SETTING THE COURSE TO
LOW CARBON SHIPPING

PATHWAYS TO SUSTAINABLE SHIPPING

ABS

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INTRODUCTION

International shipping is facing the critical challenge of sustainability in response to global regulations for pollution prevention and protection of the aquatic environment. During the past 30 years, the enacted regulations were shaped in equal parts by responses to environmental incidents, disruptive periods of technological innovation and changing priorities among marine regulators, all of which were intended to improve operational efficiency, protect the environment or enhance workplace safety.

Each new regulatory development was preceded by long periods of industry investigation and discussion, and then followed by extensive efforts from the International Maritime Organization's (IMO) Marine Environmental Protection Committee (MEPC), to achieve the IMO's strategic objectives through effective technical regulations. As the governing body on environment-related issues, the MEPC has long sought to objectively address the environmental concerns raised by its member states and partnering organizations.

In every instance – from the IMO's mandate of the double hull oil tanker design and onwards – the conception, formulation and, especially, implementation of regulations would have been greatly aided by a comprehensive, living document that summarized the challenges and offered current solutions.

As no such document existed, the maritime industry has often experienced long periods of uncertainty as it sought to interpret the new mandates, and harness technology to comply with those mandates.

As the industry adjusts to the current impact of the IMO's 2020 sulfur cap – and prepares for the emerging regulatory changes in 2030 and 2050 – there is consensus that adapting to the new rules and challenges aimed at lowering its collective carbon footprint will be another period of uncertainty driven by disruptive environmental legislation, and defined by the innovative solutions which emerge.

While reducing carbon dioxide (CO_2) and other greenhouse gases (GHG) is a separate challenge from current efforts to lower shipping's output of pollutants such as nitrogen oxides (NO_x) and sulfur oxides (SO_x), both put the health of the environment and the livelihood of those who depend on them at risk. For shipping, a "zero-carbon future" is an aspirational goal, and the associated regulatory pathways will evolve alongside the changes it inspires in ship design, technology and practices.

Importantly, progress must be achieved strategically and holistically if the maritime industry is to emerge more efficient, profitable and sustainable than it is today.

In recognition of this goal, ABS has developed the second in a series of "Outlook" documents – the first was published in June 2019 – to reference available carbon-reduction strategies and inform the shipping industry as it enters the uncharted waters of the 2030/2050 emissions challenge.

This document examines how the development of global trade will impact global emissions. Furthermore, it identifies the three main fuel pathways on the course to meeting the IMO's emission reduction targets for 2050 and beyond: light gas fuels, heavy gas fuels and bio/synthetic fuels. It also examines the possible capacity demand and related emissions output trends on a global basis to envision the environments in which those targets may need to be achieved.

This information is offered solely to help provide industry stakeholders with the information they need to make informed decisions. The nearest challenges will require them to make choices between new fuels, energy sources and emissions control systems.

It is offered as a tool to help shipowners understand the complexity of the task ahead and to move forward effectively as they assess their options for a transition to low-carbon operations, and further to the zero-carbon future of shipping.

EMISSIONS REGULATIONS

With the International Maritime Organization's (IMO) marine fuel sulfur cap now in place and air emissions and greenhouse gas (GHG) reduction targets set for the next 30 years, it is instructive to recognize how shipping got here, and what is on the near horizon from a regulatory perspective.

At every step, industry stakeholders rallied to offer equal measures of inspiration, investigation, consultation and resource allocation to achieve the goals of each regulation; it is a formula and level of collective commitment that will need at the very least to be replicated as shipping sets course for a zero-carbon future.

One recent report[1] estimated the industry would need to invest at least $1 trillion to meet the IMO's emissions targets for 2050.

From the GHG perspective, the IMO's most ambitious current target – to reduce shipping's GHG emissions by at least 50 percent by 2050, compared to 2008 – was agreed in April 2018 and for the first time brought the shipping industry broadly into line with the goals of the UN's Paris Agreement to combat climate change.

However, the IMO's focus on regulating air-emissions started in 1997 with additions to the International Convention for the Prevention of Pollution from Ships (MARPOL). MARPOL focused on pollutants: nitrogen oxides (NO_x), sulfur oxides (SO_x), volatile organic compounds, polychlorinated biphenyls and heavy metals, and chlorofluorocarbons.

MARPOL Annex VI, which entered into force in May 2005, limited airborne emissions from ships; the limits were further tightened in October 2008, revisions that came into force in July 2010. To measure carbon dioxide (CO_2) emissions, the IMO commissioned three GHG studies:

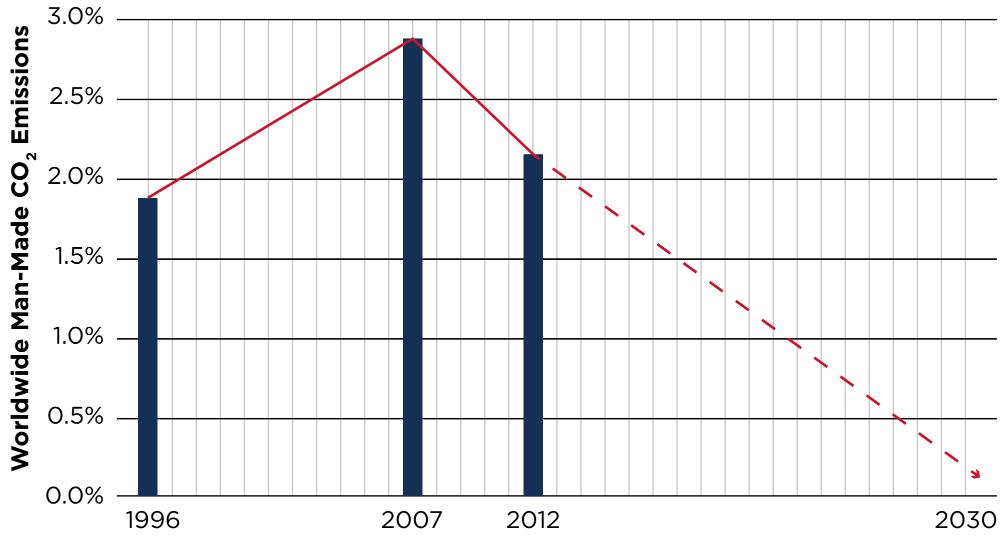


Figure 1: CO_2 emissions from shipping as a percentage of total man-made CO_2 emissions.

- In 2000, the first study estimated that, in 1996, international shipping had contributed about 1.8 percent of man-made CO_2 emissions
- In 2009, the second study estimated that, in 2007, emissions from international shipping totaled 880 million tonnes, or about 2.7 percent of man-made CO_2 output
- In 2014, the third study estimated that, in 2012, international shipping emissions had dipped to 796 million tonnes, or about 2.2 percent of man-made CO_2 emissions; it also raised the estimates for the second study to 885 million tonnes, or 2.8 percent

In 2011, MARPOL Annex VI added new requirements for the energy efficiency of ships. The Energy Efficiency Design Index (EEDI) and the Ship Energy Efficiency Management Plan (SEEMP) became mandatory measures from the start of 2013. These initiatives focused on vessel design, engines and equipment, coupled with an operational plan, to improve energy efficiency. It was the first step in preparing the industry to adopt carbon-reduction targets.

Initially, the EEDI required new ships to improve their energy efficiency by 10 percent starting in 2015, by 20 percent starting 2020, and by 30 percent from 2025. Those requirements have since been strengthened and their implementation accelerated – to 2022 for specific ship types and deadweight tonnage (dwt) segments.

For example, EEDI Phase III for containerships will now commence on January 1, 2022 with reduction rates incrementally strengthened up to negative 50 percent below the reference line for the larger size ships and kept at 30 percent for the smaller deadweight segments.

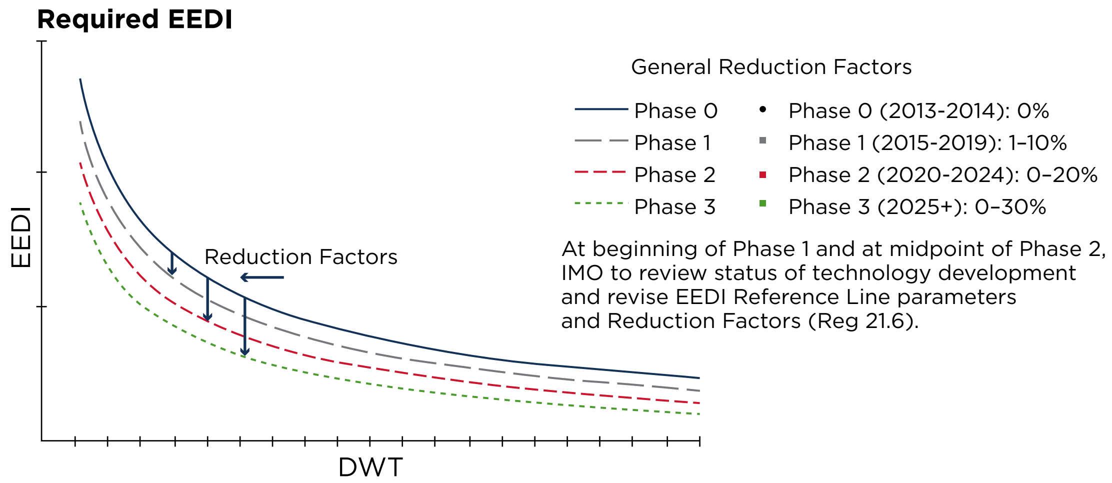


Figure 2: Energy Efficiency Design Index (EEDI).

Beyond newbuilds, existing ships are also now being considered for technical and operational CO_2-reduction measures. Discussions are ongoing at the IMO's Intersessional Working Group on GHGs and at MEPC 75.

Separate from IMO initiatives, in July 2015, Europe introduced the European Union Monitoring, Reporting and Verification (EU MRV) legislation that required shipowners and operators to monitor, report and verify CO_2 emissions each year for vessels larger than 5,000 GT that call at any port in the EU, covering the entire European Economic Area (EEA). Data collection has been taking place on a per-voyage basis from the start of 2018.

The IMO also adopted mandatory data-collection requirements to monitor the industry's consumption of fuel oil; records of other data, including proxies for transport work, was required for the same classes of ships, which account for about 85 percent of CO_2 emissions from international shipping. The data will provide a foundation for more measures.

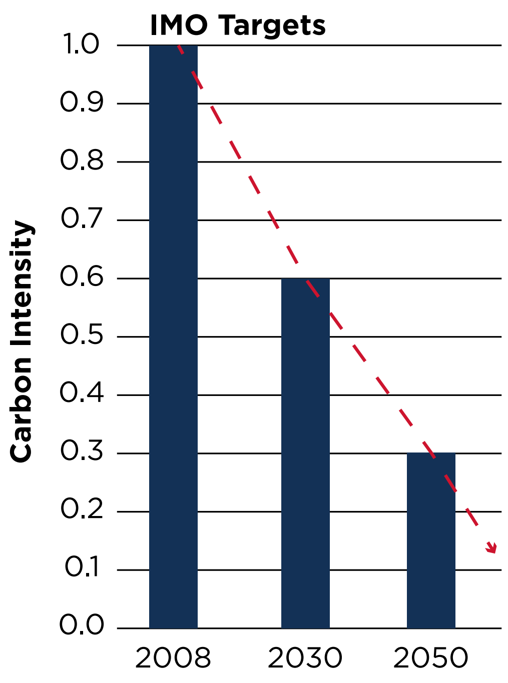


Figure 3: IMO targets for carbon intensity.

In April 2018, the IMO's Marine Environment Protection Committee (MEPC) adopted the previously mentioned strategy to reduce the GHG from ships and the carbon intensity of international shipping. Initial targets are to reduce the average CO_2 emissions per "transport work" by at least 40 percent by 2030 compared to 2008 levels, aiming at 70 percent by 2050; it also committed "as soon as possible" to pursue a 50 percent reduction of all GHGs by 2050.

The MEPC also approved a roadmap (2017-2023) for developing a "comprehensive IMO strategy on reduction of GHG emissions from ships."

The revised strategy is due for adoption in 2023, supported by data collection from ships starting in 2019 and a fourth IMO GHG study. The timeline and roadmap for the strategy include short-term, mid-term and long-term measures to be concluded from 2018-2023, 2023-2030 and beyond 2030, respectively.

The initial strategy lists a number of candidate measures which could also be considered to further reduce emissions and help achieve the targets in the strategy, in particular 40 percent reduction of carbon intensity from shipping by 2030. Short-term measures could be measures finalized and agreed by the Committee between 2018 and 2023, although in aiming for early action, priority should be given to develop potential early measures with a view to achieving further reduction of GHG emissions from international shipping before 2023.

TECHNICAL APPROACH

Proposals for a technical approach which were discussed included an Energy Efficiency Existing Ship Index (EEXI), which could require ships to meet set energy efficiency requirements after the measure taking effect. Other technical proposals relate to mandatory power limitation on ships.

OPERATIONAL APPROACH

Operational approaches would include focusing on strengthening the ship energy efficiency management plan, as required in SEEMP. This include proposals for mandatory carbon intensity reduction targets. Operational proposals also include measures to optimize speed for the voyage. Proposals to limit ship speed were also discussed.

ASSESSMENT OF IMPACTS ON STATES

Proponents of the various proposals were invited to provide further details on the initial impact assessment of their proposal, with a view to identifying the remaining issues to be further considered, including whether the proposed measure may generate disproportionately negative impact on some States.

ALTERNATIVE FUELS

With a longer-term perspective, and in order to encourage the uptake of alternative low- and zero-carbon fuels in the shipping sector, the related Working Group also agreed on the establishment of a dedicated workstream for the development of life-cycle GHG/carbon intensity guidelines for all relevant types of fuels. This could include, for example, biofuels, electro-/synthetic fuels such as hydrogen or ammonia, etc.

More than 20 years since the IMO first began efforts to regulate the air emissions from the world's commercial fleet, the industry is now officially on an ambitious course to a zero-carbon future.

ENERGY MARKET FORECAST

The current global energy landscape is centered on the use of hydrocarbon fuels to meet the energy demands of a developing world, but new and emerging emissions regulations are expected to drive significant changes to this landscape.

ABS collaborated with Maritime Strategies International (MSI) to create a global scenario for the future carbon dioxide (CO_2) emissions from shipping, which takes into account the future variation of fuels used in vessels, as well as the decarbonization of different industrial sectors on which shipping depends.

Two cases were considered: (i) a base scenario that follows the International Energy Agency's (IEA) stated policies, and (ii) an Accelerated Climate Action (ACA) scenario that follows the IEA Sustainable Development actions. Both cases are informed by projections made or commissioned by the Intergovernmental Panel on Climate Change (IPCC) and have been projected to 2050.

These scenarios consider how the supply and demand for key commodities – such as iron ore, coal, minor bulks, crude oil, refined products, chemicals, edible oils, liquefied petroleum gas (LPG) and liquefied natural gas (LNG) – and containerized goods will drive global trade until 2050. The forecasts incorporate explicit views on global economic growth, demographics, social factors, and energy intensity.

ENERGY MARKET FORECAST

The following figures present the forecast of future demand for oil, natural gas, and coal, alongside the IEA projections contained in WEO 2019. The scenarios draw on the Stated Policies and Sustainable Development cases prepared by the IEA. The data have been indexed to 2025 to simplify the projection of the trends, as there were some differences in underlying historical data.

In the case of oil and gas, the scenarios are closely aligned with the Stated Policies and Sustainable Development cases from the IEA. In the case of oil, under the ACA scenario, a rapid reduction in demand takes place after 2030, with oil consumption falling from 4.2 BnT to 2.4 BnT by 2050.

For natural gas, the reduction in demand is less severe, since it is seen as a cleaner fuel than coal and oil, with less CO_2 emissions per unit energy, less sulfur, and minimal particulate matter emissions from combustion.

In the case of coal, global consumption is expected to decline, but its continued use in India and other emerging markets to generate electricity is expected to offset this decline on a global basis.

