Updated Technology Assessment for Ocean Going Vessels

April 30, 2026

Prepared for: California Air Resources Board

Agreement No: 23TTD023

Agreement Title: Updated Technology Assessment for Ocean Going Vessels

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Disclaimer

Acknowledgements

This Report was submitted in fulfillment of ARB Agreement 23TTD023 and Updated Technology Assessment for Ocean Going Vessels by the Regents of the University of California, Irvine under the sponsorship of the California Air Resources Board. Work was completed as of April 30, 2026.

Glossary

Nomenclature of Terms, Abbreviations, and Symbols

Acronym	Definition
AEC	Alternative Energy Carriers
AFT	Adiabatic Flame Temperature
AOC	Ammonia Oxidation Catalyst
ATB	Articulated Tug Barge
B20	20% Biodiesel Blend
CA	California
CAPEX	Capital Expenditure
CARB	California Air Resources Board
CCUS	Carbon Capture, Utilization, and Storage
CHC	Commercial Harbor Craft
CMA	California Maritime Academy

CO	Carbon Monoxide
CO_2	Carbon Dioxide
DEF	Diesel Exhaust Fluid
DME	Dimethyl Ether
DMFC	Direct Methanol Fuel Cell
DNV	Det Norske Veritas
DNV AFI	Det Norske Veritas Alternative Fuels Insight
DOC	Diesel Oxidation Catalyst
DOE	U.S. Department of Energy
DPF	Diesel Particulate Filter
DWT	Deadweight Tonnage
ECA	Emission Control Area
ECU	Engine Control Unit
EGR	Exhaust Gas Recirculation
EHS	Environmental, Health, and Safety
EPA	Environmental Protection Agency (U.S.)
ESP	Electrostatic Precipitator
EU	European Union

FAME	Fatty Acid Methyl Ester
FNPP	Floating Nuclear Power Plant
g	gram
gCO_2eq	grams Carbon Dioxide Equivalent
GHG	Greenhouse Gas
H_2	Hydrogen
HC	Hydrocarbon
HFO	Heavy Fuel Oil
HVSC	High Voltage Shore Connection
HVO	Hydrotreated Vegetable Oil
ICE	Internal Combustion Engine
IGF Code	International Code of Safety for Ships using Gases or other Low-flashpoint Fuels
IMO	International Maritime Organization
ISOR	Initial Statement of Reasons
kW	kilowatt
L	Liter
LCMF	Low-Carbon Maritime Fuel

LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
MARPOL	Marine Pollution Convention
MDO	Marine Diesel Oil
MEPC	Marine Environment Protection Committee
MGO	Marine Gas Oil
MJ	Megajoule
MW	Megawatt
NMC	Nickel Manganese Cobalt
NO_x	Oxides of Nitrogen (Nitric Oxide and Nitrogen Dioxide)
OBD	On-board Diagnostics
OEM	Original Equipment Manufacturer
OGV	Ocean-Going Vessel
OPEX	Operating Expenditure
OSHA	Occupational Safety and Health Administration

PAH	Polycyclic Aromatic Hydrocarbons
PEMFC	Proton Exchange Membrane Fuel Cell
PM	Particulate Matter
R&D	Research and Development
RCW	Regulated California Waters
RPM	Revolutions per minute
SCR	Selective Catalytic Reduction
SOFC	Solid Oxide Fuel Cell
SO_x	Oxides of Sulfur
TCO	Total Cost of Ownership
TEU	Twenty-foot Equivalent Unit
TRL	Technology Readiness Level
UCI	University of California, Irvine
U.S.	United States
VLSFO	Very Low Sulfur Fuel Oil
WESP	Wet Electrostatic Precipitator

WETA	Water Emergency Transportation Authority
ZEAT	Zero Emissions and Advanced Technology

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Abstract

This report provides a comprehensive and updated assessment of technologies and strategies that can reduce emissions from ocean-going vessels (OGVs) serving California. It evaluates a broad portfolio of propulsion and fuel options alongside efficiency measures and exhaust aftertreatment technologies. A consistent evaluation framework is applied to each technology, assessing emissions (GHG and pollutant) performance, technology readiness, retrofit versus newbuild feasibility, infrastructure requirements, and economics. In addition, international regulations, and voluntary efforts to reduce OGV emissions are profiled and potential synergies identified. The study further examines projected maritime fuel demand, fuel production capacity, shipbuilding capability, and supply-chain readiness to support scalable deployment of low-carbon maritime fuels.

The maritime sector is actively transitioning toward cleaner fuels, with several alternative fuel technologies already demonstrated, commercially deployed, or nearing full market readiness. Associated propulsion, after-treatment, and companion efficiency measures are also under active development. Overall, there is no single “silver bullet” solution; multiple fuels and technologies will likely play complementary roles depending on vessel type, route, and operational profile. The driving force behind international action to increase the use of alternative fuels is GHG reduction rather than criteria pollutant reduction and the ultimate “winning” fuels will not be known for at least a decade. Development of California regulations will need to take into account the uncertainty in the future fuel mix.

Executive Summary

Background

Over the past several decades, coordinated local, state, and federal air-quality programs have driven substantial reductions in criteria pollutants—fine particulate matter ($PM_{2.5}$), diesel particulate matter (PM), oxides of sulfur (SO_x), and oxides of nitrogen (NO_x)—as well as greenhouse gases (GHG). Yet ocean-going vessels (OGVs) remain a significant source of emissions near ports and along coastal corridors. Continued progress will require both full implementation of existing rules and the development of additional control measures, informed by rigorous analysis of technologies and fuels capable of achieving lower emissions across diverse vessel types and operating profiles. This work is intended to support future rulemaking at the state, federal, and potentially international (IMO) levels.

The California Air Resources Board (CARB) has adopted, and continues to advance, measures targeting the marine and freight sectors. The 2020 Ocean-Going Vessel At Berth Regulation requires reductions in NOx, PM, and reactive organic gases (ROG) from OGV auxiliary engines—and from tanker boilers serving steam-driven pumps—while vessels are docked at California ports. The At Berth Regulation also seeks to reduce greenhouse gas (GHG) emissions through the use of shore power and other grid-neutral CARB approved emissions control strategies (CAECS). Since 2008, the OGV Clean Fuel Regulation has also mandated the use of cleaner low sulfur marine distillate fuels within 24 nautical miles of the California baseline. The OGV Clean Fuel Regulation was implemented between 2009 to 2014, with the allowable maximum fuel sulfur content decreasing to 0.1 percent by full implementation. Given the remaining need for emission reductions from this sector, future measures may need to broaden controls to vessel operations anywhere within Regulated California Waters (RCW). This report provides the analytical foundation to evaluate such pathways and guide effective, equitable implementation.

There is significant and accelerating international activity focused on reducing emissions from maritime operations, including from OGVs in transit. The focus of most international efforts is on GHG emissions. However, most alternative fuels offer co-benefits through reduction of non-GHG pollutants. In addition, the International Marime Organization (IMO) Emission Control Areas (ECAs) address SO_x and NO_x. California will need to act in concert with and seek synergies with these international efforts.

Fuel and propulsion transitions will be central to achieving emission reductions. The alternative fuels being most actively adopted or piloted are liquified natural gas (LNG), methanol, ammonia, hydrogen, biofuels (FAME and HVO), battery-electric systems, and nuclear power, alongside engine platforms including dual-/multi-fuel ICE, fuel cells, and electric propulsion. LNG is the most widely adopted alternative today, with hundreds of vessels in service; methanol, ammonia, and liquid biofuels are in the early adoption phase with activity on fuel production, engine deployment, and bunkering accelerating. Hydrogen is also a contender but is at a lower level of technical maturity. Other potential maritime fuels such as ethanol and DME are under development but are currently projected to capture a significant share of OGV fuel demand. Given the long operating life of vessels, retrofit solutions will be critical to meeting emissions reduction goals.

Methods

The present analysis is based on extensive review of published material from academic, governmental, and industry sources. The technology evaluation applies a consistent structure to each emission technology reduction option including a technology description; system/network suitability and infrastructure needs; newbuild vs. retrofit feasibility; potential emissions reductions; technology readiness; economics; and near-term next steps. The results are then used to compare and contrast engines, aftertreatment, efficiency measures, shore power, CCUS, batteries, and nuclear.

Next, an assessment of OGV program synergy is used to map technologies to current and emerging policies and initiatives at international, national, state, port/corridor, and industry levels (e.g., IMO/MARPOL, ECAs, EU/US actions, green shipping corridors), identifying leverage points and alignment gaps that influence feasibility and timing.

Additionally, maritime fuels & availability are assessed by compiling fuel properties, emissions factors, and EHS characteristics; projects demand and future fuel mixes; and quantifies total cost of ownership and carbon-abatement costs, then checks supply-chain readiness (fuel production, bunkering, and shipbuilding capacity) for scalable deployment. Across tasks, evidence is synthesized from industry data and peer-reviewed studies (as indicated by table attributions and figure sources), ensuring that technological status, costs, and performance are evaluated against current market and regulatory conditions.

Results

Alternative Technologies and Fuels

LNG and bio-based diesel substitutes are the most mature among alternative marine fuels. Among the less mature fuels, methanol, and ammonia are identified as near-term candidates for broad adoption, with full commercial readiness expected around 2030. Both fuels offer major potential for reducing SO_x, PM, and CO_2 emissions, especially when sourced from renewable feedstocks, though they still require careful management of NO_x and, in the case of ammonia, potential fuel slip. Hydrogen is considered a highly promising zero-carbon fuel, but both internal combustion and fuel cell pathways face significant challenges with energy density, cost, and the need for global infrastructure build-out. Fuel cells are closer to maturity for auxiliary shipboard power than for main propulsion systems. LNG remains the most widely adopted alternative fuel at present and offers meaningful reductions in SO_x and PM, though methane slip remains a challenge. Liquid biofuels are already available as drop-in solutions that can provide incremental reductions depending on feedstock sustainability. Batteries are identified as effective for short-sea shipping and auxiliary power applications but are limited by energy density for deep-sea use. Nuclear propulsion offers unparalleled energy density and zero pollutant and GHG emissions at the point of use, though it continues to face significant barriers in terms of economics, regulation, and public acceptance.

Emissions and Air Quality

The results indicate that conventional marine fuels, such as heavy fuel oil and marine diesel oil, produce high levels of NOx, PM, and SOx, and therefore require aftertreatment technologies such as selective catalytic reduction (SCR) to meet emissions standards. In contrast, alternative fuels like LNG, methanol, ammonia, and hydrogen substantially reduce or eliminate sulfur and particulate matter emissions and can significantly cut CO_2 when produced renewably. However, NOx emissions remain a challenge across most of these fuels, necessitating the use of SCR, EGR, or other strategies. Fuel cells, whether hydrogen-based or ammonia-based, are highlighted as offering near-zero emissions and substantial air quality benefits, with water vapor as the primary output. Finally, energy efficiency measures and operational improvements are shown to indirectly reduce greenhouse gases and pollutants by lowering total fuel use, with reductions estimated in the range of 10 to 30 percent.

Economics and Deployment

Estimates of the total cost of ownership for the various low-emission fuel, propulsion-system, and aftertreatment combinations vary and there is no consensus on the future least-cost option. Most studies project bio-derived diesel, methanol, and ammonia, with expected shares varying across studies, to be the dominant fuels for OGVs by 2050. Other fuels will be adopted in smaller shares in specific sectors. Biomass-derived fuels are projected to be lower cost than electrolytic fuels in the near term, though their long-term role may be limited by feedstock availability. Fuel cells, while offering deep emissions reductions, currently face high costs and remain at lower technological readiness levels for large marine propulsion. The report emphasizes that the shipping industry has substantial capacity to rapidly scale the production and installation of alternative fuel engines, aftertreatment technologies, energy efficiency measures, and on-board carbon capture systems once clear demand signals and supportive regulatory frameworks are in place

Conclusions

The transition toward lower-emission maritime transport is underway but uneven across fuels, vessel types, and regions. Mature solutions such as efficiency measures, LNG, biofuels, shore power, and aftertreatment systems can deliver immediate emissions reductions, while bio-based diesel, methanol, and ammonia are emerging as primary long-term decarbonization fuels. Hydrogen, battery-electric propulsion, nuclear systems, and onboard carbon capture represent longer-term or niche pathways requiring continued research, demonstration, and infrastructure development.

No single technology will achieve deep emission reductions alone. A portfolio approach is required that:

- Prioritizes air-quality improvements near ports and coastal communities
- Expands deployment of shore power, efficiency measures, and aftertreatment
- Accelerates demonstrations of low-carbon fuels along green shipping corridors
- Aligns safety, fuel certification, and bunkering standards internationally
- Coordinates port and fuel-supply infrastructure with long-term fuel demand
- Supports retrofit pathways for younger vessels while enabling zero-emission newbuilds

Together, these strategies can enable meaningful reductions in both criteria pollutants and GHG emissions from the ocean-going vessel sector while supporting practical, scalable, and economically viable maritime decarbonization.

Introduction

Marine vessels that are used to transport freight, including ocean-going vessels (OGV), are major sources of both criteria and toxic air pollutants and greenhouse gas (GHG) emissions. While significant efforts have been made in California and other locations around the world to reduce emissions from OGVs and other sources in recent decades, OGVs continue to contribute to degraded air quality, most notably in communities adjacent to or downwind of ports.

For this assessment, OGVs are defined as large vessels used for deep water navigation including those used to transport cargo such as container ships, tankers, cruise ships, bulk carriers, and car carriers. OGVs are used to transport various loads including containerized cargo, vehicles, and bulk items such as cement, petroleum coke, oil, and other petrochemicals. OGVs operate internationally and include United States (U.S.)-flagged vessels registered by the United States Coast Guard (USCG) and foreign-flagged vessels. Most OGVs that operate in California ports are foreign-flagged.

A wide-range of alternative fuels is being explored and increasingly adopted in the marine sector to mitigate the environmental impacts of OGVs including liquefied natural gas (LNG), methanol, ammonia, hydrogen, various forms of biofuels including Fatty Acid Methyl Ester (FAME) and Hydrotreated Vegetable Oil (HVO)-based fuels, nuclear power, and battery electrification. Among these, LNG has emerged as the most widely adopted alternative fuel to date. As of mid-2024, there were 535 LNG-powered ships in operation and 509 vessels on order. LNG-fueled ships currently in operation include 137 oil and chemical tankers, 93 container ships, and 53 bulk carriers [1]. Methanol-powered ships are already in service, and ammonia-powered ships are nearing operation. Hydrogen-powered fuel cell vessels are also nearing deployment, with the first passenger ferries demonstrated in the San Francisco Bay and operating in Norway (although ferries are considered commercial harbor craft (CHC), not OGVs, and thus are not covered in this report).

In many cases the use of alternative fuels requires alternative propulsion systems (with the exception of some biofuels) including pure gas, dual- and multi-fuel engines, marine fuel cells, and battery-electric propulsion systems. Dual-fuel engines are already commercially available or currently in development, including those operating on LNG, methanol, and ammonia, which has significantly increased the potential fuel flexibility of vessels. The use of a retrofit strategy to deploy such systems on existing vessels (as opposed to a new build) also increases the potential for accelerating deployment. However, the suitability and cost-effectiveness of retrofits must be carefully justified.

A myriad of advanced combustion strategies to reduce pollutant emissions have been developed such as lean burn engines, exhaust gas recirculation (EGR), improved fuel placement, split fuel injection timing, etc. In addition, aftertreatment systems can be installed on vessel engines to reduce pollutant emissions, such as oxides of nitrogen (NO_x), oxides of sulfur (SO_x), and particulate matter (PM), after combustion before they are released into the atmosphere. Common aftertreatment technologies include diesel oxidation catalysts, selective catalytic reduction (SCR) modules, diesel particulate filters (DPF), and exhaust gas cleaning systems (commonly referred to as scrubbers). These technologies are becoming essential for vessels using conventional fuels to meet increasingly stringent emission regulations, such as those imposed by the International Maritime Organization (IMO), (e.g., IMO Tier III NO_x standards) and MARPOL Annex VI requirements for SO_x, and NO_x.

It is important to note that reducing emissions from OGVs (both GHG and criteria pollutants) will require a multi-pronged approach that combines technological, operational, and fuel-based measures (i.e., no silver bullets). For example, the use of alternative fuels can be combined with efficiency improvements in hull design and operational changes. The alternative fuels described here can all reduce pollutant emissions to a varying extent, and most of them contribute to reduced GHG emissions depending on life cycle production pathways. However, few can reach the targets established by the IMO in emission intensity on a well-to-wake basis by themselves.

The marine shipping sector is incredibly diverse, encompassing a wide range of vessel types, sizes, and operational profiles, which significantly influences the selection of fuels and propulsion technologies. Factors such as voyage length, port visit frequency, infrastructure requirements and availability, power demand, and geographic routes affect the feasibility of adopting alternative fuels like LNG, methanol, ammonia, batteries, or hydrogen. OGVs may prioritize energy-dense, globally available fuels such as biodiesel, ammonia, and methanol, while short-sea and inland vessels may be better suited for lower-emission options like electric or hydrogen fuel cell propulsion. Even ships operating on similar trade routes can have significant differences in their operational profile. This diversity means that the selection of which low- or zero-emission fuels and technologies are most suitable for different segments of the fleet will also vary widely. Unlike the fairly standardized aviation or long-haul trucking sectors, maritime operations are highly variable, which means optimal fuel choices must be considered on a vessel-by-vessel basis. Regulatory environments, fuel infrastructure, retrofit potential, and economic constraints further shape decisions across different fleet segments.

As a result, fuel and technology adoption will be phased and segmented rather than uniform, with each vessel type transitioning to the most suitable option based on its specific operational and economic context. Therefore, reducing emissions from OGVs (both GHG and criteria pollutants) requires a multi-pronged, vessel-by-vessel approach that combines technological, operational, and fuel-based considerations.

OGV Engines

OGVs are typically powered by multiple engines and boilers, including large main engines used for propulsion and multiple smaller engines used in auxiliary applications such as generating electricity. Marine transportation primarily relies on compression ignition marine diesel engines due to their efficiency. These include both four-stroke and two-stroke diesel engines. Auxiliary boilers are combustion equipment designed to produce steam for non-propulsion purposes including fuel heating, water heating, powering steam turbine discharge pumps, and space heating.

Compression ignition internal combustion engines (ICE) are a proven technology with widespread use for many decades. Current ICE marine engines can generally be classified in the following configurations:

- **<u>Slow speed 2-stroke engines</u>** operating at 80-140 revolutions per minute (RPM) with a maximum of 300 RPM and are most often used for propulsion in large vessels including ships over ~100,000 dead weight tonnage (DWT) or container vessels ranging from several thousand to over 20,000 twenty-foot equivalent units (TEU).
- **<u>Medium speed 4-stroke engines</u>** operating in the range of 300-900 RPM and can be used for both propulsion and auxiliary power generation on-board a variety of ship types
- **<u>High speed 4-stroke engines</u>** operating at rates higher than 900 RPM used for propulsion in smaller vessels (including high speed vessels) and for auxiliary purposes

Except for cruise ships, most OGVs utilize very large two-stroke marine diesel engines for propulsion due to their efficiency and reliability. These engines can provide the massive power requirements of OGVs ranging from 20 to 100 megawatts (MW). For example, a nine-cylinder K98MC-C Everllence 40 MW engine measures 65’ x 60’, weighs approximately 1,500 tons, and costs approximately $15 million. The market of large two-stroke marine engines is largely dominated by Wartsila, Everllence (formerly MAN Energy Solutions), WinGD, and Mitsubishi. Diesel cycle engines are associated with high efficiency for a given maximum temperature limit since they take advantage of higher compression ratios compared to the spark ignited Otto cycle counterparts. Further, the lack of spark plugs means less operation & maintenance (O&M) costs.

To facilitate compression ignition, the fuel used must be reactive enough to self-ignite under the high temperature and pressure within the engine cylinder. Diesel fuel has been refined to facilitate self-ignition at the desired temperature and pressures used in commercial engines. This self-ignition characteristic is measured by the cetane number, which is a measure of the ignition quality of diesel fuel. The higher the cetane number, the easier the fuel is to self-ignite in the heated high-pressure air within the cylinder. Alternative fuels may or may not facilitate compression ignition when used in a pure form. Some alternative fuels may require spark ignition and/or use of small quantities of a reactive fuel (e.g., diesel) to achieve compression ignition, also called a pilot fuel.

Four-stroke diesel engines often have lower output power and are used by OGVs in auxiliary applications, including being coupled to a generator to produce electricity needed for lighting, navigation equipment, cargo refrigeration, and other equipment. Four-stroke engines can run on different fuels, offering the benefit of fuel flexibility which can allow ships to switch based on availability, cost, or environmental regulations. Common manufacturers include Everllence, Wärtsilä, Caterpillar & HiMSEN. These engines are similar to those used in on-road heavy duty trucks providing operational knowledge and performance data to apply to marine applications.

Passenger cruise ships are unique in using diesel-electric propulsion systems, where large four-stroke diesel generators provide electrical power for both propulsion and on-board electricity. The use of diesel-electric propulsion systems enables cruise ships to run the vessel at slower speeds through the use of fewer engines rather than operating one large single engine at a lower and more inefficient load.

It should be noted that Technology Readiness Levels (TRL) is often used to provide insight into the current readiness of alternative fuel engines and other emission reduction strategies. TRLs are a systematic metric used to evaluate the maturity of a technology throughout its development lifecycle. The TRL scale ranges from TRL 1 (basic scientific research) to TRL 9 (fully proven commercial system). Below is a description of the TRL that is used in this report.

Early Stage (TRL 1–3)

- Fundamental research and concept exploration
- High technical uncertainty and risk
- Typically, academic, or laboratory-driven

Mid Stage (TRL 4–6)

- Prototype development and validation
- Engineering and scaling challenges addressed
- Often supported by pilot or demonstration funding

Late Stage (TRL 7–9)

- Real-world demonstration and commercialization
- Regulatory approval and deployment
- Focus shifts to cost, reliability, and scalability

Conventional OGV Fuels

Modern day OGVs usually have multiple fuel types on-board, along with separate storage tanks, although the majority use heavy fuel oil (HFO) or very low sulfur fuel oil (VLSFO) in their main engines, auxiliary diesel engines, and auxiliary boilers due to high availability and low cost. Due to the high viscosity, HFO must be heated before it can be used in engines or boilers. Vessels can also utilize marine distillate fuel oils (i.e., marine gas oil (MGO) or marine diesel oil (MDO)) and will often have distillate fuels on-board to power emergency generators. Additionally, in order to comply with California requirements, vessels must keep MGO or MDO with a sulfur content of 0.1 percent or less for main engines, auxiliary engines and boilers when operating inside regulated California waters (RCW).

The bulk of the fuel carried on-board vessels is used for propulsion. The fuel consumption of the main engine is primarily influenced by the vessel's speed and draft profile, with power demand varying across different speed/draft combinations. Additionally, auxiliary fuel consumption occurs for hotel load, propulsion, and cargo operations, which differ considerably depending on the vessel type and operation.

The bunkering strategy will also influence the choice of engine technology and fuels, as factors like energy densities, required fuel systems (including the need for specialized tanks), and fuel availability will impact the suitability and economics of alternative fuels in replacing conventional fuels. Two common bunkering strategies for vessels that routinely call the same ports (also called a liner vessel) include refueling once per round trip or making two stops.

Most large OGV currently use a single-stop approach as it offers advantages in fuel cost control, logistics efficiency, and fuel quality assurance by consolidating supply and leveraging regional price differences. However, given the lower energy density of alternative fuels relative to conventional fuels, larger fuel tanks may be required for alternative fuels, which can reduce cargo capacity and increase capital costs. In contrast, a two-stop strategy allows for smaller tank volumes, preserving cargo space, lowering Capital Expenditures (CAPEX), shortening bunkering times, and providing greater flexibility in port selection, especially important for ultra-large container vessels. Ship operators will use these types of detailed cost-benefit analyses for key decision-making purposes such as determining which types of fuel tanks to install on a newbuild vessel. Bunkering strategies may differ for vessels not on routine port rotations (called tramper vessels) and these vessels would need to develop their own approaches to bunkering considering the unique needs of their operations. This may also require the significant buildout of alternative fuel infrastructure in California as the adoption of alternative fuels may be slowed if adequate bunkering infrastructure is not developed, since ships on Asia–California routes could opt for a two-stop fueling strategy.

Task 1: Technology Evaluation

Introduction

The following section provides an assessment of OGV emission reduction technologies including alternative propulsion systems, efficiency measures, carbon capture systems (CCUS), and exhaust aftertreatment systems. It should be noted that the assessment of the alternative fuels themselves can be found in Task 3.

Propulsion Engines

Methanol Engines

Technology Description

There are several different types of engines being considered for use with methanol in ships including both dual-fuel and single-fuel methanol engines. The two main approaches to using methanol as fuel in conventional ICE ship engines are a two-stroke diesel cycle engine or a four-stroke, lean-burn Otto cycle engine. Methanol has a low cetane number and therefore requires pilot fuel injection (generally less than 5 percent of the total energy consumed) to ignite the methanol–air mixture. Methanol injection is accomplished at pressures up to 550 bar. For current 2-stroke engines, the engine design is not significantly different than that of traditional marine fuels, with the main difference being making room for the additional fuel system in and around the cylinder covers [2]. Methanol engines are approximately as efficient as conventional diesel engines, however, due to methanol's lower energy density, they result in higher fuel consumption on a volume basis. The diesel fuel system in dual-fuel methanol engines required for pilot fuel and diesel operation is not significantly different compared with a standard marine diesel engine. Current dual-fuel methanol engines can switch over to fuel oil without any limitation in speed or load.

For methanol, the Diesel Cycle has proven more suitable than the Otto Cycle. Both Everllence and Wärtsilä have developed methanol-capable engines using diesel combustion principles, offering higher ignition reliability and better control over combustion [3]. Everllence has further expanded Diesel cycle technology to fuels such as ethane and liquid petroleum gas (LPG), which benefit from direct injection under high pressure to manage combustion characteristics effectively.

To address the limitations associated with high-pressure gas injection, Everllence developed its Methanol - Liquid Gas Injection (ME-LGI) technology. This system is designed for liquid-state fuels and avoids the complexity and cost of gaseous high-pressure fuel systems. The ME-LGI engine injects high-pressure liquid fuels using a dedicated injector with an integrated booster that raises the supply pressure to match injection requirements. This approach supports the use of methanol, LPG, dimethyl ether (DME), ammonia, and other fuels that are liquid at ambient or modest pressure levels.

Single-fuel methanol engines are designed to run solely on methanol with the exception of pilot fuel, reducing the need for dual-fuel capabilities with the benefits of maximizing efficiency and minimizing emissions from methanol combustion. These engines utilize optimized combustion chamber design specifically for methanol and use advanced fuel injection systems to handle methanol's lower energy content and higher ignition temperature compared to diesel. Challenges of pure methanol engines include the need for a consistent methanol supply and the lack of contingency to traditional fuels in case of methanol unavailability. Due to these and other challenges, main propulsion engines are expected to be mostly dual-fuel engines that can operate on HFO when necessary and otherwise operate in methanol mode with a minimum amount of fuel oil as pilot fuel.

Dual-fuel methanol engines can operate on both methanol and conventional marine fuels like HFO and MDO, which provide operational flexibility in regions where methanol availability may be limited. Dual-fuel engines use separate injection systems for methanol and diesel. Methanol is injected directly into the engine’s combustion chamber with a small amount of diesel pilot fuel to assist with combustion due to methanol having a higher ignition temperature and lower cetane number than diesel.

The use of methanol in fuel cells for marine applications is an emerging zero-emission propulsion pathway from tank to wake that combines the benefits of methanol with electrochemical energy conversion. Fuel cells are a device that electrochemically converts chemical energy stored in a fuel that contains oxygen into electricity. Fuel cell types are generally categorized by the electrolyte it contains and the type of primary fuel. Hydrogen can be used directly in fuel cells, or it can be generated from other primary fuels, including methanol, ammonia, and LNG. Direct Methanol Fuel Cells (DMFC) use a polymer membrane electrolyte with a platinum-ruthenium catalyst, enabling the direct conversion of hydrogen contained in methanol into electricity.

However, this fuel cell type is associated with low efficiency caused by methanol penetrating the cathode and reacting with oxygen. DMFC may be particularly suitable for applications where low emissions, quiet operation, and modular scalability are attractive including ferries, yachts, inland vessels, and auxiliary power on larger ships. Current fuel cell interest is focused on smaller systems as larger systems currently have challenges limiting their development including costs, durability, reliability, and lower energy densities, which must be addressed prior to adoption for larger-scale marine applications (e.g., propulsion systems). In the near- to medium-term, fuel cells using methanol will most likely be used for auxiliary purposes. It should be noted that there are currently no commercially available methanol fuel cell systems suitable for the marine environment.

Methanol tanks are similar to conventional fuel oil tanks and are less costly than LNG if installed during the newbuild phase, although tank capacities for methanol need to be considerably larger than those for HFO due to the lower volumetric energy density [2]. This can increase the required space for fuel storage (2-3 times larger) and could increase total costs. Due to methanol's toxicity and low flashpoint, the fuel tank, supply, and auxiliary systems must comply with distinct requirements, which adds additional constraints and costs for the entire system. Additional constraints for tank loading can also increase the system's footprint. These and other constraints have direct implications for the design and operation of methanol vessels and may reduce the cargo capacity. On the other hand, if cargo capacity and fuel storage space are not increased to account for methanol's lower energy density, the vessel's range will decrease, requiring more frequent bunkering.

Given the current stage of methanol production, supply, and bunkering, new methanol-fueled or methanol-ready vessels typically include three fuel tanks for methanol, MGO, and VLSFO. The benefits of this mixed fuel strategy include smaller methanol tank capacities which minimize cargo space impacts and keep shipbuilding costs moderately lower [2]. Additionally, carrying different fuel types provides greater flexibility with respect to future and regional methanol availability, permitting ship operators to adjust for regional price differences and increase preparation for compliance with regulatory requirements.

System/Network Suitability and Operational/Infrastructure Needs

The scale-up of methanol as a marine fuel will entail significant but manageable changes across maritime energy systems, ports, and vessel operations. The advantages of methanol include liquid-phase storage at ambient conditions and lower toxicity than LNG or ammonia, but methanol also has important safety, supply chain, and infrastructure requirements. These are discussed in detail in Task 3 Maritime Fuels and Availability.

The IMO regulates the use of methanol as a marine fuel through the International Code of Safety for Ships using Gases or other Low-flashpoint Fuels (IGF) and related guidelines, specifically the IMO guidelines for vessels using methyl or ethyl alcohol as fuel (MSC.1/Circ.1621). Additional regulatory standards for the use of methanol as a marine fuel include DNV's mandatory class rules for methanol-powered ships [2]. In addition to its class rules, DNV publishes regular updates in their "Alternative Fuels for Containerships," which DNV claims provides "neutral, fact-based, scientifically sound decision support for newbuilding projects." [4] The goals of the regulatory structures are to ensure safety during the use of methanol and other low-flashpoint fuels. To this end, the guidelines and codes specify the requirements for fuel storage, handling, bunkering procedures, and engine integration.

New Build or Retrofits

Existing marine engines can be retrofitted to accommodate methanol as a fuel, allowing shipowners to convert their fleets without the need of entirely new engines. This requires the modification of fuel injection systems, the integration of methanol storage, and handling systems on-board. According to Everllence, potential candidates for methanol retrofitting include large OGV in the container, pure car and truck carrier, and tanker segments. Several large shipping companies are already retrofitting older vessels to use methanol, enabling them to leverage dual-fuel technologies. Retrofitted vessels will require investment in engine overhaul, often a complete engine strip down and rebuild, supplementary fuel systems and safety measures, and the adaptation of one or more existing fuel tanks to be able to hold methanol fuel. Costs include engine rebuild, hull augmentation, piping, fuel system, tank coating, as well as design, planning and drydock costs.

Four-stroke engine retrofit packages for methanol have been in service since 2015 on the Stena Germanica cruise ferry. In 2024, the conversion of the container ship *Maersk Halifax* to a methanol dual-fuel vessel was completed [5]. The conversion was done by Everllence and included the installation of the company's methanol liquid gas injection (ME-LGIM) engines, which required systems including new fuel tanks, fuel preparation room, and fuel supply system. The hull was also augmented to support larger fuel tanks.

Potential Emission Reductions

From a criteria pollutant emission perspective, ships powered by methanol ICE can achieve significant reductions in NO_x, SO_x, and PM relative to conventional fuels depending on the combustion and emissions control strategies. Methanol burns cleanly compared to conventional fuels because it has a comparatively simple molecular structure, low carbon to hydrogen (C/H) ratio, a high oxygen content and does not contain sulfur, which allows for more complete combustion, resulting in lower emissions. For example, complete combustion eliminates the formation of partially burned hydrocarbons and soot which are key sources of PM and a result of a high C/H ratio. Similarly, the lack of sulfur in methanol eliminates SO_x and sulfate-based PM.

According to the literature, the use of methanol can attain a 30–83 percent reduction in NO_x emissions, a >99 percent reduction in SO_x emissions, and up to 95 percent reductions in PM depending on the combustion strategy and aftertreatment approach [2], [6], [7]. However, most current methanol engines cannot meet Tier III NO_X emission standards unless additional steps are taken, including aftertreatment or in-engine NO_x reduction strategies such as the addition of water during the combustion process which acts as a heat sink, lowering the high temperatures in the combustion zone where thermal NOx is produced. EGR or SCR systems can be installed to further reduce NO_x emissions for compliance with NO_x Tier III levels. Testing conducted by Everllence has shown that NO_x can be reduced below Tier III levels without the need for aftertreatment technologies by utilizing a mixture of methanol with 25-40 percent water and 3-5 percent diesel as a pilot fuel [8]. With similarity to all dual-fuel engines, the small amounts of SO_x and PM associated with methanol engines are largely associated with the use of diesel fuel as a pilot fuel, and the levels will directly correspond to the type and amount of fuel used.

Table 1. Tank-to-wake pollutant emissions (g/kWh) for marine fuels. UCI adapted from Reference [6]. Sulfur is denoted as "S."

Pollutant (g/kWh)	HFO 0.5% S	MGO 0.1% S, Tier II	MGO 0.1% S, Tier III	Methanol Tier II	Methanol Tier III	LNG Tier III
NO_x	12.8	9	2-3	5	2.2	2
SO_x	2.0	0.36	0.36	0.007	0.0007	0.009
PM_{10}	0.74	0.23	0.23	0.034	0.034	0.02

Life cycle GHG emission performance of methanol is dependent on the feedstock and energy source used during production, as well as the transmission, storage, and distribution strategies. Furthermore, direct emissions from vessels depend on engine type and performance. Methanol has a high C/H ratio which leads to lower CO_2 emissions relative to conventional fuels. Figure 1 shows the well-to-wake GHG emissions from different methanol pathways. Currently, methanol is largely produced through the reforming of fossil-based natural gas with an estimated well-to-wake emissions of approximately 90 to 110 grams (g) CO_2equivalent (eq) per Megajoule (MJ) [9]. The production of methanol from coal occurs in China, with well-to-wake emissions of approximately 300 gCO_2eq/MJ, which is significantly higher than conventional marine fuels (~90-95g CO_2eq/MJ) [10].

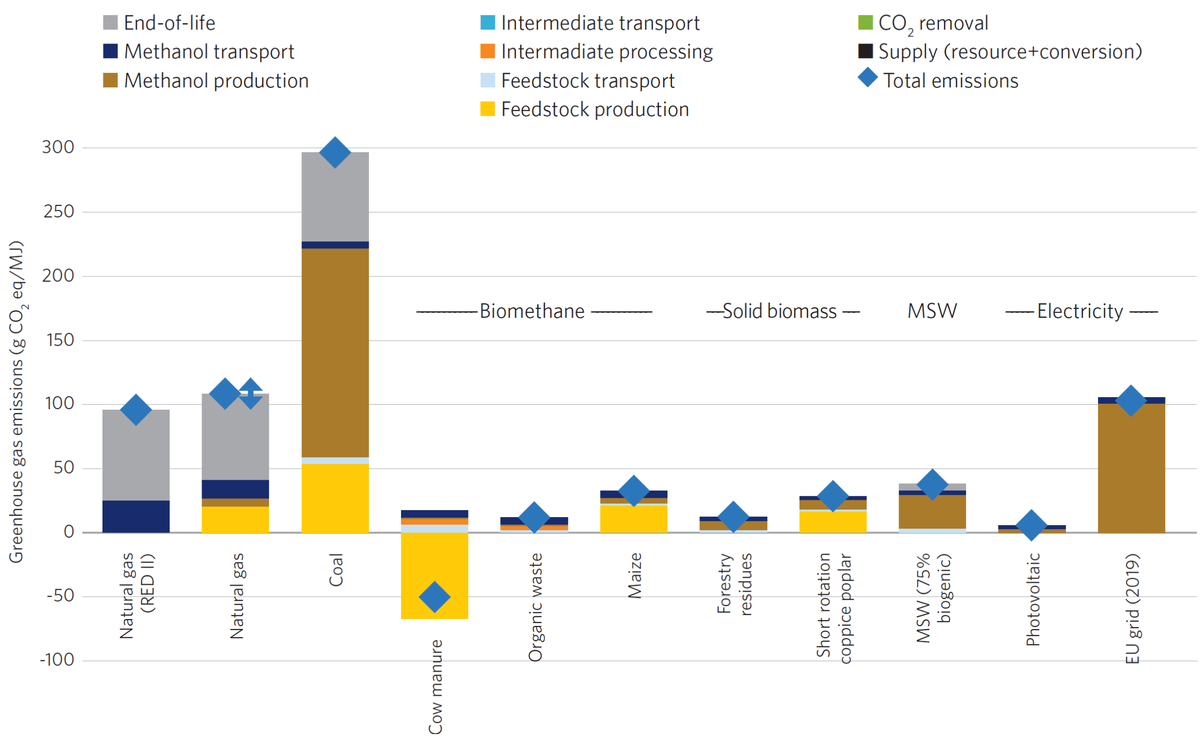

Figure 1. Well-to-Wake GHG emissions for methanol pathways in gCO_2eq/MJ. From Reference [9].

On the other hand, the production of methanol from renewable feedstock can significantly reduce GHG emissions versus emissions from conventional marine fuels. Methanol produced from biomethane, solid biomass, municipal solid waste, and renewable electricity, results in significantly lower GHG emissions, ranging from 10-40 g CO_2eq/MJ. Additionally, production from some biomethane pathways can achieve net-negative emissions due to avoided feedstock emissions of potentially -55 g CO_2eq/MJ. However, long term feedstock availability is expected to be limited. Demonstrating this, using renewable methanol as an alternative to conventional marine fuels for a Suezmax tanker reduced well-to-wake GHG emissions by 30 percent to 75 percent compared to HFO depending on the renewable energy and CO_2 source [11]. The use of natural gas-based methanol still provides a reduction of 25 to 38 percent relative to HFO.

Shown in Table 2 renewable methanol pathways are consistently among the lowest life cycle GHG emissions of those under consideration relative to other alternative marine fuels.

Table 2. Well-to-Wake GHG Emissions for Marine Fuels. Adapted from Reference [10].

Fuel	*Well-to-Wake GHG Emissions [gCO2eq/MJ)*
MGO	*88.2*
LNG – Fossil	*79.9*
LNG – Bio	*29.4*
Methanol – Fossil NG	*94.4*
Methanol – Renewable	*13.6*
Ammonia – Fossil NG	*128.1*
Ammonia – Renewable	*13.9*

Technology Readiness

Methanol engines, fuel supply technologies, and bunkering capabilities are commercially available. Methanol is a potentially suitable fuel for different vessel types and applications including cruise ships, bulk transport vessels, short-sea container and tanker ships, ferries, deep-sea container vessels, and general cargo vessels [12]. Methanol ICE have a high level of technological readiness and are commercially available, with offerings from Everllence, Wärtsilä, Hyundai Heavy Industries, Caterpillar, and Rolls Royce.

The Everllence B&W LGIM engines are a proven two-stroke engine with more than 600,000 running hours on methanol alone [13]. The engine can have 5-12 cylinders and bore sizes of 45-95 cm. The engine uses a diesel pilot injection system to ignite and combust fuels, including methanol and water mixtures. The addition of water to methanol lowers the combustion temperature, which reduces NO_X formation. These engines have been certified to meet Tier III IMO standards without the use of aftertreatment systems [8]. As of October 2024, Everllence reports 210 ME-LGIM engines are on order or in service [14].

The Wärtsilä 32 is a four-stroke dual-fuel engine used since 2015 to power a roll-on/roll-off passenger (RoPax) ferry. The engine is available in 6-16 cylinders with a power output range between 3.4 and 5.2 MW at 720 and 750 RPM. Wärtsilä also provides retrofit packages to convert existing 32 engines to methanol.

The HD Hyundai Heavy Industries HiMSEN 4-stroke engine series was approved in 2022 and supplied to Maersk for the first time in 2023. As of November 2024, 346 HiMSEN have been secured in contracts [15]. The representative model, H32DF-LM, is equipped with an electronically controlled fuel injection system and provides a power of 4,027 kilowatts (kW).

Caterpillar Marine Cat 3500E marine engines are dual-fuel to meet emission standards while delivering 100 percent power. Caterpillar Marine plans to deploy the first field demonstration engines in 2026.

Rolls-Royce is also working on developing a concept for high-speed methanol engines based on its MTU Series 4000 with Woodward L'Orange and WTZ Roßlau in a joint project called "MeOHmare" [16]. However, the smaller engines are targeting deployment in CHC including tugboats and workboats.

While still in the early stages of commercial adoption, Momentum for methanol-enabled ships is growing. An early 2025 survey by DNV reported 25 container ships and a further 208 on order, 25 oil/chemical tankers with 33 on order, 52 bulk carrier and 20 car carriers on order, with interest growing among "other offshore vessels and roro cargo vessels"[17].

New vessel builds are ready for delivery from 2023 to 2028 and consist of a growing range of vessels, with new orders being announced regularly. In addition, methanol-ready or multi-fuel ready vessels are being built for initial operation on conventional fuels, but with designs that can allow for subsequent conversion to methanol.

Everllence is set to deliver the world's most powerful two-stroke methanol engine in 2025, the MAN B&W 12G95ME-C10.5-LGIM, rated at 82,440 kW at 80 RPM [18]. The engine is being built by Chinese licensee CSSC-MES Diesel Co., and the initial delivery will be the first of 12 units for 24,000-TEU container ships with seven for OOCL (at NACKS) and five for COSCO Shipping Lines.

The engines will incorporate MAN's proprietary EGRTC emissions system, the largest two-string EGR ever installed on a two-stroke engine.

Prominent Chinese shipyard Zhoushan Xinya completed the retrofit of the *Maersk Halifax* in 2024*,* a 14,000 TEU containership owned by A.P. Moller–Maersk, to a dual-fuel methanol engine and the vessel is now commercially operational [5]. The retrofit included the integration of a ME-LGIM dual-fuel main engine, new fuel tanks, fuel preparation room, and fuel supply system. To accommodate the methanol fuel tanks, the length of the ship was extended to 15 meters to 368 meters, increasing the capacity from around 15,000 to 15,690 TEU. Another example is the *Laura Maersk,* a dual-fuel methanol enabled feeder containership delivered in 2023, which has been in commercial operation since then [17]. The *Laura Maersk's* main engines were developed in a partnership between Everllence and Hyundai Heavy Industries, and its auxiliary engine was developed by Hyundai Heavy Industries. All of the *Laura Maersk's* engines are dual-fuel systems that are capable of operating on methanol and diesel fuels.

While dual-fuel methanol engine systems have already been demonstrated and validated for use, the technology is still evolving with full maturity expected before 2030 [19]. Methanol engines are currently operating at pilot and early fleet scale, but their long-term reliability (e.g., 10–20 years of continuous operation under varying duty cycles) and durability over decades of continuous operation are still unproven. Key components require further validation to minimize wear and corrosion under real-world conditions including fuel injection, lubrication systems, seals, and exhaust treatment. In addition, the market is currently limited to a few models, primarily MAN two-stroke ME-LGIM engines and some Wärtsilä four-stroke designs. Expanding the diversity of engine types, bore sizes, and retrofit packages across multiple OEMs will be essential to build broader confidence and support widespread adoption. Further, achieving economic competitiveness with diesel engines will require more standardized and modular conversion packages to bring expenses down.

Container lines are not the only shipping segment interested in methanol engines. For example, COSCO Shipping Development (Hainan) has entered into shipbuilding contracts with COSCO

Shipping Heavy Industry (Dalian) to construct 23 new 87,000 deadweight tonnage (DWT) methanol-ready bulk cargo vessels [20].

Tanker vessel operators are also beginning to invest in methanol ships. In a joint venture, Proman-Stena Bulk worked to build six methanol-fueled tankers with the first vessel being delivered in June 2022 and the last formally christened in 2024. All six are in commercial operation today. *Stena Provident*, one of six state-of-the-art methanol-fueled ships commissioned by Proman Stena Bulk, has completed the first methanol bunkering at the US Port of Savannah. *Stena Prosperous* was the last of six vessels to be completed and is a 49,900 DWT IMOII MeMAX vessel that will be bunkered with a 20 percent green and 80 percent conventional methanol blend to achieve CO_2e reductions of 31 percent [21].

Economics

Methanol engines are currently more expensive than conventional engines for several reasons, including the need for specialized fuel injection systems, the need for corrosion-resistant materials, additional safety systems for methanol storage and handling, and limited production scale. Methanol engines are estimated to have 10-30 percent higher CAPEX than a conventional diesel engine [2], [22]. Table 5 shows estimated cost premiums of an additional 10 to 11 percent for 4-stroke and 2-stroke newbuild methanol ICE, respectively, relative to diesel. Similarly, methanol retrofit is estimated to cost 30-50 percent of a new methanol engine cost. According to current estimates, engine and fuel system costs could be in the range of 10 percent to 25 percent of a vessel's value [23]. For example, Everllence estimates the cost of retrofitting a large OGV to a dual-fuel methanol engine typically ranges around US $12 million [24]. For comparison, though it varies, the engine cost for typical conventional diesel main engine is similarly around 5 to 15% of the vessel cost, e.g., for a $120–180M large container ship, the main engine is often $6 to $15 million.

However, the CAPEX of methanol ICE is lower than some options (e.g., LNG, hydrogen) and comparable to others (e.g., ammonia) as shown in Table 5 [22]. The additional CAPEX for installing a methanol system on-board a vessel (e.g., ICE, fuel tanks, piping) is roughly one third of that required for LNG because it does not require cryogenic temperatures or pressurized fuel tanks [2]. The operational expenditure (OPEX) for methanol systems is expected to be comparable with that for oil-fueled vessels lacking scrubber technology.

Next Steps to Demonstration/Deployment

The expansion of bunkering infrastructure in key locations (particularly container and energy hubs) and the standardization of bunkering procedures (including hoses, connectors, safety protocols, etc.) are needed to support methanol vessels. Methanol already has proven ship-to-ship bunkering. It is expected that once demand for methanol is in place, land-side bunkering infrastructure, distribution, and storage will be sufficiently developed, and does not represent a barrier to proliferation and use [19]. This topic is discussed in more detail in Chapter 3.

While methanol engines are commercially available today, there is still potential for engine performance improvements including reducing methanol slip and further optimizing NO_x emissions control. Dual-fuel retrofit demonstration projects for broader vessel classes would also provide opportunities to advance methanol engine deployment. Expansion in the number and type of demonstration projects across a variety of vessel types and routes (e.g., RoPax ferries, tankers, short-sea shipping) will help clarify the feasibility and performance of methanol across the sector.

Regulatory steps that are needed include the establishment and harmonization of IGF Code updates for methanol. Policies to promote port-state acceptance are needed as some regions may still lack clear methanol bunkering regulatory frameworks. In addition, fuel certification and sustainability standards will be necessary to ensure the environmental performance of methanol vessels. Further, the establishment of green shipping corridors with methanol bunkering (e.g., Transatlantic, Asia–Europe routes) would provide assurance to owner/operators that investments in methanol are not stranded assets.

Ammonia Engines

Technology Description

The use of ammonia in combustion engines for propulsion has been in development since the late 1800s [25]. Research on ammonia combustion has focused on properties such as flammability, ignition delay, flame propagation, and chemical speciation. While flammability, ignition delay, and flame speed are crucial for optimizing energy output in engines, speciation is essential for minimizing emissions. Over the past decade, early experimental data has been used to validate chemical kinetic models and guide the development of ammonia-fueled technologies. However, as modern engine performance requirements have become more complex, existing data has proven insufficient [26]. This gap has sparked renewed interest in both experimental studies and modeling efforts to better understand and optimize ammonia combustion for contemporary marine applications.

Ammonia has a lower stoichiometric air-fuel ratio compared to diesel, so, for a given amount of air, a greater quantity of ammonia can be injected. This helps offset its lower energy content and supports maintaining engine power density. However, ammonia's low flame speed, high ignition temperature, and narrow flammability range can result in incomplete combustion in certain parts of the engine, leading to ammonia slip. To initiate combustion, a pilot fuel such as diesel is typically required. Since the 1930s, ammonia has been successfully used with both spark- and compression-ignition engines for both automotive type engines and in coal and natural gas power plants.

There are several different types of ammonia engines being considered by manufacturers for the marine sector including both two-stroke and four-stroke engines. Two-stroke engines are generally considered to be the preferred main propulsion engine for OGV due to benefits over smaller engines, i.e., larger combustion chambers and capability for longer periods of low RPM operation [25]. Additionally, ammonia engines can be dual-fuel or single-fuel. Dual-fuel engines are capable of combusting ammonia alongside conventional fuels or hydrogen. In dual-fuel mode, ammonia is used as the primary fuel and introduced into the combustion chamber through direct or port injection. A small amount of pilot fuel (usually diesel) is injected to initiate ignition to assist with igniting the ammonia. In some configurations, engines can operate on varying ammonia-to-diesel ratios depending on factors such as fuel availability, engine load, or emissions control. Similarly to methanol, dual-fuel ammonia engines provide operational flexibility, which can be particularly important in the initial roll-out of ammonia bunkering, as they can switch to conventional fuels when ammonia is unavailable.

In contrast to dual-fuel ammonia engines, the use of single-fuel ammonia combustion engines can eliminate the use of diesel pilot fuels entirely, creating a zero-carbon solution. However, this is technically challenging due to the properties of ammonia as a fuel. Current marine ammonia engines utilize 10-15 percent fuel oil as a pilot fuel with developmental targets of 5 percent [27]. The low reactivity and high ignition energy properties of ammonia require advancements in ignition systems, such as pre-chamber spark ignition or plasma ignition technologies. Further research is ongoing to optimize combustion parameters to ensure high thermal efficiency and stable engine operation. Additionally, aftertreatment technologies, such as SCR and EGR will still be required to control NO_x emissions to meet regulatory standards, including IMO Tier II and Tier III levels.

In terms of fuel cells, ammonia has primarily been considered for solid oxide fuel cells (SOFCs) as its use in Proton Exchange Membrane fuel cells (PEMFC) would require conversion to hydrogen first and PEMFC are sensitive to ammonia contamination [25]. SOFCs using ammonia are in the research phase, so there are no commercial systems available currently. The ShipFC project, funded by the European Union, was launched in 2020 with the goal of converting an auxiliary genset on an offshore vessel to a 2 MW SOFC capable of running 3,000 hours per year solely on ammonia. However, as of November 2024, the project was on hold due to "immature value chains and current high costs of SOFC at this scale" and now plans are in place to instead equip the demonstrator vessel with a dual-fuel engine capable of operating on ammonia [28]. In the near-term, ICE are considered superior to fuel cells for OGVs because of their advantageous cost, power density, load response, and reliability [25].

System/Network Suitability and Operational Infrastructure Needs

Many of the network and infrastructure needs for ammonia are related to the availability of cost-effective and environmentally beneficial ammonia, as well as the buildout of bunkering infrastructure. Ammonia bunkering has a foundation to build upon from the existing global network of storage terminals. Similar to methanol, sufficient demand for ammonia will spur the development of bunkering infrastructure, distribution, and storage capabilities, and these challenges do not appear to be a major barrier to roll-out [19]. These topics are discussed in detail in Chapter 3.

New Build or Retrofits

Engine manufacturers are developing both newbuild and retrofit solutions for dual-fuel ammonia engines with commercial availability expected by 2030. Retrofitting can be challenging for many ship types, largely due to the toxicity of ammonia. Steps that must be taken include engine conversion and reengineering of the fuel tank space and ventilation systems. Retrofitting appropriate ventilation, leak detection, and toxic gas protection can be difficult and costly. With similarity to the other alternative fuels, ammonia retrofit solutions are best suited for relatively young ships with 10–15+ years of service life remaining. Vessels with dual-fuel LNG or methanol engines (like MAN 2-stroke ME-LGIM or WinGD X-DF) may be more easily converted to ammonia.

In contrast, newbuild vessels can be optimized for operation on ammonia from the beginning with flexibility in designing the engine room, tank layout, safety systems, and the integration of ammonia handling systems. Ammonia tank size and placement can be optimized which can allow for the maintenance or improvements in available cargo space. Vessels can be designed with integrated safety systems, double-walled piping, and a ventilation system which further helps in meeting current and future regulations. Integration of emissions control systems including carbon capture can be easier.

Ammonia engine retrofit packages for both four- and two- stroke engines have not achieved commercial operation with the current state of readiness of newbuild ammonia engines estimated at TRL 3 [29]. Existing dual-fuel LNG engines can also be modified to accommodate ammonia, reducing infrastructure development time and costs.

The estimated cost of retrofitting a large OGV to operate on ammonia using a 10–16 MW two-stroke engine is between $10 million and $13 million [23]. The exact cost depends on several factors, including the type and size of the vessel, the configuration of the original engine, and whether the retrofit is carried out as part of a single project or as part of a series of conversions. Larger or more complex ships generally require more extensive modifications, while certain original engine designs may demand greater adaptation to accommodate ammonia fuel systems. Costs can also be reduced when multiple retrofits are undertaken simultaneously, as shipyards and suppliers benefit from economies of scale in both procurement and installation. A significant portion of the overall expense is tied to installing ammonia-ready fuel systems, such as specialized storage tanks, piping, and safety systems, as well as making the necessary modifications to engines and onboard safety equipment to address ammonia's toxicity and corrosive properties.

A technical study of the retrofit of the *Star Laguna*, a 51,000 DWT cargo vessel owned by Grieg Shipping found the retrofit expensive but technically feasible, with uncertainties related to return-on-investment [30]. From a technical perspective, retrofitting the *Star Laguna* to bunker, store, handle, and sail on ammonia would require more extensive modifications than initially anticipated, although the retrofit could take place within a reasonable timeframe. For large ocean-going vessels, retrofit projects that can be completed within 2–6 weeks are generally considered commercially feasible, while projects extending beyond about 6–8 weeks become challenging and require strong regulatory or economic drivers. Retrofits requiring more than 8–12 weeks of downtime, such as full fuel conversions or main engine replacements, are typically viewed as commercially non-viable due to lost revenue, yard constraints, and operational disruption. The ammonia system selected would allow the vessel to sail the longest leg of its route on ammonia and it would be possible to operate the vessel on full ammonia utilization given available bunkering at, or close to, the ports the vessel visited. From a financial perspective, retrofitting a vessel to run on ammonia has a high investment cost, e.g., the evaluated case required 50 percent higher investment than the *Star Laguna's* fair market value. The study identified the main challenges today of high retrofit investment costs, lack of availability of competitively priced ammonia, and unclear effects of regulatory frameworks.

Potential Emissions Reductions

Using ammonia in fuel cell systems would reduce tank-to-wake emissions of all pollutants and GHGs to essentially zero, as fuel cells do not have combustion products. When using ammonia in ICE (see Table 3), the emissions of SO_x, CO, heavy metals, hydrocarbons and Polycyclic Aromatic Hydrocarbons (PAHs) drop to zero if no pilot fuel is used, or close to zero if a pilot fuel is used. Ammonia has significantly less carbon and sulfur than conventional fuels which results in substantially reduced or eliminated PM and SO_x emissions. However, the usage of pilot fuel may also introduce some level of pollutant emissions, and the total amount of pilot fuel (and thus emissions) needed will depend on the engine developments that are currently underway.

Table 3. Pollutant and GHG emissions from ammonia and conventional marine fuels. From Reference [28].

Pollutant	HFO, MGO	LNG	Ammonia (combusted in engines)
SO_2 and metals	Present	Not present	Not present
Carbon monoxide and hydrocarbons	Present	Present or increased	Not present
VOCs and PAHs	Present	Reduced	Not present
NO_x **	Needs SCR for Emission Control Area	Otto engines meet Emission Control Area without SCR	Needs SCR for Emission Control Area
Direct particulate matter	Present	Reduced	Reduced
Ammonia (NH_3) ***	Low	Not present	Unknown
N_2O	Present	Present	Present or increased****
CH_4	Low	Present at Otto engines	Not present
CO_2*****	Present	Present	Not present

NO_x emissions in engine exhaust are a concern for ammonia-fueled vessels and must be controlled if ammonia is to become a viable low carbon fuel. When ammonia is used in ICE, nitrogen in the fuel and nitrogen from the intake air can both form NO_x, especially at the high temperatures typical of marine engine operations. As a result, ammonia-fueled engines may produce higher NO_x emissions than conventional marine fuels, unless effective emission control strategies are employed. However, limited data is currently available regarding impacts on NO_x emissions. It has been reported that NO_x will be approximately equivalent to MGO despite having nitrogen in the fuel which contributes to NO_x emissions, as the flame temperature during ammonia combustion is lower [25]. Additional studies are needed to quantify NO_x emissions from ammonia combustion in marine engines to determine whether this is accurate.

The primary technology expected to control NO_x emissions on ammonia-fueled vessels is SCR**.** SCR is a proven and widely used method to reduce NOx emissions in marine and land-based applications. It works by injecting a reducing agent (typically ammonia or urea) into the exhaust stream, where it reacts with NO_x over a catalyst to produce harmless nitrogen and water. In the case of ammonia-fueled vessels, the SCR system can be adapted to use the vessel's own ammonia fuel as the reductant, potentially simplifying logistics. SCR systems can potentially reduce NO_x emissions by 70 to 90 percent or more, which would allow ammonia-fueled engines to meet stringent Tier III standards. However, the deployment of NO_x control systems raises concerns about emissions of ammonia (e.g., unburned ammonia in the exhaust also called "slip") and its environmental impact, particularly if combustion is incomplete or aftertreatment systems are undersized. Designing and integrating emission controls to avoid these tradeoffs adds complexity. Additionally, space and weight constraints on vessels may limit the feasibility of installing large SCR systems or multiple emission control stages, which is a particular concern for retrofits. All these factors must be considered and addressed to ensure operational reliability under real-world marine conditions including thermal management, high-quality catalysts, and consistent system monitoring. In addition to exhaust aftertreatment, engine optimization and combustion control can be used to minimize NO_x formation. Combustion strategies such as adjusting the air-fuel ratio, lowering peak combustion temperatures, and optimizing ignition timing can help reduce NO_x emissions directly [32]. However, these approaches must be carefully managed to avoid trade-off including ammonia slip or reduced engine efficiency. Techniques like lean-burn combustion, which introduces excess air to reduce combustion temperatures, or EGR, which dilutes the intake air with inert exhaust gases, are further examples of source-control.

Ammonia is toxic and emissions can present a safety risk for crew and passengers on-board the vessel, as well as individuals or communities that come in proximity to the vessel or bunkering infrastructure. Public perception of ammonia as a marine fuel is strongly influenced by safety concerns, particularly its acute toxicity and the health risks associated with accidental releases. Although ammonia has been transported safely by the shipping industry for decades, its use as a fuel introduces new operational risks that heighten sensitivity among crews, ports, and nearby communities. Addressing these concerns will require robust, purpose-built vessel and bunkering systems, continuous monitoring, rigorous crew training, and well-defined emergency procedures to ensure that ammonia propulsion does not pose additional risks to human health or the environment [33]In addition to ammonia slip, emissions of ammonia can also come from boil-off gas from ammonia storage tanks, ventilation, and purging during tank operations [26]. Acceptable ammonia emission levels for marine vessels are not yet clearly established [34]. Existing literature shows a wide range of exposure limits, and there is limited experience with ammonia as a marine fuel [26].

To ensure effective risk management and support the safe adoption of ammonia as a fuel, the industry needs coordinated alignment on standardized thresholds and clear guidance. Significant coordinated efforts are currently underway across international regulators, classification societies, and industry organizations to establish standardized safety thresholds and clear technical guidance for the use of ammonia as a marine fuel. The primary global initiative is being led by the IMO, which in 2025 issued interim safety guidance for ammonia-fueled vessels and continues to refine fuel-specific provisions through its Maritime Safety Committee and associated sub-committees. Amendments enabling the use of ammonia as fuel under the IGC Code are scheduled to enter into force in July 2026, representing a major regulatory milestone toward formal international adoption. In parallel, the International Association of Classification Societies (IACS) and major class societies (e.g., DNV, Lloyd’s Register, and ClassNK) are developing detailed engineering and operational safety frameworks addressing ammonia-specific hazards such as toxicity, fuel containment, leak detection, ventilation, and emergency shutdown systems. Complementing regulatory work, industry collaborations such as the DNV–Yara Clean Ammonia Recommended Practice are advancing standardized operational guidance covering fuel handling, crew training, and risk mitigation. Despite this substantial progress, full global harmonization has not yet been achieved, and several areas, including exposure thresholds, bunkering safety envelopes, crew competency standards, and uniform risk assessment methodologies, remain under active development. Overall, the regulatory trajectory is moving from risk-based interim guidance toward increasingly unified technical standards that are expected to form the basis of future mandatory international rules for ammonia-fueled vessels.

Due to the lack of carbon, the combustion of ammonia produces no CO_2 at the point of use. However, current ammonia supplies are almost entirely produced from fossil feedstocks, which does not provide significant GHG mitigation relative to current fuels. Accounting for the efficiencies in conversion processes and feedstock emissions, the well-to-tank carbon intensities of ammonia produced from fossil sources using the best available technologies range from 85 kgCO_2/GJ for natural gas up to 215 kgCO_2/GJ for coal. These values are equivalent or higher than low sulfur MGO (88 kgCO_2/GJ [25]. However, green ammonia produced from renewable feedstock or nuclear production offers the potential for significant reductions in life cycle GHG emissions. For example, when renewable energy, like wind, solar or hydroelectric energy is used to produce the ammonia the GHG emissions are close to zero. The use of fossil pilot fuels will increase the overall carbon intensity of ammonia engines; although the pilot fuel could also be renewable diesel or biodiesel to decrease the life cycle GHG contribution. However, using ammonia with a fossil-based pilot fuel such as low sulfur fuel oil (LSFO) can still reduce tank-to-wake CO_2 emissions by over 85 percent compared to using only LSFO [34].

From a GHG perspective, emissions of nitrous oxide (N_2O) are a major concern as the global warming potential is much higher than CO_2 (1 gram of N_2O is equivalent to 265 grams of CO_2). This means that even minimal N_2O slip can significantly degrade the climate benefits of ammonia as a zero-carbon fuel [26]. Controlling N_2O emissions will therefore be essential to ensure that ammonia-fueled vessels meet GHG reduction goals and maintain a net environmental benefit over fossil fuels.

It is somewhat unclear how significant N_2O emissions will be from ammonia engines. Based on the current understanding and the targets established by an industry working group convened by the Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping, N_2O emissions are expected to remain relatively low, i.e., around 0.06 g/kWh [26]. This emission level is approximately double that of conventional fossil marine fuels, but it is considered a realistic upper limit based on current engine designs and aftertreatment capabilities. Higher N_2O emission levels are viewed by the industry as unlikely and unacceptable for future ammonia engine designs as they would fail to meet regulatory and climate performance targets. As a result, engine design and emission control systems must ensure N_2O emissions stay well below these thresholds.

Optimally, SCR systems that reduce N_2O and NO_x simultaneously should be identified and used. Everllence has completed 12 months of ammonia combustion testing on a two-stroke test engine and reports low N_2O emissions and a 40 percent reduction in NO_x emissions relative to fuel oil [35]. Similarly, Japan Engine Corporation (J-ENG) reports that it achieved stable operation of their 2-stroke engine and that N_2O emissions can be controlled to low levels through in-cylinder combustion controls including high-pressure, electronically controlled injection.

Technology Readiness

The development of ammonia engines is progressing rapidly and projected to reach pilot demonstration in 2025 and commercial maturity by 2030 [19]. Everllence is developing an ammonia dual-fuel two-stroke engine (ME-LGIA series) based on its proven LNG dual-fuel engine platform (B&W ME-LGI) and the first is expected to be delivered in Q1 2026 [36]. [43]. The engine will be available as a newbuild engine or retrofit option for existing electronically controlled Everllence ME-C engines. Pilot fuel is required with initial tests conducted using 10-15 percent pilot fuel as a first step and an R&D target of 5 percent pilot fuel at 100 percent load for L1-rated engines which are operated at 100% engine load [35]. An increase in SCR volume and ammonia consumption may be necessary to achieve compliance with IMO Tier III regulations. Everllence has a current estimate for sales release of additional two-stroke ammonia engine models by the end of 2026. However, this timeline is dependent on the successful demonstrations of the first vessel or vessels, and the actual time schedule will be pending shipyard delivery schedule.

Swiss marine company WinGD has a line of two-stroke dual-fuel marine engines capable of operating on ammonia with a power output of 5 MW to 31 MW [37]. WinGD has begun delivering its X-DF-A dual-fuel two-stroke ammonia engines with examples including an X52DF-A engine that was delivered and installed on an EXMAR LPG/ammonia carrier newbuild in 2025, with the first vessels expected to enter service in 2026 [38]WinGD has secured close to 30 orders to date for ammonia-fueled X-DF-A engines, with sizes ranging from 52- to 72-bore, for vessels including bulk carriers, gas carriers, container vessels and oil tankers [39]. For example, seven 25,000m^3 and 41,000m^3 LPG/ammonia carriers will be built for Tianjin Southwest Shipping and will be powered by a 6-cylinder version of the 52-bore X-DF-A engines and scheduled to enter service in 2026. WinGD's dual-fuel engine requires pilot fuel and aftertreatment the use of an SCR will be required for compliance with Tier III NO_x standards. WinGD is also co-developing ammonia-fueled engines with Belgian group CMB.TECH and has signed a Memorandum of Understanding (MOU) with Mitsubishi shipbuilding and Samsung Heavy Industries.

