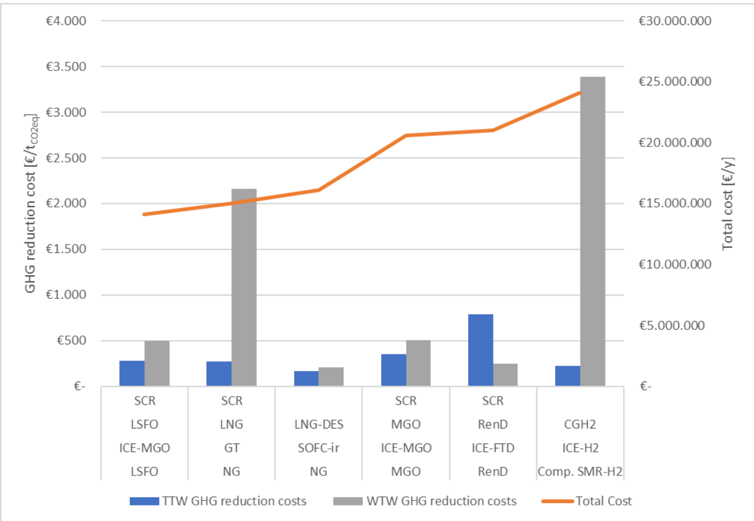

Figure 124 – Six alternatives with lowest total cost (luxury class)

Figure 124 shows the six alternatives with the lowest total cost and their associated TTW and WTW carbon dioxide equivalent emissions' reduction costs. Internal combustion engines fuelled by LSFO take the first place, with a total cost equal to almost 14 million euros per year. TTW and WTW GHG reduction cost are equal to almost 280 €/ton$_{CO2eq}$ and 490 €/ton$_{CO2eq}$ respectively. Gas turbines fuelled by fossil natural gas have the second-cheapest total cost, equal to almost 15 million euros per year. TTW and WTW carbon dioxide emission reduction costs for this system are equal to almost 275 €/ton$_{CO2eq}$ and 2160 €/ton$_{CO2eq}$

respectively. SOFC fuelled by fossil natural gas have the third-lowest total cost, which is almost equal to 16 million euros per year. A cruise ship equipped with this technical system has TTW and WTW GHG reduction cost equal to almost 170 €/ton$_{CO2eq}$ and 210 €/ton$_{CO2eq}$ respectively. Internal combustion engines are power generators used in all other spots of this standing. When these generators are fuelled by MGO and are coupled with a CCS system capable of reducing to a half TTW carbon dioxide emission from prime generators, their total cost is equal to almost 21 million euros per year, which is the fourth-lowest value. TTW and WTW GHG reduction cost for this solution are equal to almost 350 €/ton$_{CO2eq}$ and 510 €/ton$_{CO2eq}$ respectively. Internal combustion engines fuelled by renewable diesel have a total cost equal to almost 21 million euros per year and are in fifth place. This design's TTW and WTW GHG reduction cost are equal to almost 790 €/ton$_{CO2eq}$ and 245 €/ton$_{CO2eq}$ respectively. Internal combustion engines fuelled by compressed brown hydrogen have the sixth-lowest total cost equal to almost 24 million euros per year, and its TTW and WTW GHG reduction cost are equal to almost 223 €/ton$_{CO2eq}$ and 3380 €/ton$_{CO2eq}$ respectively.

These results highlight that power generation systems with the lowest total costs have the same five first alternatives for lowest total costs, confirming the power generations systems previously identified as the most favourable from a purely economic point of view.

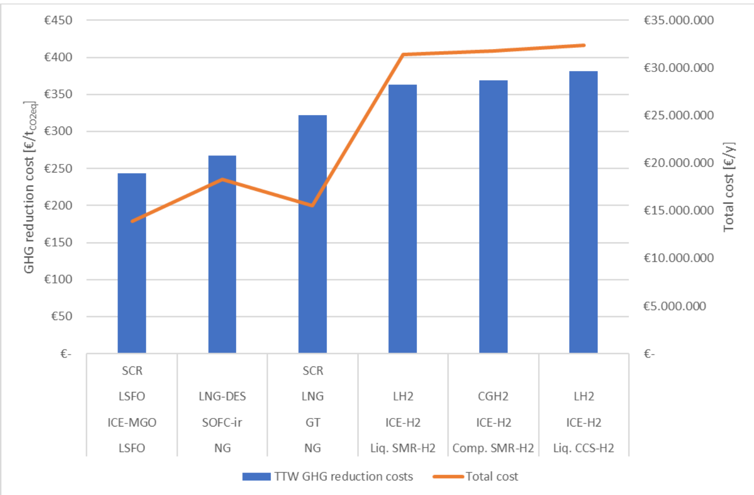

Figure 125 – Six alternatives with lowest TTW GHG reduction cost (with value lost, luxury class)

The analysis shown in previous paragraphs does not account lost payload value. For this reason, in this thesis all calculations were performed accounting also value of lost payload and selecting the six best alternatives for each metric used in previous graphs. Figure 125 shows the six alternatives with lowest TTW carbon dioxide equivalent reduction costs and their total cost. The cheapest TTW GHG reduction cost use LSFO inside internal combustion engines and has a reduction cost equal to almost 245 €/ton$_{CO2eq}$. Total cost for this option is equal to almost 14 million dollars for each year of operations, which is also the lowest total cost among the first six places. SOFC fuelled by fossil natural gas is the second-cheapest alternative design because its TTW carbon dioxide equivalent reduction cost is equal to almost 267 €/ton$_{CO2eq}$. Total cost for this option is equal to almost 18 million dollars for each year of operations. Gas turbines fuelled by fossil natural gas take third place for most economic TTW carbon dioxide equivalent reduction cost, reaching almost 320 €/ton$_{CO2eq}$. This power generation system has a total cost for its implementation equal to almost 16 million euros per year. Internal combustion engines fuelled by brown hydrogen stored in its liquefied state have the fourth lowest TTW GHG emission reduction cost almost equal to 363 €/ton$_{CO2eq}$: this technical solution has a total cost of almost 31 million euros per year for its implementation. The same configuration with a compressed storage of brown hydrogen has a TTW GHG emission reduction cost almost equal to 370 €/ton$_{CO2eq}$ and a total cost equal to almost 32 million euros. A cruise ship equipped with internal combustion engines fuelled by blue hydrogen stored in its liquid state has the sixth lowest TTW GHG reduction cost equal to almost 380 €/ton$_{CO2eq}$. This potential solution has a total cost equal to almost 32 million euros per year.