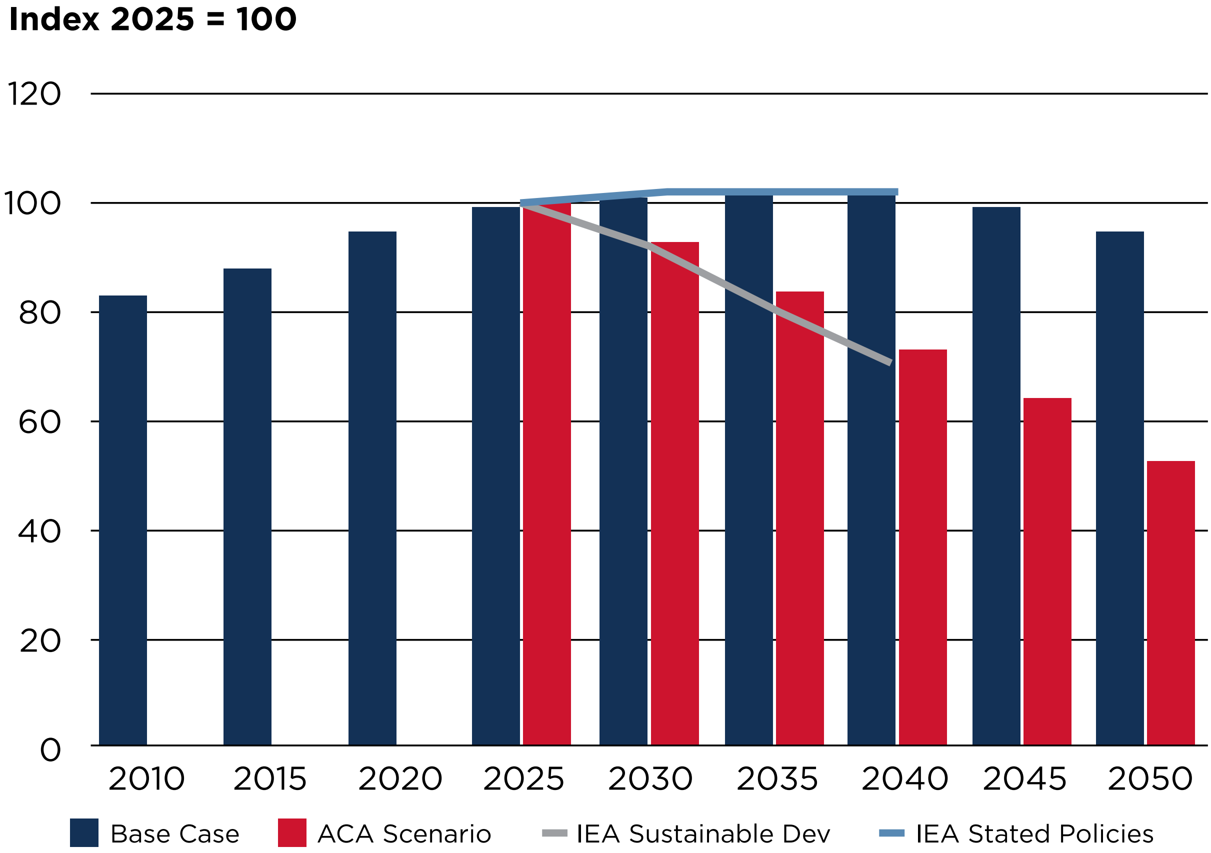


Figure 1: Forecast of global future demand for oil.

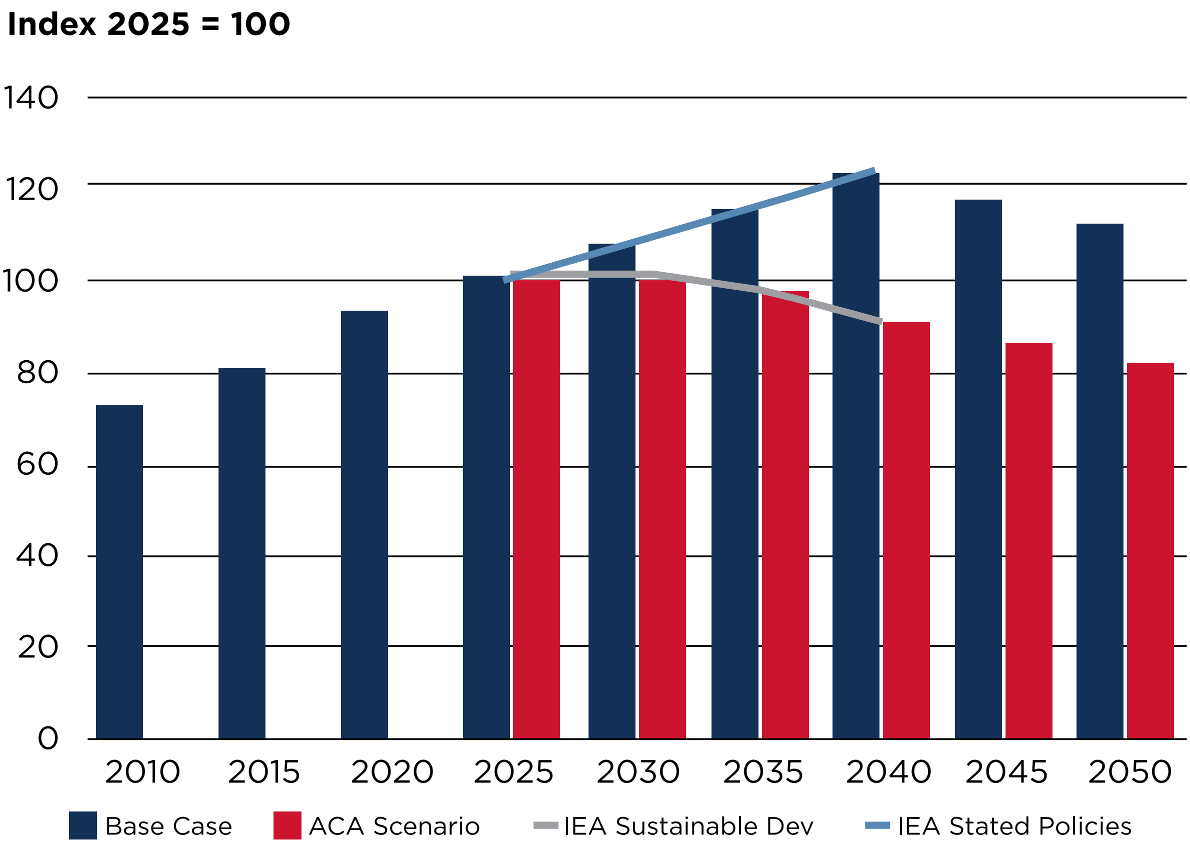


Figure 2: Forecast of global future demand for natural gas.

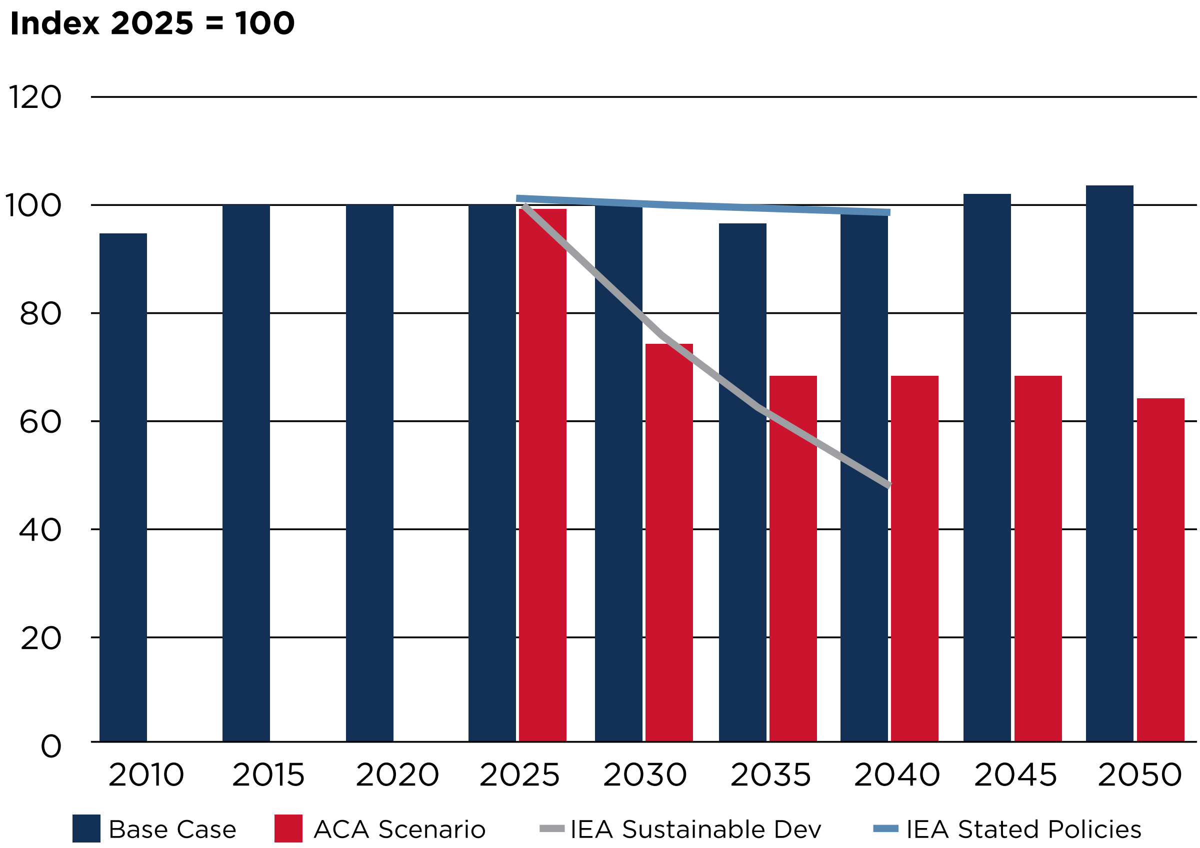


Figure 3: Forecast of global future demand for coal.

THE LINK BETWEEN TRADE AND TECHNOLOGY CHOICES

The wide range of vessels in the global fleet and their diverse trade routes create unique opportunities and challenges for shipowners as they set a course to decarbonization.

Both short- and deep-sea vessels can be used for international trade and carry similar types of goods. However, the markets are distinctly different in terms of ability to adopt new technology, available resources and the complexity of their regulatory frameworks. These differences and commonalities will greatly influence the pathways that owners choose to reach the International Maritime Organization's (IMO) greenhouse gas (GHG) reduction targets for 2030, 2050 and beyond.

Short-sea vessels are primarily used in environmentally sensitive areas, such as the Baltic Sea, inland rivers or lakes located close to urban areas, where emissions are strictly regulated.

About 60 percent of the European sea trade is handled by short-sea shipping across areas such as the Mediterranean, the North and Irish Seas, the Baltic and throughout the continental countries served by rivers. Similar national and regional trade clusters exist in Africa, Asia, North and South America. Also, the short-sea trades tend to be governed by local and regional regulations, rather than global ones.

Ownership of short-sea vessels tends to be distributed among small- to medium-sized companies that usually have limited resources to spend on new technology. Therefore, they tend to be supported by government initiatives that incentivize the adoption of any new technologies designed to benefit the public.

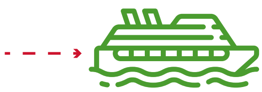
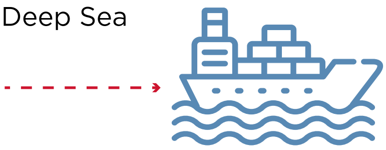
Examples of such initiatives are the European Union's (EU) Connecting Europe Facility[2] and Horizon 2020[3].

The trade and regulatory landscape of short-sea vessels make them ideal candidates for early adoption of the new technologies that promote environmental sustainability. Some examples include low- and zero-carbon fuels such as liquefied natural gas (LNG), methanol and ammonia, as well as hybrid-electric power generation and propulsion systems.

Fuels such as methanol and ammonia have strong potential to lower the carbon footprint of shipping; but one of their challenges is their low energy content and the comparatively lower amount of energy they can store in the tanks of a ship.

Short-sea shipping can accommodate the use of fuels with low energy content – such as methanol or ammonia – that require more frequent bunkering.

Trade Factors and Technology Adoption

Short Sea 	• Access to frequent refueling • Often travel on a fixed route • May benefit from government subsidies • Good early adopters of technology
Deep Sea 	• Purpose-built; designed for a function • Follow a holistic approach • High capital cost for new equipment • Built new or retrofitted

Similar challenges arise from the use of batteries in hybrid-electric propulsion systems, which require frequent recharging when the vessel is periodically operated in full electric mode. From a commercial perspective, short-sea shipping competes with ground transportation, so new technologies will need to satisfy the regulatory landscape to keep the sector environmentally and economically competitive.

Deep-sea vessels are used for intercontinental trade and are therefore subject to global regulations. The trend toward more stringent regional regulations, such as those seen in emissions control areas, may increase the complexity of maintaining the compliance of deep-sea vessels that tend to operate in multiple jurisdictions.

Also, from a commercial perspective, the large vessels used for deep-sea shipping tend to be designed for a single cargo, which is more subject to market fluctuations and supply chain risks. This uncertainty makes shipowners more cautious about adopting new technologies before they are operationally and economically proven.

Furthermore, charterers considering further ways to differentiate themselves are increasingly likely to set stronger requirements for environmental performance and compliance with strict regional regulations.

For these reasons, the technical development of large vessels requires a holistic approach to their design, so that efficient and sustainable operations can be optimized.

The adoption of low- and zero-carbon fuels for large vessels is more challenging than for smaller ones. Using fuels with low energy content, such as methanol and ammonia, would require a significant redesign, not least because their fuel tanks would need to be expanded to store enough energy for longer deep-sea travel.

With capital expenses for redesigns and retrofits rising, the vessel's employment prospects would need to justify this investment.

However, certain types of vessels could be early adopters of alternative fuels, if they carry those fuels as cargo. Aside from LNG carriers, liquefied petroleum gas (LPG) carriers also can utilize their cargo in dual-fuel engines, while reducing their carbon footprints.

In an effort to harmonize the global fleet with IMO goals and regulations, each vessel type faces a challenge to optimize the performance of its technical, financial and operational elements.

Short-sea vessels can be early adopters of new fuels and technologies that may compromise their range at sea, but offer environmental benefits; however, deep-sea vessels will require more holistic approaches to adopting new fuels and technologies so that they can improve their operational efficiency.

The nature and trade route of each cargo will have a great influence on the fuels and new technologies adopted by each vessel as they pursue a pathway to a zero-carbon future.

HOW TAXONOMIES LEAD TO FUEL PATHWAYS

The owners of internationally trading ships are facing increasingly complex investment decisions as they try to identify the optimum course to the low-carbon future mandated by the International Maritime Organization (IMO).

A number of new technologies are being developed in response to the need to decarbonize, but their practical viability may have limitations at this point in time. The same holds for some prospective fuels, even if they have the strongest potential to reduce the carbon footprint of future vessels.

All enabling technologies and fuels will need to be assessed in part on their technological readiness, their potential for large scale commercialization, and their ability to reduce the carbon footprints of vessels in the short, medium and long term.

Identifying the optimum specifications of each vessel for different types of applications can be a challenging task, since the range of available technical solutions is wide.

However, by examining the onboard technologies in whole – engines, as well as fuel containment, storage, and supply systems – common taxonomies can be identified to simplify the decision-making process.

The available fuel options can be categorized into three pathways that can propel the maritime industry to 2030 and beyond:

(i) The light gas pathway,

(ii) The heavy gas and alcohol pathway, and

(iii) The bio/synthetic fuel pathway

The first two categories include fuels, such as liquefied natural gas (LNG) and liquefied petroleum gas (LPG), which are already commercially used to reduce the carbon footprint of vessels. Practical carbon-neutral and zero-carbon solutions, however, are still under development.

The selection of the fuel pathway and the associated onboard technologies should be based on two foundational criteria: the type of vessel and its operating profile in terms of trading route and cargo.