Japan Engine Corporation (J-ENG) has completed what is believed to be the world's first full-scale commercial ammonia-fueled two-stroke marine engine (7UEC50LSJA-HPSCR) as part of Japan's Next-Generation Ship Development program under the Green Innovation Fund [40]. The engine underwent extensive performance verification tests in both ammonia fuel mode and conventional heavy fuel oil mode under the supervision of NYK Line, Nihon Shipyard, Japan Marine United (JMU), and ClassNK, and received ClassNK certification for environmental performance and safety. J-ENG shipped the engine in October 2025 for installation on an ammonia-fueled medium gas carrier being built at JMU's Ariake Shipyard, with the vessel scheduled to enter service in 2026. The development built on roughly 1,000 hours of single-cylinder tests and 700 hours of full-scale test runs, confirming high reliability, safety systems (including leak prevention and monitoring), and performance. Notably, trial data showed a ~90 % GHG reduction at a 95 % ammonia co-firing rate, very low N_2O, and NO_x emissions roughly half those of conventional engines, with thermal efficiency in ammonia mode at least on par with heavy oil operation. J-ENG is also developing a larger (60 cm bore) ammonia engine and plans a new factory to scale production by 2028.

Wärtsilä is testing ammonia-capable four-stroke engines, leveraging its existing dual-fuel technology with a focus on ensuring stable ammonia combustion, improving efficiency, and managing NO_x and N_2O emissions. Wärtsilä's engines are currently being trialed for power generation and ship propulsion. The Wärtsilä 25 is a commercially available ammonia four-stroke medium speed dual-fuel engine [41]. The engine is available with a power output range between 1.7 and 2.7 MW at 900 to 1,000 RPM. Wärtsilä has signed an agreement with Eidesvik to convert an offshore supply vessel to operate on ammonia fuel beginning in 2026. Wärtsilä is also providing similar systems on-board ammonia-fueled mid-sized gas carriers that are currently being built in South Korea.

Significant momentum exists for a wide variety of marine ammonia applications. Early orders for ammonia-fueled vessels include two LPG/ammonia carriers for Exmar LPG, to be classed by Lloyd's Register, as well as at least one series of Newcastlemax carriers and a small container feeder vessel [39]. In 2023, Eastern Pacific Shipping signed an MOU with Everllence, Hyundai Heavy Industries, and China Shipbuilding Corporation to develop ammonia engines for newbuilds due for delivery beginning in 2026 [39]. WinGD has signed an agreement with AET Tankers and sister company Akademi Laut Malaysia to develop crew training on ammonia engines and has announced a partnership with CMB Tech, a sister company of Belgian shipowner CMB, to develop ammonia-fueled engines for ten 210,000 DWT bulk carriers [42].

Beyond vessels that are immediately capable of running on ammonia, there is also growing interest in vessels that could be retrofitted to ammonia more easily in the future. At the time of this report, 144 ammonia-fueled vessels are announced or on order globally. Within this on-order group, 29 are ammonia carriers and 18 are bulk carriers with the first of these larger commercial vessels expected to enter service starting in 2026–2027[43]. Additionally, 84 ammonia-ready vessels are already in service and 302 more ammonia-ready vessels have been ordered. Approximately half of the current global orderbook are for dual-fuel vessels that could be built to run on ammonia, diesel, and LNG.

Economics

Ammonia engines are currently more expensive than conventional ICE and are likely to remain so in the near- to mid-term. A 2022 study found the cost for a newbuild ammonia engine ranges from $680-$930/kW relative to $200-$440/kW for conventional fuel IC [31]. The same study reported that retrofitting an ammonia-fueled ship equipped with a 10-16 MW two-stroke engine is in the range of $10 million to $13 million depending on the type and size of the vessel, the original engine, and the number of retrofits being undertaken [31]. The study further reported that a newbuild ammonia containership would have a total cost of ownership (TCO) that would be 100 percent to 340 percent higher than conventional engines and fuels, although the largest driver of the TCO was fuel costs (discussed in detail in Chapter 3).

However, according to Everllence, ammonia engines have been found to be among the most cost-effective options for reducing GHG from the maritime sector [44]. Similarly, a 2023 life cycle study concluded that ammonia ICE are more economically viable than fuel cells and offer a cost-competitive option for reducing GHG emissions across various vessel types, including tankers, small service vessels, and roll-on/roll-off (Ro-Ro) ferries.

Next Steps to Demonstration/Deployment

Overall, the findings suggest ammonia ICE are a promising near-term solution for decarbonizing multiple vessel types, particularly those that can tolerate the fuel system's weight or be adapted for additional volume, though further R&D is needed to address integration and safety challenges for different vessel types. Widespread deployment of ammonia engines is technically feasible, and the engines are nearing commercial maturity, but success will depend on global collaboration, standardization, and investment in fuel infrastructure. In the near-term, pilot corridors and continued commercial demonstrations of both newbuild and retrofit engines will likely support broader adoption by the early- to mid-2030s. Many of the most important steps to the adoption of marine ammonia use are largely associated with the fuel itself - rather than the engines and their associated systems - including future availability and costs, which are discussed in depth in Chapter 3.

Ammonia can potentially provide significant emission reductions of both criteria pollutants and GHGs but must be managed carefully to avoid tradeoffs of NO_x, N_2O, and ammonia slip. The management of emissions will likely require a multi-layered emission control system, typically combining three to four treatment technologies including existing solutions like reliquefication systems (to manage boil-off, safety, and fuel efficiency) and SCR, as well as adapted systems such as gas combustion units, catalytic converters, and chemical absorption systems optimized for ammonia [26]. Given the concerns regarding ammonia toxicity, interest in early detection for methane slip is receiving increasing attention including the development of sensors with high sensitivity [45]. Even for the commercially available components, the integration into ammonia-fueled vessels remains technically complex and coordinated development of engine and aftertreatment systems is essential to balance material demands, operational energy use, and overall costs.

Bunkering stations for ammonia-fueled vessels must be designed and constructed with the requirements common to all vessels using gas or low-flashpoint fuels. Achieving safety goals will require risk assessments for “worst-case” leakage scenarios, the vessels toxic area plan, and access through airlocks from non-toxic areas [39]. Bunkering facilities will need to be designed to safely contain and manage ammonia leakage. A 2023 industry study led by the Global Centre for Maritime Decarbonisation conducted comprehensive Hazard Identification (HAZID) and a coarse Quantitative Risk Assessment (QRA) for ammonia transfer and bunkering operations — including proposed ship-to-ship bunkering at a Singapore anchorage — identifying hundreds of potential hazards and demonstrating that most risks could be mitigated with appropriate safeguards. These analyses informed site selection, safety zone recommendations, and operational procedures to support future ammonia bunkering pilots and help prepare ports and stakeholders for ammonia fuel safety challenges [46].

Fuel quality standards and specifications for ammonia will need to be developed to ensure proper engine operation, e.g., to control debris (particles) in the fuel. Everllence has developed its own preliminary guidance for ammonia going into its dual-fuel ammonia engines once they reach commercial operation [39]. Unwanted particles in the ammonia could come from the catalyst used in production or from the transportation of the ammonia. Fuel quality standards will need to consider bunkering logistics and the required specifications for on-board fuel filtering between fuel tank and engine.

Workforce training and certification programs must be developed to support ammonia vessel operation and bunkering. Crew members must be trained in ammonia handling procedures, toxic exposure mitigation, and emergency response. Safety equipment including respirators, chemical suits, and leak detectors must be included in relevant places. Maintenance and inspection procedures must be updated and developed including managing corrosion through more frequent checks for seals, valves, and piping. Continuous monitoring for ammonia leaks through sensor calibration and redundancy must be considered.

Regulatory frameworks must be modified and further developed to support the use of ammonia in the maritime sector. For example, the IMO released *Interim guidelines for the safety of ships using ammonia as a fuel (MSC.1/Circ.1687)* in March 2025 to provide "high-level, goal-based provisions while acknowledging the need for future refinements" [47]. Additionally, flag state and port states will need to develop clear, harmonized rules for on-board storage, handling, and emissions concerns. Additionally, safety protocols will need to extend beyond ship and port safety to include port workers and adjacent communities, such as evacuation routes and shelter protocols, community notification systems, etc. [48]. Further, classification society standards from entities including DNV, ABS, Lloyd's Register will need to develop rules for ammonia-powered vessels, and steps are being taken now to do so.

LNG Engines

Technology Description

In the 1950s and 1960s, the shipping industry pioneered the transport of LNG cargo, and in these LNG carriers the boil-off gas was routinely used as a ship fuel in boilers and engines, effectively making LNG a marine fuel in practice since at least the late 1950s with ships such as

Methane Pioneer carrying and using LNG [49]. Formal trials of LNG as a dedicated marine propulsion fuel (i.e., beyond boil-off use) date back to the 1970s, with expanded use in LNG carriers and later in ferries, offshore vessels, and other segments. LNG tankers store and transport natural gas in liquid form near the vaporization temperature of approximately –163°C. Despite using specially designed storage tanks, a small amount of LNG will evaporate (termed boil-off), which must be removed from the tanks in order to maintain appropriate tank pressure. Beginning in the early 2000's, LNG carriers began to incorporate dual-fuel or tri-fuel diesel engines and began to use boil-off gas as a propulsion fuel. Originally powered by steam turbines, in 2012, engine manufacturers began to offer slow speed 2-stroke engines using either high pressure (compression ignition Diesel cycle) or low pressure (spark ignited Otto cycle) for vessels utilizing boil-off gas [50]. The high pressure diesel cycle offers the benefit of higher efficiency (due to a higher compression ratio) while the low pressure Otto cycle has the benefits of lower capital costs and Tier III NO_x emissions levels without requiring EGR or SCR in pure gas mode. According to an assessment of LNG as a marine fuel, approximately 80 % of the existing LNG-powered fleet is equipped with low-pressure dual-fuel engines [51]. This dominance reflects the widespread adoption of LPDF technology because it can achieve IMO NO_x Tier III compliance without SCR aftertreatment, offers lower combustion complexity, and provides operational and regulatory advantages compared with high-pressure dual-fuel alternatives.

Dual-fueled two-stroke LNG engines use the diesel cycle with non-premixed combustion to achieve high operational stability, high efficiency, and reliable operation. Typically, these dual-fuel engines can change between gas and diesel operations seamlessly. Owners and operators gain fuel flexibility and can select the most cost-effective fuel available, since the engine maintains equal efficiency whether running on gas or liquid fuel. LNG carriers are also able to use medium-speed 4-stroke engines for propulsion. The 4-stroke gas engines are Otto cycle and compliant with NOx Tier III.

In the past decade, the use of LNG as a marine fuel has gained significant momentum as a result of environmental regulations including the IMO's sulfur and NO_x regulations. Currently, LNG engines are mostly used on-board gas tankers carrying LNG as cargo as they are a natural technical and economic fit due to benefits in fuel availability, system integration, economics, and regulation. However, dual-fuel and pure gas ICE have been introduced for both propulsion and auxiliary power for a range of other vessels with different sizes and operating profiles ranging from small ferries and offshore supply vessels to large cruise ships, oil tankers, and container vessels [52]. Single-fuel LNG engines, which run entirely on LNG, are typically 4-stroke engines used in ferries, short-sea shipping, and coastal vessels where LNG infrastructure and availability are well-established. These engines use either spark ignited Otto cycle engines with LNG combusted in pre-mixed air-fuel mixtures or compression ignition diesel cycle systems with micro-pilot diesel injection (i.e., often ~0.5–1% of total fuel energy input). An example of a single-fuel LNG engine is the Wärtsilä 31SG engine, which is a pure gas, medium-speed engine used for smaller vessels or auxiliary power. Typically, spark-ignition LNG engines are less fuel efficient than compression ignition engines that use diesel pilot fuel due to the inherent engine physics including lower thermal efficiencies.

A current example of a slow speed two-stroke dual-fuel engine using high pressure is the Everllence B&W ME-GI, which has been in service since 2016. Two to three gas fuel valves inject high-pressure gas (300-350 bar) into the combustion chamber along with a small amount of pilot fuel via two or three conventional fuel oil injectors to ensure stable and reliable combustion. The ME-GI engine is ignited on HFO or MGO and can switch to gas operation at a minimum engine load of 10 percent. The diesel cycle ensures stable gas combustion under all weather conditions, such as heavy weather and high ambient temperatures. The engine has no specific requirement for gas quality and can operate on natural gas from 10 percent to 100 percent load. Furthermore, the engine can operate on any ratio of natural gas and conventional marine fuels. Benefits of high-pressure engines relative to low pressure engines include high thermal efficiencies, fuel flexibility, power output, and low methane slip. Challenges for high-pressure engines include the complexity and cost of engine gas supply systems, higher maintenance requirements and costs, safety risks, and higher upfront costs.

A current example of a slow-speed two-stroke dual-fuel engine using low-pressure is the WinGD LNG X-DF series which uses a lean burn Otto combustion process (i.e., spark ignition) when operating on gas (i.e., a compressed lean air/gas mixture is ignited with a small amount of liquid pilot fuel). Typically, low-pressure systems are designed for LNG operation which complicates seamless switches to conventional diesel fuels. Low-pressure systems offer several advantages over high-pressure systems, including lower capital and operational costs; lower NO_x emissions (avoiding the need for exhaust treatment); simpler system design for easier operation and maintenance; lower safety risks; and cost-effectiveness for vessels requiring lower power demands. Challenges for low-pressure systems include higher methane slip, lower efficiencies, limited fuel flexibilities, and power output limitations which make them less suitable for large vessels.

Because LNG must be stored in insulated, pressurized tanks to maintain liquid state, OGVs typically use one or more cylindrical Type C tanks composed of cryogenic steel, mounted on or inside the vessel hull. Additional methods include membrane tank technology (such as those used by LNG carriers) to increase fuel capacity and minimize space. For example, LNG-fueled cruise ships store 3,000 to 4,000 cubic meters of LNG using membrane tanks [53]. Key components of vessel LNG fuel systems include tank pressure control, piping and vaporizers, gas handling units, redundancy, and safety equipment. On-board heating and electrical systems can be designed to make use of cold energy from the tanks using LNG evaporators to provide refrigeration of cool air which provides a small efficiency gain. Bunkering equipment on-board typically involves a set of manifolds on deck, and bunkering operations also require detailed protocols to ensure safety.

System/Network Suitability and Operational/Infrastructure Needs

According to CARB's 2018 published "Technology Assessment: Ocean-Going Vessels", the preferred fueling option for LNG vessel operators would be the use of bunker barges, but the appropriate barges and storage tanks required for California-based coastal storage will need to be developed [54]. The first U.S.-flagged LNG bunker barge, the "*Clean Jacksonville*," was built in 2018 with a storage capacity of 2,200 m^3 and is operated by Foss Maritime. The barge provides service to TOTE Maritime, supplying LNG to the company's LNG-powered vessels, including TOTE's Marlin-class containership, which operates between Jacksonville and Puerto

Rico. The *Clean Jacksonville* sources fuel from the first U.S. coastal small-scale LNG bunkering facility which has a capacity to produce 120,000 gallons of LNG per day. The *Clean Jacksonville* has successfully completed over 100 bunkering operations and achieved other milestones including the first ship-to-ship LNG bunkering of a foreign-flagged vessel. An additional example of a U.S.-based LNG bunkering barge includes the Crowley designed *Progress,* the largest LNG bunkering barge in the U.S., measuring 416' in length with a capacity of 12,000 m^3. Shell has a long-term charter agreement with Crowley to operate *Progress* and was also involved in the design and construction of the barge which was delivered to Crowley in July 2024. The *Progress* will primarily operate LNG bunkering services in the Eastern U.S. including providing LNG for ship operators at the Port of Savannah, Georgia.

Some ports in the U.S. are also exploring other methods of bunkering LNG. For example, in December 2024, the first ship-to-ship LNG transfer to a container ship was completed at the Port of Long Beach by Seaspan Energy [55]. Additionally, LNG bunkering terminals are also increasing in availability in Europe and parts of Asia [54].

New Build or Retrofits

Existing diesel engines can be retrofitted for the use of LNG, with associated vessel modifications to provide for storage of LNG on-board, although the size and cost of LNG tanks represent a challenge for retrofit applications. Numerous cost drivers will determine whether it is economically feasible for retrofit solutions including the amount of time the vessel operates in ECAs; the remaining useful life of the vessel; the installed tank cost and impact due to displaced cargo space; the cost of delivered LNG relative to traditional compliant fuels; and the availability of fueling infrastructure [54].

Due to the various factors affecting the economics of the LNG retrofit applications, it is difficult to predict whether a retrofit approach has the potential to be widely adopted. One strategy being utilized for dual-fuel capable vessels is the concept of "LNG-ready" ships, which are vessels built with design features that will more easily allow vessels to retrofit to LNG fuel systems in the future. Many newbuild ships are utilizing this strategy, which typically involves ensuring sufficient space and structural reinforcements are present for future LNG tanks.

Potential Emission Reductions

LNG is methane that has been cooled to turn it into a liquid. Methane is the simplest hydrocarbon and contains the lowest carbon content per unit of energy in the alkane series. As a result, burning methane produces 20 to 25 percent less CO_2 compared to traditional HFO and other distillate fuels [53]. A dual-fuel two-stroke engine using fossil LNG achieves approximately a 17 percent reduction in CO_2 emissions relative to HFO on a well-to-wake basis. Greater reductions are possible when using renewable sources of methane. It is estimated that using bio-LNG as a marine fuel can reduce well-to-wake GHG emissions by approximately 80 percent [55]. Chemically, bio-LNG is equivalent to fossil LNG, has equivalent energy density, and can be used seamlessly in all existing and future LNG engines.

In April 2024, Titan Clean Fuels and STX Group carried out a ship-to-ship bio-LNG bunkering operation in Rotterdam, supplying 2,200 metric tons of bio-LNG to a Hapag-Lloyd container vessel, demonstrating that large-volume bio-LNG bunkering is both technically feasible and scalable.

In October 2024, the Rotterdam-Singapore Green and Digital Shipping Corridor (GDSC) partners conducted a pilot for bunkering liquefied bio-methane (i.e., bio-LNG) at the Port of Rotterdam. On 19 October 2024, 100 tonnes of certified mass-balanced bio-LNG was supplied by Shell to the CMA CGM containership CMA CGM Tivoli in a ship-to-ship bunker operation. This pilot was designed to test sustainability certification, regulatory acceptance, and the operational logistics of delivering bio-LNG as a lower-emission marine fuel on a major global trade route.

However, a major challenge for LNG engines in terms of GHG emissions is methane slip. The potency of methane as a GHG means even a very small amount left unburned could diminish the CO_2 benefits. Low-pressure engines have higher methane slip, estimated at 2-6 percent of fuel energy due to incomplete combustion. The FUMES (Fugitive and Unburned Methane Emissions from Ships) project represents a comprehensive dataset on real-world methane slip from LNG-fueled ships [56].. Real-world measurements, collected via drones, helicopters, and onboard instruments from 18 vessels with low-pressure dual-fuel four-stroke engines, indicate that methane slip averaged approximately 6.4 % of fuel gas supplied, which is significantly higher than the ~3.1 % and ~3.5 % values currently assumed in EU and IMO inventories, respectively. The study further found that methane slip is highly dependent on engine load, with elevated emissions at low loads, and that fugitive methane emissions can also occur during LNG cargo unloading operations. These results suggest current regulatory default factors may understate actual methane emissions from LNG shipping and support adjusting emission factors and certification protocols to reflect real-world operation conditions.

However, the FUMES study focused solely on low-pressure, premixed-combustion LNG dual-fuel engines and did not include high-pressure gas-injection, diesel-cycle LNG engines (e.g., two-stroke ME-GI architectures); therefore, its methane slip findings are not representative of high-pressure LNG engine technologies. A comprehensive review of methane emissions from LNG vessels found that high-pressure, two-stroke slow-speed engines already show very limited methane slip on the order of ~0.15–0.2% of fuel gas supplied [57]. Methane slip from high-pressure LNG marine engines is inherently low due to their diesel-cycle combustion architecture and direct high-pressure gas injection strategy. In two-stroke high-pressure dual-fuel engines (e.g., ME-GI-type systems), natural gas is injected directly into the combustion chamber at very high pressure and ignited using a pilot diesel flame, eliminating the formation of premixed gas–air mixtures and associated scavenging losses that are the dominant sources of methane slip in low-pressure LNG engines. As a result, methane emissions are limited to minor residual mechanisms such as crevice volumes and quench zones and are typically near measurement limits, often treated as negligible in lifecycle assessments. This combustion configuration fundamentally differentiates high-pressure LNG engines from low-pressure premixed systems and enables LNG operation with minimal unburned methane emissions, preserving the potential climate benefits of natural gas relative to conventional marine fuels. Everllence's ME-GI two-stroke dual-fuel engines, which operate on the diesel cycle, are designed to minimize methane slip. Everllence reports methane slip levels as low as 0.2 g/kWh, with a margin of ±0.1 g/kWh[58]. According to SEA-LNG, two-stroke diesel cycle engines have negligible levels of methane slip orders [55].

In contrast, two-stroke Otto cycle engines, like MAN's ME-GA engine, traditionally have higher methane slip. However, when equipped with EGR, the ME-GA engine can reduce methane emissions by up to 50 percent compared to Otto engines without EGR. Strides have also been made to reduce methane slip from low-pressure dual-fuel four-stroke engines including a 56 percent reduction achieved by Wärtsilä for a RoPax ferry. Additionally, LNG requires cryogenic storage tanks that vent methane under certain conditions (i.e., high tank pressure from boil-off gas) and could be a significant source of GHG emissions from LNG vessels no matter which type of engine is being used.

Table 4. Summary of Methane Slip from LNG Marine Engines. From References [56], [57], [58], [59].

Engine Type (Fully Spelled Out)	Methane Slip (% of fuel gas)
High-Pressure Dual-Fuel, 2-stroke diesel-cycle engine (HPDF 2-S)	~0.15–0.2%
Low-Pressure Dual-Fuel, 2-stroke engine (LPDF 2-S)	~1–2%
Low-Pressure Dual-Fuel, 4-stroke engine (LPDF 4-S)	~2–6% (can exceed 10% at low load)
Lean-Burn Spark-Ignited, 4-stroke gas engine (LBSI)	Often higher, especially at low load

Technology Readiness

LNG-fueled engines benefit from decades of experience powering LNG carriers that use boil-off gas as a fuel. Engine manufacturers and ship builders have developed reliable dual-fuel engines and integrated fuel systems for broader ship types. Marine engines running on LNG are fully mature and biomethane and e-methane could be directly used without technical restrictions [19]. Everllence has a long history of developing LNG engines including dual-fuel retrofits for both two- and four-stroke diesel engines. It also launched the first two-stroke dual-fuel (ME-GI) engines with high-pressure gas injection and diesel cycle combustion [60]. The development of two-stroke dual-fuel engines based on high-pressure gas injection (ME-GI) and diesel-cycle combustion fundamentally enabled LNG operation across a wide range of vessel types by preserving conventional diesel engine performance characteristics while providing fuel flexibility, high power scalability, and operational stability, thereby allowing LNG to transition from niche applications into mainstream deep-sea shipping sectors.

The TRL for all LNG propulsion system elements is 9 [44]. As previously stated, there are approximately 535 LNG-powered ships in operation as of mid-2024 including 137 oil and chemical tankers, 93 container ships, and 53 bulk carriers [1]. According to one projection, the total number of LNG-powered ships could grow to more than 1,200 by the end of 2028 [55]. Several major container operators are investing in LNG dual-fuel vessels including MSC, CMA CGM, Maersk, and Hapag-Lloyd.

Economics

The economics of LNG as a marine fuel depend on a range of factors including construction cost, operational savings, and external market conditions. LNG-fueled ships typically have higher upfront costs compared to conventional vessels [54]. Total system cost for LNG 2-stroke engines is typically 40 percent–60 percent higher than conventional HFO engines, resulting in CAPEX premiums of $15-$30 million [22], [61]. The cost for dual-fuel 2-stroke LNG engines (e.g., Everllence B&W ME-GI, WinGD X-DF) is higher as they have complex fuel injection, control, and combustion systems. A fuel gas supply system is necessary to ensure gas is supplied to the engine at the correct pressure and temperature and includes vaporizers, compressors, pressure regulation, and safety systems. Additional costs also arise from the need for insulated LNG tanks, gas piping, dual-fuel engines, and ancillary safety system. LNG tanks alone can amount to an additional $10–15 million for large container ships [53]. The cost varies by ship size and vocation. For example, cruise ships with membrane tanks have higher added costs relative to simpler container ships with standard tanks, which have seen cost reductions as more vessels are constructed. This has been noted in newbuild shipbuilding efforts (largely in Asia) where incremental costs have been reduced by standardizing designs. Retrofitting existing ships to LNG can be even costlier depending on the vessel type and vocation. Therefore, it is unknown if LNG retrofits will gain widespread acceptance. However, current LNG bunker prices are often lower than conventional fuels and have also benefited from avoiding the costs of aftertreatment systems to meet environmental regulations.

Table 5. CAPEX for propulsion systems and fuel storage systems in $2021 from Reference [62].

Component	Retrofit Cost (US$/kW)	New Build Cost (US$/kW)	Lifetime
Propulsion systems			
ICE Diesel, Biodiesel	-	240/460 [a]	30 years
ICE, Methanol	328	265/505 [a]	30 years
ICE, Ammonia		370/600 [a]	30 years
ICE, LNG, LBG, Hydrogen	900	387/850 [a]	30 years
Fuel cell, SOFC	-	4000–9000	7–12 years
Fuel cell, PEMFC	-	730–2860	7–12 years
Electrical and generator, LNG, LBG, Hydrogen	-	400	30 years
Electric motor	-	250	30 years
Fuel storage system			
Gas supply system + tank, LNG, LBG (USD$/kg)	270–420	270–420	30 years
Gas supply system + high pressure tank (700 bar), Hydrogen (USD$/kg)		576–868	30 years
Battery, Nickel manganese cobalt oxide (NMC) (USD/kWh)	-	400–1000, and expected to fall to 124 in 2030	3000–4000 cycles (8–11 years)
Battery, lithium–iron–phosphate (LPF) (USD/kWh)	-	210–1000, and expected to fall to 70 in 2030	2000–5000 cycles (7–13 years)

[a] Four-stroke engine/two-stroke engine.

While the CAPEX of a dual-fuel engine OGV is higher than a single-fuel engine, some studies have concluded that dual-fuel vessels can achieve a favorable TCO over the life of the vessel, particularly when those vessels sail on certain high-usage routes [53]. Additionally, CAPEX of a dual-fuel OGV is somewhat offset over time through lower emissions, potential fuel cost savings, and compliance with IMO emissions regulations without the use of scrubbers. The significant growth in orders for LNG-fuel ships indicates that many owner/operators believe LNG is currently the most economically viable solution for immediate emissions compliance and can represent an interim step towards more advanced fuels such as methanol and ammonia. According to SEA-LNG, LNG dual-fuel vessels provide the lowest cost option to meet IMO decarbonization regulations relative to ammonia and methanol, as even fossil LNG has lower GHG emissions than conventional fuels, and vessels can avoid using expensive MGO to comply with ECA restrictions [55].

However, fuel price volatility and the additional training and infrastructure requirements pose economic risks that must be managed. Additional considerations include the costs of workforce training and new operating procedures as crew members are required to have specialized training per the IGF Code requirements to handle LNG. To address this, many maritime training centers now offer LNG handling courses.

Next Steps to Demonstration/Deployment

LNG-fueled vessels are already commercially operating and the number of LNG vessels on the water and on order are growing rapidly. To support the growing fleet, LNG bunkering, including vessels and port facilities, is expanding globally to approximately 200 ports worldwide [53]. In order to achieve the environmental benefits of LNG-powered vessels, the use of renewable or green methane will be required. A more detailed overview of the next steps from a fuel perspective can be found in Chapter 3.

The implementation of the IMO global 0.5% sulfur fuel limit in 2020 significantly increased industry interest in LNG as a marine fuel, as LNG inherently complies with sulfur regulations while also offering co-benefits in NO_x and particulate matter reductions, and partial GHG mitigation relative to HFO. LNG vessels may be particularly attractive to operators traveling on regular routes that include significant portions in SO_x ECA zones, such as the Hawaii to California and Washington to Alaska routes. Interest in LNG may also increase if additional ECA zones are established.

Liquid Biofuels

The following section provides an overview of the use of liquid biofuels from an engine perspective. An overview of the fuels themselves can be found in Chapter 3. The chief liquid biofuels being considered for widespread use in the marine sector are HVO/renewable diesel and FAME/biodiesel.

Technology Description

HVO/renewable diesel has the benefit of being drop-in capable which allows it to be used in existing marine engines with little to no modification required. Thus, any current marine engine should be able to transition to HVO fuels without a detriment in engine performance.

Fatty acid methyl ester (FAME) biodiesel exhibits chemical and physical properties that differ significantly from fossil diesel, including higher polarity, oxygen content, viscosity, hygroscopicity, and solvent behavior, all of which can influence combustion performance, materials compatibility, and long-term engine durability [63]. For example, the higher viscosity and density of biodiesel can negatively impact the performance of fuel filters and fuel pumps in compression ignition engines [63]. As a result, the use of high biodiesel blends may necessitate targeted engine and fuel-system modifications, including the replacement of elastomers and seals with biodiesel-compatible materials, corrosion-resistant fuel system components, recalibration of injection timing and pressure, and adjustments to combustion strategies to manage ignition behavior and emissions formation. Additional system-level adaptations may include enhanced fuel filtration and water management systems, modified lubrication practices to address oil dilution and oxidation, cold-start support systems, and recalibrated aftertreatment strategies. While low-level biodiesel blends typically require minimal changes, high-blend and neat biodiesel applications often demand integrated hardware, software, and operational modifications to ensure reliable, durable, and emissions-compliant engine operation.

Additionally, engine age is generally correlated with the scope of modifications required to enable reliable operation on FAME/biodiesel fuels. Older engine platforms, particularly those developed prior to modern fuel-flexibility standards, typically require extensive hardware and materials upgrades due to incompatibilities in seals, elastomers, fuel lines, injection systems, and fuel storage components, as well as limited combustion and injection control capability. In contrast, newer engine generations increasingly incorporate biodiesel-compatible materials, electronically controlled injection systems, adaptive combustion strategies, and integrated aftertreatment, significantly reducing the need for physical modifications and shifting required changes toward calibration, software updates, and operational practices. As a result, the technical and economic burden of biodiesel adaptation decreases systematically with engine generation, making newer platforms inherently more suitable for high-blend biodiesel deployment.

Biodiesel has slightly lower energy content than conventional marine fuels which can reduce engine power and may reduce fuel efficiency by 2-10 percent [64]. Fuel handling and storage may also require additional steps including regular water draining and biocide (i.e., a chemical additive to control bacteria and prevent problems associated with contamination) in fuel tanks and preheating of fuel in colder weather. Marine engines have already operated successfully on a wide range of FAME blends, including B20–B30, B50, and even B100, often with minimal or no system modifications [65]. In particular, blends up to B30 can generally be used without modifications to engines or fuel systems. Trials with B100 in both main and auxiliary engines with over 30,000 operating hours showed positive results without major equipment changes. However, higher blends of FAME do present challenges such as cold flow limitations, oxidation, and storage stability and not all OEMs have approved B100 to be used in their engines. As a result, using high-blend FAME fuels may require minor system upgrades, including modernized hoses, filters, seals, and improved fuel treatment systems. Additionally, FAME's short shelf life means that it should ideally be consumed within eight weeks, unless stored between 14°C and 43°C or treated with stability additives [65]. These limitations make FAME especially well-suited for shorter routes or frequent refueling operations.

System/Network Suitability and Operational Infrastructure Needs

Drop-in fuels are generally easier to integrate than other alternative fuels, and the existing MGO and HFO infrastructure can be directly used by biofuels, though some fuels such as FAME may require minor fuel system modifications and other considerations like how the fuel is handled, stored, and used onboard. Slight engine tuning or aftertreatment systems may also be needed to ensure compliance with international emissions regulations, including IMO Tier III NOx limits. Reliable and scalable supply chains for sustainable feedstocks must also be established to ensure consistent fuel availability without creating competition with food systems or causing land-use conflicts (discussed in Chapter 3). Fuel suppliers need to provide standardized, traceable, and certified fuels that meet marine-grade specifications, such as the

International Organization for Standardization's (ISO) 8217 standard, and offer verified well-to-wake GHG emissions profiles to support regulatory compliance under IMO and EU directives.

Newbuild or Retrofits

Current vessels can utilize biofuels such as HVO with minimal changes to existing engines; therefore, retrofitting is not required. Lower FAME biodiesel blends can also be used with little to no modification, while higher blends may require fuel system upgrades. New build vessels that have the ability to operate on conventional fuels, including single- and dual-fuel engines using other fuels (e.g., methanol, ammonia, LNG), can utilize biofuels immediately.

Potential Emission Reductions

Life-cycle biofuel GHG emissions vary widely depending on fuel type, feedstock, process used, the transportation of feedstocks and fuels, treatment of potential co-products, and whether or not carbon capture is used. Carr et al., estimate that FAME fuels can reduce life cycle CO_2 emissions by ~50–80 percent compared to fossil diesel, depending on the feedstock [65]. Waste oils (e.g., used cooking oil) offer greater reductions than palm or soybean oil, which can involve land-use change emissions. However, the availability of waste oil feedstock is a significant limitation on production potential (discussed in Chapter 3). Life cycle HVO drop-in fuels have the potential to markedly reduce life cycle CO_2 emissions relative to conventional fossil diesel, with reductions commonly reported in the range of ~60–90 % when the fuel is produced from waste-based or residue-based feedstocks [66], [67]. High end-of-range savings (approaching ~90 %) are typically achieved when low-impact, biogenic raw materials such as used cooking oil or animal fats are used and when life cycle accounting includes the carbon uptake during biomass growth and avoids significant land-use change emissions. The magnitude of life cycle GHG reductions depends on feedstock selection and production pathways, with highest benefits associated with waste-derived HVO.

Biofuels are typically sulfur-free, which means they can significantly reduce or even eliminate SO_x emissions from marine engines. In practice, any remaining SO_x emissions would be due to pilot fuel or lubricating oil containing sulfur. If biofuels are used in blends with conventional marine fuels (rather than as pure fuels), the degree of SO_x reduction will depend on the blend ratio, e.g., B30 would achieve an approximately 30 percent reduction in SO_x. Typically, when biofuels are used as the sole fuel (i.e., not blended with conventional diesel) SO_x emissions are essentially eliminated.

Transitioning from conventional diesel to HVO fuels is generally associated with lower emissions of CO and unburned hydrocarbons due to improved combustion efficiency. HVO fuels exhibit significantly higher cetane numbers (typically 75–90) compared to petroleum diesel (around 40–55), which promotes shorter ignition delay and more complete oxidation of the fuel–air mixture, reducing incomplete combustion products [68]. Engine and vehicle studies have documented that HVO typically produces lower CO and hydrocarbon emissions than conventional diesel under a range of operating conditions, with some tests showing CO and total hydrocarbon reductions that are substantial relative to baseline diesel [69], [70]. Although the precise percentage reduction in CO and HC varies with engine type and test cycle, the trend toward reduced incomplete combustion emissions with HVO is well supported by experimental evidence, consistent with its chemical and combustion characteristics.

Impacts of biofuels on NO_x is nuanced and varies based on biofuel type, engine type, load, and the baseline fuel used for comparison. For example, at low engine loads FAME may cause a slight increase in NO_x but lead to a slight decrease at higher loads [65]. An extended ignition delay promotes greater air–fuel mixing within the combustion chamber, resulting in a larger fraction of premixed combustion. This enhanced premixing leads to more rapid pressure and temperature rises during combustion compared to operation on conventional diesel fuel. Because thermal NOx formation increases strongly with peak combustion temperature, longer ignition delays are therefore associated with elevated NOx emissions. Some studies have shown slight NO_x emission reductions (5-15 percent) in uncontrolled engine configurations due to reductions in flame temperatures [71], [72]. However, testing conducted by Lloyd's Register using FAME blends ranging from B20 to B100 in both two- and four-stroke marine engines found that NO_x emissions were not significantly different from conventional fuels, although some test conditions showed slightly higher NO_x levels. This trend has been confirmed by engine manufacturers and industry stakeholders who conducted their own independent evaluations [65]. On the other hand, other studies have shown a minor increase in NO_x due to the higher oxygen content and different combustion characteristics of HVO fuels [73]. However, adjustments to engine operation including advanced injection timing and optimized EGR can help mitigate any NO_x increases. Pure biodiesel (B100) has frequently been observed to produce higher NO_x emissions than conventional diesel fuel under comparable engine operating conditions compared with conventional diesel fuels [74], [75], [76], [77]. Most literature reviews report modest increases (on the order of 10–30%) in NO_x with B100 relative to petroleum diesel, reflecting biodiesel's fuel chemistry and combustion characteristics. In specific test programs, increasing biodiesel content was correlated with elevated NO_x across engine loads compared to ultra-low sulfur diesel fuel, although the effect can vary with engine design and aftertreatment systems.

Biofuels generally achieve reductions in PM emissions compared to conventional marine fuels, though results can vary by fuel type, engine load, and testing conditions. FAME fuels can reduce PM emissions by 38–90 percent compared to fossil marine fuels with greater PM reductions observed at higher engine loads [65]. However, one study noted a 25 percent PM increase at 50:50 FAME/conventional blend under low-load conditions [78]. Limited data is available on the PM emission impacts of HVO compared to conventional fuels, with reported impacts ranging from a 38 percent decrease (on-board testing vs. ultra-low sulfur diesel (ULSD)) to a 30 percent increase (lab testing vs. MGO) [65].

Most marine biofuel emissions studies have focused on smaller 4-stroke engines under laboratory conditions. However, recent on-board testing on large commercial vessels has begun to validate biofuel emissions signatures under operational conditions. Stathatou et al. (2022) evaluated emissions from the dry bulk vessel *Kira Oldendorff* using a 50:50 blend of MGO and FAME biodiesel and reported CO_2 emissions were slightly higher at low engine loads (0.4 percent and 5 percent increases) but lower at higher loads, resulting in an overall tank-to-wake CO_2 reduction of 1.2 percent [79]. However, the study estimated a 40 percent reduction in life cycle CO_2 emissions. NO_x emissions also showed a load-dependent pattern with slight increases at low loads (10 percent and 2 percent) but decreased at higher loads leading to a total NO_x reduction of 3 percent over the full load profile. All measured NO_x emissions remained compliant with IMO Tier II standards. SO_X emissions were estimated to decrease by 50 percent following the fuel blend level. A similar study by Chountalas et al. (2023) assessed the use of a B30 biofuel blend in a bulk carrier and found a modest increase in NO_x emissions of 7 percent compared to MGO and 3.5 percent compared to HFO, though these levels also remained within IMO regulatory limits [80]. Overall, these studies suggest that while NO_x emissions may rise slightly at lower loads, biofuel blends can significantly reduce SO_x and life cycle CO_2 emissions without requiring major modifications to vessel systems.

The existing literature on the emission impacts of biodiesel generally reports that its use can reduce emissions of unburned hydrocarbons, PM, CO_2, and CO, but may increase NO_X [64]. However, some recent studies have shown that emissions may not be reduced as originally thought. Shown in Table 6, a meta-analysis of 131 biodiesel exhaust emissions studies conducted between 1983 and 2018, across a wide range of feedstocks, engines, test cycles, and emission control technologies found that using a B20 blend of biodiesel increased NO_x by 4 percent, unburned hydrocarbons by 7 percent, CO by 10 percent, and did not reduce PM from traditional diesel [81].

Table 6. Biodiesel exhaust emissions reported in percent change in emissions between B20 and petroleum diesel fuel. From reference [81].

Pollutant	EPA (2002)	EPA (2010)	Hoekman & Robbins (2012)	This study (all data)	This study (modern conditions)
NOx	2%	2%	1%	2%	4%
PM	-10%	-16%		-6%	Insignificant
HC	-21%	-14%		-4%	7%
CO	-11%	-13%		Insignificant	10%

Technology Readiness

HVO drop-in fuels can be used by currently commercial ICE, as well as future engines designed to use alternative and conventional fuels.

Reflecting their immediate suitability for deployment in conventional marine engines, commercial operation on biodiesel/FAME blended with conventional fuels has achieved commercial maturity. Engines able to use pure biodiesel are expected to reach full maturity in the late 2020s due to their compatibility with existing diesel engines with minimal modification [19]. It should be noted that bio- and renewable diesel can also provide the 'pilot' fuel to initiate/stabilize combustion of other zero- and low-carbon fuels.

Wärtsilä has confirmed that many of their currently available engines can operate on biofuels that meet established standards including the Wärtsilä 20, 31, 32, and 46 diesel and dual-fuel engines. However, they recommend that the compatibility of engine materials and fuel-system components be confirmed prior to biofuel transitions.

Table 7 provides an overview of accepted biofuel use for Everllence two-stroke engines including suitability for engine design, Tier III equipment, and pilot fuel in dual-fuel engines as of July 2023. All current Everllence engine designs can utilize both FAME and HVO fuels and blends, as long as the biofuel meets specifications and is treated according to best practice procedures.

Table 7. Overview of accepted biofuel use from Everllence including engine design, Tier III equipment, and pilot fuel in dual-fuel engines [82].

Overview of accepted biofuel use

	Biofuel			
Technology	**FAME**	**HVO**	**Similar FAME-type**	**Blends**
Engine design: MC/MC-C, ME/ME-C, ME-B, ME-GI, ME-GIE, ME-LGIM, ME-LGIP and ME-GA	Acceptable[1)]	Acceptable[1)]	Acceptable[1)]	Acceptable[1)]
Tier III: EGR, EcoEGR	Acceptable[1)]	Acceptable[1)]	Acceptable[1)]	Acceptable[1)]
Tier III: HPSCR[2)]	Acceptable[1)]	Acceptable[1)]	Acceptable[1)]	Acceptable[1)]
Tier III: LPSCR[2), 3)]	Acceptable[1)]	Acceptable[1)]	Acceptable[1)]	Acceptable[1)]
Pilot fuel in dual-fuel engines	Acceptable[1)]	Acceptable[1)]	Acceptable[1)]	Acceptable[1)]

1) Lifetime of components may be reduced.
2) Urea consumption may slightly increase due to potentially slightly increased NO_X during biofuel operation.
3) LPSCR is only for max 0.10% S fuels.

Economics

The economics of biofuels are generally more competitive relative to other alternative fuels given their drop-in nature, which allows for the use of conventional ICE engines. Table 5 estimates the cost of ICE utilizing biofuels to be equivalent to ICE using fossil fuels. Therefore, the economics of biofuels depend largely on fuel costs rather than engine cost. which are discussed in detail in Chapter 3.

Next Steps to Demonstration/Deployment

Biofuels are available and being utilized commercially now. However, the scale-up of biofuel use in the marine sector will be dependent on production, storage, and bunkering infrastructure scale-up, which is discussed in Chapter 3.

Hydrogen Engines and Fuel Cells

Hydrogen can be used as a fuel both through combustion in reciprocating engines or turbines, or through electrochemical conversion in fuel cells. The following section discusses both options.

Technology Description

Combustion Engines

There is a substantial and growing global interest in hydrogen internal combustion engines (H_2-ICE) across multiple transportation sectors, including maritime shipping and on-road heavy-duty vehicles. As of 2023, the U.S. Department of Energy reported that over 130 original equipment manufacturers (OEMs) were either interested in, planning, or already executing hydrogen engine research and development projects, reflecting broad industry engagement in advancing hydrogen combustion technologies [83]. This documented level of OEM involvement highlights the global momentum around H_2-ICE as a potential pathway for decarbonization, particularly where existing internal combustion technologies can be leveraged to integrate hydrogen combustion with established engine platforms.

Interest in H_2-ICE is not limited to a single sector. Academic and industry analyses have identified hydrogen combustion engine solutions being explored for both heavy-duty road transport *and* maritime applications, driven by the need for low-carbon propulsion alternatives where electrification poses challenges due to range, energy density, or infrastructure constraints. In some maritime markets, hydrogen combustion has already reached early demonstration stages with dual-fuel vessels such as hydrogen-powered tugboats, evidencing real-world experimentation with hydrogen in traditional engine architectures.

Momentum appears stronger in global markets than the U.S., particularly in Europe and parts of Asia, which have incorporated more direct regulatory signals that support hydrogen combustion strategies [83]. Recent technological analyses cite the enactment of European Union emissions standards designed to encourage uptake of low- and zero-emission powertrain technologies across heavy-duty segments, which can increase OEM confidence and investment in production of H_2-ICE [84]. These kinds of legislative drivers help create a more conducive deployment environment, aligning industrial strategy with long-term decarbonization targets. Hydrogen combustion engines for marine applications use hydrogen gas as a fuel in modified internal ICE. Potential engine configurations include spark-ignition, dual-fuel, and hydrogen-diesel direct injection, using high-pressure hydrogen typically timed after pilot diesel. In addition, some experimental work has been done studying hydrogen-ammonia dual-fuel engines which use hydrogen to stabilize ammonia combustion.

The choice of combustion cycle is critical in the design and performance of hydrogen ICE, particularly for marine applications, as it directly influences the engine architecture, fuel supply system, emissions profile, and overall system costs. Two primary combustion concepts are commonly used: low-pressure dual-fuel engines operate on the Otto cycle in gas mode but switch to the Diesel cycle when using fuel oil. High-pressure (HP) dual-fuel engines use the Diesel cycle for both gas and fuel oil operation. These engines operate on a premixed air-fuel charge, with gas introduced at relatively low pressures via gas admission valves. However, with high-pressure dual-fuel (HP DF) engines, gas is directly injected into the combustion chamber at high pressures, enabling non-premixed, diffusion-based combustion.

In both engine types, the combustion process is initiated using a pilot fuel delivered either through the conventional fuel-injection system or a dedicated pilot system. The timing and method of gas injection within the combustion cycle determine the required gas supply pressure and influence ignition stability and combustion efficiency.

Hydrogen four-stroke engines are nearing demonstration level and may reach commercial operation by 2030 [19]. Hydrogen-fueled four-stroke dual-fuel engines typically follow the Otto cycle approach, utilizing premixed hydrogen-air mixtures and low-pressure gas delivery systems [3]. While the Otto cycle offers advantages over the Diesel cycle in terms of simplicity and lower peak combustion pressures, it also must overcome operational challenges, including careful control of the air-fuel ratio to avoid knocking or misfires, particularly when operating at variable loads or during rapid power transitions. This can result in slower engine response times to changes in power output demands. Hydrogen's high heat-release rate and broad flammability range lead to elevated thermal loads on engine components, particularly in the combustion chamber. These high peak temperatures can contribute to increased NO_x emissions, which are a key regulatory and environmental concern. Managing the thermal stresses on critical parts such as pistons, cylinder liners, and lubrication oil is essential to ensure engine durability and safety. These factors make combustion system design, materials selection, and cooling strategies especially important in the development of hydrogen-fueled Otto cycle engines.

As an example of an advanced system that combines multiple alternative technologies and fuels including hydrogen combustion, the HyMethShip system includes a membrane reactor, a carbon capture, utilization and storage (CCUS) systems, a storage system for CO_2 and methanol as well as a hydrogen-fueled combustion engine [7]. The HyMethShip system reforms methanol to hydrogen, which is then burned in a conventional reciprocating engine that has been upgraded to operate with multiple fuel types and specially optimized for hydrogen. Renewable methanol is used as the energy carrier and pre-combustion CO_2 capture and storage further reduces CO_2 emissions. HyMethShip converts methanol to hydrogen because separating CO_2 before combustion is far more efficient than trying to capture it from exhaust gases. By reforming methanol into hydrogen and CO_2, the system can capture a concentrated CO_2 stream and burn only hydrogen, resulting in carbon-free exhaust. Directly burning methanol would dilute CO_2 in exhaust gases, making capture technically harder, more energy-intensive, and less efficient. The design is therefore optimized for high-efficiency carbon capture and deep decarbonization, not simply fuel substitution.

Several technical and regulatory challenges exist for hydrogen ICE including the installation of on-board hydrogen storage and fuel supply systems. Hydrogen must be stored at high pressure or cryogenic temperatures, which requires considerable space and introduces complexity in terms of safety systems, insulation, and integration with existing vessel designs. Additionally, hydrogen's combustion characteristics require careful management through engine design modifications, combustion control systems, and potentially the addition of an SCR. Most hydrogen ICE also require a pilot fuel, typically a small amount of diesel or biodiesel, for ignition. Regulatory considerations are another important factor. While classification societies and flag states are developing safety and design standards for hydrogen, these regulations are still evolving. Any retrofit project must navigate emerging rules related to hydrogen bunkering, leak detection, ventilation, explosion protection, and emergency shutdown systems. This regulatory uncertainty can increase project timelines and costs.

Fuel Cells

Fuel cell vessels generate electricity through electrochemical reactions in fuel cells, most commonly using hydrogen, and this electricity is used to power electric propulsion systems (motors, propellers, or thrusters). Fuel cells can operate on fuels other than hydrogen, either by reforming hydrogen-containing fuels (such as methanol, ammonia, or natural gas) into hydrogen, or by using high-temperature fuel cells (e.g., Solid Oxide Fuel Cells) that can electrochemically oxidize these fuels directly. Fuel cell vessels can store hydrogen or other fuels as compressed gas in high pressure tanks or as a liquid using cryogenic refrigeration tanks. Hydrogen is fed to a fuel cell stack where hydrogen reacts with oxygen to produce electricity and water, with the electricity being used to power an electric motor to drive the propulsion or auxiliary systems of vessels. Water produced by marine fuel cells may be vented overboard or recovered for onboard use, depending on system integration and vessel design. While most current deployments vent the water for simplicity, future large-scale fuel cell vessels are expected to increasingly recover and reuse product water for technical systems, auxiliary services, and closed-loop hydrogen production architectures.

Additionally, fuel cell vessels incorporate a battery system that is used as an energy buffer for peak power demands or when the fuel cell is not operating, although the battery system is significantly smaller than those used for electric vessels. There are also several hybrid system configurations that can incorporate ICE engines with fuel cells, including both diesel-fuel cell hybrid and diesel-electric fuel cell hybrid engines.

There are numerous potential configurations for fuel cells, with an overview of technologies being considered for the maritime industry provided in

Table 8. These include alkaline fuel cells (AFC), PEMFCs (low temperature (LT) and high temperature (HT), and SOFCs.

Table 8. Overview of fuel cell types, characteristics, and current status for maritime applications. Adapted from Reference [85].

Fuel Cell Type	Operating Temp.	Efficiency	Fuel Flexibility	Power	Pros	Cons	Maritime Status
Alkaline Fuel Cell (AFC)	60–70°C	60–70%	Hydrogen	0.5–200 kW	High efficiency, quick start-up	Liquid electrolyte adds weight, early-stage for marine	In development
Proton Exchange Membrane Fuel Cell (PEMFC)	LT: 80–100°C HT: up to 200°C	45–60%	Hydrogen (unless used with reformer)	0.12–5 kW	Lightweight, compact, fast start-up	Sensitive to humidity, costly platinum catalyst	LT PEM: Commercially available HT PEM: In development

Solid Oxide Fuel Cell (SOFC)	500–1,000°C	50–65% (> 70% at stack level)	Very high: H_2, LNG, methanol, ammonia, etc.	0.01–2,000 kW	Fuel-flexible, high efficiency, good for waste heat recovery (WHR)	Long cold start time, high heat, large footprint	Early demonstration stage, expected commercial 2025–2026

Methanol, ammonia, and methane can either be used directly in some fuel cells or reformed on-board to produce hydrogen which can then be used. Conversion of other fuels into hydrogen facilitates a wider choice of fuel cell types but also adds complexity and cost to on-board equipment. Full commercialization of the various fuel cell technologies for propulsion is unclear due to uncertainties associated with technological feasibilities, efficiencies, and costs relative to their respective combustion engines.

Fuel cells occupy a comparable space to conventional marine ICE; however, the cryogenic fuel system and storage tanks require approximately 8 times greater storage capacity than that of conventional systems if liquid hydrogen is used [65]. Theoretically, if granted identical on-board fuel space capacities, a hydrogen fuel cell vessel could only transport ~13 percent of the energy carried by HFO. Therefore, hydrogen tanks are less flexible in terms of space utilization, and given the existing storage options, would primarily suit ships sailing short-to-medium distance voyages.

System/Network Suitability and Operational Infrastructure Needs

The scale-up of hydrogen as a maritime fuel will require the buildout of significant infrastructure to support the production, storage, transport, distribution, and bunkering of hydrogen for both fuel cells and ICE. This topic is covered in more detail in Chapter 3.

In California, the *Sea Change* remains the only example of hydrogen refueling infrastructure for vessels, although it has ceased to operate at this time. The Sea *Change* refueled using a mobile tanker truck to deliver gaseous hydrogen directly to the vessel. The *Sea Change* was the first hydrogen fuel cell vessel in the U.S. and the world's first commercial fuel cell ferry [86]. Each refueling provides approximately 70-80 kg of hydrogen, which is less than the 240 kg onboard storage capability due to the use of smaller tanker trucks. To facilitate this, Zero Emissions Industry (the operator of the *Sea Change*) has developed a unique fueling system that allows direct fueling from the tanker truck and offers the system as a commercial product [87]. Given the safety concerns around hydrogen, the current refueling process must comply with stringent regulatory and safety requirements. For example, the refueling of the *Sea Change* must follow an engineered fueling plan approved by all authorities having jurisdiction including the United States Coast Guard, the Port authority, the Fire Marshal, and others. The requirements for hydrogen are significantly more stringent than those required for conventional refueling, and similar protocols will need to be developed for hydrogen fueling of larger vessels, which may be even more intensive due to the larger amounts of hydrogen required. However, it is likely that refueling protocols and regulations will become more relaxed as experience with hydrogen is gained for maritime use.

Worldwide examples of maritime hydrogen refueling include the *MF Hydra* ferry in Norway. Reflecting the energy density benefits, renewable liquid hydrogen is trucked from a Linde electrolyzer plant. Linde also designed and built the fuel containment system, the associated onshore truck-to-ship bunkering facility, on-board storage tank, and fuel processing equipment [88]. The *MF Hydra* has been designed to utilize three tons of liquid hydrogen provided every three weeks.

As an example of a novel strategy for vessel hydrogen refueling, Hornblower Group led the design and construction of the first floating hydrogen fueling station for CHC refueling [89]. The station was built as a pioneering facility for hydrogen production, storage, and fueling, with a capacity of handling up to 530 kilograms of hydrogen per day. Glosten is leading the design and integration of the hydrogen production, storage, and bunkering equipment and working with the U.S. Coast Guard to establish the regulatory framework and design approvals. The goals of the project include demonstrating the feasibility and viability of hydrogen production, storage, and fueling on the water, establishing robust science-based protocols, procedures, operating parameters, and attendant training materials for the safe and routine generation and storage of electrolyzed hydrogen and handling of water-to-water and water-to-land hydrogen and fuel-cell power transfer.

Newbuild or Retrofits

Combustion Engines

Retrofits are actively being considered and demonstrated in hydrogen ICE particularly as a near-term strategy for short-sea and inland vessels where full electrification or fuel cell adoption is not yet feasible due to space, cost, or power density constraints. Hydrogen ICEs are based on the same mechanical principles as traditional diesel engines which simplifies integration, training, and maintenance compared to novel technologies like fuel cells. Retrofitting also avoids the high capital costs associated with building new vessels and allows operators to upgrade mid-life ships rather than scrapping them prematurely. Because hydrogen ICE can often be built on existing platforms, retrofits can also be carried out more quickly than newbuild.

BeHydro is a Belgian joint venture between CMB.TECH and Anglo Belgian Corporation that develops hydrogen and hydrogen dual-fuel internal combustion engines for marine applications, rather than fuel cell systems. Its most prominent demonstration platform is the hydrogen dual-fuel tug *Hydrotug 1*, which is powered by BeHydro V12 hydrogen-capable engines and operates on compressed hydrogen and conventional fuel [90]. Built at Astilleros Armon shipyard and developed by CMB.TECH, the vessel entered commercial service in 2024 at the Port of Antwerp-Bruges, where it is used for real-world tug operations as part of a broader hydrogen ecosystem demonstration. BeHydro's engine technology has received marine class type approval (including from Lloyd's Register), confirming its regulatory readiness for commercial deployment, and the project represents one of the most advanced operational demonstrations of hydrogen combustion propulsion in the maritime sector. Type approval is a formal certification process where Lloyd's Register independently verifies that a specific product, system, or piece of equipment complies with its technical rules, international maritime standards, and relevant regulations before it is installed on a vessel.

Regulatory considerations are another important factor. While classification societies and flag states are developing safety and design standards for hydrogen, these regulations are still evolving. Any retrofit project must navigate emerging rules related to hydrogen bunkering, leak detection, ventilation, explosion protection, and emergency shutdown systems. This regulatory uncertainty can increase project timelines and costs.

Fuel Cell Retrofits

Retrofitting a vessel with a fuel cell powertrain is more complicated than converting a combustion engine to operation on a different fuel. Additionally, there are challenges in converting fuel storage and supply systems. However, new vessels can potentially be designed to be more easily converted from conventional ICE to fuel cell operation, e.g., the use of electric propulsion systems.

Future vessels will need integrated designs that account for operational profiles and selected fuel power generation and propulsion systems. The use of fuel cell and fuel cell hybrid systems can change the architecture of current engine rooms used for conventional ICE. On one hand, fuel cell engine systems may be larger due to lower volumetric energy densities of the fuel, but they may also require less accessible maintenance space, which means there is potential to increase the efficiency of space utilization. Additionally, space on vessels is optimized with fuel cell and battery electric systems as electrical equipment is distributed throughout the vessel rather than concentrated in one place. Another challenge may include the weight of large fuel cell installations.

Potential Emission Reductions

Emissions from using hydrogen in maritime applications depend entirely on the conversion device used, including whether it is combusted in an ICE or used in electrochemical conversion in a fuel cell. Additionally, the specific fuel supply chain determines the life cycle impacts for both GHG and pollutant emissions.

Fuel cells convert hydrogen to electricity through an electrochemical reaction which produces only water vapor and negligible pollutant emissions. Pilot fuels are not required in fuel cell systems, meaning hydrogen-powered vessels using fuel cells have zero direct GHG and pollutant emissions during all stages of vessel operation. A 2023 feasibility study on a high-speed passenger ferry powered by hydrogen fuel cells and renewable hydrogen showed that such a system would reduce NO_x emissions by 99.2 percent and PM emissions by 98.6 percent, compared to a diesel-powered ferry [3]. The use of fuel cells operating on alternative fuels (hydrogen, methanol, ammonia) to replace conventional ICE using fossil fuels can also significantly reduce well-to-wake GHG emissions, potentially over 95 percent (Table 9). Fuel cells provide significant GHG reductions even relative to ICE using alternative low carbon fuels due to the higher efficiencies and lack of direct emissions. The use of an SOFC operating on renewable LNG yields the lowest emissions at 0.80 gCO_2eq/MJ. Hydrogen and methanol fuel cells also show strong reductions, especially when the fuel is renewable or low-carbon.

Hydrogen combustion can help the maritime sector to attain significant GHG reductions because it does not contain carbon and therefore produces no direct CO_2 emissions when combusted. For hydrogen-powered vessels using ICE, the only GHG emissions generated during operation come from the use of carbon-based pilot fuels. As discussed for other alternative fuels, pilot fuel GHG emissions can be mitigated if a low-carbon fuel is used. However, GHG emissions can still arise from hydrogen production and transportation processes, and these vary significantly depending on the specific pathway. The GHG impacts of hydrogen fuel supply chains are discussed in Chapter 3. However, hydrogen combustion and handling does introduce the risk of hydrogen slip, hydrogen is considered an indirect GHG because, while it does not directly trap heat, its leakage into the atmosphere triggers chemical reactions that extend the life of methane, increase ozone, and create stratospheric water vapor [3]. Hydrogen can also escape during various operational phases, including leaks from pipelines and storage tanks, boil-off and venting during startup and shutdown, and procedures for purging impurities from the fuel system. Despite these concerns, research indicates that the overall climate benefit of transitioning to green hydrogen remains significantly beneficial [3]. Thus, while managing hydrogen slip is important, it does not undermine the fundamental climate advantage of using green hydrogen in marine and other applications.

Table 9.Well-to-wake GHG emissions for fuel cells and alternative fuels. Adapted from Reference [85].

Technology	Fuel	GHG Emissions Factor (gCO_2eq/MJ)
Diesel Generator (ICE)	LSFO	93.23
Diesel Generator (ICE)	Bio-Methanol	3.82
Diesel Generator (ICE)	Bio-Methane	4.52
Fuel Cell (LT PEM)	Blue Hydrogen (liquid)	1.64
Fuel Cell (LT PEM + Reformer)	Bio-Methanol	1.74
Fuel Cell (SOFC)	Bio-Methane	0.80

Similarly, due to the chemical composition of hydrogen including the absence of carbon, the combustion of hydrogen significantly reduces emissions of several pollutant species relative to conventional marine fuels, including CO, PM, SO_x, heavy metals, and air toxic species such as benzene, formaldehyde, and polycyclic aromatic hydrocarbons [3]. However, small amounts of sulfates, hydrocarbons, and PM may still be emitted from pilot fuels and the use of lubricating cylinder oil, which are still required in some engine designs.

Therefore, NO_x is the dominant concern for hydrogen combustion in terms of pollutant emissions. The high flame temperatures of hydrogen promote thermal NO_x formation via the Zeldovich mechanism. The Zeldovich mechanism primarily explains the formation of "thermal NOx," which is produced at high temperatures when oxygen and nitrogen combine. Additionally, rapid combustion can lead to hot spots and pressure spikes that increase NO_x formation. However, a large body of research supports the idea that hydrogen combustion can be accomplished while potentially even achieving reductions in NO_x relative to baseline systems [91], [92], [93], [94], [95]. Potential combustion strategies to achieve low NO_x from hydrogen combustion include the use of lean premixed combustion, dilution, staged combustion, the use of low NO_x burner designs, and water injection. However, some strategies can lower engine efficiency and power output, presenting a trade-off between environmental performance and engine performance. The use of SCR is the dominant strategy to control NOx from hydrogen ICE and other alternative fuels. SCR systems can significantly reduce NO_x emissions but add cost, space, and system complexity to shipboard engine installations. However, it should be noted that when the exhaust gas temperature is too low, it can impact the efficiency of the SCR system and result in increased NO_x emissions.

The use of hydrogen in reciprocating engines has been studied for stationary applications. These engines could be similar to those used in the maritime sector, particularly for auxiliary power. Testing at a WEC Energy Groups A.J. Mihm power plant and validated by the Electronic Power Research Institute (EPRI) of an 18.8 MW Wärtsilä 18V50SG spark-ignition reciprocating internal combustion engine operated on up to a 25 percent hydrogen fuel blend resulted in a reduction in NO_x emissions by 46 percent and CO emissions by 21 percent when NO_x was controlled by manually changing ignition timing and increasing air-fuel ratio at 100 percent load [96]. For uncontrolled emissions (i.e., exhaust before the SCR), NO_x did increase slightly, indicating that the emissions control systems will likely be required to maintain baseline levels exactly. According to EPRI, the demonstration represented the first hydrogen blending test on a commercial-scale, grid-connected and operating reciprocating engine [97]. This idea is supported by the results from a study on a vehicle engine that reported an increase in NO_x of 29 percent, although comparison with stationary reciprocating engines is challenging [92]. McKinsey & Company notes that with control of the combustion conditions and SCR, the NO_x emissions from hydrogen combustion in marine engines can be negligible [98]. Similarly, Lewis (2021) concludes that hydrogen ICE is “likely to outperform HFO equivalents” regarding NO_x emissions [99].

Technology Readiness

Combustion Engines

A growing number of major engine manufacturers and maritime technology companies are actively developing hydrogen ICE for marine and other heavy-duty applications. Engine development is still emerging for hydrogen ICE, but notable progress has been made to date, and this is expected to continue as interest in hydrogen combustion remains high in many sectors.

The BeHydro DZ H_2 engine, developed by ABC Engines and launched in 2020, represents one of the first commercially available hydrogen internal combustion engines for marine use [3]. ABC has both dual-fuel and hydrogen single-fuel versions of the engine (Figure 2). The engine operates on the Otto cycle and covers a power range from 1 to 2.8 MW. Combustion is initiated by a 15 percent pilot fuel oil for ignition and to maintain flame stability. The DZ H_2 engine is equipped with knock sensors and pressure-relief valves that ensure safe and controlled combustion across various operating conditions. In 2023, the BeHydro DZ H_2 engine received type approval from Lloyd's Register for its hydrogen-powered dual-fuel engine [90]. ABC is also planning to develop larger dual-fuel engines of up to 10 MW, as well as a single-fuel hydrogen engine to significantly reduce GHG emissions [90].

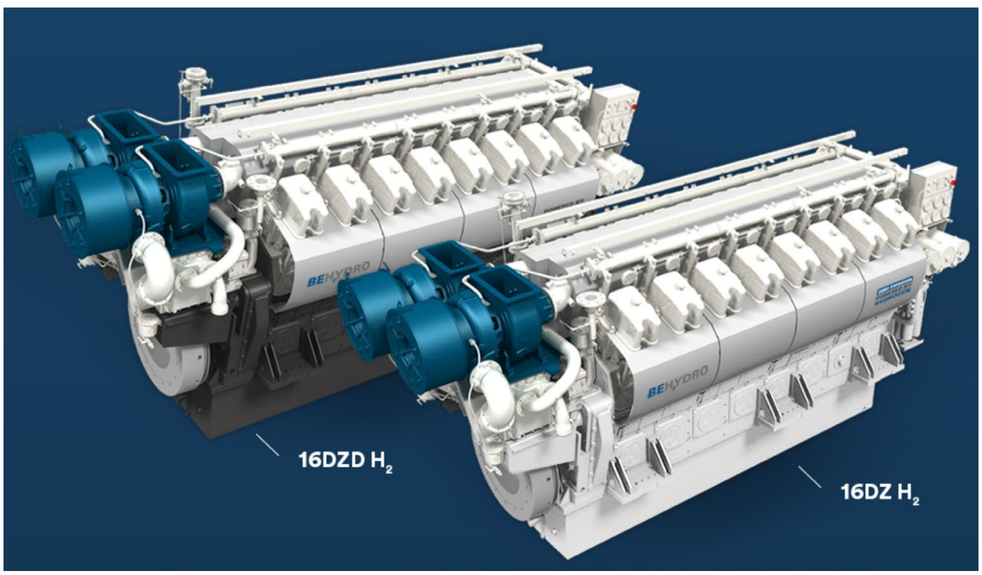

Figure 2. BeHydro DZ and DZD hydrogen engines. From Reference [100].

