LIGHTHOUSE

SWEDISH MARITIME COMPETENCE CENTRE

LIGHTHOUSE REPORTS

Mixing Hydrogen and Methane as Fuel for Ship Engines

A Feasibility Assessment of Hydrogen-enriched Compressed Natural Gas as an Alternative Fuel for Ship Engines in Short Sea Shipping

A prestudy carried out within the Swedish Transport Administration's industry program Sustainable Shipping, operated by Lighthouse, published in April 2025

www.lighthouse.nu

LIGHTHOUSE
SWEDISH MARITIME COMPETENCE CENTRE

HÅLLBAR SJÖFART

Mixing Hydrogen and Methane as Fuel for Ship Engines

A Feasibility Assessment of Hydrogen-enriched Compressed Natural Gas as an Alternative Fuel for Ship Engines in Short Sea Shipping

Authors

Ali Hedayati, Anders Hjort, Tomas Lönnqvist, Karl Jivén from *IVL Swedish Environmental Research Institute*

Simon Mischke, Alia Oualid Hessissen, Basil P. Thomas, Zhiyuan Li from *Chalmers University of Technology*

In cooperation with

Gotland Tech Development, Wärtsilä, MAN Energy Solutions, Norwegian Hydrogen, Furetank, and Energigas Sverige

A pre-study carried out within the Swedish Transport Administration's industry program Sustainable Shipping, operated by Lighthouse

Summary

The shipping industry faces increasing pressure to reduce emissions and meet the International Maritime Organization's goal of attaining net-zero greenhouse gas emissions from international shipping by 2050. One practical solution to reducing emissions is using alternative fuels like hydrogen-enriched compressed natural gas (HCNG). Currently, no studies are available investigating the potential of HCNG for ship main engines in the maritime industry.

This project evaluates the feasibility of HCNG as an alternative to conventional maritime fuels in short-sea shipping, focusing on technical and economic aspects. It examines HCNG's potential for CO_2 emission reduction to meet emission regulations and the required modifications for logistics and storage of hydrogen and methane in next-generation ferries. The assessment includes various blending ratios of H_2/CH_4 and suitable locations (on board or at the port) for blending and storage within existing infrastructure.

This project uses the current operations of so-called roll-on roll-off passenger vessel on the Gotland route between the Swedish East Coast and Gotland Island, along with the corresponding port infrastructure, as a case study. The technical assessment explores various blending ratios (H_2/CH_4) and storage opportunities, both in port and on board, addressing their characteristics and challenges. The economic assessment estimates only the costs of the required amount of fuel for different blending ratios (H_2/CH_4) for the case study vessel and routes. The economic assessment gives an idea of how the fuel cost (based on the fuel choice) can affect the economy of the system. Other technical aspects (hydrogen management and logistics, hydrogen facilities and injection systems, etc. are not included as they were out of the scope of the project. However, the economic assessment based on fuel price will provide a sufficient insight into the economic aspects for the stakeholders.

The project also focuses largely on the environmental and climate benefits (performance) of the use of green hydrogen mixed with methane (at different ratios) as a fuel for shipping (using the case study). The environmental analysis focuses on the emission of CO_2 equivalent, in line with the goal of replacing methane with hydrogen as a fuel. As an additionality, the environmental assessment considered the application of renewable methane too i.e., mixing natural gas (fossil methane), renewable methane, and hydrogen with the aim of both cutting down the natural gas share and CO_2 emissions. This goes another step forward where different sources of renewable methane are considered to give a more comprehensive overview over the resulting emissions when renewable methane is used as a fuel.

It has been concluded that the decarbonization potential of HCNG within the investigated blending ratios is marginal due to the decrease in volumetric energy density with higher hydrogen concentrations, necessitating larger fuel volumes to match the energy content of the fuel that is currently used, liquified natural gas (LNG).

Additionally, the technical and economic analysis indicates that currently HCNG may not be a viable option as an alternative to LNG. This is attributed to the high price of green hydrogen, technical complexity of hydrogen transportation and storage, lack of commercially mature technology. Major cost cut down of green hydrogen and robust regulations against CO_2 emission could potentially pave the way for applications of

HCNG. An alternative short-medium term solution would be to use renewable methane in existing infrastructure and vessels.

Regarding the CO_2 emission, while the hydrogen source remains fixed, the choice of methane significantly affects emissions. Fossil-based methane results in the highest emissions, averaging annual 225,000 tons CO_2 equivalent, followed by renewable methane at 180,000 tons. The lowest emissions, annual 64,000 tons CO_2 equivalent, are achieved with bio-methane from manure and biowaste. This highlights that methane source, not just blending ratio, plays a crucial role in emission performance.

Sammanfattning

Sjöfartsindustrin står inför ett ökande tryck att minska sina utsläpp och uppfylla Internationella sjöfartsorganisationens mål om att uppnå nettonollutsläpp av växthusgaser till år 2050. En praktisk lösning för att minska utsläppen är att använda alternativa bränslen. Hytan (HCNG) är ett bränsle bestående av en blandning av vätgas och metan, vilket skulle kunna vara ett alternativ till dagens användning av förvätskad naturgas. Det finns för närvarande inga studier som undersöker potentialen för HCNG att användas i huvudmotorer inom sjöfartsindustrin.

Detta projekt utvärderar genomförbarheten av HCNG som ett alternativ till konventionella marina bränslen inom sjöfart för korta distanser, med fokus på tekniska och ekonomiska aspekter. Studien undersöker HCNG:s potential att minska CO_2 utsläpp och uppfylla utsläppsregler samt de modifieringar som krävs för logistik och lagring av väte och metan i nästa generations färjor (ombord eller i hamn). Utvärderingen omfattar olika blandningsförhållanden (grader av inblandning av vätgas), samt lämpliga platser för blandning och lagring inom befintlig infrastruktur.

Projektet inkluderar av de s.k. RoPax-färjornas nuvarande verksamhet på Gotlandsrutten mellan svenska östkusten och Gotland, tillsammans med motsvarande hamninfrastruktur, som en fallstudie (RoPax är en färja för passagerare och rullande gods). Den tekniska analysen utforskar olika blandningsförhållanden (H_2/CH_4) och lagringsmöjligheter, både i hamn och ombord, med fokus på bränslenas egenskaper och utmaningar. Den ekonomiska analysen uppskattar endast kostnader för att täcka bränslebehovet vid olika blandningsförhållanden. Andra tekniska aspekter (vätgashantering och -logistik, vätgasutrustning och -insprutning, m.m. är inte inkluderade. Dock kan den ekonomiska analysen ge grundläggande och tillräckliga insikter). Projektet är i stort fokuserat på miljö- och klimatfördelar som uppnås av att använda grön vätgas tillsammans med metan under olika blandningsproportioner som drivmedel i sjöfart inom fallstudien.

Miljöanalysen är fokuserad på $CO2_{ekv}$ utsläppsminskningar som följd av ett bränslebyte. Dessutom, inkluderas användningen av förnybart metan, d.v.s. en blandning av fossil etan, förnybart metan och grön vätgas för att minska både användningen av fossil drivmedel och koldioxidutsläpp. Olika källor för förnybar metan utvärderas för att uppnå en omfattande översikt av olika utsläpp då förnybar metan används som bränsle.

HCNG:s potential för utsläppsminskning för de undersökta blandningsproportionerna är begränsad, främst på grund av minskad volymetrisk energitäthet vid högre vätgaskoncentrationer, vilket kräver större bränslevolymer för att matcha energiinnehåll hos det bränsle som används idag, förvätskad naturgas.

Dessutom visar den tekniska och ekonomiska analysen att HCNG i nuläget inte är ett genomförbart alternativ till förvätskad naturgas. Det beror på det höga priset på grön vätgas, tekniska komplexiteten för vätgastransport och –lagring, samt avsaknaden av kommersiellt mogna tekniker.

En betydande kostnadsminskning av grön vätgas och robusta regleringar mot CO_2-utsläpp skulle potentiellt kunna bana väg för tillämpningar av HCNG. En alternativ lösning är att använda förnybar metan i befintlig infrastruktur och befintliga fartyg.

I studien jämförs även växthusgasutsläpp från olika metankällor i en vätgas-metan-blandning. Medan vätgaskällan förblir konstant påverkar metanets ursprung utsläppen avsevärt. Fossilbaserad metan resulterar i de högsta utsläppen, i genomsnitt 225 000 ton CO2-ekvivalenter per år, följt av syntetisk metan på 180 000 ton. De lägsta utsläppen, 64 000 ton CO2-ekvivalenter, uppnås med biometan från gödsel och bioavfall. Detta understryker att metankällan, inte bara blandningsförhållandet, spelar en avgörande roll för utsläppsprestandan.

Contents

Nomenclature

Acronyms

AIS	Automatic Identification System
BSFC	Brake Specific Fuel Consumption
BTE	Brake Thermal Efficiency
CAC	Carbon Abatement Cost
CAPEX	Capital Expenditures
CNG	Compressed Natural Gas
DF	Dual-Fuel
DFI	Direct Fuel Injection
DWT	Deadweight Tonnage
ECR	Economic Continuous Rating
EEA	European Economic Area
EEDI	Energy Efficiency Design Index
EEXI	Energy Efficiency eXisting Ship Index
EGR	Exhaust Gas Recirculation
ERM	Emission Reduction Measurements
ETS	Emission Trading System
EU	European Union
FGSS	Fuel Gas Supply-System
GED	Gravimetric Energy Density
GFS	Gas-Fueled Ships
GHG	Greenhouse Gas
GT	Gross Tonnage
GWP	Global Warming Potential
HC	Hydrocarbons
HCNG	Hydrogen-enriched Compressed Natural Gas
HFO	Heavy Fuel Oil
HS	High Season
ICE	Internal Combustion Engine
IMO	International Maritime Organization
LBG	Liquefied Biogas (Term often used in Sweden. Also known as bio-LNG, is chemically identical to LNG.)
LCA	Life-Cycle Assessment
LBM	Liquefied Bio-methane (also known as bio-LNG, is chemically identical to LNG, used internationally as a synonym to Bio-LNG)

LMG	Liquefied Methane Gas (used internationally as a synonym to both Bio-LNG and LNG and refers to Bio-LNG here)
LNG	Liquified Natural Gas
LR	Literature Review
LS	Low Season
MCR	Maximum Continuous Rating
MDF	Marine Diesel Fuel
MG/DO	Marine Gas/Diesel Oil
MRV	Monitoring, Reporting, Verification
NG	Natural Gas
NTP	Normal Temperature and Pressure
OPEX	Operational Expenditures
PFOC	Pilot Fuel Oil Consumption
RES	Renewable Energy Sources
RE	Reverse-Engineering
Ro-Pax	Roll-on Roll-Off Passenger Vessel
SATP	Standard Ambient Temperature & Pressure
SCR	Selective Catalytic Reduction
SDG	Sustainable Development Goals
SFGC	Specific Fuel Gas Consumption
SFOC	Specific Fuel Oil Consumption
SMR	Steam Methane Reforming
TCO	Total Cost of Ownership
TtW	Tank-to-Wake
TWC	Three-Way Catalyst
USD	United States Dollar
UN	United Nations
VED	Volumetric Energy Density
WtT	Well-to-Tank
WtW	Well-to-Wake

Chemical Compounds

CO	Carbon Monoxide
CO_2	Carbon Dioxide
CH_4	Methane
C_2H_6	Ethane
C_3H_8	Propane
C_4H_{10}	Butane
CH_2O	Formaldehyde
CH_3CHO	Acetaldehyde

1 Introduction

Maritime traffic plays an essential role in the economy of the European Union (EU) and Sweden in particular. Despite being one of the most cost-effective and energy efficient modes of transport, shipping is a large emitter of Greenhouse Gases (GHG) accounting for about 4% of all carbon dioxide (CO_2) emissions in the EU in 2021 (IMO, 2018; European Commission, 2023a). According to the 4th International Maritime Organization (IMO) Greenhouse Gas Study, maritime transport is a large and growing source of global anthropogenic GHG emissions, accounting for about 2.89% of global emissions in 2018. This is equivalent to 1,076 million tons of CO_2eq emissions which include CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions. This share of anthropogenic emissions represents an increase in emissions from about 2.76 % in 2012 and is expected to further increase from 90% to as much as 130% by 2050 compared to 2008 emission baseline levels (IMO, 2020).

In order to restrain this alarming trend, the IMO has iteratively adopted several legislations that are legally binding across the entire shipping industry. All measurements aim to achieve the reduction of carbon intensity as well as a reduction of GHG emissions of the maritime industry according to the objectives of the Paris Agreement (IMO, 2015). In July 2023, the IMO revised its GHG reduction strategy and agreed to strive via indicative checkpoints "to reach net-zero GHG emissions by or around, i.e. close to, 2050" (MEPC, 2023 §3.3.4). That is to reduce the annual GHG emissions from international shipping via indicative checkpoints by at least 20% and 70% yet striving for 30% and 80% in 2030 and 2040 respectively (MEPC, 2023 §3.4). This amendment is a significant reaction by the IMO to the rapidly increasing GHG emissions worldwide from international shipping as the 2018 IMO Initial Strategy only targeted a minimum 50% GHG reduction in 2050 compared to 2008 levels (IMO, 2018 §3.3).

1.1 Background

EU has introduced explicit measurements for the reduction of GHG emissions from the maritime industry on the path to the attainment of climate neutrality by 2050 (European Union, 2023a, 2023b, and 2023c). The adoption of ever-stringent emission regulations for the maritime industry in the EU puts pressure on shipping companies to improve their energy efficiency and reduce emissions to ensure long-term regulatory compliance. A possible approach in the strive for decarbonization of the shipping industry is to investigate the feasibility and viability of alternative fuels and propulsion technologies.

Recent years have seen an uptake in Liquid Natural Gas (LNG) as a low-carbon fuel in the maritime industry for which technology and infrastructure are developed and mature. Although containing mainly GHG-intensive methane, LNG reduces the emission of CO_2, NO_x, SO_x, and particulate matter significantly compared to Heavy Fuel Oil (HFO) (Nerheim et al., 2021). Similarly, hydrogen (H_2) is believed to play a crucial role as an alternative energy carrier for the maritime sector in the strive for decarbonization as its combustion does not emit GHG emissions directly (DNV, 2023). However, hydrogen as a single fuel in maritime power applications is largely limited to fuel cells and gas turbines since its combustion in internal combustion engines (ICE) poses technical challenges due to its fuel properties (Nerheim et al., 2021).

A promising solution for reducing emissions is the blending of hydrogen with compressed natural gas (CNG), which combines and amplifies the advantages of both fuels. Literature typically considers fuel blends with hydrogen concentrations of up to 30% by volume (Park et al., 2013). This fuel blend, often referred to as hythane or hydrogen-enriched compressed natural gas (HCNG), has been tested in various studies using small-scale ICEs, demonstrating a reduction in pollutant emissions, particularly NOx, compared to single-fuel combustion (Banapurmath et al., 2015; Del Toro et al., 2005). Additionally, HCNG has been shown to improve energy efficiency in test engines, yielding marginally increased brake thermal efficiency (BTE) and slightly reduced brake-specific fuel consumption (BSFC) (Mehra et al., 2017). Moreover, HCNG is regarded as a potential transitional pathway toward a renewable hydrogen economy, supporting the shift from fossil fuels to sustainable energy sources (Anstrom and Collier, 2016).

Although dual-fuel (DF) engines for maritime power applications are available and capable of operating on biofuels, shipping companies often leverage this fuel flexibility by using fossil fuels such as Marine Gas Oil (MGO) and Liquefied Natural Gas (LNG). Given the technical capabilities of DF engines, the feasibility and viability of using hydrogen-enriched compressed natural gas (HCNG) in maritime applications could be of considerable interest to the maritime industry. Advancing research and development in this area could enhance fuel flexibility while simultaneously reducing emissions from shipping.

Currently, ships can bunker natural gas and hydrogen, either in compressed or liquid form (Nerheim, 2023; Ustolin et al., 2022). Furthermore, an increasing number of vessels are being equipped with DF engines capable of operating on LNG (Ushakov et al., 2019). This implied that the application of HCNG in shipping will require major modification on the fuel storage systems and the engines that are capable of using HCNG. If proven feasible for maritime engines, HCNG technology could deliver economic advantages for shipping companies by reducing emissions-related taxes and dependence on specific fuels. These benefits are expected to drive increased demand for retrofitting existing vessels and building new ships equipped with DF engines. Current research on HCNG has only investigated the technicalities of combustion processes in small-scale ICE and the blending of hydrogen into natural gas grids. However, no studies have examined the suitability of HCNG for combustion in heavy-duty maritime engines, highlighting the need for further research in this field. Additionally, economic studies on HCNG have only explored its viability in various transportation sectors, not the shipping industry.

1.2 Background Life Cycle Analysis (LCA)

In several studies (Sharafian et al., 2019, Kanchiralla et al., 2022, Malmgren et al., 2021) it is shown that emission figures from the ship engines depend a lot on the choice of engine. Thus, to keep the study relevant to the project, this LCA assessment will consolidate Well-to-Tank emission figures from existing literature and combine them with the Tank-to-Wake figures in this project to produce the full Well-to-Wake assessment of using HCNG as a fuel for the maritime services. The FuelEU regulation requires that the greenhouse gas (GHG) performance shall be calculated based on a well-to-wake basis (EU, 2023). The regulation defines WTW as follows " 'Well-to-wake' means a method for calculating emissions that takes into account the GHG impact of energy production, transport, distribution and use on board, including during combustion". This presents a holistic view approach to emissions presented by the choice of fuel. Thus, the source of the fuel, i.e., the feedstock and the corresponding fuel production processes along with the transportation are to be taken into account.

According to the International Energy Agency (IEA), almost all hydrogen produced worldwide (97 Mt) originated from fossil resources (natural gas, coal, etc) and only 1% of that was used for energy and power production applications, the rest used as feedstock in industries (IEA, 2024). Hydrogen production technologies vary widely in their environmental performance. Cho et al., (2023), studied different methods of hydrogen production and revealed that as of 2020, almost the entirety of hydrogen produced utilized fossil resources with just 0.7% (produced from natural gas) involving carbon capture and storage/utilization. It was also found that producing hydrogen from water through electrolysis, which requires large amounts of electricity, is currently 6-16 times more expensive than hydrogen from natural gas. However, it was estimated that the production costs of green hydrogen may drop to comparable rates as hydrogen production from natural gas, by 2030 (Cho et al., 2023).

Similar conclusions were drawn by Chelvam et al., (2024) where LCA of hydrogen production was gaining popularity and highlighted prospective LCA (pLCA) as a relevant approach to assessing the life cycle performance of hydrogen production to accommodate for the advancing global technology. The same was reflected by Kanchiralla et al., (2022) in the pLCA analysis done on fossil-free fuel alternatives. With sources or methods of production of hydrogen still developing and energy sources continuously changing, a prospective study assessment of emission factors is thus considered critical for this study as well.

It is not just the production technologies and sources that contribute to the environmental performance. As Sharafian et al., (2019) point out in their study, the location and transport involved, i.e., the supply chain, makes a significant contribution to the emission figures as well. The study also shows that LCA is highly sensitive to the changes in WtT figures and thus varies a lot based on the geographical scope considered. The study outlines the WtT and TtW figures found across different assessments based on different geographical locations for LNG and HFO supply chains.

The study by Kanchiralla et al., (2024) outlines a comprehensive prospective LCA conducted for biofuels, electro-fuels and blue fuels[1] for bulk carriers, container vessels and cruise ships. Emission figures have been obtained for different engine configurations and fuel supply sources. Among the fuels considered are (compressed or liquified) green hydrogen (via water electrolysis), biohydrogen (hydrogen from biogenic resources), bio-methane (biogas or any bioresource), and e-methane. The study gives the WtT emissions figures for the different fuels for the years 2030, 2040, 2050 and 2060 under various levels of Paris Agreement adoption.

[1] Blue fuels are those that enjoy technologies to reduce upstream process emissions, for example CO_2 capture.

1.3 Objectives

This study aims to evaluate the feasibility of using hydrogen-enriched compressed natural gas (HCNG) as an alternative fuel in the maritime industry. The assessment focuses on the technical, environmental, and economic dimensions of HCNG, including its emission reduction potential and the logistics of blending and storage. This work could thus assist companies when determining whether HCNG can be a solution to comply with European legislation and contribute to achieving the IMO's net-zero GHG emission targets by 2050.

Specific research questions are formulated to enable a targeted fulfillment of the purpose. To assess the blending of hydrogen and methane into main engines for ships, three essential research questions are identified which shall be investigated as part of the present study. These are:

1. What are the pros and cons of blending hydrogen and methane from technical, environmental, and economic perspectives compared to the currently used LNG fuel?
2. What is the optimal hydrogen-methane blending ratio considering technical, environmental, and economic benefits and drawbacks?
3. Where could the mixing and storage of renewable hydrogen and methane take place?