The comparison between Figure 125 and Figure 122 shows that the alternative which had the first spot (SOFC fuelled by fossil natural gas) becomes the second-cheapest option when lost payload value is accounted, while the second option (ICE with compressed SMR-H2) goes down to fifth place. Gas turbines fuelled by natural gas and internal combustion engines earn better spots in this analysis because they do not bring to a serious payload capacity decrease. Results in this case are almost like a contemporary class cruise ship.

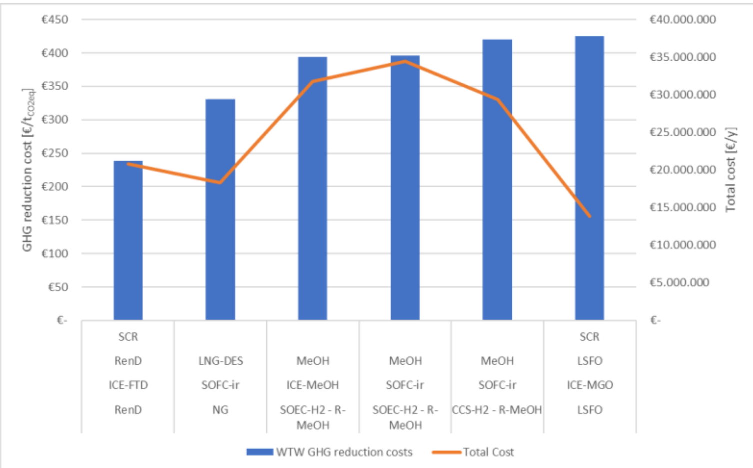

Figure 126 – Six alternatives with lowest WTW GHG reduction cost (with value lost, luxury class)

Figure 126 shows the six alternatives with lowest WTW carbon dioxide equivalent reduction costs and their total cost. Renewable methanol seems the most promising fuel for an economically feasible WTW GHG reduction when lost payload value is accounted. The cheapest WTW GHG reduction cost use renewable diesel inside internal combustion engines and has a reduction cost equal to almost 240 €/ton$_{CO2eq}$. Total cost for this option is equal to almost 21 million dollars for each year of operations. SOFC fuelled by natural gas is the second-cheapest alternative design because its WTW carbon dioxide equivalent reduction cost is equal to almost 330 €/ton$_{CO2eq}$. Total cost for this option is equal to almost 18 million dollars for each year of operations. Internal combustion engines fuelled by renewable methanol produced from green hydrogen take the third place, reaching almost 394 €/ton$_{CO2eq}$. This power generation system has a total cost for its implementation equal to almost 32 million euros per year. SOFC fuelled by renewable methanol produced from green hydrogen have a WTW GHG reduction cost equal to almost 400 €/ton$_{CO2eq}$ and this solution has a total cost of almost 35 million euros per year. SOFC fuelled by renewable methanol produced from blue hydrogen have the fifth lowest WTW GHG emission reduction cost almost equal to 420 €/ton$_{CO2eq}$. A cruise ship equipped with technical solution has a total cost equal to almost 30 million euros. Internal combustion engines fuelled by LSFO have the sixth lowest WTW GHG reduction cost, which is equal to almost 425 €/ton$_{CO2eq}$, and this potential solution has a total cost equal to almost 14 million euros per year.

Comparison between Figure 126 and Figure 123 shows that renewable diesel-fuelled cruise ships have the lowest WTW carbon dioxide equivalent reduction cost accounting lost payload cost, while without considering this figure the preferred option was SOFC and natural gas. Renewable methanol can still be considered a cost-effective option for decarbonisation of cruise ships, because for these small ships as for bigger ones is a fuel which is used in almost half of the first six places. SOFC are the power generators of two of the selected options, and thus it is confirmed their interesting possible application for luxury class cruise ships.

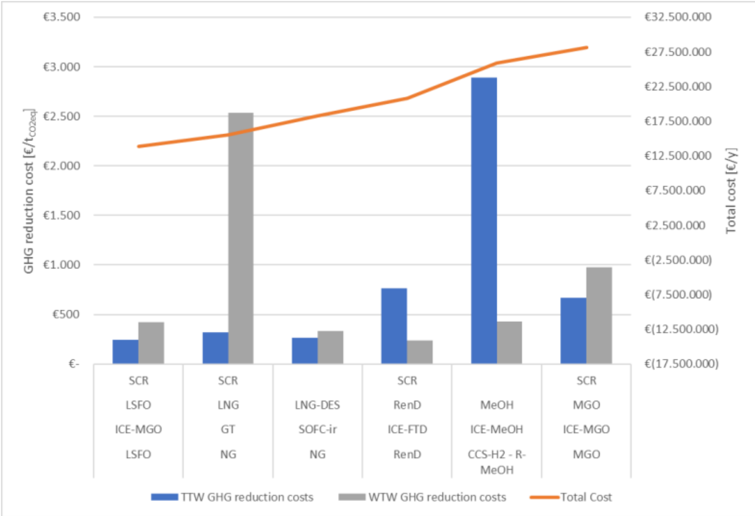

Figure 127 – Six alternatives with lowest total cost (with value lost, luxury class)