In addition to BeHydro, several other companies are actively developing hydrogen engine technology for marine applications. Yanmar has successfully completed a land-based demonstration test of a pilot-ignition hydrogen 4-stroke high-speed engine for use in small coastal vessels, achieving operation at a rated output of 500kW [101].

Wärtsilä is developing hydrogen-ready marine engines and is adapting its proven Wärtsilä 31 and Wärtsilä 32 engine platforms to accommodate hydrogen as a fuel, both in dual-fuel and spark-ignited configurations [102]. Early tests have been successful and Wärtsilä plans to have commercially available hydrogen-capable engines by the early 2030s. The company claims that these engines could operate on up to 25 to 30 percent hydrogen in dual-fuel mode as an intermediate step with an ultimate goal of 100 percent hydrogen.

Everllence is developing hydrogen-capable engines using its ME-LGI engine series [103]. The company was a participant in the HyMethShip project using methanol as a hydrogen carrier and reforming it on-board to produce hydrogen for combustion [7], [103]. As previously discussed, HyMethShip is an EU-funded research program that aims to create a near-zero-emission ship propulsion system by using methanol as a hydrogen carrier rather than storing hydrogen directly onboard. In the concept, methanol is reformed onboard to produce hydrogen, which is then used in a hydrogen-fueled engine for propulsion, while the CO_2 released during reforming is captured and stored onboard instead of being emitted to the atmosphere. By linking hydrogen use with onboard carbon capture and circular fuel production, HyMethShip demonstrates how hydrogen can be applied in shipping without the challenges of direct hydrogen storage. Everllence is also working on hydrogen ICE for other sectors as well, including the H4576 engine for use in agricultural machinery and off-road equipment with a power output of 368 kW. However, according to Everllence, hydrogen for direct combustion will probably not play a significant role on the two-stroke side, due to the challenges discussed for energy density and the long distances covered by large ships, such as container, bulk carriers, and tanker vessels [60].

Hyundai Heavy Industries is working on large-bore engines that can run on hydrogen, adapting its dual-fuel LNG and methanol platforms to support hydrogen for large OGVs. Hyundai has successfully tested a 1.5MW class HiMSEN engine that can run on a combination of LNG and hydrogen that meets IMO Tier III standards for NO_x and reduces CO_2 and methane slip [104]. While these engines are not yet commercially available, demonstration units are planned in the coming years.

A consortium including Kawasaki Heavy Industries, and J-ENG completed a risk assessment for a 17,500 DWT multi-purpose vessel powered by a first of its kind low-speed two-stroke hydrogen-fueled engine in 2023 [105]. J-ENG is designing an engine to operate primarily on hydrogen fuel with a high-pressure hydrogen direct injection system at pressures of up to 30 megapascals (MPa). This enables a high hydrogen substitution rate (up to 95 percent hydrogen) with precise control over combustion and minimal methane or CO_2 emissions.

Fuel Cells

Several companies are working on commercial fuel cell systems for maritime applications including Corvus Energy, Wärtsilä, Siemens Energy, Ballard Power Systems, Cummins Inc., ABB, and Yanmar, although the focus today is largely for CHC. With similarity to fuel cell systems used to power land-based vehicles, PEM fuel cells are often used due to their high power density, quick start-up times, and ability to support variable loads. However, other fuel cell types including SOFC, phosphoric acid fuel cells, and molten carbonate fuel cells may have applications for larger vessels including the provision of auxiliary power needs.

Hydrogen fuel cell technologies may take until the late2030s to reach full commercial maturity for marine shipping applications. Methane and methanol fuel cells are projected to begin commercial operation around 2030 and reach full maturity by 2040 [19]. While there are several companies working in the fuel cell space, the available commercial marinized fuel cell systems and other required components may not be suitable for larger vessel types and applications. Environmental conditions can be challenging for electrochemical devices including exposure to a saltwater environment. Meeting the operational performance requirements of OGV typically necessitates propulsion systems capable of sustained high-load operation, with main engines commonly operating in the 70–90% Maximum Continuous Rating range and often near 80–90% of rated power during normal service conditions [106]. This is challenging for current fuel cell systems, for example, as this requires pumps and blowers to be at or near capacity for extended periods of time. Similarly, energy density limitations of current batteries restrict their use to select CHC vocations. However, it is likely that advancements in the commercialization of marinized fuel cell systems will be achieved in coming years given the number of companies working to develop commercial systems.

According to Lloyd’s Register’s latest analysis of shipbuilding data, hydrogen-capable vessels still represent a very small segment of the global fleet: about 53 hydrogen-capable ships are either in service or on order as part of the alternative-fuel vessel orderbook, which totals 1,942 alternative-fuel ships [107]. Of the new orders reported for 2025, around 13 hydrogen-capable vessels were placed in that year. Hydrogen-capable vessels therefore make up significantly less than 1 % of the global ship orderbook, reflecting both the early stage of hydrogen adoption in shipping and the continued dominance of fuels like LNG and methanol. Current hydrogen-capable vessels are almost exclusively smaller vessels including CHC. Hydrogen fuel cell-powered commercial ferries are in the early stages of commercial operations with expanded development and commercial operation expected in the late 2020s, with examples in the U.S. and Europe. The *Sea Change* began commercial operation in 2024 in San Francisco Bay and is considered the world's first commercial hydrogen fuel cell passenger ferry, however the project has now ended, and the vessel is no longer in commercial operation [86]. A recent project in Japan installed the first maritime fuel cell system to power a hybrid sightseeing and commuter ferry called the *Hanaria* that can receive power from hydrogen fuel cells, lithium-ion batteries, and biodiesel generators [108]. The *Hanaria* uses hydrogen fuel cells consisting of two 240kW units supplied by Yanmar, which also provided the vessel's power management and remote monitoring systems.

Given the current challenges associated with fuel cells, which include high initial costs, complexity, and operational changes, it is unlikely that fuel cells will compete with or entirely replace on-board ICE for propulsion for larger vessels in the near- to mid-term, even as fuel cells reach higher technological and commercial maturities [85]. Instead, fuel cells and ICE could be combined to take advantage of the benefits of each system. According to the Maersk Mc-Kinney Møller Center for Zero Carbon Shipping, the most promising pathway for fuel cells is to provide auxiliary power which is traditionally provided by less efficient four-stroke engines [85]. For example, vessels could use a 2-stroke ICE for propulsion and fuel cell systems for auxiliary power to attain important emissions reductions. This would allow the maritime industry to gain experience with fuel cells and progressively integrate systems in lockstep with technological and economic improvements.

Economics

Combustion Engines

Published maritime decarbonization assessments consistently indicate that hydrogen ICEs face a significant upfront capital cost premium relative to conventional marine diesel engines, reflecting their early stage of commercialization and limited manufacturing scale. Conventional medium- and high-speed marine diesel engines are generally estimated to cost approximately $250–$500 per kW, benefiting from decades of optimization, standardized designs, and mature global supply chains [109]. In contrast, hydrogen-capable ICE (including single-fuel and dual-fuel configurations are typically projected in the range of $500–$1,400 per kW, depending on engine size, system complexity, and safety and certification requirements [110], [111]. These ranges imply an initial cost premium of roughly 50% to more than 100% compared with conventional diesel propulsion systems. Industry market analyses further suggest that dual-fuel hydrogen ICEs are likely to dominate early adoption, as they offer greater operational flexibility and reduced fuel-supply risk during the transition period [112]. Technical assessments from engine industry bodies emphasize that these premiums are largely driven by hydrogen-specific fuel systems, enhanced safety measures, and low production volumes, and are expected to decline over time as hydrogen engine technologies mature and scale (International Council on Combustion Engines).

Figure 3 compares the cost per kW for conventional fuel-oil engines (blue bar) and hydrogen-suitable ICE (red bar) based on data from ABS in 2022. Each bar is divided into a solid lower portion representing high-powered engines, and a dotted upper portion representing low-powered engines [3]. Lower-powered engines have a higher cost per kW due to less favorable economies of scale. For conventional engines, no future cost reductions are assumed given the maturity of the technology. In contrast, hydrogen ICE are a newer and less mature technology that may see cost reductions in the future as the technology continues to develop. As can be seen, there remains a significant cost gap between conventional engines and hydrogen dual-fuel ICE, primarily because hydrogen engines are still in early stages of commercial development.

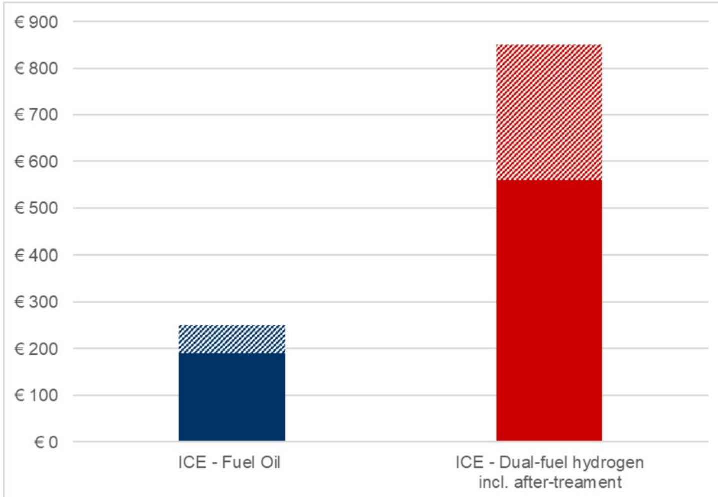

Figure 3. Cost range of diesel and hydrogen ICE (in Euros). From Reference [3].

Fuel Cells

Current fuel cell costs are high and present a barrier to widespread adoption in the maritime industry. For example, Table 5 shows CAPEX for both PEMFC and SOFC fuel cells are up to an order of magnitude higher than for ICE diesel and ICE alternative fuels. This is further exacerbated by the significantly shorter lifetimes for fuel cells relative to ICE.

The Mærsk Mc-Kinney Møller Center evaluated the capital costs, fuel costs, and TCO of integrating fuel cell systems for auxiliary power on deep-sea vessels (bulk carriers, tankers, and container ships) and compared them to conventional diesel generators using LSFO [85]. They found that fuel cells have a much higher CAPEX than diesel generators, especially LT PEM and SOFC, due to fuel cell system cost, fuel storage (notably for liquid hydrogen), and integration complexity. One of the primary cost drivers was the expensive liquid on-board hydrogen storage systems. This was particularly impactful for the CAPEX of hydrogen-fueled LT PEM systems. The Mærsk Mc-Kinney Møller Center found the lowest capital cost for a fuel cell was SOFC with bio-methane. All fuel cell options currently have higher TCO than diesel systems under current fuel and CAPEX conditions. The use of an SOFC with bio-methane could become cost competitive or even cheaper than diesel by 2030–2040 under a carbon fee. Systems using liquid hydrogen have the highest TCO due to expensive storage needs, fuel cell stack replacement costs, and fuel price. Stack replacement is particularly costly, as fuel cell stacks may require replacement every 3 to 4 years at approximately 30–40 percent of initial CAPEX, adding to life cycle costs. Overall, the report concludes that fuel cells can be economically viable for auxiliary power in the long term, especially SOFC + bio-methane, but only under the right conditions which require declining CAPEX, lower alternative fuel prices, and the implementation of carbon pricing or market-based mechanisms. However, they note that by 2040, fuel cell costs are forecasted to decline due to technology maturation and economies of scale, converging across technologies.

Next Steps to Demonstration/Deployment

Maximizing the emissions benefits of hydrogen will require the use of fuel cells rather than ICE.

Table 10 compares the use of hydrogen in ICE and in fuel cells. Potential benefits of using fuel cells include higher electrical efficiencies, compatibility with alternative fuels including methanol, LNG, and hydrogen, and fewer moving parts which allows for simpler maintenance [85]. However, the primary driver for fuel cells is their ability to provide electricity and heat with very low to negligible direct emissions, including NO_x, SO_x, PM, and GHGs. On the other hand, ICEs are much more advanced technologically and commercially, have lower costs, and have high durability, robustness, and flexibility. According to the U.S. Department of Energy (DOE), hydrogen ICE tends to have advantages over fuel cells in large vehicles, construction and agriculture applications with significant vibration and/or dust, applications with limited installation space, severe ambient conditions (cooling), difficult locations to supply hydrogen, stationary mechanical-drive applications, and retrofits including rail and marine. Therefore, ICE will likely be more favorable than fuel cells in the near- to mid-term in the marine sector. However, the use of hydrogen in ICE can help scale up other aspects of the hydrogen ecosystem, ultimately supporting fuel cell deployment when they reach competitiveness with other technologies.

Table 10. Comparison of the use of hydrogen ICE (H2ICE) to fuel cells (H2FC). From Reference [83].

Characteristic	H2ICE	H2FC
Efficiency	Good: mid – high load	**Excellent: low – mid load**
Cooling needs	**Intermediate**	High, critical for stationary and slow-moving applications
Emissions	NOx (and minor CO_2) Low with aftertreatment	**None**
Durability	**High**	Improving with new R&D
Robustness	**High**	Sensitive to vibration
Noble metal consumption	**Low – intermediate** (after-treatment)	High
Fuel purity	**Tolerant to contaminants**	High-purity H2 required
Fuel flexibility	**Diesel/NG backup**	Can be flexible, efficiency penalty
Upfront cost	**Low**	High
Cold start	No issues	Temperature conditioning
Resale value	Depending on infrastructure	Unclear

A major hurdle for hydrogen is on-board storage, particularly for larger vessels. Compressed hydrogen gas has a low volumetric energy density, even at high pressures, making it difficult to store enough on-board. High pressure requirements for on-board storage raise both cost and safety concerns, and they introduce technical challenges such as compression reliability, increased piping complexity, and stringent regulatory requirements. Liquid hydrogen storage requires low temperatures (-253°C) which requires cryogenic storage systems. These systems are costly, energy-intensive, and require management of boil off gas using reliquefication systems which increases CAPEX and OPEX. These challenges make the storage of on-board hydrogen difficult and expensive and limit the feasibility of large-scale shipping applications with longer routes.

For large marine vessels, carrying hydrogen-rich fuels such as ammonia or methanol and converting them onboard to hydrogen prior to use in engines or fuel cells offers a practical pathway to hydrogen propulsion while avoiding the substantial storage and safety challenges associated with molecular hydrogen. Ammonia and methanol are far easier to store at ship scale, benefiting from higher volumetric energy density, simpler tank designs, and established maritime handling experience. Onboard cracking or reforming enables hydrogen to be generated on demand near the point of use, improving combustion performance, reducing emissions, and decoupling hydrogen utilization from hydrogen storage. This approach also enables pre-combustion carbon management for methanol pathways and eliminates carbon emissions entirely in ammonia-based systems. As a result, hydrogen-carrier fuels provide a scalable and transitional solution for ocean-going vessels, allowing early deployment of hydrogen-based propulsion technologies without reliance on cryogenic hydrogen infrastructure.

Using hydrogen as the final energy carrier in the ICE or fuel cell, rather than combusting the carrier fuel (e.g., ammonia or methanol) directly, offers several technical and environmental advantages for large marine vessels. Hydrogen combustion (or electrochemical conversion in fuel cells) is inherently cleaner and more controllable, producing no CO_2, SOx, or carbon-based PM, and eliminating concerns related to unburned carbon species or fuel slip that can arise when burning carrier fuels directly. This is particularly true if hydrogen is used in fuel cells as it allows for true zero emissions operation. From a combustion standpoint, hydrogen has high flame speed, wide flammability limits, and stable ignition characteristics, enabling more efficient and reliable operation in reciprocating engines, particularly under the sustained high-load conditions typical of ocean-going vessels. This is especially beneficial compared to ammonia, which can be difficult to ignite and prone to high NOx formation when burned directly, and methanol, which still produces CO_2 at the point of use.

Thermo-Catalytic Decomposition (TCD) is an emerging fuel-conversion pathway that enables the use of hydrogen in marine propulsion without requiring on-board storage of molecular hydrogen. Instead of bunkering hydrogen directly, the vessel carries a hydrogen-rich carrier fuel which is converted onboard into hydrogen through a high-temperature catalytic decomposition process. In TCD, the carrier fuel is thermally cracked in the presence of a catalyst, producing hydrogen gas and solid carbon rather than carbon dioxide. Although still at a low TRL (3–4), initial results are promising and may support the development of large-bore hydrogen engines suitable for deep-sea shipping [3]. More research is also needed to better understand how to avoid hazards and develop mitigation strategies during the storage and bunkering of hydrogen. An example includes experimental testing and modeling regarding the behavior of liquid hydrogen during leakage scenarios in typical ship designs to support the development of rigorous safety measures (e.g., where ventilation shafts and exhaust fans should be located).

The current lack of fueling infrastructure represents one of the most significant barriers to the adoption of hydrogen in both ICE and fuel cells. A marine fueling network of hydrogen and/or hydrogen carriers like ammonia will be needed to maintain high reliability while minimizing cost (e.g., due to redundancy measures and maintenance) [113]. In particular, high reliability will be critical to achieving early market success for hydrogen vessels [114]. The current on-road vehicle hydrogen station network in California has experienced low reliability due to a variety of issues including component failures and low hydrogen supply. Given the similarity of the technologies currently used in vehicle stations and those that will be used for bunkering, the development of maritime hydrogen will benefit from lessons learned and technological advancements in on-road fueling [115]. Safe and secure fueling will require the adoption of standards and best practices that minimize hazards from hydrogen storage and dispensing systems and minimize risk for fueling session disruption, tampering, and data insecurity. As marine hydrogen fuel infrastructure expands, safety and security standards will need to be developed and re-evaluated to reduce risk.

Battery Electric and Hybrid Systems

Technology Description

Battery electric systems in maritime applications are gaining interest as a potential zero emission option at the point-of-use (i.e., life cycle emissions depend significantly on the source of the electricity used). There are a wide range of potential configurations for battery electric and battery electric hybrid systems. Battery-electric vessels operate using battery systems only, which are recharged using electricity obtained from shore power. Fully electric vessels utilize a battery system comprised of rechargeable batteries that store electrical energy. Common battery types include lithium-nickel-manganese-cobalt-oxide (NMC) cells, lithium iron phosphate (LFP cells), and lithium-titanium-oxide (LTO) cells.

Lithium-ion batteries with various chemistries – including NMC-- are the primary battery type suitable for marine energy [116]. Of these, NMC batteries are generally regarded as the most feasible for ship design due to benefits in cost, lifetime, specific energy and power, safety, and thermal performance. NMC batteries have a high specific energy and energy density, which is important given vessel space constraints. Several companies are working on containerized battery systems suitable for marine applications including Asea Brown Boveri, EST-Floattech, and Fleetzero.

Hybrid electric vessels generally use two power sources, usually a conventional ICE and an electric engine which can be either battery electric or hydrogen fuel cell electric systems. Hybrid systems allow vessels to switch between these engines, or use them simultaneously, based on operational needs, power requirements, and environmental considerations. Engine types that are being considered for hybrid platforms are typically conventional ICE utilizing diesel fuel, but hydrogen, methanol, and ammonia can also be used to power the ICE. Hybrid electric vessels utilize integrated battery systems to 1) optimize the overall vessel propulsion system through functions including spinning reserve, peak shaving, block out prevention, and/or load ramp-up support; and 2) provide zero-emission propulsion, allowing the ICE to shut down so that only the zero-emission engine is used. Utilizing hybrid propulsion systems can provide fuel savings leading to reductions in cost and emissions relative to a conventional diesel engine. Also, when operating at low speeds, electric propulsion helps protect the diesel engines from unnecessary wear from operation outside ideal working loads. Additional benefits include reduced noise and vibration when operating in zero-emission mode, which can be beneficial both to the crew and the surrounding environment including coastal communities and marine life.

System/Network Suitability and Operational Infrastructure Needs

Current charging strategies for battery electric and hybrid vessels are largely used in CHC applications and include AC and DC systems, with AC being common for slower charging and DC for faster charging. Given the large power demands of OGVs, DC charging methods are likely to be required for any on-board battery systems. European ferry charging systems have demonstrated the capability to deliver over 23 MW of DC power [117].

Factors that must be considered in the design and build-out of charging infrastructure include vessel routes and schedules, available charging points, vessel battery size, charging power and voltage, crew handling and manipulation, docking methods and mooring strategies, sea and weather conditions, and cargo space availability on vessels and when vessels are at dockside. The feasibility of charging strategies will be impacted by battery charging rates (C-rate), grid capacity, size and weight of the connection equipment, and the time available for charging based on operational profiles.

In addition, there are many different configurations for vessel chargers, depending on how the vessel connects to the charging system. Currently, standard manual plug-in chargers are often used, which requires crew members to manage the connection and disconnection of the vessel. An example of this type of system includes ABB's 1.65 MW chargers, consisting of a transformer, ACS880 converters, Megawatt Charging System (MCS) plugs and cable management for electric ferries [118]. While this approach is simpler and cheaper to install, it is not ideal due to increased costs for the crew, limitations on the size and weight of the charger, and increased charging times. In contrast, there are charging strategies that use various levels of automation to achieve the connection including systems that use robotic arms and inductive charging systems characterized by charging pads on the vessel and dock to transfer electricity wirelessly [119]. Other potential vessel charging strategies include battery swapping systems or mobile charging units, although these are currently less common due to cost and other barriers and would likely not be feasible for large OGVs.

Power and voltage levels must be carefully considered in the design of high-power charging systems, as they directly influence the size, weight, and handling requirements of supply cables and the selection of connector technologies. High charging currents, particularly above several hundred amperes, introduce additional challenges, as they either necessitate larger and heavier conductors or the use of actively cooled cables to maintain manageable cable dimensions. Electrical contact resistance within the plug can lead to significant heat generation at high current levels, requiring sufficient contact force between mating surfaces to ensure low resistance and thermal stability. Practical constraints such as available dock space, cable weight, and mechanical loading from handling equipment can further limit feasible charging configurations. In addition, charging systems—including connectors, cable management systems, and support structures—must be designed to accommodate marine environmental conditions such as tidal variation and wave-induced vessel motion to ensure safe and reliable operation.

For DC fast charging, current dockside infrastructure used for CHC usually requires a shore-side battery system to serve as a buffer due to the constraints that available grid capacity places on charging power without grid upgrades. Charging for battery electric vessels can be characterized by short-term and high-power demands which can cause large peaks that may challenge the resilience of electric service providers and stress local electrical grids and power generation facilities [120]. Strategies to alleviate these peaks may include battery storage systems or local, distributed power generation assets such as stationary generators or fuel cells which can provide on-site electrical power and potentially waste heat for other uses. Additionally, mobile battery energy storage systems that can be deployed on marine barges and tractor-trailers may represent a strategy to address the near-term challenges of available power supply and electrical equipment shortages [120]. From an economic standpoint, the large power demands of OGV charging can incur high demand charges due to existing utility rate structures; however, the use of a battery system can help alleviate charging costs.

In many cases the large power requirements for OGV charging will require upgrading current electrical infrastructure at ports, terminals, berths, etc. Electrical service and distribution requirements are based on the type and number of vessels, overall usage profiles, proximity to existing infrastructure, peak demands, etc. Upgrades can include increasing electrical capacities through refurbishing transformers, substations, and distribution lines. The reinforcement of existing high-voltage lines or the installation of new ones may be needed to ensure a strong grid connection to maintain stability and reliability. As previously mentioned, the integration of battery storage systems to manage peak loads and storage during off-peak times will be necessary in many situations, and planning for integration of these resources into the larger grid is needed. It will also be critical to upgrade or install appropriate safety systems to ensure compliance with applicable safety codes and standards. To accomplish many of these steps, site modifications will be necessary including trenching (to install underground electrical wiring, conduits, or cables), upgrading electrical panels, and achieving proper grounding so that excess electric current flows harmlessly into the ground rather than through people or equipment.

Ports and terminals are faced with distinct challenges to deploy infrastructure to support OGV battery charging due to factors including high energy demands, restrictive duty cycle conditions, and varied tenant and operational interests. Historically, electricity demand at these locations has been low and therefore existing grid capacity and other features is often insufficient to support the power demands of vessel charging. At most California seaports, the port authorities do not own or operate the vessels targeted for zero emission conversion and must work with private operators to deploy vessels and install required infrastructure [121]. Another barrier is the required workforce and training that crews need to understand how to operate and maintain zero-emission infrastructure. Additionally, marine environments can present difficult conditions (bad weather, saltwater intrusion, etc.) and installed infrastructure must be able to withstand such conditions, requiring an emphasis on the durability and reliability of the equipment.

Newbuild or Retrofits

For battery-electric propulsion, most current applications are being implemented as newbuilds, although they are smaller CHC including ferries, workboats, and other vessels operating on short, predictable routes. Newbuilds allow for optimal integration of battery systems, electric motors, control electronics, and charging infrastructure. Additionally, vessels are designed with appropriate space, weight distribution, cooling systems, and on-board safety systems for high-capacity batteries. Shore charging systems can also be designed concurrently, ensuring seamless compatibility between the vessel and port-based infrastructure. While retrofitting an existing vessel to battery-electric propulsion is technically feasible, it is typically more complex and costly. It requires the removal of diesel propulsion systems, major structural modifications to house large battery banks, and rebalancing the vessel’s weight and stability characteristics.

In contrast, shore power capability for auxiliary engines is commonly implemented through retrofits. This is particularly relevant for container ships, cruise vessels, and other large ships that spend significant time at berth in regulated ports. Retrofitting for shore power typically includes the installation of electrical panels, connection receptacles, switchgear, control systems, and potentially on-board transformers to accept high-voltage power from the dock. These retrofits allow the vessel's auxiliary engines to be shut down while at berth, significantly reducing emissions. Newbuild vessels, however, increasingly include shore power readiness as a standard feature, especially for ships intended to operate in areas with mandatory shore power requirements, such as California. Designing shore power systems into the vessel during its initial construction allows for greater efficiency, reduced cost, and better integration with the vessel's electrical and safety systems.

Economics

The economic viability of battery-electric propulsion is a product of route characteristics, vessel type, size, design, vocation, battery selection, and external factors like fuel used to generate electricity and electricity prices and carbon regulations. For short-sea shipping and ferry routes, systems can be competitive and may offer long-term cost savings, particularly in regulated environments, e.g., the implementation of carbon penalties.

A pre-feasibility study by the Maersk Mc-Kinney Moller center studied the potential of battery-powered vessels in deep-sea shipping concludes that battery-electric propulsion could deliver substantial emissions reductions for a portion of the U.S. domestic vessel fleet, particularly vessels operating on short and medium-distance routes with frequent port calls [122]. Some vessels under 1,000 gross tons have duty cycles that are technically compatible with battery systems using current or near-term technology, enabling electrification of most trips without requiring full route coverage in all cases. When powered by a decarbonized electric grid, battery-electric vessels can reduce CO_2 emissions by more than 70 percent by the mid-2030s, while also virtually eliminating NO_x, particulate matter, and other combustion-related pollutants, delivering meaningful air quality and public health benefits in near-shore communities. The report emphasizes that the magnitude of these benefits depends strongly on the carbon intensity of the electricity used for charging. From an economic and systems perspective, the study reported that battery-electric vessels generally have higher upfront capital costs than conventional diesel vessels, driven primarily by the cost of large onboard battery systems and associated power electronics and charging interfaces. However, these higher initial costs can be partially or fully offset over the vessel lifetime by lower operating and maintenance costs, including reduced fuel expenditures, fewer moving parts, and lower engine maintenance requirements. As battery costs continue to decline and electricity prices remain stable relative to marine fuels, the analysis indicates that battery-electric vessels can approach or achieve cost parity with conventional vessels for routes where a high fraction of operations can be conducted on electric power, particularly when vessels are right-sized for their actual duty cycles.

However, for longer-distance or high-power vessels, battery-electric remains cost-prohibitive without significant policy support or future advancements in battery performance and cost reduction [123]. An assessment by Everllence regarding batteries for propulsion of different types of merchant marine vessels found that the cost and cargo displacement was prohibitive due to the size of batteries necessary to provide the required power [44]. The assessment found that current applications for batteries in shipping include near-coastal shipping and that batteries can be integrated into on-board electric systems for large OGVs.

The cost of batteries drives the overall cost of ownership for battery electric systems. A feasibility study estimated the near- to mid-term price for propulsion battery systems to be $300 USD/kWh, using input from battery system vendors and using the expected price level for stationary utility-scale battery systems as a guide [122]. Electricity is more cost effective than e-fuels, making batteries attractive for marine energy storage from a fuel cost standpoint. However, batteries have high upfront costs which means that battery depreciation is a key factor in the economics of battery vessels. Since marine vessels often use batteries at low discharge rates with few charge cycles, battery aging is mostly time-based rather than usage-based. To ensure cost-competitiveness with alternative fuels, it is important to cycle as much energy as possible through the battery over its lifetime to fully utilize the investment.

Battery costs are expected to decline significantly over the coming decades due to advances in technology, economies of scale, and improvements in the global battery supply chains. Shown in Figure 4, battery costs for lithium-ion systems are expected to decrease over time based on projections made by the US National Renewable Energy Laboratory [3]. Innovations in battery chemistry potentially including solid-state, sodium-ion, and lithium iron phosphate (LFP) technologies can increase energy density, reduce reliance on expensive or scarce materials like cobalt and nickel, and enhance battery lifespan. At the same time, the rapid expansion of electric vehicle and energy storage markets is driving large-scale manufacturing and supply chain optimization, which will lower per-unit production costs of batteries. Automation in battery assembly and increased competition among manufacturers are also contributing to cost reductions. As a result, the maritime sector is likely to benefit from more affordable and efficient battery systems, enabling broader adoption of electric propulsion and hybrid vessel designs. It should be noted this would also provide cost reductions for fuel cell electric vessels as those systems also require batteries.

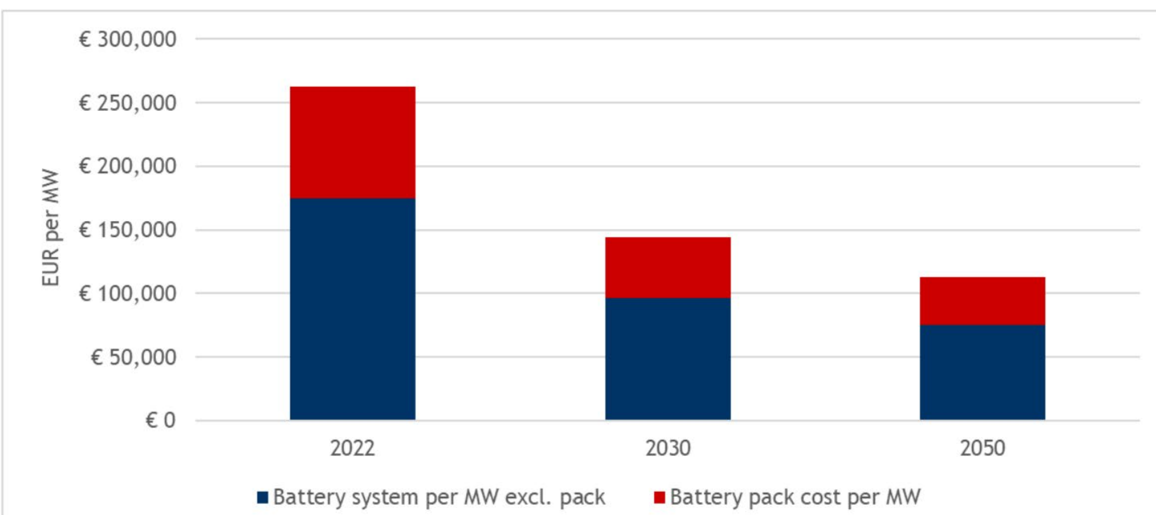

Figure 4. Battery systems cost for lithium-ion systems. From Reference [3].

Potential Emission Reductions

Switching from conventional marine engines to battery-electric systems results in substantial reductions in air pollutants and GHG emissions, for both propulsion and auxiliary engines. Battery-electric vessels produce zero emissions at the point of use, eliminating NO_x, SO_x, PM, air toxics, heavy metals, and CO_2.

However, this shift in power source transfers emissions to local or regional electrical grids and/or any on-site generators used during the charging process, meaning the overall environmental benefit depends on where the electricity is sourced from. This also means that emission impacts will vary widely from region to region, and even by time of day in some cases. The life cycle emissions depend heavily on the carbon intensity of the electricity used to charge the batteries. When renewable sources like wind or solar are used, emissions from charging can be considered near-zero, excluding life cycle emissions from equipment manufacturing. There is a substantial body of literature demonstrating that battery electric transportation technologies consistently and significantly reduce life cycle GHG emissions compared to conventional fossil fuel ICE in most cases [124], [125]. Both full battery electric and hybrid vessels have been shown to have clear GHG benefits [126]. However, in regions where higher emitting fossil fuels are used for electricity generation, the GHG benefits may be reduced or even non-existent [127]. It is therefore critical to evaluate the emissions impacts of batteries

The actual benefits of shore power will vary depending on regional electricity generation profiles. However, given the large emissions from diesel auxiliary engines [128] and the potential health impact of diesel PM [129], [130], using battery electric systems will almost certainly offer substantial reductions in air pollution and public health benefits in almost every situation. The U.S. EPA conducted an assessment using a comparative emissions and technology evaluation framework to quantify the benefits of shore power for vessels at berth including the Ports of Los Angeles, Long Beach, New York/New Jersey, Seattle, and Hueneme [131]. The study included characterizations of existing U.S. shore power installations, vessel types served, power demand, and time at berth, and combined this information with auxiliary engine emission factors and regional electricity grid emission factors from EPA's eGRID database. Emissions from conventional auxiliary engine operation were compared with emissions associated with electricity generation specific to each regional grid. The assessment found that shore power can deliver very large reductions in air pollutant emissions from vessels at berth, with near-complete elimination of onsite emissions. Across multiple studies and ports, NO_x reductions typically range from ~80% to >99%, PM reductions range from ~66% to 99%, and SO_x reductions range from ~46% to nearly 100%, depending on vessel type, fuel used, and auxiliary engine characteristics. Reported CO_2 reductions range from ~25% to ~57%, reflecting differences in regional electricity generation mixes. The assessment concludes that shore power is most effective for vessels with long hoteling durations, such as container ships, cruise ships, and refrigerated cargo vessels, and for ports with cleaner electricity grids. While capital costs for landside infrastructure and vessel retrofits remain a barrier, EPA emphasizes that shore power is a proven, near-term strategy for reducing port-area emissions and public health risk, noting CARB estimates of approximately 80% localized criteria pollutant reductions and over 50% cancer-risk reduction from expanded shore power use in California. Overall, the report identifies shore power as a high-impact emissions-reduction measure for at-berth operations, though it does not address emissions during vessel transit or maneuvering.

From a public health perspective, shifting emissions from ports and vessels to electricity generation sites typically results in benefits by relocating pollution away from urban regions with large populations and poor air quality. A key example of this is the Ports of Los Angeles and Long Beach which are located in the densely populated South Coast Air Basin which experiences some of the worst air quality in the U.S. Electricity generation often occurs outside the port area or local airshed, which helps to reduce or avoid localized air quality impacts as the emissions that do occur from power plants are 1) often cleaner than those from diesel fuel, e.g., cleaner natural gas power plants are commonly used in California, and 2) purposefully built in areas that minimize harmful impacts to communities such as regions with low populations and/or the lack of currently degraded air quality.

Technology Readiness

A general consensus among the literature is that full battery electric propulsion for OGVs may be viable and cost-effective for some short-sea fixed routes, while longer routes will require ICE or hybrid systems [122], [123]. Increasing the feasibility of electrifying large ships will require future improvements in battery technology, energy density, and grid infrastructure. A technical and economic feasibility study of battery-electric propulsion for container ships identified the length of the voyage as the major limiting factor for full-electric configurations, rather than vessel size [123].

Companies working on or providing commercial battery systems suitable for marine applications including ABB, Siemens Energy, Corvus Energy, Leclanche, Wärtsilä, DNV, Bureau Veritas, Asea Brown Boveri, EST-Floattech, Fleetzero, and Spear Power Systems, among others. Currently, lithium-ion batteries are the primary battery type currently used for marine energy systems, with various chemistries currently commercially available [31]. However, other battery chemistries are being explored, with lithium NMC appearing to be the most feasible for ship design due to a balance of cost, lifetime, specific energy and power, safety, and thermal performance. NMC batteries provide high specific energy and energy density, which is important given the limited space and high power needs for OGVs.

While there are numerous examples of battery electric CHC in operation today including tugboats, pleasure craft, fishing vessels, and ferries, there are few current examples of battery electric OGV. In 2023, COSCO began operating a 700 TEU full battery-electric container vessel operating in an inland waterway in China with an installed battery capacity of 50 MWh using a battery-swapping concept with containerized battery solutions that allows for a 600 nautical mile route [132].

Similarly, the majority of existing charger applications are for CHC with numerous examples in Europe. Generally, these systems are custom designed to meet the specific requirements of a single vessel or fleet. Kempower is developing a network of fast charging stations for smaller vessels in Norway including the deployment of multiple dockside installations ranging in total charging power from 200 kw to 600 kw. Each charger can deliver 200-220 kw, which is generally only useful for small vessels, such as private recreational boats. The concept would have to be scaled up dramatically to meet the power and duty cycle requirements of larger vessels.

In California, Crowley and the Port of San Diego are cooperating in the construction of a microgrid (a localized energy system that can generate, store, and distribute electricity to a defined area and can operate either connected to the main electrical grid or independently (i.e., islanded) shoreside charging station to support the fully electric eWolf ship assist harbor tugboat [133]. The charging station is a microgrid facility to support fast charging while reducing peak loads on the local electrical grid. The station is equipped with two containerized battery energy storage systems provided by Corvus Energy, each capable of providing nearly 1.5 MWh for a total capacity of 2.99 MWh. The station also incorporates a solar power array to provide renewable energy. In addition, the station will be equipped with a battery monitoring system, HVAC, and firefighting and detection technology for safety. A notable challenge with the eWolf is aligning charging schedules with local utility rates which may include time-of-use pricing as well as demand charges that can greatly affect the price of electricity. To address this, the charging station is designed to operate during off-peak hours from the local utility grid when electricity prices are lower.

As an example of momentum in the marine sector to address the challenges of charging electric vessels, the Charging Interface Initiative e. V. (CharIN) consortium aligned with International Electrotechnical Commission (IEC), International Organization for Standardization (ISO), and Underwriters Laboratories (UL) standards developed the Megawatt Charging System (MCS) [134]. The MCS was designed to be enabler of maritime electrification by providing a universal, standardized, high-power DC charging interface designed specifically for large commercial electric and hybrid vessels. MCS standardizes the shoreside charger, cable management system, plug, onboard inlet, and secure communication protocol, enabling interoperable charging across ports and vessel types. The system is designed to deliver up to 3.75 MW per plug, significantly reducing charging times compared to existing solutions, while relying on liquid-cooled cables and connectors to manage thermal loads at high current. By shifting AC-to-DC conversion to the shore side, MCS reduces onboard equipment requirements and improves usability. According to CharIN, widespread adoption of MCS can lower infrastructure costs through standardization and mass production, accelerate the deployment of battery-electric and hybrid vessels, and support emissions-free operations in ports and coastal regions.

Next Steps to Demonstration/Deployment

Barriers for batteries include space constraints, weight, limited energy density, and required recharging times. Current interest in battery systems for vessel propulsion are generally limited to CHC with shorter, fixed routes. For example, battery systems can fully power ferries or tugboats during shorter trips which simplifies charging infrastructure requirements. Large OGVs operate over long distances with long times under power, and the ability to recharge presenting major barriers to operation. There is currently a lack of charging infrastructure at most locations, and significant buildout of dockside charging facilities will be required to support commercial adoption of battery electric vessels.

Nuclear Power

Technology Overview

Nuclear reactors in maritime applications generate power for propulsion and other shipboard needs through the process of using nuclear fission to produce thermal energy which can also be converted to electrical and mechanical power. This process involves splitting uranium atomic nuclei with an exceptionally high energy density (i.e., 3,900,000 MJ/kg relative to 45 MJ/kg for diesel). The nuclear fuel cycle involves three general steps: the frontend (uranium mining and enrichment), the service period, and the backend (disposal of nuclear waste). Uranium is radioactive and strictly regulated from production to distribution, handling, use, and waste disposal. Nuclear energy sources vary in size, shape, and form including solid pellets, rods, and liquids. Nuclear energy sources range from low enriched uranium (LEU) which is tightly regulated but accessible to licensed private companies, to highly enriched uranium (HEU) used primarily in military reactors. A key benefit for nuclear power is that the process does not require bunkering, as nuclear reactors have the potential to run for five to eight years, and potentially as long as thirty years, without refueling [135].

The core components of a nuclear reactor include fuel, control rods, and a moderator. Control rods play a critical role in regulating the nuclear chain reaction. Made from materials with high thermal neutron absorption properties (e.g., boron, cadmium) the rods manage the reactor's reactivity. Their primary functions are threefold: first, to allow for planned operational changes such as starting up or shutting down the reactor; second, to adapt to fluctuations in operating conditions, including changes in fuel composition and the buildup of neutron-absorbing fission products (also known as poisons); and third, to serve as a safety mechanism for rapid emergency shutdown if abnormal conditions arise.

Nuclear propulsion has been a staple in military vessels including submarines and aircraft carriers for many decades, with the U.S. Navy's interest beginning in 1939 and the first vessel in-service in 1955. Many other countries have also developed nuclear-powered military vessels since then including Russia, Great Britain, Germany, China, France, and India. Currently, there are approximately 170 military vessels in service worldwide with the majority being attack submarines. It should be noted that the majority of existing nuclear-powered vessels in military applications use HEU in reactor types not suitable for commercial use [142]. This is because military vessels are designed for military objectives including long endurance, compact reactor size, and minimal refueling. To achieve this, many naval reactors use HEU as it has a very high energy density, long life that allows for potentially decades without refueling, and compact reactor designs suitable for submarines. However, HEU introduces significant nonproliferation, safety, and regulatory concerns as it can potentially be diverted for weapons use. Thus, civilian nuclear systems are strongly discouraged or even prohibited from using HEU under international safeguards frameworks (e.g., IAEA). Instead, commercial nuclear propulsion concepts instead focus on LEU fuels and reactor types adapted from civilian nuclear power including advanced small modular reactors (SMRs). These designs prioritize safety, regulatory compliance, refueling logistics, and public acceptance rather than extreme compactness or multi-decade core life. While LEU reactors are larger and may require more frequent refueling than HEU naval reactors, they are far more compatible with civilian nuclear governance, licensing, and nonproliferation requirements which make them more practical future commercial nuclear shipping.

Given that the current interest in nuclear propulsion in the maritime sector is largely driven by technological advancements in SMRs, the following section will focus on SMR technology.

Small Modular Nuclear (SMR) Reactors

A SMR is a type of nuclear reactor that is smaller in size and power output than traditional large nuclear power plants and is designed to be manufactured in standardized modules, often in factories, and then transported to a site for installation [136]. There is no firm definition of SMRs, but they generally include reactors under 300 MW in size (compared with 1,000 to 1,600 MW for conventional large reactors) with a high degree of modularity, e.g., the entire reactors can be transported by truck and installed on any site with minimal preparation [137]. Their modular design allows multiple units to be deployed incrementally, enabling capacity to grow with demand while reducing upfront capital investment and construction risk. SMRs use the same basic process as conventional reactors to generate heat (i.e., nuclear fission), which is then used to produce steam and drive turbines for electricity or provide industrial heat. SMRs generate heat by initiating a chain reaction in fissile material, which is then transferred to a power conversion system via a coolant to produce electricity. About 70 designs of SMRs are being considered today, generally falling into four main categories: Water-Cooled SMRs, High-Temperature Gas-Cooled Reactors (HTGRs), Sodium-Cooled Fast Reactors (SFRs), and Molten Salt Reactors (MSRs).

SMRs offer several structural and economic advantages compared with traditional large-scale nuclear power plants [136], [138]. SMR designs incorporate simplified systems, passive safety features, and flexible deployment options that allow them to operate in a wider range of applications, including smaller power grids, remote locations, industrial facilities, hydrogen production, and desalination. While SMRs do not fundamentally change how nuclear energy is produced, they represent a more flexible, scalable, and potentially lower-risk approach to nuclear power generation compared with traditional large-scale reactors.

One of the most significant benefits of SMR are lower upfront capital requirements. SMRs are smaller in unit size and they require less initial investment than large reactors, allowing developers to pursue incremental financing rather than committing to a single, very large project [139]. This modular investment structure reduces financial exposure, lowers the risk associated with construction delays or cost overruns, and broadens the range of potential investors and host utilities [136]. Unlike large nuclear plants, which are primarily constructed on-site and often face complex construction challenges, SMRs can be manufactured in controlled factory environments and transported to the installation site. This approach improves quality control, shortens construction timelines, and creates the potential for cost reductions through standardized serial production.

SMRs also provide greater scalability and deployment flexibility. Modules can be added sequentially, allowing generation capacity to grow in line with electricity demand. This incremental deployment model is particularly advantageous for smaller electricity grids, remote regions, and emerging markets where large reactors may be oversized or financially impractical. The compact size of SMRs also enables siting in locations where conventional reactors are not feasible, including industrial facilities, remote communities, and areas requiring combined heat and power, hydrogen production, or desalination. Some SMR designs incorporate passive safety systems and smaller reactor cores, which may allow for reduced emergency planning zones and greater siting flexibility compared with large reactors.

SMRs offer several potential advantages related to radioactive waste generation and management compared with large conventional reactors [139]. Because SMRs are smaller and can be deployed incrementally, total waste production can better match actual energy demand, avoiding the large, centralized waste streams associated with gigawatt-scale plants [139]. Some SMR designs also achieve higher fuel burnup, allowing more energy to be extracted from the same amount of fuel, which can reduce the quantity of spent fuel generated per unit of electricity. In addition, certain advanced SMR concepts are designed to improve waste characteristics by reducing long-lived radiotoxic materials or enabling more efficient use of nuclear fuel. SMRs may also simplify waste handling and long-term management. Smaller cores and, in some designs, longer refueling intervals can reduce the frequency of spent fuel handling and transport. Some concepts use sealed, factory-fabricated reactor modules that can be returned to centralized facilities for refueling and waste processing, potentially improving safety and security while minimizing on-site waste management requirements. Although SMRs do not eliminate the need for long-term disposal, they may reduce waste volumes, improve waste characteristics, and streamline handling logistics, contributing to a more manageable overall waste profile compared with traditional large reactors [136].

Finally, SMRs often feature simplified system designs and enhanced passive safety characteristics. These features can reduce system complexity, improve inherent safety performance, and potentially streamline regulatory approval compared with conventional large reactors. While the magnitude of these benefits varies by design, SMRs collectively represent a shift toward smaller, more flexible, and potentially lower-risk nuclear power deployment. Overall, SMRs exchange some of the economies of scale associated with large reactors for advantages in modularity, financial accessibility, siting flexibility, and integration with modern energy systems.

UK-based CORE POWER is a leading developer of civil nuclear propulsion for commercial shipping focusing on replacing fossil-fuel marine propulsion with SMR nuclear-electric systems capable of powering large ocean-going vessels such as container ships, bulk carriers, and tankers [140]. CORE POWER is focused on developing floating nuclear power systems (FNPP), factory-built marine reactors, and standardized nuclear ship designs that could be produced in shipyards using modular construction to lower costs and accelerate deployment [141]. CORE POWER places particular emphasis on molten salt reactor (MSR) technology because its technical characteristics align well with the operational and safety requirements of maritime propulsion. MSRs use liquid fuel dissolved in molten salt and operate at low pressure, which reduces the risk of high-pressure failure and supports inherently safer, passively stable operation which is an important consideration for shipboard deployment. MSRs can also achieve relatively high power density in a compact form, allowing integration within space-constrained vessel designs, while their high operating temperatures improve thermal efficiency and enable flexible nuclear-electric power generation. In addition, MSR concepts offer the potential for long refueling intervals, simplified fuel handling, and improved fuel utilization, which could reduce operational disruptions and lifecycle waste compared with traditional reactor designs. Taken together, these features make MSRs a strong candidate for marine nuclear propulsion, particularly for long-duration, high-power shipping applications where safety, compactness, and endurance are critical.

Floating Nuclear Power Plants

Floating nuclear power plants (FNPPs), which typically consist of SMRs installed on floating barges or marine platforms, are increasingly being explored for maritime and coastal energy applications. FNPPs could be situated at maritime “green corridor” hubs to provide very low to zero carbon fuels using only sea water and air as feedstocks to produce very low carbon hydrogen through the process of electrolysis [135]. The hydrogen can be used directly or serve as a feedstock for the production of other fuels such as ammonia or methane. For example, Figure 5 provides an overview of a conceptual approach to using FNPPs to produce electricity to produce green hydrogen/e-fuels on a floating refinery that could be used in both the maritime sector [141].

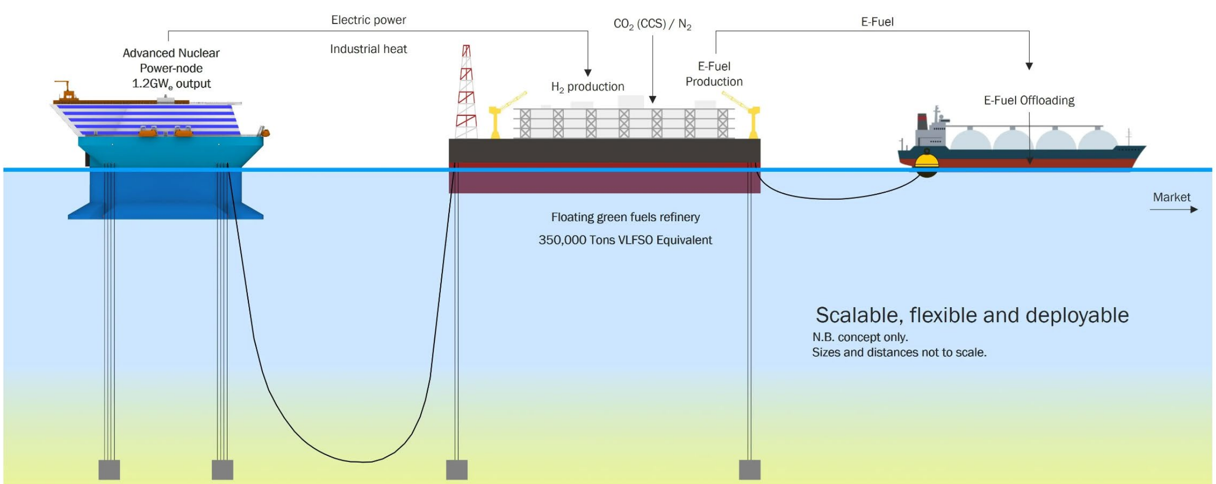

Figure 5. Overview of a FNPP concept to produce green hydrogen for the maritime sector. From Reference [141].

FNPP can function as baseload or load-following power plants that connect directly to coastal transmission networks via subsea or near-shore cables [141]. Unlike variable renewable resources, FNPPs provide continuous, dispatchable electricity, which can help stabilize coastal grids with high penetrations of wind and solar. This firm generation capability is particularly valuable in regions where grid reliability is challenged by intermittency, limited land availability, or weak transmission infrastructure. FNPPs can also be strategically positioned near major coastal demand centers, ports, desalination facilities, and industrial hubs, reducing transmission losses and supporting localized energy security. Because they are manufactured in shipyards and towed to site, FNPPs avoid many of the siting and construction constraints associated with large land-based nuclear plants, including land acquisition, seismic civil works, and complex on-site construction.

The Russian *Akademik Lomonosov* is the world's first FNPP, which began operating in 2019 to provide heat and power to isolated arctic regions, including oil and gas platforms in those areas. The construction of the *Akademik Lomonsosov* began in 2007 and was estimated to cost $248 million [142]. The *Akademik Lomonsosov* is capable of producing 70 MW of electricity and 58.1 MWhr of thermal energy, has a 40-year lifetime, and can operate for three years without refueling. It will also be used for seawater desalination in regions lacking water resources. In the U.S., CORE POWER and Glosten have officially agreed to partner on a design for a FNPP that can generate up to 175 gigawatt-hours of clean electricity annually and provide clean power to ships, equipment, and port vehicles [143].

Compared with conventional land-based nuclear plants, FNPPs have the potential to achieve meaningful cost reductions and shorter construction timelines by enabling serial production in shipyards, where standardized modules can be manufactured under controlled conditions and replicated across multiple units. This approach contrasts with traditional nuclear construction, which is typically characterized by large, site-specific facilities built to capture economies of scale but often subject to high complexity, limited production series, cost escalation, schedule overruns, and reliance on government financial support [136].

A substantial portion of the cost of conventional nuclear power plants is not directly related to the nuclear fuel or the energy-generating reactor itself. Studies commonly estimate that approximately 70 to 80 percent of total construction costs are associated with site preparation, civil works, engineering, project management, regulatory compliance, and financing, including the effects of long construction periods and interest during construction [144]. These cost drivers reflect the challenges inherent in building large, custom land-based nuclear facilities. As a result, recent efforts to improve nuclear economics have increasingly focused on modularization, standardization, and reducing construction duration, rather than on changes to the nuclear fuel cycle.

FNPP concepts aim to avoid many of these cost drivers by shifting a significant share of construction from complex, site-built environments to centralized manufacturing in shipyards, allowing completed units to be transported to their locations of operation. In addition to potential cost and schedule benefits, FNPPs may offer enhanced safety characteristics, including passive cooling supported by the surrounding water, physical separation from dense population centers, and reduced exposure to certain land-based hazards. While technical, regulatory, and economic challenges remain, FNPPs represent a pathway toward more standardized, scalable nuclear deployment, particularly for maritime, remote, and coastal applications.

System/Network Suitability and Operational Infrastructure Needs

The operational and infrastructure needs that would be required to support nuclear-powered commercial vessels are potentially substantial and complex, reflecting both the technical demands of nuclear propulsion and the associated regulatory, safety, and logistical challenges.

Currently, ports must be licensed to receive and service nuclear-powered vessels with specialized personnel, radiation monitoring, and emergency response capabilities. Security and radiation concerns require dedicated berths with restricted access. Safety systems include onshore radiation detection, shielding, containment, and decontamination facilities.

In terms of fueling and waste management, SMRs may operate for 10-30 years without needing to refuel, which has the benefit of reducing the required bunkering infrastructure. However, the initial core fueling and any required mid-life refueling will require robust, secure, and specialized facilities. Nuclear waste infrastructure must also be developed that will allow for the transport and storage of spent fuel.

A highly specialized and properly trained workforce will be required to support nuclear vessels and FNPPs, including licensed nuclear engineers and radiation safety officers. Crew training standards and certification programs will need to be developed, including extensive training in nuclear emergency procedures. Security procedures must be developed to guard against both physical security (e.g., piracy, terrorism) and cyber security for critical processes such as reactor control systems.

Newbuild or Retrofits

The development of nuclear-powered civilian vessels would require purpose-designed newbuild vessels, rather than retrofits, due to significant differences between nuclear propulsion systems and conventional ICE which make retrofitting technically and economically unfeasible. Nuclear reactors require extensive design considerations such as radiation shielding, containment structures, redundant cooling systems, and specialized propulsion configurations and these features cannot be easily or safely integrated into existing ship hulls. Additionally, nuclear-powered ships must meet stringent regulatory and safety requirements set by nuclear authorities, which demand purpose-built reactor compartments and on-board control systems. Every existing civilian nuclear ship, such as the *NS Savannah* and Germany's *Otto Hahn*, was constructed as a newbuild specifically designed for nuclear propulsion. From an economic standpoint, the high capital costs of nuclear systems are better justified when integrated into vessels optimized from the outset for long-term reactor operation.

Economics

Nuclear propulsion has characteristics that could provide long-term economic advantages, including low and stable fuel costs, high energy density, and the ability to operate at sustained high power without significant fuel penalties. These features may enable higher vessel speeds and, in theory, could allow for smaller, faster ships and reduced fleet size under certain operating models. However, this outcome remains largely conceptual, as modern shipping economics are strongly shaped by economies of scale, infrastructure compatibility, regulatory constraints, and capital costs. While nuclear power could offer favorable lifecycle economics in some scenarios, it is not yet established that it represents the only low-carbon pathway capable of improving overall shipping cost competitiveness.

CORE POWER has suggested that nuclear fuel for maritime reactors expressed on an energy-equivalent basis could reach $500–700 per metric ton of fuel oil equivalent, which would place it in a range broadly comparable to long-term LNG price assumptions in some scenarios [145]. This estimate reflects the very high energy density of nuclear fuel, and the relatively small quantity of fuel required over long operating periods, rather than a direct market price for nuclear fuel itself. However, nuclear fuel costs are only one component of total nuclear propulsion economics, and overall costs depend on reactor capital cost, regulatory compliance, crew requirements, waste management, insurance, and decommissioning.

As most nuclear reactors for maritime use are currently in the design phase, estimates for the capital costs of such ships are limited. Russia's latest generation of nuclear-powered icebreakers can provide a benchmark for the potential cost of large civilian nuclear vessels. The Project 22220 (LK-60Ya) icebreakers are approximately 560 feet long and are powered by two RITM-200 nuclear reactors. Publicly reported figures indicate construction costs in the range of $1.1–$1.3 billion per vessel [146]. It should be noted that the costs reflect not only the nuclear propulsion system, but also specialized ice-strengthened hull construction, Arctic operating capability, and associated nuclear safety and support systems. A study of nuclear propulsion found that the primary economic barrier to nuclear-powered merchant ships is the very high upfront capital cost. SMRs are estimated to cost roughly $5,000–$8,000 per kW(e), which translates to about $73–$117 million per vessel for the reactor system alone, excluding the cost of the ship and any required design changes [147]. In some cases, total initial costs for nuclear vessels could reach up to three times those of conventional ships, making financing and investor confidence a major challenge. The analysis also suggests that retrofitting existing vessels is generally impractical, meaning most nuclear ships would need to be purpose-built, further increasing capital requirements. Similarly, Core Power has identified 10,000 TEU and larger container ships as potentially feasible for adopting nuclear propulsion, with advanced reactors at between $4,000 and $7,000 per kilowatt electric (kWe). Core Power estimates the cost of reactors will come down to between $120 million and $150 million USD per reactor, and the lifetime cost of a 180 MW reactor to reach $400 to $500 million [140].

Despite the high capital cost, the operating economics of nuclear propulsion can potentially be favorable over the long term. Nuclear energy is characterized by relatively low and stable fuel costs, with an assumed electricity cost of about $0.08/kWh, equivalent to roughly $1,126 per hour of voyage energy consumption [147]. Nuclear ships do not need to refuel frequently as a single ton of uranium can power a reactor for several years, demonstrating the strong energy density and long-duration fuel advantage of nuclear propulsion compared with conventional marine fuels. For conventional ships, fuel expenses can represent more than one-third of total operating costs, and nuclear propulsion could eliminate exposure to fuel price volatility. Conceptual analyses show that nuclear-powered vessels could save thousands of tons of fuel per voyage, allowing operators to increase cargo capacity or improve profitability[147]. These benefits are most pronounced for high-power, long-distance ships where fuel consumption is especially large. Further, the structural and safety modifications needed to integrate a nuclear reactor into the vessel would have minimal impact on its cargo capacity, which is also favorable from an economic standpoint.

The CAPEX for an MSR propulsion system is significantly higher than for other fuel sources, but the lower OPEX makes up for it. A report assessing how European Union's Fit for 55 climate policies will reshape container shipping economics concluded that, under rising carbon costs and fuel uncertainty, nuclear propulsion could become economically competitive with fossil fuels [145]. Although nuclear propulsion requires high upfront capital investment, lifecycle analysis indicates that phased deployment across a fleet can quickly offset these costs through avoided fuel and carbon expenses, with economic benefits strengthening over time as carbon constraints tighten. Over a full fleet lifetime, the study found that nuclear-electric container shipping can achieve competitive or lower total costs than fossil-fuel vessels in most scenarios, suggesting that advanced nuclear propulsion could become both an economically and environmentally viable pathway for deep decarbonization of container shipping in a carbon-constrained future. Similarly, a study by ULC-Energy concluded that the use of nuclear propulsion in a Newcastlemax bulk carrier offers the lowest operational cost per ton shipped, significantly lower than alternatives like ammonia or VLSFO [148].

However, other reports have questioned the economic viability of SMRs in the near- to mid-term. For example, an assessment by the Institute for Energy Economics and Financial Analysis reported that SMRs would still be too expensive to support transitions to nuclear power in the next 10 to 15 years [149]. Thus, the overall lifecycle economics of maritime nuclear power are uncertain as both vessels and FNPP face additional costs such as specialized crew training, higher insurance and liability requirements, regulatory compliance costs, and eventual decommissioning expenses. The broader adoption of nuclear power will depend on significant reductions in lifecycle cost, improved regulatory frameworks, and collaborative financing models involving governments, industry, and research institutions. Due to its unique cost profile, nuclear-powered shipping may require new frameworks for determining chartering rates that better reflect the front-loaded investment model.

Potential Emissions Reduction

Nuclear power is widely recognized as a very low air emission energy source as nuclear reactors do not emit air pollutants or GHG during operation. Transitions to nuclear powered vessels would be highly advantageous from an emissions perspective for both GHG and pollutant emissions, as well-to-wake emissions are zero. From a life cycle perspective, minor emissions of GHG and pollutants result from fossil fuel use in nuclear fuel extraction, processing, and handling, and other stages such as waste management.

Even accounting for all emissions from a life cycle perspective, nuclear power is a source of very low GHG and pollutant emission energy relative to other fuels [150]. Figure 6 provides the results of a highly detailed and thorough life cycle assessment study of different energy sources for electrical power which found that nuclear power had the lowest GHG of all technologies considered [151]. While other studies have reported higher life cycle GHG emissions for nuclear power (i.e., a mean of 66 g CO_2e/kWh from a meta-review of 103 studies [152]), they are still significantly lower than conventional fuels and comparable to other low carbon alternative fuels such as renewable methanol and ammonia, as shown in Table 2. Specifically in the maritime sector, a study of a nuclear-powered Newcastlemax bulk carrier reported that the vessel could operate with GHG emissions lower than a vessel powered by green ammonia, demonstrating the potential of nuclear propulsion to reach maritime decarbonization goals [148]. On the other hand, the production of methanol from renewable feedstock can significantly reduce GHG emissions versus emissions from conventional marine fuels. Methanol produced from biomethane, solid biomass, municipal solid waste, and renewable electricity, results in significantly lower GHG emissions, ranging from 10-40 g CO2eq/MJ. Additionally, production from some biomethane pathways can achieve net-negative emissions due to avoided feedstock emissions of potentially -55 g CO2eq/MJ. However, long term feedstock availability is expected to be limited. Demonstrating this, using renewable methanol as an alternative to conventional marine fuels for a Suezmax tanker reduced well-to-wake GHG emissions by 30 percent to 75 percent compared to HFO depending on the renewable energy and CO2 source [11]. The use of natural gas-based methanol still provides a reduction of 25 to 38 percent relative to HFO. Shown in Table 2 renewable methanol pathways are consistently among the lowest life cycle GHG emissions of those under consideration relative to other alternative marine fuels.

Table 2. Specifically in the maritime sector, a study of a nuclear-powered Newcastlemax bulk carrier reported that the vessel could operate with GHG emissions lower than a vessel powered by green ammonia, demonstrating the potential of nuclear propulsion to reach maritime decarbonization goals [148].

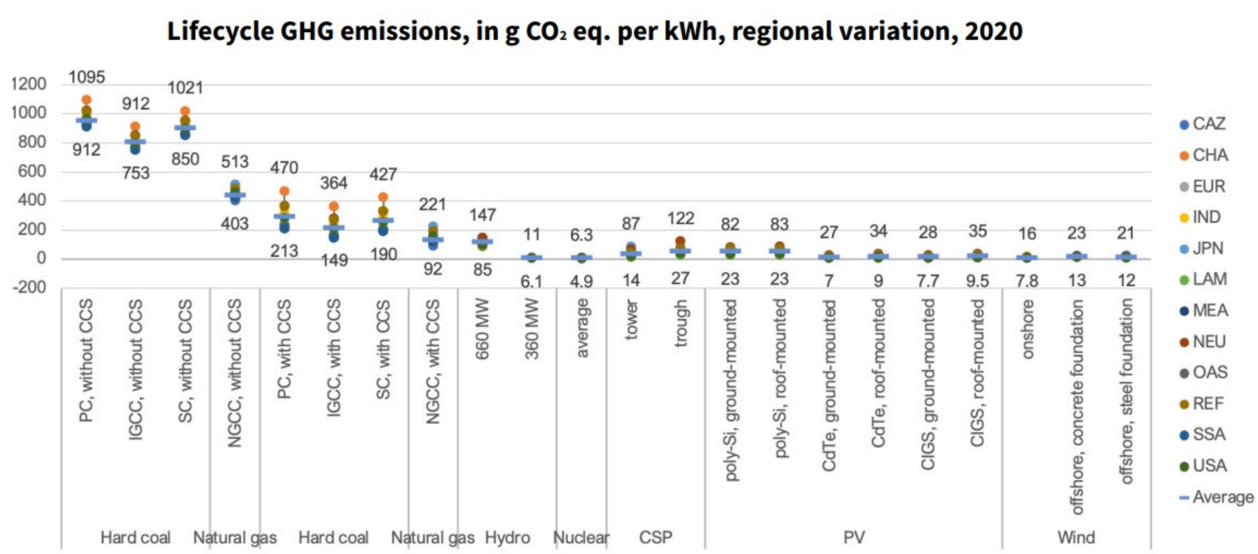

Figure 6. Life cycle GHG emissions across regions. From Reference [151].

Technology Readiness

In terms of commercial shipping, only a few nuclear-powered merchant ships have been built, primarily as experimental vessels. The U.S. built the *NS Savannah* in 1962 as a cargo and passenger demonstration ship which operated until 1972. A German built cargo and research ship, the *Otto Hahn,* was also built in the 1960s and operated until 1979. The Russian cargo vessel *Sevmorput*, commissioned in 1988, is currently the only nuclear-powered merchant ship still in operation. As of 2025, Russia remains the only country that continues to build and operate nuclear-powered icebreakers to support shipping along the Northern Sea Route and Russian Arctic outputs. Notably the Russian icebreaker *50 Let Pobedy* also functions as a tourist vessel offering cruises to the Arctic with capacity for 128 passengers [153]. The 525' *50 Let Pobedy* is powered by two nuclear reactors which generate 55 MW.

Nuclear power in commercial maritime applications is currently in the conceptual to early demonstration stages. For example, Maersk is participating in a study with Lloyd's Register and Core Power to assess the potential for nuclear-powered container shipping in Europe [154]. HD Korea Shipbuilding & Offshore Engineering (HD KSOE) has unveiled a design for a nuclear-powered container ship utilizing SMR technology and obtained Approval in Principle (AIP) from ABS. It has been reported that there are no fundamental technical "showstoppers" preventing nuclear propulsion in commercial ships and case studies have found suitable reactor types and sizes that could be integrated into existing vessel layouts [155]. Advanced Generation IV reactors (particularly MSR) offer improved safety, efficiency, and long operating intervals suitable for marine use.

