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Corso di Laurea Magistrale in Green Industrial Engineering

OFFSHORE CLIMATE REGULATION AND ALTERNATIVE FUELS SCENARIO

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Contents

1. Glossary

Definitions and abbreviations

Term	*Definition*
Scope 1 Emissions	Emissions from sources that are under the operational control of the reporting company; for example, emissions from combustion in owned or controlled boilers, generators, vehicles, etc., emissions from chemical production in owned or controlled process equipment.
Scope 2 Emissions	Indirect emissions from the generation of purchased or acquired energy (electricity or heat) consumed by the reporting company. They physically occur at the facility where electricity or heat is generated.
Scope 3 Emissions	All indirect emissions (not included in Scope 2) that occur in the value chain of the reporting company, for example emissions to produce, ship and dispose of every good used by the company; emissions from the commuting and business travels of employees.
Well-to-wake	Well-To-Wake Emissions WTW cover the entire fuel production process, delivery, and use onboard the vessel, including all emissions within these stages.
Well-to-tank	Well-to-tank Emissions ,WTT, are used to account the upstream Scope 3 emissions associated with extraction, refining and transportation of the raw fuel sources to an organization's site (or asset), prior to combustion.
GWP	Global Warming Potential GWP is used to describe how much GHGs impact on global warming it is normally used the equivalent carbon dioxide potential (CO_2eq), which compares global warming effects of a GHG given type and amount with the effects of the same quantity of carbon dioxide.

Abbreviation Table

MGO	Marine gas oil
LNG	Liquefied natural gas
FAME	Fatty acid methyl ester
HVO	Hydrotreated vegetable oil
IMO	International Maritime Organization
GHG	Greenhouse gases
RFNBO	Renewable fuels of non-biological origin
DEFRA	Department for Environment Food and Rural Affairs for the United Kingdom
LPDF	Low pressure dual fuel
HPDF	High pressure dual fuel
FSRU	Floating storage regasification unit
LHV	Lower heating value
ARMS	Ammonia Release Mitigation System
VLSFO	Very low sulphur fuel oils
DNV	Det Norske Veritas
TCO	total cost of ownership
OPEX	Operational expenditures
CAPEX	Capital expenditures
HFO	Heavy fuel oil
ABS	American Bureau of Shipping
CCS	Carbon Capture & Storage

SMR	Steam methane reforming
SFOC	Specific fuel oil consumption
MSW	Municipal solid waste

2. Scope of work

This study aims to perform a detailed technical study of the alternative fuel scenarios for the offshore marine sector, by analyzing the present and upcoming climate regulation applicable for the marine business and its effect on Saipem activities, in terms of additional fuel cost, alternative fuel scenarios and opportunities to finance low carbon solutions.

A significant part of the scope of work is utilizing sources provided by Saipem to understand the future availability and the foreseen costs of alternative fuels, that Saipem could use to decarbonize its offshore operations and using this to perform a high-level feasibility study to highlight the main technical challenges relate to the usage of alternative fuels in Saipem fleet.

An additional part of the scope of work is related to green finance, by overviewing the green financing options available at the present and foreseen in the future, in order to identify suitable tools that Saipem could use to finance its decarbonization measures.

Finally, the object is to be able to identify which alternative fuel is most suitable for Saipem but not only, and the fuel mix that can facilitate decarbonization by 2050.

3.Introduction to Saipem

3.1.History Overview

[4]Saipem as a company was established in 1957 as a merge between the drilling contractor SAIP and assembly firm Snam Montaggi. Initially, they operated as a service provider for Eni, an oil & gas giant that played a crucial role in Italy's post WWII economic boom. The companies rose to success during the early stages of globalization, transforming Italy from a mostly rural nation to a global industrial power. The founder, Enrico Mattei, an architect of the company that would become modern day Eni, believed in Italy's industrial potential and the major growth of the petroleum industry inspired his initiatives in creating integrated industrial groups. It is important to note the revolutionary events that would continue to pave the way for Saipem and its road to growth. The Treaty of Rome signed the same year Saipem was founded as well as the Treaty of Paris signed 6 years earlier massively contributed to the entrance of Saipem in the oil and gas market.

Between 1957 and 1969 Saipem would go on to establish their international reputation by drilling about 600 wells in Meseta Espinosa and another 173 wells in Comodoro Ridavia , both located in Argentina. In 1968, an installation of four drilling and production platforms in the Adriatic Sea, off the coast of Italy, would be established and thus proving their credibility in delivering successful and innovative projects. Saipem's reputation in pipelines started with the laying a natural gas pipeline that linked Santa-Cruz to Buenos Aires, about 1700 kilometers in distance.

This would then be followed by the 1225-kilometer pipeline in India and another one of more than 1100 kilometers in its home base, Italy.

The company's first lay barge, Castoro 1, would originate from a formal WWII oil tanker, which Saipem converted to a fleet that would then go on to expand to more than two-dozen major vessels. Amongst offshore activities, Saipem completed the construction of chemical and refinery plants as well as the production of fertilizers such as urea. The production of urea in particular was born from a natural extension of the petrol and gas business. Urea production is responsible for the entrance of Saipem in international markets. In 1962, a urea technology patent for producing urea from carbon dioxide and ammonia would be developed in San Donato Milanese. Withing four years a semi-industrial scale urea plant would be established in Sicily and not only. Today, Saipem accounts for almost a fifth of the world's urea fertilizers and the technologies developed and licensed by Saipem account for twice that level of production. With a growing staff of 30,000 employees of more than 130 nationalities, operating in 60 countries worldwide, Saipem is a global leader in engineering services for construction, design and operation of plants in the energy sector.

3.2.Overview of business lines: Strategic guidelines

Saipem is organized in Business Lines

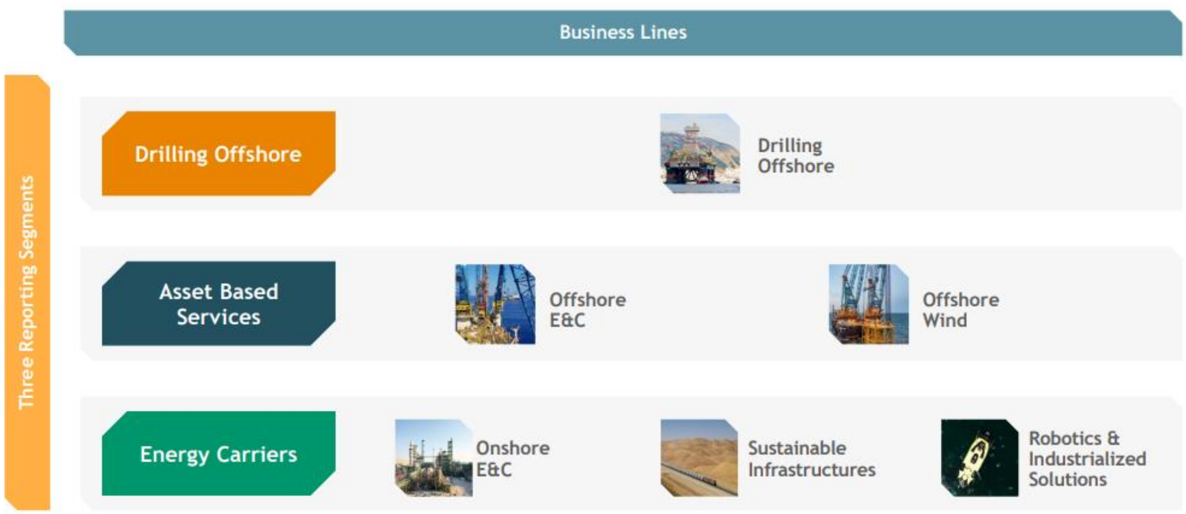


Figure 1: Saipem Business Lines

1. ***E&C Offshore***: Covers the design and construction sector of offshore plants.

This represents Engineering & Construction Offshore including SURF (Subsea, Umbilicals, Risers & Flowlines. ***This study is particularly directed to this business line.***

2. ***Drilling Offshore***: Covers drilling operations in shallow to ultra deepwater and harsh environments.

This represents versatile and heterogenous fleet composed by ;

- Ultra deep-water vessels with dual derrick capacity
- Semi-submersible vessel for harsh environments
- Rejuvenated jack up fleet for shallow waters

3. ***Offshore wind*:** Construction and laying of wind turbine foundation.

4. ***E&C Onshore***: This line includes technological projects in the Oil & Gas, energy, chemical and LNG sector like the production of fertilizers, petrochemical products, refining and energy production. An important sector going towards energy transition.
5. ***Sustainable Infrastructure***: Creation of complex, safe and sustainable infrastructures at the service of Italy and the world such as railway construction.

6. ***Robotics and Industrial Solutions*:** Subsea robotic solutions for underwater operation and maintenance.

3.3.Saipem Decarbonization Strategy and Net Zero

[5] Recognizing the actual global energy transformation and related risks and opportunities, Saipem plans to gradually reduce its dependence on the fossil fuels business with a comprehensive strategy made up of 2 pillars:

1. Reducing the footprint of Saipem own assets and operations;
2. Supporting Clients in reducing their own footprint.

Since 2021 Saipem has defined and launched in a structured way the so called "Net Zero Program", chaired by the CEO and a Steering Committee composed of Top Management, with the aim of reducing its own carbon footprint. The Program, its targets, actions and governance are compliant with recognized international standards, and it is validated by an independent Third Party.

[6] Saipem has declared its decarbonization goals in the short, medium and long term:
1. **Carbon Neutrality for Scope 2 from 2025;**
2. **50% reduction in Scope 1 and 2 emissions by 2035;**
3. **Net Zero to 2050, for all Scope 1, 2 and 3.**

These targets are supported by intermediate actions identified year by year, which feed into the Quadrennial GHG Reduction Plan, approved by CEO and Board of Directors.

The reduction of Saipem’s direct emissions will hinge on the three “R”s: retrofit, renewal and renewables.

o **Retrofit:** Phase I, increasing the energy efficiency of Saipem's operations through the use of the best available technologies (2018-2030).
o **Renewal**: Phase II, replacing assets with innovative assets that are more energy efficient and with lower GHG emissions, thanks also to digitalization and, for example, unmanned operations (2030-2040).
o **Renewables/CCS:** Phase III of massive use of renewable energies and technologies, both traditional and advanced (such as marine and floating solar energy), and possible application of Carbon Capture and Storage technologies on assets (2040-2050).

Furthermore, Scope 1 and 2 emissions will also be reduced thanks to:

- **The use of alternative fuels**: replacing fossil fuels with low carbon-emission fuels, such as the use of HVO biodiesel instead of fossil fuels;
- **Electrification**: switching from electricity generation with fuel-powered generators to grid power where possible.

To meet the Scope 2 target, priority will be given to the following criteria, in order of importance:

1. Energy saving and efficiency;
2. Renewable energy from the grid or self-produced from renewable sources;
3. Offsetting of residual emissions, after all the measures above have been implemented.

The Saipem share of Scope 1 and 2 emissions in 2023 was due to offshore assets for around 55%. Those assets can be considered a hard to abate sector, since the several options that are available onshore will not be applicable for them. According to DNV study, energy efficiency measures could reduce their consumption only up to 16%. Then part of their consumption happens in port, and if that is done with renewable electricity it would reduce that share of emissions to 0. However, since vessel spend in port just a small share of their time (and their emissions there is lower than during operation, this part could account only for 7% according to DNV study, that however is aimed more to difference ship types. However, even taking into account Saipem ships, the assumption is that this share would not be higher than 10%.

Considering this, 74% of emissions of such vessels need to be dressed in alternative fuels.

4.Introduction to alternative marine fuels

The maritime industry refers to the sector that includes transport, logistics, regulatory engineering, information technology, finance, and insurance activities related to ships and shipping. It plays a crucial part in the global supply chain. According to the DNV [1], it accounts for 3% of the global energy use.

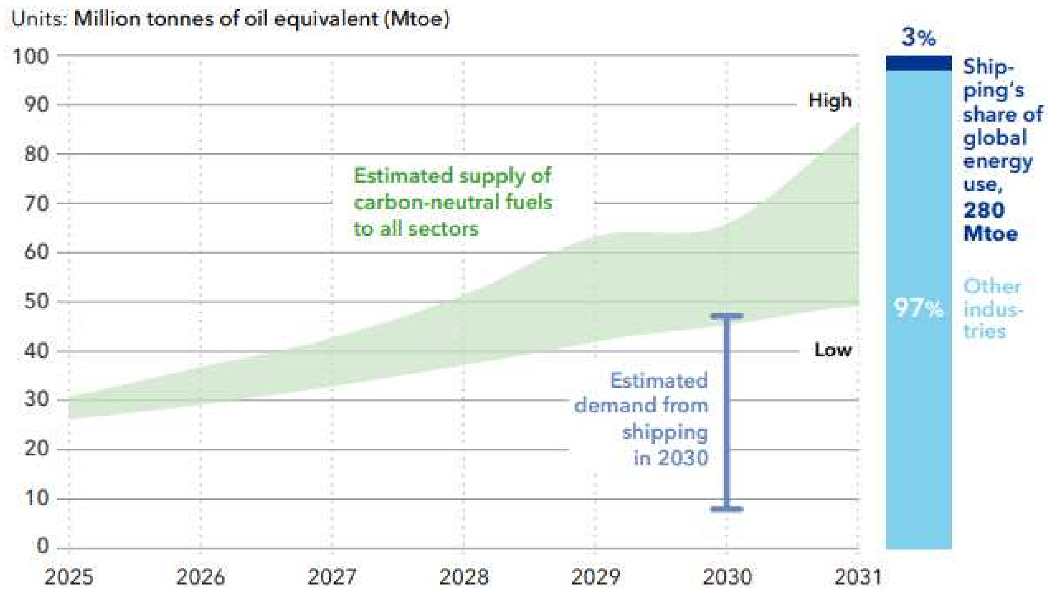


Figure 2: Estimated supply of carbon-neutral fuels to all sectors

Under the European Green Deal [2], the EU aims to become climate neutral by 2050, with an intermediate goal of a 55% reduction of greenhouse emissions by 2030. Maritime transport, which has traditionally relied on conventional fossil fuels, is preparing to transform to meet EU and international climate targets through transitioning to alternative fuels. A DNV study found that the 25,000 largest ships, 30% of the world fleet, accounted for 80% of the CO_2 emissions (DNV GL, 2019). Decarbonizing shipping will require new fuels but also better energy efficiency technology, improved logistics, and the uptake of onboard CCS.

The ongoing trend of ordering larger ships with dual-fuel propulsion systems shows that the shift in fuel technology is advancing. Figure 3 shows the growth of the number of ships capable of using selected alternative fuels. [1] In the global fleet, 92.6% of the operational tonnage relies solely on fuel oils, while half of the tonnage on order lacks alternative fuel options. LNG still remains a popular fuel choice in the containership segment, car carrier segment with significant uptake also in tankers, bulk carriers, and cruise ships. Methanol-fueled ships represent 0.09% of the world fleet tonnage in operation but 9.68% of the tonnage ordered. Despite the low maturity of ammonia energy converter technology, we have recently started to see the first orders of ammonia-fueled ships. Regarding engine technology and availability, methane and methanol engines are already widely available across a broad range of power levels, but the first ammonia engines, expected within the next two to three years, will be designed for large bulk carriers and gas tankers.

Meanwhile, the development of hydrogen marine engines appears to be focused on lower power ranges.

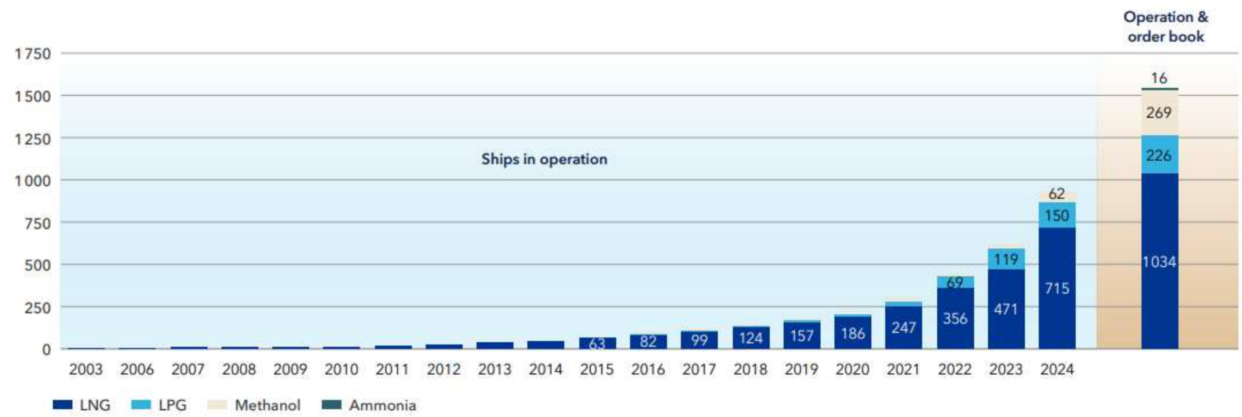


Figure 3: Growth of the number of ships capable of using selected alternative fuels, excluding LNG carriers, as of May 2024[1]

However, alternative fuels may still originate from fossil energy sources, emphasizing the necessity for regulations that address GHG emissions from a well-to-wake perspective. The differences in physical and chemical characteristics play an important role in their feasibility for the market. Figure 4 shows the technical characteristics of different alternative marine fuels [3].

Fuel type	LHV* [MJ/kg]	Volumetric energy density [GJ/m^3]	Storage pressure [bar]	Storage Temperature [°C]
MGO	42.7	36.6	1	20
LNG	50	23.4	1	-162
Methanol	19.9	15.8	1	20
Liquid ammonia	18.6	12.7	1/10	-34/20
Liquid hydrogen	120	8.5	1	-253
Compressed hydrogen	120	7.5	700	20

*LHV: Lower heating value. Based on De Vries (2019)
Source: IRENA

Figure 4: Technical Characteristics of Different Marine Fuels

5.Offshore vessel Regulation

Regulation and policy are the main drivers for the decarbonization of the maritime sector. They are guided by frameworks and standards that outline sustainability assessment criteria, emission calculation methods, as well as reporting requirements for ships and shipping companies. This chapter will present the current and future regulations on GHGs starting from the IMO and moving toward the European Union.

5.1.IMO – International Maritime Organization

The International Maritime Organization (IMO), a specialized agency of the United Nations, is responsible for ensuring the safety, security, and efficiency of maritime shipping while preventing pollution from ships. The 2023 IMO Strategy on Reduction of GHG Emissions from Ships (the 2023 IMO GHG Strategy) continues the IMO's efforts as the leading international entity to tackle greenhouse gas emissions from global shipping. This initiative builds on Assembly resolution A.963(23), adopted on December 5, 2003, which encouraged the Marine Environment Protection Committee (MEPC) to identify and develop methods to limit or reduce GHG emissions from international maritime activities.

[7] Levels of ambition directing the 2023 IMO GHG Strategy are as follows:

- Carbon intensity of the ship to decline through further improvement of the energy efficiency for new ships.
- Carbon intensity of international shipping to decline by at least 40% by 2030.
- Uptake of zero or near-zero GHG emission technologies, fuels and/or energy sources to increase. Ideally at least 5%, striving for 10% of the energy used by international shipping by 2030.
- GHG emissions from international shipping to reach net zero.

[8] Indicative checkpoints:

- Total annual GHG emissions reduction in international shipping by at least 20%, striving for 30% by 2030, compared to 2008.
- Total annual GHG emissions reduction in international shipping by at least 70%, striving for 80% by 2040, compared to 2008.

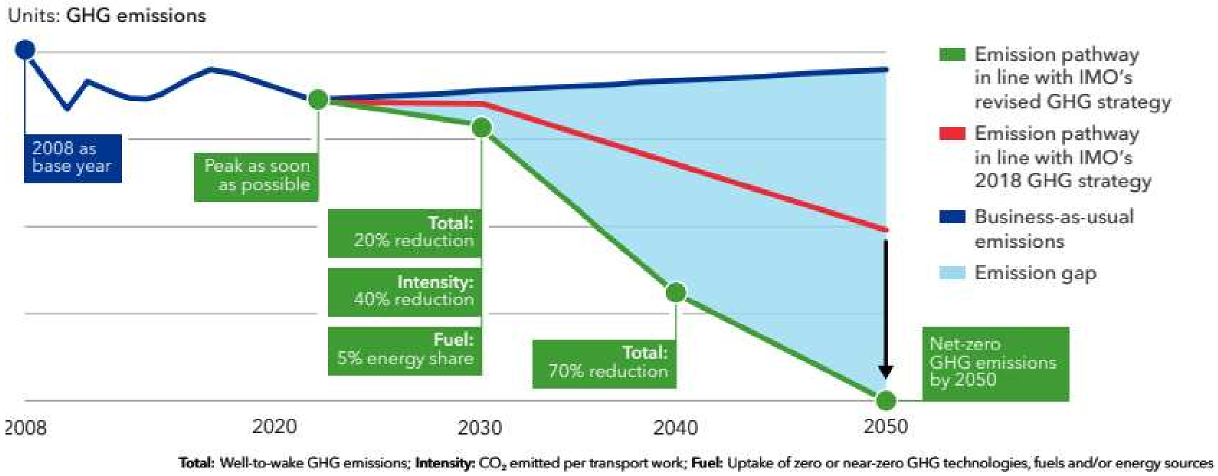


Figure 5: Outline on ambitions and minimum indicative checkpoints in the revised IMO GHG strategy [8]

The strategy now also targets lifecycle GHG emissions from shipping, aiming to reduce these emissions within the international shipping energy system and prevent their transfer to other sectors. To reach the ambitions mentioned above, the IMO has implemented a basket of regulatory measures which will be adopted in 2025 and enter into force by mid-2027.