The research questions were shaped and modified by direct engagement of the reference group (Gotland Tech Development, Wärtsilä, MAN Energy Solutions, Norwegian Hydrogen, Furetank, and Energigas Sverige) of the project at the beginning of the project, with the aim of focusing on answering the main questions and challenges that maritime industry is facing regarding the application of hydrogen as a fuel.

1.4 Scope and Assumptions

It is noteworthy that this pre-study is confined to theoretical analysis and calculations with regard to short-sea shipping, without conducting any real-life experiments in laboratories or onboard ships. Instead, numerical simulations are conducted making use of existing collected data on Destination Gotland's ferries operating on the Gotland routes along with the test bed measurements on their main engine, complemented with literature findings. The project's scope is largely defined based on the underlying research questions and can be attributed to the following aspects: (1) Storage of fuel components separately and HCNG-blend; (2) Blending of fuel components (incl. suitable blending ratio); (3) Onboard usage of fuel blends (i.e. combustion); and (4) Emissions from combustion and production of fuels.

An overview of the project's scope is illustrated as shown in Figure 1.1 where all green boxes (Tank to Wake) denote aspects that are within the project's scope where the corresponding data and analysis has been generated via this project. By implication, yellow-box aspects (Well to Tank), i.e. fuel production and distribution data will be taken from the literature. As can be seen, the two different scenarios have been considered i.e., separate storage of hydrogen and methane at the port and on board or mixing hydrogen and methane at the port and store HCNG on board.

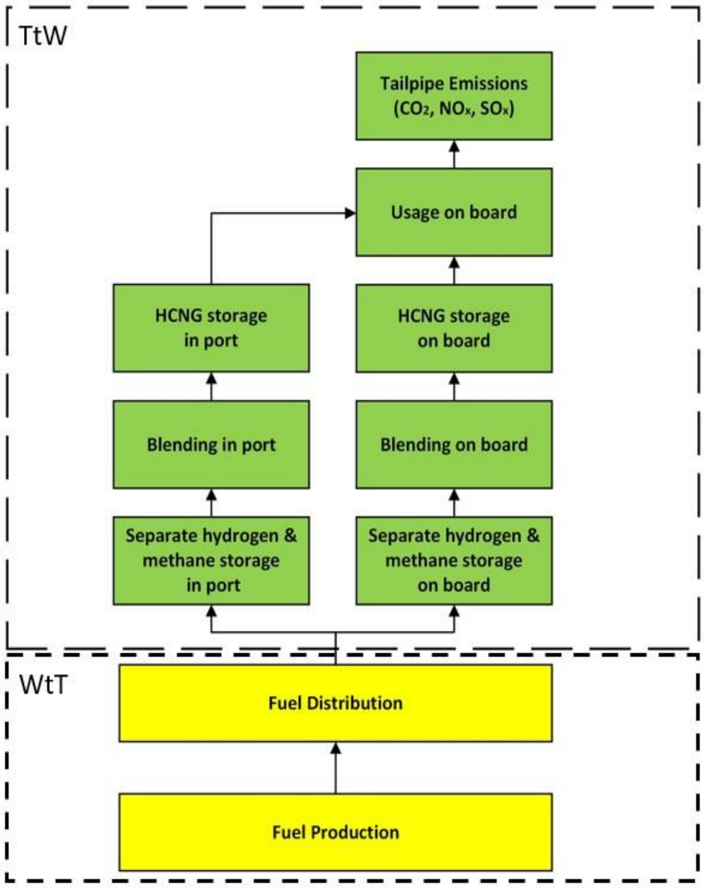

Figure 1.1: Schematic overview of this study's scope.

We investigated storage and blending to identify an appropriate solution for the current infrastructure, addressing the various possible combinations of fuel blending as shown in Figure 1.1. Before blending, both fuel components are assumed to be stored separately in compressed form for hydrogen and liquid form for methane. Blending of fuel components is considered to be done with both fuels in their gaseous phase. After blending, the HCNG mixture is assumed to be stored only in the gaseous phase while the corresponding blending conditions, i.e. pressure and temperature, are to be determined from the corresponding gas phase boundaries of the fuel components.

Selected performance parameters of the case vessel's main combustion engine are used for reference to approximate the required amount of HCNG fuel in terms of mass and volume for the reference vessels with regard to annual passes in specific routes. However, the energy consumption of the auxiliary engines on board has not been taken into account, and other energy conversion technologies such as gas turbines or fuel cells have not been considered in this study. In this project, the most relevant emission pollutants regarding European maritime emission regulations resulting from HCNG combustion were investigated. Specifically, the potential reduction of CO_2 was examined, given its significance under these regulations.

FuelEU regulation requires that the reduction in GHG emission is calculated about the installed plant power. Because the auxiliary engines and their combustion characteristics are not studied, the overall reduction in emission obtained cannot be equated with emission level reductions specified in the rule. However, the results are representative of the levels of reduction in GHG emission that is possible with the use of an HCNG blend. For the WtT assessment of the fuels, a temporal scope of the year 2030 is considered. This incorporates the technological change perspective in making different sustainable sources of fuel more viable for the project. In addition, this work is based on the following major assumptions regarding the knowledge gaps and uncertainties of some technical parameters:

- Liquified Natural Gas (LNG) (or Liquified Methane Gas (LMG)) is regarded as pure methane in this study since it is largely composed of methane, which suggests disregarding other minor natural gas constituents for simplicity. This applies to other sources of LMG as well. During the combustion phase, it is assumed that no other organic constituents are burned or contribute to emissions calculated. A similar approach is made for H_2 as well in the consideration that the fuel obtained is devoid of impurities.
- This study assumes that the engines of the reference vessels perform similarly with HCNG. For simplicity in performing this study, it is assumed that the engines can combust HCNG identically to LNG, meaning performance parameters (e.g., efficiency, specific fuel consumption) are considered the same for both LNG and HCNG combustion.
- The engine performance parameters are projected onto current operations. Consequently, all reference calculations for methane assume continuous ferry operation on LNG before comparison with HCNG. The main engine is assumed to operate at 75% engine load delivering maximum power output all of the time as it is designed to have optimal fuel efficiency at this point.
- The emission characteristics of the fuel in the production and distribution phases are obtained from existing perspective LCA assessments within the geographical scope of the EU. It is, thus considered that the emission factors obtained apply to ports accessed by the reference vessels. Further, the ferries that Destination Gotland operate on the Gotland service were found to be sister vessels making them identical both in terms of main particulars as well as their propulsion systems. Hence, the findings were assumed to be equally applicable to all of Destination Gotland's vessels on the route of interest.

In the main engine, small amounts of pilot fuel are injected additionally at high pressure into the combustion cylinder to help ignite the gas fuel instead of igniting it by a spark plug. Typically, marine diesel fuel (MDF) is used as pilot fuel which is constantly injected whether the engine is running in diesel or gas mode (Wärtsila, 2019). The pilot fuel oil consumption (PFOC) is relevant in the establishment of an LNG benchmark scenario as its combustion contributes to the overall fuel consumption and GHG emissions. However, the pilot fuel contribution to overall CO_2 emissions is very small and negligible, see Figure 3.4 (≤1% of the total fuel). It must be mentioned that in this project the pilot fuel was considered to be diesel. The reason lies in the combustion chemistry and flammability range of methane and hydrogen. According to experts at the project reference group (Wärtsilä), the pilot fuel cannot be hydrogen. However, as mentioned, the contribution of the pilot fuel to total CO_2 emission is not significant (Figure 3.4).

2 Methodology

In this project, we use both quantitative data analysis and qualitative literature analysis to investigate the technical perspectives on HCNG. Subsequently, an economic assessment was conducted.

The quantitative analysis in this study was largely characterized by a so-called reverse-engineering (RE) methodology, which is a common practice as it allows the transfer of conclusions and takeaways from existing projects to conceptual studies. The RE comprised the methodology components of data collection and analysis, followed by their assessment. The RE methodology was intended to study Destination Gotland's ferry operations between the Swedish mainland and the island of Gotland to learn about the operational characteristics. It was important to learn about the ferries' fuel consumption as it allowed us to determine the corresponding energy demand. This results in a requirement for the HCNG fuel alternative, as it must be able to supply the same amount of energy. Besides, studying the ferries' operations with a focus on fuel consumption provided an understanding of the GHG emissions from LNG combustion. Any of these performance indicators served as a reference baseline for subsequent assessment afterwards. After setting a benchmark from current operational results, HCNG properties were computed from chemical information on hydrogen and methane obtained from the literature review (LR) in parallel. Combining findings from the RE methodology allowed the projection of HCNG use for the reference ferries' operations. These projections were then used in the technical assessment to identify the benefits and drawbacks of HCNG.

2.1 Data Collection and Analysis

Several public sources were consulted to collect data on the reference vessels to study their operational characteristics and outfitting. Similarly, information on the port infrastructure and bunkering operations was obtained as this was relevant for the assessment of suitable blending and storage locations. At first, information on Destination Gotland's fleet was collected from their website to identify those vessels that operate on the route of interest. This provided an initial understanding of the vessel's technical parameters including main particulars, cargo capacity, and installed engine power. Furthermore, detailed information on the reference vessels was obtained from the Sea-web database which is an online resource (S&P Global. 2024a). The Sea-web database was consulted to source automatic identification system (AIS) data for those ferries in Destination Gotland's fleet that operate on the routes of interest. As the maritime industry's largest database, Sea-web is hosted by S&P Global and offers a wide range of relevant data modules on different levels (S&P Global. 2024b). This initial assessment aimed to understand the operational characteristics. This data was then compared to HCNG as the primary fuel to determine the potential positive or negative impacts on operations, specifically regarding sailing distance and bunkering frequencies.

Large Automatic Identification System (AIS) datasets were obtained representing one month for each ferry operating on the Gotland service to ensure that the operational pattern derived from data analysis could be considered representative. The collected data sets were linked to the vessel's unique IMO number and entailed information such as cruising speed and positional data (longitude and latitude) at a particular timestamp. In combination with included port call information from arrival and departure, this allowed verifying actual sailing times against timetable information. Besides, the AIS datasets contained information on remarkable events such as the location, time, and duration of bunkering operations.

In addition, the Sea-web database provided information on the main engines installed on the Destination Gotland ferries, including the engine type, manufacturer, and any emission reduction systems such as Selective Catalytic Reduction (SCR). This information was relevant for sourcing public, engine-specific performance data from the manufacturer. Measurement data from the manufacturer's product guide was key to investigating current fuel consumption and projecting it onto the HCNG fuel blends. Relevant measurements from the engine product guide contained data on the maximum continuous rating (MCR, the maximum power output engine can produce while running continuously at safe limits and conditions), fuel oil consumption at different engine loads, and injection conditions (i.e. pressure and temperature).

For the study of emissions, the EU's public Thetis MRV database was consulted for reference. Here, emission data was reported by the operating companies for a unique vessel and confirmed by verifiers that are accredited by the EU Member States National Accreditation Bodies. This database was set up by the European Commission with the purpose of information per §21 of Regulation (EU) 2015/757 on the MRV of CO_2 emissions from maritime transport (EMSA, 2024). The EU MRV database provided various vessel-specific annual average performance parameters of which fuel consumption and CO_2 emissions per distance were most significant. These parameters were consulted in the emission study to verify emission calculation. The data was selected for 2022 operations as this was the latest complete report year.

The assessment of the WtT phase of the prospective LCA (pLCA) required data regarding the emission characteristics of the different fuel sources. For this project, the considered fuels were named with regard to their origin (natural gas, bio-methane from different biowaste, and e-methane which directly is made from green hydrogen and pure bio-CO_2, please see Table 2.1) The emission performances per unit of fuel were obtained from a literature study of existing pLCA assessments. All relevant data on the operational characteristics of the Gotland service was processed and analyzed using the software MATLAB. AIS data sets were downloaded from Sea-web and processed in MATLAB to visualize the vessel's track in the form of geographical movement along with speed-time profiles. Specifically, information on e.g. crossing durations, frequencies, and bunkering operations were derived to understand the operational characteristics. Furthermore, fuel consumption measurements from the engine manufacturer's public product guide were read into the software to visualize and interpret the engine design points and fuel consumption trend behavior of the main engines.

To verify the trend of fuel consumption in diesel and gas mode of the reference main engine for a correct interpretation, it was compared to experimental results from a study that investigated a range of maritime DF engines. Further, public databases containing reported vessel-specific performance parameters have been consulted to verify the correct computation of the fundamental parameters. Specifically, the calculated relative fuel consumption and CO_2 emissions from LNG consumption were verified against numbers reported to the EU's MRV database to ensure the same magnitude.

The *Cantera* toolbox was implemented into MATLAB which is an open-source toolbox that has built-in functions to solve chemical problems in kinetics, thermodynamics, and transport processes (Goodwin et al., 2023). This toolbox was implemented to obtain properties of methane and hydrogen such as density or molar mass when equilibrated at set temperature and pressure. Based on the *Cantera* data, HCNG fuel blend properties were computed based on the ideal gas law. Initially, conditions were set to Standard Ambient Temperature and Pressure (SATP) and afterwards iterated for higher storage pressure at the set temperature. This allowed us to optimize storage conditions and recognize changes in the pressure-dependent properties of individual components. *Cantera* integration was useful for accounting for these property variations when determining suitable blending and storage conditions. Simulations were conducted for fuel blends ranging over a range of hydrogen volume concentrations from zero to 100%. Conversely, this made it possible to consider two extreme reference scenarios in which pure hydrogen (i.e. 100%) and methane (i.e. 0%) were considered. Since simulations were conducted for a wide range of fuel blends and calculated for different engine load points as reported by *Wärtsila* in their product guide, large datasets were expected to be obtained. Therefore, MATLAB scripts were synced with Microsoft Excel as it allowed for easier handling and visualization of large datasets. Since no further simulations of e.g. fuel blending or combustion were intended, no other software was applied in the present study.

A literature review was conducted to obtain relevant general information from state-of-the-art studies and papers on HCNG, hydrogen, and methane respectively. This was to understand their properties, production, storage, techno-economics, and relevance in the maritime industry. For hydrogen and methane, accredited resources such as classification society publications focusing on the maritime industry have been studied with preference. Since research on HCNG in the maritime industry is unavailable, the relevant information was mainly obtained from peer-reviewed studies that investigated its combustion in small-scale ICEs including emission studies. Regarding HCNG blending ratios, studies that examined the blending of hydrogen into the natural gas grid proved to be most important for the present study.

Further, the research investigation represented an extension of the literature review which aimed to narrow down relevant information regarding the solution of research questions. Here, aspects were investigated that could not be covered entirely through computation in the data analysis such as the technical challenges of fuel blending and storage. Besides, relevant information was constantly exchanged while conducting the literature review and reverse engineering methodology. This synchronization was important to ensure that the calculations behind the data analysis could be carried out with correct understanding. In turn, the results of the data analysis revealed a need for further information, which was subsequently acquired as part of the research investigation.

2.2 Viability Assessment of HCNG as fuel

In this project, we targeted at assessing projections from different blending ratios against the extreme reference scenarios based on findings from the data analysis. This was intended to highlight the benefits and drawbacks of different blending ratios and thus allow drawing recommendations regarding the research questions. HCNG results related to the annual fuel mass requirements and corresponding CO_2 emissions were determined based on the projected Gotland fleet operations as presented by the industry partner at a conference in December 2023 along with the corresponding crossing times of the Gotland service's northern and southern route. In detail, this means that the operational goals for the entire Gotland service are geared towards the following scenarios: (1) 2,300 trips in Low Season (LS) at 215 min. crossing time; (2) 700 trips in High Season (HS) at 195 min. crossing time.

Although the maximum suitable hydrogen volume concentration differed between studies, it was typically not found to be higher than 25%. The consulted studies also reported that small hydrogen volume fractions of up to six percent by volume could be injected into the NG grid by default without the necessity for major technical modifications to the infrastructure (Gaz et al., 2019). Therefore, a total of five blending ratios (5,10, 15, 20, 25 vol% hydrogens) were specifically investigated at first considering the lower and upper end of suitable blending ratios identified by various studies. In addition, two extreme references representing pure methane (0% hydrogen) and pure hydrogen (0% methane) were considered.

The viability assessment in this study was conducted to assess the economic potential of different HCNG blending ratios as an alternative fuel in the shipping industry. It was targeted at determining their corresponding annual costs of fuel demand for either component as well as emission allowances that would have to be paid under the EU ETS. The objective was to determine if the expected emission reductions from HCNG, and the corresponding avoided emission allowances, would offset the higher costs of renewable hydrogen compared to a current pure LNG scenario.

For fuel components, LNG was considered instead of bio-methane as it is currently used on the reference vessels, serving as a benchmark for cost estimation. Hydrogen from renewable energy sources was chosen due to its low emissions, improving the life cycle performance of the fuel. Average fuel prices for both HCNG constituents were obtained from the literature, which also provided projected price developments (Mahant et al., 2021; Flodén et al., 2024).

Important underlying parameters to determine the total annual expenses were the reference vessel's projected annual fuel mass requirement and the corresponding CO_2 emissions as computed for pure LNG and different HCNG blending ratios. Based on this the costs under current circumstances have been estimated for average fuel prices of LNG and hydrogen produced from renewable energy sources (RES). Emission allowance costs were determined solely from CO_2 emissions obtained during the HCNG GHG emission study. Other pollutants such as NO_x and SO_x emissions were excluded as they could not be specifically quantified for HCNG use, making a comparison to LNG emission-related costs uneven. To summarize, the following assumptions were made for mean prices to conduct the economic assessment:

- LNG price: $1.028 USD/kg
- H_2 (RES) price: $8 USD/kg

- EU ETS allowance price: $90 USD/t CO_2[2]

Furthermore, the expected emission allowance costs were considered in the assessment, as the EU ETS has covered CO_2 emissions from ships over 5000 gross tonnage (GT) since January 2024. Both reference vessels operating on the Gotland service fall under this scope, each registering 32,447 GT. The adoption of the EU ETS for the shipping sector requires shipping companies to purchase emissions allowances for their registered emissions, with one allowance unit equivalent to a ton of CO_2 or $CO_{2,eq}$ from 2027. The upper limit for registered emissions will decrease iteratively in the coming years as follows (European Union, 2023a):

a) 2025: 40% of all emissions registered in 2024

b) 2026: 70% of all emissions registered in 2025

c) 2027: 100% of all emissions registered in 2026

To obtain a result that will still be valid in the future, it was decided to consider the EU ETS allowance costs for 100% of the annual CO_2 emissions representative from 2027. Due to the volatility of the allowance price, an average value representative of the peak prices over the past two years was determined for subsequent calculations. The maritime sector has only been included in the EU ETS since January 2024, while the system itself was introduced in 2005. To obtain an average high price, it was focused on the average peak price of the past two years. Considering the entire duration since the EU ETS adoption was too extensive, and the period since including maritime transport was too brief to be representative. The past two years have seen high allowance prices on average compared to the ETS adoption in 2005, providing a good baseline for projecting increased future price development. Historic data on the varying EU Emission Allowance Prices has been made available upon request (Montel, 2024).

Further future-proofing the results of the study would also require exploration of the different fuel alternatives, such as bio-methane and bio-H_2, which, as discovered in the results, give significant emission savings in comparison with LNG. In order to assess whether the reduction in Carbon Abatement Costs can offset the increased capital expenditure on fuel, a cost assessment is carried out on the holistic LCA assessment results as well.

- Bio-Methane (Manure/biowaste) price: $2.45 USD/kg

- Bio-H_2 (RES) price: $3.89 USD/kg [3]

The final assessment concluded the methodology by evaluating the techno-economic findings from the quantitative analysis alongside the literature review, focusing on the research questions.

[2] Montel, 2024

[3] Source: Kanchiralla et al., 2024, Jiven K. et al., 2022, All numbers have been converted into USD/kg.

This study was used to identify suitable locations for HCNG blending and storage based on the impact each scenario would have on current infrastructures.

2.3 Life Cycle Assessment (LCA) of maritime fuels

Life cycle assessment (LCA) helps measure the direct and indirect environmental impacts of a product, service, or activity throughout its life cycle. In this study, LCA is used to assess and compare the potential environmental impacts of HCNG in Gotland. The LCA carried out for this study is relying on the procedure recommended in the European standards of ISO 14040 and ISO 14044. According to the standards, the applied LCA covers three main steps: (1), goal and scope definition and specification of functional unit and system boundary (2), life cycle inventory data (3), life cycle impact assessment and interpretation of results.