Initially, container vessels around 10,000 TEU represent the most feasible option to take full advantage of the high power of a nuclear reactor with minimal operational fuel costs [156]. Vessels that typically have longer routes will also require service speeds equal or higher than their conventional counterparts, which are generally around 25 knots. Projections to 2030 estimate an additional 17-20 nuclear vessels will enter the global fleet [157]. With the potential exception of new Russian icebreakers and FNPPs, commercial nuclear shipping faces major institutional and development barriers that make deployment before ~2030 unlikely, even though the technology itself is technically feasible [155]. Primary constraints are not necessarily based on technology, but include regulatory approval, licensing, financing, and international governance, all of which require significant time to develop [159].

Currently, CORE POWER is conducting extensive testing to evaluate nuclear system reliability and safety, and to provide insights on failure points and design improvements. The next phase will involve constructing an experimental micro-reactor to test system criticality and confirm real-world behavior. While simulations and modeling provide valuable insight, regulatory approval requires real-world testing that the system can operate safely and reliably before moving to commercialization. CORE POWER is targeting the final development of a commercial prototype supported by the U.S. Department of Energy (DOE), which is funding 80 percent of the experimental work. In addition to DOE funding, CORE POWER has secured investment from key global maritime and industrial players, including Wan Hai, Express Container Lines, and Hyundai Heavy Industries, positioning the project for successful completion and future deployment.

In South Korea, Korea Electric Power Corporation (KEPCO) is developing the BANDI-60S, an SMR two-loop PWR that has a thermal output of 200 megawatts thermal (MWt) and an electrical output of 60 megawatts electric (MWe) designed for FNPPs [137]. KEPCO estimates that the BANDI-60S will have a 60-year operational lifespan and a fuel cycle of 48 to 60 months. In collaboration with Daewoo Shipbuilding & Marine Engineering (DSME), KEPCO is targeting niche markets including remote locations, islands, and floating platforms.

Next Steps to Demonstration/Deployment

Available studies indicate that advanced nuclear propulsion is technically feasible and could play a major role in decarbonizing deep-sea shipping, although the timeline may be longer than other alternative fuels [155]. However, deployment depends heavily on overcoming regulatory, financial, and societal barriers.

The current lack of regulatory frameworks for commercial nuclear vessels is one of the largest existing barriers. Nuclear merchant ships must comply with both maritime regulations (IMO, class, flag state) and nuclear regulatory regimes (International Atomic Energy Agency (IAEA), national nuclear authorities). Existing rules are outdated and largely designed for older reactor types, meaning new international frameworks are required before commercial deployment becomes viable. Insurance coverage for nuclear propulsion is also not yet established. The development of commercial nuclear-powered ships and FNPPs will require the revision of existing and development of new regulatory frameworks, including both the IMO and the IAEA. Current regulatory frameworks are ill-equipped to handle commercial nuclear vessels and adapted or novel regulations will need to be developed. For example, there is no dedicated IMO regulatory framework for nuclear civilian vessels beyond the general SOLAS and MARPOL provisions. New or revised classification society standards will also be needed to support the design, construction, and maintenance of nuclear-powered vessels (e.g., those by Lloyd's Register, ABS, and DNV). Appropriate standards and rules for the deployment, operation, and decommissioning of vessels and FNPPs will need to address concerns regarding safety, security, and environmental issues. A major challenge for FNPPs is the lack of clarity regarding regulatory approval and guidance, particularly due to their mobile nature which may result in movement across international borders or operation in international waters. For example, the licensing and regulation process for FNPPs must address situations such as FNPPs being built and fueled in one country's jurisdiction and then transported to another country's jurisdiction. Lloyd's Register is actively developing and updating its regulatory framework to address nuclear-powered commercial vessels, particularly in light of advancements in SMRs and MSRs. The international nature of marine shipping will also complicate regulatory approval as the vessels will need to achieve compliance with the nuclear regulatory requirements of each flag and port state in which they operate. Currently, some countries prohibit or restrict the entry of nuclear-powered vessels. Nuclear inspection protocols must be established to guarantee routine safety inspections under IAEA and any other relevant nuclear agencies.

Perhaps the most critical hurdle will be public acceptance of, and support for, nuclear power in various roles including stationary power and maritime shipping. While studies have indicated that nuclear propulsion can be safe, particularly with modern passive-safety reactor designs, public perception remains a major challenge. Surveys show cautious optimism within the maritime industry, with many stakeholders viewing nuclear as an important contributor to decarbonization, though concerns remain about safety, waste handling, and regulatory clarity [155]. However, some studies have shown shifting attitudes on nuclear power with more positive outlooks being driven by its high power density, reliability regardless of weather conditions, significant GHG and air pollution benefits, application versatility, and recent innovations and advancements in both fission and fusion technologies [158]. The study also reported the negative viewpoints cited waste management, high capital costs, and safety concerns. It has also been shown that education on nuclear power can have a significant impact on community opinions of nuclear power, with shifts to more positive outlooks being associated with increased accessibility to fact-based evidence [159]. These findings provide insight for stakeholders on how to improve community perception of nuclear power with trust requiring transparency and accessible information.

Additional technical, operational, and infrastructure barriers, including the need for specialized crew training, waste handling systems, port infrastructure, and global fuel-cycle logistics. In addition, nuclear risks are currently excluded from most marine insurance policies, meaning new international agreements and risk frameworks must be developed before insurers will cover nuclear-powered ships.

Examples of actions that could be taken by stakeholders to potentially impact public perception of nuclear power positively include:

- Research institutions could conduct environmental impact assessments and safety evaluations tailored to maritime nuclear technologies.
- Government agencies and community groups could implement evidence-based campaigns to inform the public about the value, risks, and safety of advanced nuclear technologies in shipping, helping to destigmatize the concept.
- Shipping companies could publish real-world data beyond modeling to demonstrate the safety and environmental benefits of nuclear-powered shipping (such as what Core Power is doing with its current testing).

Aftertreatment Systems

Selective Catalytic Reduction (SCR)

Technology Description

Marine SCR is a mature approach and is widely used to meet IMO MARPOL Annex VI Tier III NOx limits in NOx Emission Control Areas (NECAs). SCR is an exhaust aftertreatment system used in diesel engines across many industries, including the marine industry. Generally, the SCR system is designed to inject a reducing agent (almost always aqueous urea (AUS40) in marine use) into the exhaust stream, where it mixes with the exhaust gases. This mixture then passes through a catalytic reactor containing catalyst materials, allowing the reduction reaction to occur. When urea solution (NH_2CONH_2) is used, the process occurs in two main steps. First, the urea decomposes into ammonia. Second, the NO_x in the exhaust is reduced to nitrogen through a catalytic reaction with ammonia and oxygen (O_2). The reduction reaction (shown below) takes advantage of the phenomenon that occurs when NO_x in exhaust gas reacts with ammonia on the catalyst surface after ammonia is adsorbed onto the catalyst surface.

$$4NO+4NH_3+O_2 \rightarrow 4N_2+6H_2O$$

Similar reactions occur that will reduce NO_2 as well. The catalyst available in the SCR system is coated onto a metal or ceramic-based porous substrate structure and includes precious metals such as platinum. While platinum is used widely in some SCR catalysts, it is susceptible to sulfur poisoning. Since ULSD is not widely available, platinum is not typically used. Instead, the SCR catalysts for marine applications tend to be Vanadium based which has been demonstrated to be highly sulfur tolerant [160].

The advantage of SCR is that it can potentially remove over 90% of NOx emissions under suitable conditions. In practice, Vanadium type SCR systems can achieve 50 to 90% NOx reduction [161]. A typical marine SCR installation consists of several integrated subsystems. Urea storage and handling include dedicated AUS40 tanks sized according to anticipated hours of operation in Tier III mode, transfer pumps, filtration, and heating or insulation to prevent crystallization or degradation of the solution. The dosing and injection subsystem meters urea based on engine load, NO_x levels, and exhaust temperature, and delivers it through injection lances or nozzles using compressed air or mixing devices to ensure good atomization and evaporation. Downstream of the injector, a mixing or decomposition section ensures uniform ammonia distribution before the gas reaches the catalyst reactor. The reactor itself contains multiple catalyst blocks which are commonly honeycomb or plate-type structures which are formulated to promote NO_x reduction within a specific temperature range while minimizing ammonia slip. Instrumentation and controls continuously monitor exhaust temperature, pressure, and reductant flow, enabling closed-loop control of dosing and protection against under- or over-injection.

Theoretically, one molecule of ammonia will react with one molecule of NO in the presence of oxygen. Ideally, the precise amount of urea will be injected such that every molecule of NO will react with one molecule of ammonia. This requires precision metering and thorough mixing of the exhaust stream, which may not be the case in practice. Gas mixers and careful injection of ammonia are required to help make the exhaust species as spatially uniform as possible. However, to ensure maximum removal of NO_x, it is recommended to react with more ammonia than theoretically needed. But when an excess amount is added, unreacted ammonia may be discharged, which is called "ammonia slip." As discussed previously, ammonia emissions are problematic as they themselves are toxic, and they further react with NO_x and SO_x to create secondary PM which contributes to health detriments in coastal communities. In addition, if excessive ammonia is supplied and any fuel sulfur is present, a side reaction occurs in which ammonium sulfate (e.g., $(NH_4)_2SO_4$) is produced. This "toothpaste" like material accumulates on surfaces within the aftertreatment system and can physically block passages and reduce effectiveness of the SCR With high enough temperatures, this side reaction can be mitigated. And the use of low or zero sulfur fuels will also mitigate the ammonium sulfate formation.

The effectiveness of the SCR is dependent on temperature which governs both urea decomposition and catalytic activity with the optimal range varying from 350°C to 400°C [162]. At temperatures below the optimal window, NO_x conversion falls and urea deposits may form. Conversely, at excessively high temperatures, catalyst aging and undesirable reactions can occur. For this reason, SCR units on large marine engines are often installed either in a high-temperature “close-coupled” position near the engine outlet or further downstream with thermal management strategies. Low-load operation presents a particular challenge for marine SCR because exhaust temperatures may fall below the effective range, requiring careful system design and control strategies consistent with the IMO NOx Technical Code. Fuel quality also affects durability: high sulfur fuels and lubricant-derived ash can accelerate catalyst poisoning or fouling, and the reactor introduces some backpressure that must be considered in engine-turbocharger matching. Several strategies are used to maintain optimal exhaust temperatures for the SCR. One method is to place the SCR before the turbochargers, which means putting it in the engine room where the exhaust temperatures are higher, rather than in the exhaust stack. This is typically done with 2-stroke engines, as their higher efficiencies mean lower exhaust temperatures. Comparatively, 4-stroke engines typically have less trouble maintaining an optimal exhaust temperature for the SCR. Operational strategies to increase exhaust temperatures during low engine load conditions include reducing the level of charge, air cooling, modifying injection timing, or using burners to heat up the exhaust. Using an SCR at low engine loads without an optimal temperature may also result in the formation of hydrogen bisulfate, which can block the catalytic converter, therefore reducing its effectiveness and producing sulfate PM.

Fuel sulfur content is also a limiting factor for SCR effectiveness. High sulfur content in the exhaust can lead to increased sulfate particulate emissions and the fouling of the catalyst. The use of an SCR system is therefore well suited for usage with low sulfur fuels, which are already mandated in SO_x Emission Control Areas.

System/Network Suitability and Operational Infrastructure Needs

Because the SCR exhaust system is fully contained on the vessel, there is no need for external infrastructure changes. However, SCR systems add weight and complexity due to additional equipment such as a urea tank. Urea tanks are typically 4-10 cubic meters per MW of engine power [163]. The added weight and complexity of SCR systems will have implications for retrofitting and cargo space. Further, a supply of diesel exhaust fluid (DEF), composed of urea and water, must be available for refilling the system. This requires local storage and/or transport of this material. Analogous to heavy duty vehicles, urea filling stations may need to sit alongside diesel fueling systems. Like all other engine technologies, operational requirements include additional training resources for maintenance, operation, and repairs.

One other consideration is the potential for ammonia to be injected (vs urea). If ammonia is used as a propulsion fuel in the OGVs, it may be available for direct use in the SCR. This simplifies the chemistry associated with the reducing agent as the urea decomposition step is removed. Also, the use of ammonia directly reduces storage requirements and associated dock side infrastructure. The injection of ammonia instead of urea would require additional modification to the dosing system and therefore the OEM would have to develop an ammonia specific version of the engine.

Potential Emissions Reductions

In terms of emissions performance, current marine SCR systems are highly effective for NO_x reduction. The IMO Tier III standard represents roughly an 80 percent reduction in allowable NO_x emissions and well-designed SCR systems commonly achieve greater than 90 percent NO_x reduction when operating within their intended temperature and load range. However, SCR does not significantly reduce PM, SO_x, or CO_2. Additionally, a small efficiency penalty may occur due to exhaust backpressure and auxiliary power requirements, although modern SCR systems can partially mitigate this effect. Proper control is also required to limit ammonia slip and avoid secondary formation of NO_x.

Another problem that occurs when using SCR is that it causes CO_2 during the urea decomposition process. As shown, urea contains a carbon atom. During the decomposition, this carbon atom eventually results in CO_2 via formation of isocyanic acid (HNCO). Shown below, the isocyanic acid further decomposes into another ammonia molecule (via reaction with water) and the oxygen from the water results in CO_2. Relative to combustion of diesel fuel, the amount of CO_2 associated with decomposition of urea is less than one percent by mass.

$NH_2CONH_2 + H_2O + heat \rightarrow 2NH_3 + CO_2$

Technology Readiness

Marine SCR systems are considered a fully commercial, mature emissions-control technology in for OGV and represent a primary compliance pathway for meeting NO_x regulatory requirements. Multiple regulatory, classification-society, and industry assessments consistently describe SCR as a proven, widely available technology with extensive operational history across commercial vessel classes, including container ships, tankers, ferries, offshore vessels, and cruise ships [160], [164]. SCR has a long history of operation under real marine conditions, with documented installations accumulating more than 80,000 operating hours, demonstrating long-term durability, and confirming the technology's maturity for continuous marine service [165]. Industry assessments report a large number of marine SCR systems currently installed with significant expansion annually [165], [166].

Retrofitting SCR onto existing OGV is technically feasible but significantly more complex and costly than integrating SCR into newbuild designs [166]. A major challenge in retrofit applications is space and layout constraints as SCR reactors for large slow-speed engines are physically large to accommodate high exhaust gas flow while maintaining sufficient catalyst volume for NO_x conversion, especially at lower operating loads. Existing vessels generally are not designed with extra space for large exhaust aftertreatment units, so retrofits can require substantial modification of exhaust trunks, funnel structures, and sometimes surrounding machinery spaces. Structural reinforcement, relocation of auxiliary systems, and redesign of exhaust routing are common, which increases installation complexity, shipyard time, and cost relative to newbuild integration. Because auxiliary engines are much smaller than the main propulsion engines, retrofits for auxiliary engines are less challenging. SCR technology is also used on stationary boilers; however, the effectiveness of SCR use on marine boilers is unclear due to the fact that boilers do not ignite under high pressure and high temperature conditions, resulting in minimal NO_x, which allows boilers to meet NO_x regulation standards without the need for SCR.

Economics

Economically, SCR represents a moderate cost for large vessels. Capital costs vary with engine size, reactor volume, and installation complexity, but published case studies indicate installation costs range from several hundred thousand dollars to approximately $1 million-scale system costs depending on configuration and vessel integration requirements [167]. According to IACCSEA, the investment cost of an SCR system is on the order of $500,000 [160]. Major cost drivers include the size of the catalyst reactor required to achieve target NO_x conversion at low loads, structural and ducting modifications (particularly in retrofits), integration with engine control systems, and certification under the IMO NO_x Technical Code framework. Operating costs are dominated by urea consumption and catalyst maintenance. Typical urea use is often cited on the order of about 7 grams per kilowatt-hour and urea prices commonly range from roughly $150 to $400 per metric ton [168]. Catalyst elements are consumables and generally require replacement after approximately 12,000 to 24,000 operating hours, depending on fuel quality, exhaust conditions, and fouling rates, and lifecycle assessments commonly estimate hundreds of thousands of dollars in catalyst replacement cost over long-term operation [169]. These ongoing costs, together with modest efficiency impacts, define the overall lifecycle economics of marine SCR systems, which remain one of the most widely deployed and technically proven pathways for achieving significant NO_x reductions from large ocean-going vessels.

Due to its effectiveness in NO_x emissions control, the use of SCR systems is increasing in response to the 2016 Tier III IMO NOx requirements[170]. Reflecting this, the market is expected to be valued at $5.3 Billion in 2025 and is anticipated to reach $9.4 Billion by 2035 [166].

Next Steps to Demonstration/Deployment

Overall, marine SCR systems are fully commercial, widely deployed, and operationally proven. While challenges such as low-load temperature management, catalyst fouling, and deposit formation remain active engineering considerations, these are well understood and routinely managed in modern installations. Deployment is expected to continue growing as additional vessels enter Tier III regulatory regimes and as retrofits expand across existing fleets [166].

Because of this, the future development of SCR systems is focused less on fundamental chemistry and more on improving operability, durability, integration, and cost-effectiveness under evolving marine operating and regulatory conditions. As NO_x regulations remain stringent and vessel operating profiles continue to shift (e.g., slow steaming, hybridization, alternative fuels), the next generation of marine SCR is expected to seek broader temperature operability, reduced maintenance, and smarter system integration.

Integration with alternative fuels and emerging propulsion systems is also shaping the future of marine SCR [171], [172]. As vessels transition toward alternative fuels, SCR systems must adapt to different exhaust compositions, temperature profiles, and transient behavior. For example, lean-burn gas engines may require different catalyst optimization compared with conventional diesel engines, and ammonia-fueled engines may require careful coordination between combustion-generated ammonia slip and SCR dosing. Future SCR systems are therefore expected to become more fuel-flexible and better integrated with advanced engine control systems and digital vessel management platforms.

One of the most important development pathways is improving low-temperature performance [172]. Research and commercial development are focused on advanced catalyst formulations (e.g., improved vanadia-titania systems, zeolite-based catalysts, and multi-layer catalyst stacks) that enable effective NO_x conversion at lower temperatures while reducing deposit formation and catalyst poisoning. Some system developers are also exploring improved thermal management, including closer-coupled reactor placement, exhaust bypass control, and integration with engine tuning strategies to maintain sufficient catalyst temperature across wider operating envelopes.

Exhaust Gas Recirculation (EGR)

Technology Description

Marine EGR is an emissions-control technology primarily used on large marine diesel engines to reduce NO_x. Fundamentally, EGR works by diverting a controlled portion of exhaust gas (typically 30 to 40 percent) from the engine outlet, cooling and cleaning it, and then routing it back into the engine's combustion chamber. By recirculating exhaust gas, the oxygen concentration in the combustion chamber is reduced and peak combustion temperatures are lowered, which suppresses the formation of thermal NO_x. Shown in Figure 7, a typical marine EGR installation includes exhaust gas take-off and control valves, an EGR cooler, gas cleaning or scrubbing equipment, demisters and separators, and an integrated control system linked to the engine automation platform.

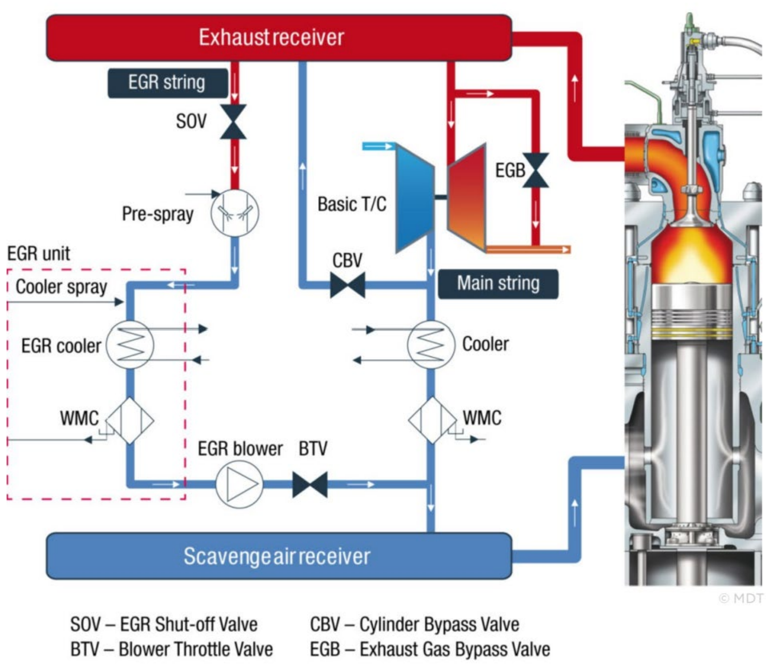

Figure 7. Overview of a marine EGR system from Reference [172].

One of the key operational challenges associated with marine EGR systems is the formation and management of sludge and contaminated residues within the EGR loop and washwater treatment system. Sludge is primarily generated when exhaust gas is cooled and cleaned before being recirculated back to the engine. During this process, PM, unburned hydrocarbons, soot, sulfur compounds, metallic ash, and acidic species are removed from the exhaust stream and transferred into the scrubbing liquid. The interaction of these contaminants with water, lubricating oil residues, and neutralization chemicals leads to the formation of a viscous sludge that must be periodically removed and properly handled. This issue is particularly pronounced when engines operate on higher-sulfur fuels, as SO_x can form sulfuric acid in the presence of water, increasing corrosion potential and contributing to sludge accumulation.

Sludge management is an important operational and maintenance consideration for EGR-equipped vessels. Accumulated sludge can foul scrubbers, separators, coolers, and piping, reducing heat transfer efficiency, increasing pressure drop, and potentially affecting engine performance and reliability if not properly controlled. As a result, EGR systems typically include bleed-off and treatment units designed to separate solids, neutralize acidic components, and concentrate waste streams for storage and disposal. The collected sludge is generally classified as oily or hazardous waste and must be discharged to approved port reception facilities in accordance with MARPOL Annex VI and related environmental regulations. Effective sludge handling therefore introduces additional operational tasks, storage requirements, and disposal costs. Use of low-sulfur fuels significantly decreases acid formation and sludge generation, improving system cleanliness and reliability. Nevertheless, sludge management remains one of the primary operational considerations influencing maintenance planning, lifecycle cost, and crew workload for EGR-equipped marine engines.

System/Network Suitability and Operational Infrastructure Needs

Marine EGR systems are fundamentally self-contained onboard emissions-control technologies and therefore do not require dedicated at-berth infrastructure in the same way as shore power, alternative fuels, or SCR reagent supply systems. EGR operates entirely within the engine and exhaust loop, recirculating and treating exhaust gases using onboard coolers, scrubbers, separators, and control systems. As a result, no external utilities, energy supply, or shoreside process connections are required for routine operation while a vessel is at berth. This characteristic is one of the practical advantages of EGR compared with compliance strategies that depend on external consumables or port-based energy systems.

However, EGR systems can create indirect port-side infrastructure needs related to waste handling and environmental compliance. During operation, the exhaust cleaning and recirculation process generates a bleed-off or washwater stream containing captured particulate matter, acidic compounds, metallic ash, and sludge. While some vessels treat and discharge washwater at sea in accordance with regulatory limits, sludge and concentrated residues typically must be retained onboard and periodically discharged to approved port reception facilities. Consequently, ports serving EGR-equipped vessels must have adequate capability to receive and manage oily sludge or contaminated waste streams under MARPOL requirements. This need is broadly similar to existing infrastructure used for handling oily bilge waste and scrubber residues rather than representing a new specialized system.

Additionally, some operational and compliance considerations may arise at berth depending on local environmental regulations. For example, restrictions on washwater discharge in certain ports or coastal regions may require vessels to operate in closed-loop mode, increasing onboard storage requirements until waste can be offloaded. Ports with stringent environmental oversight may also require documentation of EGR washwater management, sludge disposal, and emissions compliance. These requirements are generally administrative, and waste-management related rather than involving new physical infrastructure.

Potential Emissions Reductions

The primary environmental benefit of marine EGR is substantial reduction of NO_x emissions. The magnitude of NO_x reduction depends on the EGR rate and engine operating conditions. Increasing the fraction of recirculated exhaust gas generally leads to progressively lower NO_x emissions, although practical limits exist due to impacts on combustion stability, fuel consumption, and PM formation. Research has shown that moderate EGR rates around 10–25 percent can produce significant NO_x reductions, while higher recirculation levels can drive emissions down further but can introduce performance trade-offs [173].

Experimental and operational data from marine two-stroke engines consistently show large reductions in NO_x emissions, typically sufficient to meet IMO Tier III limits which require approximately 70–80 percent lower NO_x emissions compared with earlier regulatory levels [174]. In controlled engine studies, EGR-equipped low-speed marine engines achieved NO_x reductions of up to ~76 percent [175]. Across the literature, marine engine testing and modeling consistently confirm that EGR can reduce NO_x emissions by more than 70 percent under optimized conditions, with the highest reductions occurring at higher engine loads where thermal NO_x formation is most significant [174].

EGR is not intended as a GHG mitigation technology and does not directly reduce CO_2 emissions. Depending on engine tuning and operating conditions, it may introduce a small fuel-consumption or efficiency penalty which could increase CO_2 emissions. In general, the fuel consumption penalty introduced by the use of an EGR when operating in Tier III mode is approximately 3% greater than in Tier II mode, which is roughly 2% higher than that introduced by the use of an SCR system [172]. The technology also does not primarily target SO_x or PM, although cleaning of the recirculated exhaust stream is necessary to prevent equipment damage and maintain engine performance, particularly when sulfur is present in the fuel. Overall, EGR is best characterized as a targeted in-cylinder NO_x control strategy rather than a multi-pollutant emissions solution.

Technology Readiness

EGR is a mature and commercially deployed technology in the marine sector, particularly for large two-stroke propulsion engines designed to comply with International Maritime IMO Tier III NO_x standards within designated NO_x ECAs. Over the past decade, EGR has transitioned from early demonstration and prototype installations to routine deployment on commercial vessels. Early large-scale validation occurred in the early 2010s when the first two-stroke marine engines equipped with EGR were installed on container vessels and successfully demonstrated Tier III compliance, confirming that EGR could meet regulatory limits without major performance penalties [176]. Regulatory and technical assessments indicate that modern Tier III vessels routinely rely on either SCR or EGR, with EGR serving as a fully approved and certified compliance strategy under MARPOL Annex VI [177]. Industry documentation further confirms that EGR-equipped engines are commercially available across a wide range of fuel types including heavy fuel oil, low-sulfur fuels, LNG, and methanol, demonstrating the technology's adaptability and operational maturity [178].

The technology is widely available from major engine manufacturers and has been implemented in numerous newbuild vessels. Notably, Wabtec (formerly GE Transportation) makes an EGR based marine engine that meets IMO Tier III and EPA Tier 4 (0.4 g/kW-hr of NOx and NMHC combined) emissions standards without using SCR [179]. This offers a significant benefit in terms of equipment space and elimination of the infrastructure associated with urea handling. Everllence offers EGR based engines that meet IMO Tier III standards without SCR as well [180].

EGR is largely associated with newbuild installations, where engine-room layout, cooling capacity, and washwater treatment systems can be integrated from the design stage. Retrofit applications are technically feasible but remain more complex due to space, utilities, and system-integration requirements. Nevertheless, engine manufacturers now routinely offer "Tier III-ready" engine designs that allow future installation of EGR systems, further underscoring the technology's established status in the marine sector [180].

Economics

The economics of EGR in large marine engines are shaped by capital investment, operating costs, maintenance requirements, and the value of regulatory compliance, and its cost-effectiveness is frequently evaluated relative to SCR. In newbuild vessels, EGR can be integrated into the engine and exhaust architecture during the design phase, reducing lifecycle cost and installation complexity [172]. Retrofit installations, by contrast, can be more expensive due to required modifications to exhaust routing, cooling capacity, washwater treatment systems, and automation controls, as well as vessel downtime during installation.

Capital expenditures for EGR systems vary depending on engine size, configuration, and level of integration with industry assessments generally estimating installed costs ranging from $55–

$80 per kW of main engine capacity [172]. For large slow-speed propulsion engines, this can translate to total installed costs of several million dollars per vessel when including associated pumps, coolers, scrubbers, and control systems. These costs are broadly comparable to SCR installations, though the relative advantage depends on vessel operating profile and system configuration.

Operating expenditures for EGR arise from several sources. First, EGR can introduce a modest fuel-efficiency penalty associated with increased pumping work, exhaust backpressure, and cooling demand, although modern engine tuning and control strategies have reduced this impact in recent designs. Second, periodic maintenance is required for EGR coolers, scrubbers, separators, and sensors, as well as for managing corrosion and fouling in the recirculation loop. Third, the exhaust cleaning process generates a bleed-off or washwater stream that must be treated, monitored, and discharged or stored in accordance with environmental regulations, adding operational and compliance costs. Despite these factors, EGR systems generally have lower consumables costs than SCR because they do not require continuous use of urea or ammonia reagent.

Next Steps to Demonstration/Deployment

A comparison of EGR and SCR is provided in Figure 8 demonstrating considerations and tradeoffs [181]. Although widely used, EGR represents a smaller share of Tier III installations compared with SCR, which remains the dominant solution across most engine classes. Industry data indicate that approximately one-quarter to one-third of Tier III engines employ EGR, with the remainder relying primarily on SCR systems [177]. EGR is technically capable of meeting Tier III NO_x requirements and remains an important control strategy, particularly for certain dual-fuel and low-pressure gas-injection engine configurations where NO_x is already reduced and combustion-based control is advantageous [177]. However, compared with SCR, EGR faces greater technical challenges providing effective NO_x control to very low engine loads. Specifically, EGR has an increased risk of condensation and associated operational concerns at low load, as well as implementation complexity and potential efficiency penalties when higher EGR rates are required [177]. While combining EGR with SCR is technically feasible, such an approach would likely be costly, complex, and difficult to integrate onboard most vessels. One benefit of EGR technology has over SCR is its smaller physical footprint allowing it to be incorporated into ships without requiring large vessel infrastructure changes. Overall, EGR is characterized as a viable but more constrained pathway relative to SCR, particularly in scenarios targeting NO_x reductions during low-load operation.

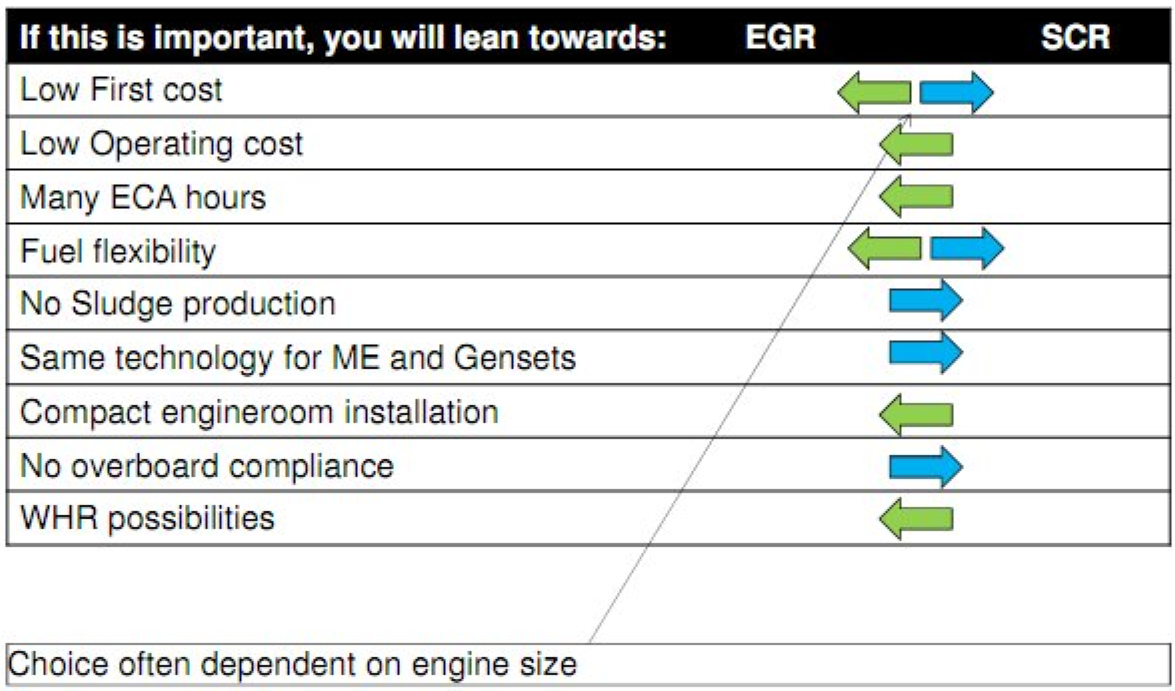

Figure 8. Comparison of drivers and considerations in the selection of EGR and SCR. From Reference [181].

Looking ahead, continued improvements in EGR system design are expected to strengthen economic performance. Current development priorities include reducing fuel-efficiency penalties, improving corrosion resistance, minimizing fouling and maintenance, and optimizing washwater treatment and discharge management. As emissions regulations remain stringent and marine engine platforms evolve to include dual-fuel and alternative-fuel engines, EGR is expected to remain a competitive and economically viable Tier III compliance pathway, particularly for newbuild vessels where integration costs are lowest and lifecycle economics are most favorable.

Scrubbers

Technology Description

Marine scrubbers are aftertreatment devices installed on large OGV primarily to remove SO_x and, to a lesser extent, PM from ship exhaust. Scrubbers can be used to control the emissions on all of a vessel's main and auxiliary engines. They enable ships to continue using high-sulfur HFO while complying with the IMO 2020 global sulfur cap of 0.50% and stricter ECA limit of 0.10%. When fuel containing sulfur is burned, sulfur is converted mainly into sulfur dioxide (SO_2). Inside the scrubber tower, exhaust gas flows upward while water is sprayed downward (counter-flow), creating intense contact between gas and liquid. The SO_2 dissolves into the water and is chemically converted into sulfate, which is far less harmful. At the same time, some PM and soot are captured in the liquid phase. The cleaned exhaust gas is then released through the stack.

Shown in Figure 9, scrubbers work by bringing exhaust gas into contact with water, which absorbs and neutralizes SO_x. A typical marine scrubber installation consists of several integrated components that work together to remove SO_x [182]. At the core of the system is the scrubber tower (reactor), where hot exhaust gas is brought into contact with water, allowing sulfur compounds to dissolve and neutralize before the cleaned gas is released to the atmosphere. Washwater pumps and spray nozzles deliver and distribute seawater or treated freshwater within the tower, creating fine droplets that maximize contact between the liquid and exhaust stream for efficient pollutant removal. Downstream of the reactor, a mist eliminator (demister) captures and removes entrained water droplets from the exhaust gas to prevent liquid carryover and ensure compliant emissions. The system also includes a water treatment unit, which processes used washwater by removing suspended solids, oil residues, and other contaminants prior to discharge or recirculation, depending on whether the system is open-loop, closed-loop, or hybrid. Captured pollutants and solids are routed to a sludge handling system, where residues are concentrated, stored, and later discharged ashore for proper disposal in accordance with environmental regulations. Finally, a continuous monitoring system tracks key operational and compliance parameters, including pH, turbidity, temperature, and discharge quality, to ensure the scrubber operates within IMO and local regulatory limits.

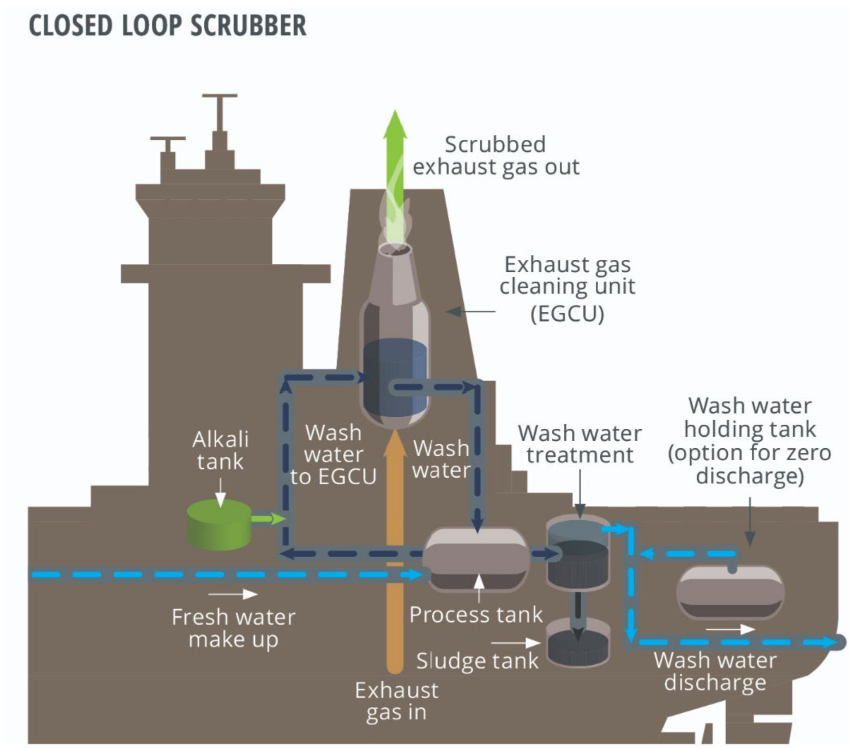

Figure 9. Example of closed loop scrubber from Reference [182].

There are both closed and open-loop scrubbers [182]. Open-loop scrubbers use natural seawater alkalinity to neutralize SO_2. Large volumes of seawater are pumped through the scrubber, and after treatment and monitoring, the washwater is discharged back to the sea. Open-loop systems are simpler and often cheaper to operate but may be restricted in some ports or regions due to discharge concerns. Closed-loop systems use freshwater mixed with an alkaline additive (commonly sodium hydroxide) to neutralize sulfur. The water is continuously recirculated, and only a small bleed-off stream is discharged after treatment. Residues and sludge are stored onboard and discharged to port reception facilities. These systems are more complex but can operate in zero-discharge or restricted waters. Hybrid systems can operate in either open-loop or closed-loop mode, allowing operational flexibility depending on local discharge regulations, water alkalinity, and operating conditions. However, hybrids are more complex in design, more costly and still require port infrastructure to receive waste collected from operation in closed-loop mode

As mentioned, some regions do not allow scrubber discharge in their waters, which constrains these open-loop designs. U.S. regions banning open-loop designs include California, Connecticut, and Seattle. Globally, Singapore, Portugal, and Canada are among many other regions internationally that ban open-loop operation [183].

System/Network Suitability and Operational/Infrastructure Needs

Scrubbers are installed entirely on-board the vessel but do require port-side infrastructure to manage the wastewater. Therefore, ports must have waste reception facilities to accept this material. Tanks, trucks, or pipelines will be needed for compliant disposal. It does not appear that major ports in California have compliant scrubber wastewater reception. Like SCR systems, the scrubber’s size may make retrofits challenging on vessels with space constraints in the engine room or funnel. Figure 10 provides an overview of internal and external scrubber designs. In some cases where internal space is limited and cannot accommodate scrubber installation inside, the scrubber can be installed externally in a tower structure protruding upward from the deck. This may reduce vessel stability due to increased surface area to wind. Like SCRs, scrubbers are easier to implement on new builds. Additional requirements for scrubbers include adequate exhaust backpressure (the scrubber will induce more backpressure on the exhaust effluent) and on-board electrical power (scrubbers require pumping power, circulation pumps, washwater treatment, etc.). A typical open loop scrubber may consume 300 kW of power [184]. It is expected that closed loop scrubbers consume even more on board power.

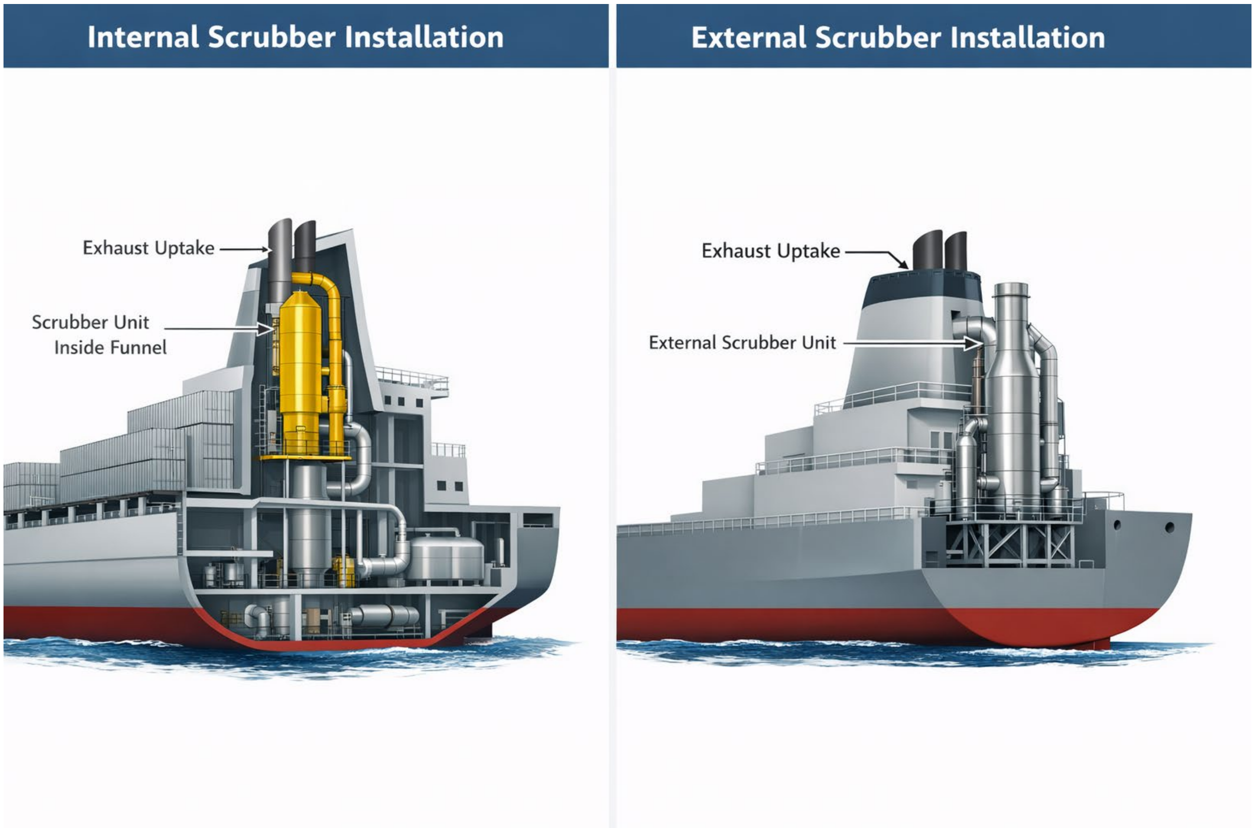

Figure 10. Diagram of marine scrubber installations comparing internal and external installations from Reference [185]

Potential Emissions Reductions

Marine scrubbers are highly effective at reducing sulfur emissions, typically achieving 90–99% SO_x removal, enabling ships burning high-sulfur fuel to meet IMO sulfur limits equivalent to using low-sulfur fuel [186]. Scrubbers also reduce PM by approximately 50–80 percent, primarily through the removal of sulfate particles and associated condensable material formed during combustion [187]. The variation in PM performance is attributed to details of the design. Longer contact time and finer drops help increase PM removal. But because SOx is the primary target, the scrubber design may vary along with cost and still be effective for SOx. PM is more difficult to measure as well, leading to increased variability. Reductions in black carbon are more modest and variable, generally in the range of 10–30 percent, depending on engine load, fuel composition, and scrubber configuration. Scrubbers do not significantly reduce NO_x, although minor reductions (typically <5 percent) may occur due to incidental scrubbing and exhaust cooling effects.

There is also a difference in performance based on the sulfur fuel content. An experiment was performed by the University of California at Riverside where the performance of a scrubber controlling 3 auxiliary engines on a container vessel was measured while using 0.5 percent sulfur distillate fuel [184]. The sulfur distillate fuel corresponded to reductions of 95-98 percent for SO_x, 68-75 percent for PM, and 2-8 percent for NO_x. Additional tests using 0.92 percent sulfur heavy fuel resulted in reductions of greater than 96 percent for SO_x, and 40-50 percent reduction in PM.

In contrast, the impact of scrubbers on GHG emissions is limited because scrubbers do not fundamentally change the carbon content of the fuel being burned. In most cases, scrubbers have a neutral to slightly negative GHG effect, as they enable continued use of carbon-intensive HSFO and impose a small parasitic energy load from pumps, fans, and treatment systems [187]. This energy penalty typically increases fuel consumption by about 1–3 percent, resulting in a corresponding small increase in CO_2 emissions relative to a comparable vessel without a scrubber operating on low-sulfur fuel. Scrubbers do not directly reduce CH_4 or N_2O emissions and therefore provide minimal direct climate benefit. However, when compared with switching to ULSD, lifecycle GHG differences are generally modest and depend on refinery emissions, fuel production pathways, and operational conditions.

However, although scrubbers effectively reduce emissions to the atmosphere, studies have shown that they shift pollution from air to ocean. Open-loop scrubbers discharge large volumes of acidic and contaminated washwater containing metals, polycyclic aromatic hydrocarbons, and other pollutants, often at pH levels around 3–4 [188]. Globally, open-loop systems release on the order of 10 billion cubic meters of washwater per year. The discharge has been linked to toxic effects on marine organisms, eutrophication impacts, and localized acidification, indicating that the technology mitigates air pollution while introducing new environmental pressures in marine ecosystems.

Technology Readiness

Scrubbers are a fully commercial, mature emissions-control technology for OGV. Several major OEMs design, manufacture, and commercially supply large scrubbers for OGVs including Wartsila, Alfa Laval, Valmet, Mitsubishi Heavy Technologies, and Yara Marine Technologies [189]. Their development accelerated significantly following the International Maritime Organization (IMO) global sulfur cap implemented in 2020. Since 2020, over 5,400 ships across various segments of the global fleet have adopted scrubber systems including bulk carriers, container ships, tankers, and even cruise liners. Notably, container ships have been among the earliest and most aggressive adopters, with nearly one in five now scrubber-equipped, representing over a third of global container capacity [189]. Bulk carriers and tankers are pursuing scrubbers due to their high fuel consumption on long-haul voyages. Additionally, their relatively simple deck and engine configurations have made retrofits more feasible and cost-effective than other vessel types.

The commercial readiness of marine scrubbers differs somewhat between newbuild installations and retrofit applications, primarily due to engineering complexity, cost, and integration requirements. However, both pathways are fully commercial and widely deployed, with differences reflecting implementation risk rather than technological maturity. Retrofitting scrubbers onto existing vessels is technically possible but more complex and is generally recommended only for larger ships with sufficient remaining service life to recover the investment [190].

The global fleet of installed marine scrubbers is currently dominated by open-loop systems (55-70 percent of currently installed systems), though the share of hybrid and closed-loop configurations has been steadily increasing in response to regulatory and operational pressures [191]. Overall, open-loop scrubbers remain the most widely deployed configuration due to their lower capital cost, simpler design, and historically broad acceptance in international waters, but their relative share has gradually declined as washwater discharge restrictions expand. In contrast, closed-loop scrubbers represent a smaller share of the installed base (10–20 percent) and are most commonly used where washwater discharge restrictions are strict or where vessels frequently operate in enclosed or sensitive waters. Closed-loop systems recirculate freshwater with alkaline additives and retain sludge and contaminated water onboard for controlled discharge at port reception facilities. While they provide greater regulatory compliance flexibility and reduced marine discharge impacts, they are more complex, require additional consumables and storage capacity, and typically involve higher capital and operating costs. As a result, purely closed-loop systems have historically been less common, particularly in deep-sea commercial shipping. Hybrid scrubbers, which can operate in either open-loop or closed-loop mode, now account for an estimated 20–30 percent of the global installed fleet and represent the fastest-growing configuration. Hybrid systems provide operational flexibility by allowing vessels to operate in open-loop mode in unrestricted waters while switching to closed-loop mode in ports or regions with discharge limitations. This flexibility has made hybrid designs increasingly attractive for newbuild installations and for vessels with diverse operating profiles. Over time, hybrid systems are expected to capture a larger share of future deployments as shipowners seek to manage regulatory uncertainty and ensure long-term operational compliance. Overall, while open-loop scrubbers still dominate the installed base due to earlier large-scale adoption, the market trend is shifting toward hybrid and, to a lesser extent, closed-loop systems, driven by expanding washwater discharge restrictions, environmental scrutiny, and the desire for greater operational flexibility.

Economics

The economics of closed-loop marine scrubbers are determined by fuel cost savings, capital investment, operating expenses, and vessel characteristics, with fuel price differentials acting as the single most important driver of profitability [190]. The primary economic benefit of installing a scrubber is the ability to continue burning lower-cost HFO instead of more expensive low-sulfur MGO or ULSD. As a result, scrubber investments are fundamentally fuel arbitrage technologies, and their viability depends strongly on the price spread between high- and low-sulfur fuels.

Marine scrubber installations require significant upfront investment estimated to range from $2 to $5 million depending on vessel size, engine power, and system type (open-loop, closed-loop, or hybrid) [189]. A study from 2024 by a group in Sweden estimated that 95 percent of a fleet installing scrubbers and using HFO (as opposed to using higher cost low sulfur alternatives) would break even on the CAPEX and operational costs within 5 years [192].

Vessel size and operating profile are determinants of scrubber profitability. Scrubbers are most economically attractive for medium and large vessels, including large crude oil tankers, bulk carriers, and high-power container ships, where fuel consumption is substantial [190]. In contrast, smaller ships tend to experience lower fuel savings relative to installation and operating costs, making scrubber investments less viable. Fixed costs such as maintenance and system weight also have a proportionally greater impact on smaller vessels, further weakening the business case.

Capital costs and payback expectations vary significantly between newbuild and retrofit installations. For newbuild vessels, scrubber systems can be integrated during the design stage, resulting in lower installation complexity and relatively short payback periods when fuel price differentials are favorable. In contrast, retrofit installations are more economically challenging due to higher installation costs, increased engineering complexity, and vessel downtime during installation. It has been estimated that retrofit costs may be approximately 40 percent higher than comparable newbuild installations and must also account for lost income during extended docking and commissioning periods [190]. Because of these factors, retrofit projects typically require shorter payback periods and are most viable for vessels with long remaining service lives. Older ships, particularly those nearing the end of their operational life, are unlikely to justify scrubber investment.

Overall, a 2024 study found that marine exhaust gas scrubbers create strong economic incentives for shipowners. Based on real-world simulations of global vessel activity between 2014 and 2022, approximately 51% of the global scrubber-equipped fleet had reached economic break-even by the end of 2022, generating a net surplus of about $5.5 billion. More than 95% of vessels using the most common scrubber configurations recover their investment within five years, and total savings from continuing to burn cheaper heavy fuel oil instead of switching to low-sulfur fuels reached roughly $21.3 billion. These results demonstrate that scrubbers remain financially attractive under most fuel-price conditions and provide a sustained cost advantage to shipowners.

However, the ecotoxicity caused by scrubber discharge incurs a societal cost that must be considered. Using the Baltic Sea as a case study, the 2024 study estimated that the costs of marine ecotoxicity from scrubber discharge exceeded $1 million between 2015 and 2022 [188]. Over the same period, shipowners saved more than $2.2 billion by continuing to use heavy fuel oil rather than cleaner but more expensive fuels, illustrating a significant externality gap in which private economic gains exceed the environmental costs borne by society. The study emphasizes that this estimate represents only one portion of total environmental damages and likely understates the broader ecological impacts of scrubber discharge.

Next Steps to Demonstrate Technology

As scrubbers are fully commercial today, the next phase of marine scrubber deployment is expected to focus less on basic technology adoption and more on optimization, regulatory alignment, environmental performance, and integration with broader emissions-control strategies.

One of the most immediate deployment priorities is the continued shift from open-loop scrubbers to hybrid or closed-loop configurations. Increasing restrictions on washwater discharge in ports, coastal waters, and certain national jurisdictions have created operational limitations for open-loop systems. Hybrid systems allow vessels to operate in open-loop mode in the open ocean and switch to closed-loop mode in restricted waters, improving compliance flexibility.

Growing regulatory and stakeholder scrutiny of marine scrubber washwater is driving the development of next-generation exhaust gas cleaning systems with improved environmental performance and verification. Key concerns include washwater acidity and the presence of contaminants such as suspended solids, heavy metals, and polycyclic aromatic hydrocarbons (PAHs). In response, modern systems are incorporating more advanced multi-stage treatment and filtration to better remove pollutants and reduce turbidity, along with continuous, real-time monitoring of parameters such as pH, PAH concentration, and discharge quality to support compliance and transparency. Increased focus is also being placed on improving sludge handling through enhanced dewatering, reduced waste volumes, and more standardized disposal practices at port reception facilities. Collectively, these advances aim to strengthen regulatory confidence, improve environmental protection, and ensure that marine scrubbers remain a credible long-term emissions compliance solution under increasingly stringent environmental oversight.

Diesel Particulate Filters (DPF)

A diesel particulate filter (DPF) is an exhaust aftertreatment device designed to capture and remove PM such as soot, organic carbon, and ash from diesel engine exhaust before it is released to the atmosphere. In marine applications, DPFs are used primarily on medium- and high-speed diesel engines, particularly in harbor craft, ferries, tugboats, offshore vessels, and some auxiliary engines on larger OGV. DPFs are widely used in the on-road sector and have increasingly been adapted for marine use where stringent PM and black carbon controls are required (e.g., near ports, ECAs, and sensitive air-quality regions such as California). Due to the combustion characteristics of diesel fuels, diesel engines produce significantly higher concentrations of soot particles than gasoline engines and soot formation can be elevated in some duty cycles (at low load, combustion temperatures are low and can result in emissions of unburned hydrocarbons, including soot). By physically trapping PM within a porous ceramic filter structure, DPF systems can achieve very high reductions in particulate emissions, making them one of the most effective technologies available for controlling diesel PM.

Shown in Figure 11, a marine DPF typically consists of a wall-flow ceramic filter substrate, commonly made of cordierite or silicon carbide, housed within a thermally insulated exhaust casing. Exhaust gas is forced through porous channel walls, where PM is captured while cleaned exhaust exits downstream. Most marine DPF systems include a regeneration system, temperature and pressure sensors, and an electronic control unit to monitor soot loading and manage filter operation. Many installations also incorporate a diesel oxidation catalyst (DOC) upstream of the filter to promote oxidation of hydrocarbons and facilitate passive regeneration.

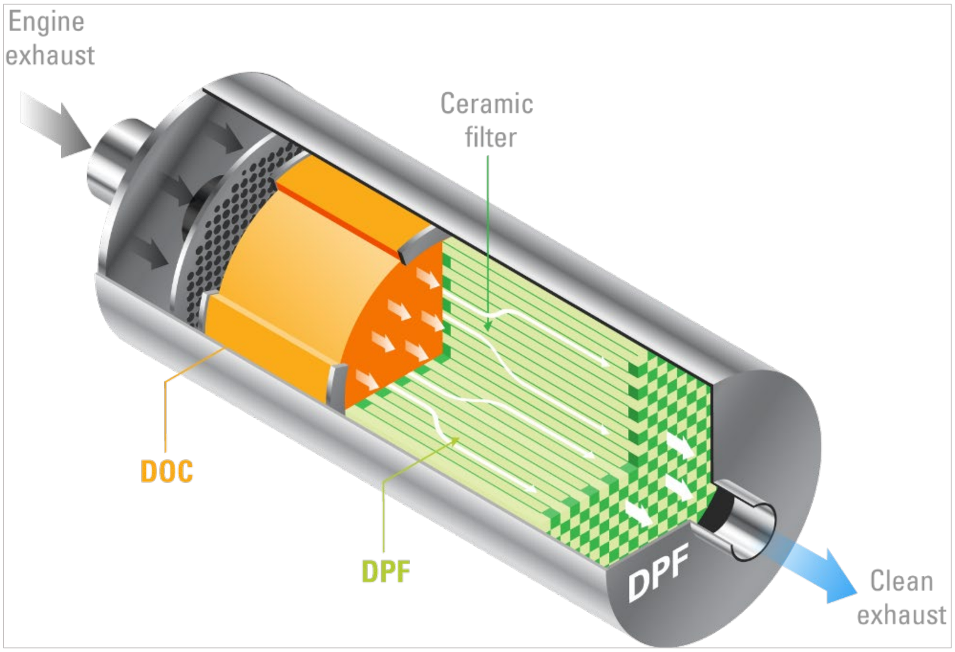

Figure 11: Diesel Particulate Filter (DPF) Schematic from Reference [193]

Because PM accumulates in the filter over time, the system must periodically regenerate by oxidizing stored soot (essentially burning it off) [194]. Passive regeneration occurs when exhaust temperatures are sufficiently high (above approximately 570˚F), typically during steady-load operation, while active regeneration may be required under low-load or variable-duty cycles and can involve fuel burners, electric heaters, or late fuel injection to raise exhaust temperatures. Ash from lubricating oil additives gradually accumulates in the filter and must be removed through periodic maintenance. Duty cycle can play a role in the amount of active regeneration triggered. At low power, soot production is high and minimal opportunity for passive regeneration exists at low temperature. Thus, active regeneration may be used more frequently if the engine operates at low power for extended periods. When active regeneration occurs, it results in higher exhaust temperatures for short periods of time, as noted by some end users [195]. These higher temperatures may be a consideration for the engine compartment ventilation and insulation requirements. A US Department of Agriculture study from 2008 demonstrated that exhaust output temperatures of about 400˚F during normal operation increased to about 700˚F during regeneration [196]. The higher exhaust temperatures from DPF regeneration can cause a modest CO_2 and fuel-use penalty, NO_x shifts if not integrated with SCR, and other thermal and operational management requirements.

One challenge with the advancement of aftertreatment technologies is the required step of joining the SCR system with a DPF. One option is to place the DPF upstream of the SCR system, as shown in Figure 12 [197]. This approach is both attractive and typical, as it exposes the DPF to higher temperatures, promoting longer periods of passive regeneration. For OGV engines, a retrofit or newbuild engine may have an SCR already incorporated. Adding a DPF would then require a reworking of the exhaust system to incorporate a DPF upstream. Another option is to simply place the DPF after the SCR system, like the methods used in the Ford Powerstroke diesel engines [198]. Such strategies have been considered in the amended CARB CHC regulation, which essentially requires installation of a DPF to meet the performance standards required for most CHC vessel categories, and a retrofit DPF that is not part of the EPA-certified engine configuration would need to be placed after the SCR. Thus, experience with DPF positioning for use on OGVs may be forthcoming via CHC applications.

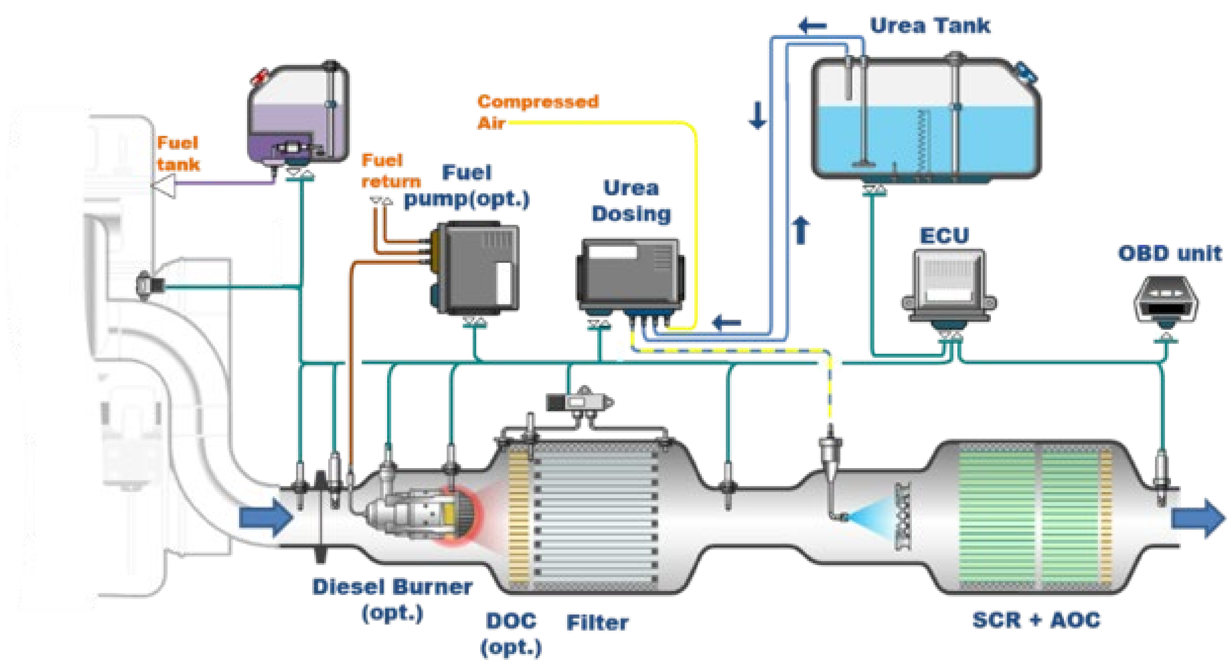

Figure 12: Illustration of possible exhaust aftertreatment components to reduce NOx and particulate from diesel engine combustion [129]

System/Network Suitability and Operational/Infrastructure Needs

DPFs are fully on-board the vessel, meaning no changes to the port infrastructure are needed. Like SCR systems or scrubbers, the DPF size may result in challenges for retrofitting. They are better suited for new builds where the size of the device and any center of gravity (COG) requirements can be accounted for during the design phase. If the systems are actively regenerated, additional infrastructure on the vessel may be required for powering any electrical heater and/or injecting fuel. Any parasitic loads (additional energy consumption within a system that does not directly contribute to its primary useful output but instead supports its operation) associated with resistive power for electric based regeneration or fuel consumed for regeneration will also cause a penalty in efficiency.

Potential Emissions Reductions

Marine DPFs are highly effective at reducing PM, typically achieving 85–99 percent reduction in total PM and 90–99 percent reduction in black carbon [199]. They also substantially reduce ultrafine particles and toxic organic compounds associated with diesel exhaust. However, DPFs do not directly reduce NO_x or SO_x, which require separate technologies such as SCR, EGR, or low-sulfur fuels and scrubbers. GHG emissions are generally neutral, although a small fuel penalty (1-3 percent) may occur due to increased exhaust backpressure and regeneration energy requirements. Despite this minor efficiency impact, DPFs are considered one of the most important technologies for reducing black carbon, particularly in Arctic and port environments where soot has strong climate and public health implications.

Technology Readiness

The commercial readiness of DPFs on the main propulsion engines of large OGVs (particularly those powered by low-speed two-stroke engines exceeding ~15–20 MW) remains limited and is generally considered to be in the early demonstration to pre-commercial stage. While DPF technology is highly developed and widely commercialized for smaller marine engines, its deployment deep-sea vessels is still constrained by fundamental technical and operational challenges. From a market perspective, there are currently few full-scale commercial installations of DPF systems on large two-stroke propulsion engines, and most deployments remain limited to pilot projects, auxiliary engines, or smaller vessel classes. Because regulatory drivers for PM control have historically focused more on smaller vessels operating near populated ports, market demand for large-engine DPF systems has been relatively limited compared with technologies such as scrubbers and SCR/EGR for NO_x control.

One of the primary barriers for OGV is the extremely large exhaust gas volume produced by slow-speed two-stroke engines, which can be an order of magnitude higher than that of medium-speed engines commonly equipped with DPFs. Scaling conventional wall-flow filter systems to handle these flow rates requires very large filter modules, leading to significant space, weight, and integration challenges within the engine casing and funnel structure. In addition, large propulsion engines often operate on residual fuels or fuels with higher ash content, which can accelerate filter fouling and increase maintenance frequency. Managing exhaust backpressure is also critical in large engines, as excessive pressure can reduce engine efficiency and increase fuel consumption, further complicating full-scale deployment.

Another major constraint is exhaust temperature and regeneration control. Large slow-speed marine engines frequently operate at lower exhaust temperatures, particularly during slow steaming or part-load operation, which can be insufficient to sustain passive soot oxidation. Active regeneration systems for very large exhaust streams require substantial energy input and introduce operational complexity, reliability concerns, and potential safety considerations. Ensuring stable and reliable regeneration over long ocean voyages without excessive maintenance remains a key technical hurdle. Furthermore, ash accumulation from lubricating oil additives and fuel impurities requires periodic cleaning, which is more difficult to manage in large, continuously operating propulsion systems compared with smaller engines operating closer to shore-based maintenance infrastructure.

Additionally, reliability is critical for OGV and the volume of an appropriate DPF system creates technical and perceived risk which results in less frequent adoption compared to CHC. Further, adaptation for high sulfur fuels remains an overall challenge.

In contrast, DPFs are moving past demonstration projects to commercial use for harbor craft, ferries, offshore vessels, and auxiliary engines on larger ships. CARB's Commercial Harbor Craft Regulation requires vessels (except commercial fishing vessels) to meet performance standards using U.S. EPA-certified Tier 4 or Tier 3 engines with CARB-Verified Level 3 DPFs capable of removing 85 percent or more of diesel PM [193]. The MV *Karl*, a high speed passenger ferry that has been in operation since April 2025 in San Francisco Bay, utilizes DPFs as a central emissions-control technology enabling the ferry to meet California's strict harbor-craft air-quality standards [200]. The ferry is among the first U.S. passenger ferries equipped with marine-certified DPF systems, with one filter installed on each of its four Tier-4 diesel engines.

Economics

Cost estimates associated with the large-scale DPF systems needed for large OGVs are not readily available. The economics of marine DPF systems vary widely depending on engine size, vessel configuration, and system complexity. Capital costs for small marine engines are typically on the order of tens to a few hundred thousand dollars, while medium-sized installations may range into the hundreds of thousands, and large custom systems can exceed one million dollars [201]. Operating costs are driven by periodic ash removal, occasional catalyst replacement, and the modest fuel penalty associated with regeneration and backpressure. In regions with strict particulate emission regulations, DPFs are often cost-effective due to their ability to achieve near-zero PM emissions and comply with local air-quality standards. They are frequently deployed in combination with other aftertreatment systems, such as SCR, to provide comprehensive control of both PM and NO_x.

Next Steps to Demonstrate Technology

Although DPFs are a mature and highly effective technology for reducing PM emissions in on-road and non-road diesel applications, their use in large marine vessels remains limited. Expanding deployment in the marine sector will require targeted technical development, operational validation, and system-level integration research to address challenges associated with fuel quality, engine scale, durability, and lifecycle economics.