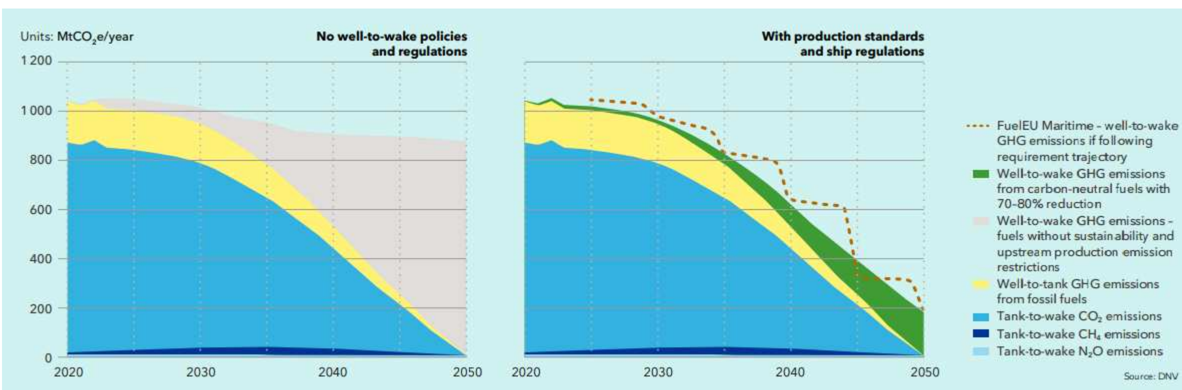


Figure 6: Comparing well-to-wake GHG emissions in a scenario without policies and regulations (left) and with production standards and ship regulations(right)[8]

Figure 6 portrays a comparison between two scenarios. The left image shows Well-to-Wake GHG emissions in the case that there are no policies and regulations. The right image shows the same but with production standards and ship regulation. On the right panel we also compare with the GHG emissions if all ships globally follow the requirement trajectory in FuelEU Maritime. It is important to highlight that unless there are restrictions on sustainability and well-to-tank GHG emissions of fuels, the well-to-tank emissions could be shifted upstream to other sectors producing the fuels, thereby cancelling the emission-reduction gains achieved to 2050.

This scenario assumes that alternative fuels have well-to-wake emissions comparable to those of current fossil fuels. Conventional biofuels and grey electrofuels can sometimes have even higher well-to-wake emissions than fossil fuels [45] Therefore, this projection might underestimate the total well-to-wake greenhouse gas (GHG) emissions.

Energy Efficient Design Index regulations (EEDI)

The Energy Efficient Design Index (EEDI) plays a key role in ensuring that the IMO's regulations are lowering the carbon intensity of fleet. [9]This index requires that the amount of CO_2 emitted in grams by a vessel per tonne-mile of work be set using a formula based on the technical design parameters for each given ship. In the meantime, shipowners are free to explore any technology or design solution that will help attain the target. The EEDI was initially developed for large and energy intensive fleet covering ship types like tankers, gas carriers, cargo ships, etc. In 2014 MEPC adopted amendments to the EEDI regulations to extend the scope to LNG carriers, vehicle carriers, roro cargo and passenger ships and cruise passengers ships.

However, the EEDI is not applicable for Saipem as it is not possible to measure Saipem vessel operation by a tonne-mile of work indicator.

- Initial phase: 10% reduction in CO_2 emissions compared to ships built between 2000-2010.
- Target tightened every five years to align with technological advancements in efficiency and reduction measures.
- By 2025: 30% reduction

Energy Efficiency Existing Ship Index (EEXI)

Under the EEXI framework, all existing ships of 400 GT and above must calculate their Energy Efficiency Existing Ship Index (EEXI), reflecting their technical or design efficiency. [10] The requirements for EEXI certification entered into force on the 1st of November of 202. Ships must meet a "required EEXI," equivalent to the Required EEDI levels for 2022, ensuring a level playing field among the fleet. This certification is obtained only once. The framework is technology-neutral, allowing shipowners or charterers to choose the best methods to meet IMO regulations, such as engine/shaft power limitation, waste heat recovery, and wind-assisted propulsion. Furthermore, the EEXI is currently not applicable to Saipem offshore fleet. However, the next revision of the regulation is set to take place in 2025 and there is a possibility of inclusion for Saipem.

SEEMP Ship Energy Efficiency Management Plan

The SEEMP is a ship-specific plan aiming at the improvement of energy efficiency for ships above 400 GT that engage in international voyages[11]. All ships that take part in this category must develop and then keep on board the documentation set out by the IMO. However, certain types of vessels, including floating production storage and offloading units (FPSOs), floating storage units (FSUs), and drilling rigs, are not required to have a SEEMP. This exemption is because these types of units are typically stationary or semi-stationary and do not engage in international voyages like other commercial ships that SEEMP targets.

The SEEMP consists of three parts:

- Part I: Ship management plan to improve energy efficiency
- Part II: Ship fuel oil consumption data collection plan
- Part III: Ship operational carbon intensity plan

Part I of the SEEMP is mandatory and must be kept on board all ships above 400 GT. A verified Part II is mandatory for all ships above 5,000 GT as part of the Data Collection System. A verified Part III is required for all ships subject to the Carbon Intensity Indicator (CII) – i.e. cargo, Ro-Pax and cruise passenger vessels above 5,000 GT.

SEEMP I and II are already applicable to Saipem, only for the propulsive vessels, excluding rigs and barges. Part III is not applicable to Saipem.

Carbon Intensity Indicator (CII)

The Carbon Intensity Indicator (CII) measures the operational energy efficiency of ships, utilizing fuel oil consumption data from the IMO DCS and SEEMP as a management tool. [12]It entered into force in January 1st 2023. It is mandatory for ships of 5,000 gross tonnage and above. Ships must document and verify their attained annual operational CII against the required annual operational CII. The annual carbon intensity reduction factor will remain at business-as-usual levels until it takes effect, then decrease by 2% annually from 2023 to 2026, with further reductions planned for 2027 to 2030.

The IMO DCS stands for IMO's fuel data collection system. It was first introduced on 1 January 2019 and it aggregates data such as fuel consumption, distance travelled and hours underway for individual ships of 5,000 GT and above. The aggregated DCS data forms the basis for the CII rating and SEEMP III.

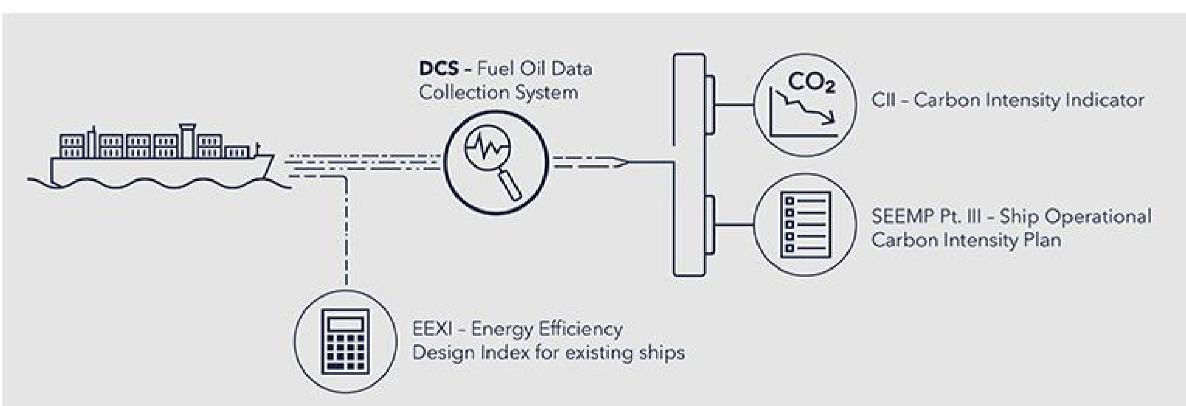


Figure 7: Connection between the DCS, CII and SEEMP Part III

Summary

	CII	EEXI	SEEMP III	SEEMP I	EEDI	SEEMP II
Description	Measures the operational energy efficiency of ships	Indicates technical and design efficiency.	Planning of the CII monitoring and improvement for the next 3 years	Ship management plan to improve energy efficiency	A standard, assuring that ship designs achieve a certain level of efficiency and decrease carbon emissions.	Ship fuel oil consumption data collection plan
Applicability	All ships above 400 GT	All ships above 400 GT	All ships above 400 GT	All ships above 400 GT	Large and intensive fleet	All ships above 5,000 GT as part of the DCS
Entry into force	January 1st 2023	November 1st 2022	1 January 2023	2013	2013	2019
Requirements	Decrease by 2% annually from 2023-2026 and then further reductions from 2027-2030.	Ships must meet a "required EEXI," equivalent to the Required EEDI levels for 2022	Must be kept on board	Must be kept on board	10 % reduction in CO_2 emissions by the initial phase then 30% reduction by 2025.	Must be kept on board
Applicability to Saipem	No	No	No	Yes	No	Yes

5.2.European Commission Regulation

In addition to the IMO, the European Union has also set legally binding targets to reduce emissions become climate-neutral by 2050. The EU views this as a chance to separate economic growth from resource consumption, fostering opportunities for industries in clean technology and innovative solutions. The two pieces of legislation introduced by the EU are the EU Emission Trading Scheme and FuelEU Maritime. They set specific requirements for ships and ensure that operations, cost and emission reduction is in line with their ambitions. Furthermore, EU requirements are mandatory for Saipem activities.

FuelEU Maritime

FuelEU Maritime are a series of regulations adopted by the EU in order to increase the share of renewable fuels in the fuel mix of international transport in the EU. It is set to be implemented from January 1st, 2025.

[13] Requirements to the yearly average well-to-wake GHG emissions:

- Ships over 5000 GT trading in the EU.
- Account for 50% of energy used on voyages between EU and non-EU ports, and 100% of energy used for voyages within EU ports and at berth.
- Emissions included are those from CH_4 and N_2O
- 2% mix of RFNBO into fuels might potentially enter into force from 2030.

[13] The regulation mandates that, starting in 2030, passenger and container ships must connect to onshore power supplies when docked at major EU ports for over two hours. This requirement will expand to include all ports with onshore power supplies by 2035.

Calculations will be set relative to the average well-to-wake fuel GHG intensity of the fleet in 2020 of 91.16 gCO_2e per megajoule (MJ). This will start at a 2% reduction in 2025, increasing to 6% in 2030, and accelerating from 2035 to reach an 80% reduction by 2050. The FuelEU Maritime regulations are not applicable to Saipem.

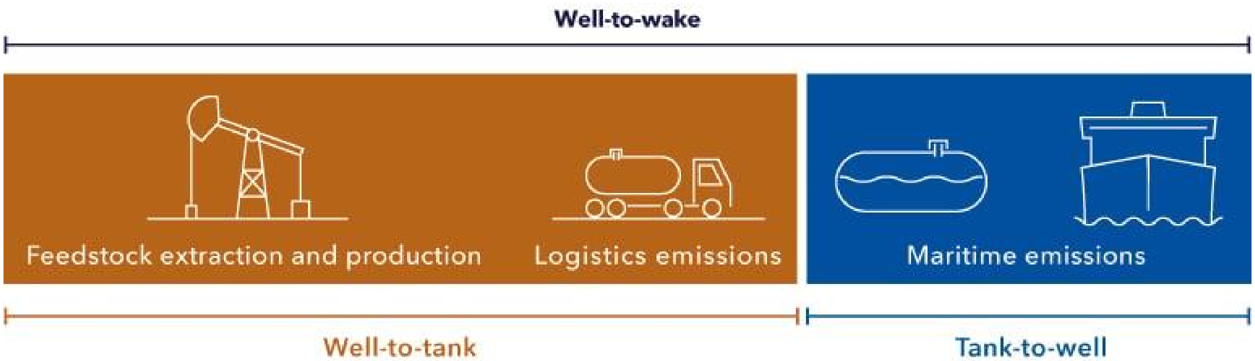


Figure 8: Well-to-wake

The European Union European Trading Scheme (EU ETS)

The EU European Trade Scheme is a cap-and-trade system for emissions, where a limited number of emission allowances—known as the cap—are available for trading on the market. This cap decreases annually to align with the EU's 2030 goal of reducing emissions by 55% compared to 1990 levels and achieving climate neutrality by 2050.

The differences between MRV and EU ETS

	MRV	**EU ETS**
Purpose and scope	MRV is a data-gathering and transparency initiative.	The EU ETS is a market-based mechanism aimed at directly reducing emissions.
Functionality	MRV involves monitoring and reporting emissions.	The EU ETS involves trading emissions allowances under a capped system.
Application	MRV applies specifically to the maritime sector (among others for data purposes).	The EU ETS has a broader application across multiple sectors, including a plan to incorporate shipping emissions.

[14] The EU Emission Trading System will extend to maritime transport starting from 2024.

- Companies must pose their emission allowances by September 2025 for emissions reported in 2024.

- Share of emissions:

  2025: 40% of emissions reported for 2024 must be covered by emission allowances

  2026: 70% of emissions reported for 2025

  2027 and beyond: 100% of reported emissions

- The directive applies to:

  Cargo and passenger ships of or above 5000 gross tonnage (GT) (From 2024)
  Offshore ships of or above 5000 GT (From 2027)

- Types of GHG within the scope of MRV and ETS:

  MRV: CO_2, CH_4, N_2O (as of 2024)
  ETS: CO_2 and CH_4 and N_2O as of 2026

- The system is flag-neutral and route-based

- Stopping for the reasons mentioned below is exempted from the directive:

  The EU Commission must clarify the definition of 'PORT OF CALL' and 'VOYAGE' to address operational peculiarities and make regulations more suited for companies like SAIPEM.

  - stops for the sole purposes of refueling,
  - stops for obtaining supplies,
  - stops for relieving the crew (other than an offshore ship),
  - stops for going into dry-dock or making repairs to the ship and/or its equipment,
  - stops in port because the ship is in need of assistance or in distress,
  - ship-to-ship transfers carried out outside ports,
  - stops for the sole purpose of taking shelter from adverse weather or rendered necessary by search and rescue activities,
  - stops of containerships in the neighboring container transshipment ports listed in the corresponding implementing act.

- Shipping companies that fail to surrender allowances are liable to an excess emissions penalty of EUR 100 (corrected for inflation) per tonne of CO_2 equivalent and are still liable for the surrender of the required allowances. The names of the penalized companies are also disclosed to the public.

- Emissions resulting from the combustion of sustainable biomass compliant with the sustainability criteria established by the Renewable Energy Directive have a CO_2 emission factor of zero under the ETS.

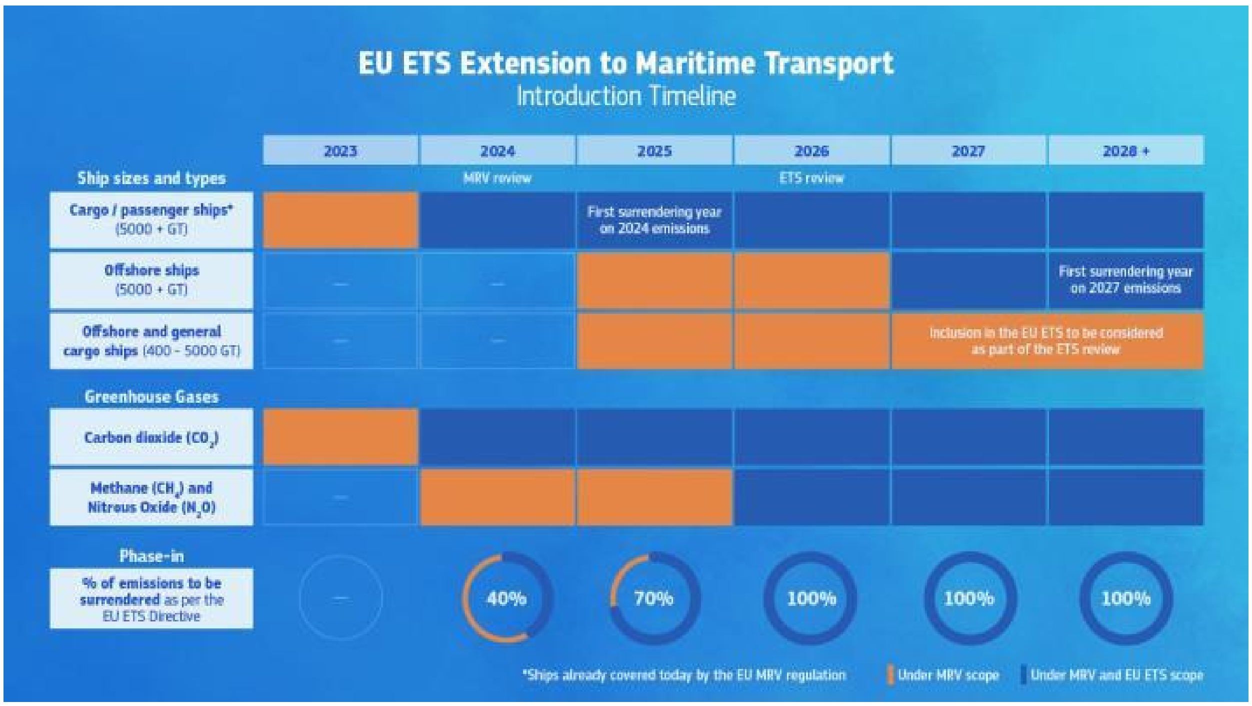


Figure 9: EU ETS Timeline for maritime transport[14]

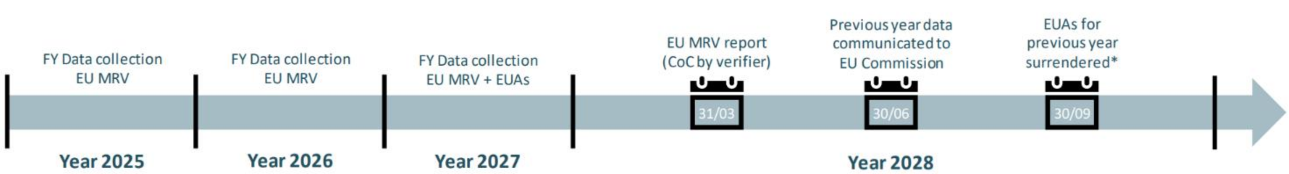


Figure 10: Steps of applicability to Saipem

6.Liquefied natural gas

6.1.Introduction

Liquefied natural gas (LNG) is natural gas that has been cooled to approximately -160° Celcius, transforming it into a liquid [15]. In this liquid form, its volume is roughly 600 times smaller than in its gaseous state, facilitating its transport to locations not served by pipelines. The specific composition of LNG varies based on its source and the liquefaction process used. However, methane is always the primary component, with minor amounts of heavier hydrocarbons like ethane, propane, butane, and pentane. Additionally, small quantities of nitrogen may also be present.

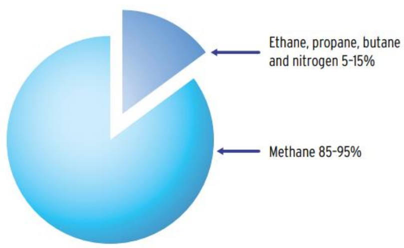


Figure 11: Composition of LNG

The liquefaction process of natural gas involves the removal of components such as dust, acid gases, helium, water, and heavy hydrocarbons to prevent issues downstream. Once purified, the natural gas is cooled to approximately -160 °C to condense it into a liquid state. This process occurs at near atmospheric pressure, with the maximum transport pressure set around 25 kPa (4 psi), which is about 1.25 times the atmospheric pressure at sea level [16]. The density of LNG is roughly 0.41 kg/litre to 0.5 kg/litre, depending on temperature, pressure, and composition,[3] compared to water at 1.0 kg/litre.

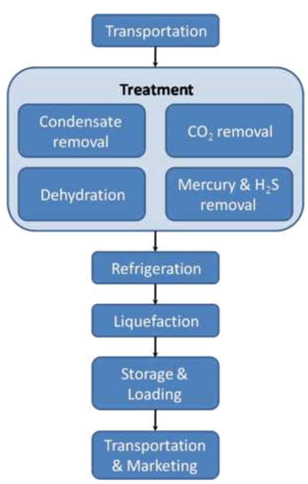


Figure 12: A typical LNG process

6.2.Life cycle and production

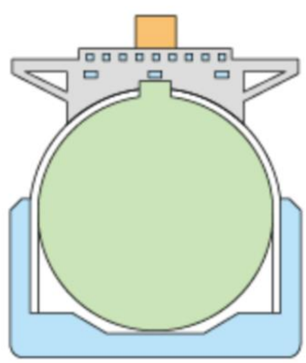
The life cycle of LNG starts with the pre-treatment of the feedstock of natural gas. Before entering the system, the natural gas needs to be stripped from impurities such as H_2S, CO_2, mercury, water or other long-chained hydrocarbons. Removed hydrocarbons can be stored and sold separately. The remaining gas mostly consists of methane and some ethane, which is brought to liquefaction. Then, it enters the liquefaction unit, where the cooling process takes place. Here, the feedstock gas is cooled to between -159 and -162 degrees Celsius[16]. The liquefaction and cooling of LNG utilize thermodynamic refrigeration cycles, carried out in cryogenic heat exchangers that extract heat from the natural gas. Flash gas and boil-off gas (BOG) can be harnessed as fuel for turbines used in onsite power generation. The end product is stored in cryogenic tanks on site and then shipped off.