Figure 127 shows the six alternatives with the lowest total cost and their associated TTW and WTW carbon dioxide equivalent emissions' reduction costs when lost payload value is accounted. Internal combustion engines fuelled by LSFO take the first place, with a total cost equal to almost 14 million euros per year. TTW and WTW GHG reduction cost are equal to almost 240 €/ton$_{CO2eq}$ and 425 €/ton$_{CO2eq}$ respectively. Gas turbines fuelled by fossil natural gas have the second-cheapest total cost, equal to almost 16 million euros per year. TTW and WTW carbon dioxide emission reduction costs for this system are equal to almost 320 €/ton$_{CO2eq}$ and 2530 €/ton$_{CO2eq}$ respectively. SOFC fuelled by fossil natural gas have the third-lowest total cost, which is almost equal to 18 million euros per year. A cruise ship equipped with this technical system has TTW and WTW GHG reduction cost equal to almost 270 €/ton$_{CO2eq}$ and 330 €/ton$_{CO2eq}$ respectively. Internal combustion engines are power generators used in all other spots of this standing. When these generators are fuelled by renewable diesel, their total cost is equal to almost 21 million euros per year, which is the fourth-lowest value. TTW and WTW GHG reduction cost for this solution are equal to almost 770 €/ton$_{CO2eq}$ and 240 €/ton$_{CO2eq}$ respectively. Internal combustion engines fuelled by renewable methanol produced from blue hydrogen have a total cost equal to almost 21 million euros per year and are in fifth place. This design's TTW and WTW GHG reduction cost are equal to almost 2890 €/ton$_{CO2eq}$ and 430 €/ton$_{CO2eq}$ respectively. Internal combustion engines fuelled by MGO and are coupled with a CCS system capable of reducing to a half TTW carbon dioxide emission from prime generators have the sixth-lowest total cost equal to almost 28 million euros per year, and its TTW and WTW GHG reduction cost are equal to almost 670 €/ton$_{CO2eq}$ and 970 €/ton$_{CO2eq}$ respectively.

In this case, the sixth-lowest total costs are the same of the contemporary class cruise ship. Thirst three spots are the same when payload was not accounted. Other places have changed, mainly because MGO with CCS system have an impact on payload higher than internal combustion engines fuelled by renewable diesel or methanol.

Calculation of CII for the luxury class cruise ship were performed and results are surely important and different from what has been obtained for contemporary class cruises. All alternative power generation systems proposed in previous chapters have been analysed from this potential new regulation's perspective to assess which alternative design can fulfil these requirements and particularly highlighting that some designs behave differently considering only TTW emissions or the whole WTW cycle.

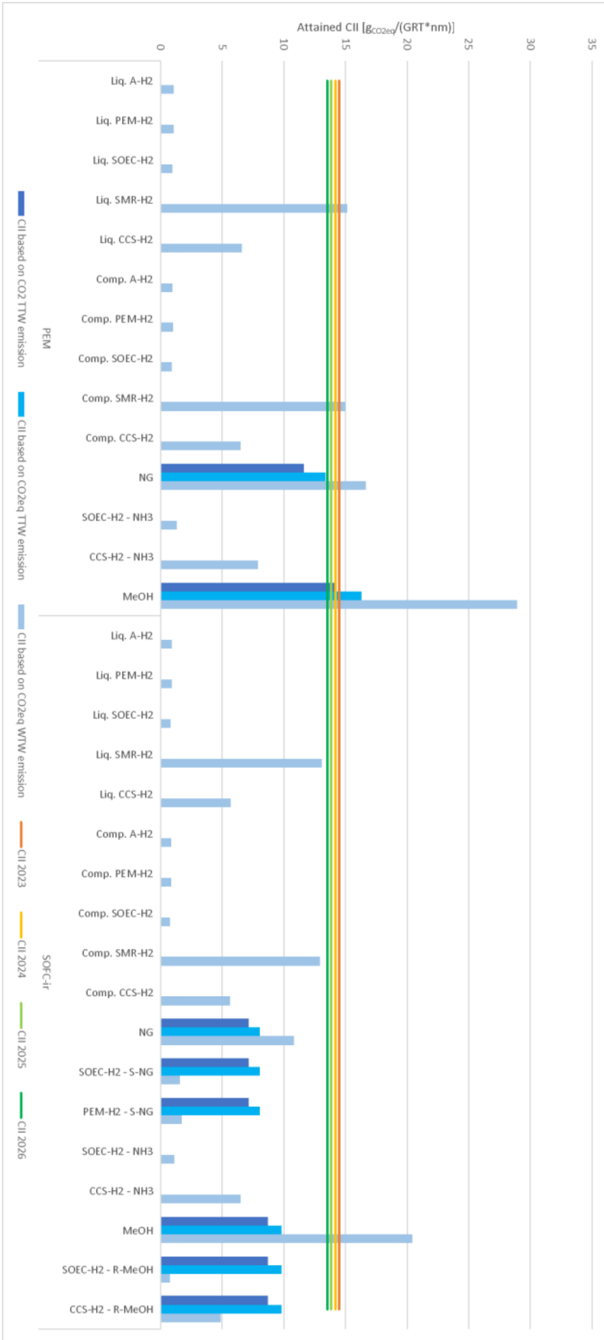

Figure 128 – CII for fuel cells-based systems (luxury class)

Figure 128 shows CII attained value for all different power generation system configurations based on fuel cells. CII threshold values have been calculated for 4 different values using the gross tonnage of the reference vessel equal to almost 50,000 GRT. Every CII threshold value is corrected and thus decreased as outlined by IMO. Blue and green hydrogen are surely the alternative which brings to an attained CII below 2026 threshold value accounting only TTW emissions or the whole life-cycle. Brown hydrogen can surely contribute to lower TTW emissions and an acceptable attained CII value. When WTW carbon dioxide emissions are considered for attained CII calculation, the resulting value is over threshold. Fossil natural gas and methanol used with a reforming system to power PEM fuel cells onboard luxury class cruise ships in this case have different behaviours. Natural gas and reforming bring to an acceptable CII when only TTW carbon dioxide emissions are considered. When WTW carbon dioxide emissions are used for the calculation, attained CII is higher than threshold. When TTW methane slip is accounted, natural gas with reforming brings to a CII almost equal to threshold value in 2026. Fossil methanol does not bring to an acceptable value, even when only TTW carbon dioxide emissions are considered. Ammonia produced from green or blue hydrogen can be considered a feasible option even when coupled with PEM fuel cells because the attained CII is below threshold values. SOFC fuelled by fossil natural gas have an attained CII below threshold values for each emission pathway considered. Synthetic natural gas brings to lower WTW carbon dioxide equivalent emissions and thus to lower CII threshold values. SOFC can thus be considered a good technology which can help to comply with regulations using fossil natural gas for the next years and then can be converted for the use with hydrogen, ammonia, or synthetic natural gas when regulation will become stricter and consider the whole WTW cycle. Fossil methanol complies with CII regulation when only TTW carbon dioxide equivalent emissions are considered. Its renewable option complies with CII regulation.