One of the critical steps to expanding DPF use on large OGV is large-scale pilot and demonstration projects. While DPF systems are well-established in land-based and are emerging in the maritime sector for smaller vessels, their effectiveness and durability in high-sulfur, high-temperature, high-flow marine diesel environments (i.e., particularly for two-stroke engines typical of OGVs) must be rigorously validated. Pilot programs supported by government or port authorities can generate valuable performance data, identify design optimizations, and build operator confidence in these technologies. Demonstrations on vessels operating in ECAs or near ports would be particularly valuable.

A significant technical barrier to DPF deployment is fuel sulfur content. DPFs require low-sulfur fuel (e.g., <15 ppm) to prevent filter clogging and catalyst deactivation. Although OGVs operating in ECAs must use 0.1 percent LSFO, and vessels operating in RCW must use 0.1 percent MGO/DO fuel, vessels outside ECAs often continue to use high-sulfur fuel (up to 0.5 percent sulfur globally (IMO cap), or higher if scrubbers are installed). For reference, 0.1 percent MDO/MGO fuel corresponds to a sulfur level of 1,000 ppm, significantly larger than the <15 ppm to prevent filter clogging and catalyst deactivation. Therefore, DPF expansion may need to be coupled with policies promoting or mandating low-sulfur fuel usage, either globally or within more regional clean fuel corridors. Research into DPF designs that can tolerate higher sulfur fuels, or the integration of DPFs with scrubbers, could also expand their applicability.

Key research needs include improved thermal management and regeneration control to ensure reliable soot oxidation under low exhaust temperatures common in marine duty cycles, particularly for auxiliary engines and variable-load operation. Optimization of active and passive regeneration strategies (e.g., burner-assisted, electrically assisted, catalytic, and hybrid approaches) remains important, along with understanding the effects of slow steaming, port operation, and variable load on regeneration performance.

Scaling DPF systems for large marine engines is another priority. Application to large two-stroke propulsion engines presents challenges related to system size, pressure drop, thermal gradients, and durability, requiring development of modular, high-flow, and low-restriction filter designs. Long-term durability under marine conditions also requires further validation through extended field testing to assess degradation, catalyst stability, and maintenance needs.

Economic and operational research is needed to support wider adoption, including improved marine-specific lifecycle cost data and evaluation of integration with other emission-control technologies such as scrubbers, SCR, and ESP systems. Finally, additional research is needed to better quantify reductions in black carbon and PM from marine DPF deployment, supported by improved measurement methods, onboard monitoring, and standardized testing protocols to strengthen regulatory and operational confidence.

Electrostatic Precipitators (ESP)

Technology Description

ESPs are advanced exhaust aftertreatment systems designed to remove PM from combustion exhaust streams using electrostatic forces. In the marine sector, ESPs are increasingly being evaluated as an option for PM from large OGVs, particularly those operating on HFO, MGO, or other fuels that produce soot and ash. ESPs are capable of capturing very fine and ultrafine particles, including black carbon, and are often considered a complementary technology to DPFs and scrubbers. Their ability to operate with relatively low exhaust backpressure and reduced sensitivity to ash loading makes them particularly attractive for large marine engines where conventional filtration systems may face operational constraints.

An ESP functions by electrically charging particles in the exhaust stream and collecting them on oppositely charged surfaces. The system typically consists of a high-voltage discharge electrode that ionizes the exhaust gas and imparts a negative charge to PM, collection plates that attract and capture the charged particles, and a transformer-rectifier unit capable of generating high voltage, typically in the range of 20 to 70 kilovolts. Marine ESP systems also include a rapping, vibration, or washing mechanism to periodically remove accumulated particulate deposits from the collection surfaces, along with monitoring and control equipment to regulate voltage, current, and collection efficiency. Because ESPs rely on electrostatic attraction rather than physical filtration, they generally produce a lower pressure drop than DPF systems and are less prone to clogging when treating exhaust streams from engines burning high-ash residual fuels.

There are several different types of ESP, with the primary distinction in how collected particles are removed and how they handle fine, sticky, or condensable aerosols. In a dry ESP, collected particulate is periodically removed through mechanical rapping or vibration, allowing solids to fall into hoppers for disposal. While effective for coarse, dry particulate, dry ESP systems are less efficient for very fine particles, sticky aerosols, and condensable species, and they can experience particle re-entrainment during the rapping cycle. These limitations make dry ESP systems less suitable for exhaust streams containing high moisture, sulfuric acid mist, or condensable particulate fractions, conditions that are common in marine combustion exhaust.

Typically, marine ESP (shown in Figure 13) are wet ESP (WESP) which continuously wash the collection surface using a liquid film or spray, preventing particle buildup, and eliminating re-entrainment [202]. This configuration enables very high removal efficiency very small particles, condensable particulate, sulfuric acid mist (SO_3), metals, and other aerosol species that are difficult to capture with dry systems. Because the collection surface remains clean and wet, WESP systems maintain stable performance even in exhaust streams with high humidity, sticky or hygroscopic particles, or significant condensable fractions. Typical particulate removal efficiencies for WESP systems are on the order of approximately 90–98 percent, with particularly strong performance for ultrafine particles and black carbon [203]. WESP systems are also being deployed as pre-treatment stages for onboard carbon capture systems, where removal of PM and acid mist is necessary to protect downstream capture equipment and maintain system performance. However, WESP systems generate a liquid waste stream that must be managed, typically consisting of washwater and captured particulate sludge.

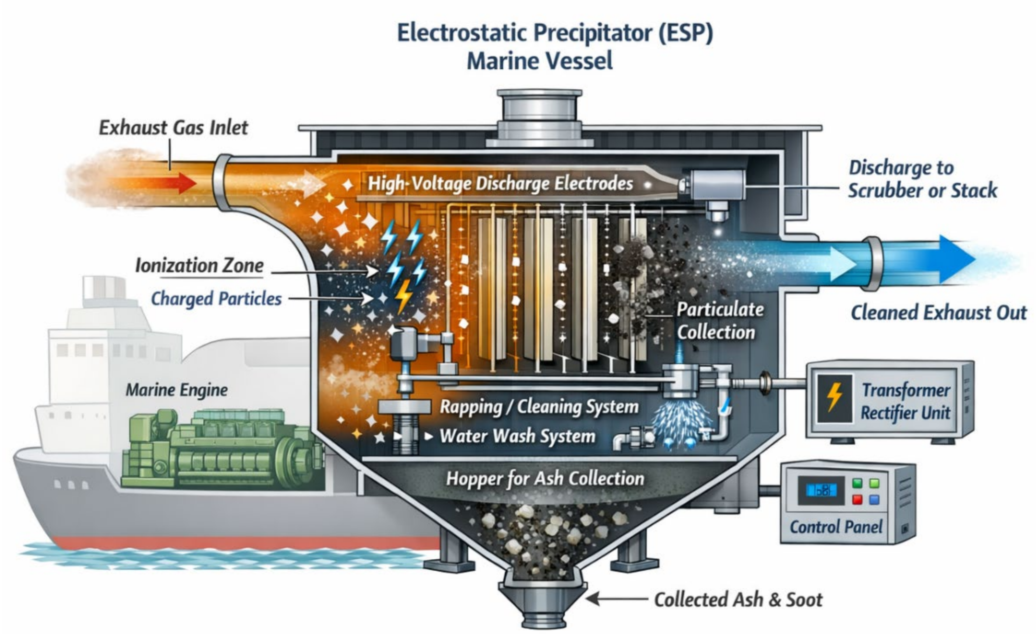

Figure 13. Schematic of a marine WESP for a large OGV. Source: UCI

Several operational and integration considerations influence the feasibility of ESP deployment on large OGV. Space and weight requirements can be substantial, particularly for systems sized to treat exhaust from large two-stroke propulsion engines. Reliable onboard electrical supply is necessary to support high-voltage operation, and system performance can be influenced by fuel characteristics, particulate composition, and exhaust temperature. Routine maintenance is required to ensure effective removal of collected particulate matter and proper functioning of electrical components. Integration with existing exhaust-gas systems, including scrubbers, silencers, and ducting, must be carefully engineered to optimize performance and minimize operational disruption.

ESPs are particularly suitable for vessels operating frequently in ports, ECAs, or environmentally sensitive regions where reductions in PM and black carbon are prioritized. Because ESPs target PM emissions without affecting fuel combustion chemistry, ESPs are compatible with a wide range of marine fuels, including heavy fuel oil, marine gas oil, biofuels, and some alternative fuels that still generate PM. Their role is therefore complementary to broader decarbonization strategies, focusing primarily on local air-quality improvement rather than greenhouse-gas reduction.

System/Network Suitability and Operational/Infrastructure Needs

Successful deployment of marine ESP systems requires several onboard operational and infrastructure provisions. A major need is a reliable electrical supply capable of supporting high-voltage operation, as ESP systems typically operate in the tens-of-kilovolts range. Electrical demand is generally modest relative to engine output but must be stable to maintain consistent particle charging and collection efficiency. Integration with the vessel's power management system is therefore necessary to ensure reliable operation under varying load conditions.

No specialized shoreside infrastructure is typically required for ESP operation, as systems function entirely onboard the vessel. However, periodic handling and disposal of collected particulate residues or sludge may be necessary, particularly for wet systems integrated with scrubbers. In addition, monitoring and control systems are needed to track electrical performance, particulate removal efficiency, and system health, supporting compliance with emission-control requirements and ensuring consistent operation over time.

Potential Emissions Reductions

ESP are capable of achieving substantial reductions in PM from marine engines. Reported performance indicates PM reductions typically ranging from approximately 70 to 95 percent, with black carbon reductions often exceeding 80 percent under favorable operating conditions [202]. Fine particulate matter ($PM_{2.5}$) removal efficiency is commonly reported in the range of 80 to 95 percent, depending on exhaust composition, temperature, and system configuration [204], [205]. ESPs do not significantly affect NO_x, SO_x, or CO_2 emissions, as the technology is designed specifically for PM removal. However, when combined with other emission-control technologies such as scrubbers or low-sulfur fuels, ESPs can substantially reduce visible smoke and PM, improving local and regional air quality, particularly in port and coastal environments.

Technology Readiness

Although ESP technology is mature in land-based industrial and power-generation applications, its adoption in marine propulsion systems remains at an emerging stage [206]. ESP have long been used in coal-fired power plants, waste incinerators, and heavy industry, demonstrating reliable high-efficiency PM capture at large scales [205]. In marine applications, several demonstration and early commercial installations have been carried out by technology providers including Wärtsilä, Mitsubishi Heavy Industries, and Panasia, often in conjunction with exhaust-gas scrubber systems. Deployment to date has focused primarily on auxiliary and medium-speed engines, where exhaust flows are more manageable and installation constraints are less severe. Technology readiness for auxiliary engine applications is generally considered moderate to high, while application to very large low-speed two-stroke propulsion engines remains more limited due to challenges associated with system size, integration, and high exhaust flow rates.

ESP systems are generally most effective when exhaust temperature, particulate composition, and gas flow remain within predictable ranges, conditions commonly observed in auxiliary power generation and hoteling operations. As a result, ESP deployment is often considered more immediately feasible for auxiliary engines than for very large low-speed main propulsion engines, although larger systems are technically possible.

From a vessel-network perspective, ESPs are compatible with both newbuild and retrofit installations, though integration complexity varies. Auxiliary engine installations are typically more straightforward due to smaller exhaust flow, lower space requirements, and easier integration within existing engine room layouts. For main engines, system size, weight, and ducting modifications can be substantial, requiring careful engineering and structural considerations. ESPs can be installed either upstream or downstream of exhaust gas cleaning systems such as scrubbers, and in some configurations, they are deployed in combination with scrubbers to enhance overall particulate removal efficiency. This flexibility allows ESPs to be integrated into multi-pollutant control architectures alongside sulfur-control, nitrogen-oxide reduction, and emerging carbon-capture technologies.

In 2024 Solvang successfully installed WESP systems supplied by Wärtsilä on the main engines of five gas carriers (*Clipper Eris*, *Clipper Eirene*, *Clipper Enyo*, *Clipper Eos*, and *Clipper Wilma*), achieving approximately 95% reduction in particle mass, representing a major improvement in exhaust cleaning performance across the fleet [204]. The WESP units are also used as pre-treatment for onboard CCUS systems, which was piloted on *Clipper Eris*. According to Solvang, the technology performs effectively but required initial adjustments to handle high-sea operating conditions and management of collected particulate sludge and washwater. Despite these challenges, Solvang reports the exercise was a success and expects final design and operational decisions for full deployment to follow based on ongoing technical validation.

Economics

The economics of ESP systems for large OGVs depend on engine capacity, exhaust flow volume, integration complexity, and whether the system is installed as a standalone PM control device or in combination with other emission-control technologies. Installation expenses can be significant due to structural modifications, electrical integration, and space limitations within existing exhaust systems. Capital costs are typically estimated in the range of approximately $100 to $300 per kilowatt of treated engine capacity, although costs vary widely depending on vessel size and configuration [207].

Operating costs are generally moderate and are driven primarily by electricity consumption for high-voltage generation, routine maintenance, and periodic cleaning of collection surfaces. Because ESPs impose a lower exhaust pressure drop than filtration-based systems, fuel-consumption penalties are typically lower than those associated with DPF installations, which may offer lifecycle operational advantages in high-ash marine applications. Additional cost studies show that ESP installations require upfront capital investment but generally have moderate operating costs dominated by electricity consumption and maintenance, with high particulate removal efficiencies often exceeding 90 percent [208]. While marine-specific cost data remain limited, installation costs for shipboard systems may be higher than land-based installations due to space constraints, structural integration, and marine engineering requirements.

However, this may be justified in cases where ultra-low PM emissions are needed, such as in sensitive port regions or near populated coastlines. Operating costs are relatively low, primarily consisting of power for ionization and periodic maintenance. If PM emissions are eventually regulated from OGVs and ports impose stricter air quality standards, the cost-effectiveness of ESPs could improve, particularly if they are integrated into scrubbers or applied to vessels already using low-sulfur fuels. Economies of scale and ongoing marine-specific engineering advances could further reduce costs and make ESPs a more viable option for widespread maritime adoption.

Next Steps to Demonstrate Technology

Although ESPs are a mature particulate-control technology in land-based applications, their broader adoption in the marine sector requires additional technical validation, system optimization, and operational experience. One of the primary research needs is scaling and system integration for large propulsion engines. Treating the very high exhaust flow rates of large two-stroke marine engines requires development of compact, high-throughput ESP designs with improved gas distribution, electrical stability, and minimized footprint. Demonstration projects on large engines are needed to validate performance, durability, and installation feasibility under real operating conditions.

Further work is needed to improve performance across variable marine duty cycles. ESP efficiency depends on exhaust temperature, particle composition, and electrical charging characteristics, all of which can vary significantly with engine load, fuel type, and operating mode. Research is needed to optimize control strategies for stable operation during low-load conditions, transient operation, and slow steaming, and to better understand performance across different fuels, including heavy fuel oil, distillate fuels, and emerging alternative fuels.

Durability and marine environmental resilience represent another important research area. ESP systems must operate reliably under vibration, thermal cycling, salt exposure, and corrosive exhaust environments, particularly when installed downstream of scrubbers where moisture and acidic compounds may be present. Long-duration field testing is needed to evaluate electrode wear, corrosion, fouling, insulator performance, and maintenance intervals, as well as to improve materials and marine-grade system design.

Additional research is required to refine system economics and lifecycle performance. While ESPs generally impose low exhaust backpressure and modest energy penalties, more marine-specific cost data are needed to quantify capital costs, installation complexity, maintenance requirements, and long-term operational performance across vessel classes. Evaluation of hybrid configurations including ESP combined with scrubbers, DPF, or CCUS may identify optimized multi-pollutant control strategies and improve overall cost-effectiveness.

Improved understanding of black carbon and ultrafine particle reduction is also needed, particularly for vessels operating in sensitive regions such as the Arctic and near-port communities where particulate emissions have significant climate and public-health impacts. Development of standardized measurement methods, onboard monitoring systems, and long-term emissions datasets will support regulatory validation and help quantify environmental benefits.

Finally, expanded pilot and demonstration programs are essential to accelerate technology maturation. Deployments across different vessel classes, engine types, and operating conditions will provide critical data on performance, durability, maintenance, and cost, supporting broader commercial adoption and integration of ESP systems into multi-pollutant marine emissions-control strategies.

Energy Efficiency Measures and Technologies

Technology Description

From a goods movement perspective, OGVs are reasonably efficient in terms of emissions per ton-mile. However, there are strategies that can further reduce emissions through increased efficiencies when vessels are both at-berth and at-sea. To reduce fuel costs and satisfy regulatory requirements, the industry has historically developed and applied energy efficiency technologies and measures. Potential energy efficiency measures and technologies to reduce fuel consumption and emissions from OGVs include a wide range of different approaches. A recent report by DNV listed and evaluated approximately 50 different items including operational, propulsion and hull, machinery, energy consumers, and energy harvesting strategies [209].

While a comprehensive and detailed assessment of every possible efficiency technology and measure is outside the scope of this report, the following section discusses some of the more important from an emissions reduction standpoint including:

- Speed Optimization
- Weather Routing
- Trim and Draft Optimization
- Air lubrication Systems
- Advanced Hulls Including Bulbous Bow
- High-performance coatings
- Advanced Propeller Designs
- Shaft Generators
- Waste Heat Recovery
- Engine de-rating
- Energy-efficient Lighting
- Auxiliary System Optimization
- Wind-Assisted Propulsion
- Solar Panels

The technologies considered span operational measures, vessel design improvements, and onboard energy systems, each with differing suitability, retrofit potential, emissions performance, technology maturity, and economic characteristics. It should be noted that, given the large number and wide range of efficiency technologies presented in this section, the results will be presented in Table 11 in order to clearly organize and compare the large volume of information generated in this assessment and the wide range of technologies evaluated.

Vessel Operational Measures

Voyage optimization is the process of carefully planning a ship's schedule so that its voyage is as efficient as possible. This can be done through several methods including just-in-time shipping, minimal speed or power variation, routing for weather concerns or tides, and optimum ballast and trim levels. Voyage optimization increases the efficiency of OGVs, therefore translating to reduced engine loads, fuel consumption, voyage times, and reduced power variation. Combined, these improvements lead to reductions in emissions.

Improved training and vessel optimization software can also improve efficiency, reduce fuel consumption, and reduce emissions. Performance monitoring software can relay information to shore-side weather routing companies for even more efficiency optimization. Further testing to quantify savings through voyage optimization would provide detailed information about the benefits of voyage optimization.

The following section provides an overview of several voyage optimization strategies.

Speed Optimization (Slow Steaming)

Slow steaming is the purposeful operation of OGVs at speeds lower than maximum or typical cruising speeds, primarily aimed at reducing fuel consumption and emissions. As ship speed decreases, fuel consumption per mile is reduced significantly as the relationship between speed and fuel use is not linear, i.e., main engine power is approximately proportional to the cube of the ship's speed. Therefore, small reductions in speed can potentially lead to reductions in fuel consumption and emissions [209]. While reducing speed also increases the travel time of vessels, the overall emissions are theoretically still lower as the emissions from main and auxiliary engines are linear with ship speed during the increased time. However, these reductions are not universal. At very low engine loads, especially in Tier III engines equipped with SCR systems, emissions of NO_x and PM can increase due to reduced combustion efficiency and ineffective catalyst temperatures.

Slow steaming is not universally applicable across all vessel categories. It is most effective for cargo ships with flexible delivery windows, such as bulk carriers, tankers, and container vessels, where scheduling and logistics systems can accommodate longer transit times. In contrast, vessels with fixed schedules, time-sensitive cargo, safety-critical missions, or operational constraints—including ferries, cruise ships, refrigerated cargo vessels, LNG carriers, offshore support vessels, and naval ships—face significant limitations in adopting slow steaming. These operational, commercial, and technical constraints mean that slow steaming must be applied selectively based on vessel type, mission profile, and system design rather than as a universal efficiency strategy.

Slow steaming has significant challenges including commercial and contractual constraints as many ships operate under charter party agreements that define strict schedules, delivery windows, and performance expectations. In time-sensitive trades like container shipping, reducing speed can conflict with service reliability and customer expectations, especially in just-in-time supply chains. This makes it difficult for ship operators to adopt slower speeds without renegotiating contracts or facing potential penalties. In addition, when freight rates are high or ship availability is tight, there may be stronger commercial incentives to operate at higher speeds to maximize cargo throughput and revenue. Another challenge is fleet utilization and vessel scheduling. Slow steaming increases voyage duration, which can require more vessels to maintain the same cargo flow in fixed-route services, especially in liner trades. This can offset some of the emissions savings and introduce additional operational complexity and CAPEX. For shipping companies with limited fleets or tight schedules, this trade-off can be a significant deterrent. These and other operational challenges including low-load engine inefficiency, degraded emissions-control performance, increased maintenance, schedule inflexibility, weather exposure, and reduced effectiveness of onboard efficiency technologies can complicate the feasibility of slow steaming.

Technical limitations can also constrain slow steaming. While most modern marine engines can safely operate at lower speeds, prolonged operation at low loads can result in incomplete combustion, increased engine wear, and higher maintenance requirements, particularly for older engines not optimized for part-load conditions. Engine de-rating or tuning can mitigate these effects, but such modifications involve cost, downtime, and engineering considerations that not all shipowners are willing to undertake.

Weather Routing

Weather routing is a voyage planning strategy that uses meteorological and oceanographic data to determine the most efficient and safest path for a vessel. It optimizes routes based on weather patterns, sea states, currents, and wind conditions, with the goal of minimizing fuel consumption, reducing emissions, improving safety, and ensuring timely arrival. Weather routing improves the vessel safety by minimizing risks from storms, high waves, or heavy winds that could endanger cargo, crew, or equipment. Weather routing also has the benefits of enhancing schedule reliability which supports just-in-time arrival, allowing slow steaming without risking late arrival, and avoids costly waiting times at ports. It also optimizes commercial performance by providing better predictability of fuel use, voyage duration, and charter performance.

Modern weather routing relies on a suite of advanced technical tools and systems including the Voyage Management System (VMS), which integrates vessel performance data, weather forecasts, and routing algorithms to support both on-board and shore-based planning. Dedicated weather routing software, such as StormGeo, NAVTOR, MeteoGroup, and Weathernews Inc. (WNI), provides dynamic route recommendations by analyzing real-time meteorological and oceanographic data in combination with vessel-specific parameters. These solutions are often cloud-based, allowing continuous updates and adjustments throughout a voyage. On-board, bridge decision support tools present navigators with real-time routing options, visual overlays of weather conditions, and alerts, enabling informed navigation choices. Increasingly, artificial intelligence (AI) and machine learning are being integrated into routing systems to improve predictions based on historical data, vessel behavior, and changing environmental conditions. Furthermore, these routing tools are frequently integrated with Electronic Chart Display and Information Systems (ECDIS), allowing optimized routes to be visualized directly on navigational charts for situational awareness and compliance. In more advanced installations, autopilot systems can be linked to routing recommendations, automatically adjusting the vessel's course and speed to follow the optimal path without requiring constant manual input.

Weather routing is particularly effective for long ocean crossings. For example, a Panamax bulk carrier on a Pacific crossing could avoid a frontal system with 5m waves and 40-knot headwinds and instead follow a southern arc with calmer seas and favorable currents resulting in a 7 percent fuel savings, 20-hour delay avoided, and safer transit for crew and cargo [209].

Despite its benefits, weather routing faces several barriers and limitations that can hinder its effectiveness and widespread adoption. One of the primary challenges is integration complexity as weather routing requires reliable on-board sensors, digital infrastructure, and crew training to ensure accurate data collection and effective use of routing recommendations. In some cases, crews may resist adopting new systems, preferring traditional navigational practice which is a phenomenon known as crew acceptance. Accuracy of weather forecasts is a challenge as, while short-term predictions are generally reliable, long-range forecasts can be uncertain, especially in volatile regions, potentially reducing the effectiveness of route optimization. Additionally, contractual constraints can pose a significant barrier. Many charter party agreements specify fixed delivery windows or preferred routes, which can limit a shipowner's ability to deviate from a planned course even when weather routing suggests a more efficient path. Moreover, optimizing fuel efficiency may sometimes conflict with other operational priorities, such as minimizing transit time or meeting port schedules.

Trim and Draft Optimization

Trim and draft optimization are operational measures used to improve the hydrodynamic efficiency of a vessel, thereby reducing fuel consumption and emissions. Technically, trim refers to the longitudinal balance of the ship which is the difference in draft between the bow and stern, and draft refers to the vertical distance between the waterline and the bottom of the hull. Both parameters significantly affect how water flows around the hull, which in turn influences resistance and propulsion efficiency. By continuously monitoring and adjusting trim and draft based on vessel load, speed, sea conditions, and hull form, operators can minimize resistance and improve fuel economy. Trim optimization is typically achieved through software-based decision support tools that use on-board sensor data to identify the most efficient trim settings for current conditions, while draft optimization may involve managing ballast water and cargo distribution to maintain an ideal draft profile.

Fleet-wide statistics on trim and draft optimization adoption are not systematically reported in public databases, but vendor deployment figures indicate substantial uptake, e.g., DNV reports more than 1,000 installations of its ECO Assistant trim optimization tool, suggesting that trim optimization is already in widespread operational use [210]. Regulatory frameworks such as IMO's SEEMP and the industry's increasing reliance on digital operational efficiency tools are expected to further accelerate adoption of trim/ballast optimization and related voyage performance management practices.

Barriers to trim and draft optimization include the need for high-quality, real-time sensor data; integration with vessel automation or performance management systems; and crew training to interpret and act on optimization recommendations. For older vessels, retrofitting trim and draft optimization systems may involve structural changes or investments that are not always economically viable. Operational constraints, such as port draft limits, cargo requirements, and stability considerations, can also limit how much a vessel's trim or draft can be adjusted in practice.

Vessel Technology Measures

Air Lubrication Systems

Air lubrication involves air being injected along the hull of a vessel to reduce drag and improve efficiency (Figure 14). First developed by Mitsubishi as the Mitsubishi Air Lubrication System (MALS), this technology is well suited for flat-hulled vessels and is typically used in new-build applications as the hull must be appropriately designed. However, Mitsubishi has developed a retrofit system that can be installed at a dry-dock. There are two major variants of this technology: air cavity systems and microbubble systems. The air cavity system consists of a large cavity that runs the length of the hull where compressed air is pumped to fill the void. In the microbubble variant, a continuous stream of bubbles is injected at the bottom of the hull. This variant requires additional energy to run the pumps and faces additional challenges to keep the air under the vessel during vessel motion, such as rolling or pitching. As noted above, air lubrication systems (ALS) are better suited for new vessels as the hull design needs to be compatible with the system. The hull shape most suitable for the single cavity system is a hull consisting of a large pocket that would allow air to fill, while flat bottom vessels are best suited for the microbubble system. Air cavity hulls (ACH) are an advanced air-lubrication technology used to reduce hydrodynamic resistance and fuel consumption in large cargo ships by creating a stable layer of air between the hull and seawater. Instead of injecting bubbles across the hull (like conventional air-lubrication), ACH systems form engineered air pockets (cavities) in specially shaped recesses along the flat bottom of the vessel.

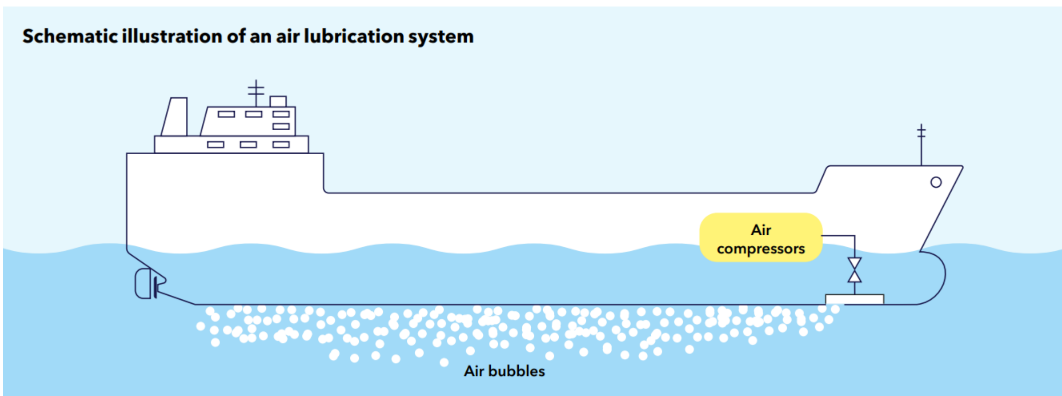

Figure 14. Schematic of a microbubble air lubrication system on a large vessel. From Reference [209]

ALS involves mechanical components such as compressors, air valves, and piping, which require regular maintenance and are susceptible to fouling, corrosion, or mechanical failure, especially in the harsh marine environment. Blocked nozzles or malfunctioning valves can reduce system performance and increase operating costs. Maintaining consistent air distribution across the hull surface is also challenging and essential for achieving optimal drag reduction.

The air compressors required to generate and distribute air under the hull consume energy, which offsets some of the fuel savings achieved from reduced resistance. If the system is not optimized (e.g., if compressors run too frequently or inefficiently) the net efficiency gain can be significantly diminished. This makes careful system tuning and energy management essential.

The performance of ALS is highly dependent on vessel speed, draft, hull shape, and sea conditions. ALS are generally more effective at higher speeds and shallower drafts, while its efficiency can drop significantly in heavy seas or when biofouling is present, which is the accumulation of marine organisms like algae, barnacles, and slime. Fouling increases the hull's surface roughness, which leads to greater hydrodynamic drag, higher fuel use, and ultimately, increased emissions. These dependencies make it difficult to predict or guarantee fuel savings across different routes and operating profiles, reducing shipowner and operator confidence in the technology.

Advanced Hulls Including Bulbous Bow

Advanced hull designs, including bulbous bows (Figure 15) and other hydrodynamic enhancements, play a key role in improving vessel energy efficiency by reducing resistance through the water. The bulbous bow is a prominent feature of modern hulls and features a protruding bulb at the bow just below the waterline. The bulbous bow can alter the wave pattern generated by the hull as the ship moves, creating interference with the bow wave to reduce overall wave resistance. When designed and tuned properly for a vessel's typical speed and draft, the bulbous bow can yield substantial drag reduction, leading to significant fuel savings and lower emissions.

Figure 15. A bulbous bow typical of OGV from Reference [211]

Industry and technical analyses cite fuel consumption reductions on the order of roughly 5–15% when vessels operate near their design speed, and the bulb is properly optimized. Specific design studies have found ~12–15% reductions in fuel use for modern bulbous bow designs, and hydrodynamic assessments commonly report ~10–12% reduction in resistance, which translates directly to lower fuel demand [212].

The benefits of a bulbous bow depend heavily on matching its shape and dimensions to the vessel's operating profile. For vessels traveling at higher speeds above 12–15 knots, including container ships, car carriers, and some bulk carriers, bulbous bows are particularly effective. However, older vessels that were designed for faster service speeds and now operate at lower speeds due to slow steaming practices can have original bow designs that are no longer optimal. In such cases, retrofitting the bulbous bow to suit current operating speeds can improve efficiency.

Beyond bulbous bows, other advanced hull modifications include hull form optimization, stern flaring, hull fins, and air lubrication compatibility. These are increasingly being explored to maximize hydrodynamic efficiency and are often considered in combination with energy-saving devices located near the propeller, as part of an integrated hull optimization strategy. Taken together, advanced hull solutions are considered technically mature, commercially proven, and economically justified under current and future regulatory and fuel cost scenarios. They represent a practical and scalable pathway for shipowners seeking to reduce emissions and fuel expenses without relying solely on fuel switching or high-risk innovations.

One of the most significant challenges with advanced hull forms and bulbous bow optimization is that their effectiveness is highly sensitive to speed and draft. Bulbous bows are designed for specific speed and loading conditions; if a vessel operates outside of those conditions the bulb may actually increase resistance instead of reducing it. This makes advanced hull designs less effective for vessels with variable operating profiles, such as general cargo ships or multi-purpose vessels.

The fuel savings from advanced hull design or bulbous bow retrofitting are highly case-specific. On ships already optimized for their design speed or on smaller vessels with lower fuel consumption, the marginal gains may not justify the cost of redesign and modification. Furthermore, vessels that already operate at low speeds or in protected coastal routes may experience only limited benefits from improved hull hydrodynamics, making the investment harder to justify.

High-performance Coatings

High-performance hull coatings are a relatively simple yet effective way to reduce fuel consumption and associated emissions. These coatings are applied to the underwater portion of the vessel hull and are designed to minimize frictional resistance by preventing biofouling. High-performance coatings combat this by maintaining a smoother hull surface for longer periods, thus preserving vessel efficiency between drydocking.

There are several categories of high-performance coatings, including self-polishing copolymer antifouling paints, foul-release silicone-based coatings, and ultra-low-friction hydrophobic formulations. These advanced coatings can maintain their performance over multiple years, sometimes for up to five years or more, depending on the product and operational profile. The key technical benefit lies in reducing the wetted surface resistance, which accounts for a significant portion of total hull resistance, particularly at lower speeds.

Advanced Propeller Designs

Shown in Figure 16, advanced propeller designs that improve propulsive efficiency include technologies such as propeller boss cap fins (PBCF), pre- and post-swirl stator fins, ducted propellers, high-efficiency blade profiles, and contra-rotating propellers. Each of these solutions targets the reduction of energy losses in the propeller's wake by optimizing water flow and reducing turbulence. For instance, PBCFs are small fins attached to the hub of the propeller that reduce hub vortex energy losses, while pre-swirl stators modify the inflow to the propeller, improving thrust and lowering load fluctuations. Contra-rotating systems use two propellers rotating in opposite directions to recover rotational energy lost in a single-screw setup, significantly enhancing efficiency.

Figure 16. Examples of advanced propellor designs for OGV from Reference [209].

Shaft Generators (PTO/PTI)

Shaft generators, also known as power take-off (PTO) and power take-in (PTI) systems, are an increasingly important technology for improving energy efficiency in marine vessels. A shaft generator is connected to the ship's main propulsion shaft and can be used to generate electrical power (PTO mode) when the main engine is operating, or alternatively to provide mechanical power to the shaft (PTI mode) from an electric motor when auxiliary power is available or when operating in electric or hybrid mode. In PTO mode, the generator captures excess mechanical energy from the main engine to produce electricity, which is then used to power on-board systems, reducing or eliminating the need to run auxiliary diesel generators. In PTI mode, energy can be supplied from shore power or batteries to drive the shaft, enabling low-emission or silent operation in important locations including ports or ECAs.

While shaft generators are effective efficiency technologies for large vessels with steady operating profiles, they face barriers related to mechanical integration, variable-speed operation, low-speed performance, system complexity, redundancy requirements, retrofit difficulty, and capital cost. Therefore, their adoption is situationally- and vessel-specific, not universal.

Waste Heat Recovery

Waste heat recovery (WHR) systems are technologies that capture and repurpose heat generated by a ship's main and auxiliary engines that would otherwise be lost to the environment. These systems typically extract thermal energy from engine exhaust gases, cooling water, or other hot streams, and convert it into useful energy, usually in the form of steam or electricity. The recovered energy can be used to power auxiliary systems, support propulsion (in steam turbine arrangements), or reduce the load on fuel-consuming generators. WHR is particularly effective on large vessels with high engine loads, such as container ships, tankers, LNG carriers, and cruise ships, where continuous operation and high-power output make the recovery of waste heat economically and technically viable. Waste heat recovery systems are increasingly being adopted on large commercial vessels, especially on large bulk carriers, container ships, and LNG carriers, driven by fuel-efficiency and emissions-reduction incentives.

Engine De-rating

Engine de-rating is a fuel-saving and emissions-reduction strategy that involves adjusting a marine engine's performance parameters to operate at a lower maximum output than originally designed. De-rating allows the engine to operate closer to its optimal load (usually around 75–85 percent of maximum continuous rating (MCR), where combustion is more efficient. Standard marine engines often operate inefficiently at low loads, consuming more fuel per unit of power. This measure aligns the engine's operating range with the vessel's actual propulsion needs (e.g., due to slow steaming or other efficiency measures) allowing the engine to operate closer to its optimal load range. De-rating is typically achieved by modifying the engine's turbocharger configuration, fuel injection settings, or control systems, and can also involve hardware changes depending on the extent of the power reduction. By optimizing combustion and thermal efficiency at reduced loads, de-rating improves fuel economy and reduces specific fuel oil consumption, especially under part-load conditions where conventional engines may perform inefficiently. It should be noted that the engine de-rating process on large marine engines is not a simple step and includes technical engineering modification requiring careful redesign, certification, and integration work

A large container ship de-rated to match lower design speeds may achieve 10–15 percent fuel savings, especially when paired with optimized hull and propeller upgrades. For example, a Panamax bulk carrier with a 10,000 kW main engine de-rated by 20 percent may save 6–10 percent fuel per voyage under typical slow steaming conditions [209].

Energy-efficient Lighting

Energy-efficient lighting is a simple yet effective measure for reducing on-board energy consumption on ships, particularly in accommodation areas, engine rooms, cargo spaces, and navigation lighting. The transition from traditional incandescent or fluorescent lighting to light-emitting diode (LED) systems offer significant efficiency gains. LEDs use semiconductors to emit light more efficiently than conventional lighting sources, converting a much larger portion of electrical energy into visible light while producing less heat. This not only reduces the electrical load on the ship's power system but also decreases the burden on ventilation and cooling systems, further enhancing overall energy efficiency. In addition, LEDs have longer lifespans (e.g., 25,000 to 50,000 hours) which reduces maintenance frequency and associated costs, improving safety and operational efficiency.

The operational savings are driven by the reduced power demand, e.g., LEDs consume up to 80 percent less electricity than incandescent bulbs and 30–50 percent less than compact fluorescent lights [209]. This reduces the need for auxiliary engine power generation, translating into fuel savings of around 0.1 to 1 percent of total vessel fuel consumption, depending on the vessel's configuration and lighting load.

Auxiliary System Optimization

Auxiliary engine optimization refers to strategies and technologies that improve the efficiency of a vessel's auxiliary power systems, which supply electricity for non-propulsion uses such as lighting, ventilation, cargo handling, navigation, and crew accommodations. Auxiliary engines are typically medium-speed diesel generators and operate for extended periods, particularly while the vessel is in port or during maneuvering. Optimizing their performance can lead to meaningful fuel savings and emissions reductions, especially on ships with high hoteling loads such as cruise ships, ferries, container ships, and offshore support vessels.

One key aspect of optimization is load management, which ensures auxiliary engines operate close to their optimal load range where fuel consumption per unit of power is lowest, generally around 70 percent to 85 percent of rated capacity [213]. When generators operate at low loads, they suffer from incomplete combustion, leading to higher specific fuel oil consumption, increased wear, and greater emissions of unburned hydrocarbons and particulates. Through load sharing, automatic start/stop systems, and integrated energy management systems (EMS), vessels can avoid running more generators than necessary and ensure efficient use of those generators in operation. Additionally, advanced engine control systems can dynamically adjust fuel injection timing, air/fuel ratios, and turbocharger performance to match demand in real time. Auxiliary engine optimization can be implemented through a combination of software upgrades, sensor integration, and control logic enhancements, often without significant hardware changes.

The technical complexity and system integration required is a barrier for optimization. Auxiliary systems are often numerous, distributed throughout the vessel, and managed by different subsystems. Optimizing them requires installing monitoring equipment, integrating sensors and control software, and coordinating these systems with the ship's main energy management platform. Older vessels, in particular, may lack the digital infrastructure or modular system architecture needed for easy integration, making retrofits costly and technically demanding.

Another barrier is the lack of real-time data and system visibility. Without accurate, high-resolution data on energy consumption by auxiliary systems, ship operators may not know where inefficiencies exist or how much energy specific systems consume. This lack of transparency makes it difficult to justify investments in optimization or to assess the performance of implemented measures. Energy audits or condition assessments may be needed before any optimization can begin, adding time and cost.

Crew awareness and operational practices also present a challenge. Many auxiliary systems are operated manually or based on outdated procedures, leading to unnecessary energy use (e.g., overcooling or running fans and pumps at full capacity). Without proper training and involvement of the crew, energy-saving measures may be bypassed or underutilized.

Additionally, shipping companies may not consistently prioritize or incentivize energy-conscious behavior among crew members.

Maintenance and reliability concerns can also arise when new automation or control systems are added. Optimizing auxiliary systems often involves variable speed drives (VSDs), automated setpoints, and advanced software that require specialized maintenance skills. In cases where systems are not properly maintained, the expected efficiency gains may be lost, and failures can lead to increased operational risk.

Wind-assisted Propulsion (e.g., rotor sails, kites)

In order to increase efficiency of marine propulsion systems while reducing fuel consumption, vessel operators are looking towards wind power as a potential supplemental energy source. Wind-assisted propulsion is a suite of technologies that harness wind power to reduce the fuel consumption and emissions of conventionally powered ships. These systems do not replace conventional propulsion but instead supplement it, reducing the engine load by providing additional thrust or reducing hydrodynamic resistance. At this time, wind power is only useful for propulsion and cannot be used to effectively generate electricity. Wind-assisted technologies vary widely in design, performance, and applicability but all involve capturing wind energy to improve vessel efficiency and support decarbonization. Two examples are shown in Figure 17.

Figure 17. Two examples of wind assist technologies for OGV from Reference [209].

Several wind-assisted technologies are currently in use or development:

- **Rotor sails (Flettner rotors):** These are tall, spinning cylindrical structures mounted vertically on a ship's deck. They utilize the Magnus effect—where wind passing over a rotating cylinder creates a pressure differential—to generate forward thrust. Rotor sails are powered by small electric motors to maintain rotation, and their operation is automated. Vessels that utilize Flettner rotors are commonly known as Flettner ships or rotor ships.
- **Rigid wing sails:** Inspired by airplane wings, these solid or semi-rigid sails can be adjusted for optimal angle and camber to harness wind efficiently. They can be automated and folded when not in use or in high-wind conditions.
- **Soft sails:** These include traditional fabric sails enhanced by modern materials and control systems. Although less commonly used on large commercial vessels, soft sails are being tested for smaller or slower vessels.

- **Kites:** Tethered airfoils (like large parafoils) fly hundreds of meters above the ship and generate pull that assists in forward motion. Kite systems are attached to the bow of the ship and can be deployed in less than 15 minutes. Kites can be launched and retracted automatically and are most effective in strong, steady winds. Kites are easier to retrofit in comparison to Flettner rotors due to their compact design.

Each of these technologies can be installed on different vessel types, though bulk carriers, tankers, and Ro-Ro vessels are currently the primary focus due to their deck space and speed profiles.

Wind-assisted propulsion technologies face a number of technical, operational, economic, and regulatory barriers that have limited their widespread adoption, despite their potential for reducing fuel consumption and emissions.

One of the most significant barriers is the physical integration of wind-assisted systems onto existing vessels. Technologies like rotor sails, wing sails, and kites require adequate deck space, structural reinforcement, and careful consideration of vessel stability and aerodynamics. On ships with complex superstructures or limited free deck space installing these systems can interfere with cargo handling equipment or visibility from the bridge. Retrofitting existing vessels may require costly structural modifications, while newbuilds need to be designed from the outset to accommodate these systems efficiently.

The performance of wind-assisted technologies is highly dependent on wind availability and direction, meaning that fuel savings vary significantly based on a vessel's operating route and season. Vessels on trade routes with weak or highly variable wind patterns which often include coastal or cross-equatorial routes may experience minimal benefit. This inconsistency in performance makes it difficult for shipowners to accurately project cost savings, reducing the attractiveness of the investment. Additionally, wind assistance cannot be utilized for any efficiency gains in port or while maneuvering.

Wind-assisted systems add new layers of operational complexity. To optimize fuel savings, crews must coordinate wind-assisted devices with engine load, course adjustments, and real-time weather data. This often requires new training, decision-support tools, and automation to ensure efficient use without compromising safety or navigational performance. Crew resistance to unfamiliar equipment and concerns over increased workload can be a barrier to effective implementation, especially in smaller or less technologically advanced fleets.

Solar Panels

Installing solar panels on vessels can help reduce auxiliary power consumption and lower fuel use. These systems typically involve the installation of photovoltaic (PV) panels on available flat surfaces such as rooftops, decks, or cargo hatches. The electricity generated from PV can be used to power low-voltage systems such as lighting, communications, navigation equipment, and HVAC systems, thereby reducing the load on auxiliary diesel generators. In hybrid configurations, solar energy can also charge on-board batteries, which can later be used to supplement power needs during peak loads or port stays.

One of the most significant barriers is the limited available surface area on most vessels for installing solar panels. Ships are designed primarily for transporting cargo or passengers, and much of the deck and superstructure space is occupied by cargo, cranes, lifeboats, ventilation systems, and cargo handling equipment. As a result, there are relatively few large, unobstructed areas where solar panels can be installed without interference. Even where space is available, the orientation of panels is often suboptimal for consistent sunlight exposure due to vessel movement and changing headings.

Another major challenge is the variable and unpredictable nature of solar energy at sea. Power generation depends on geographic location, time of year, weather conditions, and the vessel’s operating route. Ships operating at high latitudes, in cloudy or storm-prone regions, or with frequent changes in heading may experience inconsistent or limited solar energy generation. Unlike land-based systems, marine solar installations cannot rely on fixed positioning or optimal tilt angles, reducing their overall efficiency.

The energy contribution from solar panels is generally modest, especially on large OGVs with high auxiliary and propulsion power demands. While solar panels can meaningfully offset some of the auxiliary power load, they typically provide only 1 to 3 percent of total on-board energy needs [209]. This limited fuel savings potential, while helpful for improving carbon intensity ratings, is often not enough to justify the investment without external incentives (in contrast to energy efficient lighting for example).

Environmental durability and maintenance present additional hurdles. The marine environment exposes solar panels and associated systems to saltwater spray, corrosion, high humidity, temperature fluctuations, and vibration from ship operations. Over time, these factors can degrade panel performance and shorten system lifespan. Regular cleaning and maintenance are also more difficult at sea due to access limitations and safety concerns.

Integrating solar power into a ship's existing electrical and control systems can also be complex, particularly for older vessels not designed for renewable energy inputs. Retrofitting may require modifications to power distribution systems, additional monitoring and control equipment, and, in some cases, battery storage for managing variable output. These upgrades increase both the cost and technical complexity of solar panel adoption.

Suitability, Technological Readiness and Retrofit Potential

A summary of commercial readiness and OGV retrofit potential is shown in Table 11. Across the maritime sector, most vessel efficiency technologies are commercially available, though adoption varies based on cost, complexity, and operational constraints. Widely adopted and mature measures include speed optimization, weather routing, high-performance hull coatings, shaft generators, advanced propeller designs, engine de-rating, and energy-efficient lighting, with remaining barriers largely tied to operational incentives, integration, or relatively small standalone gains. Growing or established technologies such as trim and draft optimization and auxiliary system optimization are increasingly incorporated into modern energy-saving systems but depend heavily on data quality and system complexity. Newbuild-oriented solutions like advanced hull design and waste heat recovery are technically mature yet constrained by high capital cost, space requirements, and retrofit difficulty. Meanwhile, emerging technologies including air lubrication, solar panels, and wind-assisted propulsion are being deployed selectively, with adoption limited by cost, maintenance, space, and variable performance, though wind-assist in particular is gaining momentum with a growing number of commercial installations.

Table 11. Overview of suitability and retrofit potential for OGV energy efficiency measures. Green denotes high, yellow denotes medium, and red denotes low commercial readiness. UCI from [209], [214], [215].

Technology	Commercial Readiness	Retrofit Potential
Speed Optimization	Commercial	High. Can be applied to both existing and new vessels
Weather Routing	Commercial	High. Can be applied to both existing and new vessels
Trim and Draft Optimization	Commercial	Medium. Retrofit possible but complex due to needed sensors and software
Air Lubrication Systems	Early commercial	Medium/Low. Primarily newbuild but some retrofit possible
Advanced Hulls	Commercial	Low. Retrofit costly and difficult
Hull Coatings	Commercial	High. Can be applied to existing vessels
Advanced Propeller Designs	Commercial	Medium. Shaft access can be a challenge for retrofit.
Shaft Generators / PTO-PTI Systems	Commercial	Medium. Retrofit challenges with space and integration constraints
Waste Heat Recovery	Commercial	Medium/Low. Retrofit possible but complex and expensive
Engine De-rating	Commercial	Medium. Can require parts changes and engine tuning
Energy-Efficient Lighting	Commercial	High. Simple retrofit
Auxiliary System Optimization	Commercial	Medium/high. Requires control systems and sensors
Wind-Assisted Propulsion	Demonstration to early commercial	Medium. Deck space and stability limit constraints
Solar Panels	Commercial, niche for large ships	Medium. Deck space and control integration

Retrofit potential varies widely across vessel energy-efficiency technologies, with software- and operational-based measures offering the greatest ease of implementation. Speed optimization and weather routing have high retrofit potential due to their reliance primarily on software and crew training, while high-performance hull coatings and energy-efficient lighting are also relatively straightforward to implement during routine drydock or maintenance. Technologies such as trim and draft optimization, advanced propellers, shaft generators, engine de-rating, auxiliary system optimization, wind-assisted propulsion, solar panels, and air lubrication systems have moderate retrofit potential, typically requiring additional space, sensors, control integration, or mechanical access. In contrast, advanced hull design changes and waste heat recovery systems present low to low/medium retrofit feasibility because they involve complex structural modifications, significant engineering, high costs, and operational disruption, making them less attractive for much of the existing fleet.

Table 12 provides an overview of the suitability of various efficiency measures for OGV. Most vessel energy-efficiency technologies are broadly applicable across OGVs, though their effectiveness often depends on vessel size, operating profile, and route characteristics. Operational measures such as speed optimization, weather routing, trim and draft optimization, energy-efficient lighting, and auxiliary system optimization are suitable for virtually all OGVs, with the greatest benefits typically realized in long-haul, steady cruising conditions. Capital-intensive technologies including ALS, advanced hull forms, advanced propeller designs, shaft generator/PTO-PTI systems, and waste heat recovery, are generally best suited for large OGVs such as container ships, LNG carriers, bulk carriers, and tankers, particularly those operating at sustained high engine loads. Engine de-rating is most appropriate for vessels operating below original design speeds, while wind-assisted propulsion is best suited for large vessels on wind-favorable routes. Solar panels are applicable to most OGVs but primarily support auxiliary loads rather than main propulsion.

Table 12. Overview of suitability for OGV energy efficiency measures. UCI from References [209], [214], [215], [216]

Technology	Suitability
Speed Optimization	All OGV; strongest for long-haul deep-sea shipping
Weather Routing	All OGV; most effective on long ocean routes
Trim and Draft Optimization	All OGV; most effective at steady cruising conditions
Air Lubrication Systems	Large OGV (container, LNG, bulk, tanker)
Advanced Hulls	Most large OGV
Hull Coatings	All OGV
Advanced Propeller Designs	Most OGV; especially large OGV
Shaft Generators / PTO-PTI Systems	Large OGV with steady engine loads
Waste Heat Recovery	Large OGV with high engine load (container, LNG, bulk, tanker)
Engine De-rating	OGV operating below original design speed
Energy-Efficient Lighting	All OGV
Auxiliary System Optimization	All OGV
Wind-Assisted Propulsion	Large OGV on wind-favorable routes
Solar Panels	Most OGV; best for auxiliary loads

Potential Emission Reductions and Economics

Shown in Table 13, the use of energy efficiency technologies can achieve reductions in fuel consumption which can potentially translate to emission reductions. Overall, energy-efficiency technologies provide a broad spectrum of fuel- and emissions-reduction opportunities, ranging from small incremental gains to major operational savings. Operational measures such as speed optimization (5–40%), weather routing (3–10%), trim/draft optimization (2–7%), and engine de-rating (5–15%) are generally low cost with rapid or immediate payback, making them among the most cost-effective options. Hydrodynamic and propulsion improvements, including advanced hulls (2–20%), hull coatings (2–8%), advanced propellers (2–7%), and air-lubrication systems (0–8%), typically require moderate to high capital investment but deliver strong lifetime fuel savings. Energy-recovery and hybridization technologies, such as waste heat recovery (5–12%) and shaft generator/PTO-PTI systems (2–5%), involve higher CAPEX and longer payback, though benefits depend on vessel operating profile. Smaller efficiency measures, including auxiliary system optimization (0.5–2%), efficient lighting (<1–2%), and solar panels (<1–2%), provide modest reductions at low or moderate cost. Finally, wind-assisted propulsion (5–40%) offers potentially large but route-dependent savings, with variable economics tied to fuel price, wind conditions, and vessel utilization.

Table 13. Summary of potential emission reductions and economics of OGV energy efficiency strategies. UCI from References [209], [217], [218]

Technology	Potential Emissions Reduction	Economics
Speed Optimization	5–40%	Low cost with immediate fuel savings
Weather Routing	3-10%	Low cost; rapid payback (<1 year typical)
Trim and Draft Optimization	2-7%	Low-moderate cost; short payback
Air Lubrication Systems	0-8%	Moderate-high CAPEX; payback ~3–7 years depending on fuel price

Advanced Hulls	2–20%	Newbuild cost; strong lifetime savings
Hull Coatings	2–8%	Moderate CAPEX; payback ~1–3 years
Advanced Propeller Designs	2–7%	Moderate CAPEX; payback ~2–5 years
Shaft Generators / PTO-PTI Systems	2–5%	Moderate CAPEX; savings depend on operating profile
Waste Heat Recovery	5-12%	High CAPEX; longer payback (~5–10 years)
Engine De-rating	5-15%	Low cost; improves efficiency at lower loads
Energy-Efficient Lighting	Small (<1–2%)	Very low cost; rapid payback
Auxiliary System Optimization	Small (0.5%-2%)	Low-moderate cost; short payback
Wind-Assisted Propulsion	5–40% (route dependent)	Moderate-high CAPEX; variable payback
Solar Panels	Small (<1-2%)	Moderate CAPEX; long payback; improves auxiliary efficiency

While Speed Optimization/Slow Steaming can reduce CO_2 emissions substantially [209], it is important to note that operating ships at sustained low engine loads introduces several engineering, environmental, and logistical challenges that may offset or limit the expected benefits. While lower speeds generally reduce fuel consumption and CO_2 emissions, operation at low loads can degrade combustion efficiency due to poorer air–fuel mixing, lower in-cylinder temperatures, reduced injection quality, and unstable combustion phasing. In Tier III engines, emissions-control performance can also deteriorate at low loads. For example, EGR systems become less effective under low exhaust energy conditions, and SCR systems may operate outside their optimal temperature window, reducing NO_x conversion efficiency. As a result, very low-speed or low-load operation can lead to incomplete combustion, localized hot spots, and reduced aftertreatment performance, producing non-linear NO_x responses and, in some cases, higher-than-expected NO_x emissions despite lower fuel use. Additionally, not all OGV routes can feasibly integrate speed reduction strategies, e.g., those that operate on a just-in-time basis with fleets and routings designed around short, highly optimized transit windows.

The energy efficiency measures discussed above can be used in parallel or combined, achieving larger emission reductions, e.g., by enabling just-in-time arrival strategies alongside weather routing services, vessels can reduce the time they spend idling near ports or traveling at inefficient speeds enroute to their destination, reducing emissions. When implemented synergistically and concurrently, these measures can reduce total fuel use by 20 to 50 percent or more, depending on vessel type, operational profile, and age [209]. A study by the International Council on Clean Transportation analyzed the long-term potential for increased shipping efficiency, including a wide range of operational and technical fuel-saving measures, and reported reductions in fuel use and CO_2 by 20–40 percent by 2020 and 30–55 percent by 2030 in aggregate under certain assumptions [219]. The 2023 IMO GHG Strategy seeks a reduction in carbon intensity of international shipping (to reduce CO_2 emissions per transport work), as an average across international shipping, by at least 40% by 2030 [220].

Shore-Side Electrical Power

Technology Description

Shore power, also known as cold ironing or alternative maritime power (AMP), enables ships to connect to onshore electrical systems while docked. By "plugging in" at berth, vessels can shut down their auxiliary diesel engines, significantly reducing emissions such as CO_2, NO_x, SO_x, and PM at the port.

Both the pier infrastructure and the maritime vessels themselves must be equipped with the capability (and the plugs) to use shore power. The electrical power provided to the vessel can either be sourced from the wider electrical grid, or through fuel cells, gas turbines, micro turbines, or combined cycle plants located nearby (i.e., distributed generation, microgrids). Recognizing this linkage, many ports are actively working to integrate renewable energy into their shoreside power systems to maximize emissions benefits [221], [222]. Strategies include procuring renewable electricity through utility green-power contracts, installing on-site solar and wind generation, incorporating battery energy storage to manage peak demand and smooth intermittent renewable output, and developing port microgrids powered by clean energy. Some ports are also exploring dedicated renewable supply for shore power, including direct connections to offshore wind or local renewable generation, to ensure that vessels plugging in receive low-carbon electricity [222]. Together, these efforts aim to transform shore power from a local air-quality solution into a broader decarbonization tool aligned with long-term climate goals.

As shown in Figure 18, shore power systems are composed of three main components that work together to deliver electricity from the grid to a vessel while it is at berth. The first component is the electrical substation, which converts electricity from the local grid to the appropriate voltage and frequency required by the vessel. The second component is the interface system, which includes the power and control cables which serve as the physical connection between the dock and the vessel. The interface systems may be fixed, movable, or mounted on a barge. Finally, the third component involves the on-board electrical equipment receiving electricity from the shore connection and distributes it throughout the vessel to power on-board systems while the main engines are shut down.

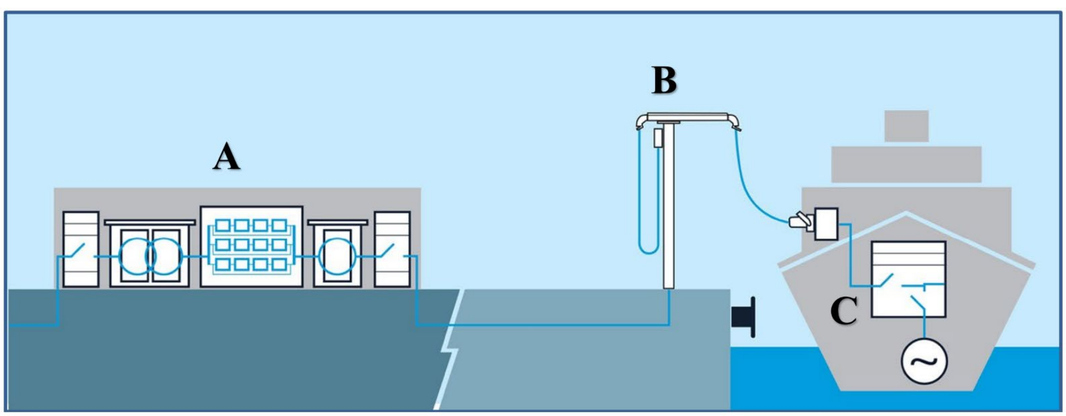

Figure 18. Example shore power infrastructure including the A electrical substation, B cable interface, and the C ship's electrical equipment. From Reference [131].

When a vessel docks, it connects to shore power via the interface system, and its on-board electrical load is gradually transferred from internal generators to the shore-based supply. The on-board engines are then synchronized with the grid by matching voltage, frequency, and phase, to avoid damaging surges and are subsequently shut down. With engines off, the vessel operates entirely on shore electricity, potentially reducing GHG and pollutant emissions if the source of power (e.g., the wider electrical grid) is composed of cleaner technologies, reducing noise, and reducing fuel consumption while at berth. Before departure, the process is reversed: the electrical load is shifted back to the vessel's generators, which are synchronized before shore power is disconnected and the vessel gets underway.

Shore power systems can be deployed in several configurations, including dock-mounted, containerized, or barge-mounted setups. The most common approach is dock-mounted systems, where fixed electrical equipment is installed directly on the pier to provide reliable grid connections to vessels at berth. Dock-mounted systems involve the installation of power metering and transformer equipment directly on the dock, along with a cable-positioning device to facilitate the vessel's connection to the power supply while at berth. These systems are typically integrated into the port infrastructure and are well-suited for terminals with available dockside space. Containerized shore power systems are modular, self-contained electrical supply units housed within standard shipping containers, designed to provide flexible and scalable shore-to-ship power where permanent infrastructure is not feasible or demand is variable. These systems typically integrate key components such as transformers, frequency converters, switchgear, cable management systems, and control equipment within a transportable enclosure. Because they are containerized, they can be rapidly deployed, relocated, or expanded with minimal civil works, making them well suited for ports with space constraints, temporary installations, pilot projects, or lower-traffic berths where fixed shore power infrastructure would be uneconomical. While typically smaller in capacity than large, fixed installations, containerized shore power provides a practical pathway for ports to begin electrification, reduce vessel emissions at berth, and scale infrastructure over time as demand increases. In contrast, barge-mounted systems require little to no dockside footprint. These are self-contained units that can float alongside vessels and often utilize alternative fuels or technologies, such as LNG or fuel cells, to generate electricity. This approach offers flexibility in deployment, especially in ports with limited dockside space or where permanent infrastructure is not feasible.

Commercial shore power systems are generally divided into high-voltage and low-voltage connections. High-voltage shore connection (HVSC) systems operate at 6,600 or 11,000 volts and are designed to serve large vessels such as cruise ships, container ships, and reefer vessels. These systems provide the necessary power capacity for energy-intensive vessels and are increasingly being adopted at major ports. At berth, large container ships typically draw several MW of electrical power from shore power systems to supply hotel loads, auxiliary machinery, and refrigerated container demand while main engines are shut down. The exact load depends on vessel size, number of reefers, ambient conditions, and onboard systems in operation, but representative ranges are well established in the literature. Large post-Panamax and ultra-large container vessels commonly require 6–12 MW of shore power, with peak loads sometimes approaching 15–20 MW when reefer demand is high and cargo operations are intensive, while smaller container vessels more typically draw 3–6 MW [131]. A substantial portion of this demand can come from refrigerated containers alone, which may account for 2–8 MW depending on the number of active reefers and temperature conditions. Shore power systems serving these vessels are therefore usually designed in the 6.6 kV or 11 kV high-voltage range, with sufficient capacity margin to accommodate peak auxiliary and cargo-related loads.

California has a robust regulation requiring the use of shore power or other CARB approved emission control strategies (CAECS), such as barge-based capture and control systems. California’s At-Berth Regulation, originally adopted by CARB in December 2007 as the *Airborne Toxic Control Measure for Auxiliary Diesel Engines Operated on Ocean-Going Vessels At-Berth in California Ports*, was the first large-scale mandatory shore power rule globally and was designed primarily to reduce diesel PM and other harmful pollutants in near-port communities [223]. Implemented between 2014 and 2020, the regulation required container ships, cruise ships, and refrigerated cargo vessels visiting six major California ports (Hueneme, Los Angeles, Long Beach, Oakland, San Diego, and San Francisco) to shut down auxiliary engines and connect to shore power, achieving roughly an 80 percent reduction in at-berth emissions through phased compliance. Early implementation guidance was issued by CARB to clarify reporting, infrastructure timelines, and technical requirements as ports and vessel operators installed electrification systems. In August 2020, CARB adopted a major amendment to the At-Berth Regulation, renamed the *Control Measure for Auxiliary Diesel Engines and Diesel-Electric Engines Operated on Ocean-Going Vessels At-Berth in California Ports*, which significantly expanded coverage to include additional container, refrigerated cargo, and cruise vessels; new vessel categories: tankers, Ro-Ro vessels, and vehicle carriers; introduced flexible compliance pathways such as Terminal and Vessel Incident Events (TIEs/VIEs), Innovative Concepts, and the use of a remediation fund in specific qualifying circumstances; and established a phased implementation schedule extending from 2023 through 2027. It also placed greater responsibility on terminals to provide supporting infrastructure and reinforced emissions performance standards for NOx, PM, and ROG and seeks to reduce GHG emissions through the use of shore power and grid-neutral CAECS. As of January 1, 2023, the At Berth Regulation requires 100 percent of container, cruise, and refrigerated cargo vessel calls at regulated terminals to reduce emissions through use of shore power or a CAECS while at berth. Requirements for Ro-Ro vessels began on January 1, 2025 statewide. Tanker vessel compliance requirements are still being phased in at the publication of this report. Compliance requirements for tankers began on January 1, 2025, for tankers calling regulated terminals at the Ports of Los Angeles and Long Beach. Compliance dates for tankers calling all other regulated ports and marine terminals statewide will begin January 1, 2027 (final compliance date).

The international standard IEC/ISO/IEEE (Institute of Electrical and Electronics Engineers) 80005 has been developed to ensure global compatibility and safety for shore power connections between vessels and ports. For HVSC systems, the current applicable standard is the 2019 IEC/ISO/IEEE 80005-1:2019/AMD 1:2022 standard, which replaces the earlier 2012 version [131]. This standard applies to systems delivering 1 megavolt-ampere (MVA) or more and introduces significant technical updates aimed at enhancing operational safety. Key improvements include stricter grounding requirements, updated procedures for alternative testing, a minimum safety circuit current of 50 milliamps, and a maximum automatic breaker opening time of 200 milliseconds. The revised standard also clarifies the use of on-board transformers as optional and provides detailed specifications for fixed and movable onshore supply points. Additional updates to the standard are expected in the future, particularly to address specific requirements for vehicle carriers, which differ from Ro-Ro vessels.

System Network Suitability and Operational/Infrastructure Needs

Shore power systems must be compatible with both the electrical infrastructure at the port and the vessel's on-board systems. On the port side, suitability depends on whether the local grid can support the high power demands of docked ships without compromising grid stability or service to nearby communities. Large vessels like container ships or cruise ships can require potentially exceeding 10 MW of power while at berth, making grid capacity and redundancy key concerns. This often necessitates upgrades to substations, transmission lines, and load management systems, particularly in older port areas or regions with constrained electrical supply.

Vessel compatibility is also central to the suitability of shore power. Vessels must be equipped with standardized shore power connectors and on-board systems that can safely receive power at the required voltage and frequency. International standards such as IEC/ISO/IEEE 80005 help ensure interoperability between ports and ships, but even with standards in place, vessels utilizing shore power may encounter compatibility issues, especially if their power needs or on-board configurations deviate from the norm [224], [225].