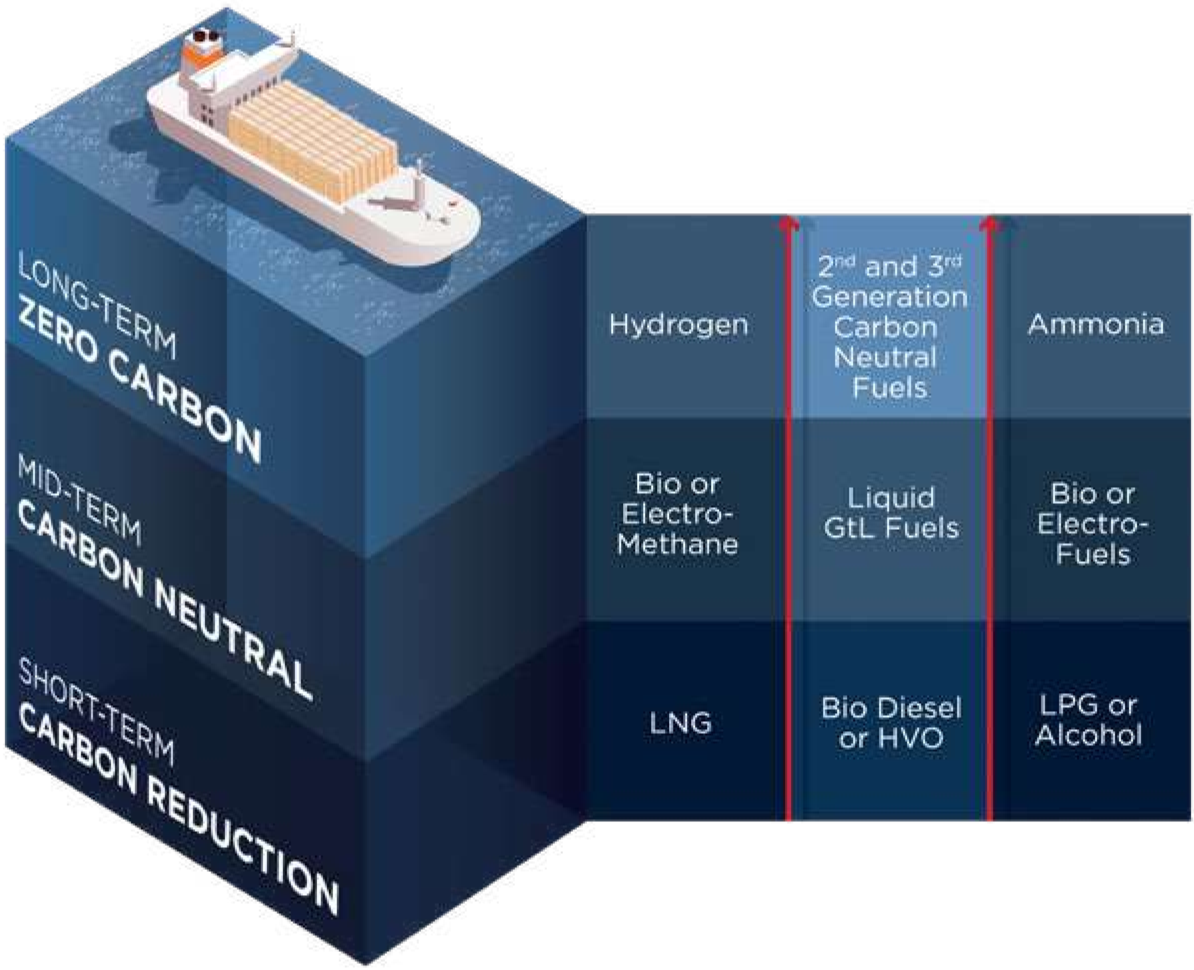
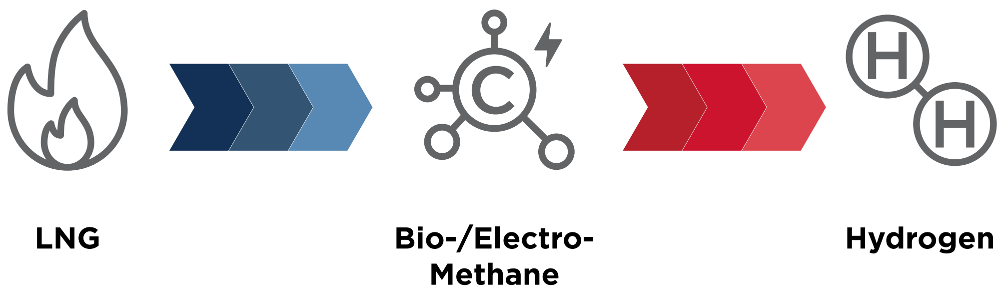


Figure 1: The three fuel pathways to carbon-neutral and zero-carbon shipping.

THE LIGHT GAS PATHWAY

This category includes fuels comprised of small molecules with low-carbon/hydrogen (C/H) ratio, which helps to reduce carbon emissions, and in the case of methane (CH_4) high energy content. However, they require cryogenic storage and more demanding fuel delivery systems.

Such fuels include LNG, bio-LNG, and synthetic natural gas (SNG) or renewable natural gas (RNG), which can be produced from biomass and/or by using renewable energy. The production of the synthetic or renewable fuels from biomass is currently limited in scale and will have to be increased before they can be considered as viable commercial solutions.



LNG is a relatively mature low-carbon fuel, comprised primarily of methane. Its C/H ratio offers a reduction in carbon dioxide (CO_2) emissions of up to 21 percent compared to baseline heavy fuel oils[4]. This value does not include carbon release from methane slip, which may be an issue in two-stroke or four-stroke engines that operate on LNG in the Otto cycle.

Minimizing methane slip is critical to the commercial adoption of these renewable fuels. The industry is currently developing in-cylinder emissions control strategies, which could be combined with aftertreatment systems. By minimizing methane slip, fuels such as bio-LNG and SNG/RNG can offer carbon-neutral propulsion.

The two-stroke and four-stroke engine manufacturers already offer solutions for minimizing methane slip from combustion, using high-pressure gas injection in the cylinder. These can be combined with methane oxidation catalysts and other aftertreatment systems used to treat the exhaust gas to further reduce the methane emissions and minimize the carbon output of using LNG.

As a low-carbon fuel, LNG can be combined with new technologies and/or operational measures to meet the 2030 emissions-reduction goals, and it can contribute to further reductions in future, if blended with bio-LNG or SNG/RNG. If the latter can be commercialized and made available at large scale in the medium term, the carbon footprint from using LNG would be reduced in proportion to the amount of renewable fuel used in the blend.

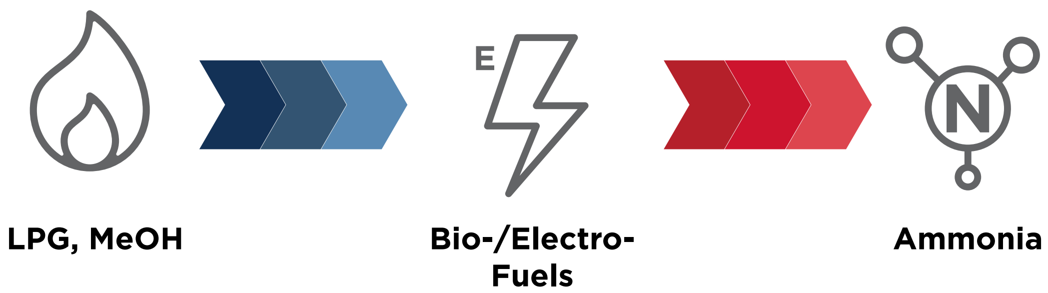
Given the carbon neutral promise of bio-LNG and SNG/RNG, significant efforts are currently being made to explore these solutions for commercial use.

At the end of the light gas spectrum, hydrogen may be a solution for future zero-carbon marine vessels. It offers the highest energy content per mass among all candidate fuels, high diffusivity, and high flame speed. However, it also requires cryogenic storage and dedicated fuel supply systems for containment.

Hydrogen as a fuel has been demonstrated in internal combustion engines, gas turbines, and fuel cells, all of which will play a role in marine power generation and propulsion systems. Nevertheless, significant technical advances are needed before hydrogen can be considered a viable, large scale, commercial fuel option.

THE HEAVY GAS AND ALCOHOL PATHWAY

This category includes fuels comprised of larger molecules than the light gas group. As such, they have higher C/H ratios – therefore, lower carbon-reduction potential – and lower energy content. Their fuel storage and supply requirements are also less demanding.



These fuels include LPG, methanol, ethanol and ammonia. The alcohols tend to have lower energy content and the presence of oxygen in the fuel can create issues pertaining to chemical compatibility in fuel-supply systems.

When used as the primary fuel, methanol can reduce CO_2 emissions by around 10 percent[5]. However, methanol has the potential to be a carbon-neutral fuel in the future, if it is produced renewably as bio-methanol or electro-methanol.

The lower energy content of some of these fuels (e.g. methanol) limits the amount of fuel energy that can be stored on board a ship; thus, they only may be suited to the types of vessels, trades and routes that allow for frequent refueling.

LPG has higher energy content than the alcohols and may be more conducive to use in modern dual-fuel engines, but it has not been as widely adopted as LNG due to its lower potential to lower emissions, and its different safety challenges.

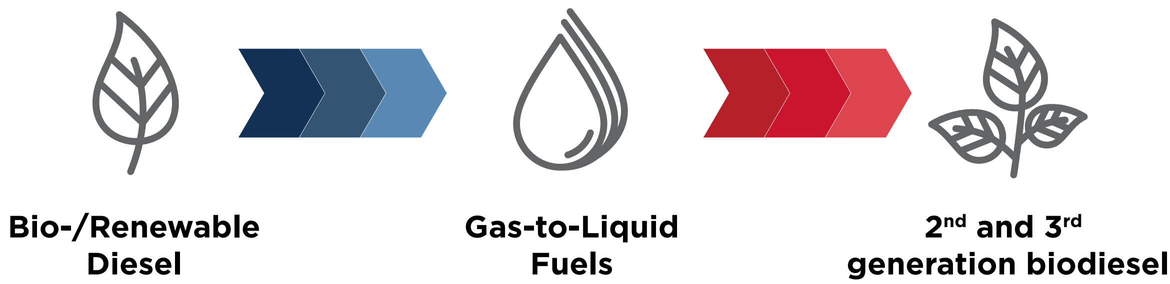
However, methanol and LPG are currently thought of as mature fuels by engine manufacturers, which have marketed engine platforms able to use them. Therefore, they can be used to meet the carbon-reduction goals of 2030 and can pave the way to carbon-neutral propulsion, if they are produced renewably in the future.

At the end of the heavy gas or alcohol spectrum, lies ammonia, which can be a zero-carbon fuel if produced renewably. Despite its toxicity and more stringent handling requirements, ammonia engines are in the design process.

Recently, designs for ammonia-fueled feeder ships also have been unveiled by consortia that variously include designers, class and shipyards. However, for ammonia to become a commercially viable long-term fuel option, comprehensive supply-side infrastructure would need to be built and new, stringent safety regulations designed and implemented.

THE BIO/SYNTHETIC PATHWAY

This category includes fuels that are produced from biomass, including plants, waste oils and agricultural waste. Catalytic processing and upgrading of biomass can yield liquid fuels with physical and chemical properties comparable to diesel oil; this is desirable from a design standpoint because they can be used as drop-in biofuels with minimal or no changes to marine engines and their fuel delivery systems.



Currently, the most widely used component is fatty acid methyl esters (FAME) or biodiesel, which is described in the latest ISO (8217/2017) specifications for marine fuel blends and is being offered by major oil companies.

The standard allows for seven percent biodiesel in the fuel blend, but some shipowners are testing richer blends, from 20 to 100 percent. FAME is a first generation biofuel and faces challenges associated with its poor oxidative stability, and its potential to degrade over time.

Hydro-treated vegetable oil (HVO) is a second generation biofuel, which is not produced from food crops. It is often referred to as renewable diesel and produced using modern hydro-treating processes, which yield high-quality fuels with better stability than FAME biodiesel.

HVO has similar physical and chemical properties to marine gas oil (MGO), making it fully compatible with existing engines and fuel-delivery systems. Renewable diesel also can be produced from biomass gasification, using the Fischer-Tropsch (FT) process. It is often referred to as a gas-to-liquid or biomass-to-liquid fuel.

Renewable diesel fuel is thought to be a promising medium- to long-term solution for shipowners, because it can offer a significant reduction in carbon output with minimal capital expenditures.

Electro-fuels: Using renewable energy to produce electro-fuels from biomass could reduce the energy required for their production, and thus reduce their life-cycle carbon footprint. This technique can be applied to any of the three fuel pathways to produce bio-LNG, bio-methanol or renewable diesel.

Electro-fuels have the potential to offer carbon-neutral propulsion and can provide solutions in the medium- to long-term. In addition to fossil and biomass sources, electro-fuels can be produced by carbon dioxide recovery (CDR), a technique that converts CO_2 to syngas, which in turn can be used to produce bio-LNG or bio-methanol.

CDR has the potential to remove CO_2 from the atmosphere and use it for production of electro-fuels, thereby minimizing the energy needed for fuel production and their potential to reduce global warming.

The following three sections (pages 15-40) present a detailed discussion on each fuel pathway.

LIGHT GAS PATHWAY

The light gas group consists of gaseous fuels that contain small molecules and have relatively high energy content. Liquefied natural gas (LNG) is a prime example, which is currently in use in a small but growing part of the global shipping fleet. Currently this pathway is a focal point because the maritime industry is exploring ways of adopting LNG as a primary fuel. Furthermore, LNG related technologies have been used extensively on LNG carriers and the industry has gained substantial experience. This section presents in more detail the related technology and highlights the benefits and challenges associated with the use of light gases.

CURRENT STATE OF THE ART

LNG is a fossil fuel that offers low emissions compared to heavy fuel oil (HFO), is economically attractive, and is available at large scale. It is stored in cryogenic conditions, at -162° C on board ships, and its use in marine vessels is supported by established engine technologies, either dual fuel with the use of micro-pilot diesel injection in large two-stroke and smaller four-stroke engines, or as single fuel for small- and medium-sized engines.

LNG contains negligible amounts of sulfur, therefore its combustion does not produce sulfur oxides (SO_x). It also minimizes or eliminates the emission of particulate matter, reduces the carbon dioxide (CO_2) emissions from combustion compared to HFO due to its lower carbon content, and reduces nitrogen oxides (NO_x) emissions due to the lower cylinder temperatures during combustion. However, the use of LNG may lead to methane slip, when the fresh fuel-air mixture escapes unburned from the cylinder to the exhaust, or from incomplete combustion.

The large two-stroke engines currently in production use LNG in combination with HFO/marine gas oil (MGO) in a dual-fuel combustion process. Two main injection concepts have been used: the low-pressure gas injection used by WinGD in the X-DF engines; and the high-pressure gas injection used by MAN in the ME-GI engines (Figure 1). The key difference between them is that the low-pressure system injects gas into the cylinder early in the compression stroke at pressures of up to 13 bar, while the high-pressure system injects gas into the cylinder late in the compression stroke at pressures up to 300 bar.

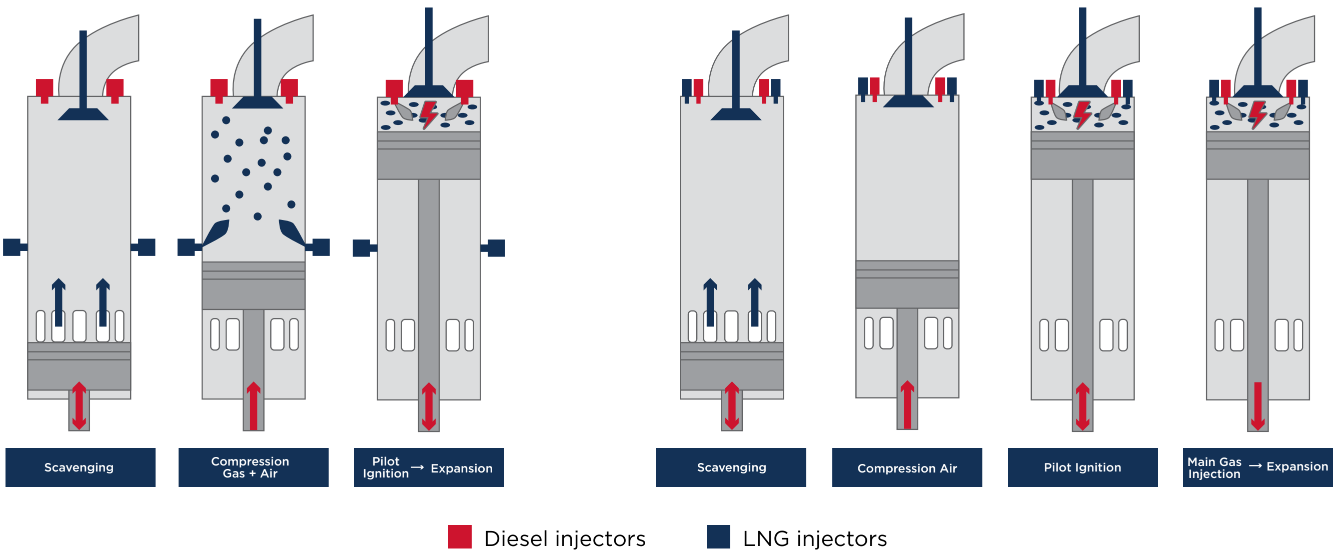


Figure 1: Comparison of low-pressure X-DF (WinGD) vs. high-pressure ME-GI (MAN) gas injection DF engines.

In the low-pressure concept, gas may be injected into the cylinder while the exhaust valve is still open, which may lead to some fresh fuel-air mixture escaping to the exhaust, contributing to unburned hydrocarbon emissions and methane slip. The high-pressure system helps to avoid methane slip by injecting the gas after the exhaust valve closes. In both concepts, however, fuel that is not burned during the combustion process can result in small amounts of methane slip.

In the low-pressure concept, the injection of the fuel early in the compression stroke creates a nearly homogeneous background gas-air mixture, which is ignited by a pilot diesel injection late in the compression stroke. This process leads to relatively low burned gas temperature that results in comparatively low NO_x emissions and can make the engine International Maritime Organization (IMO) Tier III compliant without the need for aftertreatment.

On the other hand, in the high-pressure concept gas is injected as soon as the pilot fuel combustion begins, and the gas burns in a diffusion combustion process, which leads to higher burned gas temperatures and a relatively higher formation of NO_x that will require aftertreatment to achieve IMO Tier III compliance.

	Low Pressure	High Pressure
Gas mode cycle type	Otto	Diesel
Main engine manufacturers	Winterthur Gas and Diesel (WinGD) "X-DF"	MAN Energy Solutions (MES) "ME-GI"
Gas injection	Through cylinder wall, well above scavenge ports, with gas admission valves, soon after start of compression stroke	Through cylinder head with separate gas injection valves, once pilot fuel ignites
Gas supply pressure [bar]	< 13	300
Liquid pilot fuel [%]	1.0	0.5–1.5
BMEP [bar]	17.3	21–22
Min. load for DF Mode [%]	5	5
IMO NO_x Compliance	Tier III (gas mode) Tier II (oil mode)	Tier II (oil mode) Tier II (gas mode)
Methane Number/ gas quality sensitive	Yes	No
Methane slip	Yes	Negligible
Knock/misfire sensitive	Yes	No

Table 1: Low-pressure X-DF vs. high-pressure ME-GI engine specifications.