The LCA goal in this work is to study and compare the environmental indicators connected to the production, transportation and use for different systems based on various input fuels. In order to compare various systems, a similar 1 MJ consumed fuel for all cases has been considered as the functional unit of the system. The scope conducted in this work presents an LCA, which contains a Well-to-Wake (WtW) evaluation for the fuel cycle. In fact, the WtW comprises two stages of Well-to-Tank (WtT) and Tank-to-Wake (TtW). WtT represents primary energy extraction, energy carrier production and delivery and TtW refers to the onboard usage where the energy carrier is used. The LCA in this study is conducted with a temporal scope set for the year 2030.

It is considered that the engines onboard can run on the HCNG blends studied and the changes to be made are limited to the fuel handling and storage. However, the LCA study does not take into account the cost of refitting and the emissions produced therein.

The different fuels considered from their different production/refining processes constitute the input for the LCA. The fuels considered are outlined in Table 2.1. The extraction methods of hydrogen considered for this study include steam methane reforming (SMR) of natural gas, gasification of forestry residue (biomass) and electrolysis. SMR of natural gas is the most common method of producing hydrogen, as identified from various literature outlined in the literature study section. Gasification of forestry residue and water electrolysis are considered as sustainable alternatives to hydrogen produced by SMR of natural gas. The electrical energy required for the water electrolysis is assumed to be sourced from wind power.

Table 2.1: Fuel types, symbols, and production methods.

Fuel	Symbol	Description
MDO	D	Fossil-based refined marine diesel oil
e-LH$_2$	1H	Liquified hydrogen made from water electrolysis. Includes electricity from wind turbines, the electrolyser, and hydrogen liquefaction
Bio-LH$_2$	2H	Liquified hydrogen produced from the gasification of biomass. Included: Forestry residue, biomass pretreatment, gasification, gas cleaning and CO_2 separation, and hydrogen liquefaction
Blue-LH$_2$	3H	Liquified hydrogen from methane (fossil) steam reforming followed by carbon capture and storage (CCS), Included: SMR of natural gas, CCS, and liquefaction of hydrogen
Syn-LMG	1M	Liquified Methane made from pure CO_2 and pure H_2, Synthetic methane. Included: Wind power electricity, electrolyser, CO_2 from Direct Air Capture (DAC), CO_2 conversion, and methane liquefaction
Bio-LMG	2M	Liquified methane made form syngas ($CO+H_2$) and syngas made from biomass gasification. Included: Forestry residue, biomass pretreatment, gasification, syngas cleaning, methanation process and methane liquefaction
LNG	3M	Liquified fossil natural gas
LBM (Biowaste)	4M	Liquified methane made from biogas plants that do not use manure. Included: Anaerobic digestion, upgrading, polishing and liquefaction, Biowaste,
LBM (Manure/ biowaste)	5M	Liquified methane made from biogas plants that use manure. Included: Anerobic digestion, upgrading, polishing and liquefaction. 25% Manure, 75%

Sources considered for methane include natural gas obtained from fossil sources, syn-LMG produced using pure CO_2 (bio- or air-origine) and pure hydrogen (electrolysis), bio-methane obtained from gasification of forest residue followed by methanation, bio-methane obtained from biowaste using close digestate with no off-gas combustion and bio-methane produced by anaerobic digestion of a mixture of 25% manure and 75% biowaste with no off-gas combustion.

Regarding the required amount of fuel, the mass of fuel consumed per ferry crossing was measured and the total estimate for annual emissions was calculated. The outputs considered for the first stage of the study (fuel production and transportation to the ports, obtained from the literature) constitute the GHGs emitted during the process of extracting, treating, and transporting the fuels selected. This output is then combined with the emissions from onboard (calculated in this project) usage of the fuel on the reference vessels.

The GHG emission factors obtained through a literature review of existing LCA studies that were selected for the study are outlined in Table 2.2. By considering the calorific value of hydrogen, methane, and pilot diesel oil, the GHG emission factor is obtained per unit mass of fuel consumed. Using the fuel consumption and the emission factor per unit mass of fuel, the total emissions are calculated for each fuel type in the WtT phase of the life cycle. Different blend compositions are considered. The WtT result is combined with the TtW emission figures calculated. The total emissions obtained are then used to calculate the cost of emission.

Table 2.2: WtT emission factors.

Fuel	**WtT Emission factor (gCO_2 eq/MJ)**
MDO	17.7 (IMO, 2024)
e-LH_2	29 (Kanchiralla et al., 2024)
Bio-LH_2	24.5 (Kanchiralla et al., 2024)
Blue-LH_2	40.1 (Kanchiralla et al., 2024)
Syn.-LMG	45.1 (Kanchiralla et al., 2024)
Bio-LMG	27.5 (Kanchiralla et al., 2024)
LNG	57.3 (IMO, 2024)
LBM (Biowaste)	40 (Jiven et al., 2022)
LBM (Biowaste/Manure)	15 (Jiven et al., 2022)

The emission factors of LBM (biowaste) & LBM (biowaste/manure) in Table 2.2 were derived from Jivén et. al., (2022), which are also illustrated in Fig 2.1. The reason for that is that the national mix of LBM in Sweden today is around 75 % biowaste and 25 % manure and the share of manure is expected to rise. LBM (biowaste/manure) is therefore calculated assuming 25 % of the emission factor for manure and 75 % of the emission factor for biowaste, i.e., would give a mixed emission factor of approximate 15 gCO_2 eg/MJ.

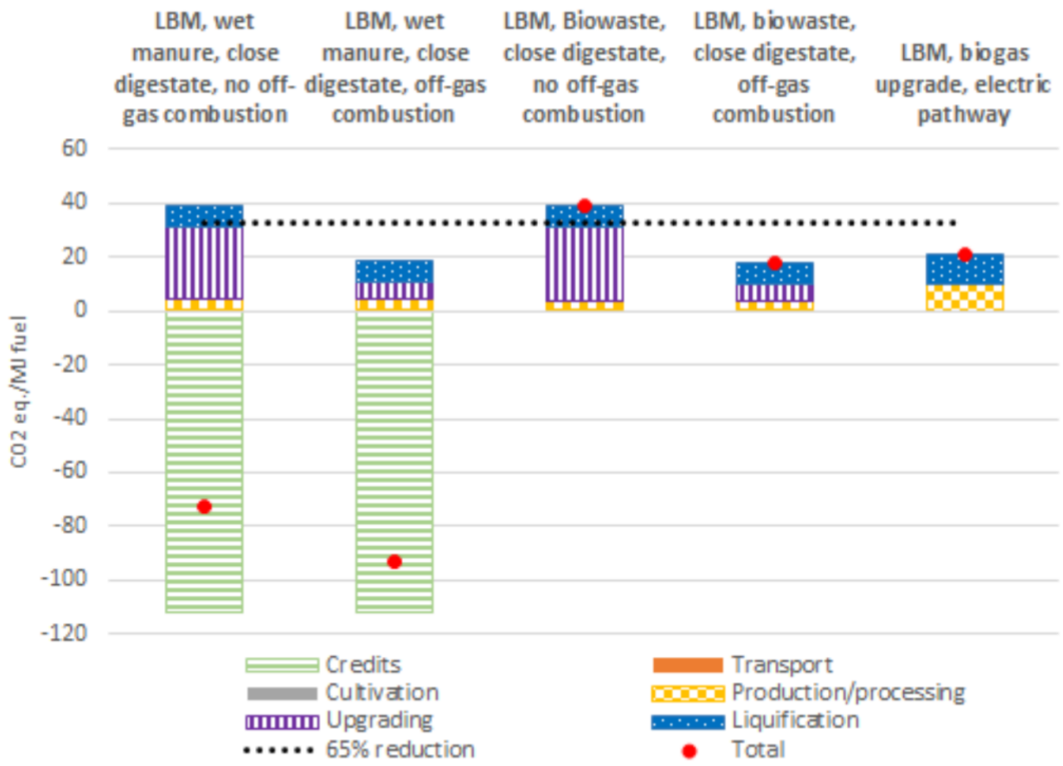

Figure 2.1: Calculations of three different LBM production pathways based on RED II, assuming Swedish electricity grid for support systems and fully renewable electricity as the main input for electric pathway. (Jivén et al., 2022).

FuelEU Regulation (EU, 2023b) also states that "for the purpose of this Regulation, only default well-to-tank emission factors and default tank-to-wake CO_2 emission factors for fossil fuels should be used". Following this recommendation, emission factors for LNG and diesel oil (MDO/MGO) have been taken from Annex 10 of Resolution MEPC.391(81).

3 Case study and analysis

The Swedish shipping company Destination Gotland primarily operates ferries on the Swedish East Coast, connecting mainland ports with the island of Gotland. This study uses the operations of the Gotland service as a case study to establish a baseline for current LNG operations in terms of fuel consumption and CO_2 emissions. The goal is to derive relevant information to answer the research questions. Additionally, the study examines the effect of hydrogen blending with methane on fuel properties.

We aim in this case study to understand the transit characteristics of the ferries on the Gotland service to determine their energy demand. This would ensure the development of reliable operations with alternative energy carriers like HCNG, to replace currently used fuels. The information on onboard fuel capacity and bunkering frequencies was inferred from the operational data obtained from Sea-web. Based on that, the fuel mass consumption and corresponding volume per crossing were calculated to establish a comprehensive benchmark scenario. It is noteworthy that only two Destination Gotland ferries regularly operated on the Gotland service during the investigated period which served as reference vessels henceforth. Since both ferries are identical in terms of main particulars and propulsion equipment, all conclusions were considered applicable to both vessels.

The port bunkering infrastructure is an important link in the logistics chain to ensure continuous, reliable fuel supply to the reference vessels. Thus, determining whether fuel blending and storage is suitable in port or on board necessitates understanding the interaction between the bunkering infrastructure on land and the reference vessels' bunkering characteristics. Note that the present study on bunkering focused on the availability of LNG and hydrogen in ports, other fuel types have been disregarded as they are not relevant for the assessment of HCNG. The combined analysis of the transit and bunkering study provided an estimate of current bunkering frequencies. By combining the fuel mass consumption per crossing from the transit study with the number of crossings between bunkering operations, the volume currently occupied by LNG on board the reference vessels were estimated.

3.1 Power & Fuel Energy Study

After calculating the required amount (mass) of LNG for the reference vessel for annual crossing, the energy content of that amount of LNG was calculated. This number (unit of energy) served as a baseline reference parameter for subsequent required HCNG calculations, assuming the fuel alternative must deliver the same amount of energy. The results presented herein consider continuous maximum power output and do not necessarily reflect operational variations in e.g. the engine load as this was unknown.

The reference vessels are equipped with a set of four type 12V50DF main engines designed by Wärtsila. The engine is a dual-fuel ICE that offers fuel flexibility to the operator by running either on HFO or LFO in diesel mode or LNG in gas mode. Moreover, the 12V50DF is a 4-stroke, turbocharged engine with direct injection of liquid fuel at high pressure in diesel mode and indirect injection at low pressure in gas mode. Since real-time engine performance data was unavailable, test bed measurements of the main engine were sourced from the manufacturer's product guide instead. The Wärtsila 12V50DF parameters are listed in Table 3.1.

Table 3.1: Wärtsila 12V50DF Engine Data.

Parameter	Unit	Main Engine
Fuel	[-]	HFO/ LFO/ GAS
Speed	[rpm]	500, 514
MCR	[kW]	11700

Figure 3.1 illustrates the specific fuel oil consumption (SFOC) in diesel mode and the specific fuel gas consumption (SFGC) in gas mode for the dual-fuel (DF) engine when achieving the maximum continuous rating (MCR) to drive a propeller in various modes. The bullet data points represent Wärtsilä's test bed measurements at different engine load levels. These measurements were subsequently interpolated using polynomial regression to highlight the fuel consumption trends. Fuel consumption is dependent on engine load in both operating modes. In diesel mode, running on heavy fuel oil (HFO) or light fuel oil

(LFO), the SFOC is lowest in the 70–85% MCR range, reflecting the engine's design for optimal efficiency within this range (Corbett and Koehler, 2003). Conversely, the regression trend for SFGC suggests that fuel gas consumption is lowest at 100% engine load. However, continuous operation at 100% engine load is not advisable to avoid overloading the engine. Consequently, it was inferred that fuel energy calculations for gas mode should focus on load points between 75–85% MCR, aligning with the optimal range identified for diesel mode.

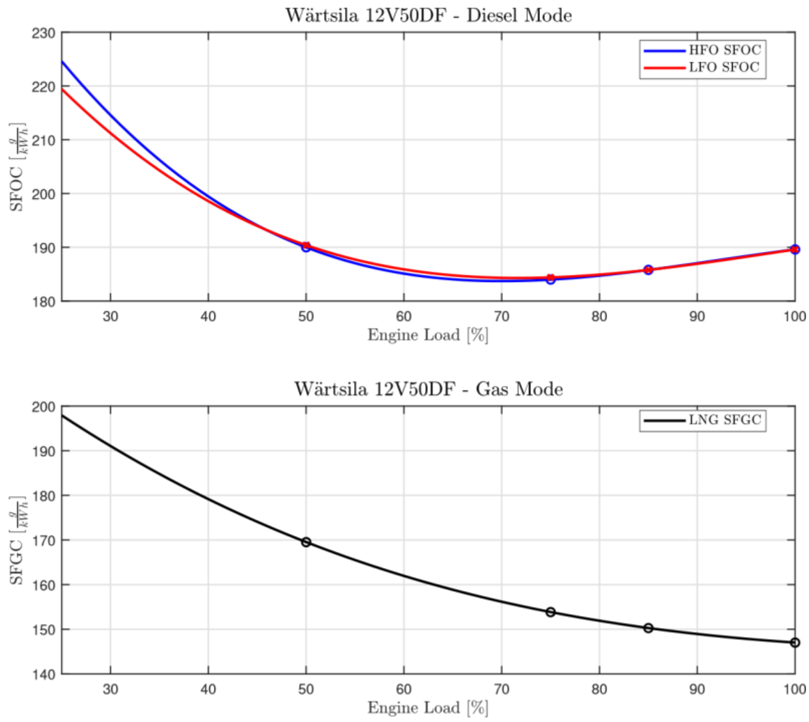

Figure 3.1: SFOC & SFGC of Wärtsila 12V50DF.

As mentioned in the Scope and Assumption, a small amount of pilot fuel oil is required for the proper ignition of the fuel and function of the engine. The pilot fuel oil consumption (PFOC) is relevant in the establishment of an LNG benchmark scenario as its combustion contributes to the overall fuel consumption and GHG emissions.

To ensure proper estimation of the fuel energy requirement, fuel consumption data from a separate study was consulted to validate the trend lines derived from the Wärtsilä engine. An empirical assessment of fuel consumption for two-stroke dual-fuel engines on LNG carriers was performed, based on the performance of twelve engines from two manufacturers i.e., MAN B&W and Winterthur Gas & Diesel (Gutierrez and Labajos 2018). Only results relevant to the Wärtsilä 12V50DF engine were considered, specifically high-pressure injection in diesel mode and low-pressure injection in gas mode. Reference fuel consumption for HFO and LNG, as reported in the study, is shown in Figure 3.2. Similarly, pilot fuel oil consumption (PFOC), as measured by Wärtsilä, is compared with the study's findings in Figure 3.3. Given that the results from Gutierrez and Labajos (2018) represent average fuel consumption across twelve engines, the trend lines for reference SFOC and SFGC exhibit similar behavior in both combustion modes when compared with Wärtsilä's test bed measurements. Likewise, the PFOC trend lines show a consistent increase as engine load decreases. This alignment supports the assumption that the interpretation of fuel consumption measurements and corresponding trends is accurate for subsequent calculations.

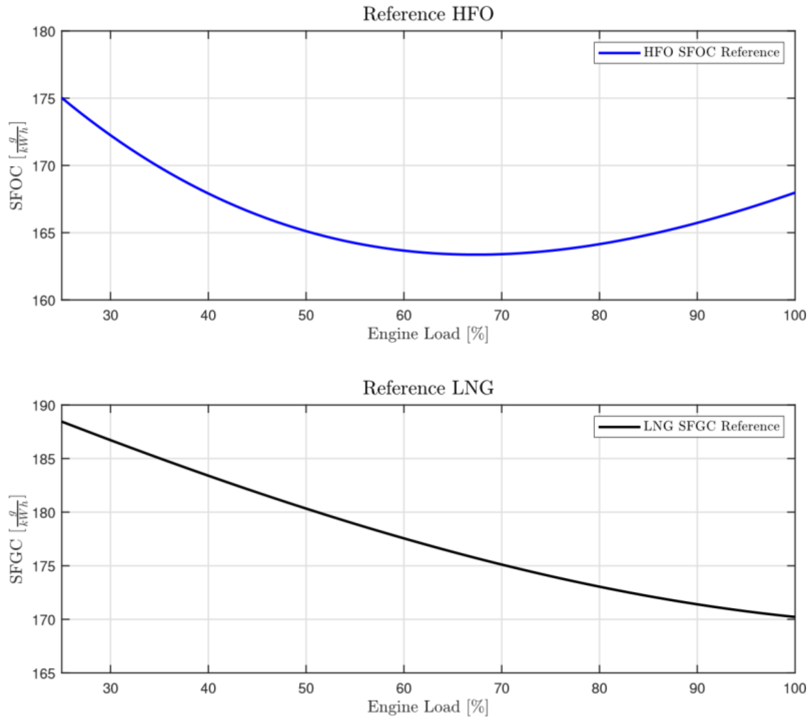

Figure 3.2: SFOC & SFGC from Reference Study (Gutierrez and Labajos, 2018).

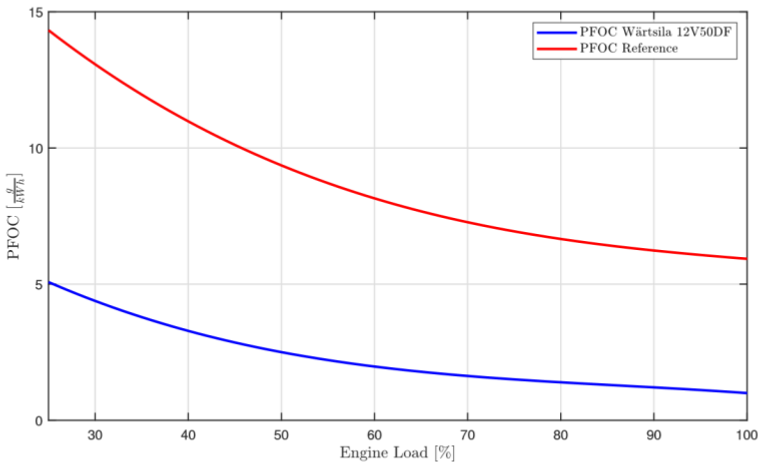

Figure 3.3: PFOC from Wärtsila 12V50DF vs. Reference Study (Gutierrez and Labajos, 2018).

Using the total engine power output and specific fuel gas consumption (SFGC) data from the manufacturer's product guide, the LNG fuel mass consumed by the reference vessels was estimated for the respective crossing times between the Swedish mainland and Gotland. To ensure completeness, this estimation was performed for all four test bed load points (50%, 75%, 85%, and 100% MCR) to illustrate the impact of engine load on fuel consumption. The total energy generated by all the engines per crossing was determined from:

$$E_{tot} = P_e \cdot t \tag{3.1}$$

where P_e is the total power output of all main engines (i.e. 4 MCR) in [kW]; t is the respective crossing time in [h].

The corresponding total LNG fuel mass M_{LNG} consumed per crossing at the corresponding load points can then be derived from Equation 3.2. Similarly, the pilot fuel mass consumption has been determined except for using PFOC instead of SFGC.

$$M_{LNG} = \frac{SFGC \cdot E_{tot}}{10^3} \quad [\text{kg}] \tag{3.2}$$

where SFGC is the specific fuel gas consumption at the load points in [g/kWh]. Generally, the fuel mass consumption is higher when operating the engine at lower load points and when the crossing time increases. The pilot fuel mass consumption is relatively low compared to the LNG main fuel but was considered for completeness in the establishment of the benchmark scenario, particularly for its contribution to overall GHG emissions.