Tank types

The mainstream vessels show a capacity between 150,00-170,000m3. There are three types of tanks for transportation [17]:

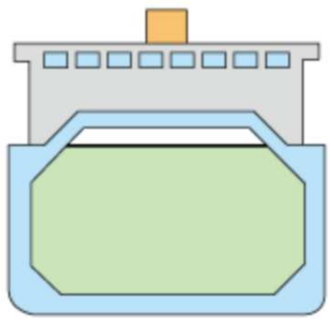
1. Moss type

This is a spherical cargo tank that is independent from the hull. Its surface area is smaller compared to other tanks but that contributes to the suppression of boil-off gas. Additionally, it simplifies quality control as there are less welding points, reducing potential weak spots and making it easier to ensure structural integrity during inspections. In 2014, a new spherical tank was introduced called the continuous tank cover type or Sayaendo.



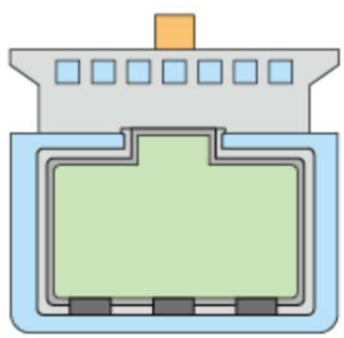
2. Membrane type

The cargo is kept at a lower temperature to accommodate the gas expansion, using thin internal tanks covered with a wrinkled stainless-steel membrane. This design allows for excellent visibility at the front of the vessel due to the efficient use of space in the cargo tanks and the minimal deck protrusions. Some ethane carriers utilize this type of cargo tank.



3. Self-supporting prismatic shape IMO type B

This shape tank is composed of aluminum alloy or stainless steel as well as heat insulation on the exterior parts. One of the main advantages for this tank is that it allows for broader use on deck as it easily fitted on the hull compared to spherical tanks. Additionally, this tank has no protruding structures on deck.



Capacity

-Small scale carrier have a capacity of approximately 1000m3 to 40,000m3.

-Medium scale carriers can vary from 40,000m3 to 80,000m3.

-Large scale carrier also known as Q-max ships go from 120,000m3 to 260,000m3

However, these figures are estimates as the actual capacity heavily depends on the design, technology and purpose of the ship.

Regasification of LNG

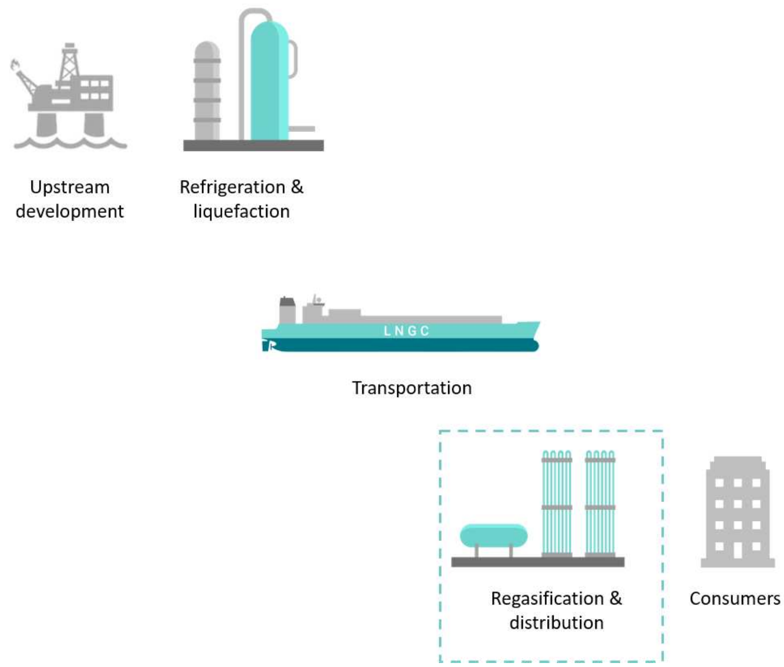


Figure 13: Regasification of LNG[18]

[18]For transportation purposes over large distances, gas is kept in liquid state. This is because its volume is decreased about 600 times compared to at gaseous state and that makes it easier and more convenient to store onboard. However, to be utilized as fuel, power generation, for heating or cooking, LNG must be regasified. This is achieved by heating the liquefied gas until it reaches a gaseous state. A regasification plant uses a heat exchanger with sea water as the heat medium to increase the heat of the natural gas to switch from liquid to gaseous state. Typically, this process takes place at large import terminals where LNG carriers discharge their LNG cargo.

However, lately, floating solutions have been heavily considered. A floating storage unit (FSU) is used to store the LNG before regasification onshore. In addition, it can also be connected to a regasification unit (FSRU). These units can either be specifically designed for storing and regasifying LNG or be modified LNG carriers.

Constructing an onshore regasification terminal is a significant long-term investment that needs a reliable LNG supply. In contrast, an FSRU can be leased, converting capital expenses to operational costs. Additionally, converting old LNG carriers to FSRUs offers shorter lead times. However, FSRUs have limitations in capacity and lifespan, often making onshore terminals more durable.

6.3Emissions

Tank -to-wake

Fuel	Unit	Total kg CO_2e per unit	kg CO_2e of CO_2 per unit	kg CO_2e of CH_4 per unit	kg CO_2e of N_2O per unit
LNG	tonnes	2581,98	2576,94	3,85	1,19
	litres	1,17	1,16604	0,00175	0,00054
	kWh (Net CV)	0,20	0,20379	0,00031	0,00010
	kWh (Gross CV)	0,18	0,18395	0,00028	0,00009

Marine gas oil	tonnes	3245,30	3.205,99	0,91	38,41
	litres	2,77	2,73782	0,00077	0,03280
	kWh (Net CV)	0,27	0,27113	0,00008	0,00325
	kWh (Gross CV)	0,26	0,25486	0,00007	0,00305

According to DEFRA [19]:

In this section I will be analyzing and comparing Scope 1 emissions for LNG and MGO according to data taken from DEFRA 2023.

The reduction in percentage is found for kilogram equivalent of carbon dioxide for CO_2, CH4 and N_2O. CO_2e is the universal unit of measurement to indicate the global warming potential (GWP) of GHGs, expressed in terms of the GWP of one unit of carbon dioxide. This data takes into account scope 1 emissions. Examples of Scope 1 emissions include emissions from combustion in owned or controlled boilers, furnaces and vehicles; and emissions from chemical production in owned or controlled process equipment, etc.

The results are displayed below:

	Total kg CO_2e per unit	kg CO_2e of CO_2 per unit	kg CO_2e of CH_4 per unit	kg CO_2e of N_2O per unit
Reduction, %	26	25	400 (increase)	96

According to the results shown above, there is a total kg CO_2 equivalent reduction of 26%. However, this study does not account for the fugitive emissions. To be able to estimate the correct emissions, in realistic conditions, is going to require additional data.

Methane emissions from LNG-fueled ships depend on factors such as the type of engine, engine load, and leaks from fuel and cargo tanks. Estimating the total emissions is challenging due to the reliance on emission factors derived from a limited number of studies, which are based on either specific onboard measurements or controlled laboratory tests of individual engines.

Well-to-tank

Well-to-tank (WTT) fuels conversion factors should be used to account for the upstream Scope 3 emissions associated with extraction, refining and transportation of the raw fuel sources to an organization's site (or asset), prior to combustion.

The data was taken from DEFRA [19]:

Fuel	Unit	kg CO_2e
LNG	tonnes	912,22817
	litres	0,41277
	kWh (Net CV)	0,07214
	kWh (Gross CV)	0,06512
Marine gas oil	tonnes	743,83524
	litres	0,62665
	kWh (Net CV)	0,06291
	kWh (Gross CV)	0,05913

In this case, there is an increase in kgCO_2eq for LNG, approximately 13% higher.

The higher WTT emissions for LNG compared to MGO are mainly due to the energy-intensive processes of liquefaction, transportation, and the potential for methane leakage. These factors contribute to the overall carbon footprint of LNG, making its WTT emissions higher despite its potential for lower emissions during combustion in engines.

Fugitive emissions

Fugitive emissions are part of Scope 1 emissions. The term describes unintended methane emissions that can happen at various stages of the natural gas life cycle, including during drilling and extraction, as well as during transportation by LNG carriers and the use of LNG as marine fuel. However, they are not included in the conversion factors presented by DEFRA.

When LNG is used as fuel, most of the methane is utilized in the energy conversion process. However, any methane that remains unburned is released from the engine into the atmosphere, leading to fugitive emissions. Since methane is so potent, having a GWP of 28 and being 28 times more potent than carbon dioxide, even low fugitive methane emissions can be as harmful as high CO_2 emissions levels.

How they are identified:

[20] LNG carriers are meticulously designed to minimize methane leakage, given its flammable nature. Ensuring the safety of the ship involves reducing the presence of flammable gas and eliminating potential ignition sources. Fugitive leaks are generally leaks from equipment from either imperfections or routine wear in joints such as flange gaskets, screwed connections, valve stem packing and poorly seated valves [21]. Examples of areas that should be considered as potential sources of fugitive leaks are shown in figure 14.

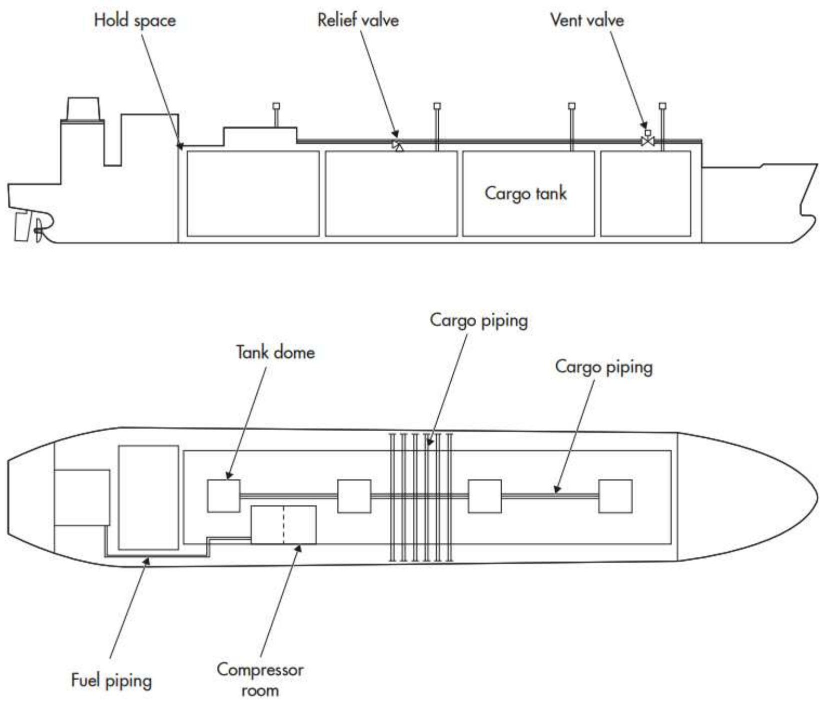


Figure 14: Areas to consider as sources for fugitive leaks [24]

Additional areas to monitor for fugitive leaks include:

- **Cargo tanks:** Pay special attention to potential leaks after maintenance, particularly post-drydocking. Hatches should be inspected closely after maintenance and following cargo loading.
- **Cargo and fuel piping:** Possible sources of emissions include flanges and threaded connections. Temperature probe pockets, liquid sensors, and sampling points are also critical areas to monitor.
- **Cargo and fuel valves:** Valves subjected to frequent temperature changes, vibration, or operational wear should be inspected more frequently. The inspection should be based on the valve's design.
- **Cargo equipment:** Leaks may occur from areas such as shaft seals, casing, gaskets, and penetrations where instruments and equipment valves are installed.
- **Combustion equipment:** The fuel gas system, consisting of valves, piping, and instrumentation, must be regularly checked for leaks. These checks should be documented as part of the ship's fugitive emissions reduction plan.

Methane Slip

Methane slip refers to the unburned portion of LNG, mainly methane, that escapes from the engine. Measurements taken from 18 ships equipped with LPDF 4-stroke LNG engines showed an average methane slip of 6.4%. This contrasts with EU regulations, which estimate a methane slip of 3.1%, and the International Maritime Organization (IMO), which estimates 3.5%. Onboard data indicated that methane slip and NOx emissions were highest at low engine loads.

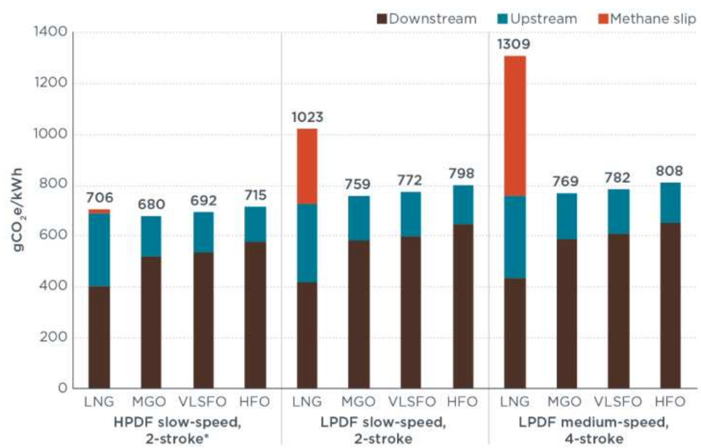


Figure 15: Life cycle GHG emissions by engine and fuel type. 20-year GWP, higher methane scenario

Figure 15 shows the life-cycle emissions by engine and fuel type for the 20-year GWP and we notice a substantial increase in gCO2eq /kWh for LNG caused by methane slip. Especially, for the LPDF medium-speed 4 stroke engine type. However, even if the downstream emissions are lower for LNG compared to MGO, the study above suggests that the overall emissions are higher due to contribution of the methane slip.

According to a study conducted by the International Council on Clean Transportation (ICCT) regarding real-world methane emissions from LNG-fueled ships[21]. They conducted work for three campaigns: the plume campaign, the onboard campaign and the fugitive campaign. They concluded that:

- For the Plume campaign they found that LPDF 4-stroke engines, on average, emit 6.4% methane slip, which is more than twice as much methane slip as assumed by the EU (3.1%) and over 80% more than assumed by the IMO (3.5%).
- From the onboard campaign, they concluded that modern LPDF 4-stroke engines can emit lower methane slip than assumptions from EU regulations and the IMO, but methane slip can still be substantial, especially at low loads.
- From the fugitive campaign, they concluded that LNG cargo unloading operations can release 11–21 kg/h of methane for a small, 10,000 m3 capacity LNG tanker that uses conventional diesel engines.

- Regarding measurement approaches, they found that mounting sensors to drones and helicopters is useful for estimating ship-level methane slip from LNG-fueled ships and for estimating fugitive methane emissions from LNG cargo unloading operations.

The table below summarizes the emission comparison for LNG and MGO and the reduction without considering the methane slip. That is because, to be able to correctly measure the fugitive emissions, it is necessary to conduct additional studies that require information that was not possible to acquire for the sake of the study.

Table 1

Emission type	**Emissions LNG in kg CO_2eq**	**Emissions MGO in kg CO_2eq**	**Reduction in %**
Well-to-wake	0.20	0.27	26%
Well-to-tank	0,07214	0,06291	~+13%
TOTAL	0.27214	0.33291	~18.5%

Version 2 of the table, considering a rough estimate of the methane slip. However, that will not be taken into account for the final comparison as the methane slip varies greatly with the type of engine and the methodology of estimation. For Table 2, I will be considering an average value taken from a study conducted by the International Council on Clean Transportation (ICCT) regarding real-world methane emissions from LNG-fueled ships, for LPDF 4-stroke engines.

Table 2

Emission type	**Emission LNG in kg CO_2eq**	**Emission MGO in kg CO_2eq**	**Reduction in %**
Well-to-wake	0.20	0.27	26%
Well-to-tank	0.07214	0.06291	~+13%
Fugitive emissions	0.559	0	
TOTAL	0.83114	0.33291	~+60%

6.4.Availability and Cost

LNG is a global commodity, exported by 21 countries to 42 importers, and makes up about 11% of the world's gas consumption. Its market presence is growing in regions like China, Latin America, the Middle East, Africa, and parts of Southeast Asia, with 26 import terminals currently being built.

Short-term

The pipeline gas supply disruption caused by the Russia-Ukraine war increased LNG demand in Europe, leading to higher prices and redirecting additional cargo from Asia to Europe, as reported by the International Gas Union's (IGU) LNG report [23].

In 2023, natural gas markets began to stabilize despite ongoing tight supply conditions. A reduction in demand in Europe and established markets in Asia helped mitigate the effects of the 2022 gas supply shock. Consequently, prices dropped considerably in 2023, though they remained significantly above historical averages in both Asia and Europe.

The increase in LNG imports in 2022 was largely driven by Europe, which experienced a substantial annual rise of 50.4 million tonnes, marking a 66% increase compared to 2021, according to GlobalData. Europe imported 126.6 million tonnes of LNG last year, becoming the world's second-largest LNG importing region as it sought to offset the decline in Russian pipeline gas supplies.

However, according to the IEA, the anticipated tight supply in 2024 will result in only a modest increase in global LNG production, which will constrain demand growth, especially in Europe and mature Asian markets. This year, LNG supplies are expected to grow by 3.5%, a notable decrease from the 8% growth rate seen between 2016 and 2020.

The global LNG industry has undergone notable changes in demand and supply dynamics due to geopolitical tensions and market uncertainties. Although the LNG market has gradually stabilized in 2023, geopolitical factors still present risks and challenges for the industry moving into 2024. As the industry tackles these challenges, attention remains on LNG investments, contracting activities, and the evolving energy transition landscape. With global gas demand anticipated to rise in 2024, the industry needs to address production constraints to meet the increasing demand.

Figure 16 shows the investment and cumulative capacity in LNG liquefaction plants throughout the past 10 years. According to the IEA investments are expected to double in value from 2015 up to 2030.

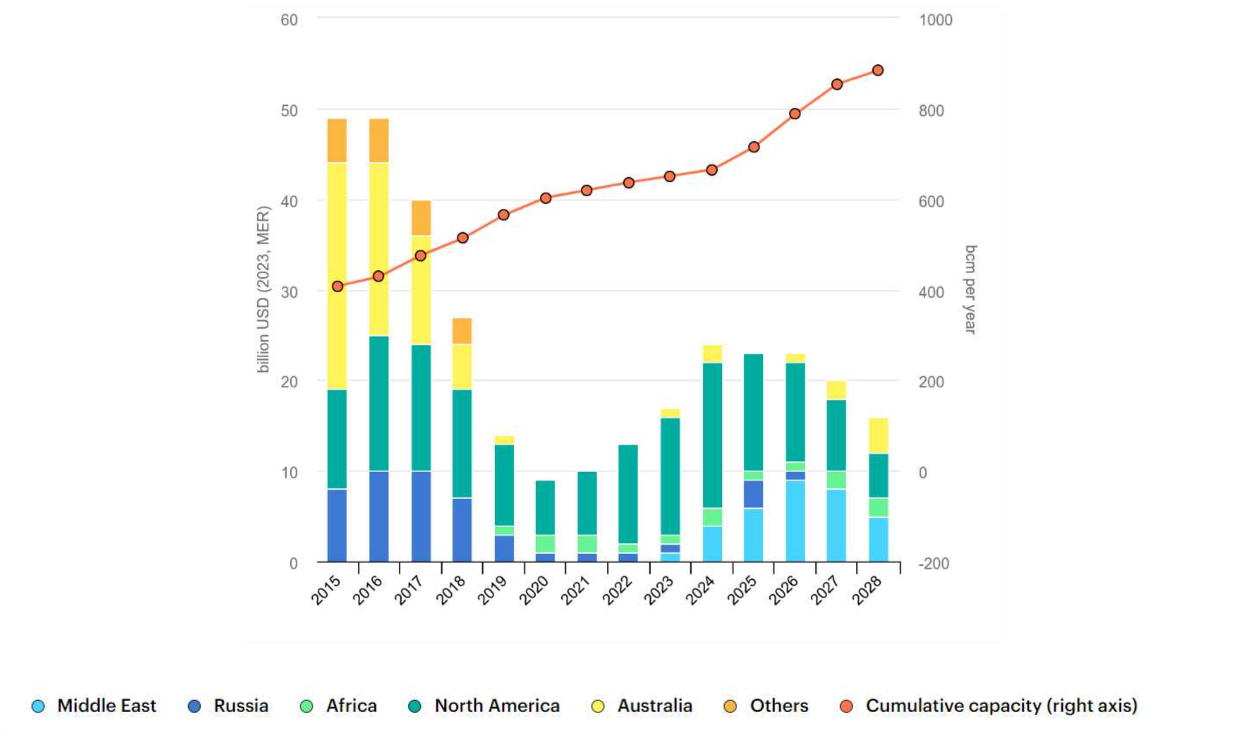


Figure 16: Investment and cumulative capacity in LNG liquefaction, 2015-2028. IEA

Long-term

Figures 16 and 17 , present graphs reported by the DNV[8] that show the uptake over time (up to 2050) expressed by the range from minimum to maximum across all scenarios within the pathways IMO ambitions (dark blue) and Decarbonization by 2050 (light blue) for LNG and carbon neutral LNG where Carbon-neutral LNG involves offsetting the carbon emissions from the LNG supply chain through the purchase of carbon offsets.