Operationalizing shore power requires detailed planning and coordination across port authorities, terminal operators, utilities, and vessel operators including the development of a reliable scheduling system to ensure that vessels arrive at berths equipped for shore power and are able to connect without interruption. To maintain efficient port operations, shore power systems must be available, functional, and quickly accessible, with minimal downtime due to maintenance or grid issues. Staff training and standard operating procedures are also essential. Both vessel crews and port personnel need to understand how to safely connect and disconnect shore power systems, monitor energy use, and respond to potential electrical or mechanical failures. Additionally, connection and disconnection procedures must be carefully managed to minimize emissions during transitional periods. Another operational consideration is that shore power typically does not replace all on-board power needs. For instance, steam or hot water boilers often remain in operation at berth and continue to emit pollutants unless additional electrification or alternative zero-emission technologies are used.

From an infrastructure standpoint, several key components are essential to support effective and reliable shore power systems at ports. First, electrical substations are required to transform and condition electricity from the local grid to the appropriate voltage and frequency needed by vessels. These substations must be capable of handling large and often fluctuating power loads, especially for high-voltage systems serving large container ships or cruise vessels. Cable management systems are also critical and must be designed to suit the specific port layout and vessel types being served. These systems may be on-board the vessel, fixed to the dock, movable to accommodate varying vessel configurations, or barge-mounted to provide flexibility in ports with space constraints or where permanent infrastructure is not practical. For large container vessels calling at multiple ports, it is common to install the cable management system onboard as part of a containerized Alternative Maritime Power system. In this configuration, the shore power interface equipment including cable reels, high-voltage connectors, transformers, switchgear, and control systems is housed inside one or more standardized ISO containers mounted on deck. Proper cable management ensures safe and efficient connection and disconnection to minimize delays in vessel operations. To ensure broad compatibility, connection vaults and interface points should be strategically placed in flexible locations along the berth. This allows different vessel sizes and docking arrangements to access shore power without requiring major repositioning or custom configurations. These interface points must meet international standards to ensure safe and universal connections. In ports that rely on intermittent renewable energy or face limited grid flexibility, load balancing and energy storage systems will likely be required to help stabilize power delivery, absorb peak loads, and improve the resilience of shore power operations. By integrating battery energy storage or microgrid controls operators can achieve uninterrupted service when renewable generation fluctuates or during periods of high demand.

Shore power infrastructure should also be integrated into broader port electrification strategies, which may include the use of electric cargo handling equipment, yard trucks, and other terminal machinery. Coordinating these systems allows ports to optimize infrastructure investments and maximize emissions reductions by electrifying multiple sources of emissions. For ports where installing permanent dockside infrastructure is not feasible including such as smaller or emerging terminals, barge-mounted or containerized shore power systems may provide a practical and scalable solution. Self-contained systems can be deployed temporarily or relocated as needed, giving terminals additional flexibility that supports transitional or lower-traffic operations in maximizing the benefits of shore power.

In parallel with infrastructure deployment, there is also a need for the monitoring and verification of emissions reductions associated with shore-power use. Advanced automation and data monitoring systems are being deployed to track real-time energy consumption, connection duration, and operational parameters when vessels are plugged into shore power [226]. These systems enable the generation of detailed reports quantifying electricity use and associated emissions reductions, providing transparency for ship operators, ports, regulators, and other stakeholders. Accurate measurement and verification are becoming increasingly important for demonstrating environmental performance and supporting regulatory compliance.

Newbuild or Retrofit

Shore power can be implemented through both retrofits of existing vessels and integration into newbuild vessels, with each approach having different economic and technical implications.

For existing vessels, shore power is typically added through retrofit projects, which involve installing electrical infrastructure such as shore connection panels, switchgear, transformers (if needed), and synchronization systems that allow the vessel to safely connect to a port's shore power supply. Retrofitting is often necessary for vessel operators seeking to comply with emissions regulations in ports like those in California or China, or to access incentives related to clean port operations. However, retrofit installations can be complex and expensive with costs ranging from $300,000 to $2 million per vessel, depending on vessel size, existing systems, and required modifications [131]. Space constraints and outdated on-board electrical architecture can make integration challenging. Additionally, retrofitting may require vessels to be taken out of service for installation, adding to operational costs and downtime.

In contrast, newbuild vessels can be equipped with shore power capability during construction, offering significant advantages in terms of cost-efficiency and integration. When incorporated from the design phase, shore power components can be optimized for space, performance, and regulatory compliance, ensuring full compatibility with international standards such as IEC/ISO/IEEE 80005. The incremental cost of including shore power in a newbuild is generally lower than the cost of a retrofit, and the system tends to be more reliable and better integrated with the vessel's overall power management system [131]. As global regulations tighten and more ports mandate shore power use, many shipbuilders are now including shore power readiness as a standard feature, especially for vessel types that frequently operate in regulated areas, e.g., cruise ships, container vessels, and ferries. Shore power ready means the vessel has been designed and partially outfitted to enable future connection to shore-side electricity but does not yet possess the full equipment required for immediate use. A shore-power-ready vessel typically includes reserved space for transformers and frequency converters, structural supports, cable routing pathways, and switchboard provisions, thereby avoiding major structural modifications during a later retrofit. However, it lacks key operational components such as the shore connection receptacle, cable handling system, power conversion equipment, protection and synchronization systems, and associated certification required to actually connect and operate on shore power at berth. By contrast, a vessel with shore power fully installed and ready to use is equipped with all necessary onboard hardware and can immediately plug into compatible port. While "shore power ready" status reduces future retrofit cost, downtime, and engineering complexity, only a fully installed system enables immediate compliance with port requirements and delivers near-term reductions in at-berth emissions.

Potential Emissions Reduction

The environmental benefits of shore power are closely linked to the emissions intensity of the electricity supplying the port. Shore power eliminates combustion emissions at berth which removes local emissions of NO_x, SO_x, PM, and onboard CO_2. The emission reduction benefits are similar as those described for battery electric technologies, e.g., electricity generation often occurs outside the port area or local air shed, which reduces or avoids localized air quality impacts. This is particularly important given the significant emissions generated from conventional auxiliary diesel engines and the common co-location of ports with urban areas, which heightens the importance of benefits to public health given the co-location of sensitive populations often occurs near ports, e.g., the communities adjacent to the Ports of L.A. and Long Beach [227]. CARB performed a comprehensive analysis as part of the new At Berth Regulation that was adopted in 2020. CARB's analysis showed that the At Berth Regulation will avoid 237 premature deaths statewide in California with a value of $2.31 billion in public health savings and reduce cancer risk by 55 percent for Californians living near the Ports of Los Angeles, Long Beach, and Richmond, specifically [48]. Further, reductions in NO_x and CO_2e are estimated at 17,500 tons and 356,000 MT, respectively, between 2021 and 2032 [65]. According to the U.S. EPA's Shore Power Technology Assessment, shore power can achieve up to a 99 percent reduction in NO_x, 53–97 percent reduction in PM, 55–80 percent reduction in SO_x, and 26–55 percent reduction in CO_2 [131]. Therefore, the actual benefits of shore power will vary depending on regional electricity generation profiles. However, given the large emissions from diesel auxiliary engines [128] and the potential health impact of diesel PM [129], [130], shore power will offer substantial air pollution and public health benefits in almost every situation.

However, the life cycle GHG emission impacts depend on the broader electrical grid mix. In regions where grid electricity is generated primarily from fossil fuels, especially coal, the upstream emissions associated with power generation can offset a portion of the climate benefits, though local air quality improvements still remain substantial. Conversely, in grids with high shares of low-carbon generation (e.g., renewables, nuclear, hydropower) shore power can deliver very large life-cycle emissions reductions compared with running auxiliary diesel engines. As grids continue to decarbonize over time, the life-cycle climate benefits of shore power improve correspondingly, making it an increasingly effective emissions reduction strategy for ports and vessels.

As an example of the benefits of shore power, cruise ships typically spend about 10 hours at berth in Seattle handling passengers and resupplying. By connecting to shore power during this time, ships can shut down their diesel engines, significantly reducing pollutant and GHG emissions, including roughly 25% of a cruise ship's total emissions in Puget Sound [221].

Technology Readiness

As a result of the At Berth regulations, shore power is available at most California ports including Hueneme, Long Beach, Los Angeles, Oakland, San Diego, and San Francisco. In total, shore power is available at approximately 65 berths in California. Globally, as of 2022, approximately 4,500 commercial vessels over 5,000 gross tons were equipped for shore power connections. Many of these vessels operate in the Pacific region, where regulatory mandates in California and China require shore power use at ports [65].

Figure 19 shows that there are currently 10 U.S. ports providing shore power to cruise, container, and refrigerated vessels [65]. The number of ports considering providing shore power is expanding rapidly, particularly in Europe where, starting January 1, 2030, the FuelEU Maritime regulation mandates that container and passenger ships over 5,000 GT must use Onshore Power Supply (OPS/shore power) at berth in major EU (TEN-T) ports [2]. This rule enforces zero-emission, "cold-ironing" to reduce pollution, extending to all EU ports with available infrastructure by 2035. However, very few ports currently have shore power available at the scale required for large containerships (~3 to 5 MW). However, if favorable policy and commercial development for larger vessels can result in firm demand and clear financial benefits to vessel operators or ports, shore power could experience widespread use by the 2030s [19].

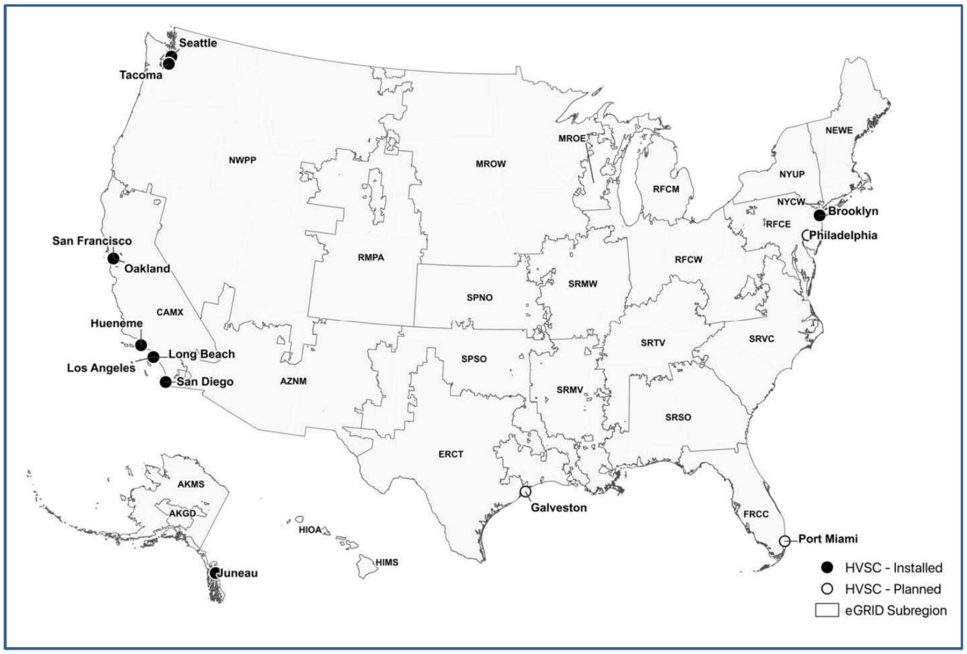

Figure 19. U.S. ports with existing and planned high-voltage shore power connections (HVSC) along with EPA eGRID subregions. From Reference [131].

Economics

Implementing shore power requires substantial capital investment, both on the port side and the vessel side. An assessment by the U.S. EPA reported that the primary barrier to widespread deployment of shore power is the high capital cost of both port-side infrastructure and vessel retrofits, although long-term operating costs can be favorable under the right conditions [131]. Shore power installation often requires major investments in electrical distribution upgrades, transformers, cable management systems, and high-voltage grid connections at the berth. The EPA concluded that infrastructure costs have been estimated at roughly $2.5 million per berth, although actual costs vary widely depending on port configuration, grid connection requirements, and vessel power demand [131].

On the port side, infrastructure costs vary significantly depending on site-specific conditions such as port layout, berth configuration, vessel types served, and power demand. HVSC shore power systems, which are typically installed to serve large vessels like cruise ships and container ships, can cost between $5 million and $15 million per berth [131]. These costs cover the installation of electrical substations, transformers, cable management systems, power metering equipment, and any required upgrades to the port's electrical grid. In addition, costs for engineering, permitting, and construction oversight further increase total project expenses. In addition to landside infrastructure, ships must be retrofitted with onboard transformers, switchgear, cabling, and control systems to connect to shore power. These vessel-side modifications can be costly and require careful engineering and planning, particularly for existing ships. However, retrofit economics improve for vessels that make frequent port calls or spend long periods at berth, since higher utilization spreads capital costs over more operating hours. The Pacific Merchant Shipping Association (PMSA), which represents terminal operators and ocean carriers that move cargo through the West Coast ports, estimates the cost of retrofitting a ship to plug into shore-side power can range from $500,000 to $1.5 million, depending on the vessel [228]. Newer ships are more likely to be designed with shore power compatibility in mind, whereas older vessels often require substantial modifications. These vessel-side upgrades may include switchgear, connection panels, transformers, and control systems, all of which must comply with international standards for safety and interoperability.

Operating costs depend primarily on the relative price of electricity versus marine fuel, and shore power becomes more economically attractive when fuel prices are high or when electricity is competitively priced. Electricity costs vary widely across ports, reflecting differences in local power markets and delivery charges, but studies indicate a typical range of approximately $0.056 to $0.26 per kWh for shore power supply [131]. However, electricity pricing is complex and may include demand charges, time-of-use rates, and connection fees, which can significantly affect the total cost of operations for shore power. Other ongoing operating expenses include routine maintenance of shore power equipment, staff time for connecting and monitoring ship connections, and system inspections. These costs are typically lower than the maintenance costs associated with running auxiliary engines at berth, which are subject to wear and tear and require periodic overhauls. Nevertheless, ports must evaluate total ownership costs, including both fixed and variable components, to understand the full financial impact. Public funding, grants, and incentive programs are often critical to making projects financially viable, particularly for initial infrastructure deployment.

Therefore, the economic conditions for shore power are largely determined in a tradeoff with the cost of running auxiliary engines while at berth. When marine fuel prices are high, shore power may offer significant fuel savings if electricity costs are comparatively lower, especially for vessels that spend many hours docked. In addition to reducing fuel costs, shore power helps ship operators avoid the compliance costs associated with emissions control technologies like scrubbers and the purchase of cleaner fuels. It should be noted that in California scrubbers cannot be used in regulated California waters to comply with the OGV Fuel Regulation which requires cleaner 0.1% MGO/MDO fuels to be used. This is not the case in other parts of the world, but it is for California. In some situations, shore power can be cost-neutral or even cost-saving when compared to auxiliary engine use [131]. However, this is highly dependent on the duration of time spent at berth, the vessel's power demand, and local utility pricing.

CARB estimates that the 2020 At Berth Regulation will cost approximately $2.23 billion to fully implement. When broken down by cargo type, the cost per freight unit is relatively low, including about $1.14 per TEU, $4.65 per cruise passenger, $7.66 per vehicle transported on auto carriers, and less than $0.01 per gallon of finished oil product [65]. This highlights the relative cost-effectiveness of shore power in supporting clean air goals.

One additional consideration with shore power implementation is that equipment failures and operational constraints may occasionally prevent vessels from complying with shore power requirements. CARB has developed protocols, incentives, and compliance flexibility to deal with these situations. An example includes CARB's Remediation Fund, which is an alternative compliance option under California's 2020 Ocean-Going Vessels At-Berth Regulation that allows regulated entities to pay into a fund to address uncontrolled emissions during a vessel's visit to a regulated berth if they could not reduce emissions using an approved emissions control strategy during specific qualifying circumstances [229]. Eligible situations include things like terminal or vessel equipment failures, interruptions in emissions control, construction impacts, or other unavoidable constraints that prevented CAECS use during the visit.

Next Steps to Demonstrate Technology

Despite its emissions reduction potential, several challenges hinder widespread adoption of shore power that will need to be addressed prior to the scale-up. Significant capital investment will be required for both port and vessel infrastructure. Many ports lack the necessary facilities and grid upgrades to support shore power connections. Vessels must be retrofitted with compatible electrical systems, which can be expensive and require strategic planning for equipment placement. Additional barriers include berth availability, compatibility of vessel and shoreside systems, physical alignment of vessel and fixed shoreside systems, and high local grid loads. It will be important to ensure shore power compatibility exists between ports; therefore, new installations should follow standardized guidelines such as the IEEE Electrical Shore-to-Ship Connections working group's guidelines.

A summarization of experience with shore power from major U.S. ports by the U.S. EPA reported several best practices and critical considerations for shore power deployment [131]:

- **Early Coordination**: Proactive and continuous collaboration among ports, regulatory agencies, and utilities is essential to align infrastructure development with both commercial and local power needs.
- **Flexible System Design**: Shore power systems should be adaptable to accommodate a wide range of vessel types and sizes by allowing flexible placement of connection vaults and cables.
- **Future-Proofing**: Infrastructure should be designed to meet anticipated increases in demand, including the electrification of adjacent berths, terminals, or other port equipment.
- **Operational Reliability**: Ensuring the reliability of shore power components and grid supply is vital for maintaining efficient port operations and avoiding vessel delays. Reliable scheduling and consistent plug-in procedures are key to minimizing disruptions.
- **Pre-Approval for Repeat Vessels**: Establishing a ship pre-approval system can expedite shore power connection for vessels that regularly call at the port.

- **Public Funding**: Access to public funding is often essential to support the high capital costs associated with shore power infrastructure.
- **Community Impact**: Shore power contributes directly to local air quality improvements. Community members are aware of system performance and notice when shore power is unavailable or not functioning as expected, underscoring the importance of reliability and accountability.

Additionally, several important international initiatives are advancing the deployment of shore power globally. Under the EU's FuelEU Maritime Regulation, passenger and container ships will be required to use onshore power supplies at relevant ports starting in 2030 when berthed for more than two hours. In parallel, the EU's Alternative Fuels Infrastructure Regulation (AFIR) mandates that core and comprehensive ports install sufficient shore-side electricity infrastructure to meet the power needs of container and passenger vessels. Together, these regulations are expected to drive widespread expansion of shore power infrastructure, greater standardization of operational procedures, and increasing pressure to align U.S. regulations and technical standards with emerging international frameworks.

Carbon Capture, Utilization, and Storage (CCUS) Systems

Technology Description

Carbon capture, utilization, and storage (CCUS) systems separate and collect carbon from the fuel or exhaust and convert into a useful or benign product and/or sequester it such that it is not released into the atmosphere. The greatest potential suitability for the use of CCUS on OGVs is for existing vessels where conversion to other alternative fuels is cost prohibitive. Additionally, CCUS has the potential benefit of extending the lifespan of vessels that otherwise may not be able to comply with current and future GHG regulations.

The three types of CCUS under consideration for the maritime sector include post-combustion, pre-combustion, and oxy-fuel combustion. Pre-combustion strategies remove carbon from the fuel before it is combusted and will likely require complete engine redesigns to be integrated into the fuel supply and power generation systems. Pre-combustion CCUS is generally poorly suited to the marine sector because it requires complex, capital-intensive fuel-processing systems such as gasification or reforming units, shift reactors, hydrogen separation, and CO_2 capture infrastructure before combustion. These systems are large, heavy, energy-intensive, and slow to operate, making them incompatible with the space, weight, power, safety, and operational constraints of ships. The long residence times and processing requirements for fuel conversion and CO_2 separation also conflict with the need for compact, fast-responding, and flexible onboard energy systems, making pre-combustion CCUS impractical for most marine applications. [230].

In contrast, the post-combustion process captures CO_2 from exhaust gas produced after combustion and can be added to traditional engine design without the need for large changes. Typically, post-combustion CCUS uses chemical solvents (e.g., amines) or physical adsorbents to separate CO_2 from exhaust streams.

The following describes three typical post-combustion CCUS approaches:

- **Chemical absorption/Wet Capture:** CO_2 in the exhaust dissolves into an absorbent including substances with high reactivity with CO_2. Typical substances used are amines, especially alkanol-amine-based chemicals, e.g., monoethanolamine. Although the reaction mechanism may differ for each substance, these amine-based substances selectively react with CO_2 to become ionic substances that are soluble in water.

- **Adsorption/Dry Capture**: CO_2 is separated using a substance that has a strong physically and chemically corresponding attraction to CO_2. Porous materials such as alkali metal-based adsorbents based on chemical adsorption and zeolite using physical adsorbents have a large surface area and are suitable as adsorbents. Adsorption refers to the accumulation of molecules on a surface, whereas desorption refers to their release from that surface.

- **Separation Membrane:** Selective permeation of gases in the exhaust through a physical membrane. Separation membranes are thin films with fine pores, that selectively allow CO_2 to pass through and be separated from other products in the exhaust stream. Depending on the material and processing method of the separation membrane, it is possible to obtain various sizes of pores, so various solid materials are being studied. Separation membrane CCUS is promising for the marine sector due to compact designs and the lack of required solvents but is currently still in the R&D phase.

Lastly, oxy-fuel capture (typically referred to as oxy-fuel combustion) involves the combustion of fuel in pure oxygen rather than ambient air, resulting in a flue gas that is mostly CO_2 and water vapor, which simplifies CO_2 separation. Water can be easily condensed out of the mixture, and CO_2 can be captured more efficiently with less purification needed. Oxy-fuel combustion can be adapted to existing engines offering the potential for retrofits. However, Oxy-fuel combustion is difficult to implement on ships because it requires onboard air-separation systems to produce pure oxygen, which are large, energy-intensive, and space- and weight-constrained in marine environments. The process also generates a CO_2-rich exhaust stream that must be compressed, stored, and offloaded, adding further complexity, safety risks, and infrastructure needs. In addition, managing extremely high flame temperatures requires flue-gas recirculation and advanced thermal controls, while the lack of established marine regulations and safety standards for oxygen handling and onboard CO_2 storage creates additional barriers to practical deployment [230]. Currently, oxy-fuel systems have been tested mostly in stationary on-land applications and not on vessels. While promising from a performance and emissions standpoint, oxy-fuel combustion energy requirements, and engineering complexity limit near-term use in the marine sector. Future technological advancements in compact oxygen generators, advanced materials, and modular boiler design may increase the suitability of oxy-fuel systems for ships in the long term. Modular boiler design can enhance the technical suitability of oxy-fuel combustion for marine applications by enabling distributed heat generation, improved thermal control, safer compartmentalization of oxygen and combustion systems, and more flexible integration with flue-gas recirculation and carbon capture components. By breaking large systems into smaller, controllable units, modular architectures improve system stability, safety, and operational flexibility

Figure 20 shows that once CO_2 is captured on-board, it can be stored in liquid, gaseous, or solid form. Liquid storage can involve compression into high-pressure tanks or cooling it to a liquid state for low-pressure storage. The storage of CO_2 on-board vessels is a major technical challenge for CCUS. Typically, CO_2 is liquefied at ~-50° C and 6-7 bar which requires specialized tanks that are insulated and pressurized. Solid storage options include converting CO_2 into stable minerals like limestone or binding it to solid sorbents that are simpler to handle and transport. The CO_2 must then be offloaded when the vessel calls at ports and transferred to facilities for permanent sequestration in geological storage reservoirs or conversion into useful materials that can be used by a variety of sources, including construction, manufacturing, agriculture, or chemicals industries. Another potential option is the use of the CO_2 to produce synthetic fuels on-board the vessel itself; however, such technologies are highly experimental at this time. No matter how the CO_2 is treated or used, it must be ensured that CO_2 is not later released back into the atmosphere, as this would negate the climate benefits of CCUS.

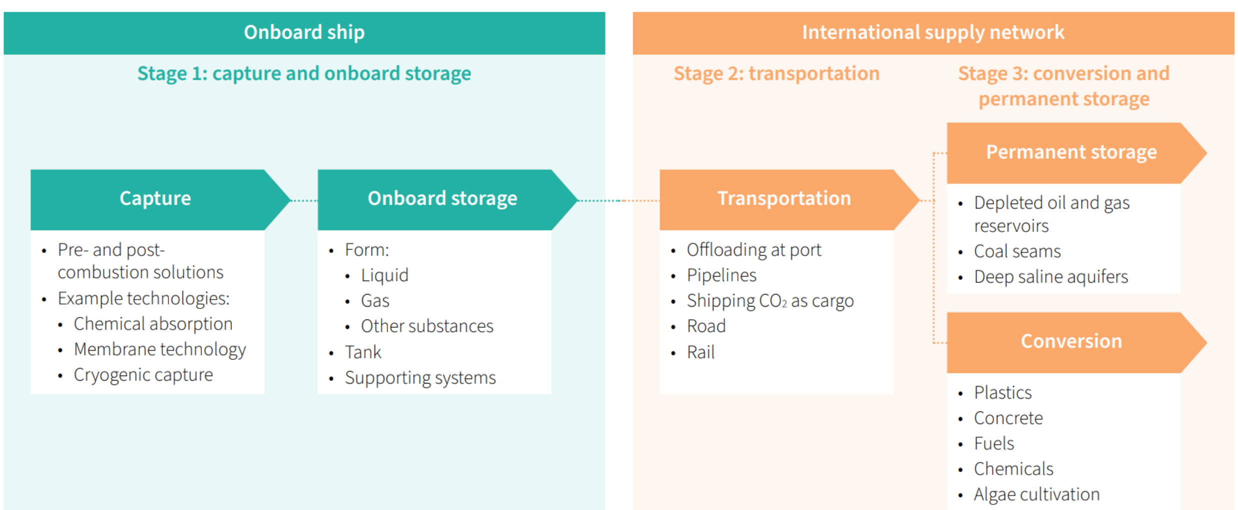

Figure 20. On-board supply chain for CCUS on marine vessels. From Reference [230].

CCUS results in a significant energy penalty as a considerable amount of energy is spent to capture, transport, utilize, and store CO_2, which increases fuel consumption and costs, and detrimentally impacts emissions. The amount of energy required for capturing CO_2 depends on many factors including the amount of CO_2 in the exhaust gas, the desired removal rate, and impurities in the exhaust that must be addressed. This penalty is estimated to be 11 to 40 percent for land-based stationary systems, depending on technology and resource recovery [231]. Current estimates for on-board CCUS systems show growth in vessel fuel consumption by 10–25 percent. A case study by Realising Maritime Carbon Capture to Demonstrate the Ability to Lower Emissions (REMARCCABLE) involving the retrofit of an on-board CCUS reported a 10 percent fuel penalty for the medium-range tanker *Stena Impero* [232]. The consortium concluded that incorporating CCUS on newbuild vessels could improve capture rates and reduce fuel penalties using more efficient engines, heat pumps, and alternative solvents. Solvang is conducting a pilot CCUS demonstration on the LPG carrier *Clipper Eris* and they expect a 10 to 20 percent fuel penalty with a 70 percent capture rate. Fuel typically represents 30 to 60 percent of a vessel's operating costs (and often more for large ocean-going vessels) so this penalty is substantial and represents a challenge for deployment.

System/Network Suitability and Operational/Infrastructure Needs

The substantial development of global and national infrastructure will be essential to make CCUS viable at-scale. Infrastructure is needed to support the handling, transportation, and long-term storage of CO_2 with potential long-term storage in geological features such as saline aquifers, depleted oil & gas fields, or basalt formations. If the use of CCUS becomes widespread in the marine sector (and other stationary applications), this will require significant coordination between ship owner/operators and other stakeholders including port operators, local, regional, and national policy makers, among others.

The second half of the CCUS supply chain is already established, supported by the existing CO_2 industry. In contrast, the on-board CCUS systems are the emerging and novel component of the supply chain. However, as CCUS expands globally, the international infrastructure will need to adapt and scale to handle significantly larger CO_2 volumes and the requirement for expanded offloading capabilities globally.

Handling CO_2 at any point along the supply chain involves safety risks requiring technical solutions, operational protocols, and regulatory frameworks. A broad set of existing regulations already applies to different stages of the CO_2 supply chain. From a maritime operations standpoint, some regulations govern activities on-board the vessel and the management of waste generated during normal operations, while others address the discharge of waste into the sea from land-based sources. Additionally, once CO_2 is offloaded at port, a separate set of regulations applies to its downstream handling, e.g., whether it is permanently stored or used in different applications.

Port-based CO_2 terminals are currently under development in Europe, including the Ports of Antwerp, Gdansk, Gothenburg, and Dunkirk. Another example includes Wilhelmshaven on Germany's North Sea coast as part of Germany's BlueHyNow project [230]. Various CO_2 offloading solutions are being considered and developed. For example, Dutch maritime engineering firm Value Maritime is using a modular "CO_2 battery" system comprised of a containerized unit that can be removed from the ship, transported, processed, and reused. On a larger scale, multi-purpose CO_2 pipeline networks are emerging globally to transport captured CO_2 to end-use applications or permanent storage sites. Notable examples include the Midwest Carbon Express in the U.S., an offshore pipeline linking Belgium to Norway, and the Delta Corridor connecting parts of Germany and the Netherlands.

For carbon storage to be effective in mitigating climate change, captured CO_2 must remain securely stored for thousands of years. However, the specific definition of such timescales and whether current storage methods meet this requirement are unclear. The 1996 London Protocol, which regulates marine pollution, initially prohibited both offshore geological CO_2 storage and the transboundary transport of CO_2. This represented a major challenge as not all ports and flag states have suitable access to appropriate storage sites. The Protocol has since been amended to allow geological storage and transboundary CO_2 movement, but only a few countries have provisionally accepted the amendments. In 2022, Denmark and Flanders, a regional district in Belgium, signed the first bilateral agreement enabling cross-border CO_2 transport for offshore storage which was a significant step toward building an international CO_2 network [233]. As more agreements emerge, this market is expected to grow.

Potential Emissions Reductions

CCUS has the potential to significantly reduce direct or tank-to-wake GHG emissions from vessels by capturing CO_2 in the exhaust gas of both main and auxiliary ICE, or the hydrogen fuel reformer in some fuel cell systems. As an example, the study done in Project REMARCCABL estimated an approximately 20 percent reduction in annual net CO_2 emissions by the *Stena Impero*, despite the 10 percent increase in fuel consumption [232]. However, the full emissions profile must consider both GHG and pollutants (NO_x, SO_x, PM, etc.), as well as emission impacts from the additional energy and infrastructure required. Exact CO_2 capture rates are not known, and current technologies are estimated to achieve a capture rate of about 30 to 80 percent with a goal of a 90-100 percent capture rate in future systems [230]. Measuring exact CO_2 capture rates in marine carbon capture and storage (CCS) systems is difficult because shipboard operations are dynamic, non-steady-state, and highly variable, unlike controlled industrial plants. Exhaust flow rates, engine loads, fuel composition, and operating conditions change continuously with speed, weather, routing, and power demand, which causes large fluctuations in CO_2 concentration and mass flow. Capture rates for onboard ship carbon capture systems are expected to improve over time as the technology matures through advances in capture materials, absorber and contactor design, thermal integration with waste heat systems, and increasingly sophisticated process control and automation. Improvements in exhaust conditioning, modular system architecture, and operational learning further enhance system performance and stability across variable operating conditions. As with other industrial capture technologies, these combined material, engineering, and operational improvements are expected to progressively increase achievable capture efficiencies while reducing energy penalties and system losses.

Actual capture rates will be based on factors including vessel design and operating parameters and may be below the theoretical maximum, possibly in the range of 30 to 50 percent [230]. The installation of the Value Maritime system on the M/T Pacific Cobalt projected a 40 percent capture rate [234]. However, so far, the few pilots and trials available have not published verified results and the limited availability of real-world data on on-board CO_2 capture rates makes it difficult to accurately determine the level of CO_2 emission reductions achievable by CCUS. It is important for stakeholders to publish the results of trials and build the evidence that will support the use of CCUS as a viable GHG reduction strategy for the maritime sector. Companies often avoid publishing early trial results for emerging technologies due to concerns about commercial confidentiality, intellectual property protection, reputational risk, and the uncertainty of immature performance data. Early results can be unstable or misleading without proper context, and the lack of standardized testing and validation frameworks further discourages disclosure. Potential solutions include third-party validation, pre-competitive research consortia, standardized reporting frameworks, tiered data-sharing models, and transparency requirements tied to public funding or regulatory incentives. As practical operational experience builds, optimal capture rates for technical and commercial viability will become clear. This will further demonstrate what role CCUS can play in transitions to meet IMO GHG guidelines.

Furthermore, the requirement of more fuel to produce the same amount of useful heat increases the "upstream" environmental problems of fossil fuels, including GHG and pollutant emissions. The energy penalty CCUS incurs can lead to net increases in pollutants if aftertreatment is not co-deployed. For example, the extra energy required increases the engine load and leads to net increases in PM and NO_x, unless SCR and scrubber systems are scaled to address this issue. One way to avoid this penalty from a GHG emissions perspective is by using low-carbon fuels instead of fossil fuels, such as HVO in place of HFO. On the other hand, from a pollutant emission standpoint, the use of alternative fuels may not result in overall emissions reductions in NO_x, PM, $SO_{x,}$ and other pollutants across the CCUS supply chain due to increased fuel consumption.

In addition, the potential impact on life cycle GHG reductions must be considered, as CCUS does not prevent emissions both upstream and downstream of vessel operation. All stages of the CCUS supply chain consume energy and result in emissions of both GHG and pollutant emissions. Depending on capture efficiency and storage permanence, it is estimated that well-to-wake GHG emissions can be reduced by 60–90 percent compared to conventional fossil-fueled vessels.

Potential impacts on pollutant emission rates varies by species and situation. CCUS systems themselves can co-remove some PM, especially in amine-based post-combustion systems. Amine-based CCUS systems (e.g., MEA) may emit trace amounts of amines or degradation products, which can form secondary pollutants like nitrosamines or formaldehyde.

Furthermore, CCUS systems can be integrated with emissions control systems, including scrubbers. Water-based scrubbing systems can reduce PM and aerosols, and SO_x can be reduced by up to 95 percent [235].Similarly, the use of CCUS with SCR can help control NO_x, however CCUS systems alone do not provide reductions in NO_x.

Table 14 summarizes the emissions impacts of on-board CCUS systems on marine vessels across greenhouse gases and key criteria pollutants. CCUS provides its most significant benefit in reducing CO_2 emissions, with typical tank-to-wake capture rates ranging from 60–95%, making it one of the few technologies capable of delivering deep decarbonization for existing ocean-going ships. Well-to-wake GHG reductions are more variable (approximately 30–80%) due to energy penalties associated with capture, compression, liquefaction, and storage, as well as the carbon intensity of the energy used to operate CCUS systems. For air pollutants, CCUS offers limited direct control of NO_x, which are primarily driven by combustion temperature and engine load, and may even increase slightly due to the additional energy demand of capture systems. Moderate co-benefits are observed for PM and SO_x through incidental co-capture and acid gas absorption processes, although CCUS is not designed as a primary pollution-control technology. Overall, the table highlights that on-board CCUS functions primarily as a climate-mitigation strategy rather than a comprehensive air-quality control solution, and that its net environmental performance is highly dependent on system design, energy sourcing, and the availability of permanent CO_2 transport and storage infrastructure.

Table 14. Potential impacts on GHG and pollutant emissions from on-board CCUS. References: [232], [236], [237], [238], [239], [240], [241], [242], [243], [244]

Pollutant	Impact of CCS	Net Effect	Notes / Caveats
CO_2 (Tank-to-Wake)	↓ 60–95% captured (system-dependent)	Major reduction	Capture varies by tech (amine, membrane, cryogenic)
CO_2 (Well-to-Wake)	↓ 30–80% net reduction	Moderate–high reduction	Net benefit depends on low-carbon energy for CCS
CH_4 / N_2O	No direct removal	Neutral	LNG methane slip unaffected
NO_x	Indirect ±0–5%	Neutral / slight increase	Requires SCR/EGR for real reductions
PM	↓ 10–40% (co-capture)	Moderate reduction	Not a PM-control technology
SOx	↓ 90–99% (with acid gas absorption)	Major reduction	Functionally similar to wet scrubbers
CO	↓ 10–30%	Minor reduction	Secondary benefit
Air Toxics	↓ 10–40% (variable)	Minor–moderate reduction	System-specific

Technology Readiness

CCUS has a long history of commercial operation for land-based stationary systems but is still in the R&D stage for marine vessels with only a few demonstrations. A 2023 report by Lloyd's Register estimated the TRLs for CCUS of 6, 5, and 8 for the supply chain stages "Capture and On-board Storage", "Transportation", and "Conversion and Permanent Storage", respectively

[230]. Similarly, a 2023 report by DNV/Ricardo estimated that on-board CCUS systems currently have a TRL of 5-6 with commercial maturity not expected sooner than the 2030s [44]. CCUS for on-board vessel fuel reformers, such as those used for fuel cells, is expected to occur at a slower pace. Forecasting the commercial development on-board CCUS is difficult due to the current barriers and the dependence on other factors including policy requirements/incentives [19].

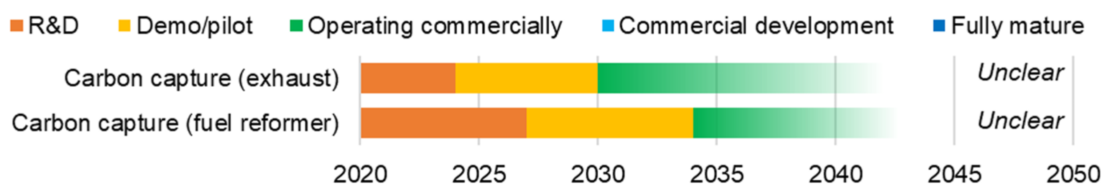

Figure 21. Technological readiness and commercial availability for on-board CCUS systems. From Reference [19].

CCUS systems from several vendors have reached the pilot stage of development. The Dutch maritime engineering firm Value Maritime has developed a 'plug and play' CCUS system called the Filtree, which is designed for small to medium sized vessels and has been awarded an AIP by Lloyd's Register [245]. The Filtree system is an on-board CO_2 capture and storage unit that uses post-combustion chemical absorption in an on-board tank. The Filtree system allows vessels to capture up to 40 percent of CO_2 emissions, with the potential of exceeding 90 percent in the future. The Filtree does not liquefy CO_2, and uses a CO_2 absorber called monoethanolamine, which is stored in tanks which simplifies offloading procedures. The Filtree system has been fitted on Eastern Pacific Shipping's carriers *Pacific Cobalt* and *Pacific Gold*, making them the largest OGV to be fitted with CCUS. It is anticipated that the system will capture up to 40 percent of the vessel's main and auxiliary engine emissions. However, there is currently insufficient evidence to validate the real-world performance of these systems or the systems from other vendors [230], [245].In contrast with many one-off pilot projects, the OCC system developed by Value Maritime has seen multiple installations including MOL, Eastern Pacific Shipping, JR Shipping and Solvang have all installed their system. [234].

There are many other demonstration projects involving CCUS globally. Evergreen Marine Corp has announced that it had installed a CCUS system on-board the *Ever Top*, a 14,110 TEU containership with the captured CO_2 offloaded to a shore facility and recycled [234]. In early 2025, Solvang ASA, a Norwegian shipping company that specializes in the transportation of liquefied gases, installed a CCUS system on-board the 21,200 m^3 LPG carrier *Clipper Eris* which separates, liquefies through refrigeration, and stores the CO_2 on deck [246]. A pilot system operated by Wärtsilä concluded the expected capture rates to range from 70-80 percent of the main and auxiliary engines [234]. Additionally, South Korean shipping company HMM has completed the installation of a CCUS on a 2,200 TEU container ship called the *Mongla* and is currently conducting operational testing [247].

The conversion and permanent storage of CO_2 has a higher TRL than the technologies used to capture and transport captured CO_2, as operational storage facilities are already in full-scale use. However, current global capacity is limited to just 10 million tonnes of CO_2 per year, which is far below the level needed to meet projected maritime demand. For example, the shipping industry alone emits approximately 1,050 million tonnes of CO_2 annually, highlighting the urgent need for substantial expansion of storage infrastructure [230]. Studies have concluded the expansion is potentially feasible but requires decade-scale infrastructure build with permitting and delivery risk (3–10+ year lead times are common for storage development) [244]. For maritime, onboard capture can be a meaningful lever on specific routes and segments once offloading and storage hubs exist, but widespread adoption will be constrained by how rapidly storage capacity, terminals, and CO_2 transport networks scale.

Global efforts to expand CO_2 storage capacity are underway, including in Europe. A project in the UK is targeting the potential first CO_2 injection by 2027. Project Greensand is a pioneering CCS initiative in the Danish sector of the North Sea with the goal of storing large volumes of CO_2 permanently underground in depleted offshore oil and gas reservoirs [248]. A consortium led by INEOS, Wintershall Dea, and partners is developing the project to repurpose the former Nini West oil field's sandstone formation as a secure storage site for injected CO_2, leveraging geological stability and existing subsurface data and infrastructure. A first demonstration phase successfully injected small volumes of CO_2 in 2023, proving the full value chain of transport and offshore injection. The project's commercial phase, now called Greensand Future, has received regulatory approval and is progressing toward operational storage of several hundred thousand tonnes of CO_2 per year by around 2026, with ambitions to scale to millions of tonnes annually (potentially up to 8 million t/year by 2030)—contributing to Danish and broader EU climate goals. Dedicated transport infrastructure (including a new terminal and purpose-built CO_2 carriers) is being developed to move captured CO_2 from industrial sources to the offshore storage site. However, despite these initiatives, Lloyd's Register projects that the global CO_2 storage capacity represents only 17 percent of what is needed by 2030 to stay on track for achieving zero-carbon shipping by 2050 [230]. Currently, the shipping industry has not yet aligned with these storage developments at the scale required for widespread CCUS adoption. Moreover, the geographic distribution of storage hubs could pose logistical challenges, potentially increasing emissions due to the need for long-distance CO_2 transport. Regional disparities in the legal frameworks governing the export of CO_2 for offshore storage further complicate projections.

Economics

Widespread adoption of CCUS will require a mature and well-developed market, substantial capital investment (particularly in supply chain infrastructure), and the establishment of a strong economic case for all stakeholders. Several critical factors currently challenge the economic viability of CCUS, including the unproven performance of on-board capture technologies, the need for large-scale infrastructure expansion, and unresolved trade-offs that affect the overall operational and economic feasibility of the system.

For example, achieving higher capture rates increases both capital and operating costs, as well as on-board energy consumption. Additionally, CCUS equipment may occupy valuable cargo space, potentially reducing revenue. These factors can lead to diminishing returns and may even generate additional carbon emissions at higher capture levels. Compounding these challenges is the current lack of clear standards for measuring and reporting captured CO_2, creating uncertainty about how shipowners can realize financial benefits from CCUS.

The retrofit cost of building and installing the full CCUS on the cargo vessel *Stena Impero* was estimated to be $13.6 million, and the OPEX was estimated at $830,000/year for additional support personnel, fuel consumption, maintenance, and periodic amine replacement [232]. It should be noted that the system was a first-of-a-kind prototype, and future technologies would experience cost reductions due to experience and economies of scale.

Funding for both land-based and maritime CCUS is beginning to grow (e.g., the UK government announced £20 billion in CCUS funding in 2023), helping to advance market maturity and improve the economic case for long-term adoption [230]. In Scotland, the Acorn CCUS project—supported by the European Commission and UK and Scottish governments—is developing a major hydrogen and CO_2 storage hub at the St. Fergus gas terminal, along with a defined revenue model to support long-term stakeholder engagement and infrastructure growth in the North Sea [230]. While current investments are making CCUS more financially attractive, additional government support from many flag states will almost certainly be necessary to scale-up the global CCUS industry.

Next Steps to Demonstrate Technology

The CCUS market is currently being driven by technological development, with multiple technical solutions in progress but relatively few commercially available products. To enable broader adoption, the maritime industry must converge on a select set of proven on-board and offloading systems that can serve as standardized solutions, allowing for economies of scale and improved cost-effectiveness. A key barrier is the disjointed availability across the supply chain as vessels often operate independently from ports, transport providers, and CO_2 storage or utilization facilities. This lack of integration will need to be harmonized to allow for feasible end-to-end solutions for shipowners. However, some shipowners may choose to install CCUS systems as a way to "future-proof" their vessels, particularly those vessels that are already equipped with SO_x scrubbers due to the high levels of reductions achievable when these two technologies are used in tandem. Further down the supply chain, significant investment and development are needed, especially in port infrastructure, which remains a critical gap.

However, ports are hesitant to invest without clear demand signals. Additionally, it remains unresolved whether CO_2 liquefaction should occur on-board or at port.

Overall, while on-board systems may advance more quickly, the larger challenge involves scaling and coordinating the necessary infrastructure on land. Similarly, there is a lack of required regulation and policy which will ensure the effectiveness and economic viability of CCUS. The successful adoption of CCUS will depend on establishing clear economic value for all stakeholders involved and updating regulatory frameworks to address practical challenges including carbon accounting. Achieving commercial viability will require significant infrastructure investment and expansion, as well as the development and adoption of standardized on-board storage and offloading systems. These steps will be crucial to generating the economies of scale and scope needed to support widespread deployment and long-term sustainability of CCUS technology.

Technical challenges that must be addressed to advance demonstration of CCUS systems include space needs, weight, energy penalties, vessel design, installation challenges, and energy demand for solvent regeneration. Storing CO_2 on-board ships presents several safety challenges that must be addressed through technical design, operational procedures, and regulatory oversight. High concentrations of CO_2 (above 10 percent) can cause asphyxiation, and pressurized CO_2 poses risks including the potential for explosions. As such, CO_2 should be treated as a hazardous substance. While MARPOL, the primary international convention for preventing pollution from ships, regulates many ship-generated wastes, it does not currently classify CO_2 captured on-board as a waste product, leaving a regulatory gap. There are no internationally established standards for CO_2 reception facilities at ports or for the design, transport, and offloading of captured CO_2 from ships. Carbon accounting practices for on-board capture are still evolving. In the EU, a growing body of legislation and policy (e.g., the inclusion of shipping in the EU Emissions Trading System) is slowly beginning to incentivize CCUS adoption [230]. Discussions at the IMO regarding the integration of CCUS into maritime GHG regulations are ongoing but progressing slowly.

The current CO_2 utilization market is relatively small and mature and is focused mainly on non-permanent applications in the food and beverage industry, as well as some use in agriculture and construction. An ideal outcome for CCUS would be a circular economy in which CO_2 is fully reused and retained in useful products. However, most CO_2 end-uses are still more costly to produce than their current conventional method counterparts [249]. As a result, the economic viability of CO_2 utilization depends on carefully evaluating the costs of purifying and supplying CO_2 as a usable input, rather than treating it solely as a waste by-product.

An additional barrier that must be addressed is societal acceptance of CCUS at-scale. The support and acceptance of CCUS by industry and the general public will require clear evidence that CO_2 can be stored safely and permanently, without risk of future release. The safety of CCUS will need to be reinforced through increased public awareness and education. This is complicated by the limited availability of real-world data on capture rates, which makes it difficult to build public trust in the effectiveness of CCUS technologies.

Task 2. Local, State, National, and International Programs Synergy

Programs

International

International Maritime Organization (IMO)

The IMO, operating under the United Nations is the primary international organization developing maritime emissions standards. GHG reduction targets are established in the IMO Revised GHG Strategy published in 2023 [250]. The strategy establishes indicative checkpoint targets for reductions in emissions relative to 2008 of 30 percent by 2030 and 70 percent by 2040 with stretch goals 10 percent higher at each time point. Full net-zero carbon maritime operations are targeted for "around 2050". The strategy also establishes a goal of reaching "uptake of zero or near-zero GHG emission technologies, fuels and/or energy sources to represent at least 5%, striving for 10%, of the energy used by international shipping by 2030." The IMO GHG program is voluntary, but many nations have committed to targets that align with IMO goals. However, some stakeholders do not believe the IMO revised GHG strategy ramps down GHG emissions rapidly enough to achieve the IPCC goal of limiting global temperature rise to 1.5 °C [252]. In addition, efforts are underway to make IMO targets mandatory by incorporating the IMO measures into MARPOL Annex VI as discussed below in the MARPOL section.

IMO Design and Operation Regulations Impacting Emissions

The IMO has adopted several regulations that impact emissions. The Energy Efficiency Design Index (EEDI) and the Energy Efficiency Existing Ship Index (EEXI) are design standards for new and existing ships [253][254]. Under these standards, ships are given a rating for GHG emissions based on their propulsion system and design and must meet minimum standards to be certified, so the program is essentially "pass/fail." Certification is required once during the lifetime of the ship. Certification requires the ship owner to submit a technical file and "if verified, a new International Energy Efficiency Certificate (IEEC) will be issued by the classification society on behalf of the relevant flag state."[255].

Another program, the Carbon Intensity Indicator (CII) rates the operational performance of the vessel relative to a benchmark and the rating is performed annually. The vessel is assigned a ranking from A to E with A being the best performance indicator and E the worst. Thresholds for achieving the rating become increasingly stringent over time. With the required CII declining to 89% of the 2019 benchmark in 2026 (2% per year decline in the threshold) and post-2026 requirements to be determined [256]. Ship owners are required to file Ship Energy Efficiency Management Plans (SEEMPs) targeting operational efficiency improvements over a three-year horizon. Ships with a D rating from three consecutive years or an E rating in a single year must include a corrective action plan within their SEEMP.

Maritime Environmental Protection Committee (MEPC)

The MEPC, a committee of the IMO, meets regularly to discuss potential updates to IMO GHG strategy and MARPOL Annex VI regulations (discussed below). Recent actions have included expansion of protected areas, and efforts to include GHG as a regulated emission under MARPOL Annex VI which would make international GHG limits for ships mandatory. Figure 22 shows a timeline of recent and planned near-term actions on implementing the IMO GHG strategy.

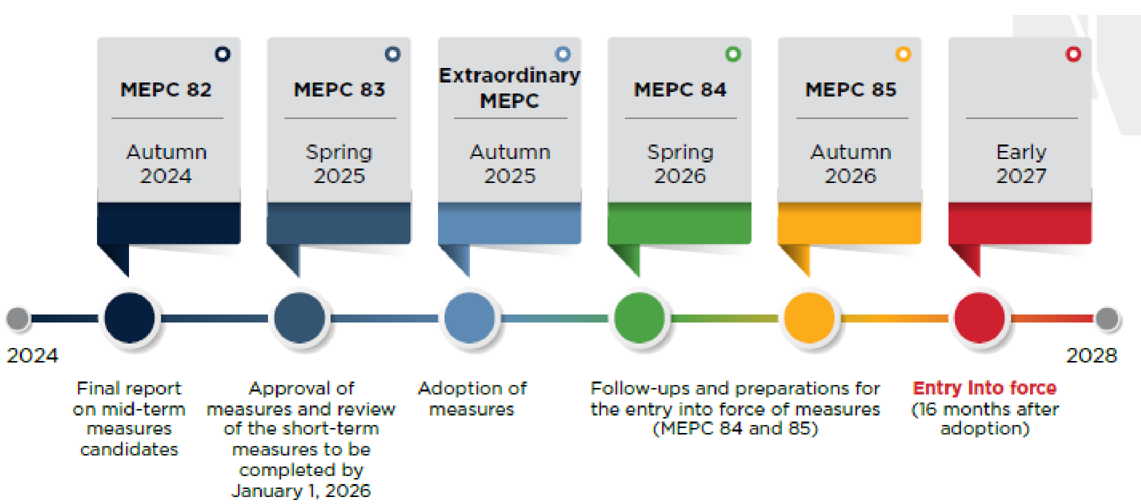

Figure 22. Timeline of recent and near-term MEPC actions on GHG emissions. Source: [257].

At the April 2025 MEPC meeting a new North-East Atlantic ECA was approved, and the IMO Net-Zero Framework, discussed later in this section, was approved and set for formal adoption at the 2nd Extraordinary Session of MEPC in October of 2025. However, member states at IMO did not reach a consensus on the formal adoption of the Net-Zero Framework at the 2nd Extraordinary Session and the decision was delayed for one year. Formal adoption will be reconsidered at MEPC 85 in late 2026 [258].

International Convention for the Prevention of Pollution from Ships (MARPOL)

MARPOL Annex VI, first adopted in 1997 and put into force in 2005, sets limits and standards for marine air pollutant emissions. MARPOL regulations are mandatory as they are established under international treaty. MARPOL Annex VI is continually updated via the MEPC. As noted above, the process of formally approving the addition of GHG regulations to MARPOL Annex VI (new Chapter 5) is currently ongoing.

Regulated pollutants under MARPOL Annex VI include NOx, SOx, and PM. NOx is regulated through stack emissions limits on emissions mass per unit of engine power. The limits are set in Tiers based on the age of the ship as seen in Figure 23. Sulfur and PM emissions are regulated indirectly through limits on fuel oil sulfur content which reduces both sulfur emissions and particulate formation. The current limit is 0.5 percent mass fraction outside emissions control areas and 0.1 percent mass fraction inside ECAs [259].

The United States is collaborating with other parties to seek to introduce more stringent NOx limits into MARPOL Annex VI. The group comprising Belgium, Canada, Denmark, Germany, Ireland, Netherlands (Kingdom of the), Norway, and the United States submitted a paper at MEPC 81 expressing concern that the goals of the MARPOL Annex VI NOx reduction goals were not being met. A working group was formed as a result, and recommendations are due in 2027 [260].

Sulfur and NOx Emissions Control Areas (ECAs)

MARPOL Annex VI establishes ECAs as designated areas near population centers and environmentally sensitive areas where ship emissions limits are lower than in open waters. Current ECAs, including those added in 2025 are shown in Figure 24. Emissions regulated in each ECA are noted on the figure.

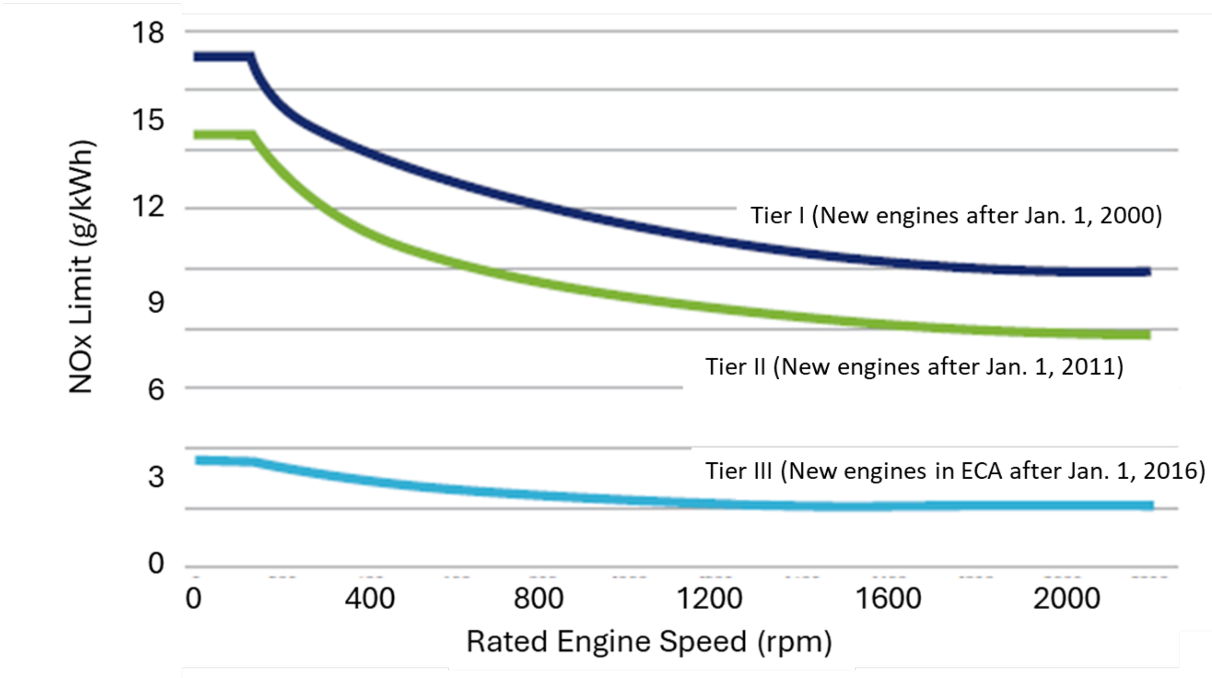

Figure 23. NOx Limits Under MARPOL Annex VI as of late 2024. Source: IMO as presented in [6].

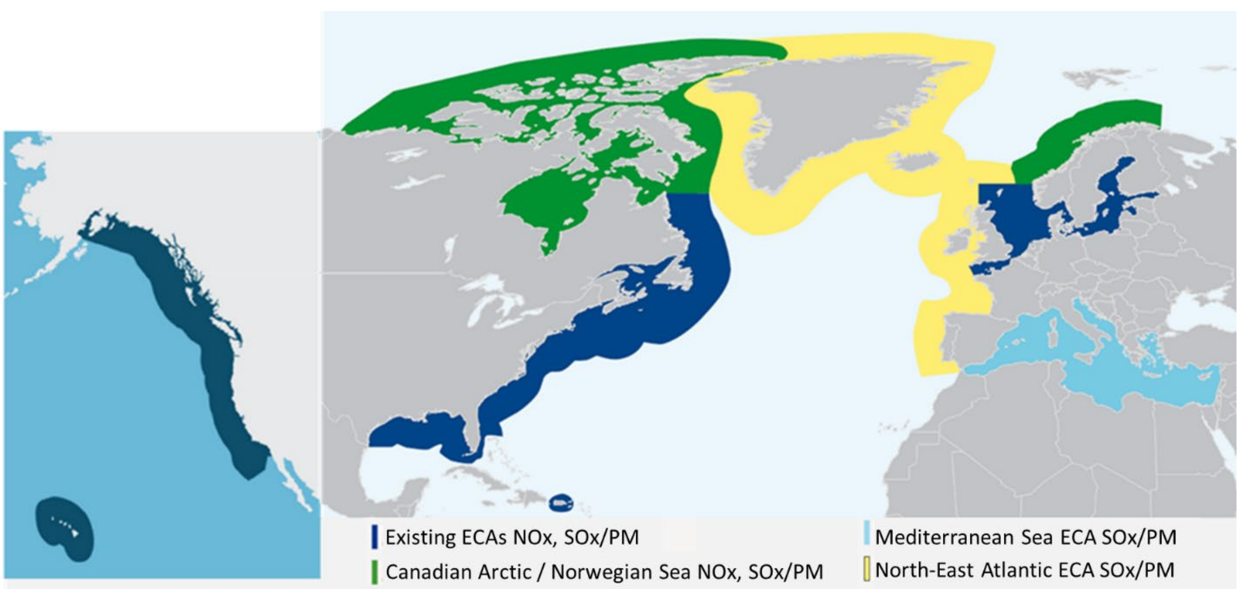

Figure 24. Global Emissions Control Areas as of mid-2025. Source: [261],[262].

IMO Mid-term GHG Measures

Table 15 summarizes the mid-term GHG measures that have been developed by the IMO. The MEPC had planned to adopt the measures at its October 2025 meeting, but ratification has been pushed back due to opposition by a few member nations. The measures are grouped into economic measures such as a feebate program (rebates or penalties based on emissions, similar to cap and trade) and technical measures or mandates such as a fuel carbon intensity standard.

Table 15. Mid-term GHG Reduction Measures Proposed by the MEPC. Source: [257].

Proposals for Mid-Term Measures	Description	Technical Measure	Economic Measure
GHG Fuel Standard (GFS) with its Flexibility Compliance Mechanism	Incentivizes the uptake of sustainable low- and zero-carbon fuels, offering flexibility mechanisms such as rewarding of overcompliance for early movers via Surplus Reward Units (SRUs) and alternative compliance options such as GFS Remedial Units (GRUs).	X	
International Maritime Sustainable Fuels and Fund (IMSF&F) mechanism	Aims at the promotion of sustainable marine fuels by setting up an annual GHG fuel intensity target for shipping, while providing flexible compliance approaches (pooling, banking, and fund contribution/reward).	X	X
Feebate Mechanism	Comprises of a mandatory contribution on GHG emissions and reward for zero emission vessels by the ZESF, to be complemented by the GFS as technical element.		X
Universal mandatory GHG levy	A mandatory levy on all GHG emissions from international shipping will address the price differential between business-as-usual emission-based technology options, including fuels and decarbonize alternatives.		X
Simplified Global GFS with an energy pooling compliance mechanism	A performance standard, independent of fuel type, which includes a voluntary energy pooling compliance mechanism and may help increase the production and uptake of all types of low-, near-zero and zero-GHG fuels.	X	

Zero Emission Shipping Fund (ZESF)	Funds collected from mandatory contributions by ships per tonne of CO_2 equivalent emitted will be utilized to provide rewards to ships using eligible zero/near-zero GHG fuels through a "feebate" mechanism narrowing the cost gap with conventional fuels.		X
Green Balance Mechanism	Uses a cost balancing approach to reconcile emissions reductions with economic realities. It can be fully integrated with a GHG fuel-intensity standard.		X
Maritime GHG Pricing Mechanism	A direct per-tonne-of CO_2 equivalent regulatory charge on the tank-to-wake GHG emissions reported by each ship, determined by adjusting a universal GHG price signal according to each fuel type and pathway's well-to-wake emissions profile.		X

National and Regional

All countries and regions discussed in this section are subject to compliance with MARPOL Annex VI. This section highlights additional initiatives relevant to OGV emissions reductions. In most cases, the national programs focus on GHG reductions without specific emissions regulations for other pollutants beyond MARPOL limits. Countries included in this section are either leaders in maritime decarbonization, have emission regulations beyond MARPOL Annex VI, are major trading partners with the U.S. West Coast, or a combination of these factors.

European Union (EU)

Most of the coastal waters of EU member states lie within IMO ECAs and emissions are governed under the applicable MARPOL Annex VI provisions. The EU has the most advanced regional program addressing GHG emissions from ships. The program established binding limits on GHG emissions from ships embarking from or landing in ports in the EU [263]. The overall maritime GHG reduction program has several elements as described below [253][257][6][263].

EU Renewable Energy Directive

The EU Renewable Energy Directive (RED) first adopted in 2009 was revised in 2023 raising the EU's binding renewable energy target for 2030 from 32% to a minimum of 42.5%, with a focus on sectors where progress has been slower to date including transport [265].

EU Emissions Trading System (ETS)

Under EU directive EC/2003/87/EC, effective January 1, 2024, ships trading in the EU must participate in the EU emissions trading system, which is a cap and trade program with declining GHG emissions allocations [266]. The EU ETS was established in 2005 and is the world's first international emissions trading system. It is now in its fourth phase (2021-2030). The ETS regulation places a cross-sectoral cap on GHG emissions and covers CO2, CH4, and N2O. Large offshore ships (ships larger than 5,000 gross tonnes) must participate in the program beginning on January 1, 2027. Under the regulation emissions credits must be purchased for 50 percent of emissions from voyages starting or ending outside of the EU (allowing the third country to decide on appropriate action for the remaining share of emissions); 100 percent of emissions that occur between two EU ports and when ships are within EU ports. The requirement to surrender ETS credits is phased in with a 40 percent obligation in 2025, 70 percent in 2026, and 100 percent in 2027 [266]. The regulation also requires use of shore power when ships are at berth.

FuelEU Maritime Regulations

The FuelEU Maritime regulations, which came into effect in January 2025, are regulations requiring the reduction of GHG emissions from ships [267], [268]. The regulation is part of the EU's "Fit for 55" package. The regulation has the same provisions for ship size and allocation by voyage type as the ETS regulation described in the prior paragraph. The required emissions reductions, relative to 2020, are shown in Figure 25.

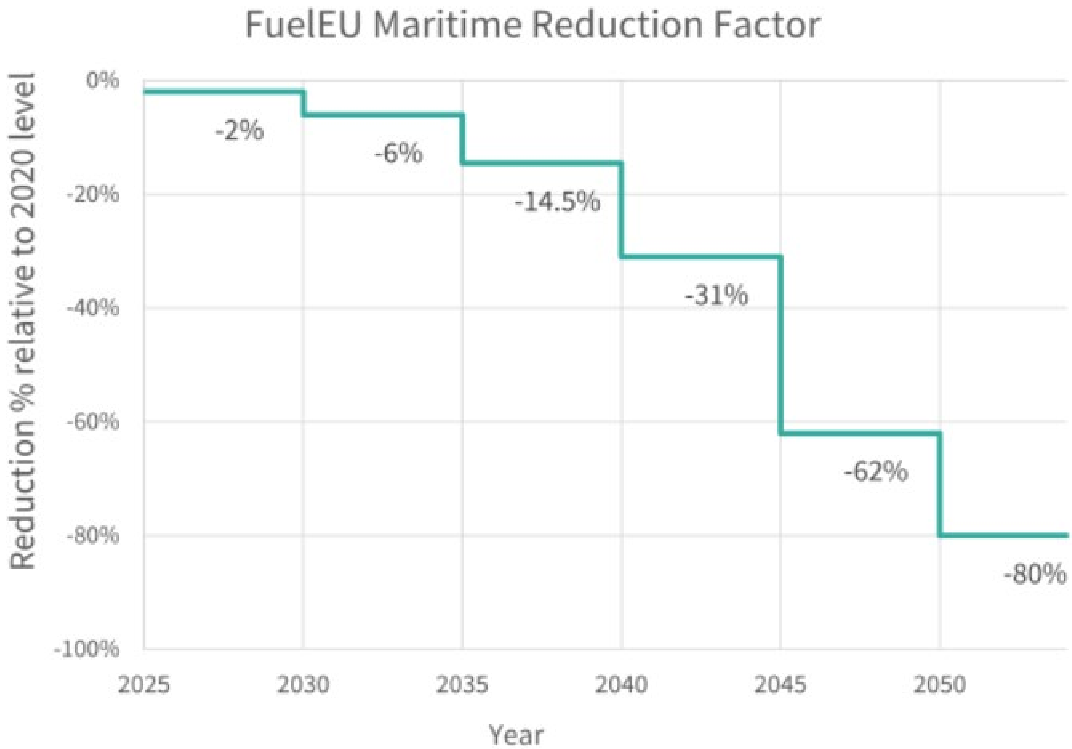

Figure 25. FuelEU tank-to-wake GHG Emissions Reduction Requirements. Source: [269].

United States

The U.S. regulates emissions from ships through the U.S. Environmental Protection Agency under the authority of the U.S. Clean Air Act. The regulations are based on certification of engine emissions based on engine size and type. Standards are tiered, with Tier 1 being the least stringent and Tier 4 being the most stringent, generally requiring significant aftertreatment to achieve compliance. Standards for large-displacement engines which apply to OGVs are shown in Table 16. Tier 2 and Tier 3 mirror the corresponding IMO tiers, and the EPA also regulates compliance with MARPOL Annex VI [259]. Tier 4, which applies to certain vessels but does not currently apply to OGVs, is shown for reference. Tier 4 also limits hydrocarbon emissions to 0.19 g/kWh and PM emissions to 0.06 g/kWh.