We can now calculate from the transit and bunkering study the onboard volume corresponding to the LNG fuel mass consumed per crossing. In combination with the number of crossings sailed between bunkering operations of the vessels, we can estimate the volume of LNG fuel tanks onboard. By this means, we find out how much energy could be contained in the same HCNG volume compared to LNG if the current tanks onboard were to be replaced. This will answer the question of how much the fuel alternative would affect the distance that could be sailed by the vessels. The fuel volume V_{LNG} is obtained through Equation 3.3:

$$V_{LNG} = \frac{M_{LNG}}{\rho_{LNG}} \; [m^3] \tag{3.3}$$

where ρ_{LNG} is the density of LNG[4] [kg/m^3]. After obtaining the LNG fuel mass consumption per crossing, we can determine the energy content E_{con} that the consumed fuel contains as this would be matched by HCNG as well. Since LNG is bunkered in liquid form on board, its Gravimetric Energy Density (GED) was consulted to determine the energy content E_{con} of the LNG fuel per crossing. This can be obtained through Equation 3.4. Note that we calculated similarly for the pilot MDF that is also bunkered in liquid form. The combined energy contents have been scaled up by the number of crossings between bunkering operations to approximate the amount of energy that would have to be contained within the corresponding HCNG volume.

$$E_{con} = \frac{M_{LNG}}{GED_{LNG}} \quad [\text{MJ}] \tag{3.4}$$

[4] at T=111K & p=1atm

3.2 Emissions from LNG

To assess any emission reduction potential from HCNG, the emissions related to the combustion of LNG today were studied first to attain a benchmark scenario. The objective was to determine the absolute (i.e. annual mass) and relative emissions of the pollutants (i.e. per nautical mile or kWh). The combustion of methane is an exothermic reaction that mainly produces carbon dioxide, water vapor, and some other minor species. In contrast, hydrogen combustion does not emit carbon dioxide as it does not contain carbon. The corresponding general combustion reactions for methane and hydrogen are given in Equation 3.5 and Equation 3.6 respectively.

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O \tag{3.5}$$

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

Equation 3.5 shows that one mole of methane yields one mole of carbon dioxide after combustion. Thus, to determine the CO_2 emissions corresponding to the LNG fuel mass per crossing and annually, the number of methane moles contained in the specific fuel mass was determined. Subsequently, the total mass of CO_2 emissions could be obtained as the product of the number of methane moles and the molar mass of carbon dioxide (i.e. 44.01 kg/kmol). The total annual CO_2 emissions were subsequently essential in the economic assessment to approximate the costs related to emission regulations (i.e. EU ETS). An overview of the total annual CO_2 emissions from LNG combustion at various engine load points including pilot fuel contribution is shown in Figure 3.4. Similar to the LNG fuel mass consumption, the CO_2 emissions increase as the engine load decreases due to higher SFGC. The pilot fuel contribution to overall CO_2 emissions was found to be marginal ($\leq$1% of the total).

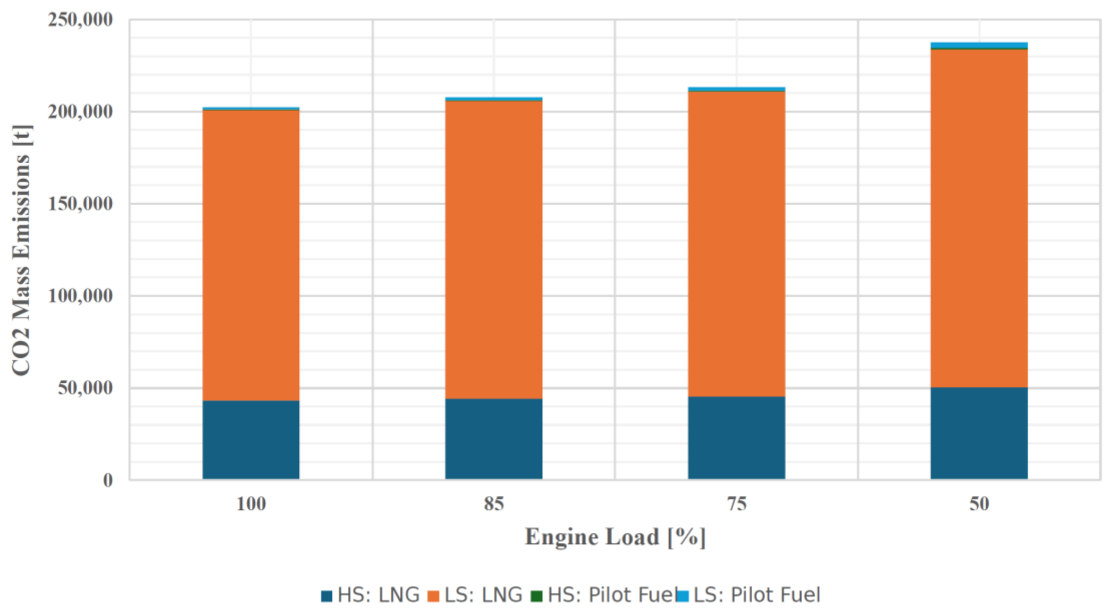

Figure 3.4: Combined Annual CO2 Emissions from LNG (incl. Pilot Fuel) for Crossings during High Season (HS) & Low Season (LS) at Different Engine Loads.

Furthermore, the CO_2 emissions per crossing were expressed in relative terms for better assessment (i.e. per nautical mile). Figure 3.5 shows the graphic visualization of the reference vessel's mean SFGC per nautical mile (left y-axis) against the corresponding mean CO_2 emissions per nautical mile (right y-axis) when the main engines are operated at different load points on LNG. These relative parameters were determined to generate a reference for two purposes. On the one hand, it allowed verifying the results obtained from theoretical calculations against reported numbers from actual vessel performance (i.e. EU MRV). On the other hand, expressing fuel consumption and corresponding CO_2 emissions in relative rather than absolute terms allowed to better evaluate any decarbonization potential of the HCNG fuel blend subsequently. This will also simplify the application of results to other vessels in future studies.

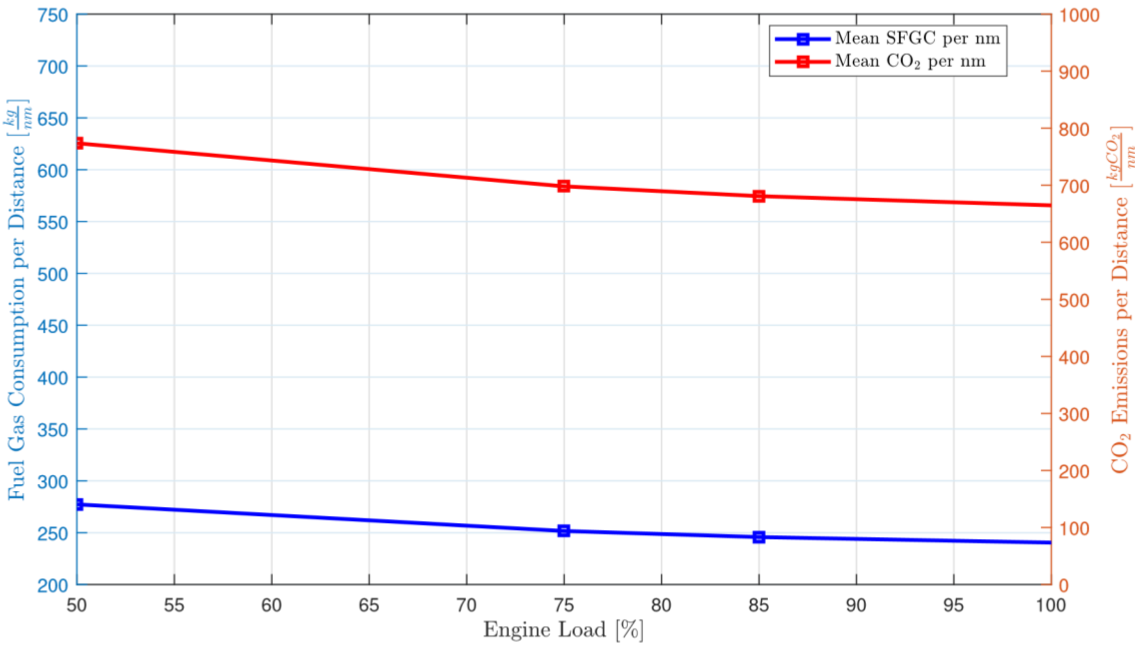

Figure 3.5: Mean SFGC vs. CO2 Emissions per Distance of the Reference Vessel.

The relative emission parameters have been checked against a pair of annual average performance parameters that were reported by the operator to the EU MRV database for both reference vessels. An overview of the relevant annual average performance parameters of both reference vessels from 2022 is provided in Table 3.2. Comparing the reported parameters to the theoretical results displayed in Figure 3.5, it was observed that the relative fuel consumption and CO_2 emissions results per nautical mile match well in the range of 75 to 85% engine load (about + 10% tolerance) which is presumed to be around the typical load range the engines are operated at. Therefore, it was understood that the computations to determine CO_2 emissions were correctly executed so similar computations could be applied to HCNG further on.

Table 3.2: Reported vs. Computed Annual Average LNG Performance Parameters from Reference Vessels (EMSA, 2024).

	Unit	Reference Vessel No.1	Reference Vessel No.2	Computed
Fuel Consumption	[kg/nm]	226	224.13	248.69
CO_2 Emissions	[kg CO_2 /nm]	678.15	671.81	689.55

3.3 Fuel Blending

When studying fuel blending to identify a suitable blending ratio, it was essential to understand how the properties of the HCNG blend change when increasing the hydrogen volume concentration relative to pure methane. The most important parameters in the following study were the volumetric and gravimetric energy densities of methane and hydrogen per SI unit mass (kg) and volume (m^3).

Hydrogen has the highest energy content per mass of all chemical fuels, exceeding that of methane by about 2.5 times. On a volume basis, however, hydrogen's Volumetric Energy Density (VED) is only about a third of methane due to its lower density. It was crucial to be aware of this difference in energy density to ensure the correct estimation of fuel mass requirements. Furthermore, the correct distinction was essential as the superior objective was to attain the same amount of heat energy from HCNG combustion as with pure methane at any time.

This project considered the blending and storing of HCNG in gaseous phase. Hence, volume is particularly interesting over mass, and the impact of hydrogen addition on overall volumetric energy density is a key parameter. Nevertheless, gravimetric calculations are presented additionally hereafter to evaluate the fuel mass consumption as a function of the hydrogen volume concentration. First, HCNG properties were calculated based on the ideal-gas law at standard ambient temperature and pressure (SATP) using the MATLAB-integrated *Cantera* toolbox which provided key properties of hydrogen and methane. The computation was set up in a way that allowed subsequent varying of input pressure and temperature to obtain component properties and identify alterations. This was considered as the final storage condition of the HCNG was unknown at this point. These component properties have then been combined respective to their volumetric concentration to obtain HCNG properties. For instance, the hydrogen volume concentration in the blend was defined as shown in Equation 3.7 (Liu et al., 2023). Similarly, the methane volume fraction was determined.

$$\phi_{H2} = \frac{V_{H2}}{V_{H2}+V_{CH4}} \tag{3.7}$$

where $\phi H2$ is the hydrogen volume fraction; V_{H2} is the hydrogen volume; V_{CH4} is the methane volume.

Examining scenarios also involved two extreme references which represent pure methane and pure hydrogen. Generally, the hydrogen volume concentration ranged from 0% to 100%, with the former representing pure methane and the latter representing pure hydrogen. Similar to previous studies, suitable blending ratios were considered in the range of up to 25 % hydrogen volume concentrations.

Regarding the energy densities, Figure 3.6 shows the effect of an increase in hydrogen volume concentration on the Gravimetric Energy Density (GED) per unit mass (left axis) and Volumetric Energy Density (VED) per unit volume (right axis) of the fuel blend. The relation between hydrogen volume concentration and HCNG's GED is non-linear. Meanwhile, the VED is decreasing linearly as it is largely dependent on the density of the blend. Besides, it was noticed that the fuel blend's weight per unit mass (i.e. kg) decreased **significantly** with increased hydrogen volume concentration due to hydrogen's lightweight molecular mass suggesting that fuel mass on board would decrease. Thus, to attain the same amount of energy per unit mass, less fuel mass would be required. More importantly though, since the VED decreases, more fuel volume is needed to attain the same amount of heat energy from combustion.

Because of this key natural fact, it was of central relevance to determine how much more fuel volume would be required to compensate for the decrease in volumetric energy density. Therefore, the required VED equivalence for all blending ratios within the range was computed relative to pure methane which could be translated into volume. Figure 3.7 shows how the volume and mass of the fuel blend would need to increase respectively decrease relative to a base unit of methane (i.e. per m^3 and kg) to attain the equivalent amount of heat energy relative to pure methane. On the left y-axis, it can be seen that pure hydrogen fuel would require about 3.3 times as much volume as pure methane to deliver the same energy content. However, on a mass basis (right y-axis), pure hydrogen that contains the same amount of energy as pure methane would only weigh about 40% compared to methane.

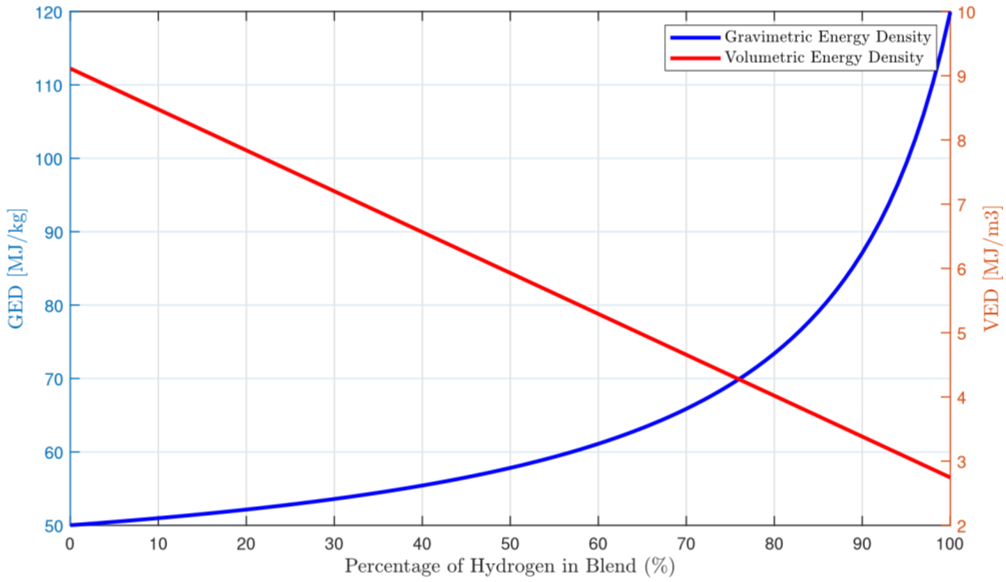

Figure 3.6: Gravimetric and Volumetric Energy Density of HCNG Blends at SATP.

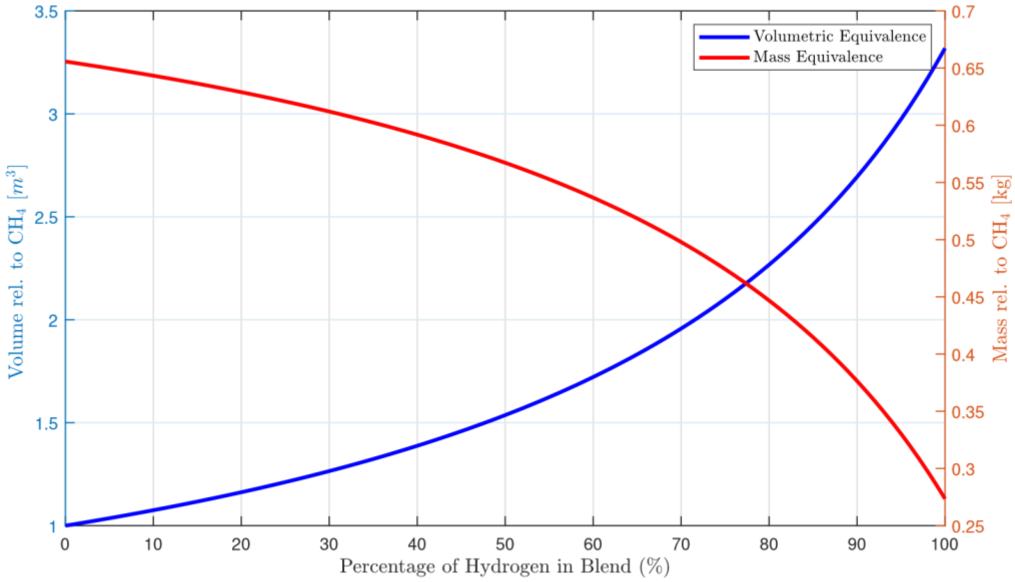

Figure 3.7: Gravimetric and Volumetric Equivalence of HCNG to Methane at SATP.

3.4 On-board Performance of the Fuel Blend

This sub-section explores the implications of hydrogen blending with methane on the altered fuel properties of HCNG for both onboard and on-land applications. The onboard findings are primarily based on vessel-specific data, evaluating whether certain factors could impact the feasibility of on-land fuel blending and storage scenarios. On-land blending is analyzed using insights from state-of-the-art research.

Following a general examination of fuel blend properties, the implications of HCNG's altered properties on the main engines onboard were analyzed. Specifically, the focus was on assessing how it impacts the ability to meet the reference vessels' energy demands. Additionally, there was an interest in verifying whether HCNG combustion improves fuel efficiency, as suggested by previous studies. This analysis included calculating the required volume and corresponding mass of fuel components needed to achieve the combined MCR (maximum continuous rating) of all four onboard engines.

To illustrate the effects of hydrogen addition on engine performance, the mass and molar flow rates required to achieve the total MCR of all four Wärtsilä engines combined over one hour (46,800 kWh ≡ 168,480 MJ) were calculated. Determining molar flow rates is a standard method in the study of internal combustion engines (ICE).

This analysis enabled an estimation of the fuel volume required by scaling up based on the respective crossing time. The results were then intended for extrapolation to determine the total fuel requirements for the targeted number of trips per year. The molar flow rates ($\dot{n}$) of the blend were calculated using Equation 3.8. The resulting hourly molar flow rates needed to achieve the MCR of all onboard engines is displayed in Figure 3.8, including the proportions of hydrogen and methane in the blend.

$$\dot{n} = \frac{P_e}{GED_{mix}} \cdot \frac{1}{M_{mix}} \; [kmol/h] \tag{3.8}$$

where P_e is the total engine power output of all engines per hour in [MJ/h]; GED_{mix} is the gravimetric energy density of the fuel blend in [MJ/kg]; M_{mix} is the molar mass of the fuel blend in [kg/kmol].

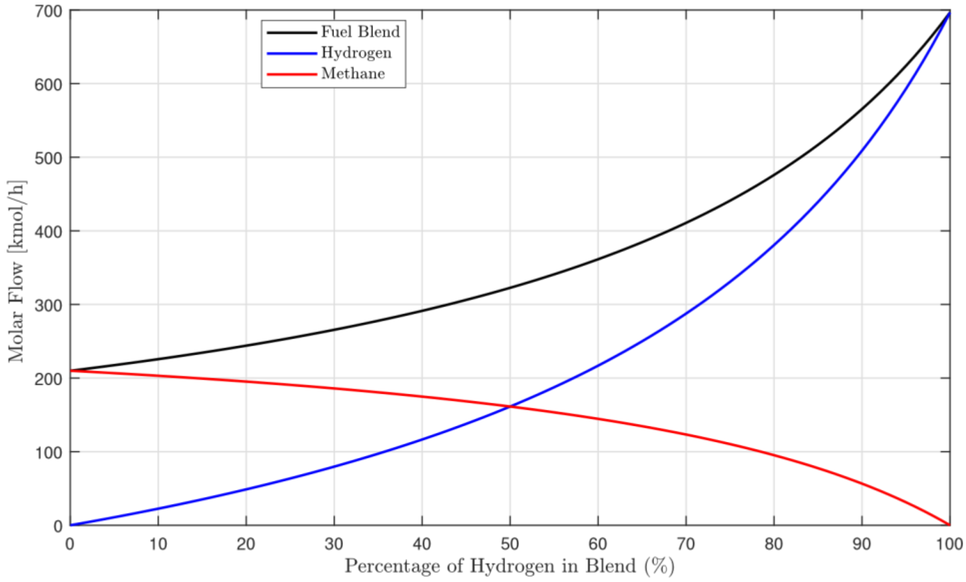

Figure 3.8: HCNG Molar Flow Rates required to attain MCR of the Wärtsila 12V50DF.

Figure 3.8 illustrates that the molar flow rates for any HCNG blend ratio are higher than those for pure methane due to the addition of hydrogen, which has a lower volumetric energy density (VED). Even small blending ratios, such as a hydrogen concentration of approximately 5%, would increase the total fuel volume by about 4% compared to LNG, to store equivalent energy. This increase in fuel volume can reach up to 21% for blends containing 25 vol% hydrogen. For pure hydrogen, the required fuel volume would be approximately 3.3 times greater than that of pure methane.

The increased total volumetric flow rate results in a drop in static pressure within the fuel gas supply system (FGSS) as the velocity of the gas flow increases. Depending on the severity of the pressure gradient, this drop could pose challenges for end-use applications, such as internal combustion engines (ICE), where insufficient injection pressures might lead to efficiency losses. To address this issue, additional components, such as onboard compressors, may be required in the FGSS to compensate for and regulate pressure losses (Chae et al., 2022). This increased flow rate and associated pressure drop present a significant drawback of HCNG blending.