From a regulatory perspective, the International Code of Safety for Ships Using Gases or Other Low Flashpoint Fuels (IGF) defines a high-pressure system as anything that supplies gas at 10 bar or higher. Therefore, both systems carry that designation, which is mainly for the purposes of piping, pressure-vessel design, and certification.

MAN Energy Solutions was the first large engine manufacturer to offer an DF engine equipped with a high-pressure system. The ME-GI family was introduced in 2013 and is an evolution of the “ME” series electronic engine and the “MC-GI” mechanical dual-fuel (DF) engine of the 1990s, used in a range of marine and stationary power generation applications. WinGD joined the DF engine market later, but they have achieved significant market share after building on Wärtsilä’s extensive experience with low-pressure gas supply systems used in their four-stroke medium-speed DF engines.

Aside from the use of dual-fuel two-stroke engines, a range of dual-fuel four-stroke engines have been used for applications of marine and stationary power generation. Initially, these engines were introduced in diesel-electric gas carriers with outputs in the 6-18 MW range, such as the Wärtsilä 50DF and MAN 51/60DF engines.

As the size and type of ships using gas as fuel increased, so did the number of available marine-gas and DF engines. The established marine engine manufacturers have expanded their ranges and other manufacturers have entered the market. An example is the Wärtsilä 31 family of engines, which was recently introduced as a new generation of medium-speed engines, and is offered in diesel, DF and spark gas (SG) configurations.

In its DF configuration, the engine uses low-pressure gas injection into the intake port, which creates a nearly homogeneous gas-air mixture in the cylinder, ignited by a diesel injection late in the compression stroke.

However, in the gas-only configuration, the engine uses a pre-chamber ignition system, which includes a gas injector in the intake port and a second gas injector directly into the pre-chamber (Figure 2).

Combustion is started in the pre-chamber using a spark discharge. After the pressure rises in the pre-chamber, the gas forms high-speed jets in the main chamber, which create distributed ignition sites in the cylinder. This process results in rapid combustion of the fuel-air mixture – avoiding end-gas knock – and enables the use of high compression ratio for higher thermal efficiency. It also offers high combustion efficiency, which helps to eliminate methane slip. The second fuel injector placed directly into the pre-chamber enables the engine to operate at very lean mixtures by injecting additional gas into the pre-chamber and promoting lean ignition.

Figure 2: Wärtsilä 31 engine in spark gas (SG, left) and dual fuel (DF, right) versions.

STORAGE

The design and operational requirements for different LNG fuel containment systems are described in the International Code for the Construction and Equipment and Ships Carrying Liquefied Gases in Bulk (IGC) and IGF, namely independent tank types A, B and C and dependent membrane tanks (Figure 3). Types A, B and membrane are low pressure, nominally "atmospheric" tanks, and Type C are designed using pressure vessel codes. The predominant technologies used for LNG carrier fuel containment in the past 20 years are the membrane and Type B Moss systems. Type A, B and membrane tanks require a secondary barrier to contain leaks from the primary barrier. Type A and membrane systems require a full secondary barrier. Type B require a partial secondary barrier, since they are designed using advanced fatigue analysis tools and a "leak-before-failure" concept, for which small leaks can be managed with partial cryogenic barrier protection and inert gas management of the inter-barrier space. Type C tanks are designed using pressure vessel code criteria and conservative stress limits; therefore they do not require a secondary barrier.

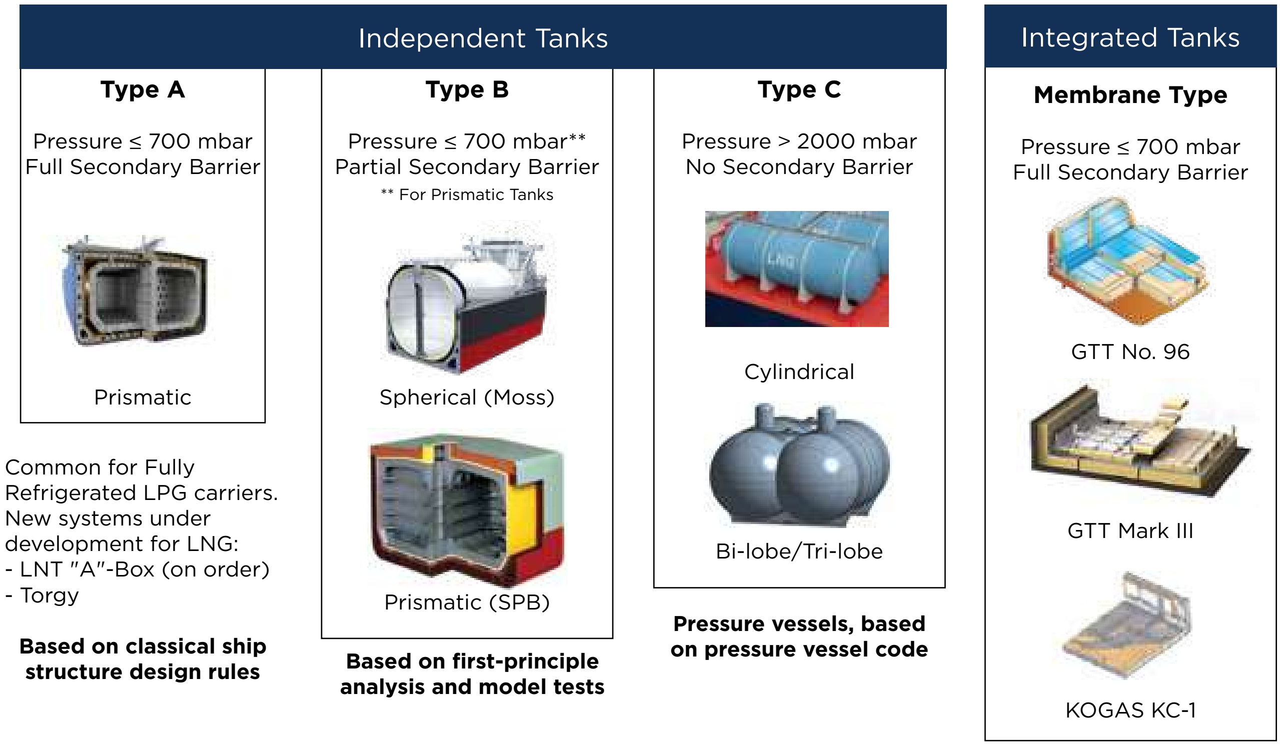


Figure 3: Tank options for LNG storage on board.

The easiest way to keep the LNG cooled at ambient pressure is to let part of the cargo boil off. LNG is stored and transported as a boiling liquid and therefore requires an effective boil-off gas (BOG) management strategy. Historically, cargo-containment systems were designed with maximum boil-off rates (BOR) of 0.15 percent volume per day, which matched well with the fuel requirements of the relatively low-efficiency steam turbine plants. The transition to diesel-electric and slow-speed DF engines that started in 2005 and 2014, respectively, has driven designs with improved LNG tank insulation and BOR as low as 0.08 percent to better match the available BOG to the higher efficiency of the internal combustion engines.

For gas-fueled ships, the amount of BOG available may not be enough to sustain the power demands of propulsion, so the fuel gas supply systems need to force vaporize the LNG into conditions suitable for the engines. But the ship will still need to manage the BOG and LNG tank pressures at all times, which can lead to many potential combinations for fuel supply and BOG management equipment.

The available fuel storage and engine technologies support the use of LNG and other gaseous fuels in the short and medium term as robust options for power generation and propulsion. While the potential of LNG to reduce the carbon footprint of shipping in the short term is well understood, it also paves the way for the blended use of renewable and zero-carbon gaseous fuels.

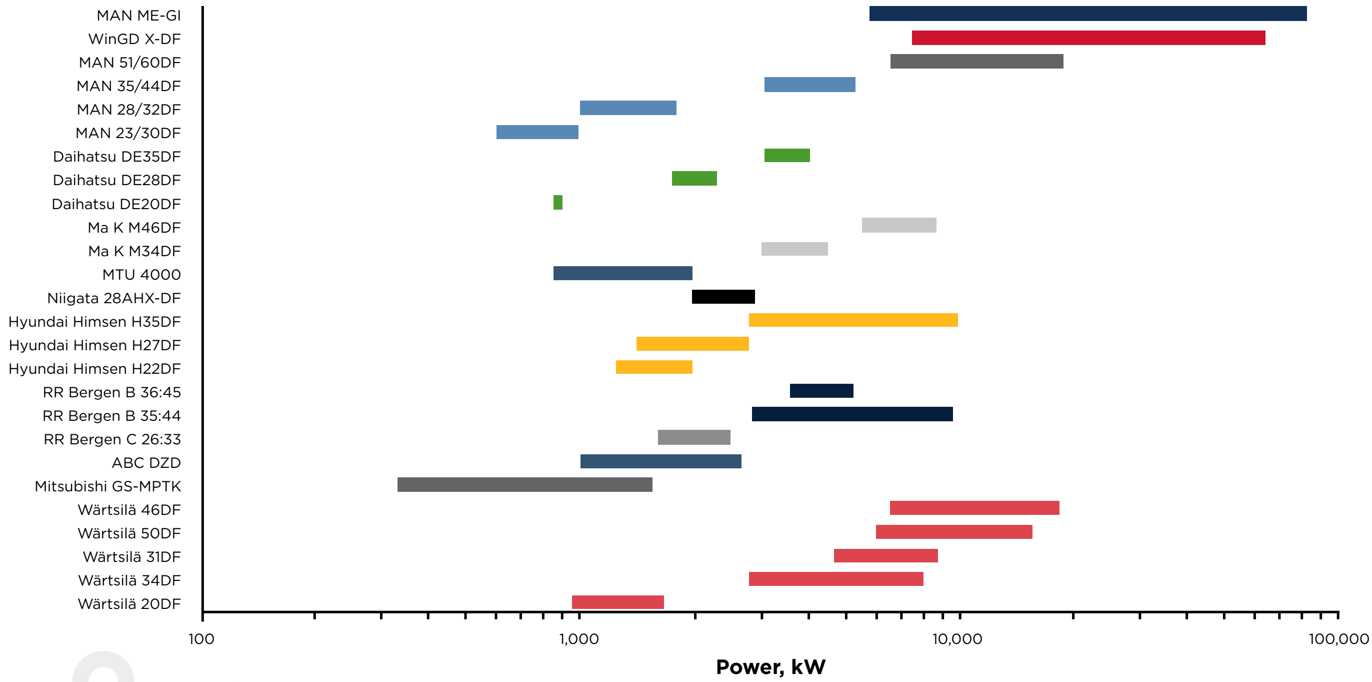


Figure 4: Range of marine dual fuel and gas engines.

MEDIUM-TERM DEVELOPMENT

The carbon footprint of LNG can be reduced or eliminated if it is produced from renewable sources. These fuels are known as bio-LNG, synthetic natural gas (SNG), renewable natural gas (RNG), or electro-methane, in which renewable energy is used to produce LNG with the use of electric power.

SNG can be produced from coal or biomass through gasification and methanation, which yield mixtures that have at least 90 percent methane content by volume with the same physical and chemical properties as fossil natural gas. The coal-to-SNG conversion produces CO_2 in amounts that can be higher than if coal was burned. Therefore, it is not a viable production pathway, unless the carbon capture and sequestration of CO_2 is used in the production process.

On the other hand, biomass can be used to produce SNG/RNG at efficiency of up to 70 percent[6, 7]. In this process, production costs can be minimized by maximizing the scale of production and by locating an anaerobic-digestion plant next to transport sites (such as ports) for the biomass. Present gas storage infrastructure can allow the plants to continue to produce gas at a full rate even during periods of low demand, which helps to reduce the cost per unit mass.

SNG/RNG are produced through three main processes:

- Anaerobic digestion of organic (typically moist) material
- Thermal gasification of organic (typically dry) material
- Production through the Sabatier method[1], and upgrading

A 2011 analysis conducted by the Gas Technology Institute showed that RNG produced from waste biomass (e.g. agricultural waste) has the potential to offer up to 2.5 quadrillion British thermal units (Btu) annually, or equal to the natural gas needs for 50 percent of the homes in the United States[8]. Similar studies have been performed in the U.K.[9], Netherlands[10], Sweden and other countries, showing the strong potential of renewable natural gas to satisfy the energy needs of the future.

Based on these findings, SNG/RNG seems to be well suited to countries with extensive natural gas distribution networks. The core advantages of SNG/RNG are their compatibility with existing infrastructure, higher production efficiency than Fischer-Tropsch (FT) fuels, and smaller production scale than other, second generation, biofuel-production systems[11].

Property	SNG/RNG	MGO
Liquid Density (kg/m^3)	430-470	825
Lower Heating Value (MJ/kg)	45.3	43.1
Air/Fuel stoichiometry (A/F)	17.2	15.0
Research Octane Number (RON)	~130	N/A
Oxygen content (% vol.)	0	0
Aromatics content (% vol.)	0	~30
Sulfur content (ppm)	0	< 10

Table 2: Properties of synthetic or renewable natural gas.

Another method of producing RNG is through the use of electric power that is produced renewably. This set of technologies is often described as "power-to-gas" and the fuels are generally described as "electro-fuels." Currently, there are three methods for producing gaseous fuels through electric power; all of them use the electrolysis of water to form hydrogen and oxygen. The methods are described below:

- Hydrogen is fed directly into the natural gas grid or used in transportation, or the industry
- Hydrogen reacts with carbon dioxide to produce methane or SNG/RNG using a methanation reaction, which can then be used in any natural gas application
- Biogas is used as a low-quality fuel and then upgraded using the available hydrogen

Using natural gas pipelines for hydrogen has been studied by the EU NaturalHy project[12] and the U.S. Department of Energy[13]. This blending technology is currently used to produce hydrogen-compressed natural gas (HCNG), a mixture of compressed natural gas and four to nine percent hydrogen by energy. HCNG can be used as fuel for internal combustion engines and fuel cells, and can directly reduce the carbon footprint of natural gas in proportion to the blending level. Overall, the use of RNG has the potential to offer carbon-neutral propulsion for marine vessels, in DF or single-fuel applications, without any modifications to existing two-stroke or four-stroke engines and their fuel supply systems.

LONG-TERM DEVELOPMENT

At the end of the light gas spectrum, hydrogen has the potential to offer zero carbon propulsion for marine vessels. It can be produced from a variety of sources using conventional or renewable energy and can be used directly in internal combustion engines or fuel cells.

Hydrogen can be extracted from fossil fuels and biomass, or from water, or from a combination of the three. Currently, the energy used worldwide for the production of hydrogen is about 275 Mtoe (million tonnes of oil equivalent), which corresponds to two percent of the world energy demand[14]. Natural gas is currently the primary source of hydrogen production (75 percent) and is used widely in the ammonia and methanol industries.

The second source of hydrogen production is coal (23 percent), which is dominant in China. The remaining two percent of global hydrogen production is based on oil and electric power (Figure 5).

The strong dependence on natural gas and coal means that the current production of hydrogen is very carbon intensive, ranging between 10 tCO_2/tH_2 for natural gas to 19 tCO_2/tH_2 for coal (Figure 6), but these emissions can be reduced with the use of carbon capture and sequestration technology.

The extraction of hydrogen from natural gas is accomplished through reformation using three established methods: (i) steam reforming, which uses water as an oxidant and a source of hydrogen, (ii) partial oxidation, which uses the oxygen in air in the presence of a catalyst, and (iii) autothermal reforming, which is a combination of the first two.

In all cases, syngas ($CO + H_2$) is formed and then converted to hydrogen and CO_2 through the water-gas shift reaction. However, to reduce the carbon intensity of hydrogen production, biomass can be used for production of syngas though gasification, or renewable electric power can be used to electrolyze water.

Once produced, hydrogen can be stored as a gas or liquid, depending on the amount, the storage time, and the required discharge rate. Its use can range from small-scale mobile and stationary applications to large-scale intercontinental trade; different applications create different storage needs.