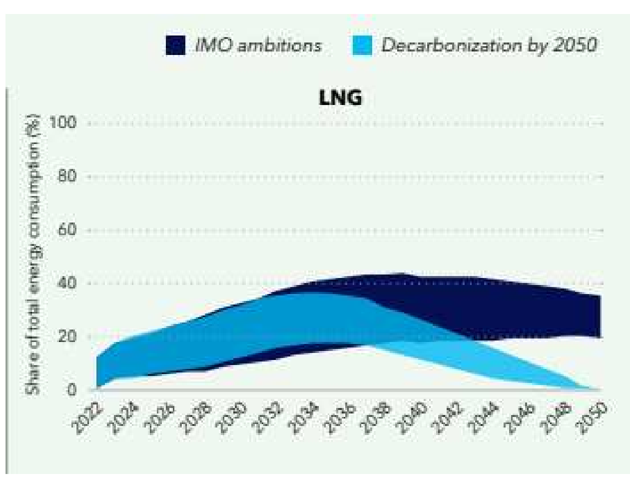


Figure 17: The uptake over time – expressed by the range from minimum to maximum across all scenarios

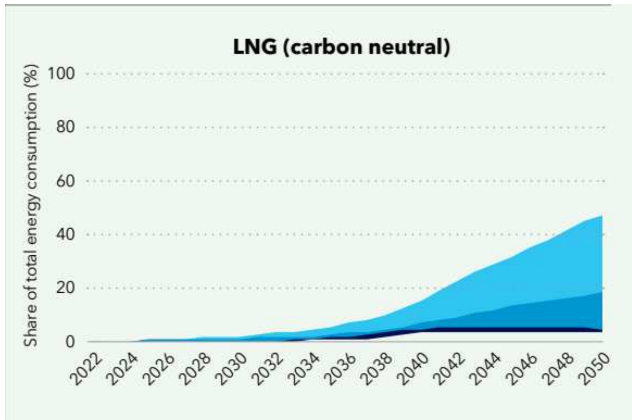


Figure 18: The uptake over time – expressed by the range from minimum to maximum across all scenarios

According to IMO ambitions the share of total energy consumption for LNG is expected to peak around 2040 and then gradually start decrease. Whereas, in a total decarbonization scenario, LNG shares will rise to 2034, and from there we will start to see a significant decline up to 0 by 2050.

LNG Cost Analysis

The supply costs of an LNG project primarily include the costs of natural gas extraction, purification and liquefaction, transportation, and regasification. The LNG industry chain is segmented into upstream, midstream, and downstream sectors. Depending on resource availability and market conditions, these costs account for different proportions.

Upstream

- Includes exploration, development, purification, separation, and liquefaction.
- Upstream natural gas developers require a minimum return of investment at around 8-10%.

Midstream

- Includes storage and transportation as well as the construction of recieving terminals and gas supply pipelines.
- This process primarily entails the depreciation costs of receiving terminals and pipeline facilities, regasification energy expenses, along with labor and management costs.

Downstream

- Entitled to end users. Power stations, gas companies, industrial parks etc.
- Is related to the profit requirements of the LNG project company and the preferential policies and tax breaks that support LNG projects in different countries.

The price of LNG in the international market is usually Free-on-board cost. FOB cost is a pricing mechanism that reflects the transfer of LNG cargo from the liquefaction facility to the ship. Similar to international crude oil prices, FOB cost is sensitive to geopolitical, economic and trade factors.

For instance, the average construction cost of an LNG plant ranges from $600 to $1,100 per ton [26]. In the Middle East, these costs are relatively lower, around $500 to $800 per ton, with Qatar having the lowest costs. However, the construction cost of specialized LNG plant projects can reach $1,500 to $2,400 per ton. For example, projects in Norway, Australia, and the United States report an FOB cost exceeding $10/MMBtu, indicating poor economic benefits.

The export economics of LNG projects dictate that profits from LNG exports must exceed those from direct domestic sales of natural gas; otherwise, the incentive to sustain long-term exports diminishes. From an international and regional perspective on LNG imports, the cost of importing LNG from a specific location should not surpass the cost of importing natural gas from other global sources. The economics of this process ultimately depend on the end market's LNG import demand, the cumulative costs across each segment of the industry chain, and the end users' ability to afford it.

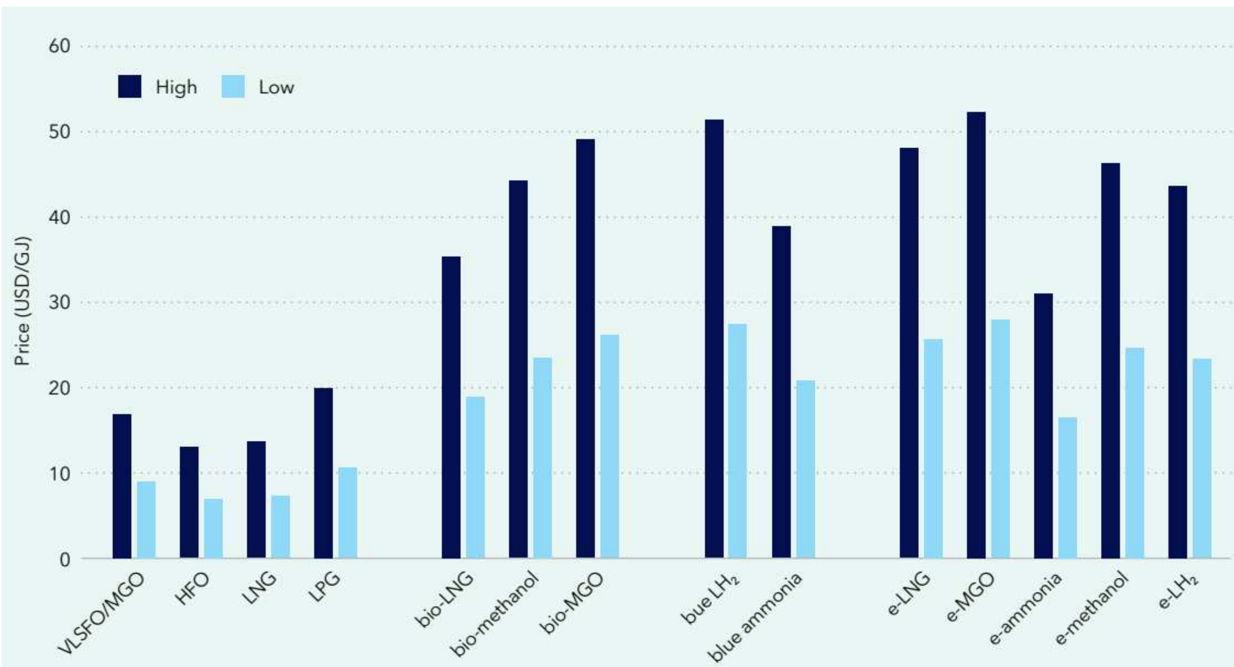


Figure 19: Estimated high and low prices for fuels in 2050. Source: DNV

Figure 19 shows a chart of a study conducted by the DNV [8] that estimates high and low prices for fuels in 2050. These prices include both production and distribution costs and have been taken as a global mean average of all regions. For fossil fuels, the carbon price is not included. We observe that LNG is priced very similarly to the rest of the conventional fuels like HFO, MGO VLSFO, unlike other alternative fuels like biofuels, methanol and ammonia, which all present almost double the price of LNG.

According to the Ship and Bunker website, the Global Average Bunker Price for MGO is estimated at 808.5$ per metric ton.

When it comes to LNG, it wasn´t possible to estimate an average global bunker price but rather the current bunker price for Rotterdam as of **23.09.2024** is around 742$ per metric ton[25]. Similarly, in Rotterdam the bunker price for MGO is estimated around 637.5 $ per metric ton. If we convert those values to $/GJ, we can compare to the DNV results. Assuming the calorific value for MGO is 42.5GJ/mt and for 50 GJ/mt for LNG according to the Ship and Bunker website.

Table 3: Bunker prices for Rotterdam

September 23 , 2024		
Bunker Country	**Bunker price MGO $/GJ**	**Bunker price LNG $/GJ**
Rotterdam	15	14.8

We observe in Table 3 that the price of LNG is roughly **2% lower** than the price of MGO.

6.5.Technical Aspects

1. Onboard storage

LNG has a density ranging from about 430 kg/m³ to 480 kg/m³ and a gross calorific value between 54 MJ/kg and 56 MJ/kg[27], depending on its composition. The density of gaseous natural gas is about 1/625 of that of liquefied natural gas. This enables LNG to be conveniently transported and a very practical fuel option in regions lacking gas pipelines and established gas infrastructure.

One of the main challenges for LNG-fueled vessels is optimizing the use of available space for the fuel tank and associated systems. LNG storage on board takes up more space compared to conventional fuel oil storage. This is because LNG has a lower energy density than fuel oil, necessitating a larger tank to achieve the same operational range. Additionally, the low temperature of LNG requires extensive tank insulation and gas handling systems, which further increases the space needed.

The IMO has defined three basic, independent LNG tank types: Type A, Type B and Type C. In addition, there are membrane tanks which are fully integrated into the ship structure. Figure 20 displays a comparison between these types.

Parameters	Type A	Type B	Type C	Membrane
Barrier	Full secondary barrier	Partial secondary barrier	No barrier	Full secondary barrier
Self-supporting	Independent self-supporting	Independent self-supporting	Independent self-supporting	Non-self-supporting
Pressurize condition	Fully refrigerated at atmospheric pressure	Fully refrigerated at atmospheric pressure	Pressurized at ambient temperature or lower temperature	Fully refrigerated at atmospheric pressure
Capability to retain boil-off Inside the Tank	Can not withstand the pressure developed by the boil-off for a long time	Design pressure is not higher than 0 7 bar and cannot withstand the pressure developed by the boil-off for a long time	High-pressure accumulation capability; e g LNG tanks 10 bar and LPG 18 bar	Design pressure is not higher than 0 7 bar and cannot withstand the pressure developed by the boil-off for a long time
Design vapour pressure	< 0.07 MPa	< 0.07 MPa	High pressure	≤ 0.025 MPa
Records of gas-fuelled ship	Nil	Nil (under consideration)	good	nil
Features	Good volume efficiency (prismatic tank)	Volume efficiency spherical: low, prismatic: good	• Simple design & construction • The flexibility of working pressure • Low volume efficiency	• Good volume efficiency • Sloshing concern

Figure 20: Comparison of tank types for LNG onboard storage

2. Engine types

It is important to consider the type of engine required for LNG onboard utilization. Currently, there are both high-pressure (diesel cycle) and low-pressure (Otto cycle) two-stroke engines available. High-pressure engines offer lower fuel consumption and virtually eliminate methane emissions, whereas low-pressure engines have simpler designs and lower investment costs. Additionally, smaller four-stroke engines are available in both dual-fuel and spark-ignition (gas-only) types.

Concept	Cycle	Abbreviation in this study	Speed range	Power range
Lean-burn spark ignition	2/4-stroke	LBSI	medium-high	0.5–8.0 MW
Low-pressure dual-fuel	4-stroke	LPDF 4-stroke	medium	1.0–18.0 MW
Low-pressure dual-fuel	2-stroke	LPDF 2-stroke	low	5.0–63.0 MW
High-pressure dual-fuel	4-stroke	N/A	medium	2.0–18.0 MW
High-pressure dual-fuel	2-stroke	HPDF 2-stroke	low	>2.5 MW

Note: High-pressure, dual fuel, 4-stroke engines are not commercially available.

Figure 21: Marine gas engine types

3. Safety concerns

LNG occupies1/600th of the volume of the gaseous state of natural gas, but retains all of the energy potential. Therefore, the energy potential of a specific volume of LNG is significantly larger than the same volume of natural gas in its gaseous state.

Natural gas becomes flammable when mixed with air in concentrations typically between 5% and 12%. Consequently, if LNG is released and vaporizes, the resulting cloud of natural gas vapor can ignite. In this respect, LNG is similar to other common petroleum fuels like gasoline, kerosene, and LPG. However, if there is no ignition source, the vapor will dissipate completely, as it is lighter than air. In its liquid state, LNG is highly unlikely to ignite.

Key aspects of LNG risk and safety are:

- High energy content of the LNG tank
- Explosion hazard
- Extremely low temperatures of LNG
- Location of LNG ship systems
- Hazardous vs. non-hazardous spaces
- Ship-shore interface in bunkering

Potential hazards in an LNG facility can be:

- Temperature. Cryogenic liquid releases can cause embrittlement in materials not designed to withstand such extreme cold, and they can also result in freeze burns if they come into contact with personnel. Additionally, hot vapor releases from turbines, boilers, and engines used for power and heat generation pose their own hazards.
- Toxicity. From H2S or ammonia releases.
- Pool fire
- Jet fire
- Flammable vapor dispersion/flash fire
- Vapor cloud explosion
- LNG leaks
- Asphyxiation from vapour release

4. Capacity study

In this section, a comparison is done between the capacity of a MGO vessel and that of an LNG vessel. We assume 40 days of autonomy for both ships. We assume a load of 85% for both ships.

	MGO Saipem 7000		LNG fueled ship
Daily consumption (t MGO/d)	50[a]	Daily consumption (t LNG/d)	40,93
SFOC (t/MWh)	0.215[a]	SFOC LNG (t/MWh)	0.176[b]
Daily consumption (m^3 MGO/d)	58.139	Daily consumption (m^3 LNG/d)	81,86
Density t/m^3	0.86[a]	Density t/m^3	0.5
Days of operation	40	Days of operation	40
Tank volume needed m^3	2325	Tank volume needed m^3	3274

Table 4: Tank volume comparison. [a] Provided by Saipem. [c]MAN L51/60DF Fuel consumption at 85% MCR

In Table 4 we observe that the tank volume for LNG is 29% bigger. Meaning we would need 20% more space if we were to switch from MGO to LNG.

6.6.Advantages and challenges

Advantages

1. Security and diversity

Since LNG accounts for 15% of the EUs gas imports, it majorly contributes in energy security and diversity of supply. However, supply is heavily concentrated and dependent to a small number of countries which might pose potential negative effects. The GECF (Gas Exporting Countries Forum) is responsible for controlling more than 85% of LNG supply.

2. Emissions

Based on DEFRA, without considering the fugitive emissions, LNG proves to have 18.5% reduced greenhouse gas emissions when compared to MGO. However, fugitive emissions are inevitable and should be monitored using proper methodologies and technologies.

3. Energy efficiency and greenhouse gas emissions

The supply chain for LNG is more energy intensive and consequently more greenhouse gas emission intensive than pipeline gas because of the additional processing steps that it takes. However, when we deal with very remote pipeline deliveries of gas or when LNG is brought to the end-user in liquid form and then re-gasified on site, LNG is more favorable when it comes to greenhouse gas emissions compared to pipeline supplies.

4. Availability

Based on studies conducted by the DNV, LNG is projected to have a larger percentage in the fuel mix only if also bio-LNG and LNG coupled with CCS are part of it.

5. Cost

Cost of LNG compared to MGO is slightly lower, around 2%, which can facilitate the transition.

Challenges

6. Cost

LNG shipping costs are the most volatile element in the overall LNG supply chain, significantly influencing the competitiveness of LNG supplies. Despite the potential need for more ships to meet increasing demand, LNG is unlikely to cause substantially more shipping congestion unless stricter safety and security regulations for handling LNG carriers are implemented. Also, these ships are likely to encounter challenges related to shortages of skilled crew members. However, the need for maintenance on board and hence present additional job opportunities in shipyards.

7. Tank volume

LNG fueled ships will require a 29% larger fuel tank volume than MGO which imposes additional costs.

7. Methanol

7.1. Introduction

Methanol (CH_3OH) is an organic compound and the simplest alcohol that is available worldwide and used in various fields for many decades. It is a colorless liquid at room temperature and atmospheric pressure with a distinct pungent smell.

Molecular formula	CH3OH
Carbon content (wt)	37.5%
Density at 20°C kg/m3	792
Volumetric energy density MJ/l	15.8
Calorific value MJ/kg	20
Autoignition temperature °C	464
Flash point °C	11

Table 5: Properties of methanol as a fuel[28]

Compared to LNG, ammonia, and hydrogen fuels, methanol is easier to store and manage. Additionally, it presents fewer challenges when being adopted as a marine fuel compared to these other options. Methanol possesses the highest hydrogen-to-carbon ratio of any liquid fuel. This means that CO_2 emissions coming from combustion are very low compared to conventional fuel oils. In addition, if methanol is produced renewably from biomass, it has the potential to be completely carbon neutral.

The use of methanol in marine vessels is regulated by the IMO IGF Code on low flashpoint fuels that mandates a series of practical actions that need to be considered when using methanol as a marine fuel.

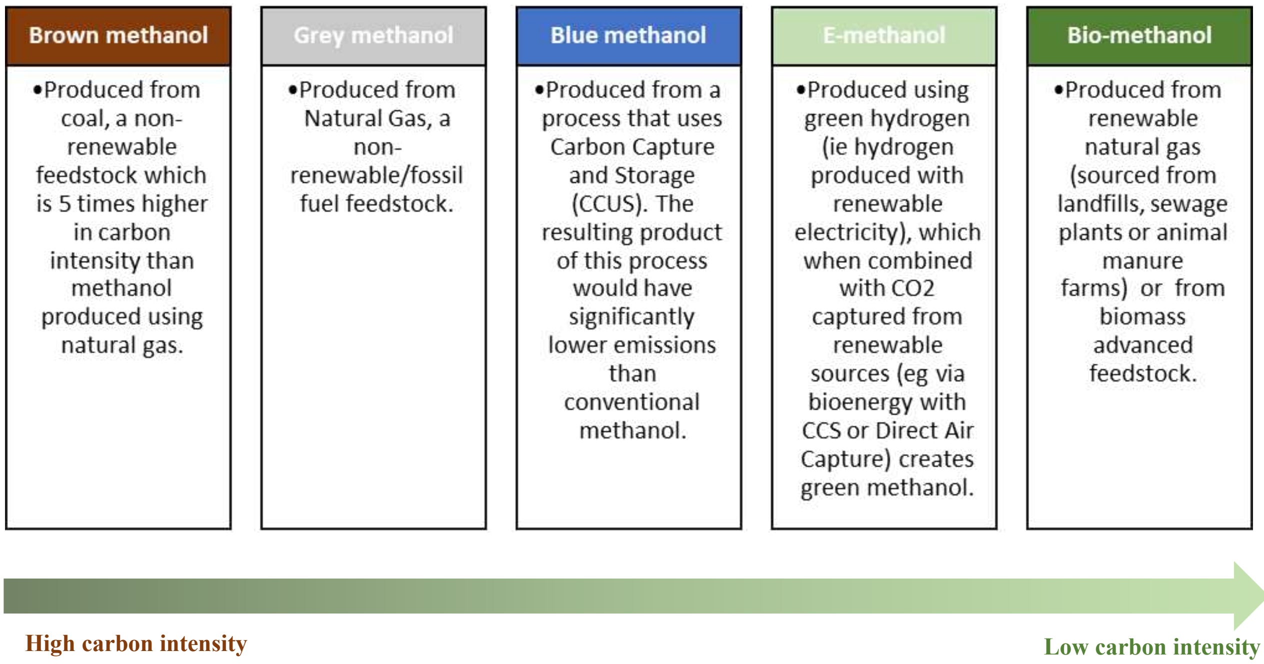
Other standards include;

- DNV – Fuel Ready Ships
- ABS – Guide for Methanol and Ethanol Fueled Vessels
- IRS – Guidelines on Methanol Fueled Vessels

There are currently 122 ports with methanol storage facilities worldwide, and various ports – such as Gothenburg – have issued methanol bunkering rules or are preparing to do so.

7.2 Life cycle and production

Methanol is typically produced by steam reforming natural gas to generate synthesis gas. This synthesis gas is then introduced into a reactor with a catalyst, which results in the production of methanol and water vapor. While methanol can be made from various feedstocks, natural gas is currently the most cost-effective option. Based on the source of production it is classified in different colours;



The production method of renewable methanol with the lowest carbon intensity can be from the municipal solid waste feedstock[29]. Biomass composed of MSW is first sent to a pre-treatment unit where it is homogenized, and then fed to the gasifier. In the gasifier, under very high temperatures at around 900-1000 degrees Celsius, the feedstock is converted to syngas which is a mixture of mainly carbon monoxide (CO) and hydrogen (H_2), as well as CO_2 and water (H_2O). Depending on the composition of the feedstock, it may also contain various impurities that must be treated in order to comply with the quality standards. This is why, after gasification, the syngas is sent to a conditioning unit where it is stripped of tars, dust and other trace components, and then an acid gas removal unit for CO_2 and sulphur removal. Gas conditioning also includes adjustment of the H_2/CO ratio to around 2 to 1 for optimal methanol synthesis and methane reforming in order to maximize the syngas yield and avoid energy loss in the form of methane leaving the methanol synthesis unit as a purge stream. After being sent to the synthesis unit, it is ran through the distillation unit to reach the final product that is methanol.

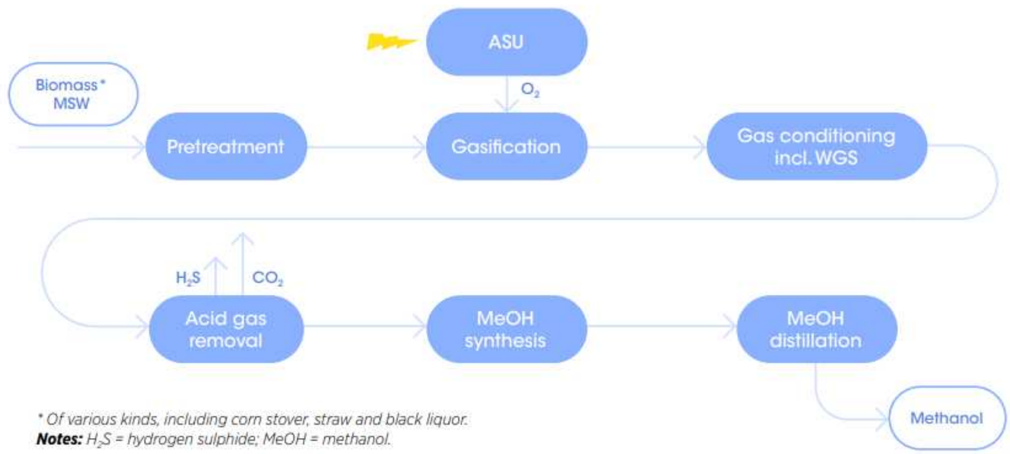


Figure 22: Gasification- based methanol plant scheme. IRENA Innovation Outlook 2021

Similarly to the method above, bio-methanol can also be produced from pulp mills [29].