Having the first research question in mind (benefits of HCNG over LNG), the increase in HCNG fuel volume is observed as a significant drawback of blending hydrogen with methane, especially considering the typically limited space available on board. Additionally, the drop in static pressure due to the increased fuel volume flow introduces further technical challenges and modification requirements for both the fuel gas supply system (FGSS) components and the main engine. These modification needs limit the feasibility and practicality of HCNG as a fuel. The issue of increased fuel volume is particularly problematic for retrofit projects with fixed space allocations. If the storage space for HCNG remains the same as for the current fuel (i.e., LNG), the energy content would decrease, resulting in reduced sailing distances and more frequent bunkering. Accordingly, the optimal blending ratio would depend significantly on how much additional space can be made available and tolerated for larger HCNG storage tanks.

3.5 HCNG Fuel Mass Requirements

The fuel masses for different HCNG blends, along with their components, were calculated based on the increase in fuel blend volume required to operate the engine at its MCR. By scaling up the molar flow rates to the respective crossing times, the necessary fuel volume onboard was estimated. Using the ideal-gas law (see eq. 3.9), the molar quantities of the methane and hydrogen blend were calculated across various concentrations. The ideal gas law is an equation of the state of an ideal gas:

$$pV = nRT \tag{3.9}$$

where p, V and T are the pressure, volume and temperature respectively; n is the amount of substance (number of moles); and R is the ideal gas constant[5]. The molecular weights of hydrogen and methane were then applied to determine the mass of each fuel component and the total resulting fuel weight.

Figure 3.9 provides an overview of the reference vessel's average fuel mass consumption per crossing when operating on different HCNG blends at an estimated engine load of 75%. Additionally, the fuel mass consumption for each component (i.e., hydrogen and methane) is shown, while only the total HCNG mass is explicitly indicated. When comparing the fuel mass consumption per crossing in Figure 3.9, it was observed that the total fuel mass decreased moderately as the hydrogen volume concentration increased, despite the fact that more fuel volume was required to achieve the MCR.

Similarly, the total annual fuel mass requirement for the entire Gotland fleet was calculated, as shown in Figure 3.10. The total fuel mass reduced only marginally, even for high hydrogen volume concentrations of up to 25 vol%. This is primarily due to the fact that methane is approximately eight times heavier than hydrogen, based on molecular weight, which is reflected in the relative height of the hydrogen bars compared to methane.

[5] The values of R can be found in in different units here: https://www.engineeringtoolbox.com/individual-universal-gas-constant-d_588.html

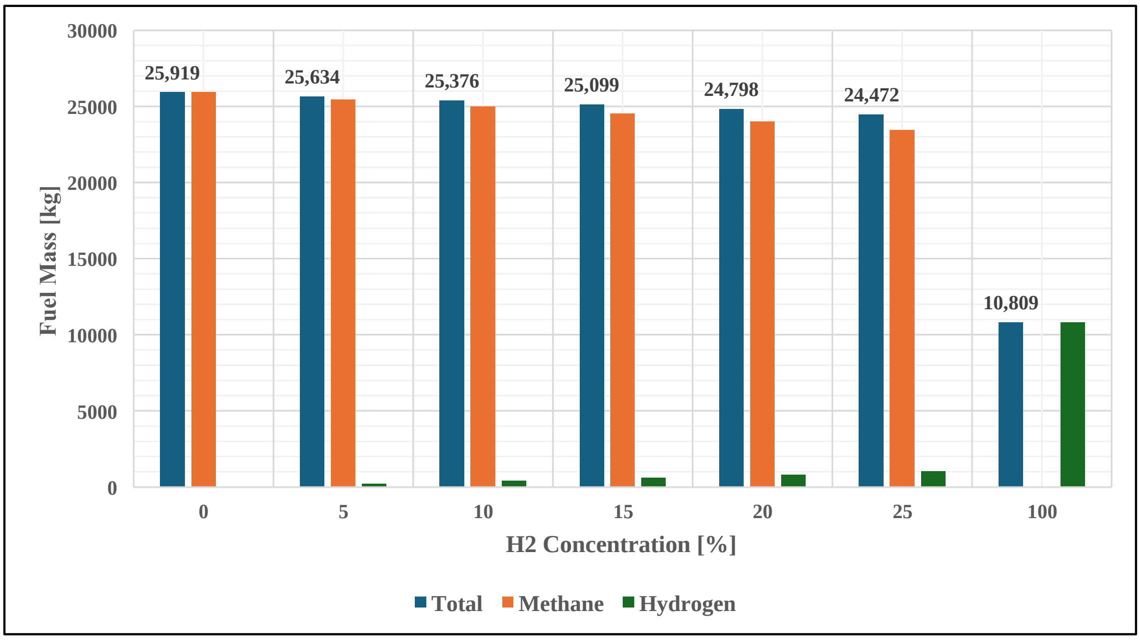

Figure 3.9: Overview of Fuel Mass Consumption per Crossing for HCNG Blending Ratios.

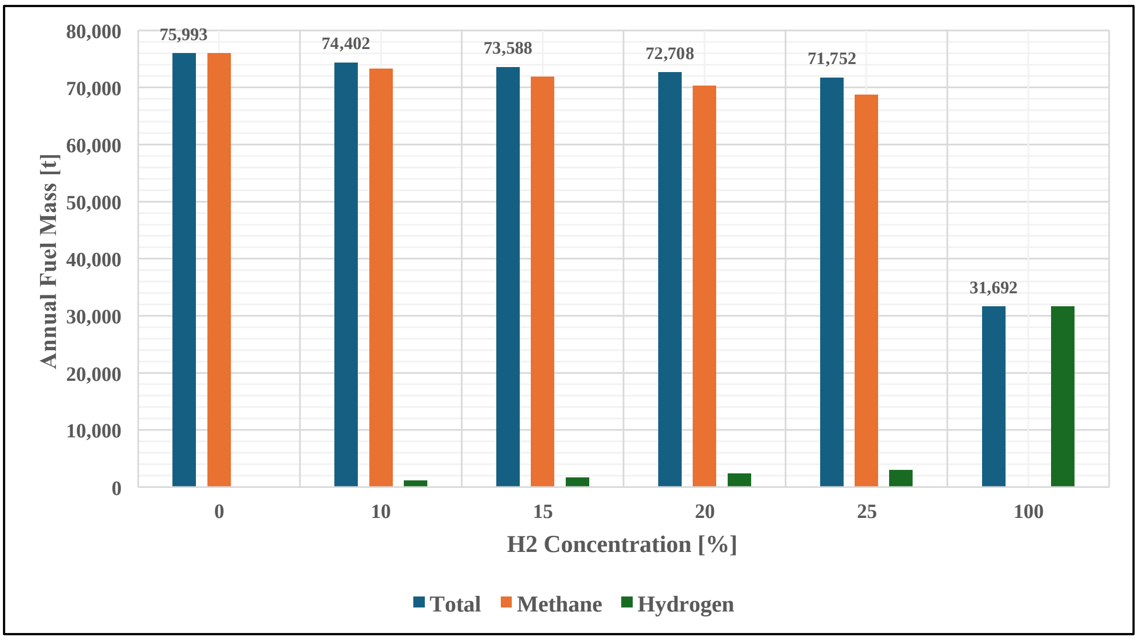

Figure 3.10: Overview of HCNG Annual Fuel Mass Requirement for Blending Ratios

The potential for fuel consumption reduction became more apparent when considered relative to the overall fuel mass, as this reduction can be extrapolated and applied analogously to vessels with different operational profiles. As the hydrogen volume concentration increased, the total fuel mass decreased, leading to an improvement in the engine's specific fuel gas consumption (SFGC) per unit of energy (i.e., kWh) when operating on HCNG. This trend is illustrated in Figure 3.11, which shows the behavior of SFGC per unit of energy at different engine load points. Similarly, the fuel consumption reduction per nautical mile which is provided in Figure 3.12 was found to decrease with increased hydrogen concentration in the blend.

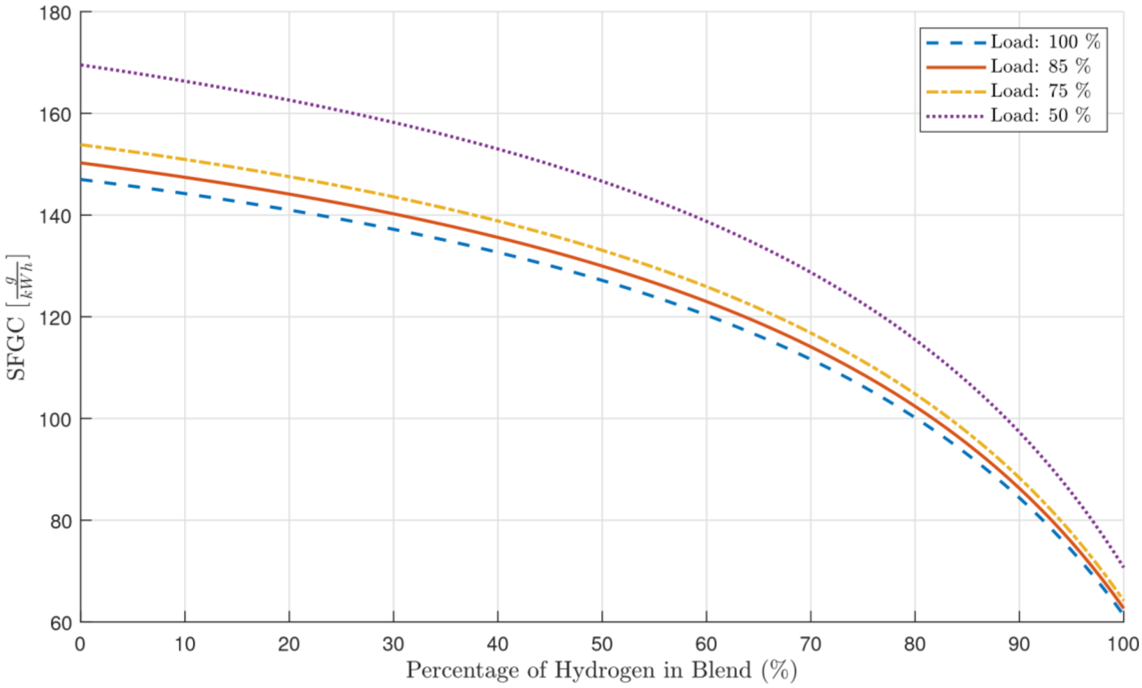

Figure 3.11: HCNG Fuel Mass Consumption Reduction per Unit Energy at Different Engine Loads.

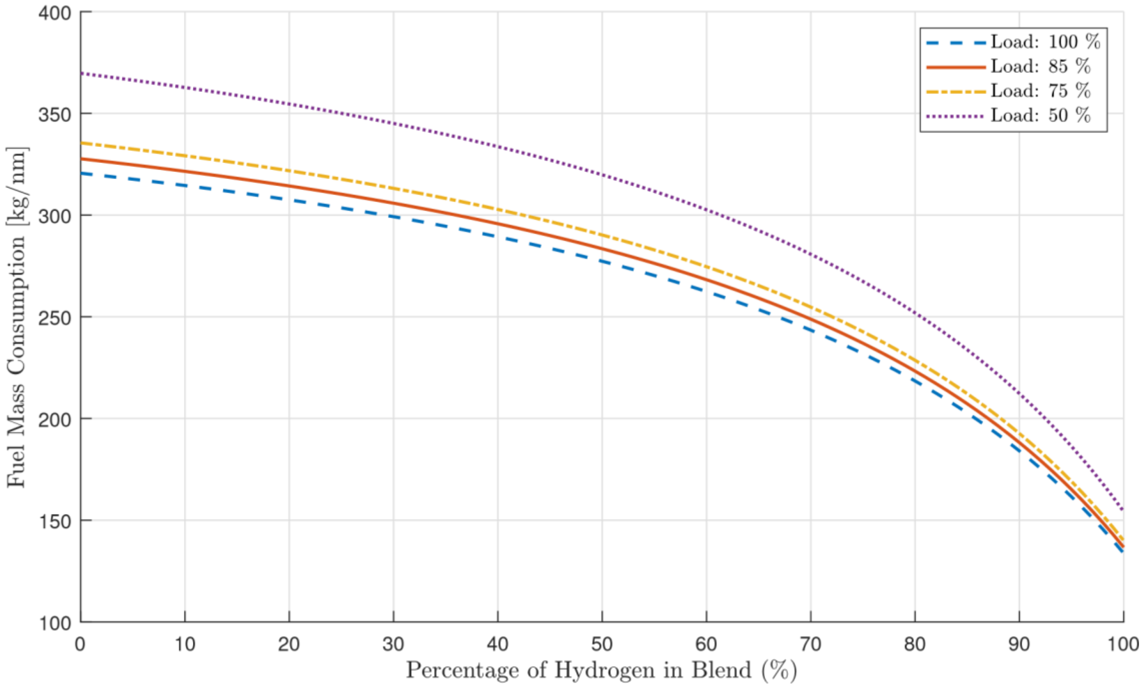

Figure 3.12: HCNG Fuel Mass Consumption Reduction per Unit Distance at Different Engine Loads

Figures 3.11 and 3.12 confirm that any HCNG fuel blend ratio results in improved specific fuel mass consumption, despite the increase in HCNG volume relative to LNG. However, the improvement was marginal within the range of interest, up to a 25% hydrogen volume concentration. For smaller blending ratios, up to 10% hydrogen concentration, the reduction in specific fuel consumption was only about two percent compared to LNG. When blending up to 25% hydrogen concentration, the reduction increased to 5.3% relative to the current fuel. This latter fuel consumption reduction potential is competitive with other common energy efficiency technologies for vessels (e.g., hull cleaning or waste heat recovery). However, it comes with a lower level of technical maturity, resulting in a higher implementation barrier. While this relative reduction is also relevant for other vessels, the marginal decrease in specific fuel mass consumption must be considered in the context of the economic implications of the increased fuel volume and the environmental benefits, which will be discussed further.

3.6 Fuel Storage

The assessment of HCNG blend storage required an understanding of the properties of the individual fuels in both their liquid and compressed states. The goal was to determine the optimal storage conditions in terms of pressure, temperature, and location. Key factors such as fuel properties, energy storage capacity, and volume were considered when selecting the ideal fuel containment solution. Regardless of the blending scenario, methane and hydrogen were stored separately before blending. Methane was assumed to be stored in its liquefied form due to its higher energy density compared to its compressed state. This decision was further supported by the existing LNG storage infrastructure onboard the reference vessels and at the case ports.

Hydrogen is assumed to be stored in its compressed form. Compressed hydrogen gas tanks were preferred over liquid hydrogen tanks due to the significant energy cost required to maintain the extremely low temperatures needed for liquid hydrogen storage. However, compressed gas storage has lower energy density and requires larger volumes than liquid hydrogen. To ensure hydrogen and methane are miscible in the gaseous phase and minimize the risk of phase separation, the storage conditions (pressure and temperature) were aligned with the blending conditions. The compatibility of the storage tank materials for both fuels suggest that storing the blend in a compressed hydrogen tank is feasible, as these tanks can withstand higher pressures.

Since no dedicated commercial solutions for HCNG blend storage currently exist, phase diagrams of both HCNG components were studied to determine the boundaries of their gaseous phase. It was found that both hydrogen and methane are in their gaseous phase at ambient temperature (25°C) and pressure, making this a suitable storage temperature. The study then focused on determining the appropriate storage pressure, referencing Cheng et al. (2023) (Figure 3.13), assuming the findings could be applied to large fuel storage tanks commonly used on vessels. The study suggests several advantages to using Type III tanks operating at 350 bar, which are favorable for maritime applications. Type III tanks (350 bar) have the largest internal tank size of all the tanks studied by Cheng et al. (2023), maximizing the HCNG storage volume. Additionally, the ratio between internal and external tank size is optimal, making the best use of limited onboard space, which is especially relevant given the volumetric fuel increase. Although Type III (350 bar) tanks have the highest specific weight of all compressed hydrogen tanks investigated, this is not necessarily a drawback, as the fuel mass of HCNG decreases (see Figure 3.9). Therefore, the increased specific tank weight and reduced fuel mass could offset each other, resulting in minimal changes to the overall deadweight of the vessel. Limiting changes in carrying capacity is crucial for maintaining vessel stability and safety. Furthermore, Type III (350 bar) tanks were found to have the lowest specific costs among the compressed hydrogen tanks studied.

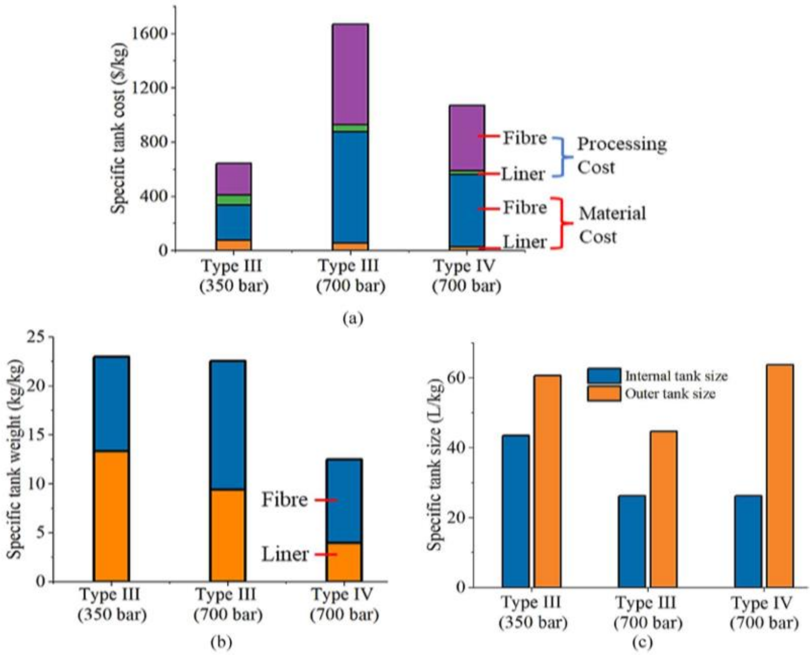

Figure 3.13 Comparison of (a) Specific Costs, (b) Specific Weights, and (c) Specific Sizes of the Three Types of commonly used Hydrogen Tanks for storing 1 kg Hydrogen (Cheng et al. 2023).

Given the favorable properties of Type III tanks (350 bar), this pressure was chosen as the suitable storage pressure for the HCNG blend. At 25°C and 350 bar, both hydrogen and methane remain in their gaseous phase. Hydrogen, with a critical temperature of -240°C and a critical pressure of 13 bar, remains gaseous due to the significantly higher temperature and pressure compared to its critical values. Similarly, methane, with a critical temperature of -82.6°C and a critical pressure of 46 bar, also stays gaseous under these conditions. The higher ambient temperature ensures both gases remain in their gaseous forms. After determining the storage temperature and pressure at 25°C and 350 bar, the study turned to evaluating suitable locations for blending and storage.

3.6.1 Case Scenario No.1

Scenario No. 1 focuses on pre-compression HCNG blending, which takes place entirely in port. Both compressed hydrogen and LNG are stored separately at the port before being blended and compressed. LNG must first be gasified before being fed into the HCNG blender, requiring additional equipment between the LNG storage tank and compressor. Hydrogen and methane are then fed in their gaseous form into a compressor, which blends and compresses them at 350 bar to form HCNG. After blending, the HCNG can either be stored in a tank for future use or supplied on demand to the dispenser.

A schematic overview of Scenario No. 1 is presented in Figure 3.14. The fuel distribution form (i.e., pipeline) in this schematic is for illustration purposes and does not preclude other distribution methods. Separate storage tanks for methane and hydrogen are shown, along with the key blending components. After blending, HCNG can either be stored in an optional buffer tank or supplied to the vessel through on-demand blending in port. This scenario is designed to integrate with the existing LNG infrastructure in the ports where the reference vessels operate. Scenario No. 1 does not involve fuel blending onboard the vessels but requires them to have designated HCNG storage capacities. The onboard installation of a new Type III (350 bar) storage tank would be necessary to bunker the pre-blended HCNG.