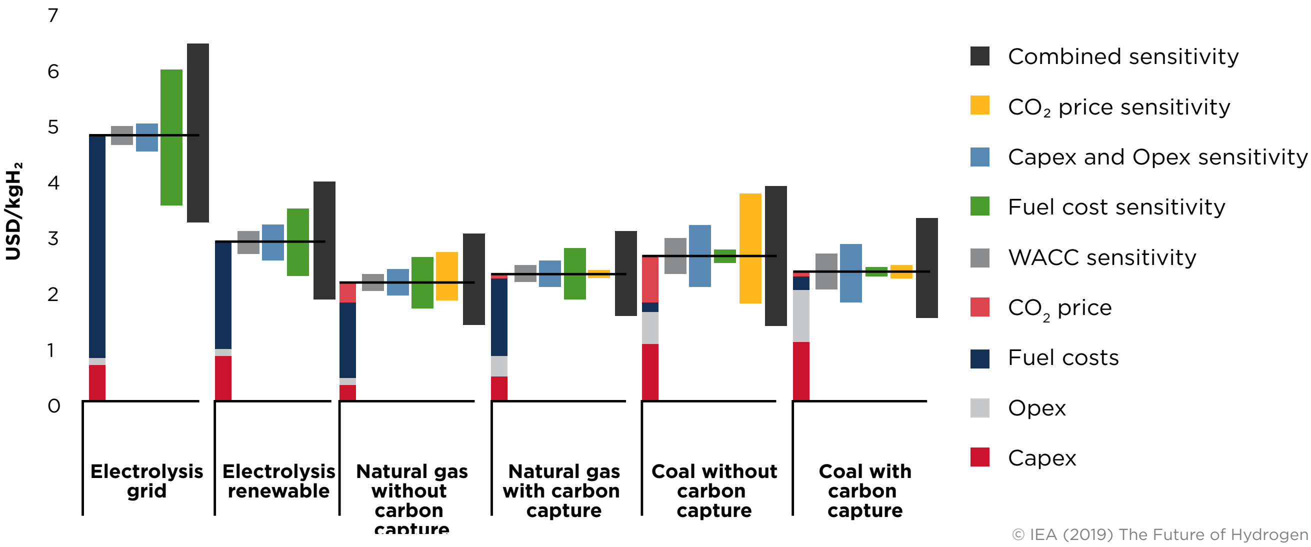


Figure 5: Hydrogen production costs for different technologies in 2030. (WACC = Weighted Average Cost of Capital) (WACC = Weighted Average Cost of Capital).

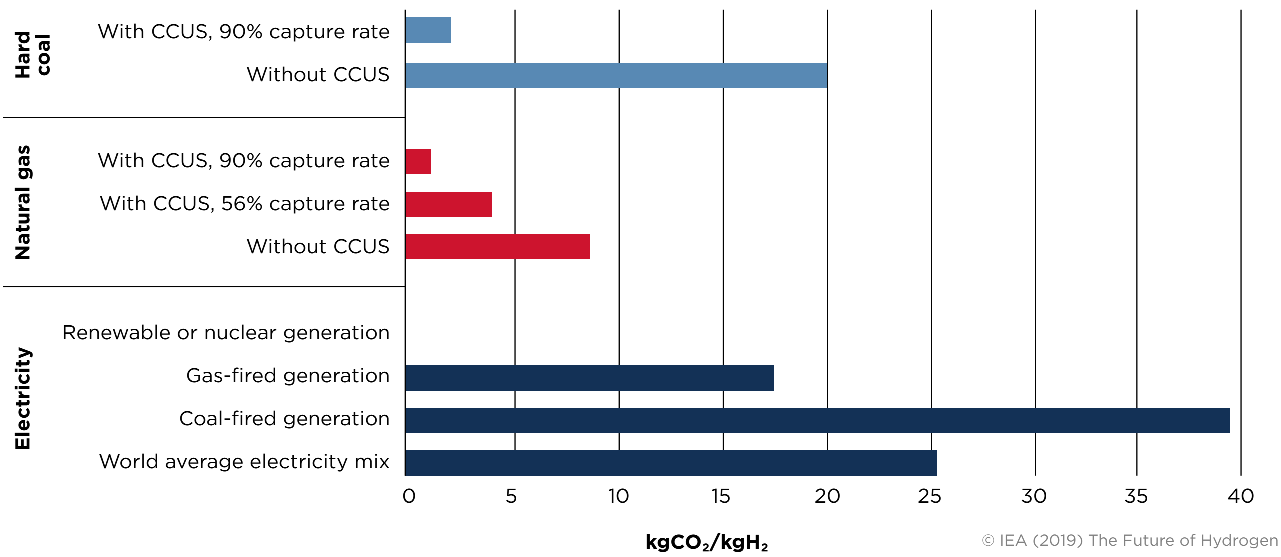


Figure 6: Carbon intensity of hydrogen production with and without utilizing Carbon Capture Utilization and Storage (CCUS).

The heating value of hydrogen is the highest among all candidate marine fuels at 120.2 MJ/kg. However, its energy density per unit of volume, even when liquefied, is significantly lower than that of distillates.

Compressed hydrogen at 700 bar has only approximately 15 percent the energy density of diesel, thus storing the same amount of energy requires about seven times larger tanks on board a ship. This means that compressed or liquefied storage of pure hydrogen may be practical only for small ships that have frequent access to bunkering stations. The deep-sea fleet will likely need a different fuel as a hydrogen carrier, such as ammonia, to limit significant loss of cargo space.

Ammonia (discussed in the following section) has higher energy density than hydrogen, which reduces the need for larger tanks. But its advantages need to be weighed against the energy losses and additional equipment required for conversion to hydrogen before it is used in the engines or fuel cells[14].

Alternatively, ammonia can be used directly as a liquid fuel in engines, rather than as a hydrogen carrier. Reducing the size of the tanks for hydrogen storage is an active research topic. In addition, hydrogen storage in solid-state materials, such as metal and chemical hydrides, is in the early stages of development. This technology can enable higher density of hydrogen to be stored at atmospheric pressure.

The use of hydrogen as a marine fuel is covered within the scope of the IGF Code but, at present, there are no specific initiatives at the IMO to develop hydrogen-focused requirements. However, this could favor applying the risk-based approach of the alternative-design process, allowing for greater freedom in design solutions.

The only existing IMO reference instrument was developed to support the carriage of liquefied hydrogen, MSC.420 (97)(32); it is applicable to ships subject to the IGC Code. There are pilot projects investigating the use of hydrogen as a fuel, the deep-sea transport of liquefied hydrogen and liquefied hydrogen bunker-ship concepts.

Developing the hydrogen economy is seen in energy and transport sectors as a potential long-term objective that would provide a sustainable and clean future. This would require the production of hydrogen from clean renewable sources and the commercialization of fuel cells. Fuel supplied directly from hydrogen-fuel sources (rather than through the reforming of other hydrogen carriers) is the preferred option.

The IMO has been developing requirements for fuel cells and currently plans to release these as "interim guidelines."

Information on the cost of using liquid hydrogen for international shipping is currently scarce. It is estimated that the additional cost of bunkering facilities and suggested that liquid hydrogen infrastructure could be 30 percent more expensive than LNG, but this estimate may be conservative.

The main cost components are the storage and bunker vessels, which need to be scaled based on the number of ships serviced[14]. On-site availability of hydrogen would be needed for small ports, given the lower flows and high cost of dedicated hydrogen pipelines. However, ship and infrastructure costs are a relatively small fraction of total shipping costs over a 15–20-year lifespan, with the fuel cost being the primary factor[14].

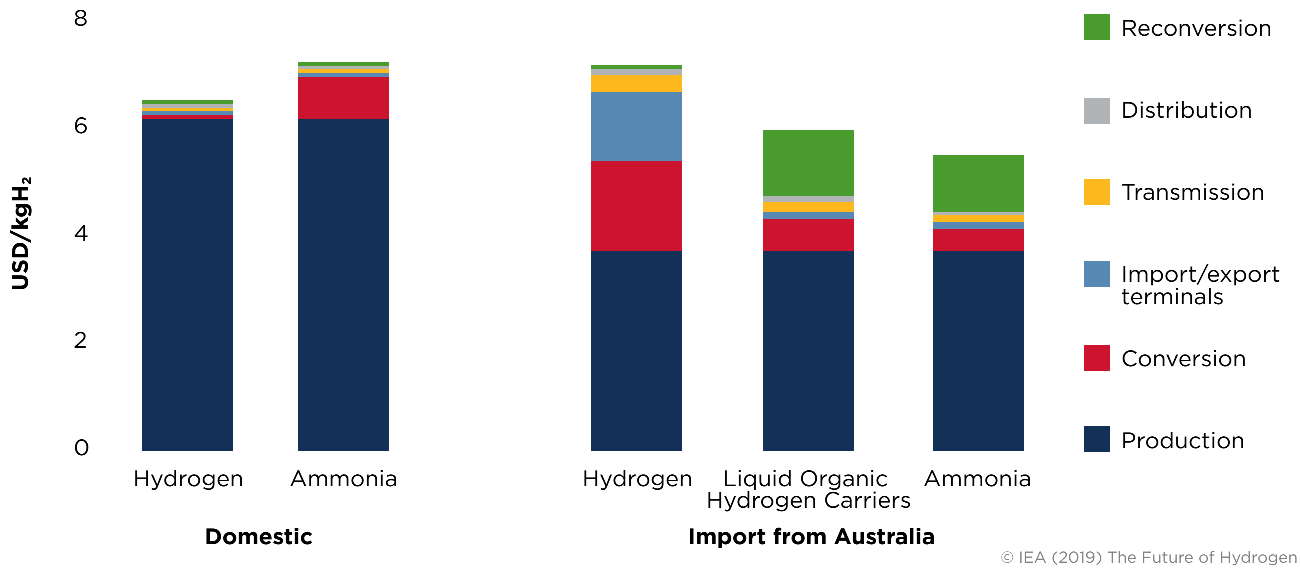


Figure 7: Cost of delivering hydrogen or ammonia produced by electrolysis from Australia to Japan in 2030.

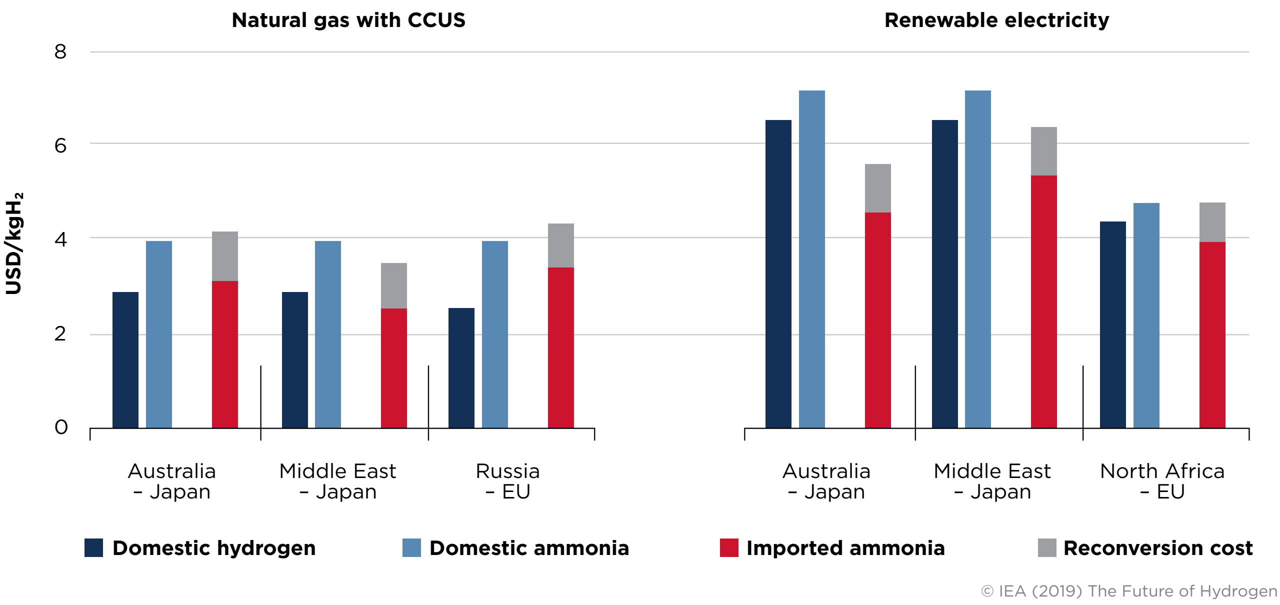


Figure 8: Comparison of delivered hydrogen costs for domestically produced and imported hydrogen for selected trade routes in 2030.

From an economic perspective, deep-sea vessels provide favorable platforms because the cost of the storage and alternative-power generation systems (e.g. fuel cells) has a comparatively lower impact than fuel costs[14].

Storage of liquid hydrogen requires at least five times more volume compared to petroleum-based fuels; ammonia requires about three times more volume. Therefore, as a long-term solution, zero carbon fuels would require the redesign of vessels and optimization of operational factors to avoid compromising the travel distance, refueling needs, or cargo volume.

The long-term adoption of hydrogen as a marine fuel for the deep-sea fleet would require substantial developments in hydrogen fuel supply and fuel cells. This may be achievable in the 2050 timeline, but there are also projects looking at using hydrogen as a supplementary/mixed fuel, in conventional diesel and DF engines to reduce their carbon footprint. This route may stimulate the longer-term use of hydrogen as a marine fuel and support the combustion of hydrogen in internal combustion engines.

CHALLENGES

The use of LNG as a marine fuel is increasing. The Society for Gas as Marine Fuel (SGMF) expects the number of gas-fueled ships to triple to about 3,000 units by 2030; in 2018, the Oxford Institute for Energy Studies found a broad consensus that 20-30 million tonnes per annum (mtpa) (28-40 billion cubic meters) would be needed for marine fuels by 2030; their projection for the number of ships was broadly in line with SGMF forecast. This trend provides a pathway to the adoption of renewable gaseous fuels. However, certain challenges need to be addressed: the regulatory landscape remains incomplete, bunkering infrastructure is limited, and newbuilding and conversion costs are high.

The industry is transitioning from fuels that are static in nature to fuels that are dynamic. LNG is a dynamic fuel whose condition changes over time. Change is inherent in the behavior of the fuel and this needs to be accounted for in the design of supporting infrastructure. Therefore, linking the design of the vessel to the operational profile is of utmost importance to ensure effective handling during operation in real-life conditions.

Hydrogen faces a number of challenges that need to be addressed in order to make it a competitive marine fuel option in the long term. The costs of its transport and distribution can be three times as high as its production. For long distance transport, hydrogen needs to be liquefied or transported as ammonia or in liquid organic hydrogen carriers (LOHC). Ammonia and LOHC are cheaper to ship but the costs of conversion before export and reconversion back to hydrogen before consumption are significant[14].

As a light gas and small molecule, hydrogen requires special equipment and procedures to handle it. It can diffuse into some materials, including some types of iron and steel pipes, and increase their chance of failure. It can also leak through seals and fittings more easily than natural gas[14]. The hydrogen flame is invisible to the naked eye and it is colorless and odorless, making it hard for people to detect fires and leaks. Hydrogen has been used industrially for decades, therefore protocols for safe handling have been developed. However, they remain complex compared to those of other fuels. Wide adoption of hydrogen as a marine fuel will necessitate further development of safety protocols and potentially alleviation of public concerns.

REGULATORY

While the IGF Code for LNG has been in force since 2017, there are aspects, mainly related to its supply, that have not been addressed on a global level. For example, not all ports have established local regulations to govern the procedures of LNG bunkering. However, several bodies and industry societies, such as the International Association of Classification Societies (IACS), SGMF and the International Organization for Standardization (ISO) are working to adopt universal regulations and have issued guides to accommodate its bunkering.

BUNKERING

Loading LNG into fuel tanks is a different process from loading HFO due to the their different characteristics. One difference is that LNG is carried as a boiling liquid, which means that temperature and pressure influence the behavior of the liquid. A second difference is that LNG is a cryogenic liquid at temperatures of about -162° C (-259° F), and consequently, it is hazardous to personnel and any conventional steel structures or piping with which it comes in contact.

A third difference is that the vapor from typical petroleum bunkering is not considered to create a hazardous zone because the flash point is above 60° C (140° F) and is simply vented through flame screens into the atmosphere. In contrast, LNG vapor can form flammable clouds in confined spaces and is considered hazardous. This requires special handling of the vapor when bunkering.

LNG storage tanks have been developed so that there is no vapor emitted from the tanks, or the vapor is returned to the bunkering vessel or terminal. Lines used for bunkering must be drained of LNG at the completion of bunkering and the remaining gas vapors removed using nitrogen. Any liquid remaining in the pipes that is trapped between closed valves will boil and expand to fill the available space. If that space is small, the pressure developed by the expanding vapor can increase to dangerous levels and cause the pipes to burst or valves to be damaged. Where there is a risk of natural gas pressure buildup, such as LNG storage tanks and piping systems, relief valves are required to safely allow the excess pressure to be released. Relief valves need to be properly located so the hazardous zone created by the release of vapor is not near operational areas on board the vessel. In general, relief valves should tie into a vent mast that directs the gas away from all critical areas.

LNG is bunkered at cryogenic temperatures so special equipment and procedures are required. Any contact of personnel with the fuel will cause severe frostbite. Spills of even small amounts of LNG can cause structural problems, as unprotected steel can be made brittle by the cold liquid, leading to fracture. Stainless steel drip-trays, breakaway couplings, and special hose connections that seal before uncoupling are often used to protect from spillage.

Communication between the receiving ship and the bunkering facility is always important, but it is even more critical when handling LNG. Because of the greater potential for hazards with LNG bunkering, proper procedures should be followed and understood between the person in-charge on the bunkering facility and the receiving ship.

Security and safety zones around the bunkering operation need to be set up to reduce the risk of damage to property and personnel from the LNG hazards; reduce the risk of outside interference with the LNG bunkering operation; and limit the potential for expansion of a hazardous situation should an LNG or natural gas release occur.