Table 16. EPA NOx Emissions Limits for Large Vessels (Category 3) [270].

Tier	Model Years	Limit (g/kWh)
Tier 1	2004 - 2010	9.8 – 17.0
Tier 2	2011 - 2015	7.7 – 14.4
Tier 3	2016+	2.0 – 3.4
Tier 4 > 3700 kW (for reference)	N/A	1.8

Legislation has recently been introduced in the House and Senate to add OGVs to the list of eligible vehicle types for generating U.S. federal renewable fuel credits (the program is restricted to specified transportation uses and does not currently include OGVs). [271]. In addition, the U.S. DOE has a program and several international partnerships to advance the use of clean maritime fuels [272] .

Canada

Canada regulates emissions in line with IMO regulations through a government agency called Transport Canada [273]. Fuel sulfur content has been limited to 0.10 percent since 2016 [274]. Maritime emissions are included within the Canadian statute requiring net-zero GHG emissions by 2050 with an intermediate target to reduce emissions by 40 percent to 45 percent relative to 2005 by 2030 and Canada is a signatory to the Clydebank Declaration and the U.N. Zero-emissions Shipping 2050 Initiative. Canada has developed a national green shipping corridors framework to guide the people and organizations who are developing the green shipping corridors. This framework supports actions, technologies, clean fuels, and infrastructures that will result in real, measurable emissions reductions and that can be implemented at scale to reduce emissions now while setting the path to net-zero by 2050. It was announced and released the Canadian Green Shipping Corridors Framework during COP27 in November 2022 [275].

Japan

Japan is among the largest trading partners of California and has a strong commitment to decarbonization of the maritime sector. In March 2023, the governments of Japan and California signed a "Letter of Intent to Support Port Decarbonization and the Development of Green Shipping Corridors."[276]

In 2020, Japan adopted policies to accelerate efforts to decarbonize energy use in maritime transport as well as industrial sectors [277]. The policy calls for the development of action plans to: 1) for zero-emission ships; 2) to expand the production of low-carbon fuels; and 3) to promote technology development to improve the energy efficiency of ships. As part of the effort, Japan has establishment of a 2-trillion-yen ($13.3 billion) Green Innovation Fund, which will support ambitious R&D and implementation efforts over the next 10 years [276]. Japan does not currently have an ECA but is exploring the idea and is considered likely to apply for one in the future [278].

Japan's Ministry of Land, Infrastructure, Transportation, and Tourism (MLIT), with participation from academia and industry, developed a roadmap of steps to be taken to advance decarbonization through 2030 and beyond. Initial planned activities include investment in R&D and pilot projects, development of bunkering guidelines to address issues unique to zero-emission fuels (e.g., green-methanol, ammonia, and hydrogen), and support for facility and equipment, fuel transfer/supply, and emergency response procedures. MLIT also promotes "Carbon Neutral Port (CNP) Initiatives," including the introduction of zero- and near-zero-emission cargo handling equipment and onshore power supply facilities, and has committed to achieve carbon neutrality by 2050 [279]. MLIT formally launched the Carbon Neutral Ports Certification scheme in June 2025 [279].

China

Ship emissions in Chinese waters are subject to MARPOL Annex VI regulations and maritime GHG emissions are included in its GHG strategy. At the 75th UN General Assembly in September 2020, Chinese President Xi Jinping announced that China would reduce the increase in overall

CO2 emissions to zero by 2030 with declines thereafter achieving carbon neutrality before 2060. Specific to maritime emissions, China proposed in 2022 the creation of an International Maritime Sustainability Funding and Reward (IMSF&R) mechanism that, based on benchmarks for CO_2 emissions, would collect funding contributions from ships with actual CO_2 emissions above the upper benchmark level and reward ships with CO_2 emissions below the lower benchmark level [276]. Norway, Brazil, and UAE have since co-sponsored the proposal [280].

South Korea

Republic of Korea's Ministry of Oceans and Fisheries and the 2050 Carbon Neutrality & Green Growth Commission have announced the "Strategy for Decarbonization of International Shipping" to decarbonize the shipping sector by 2050 [276]. Four goals have been established:

- Convert ships owned by national shipping companies into ships that use eco-friendly fuels,
- Encourage timely investment in the transition to eco-friendly fleets,
- Develop eco-friendly technology and expand infrastructure for future fuels, and
- Establish zero-carbon shipping routes.

The Republic of Korea has also designated SOx control areas around its major ports [281].

Singapore

The Port of Singapore leads Singapore's national Maritime Singapore Green Initiative to promote the decarbonization of shipping. The initiative includes four programs: Green Ship Program, Green Port Program, Green Energy and Technology Program, and Green Awareness Program. These are voluntary programs designed to recognize and provide incentives to companies that adopt clean and green shipping practices, such as reductions and/or waivers in ship registration fees, tonnage taxes, and port dues for ships that exceed IMO environmental regulatory standards or use low- or zero-carbon fuel. The port authority has initiatives ongoing to establish bunkering capability for both methanol and ammonia and is in active green corridor development with several partners including the ports of LA and Long Beach. The Maritime and

Port Authority of Singapore (MPA), in consultation with industry partners, has developed a blueprint for achieving Singapore's maritime decarbonization goals [282].

India

In 2021 India released a plan called Maritime India Vision 2023. Approved by Prime Minister Modi, the plan includes a push for clean fuels with initial focus on LNG (and electric and CNG for smaller vessels) but also includes hydrogen, ammonia, methanol, batteries, and fuel cells. In May 2023, the shipping Ministry issued guidelines setting a target of 2035 for establishing green hydrogen fuel bunkering and refueling facilities at major ports. Three major ports, Deendayal Port (Kandla), Paradip Port, and Tuticorin Port, have been designated as hubs for green hydrogen, green ammonia, and green methanol. The ports will develop infrastructure to facilitate storage, handling, and bunkering of green hydrogen, green ammonia, and their derivatives. India has established a National Centre of Excellence for Green Ports and Shipping (NCoEGPS) which supports the development of regulatory frameworks and alternative technology road maps for Green Shipping [276].

Australia

As part of its national commitment to reach net-zero GHG emissions by 2050, the Australian government is developing a Maritime Emissions Reduction National Action Plan (MERNAP) [283]. The development of the plan is in progress following a public consultation on a series of white papers supporting the development of the plan closed in spring of 2024 [283]. Australia is a leader in advancing hydrogen as a future maritime fuel while also exploring other options [284].

Indonesia

In November 2022, the government of Indonesia and the International Partners Group (IPG) [1] launched their Just Energy Transition Partnership (JETP). Although Indonesia has not made a specific commitment to a decarbonization timeline specific to the maritime sector, it has committed to national carbon neutrality by 2060 and maritime is viewed as a key element of the Indonesian energy transition [285][286].

Multi-national Initiatives

Several international initiatives and collaborations have been established to advance decarbonization in the international shipping sector. They generally seek to fully decarbonize global shipping by around 2050. These include:

The COP 26 Clydebank Declaration [287]

This declaration, signed at COP 26 in and named to pay tribute to the nearby historic River Clyde's significant maritime, engineering, and shipbuilding heritage, set the goal of establishing no less than six green shipping corridors by the middle of the decade with signatories pledging to:

- facilitate the establishment of partnerships, with participation from ports, operators, and others along the value chain, to accelerate the decarbonization of the shipping sector and its fuel supply through green shipping corridor projects
- identify and explore actions to address barriers to the formation of green corridors. This could cover, for example, regulatory frameworks, incentives, information sharing, or infrastructure
- consider the inclusion of provisions for green corridors in the development or review of National Action Plans
- work to ensure that wider consideration is taken for environmental impacts and sustainability when pursuing green shipping corridors.

The signatories were: Australia, Belgium, Canada, Chile, Costa Rica, Denmark, Fiji, Finland, France, Germany, Ireland, Italy, Japan, Lithuania, Republic of Korea, Republic of the Marshall Islands, Morocco, Netherlands, New Zealand, Norway, Palau, Singapore, Spain, Sweden, The United Arab Emirates, The United Kingdom of Great Britain and Northern Ireland, The United States of America.

Mission Innovation: Zero Emission Shipping [288]

Mission Innovation is co-lead by Denmark, the U.S., and Norway. Other participants are the U.K., Morocco, India, Singapore, and Australia. Supporting countries are France, Ghana, South Korea, Canada, and Germany. The initiative goals are to achieve the following by 2030:

- 600 large ships in international shipping running on well-to-wake-zero-emission fuel
- Enable annual production of 16 million metric tons of HFO equivalent zero-emission fuels
- 20 key ports covering at least three continents offering well-to-wake-zero-emission fuel bunkering

State Level

Based on data reported in the U.S. Department of Transportation Bureau of Transportation Statistics Port Performance Freight Statistics Annual Report 2025 (Figure 6 of the report) [289], the states with the highest volume of international maritime freight traffic (import plus export tonnage) are:

- New York / New Jersey
- California
- Texas
- Louisiana
- Virginia
- Georgia
- Alabama
- South Carolina
- Washington

All of these states are within ECAs and regulate both SOx and NOx emissions in accordance with MARPOL Annex VI via their state environmental protection agencies and port authorities. Currently, only California and Washington have or are advancing regulations with stricter limits than the MARPOL limits. California's Vessel Fuel Regulation, which has been in place since 2008, is stricter than the MARPOL limits specifying specific cleaner distillate fuels and over-riding the alternative compliance provision in MARPOL allowing the use of scrubbers [290]. California is also developing OGV In-Transit regulations to further limit emissions from OGVs [291]. Under proposed legislation (Senate Bill 5519 (Salish Sea Protection and Marine Clean Fuels Act) proposed in the 2025/2026 session), beginning in 2028, the state of Washington will impose fuel requirements matching California's current regulation [289]. Additionally, many of the larger maritime shipping states offer incentives for retrofitting higher-emitting engines.

Ports and Green Shipping Corridors

Numerous ports around the globe have decarbonization and air pollution reduction programs in place, many of which are tracked in the World Port Sustainability Program (WPSP) [292]. Most initiatives focus on emissions from port land-side operations, such as cargo-handling equipment, shore power programs, and emissions reductions from land freight to and from the ports. With respect to OGV in-transit emissions, port-to-port Green Shipping initiatives have the most relevance and impact. Several Green Shipping Corridors connected to California ports have been announced [293]:

- Hueneme-Pyeongtaek Green Automotive
- Hueneme-Yokohama Green Automotive
- LA-Nagoya
- LA-Yokohama
- LA-Guangzhou
- LA / Long Beach - Shanghai
- LA / Long Beach - Singapore GDSC
- Oakland - Yokohama

None of the California initiatives has reached the preparation stage but one West Coast corridor, the Pacific Northwest – South Korea car carrier corridor, is currently at the preparation stage. Given construction timelines, the first fully operational corridors are expected to emerge in the late 2020s and early 2030s. East Asia is the dominant trading partner with California ports comprising roughly 90 percent of trade volume with the ports of Los Angeles and Long Beach, and 74 percent of volume at the Port of Oakland [294][295][296], so corridors connecting California and East Asia will be of the greatest direct impact to California.

Based on corridor initiative descriptions and the WPSP database, none of the corridors listed above has committed to or emphasizes a specific low-carbon fuel. Most of the Green Shipping Corridors have a focus on digital technology to optimize logistics and ship operations which reduce emissions through improved efficiency. Japan is most active in LNG and hydrogen while China and Singapore are currently pursuing all LCMFs covered by this report. One notable aspect of the Hueneme corridor is that the port is piloting a stack-emissions reduction technology that uses an external vessel equipped with emission control systems and stack-exhaust capture system to mitigate ship emissions [297] Green Shipping Corridors are discussed further in the fuels section in the context of fuel and bunkering infrastructure availability.

Maritime Industry

We use the term "maritime industry" to include shipping companies, ship owners, ship builders, engine and clean-up system manufacturers, and bunkering infrastructure providers. Currently, the major shipping companies and ship operators, in consultation with equipment manufacturers, are the drivers of activity in piloting LCMFs requiring new engine technologies and bunkering infrastructure (LNG, methanol, and ammonia). Notable activity from industry leaders is summarized below.

Engine Manufacturers

Everllence (formerly Everllence Energy) and Wärtsilä provide major suppliers of high-horsepower OGV engines, and both are leaders in advancing LCMF-capable engines. Everllence offers high-horsepower two-stroke and four-stroke new-build and retrofit engines capable of operating on LNG, methanol, and ammonia [298]. The four-stroke engines are offered at power ratings up to 20 MW, so the larger end of the four-stroke product line is suitable for OGVs. The Everllence engines can operate in dual-fuel mode on variable fractions of diesel and can operate on close to 100 percent alternative fuel requiring only 5 percent or less diesel fraction to allow compression ignition (per direct discussion with Everllence).

Like Everllence, Wärtsilä offers marine engines capable of running on LNG, methanol, and ammonia. The Wärtsilä ammonia engine is a four-stroke engine below the size range suitable for large OGVs [299]. However, the engine creates a platform for developing larger ammonia-capable ships.

International Shipping Companies and Shippers

The major international shipping companies and their shipping customers are also key actors in the transition to LCMFs, and several have made specific commitments to advance the use of LCMFs.

A joint declaration from CEOs of leading global shipping lines at COP 28 in December 2023 called for the phase out of construction of new fossil-only powered ships. The statement also calls for governmental action to reduce emissions from OGVs. The declaration also advocates a pricing mechanism to make green fuel cost competitive by distributing the premium for green fuels across all fossil fuels used in shipping [276][300].

Thirty-five major retail brands including Amazon, IKEA, Phillips, Levi Strauss, Schneider Electric, Meta, Nestle, Electrolux, and REI Co-op are part of a clean shipping initiative called the Cargo Owners for Zero Emission Vessels (coZEV) Initiative. Signatories to the initiative have established a goal to purchase ocean freight services only powered by zero-carbon fuels by 2040 [301]. In September 2023, coZEV, through its Zero Emission Maritime Buyers Alliance (ZEMBA) launched a Request for Proposals (RfP) for 600,000 TEUs transported using zero-emissions fuels over the following three years [302]. Links to information on low-carbon fuel strategies of some of the major shipping companies are provided in Table 17.

Table 17. Major International Shipping Company Low-Carbon Fuel Strategies

Shipper	Links to Company Clean Fuels Strategies and Initiatives
Maersk	Embracing methanol with supplemented by biomethane https://enkiai.com/maersk-green-methanol-initiatives-for-2025-key-projects-strategies-and-market-impact
Mediterranean Shipping Group (MSG)	MSG views renewable (bio and electrolytic) LNG as preferred solutions but is also exploring green methanol and ammonia https://enkiai.com/mediterranean-shipping-company-green-methanol-initiatives-for-2025-key-projects-strategies-and-market-impact https://www.msc.com/en/sustainability/enabling-logistics-decarbonization
CMA CGM	CMA is focused on methanol as a long-term solution but also uses LNG and biofuels https://enkiai.com/cma-cgm-group-green-methanol-initiatives-for-2025-key-projects-strategies-and-market-impact
COSCO	COSCO is focused on methanol as a long-term solution but is exploring other LCMFs https://enkiai.com/cosco-shipping-lines-green-methanol-initiatives-for-2025-key-projects-strategies-and-market-impact
NYK	NYK sees ammonia and hydrogen as the most viable long-term alternatives with LNG and biofuels as bridges and methanol as a fallback alternative https://www.nyk.com/english/ir/library/investors/2/__icsFiles/afieldfile/2025/10/29/251024_NextGenerationFuels.pdf
Cruise Lines International Association	Cruise Lines International Association states that the industry is pursuing a variety of low-carbon fuels including liquid biofuels, LNG, methanol, and hydrogen. Ammonia is notably absent from the list. https://cruising.org/alternative-fuels-and-fuel-flexibility

Shipbuilders

Shipbuilders in China, Korea, and Japan represent almost 100 percent of alternative-fuel-capable shipbuilding [303]. As seen in Figure 26, 11 of 15 large international shipbuilders assessed have a firm commitment to reach zero carbon by a specific date. All 15 have decarbonization strategies that include the adoption of LCMFs. Eight companies included in the mapping have committed to achieving net-zero emissions by 2050. Notably, Hanwha stands out for setting a target of reaching net-zero by 2045. Conversely, Chinese firms deviate from this trend, aligning instead with their national government's objective of attaining carbon neutrality before 2060. Four companies have not specified a clear net-zero target date. Korean shipbuilding companies, overall, demonstrate the most stringent approach to their decarbonization commitments, uniformly aligning with the net-zero by 2050 goal.

China	Korea	Japan	European Union	ROW
China State Shipbuilding Corp (CSSC)	Hyundai Heavy Industries Group (HD Hyundai)	Imabari Shipbuilding Co Ltd	Meyer Neptun GmbH	CSBC Corporation
Yangzijiang Shipbuilding Holdings	Samsung Heavy Industries	Japan Maritime United (JMU) Corporation	Fincantieri SpA (*including VARD)	Seatrium Ltd
China Merchants Group	Hanwha Group	Tsuneishi Holdings Corporation	Damen Shipyards BV	
COSCO Shipping Heavy Industry Co Ltd (CHI)				

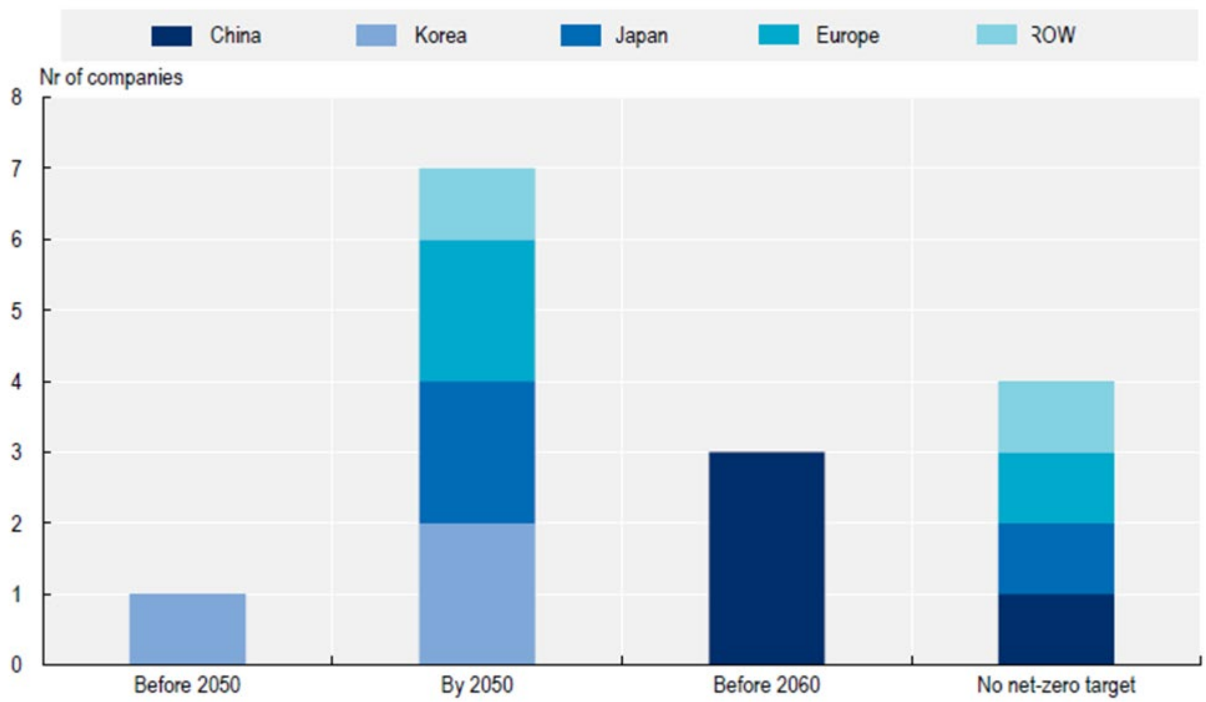

Figure 26. Zero-carbon commitments of 15 large international shipbuilders listed above the graphic . Source: [303].

China State Shipbuilding Corporation (CSSC) and DNV have established a Future Ship Joint Innovation Centre in Shanghai [304]. This center will support CSSC's goal of becoming the global leader in alternative fuel shipbuilding. CSSC also launched an initiative in 2022 to develop marine engines capable of running on methanol, ammonia, and hydrogen [304] [305]. As of the end of 2024, CSSC had achieved certification of a medium-speed methanol dual-fuel engine in the 1 MW to 2 MW engine power range [306].

Synergies and Leverage Opportunities

For purposes of this section, a program or regulation is defined as providing leverage if it directly acts to reduce emissions in California without the need for California to enact a policy or regulation. A program or regulation is defined as synergistic if it acts to reduce emissions in a manner that could be emulated in California or that leads to emissions reductions in California without regulatory action in California.

IMO / MEPC / MARPOL Annex VI

The IMO through its MEPC plays a primary role in advancing MARPOL Annex VI standards. The inclusion of GHG reduction mandates and more stringent NOx standards in MARPOL Annex VI would bring MARPOL into closer alignment with California's emissions goals. As MARPOL regulations are binding, this program provides a leverage opportunity. Action is already under way to incorporate the IMO GHG reduction strategy and targets into MARPOL. Medium term GHG-reduction measures were approved at MEPC 83; however, formal ratification of the measures were delayed at a special meeting of the MEPC in fall of 2025 [307]. Formal adoption is now being considered at MEPC 85 in late 2026. The proposed measures include several approaches to placing a price on GHG emissions. The final program design could be emulated in California and incorporated into the state's LCFS program. Also, as noted above, the U.S. and other parties have initiated an effort to make MARPOL Annex VI NOx limits more stringent [308]. If more stringent regulations are adopted, they will apply directly to ships in California waters.

Emission Control Areas

The North American West Coast is an ECA regulating both SO_x and NO_x. California can leverage the ECA limits to the extent that they are made more stringent in line with California goals. East Asia is the largest trading partner with California, however, there is currently no international ECA in the area (although China has domestic ECAs). As previously noted, Japan has been planning to apply for an ECA. This would create synergy with California by establishing similar regulations on both ends of a major trading route. Establishing an "East Asia" ECA would have even more potential synergy.

European Union

The EU emission control regimes are synergistic with California as they will provide real-world experience and data on the feasibility and cost of achieving emissions reductions on the shipping sector. Program design and lessons learned in implementing EU regulations can be applied in California. Both carbon pricing and fuel carbon intensity standards could be emulated in California. Although these are GHG regulations, they generally provide criteria emissions co-benefits. Programs and regulations could also be emulated for non-GHG emissions.

Washington State

The state of Washington plans to mirror California's ultra-low-sulfur maritime fuel regulation. This is synergistic because it brings virtually all trans-oceanic shipping to and from the West Coast under a common regulation on sulfur content in fuel.

Green Corridors and Ports

Many port decarbonization programs focus on harbor craft and land-side activities such as cargo-handling equipment, and freight transport to and from ports. These programs are important but not of direct impact on OGVs. However, as discussed above, several ports are advancing efforts to introduce LCMFs including ports in Japan, Singapore, Korea, and China comprising a major fraction of California shipping trade. These activities are synergistic with California's efforts by validating use cases, raising awareness on LCMFs, and pioneering bunkering processes and protocols that could be adopted in California. The port of Corpus Christi has established a goal and supporting strategy to become a major LCMF hub. Plans include fuel production, pipeline transport infrastructure to the port district, fuel storage, and bunkering for multiple LCMFs [309], [310].

Maritime Industry

Shipbuilders and shippers have made significant commitments to increase the number of LCMF-capable ships in service through both new-build and retrofit programs. Engine manufacturers have already begun to add LCMF-capable engines to their product lines. California can create synergy with these efforts by engaging with these stakeholder groups to ensure that non-GHG emissions are included in their programs. Building and retrofitting ships to be both ultra-low GHG and ultra-low non-GHG emissions will be lower cost than overlaying non-GHG compliance after the fact.

Benefits

The benefits of the programs described above would be the virtual elimination of GHG emissions and deep reductions in non-GHG emissions from the global international maritime shipping sector over time. Reductions in non-GHG emissions will depend upon the mix of fuels adopted in the sector. All LCMFs have little or no sulfur content and many produce lower NOx emissions than incumbent fuels. In the near term, moving the global fuel sulfur content limit from 0.50 percent to 0.10 percent would reduce SO_x emissions by roughly 80 percent (generally proportional to fuel sulfur content) and would reduce PM by 62 percent to 67 percent at 50 percent to full engine load based on measured emissions from a ship operating in the Baltic Sea [311]. As previously noted, a proposal from the IMO for more stringent NO_x limits are not expected until 2027. However, the intent of the Tier III standard is to reduce emissions by 70 percent relative to Tier II.

One way of quantifying the benefits of emissions reductions is through the use of monetized life cycle assessment. This method assigns a cost to pollutant emissions. Different monetization approaches are used including mitigation cost, damage cost, willingness to pay and other approaches. In this study, we use damage cost which represents externality costs that are reduced by adopting low-emission technologies and fuels and follows a methodology used in a recent UCI project assessing the societal costs and benefits of renewable hydrogen.[1] Because externality costs are borne by the public, mandates or fees for operators are generally required to undertake abatement measures. Damage costs can provide important guidance in assessing the cost effectiveness of policies and regulations.

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[1] The article "The Social Value of Electrolytic Hydrogen," by R. Flores et al. is scheduled for publication in *Joule* in August 2026. Prior to publication, pre-prints available upon request from J. Reed at jgreed@uci.edu .

A 2020 study looked specifically at damage costs of emissions from the global maritime shipping sector [312]. The study reviewed a large number of studies to estimate damages caused by maritime emissions of PM, SO_2 and NO_x. The present analysis uses the mean values from that study. For GHG, the EPA 2023 updated guidance of $190/metric-tonne of CO_2e updated to 2025 is used [313]. The damage cost factors used here are shown in Table 18.

Table 18. Emissions Damage Costs (Values in 2025$). Source: The authors based in references above.

Emission Type	Damage Cost (2020$/kg)
CO_{2e}	0.26
$PM_{2.5e}$	33
SO_{2e}	8.8
NO_x	5.8

For establishing the global emissions baseline, we use a 2018 inventory from [314]. Baseline fuel use is an estimated 87 billion gallons, doubling every 20 years [315]. Table 19 shows the global damage cost of international shipping based on the monetization factors above and escalating the 2018 global emissions baseline 3.5 percent per year. The table also shows the damage per gallon of marine fuel consumed.

The overall net benefit of pollution reductions is the benefit less the mitigation cost of achieving the reductions. For GHG, the mitigation cost is the increase in the cost of delivered fuel relative to the base case, the levelized cost differential of the ship propulsion system, and the difference in non-fuel operations and maintenance costs. GHG abatement costs are discussed further in the fuels chapter of this report. The average of the abatement cost estimates presented in Table 23 is $60/MTCO2e. This suggests that GHG abatement through the use of LCMFs is cost-effective as the benefits exceed the costs. NO_x abatement costs for new and retrofit vessels were assessed in a 2017 study that estimated costs ranging from $1/kg-NOx to $12/kg-NOx when updated to 2025 dollars [316]. The study concluded that the overall cumulative benefit to cost ratio for NOx mitigation was 1.75. A study specific to China

Table 19. Business-as-Usual Global International Ocean Maritime Shipping Emissions. Source: The authors based on references above.

Pollutant	2025 Annual Emissions (Tg)	Global Damage (Billion 2025$)	Normalized Damage (2025$/gallon)
CO_{2e}	1106	288	3.31
$PM_{2.5e}$	2.04	68	0.78
SO_{2e}	15.0	132	1.52
NO_x	20.9	122	1.40

assessing the benefits and costs of extending NECA zones up to 100 km showed a benefit to cost ratio of 3.9 and also found NOx abatement benefit to cost ratio to be significantly positive [317]. In addition, it should be noted that many of the LCMFs under consideration have inherently lower NOx emissions than diesel and so would potentially make NOx abatement more cost effective from a social cost perspective.

LCMFs have little or no sulfur and low PM formation. Assuming that LCMFs are adopted to achieve GHG reduction, the virtual elimination of SO_x and PM emissions is a co-benefit at no incremental cost. In the near term, SO_x and PM abatement will be achieved through the use of very-low or ultra-low marine fuels. In this case, the abatement cost is dependent upon the reductions achieved through fuel substitution and the cost differential between standard fuel (3.5 percent sulfur mass fraction as baseline) and ultra-low sulfur (0.1 percent mass fraction).

Mapping benefits to individual programs is generally difficult due to overlapping goals and incomplete spatially resolved emissions inventories. There are many initiatives ongoing to reduce GHG. Overall, the IMO GHG reduction program can be credited with worldwide GHG reduction projects. However, national and multi-national programs such as the EU GHG regime reinforce the IMO program and may accelerate action by the IMO. Fuel sulfur-content regulations are the primary driver of SOx reductions, and these regulations also lead to PM reductions. Benefits from NOx reduction are primarily a result of MARPOL Annex VI regulations, especially through NOx ECAs. However, locational emissions inventories are not readily available to allow benefits mapping to localized programs. Wang et al. did assemble a large data set of ship routes and emission factors to making it possible for them to do localized emissions modeling across the globe. However, these data sets are not available for the present study and the analytical complexity of manipulating those data exceed what is feasible for the current effort.

Task 3. Maritime Fuels and Availability

Overview

Low-Carbon Maritime Shipping Fuels

There are several fuels being explored by the shipping industry as lower-carbon substitutes for current fossil maritime fuels (HFO, MGO, MDO, and VLSFO. Six fuels have been identified as having wide adoption potential for the purpose of achieving deep decarbonization of the ocean-going maritime sector:

- Hydrogen (H_2)
- Liquified Natural Gas (LNG) -- (Methane (CH_4))
- Methanol (CH4-OH)
- Ammonia (NH_3)
- Biodiesel (C_nH_{2n+1} – $COOCH_3$)
- Renewable Diesel (C_nH_{2n+2})

Collectively, these will be referred to as low-carbon maritime fuels (LCMFs). The fuels are synthesized using electrochemical, thermochemical, or biochemical conversion pathways as seen in Figure 28.

In addition to these molecular fuels, battery electric drive in either hybrid or all-electric configurations is a maritime decarbonization option, although challenging for OGVs as a primary power source due to required battery volume. As shown in Figure 27, UC Irvine analysis shows that current generation batteries would displace more than 80 percent of cargo weight capacity for a container ship with a fuel capacity of 250 diesel gallons per twenty-foot equivalent unit (TEU). Even with improvement in battery energy density, the weight penalty will pose a barrier to adoption. However, the resurgence of interest in nuclear propulsion could lead to significant adoption of all-electric drive without the need for bulk energy storage in batteries. On-board carbon capture offers the potential for continued use of fossil fuels. This chapter focuses on the low-carbon molecular fuels listed above.

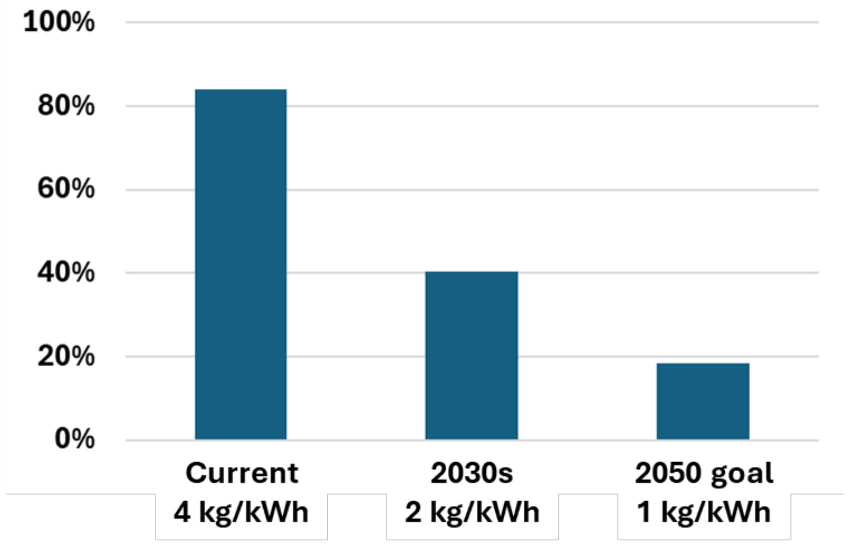


Figure 27. The percentage of cargo weight displaced for ocean-going vessels as a function of battery energy density assuming battery systems are twice as efficient as diesel and the on-board diesel storage baseline is 250 gallons per TEU. Source: The authors and colleagues at UC Irvine.

The current push by the global maritime industry to identify and deploy the most promising alternative fuels is driven by the global industry goal of achieving near-full decarbonization by 2050. As host to several of the world's highest-volume ports, California is a key stakeholder in the maritime fuel transition, but California will not drive how the global maritime fuel mix evolves and must develop its policies and regulations in the context of an uncertain mix of future fuels and propulsion system designs. To meet the CARB mandates for reduction of criteria pollutant emissions, toxic air contaminants, and greenhouse gas reductions within its jurisdiction, California policies and regulations will need to be developed based on the most likely future fuel mix scenarios. Ultimately, the global maritime sector will adopt the fuel mix that minimizes their operating cost while meeting operational requirements and environmental regulations.

Each of the LCMFs is profiled at a summary level in the paragraphs below with more detailed information on properties, emissions, environmental health and safety characteristics, supply outlook, and bunkering discussed in more detail in later sections of this chapter

Fuel Oil – Renewable Diesel ($CH3(CH2)_nCH3$)and Biodiesel ($CH3(CH2)_nCOOCH3$)

Renewable diesel and biodiesel are mildly toxic, flammable liquids with distinctive odors. Renewable diesel has properties that are virtually identical to conventional diesel and is considered a "drop-in" fuel, meaning it can be used without modification to the existing supply chain, bunkering infrastructure, engines, or aftertreatment system. On the other hand, biodiesel, is "semi-drop-in" as it has properties and chemical composition that differ slightly from diesel which may require modifications in engine operation, gaskets, and storage to accommodate its use. Use of biodiesel may also result in higher NOx emissions compared to renewable diesel if no fuel-specific engine tuning has occurred [318]. In addition, biodiesel is susceptible to degradation and microbial growth which may limit the "shelf life" of this fuel. The composition of each fuel is governed by international standards that ensure uniform properties. The international standard for renewable diesel and biodiesel used in maritime applications is ISO 8217:2024.

Renewable diesel is most commonly synthesized from fats and oils through processes similar to petroleum refining. Renewable diesel can also be produced using other biomass feedstocks through biochemical and thermochemical conversion. Renewable diesel can also be derived from electrolytic hydrogen and biogenic CO_2. Due to its low carbon footprint and low soot formation, California has required the use of renewable diesel for CHC since January 1, 2023 (2022 Amendments to the CHC Regulation in California: California Code of Regulations, Title 17, Section 93118.5) although this regulation does not apply to OGVs. Renewable diesel can also be blended with fossil derived diesel with the designation RXX, where XX indicates the percentage by volume of renewable diesel in the blend (e.g., R20 is 20 percent renewable diesel). Both biodiesel and renewable diesel are in commercial use today, although the quantity used in ships is small.

Biodiesel is a long-chain hydrocarbon composed of fatty acid methyl esters (FAME). It is very similar in structure to conventional diesel but with an ester functional group (COO-CH3) at the end of the chain. The same nomenclature that is used for renewable diesel (e.g., R20) is used for biodiesel blends with diesel but using B in place of R (e.g., B20). The presence of oxygen changes the properties slightly in comparison to diesel, but biodiesel can be used in conventional diesel engines. Although, a recent study by National Renewable Energy Laboratory (NREL) found that property differences (such as viscosity, vapor pressure, and flammability) were of enough significance that further investigation is needed to ensure fuel interchangeability at high blend fractions up to B100. For example, the study hypothesizes that fuel atomization behavior may differ significantly enough to impact fuel system performance in the absence of engine modifications. Current use of blend fractions above B20 is uncommon [319]. Ultimately the supply of fatty oils will likely limit the role of biodiesel in the global transportation system to a minor fraction, but this fuel category will be a key contributor at the front end of the transition to low-carbon shipping.

Typical molecular structures for renewable and biodiesel are shown in Figure 29. Note that, for each fuel, there are a number of different molecules present containing differing numbers of carbon atoms (the parameter “n” in the formulae $CH_3(CH_2)_nCH_3$ for renewable diesel and $CH_3(CH_2)_nCOOCH_3$ for biodiesel. As noted above, the combustion properties of renewable diesel are virtually identical to fossil diesel. Biodiesel has a significantly different viscosity and distillation curve (range of boiling points among the molecules in the fuel) than diesel [320] requiring engine tuning and other adjustments for biodiesel to function properly in conventional diesel engines.

CARB’s OGV Fuel Regulation does not permit the use of biodiesel or renewable diesel for OGVs for compliance unless a research exemption has been granted. Neither fuel is a petroleum-based fuel that meets regulatory requirements as specified in ISO 8217 (2005 and 2010 versions).

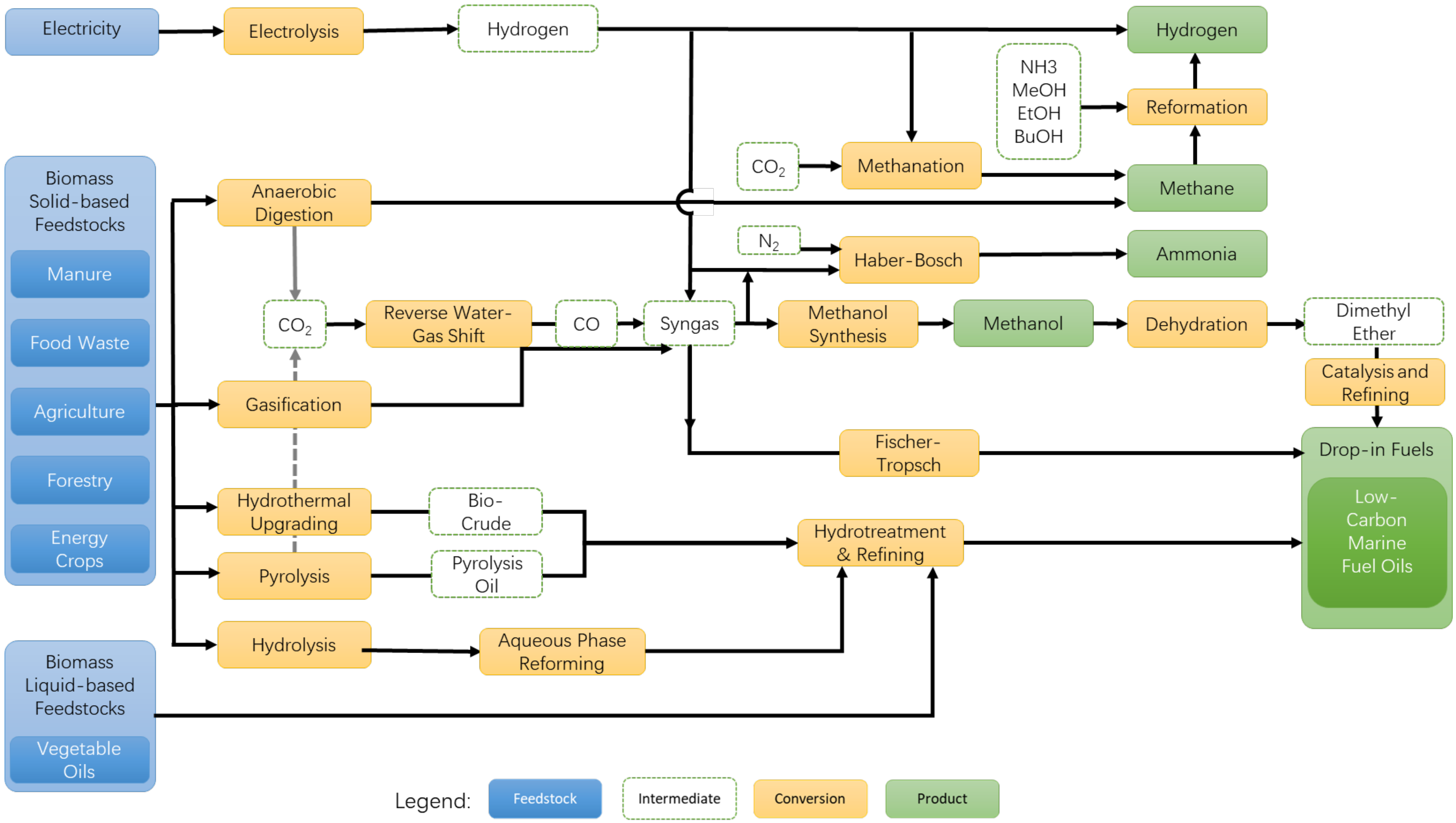
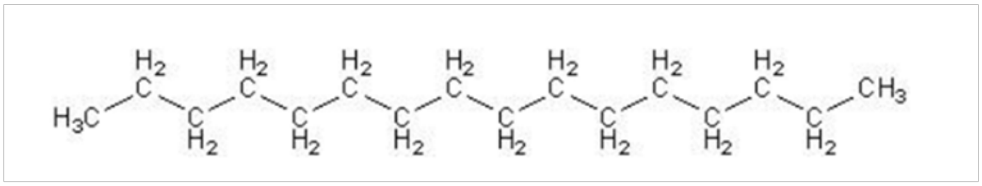


Figure 28. Potential Low-carbon Maritime Fuel Production Pathways. Source: Adapted from Reed and Forrest [321].

Typical Diesel Molecule



Typical Bio-diesel Molecule

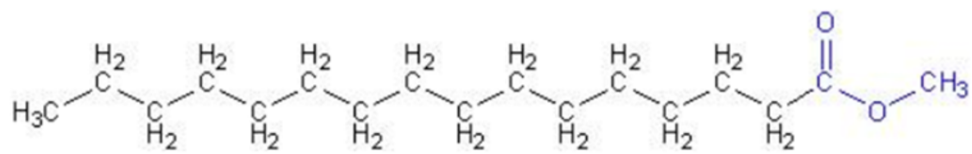


Figure 29. Typical Diesel and Biodiesel molecules (precise structure and chain length may vary). Source:[322]

LNG (Methane) – (CH_4)

Methane is a non-toxic, flammable gas with no odor (the distinctive odor of natural gas is due to the addition of mercaptan in parts per billion for safety reasons). Methane use in the maritime sector is in the form of LNG. LNG is typically more than 95 percent methane but contains some residual higher hydrocarbons like ethane, propane, and butane that remain after natural gas processing. Renewable natural gas (RNG) produced through biomass conversion or electrolysis may have a slightly different composition of non-methane constituents than pipeline gas, but if the product gas is injected into the natural gas system for transportation to an LNG facility, the blended gas will have the same composition as pipeline gas. LNG is already well established in the oceanic shipping sector. Statistics vary somewhat from source to source but, by one estimate, there were 535 LNG-powered ships in operation as of mid-2024. This includes, but is not limited to, 137 oil and chemical tankers, 93 container ships, and 53 bulk carriers [1]. About 30 percent of the global LNG tanker and floating storage unit fleet of 772 vessels operate on LNG [323]. There were 509 LNG-powered ships on order in mid-2024 including 20 cruise ships.[324]. According to SEA-LNG, LNG-powered ships (both in use and on order) comprise 4 percent of the global shipping fleet and 6 percent of global tonnage [325][326].

Due to the significant number of ships operating on LNG, bunkering infrastructure for LNG is more mature than for other emerging fuels although still far less ubiquitous than for petroleum fuel bunkering.

According to Everllence and Wärtsilä, both have developed marine engines capable of running on natural gas [327], [328]. Due to the properties of natural gas, these engines require spark ignition or dual-fuel configurations using diesel as a pilot fuel or fuel blend to achieve compression ignition.

As with other hydrocarbon fuels, combustion of LNG results in pollutant emissions. However, LNG generates significantly lower levels of sulfur and particulate emissions compared to both fossil and bio-based diesels. On-road natural gas vehicles have demonstrated the potential for ultra-low NOx emissions [329]. However, the combustion of LNG may also result in methane slip (i.e., the release of unburned methane), which reduces the GHG benefit of the fuel.

It is worthy of note that the GHG benefits of conventional LNG are modest. However, as with diesel, renewable forms of LNG can be derived by biomass conversion (generally referred to as RNG and from electrolytic hydrogen and biogenic CO_2. RNG production and fueling infrastructure are well established for land-based trucking applications.

Methanol (CH_3OH)

Methanol (also known as wood alcohol) is a toxic, flammable liquid with a distinctive odor. Methanol can be readily synthesized from various sources of hydrogen and carbon (such as methane) and oxygen extracted from the air. Methanol has a similar molecular structure to methane (CH_3OH for methanol vs CH_4 for methane).

Methanol production, transmission, and storage operations are well established for non-maritime applications. Use of methanol as a marine fuel is at the pilot and early commercial stage, with only a few bunkering operations having been completed and 60 methanol-capable ships currently in operation, although there are 340 ships on order [329].

An advantage of methanol is that it is in a liquid state at ambient conditions which facilitates convenient tank storage (compared to high pressure gas storage or cryogenic storage for hydrogen or LNG).

However, methanol has been found to be incompatible with several seal and gasket materials common in diesel engines [330]. Hence, gaskets and other soft materials (e.g., fuel lines or O-rings) may need to be evaluated for possible replacement. Methanol is toxic to aquatic life and humans. Inhalation of vapors, ingestion, and/or contact of the liquid with skin can cause blindness and death. However, Environmental Health and Safety (EHS) standards and protocols for handling and use of methanol are well established for non-transportation applications and several organizations are working on adapting standards and protocols for methanol use as a maritime fuel.

Hydrogen (H_2)

Hydrogen is a non-toxic, highly flammable gas with no odor. Hydrogen is the lightest molecule and has the highest energy density on a mass basis among alternative fuels. However, hydrogen has a lower volumetric energy density under standard conditions than the other alternative fuels. For this reason, on-board storage requires hydrogen to be in a liquid state which, at ambient pressure, requires cooling to -223 ^{o}C.

Hydrogen is widely used in refining and ammonia fertilizer production, so distribution and storage infrastructure are well established in some regions. These supply chains transport and store hydrogen in the compressed gas phase. Hydrogen use as a transportation fuel is in the early commercial stage for on-road vehicles with a growing focus on trucks and buses, but deployment in the marine sector is at the prototype and early demonstration phase. The hydrogen supply chain in California has shifted from compressed gas in the early deployment stage to predominantly cryo-liquid in the current market. There is no hydrogen bunkering infrastructure currently available in California, but the development of hydrogen fueling infrastructure for vehicle applications is ongoing and additional infrastructure, including at ports, is planned for the California DOE Hydrogen Hub.

Like other fuels, hydrogen fuel energy can be converted to shaft power through combustion in reciprocating engines and turbines. However, hydrogen has the advantage that it can also power fuel cells which produce no tailpipe emissions. In either case, there are no CO2, CO, sulfur, or particulate emissions produced directly by use of hydrogen. Fuel cells produce no NOx, while hydrogen combustion requires NOx mitigation via fuel-air management and aftertreatment, using techniques and technologies similar to those used in natural gas combustion systems. Hydrogen-methane blends are being explored by several (OEMs [331][332]. The use of hydrogen-methane blends may serve as a bridge to an all-hydrogen supply chain allowing hydrogen to take advantage of existing natural gas and LNG infrastructure during early market development.

Methanol and ammonia can be used as feedstocks to produce hydrogen through reformation. This opens the possibility of hybrid supply chains in which methanol or ammonia is used as the energy carrier for transport and storage, while hydrogen is used as the propulsion fuel. For example, systems are being developed by RIX Industries and GenCell [333][334]. The technoeconomic and emissions optimal approach is under active investigation and development and may differ between harbor craft, regional shipping, and transoceanic shipping vessels.

Ammonia (NH_3)

Ammonia is a toxic, flammable gas with a boiling point near standard temperature and distinctive odor. Ammonia is transported and stored in a liquid state by blending with water or mild pressurization (order of 30 psi). Ammonia is an inorganic molecule that differs from other LCMFs in that nitrogen is contained in the fuel (fuel-bound nitrogen). Ammonia production, transmission, and storage operations are well established for applications such as fertilizer production (dominant use) and use as a refrigerant. The use of ammonia as a combustion fuel for transportation or power generation is at the exploration and piloting stage. The deployment status is similar to but slightly behind methanol with few ammonia-capable ships in operation and only pilot bunkering capability.

The presence of fuel-bound nitrogen and the potential for ammonia in combustion exhaust (known as "fuel slip") makes emissions control more challenging than for other fuels. While EHS standards and protocols for transport, storage, and handling are well established, new protocols will need to be established for the use of ammonia in transportation applications where incident and exposure risk differ from established uses. In addition, California has additional safety guidelines that must be followed regarding storage and use of ammonia [40], including specialized response requirements when more than 450 lbs. are stored in one control zone.

Other Potential Fuels

The present study focuses on the fuels that are projected represent a significant share of future fuel use for OGVs. However, other candidates are being pursued including ethanol, propane, and dimethyl ether. These fuels are not treated further in this report, but it is noted that, like other LCMFs, they are sulfur free and have low propensity for PM formation and may require after-treatment to address NOx. In addition, they can be produced through both thermochemical and electrochemical processes (see Figure 28).

Low-carbon Fuel Properties and Characteristics

The fossil versions of the LCMFs discussed in this chapter are widely used either in the transportation sector or other industrial uses and their properties and characteristics are well understood. The low-carbon versions have properties and characteristics that are identical to or similar to their fossil variants. One slight exception is biodiesel which has a chemical composition slightly different than diesel and so exhibits slightly different combustion, EHS and emissions properties and characteristics.

General Properties

The general properties of the LCMFs are shown in Table 20 with discussion of each fuel provided in the sections below. Note that methanol characteristics are similar to other alcohols such as ethanol or butanol.

Figure 30 shows the relative energy densities (both volumetric and gravimetric) of the LCMFs. The circles represent energy densities for fuel only, while the square symbols show the energy density including the penalty for compression or liquefaction if required to maintain the fuel in liquid state. As seen in the figure, fuel oils have a remarkably high energy density from both a volumetric and gravimetric view. Essentially, all alternative fuel options are less energy dense on both a mass and volume basis which means they require more space and weigh more than diesel. Gaseous fuels like natural gas and hydrogen can be liquified to gain substantial improvements in volumetric energy density but this comes at a cost. Even in liquefied form, these fuels are less energy dense than hydrocarbon fuels, alcohols, or ammonia. The comparatively low energy density of batteries to molecular fuels is the reason that, while hybridization and part-time all-electric drive are likely to see significant adoption for oceanic shipping, all-electric drive is not feasible for transoceanic shipping at current and projected battery energy density.

Table 20. General Properties of LCMFs. Source: American Bureau of Shipping [257] and UCI Commercial Harbor Craft Study (publication pending).

Property	Hydrogen	Methane	Ammonia	Methanol	Renewable Diesel	Bio-diesel
Formula	H2	CH4	NH3	CH3-OH	$CH_3(CH_2)_nC$	$CH_3(CH_2)_nCO$
Molecular Weight (g/g-mol)	2	16	17	32	198	242
Liquid Density (kg/m^3)	71	428	682	790	790	880
Lower Heating Value (MJ/kg)	120	48.6	18.8	19.9	39	37.5
Volumetric Energy Density	8.5	20.6	12.8	15.7	34	32
Boiling Point (Deg-C)	-253	-163	-33	65	360	360
Flammability Range (Vol.)	4 - 75	5 - 15	15 - 28	6 - 36	1 - 8	1 - 8
Adiabatic Flame Temp. (K)	2320	2223	2073	2143	2366	2366
Min. Autoignition Temp. (K)	844	903	924	738	483	483

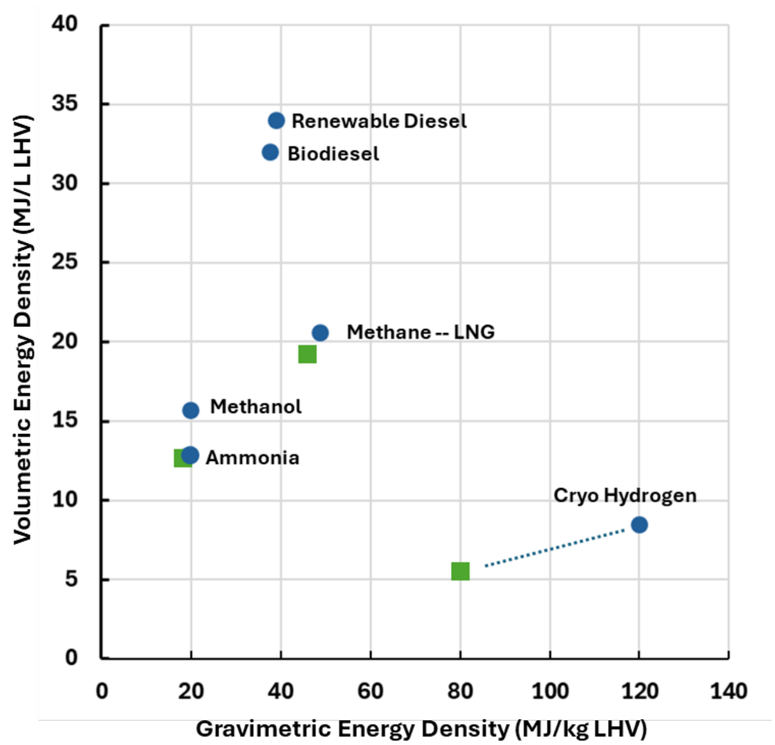


Figure 30. Energy Densities for various energy carriers based on values in Table 20. Squares represented values adjusted for liquefaction or compression to achieve liquid state.

Emissions Factors

The carbon intensities of the LCMFs depend on the specific feedstock and conversion processes used to synthesize the fuels. All fuels can achieve ultra-low emissions below 10 g/MJ on a well-to-wake basis[2] (90 percent below diesel which has a carbon intensity of roughly 100 g/MJ). Some production pathways can achieve negative emissions (well-to-gate basis) if credit is given for avoided methane emissions, or carbon removal through solid byproducts such as biochar. The well-to-tank emission factor achieved in maritime deployment depends on the conversion technology and fuel pathway used. The fuels and propulsion systems ultimately adopted will be determined based on minimizing total cost of operation within carbon emissions constraints. Total cost of operations and carbon abatement cost are discussed in a later section of this report.

[2] This method does not include upstream emissions related to material extraction or manufacturing but include emissions from energy inputs and direct emissions from fuel production and transport.

The emissions of non-GHG pollutants for each fuel depend upon the propulsion technology (type of engine or other primary propulsion system such as fuel cell or electric motor), and the pollution control equipment employed. All fuels must meet IMO standards but differ in the equipment needed to meet the standard as discussed in Task 1. Table 21 below presents emissions factors reported in Carr et al. [65] for SOx and PM2.5. All LCMFs produce no or negligible SOx when combusted. One characteristic of the lighter low-carbon fuels (those other than fuel oils) is that they do not form appreciable soot, even when burned in a non-premixed manner (like diesel engines) which means such engines can potentially meet soot regulations without a diesel particulate filter [335]. Fuel slip (unprocessed fuel in the exhaust gas) can contribute to the emissions profiles. This is of the greatest consequence for ammonia (secondary particulate and N_2O formation), and methane (high GHG impact).

Table 21. Emission Factors for LCMFs. Source: Carr et al. [65] Tables 5, 9, 11 and 12. NC = Negligible Concentration.

	Stack (TtW) Emission Factor (kg/GJ)	
Fuel	SOx	$PM_{2.5}$
Hydrogen	NC	NC
Methane	NC	0.01
Methanol	NC	NC
Ammonia	NC	NC*
Renewable Diesel	NC	~ 0.02
Biodiesel (FAME)	NC	~ 0.02

* Not reported in Carr et al. but ammonia has negligible direct PM emissions per source referenced in Carr et al. Ammonia slip can lead to significant secondary PM.

explosion characteristics, corrosivity, and exposure effects. Each of the fuels has existing EHS standards in place for use in maritime and/or other industrial applications that will be employed in the expanding transport, storage, and bunkering operations in the maritime sector.

Table 22. Environmental, Health, and Safety Properties of LCMFs. Source: Reed and Forrest [321].

		Hydrogen	Methane	Methanol	Ammonia	Fuel Oil
Safety and Health	**Fire**	High flammability, potential flame jetting, difficult to suppress/fight	High flammability, difficult to suppress/fight.	High flammability, water jets may not be sufficient	Narrow flammability range under high heat	High flammability, difficult to suppress/fight.
	Explosion	High explosion energy	Explosive under some circumstances	Vapor can form explosive mixture	Generally non-explosive but can explode if pressurized	Not classified as an explosion risk
	Leak Propensity	Small molecule – difficult to seal Seal material compatibility issues	Prone to leak but manageable	Not difficult to contain	Not difficult to contain	Not difficult to contain; corrosion risk higher than diesel
	Detection	Odorless and non-visible flame but sensors available to detect	Odorized, colorless vapor, sensors available to detect	Significant odor and leaks visible	Strong odor, colorless vapor, sensors available to detect	Leaks are visible and produce odor
	Temperature and Pressure	Transported and stored at high pressure; may be cryo liquid	Transported and stored at mid to high pressure; may be cryo liquid	Transported and stored at room temperature under low pressure	Transported and stored at room temperature under low pressure	Transported and stored at room temperature under low pressure
	Reactivity	Embrittlement and corrosion risk under some conditions	Corrosion risk, embrittlement risk at high hydrogen fractions	Reactive with oxidants	Acids, hypochlorites	Not classified as reactive but reacts with strong oxidants + corrosive
	Toxicity	Non-toxic	Non-toxic	Toxic if ingested; can cause blindness and death	Toxic	Toxic if ingested or aspirated
	Asphyxiation	In closed areas	In closed areas	In closed areas	In closed areas, 2500 to 4500 ppm fatal in 30 minutes	Low likelihood of exposure to concentrated vapor
	Long-term Exposure	Not an issue and highly unlikely to occur	Not an issue and highly unlikely to occur	Organ toxicity	Not an issue for long term exposure under 100 ppm	No long-term exposure risks/hazards reported
Environment	**Water and Land**	Will dissipate as gas if spilled	Will dissipate as gas if spilled	Highly biodegradable; no bio-accumulation; toxic to some fish	Ammonia, products like fertilizer may contaminate groundwater	Water and soil contaminant
	GHG and Pollutant Emissions	See Tables above				

Maritime Fuel Demand and Fuel Mix Projections

Current Global Fuel Demand for Oceanic Shipping

As seen in Figure 31 the demand for fuel in the global maritime shipping sector is currently 213 million heavy fuel oil equivalent (HFOe) metric tonnes (87 billion diesel gallons equivalent) annually with 95 percent of fuel consumed in the form of fuel oil and only 5 percent of current consumption served by alternative fuels [336]. Among alternative fuels (5 percent of the total), 96 percent is LNG, with biofuels, ethane, butane, methanol, and ethanol comprising the remaining 4 percent. Demand is expected to be relatively flat according to ABS (see Figure 32).

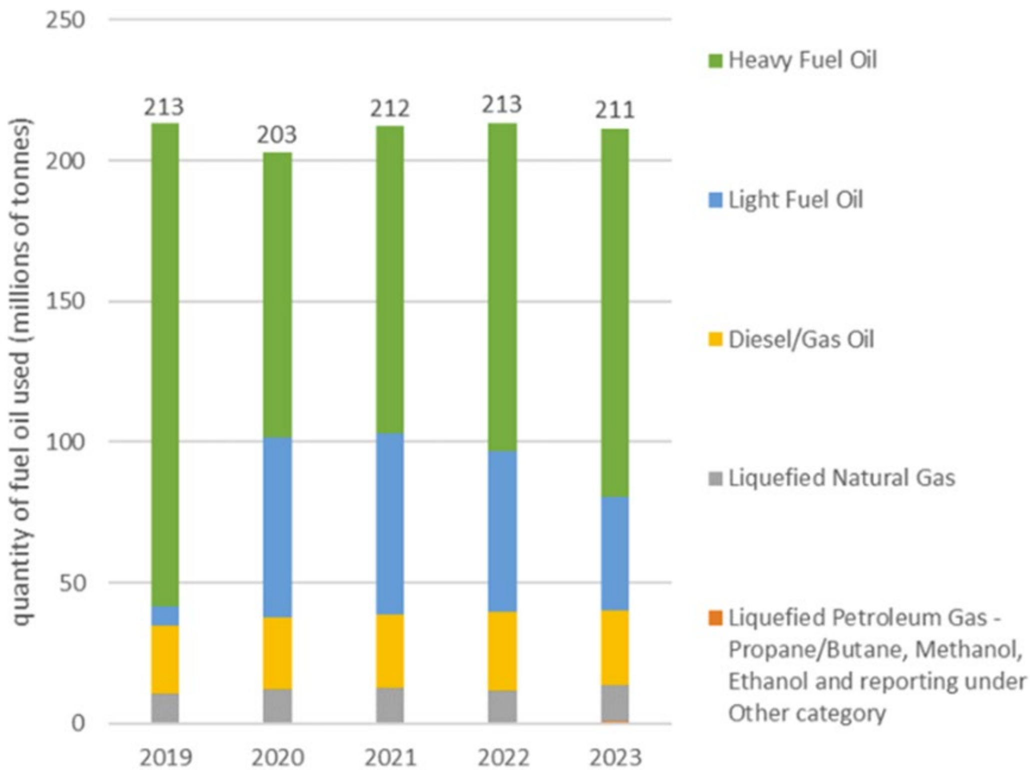


Figure 31. Marine Fuel Demand and Mix, Source: [337]

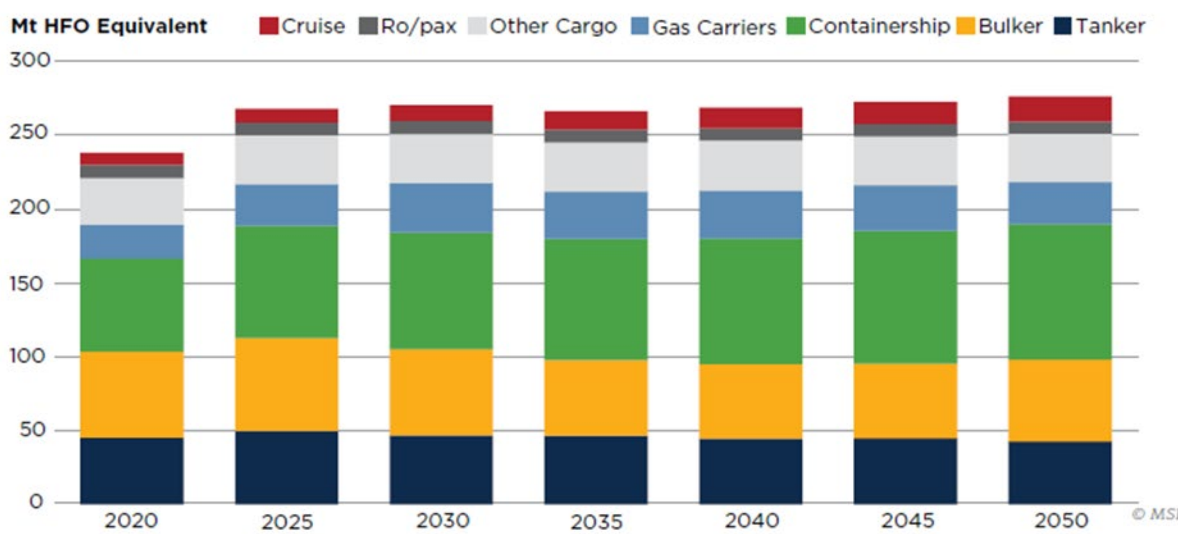


Figure 32. Global Martime Fuel Consumption from 2020 through 2050 by OGV type. Source: ABS [257].

Projections of Demand and Fuel Mix for Low-carbon Maritime Shipping

Several recent studies have examined the projected share of low-carbon fuels in the future global maritime industry. The studies show that there is currently no consensus on what fuels will be dominant beyond 2040 [257][264][65] [267] [338]. The candidate fuels can be characterized in two groups. The first group is gaseous and short chain liquids (light liquids), and the other is longer-chain hydrocarbons with diesel-like properties (diesel substitutes). In general, the diesel substitutes have the highest volumetric energy density and require the fewest modifications to existing ships and require the least investment in new fuel transport and storage infrastructure.

Ultimately, the maritime industry will adopt the fuel(s) that offer the lowest cost of ownership while meeting environmental mandates. However, the future costs of the alternative fuels under consideration, associated infrastructure costs, and on-board system costs are highly uncertain making prediction of ultimate shares difficult. DNV surveyed several studies and found scenarios that were dominated by diesel substitutes while others were dominated by lighter fuels derived from hydrogen or methane [267]. Among the studies reviewed by DNV, biodiesel and ammonia were projected to be the most common maritime fuels in 2050. On the other hand, a recent study by ABS projects methanol as the fuel with the highest share of demand in 2050 as seen in Figure 33 [257]. Currently, methanol shows the largest population of alternative fuel-capable vessels on the water, and on order, followed by ammonia as seen in Figure 34.

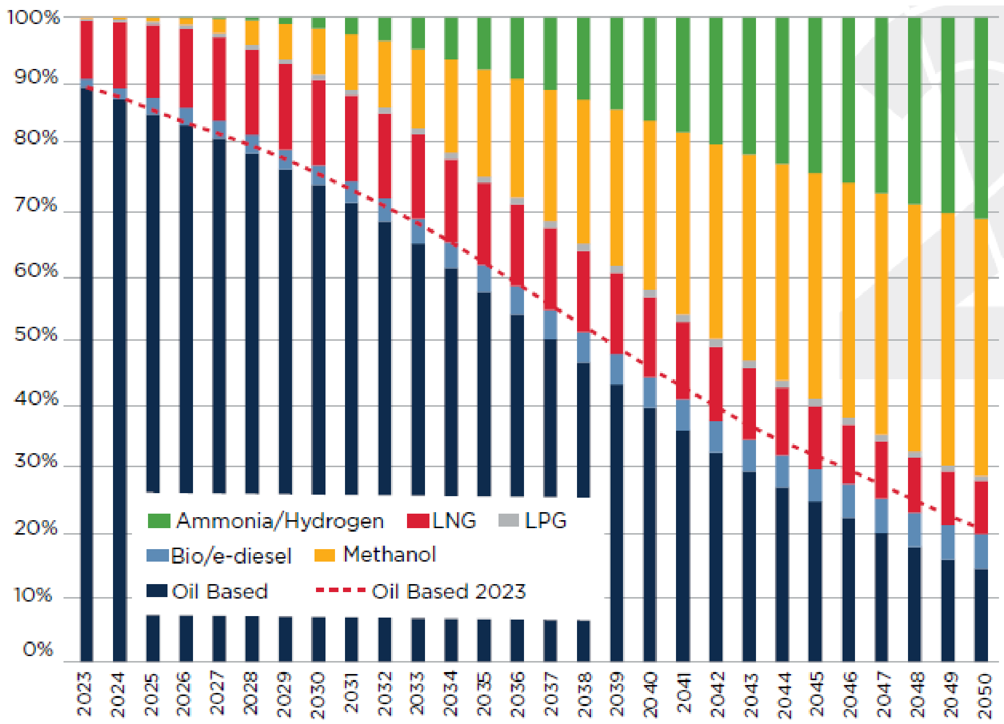


Figure 33. ABS Fuel Shares Projection through 2050 (HFO Equivalent). Source: ABS 2024 [257].