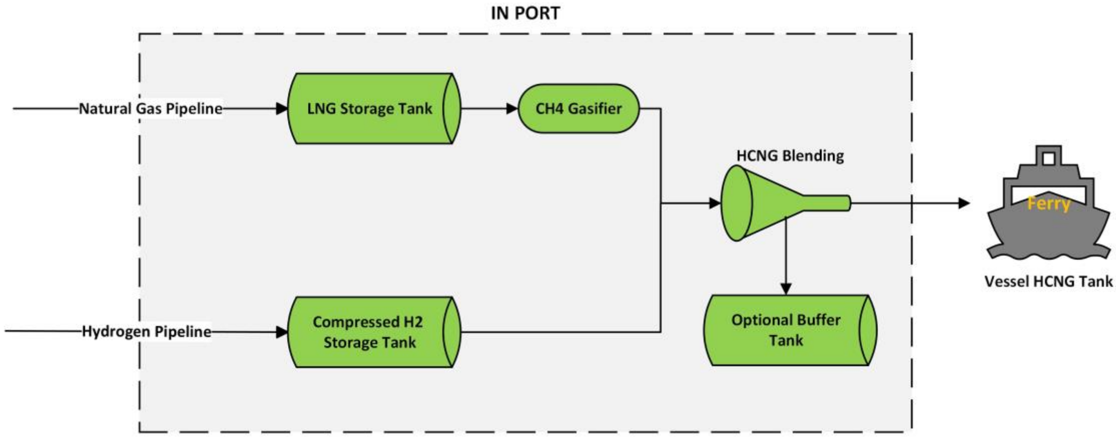

Figure 3.14: Schematic Overview of Scenario No.1.

The accommodation of larger fuel storage tanks is easier to implement in port than onboard, as the available space in port is less constrained. With the existing LNG infrastructure in the case ports, only fuel blending equipment and hydrogen storage facilities would need to be added. Limiting the need for modifications and leveraging existing fuel infrastructure is an advantage in terms of sustainability. The availability of HCNG in port extends the (limited) environmental benefits of HCNG if it is made accessible to other stakeholders, allowing the investment costs for infrastructure modifications to be shared. These stakeholders could include municipalities, port authorities, and fuel suppliers.

In Scenario No. 1, it was assumed that the risks associated with fuel component failure mechanisms (e.g., leaks, fire, explosions) are minimized due to the storage dimensions onboard. This is particularly important since the reference vessels operate as RoPax ferries. While the consequences of such failure mechanisms would also be severe in ports, fuel blending and storage typically occur in sparsely populated industrial areas on the outskirts of a port. In these areas, the environmental consequences of HCNG failure modes can be more effectively monitored and controlled, reducing the operational risks. This is considered a significant advantage of in-port blending and storage.

However, the most notable drawback in this scenario is the reduction in sailing distance. If the volume currently occupied by LNG tanks were replaced one-for-one with HCNG storage tanks, the contained energy may not be enough even for one crossing. As a result, the time and distance over which the engine could operate at maximum power output would be significantly reduced. As an example, 1 m^3 LNG (20 GJ energy content) contains five times more energy that the same volume (1 m^3) of pure hydrogen at 350 bar (~4 GJ energy content). This ratio is definitely lower if HCNG with high methane content is used, however, the emission reduction potential is significantly lower for HCNG at low hydrogen content (>60 %, see section 3.7). Based on the previously conducted bunkering study, this issue becomes pronounced only when hydrogen blending ratios exceed 20%, leading to increased bunkering frequencies or possibly being impossible to cross with one fuel tank. This can present serious challenges for retrofit projects or new ship orders, especially when available space is limited or when bunkering infrastructure is only partially developed.

3.6.2 Case Scenario No.2

Scenario No. 2 involves real-time HCNG blending onboard the reference vessels, meaning hydrogen and methane are blended instantaneously right before entering the engine. Similar to Scenario No. 1, both components are stored separately: methane is kept in the liquid phase at cryogenic temperatures around -162°C and at ambient pressure in the existing tanks, while hydrogen is stored in compressed form at a pressure of 350 bar and ambient temperature. LNG is gasified after being released from the storage tank and then blended with compressed hydrogen just before being injected into the engine.

For hydrogen alone, a new tank would need to be installed to replace the existing HFO tanks, while the current LNG storage can still be utilized. Additionally, this design leverages the main engine's dual-fuel (DF) capability, provided it is adjusted to accommodate higher hydrogen concentrations. This layout aims to maximize the use of existing onboard installations, minimizing the need for technical modifications and, in turn, reducing investment costs. A schematic overview of Scenario No. 2 is shown in Figure 3.15.

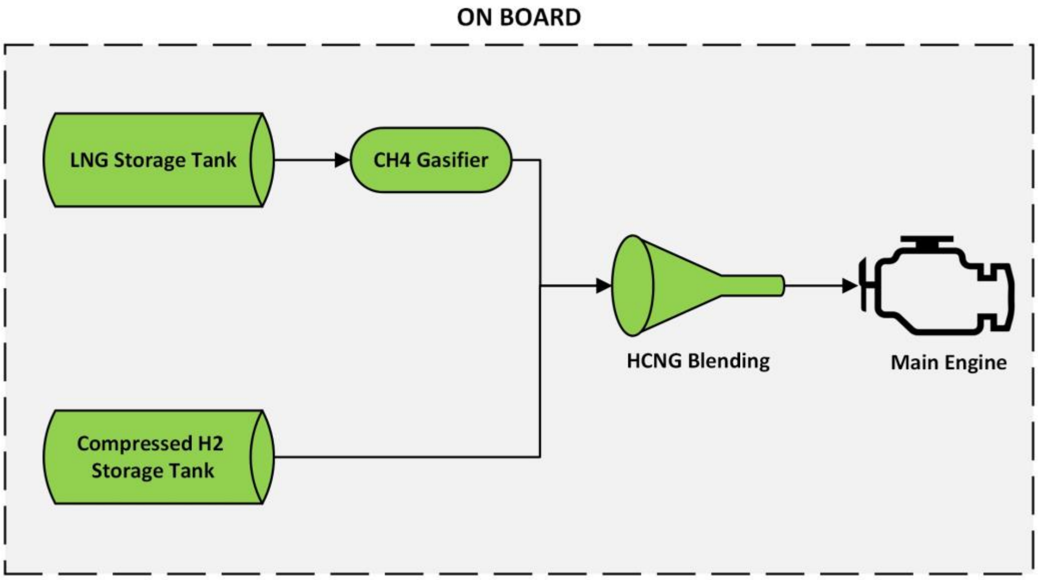

Figure 3.15: Schematic Overview of Scenario No.2

Considering the technical aspects of this scenario, the unknown exact tank volumes of the reference vessels made it challenging to assess the feasibility of accommodating new compressed hydrogen tanks onboard. However, it is noted that the tanks storing compressed hydrogen would be relatively large compared to LNG tanks. For instance, blending ratios containing a quarter of hydrogen by volume concentration (i.e., 25%) would take up about a third of the volume of LNG tanks. Thus, the feasibility of this scenario, especially regarding the accommodation of new compressed hydrogen tanks, is largely dependent on the available space onboard. This is particularly relevant in retrofit projects for vessels equipped with DF engines, which typically use HFO or MGO in secondary fuel tanks that would be replaced by compressed hydrogen tanks in this scenario.

Regarding the environmental safety of blending and storage and associated risks, Scenario No.2 was found to have a higher risk for the shipping company. This is because the layout comprises two storage tanks with different characteristics in terms of failure mechanism (boil-off for LNG, leakages for compressed hydrogen) which are very fatal. Both failure mechanisms occur naturally and gradually over time so their continuous monitoring for risk mitigation is mandatory. Regarding the economic aspects of this scenario, Scenario No.2 is deemed less advantageous for the shipping company compared to Scenario No. 1. In Scenario No.2, the operator of the vessels would bear all investment and operational costs independently, with little likelihood of cost-allocation with other stakeholders.

3.6.3 Blending and Storage Conditions & Location

Both scenario No. 1 and No. 2 propose benefits and risks or uncertainties and are case-sensitive regarding the shipping purpose, crossing distance, and even ship design.

Scenario No. 1 has several benefits such as availability of the land at the port, less complex handling of high-pressure pure hydrogen, and already available LNG facilities. However, the important and impactful challenge is that the HCNG (fuel) must be stored in gas form on-board. This implied that a very large tank (for example minimum 2 times larger than the LNG tank if 50/50% blend is used) at high pressure (minimum 350 bar) should be installed on-board to store enough fuel for normal crossings (assuming a current ferry that uses LNG). Otherwise, most probably the ship will not have enough fuel stored on board for even one crossing between two ports. This is a considerable technical challenge in the case of scenario No. 1.

Scenario No. 2 (LNG and compressed H_2 stored on board) may address the crossing range to some extent as at least CH_4 is stored in liquid form. However, a rather large tank of pressurized (at least 350 bar) pure hydrogen, and required equipment and installation for hydrogen management may result in complexity and elevated costs.

Scenario No. 2 places the burden of modification costs and operational risks entirely on the shipping company, as they are the sole beneficiary of HCNG usage. In contrast, Scenario No. 1 involves higher investment costs, as LNG bunkering infrastructure is only available in one of the three case ports investigated. Additional equipment for compressed hydrogen storage, HCNG blending, and storage would need to be implemented. However, on-land blending could be managed by a different entity, such as the current LNG terminal operator. Joint ventures between fuel suppliers, shipping companies, and local municipalities could help share investment costs and mitigate risks. In-port HCNG dispensing would also allow other vessels to use the alternative fuel, supporting the transition to a (renewable) hydrogen economy.

In summary, the choice of the place of fuel blending and storage may depend greatly on the future technological developments where any of the challenges (technical, economic, safety, etc.) is addressed. Therefore, no concrete recommendation can be made regarding where to mix and store the fuel.

3.7 TtW Emissions from HCNG

It is obvious that blending green or low-carbon hydrogen with LNG in maritime applications can result in CO_2 emission reduction (Banapurmath et al., 2015). In this section, the effect of blending hydrogen with LNG on CO_2 emissions is discussed to better evaluate the potential environmental effect of application of hydrogen as a fuel in maritime sector.

Carbon Dioxide

The theoretical decarbonization potential of HCNG was studied as part of this project, as it is largely dependent on the blend's properties, specifically the volumetric energy density (VED). It is known that continuous hydrogen enrichment of CNG reduces the carbon content of the fuel blend, leading to lower CO_2 emissions. However, the fuel blending study also revealed a decrease in the VED of HCNG as the hydrogen volume concentration increased, requiring a greater fuel volume to match the energy provided by pure methane.

This additional fuel volume limits the decarbonization potential, as more methane containing HCNG is needed to compensate for the decrease in VED. Initially, it was assumed that the reduction in CO_2 emissions would directly correlate with the hydrogen volume concentration. However, it was found that a specific volumetric fraction of hydrogen does not correspond to the same percentage of decarbonization potential. The theoretical CO_2 reduction potential of HCNG was calculated based on the proportion of hydrogen's VED relative to the total VED of the blend, as shown in Equation 3.9 (Longo et al., 2024).

$$CO_{2,red} = \frac{\phi_{H_2,i} \cdot VED_{H_2}}{\sum_{i=1}^{100} \phi_{H_2,i} \cdot VED_{H_2} + \phi_{CH_4,i} \cdot VED_{CH_4}} \; [\%] \qquad (3.10)$$

where, $\phi_{H2,i}$ and $\phi_{CH4,i}$ are the volumetric fraction of H_2 and CH_4 in the blend (i.e. 0 - 100%), respectively; VED_{H2} and VED_{CH4} are the VED of H_2 and CH_4 in the blend in [MJ/m^3].

The resulting decarbonization potential of HCNG across the full range of hydrogen volume concentrations is shown in Figure 3.16. Literature typically examines hydrogen volume fractions up to 25%, within which the decarbonization potential is limited (≤ 10% max.). A more significant reduction in CO_2 emissions becomes apparent only when the hydrogen volume concentration exceeds 50%.

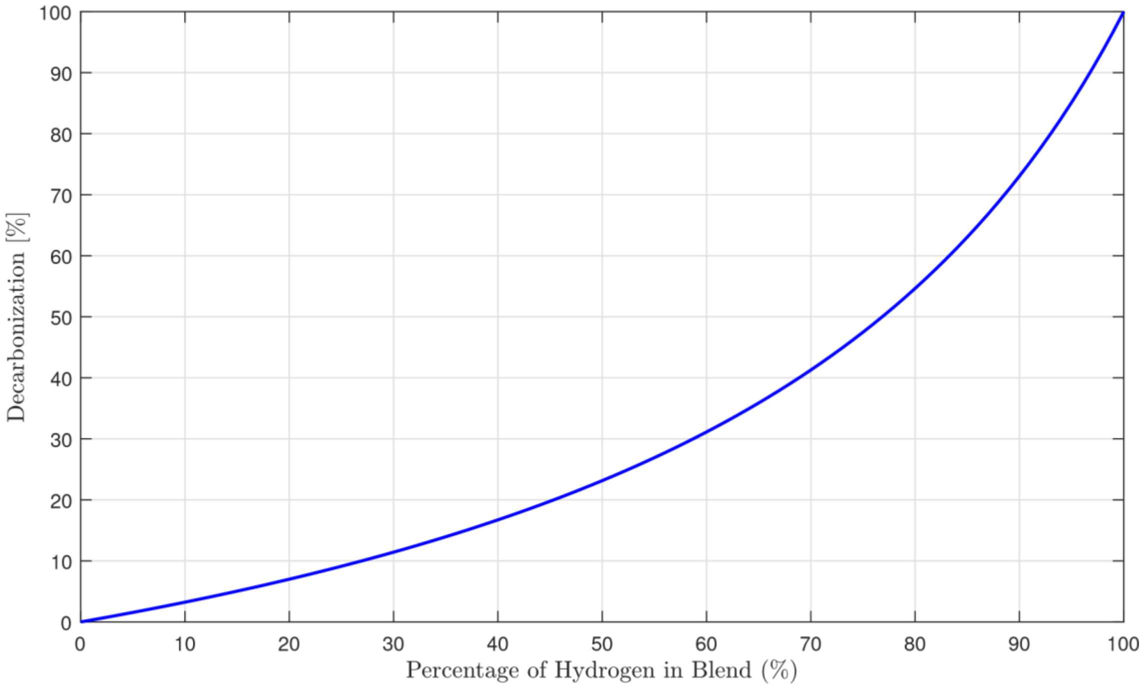

Figure 3.16: Decarbonization Potential of HCNG.

IMO's carbon-neutrality goals (IMO, 2024), to achieve a minimum of 20% CO_2 reduction compared to pure methane by 2030, relative to the 2008 baseline, approximately 46% hydrogen would need to be blended with methane. For a minimum of 70% CO_2 reduction by 2040, about 90% hydrogen would need to be blended. However, achieving such high hydrogen blending may prove unfeasible due to the technical challenges associated with blending large volumes of hydrogen, as previously discussed.

To better illustrate the decarbonization potential of HCNG, CO_2 emission reduction has been expressed relative to the grams of combusted fuel at different engine loads, as shown in Figure 3.17. This corresponds to the main fuel emission factor provided in Table 2.2. As seen in Figure 3.16, the CO_2 emission reduction is relatively limited with hydrogen concentrations up to 25%. When the hydrogen volume concentration exceeds 50%, the CO_2 reduction per gram of HCNG fuel becomes more pronounced and increases as more hydrogen is blended.

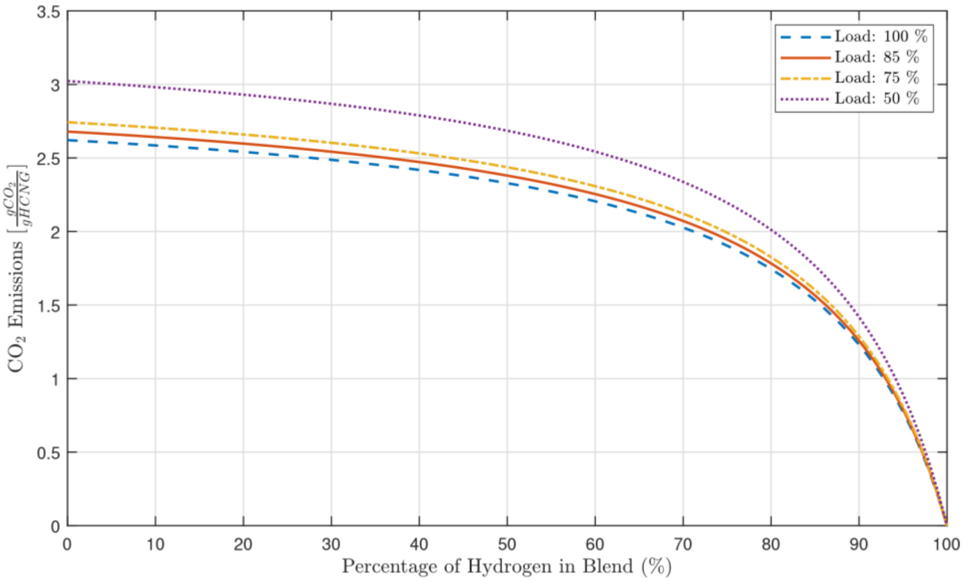

Figure 3.17: Relative CO2 Emissions per Gram of HCNG Fuel Mass.

Figure 3.18 further explores the relative specific fuel mass consumption and CO_2 emission reduction per nautical mile for the reference vessels when using HCNG blends, based on Figure 3.5. The dashed lines represent HCNG blends, with only the smallest (5%) and largest (25%) hydrogen volume concentrations shown for clarity. It is evident that both concentrations result in a reduction in specific fuel mass consumption and CO_2 emissions. The savings increase as the hydrogen concentration in the blend rises. This confirms the benefits of HCNG blending, supporting findings from previous studies within the context of this analysis. The total annual CO_2 emissions from HCNG consumption for the reference vessel's operational characteristics were calculated using combustion chemistry. These calculations were based on the methane masses shown in Figure 3.10. The number of moles within the methane fuel mass fraction was key, as it directly corresponded to the number of CO_2 moles produced during combustion. Total annual CO_2 emissions were determined by multiplying the number of CO_2 moles by its molar mass. The resulting total annual CO_2 emissions are presented in Figure 3.19, assuming the vessel operates at an estimated engine load of 75%.

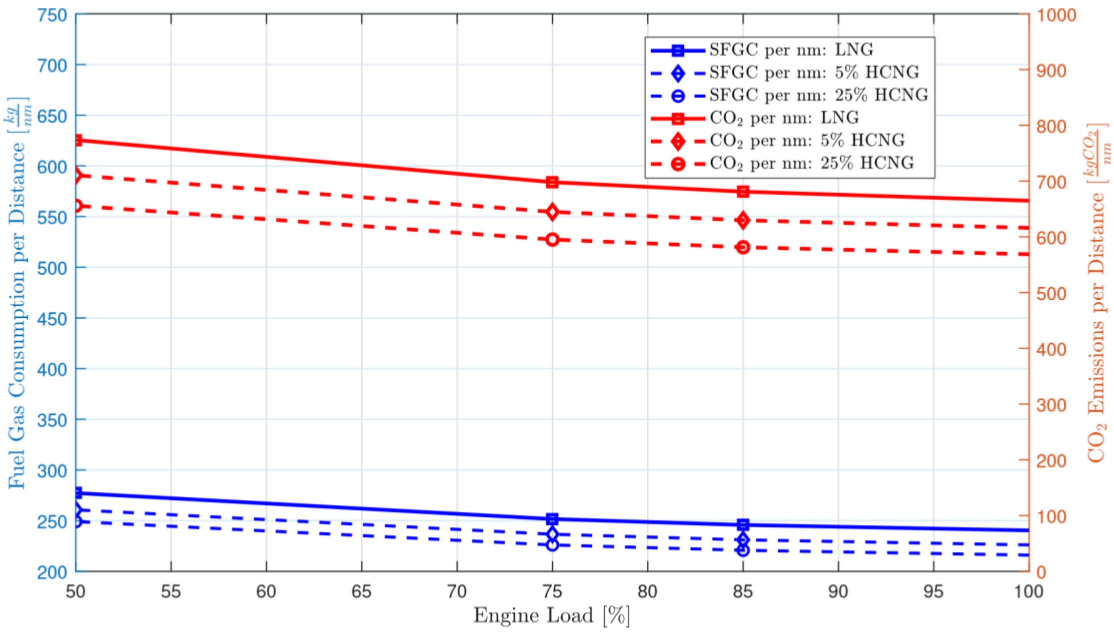

Figure 3.18: Mean SFGC vs. CO2 Emissions per Distance of the Reference Vessel using HCNG vs. LNG.