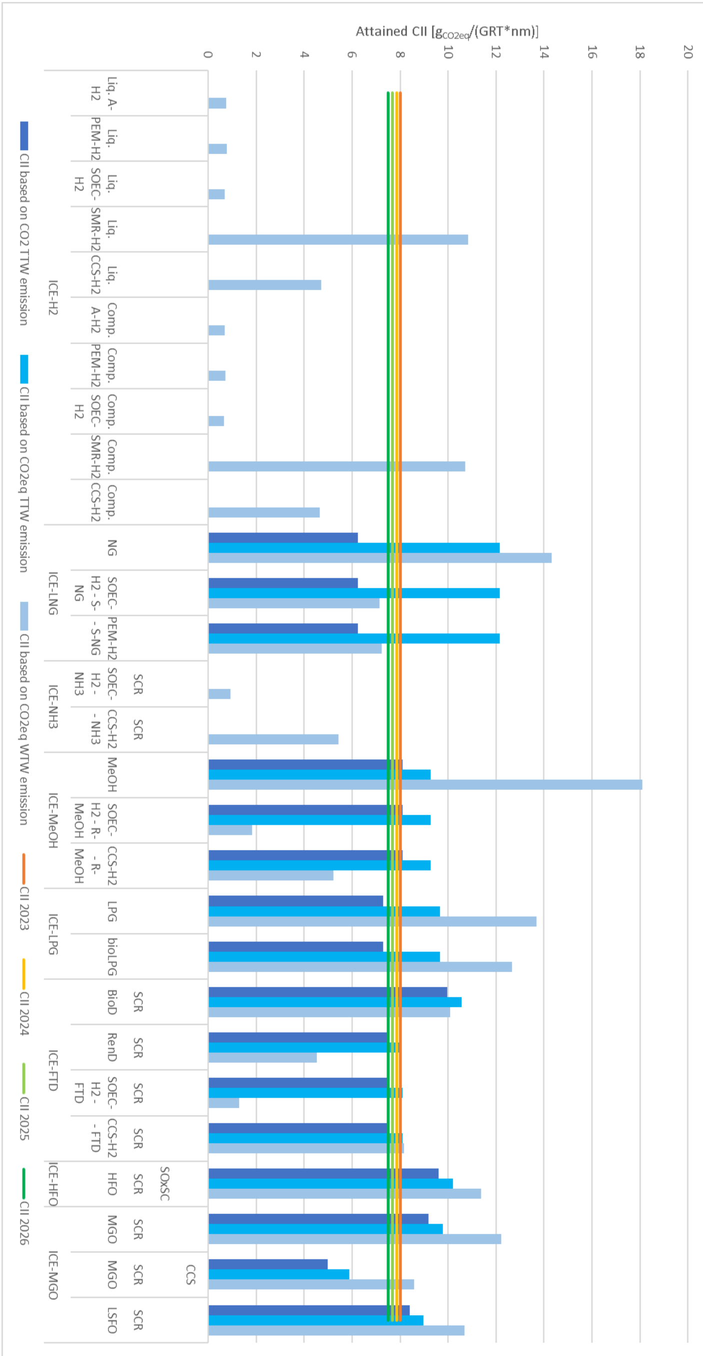

Figure 129 – CII for internal combustion engines-based systems (luxury class)

Figure 129 shows CII attained value for all different power generation system configurations based on internal combustion engines. For these power generators, green and blue hydrogen are the key fuel to cut emissions and to comply with CII regulation accounting only TTW emissions or the whole WTW cycle. Even in this case, brown hydrogen is not a feasible option when WTW carbon dioxide emissions are accounted during attained CII calculations. Internal combustion engines fuelled by natural gas have a particular behaviour because of methane slip. They comply with the proposed CII regulation when only TTW carbon dioxide emissions are considered, but when methane slip is accounted as carbon dioxide equivalent emission, their attained CII is almost 50% higher than threshold values. Also, attained CII calculated by considering the whole WTW cycle is over threshold values. When synthetic natural gas is used as internal combustion engine fuel, attained CII calculated using WTW carbon dioxide equivalent emissions is slightly below threshold value. Ammonia, as hydrogen, allows the cruise ship to comply with all CII required values. Fossil methanol and internal combustion engines does not comply with proposed CII regulation, but when renewable methanol is considered, attained CII calculated using WTW carbon dioxide equivalent emissions is lower than threshold value. LPG and bio-LPG can enable the ship to comply with threshold value when only TTW carbon dioxide emissions are considered. Renewable diesel and FTD produced from renewable hydrogen have attained CII values calculated using TTW emissions almost equal to threshold values, but well below these limits when WTW GHG emissions are accounted. FTD produced from blue hydrogen has higher WTW emissions, and it does not comply with CII requirements. It is also highlighted the fact that an HFO fuelled luxury class cruise ship would not comply with proposed CII regulation for each set of emissions considered. This result is valid also for MGO and LSFO, so it is important to highlight that with current oil-based fuel options, a luxury class cruise ship would not comply with CII regulation. If a CCS system capable of cutting of almost a half carbon dioxide emissions of internal combustion engines is installed, attained CII for the reference vessel is below threshold limit when TTW carbon dioxide equivalent emissions are accounted. When WTW emissions are considered, this technical option does not comply with current CII regulation and would not be considered a feasible option.