7.3 Emissions

According to studies conducted from different sources, emission reduction varies significantly depending on the production process.

[30]Chryssakis highlights that one of the major challenges is that fossil methanol can actually increase total life cycle greenhouse gas (GHG) emissions by about 10% compared to marine gas oil (MGO), while liquefied natural gas (LNG) can reduce these emissions by 10 to 20%, depending on the engine technology used. Currently, the International Maritime Organization (IMO) regulations only consider tank-to-propeller emissions, which gives fossil methanol some carbon credit and a grace period until the mid-2030s before a transition to green methanol will be required. However, this could change in the future. For example, the European FuelEU Maritime initiative, which will come into effect in 2025, will penalize the well-to-wake emissions of fossil fuels.

According to DEFRA 2023;

Tank-to-wake emission factors

Fuel	Unit	kg CO_2e
Methanol (bio)	litres	0.00669
	GJ	0.42339
	kg	0.00844

0.42339 kgCO_2e per GJ = 0.001524 kgCO_2e per kWh

Marine gas oil	tonnes	3245.30
	litres	2.77
	kWh (Net CV)	0.27
	kWh (Gross CV)	0.26

By transforming GJ to kWh we can compare the TTW emissions.

Using the same unit, there is a reduction % of 99.43% .

Well-to-tank emission factors

Modern facilities today produce methanol with an estimated carbon footprint of about 110 g CO_2 eq/MJ[29]. When methanol is produced from natural gas sources with lower carbon emissions, the supply chain emissions can drop to around 103 grams of CO_2 equivalent per megajoule (g CO_2 eq/MJ). If the CO_2 from exhaust gases is recycled back into the methanol reactor, the production of methanol increases, and emissions from the facility are reduced. Consequently, the life cycle emissions per megajoule of methanol decrease to between 93 and 101 g CO_2 eq/MJ.

Production from coal only takes place in China and has a higher carbon footprint of nearly 300 g CO_2 eq/ MJ, due to large emissions associated with both the mining of coal and the methanol conversion process.

Producing methanol from renewable sources like biomethane, solid biomass, municipal solid waste (MSW, which includes a significant amount of organic waste), and renewable energy results in a low carbon footprint. Most of these production methods achieve emissions of 10-40 grams of CO_2 equivalent per megajoule. Some methods can even result in negative emissions, such as methanol produced from biomethane derived from cow manure, which can achieve -55 g CO_2 eq/MJ. This means that CO_2 is effectively removed from the atmosphere or that emissions are avoided that would have occurred in other processes. However, in order to compare we consider DEFRA 2023 for bio methanol and marine gas oil in order to maintain coherence in the study.

Methanol (bio)	litres	0,59447
	GJ	37,62
	kg	0,74964

37.62 kgCO_2e per GJ = 0.135kgCO_2e per kWh

Marine gas oil	tonnes	743,83524
	litres	0,62665
	kWh (Net CV)	0,06291
	kWh (Gross CV)	0,05913

For WTT emissions there is a **53% increase** in emissions.

The results are summarized below;

	Tank to wake emissions kgCO_2e/ kWh	Well to tank emissions kgCO_2e/kWh	Total emissions kgCO_2e/kWh	Reduction in total emissions%
Bio methanol	0.001524	0.135	0.1365	**59%**
MGO	0.27	0,06291	0.3329	

If we were to consider other production pathways and their emission factors, we would have to assume different sources. IRENA Innovation Outlook on Methanol [29] published a table containing GHG emissions of methanol from various sources, ordered by feedstock type. Examples are below;

Resource type	Feedstock	Raw material to final use GHG emitted in kg CO_2eq/kWh*	Source
Fossil-based	Natural gas	0.3276	Ellis and Svanberg, 2018
Fossil-based	Coal	0.9504	Ecoinvent, 2019
Power-based	Renewable electricity, CO_2 from biomass plant	0.006264	Hoppe et al., 2018

Figure 23 below illustrates in a chart the difference in emissions for different feedstock. It is very clear that if methanol is produced from fossil feedstocks, the GHG emissions can increase (coal) or remain almost the same as MGO (natural gas). Whereas, for methanol produced from renewable electricity the reduction in emissions is substantial.

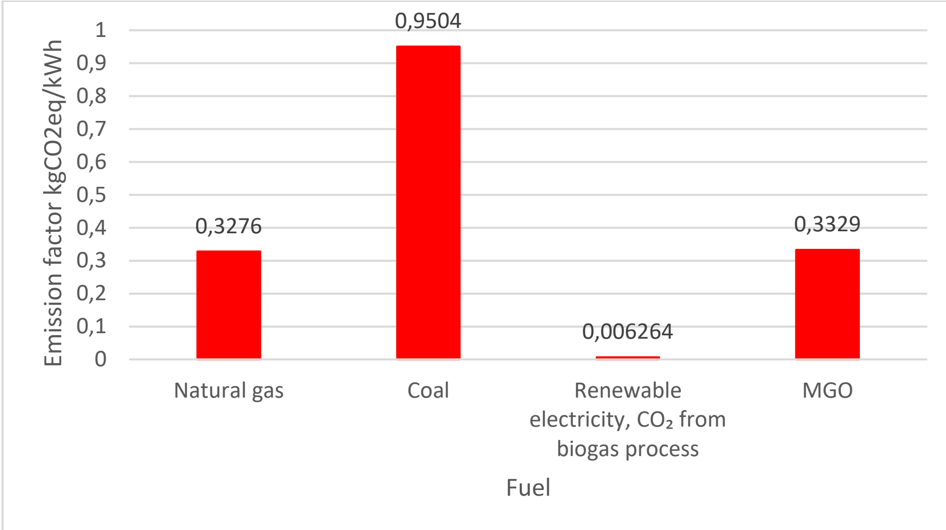


Figure 23

7.4.Availability and Cost

In September 2024 the DNV released the latest edition of the Maritime Forecast where they analyzed various fuel scenarios and their part of the fuel mix from 2024 to 2050. In the methanol scenario early, successful adopters expand the use of methanol technology, accelerating the development of methanol production and bunkering infrastructure. As economies of scale are achieved in both production and transport, bio-methanol becomes cheaper to produce than bio-MGO and bio-LNG, both of which face high demand from other sectors, driving up their prices. Given the limited supply of sustainable biomass and competition for biofuels, e-methanol ultimately emerges as the most cost-effective option for producing carbon-neutral methanol.

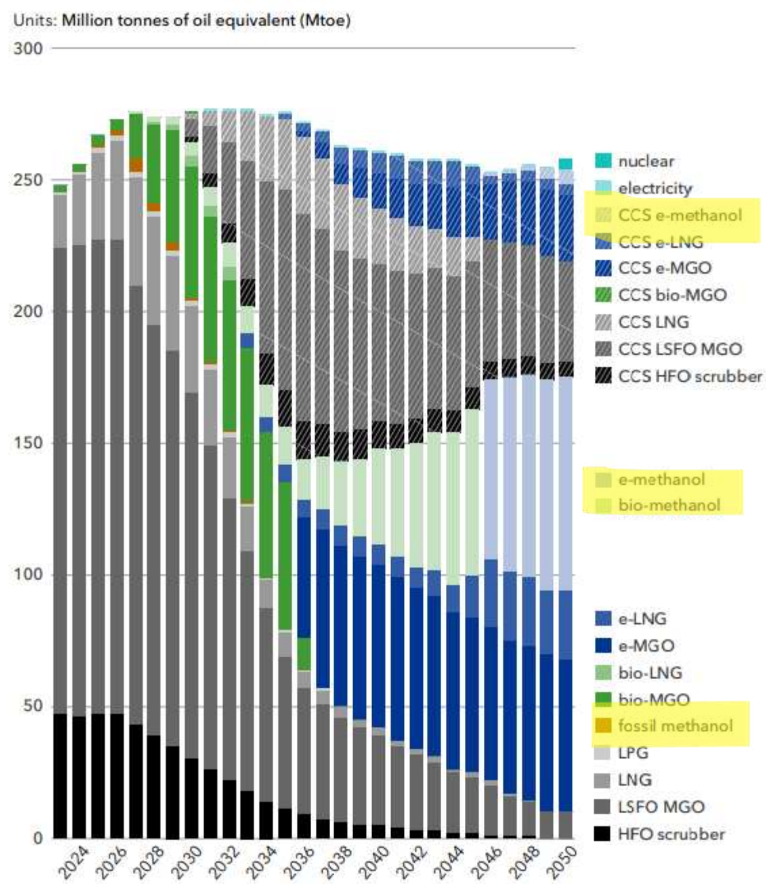


Figure 24: Methanol scenario fuel use in shipping by energy

According to the graph, currently methanol is not present in the fuel mix, by 2030 it will account for 1.93%, by 2030 5.04% and by 2050 33.33% of the fuel mix [1]. We observe that by 2035 fossil methanol will be phased out and bio-methanol will dominate until 2044 and then it will be almost completely replaced with e-methanol up to 2050. There are also small percentages of CCS e-methanol that will be included in the mix after 2045 and up to 2050.

Moreover, in November 2023, shipping giant AP Moller-Maersk announced that it had finalized a long-term agreement to purchase 500,000 tonnes of methanol annually, consisting of a blend of green bio-methanol and e-methanol, from Goldwind, a leading new energy company in China. This methanol will supply a significant portion of the fuel required for Maersk's 12 large methanol-powered container ships currently being built, with initial deliveries expected in 2026. Production is set to begin in 2026 at a new facility in Hinggan League, in northeast China. It is projected that methanol production for energy purposes, such as transport fuel, will reach 5.5 million tonnes by 2030 and nearly 60 million tonnes by 2050, mainly from non-fossil sources. Only 10% of this methanol will be produced from fossil sources equipped with carbon capture and storage (CCS) technology.

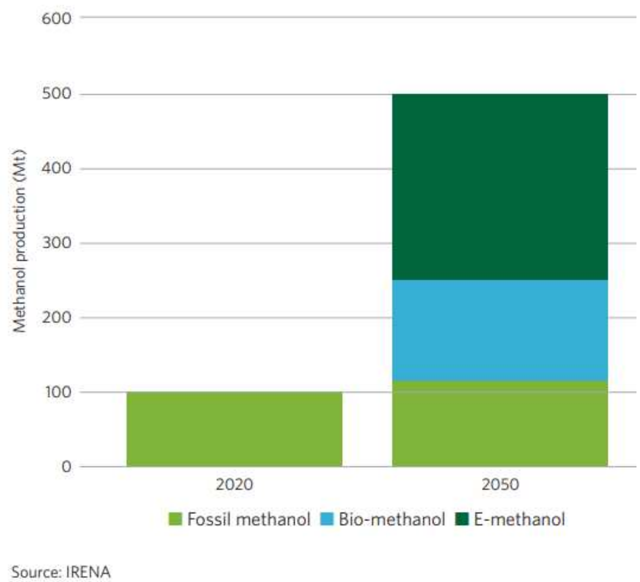


Figure 25: Methanol Production by 2050

The International Renewable Energy Agency (IRENA) estimates that by 2050, e-methanol and bio-methanol—both forms of "green" methanol—will account for around 80% of total methanol production, which could reach 500 million tons annually. However, the availability of feedstocks for bio-methanol and e-methanol will likely limit most production facilities to capacities between 50,000 and 250,000 tons per year. Regardless of whether methanol is produced from gray, blue, or green sources, its physical properties remain the same, allowing for a smoother transition to marine methanol as more low- and net-carbon-neutral methanol enters the global supply chain.

Another important aspect also mentioned above is feedstock availability. For bio-methanol production, the feedstocks include a variety of biogenic matter such as agricultural and forestry residues, biogas and biomethane, manure, municipal solid waste, and black liquor from pulp and paper mills. In particular, biogenic feedstock must not compete with food crop production and must not lead to additional emissions in order to be considered sustainable.

An additional consideration is that the infrastructure needs to be set up to gather and transport waste biomass to biofuels production centers at large scale and low cost. IRENA estimates the bio-methanol production could reach 135 million tons per year by 2050.

Cost

The cost of production for methanol heavily depends on the feedstock, technology, production capacity, operating conditions and availability of tax incentives. Aside from the production cost, it is necessary to also analyze the bunker price.

Irena presented various studies in the Innovation Outlook 2021 regarding CAPEX, OPEX and other factors influencing cost of bio-methanol from biomass or MSW [29]. The results were shown in the figure below. From 2020 to 2050 we observe an average decrease in bio-methanol cost from biomass by 18% and by MSW a decrease in 27%.

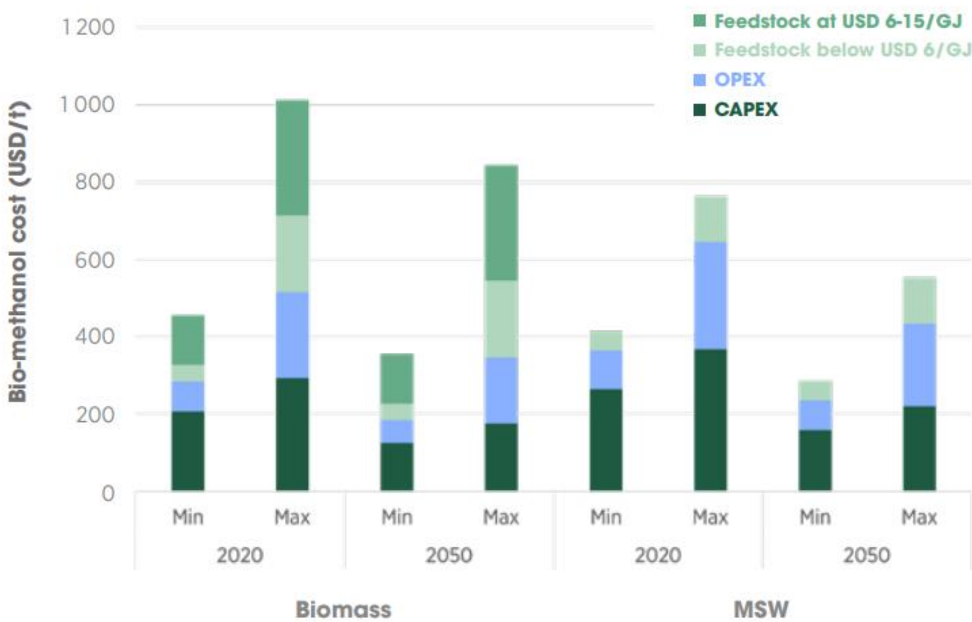


Figure 26: Estimated costs of bio-methanol up to 2050

Bunker prices on the other hand are only available as of right now for grey methanol or a quantity of methanol that delivers the same amount of energy as one metric tonne of MGO(**MeOH-MGOe)** and VLSFO(**MeOH-VLSFOe)**. [35]. If we compare, similarly, to LNG with the Rotterdam port;

Fuel	**MGO**	**Grey MeOH**	**MeOH-VLSFOe**	**MeOH-MGOe**
Price $/mt	625.00	383.00	787.50	816.50
Price $/GJ	14.7	19.2	19.94	19.93
Difference between the price of MGO in %	0	**+30%**	**+35%**	**+35%**

*LHV_{MGO} = 42.5 GJ / mt ; LHV_{MeOH} = 19.93 GJ/mt ; LHV_{VLSFO} = 41.0 GJ/mt [35]

We see that for methanol blended with conventional marine fuels such as MGO and VLSFO the bunker price is around 35% higher than the bunker price for MGO. Grey methanol on its own has a bunker price 30% higher than MGO.

Methanol Bunker Prices

	Gray Methanol $/mt	+/-	MEOH-VLSFOe $/mte	+/-	MEOH-MGOe $/mte	+/-
Singapore	365.00	▲ 4.00	751.00	▲ 5.50	778.50	▲ 6.00
Rotterdam	383.00	▼ 2.00	787.50	▼ 20.00	816.50	▼ 20.50
Houston	363.50	▼ 1.50	748.00	▼ 3.50	775.50	▼ 3.50
Fujairah	238.00	▲ 5.00	490.00	▲ 7.00	508.00	▲ 7.50

Figure 27: ShipandBunker bunker prices for 02/10/2024

7.5.Technical Aspects

Engine availability

Two-stroke dual-fuel engines that use methanol as fuel are nearly fully developed, with many orders placed for engines in the container shipping segment. Meanwhile, four-stroke engines are also advancing rapidly. The first MAN B&W ME-LGIM engines were introduced in 2016 and have collectively accumulated over 600,000 operating hours using methanol. These low-speed engines inject liquid methanol along with a pilot fuel at the top of the stroke and cover a power range from 5.4 to 82 MW, depending on the engine type and rpm.

Bunkering facilities

Since methanol is a widely traded chemical, there are already established facilities in place that could be further modified to fit the marine guidelines. Furthermore, even facilities for MGO or HFO can be adapted to fit methanol. The most common form of bunkering for methanol is by trucks to one or more vessels. In the future, if methanol becomes a more popular fuel for the marine industry, bunker vessels will see further development. The first methanol ship-to-ship bunkering operation has already taken place in 2021 in Rotterdam.

Methanol is available at over 100 ports around the world, with this number increasing all the time[31].

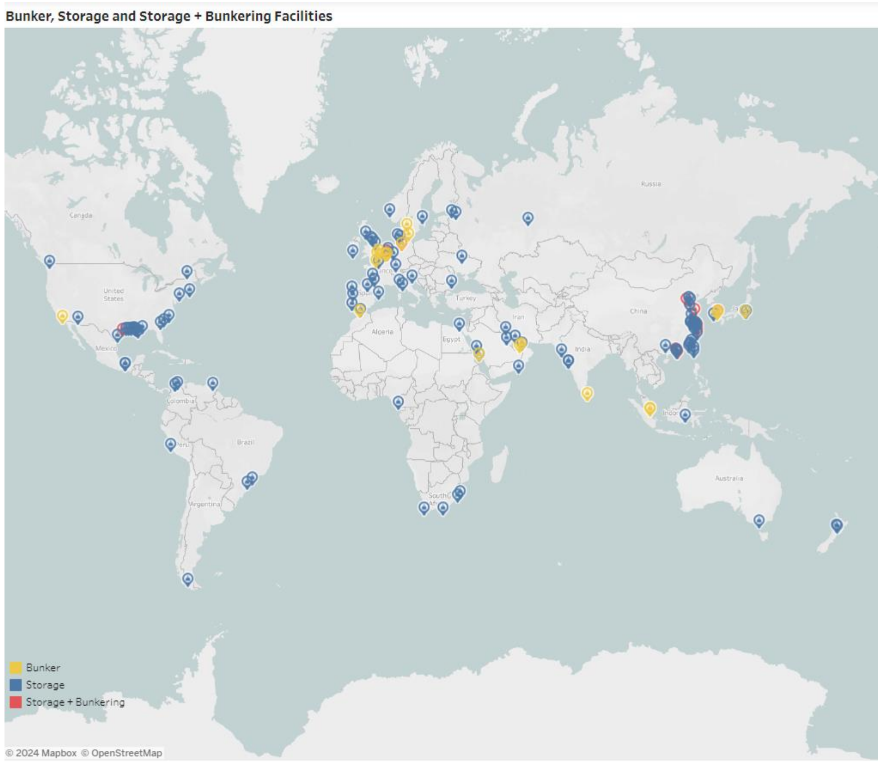


Figure 28:E-Methanol & Biomethanol Plants and Ports. Methanol Institute

Onboard storage

In order to convert a vessel running on marine gas oil, to run on methanol requires approximately double the fuel tank volume to have the same fuel endurance. That is because the volumetric energy density for methanol (15.8 GJ/m3) is almost 2.5 times larger than the volumetric density for MGO (36.6 GJ/m3). Additionally, methanol tanks need cofferdams to safeguard against potential leaks into machinery areas. Space limitations for methanol fuel tanks or containers, as well as fuel handling equipment, can present challenges in conversion projects.

Safety concerns

Even though onboard containment of methanol is easier than that of LNG, modifications are still required since it is a liquid fuel [33]. Major safety aspects have to do with the low flash point of methanol and they include;

- Methanol tank location
- Methanol protection
- Inerting and venting of a methanol tank
- Spill containment
- Vapor and fire detection
- Fire fighting

Methanol is toxic to the central nervous system and can cause blindness, coma, or death if ingested in large amounts. Its vapor, being heavier than air, poses an inhalation risk to crew members, especially in confined spaces. At high concentrations, methanol vapor can also lead to asphyxiation, so spills and leaks must be handled with caution. Methanol vapor tends to collect in low areas, such as the bottoms of tanks or low points in pipes. As a result, careful consideration must be given to the placement of ventilation and detection systems in areas where methanol leaks might occur.

Corrosion

Methanol is corrosive to certain materials, so using it as marine fuel may require redesigning some engine components. Corrosion-inhibiting additives or special coatings can help reduce methanol's corrosive effects. Due to methanol’s conductivity, it can corrode metals like aluminum and titanium alloys, which are commonly used in natural gas and distillate fuel systems but are unsuitable for methanol fuel pipes or fittings [33].

Storage tanks for methanol must be made from an appropriate grade of stainless steel or have methanol-resistant coatings inside. If coatings are used, any acidic impurities that could damage them should be addressed promptly to prevent accelerated corrosion, such as pitting, iron contamination, or further methanol degradation.