The global infrastructure for LNG bunkering is currently limited. Ports and shipowners in northern Europe have led the way; in the U.S., several ports in the Gulf Coast are building capability at a pace driven by the number of U.S.-owned LNG fueled vessels built by the yards; the Port of Singapore is leading the way in Asia.

HEAVY GAS AND ALCOHOL PATHWAY

The heavy gas-alcohol group consists of gaseous and liquid fuels that are comprised of larger molecules than liquefied natural gas (LNG). Liquefied petroleum gas (LPG) and methanol are prime examples and have the potential to contribute significantly to the carbon-reduction targets of 2030 and beyond.

CURRENT STATE OF THE ART

LIQUEFIED PETROLEUM GAS

LPG is primarily a mixture of propane and butane, with small fractions of propylene and other light hydrocarbon species.

Similar to natural gas, the composition of LPG may vary depending on the source and season. It is produced as a byproduct of the processing of natural gas, or from oil refining, and can be liquefied at low pressures and ambient temperature, which is a major advantage for its transportation compared to other gaseous fuels. It is stored or transported in pressure vessels at around 18 bar or semi-pressurized/refrigerated tanks at five to eight bar and -10 to -20° C.

Currently, more than 60 percent of the global LPG supply is sourced from natural gas processing plants[15]. Based on its production pathway, LPG is available at large scale and is economically attractive. These characteristics have made it the fuel of choice for automotive fleets in several countries around the world.

The combustion of LPG results in lower carbon dioxide (CO_2) emissions than diesel fuels due to its lower carbon/hydrogen (C/H) ratio (approximately 0.38). Its C/H is higher than LNG (approximately 0.25), so its CO_2 emissions are also marginally higher.

However, when considering the life cycle of LPG, its production is less carbon intensive than that of diesel oil or natural gas. The life-cycle greenhouse gas (GHG) emissions of LPG have been reported to be 17 percent lower than that of heavy fuel oil (HFO) or marine gas oil (MGO)[15]. This is comparable to the life-cycle GHGs generated by the production and combustion of LNG; however, the latter is affected by the amount of methane slip, which can vary depending on the engine and fuel injection technology.

Chemical composition	C_3H_8/C_4H_{10}
LHV (MJ/kg)	46.1
Energy Density (MJ/L)	~26.5
Heat of Vaporization (kJ/kg)	426
Autoignition Temperature (° C)	405
Liquid Density (kg/m^3)	493
Cetane Number	~0
Octane Number	~104
Flash point (° C)	-104
A/F ratio	15.8
Adiabatic Flame Temperature at 1 bar (° C)	1980

Table 1: Properties of LPG.

Table 2 shows the GHG emissions, in kg CO_2eq/GJ, for LPG and LNG compared to HFO and MGO, as published by the World LPG Association (WLPGA). Methane slip of one percent and energy consumption for liquefaction of seven percent were assumed for the LNG calculations.

	HFO	MGO	LPG	LNG (Qatar)
Well-to-tank	9.79	12.69	7.15	9.68
Tank-to-propeller	77.70	74.40	65.50	61.80
Total	87.49	87.09	72.65	71.48

Table 2: GHG emissions (kg CO_2eq/GJ) of HFO, MGO, LPG and LNG[15].

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Figure 1: Cylinder cover with dual fuel LPG-diesel injection system on the MAN ME-LGIP engine.

LPG has lower production emissions than LNG, but they are offset by higher tank-to-propeller emissions, due to its higher C/H ratio.

Results from large two-stroke engines have shown that the use of LPG decreases nitrogen oxides (NO_x) emissions by 10–20 percent compared to HFO, primarily due to the lower adiabatic flame temperature of LPG[15].

However, to comply with Tier III NO_x emissions regulations, current two-stroke LPG engines will need to employ exhaust gas recirculation (EGR) to control rising temperatures during combustion, or selective catalytic reduction (SCR) systems to treat the exhaust gas. Both solutions are proven and commercially available.

Results from four-stroke engine testing with LPG indicate they have greater potential to reduce NO_x and may comply with the Tier III regulations without NO_x aftertreatment[15]. The use of LPG virtually eliminates sulfur emissions and particulate emissions, since the combustion process does not form the traditional diesel-spray, fuel-rich pockets in the cylinder.

The properties of LPG make it a suitable fuel for marine applications. It is non-toxic, not harmful to soil or water, and has low handling requirements as a liquid. Its combustion can provide a short- to medium-term solution for meeting the IMO emissions regulations. Handling of LPG also reduces the evaporative emissions of volatile organic compounds (VOCs), a new requirement in ports around the globe.

From an economic perspective, the retrofit cost for using LPG is lower than LNG, the fuel cost is lower than MGO, and it is available from a sustainable supply chain.

The suitability of LPG as a marine fuel has led engine manufacturers to offer new two-stroke engine platforms. The MAN ME-LGIP dual-fuel (DF) engine was revealed in September of 2018, closely related to the ME-LGIM engine that was introduced to burn methanol.

The DF injection uses a fuel-booster injection valve that supports the use of a low-pressure fuel supply system; this significantly reduces the capital cost and increases engine reliability. This system is a key enabler for utilizing low-flashpoint fuels such as methanol, ethanol, dimethyl ether and LPG. The injection pressure of LPG is 600–700 bar, and is injected as soon as ignition of a pilot diesel fuel (about three percent of the total fuel) begins.

High-pressure direct injection helps to minimize fuel slip to the exhaust, lessening the environmental impact. According to MAN, using LPG in the ME-LGIP engines reduces CO_2 emissions by as much as 18 percent, and particulate matter by 90 percent, compared to HFO.

Wärtsilä recently introduced the "31" family of engines, a new generation of four-stroke, medium-speed engines, available in diesel, DF, and spark-gas (SG) configurations. In the gas-only SG configuration, the engine uses a pre-chamber spark ignition system, which includes a gas injector in the intake port and a second gas injector directly into the pre-chamber. The development of gas-only, lean-burn, spark-ignition technology provides high thermal efficiency, low emissions and a simple adaptation to other heavy gas fuels such as LPG.

The infrastructure required to supply and transport LPG is growing in parallel with the global demand for the gas; comparatively more LPG carriers are being built and retrofitted recently. The first two commercial ME-LGIP engines were installed in two very large gas carriers for EXMAR in late 2019. Built by Korea's Hanjin Heavy Industries (HHI) in Korea, Wärtsilä provided their integrated cargo handling and the fuel supply systems.

MAN also announced the first retrofit orders for the ME-LGIP in September 2018, when it signed a contract with Oslo-listed BW LPG to convert four MAN B&W 6G60ME-C9.2 HFO-burning engines to 6G60ME-C9.5-LGIP LPG-propelled DF engines. The order includes options for further retrofits, with work expected to begin during 2020[16].

METHANOL

Methanol (CH_3OH) is a low-reactivity alcohol fuel with low C/H ratio, which can offer similar CO_2 emission reductions as natural gas. It is currently used widely in the chemical industry and is produced primarily from natural gas.

The presence of oxygen in the molecule affects its physical and chemical properties. Methanol has a comparatively low energy content, which limits how much fuel energy can be stored on board a ship. However, methanol has high enthalpy of vaporization, which creates evaporative cooling effects in the cylinder after fuel injection.

Chemical composition	CH_3OH
LHV (MJ/kg)	20.1
Energy Density (MJ/L)	15.7
Heat of Vaporization (kJ/kg)	1089
Autoignition Temperature (° C)	450
Liquid Density (kg/m^3)	798
Cetane Number	< 5
Octane Number	109
Flash point (° C)	12
Stoichiometric air/fuel ratio	6.5
Adiabatic Flame Temperature at 1 bar (° C)	1980

Table 3: Properties of methanol.

The low reactivity of methanol – indicated by its comparatively low cetane number (CN) and high octane number (ON) – makes it resistant to auto-ignition. Therefore, it requires the presence of an ignition source, such as a pilot diesel injection in dual-fuel engines, to ignite the fuel-air mixture. The presence of oxygen also results in lower stoichiometric air/fuel ratio than LNG, which may increase the required mass flow rate of fuel in an engine of given displaced volume.

Methanol also has lower adiabatic flame temperature than diesel, which can reduce the peak cylinder temperature and limit NO_x formation during combustion.

Methanol is an attractive fuel for marine applications because it is liquid in ambient conditions, which simplifies storage on board a vessel. It does not contain sulfur and requires limited modifications to the engine and fuel supply system compared to LNG. Therefore, it presents a more cost-effective solution than LNG. However, the low energy density makes it less attractive for deep-sea vessels, as bunkering is required at a two to three times higher frequency compared to current liquid fossil fuels.

The major two-stroke and four-stroke engine manufacturers have introduced engine platforms that can use methanol and diesel for dual-fuel combustion. The MAN ME-LGI engine was introduced in 2012 to accommodate low-flashpoint fuels that are injected in liquid form (in contrast to the ME-GI engine where the natural gas is injected in vapor state). The difference in fuel properties between methanol and LNG requires some changes to the fuel supply systems between these two engines, but methanol presents fewer handling constraints than LNG[5].

In order to use methanol in a dual-fuel combustion mode, the cylinder covers need to be equipped with fuel-booster injection valves that can inject liquid methanol into the cylinder at about 600 bar.

In 2019, Marinvest announced that two of its vessels using the ME-LGI engine accumulated more than 50,000 operating hours using methanol and showed a slight improvement in fuel conversion efficiency compared to baseline diesel operation.

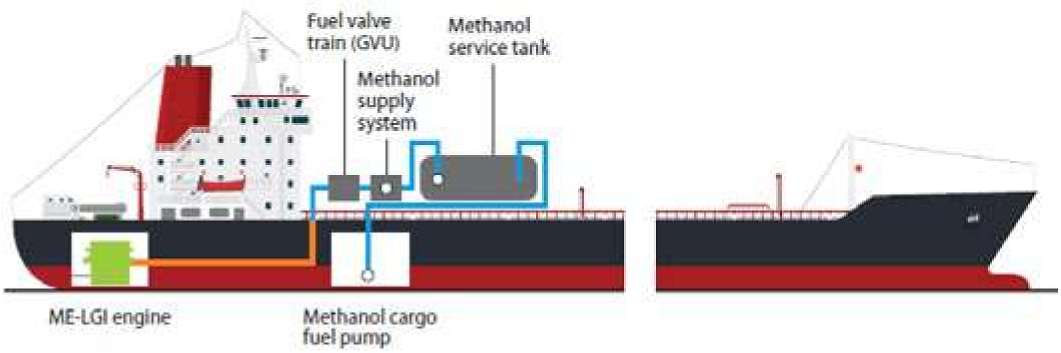

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Figure 2: MAN ME-LGI engine system overview.

In 2015, Wärtsilä converted the ro/pax ferry *Stena Germanica* to operate on methanol and showcased the retrofit kit required for the conversion. The base engine was modified to add a common rail-methanol injection system and changing the cylinder head, fuel injectors and fuel pump plungers.

The conversion also added a standalone high-pressure methanol pump, an oil supply unit for the sealing and control oil to the fuel injectors, and an updated engine management system. The dual-fuel injector assembly is used to directly inject methanol at 600 bar and pilot diesel at 1300 bar[17].

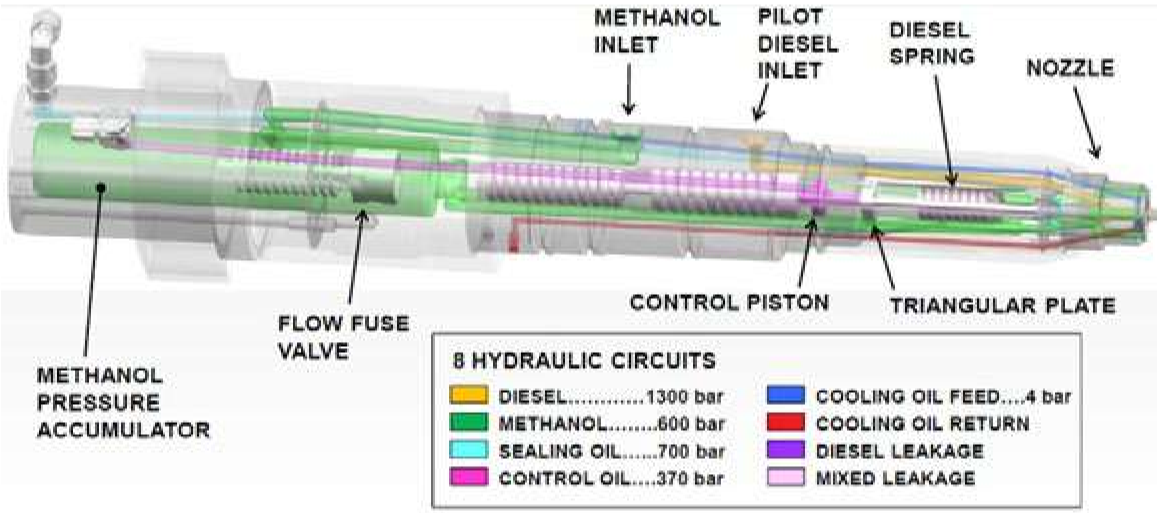

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Figure 4: Wärtsilä methanol injector assembly.

MEDIUM-TERM DEVELOPMENT

To meet the GHG reduction targets of 2030 and beyond, marine vessels will need fuels that have a low-carbon or carbon-neutral life cycle; two examples of these fuels that belong to the heavy gas/alcohol pathway are bio-LPG and bio-methanol.

Bio-LPG is a byproduct of the biodiesel production process, similar to LPG being a byproduct of oil refining. During production of biodiesel, the biomass material undergoes some catalytic processing and is then refined to biodiesel.

A range of waste gases is produced that contain propane or bio-LPG; this byproduct is then purified to make it identical in composition to conventional LPG.

In 2018, Neste operated the world's first, large scale, renewable propane production facility in Rotterdam, Netherlands. The bio-LPG is used across Europe for a range of LPG applications, including transportation to residential and commercial heating. It is also used as a drop-in biofuel in marine applications.

Bio-LPG can be produced from a variety of feedstocks, such as agricultural waste and residue, wood and vegetable oils; as such its life-cycle carbon footprint can be very low, and it can offer a solution to the emissions challenge for marine vessels in the short- to medium-term.

Bio-Methanol: The ability to produce methanol from a variety of feedstock makes it a logistically and economically attractive commodity and fuel.

The typical feedstock is natural gas, but methanol can also be made from renewable sources such as wood, municipal solid waste, waste CO_2 and sewage waste. When renewable electricity is used for production, methanol becomes an electro-fuel.

Methods of industrial methanol production include: synthesis gas (syngas) from feedstock; catalytic conversion to crude methanol; and distillation to pure methanol by water removal.

In addition to fossil and biomass sources, methanol can be produced by carbon dioxide recovery (CDR), a technique that converts CO_2 to syngas and then methanol. CDR has been developed by Mitsubishi Heavy Industries (MHI) and used by the Gulf Petrochemical Industries Company in Bahrain and the Qatar Fuel Additives Company in Qatar. The Azerbaijan Methanol Company in Baku and the South Louisiana Methanol facility also are using CDR for additional methanol production.

To assess the environmental impact of marine fuels, it is critical to consider the emissions from their production. Figure 4 shows a graphical representation of a life-cycle analysis (LCA) of fuels, which includes emissions from extraction of the raw material (either fossil or biomass), fuel production, transportation and storage, bunkering and, finally, from combustion on board the vessel.

Fuel production pathways that are energy and carbon intensive will not be attractive in the future and may increase the fuel price. Carbon-intensive production methods also may be restricted by new regulations.

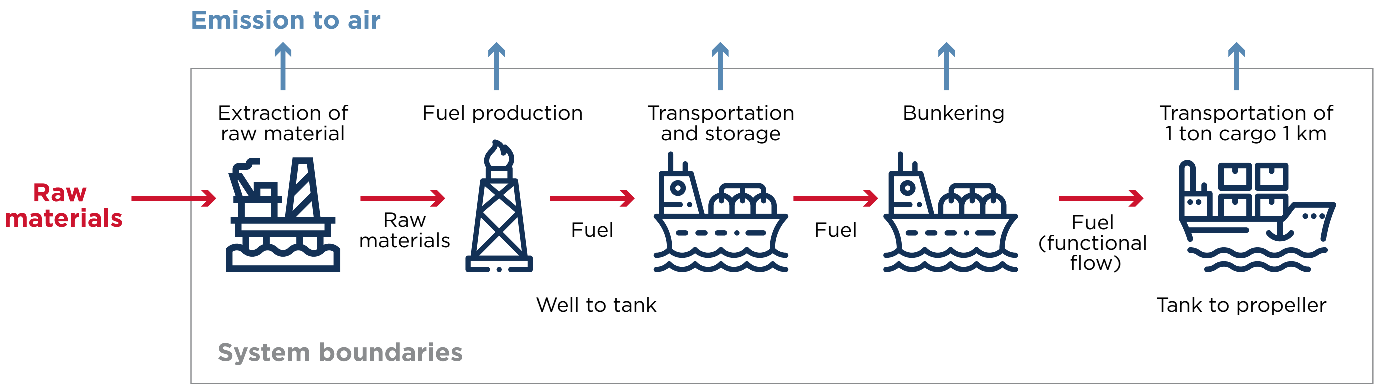

Figure 4: Life-cycle analysis of marine fuels from well to propeller[17].