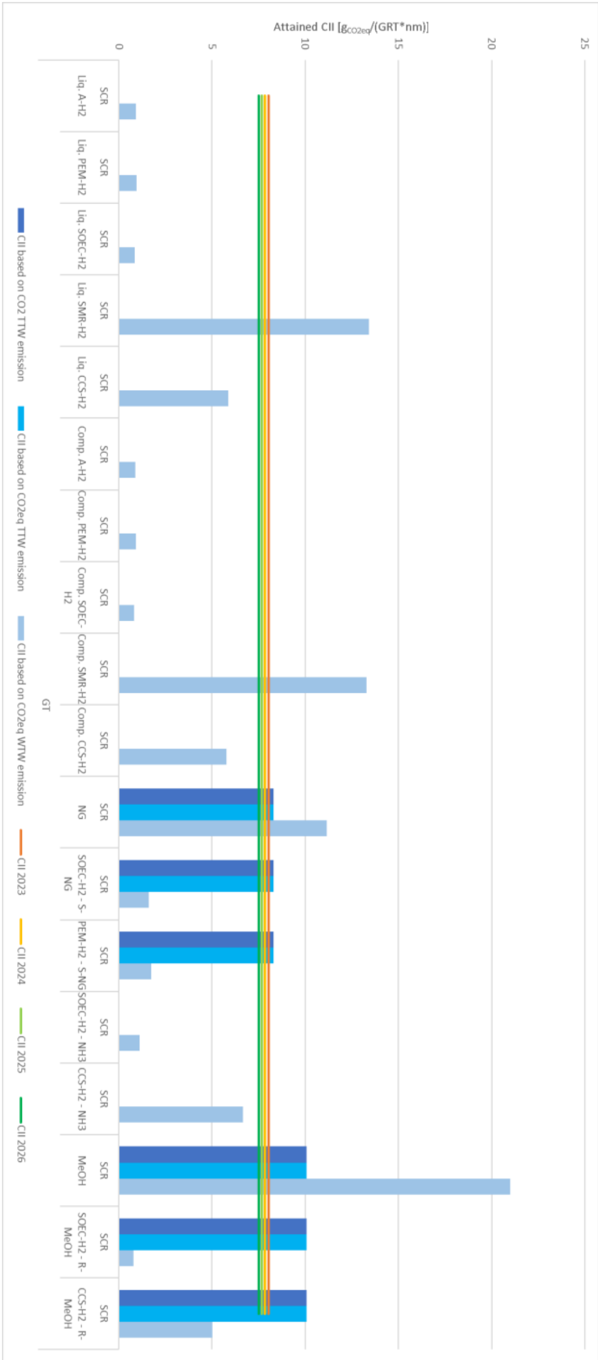

Figure 130 – CII for gas turbines-based systems (luxury class)

Figure 130 shows CII attained value for all different power generation system configurations based on gas turbines. For these power generators, green and blue hydrogen are the key fuel to cut emissions and to comply with CII regulation accounting only TTW emissions or the whole WTW cycle. Even in this case, brown hydrogen is not a feasible option when WTW carbon dioxide emissions are accounted during attained CII calculations. Fossil natural gas fuelled gas turbines have an attained CII higher than threshold value for each set of emission considered. If synthetic natural gas is used as fuel, attained CII calculated considering WTW carbon dioxide equivalent emissions is lower than regulation's limits. Ammonia is another potential fuel which guarantees a CII value below threshold, even if this fuel is produced from blue hydrogen. Methanol case is like natural gas's one: its fossil feedstock gives attained CII over the threshold, but synthetic fuel complies with CII regulations when WTW carbon dioxide emissions are considered.

Results for luxury class cruise ships are like the ones of contemporary class vessels, but one of the key differences is the fact that the same technical solutions have generally lower values than the proposed limits. It is thus confirmed that probably, smaller luxury class cruise ship would be preferred to big ones because it could be easier to comply with CII limits using these technologies.

Discussion

The aim of this study was to assess the usefulness of a simulation tool based on a holistic approach able to assess fuel cells and innovative fuels impact on a cruise ship electrical and thermal power generation system.

Key findings obtained by the simulation tool based on a holistic approach for cruise ships power generation systems can be summarised as follows:

- *Innovative fuels prices will be highly dependent on natural gas price and electricity price*. Today's oil-based ship's fuels prices depend highly on their feedstock, which is crude oil price, regulated by international markets. Possible future fuels, like green hydrogen, green ammonia or synthetic fuels costs will be highly related to renewable electricity price of the plant in which they will be produced since their feedstock price influence will be negligible. All fuels produced from blue hydrogen will be dependent on natural gas price and thus will surely be more expansive than this hydrocarbon.
- *Innovative fuels production emissions are mainly related to their feedstock emissions*. Today's oil-based ship's fuels production emissions are mainly related to their extraction and their refining, but they are relatively low when compared to the emissions related to their combustion. Emissions related to innovative fuels production will be related to their feedstock: hydrogen is renewable and thus almost a zero-emission fuel when produced from water by electrolysis using only renewable energy sources, but it cannot be considered renewable and a zero-emission fuel when produced from natural gas. This is the same for methanol, ammonia or other synthetic fuels based on hydrogen: if this feedstock has emissions related to its production, those fuels will not be 100% renewable.
- *TTW carbon dioxide equivalent emissions of electrical power generators can be deceiving.* All electrical power generators that can be fuelled by hydrogen claim that they can allow a zero-emission sailing, but this cannot be considered true. First, it must be considered that hydrogen or other synthetic fuels may bring to zero TTW emissions, but their whole life-cycle must be considered. Second, even if some electrical power generators can bring to substantial TTW emission reduction, like SOFC fuelled by natural gas (almost 52% of HFO-fuelled internal combustion engines), they may not allow a significant heat recovery and thus higher fuel consumption for thermal power generation would be needed.
- *Hydrogen and ammonia fed fuel cells are penalised by volume and mass requirement.* These zero-carbon fuels, particularly when coupled with fuel cells,

have a high requirement for masses and volumes onboard, not for the fuel itself but for its storage system and for the high payload capacity required by these power generators. This downside of hydrogen application is compensated by two aspects. First, hydrogen application onboard cruise ships could be considered if lower vessel's sailing autonomy requirements will be accepted by shipowners. A lower autonomy brings to a lower quantity of fuel onboard, so to smaller storage systems, and to a lower impact on onboard payload. Second, hydrogen is the key energy vector and feedstock for all zero emission fuels, and thus it will be the cheapest zero emission fuel per energy content.