For non-metallic components like pipes and fuel tanks, materials must be methanol-compatible, such as nylon, neoprene, or non-butyl rubber.

Capacity study

This section aims to estimate the tank volume needed in comparison to Saipem 7000, a ship that runs on MGO. We assume 40 days of autonomy and 85% load.

	MGO Saipem 7000		**Methanol fueled ship**
Daily consumption (t MGO/d)	50	Daily consumption (t CH3OH/d)	42,093
SFOC (t/MWh)	0.215	SFOC (t/MWh)	0.181[a]
Daily consumption (m^3 MGO/d)	58,139	Daily consumption (m^3 CH3OH/d)	53,147
Density t/m^3	0.86	Density t/m^3	0.792
Days of operation	40	Days of operation	40
Tank volume needed m^3	2325	Tank volume needed m^3	2126

[a] According to MAN V51/60DF Propulsion – High power variant engine for 85% load

In summary, according to this scenario, the tank volume for a methanol fueled ship would need to be **8.5%** smaller than that of Saipem 7000, an MGO fueled ship.

7.6.Advantages and challenges

Advantages

- Methanol is a widely traded commodity under the IBC Code, supported by a strong network of existing ports and infrastructure.
- Substituting marine gas oil for methanol in ships will reduce greenhouse gas emissions by 59%.
- Methanol fueled ships would require only 8.5% less tank space to store the same amount of energy as an MGO fueled ship.
- Because methanol is a liquid at ambient temperatures, ships do not need cryogenic or high-pressure containment systems to use methanol as fuel.
- Mature engine technology, with two-stroke main engines and four-stroke auxiliary methanol engines already commercially available.
- As a substance which can be produced from renewable energy and carbon capture, methanol could be a carbon-neutral fuel.

Challenges

- The bunker price for Grey Methanol is almost 30% higher than that of MGO. Moreover, it is important to note that according to the DNV scenarios Grey Methanol will be slowly phased out by 2035, and replaced with methanol produced from renewable sources which may present even higher costs.
- Its flame is almost invisible when burned, requiring the installation of specialized fire detectors on ships.
- Additionally, it is toxic, with strict limits on human exposure through inhalation, contact with the skin, and other forms of exposure.

8.Ammonia

8.1. Introduction

Ammonia is a widely traded chemical that has traditionally been transported in liquefied petroleum gas (LPG) tankers, which are also suitable for carrying ammonia. When produced using renewable energy, ammonia is referred to a "green ammonia," a zero-carbon fuel throughout its production and use. This offers shipowners a fuel option with potentially no well-to-wake CO_2 emissions, aiding in meeting the International Maritime Organization's (IMO) 2050 emissions reduction targets.

DNV predicts ammonia use in shipping will be 170 PJ (1% of the shipping fuel mix) in 2030, 1,900 PJ (13% of the fuel mix) in 2040, and 5,000 PJ (36% of the fuel mix) in 2050.[1]

Despite its benefits, ammonia poses challenges due to its toxicity at low concentrations, raising health and safety concerns for crew members. To use ammonia onboard, shipowners must ensure safe handling in accordance with applicable regulations.

When transported as cargo, ammonia is governed by the IGC Code. Design requirements for ships intending to use ammonia as fuel are detailed in the newly issued NR 671 Rules. The design must be evaluated through the Alternative Design procedure of the IGF Code and SOLAS regulations.

DNV class rules for ammonia

DNV has issued classification rule updates relating to ammonia that took effect in January 2022 and January 2023. Two new class notations were introduced that are relevant for ammonia as ship fuel[39].

The Fuel Ready class notation provides shipowners with the option to prepare their newbuilds for later conversion to multiple different alternative fuel options, including ammonia, LNG, LPG and methanol. It comes with several qualifiers specifying mandatory basic as well as optional levels of preparation, relating to structural aspects, engine and machinery, piping and bunkering, and miscellaneous other requirements.

The Gas Fuelled Ammonia class notation gives owners the option to start building ships for future ammonia propulsion today, setting out the requirements for the ship's fuel system, fuel bunkering connection and piping through to the fuel consumers.

8.2. Life cycle and production

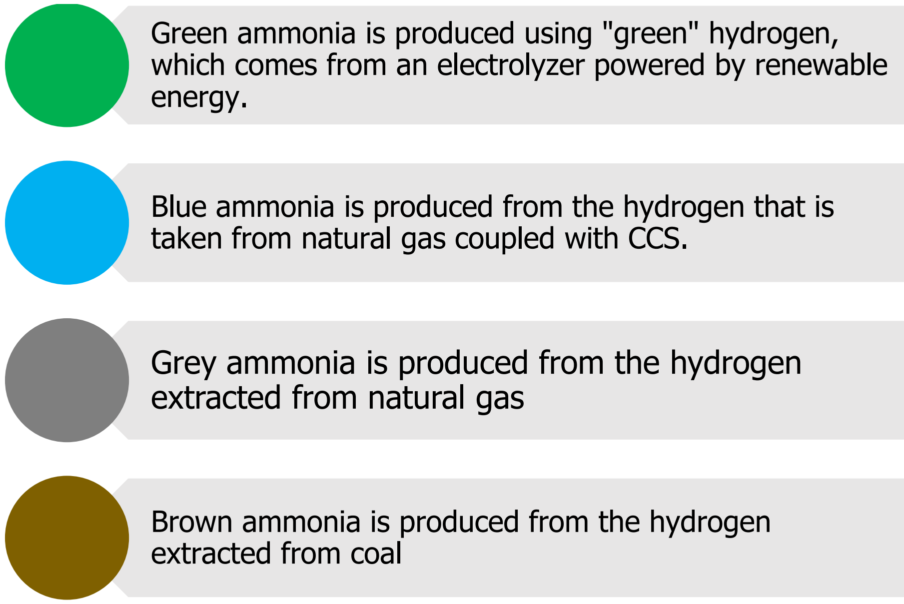


Figure 29: Ammonia colours production

Green ammonia, also referred to as e-ammonia, is produced through the Haber-Bosch process using green hydrogen and nitrogen. This method involves:

1. **Green Hydrogen Production**: Green hydrogen is produced via electrolysis of water using renewable energy sources (such as wind, solar, or hydroelectric power) to split water into hydrogen and oxygen. This process is environmentally friendly as it emits no greenhouse gases if the energy used is entirely renewable.
2. **Nitrogen Source**: Nitrogen is obtained from the air through a process called air separation, which isolates nitrogen from other atmospheric gases.
3. **Haber-Bosch Process**: In the traditional Haber-Bosch process, hydrogen and nitrogen gases are combined under high pressure and temperature in the presence of a catalyst to produce ammonia (NH_3).

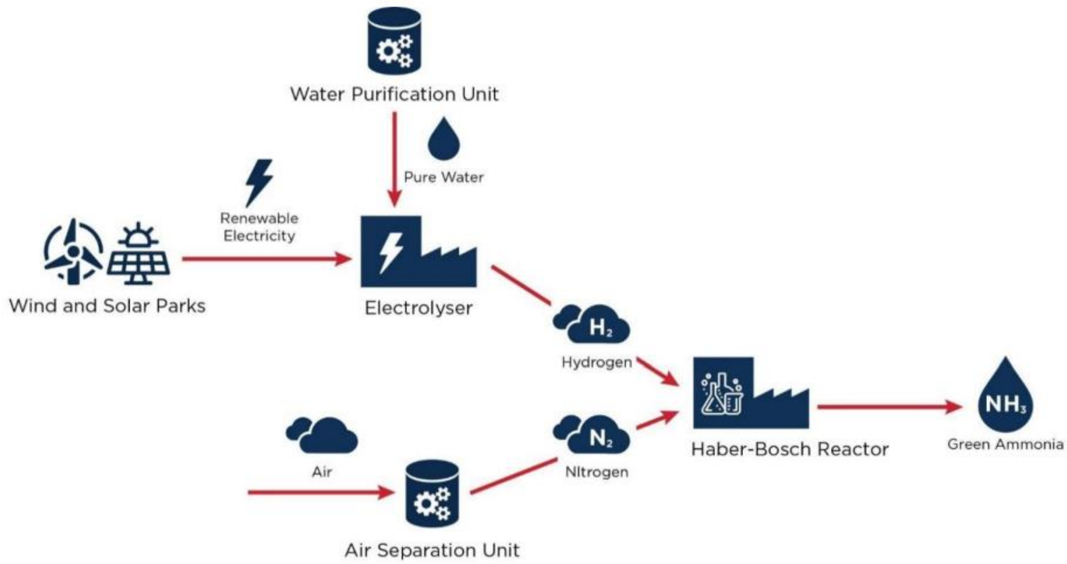


Figure 30: Production process of green ammonia using electrolysis and the Haber-Bosch synthesis

Other Methods for Producing Green Ammonia

Electrochemical Nitrogen Reduction

An alternative method for producing green ammonia involves the electrochemical reduction of nitrogen (N_2) directly to ammonia. This process is currently in development and offers potential benefits such as:

- Lower energy requirements compared to the traditional Haber-Bosch process.
- The possibility of decentralizing ammonia production, allowing for smaller-scale operations closer to end-users.

Blue ammonia is produced from the hydrogen that is taken from natural gas coupled with CCS. Hydrogen is separated from the natural gas through another process called SMR (Steam Methane Reforming). The carbon that is vented is then sequestered by CCS systems.

Brown ammonia is produced from converting coal into synthesis gas by a gasification process at high temperatures. The syngas that is composed of a mixture of gases (CO, CO_2, H_2), is then sent to a pre-treatment unit where it is stripped of impurities and finally air is introduced to provide N2.

Grey ammonia is produced from the hydrogen in natural gas. Both brown and grey ammonia, produced from hydrogen that is deriving from fossil fuels have the highest carbon intensity as no CCS is used.

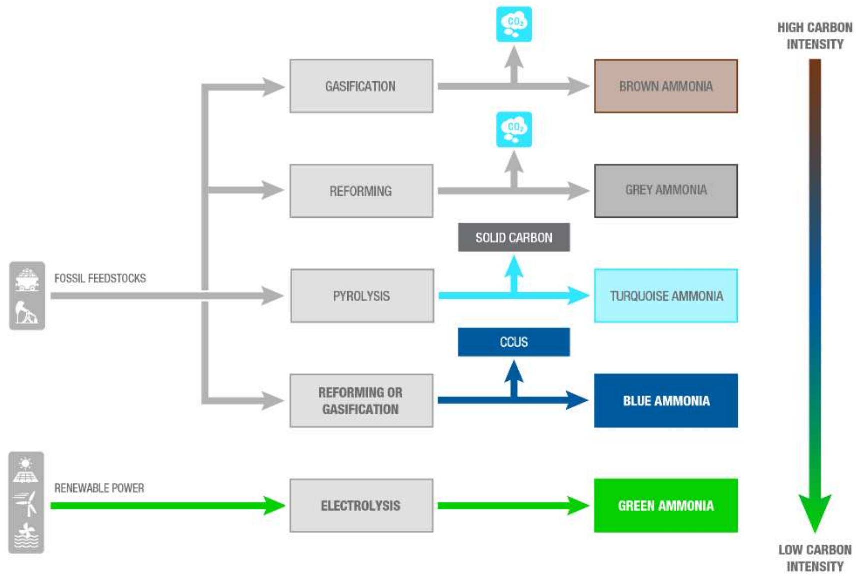


Figure 31: Production pathways for ammonia

8.3. Emissions

Unlike conventional marine fuels, ammonia does not produce significant sulphur oxide (SO_x) or particulate matter (PM) emissions. If produced with renewable energy, ammonia can reduce lifecycle greenhouse gas (GHG) emissions by up to 90% compared to traditional fossil fuels. This makes ammonia a promising option for meeting the International Maritime Organization's (IMO) goal of cutting GHG emissions by at least 50% by 2050.

Since ammonia does not contain carbon, CO_2 emissions from burning ammonia only occur if a pilot fuel is used, which is unnecessary when a ship is powered by fuel cells[36]. This applies to grey, brown and green ammonia. The primary emissions generated by the overall system, including the engines and related equipment, are N_2O, NO_x, and ammonia slip.

NO_x emissions are managed using abatement technology like Selective Catalytic Reduction (SCR), while ammonia slip is addressed through subsequent combustion in the ARMS (Ammonia Release Mitigation System). One of the main areas still being analyzed by different providers is the management of potential N_2O emissions. In general, catalysts are being developed to reduce N_2O emissions, aiming to make ammonia a more sustainable solution by minimizing N_2O formation rather than relying on a post-treatment unit. For instance, the Wärtsilä 25 engine model, features optimized combustion and integrated aftertreatment to minimize all greenhouse gas emissions. The aftertreatment system is split into two subsystems based on their function: the SCR system, which handles only the engine's exhaust, and the ARMS, which manages emissions from the entire system, including the engine, storage, and fuel supply.

The generation of N_2O is a significant concern because it is a far more potent greenhouse gas than methane and CO_2. According to the IPCC AR5 report [37] N_2O is 264 times more powerful than CO_2 over a 20-year period (GWP20) and 265 times more potent over a 100-year period (GWP100).

A comparison is done between ammonia and its different production pathways, characterized by colors, and marine gas oil based on the life cycle emissions for both. We assume that green ammonia is produced from high-temperature electrolysis, and nitrogen from PSA (pressure swing adsorption).

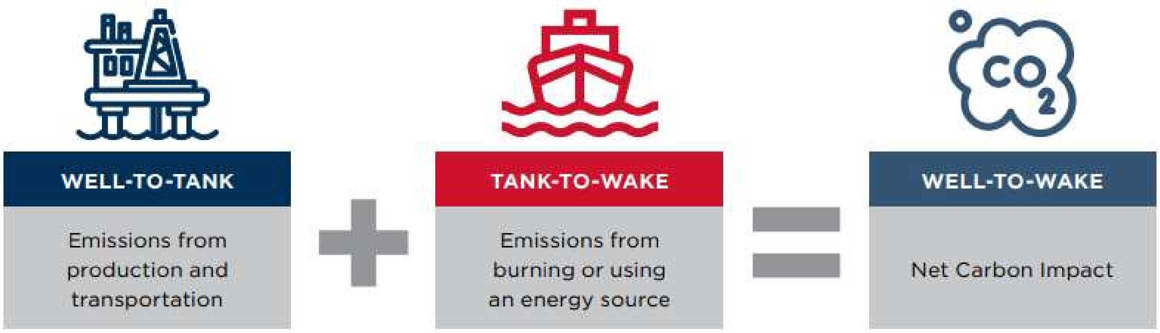


Figure 32: Life cycle emissions. Source ABS

Ammonia does not contain carbon and, therefore, its combustion does not emit any CO_2. However, due to poor combustion characteristics, secondary or pilot fuel is required (5-15% for two-stroke engines and up to 30% for four-stroke engines, based on suppliers' latest forecasts).[36]

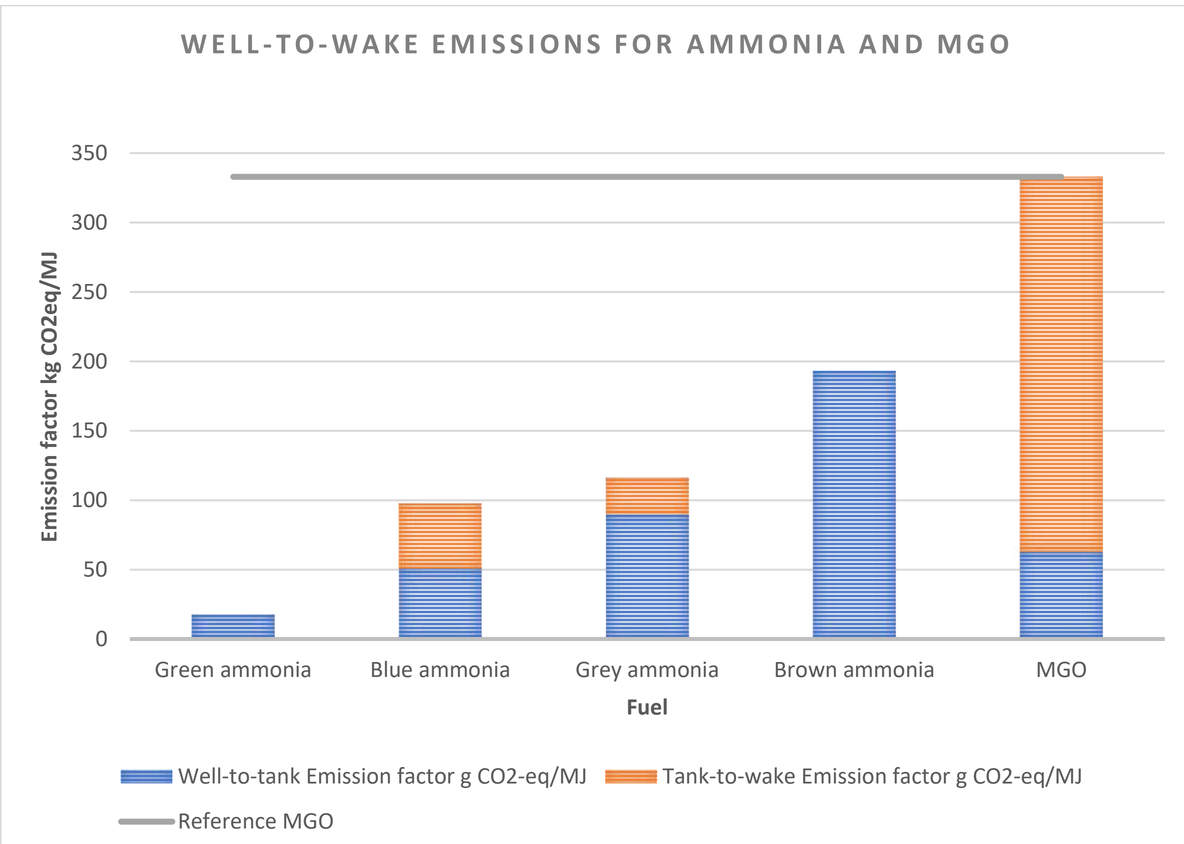
Table 6

Fuel	**Production**	**Source**	**Well-to-tank Emission factor g CO_2-eq/MJ**	**Tank-to-wake Emission factor g CO_2-eq/MJ**	**Well-to-wake TOTAL g CO_2-eq/MJ**	**Reduction %**
Green ammonia	High-temperature electrolysis, and nitrogen from PSA	Liu, Elgowainy and Wang, 2020	17.7	0	17.7	95
Blue ammonia	Natural gas with CCS	Royal Society, 2020	50.9	46.7	97.6	71
Grey ammonia	Natural gas	Smith, Hill and Torrente-Murciano, 2020	89.7	26.7	116.4	65

Brown ammonia	Coal	Rouwenhorst et al., 2020b			193.1	42
MGO	-	DEFRA 2023	62.91	270	332.91	-

Note : PSA= pressure swing adsorption, SMR = steam methane reforming *Source: IRENA*

The results are displayed in the graph below; The percentages represent the reduction in Well-to-wake emissions for each type of fuel. The biggest reduction is observed for green ammonia and smallest reduction for brown ammonia. Since producing green ammonia does not include combustion processes, the TTW emissions are assumed to be zero. However, emissions produced by the power plant or from transportation still remain, although in low values.



8.4. Availability and Cost

Estimating the potential supply of green ammonia for the global maritime shipping industry is challenging due to various market factors. These include industry investment strategies, fluctuations in the demand for renewable energy and electricity, and technological progress in electrolysers and ammonia synthesis. The projected global supply of renewable electricity in 2040 seems ample enough to produce green ammonia for the entire maritime fleet using electrolysis and the Haber-Bosch process. However, the shipping industry will need to compete with other sectors for access to renewable electricity and green hydrogen. The agricultural sector, which is also likely to face pressure to reduce carbon emissions, will add to the growing demand for green ammonia. According to the latest edition of the Energy Transition Outlook by the DNV [1], green and blue ammonia make up about 3,30% of the total fuel mix by 2035 and 26,49% of the total fuel mix in 2050.

The DNV states that as of 2024 there are 25 ammonia-fueled ships in order. In addition, they state that the first ammonia engines will become available in the next two to three years. These engines are sized for use in large bulk carriers and gas tankers. However, bunkering infrastructure remains immature.