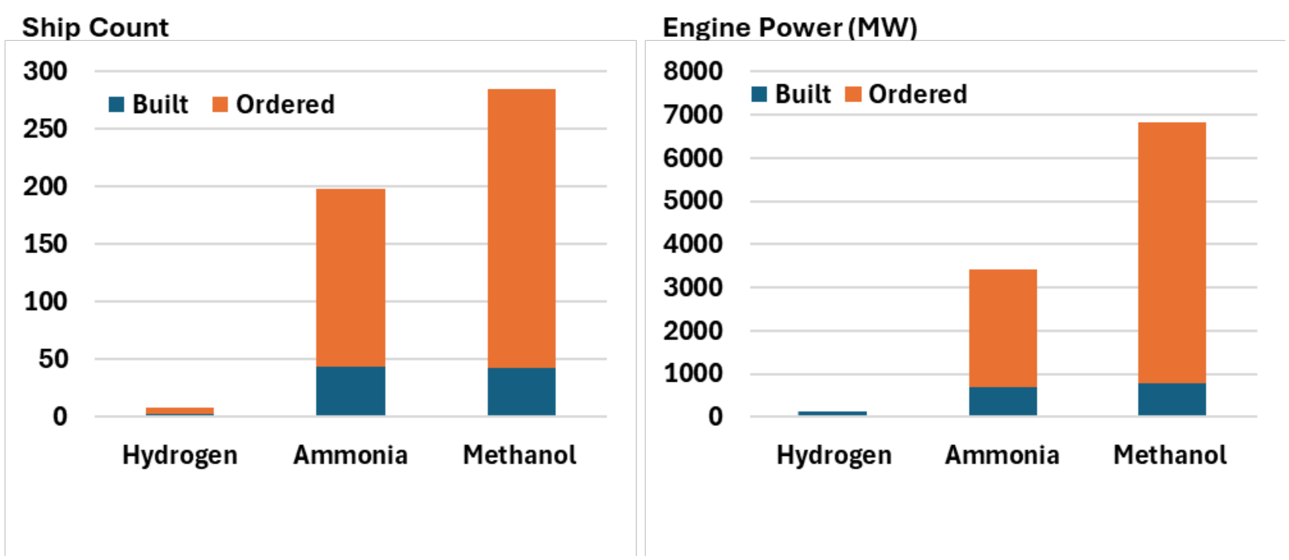


Figure 34. Built and Ordered Alternative Fuel Vessels as of 2023. Source: Carr et al. 2024 [65].

Total Cost of Ownership and Carbon Abatement Cost Projections

The studies by ABS, DNV, Lloyd's, Carr et al., and NREL [65][257][267][264][338] project future fuel costs and/or TCO, and carbon intensity. The unit cost of reducing carbon emissions expressed as $/MTCO$_{2e}$, referred to as carbon abatement cost, is the increase in TCO relative to the base case (conventional bunker fuel) per unit of fuel consumed divided by the emission reduction for the alternative fuel and propulsion system. Table 23 shows the results for 2050 TCO and carbon abatement cost using the carbon intensity ranges from the cited studies (Carr et al. [65] primary source). Figure 35 shows the carbon abatement cost ranges from Table 23.

Ship owners will generally be motivated by TCO. However, if there is a binding carbon cap or carbon fee on the maritime sector, carbon abatement cost will be the driving metric. Although the studies reflect a significant range in cost projections, they are consistent on relative costs. In general, electro fuels other than hydrogen show the highest abatement cost, while biofuels tend to have the lowest. Overall, there is no clear "winner," so emissions regulation development needs to be flexible and adaptable to various potential fuels.

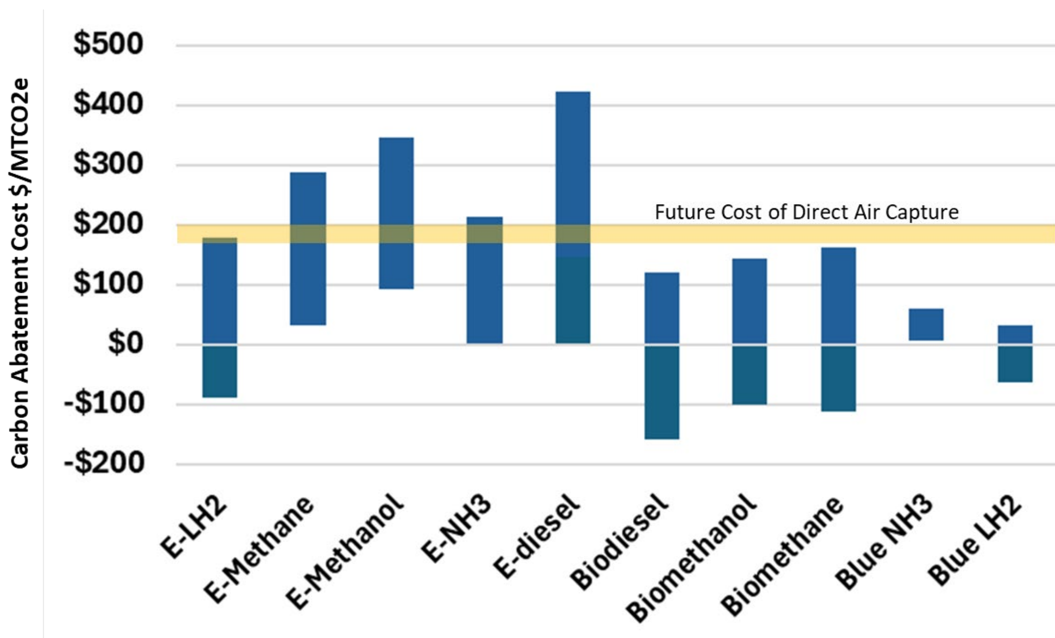


Figure 35. Graphical Represenation of Abatement Costs from Table 23 with Overlay of Projected Abatement Cost Using Direct Air Capture.

Table 23. Projected Fuel Cost and Carbon Abatement Cost for LCMFs for a Range of Production Pathways. Source: UCI from studies cited above.

	\$/GJ Low	\$/GJ High	\$/MTCO2e Low	\$/MTCO2e High
E-LH_2	22.9	32.0	-88.1	90.6
E-Methane	34.0	47.5	32.7	286.5
E-Methanol	40.0	55.9	92.9	345.4
E-NH_3	31.3	43.8	0.5	214.0
E-diesel	44.7	62.5	145.1	421.9
Biodiesel	14.2	19.9	-160.0	-39.1
Biomethanol	19.5	27.3	-100.1	42.9
Biomethane	19.5	27.3	-112.7	48.3
Blue NH_3	24.0	33.5	6.8	60.5
Blue LH_2	18.4	25.8	-64.2	-33.5

Conclusions on Future Alternative Fuel Mix

The future mix of low-carbon maritime fuels is uncertain, but the global shipping industry is focusing on a handful of options. Among fuels that are not drop-in replacements for diesel, LNG has seen the greatest deployment, although low-carbon LNG is not currently in significant use. Among emerging renewable and very-low-carbon fuels, methanol is currently leading in alternative-fuel-ready ships and orders and related infrastructure.

Considering projections from different sources, it appears likely that all of the LCMFs discussed above will see significant global deployment. With the exception of electrolytic hydrogen which would require a “built from scratch” supply and bunkering chain, the carbon abatement costs of biofuels are forecast to be lower than those of e-fuels. This suggests that, if adequate feedstock is available to meet demand, biofuels (diesel replacements, bio-methanol and bio-ammonia) will be the most widely used fuels for OGVs in the future with significant adoption beginning in the early 2030's to meet IMO emissions standards and achieving high penetration by 2050 to meet more stringent standards as seen in Figure 31. Marine Fuel Demand and Mix, Source: [337]. LNG will also achieve a significant share of fuel use for some shipping applications.

Ability to Meet Demand for Fuel and Ships

Low-Carbon Maritime Fuel Supply

Figure 36 shows the global supply of the fossil versions of the primary alternative fuels under consideration for oceanic shipping. Production capacity for the low-carbon variants is currently minimal, but the scale of the existing production, storage, and distribution systems is indicative of the potential impact of maritime adoption on the global market. As seen in the figure, maritime adoption of hydrogen, methanol, or ammonia would require a capacity comparable to, or greater than, the existing global supply. Figure 37 shows the active and announced capacity additions for LCMFs through 2030 relative to the projected demand for low-carbon maritime fuel in 2030.

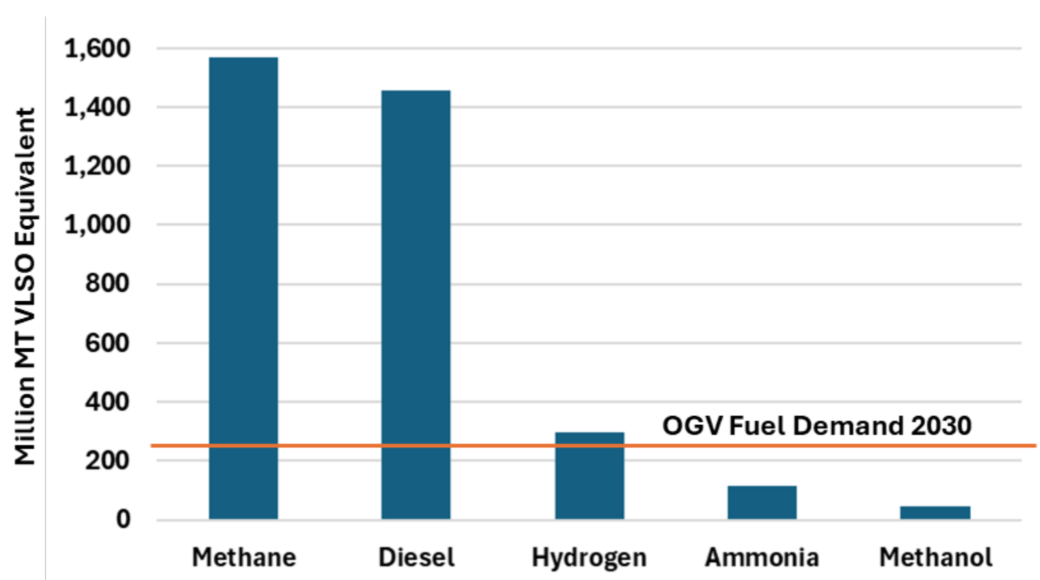


Figure 36. Current Global Production of Candidate Conventional form of Candidate LCMFs.

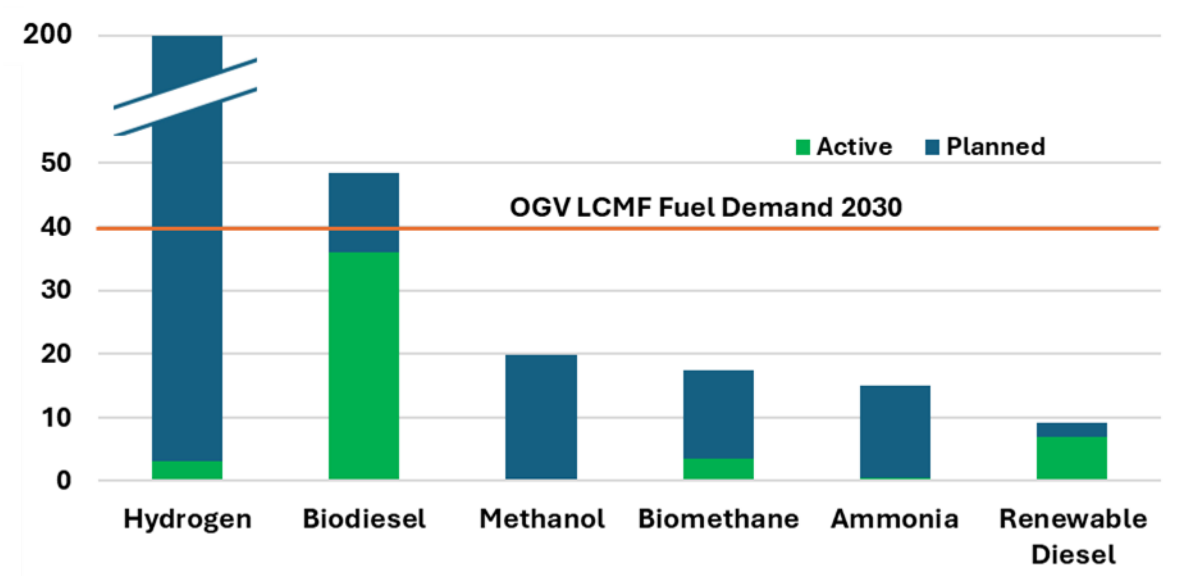


Figure 37. Existing and Announced Production Capacity for LCMFs. Sources: Hydrogen [339], *Biodiesel, Renewable Diesel, Methanol, and Ammonia* [340], *Biomethane* [341].

The quantities shown in Figure 37 for hydrogen, biodiesel, renewable diesel, and biomethane are for all applications, not only the maritime shipping sector. Only hydrogen shows enough planned capacity to meet potential demand. That said, hydrogen adoption in the shipping sector is not expected to be significant until at least the mid-2030s. Biofuels, including biomethane, are likely to see earlier adoption through 2030 or beyond, and currently dominate alternative fuel use for maritime shipping.

The planned capacity shown in Figure 37 for methanol and ammonia is specific to shipping. These planned capacity for ammonia and methanol are significant as a fraction of total LCMF demand. However, the Ammonia Energy Association (IMO Future Fuels website referencing Ammonia Energy Association analysis) finds that planned supply expansion covers only half of their projected demand for low-carbon ammonia in the shipping sector in 2030. It is also important to note that only a modest fraction of announced alternative fuels projects actually reach a positive final investment decision (FID), as discussed in the IEA Global Hydrogen Outlook 2024 [339].

The extent to which supply capacity may constrain the pace of adoption of LCMFs is uncertain, but there are a few examples of production capacity for new fuel classes scaling rapidly. Figure

38 shows the growth in global capacity for LNG liquefaction and ethanol production capacity, and U.S. shale gas production during phases of rapid growth. These fuels illustrate the real-world supply capacity growth achieved when market and/or policy conditions create a strong incentive for supply of a new class of fuel. The feasibility of meeting growing demand can be considered both from the perspective of year-over-year rate of market growth, and from the perspective of absolute growth in supply.

Figure 39 shows the projected growth in global demand for LCMFs, assuming a ramp up to 85 percent of total supply as assumed in the ABS study [257]. The peak growth rate occurs around 2030 and reaches 25 percent year-over-year. Absolute annual demand growth peaks at 12.5 million metric tonnes of diesel fuel equivalent from 2030 to 2035.

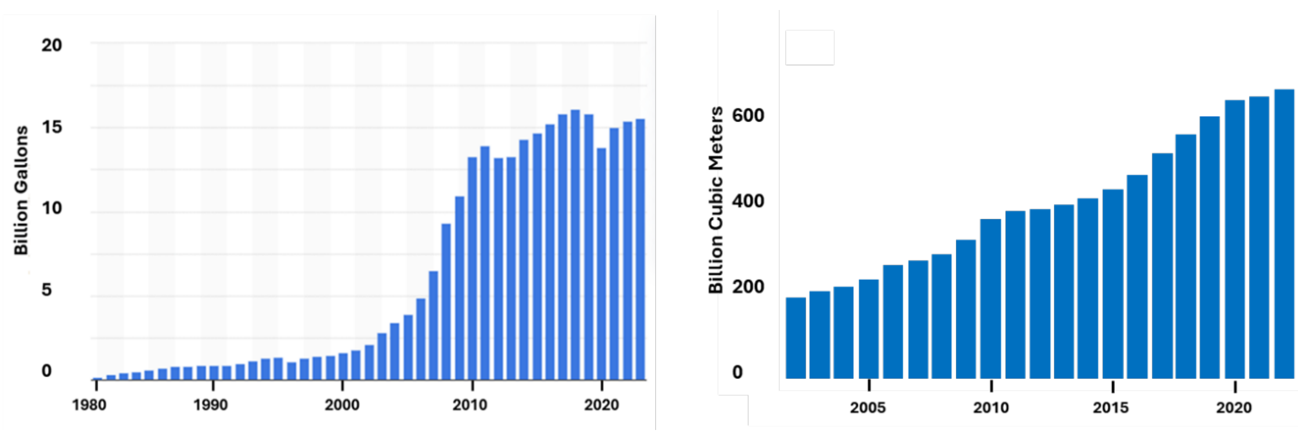


Figure 38. Historical Supply Expansion for Ethanol (left) and LNG (right). Sources: Statista for ethanol and IEA for LNG.

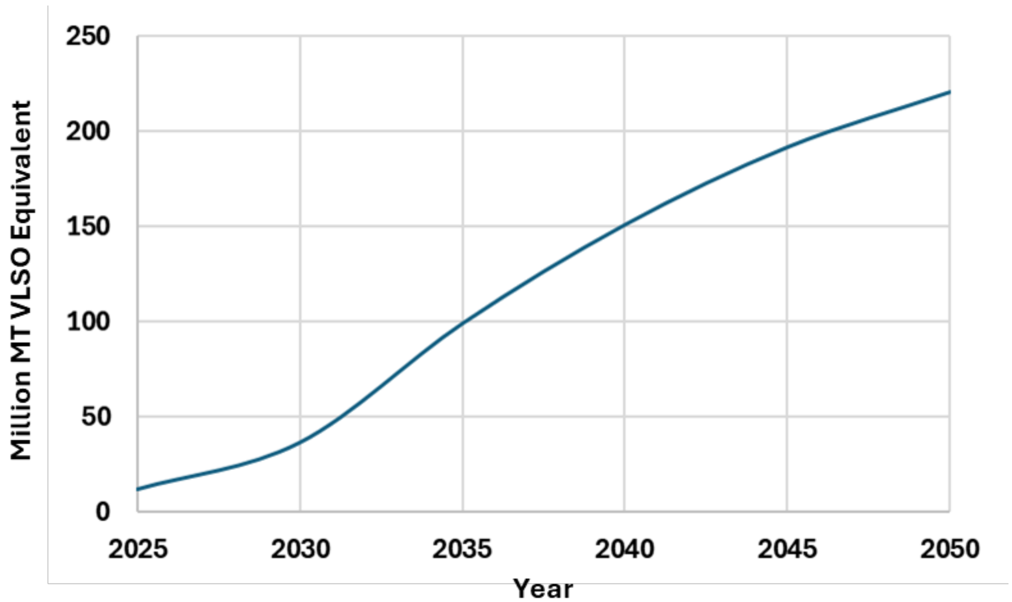


Figure 39. Aggregate Demand Growth Projection for LCMFs. Source: UCI Analysis from Multiple Sources.

Table 24. Maximum Historical Capacity Growth for LNG Liquefaction and Ethanol Production in Comparison to Projected Need for Supply Expansion for LCMFs.

Fuel	Peak Annual Growth
LCMFs Demand	12.5 MMT VLSO-e/yr
LNG Export Capacity	42 MMT VLSO-e/yr
Ethanol Production Capacity	5.8 MMT VLSO-e/yr

Low-Carbon Fuel Capable Ships

Fuel supply capacity is one constraint on expansion of LCMF use. Shipbuilding and ship retrofit capacity may also constrain growth in LCMF use. Carr et al. examined this issue and project that added shipbuilding and retrofit capacity will be needed to meet global decarbonization goals, as illustrated in Figure 13. A potential shortage of shipyard capacity suggests that global decarbonization strategies must include consideration of shipyard capacity, and policy frameworks may need to provide government support to ensure adequate capacity.

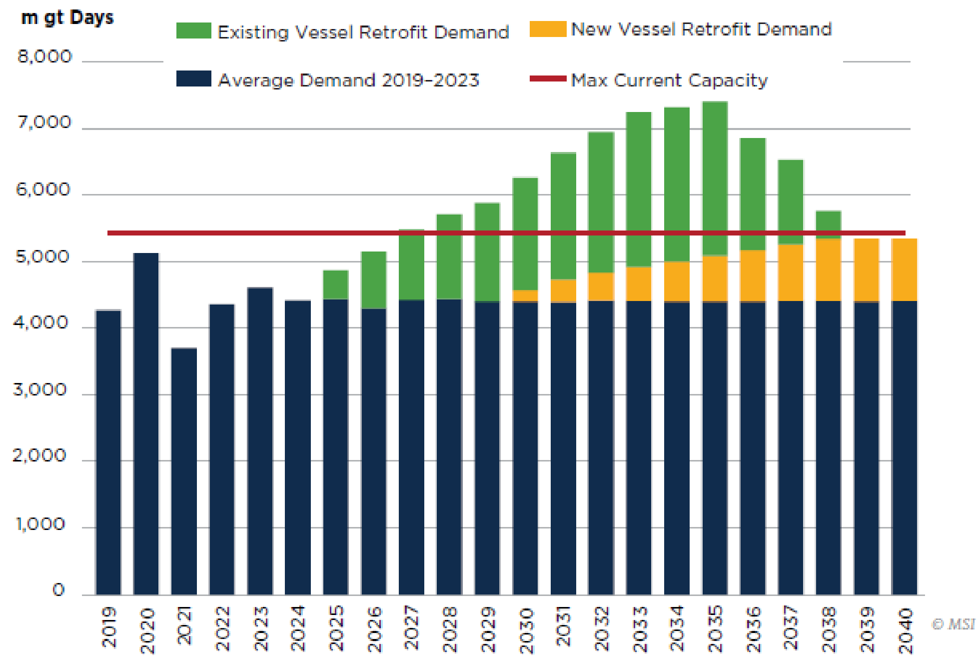


Figure 40. Shipbuilding Demand versus Capacity. Source: Carr et al. [65].

Bunkering Requirements and Deployment Status

DNV's assessment of the bunkering requirements and status for the primary alternative fuel groups is shown in Table 25. As discussed below, fuel oils and methane are the closest to commercial readiness for maritime fueling operations, methanol and ammonia have existing distribution and storage infrastructure serving ports but limited bunkering capability, and hydrogen is the least mature with respect to maritime applications. The status and outlook for distribution and storage (D&S) infrastructure and bunkering capabilities are discussed below for each fuel.

Table 25. Status of Distribution, Storage and Bunkering Capabilities for Low-carbon Maritime Fuels. Green represents greatest maturity, red least, and pink intermediate. Adapted from DNV 2024 [267].

Fuel	Distribution and Storage Infrastructure	Bunkering
Fuel oils (e-diesel, biodiesel)	Green - Can use existing distribution and storage facilities for distillate fuel	Green - Can use existing bunkering infrastructure for distillate fuel
Methane (e-methane, biomethane)	Green - Can use existing (and still developing) distribution and storage facilities for LNG	Green - Can use existing (and still developing) bunkering infrastructure for LNG
Hydrogen (e-hydrogen, blue hydrogen)	Red - Distribution and storage infrastructure is very limited (associated with refining and chemicals manufacturing) Numerous international plans for H2 infrastructure build-out in the 2030s	Red - No existing bunkering infrastructure Local bunkering operations have been demonstrated
Methanol (e-methanol, bio-methanol)	Green - Can build on existing distribution and storage facilities from the global network of terminals, used for global methanol trading/transport	Pink - Partially developed bunkering infrastructure at 90 ports worldwide Demonstration of bunkering operations has been successful, and ship-to-ship bunkering proven
Ammonia (e-ammonia, blue ammonia)	Green - Can build on existing distribution and storage facilities from the global network of terminals, used for global ammonia trading/transport	Red - No existing bunkering infrastructure Local bunkering operations have been demonstrated

Fuel Oils

Fuel oils can use existing distribution and bunkering infrastructure. For fuel variants that differ chemically from fuel oils currently in use, protocols for segregating alternative fuels during transport and storage need to be established. Pipelines serving more than one fuel type would need to run on a batch schedule and storage facilities would need to be dedicated to the alternative fuel. Biodiesel and renewable diesel for maritime applications are already in limited use and bunkering operations have been established. The ability to use existing infrastructure and bunkering operations enhances both the economics and ease of adoption for drop-in fuel oils.

Methane - LNG

Infrastructure to deliver methane to ports is in place worldwide and facilities to compress or liquify, and store methane are relatively widespread for land-based applications and at ports where LNG import-export operations are in place. To meet the on-board fuel storage volumetric energy density requirements, liquefaction and on-board cryogenic storage are required for maritime operations. Bunkering operations have been established in numerous ports worldwide. Figure 41 shows the facilities in the U.S. with LNG bunkering infrastructure. In California, the Ports of Los Angeles and Long Beach have LNG bunkering capability, and a green-LNG facility (LNG from biomass or from renewable electricity and biogenic or atmospheric CO_2) is under development for planned operation in 2030. The existing operation, with 540,000 gallons of capacity, is the first LNG bunkering operation on the West Coast serving container ships [342].

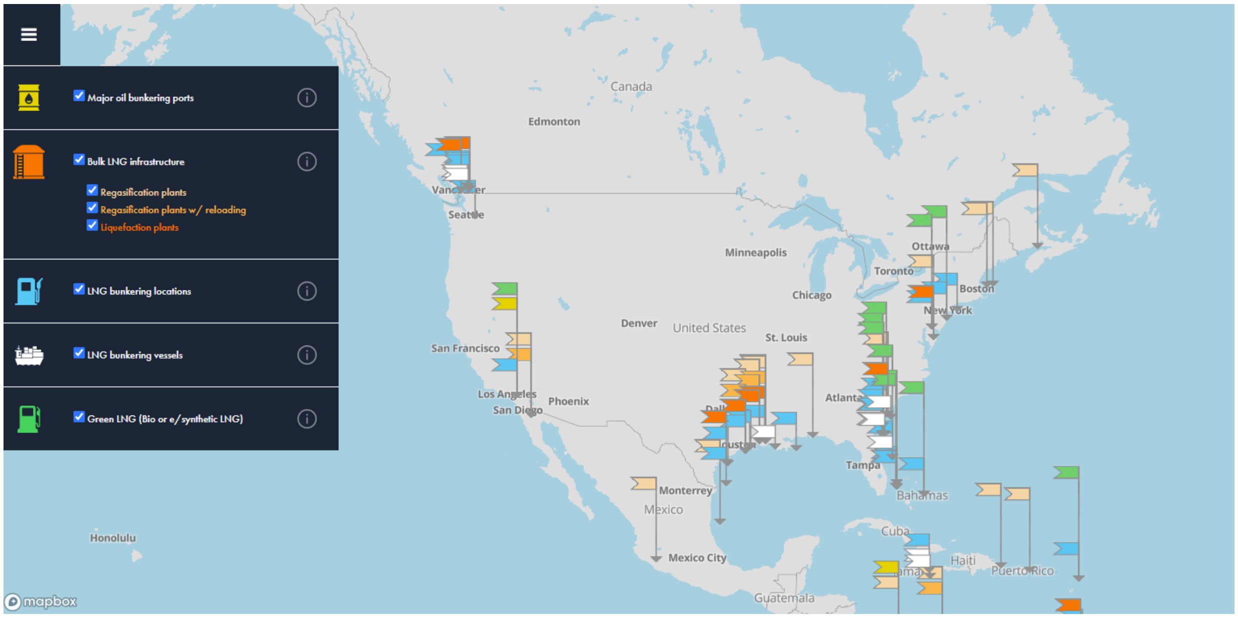


Figure 41. Global LNG Bunkering Infrastructure. Source: [343] IMO

Hydrogen

Hydrogen distribution and bunkering requirements are functionally similar to methane, although hydrogen imposes additional safety requirements on operations and equipment / facility design. Hydrogen bunkering has been demonstrated on a very limited basis for smaller ships such as the Sea Change hydrogen ferry operating on the San Francisco Bay. However, the global interest in developing hydrogen clusters and hydrogen hubs is accelerating the planning and demonstration of hydrogen use at ports, including use as a maritime fuel. According to the IEA Hydrogen Infrastructure Database,[344] there are 22 hydrogen infrastructure projects at the concept or feasibility stage (not including those focused on hydrogen derivatives). Only two projects, both at Kobe Island Airport in Japan, have reached the demonstration phase: a liquid-hydrogen carrier dehydrogenation facility and a liquid hydrogen regasification facility.

In California, the Advanced Renewable and Clean Hydrogen Energy Systems (ARCHES) hydrogen hub [345] has plans to develop hydrogen pipeline and storage infrastructure to serve the ports of the San Pedro Bay and Oakland. The anchor project is the Southern California Gas Company Angeles Link pipeline project which will have a planned capacity of up to 1.5 million metric tonnes per year of hydrogen delivery capacity [346]. Given the time required for hydrogen infrastructure development, significant hydrogen bunkering is unlikely to be available in California before the mid-2030s.

Methanol

There is extensive global infrastructure for the distribution and bulk storage of methanol. In the U.S., methanol production, distribution, and storage infrastructure are concentrated on the Gulf Coast as seen in Figure 42. The only large-scale storage facility on the West Coast is in Vancouver. There is also a concentration of infrastructure on the east coast of China, which will support initial development of expanded use of methanol as a maritime fuel in the Pacific. A large-scale production and storage facility planned for Washington state was denied construction permits due to environmental concerns [347] Methanol bunkering facilities are not yet widely available, but there is significant development activity ongoing worldwide to expand bunkering capability. The Port of Los Angeles has completed one bunkering operation for a large container ship capable of operating on methanol [348] and, as discussed below, several green shipping corridors serving the West Coast that include methanol are under development. Among non-drop-in fuels, methanol distribution, storage, and bunkering are currently seeing the most development activity.

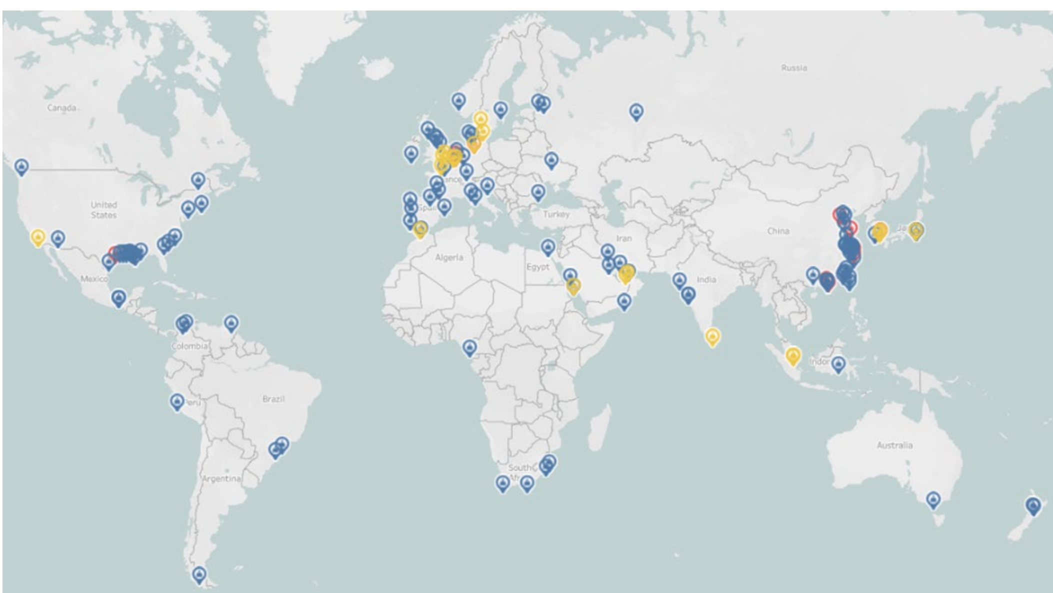


Figure 42. Global Methanol Bunkering (yellow), Storage (blue), and Bunkering + Storage (red) Facilities. Source: [349]

The International Standards Organization has developed draft standard ISO/CD 22120 to define the safety and operational protocols governing methanol marine bunkering. The regulation draft is complete and currently under review.

Ammonia

As with methanol, there is extensive global infrastructure for distribution and bulk storage of ammonia. U.S. infrastructure is concentrated in the Midwest and Gulf Coast, which are the production centers. Globally, there are well over 100 ammonia terminals for ammonia import or export as seen in Figure 43. Development of ammonia bunkering facilities is in the early stages, but significant development activity is ongoing as discussed in the Green Shipping Corridors section below. California imports on the order of 200,000 metric tons of ammonia annually via the Port of Stockton [350].[3] This capability provides an initial platform for developing a maritime ammonia supply chain in California. The California ammonia collaborative, CALAMCO, and several maritime partners have announced a plan to demonstrate ship-to-ship bunkering at the ports of Stockton and Benicia [351]. Outside of California, a major ship-to-ship bunkering demonstration was completed at the Port of Dampier, Australia in 2024 [352]. In addition, the ABS has issued a technical advisory document, and the IMO has published interim guidelines for ammonia bunkering [353], [354].

[3] It is unclear why the Stockton facility is not shown on the IMO map.

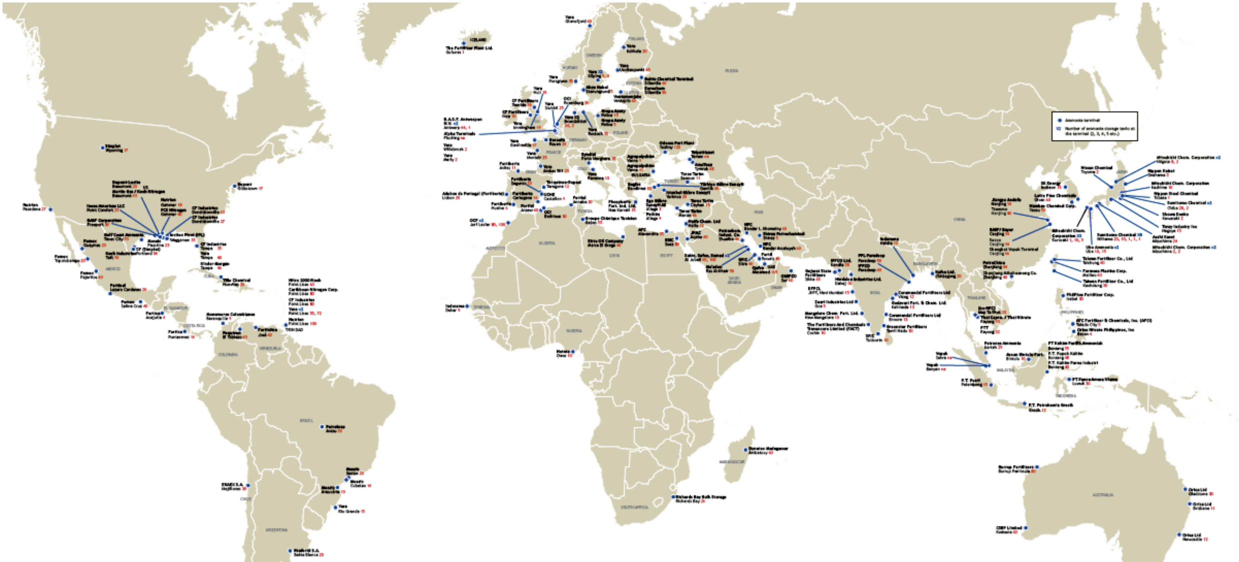


Figure 43. Ammonia Terminal Locations. Larger format and link to interactive map at reference [355].

According to the Getting to Zero Coalition 2024 progress report [293], there are 62 green shipping corridors under development globally.[4] The purpose of the corridors is to facilitate the transition of maritime shipping to clean fuels through coordinated planning and infrastructure development. Of the 62 corridors under development, eight serve California ports. They are:

- Hueneme-Pyeongtaek Green Automotive
- Hueneme-Yokohama Green Automotive
- LA-Nagoya
- LA-Yokohama
- LA-Guangzhou
- LA / Long Beach - Shanghai
- LA / Long Beach - Singapore GDSC
- Oakland - Yokohama

As seen in Figure 44 no corridor has reached the full-implementation stage, but six corridors are at the late pre-implementation stage. None of the California initiatives has reached the

[4] Three corridors are electric-only.

preparation stage but one West Coast corridor, the Pacific Northwest – South Korea car carrier corridor, is currently at the preparation stage. Given construction timelines, the first fully operational corridors are expected to emerge in the late 2020s and early 2030s.

Figure 44. Green Shipping Corridors by Stage of Development. Source: [293].

As seen in Figure 45, all of the primary candidate low-carbon fuels are represented in the corridor plans, some of which are focused on a single-fuel and some of which are developing multi-fuel capability.

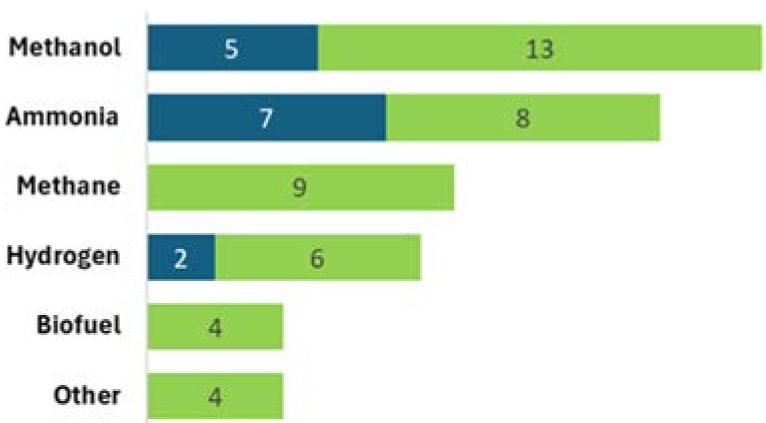


Figure 45. Green Corridor Projects Count by Fuel Type. Blue indicates that the corridor is single-fuel and green indicates that the corridor is multi-LCMF. Source: [293].

Consistent with the findings on ship conversion and build orders, methanol corridors are advancing the most rapidly among non-drop-in fuels, followed closely by ammonia.

Alternative Fuels Summary and Conclusions

Multiple low-carbon fuel types are under consideration for wide-scale adoption in international shipping. All of these alternative fuels are in the piloting or early deployment stage with LNG and biodiesel showing the greatest current bunkering activity. Forward-looking analyses show a diversity in projections of future operating costs and carbon reduction for the candidate LCMFs and, consequently, a diversity of expectations for which LCMFs will be dominant. Among non-drop-in alternatives, LNG and methanol are currently seeing the most active development with respect to shipbuilding (retrofit and new build), and bunkering infrastructure development. As a group, the LCMFs contain negligible or no sulfur and have low soot-forming propensity which provides an immediate co-benefit to their adoption for carbon mitigation. However, NO_x mitigation will be required for all fuels and pollutant formation due to fuel slip is an issue that will need to be addressed, particularly for ammonia and LNG.

Major Conclusions

Overall Conclusions

The transition to cleaner fuels in the maritime sector is already underway, with successful demonstrations and commercial operation, orders being placed for new technologies, and regulatory guidelines being drafted. Some of the alternative fuels with the potential to significantly reduce GHG and pollutant emissions are fully in commercial operation today (liquid biofuels, LNG), while others are in the early stages of commercial operation (methanol) or nearing commercial operation (ammonia). Currently, alternative fuel use in the maritime sector is dominated by LNG, including use by LNG carriers, containerships, tankers, and passenger/cruise vessels. Interest in other alternative fuels, including hydrogen (in both ICE and fuel cells), methanol, ammonia, and battery electric for propulsion, is growing but will require additional R&D to address barriers including energy density, cost, and technical performance. Alternative fuel combustion engine technologies including methanol and ammonia are forecast to reach full commercial development by 2030. Conversely, fuel cell technologies for propulsion will not reach full commercial maturity until late 2030s to 2040s, although systems for auxiliary applications are closer to commercial maturity. Many energy efficiency technologies are already mature with potential for more widespread deployment while others are operating commercially providing even further potential for greater uptake. Similarly, exhaust aftertreatment strategies including SCR and EGR are commercially available today and have experience being used in maritime applications. On the other hand, others, including DPFs, are less commercial and will require commercial advancement prior to widespread use.

The commercial availability of many of the most promising emission reduction technologies and fuels will depend on R&D efforts, which in turn will be largely driven by sector-wide fuel demands and the regulations which require them. There is significant capacity in the industry to scale up the production and installation of emission reductions technologies including alternative fuel engines, energy efficiency technologies, and post-combustion on-board carbon capture technologies relatively quickly once the demand emerges. This conclusion was supported by conversations with several major engine manufacturers[5], as well as expert survey in the literature. Thus, the technologies and fuels needed to achieve ambitious emission reductions will be technically and commercially ready in time and are not expected to be hindered by commercial and technical barriers. Similarly, assessment of the technical and commercial readiness of the technologies needed to lower vessel energy demands, produce, store, and distribute alternative fuels, and use by vessels, concluded that technology development is not expected to be a barrier to their introduction and expansion of use in the industry. In terms of cost, low- and zero-carbon fuels are, and will be in the near-term, more expensive than current fuels but this is not necessarily a barrier to deployment if demand is clear over well-defined timescales as increased costs can be planned for and addressed. Alternatively, a ship using fossil fuels could potentially be subjected to some form of an emissions penalty or fee, as well as geographical prohibitions for fossil-fueled ships as future global GHG and criteria pollutant regulations evolve for the shipping industry.

Marine engines are able to use renewable diesel and biodiesel/conventional blends now and full maturity to allow operation on pure biodiesel is expected in the near-term. Similarly, marine engines running on LNG are fully mature and used commercially today. Methanol engines have begun early stages of commercial operation and are forecasted to reach full maturity before 2030 (particularly due to increasing commercial development for 2-stroke engines). Hydrogen combustion engines remain 4-strokes at this stage and are nearing demonstration and may reach commercial operation by 2030. While ammonia engines are just beginning commercial operation, development is progressing rapidly with pilot demonstrations now and commercial operation in the next few years.

It is clear that there is no “silver bullet” fuel or strategy to reduce emissions from OGV, and a wide portfolio of options are being considered and pursued in the maritime industry. Each option has pros and cons, which will determine the suitability for different maritime vessels and applications. It is not currently clear if one fuel or groups of fuels will become the dominant

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[5] UCI conducted interviews with Everllence and Wartsila

maritime fuel in the short to long term. It is more likely that multiple fuels will play important roles in the transition to zero- and near-zero carbon shipping. In the near-term, stakeholders are challenged to select a fuel or fuels and start implementation and to minimize risk, shipping initiatives seeking the deployment of alternative fuels (e.g., green shipping corridors) should carefully assess the regional multi-sectors fuel supply dynamics to identify synergies in aggregating demand.

As an example of the evolution pattern that alternative technologies and fuels may follow, Everllence's outlook for four-stroke marine engines includes a phased transition toward low- and zero-carbon fuels with LNG as the most practical fuel for immediate emissions cuts, followed by biogas and later synthetic natural gas produced from green hydrogen, with a growing share of these fuels expected over time through increased blending. While the long-term role of methanol and ammonia in four-stroke propulsion is less certain, Everllence is working on medium-speed engines compatible with both fuels highlighting the potential importance of those fuels. Additionally, hydrogen combustion is being considered as a potential solution, particularly for short-sea and near-coastal shipping, where fuel storage and range requirements are more manageable. While this is only one possible pathway, it highlights the lack of a "silver bullet" and emphasizes the importance of developing and applying a portfolio approach to transitions.

Alternative Fuels and Technologies

Key considerations that will need to be addressed in the development of safe and efficient hydrogen refueling infrastructure include:

- **Location:** Identify strategic locations for infrastructure based on the patterns of OGV travel, docking areas, operator needs, and others including marinas, ports, and destination sites.
- **Compatibility and Standards:** Meet industry standards for OGV infrastructure to ensure feasibility across different vessel types including using widely accepted standards such

as those established by the International Electrotechnical Commission (IEC) or other regional standards.

- **Safety and Compliance:** Adhere to safety regulations and standards in maritime environments. Implement safety features, such as proper grounding, protective enclosures, and emergency shut-off systems.
- **Scalability:** Design charging infrastructure with scalability in mind to accommodate the increasing adoption of hydrogen vessels including potential expansion and upgrades as the demand for hydrogen grows.
- **Environmental Impact:** Consider the environmental impact of hydrogen infrastructure. Favor energy-efficient systems and consider renewable energy sources, when possible, such as solar or wind resources to power electrolytic hydrogen.
- **Maintenance and Support:** Establish a maintenance plan for regular inspections and repairs of infrastructure. Provide customer support services to address issues and ensure the reliability of hydrogen infrastructure.

Energy efficiency is an important opportunity for both short-term emissions reductions and long-term adoption of carbon-neutral fuels, which will be more expensive and less available in the near future. Many energy efficiency technologies are commercially mature and have a history of use in the shipping industry. However there remains potential to expand the use of existing technologies, as well as develop and apply new technologies and measures.

Biofuels, including HVO and FAME, are an attractive option for decarbonizing shipping due to their drop-in fuel for most diesel engines. Multiple marine engine manufacturers, including Wärtsilä and Everllence, have approved the use of HVO in both 2-stroke and 4-stroke engines. HVO is preferable to FAME as FAME has several technical drawbacks when used at high concentrations. These include lower oxidative stability, potential for microbial growth in storage tanks, and compatibility issues with engine elastomers. Moreover, the cold flow properties of FAME pose challenges for use in colder marine environments. Marine engines require some adaptation or careful fuel handling procedures to operate on high FAME blends. Due to this FAME is typically constrained to lower blend ratios while HVO fuels can be used neat. However, the supply chain for HVO remains limited and is a barrier to widespread adoption, especially given that demand from the road and aviation sectors may compete for feedstock availability. Both HVO and FAME can contribute significant GHG reductions relative to fossil marine fuels, particularly when produced from waste-based feedstocks. However, the use of biofuels does not achieve any meaningful reduction in air pollution.

LNG is the most prevalent alternative maritime fuel today by a wide margin, including deployment in a broad mix of container ships, oil and chemical tankers, and bulk carriers. Engine technologies to support LNG use are commercially mature, with multiple engine manufacturers (e.g., Everllence, Wärtsilä, and WinGD) offering a range of dual-fuel two-stroke and four-stroke LNG engines. These engines are available for both newbuilds and, in some cases, retrofits. Global bunkering infrastructure for LNG has also expanded significantly, with key ports in Europe, Asia, and North America now equipped for LNG refueling. While its economics can be favorable under the right conditions, high capital costs, and concerns over near- and long-term GHG benefits due to methane slip have prompted some stakeholders to view LNG as a bridge fuel rather than as a final destination in maritime decarbonization.

Methanol is an emerging alternative marine fuel that offers several advantages for decarbonizing OGVs. It can be produced from a variety of feedstocks, including natural gas, coal, biomass, and renewable electricity (via green hydrogen and captured CO_2), making it a flexible and potentially low-carbon fuel. Methanol is a liquid at ambient conditions, allowing it to be handled and stored using existing fuel infrastructure with minimal modifications. It has lower volumetric energy density than diesel but higher than hydrogen or ammonia, and its combustion produces significantly lower emissions of SO_x, PM, and CO_2.

From a technological standpoint, methanol can be used in either dual-fuel or dedicated methanol ICE, several of which have already been commercialized by major engine manufacturers like Everllence and Wärtsilä. Methanol-fueled engines are being installed on newbuild ships and are being considered for retrofit applications, aided by their relative simplicity and operational familiarity. The scalability of green methanol depends heavily on the availability and cost of renewable hydrogen and carbon capture. Nonetheless, methanol presents a viable transitional solution with a growing number of pilot and commercial projects underway in the marine sector, and it is well-aligned with both near- and mid-term decarbonization pathways for shipping

Ammonia is emerging as a promising long-term choice for alternative fuels in the maritime sector due to its potential for significantly reduced or eliminated emissions at the point of combustion, existing base for the build-out of bunkering infrastructure, the potential for use in low- or zero-emission fuel cells and others. Similar to methanol, ammonia can be used in a variety of marine engines including both conventional and dual-fuel engines. Ammonia has a high energy density and low viscosity which increase its suitability as a marine fuel. Several major engine companies in the maritime space believe ammonia will play a major role in future fleets, including Everllence and Wärtsilä[6]. While LNG and methanol engines are more commercially advanced, ammonia-capable engines are catching up rapidly and the first dual-fuel vessels are expected to begin operation in 2025. Challenges that will need to be overcome to achieve widespread adoption include addressing toxicity concerns to vessel crew, port and terminal workers, and nearby communities, as well as safety concerns associated with storage, bunkering, and handling. Additional engine development will also be needed to address high ignition temperatures which currently require the use of pilot fuel.

With adequate support and investment, green hydrogen will likely serve as a cornerstone of a sustainable maritime sector, particularly the electrolysis of water using renewable electricity. However, hydrogen's primary role will likely not be a direct fuel for combustion, rather as a key feedstock for the production of other low- or zero-carbon fuels including e-LNG, green ammonia, and green methanol that are more compatible with current infrastructure and engine technologies [60]. Storing hydrogen as cryogenic liquid increases density but may reduce cargo space and present boil-off issues, particularly during long dormant periods. These losses can be minimized with improved insulation or by consuming boil-off gas in engines or fuel cells.

[6] Personal communication with Everllence and Wartsila, 2025

Hydrogen-derived fuels offer a scalable and flexible pathway for decarbonizing the shipping sector while utilizing green hydrogen's clean energy potential.

Hydrogen ICE are a near-term, transitional decarbonization option that use conventional engine platforms modified to combust hydrogen instead of diesel or heavy fuel oil. They are more mature than hydrogen fuel cells and benefit from existing engine know-how, supply chains, and servicing infrastructure. Several engine manufacturers including Everllence, Wärtsilä, and Kawasaki Heavy Industries are developing or testing hydrogen ICE for marine use including both dual-fuel and mono-fuel versions. Hydrogen ICEs are viewed as more feasible for short-sea shipping and coastal vessels rather than transoceanic voyages due to current limitations in hydrogen storage and bunkering infrastructure.

However, maximizing the environmental benefits of hydrogen will require the use of fuel cells rather than ICE. Fuel cells generate electricity through electrochemical reactions without combustion in many different types and configurations, each of which has relative strengths and advantages. Fuel cells produce GHG and pollutant emissions at the point of use and emit only water vapor and trace amounts of heat. This makes them a zero-emission technology when fueled with green hydrogen. Marine fuel cell systems are less mature and more expensive than ICE. However, fuel cells are less mature and commercially available than ICE with challenges including low power densities, limited durability under marine conditions, high capital costs, and the complexity of integration with marine propulsion and energy systems. While current barriers to fuel cells likely will prevent them being used for vessel propulsion in large vessels, they may have applications for providing auxiliary power or propulsion for coastal and short-sea shipping, particularly in hybrid configurations. Hydrogen faces technical challenges for large-scale commercial use, especially for long or deep-sea voyages requiring large on-board fuel volumes.

While the concept of nuclear-powered ships has a historical precedent, civilian marine nuclear power has not gained widespread acceptance due to barriers including high CAPEX, significant and challenging to solve regulatory hurdles, and negative public perception. Advanced nuclear power, including SMR, is potentially a “game changer” for marine shipping in that it offers the potential for safe, operationally efficient, and zero tank-to-wake emissions (e.g., both GHG and pollutant) power at-scale for a range of maritime applications, including vessels and FNPP. Additional benefits include very long periods between refueling, high reliability, limited maintenance while in an operating mode, and long-term energy security by reducing reliance on volatile fuel supply chains. Nuclear power also enables energy independence from volatile global fossil fuel markets and is advantageous for ships operating in remote regions. These characteristics have led to growing interest from shipbuilders, owners, operators, governments, industry, and regulatory bodies. While the current status of nuclear power as a maritime fuel is behind other alternative fuels in terms of commercial maturity, companies are actively developing marine-specific systems, with examples including Core Power, Hyundai Heavy Industries, and TerraPower. Reflecting this, government support for nuclear is accelerating investments in research, infrastructure, and demonstration projects seeking to advance prototype development and commercialization. Public perception of nuclear energy is a major barrier and will need to improve, and regulatory frameworks are evolving to support the safe deployment of nuclear propulsion in shipping.

CCUS is generally considered to be a steppingstone to a zero- or very-low GHG marine sector, rather than the endgame. Nonetheless CCUS could play a significant role in decarbonizing vessels in the near- to mid-term, particularly if technological development leads to increased CO_2 capture rates. The business case for shipowners adopting CCUS depends on several key trade-offs, including the balance between high CO_2 capture rates and the increased fuel consumption, reduced cargo capacity, or more frequent port calls needed to accommodate CCUS equipment and CO_2 storage. These impacts vary significantly depending on the vessel's operating profile as factors like tank size, offloading logistics, and available on-board energy all influence economic feasibility. The suitability of CCUS depends on individual vessel characteristics and operational patterns and the choice of technology will depend on factors such as installation costs, the nature of the flue gas, required CO_2 purity, and how well the system integrates with the vessel’s existing operations. A use case that may be particularly valuable for CCUS is deployment on existing ships at risk of early scrappage due to tightening efficiency regulations, such as CII, if conversion to zero-carbon fuels proves too costly.

A major barrier to deploying zero-emission vessel technologies, such as battery-electric and fuel cell systems, is the lack of suitable charging and hydrogen fueling infrastructure. In California, there is currently little to no dedicated infrastructure to support these vessels, and building out such a network will require new technologies and coordinated strategies. Installing marine-grade charging/fueling systems is technically challenging, as the equipment must be able to tolerate harsh marine conditions. Additionally, a reliable distribution network will be needed, requiring collaboration among port authorities, utilities, vessel operators, and local governments to ensure access and coordinated development. The costs of building and operating this infrastructure are high, and the financial burden currently falls mostly on vessel owners and operators. Utility rate structures can further complicate the economics of electric vessel charging. Space limitations at crowded ports add another layer of difficulty, as these systems require significant land area. Finally, outdated and complex permitting and regulatory processes often involving multiple agencies can delay or constrain projects, making deployment even more difficult.

Economics

Investment will play a critical role in enabling the transition to alternative maritime fuels and technologies. Significant capital will be needed to develop the infrastructure, retrofit existing fleets, or build new vessels designed to operate on low- and zero-emission fuels such as hydrogen, ammonia, methanol, or battery-electric systems. Establishing a viable market for these alternative fuels requires coordinated efforts across the value chain including technology developers, shipowners, fuel suppliers, and port authorities, and these efforts cannot move forward without substantial and targeted financial backing.

The maritime sector has the potential to become a major driver of global demand for clean fuels, given the substantial energy requirements of international shipping. This could allow the industry to play a leading role in driving economies of scale and unlocking broader investment cases for alternative energy sources. However, more research is needed to fully understand the impact of shipping’s fuel demand on global supply chains and the clean energy transition. If strategically leveraged, shipping’s demand could serve as a key anchor for early market development of fuels like green hydrogen or e-ammonia, helping to bring down costs and stimulate production at scale.

To realize this potential, investment strategies advance beyond traditional procurement practices with fuel supply and purchase agreements evolving and incorporating new risk-sharing mechanisms that reflect the volatility and uncertainty of emerging markets. Buyers and sellers must develop more flexible and innovative contracting models, including long-term offtake agreements, co-investment structures, and public-private partnerships. Engaging key stakeholders can provide financial guarantees, lower the risks on expensive projects, and help align fuel strategies with broader environmental goals. In the short term, fostering strategic partnerships and exploring cooperative investment models can accelerate deployment by helping to overcome the "chicken-and-egg" problem of fuel availability versus vessel readiness, ensuring that fuel production capacity and vessel technologies can advance in parallel.

Estimating the economics (e.g., TCO) of many alternative fuels and technologies for OGV is challenging given the wide variation reported in the studies, and the significant uncertainties associated with drivers including the capital costs of engines and assorted on-board supply and storage systems, impact of cargo displacement on cost, fuel costs, efficiencies of the technologies, regulatory drivers such as incentive programs and carbon fees, and many others. Notwithstanding the uncertainties, biomass-derived fuels are projected to be lower cost than electrolytic fuels, especially in the near term. According to a report by Everllence, ammonia and methanol engines appear to be the most cost-effective options for decarbonizing shipping. Biomethane is cost-effective but will be limited by feedstock availability, particularly given the competition with other sectors. Fuel cells offer significant emissions reduction potential but come with higher costs and are still at a low TRL for larger marine applications.

GHG Emissions and Air Quality

Table 26 provides a summary of the GHG, pollutant emission, and air quality impacts of the strategies considered in this report. While all of the strategies considered in this report have the potential to reduce GHG emissions from conventional engines and fuels, the carbon footprint is entirely dependent on the production pathway and achieving environmental benefits will require renewable and other green pathways. For example, to achieve deep reductions in GHG non-carbon containing fuels (e.g., hydrogen, ammonia) must be sourced from renewable sources and carbon-containing fuels (methanol) must be sourced from renewable hydrogen and captured CO_2.

Life cycle GHG savings for HVO and FAME can vary widely depending on the feedstock and production method, but reductions in the range of 60–90 percent relative to fossil fuels are typically achievable. However, the variability in emissions depends on supply chain factors, e.g., if HVO or FAME is produced from virgin crops (e.g., palm or soybean oil), land-use change emissions can significantly offset GHG benefits. Therefore, fuel certification schemes and sustainability criteria are critical for ensuring genuine emission reductions from biofuels. HVO and FAME both can reduce in PM emissions and eliminate SO_x emissions. Impacts on NO_x are more complex and engine-specific. FAME may slightly increase NO_x emissions due to its high oxygen content, which can elevate combustion temperatures and promote NO_x formation. Conversely, HVO generally shows neutral to slightly reduced NO_x emissions, depending on the engine's combustion characteristics and calibration. To meet IMO Tier III NO_x emission regulations, aftertreatment systems are often required including SCR.

LNG offers moderate reductions in CO_2 emissions when compared to conventional marine fuels. When combusted efficiently, fossil based-LNG can reduce CO_2 emissions by approximately 20–25 percent compared to HFO, and the use of green pathways for LNG can achieve significant reductions potentially including net negative emissions from waste biogas. However, methane slip can significantly erode or negate the GHG benefits of LNG, particularly in low-pressure, dual-fuel, four-stroke engines, which exhibit higher slip rates. As a result, the GHG emissions of LNG are highly engine-dependent. However, LNG can significantly reduce air pollutants compared to traditional marine fuels including the near-elimination of SO_x as LNG contains virtually no sulfur. LNG also greatly reduces emissions of PM because LNG contains no aromatic compounds or heavy hydrocarbons and it produces far less soot and black carbon. This is particularly important for improving air quality near ports and reducing the environmental impact of shipping in sensitive regions like the Arctic.

Table 26. Summary of GHG and Air Quality Impacts relative to conventional marine fuels

Technology	GHG Emissions	Pollutant Emissions	Air Quality Impacts	Aftertreatment for IMO Tier III NO_x
HFO	High	High NOx, PM, SOx	Significant	Yes
LNG	Lower than HFO to net-negative	Low PM and SOx, moderate NOx	Beneficial if NOx is controlled	Potentially
Methanol	Moderate to major reductions	Low PM/SOx, moderate NO_x	Beneficial if NOx is controlled	Potentially
Ammonia	No TtW CO_2, Moderate to major reductions	No PM/SO_x, potential NOx and NH3	Beneficial if NOx and NH_3 are controlled	Yes
Hydrogen (ICE)	No CO2, Moderate to major reductions	No PM/SOx/CO_2, but NOx possible	Beneficial if NOx is controlled	Potentially
Hydrogen (Fuel Cell)	No CO_2, Moderate to major reductions	None (water vapor only)	Highly beneficial	No
Efficiency Measures & Technologies	Varies, Minor to moderate Reductions	Minor/moderate reductions but low loads can have NOx and PM concerns	Varies depending on low load impacts	Depends on baseline vessel
Renewable Diesel/Biofuels	Varies, Likely significant reductions	Low PM and SOx, NOx impacts are variable	Potentially beneficial, especially in port areas	Yes
CCUS	CO_2 significantly reduced	No reduction to slight worsening	Neutral to slight worsening	Depends on baseline vessel
Nuclear	Very low	None	Highly beneficial	No

Bio-LNG, bio-methanol, and biofuel oils can provide significant GHG reductions, but e-fuels will almost certainly be needed to reach the goal of carbon-free transportation. Some strategies, including biofuels and efficiency measures, are effective at achieving near-term benefits to emissions and represent an intermediate step until more advanced e-fuels are available at scale.

Due to the PM and SO_x reductions, the use of ammonia, methanol, and LNG can significantly improve air quality in port-adjacent communities, although NO_x will have to be managed to prevent increases and achieve reductions from current fuels. Emissions of ammonia are also a concern as they represent a health concern, and they further contribute to secondary PM formation in the atmosphere.

It should be noted that a small amount of pilot fuel will likely be required for many fuels in ICE, including LNG, hydrogen, ammonia, and methanol, which can contribute to both GHG and pollutant emissions. Typically, this would be done with traditional diesel fuels, but liquid biofuels could also be used, which could negate any GHG emissions penalties [44]. However, the use of liquid biofuels as pilot fuel would not prevent emissions of pollutants associated with traditional diesel fuel combustion, including NO_x, PM, CO, and SO_x. Therefore, the location of pilot fuel injection becomes important in terms of the ultimate impacts on air quality and human health. For example, if pilot fuel is used while ships are at berth or anchored near-shore, the emissions can impact communities adjacent to ports and other locations of vessel operation. Conversely, if pilot fuel is used further offshore, the emissions may not result in significant human health concerns.

Retrofits

Retrofitting vessels with alternative fuel engines is a viable strategy for reducing emissions and extending vessel lifespans without requiring the construction of entirely new ships. This approach offers several advantages for shipowners looking to comply with stricter environmental regulations and decarbonize their operations in a cost-effective and timely manner. One of the primary benefits of retrofitting is the potential to reduce emissions from existing vessels without fully replacing the ship. By upgrading to engines that run on low- or zero-emission fuels, operators can achieve significant reductions in GHGs and pollutants. This is particularly valuable for meeting international regulations such as the IMO's GHG reduction strategy or regional rules within ECAs. At the same time, retrofits typically require lower capital investment compared to ordering a new alternative-fuel vessel which makes them a potentially attractive option for shipowners looking to maximize the return on investment for their existing fleets. In addition to being more affordable, retrofits can often be completed on shorter timelines than newbuilds as they can make use of existing structure, machinery, and layout, which could accelerate the deployment of cleaner technologies and fuels.

Generally, retrofit packages are being considered and developed for the alternative fuels that can be used in ICE, including LNG, methanol, ammonia, and hydrogen. Similarly, CCUS technologies can be retrofitted on vessels. Retrofits are not as suitable for some, including fuel cell and battery electric systems, and not suitable for nuclear ships. Additionally, efficiency measures run the full spectrum from straightforward to retrofit to unable to retrofit. The suitability of retrofitting is also highly specific to the vessel under consideration. For example, the following vessel types have been identified as being more viable for retrofit:

- Vessels with electronically controlled engines
- Vessels from the current fleet with a maximum age of eight years
- Vessels with the following minimum size: – Container ships: 8,000 TEU – Tankers: 50,000 DWT – Bulk carriers: 150,000 DWT

However, despite these benefits, retrofitting is also faced with challenges. Technically, converting a ship to run on an alternative fuel often requires significant engineering modifications which can include engine replacement, new fuel storage tanks and piping, combustion control systems, and on-board safety features. Any modifications must be carefully integrated into the vessel’s design and may be more difficult for older ships or those with limited available space. The integration of alternative technologies and fuels in newbuild vessels will always have the benefit of allowing for the optimization of the vessel design and construction specifically for the technology and fuel itself, leading to a more optimal system and vessel overall.

Space and weight constraints are particularly relevant when considering fuels with lower energy densities like hydrogen and ammonia and the fuel storage systems for these fuels tend to be larger and heavier, potentially reducing cargo capacity or requiring trade-offs in layout and design. Moreover, alternative fuels often pose unique safety hazards, such as flammability (hydrogen), toxicity (ammonia), or cryogenic storage requirements (liquefied hydrogen or LNG). These risks necessitate new safety systems and compliance with evolving regulatory standards.

The regulatory frameworks also complicate decisions to retrofit. Classification societies and flag states are developing safety and design guidelines for alternative fuels, but these standards are still emerging and can add complexity and cost to the process. Additionally, vessel downtime during retrofitting can disrupt operations and lead to lost revenue if not carefully scheduled during planned maintenance periods. An additional regulatory challenge for engine retrofits is NO_x recertification obligatory under MARPOL after a major conversion. If an identical certified engine does not exist, which is likely for early retrofit projects, recertification can be complicated and costly.

Therefore, a decision to retrofit must be guided by a detailed evaluation of vessel-specific technical limitations, fuel infrastructure, regulatory compliance, and long-term operational costs. As the maritime industry transitions toward cleaner propulsion technologies, retrofits will likely play an important role alongside newbuild strategies.

These and other challenges will need to be considered along with economic factors to determine if retrofit or newbuild should be pursued for different alternative fuels. There are also human factor elements associated with impacts on crew including appropriate training, development of procedures and processes, occupational health, and ergonomics.

LCMF Availability

All of the LCMFs discussed in this report have limited global production capacity. LNG has a significant foothold, but the supply of low-carbon variants is minimal as it is for the other LCMFs. Although there is significant international activity aimed at increasing the supply of LCMFs, supply availability will not begin to expand rapidly until the early 2030s and LCMFs will not reach 25 percent of overall supply until around 2040. For LCMFs that are not drop-in or near-drop-in, the build out of bunkering infrastructure will also be a pacing item and investment in bunkering will need to be made ahead of widescale adoption of LCMFs to provide bunkering for early adopters. This is the focus and purpose of the Green Shipping Corridors.

Policy and Regulatory Synergies

Policy and regulatory activity and development of associated strategies and plans for adoption of LCMFs is active across the entire international shipping sector including governments, ports, shipbuilders, shippers, fuel producers, and equipment manufacturers. Although less pervasive than GHG mitigation action, there is also significant effort internationally to reduce non-GHG pollutants from trans-oceanic shipping. The IMO will be the driving force on both GHG and non-GHG emissions regulation through MARPOL Annex VI. California can create the most leverage by engaging in the MEPC process to increase the stringency of global NOx and sulfur content regulations. There is a trend toward financial measures such as fees, and tradeable emissions credits. California has the existing platform of the LCFS that could be expanded to include marine fuels. Similar program designs could be developed for non-GHG emissions.

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