- *PEM fuel cells fuelled by fossil fuels does not make sense, while SOFC seem more promising.* The potential application of a reforming system onboard to use natural gas or methanol to feed PEM fuel cells does not make sense from an emission point of view, mainly because it does not avoid any TTW carbon dioxide emission. Also, PEM fuel cell does cannot be coupled with a heat recovery system and thus thermal power requirement is the highest among alternatives considered. SOFC fuelled by natural gas on the other hand seem a promising power generation technology: they do not suffer from methane slip, they use a fuel already known for onboard application and are intrinsically ready to use zero-carbon or carbon-neutral fuels like synthetic natural gas, hydrogen, and methanol.
- *Carbon capture and storage onboard bring to an increased fuel consumption with today's technologies.* Exhaust gas treatment is the main solution for sulphur and nitrogen oxides emission reduction and for this reason a system like this one could be considered in future also for carbon dioxide emissions reduction. State-of-the-art technologies for carbon capture and storage for onshore applications are still under development, but values of electrical and thermal energy requirement are known. This system would require an increase in electrical and thermal power generation, which will increase the need for carbon capture and storage. For a system capable of capturing 50% of carbon dioxide emissions, electric energy requirement increases by 15% and thermal energy requirement is equal to almost 40% of all electrical energy. This technology could be considered for future applications only if a lower capture rate will be required for onboard systems or if their technical improvement will significantly reduce electrical and thermal energy requirement.
- *Most contemporary class cruise ship designs with fuel cells and gas turbines power generation systems are not economically feasible*. Cost premiums for

fuel, power generation systems and lost payload require an increased annual cost that exceeds annual revenues for the considered cruise ship class. The only combination based on fuel cells which can be considered truly economically and technically feasible is SOFC fuelled by fossil natural gas: its cost premium is equal to almost 37% of calculated annual revenues. Gas turbines fuelled by fossil natural gas are the only technical solution which is also economically feasible when considering those power generation systems: their cost premium is equal to almost 20% of calculated annual revenues.

- *Some systems have higher TTW carbon dioxide emissions than internal combustion engines fuelled by HFO.* It shall be highlighted that PEM fuel cells fuelled by natural gas and methanol bring to higher TTW GHG emissions than reference case scenario. The same conclusion has been found for internal combustion engines fuelled by natural gas (both fossil and synthetic) and biodiesel. The case of natural gas shall be carefully analysed and considered by national and international regulators, since methane slip is a big issue still unresolved and those emissions have a high influence on the environment. For biodiesel this increased emissions are caused by a disadvantageous combination of density, LHV and carbon content.
- *Some systems have higher WTW carbon dioxide emissions than internal combustion engines fuelled by HFO.* Power generation systems composed by PEM fuel cells fuelled by brown hydrogen, natural gas and methanol have higher WTW GHG emissions than reference case scenario. The same conclusion has been found for SOFC fuelled by methanol, for internal combustion engines fuelled by fossil natural gas, fossil methanol, fossil LPG, bio-LPG and MGO and for gas turbines fuelled by brown hydrogen and methanol.
- *Lowest TTW carbon dioxide equivalent emission reduction cost relies on natural gas.* For contemporary class cruise ships, the lowest TTW carbon dioxide equivalent emission reduction cost is given by internal combustion engines fuelled by LSFO. Among lowest TTW GHG emissions reduction cost it must be noted that gas turbines and SOFC fuelled by natural gas are among them alongside internal combustion engines fuelled by brown or blue hydrogen. Natural gas thus confirms to be a valid option as transitional fuel to a fully renewable future, when renewable fuels will have lower production costs. Also, hydrogen could play a role in decarbonising maritime transportation when employed inside internal combustion engines.

- *Lowest WTW carbon dioxide equivalent emission reduction cost can be archived by different technical options, which include internal combustion engines*. For contemporary class cruise ships, the lowest WTW carbon dioxide equivalent emission reduction is given by internal combustion engines fuelled by renewable diesel, which has WTT emissions highly dependent on feedstock as described in the dedicated paragraph. Other options rely on internal combustion engines fuelled by renewable methanol, by LSFO and by green hydrogen. Among top six alternatives there is also a power generation system based on SOC fuelled by renewable methanol. It must be noted that renewable methanol plays an important role when considering WTW GHG emissions reduction cost, mainly because it allows to have low life-cycle emissions while having a minimum impact on payload onboard. This impact can partially compensate the high cost premium related to this fuel's cost, which is obviously higher than its feedstock, namely green hydrogen.
- *Lowest total costs can be archived only with fossil fuels or internal combustion engines.* For contemporary class cruise ships, alternatives with the lowest total costs are vessels powered by internal combustion engines fuelled by LSFO, by renewable diesel, by synthetic methanol produced from blue hydrogen and by MGO with a CCS system. Gas turbines and SOFC take second and third spot in this standing when fuelled by natural gas. It shall be noted that all these solutions, except renewable diesel, would be required to rely on fossil fuels to maintain lower annual total costs for an alternative power generation system.
- *Lower natural gas or electricity prices will not compensate cost premiums introduced by alternative power generation systems.* It has been found out that cost premiums related to alternative power generation systems for cruise ships cannot be totally compensated by potential low renewable electricity cost or low cost of natural gas. Lowering these costs would surely be beneficial for economics of alternative power generation systems, but this cannot be the only driver to boost installation of less emitting technologies.
- *Ships can comply with proposed CII regulation quite easily until only TTW carbon dioxide emissions are accounted.* TTW carbon dioxide emissions are lower than WTW emissions for most alternative fuel options, except for synthetic hydrocarbons and biofuel. Most alternative power generation systems for cruise ships considered guarantee compliance with proposed CII regulation, starting from internal combustion engines fuelled by natural gas. When TTW carbon dioxide equivalent emissions are considered, so when methane slip is

accounted, it must be noted that some alternative systems do not guarantee compliance with CII regulation, particularly when considering internal combustion engines and hydrocarbons. For this reason, natural gas and dual fuel internal combustion engines applications shall be carefully considered and the real impact on environment shall be examined.