The contribution of each fuel to GHG emissions is expressed as the global warming potential (GWP). The fossil-based fuels have a comparable GWP to HFO. The bio-methanol has considerably lower GWP than HFO, but not zero, due to the fossil energy used to grow, harvest, process and transport biomass for production.

Using renewable energy for the production of methanol as an electro-fuel has the potential to reduce the total energy expended for production. Therefore, it would further reduce the GWP of bio-methanol.

In addition to achieving a lower carbon footprint, the liquid state of methanol makes it easy to store, and be readily available for bunkering. The current infrastructure for methanol distribution was built for its use by the chemical industry, which ensures adequate availability. But it is thought that several more terminals will be needed if methanol is to be used in marine vessels.

Figure 5 shows the estimated capacity of methanol storage around the world, which would support its logistical suitability as a marine fuel for the medium-term.

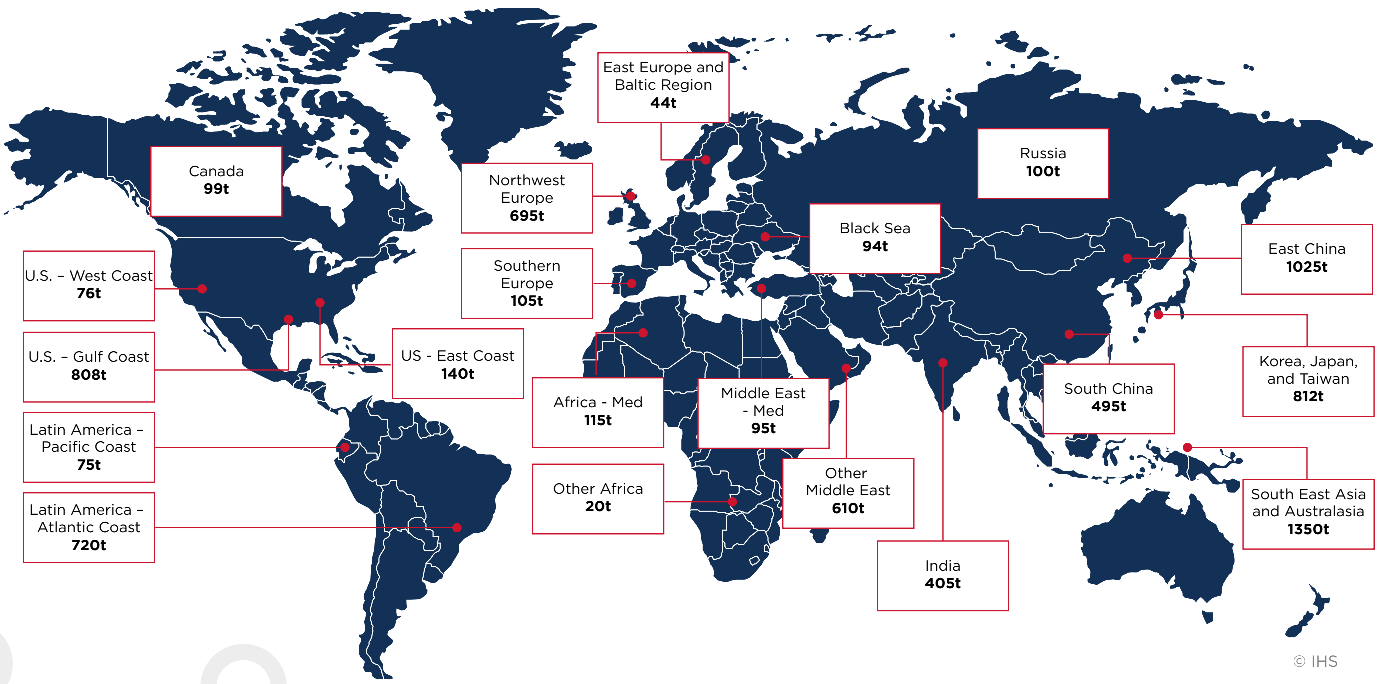

Figure 5: Estimated methanol storage capacity in thousands of tons.

LONG-TERM DEVELOPMENT

At the end of the heavy gas pathway, ammonia seems to be a disruptive, zero-carbon fuel that has the potential to enter the global market relatively quickly and significantly contribute to meeting the GHG-reduction target for 2050 set by the IMO.

Ammonia (NH_3) is a compound of nitrogen and hydrogen, and a colorless gas in ambient conditions with a characteristic pungent smell. It is a common nitrogenous waste, particularly among aquatic organisms, and is used as fertilizer because it contributes significantly to the nutritional needs of terrestrial organisms. It is also used as a building block for the synthesis of pharmaceutical and cleaning products.

Although ammonia is common in nature and widely used, it can be toxic in concentrated form. It is classified as a hazardous substance in the U.S. and is subject to strict reporting requirements by facilities that produce, store or use it in significant quantities[18].

Chemical composition	NH3
Latent heat of vaporization (LHV) (MJ/kg)	18.8
Energy Density (MJ/L)	12.7
Heat of Vaporization (kJ/kg)	1371
Autoignition Temperature (° C)	651
Liquid Density (kg/m3)	600
Cetane Number	0
Octane Number	~130
Flash point (° C)	-33
Stoichiometric air/fuel ratio	6.05
Adiabatic Flame Temperature at 1 bar (° C)	1800

Table 4: Properties of ammonia.

It can be synthesized from fossil fuels or biomass with the use of conventional or renewable energy. Currently, ammonia is produced in large scale from hydrocarbon fuels that are used to produce hydrogen by reforming methane with steam. The nitrogen required for production is separated from air after liquefaction.

Renewable energy sources can be used to produce hydrogen from the electrolysis of water and later synthesized to ammonia. In this case, it can be considered an electro-fuel, with zero-carbon intensity during production or use.

Based on its physical and chemical properties, ammonia can be a viable marine fuel. It is free of carbon and sulfur, and thus eliminates the formation of CO_2 or SO_x during combustion. It has higher energy density by volume than hydrogen and can be liquefied at 8.6 bar and at ambient temperature, which makes it easy to store on board the vessel. It is commonly stored at 17 bar to keep in a liquid state, even when the surrounding temperature increases.

The widespread use of ammonia in industrial and agricultural processes makes it a logistically attractive and affordable fuel that can be distributed in the existing network of infrastructure.

Historically, ammonia was first demonstrated as a fuel for internal combustion engines in 1822, in a locomotive; later, during World War II, it was used in Belgium to fuel buses for public transportation[19].

It is a low reactivity fuel – high octane number (ON), low centane number (CN) – which has high resistance to auto-ignition and is conducive to spark-ignition combustion. Ammonia also has been used in compression-ignition engines with the aid of a pilot diesel injection to ignite the mixture.

Ammonia has high heat of vaporization, which results in considerable evaporative cooling of the mixture after injection and reduces the cylinder temperature at the start of combustion; helping to control NO_x formation. However, any benefit may be offset by the fuel-bound nitrogen, which may increase NO_x formation. Ammonia has low heating value (18.8 MJ/kg), but it also has a low stoichiometric air/fuel ratio.

MAN recently introduced the ME-LGIM engine, which was designed to operate on a DF combustion mode with methanol and diesel. The same engine can be used with ammonia instead of methanol with slight modifications to the fuel-delivery system to supply ammonia at 70 bar and inject it into the cylinder at 600–700 bar.

Experimental studies have shown that combustion with ammonia results in similar or lower NO_x formation than diesel[20], and two to six times lower CO_2. However, it can result in some ammonia slip if it is injected into the cylinder during the exhaust valve event. The high-pressure direct-injection systems used in DF engines, such as the MAN ME-LGIM, can inject fuel late in the compression stroke to avoid ammonia slip; NO_x emissions can be further reduced by using exhaust gas recirculation (EGR), or selective catalytic reduction (SCR) aftertreatment for the exhaust gas.

Table 5 shows the well-to-tank emissions for ammonia production, transmission and distribution. The production emissions include those associated with electricity generation for production and synthesis of ammonia[21]. The transmission and distribution emissions were calculated using the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model output of emissions for the transmission and distribution of LNG as a proxy, since natural gas pipelines could be converted to carry ammonia.

Electricity Source	Production Emissions (g CO_2e/MJ)	Transmission and Distribution Emissions (g CO_2e/MJ)	Total Emissions (g CO_2e/MJ) (A+B)
Municipal Waste	18.31	0.42	18.73
Hydropower	20.46	0.42	20.89
Nuclear Power	45.23	0.42	45.66
Biomass	45.77	0.42	46.20

Table 5: Well-to-tank emissions for ammonia by energy source for the production process.

In the light gas group presented in the previous section, hydrogen was shown to be the zero-carbon fuel that can provide solutions for long-term decarbonization of the global fleet. In the heavy gas group, ammonia can provide similar solutions in the medium-term.

However, since ammonia is synthesized from hydrogen, these fuels are linked in terms of infrastructure and technology development. In comparison, ammonia is a logistically attractive and affordable fuel, which is easier to handle, store and transport. It can be used neat in compression-ignition or spark-ignition engines, or as a hydrogen carrier for future applications.

Figure 6 shows a summary of hydrogen and ammonia production, transportation and utilization as presented by the Japanese Science and Technology Agency. Both fuels can be produced renewably as electro-fuels from electrolysis of water and can be used according to the market demand and technical requirements for different applications.

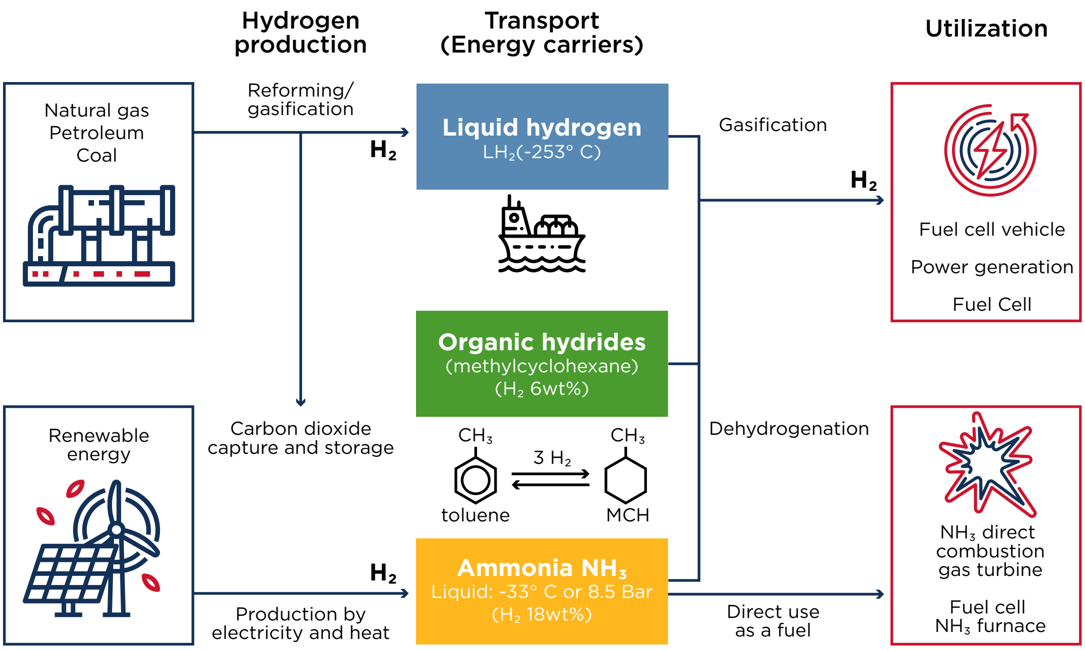

Figure 6: Hydrogen and ammonia production and use.

Nevertheless, the cost of producing ammonia-based fuels and making them safe for marine use needs to be explored further. Apart from the cost of adapting infrastructure, ammonia is toxic to humans and aquatic life. Considerable safety measures must be taken.

Advantages
• Carbon free – no CO_2 or soot • Low flammability risk – 15-25 percent in air • Can be produced from electrical energy – renewable • Easily reformed to H_2 and N_2 • Can be stored and transported as liquid at relatively low pressure or temperature • Established commercial product • Direct ammonia fuel cells under development

Disadvantages
• Toxicity • Fuel infrastructure • Missing regulations • Engine development 2-3 years • Cost • Needs SCR • Low energy content – tank almost three times larger than HFO

CHALLENGES

LPG has a higher density than air and any spills will collect in lower spaces, requiring a different approach to leak detection and ventilation. LPG is also a low-flashpoint liquid and, when used in a high fire risk space of the ship with a constant personnel presence, such as in the engine room, a double-walled pipeline must be used for secondary containment.

Hydrocarbon sensors will detect any leakage and contain the fuel within the secondary containment before it reaches areas where humans are present and double-walled pipelines must be used below the deck line. The auto-ignition temperature of LPG (490° C) is lower than that of LNG (580° C), which may require a lower surface temperature near electrical equipment. Compared to LNG, LPG has fewer challenges related to temperature because it is not cryogenically stored. But it has challenges related to higher density as a gas and a lower ignition range, with a lower flammability limit of about two percent.

Methanol is currently more expensive than low-sulfur MGO, which makes it a less attractive solution under the current regulatory landscape. In addition, the shipping industry is greatly affected by fuel price volatility, therefore the supply of methanol needs to be supported by contractual measures that limit this volatility.

Ammonia is a promising zero-carbon fuel for future vessels but the cost of producing it and making it safe for marine use needs to be further explored and understood. It addition, it requires considerable safety precautions due to its toxicity to humans and aquatic life.

Early applications of methanol in dual-fuel engines identified issues with the degradation of lubricating oil due to the oxygen in the fuel, but were easily addressed. Methanol slip to the exhaust may lead to the formation of formaldehyde at 400–600° C, which needs to be treated, but engines that use direct fuel injection have shown very little methanol slip.

	MGO	Methane	Ethane	Propane	Butane	Hydrogen	Ammonia	Methanol	Ethanol
Flash point, ° C	> 60	-188	-135	-104	-60	-	132	11	16
Boiling Point, ° C 1bar	180 - 360	-162	-86	-42	-1	-253	-33	65	78
Density, kg/m^3 liquid	900	450	570	500	600	76.9	696	790	790
Conventional or cryogenic/ pressurized tanks	CONV	CRYO	CRYO	CRYO	CRYO	CRYO	CRYO	CONV	CONV
Secondary tank barrier required	No	Yes*	Yes*	Yes*	Yes*	Yes*	Yes*	No	No
Additional cofferdam or hold space requirements	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Volume comparison MGO, energy density	1	1.78	1.41	1.66	1.40	4.16	2.45	2.44	1.82

* Except type C tanks

Table 6: Storage requirement of different fuels.

REGULATORY

The revised International Code for the Construction and Equipment and Ships Carrying Liquefied Gases in Bulk (IGC) allows gases other than natural gas to be used as fuel. If acceptable to the administration, other cargo gases may be used as fuel, providing that the same level of safety as natural gas in the code is ensured. However, the use of cargo identified as toxic in chapter 19 would not be permitted.

The International Code of Safety for Ships Using Gases or Other Low Flashpoint Fuels (IGF) contains functional requirements for all appliances and arrangements to the usage of low-flashpoint fuels. Part 1 of the IGF Code covers only natural gas, but other fuels can be used as well, provided that they meet the intent of the goals and functional requirements, and provide an equivalent level of safety. The latter has to be demonstrated as specified in the SOLAS regulation II-1/55 II-1/55, which refers to the IMO Guidelines for alternative design and arrangements, MSC.1/Circ.1212. This approach is already in the MVR under 5C-13-2/3.

BIO/SYNTHETIC FUEL PATHWAY

The bio/synthetic fuel pathway consists of fuels that have similar physical and chemical properties to diesel but are produced from renewable sources. These properties allow them to be used as drop-in fuels for power generation and propulsion systems and take advantage of the existing fuel transport and bunkering infrastructure. As such, they can provide logistically and economically attractive solutions for current and future marine vessels. Biofuels can be produced from different types of biomass feedstocks using established techniques (Figure 1). When produced from plant fibers, they have the potential to reduce the life-cycle carbon footprint of a vessel, because the carbon dioxide (CO_2) absorption from the plants offsets the emissions from combustion. However, the carbon reduction potential, economics, and viability of different biofuels depend on their source feedstock and production pathways.