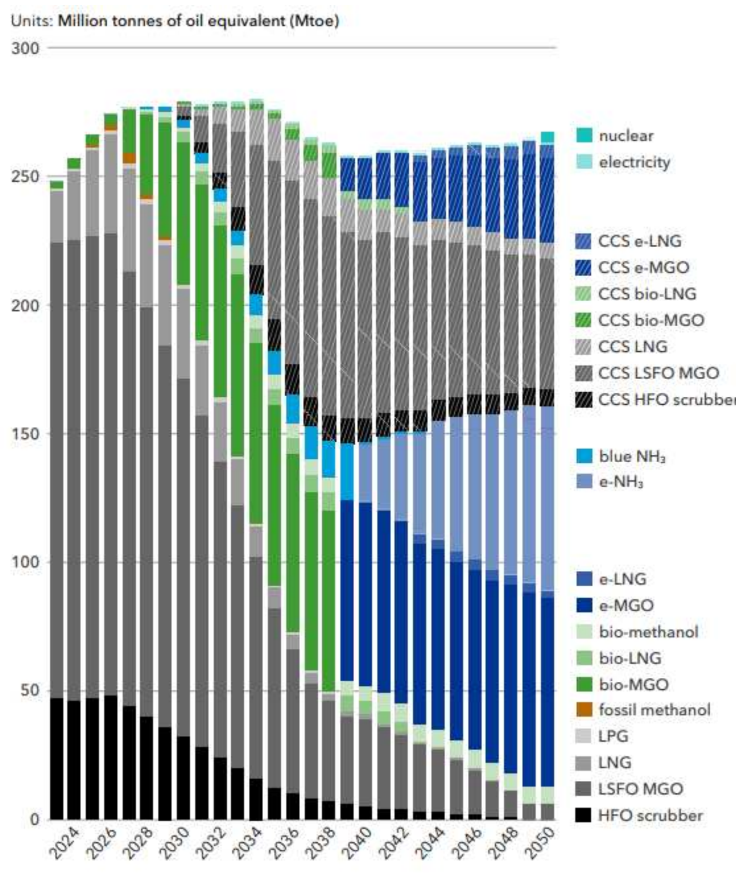


Figure 33: Ammonia scenario-fuel use in shipping by energy

Cost of ownership

In 2030, the total cost of ownership (TCO) for vessels powered by blue or green ammonia is expected to be higher than for those using conventional fuel oils. For instance, the TCO for containerships and bulk carriers is estimated to be about 2.5 to 3 times higher with green ammonia and 1.5 times higher with blue ammonia when accounting for carbon pricing [38]. However, by 2050, the cost gap between ammonia-fueled ships and those using traditional fossil fuels could potentially close, driven by lower ammonia production costs, decreased capital expenses for ammonia installations, and increased carbon prices for fossil fuels. This will also depend on the global price trends for fuel oil.

Production cost

The data below was taken from a report published by Irena [34].

The cost of renewable ammonia depends on the cost of renewable hydrogen, representing more than 90% of the cost for ammonia production. The two other significant steps in ammonia production – nitrogen purification and the Haber-Bosch process – represent only a minor fraction of the total cost. The future cost of renewable hydrogen depends on the combination of further reductions in the cost of renewable power generation and electrolysers, and gains in efficiency and durability.

	Electricity source for electrolysis	**Capacity (kt/y)**	**CAPEX (million USD)**	**OPEX (million USD/yr)**	**Ammonia cost USD/t**
Production cost	Grid	2.0-6.8	10.2- 29.0	3.0-9.6	1725-1640
	Hydropower	263	451	83.7	405
	Location and company	**Capacity (kt/y)**	**CAPEX (million USD)**	**OPEX USD/kWh**	**Source**
Capital cost	Esbjerg, Denmark Copenhagen Infrastructure Partners, Maersk, DFDS	650	1210	3 150	Barsoe, 2021

Moreover, the DNV presents maximum and minimum estimated prices for carbon-neutral ammonia for 2030-2050 as a global mean average of all regions.

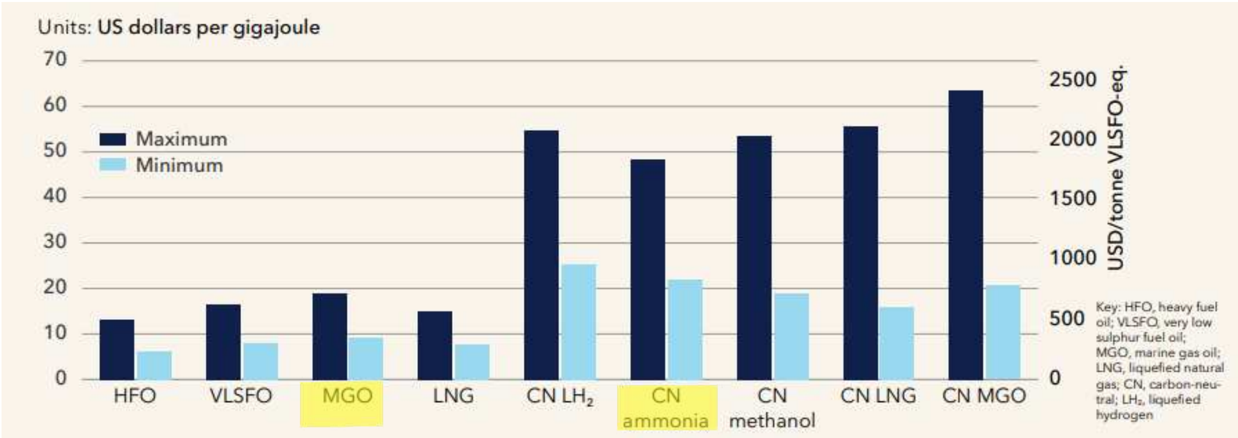


Figure 34: Estimated high and low prices for fuels in 2030–2050 include production and distribution costs as a global average. DNV Maritime Forecast to 2050 (2024)

	MGO	CN ammonia	Difference in %
Minimum $/GJ VLSFO eq	9	21	57% higher
Maximum $/GJ VLSFO eq	19	47	60% higher

Table 7: Results

On average, we can say that between 2030 and 2050 carbon-neutral ammonia such as green ammonia or blue ammonia will cost around 58% more than MGO. However, the investment cost of green ammonia production using electrolysis can be heavily influenced by the capacity factor. This is because renewable energy sources like solar and wind are variable, and without sufficient storage or buffering, the actual annual ammonia output will be lower than the facility's maximum capacity. As a result, capital intensity may be higher. Assets for green ammonia are constructed upfront which means that the cost is driven mainly by the capital investment. This is why the capital investment has such a huge influence on the price.

8.5. Technical aspects

Loading systems

Vessels can receive liquid ammonia fuel from a bunkering storage tank via flexible hoses or marine loading arms (referred to as the "transfer system"), which are connected to the bunker stations during refueling operations. Since ammonia vapor is generated during the fuel transfer process (as the liquid level rises in the storage tank), a vapor return line/system back to the bunkering storage is required. Therefore, the transfer system must accommodate both fuel loading and vapor return functions simultaneously. The transfer system features a quick disconnect and connect coupling that interfaces with the bunker stations installed on the vessel.

Storage systems

Ammonia can be stored under pressure at atmospheric temperature or in a refrigerated state. This means that ships using ammonia as fuel and bunkering vessels may carry different combinations of pressurized, semi-refrigerated or fully refrigerated ammonia.

A capacity study was conducted by Saipem considering that the storage system is composed by two Type C semi-pressurized tanks which work at a pressure around 2-3 barg and a temperature around -10°C with a single volume of 1500m^3. The study with 5 MW assumed dual fuel with MGO.

The following requirements were taken into consideration for the study:

- Autonomy period (between two subsequent refills) is 40 days.
- Ammonia density given by the operating conditions of tank.
- Total ammonia consumption of both engines (one engine consumes 960 kgNH_3/h at 100% load).
- Margin percentage at least 15% to calculate the geometrical volume (to account for maximum filling degree, liquid inventory below Low Liquid Level setting, etc).

The data is displayed in the table below.

Table 8: Calculations for volume of tank

Description	Unit	Value
NH_3 mass flow rate $_{real}$ (100% load, see note 1)	kg NH_3/h	1920
NH_3 mass flow rate $_{real}$ (at nominal 5 MW output power, see note 2)	kg NH_3/h	1778
Autonomy required	days	40
$NH_{3,liq}$ density (T: -10°C,P=3barg)	kg/m^3	652
$NH_{3,liq}$ volumetric flow rate	m^3/h	2.73
Volume required	m^3	2618

*Note 1: at 100% load, each engine provides 2.7 MWe (@ 60 Hz), leading to a total output power of 5.4 MW.
*Note 2: 5MW is equivalent to 93% of maximum load (5.4 MW)

The study above is compared to SAIPEM 7000 running on solely MGO that was found to require about 2326 m3 in order to achieve 40 days of autonomy. This value is consistent with the average consumption of the ship, but it must be adjusted to have the same energy output as ammonia. A consumption consistent with 5 MW is 25 tons per day of MGO.

The table below shows the volume of the tank needed for 40 days of autonomy if we assume that Saipem 7000 consumes 25 tonnes MGO per day.

	MGO Saipem 7000		**Methanol fueled ship**
Daily consumption (t MGO/d)	25	Daily consumption (t NH3/d)	21,046
SFOC (t/MWh)	0.215	SFOC (t/MWh)	0.181[a]
Daily consumption (m^3 MGO/d)	29.06	Daily consumption (m^3 NH3/d)	53,147
Density t/m^3	0.86	Density t/m^3	0.652
Days of operation	40	Days of operation	40
Tank volume needed m^3	1163	Tank volume needed m^3	1291

The tank volume for an ammonia fueled ship compared to an MGO fueled ship will be **11% larger**.

Engine availability

Currently, no commercial vessels are using ammonia as fuel, but the first orders for ammonia dual-fuel engines have been placed for delivery starting in 2025[1]. The Fortescue Green Pioneer, a converted supply vessel, became the first ocean-going ship to be powered by ammonia after completing trials in Singapore in May 2024. MAN, J-Eng, and WinGD are exploring the two-stroke diesel principle for ammonia engines. MAN began testing its two-stroke ammonia engine in June 2023 and aims to offer ammonia-powered engines to customers after 2027, allowing time for extensive testing and demonstrations on selected projects.

For four-stroke medium and high-speed engines, ammonia can be used with high-pressure injection of either liquid or vaporized ammonia and pilot fuel at the top of the stroke, or with vaporized ammonia injected upstream of the inlet valves or directly into the cylinder early in the stroke. Wärtsilä is reportedly testing both methods in its development of an ammonia-fueled engine.

Corrosion

Due to ammonia's corrosive properties, special attention must be paid to the selection of the tank, piping and equipment materials, to avoid stress corrosion cracking.

8.6. Advantages and challenges

Advantages

- **Emissions**. When it is produced using renewably sourced hydrogen, it has very low carbon emissions, around 95% less than MGO.
- **Availability**. Atmospheric nitrogen (N2) is widely and freely available.
- **Ammonia storage.** Ammonia also benefits from well-developed storage infrastructure and a worldwide terminal network.
- **Developing technology**. Internal combustion engines which consume ammonia directly are closer to at-scale development than other solutions for alternative fuels.

Challenges

- **Safety**. Ammonia is highly toxic to both people and marine life, and its powerful smell can be a physical irritant.
- **Storage**. It has low energy density – about three times less than conventional fuels – requiring greater amounts to be carried onboard and reducing space for other cargo. Due to the poor combustibility properties of ammonia, it may be necessary to use pilot fuels. Ideally, these pilot fuels should be carbon-neutral, such as biofuels or green hydrogen, to ensure environmentally friendly operations.
- **Supply**. The supply of green ammonia is currently extremely limited, and competition from other sectors could make this green fuel expensive.
- **Ammonia is corrosive**. Selection of materials for fuel handling systems and tanks is to be adequate with regards to ammonia corrosivity.

9.Biofuels

9.1. Introduction

Biofuels are generated from biomass as the main source to create gaseous or liquid fuels. The production of biofuels involves various processes and feedstocks, making it complex. In theory, using biofuels is advantageous because it should lead to a minimal or zero increase in atmospheric CO_2 when considering the entire life cycle. However, the sustainability of biofuels largely depends on the type of feedstocks used.

Biofuel blends are identified by the percent content of biofuel. For biodiesel, the percentage of biomass-sourced fuel is indicated with the prefix B, such as B7, B10, B20, and B100 indicates an unblended pure biodiesel liquid which can provide the maximum carbon reduction option for users[40]. Biodiesel blends, unlike most other biofuels, are regulated by American Society for Testing and Materials (ASTM) and European Standard (EN) regulatory bodies.

One of the various approaches to align with the IMO's strategy for reducing greenhouse gas (GHG) emissions from ships is to utilize biofuels or biofuel blends. However, there are different types of biofuels that are fit for marine use. FAME and HVO are the main first-generation biofuels in the shipping industry.

1. **FAME** (fatty acid methyl ester) is produced through the transesterification of vegetable oils, animal fats, or used cooking oils, where triglycerides are transformed into methyl esters. This type of biodiesel is the most commonly available and is frequently mixed with regular marine diesel. According to the marine fuel specification standard ISO 8217:2017, there are additional requirements for distillate marine fuels that contain up to 7.0 volume % FAME.

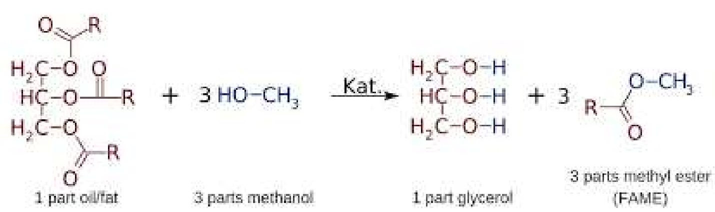


Figure 35: FAME chemical reaction and composition

The FAME used for blending must comply with the EN 14214 or ASTM D6751[41] standards. Additionally, FAME-diesel blends with up to 30% BTL content are utilized in automotive applications and are known as B20 or B30.

EN 14214: This is a European standard that outlines the specifications for FAME used as biodiesel. It covers various quality parameters, including the chemical composition, physical properties, and performance characteristics necessary to ensure the fuel's reliability and efficiency in diesel engines.

ASTM D6751: This is an American standard that sets the specifications for biodiesel (FAME) intended for use in diesel engines. It includes similar quality parameters to those in EN 14214, such as viscosity, flash point, and purity, to ensure that the biodiesel performs effectively and safely.

2. **HVO** (hydrotreated vegetable oil), also known as hydrogenation-derived renewable diesel, is produced by refining fats or vegetable oils—either alone or blended with petroleum—through a hydrotreating process called fatty acids-to-hydrocarbon hydrotreatment. Unlike FAME biodiesel, which is produced through transesterification, HVO is often referred to as renewable diesel. Although the production of HVO is generally more expensive than that of FAME biodiesel, it has the advantage of being a drop-in fuel. This means it can be used directly in existing distribution and refueling systems, as well as in diesel engines, without requiring any modifications.

Biofuels are the most widely used carbon-neutral fuels in shipping today and can be blended in with a variety of different marine fuels. In 2023, fuels blended with biodiesel accounted for more than 7% of the total bunker sales in the Port of Rotterdam and around 1% in the Port of Singapore, totaling an estimated 0.4 Mtoe pure bio-based diesel, an increase from about 0.3 Mtoe in 2022 [8].

A key reason why biofuels are seen as an attractive decarbonization pathway for vessels, is their ability to be used onboard existing vessels without modifications (i.e., drop-in capability).

HVO has a higher energy content than FAME and has the advantage that it can be used in diesel engines without the need for complex modifications. However, a challenge for HVO is feedstock sourcing.

The chemistry and composition of FAME differ from those of purely hydrocarbon-based fuels. Consequently, blending FAME with hydrocarbon fuels presents certain challenges that need to be carefully managed during the production, blending, distribution, and supply of diesel fuels. The main concerns are: poorer fuel stability, an increased risk of deposit formation, poorer cold temperature handling, filterability, and operability, increased solvency, greater potential for microbiological contamination, poorer water shedding, different material incompatibilities, increased foam decay times, and impact on fuel additive performance.

Equipment and transport media that are routinely exposed to B100 and used throughout the supply chain (tanks, vessels, pumps, filters, piping, fittings, instruments, gaskets, hoses, etc.) should be made of materials that are compatible with FAME. Where existing materials are not compatible, they should be replaced.

9.2. ABS Notation

Vessels using biofuels are effectively covered by the ABS Marine Vessel Rules (MVR)[42] by compliance with the requirements for prime movers and fuel oil storage and transfer systems. Biofuels in fuel oil tanks should comply with **MVR 4-6-4/13**, which includes requirements for shipboard fuel oil storage, transfer, heating and purification.

Since biofuels have various levels of flammability, those fuels and biofuel blends that are flammable in the tanks onboard a vessel should comply with the provisions of **MVR 4-6-4/9**, which includes the tank vents and overflow requirements. Furthermore, **MVR 4-6-5/3** applies to fuel oil systems supplying internal combustion engines, together with MVR Sections **4-6-5/3.3** and 4-6-5/3.5 describing the rules related to the fuel oil service systems for propulsion and auxiliary engines.

As per MVR 4-6-4/13.5.1(d) and SOLAS requirements, for vessels of 500 gross tonnage and above, at least two fuel service tanks for each type of fuel used on board of at least eight hours capacity are to be provided.

Classification

1. For blends between 7-30% and blends more than 30% of biofuel, a confirmation from the OEM should be submitted to ABS on the suitability of the engines to burn the proposed biofuels and that they have no objection and/or applicable conditions to the biofuel use. Any limitations or requirements for application on board are to be followed.

2. For blends of more than 30% of biofuel, specifications of the proposed biofuel(s), engines intended to run the fuels, and, as applicable, trial testing dates, are to be submitted. The fuel specification may include a lab test providing the fuel parameters demonstrating compliance with IMO's flashpoint and sulfur content requirements under SOLAS and MARPOL.

The use of biofuels is not regarded as a parameter that defines engine type (as stated in MVR 4-2-1 Table 4), so it does not necessitate retesting engine types. However, the appropriateness of any fuel, such as HFO or biofuel, for which an engine is designed or capable of running should be validated or agreed upon by the engine manufacturer. Most engine suppliers offer specific guidance for operating with biofuels, along with related considerations for storage, filtration, fuel transfer equipment, and operation.

FAME Design Considerations

FAME has distinct chemical properties compared to diesel, which should be considered when using it in engines. It offers better lubricity than diesel, leading to reduced wear on fuel pumps and injectors. However, due to its oxygen content, FAME has a lower energy density than diesel, which may necessitate larger fuel tank volumes for long-distance travel when used in significant quantities. In regions where travel distances are shorter and refueling is easily accessible, modifications to tank size may not be necessary.

- System corrosion of certain materials due to fuel acidity. (mostly for high concentration biofuels)
- The degradation of certain biofuels, caused by the presence of water in gasoil-grade biofuels that can lead to bacterial and fungal growth. This can be managed by removing water from tanks, regular testing, frequent draining, or using high-quality fuel filters. Additionally, fuel suppliers may add biocides or antimicrobial additives to prevent microbial build-up.
- Cold temperatures can lead to cloud or gel formation. Cold flow and anti-gel additives may improve the cold-flow operability. However, these additives are common for conventional petroleum fuels with the same problem.

Storage considerations

- Biofuel storage temperatures should be kept 10-15° C above the cloud point, and hot spots should be cooled.
- B100 has about an 11 percent lower energy content than diesel fuel but this may be compensated for by improved combustion performance. This can affect the frequency of bunkering, or the storage space needed on board. The vessel may require a larger tank space to accommodate a larger volume of oil.
- Biofuel quality standards state that vessel owners should analyze the materials of the fuel supply system, such as the ship's storage, handling, treatment, service and machinery systems and other machinery components (such as oily-water separator systems).

Biofuel storage requirements may vary by biofuel type; therefore, ship owners and operators should contact their fuel supplier, bunkering agency and engine manufacturer for specific fuel storage measures or other requirements.

Bunkering considerations

The characteristics of biofuels may require adjustments in the bunkering process compared to marine fossil fuels. Blending biofuels can occur at the refinery, by bunkering parties, on the bunker ship, or onboard the vessel. However, onboard blending introduces operational risks for shipowners, so industry recommendations favor blending by bunkering organizations. This allows for a single Bunker Delivery Note per fuel supply, ensuring the blend meets specified standards and protecting engines from off-specification fuels.

Due to issues like degradation, oxygen stability, and corrosion, evolving regulations and fuel testing standards are expected for biofuels. Regular tests should be conducted onboard to monitor fuel quality and detect any degradation or corrosion. During bunkering, safety protocols from the bunker provider, flag States, and other authorities should be followed.

Maintenance

Vessels using high biofuel blends may require additional maintenance for fuel supply systems, onboard fuel tanks, and filters. Periodic fuel testing can detect moisture content and microbial growth, which increase the risk of clogged filters and fuel deposits. Due to the detergent properties of biofuels, they can dislodge old deposits from petroleum fuels, potentially clogging the fuel system. After initial use in an existing system, more frequent fuel filter changes may be necessary. The fuel system should be flushed when not in use, and increased filter servicing may be required based on the blend percentage and feedstock.

9.3. Emissions

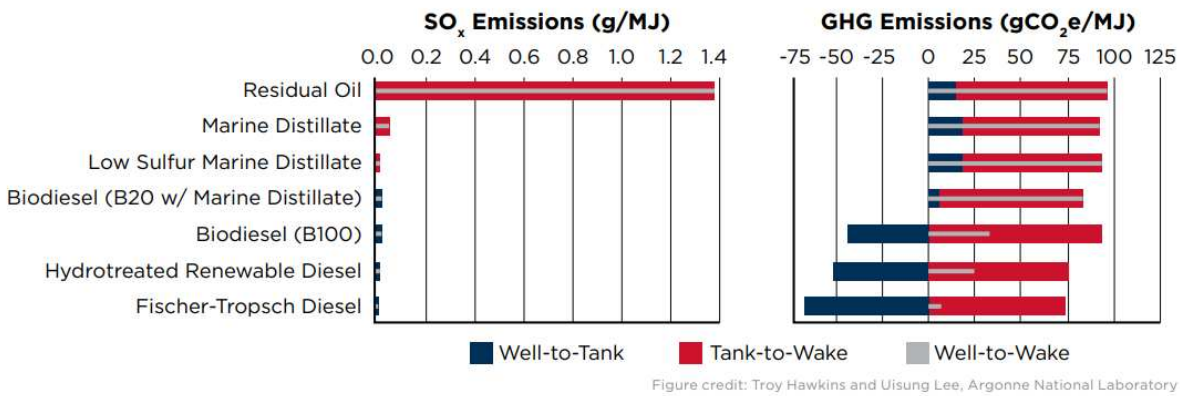


Figure 36: WTW life cycle SOx and GHG emissions per megajoule of fuel combusted for marine applications.