- *Economic feasibility for luxury class cruise ship can be met easier than for contemporary class vessels.* Luxury class cruise ships are smaller and more exclusive than contemporary class ones: they require less power installed onboard and thus less fuel, but they embark less payload, which is also more valuable. It was found out that cost premiums for luxury cruise ships are closer to annual revenue than for contemporary class vessels. The only combination based on fuel cells which can be considered economically and technically feasible is SOFC fuelled by fossil natural gas: its cost premium is equal to almost 37% of calculated annual revenues. Gas turbines fuelled by fossil natural gas are the only technical solution which is also economically feasible when considering those power generation systems: their cost premium is equal to almost 18% of calculated annual revenues.
- *For luxury class cruise ships, lowest TTW carbon dioxide equivalent emission reduction cost relies on SOFC and internal combustion engine fuelled by hydrogen*. Lowest TTW carbon dioxide equivalent emission reduction cost is given by internal combustion engines fuelled by LSFO. SOFC fuelled by natural gas have the second lowest TTW GHG reduction cost, while gas turbines fuelled by natural gas take the third spot. Other options with lowest TTW GHG reduction cost are all powered by internal combustion engines fuelled by brown or blue hydrogen. In is confirmed that hydrogen could play a role in decarbonising maritime transportation when employed inside internal combustion engines, but also the fact that SOFC and gas turbines are a promising solution for TTW carbon dioxide emission reduction compatible with economic requirements, even onboard these smaller cruise ships.
- *For luxury class cruise ships, lowest WTW carbon dioxide equivalent emission reduction cost can be archived by SOFC or internal combustion engines*. Lowest WTW carbon dioxide equivalent emission reduction cost is given by internal combustion engines fuelled by renewable diesel, while SOFC fuelled by natural gas take the second place. Internal combustion engines fuelled by synthetic methanol produced from green or blue hydrogen or fuelled by LSFO and SOFC fuelled by renewable methanol are other notable options with low WTW carbon

dioxide equivalent emission reduction costs. It must be noted that renewable methanol and SOFC confirm their important role when considering WTW GHG emissions reduction cost. Also, renewable diesel confirms its importance as potential future solution, but only when used inside internal combustion engines.

- *For luxury class cruise ships, the lowest total costs can be archived mainly with fossil fuels or internal combustion engines.* Alternatives with the lowest total costs are vessels powered by internal combustion engines fuelled by LSFO, by renewable diesel, by synthetic methanol produced from blue hydrogen or by MGO with a CCS system. Gas turbines and SOFC take second and third spot in this standing when fuelled by natural gas. It shall be noted that all these solutions, except renewable diesel, would be required to rely on fossil fuels to maintain lower annual total costs for an alternative power generation system, as found out for contemporary class cruise ships.
- *Smaller vessels would not rely on hydrogen for an economically feasible emission reduction.* As pointed out, hydrogen does not appear as a fuel used in the most economically desirable options for luxury class cruise ships, both when considering total cost or emission reduction costs. Synthetic methanol and renewable diesel seem to be the most desirable options alongside natural gas, but this fuel shall be used for SOFC or gas turbines.
- *CII requirements should be met easily with luxury class cruise ships.* It has been found out that all power generation systems analysed for luxury class cruise ships have attained CII compared to required values, which are proportionally lower than attained CII of contemporary class vessels. This means that with the proposed formulation of CII, it is easier to comply with this regulation with smaller cruise ships than with bigger ones. Lower CII also mean that, if this regulation will reduce the required value year by year, it is easier for this class of cruise ships to comply for more years with this regulation, giving them more longevity.

These findings confirm the initial hypothesis that a simulation tool based on a holistic approach is useful to assess fuel cells and innovative fuels' impact on cruise' ships electrical and thermal power generation systems.

This PhD thesis and the proposed tool able to simulate different power generation systems over one year of operations can help during basic design phases to highlight the best-performing designs when considering total emission reduction, impact on onboard payload, emission reduction cost, total cost, and compliance with regulations. This work should also bring attention of all stakeholders and particularly of national and international organisation on the need of regulations able to employ a holistic approach and to issue regulations which are able to reflect whole life-cycle of the ship.

Common literature publications are mainly focused on one fuel or on one specific combination of fuel and power generation system. These studies also often account only emissions related to fuel operations, in compliance with emissions considered by national and international regulations. Only literature about biofuels or other carbon-neutral fuels highlight the poor consideration given to the whole life-cycle of the fuel. Since works available in literature are focused mainly on emissions, there is a low emphasis on cost for both installation and operations of innovative fuels and power generation systems, and most importantly there is a lack of information about impact on payload capacity and about emissions related to thermal power generation onboard. These issues are all addressed in the proposed work to open the way to a holistic approach for the decarbonisation of maritime vehicles, and particularly of cruise ships.

This study does not account emissions and costs related to fuel and feedstock transport from production sites to utilisation sites. The contribution of this figure has been considered too variable and not easily predictable for cruise ships, which travel around the world and do not have stable routes and bunkering sites. These results may not be generalised to all types of vessels and particularly to ships which operate on pre-defined and stable routes, like regional ferries.

Further studies are necessary to verify if this tool could predict most desirable power generation systems for different types of vessels or for small cruise ships dedicated to specific routes, like polar ones. Also, feedbacks from shipowners and main-equipment suppliers could enhance both technical and economical parameters that have been considered when developing the proposed simulation tool.