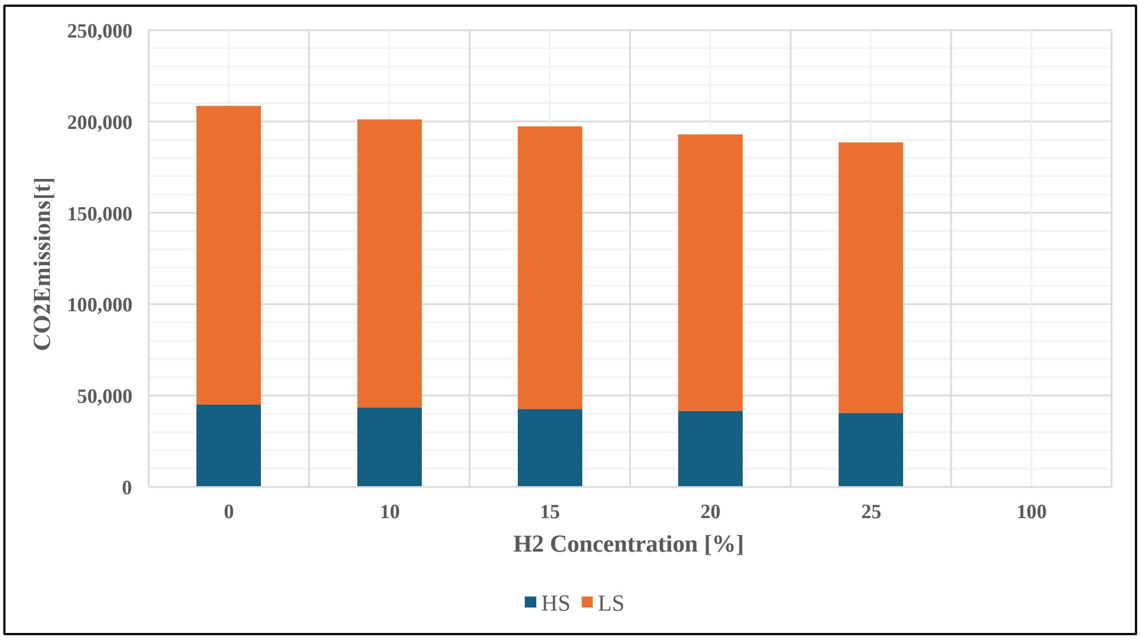

Figure 3.19: Combined Annual CO2 Emissions from High Season (HS) & Low Season (LS) Crossings for HCNG Fuel Blends [1].

3.8 Economic Assessment

To ensure a holistic assessment of HCNG's potential as an alternative fuel in the shipping industry, an economic assessment was conducted. The assessment was intended to investigate whether any HCNG blend could offer economic advantages over LNG use through savings from emission reductions.

An overview of the estimated total annual costs for different blending ratios comprising fuel and carbon allowance expenses is given in Table 3.3 (referring to section 2.2 "Viability Assessment": LNG price: $1.028 USD/kg, H_2 (RES) price: $8 USD/kg, EU ETS allowance price: $90 USD/t CO_2). Since some studies suggest that a hydrogen volume concentration of around five percent can be implemented by default without the necessity for major technical modifications to the transmission infrastructure, it was decided to include a scenario for this concentration as well.

Under the given assumptions, it can be seen that the HCNG blending ratios turn out to be more expensive despite the reduction in emission allowance cost relative to LNG. The total expenses for an HCNG blend with up to five percent hydrogen volume concentration increased by approximately three percent which was still considered to be within acceptable cost increase for a shipping company. However, annual costs increased by up to 17% higher costs compared to LNG with 25% hydrogen volume concentration. Although not emitting any $CO_{2,eq}$ tailpipe emissions and thus avoiding EU ETS allowance costs, a scenario in which pure hydrogen from RES is employed as a single fuel is currently estimated to be almost three times as expensive as LNG. This is due to the production's dependency on electricity prices (IEA, 2023).

Table 3.3: Overview of Total Annual Fuel Costs (p.a. in MUSD) for Different Blending Ratios against Pure Methane and Hydrogen Scenarios.

H_2 vol%	**0%**	**5%**	**10%**	**15%**	**20%**	**25%**	**100%**
CH_4	78.1	76.9	75.6	74.2	72.6	71	0
H_2	0	4.3	8.9	13.8	19.2	25	273.8
Total Fuel	78.1	81.2	84.5	88	91.8	96	273.8
CO_2	18.8	18.5	18.1	17.8	17.4	17	0
Total	**96.9**	**99.7**	**102.6**	**105.8**	**109.2**	**113**	**273.8**

H_2 vol%	**Unit**	**0%**	**5%**	**10%**	**15%**	**20%**	**25%**	**100%**
CH_4 Costs	[USD]	$78,120,767	$76,901,205	$75,590,034	$74,176,528	$72,648,222	$70,990,536	$0
H_2 Costs	[USD]	$0	$4,274,694	$8,870,489	$13,824,976	$19,181,853	$24,992,216	$273,821,582
Total Fuel Costs	[USD]	$78,120,767	$81,175,900	$84,460,524	$88,001,505	$91,830,075	$95,982,753	$273,821,582
CO_2 Costs	[USD]	$18,761,683	$18,468,790	$18,153,896	$17,814,425	$17,447,383	$17,049,269	$0
Total	**[USD]**	**$96,882,451**	**$99,644,691**	**$102,614,420**	**$105,815,930**	**$109,277,459**	**$113,032,022**	**$273,821,582**

Therefore, an intermediate conclusion was that HCNG blending under present price levels is associated with an overall increase in expenses. Only the five percent hydrogen blending ratio is within the set five percent cost increase tolerance relative to current expense levels, all other blending ratios would currently cost more. Hence, the viability of HCNG as an alternative fuel is currently limited while its employment depends largely on the financial flexibility of an individual shipping company.

4 Results of prospective LCA

This section presents the results of the well-to-tank LCA results and the combined well-to-wake LCA results. The fuel consumption, obtained as a result of the study in the previous section, is utilized along with the emission performance factors established through the literature study carried out. The economic assessment of the project inclusive of the fuel cost and CAC is calculated. Based on the results, the viability of the HCNG blend is assessed.

4.1 WtT (Well-to-Tank) Assessment

This sub-section discusses the results from the assessment of the Well-to-Tank (WtT) phase of the Life Cycle Assessment (LCA). Figure 4.1 shows the annual GHG emissions (for the entire Gotland service) for different blending ratios of a combination of pilot diesel oil with a blend of e-Hydrogen and syn-LMG. It is observed that a 25% hydrogen blend results in a reduction of over 7,000 tons in GHG emissions.

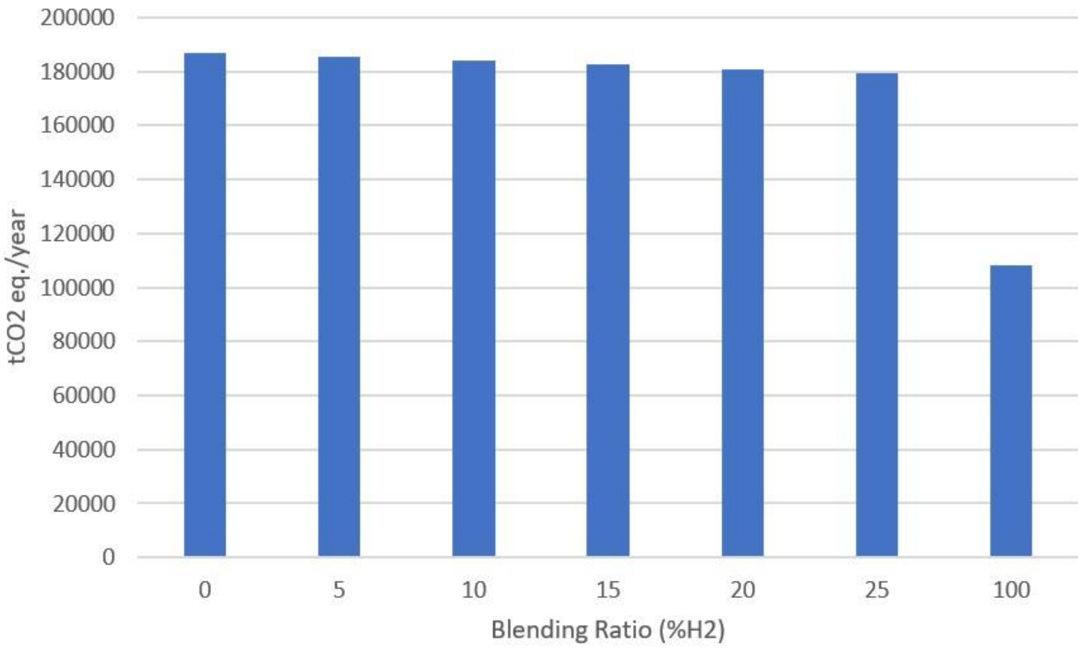

Figure 4.1: Annual WtT GHG emission at 100% engine load for D1H1M blend.png

Similar figures were developed for comparison of the different blends at different engine loads and at different blending ratios. Combining the six types of fuel (based on sources), gives a wide spectrum of results (3 H_2 sources x 3 CH_4 sources = 9 combinations of blends). Visualization of such a wide array of results would divert the goal of the project which is to assess the potential for HCNG as a viable alternative for the fleet. In order to simplify the results, a comparative assessment is conducted between the different sources of hydrogen and methane by studying the GHG emission performance in the blend. The goal of the comparative study is to select the best fuel sources in terms of emission performance.

Methane

For comparing the performance of different sources of methane in the blend, one source of hydrogen is fixed arbitrarily. Figure 4.2 shows the study conducted for a blend of hydrogen produced by electrolysis with the different methane sources considered.

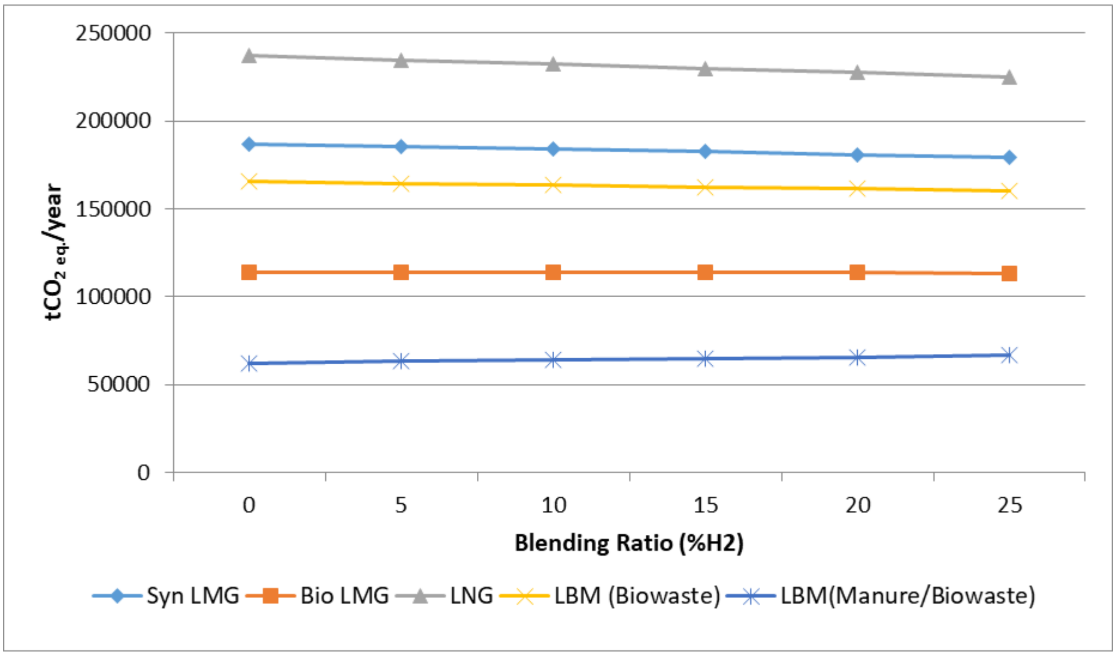

Figure 4.2: Comparing different sources of methane (at 100% Engine load)

It is seen that the choice of the type of methane used produces a significant variation in the GHG emission. Across the different blending ratios, using natural gas resulted in an average GHG emission of 225,000 tons of CO_2 equivalent. Using syn-LMG resulted in an average GHG emission of 180,000 tons CO_2 equivalent while using bio-methane produced from the mixture of manure and biowaste gave an average of 64,000 tons CO_2 equivalent. Thus, it is evident that it is not just the blending ratio that heavily impacts the emission performance.

Hydrogen

The comparison of the different sources of hydrogen is conducted by fixing the source of methane. For the following comparison, bio-methane produced from forest residue was selected as the methane source blended with hydrogen from different sources.

The result of the comparison is depicted in Figure 4.3 below.

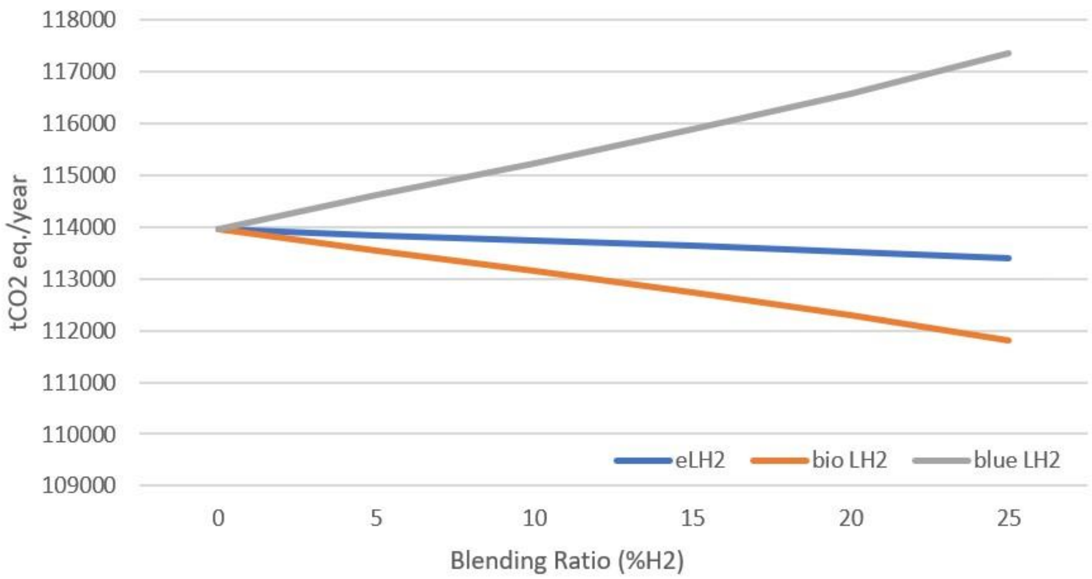

Figure 4.3: Comparing different sources of Hydrogen (at 100% Engine load).

It is evident from the comparison that using blue hydrogen, i.e., hydrogen sourced from natural gas, results in increased GHG emissions with increased blending ratio of hydrogen. The result is also reasonable considering that, on top of the emissions produced during the extraction and processing of natural gas, more energy is utilized to extract hydrogen. Thus, for further analysis blue hydrogen is disregarded as a viable alternative for the blend.

Both the hydrogen produced through wind powered electrolysis and that produced through gasification and treatment of forest residue when used in the blend results in a decrease in total emission. However, it is seen from the results that bio-hydrogen is most effective in increasing the GHG emission performance of the blend. For further analysis, the study focuses on the usage of bio-hydrogen as source.

4.2 WtW (Well to Wake) Assessment

The final Well to Wake assessment is conducted by adding the emissions during combustion to the well-to-tank emissions calculated. As observed from the WtT assessment of the different fuel sources, bio-methane and bio-hydrogen are the most viable alternatives in terms of emission characteristics. The following results consider a blend of bio-hydrogen and LBM along with pilot diesel oil.

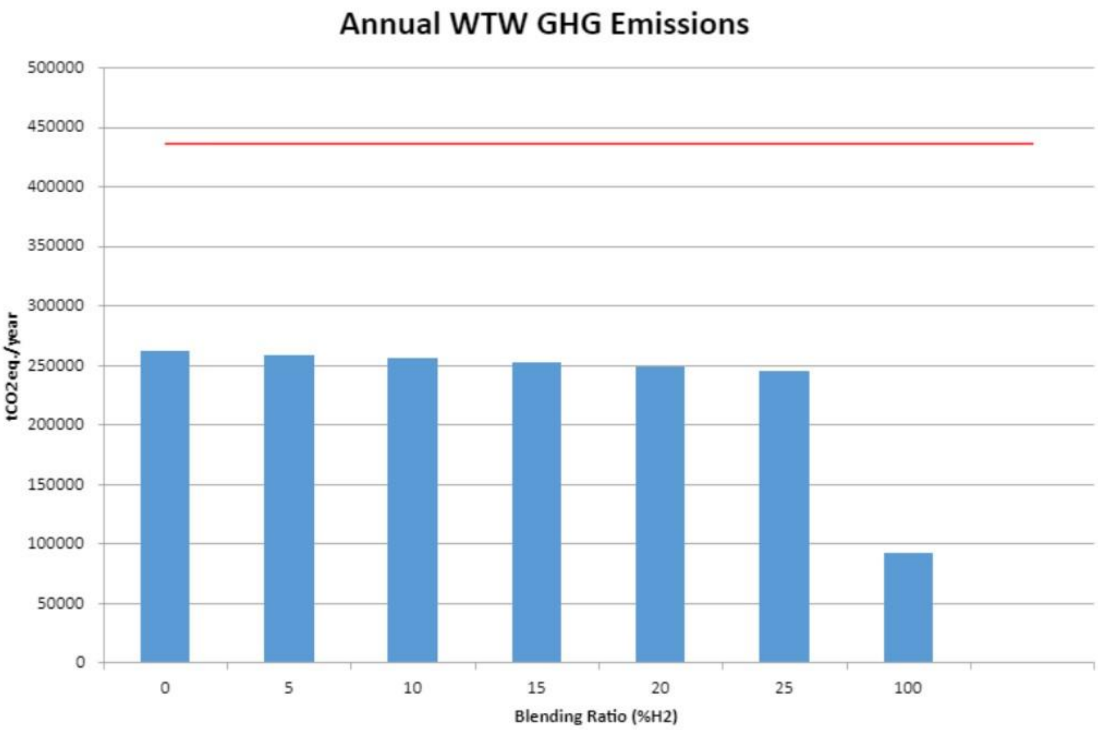

Figure 4.4: GHG emissions per year at 100% engine load along with current emission level.

The horizontal red line is the 'current emission level' in Figure 4.4 and shows the GHG emissions per year at 100% engine load using pure LNG. This depicts the emission level of the Gotland service with the current fuel profile. With bio-methane and no hydrogen, the GHG emissions produced per year is 261,515 ton CO2eq. A 25% blend results in a GHG emission of 245,230 ton CO2eq., i.e., over 16,000 ton reduction in the equivalent CO2 emission. The current WtW emission level is also depicted in the plot. With fossil-based LNG and no blend, 436,000 ton CO2 eq. of greenhouse gases are emitted. Thus, it is seen that a switch to bio-methane and bio-hydrogen blend results in a significant decrease (43% at 25% H2 blend) in GHG emissions compared to when just LNG is used. However, it is clear from the plot that the major contribution to the reduction in GHGs (40%) is due to the substitution of bio-methane instead of LNG. This, however, does not constitute the goal of the study. The viability of using hydrogen needs to be further assessed.

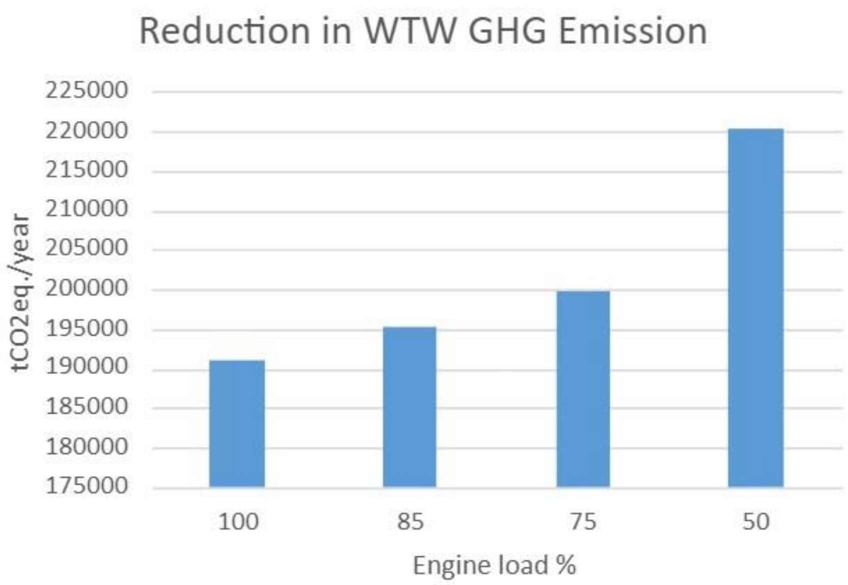

Figure 4.5: Reduction in WtW GHG emission at different engine loads

Figure 4.5 shows the reduction in GHG emission when LNG is substituted with a 25% HCNG blend (using bio-methane (with manure and biowaste composition) and bio-hydrogen). The largest reduction in emission is seen when the engine is at 50% load and the lowest at 100% engine load.