Figure above shows the approximate SO_x and GHG emissions of biofuels and typical marine petroleum fuels, showing potentially large SO_x reduction when using biofuels compared to residual oil and other reductions of carbon emissions based on carbon uptake during the well-to-tank (WTT) production. Note that in the figure, the feedstock for hydrotreated renewable diesel and biodiesel is soybean, and the feedstock for the FT diesel is forest residue. The negative well-to-tank values of biofuels indicate the carbon uptake during feedstock growth but can be offset by carbon emissions during production. When produced from renewable biomass such as plant fibers and other materials, biofuels have the potential to offset the carbon footprint of a vessel due to the CO_2 absorption of the plant feedstock, which can help counterbalance the combustion emissions.

Tank-to-wake

Regarding tank-to-wake emissions, they are very similar to those of diesel. According to DEFRA 2023[19], the scope 1 emissions for biofuels are as shown below:

Fuel	Unit	kg CO_2e
Biodiesel HVO	litres	0,03558
	GJ	1,03677
	kWh	0.00373
	kg	0,04562

Biodiesel ME	litres	0,16751
	GJ	5,05961
	kWh	0.01821
	kg	0,18822

Marine gas oil	tonnes	3245,30
	litres	2,77
	kWh (Net CV)	0,27
	kWh (Gross CV)	0,26

Compared to MGO HVO emits around **98.6%** less kg of CO_2 equivalent emissions.

Similarly, for biodiesel methyl ester, the value is **93.2%** less kg of CO_2 equivalents.

Well-to-tank

Biodiesel HVO	litres	0,27844
	kWh	0.0292
	GJ	8,11
	kg	0,35698

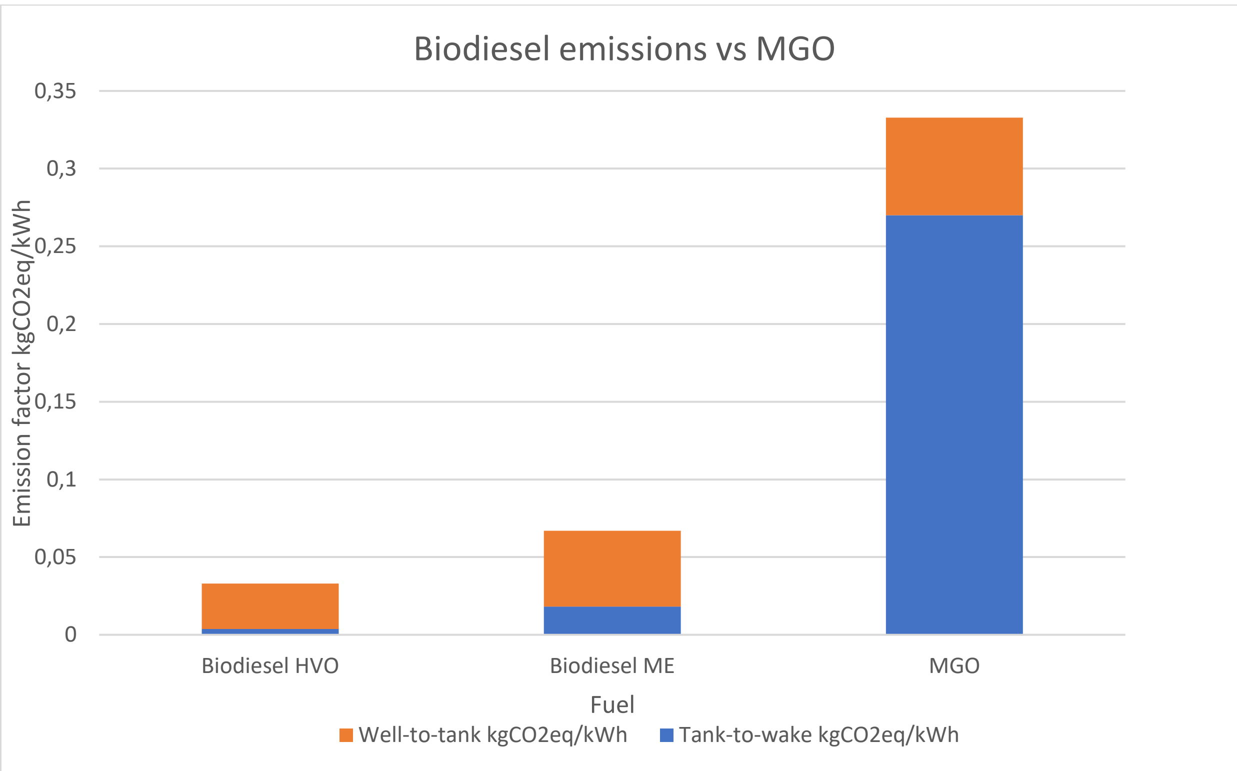
Biodiesel ME	litres	0,44759
	kWh	0.0487
	GJ	13,52
	kg	0,50291

Marine gas oil	tonnes	743,83524
	litres	0,62665
	kWh (Net CV)	0,06291
	kWh (Gross CV)	0,05913

For WTT emissions when compared to MGO, HVO emits about **53.6%** less kg CO_2eq and biodiesel methyl ester about **22.6%** less.

Summary of emissions

Fuel	Tank-to-wake $kgCO_2eq/kWh$	Well-to-tank $kgCO_2eq/kWh$	Total $kgCO_2eq/kWh$	Reduction %
Biodiesel HVO	0.00373	0.0292	0.03293	90
Biodiesel ME	0.01821	0.0487	0.06691	80
MGO	0.27	0.06291	0.33291	-



In summary, total emissions for HVO and Biodiesel ME are reduced by 80-90% compared to HVO. The most significant reduction is made in TTW emissions, because the carbon footprint is offset by the carbon dioxide absorption of the plant feedstock, which can help counterbalance the combustion emissions. However, WTT emission still remain relatively high considering the sourcing of feedstock, production pathways and transportation.

9.4.Availability and cost

The global biofuel market is largely shaped by agricultural policies aimed at supporting farmers, lowering GHG emissions, and reducing energy dependence. In the U.S., biofuels are widely available for the automotive sector, and existing infrastructure and production methods could facilitate an easier transition into the marine industry. HVO production can potentially occur at oil refineries equipped with hydrotreating facilities, though modifications may be necessary to scale up for dedicated HVO production. However, the production process for HVO is more costly compared to FAME biodiesel.

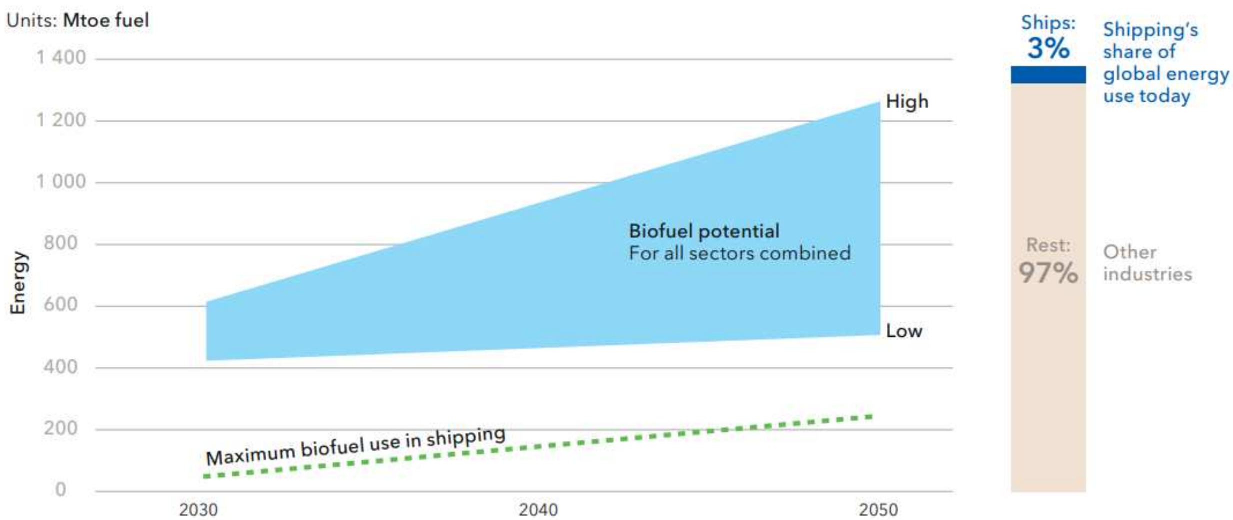


Figure 37: Potential of global supply for sustainable biofuel compared to maximum simulated demand from shipping (DNV)

The DNV estimates that the global sustainable and economical biofuel potential lies between 400 – 600 Mtoe per year in 2030, after converting biomass to biofuel assuming a 50% conversion efficiency. This could grow to 500 –1 300 Mtoe per year in 2050[1].

Biofuels are projected at low costs today, but their availability and competition from other sectors for them are uncertain and biofuel prices could increase from our reference projections. The DNV presents a set of exploratory scenarios

The exploratory scenarios are as follows:

Bio and fossil with CCS

There is a high availability of sustainable biomass as feedstock for making bio-MGO, bio-LNG, and bio-methanol for shipping, though with a moderate increase in price over time. At the same time, the CCS industry and infrastructure develops onshore, making onboard carbon capture available for ships from 2030. We assume that nuclear propulsion is available from 2040 onwards. While the production of biofuels (bio-MGO, bio-LNG, bio-methanol) and electrofuels is increasing, and while carbon capture projects come online allowing for both increased production of blue fuels and the use of onboard carbon capture at scale, shipping should mitigate the potential shortfall by improving the energy efficiency of ships as far as possible.

As of 2024, according to the figure above, the only biofuel part of the mix is bio-MGO but only approximately 1.8%. However, we see that the percentage will increase massively up to 2050 reaching 37.6% and overall almost **65%** of the fuel mix will consist of biofuels.

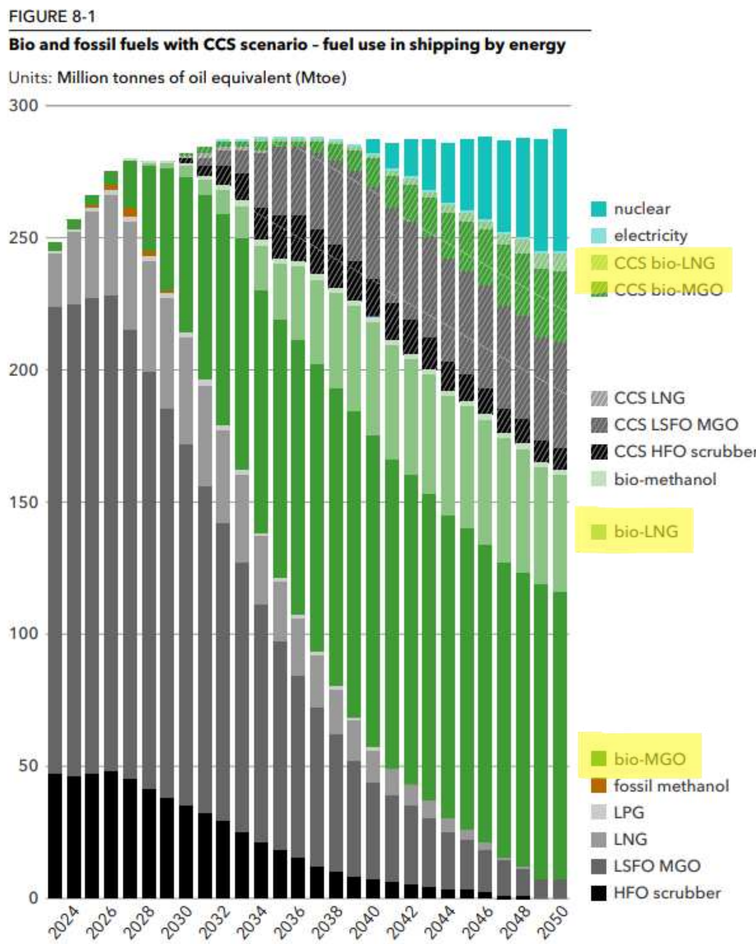


Table 9: Bio and fossil fuels with CCS scenario – fuel use in shipping by energy

The future of biofuel prices is largely impacted by the market and considerations of supply and demand. As estimated by the International Renewable Energy Agency (IRENA), by about 2040, the price of biofuels is expected to become competitive. Another aspect of the cost of biofuels is the conversion (if necessary) of vessels to suit biofuel storage, transfer and use. The cost of conversion may be lower for biofuels compared to other alternative fuels due to the nature of drop-in biofuels. Relatively minimal investments to modify the hoses (or pipes), filters, seals and other synthetic material components may be all the changes necessary.

The DNV also claims that biofuels are projected at low costs today, but their availability and competition from other sectors for them are uncertain and biofuel prices could increase from their reference projections so far.

The Ship and Bunker website produced a study in 2022 comparing FAME and HVO bunker prices to other conventional fuels like MGO or VLSFO[44]. They emphasize that a good alternative would be HVO blended with VLSFO. However, in figure 38 it is seen that high amounts of HVO increase the final blend price when compared to pure VLSFO. Using 100% HVO spikes the price to 2000$/ton, a price that is more than **double** the price of pure VLSFO. The goal is to achieve a blend that fulfills price and quality requirements.

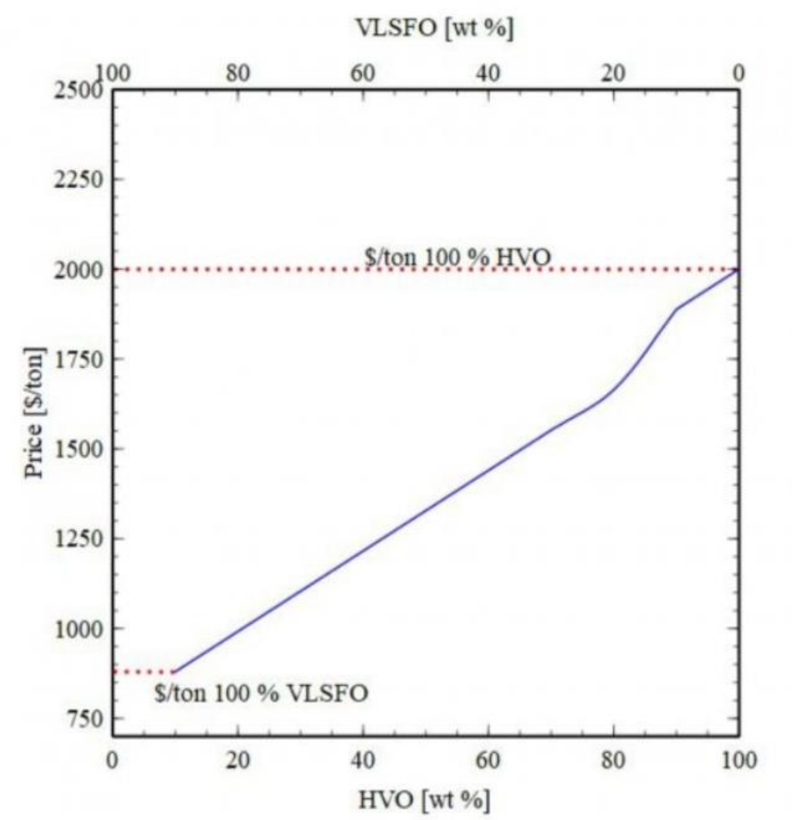


Figure 38: Price of final blend HVO+VLSFO for a different mass percentage of HVO[44]

9.5. Technical aspects

Several technical aspects are given in the chapter about the ABS Notation.

Chemical properties of FAME, HVO and Diesel are presented in figure 39 for the purpose of analyzing the technical problems that can arise from the differences in these properties. When combusted, biofuels may affect engine performance due to the differences in characteristics between biofuel and fossil fuels. For example, biodiesel is typically more viscous than petroleum diesel, but drop-in biofuels for HFO are less viscous, which can result in less heating required and improved fuel lubricity.

Generator usage is fairly similar both FAME, HVO and diesel. This is one of the main advantages of biodiesels, the compatibility with all diesel engines.

HVO has a high cetane number, which makes it a cleaner fuel when used on its own while also allowing it to blend with conventional fossil diesel.

The main challenges that HVO presents are filter plugging and cold weather performance. However, fuel blending using a 20% HVO and 80% diesel blend in colder months has improved the fuel's cold weather performance and reduced filter plugging issues.

CHEMICAL COMPOSITION	FAME	HVO	DIESEL
Density at 20° C (kg/m³)	885	780	825
Lower Heating Value (LHV) (MJ/kg)	37.1	44.1	43.1
Viscosity at 20° C (mm²/s)	7.5	3.0 (at 40° C)	5.0
Surface Tension (N/m)	0.026	-	0.028
Cetane Number (CN)	56	80-99	40-50
Stoichiometric Air/Fuel Ratio	12.5	-	15
Oxygen Content (% vol.)	-11	0	0
Aromatics Content (% vol.)	-	0	-30
Sulfur Content (ppm)	-	0	< 3.5

Figure 39: Properties of FAME and HVO. Source: ABS [43]

The DNV suggests following the steps shown in the figure below to reduce the risk of damage to equipment onboard the vessel, before a transition to biofuels.

Figure 40: Technical aspects of a biofuel transition process and relevant items recommended to consider for a ship owner.

9.6. Advantages and challenges

Advantages

- Greenhouse gas emissions for biofuels are reduced by 80-90%.
- The drop-in characteristic of biofuels allows them to take advantage of existing fuel transport and bunkering infrastructure.
- Biofuels are biodegradable in nature, which means that in case of spills, the environment effect may not be as impactful as that of conventional marine fuels.

Challenges

- Due to the supply of feedstock, the cost for biofuels may be unstable. The bunker price of 100% HVO is double the price of VLSFO.
- High vulnerability to bacterial contamination

10. Conclusions and remarks

To conclude my findings, the results are summarized in the table below.

Fuel	**Emission reduction % (WTW. No fugitive)**	**Tank volume needed**	**Integration with MGO**	**Technology maturity**	**Cost reduction**	**Availability 2030 (% of fuel mix)**	**Availability 2035 (% of fuel mix)**	**Availability 2050 (% of fuel mix)**
LNG	-18.5%	+29%	Excellent	Very good	-2%	15.6%	16.5%	17.6
Methanol	-59%	-8.5%	Good	Good	+35%	1.93%	5.04%	33.33%
Ammonia	-77%	+11%	Good	Poor	+58%[a]	0.81%	3.33%	26.49%
Biofuels	-85%	-	Excellent	Excellent	+56%[c]	20.90%[b]	34.87%[b]	65%[b]

[a] taken as an average for carbon-neutral ammonia

[b] including biofuels integrated with CCS

[c] For 100% biofuel (B100)

The alternative marine fuels are compared to MGO based on a series of criteria ranging from WTW emissions, tank volume, technology maturity, cost, and availability up to 2050. It is important to highlight that for these results, fugitive emissions were not considered. Furthermore, the availability section includes additional alternatives, for example, LNG availability will include carbon-neutral LNG and the same is applicable to methanol and ammonia. Regarding biofuels, CCS integration is included in the availability. The integration with MGO is evaluated from Good to Excellent, considering that all these fuels are well integrated when it comes to bunkering facilities, storage, and capacity. LNG and biofuels are the alternatives best integrated with MGO, as they share similar physical-chemical properties, high energy content, as well as biofuels' drop-in characteristic makes them perfectly suitable for dual-fuel vessels. Methanol and ammonia are evaluated "Good" since technological maturity for them is still under development which may pose risks.

Based on the results, biofuels seem like the perfect alternative having the highest emission reduction in comparison to MGO as well as being the fuel best integrated with MGO and with the most mature technology. Availability by 2050 is estimated to be up to 65%. This makes biofuels the safest alternative, although attention must be paid to the availability of feedstock and its relation to land and water use as well as competition with other chains. Moreover, it has the highest cost reduction but only because it is considered to be used as pure (B100).

When it comes to the marine sector it is important to mention that a vessel purchased now will still be sailing in 2050, therefore, it needs to have the possibility to run with fuels consistent with 2050 ambitions of Net Zero as well as consistent with the availability during that time. There is uncertainty on the availability of alternative fuels, therefore a decision on the fuel to be used in the future, taken in 2024, poses several risks.

One option worth considering is a dual-fuel vessel, capable of operating on the fuels available in 2024 initially, and transitioning to alternative fuels as their availability and technological readiness improve in the future. Another approach would be to design the vessel with future retrofitting in mind, allowing for modifications when clearer information about future fuel options becomes available.

I propose several alternative solutions.

1. LNG as an alternative fuel for offshore vessels is a good option only for short-term, unless it is completely replaced with bio-LNG or LNG integrated with CCS.
2. Biofuels blended with MGO allow for existing infrastructure to be utilized to the maximum extent possible while still reducing emissions and keeping a leveled cost margin.
3. Dual-fuel MGO and Ammonia. The vessel can run on MGO in the short term and easily switch to biofuel when needed. Ammonia implementation then poses some risks, since the technological maturity is low and for some scenarios the availability is equal to 0. However, the dual fuel system reduces this risk because in the scenario with low ammonia the biodiesel share is the highest.
4. Dual-fuel MGO with methanol is another option similar to that of dual-fuel MGO and ammonia.

In conclusion, if Saipem would consider exploring alternative fuels such as LNG, methanol, ammonia and biofuels, it is suggested to do so using dual-fuel systems with MGO. Using MGO short-term, ensures its resources, existing infrastructure and technology are being utilized at the fullest while keeping a cost that is consistent with today's global scene. As the years progress and the availability of fossil fuels declines, the technology for methanol and ammonia will have matured meaning they can slowly start to be integrated into the mix. Finally, by 2050, the way would be paved for the full transition to take place.

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