These findings, alongside the proposed holistic approach and the developed tool, can contribute to better address the real impact that international shipping and in particular cruise ships have on climate change. The main purpose of all stakeholders involved, from national and international regulators to ship designers, shipowners, and various suppliers, is to find technical solutions to reduce carbon dioxide equivalent emissions from shipping that are technically and economically feasible. Meeting ambitious requirements of global emissions reduction is only possible with a clear dialogue between these stakeholders that shall start by sharing information and data, tracing a pathway to reduce emissions as soon as possible while maintaining volumes of goods transported by ship.

Conclusions

The research question investigated in this PhD is related to the usefulness of a simulation tool based on a holistic approach able to assess fuel cells and innovative fuels impact on a cruise ship electrical and thermal power generation system.

The work proposed in this thesis started by analysing literature available about innovative fuels and power generators for marine applications. Since there is no clear solution for future power generation systems for onboard applications, a lot of potential systems analysed in literature are considered individually.

During the cruise ship's basic design phase, the choice between different power generation systems is made by ship designers. Choice is influenced by client's requirements, but also by all limits issued by national and international organisations. These requirements and limits are mainly focused on the reduction of carbon dioxide emissions and on the return of the initial investment. For this reason, this work first described development of a simulation tool based on a holistic approach that shall be used during basic design phase, and then it described its testing showing results obtained for two different cruise ships. Simulation tool evaluated emissions directly related to different power generation systems for cruise ships. Since this tool is based on a holistic approach, it also calculated whole life-cycle emissions related to different fuels and power generation systems combinations, their impact on vessel's payload and the economics of a cruise ship equipped with these systems.

It was found that there is not a unique solution for future power generation systems for cruise ships, but that simulation tool based on a holistic approach helps to identify which are the most promising technologies and what are main parameters that affect them. First, natural gas and renewable electricity price will affect which solutions will be considered among the most economic ones for shipowners. Also, potential reduction of renewable energy or natural gas price will not be enough to compensate cost premium introduced by innovative power generation systems, particularly in terms of lost payload. Then, GHG emissions related to the whole life-cycle should be considered to address climate change problem. There might be some deceiving results if only Tank-To-Wake emissions are accounted. For example, PEM fuel cells fuelled by brown hydrogen or dual fuel internal combustion engines fuelled by natural gas have lower TTW emissions than internal combustion engines fuelled by HFO, but their WTW carbon dioxide equivalent emissions are higher. Finally, proposed CII regulation can be easily complied with current technology if only TTW carbon dioxide emissions are accounted and compliance with these limits will be easier for smaller cruise ships (luxury class ones).

These findings represent a first example of the powerfulness of a simulation tool based on a holistic approach, and they are also important because they highlight the important contribution of thermal power generation systems onboard cruise ships. Also, findings about CII are among the first public comments about this proposed regulation, and they have already indicated a potential flaw of these limits and a type of cruise ship which should have fewer problems to comply with them.

Maritime contribution to global world carbon dioxide emissions is comparable to some of the most emitting countries, and this issue cannot be solved by one of the many stakeholders involved in this industry. The only possible way to address this important challenge is to establish a dialogue between these stakeholders from which anyone would benefit. Sharing results obtained by the proposed simulation tool should bring to more studies and results about applying a holistic approach to carbon dioxide emissions from shipping. Public availability of this discussion should bring every stakeholder to share more information and to perform better analysis to find for each type of vessel the best environmental and economical solution for onboard power generation.

Future developments

In this work, power generation systems composed by one fuel and one type of power generator has been analysed for two different cruise ships applying four different operative profiles which are representative of navigations in different parts of the world. This analysis allowed understanding how each technology behaves during one year of operations. To the best of the author's knowledge, there have been no study of this kind in literature and no tool capable of this type of simulation, which comprehends also CII attained value and yearly cost calculations.

The proposed approach if further developed to allow more technological solutions and more freedom in the choice of the power plant configuration could help ship designers during first engineering phases, considering all important aspects of ship design from the beginning with its holistic approach.

For example, it is possible that different kind of power generators will be employed onboard during a transitional phase from internal combustion engines to fuel cells or gas turbines, as today happens on some naval ships. The proposed tool could be improved by allowing the choice of two or more kinds of power generators or fuels onboard the same cruise ships. If more than one fuel will be employed onboard, it will be probable that at least one of them will be a fuel liquid at ambient temperature and pressure, so an oil-based fuel, a biofuel or methanol.

Some power generators could be added to the proposed tool. Batteries could help to run smoother other power generators, generating power when peaks of demand are reached and being recharged when there is a steep decrease in power request. Their contribution has not been considered crucial for cruise ships, particularly considering the payload required for a substantial installation of batteries. Another system that could be installed for emissions reduction is a shore connection, which is a system that allows all ship's electrical load to be powered by an onshore grid. This technology can substantially reduce emissions in ports, but it should be considered with a holistic approach both emissions related to electrical energy generation onshore and to thermal power generation onboard via boilers. These systems are also currently not available in all ports and are more beneficial for ships with low thermal requirements. Last, potential application of nuclear reactors for power generation should be assessed, but since applications of this technology is still limited to naval sector and since it has a high impact on public opinions, it has not been assessed.

Economics could be further analysed, estimating fuel transportation cost from production sites to ports and additional operating cost for crew training and for technicians specialised on new technical solutions to be employed onboard.

Another potential development is the implementation of calculations of different efficiency indexes, both required by national and international regulators, like EEDI, or given in literature as indicators of efficiency in fuel consumption.

Most important, proposed tool could be applied to all different kind of ships if data like operative profiles, payload capacity, propulsion curves, auxiliary electrical loads and thermal power requirements are known. Knowing these data, this tool could be used to calculate emission reduction cost, total cost and attained CII of all other types of ships, identifying best power generation systems for each type of vessel.

All the observations proposed could lead to the development of a powerful computational tool for basic design of ships and their power generation system's optimisation that could help to find best alternative power generation systems for all type of ships.

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