4.3 Cost comparison

In this section the cost of fuel based on the source of hydrogen and methane are presented. The hydrogen and the methane are sourced from biomass. The analysis reveals the following data shown in table 4.1 for an engine load at 75%.

Table 4.1: Cost comparison of different blending ratios at 75% engine load. The prices are in MUSD.

H2 fraction (V%)	0	5	10	15	20	25	100
Bio H_2	*0*	*2,38*	*4,53*	*6,85*	*9,35*	*12,1*	*126.1*
Bio LMG	190,5	186,9	183,7	180,2	176,4	172,3	-
Total fuel cost	190,5	189,3	188,2	187	185,7	184,3	126,1
CO_2 costs	24,6	24,3	24,1	23,8	23,5	23,1	8,6
Total cost	215,2	213,6	212,3	210,8	209,2	207,4	134,7

**CAC – Carbon Abatement Cost, all units are in USD*

The cost analysis of different blending ratios of bio-hydrogen with bio-methane is shown in Table 4.1. It is seen that the usage of a 25% blend of HCNG gives a cost saving of roughly 7.7 million USD per year. This comes at saving in cost for fuel which amounts to 6.2 million USD per year.

5 Concluding remarks

This project investigated the feasibility and viability of hydrogen-enriched compressed natural gas as an alternative fuel to conventional fossil fuels (100% LNG) in the shipping industry. The key target of the alternative fuels is to decrease CO_2 emissions that are also backed with regulatory mandates. For the given case study, it was of interest to determine the optimal HCNG blending ratio for its technical, environmental, and economic benefits and drawbacks. Furthermore, a suitable location for blending and storage of the fuel blend (CH_4/H_2) was investigated. This project focused on specific questions (referred to as research questions) from a wider angle of view, i.e., to give a bigger picture of the challenges, costs, and benefits of blending low carbon hydrogen with natural gas. Thus, no deep technical analysis of the details of the components (pumps, pipelines, materials, etc.) was done. Instead, and according to the interest of the Reference Group, three main research questions were shaped to answer complicated questions before dicing into detailed system design and analysis.

The project found that blending hydrogen with methane presents several technical challenges. As the hydrogen volume fraction increases, the blend's volumetric energy density decreases, necessitating higher fuel volumes and flow rates to achieve energy equivalence with conventional maritime fuels. This results in technical challenges for the blending infrastructure and limits the economic potential due to required modification costs. Although the study confirmed improvements in fuel mass consumption and reductions in CO_2 emissions, the benefits were marginal. According to the mandates by IMO regarding targeted CO_2 reduction from maritime freight, the project found out that the share of hydrogen in the blend should be at least 50-60% to make any environmental benefit. Consequently, the project did not identify a specific optimal blending ratio, as any ratio involves compromises between technical, economic, and environmental impact (CO_2 emission). Low hydrogen concentrations ($\leq$ 10%) have low implementation barriers and can be managed with existing components but offer minimal reductions in fuel mass consumption and CO_2 emissions. Higher hydrogen concentrations (10-25%) provide larger decarbonization and less fossil fuel, but also present significant technical challenges and require a balance between environmental benefits (CO_2 emission reduction) against economic and technical constraints. The technical challenges of managing hydrogen (storage tanks, safety, etc.) are associated with the high price of renewable hydrogen as of today.

The optimal location for blending and storage of hydrogen and methane will depend on the risks associated with technical, economic (costs), and safety issues. On land, the increased fuel volume is less challenging due to available space, and HCNG failure modes, such as hydrogen leakages, auto-ignition, and explosions, can be better monitored and controlled within a suitable infrastructure network, minimizing operational risks and ensuring safer and more reliable operations. However, the pressurized HCNG on board may not be enough for crossings between ports as the energy content of HCNG at any blending ratio is considerably lower compared with LNG, assuming a unit of volume. On-board storage of pressurized hydrogen will also arise safety and technical issues and the need for necessary equipment (new to shipping sector) to manage pure hydrogen.

Based on the environmental and economic analysis, it is concluded that it is currently challenging to count on HCNG as a shipping fuel. The technical challenges – attributed mostly to hydrogen storage and management – together with high cost of green hydrogen production and distribution (transportation) makes it economically unfavorable to use HCNG as a shipping fuel. However, investment costs and fuel prices are subject to change with increased technological development and availability, therefore, HCNG may evolve as a shipping fuel in the future if the challenges (costs related to production, transportation, and storage of pure hydrogen) are mitigated.

Nonetheless, this project contributes to the research on alternative fuels for the shipping industry by exploring the use of HCNG in a transportation sector other than those researched previously. The general conclusions drawn from the case studies are similarly applicable to other shipping companies with different operational profiles. Nonetheless, it is acknowledged that the conclusions of this study are valid within the underlying assumptions made at the outset and state of the technology. Maritime engines capable of running on HCNG are currently unavailable, therefore there is uncertainty about equivalent engine performance compared to well-established conventional fuel technology. This stimulates further research and development of such engine technology to verify performance improvements and emissions.

As concluding remarks, the answers to the specific research questions can be given:

1. What are the pros and cons of blending hydrogen and methane from a technical, environmental, and economic perspective compared to the currently used LNG fuel?
As for the technical and environmental benefits of HCNG as an alternative fuel, it was found that HCNG reduces the (specific) fuel mass consumption of the reference vessel compared to the currently used LNG. Correspondingly, overall CO_2 emissions from combustion also decreased relative to LNG.

The major drawback of HCNG as an alternative fuel is related to the decrease in volumetric energy density (VED) as it requires larger fuel volumes to be supplied to the engine for equivalent power output to LNG. The VED decrease triggers additional technical challenges for the blending and storage infrastructure which become more pronounced the more hydrogen is blended. The environmental advantages (CO_2 emission reduction) were found to be marginal from the TtW perspective applied in this study as CO_2 reduction potential was found to be limited in the range of blending ratios investigated. Economically, the analysis revealed that although HCNG could potentially reduce CO_2 emissions and, consequently, emission allowance costs, the high cost of renewable hydrogen remains a significant barrier. Thus, HCNG employment lacks economic viability now and under future scenarios. This is because the emission savings under the EU ETS were not found to offset the increased fuel costs considering natural gas and renewable hydrogen.

2. What is the optimal hydrogen-methane blending ratio considering technical, environmental, and economic benefits and drawbacks?
The present assessment did not determine one particular optimal blending ratio that should be applied by default. Rather it was observed that any blending ratio is a compromise between technical, economic, and environmental challenges that come from hydrogen enrichment.

Small hydrogen concentrations ≤ 10% by volume were found to have a low implementation barrier meaning they can likely better be handled by existing components and be implemented by default. However, the benefits regarding fuel mass consumption reduction and CO_2 emission reduction are insignificant as they only allow a reduction up to three percent for both parameters relative to LNG. Therefore, the implementation of such blending ratios was found to be more straightforward for any shipping company, but the economic viability is limited due to the limited technical benefits.

In return, larger blending ratios with hydrogen volume concentrations ≥ 10% and ≤ 25% yield more pronounced benefits in terms of decarbonizing operations and fuel savings. It was found that by blending up to 25% hydrogen by volume, CO_2 emissions could be reduced by 150,000 ton CO_2 equivalent. Such large hydrogen volume concentrations would allow for improved long-term compliance with European and international maritime emission regulations. However, larger hydrogen volume concentrations have a higher implementation barrier as the technical challenges associated with hydrogen failure mechanisms become more pronounced and need to be controlled for safe and reliable operations. Therefore, the choice of optimal blending ratio has to balance the operational and environmental benefits against the economic constraints associated with modification requirement costs.

This study clearly shows that the source of methane in a hydrogen-methane blend has a major impact on greenhouse gas emissions. While the hydrogen source stayed the same, natural gas combustion produced the highest emissions, followed by syn-LMG. On the other hand, bio-methane from manure and biowaste had the lowest emissions. This means that beyond just the blending ratio, the type of methane used plays a key role in overall emission levels. Choosing renewable sources like bio-methane can significantly cut the carbon footprint of hydrogen-methane fuel blends. The analysis also highlights that the source of hydrogen plays a key role in determining the overall GHG emissions of the blend. Blue hydrogen, which is derived from natural gas, results in higher emissions due to the additional energy needed for extraction and processing, making it a less sustainable choice. In contrast, hydrogen produced via wind-powered electrolysis and biomass gasification leads to lower emissions, with bio-hydrogen proving to be the most effective in reducing the carbon footprint. Therefore, bio-hydrogen stands out as the ideal option for a more sustainable fuel blend and warrants further analysis.

3. Where could the mixing and storage of renewable hydrogen and methane take place?

Based on the two case scenarios that were set up to answer the third research question, it was concluded that blending hydrogen and methane with subsequent storage should be conducted in port rather than on board. This is largely because the fuel volume increase is less of a challenge on land than on board where available space for larger fuel tanks is limited. Furthermore, the risk of HCNG failure modes is assumed to be better monitored and controlled within a suitable infrastructure network rather than on board a vessel. Even if the probability might be low, failure modes due to hydrogen leakages, auto-ignition, and explosions are fatal in shipping.

6 Future work

The present techno-economic assessment was carried out to investigate the feasibility and viability of hydrogen-enriched compressed natural gas as a fuel alternative to conventional fuels in the shipping industry. For the given case study, it was of interest to determine the optimal HCNG blending ratio for its technical, environmental, and economic benefits and drawbacks. Furthermore, a suitable location for blending and storage of the fuel blend was investigated.

The study found that blending hydrogen with methane presents several technical challenges. As the hydrogen volume fraction increases, the blend's volumetric energy density decreases, necessitating higher fuel volumes and flow rates to achieve energy equivalence with conventional maritime fuels. This results in technical challenges for the blending infrastructure and limits the economic potential due to required modification costs. Although the study confirmed improvements in fuel mass consumption and reductions in CO_2 emissions, the benefits were marginal.

Consequently, the study did not identify a specific optimal blending ratio, as any ratio involves compromises between technical, economic, and environmental factors, requiring a balance between the environmental benefits of higher hydrogen proportions and the associated technical challenges and economic constraints. Low hydrogen concentrations (≤ 10%) have low implementation barriers and can be managed with existing components but offer minimal reductions in fuel mass consumption and CO_2 emissions. Higher hydrogen concentrations (10-25%) provide greater decarbonization and fuel savings benefits, but also present significant technical challenges and require balancing operational and environmental benefits against economic constraints.

The optimal location for blending and storage of hydrogen and methane is in port rather than on board. On land, the increased fuel volume is less challenging due to available space, and HCNG failure modes, such as hydrogen leakages, auto-ignition, and explosions, can be better monitored and controlled within a suitable infrastructure network, minimizing risks and ensuring safer and more reliable operations.

At present, the project suggests that currently HCNG may not be an alternative fuel for the shipping industry. Although adding hydrogen to methane directly decreases the CO_2 emissions, this solution brings more complexity and economic losses mainly due to the price of hydrogen and technical complexities to manage pressurized pure hydrogen. However, investment costs and fuel (component) prices are subject to change with increased technological development and availability thus HCNG may evolve as an enabling pathway for a hydrogen economy in the future if the challenges are mitigated.

This project has laid the groundwork for understanding the feasibility and viability of blending hydrogen and methane for maritime engines in short-sea shipping and provides a basis for future studies based on this. However, there remain some areas that require further investigation to fully realize the potential of HCNG as an alternative fuel in shipping.

This study was limited by the lack of experimental data on HCNG's performance in heavy-duty maritime engines. Future research should focus on experimental validation of HCNG's performance in various maritime engine configurations. These can also investigate the use of HCNG in other energy converters including gas turbines or fuel cells. Long-term testing can provide insights into engine efficiency and specific emission reductions, particularly from NO_x and SO_x (originating from the pilot fuel). Theoretical advancements in understanding the combustion characteristics of HCNG can contribute to the design of HCNG-capable marine engines.

Expanding the scope for green HCNG components necessitates another iteration of the economic analysis. Since the current price levels of fossil and renewable energy carriers are significantly different, addressing these limitations provides opportunities for further research. In addition, future studies could also examine the regulatory and policy implications of adopting HCNG as a maritime fuel in more detail. Understanding the legal framework and potential incentives in terms of viability adds another important dimension to the assessment of HCNG.

In conclusion, while this study has provided valuable insights into the use of HCNG as a maritime fuel, further research is essential to address existing limitations and explore new directions. According to the results obtained within this project, the solution to the technical, economic, and safety challenges may depend on potential future advancements, cost reductions, and enhanced regulatory frameworks. Therefore, HCNG may still be an interesting option in the future if such advancements are realized. Besides, the case of production and distribution of low-carbon hydrogen may have a significant effect which implies the need for deep LCA analysis.

An extended study should include a comparison with LBM replacing the current use of LNG. That is, a simple fuel switch from natural gas in liquid form (LNG) to renewable methane in liquid form (LBM). The comparison should include an economic analysis as well as an LCA.

7 References

Anstrom, J., & Collier, K. (2016). Blended hydrogen–natural gas-fueled internal combustion engines and fueling infrastructure. In Compendium of hydrogen energy (pp. 219-232). Elsevier.

Banapurmath, N., Gireesh, N., Basavarajappa, Y., Hosmath, R., Yaliwal, V., Pai, A., Gopal Navale, K., Jog, P., & Tewari, P. (2015). Effect of hydrogen addition to CNG in a biodiesel-operated dual-fuel engine. International Journal of Sustainable Engineering, 8(6), 332-340.

Brynolf, S., Hansson, J., Kanchiralla, F. M., Malmgren, E., Fridell, E., Stripple, H., & Nojpanya, P. (2023). Nordic Roadmap Publication No. 1-C/1.1/2023.

Chae, M. J., Kim, J. H., Moon, B., Park, S., & Lee, Y. S. (2022). The present condition and outlook for hydrogen-natural gas blending technology. Korean Journal of Chemical Engineering, 39(2), 251-262.

Chelvam, K., Hanafiah, M. M., Woon, K. S., & Al Ali, K. (2024). A review on the environmental performance of various hydrogen production technologies: An approach towards hydrogen economy. Energy Reports, 11, 369-383.

Cheng, Q., Zhang, R., Shi, Z., & Lin, J. (2024). Review of common hydrogen storage tanks and current manufacturing methods for aluminium alloy tank liners. International journal of lightweight materials and manufacture, 7(2), 269-284.

Cho, H. H., Strezov, V., & Evans, T. J. (2023). A review on global warming potential, challenges and opportunities of renewable hydrogen production technologies. Sustainable Materials and Technologies, 35, e00567.

Corbett, J. J., & Koehler, H. W. (2003). Updated emissions from ocean shipping. Journal of Geophysical Research: Atmospheres, 108(D20).

Del Toro, A., Frailey, M., Lynch, F., Munshi, S., & Wayne, S. (2005). Development and demonstration of hydrogen and compressed natural gas (H/CNG) blend transit buses. National Renewable.

DNV. (2023). Hydrogen Forecast to 2050. In: Det Norske Veritas.

EMSA. (2024). Information System to Support Regulation (EU) 2015/57 - THETIS MRV In: European Maritime Safety Agency

EU. (2023a). Directive (EU) 2023/959 of the European Parliament and of the Council of 10 May 2023 amending Directive 2003/87/EC establishing a system for greenhouse gas emission allowance trading within the Union and Decision (EU) 2015/1814 concerning the establishment and operation of a market stability reserve for the Union greenhouse gas emission trading system. Official Journal of the European Union, 50, 134. In.

EU. (2023b). European Parliament Regulation (EU) 2023/1805 of the European Parliament and of the Council of 13 September 2023 on the use of renewable and low-carbon fuels in maritime transport, and amending Directive 2009/16/EC. In Off. J. Eur. Union (Vol. 234, pp. 48-100).

European Union. (2023c). Regulation (EU) 2023/957 of the European Parliament and of the Council of 10 May 2023 amending Regulation (EU) 2015/757 in order to provide for the inclusion of maritime transport activities in the EU Emissions Trading System and for the monitoring, reporting and verification of emissions of additional greenhouse gases and emissions from additional ship types.

Flodén, J., Zetterberg, L., Christodoulou, A., Parsmo, R., Fridell, E., Hansson, J., Rootzén, J., & Woxenius, J. (2024). Shipping in the EU emissions trading system: implications for mitigation, costs and modal split. Climate Policy, 1-19.

Gaz, R. D. F.-G., Storengy, F., Reseau, G., & Syndicat, P. d. E. G. N. (2019). Technical and economic conditions for injecting hydrogen into natural gas networks-Final report June 2019.

Goodwin, D. G., Speth, R. L., Moffat, H. K., & Weber, B. W. (2018). Cantera: An object-oriented software toolkit for chemical kinetics, thermodynamics, and transport processes. Zenodo.

Gutierrez, C. G., & Labajos, C. Á. P. (2018). Empirical fuel consumption assessment for two-strokes dual-fuel engines on LNG Carriers. Journal of Maritime Research, 15 (1), 80–85.

Howarth, R. W., & Jacobson, M. Z. (2021). How green is blue hydrogen? Energy Science & Engineering, 9(10), 1676-1687.

IEA, Hydrogen, 2024

IEA. (2023). Global Hydrogen Review 2023, . In: International Energy Agency, Paris https://www.iea.org/reports/global-hydrogen-review-2023, Licence: CC BY 4.0.

IMO. (2024). Resolution MEPC.391(81) (adopted on 22 March 2024) - Guidelines on Life Cycle GHG Intensity of Marine Fuels. In: International Maritime Organization.

Jivén, K., Hjort, A., Malmgren, E., Persson, E., Brynolf, S., Lönnqvist, T., Särnbratt, M., & Mellin, A. (2022). Can LNG be replaced with Liquid Bio-Methane (LBM) in shipping? In: IVL Svenska Miljöinstitutet AB.

Kanchiralla, F. M., Brynolf, S., Malmgren, E., Hansson, J., & Grahn, M. (2022). Life-cycle assessment and costing of fuels and propulsion systems in future fossil-free shipping. Environmental science & technology, 56(17), 12517-12531.

Kanchiralla, F. M., Brynolf, S., & Mjelde, A. (2024). Role of biofuels, electro-fuels, and blue fuels for shipping: environmental and economic life cycle considerations. Energy & Environmental Science, 17(17), 6393-6418.

Mahant, B., Linga, P., & Kumar, R. (2021). Hydrogen economy and role of hythane as a bridging solution: a perspective review. Energy & Fuels, 35(19), 15424-15454.

Malmgren, E., Brynolf, S., Fridell, E., Grahn, M., & Andersson, K. (2021). The environmental performance of a fossil-free ship propulsion system with onboard carbon capture–a life cycle assessment of the HyMethShip concept. Sustainable Energy & Fuels, 5(10), 2753-2770.

Mehra, R. K., Duan, H., Juknelevičius, R., Ma, F., & Li, J. (2017). Progress in hydrogen enriched compressed natural gas (HCNG) internal combustion engines-A comprehensive review. Renewable and Sustainable Energy Reviews, 80, 1458-1498.

Montel. (2024). EEX EUXP European Carbon Spot. In.

Nerheim, A. R. (2023). Maritime LNG fuel systems for small vessels—A survey of patents. Transportation Research Part D: Transport and Environment, 119, 103766.

Nerheim, A. R., Æsøy, V., & Holmeset, F. T. (2021). Hydrogen as a maritime fuel–can experiences with LNG Be transferred to hydrogen systems? Journal of Marine Science and Engineering, 9(7), 743.

Park, C., Kim, C., Choi, Y., & Lee, J. (2013). Operating strategy for exhaust gas reduction and performance improvement in a heavy-duty hydrogen-natural gas blend engine. Energy, 50, 262-269.

Sharafian, A., Blomerus, P., & Mérida, W. (2019). Natural gas as a ship fuel: Assessment of greenhouse gas and air pollutant reduction potential. Energy policy, 131, 332-346.

S&P Global. (2024a). Maritime Portal. https://maritime.ihs.com

S&P Global. (2024b). Sea-web™: The ultimate Marine Online Database. https://www.spglobal.com/marketintelligence/en/mi/products/sea-web-maritimereference.html

UN. (2015). Transforming our world: the 2030 Agenda for Sustainable Development. In: United Nations.

Ushakov, S., Stenersen, D., & Einang, P. M. (2019). Methane slip from gas fuelled ships: a comprehensive summary based on measurement data. Journal of Marine Science and Technology, 24(4), 1308-1325.

Ustolin, F., Campari, A., & Taccani, R. (2022). An extensive review of liquid hydrogen in transportation with focus on the maritime sector. Journal of Marine Science and Engineering, 10(9), 1222.