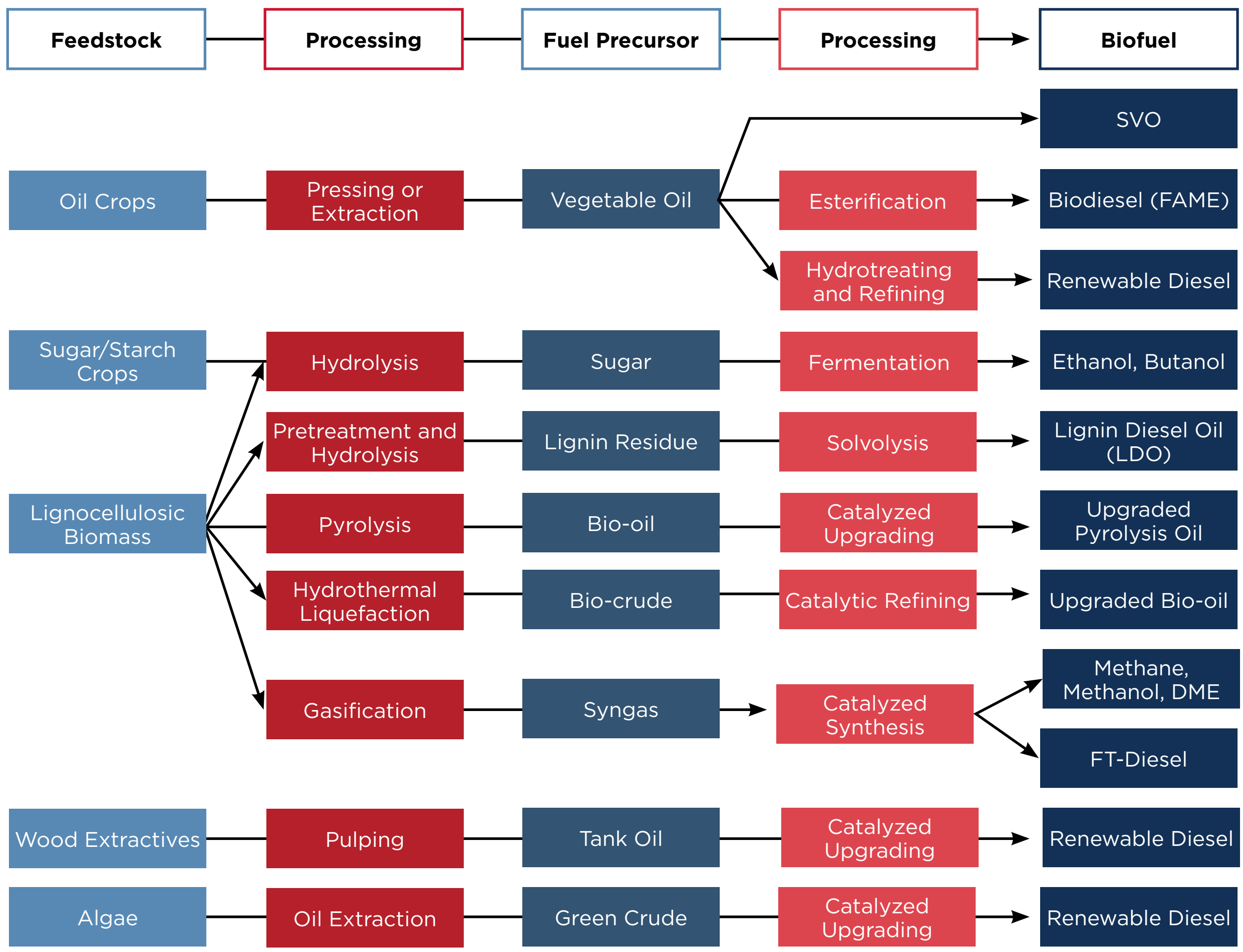

Figure 1: Overview of biofuel production pathways from different biomass feedstocks.

Biofuels are often categorized by the biomass feedstock. First generation biofuels are generally produced from food crops, such as corn, soy and sugarcane, which make them unattractive from a socioeconomic perspective; second generation biofuels do not compete with food crops and are produced from lignocellulosic biomass, such as switchgrass, trees, bushes and corn stalks; third or higher generation biofuels can be produced from sources such as algae, which has the potential for higher fuel yield during production with the use of conventional or renewable energy.

In the latter case, the use or renewable energy can further reduce the carbon footprint of such fuels during production. Second- the third-generation biofuels produced from non-food feedstock (e.g. agricultural and forestry residue, energy crops, algae) are also referred to as "advanced biofuels."

CURRENT STATE OF THE ART

Fatty Acid Methyl Ester (FAME) is the most common first-generation biodiesel and is produced from a variety of plant or animal oils. Plant feedstocks include rapeseed (common in the EU), soybean (the U.S. and

South America), coconut (Pacific Islands), palm (Southeast Asia) and corn (U.S.). Animal feedstocks include rendered beef, poultry litter, and other animal fats. Used cooking oil can also be used to produce FAME biodiesel[23].

Chemical composition	FAME (B100)	Diesel
Density at 20° C (kg/m³)	885	825
LHV (MJ/kg)	37.1	43.1
Viscosity at 20° C (mm²/s)	7.5	5.0
Surface Tension (N/m)	0.026	0.028
Cetane Number (CN)	56	40-50
Stoichiometric air/fuel ratio	12.5	15
Oxygen Content (% vol.)	~11	0

Table 1: Properties of FAME biodiesel.

FAME is produced through transesterification, where various oils (triglycerides) are converted to methyl esters. This process yields hydrocarbon species that are similar to those of petroleum diesel. FAME has similar physical processes to diesel (Table 1); it is not toxic and biodegradable. However, it has somewhat different chemical properties, which should be taken into consideration when used in engines. Specifically, it has a higher flash point (149° C) than diesel and degrades in the presence of water. It also has a high cloud point, which may result in clogging of fuel filters and lines and poor fuel flow below 32° C.

Biodiesel is produced at large scale in several countries and has already been used in automotive, locomotive, and home heating applications. In the U.S., it is used as a blendstock for ultra-low sulfur diesel, regulated to a maximum of five percent vol. per ASTM D975, D6751 and D7371 specifications. In the EU, it is regulated to a maximum of seven percent vol. in diesel per the EN 14214 and 590 specifications. The CIMAC Working Group seven recently revised the ISO 8217:2012 standards for marine gas oil/marine diesel oil (MGO/MDO) to allow the use of marine distillate fuel with up to seven percent vol. of FAME (B7).

The blended fuel is expected to meet the same technical specifications and requirements as marine distillate fuels containing no biodiesel, so no heating will be required prior to injection. FAME has similar density and surface tension as diesel, which result in similar behavior when injected into the cylinder for mixture preparation. It also has higher cetane number (CN) than diesel, which promotes autoignition and may reduce the ignition delay and noise during combustion.

FAME has good lubricity properties and thus protects the fuel pumps and injectors against wear. However, it contains oxygen and thus has lower energy content than diesel, which may increase the required tank volume when used in large amounts.

The presence of oxygen in the fuel results in low oxidative stability, so it is prone to degrade over time and form peroxides, acids, and other insoluble compounds; oxidation can also lead to bacterial growth in tanks and sludging of the fuel lines, filters and injectors.

Although biodiesel is not miscible with water, it is very hydroscopic and tends to form emulsions that may increase the acid content in the fuel and the microbial contamination[23]. Biocide can be used as an additive to inhibit bacterial growth and a number of other additives can be used to lower the cloud point of FAME to make it suitable for use in diesel engines.

Benefits and Challenges	Diesel	FAME
Energy content	+	-
Tank volume requirement	+	-
Engine efficiency	+	+
Mixture preparation	+	+
Combustion noise	-	+
Lubricity	+	+
Fuel degradation	+	-
Emissions	- -	-
Cost	+	- -

Several experimental studies on automotive light- and heavy-duty engines have documented some of these effects of using biodiesel. For blends up to B20, it was found that the fuel-bound oxygen tends to decrease carbon monoxide and non-methane hydrocarbon emissions. However, they increase nitrogen oxides (NO_x) formation[24].

Regarding biodiesel degradation, it was found that blending up to 10 percent may not have any effects, but larger blends lead to the degradation of fuel filters and oil sludging[25]. Based on the above, the recommendations of the CIMAC WG7 for using blended diesel up to B7 are to avoid storage for more than six months and implement fuel condition monitoring, and to avoid storing biodiesel in isolated individual unit tanks.

The production of first-generation biodiesel generally results in high fuel cost due to the limited supply of feedstock and competition from the food, pharmaceutical and cosmetic industries. In addition, the feedstock supply for biodiesel is significantly less than petroleum diesel, so present biodiesel production cannot fully replace the consumption of diesel. Based on these limitations, biodiesel can be used in blends, but as a long-term solution it would be economically and logistically unattractive to use it as a large-scale marine fuel.

Hydrotreated vegetable oil (HVO) or renewable diesel is an advanced biofuel that is produced from plant oils or animal fat through hydrotreating and refining, typically in the presence of a catalyst. Hydrogen is used to remove the oxygen from oil to yield a fuel that does not have the inherent limitations of FAME.

Unlike FAME, no chemicals are needed to produce HVO and no glycerol is produced as a side product. However, LPG is produced as a side product and is commonly used to fulfill some of the energy requirements of the plants. This process yields a hydrocarbon composition that meets the conventional diesel requirements (ASTM D975, EN 590). HVO is a mixture of paraffins, free of sulfur, aromatics and esters; it has very high CN, a heating value that is slightly higher than diesel, and good stability for storage. Also, its cold-flow properties can be tailored by additional catalytic processing during production.

Chemical Composition	HVO	Diesel
Density at 20° C (kg/m^3)	780	825
LHV (MJ/kg)	44.0	43.1
Viscosity at 40° C (mm^2/s)	3.0	3.5
Cetane Number (CN)	80-99	40-50
Aromatics Content (% vol.)	0	~30
Oxygen Content (% vol.)	0	0
Sulfur Content (ppm)	< 10	< 10

Table 2: Properties of HVO renewable diesel.

In a similar fashion to FAME, several experimental studies on engines have used 100 percent HVO in automotive light- and heavy-duty diesel engines. Combustion with HVO resulted in 28–46 percent less particulate emissions and Filter Smoke Number (FSN) than diesel, attributed to the absence of aromatic compounds in HVO, which form soot precursors[26].

NO_x formation was also reduced by five to 14 percent due to the differences in peak cylinder temperature resulting from lower ignition delay with HVO. HVO also produced less CO_2 due to its favorable hydrogen/carbon ratio (0.18) compared to diesel (0.16). The higher gravimetric heating value of HVO resulted in three to four percent lower specific fuel consumption, thus higher engine efficiency; however, the lower density of HVO resulted in four to five percent higher volumetric fuel consumption[27]. Among all the studies performed it was concluded that no changes to the hardware or control parameters were required to the diesel engines to use HVO, but specific engine optimization may yield greater benefits. The following table summarizes the benefits and challenges of HVO in comparison to diesel.

Benefits and Challenges	Diesel	HVO
Energy content	+	+ +
Tank volume requirement	+	-
Engine efficiency	+	+ +
Mixture preparation	+	+
Combustion noise	-	+
Lubricity	+	+
Fuel degradation	+	+
Emissions	- -	+
Cost	+	-

Production of HVO can take place in oil refineries, as they are equipped with hydrotreating facilities. However, modifications may be needed to develop HVO-only production facilities. The production process is more expensive than for FAME biodiesel; however, the result is a drop-in renewable fuel, which can be introduced to the distribution and refueling facilities and diesel engines without modifications. HVO is currently produced commercially at large scale and its production has consistently increased in the last decade (Figure 2). Since it is a drop-in renewable fuel, it can be used neat or in blends with heavy fuel oil (HFO)/MGO and it will reduce the carbon footprint of the vessel in proportion to the blended amount.

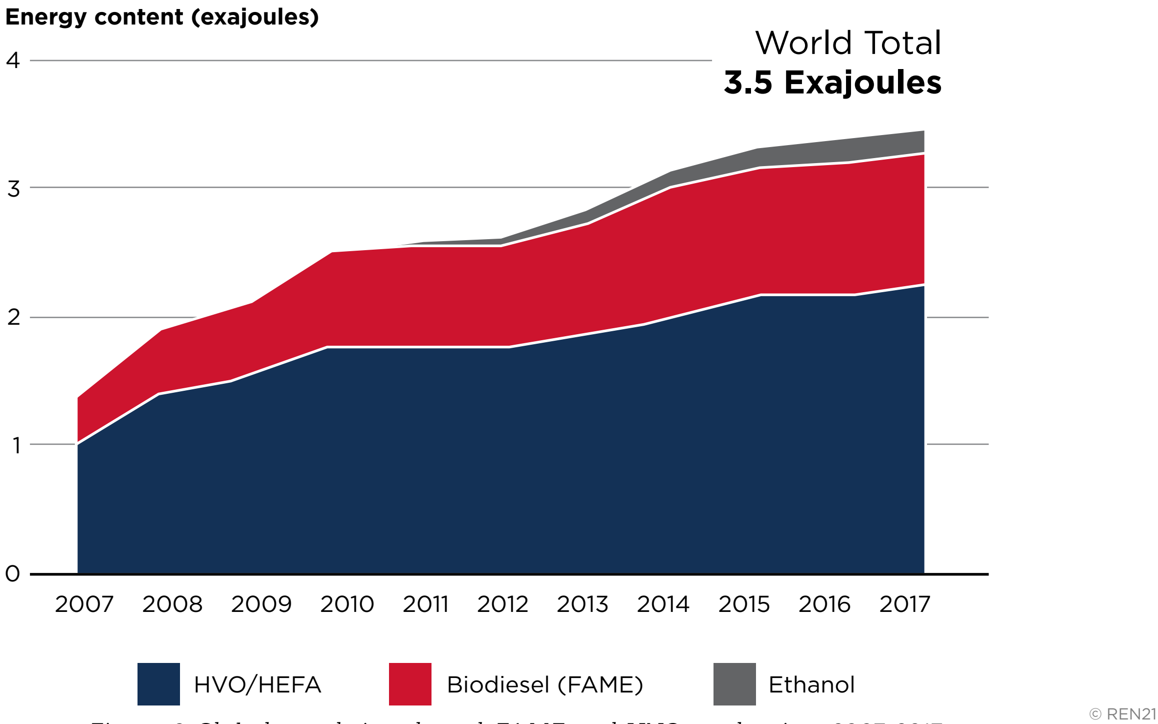

Figure 2: Global trends in ethanol, FAME and HVO production, 2007-2017.

Although HVO is based on renewable feedstock, its production capacity is currently not enough to satisfy the needs of short- and long-distance shipping; therefore, it will have to be used in blends with HFO/MGO in the short- to medium-term. HVO feedstock prices tend to vary depending on the source and season[23]. For example, the price of palm oil peaked at $1,250/Mt in February 2011 but fell to $650/Mt in 2016. In a similar fashion, the price of cooking oil peaked at $720/Mt in January 2013 but fell to $400/Mt in 2016[23]. Lipid prices are affected by the season, but also by labor costs and land utilization, adding to their volatility. The following table compares the basic properties and prices of different fuels relevant to marine vessels.

Property	HFO	MGO	LNG	FAME	HVO	Ethanol	Methanol
LHV (MJ/kg)	39.0	43.1	47.1	37.1	44.1	26.7	19.9
Sulfur content (% m)	< 3.5	2	0	0	0	0	0
Cost (USD/Mt)	290	482	270	1040	542	503	464

Table 3: Comparison of energy content, sulfur content, and cost or alternative fuels[28].

MEDIUM- AND LONG-TERM DEVELOPMENT

FAME and HVO can provide short-term solutions for reducing the carbon footprint of marine vessels. But to approach carbon-neutral shipping, second- or higher-generation biofuels will need to be adopted in large scale.

Second-generation biofuels are produced from lignocellulosic feedstock and their production pathway includes thermochemical processes. These use high temperature and pressure in the presence of a catalyst to convert biomass to liquid fuels, chemicals, as well as heat and power, which reduces the carbon footprint from production. Thermochemical processing starts by converting biomass to fluid intermediates (gas or liquid) and continues with catalytic upgrading or hydroprocessing to hydrocarbon fuels[23].

Biomass gasification can be used to produce synthetic diesel, often referred to as gas-to-liquid (GTL) or biomass-to-liquid (BTL) fuels. Gasification is used to convert biomass, under high temperature and pressure in the presence of oxygen, to syngas ($CO + H_2$). Syngas can be used directly as a fuel for internal combustion engines and gas turbines or it can be further processed to produce liquid hydrocarbon fuels.

Further processing is performed by using Fischer-Tropsch (FT) catalysts and hydrotreating to produce synthetic diesel, methanol, or other fuels that are relevant to marine vessels. The technology used to produce

	BioGrace	GREET
Soybean FAME	56.9	34.5
Soybean HVO	50.6	47.6
Palm FAME	36.9	24.2
Palm HVO	58.9	37.5
Cooking oil FAME	21.3	-
Cooking oil HVO	11.6	-

Table 4: Comparison of well-to-tank emissions for FAME and HVO in gCO_2eq/MJ from different feedstocks, based on the BioGrace[1] and GREET[2] life-cycle analysis models[28].

FT fuels is established, although it is energy intensive, and was historically used at large scale to produce liquid fuels in Germany during World War II and in South Africa during the apartheid embargo. During World War II, Germany produced 4.5 million barrels of synthetic diesel from coal.

To produce synthetic diesel, the FT process can be applied to natural gas or biomass, and the properties of the synthetic fuel can be tailored to meet the needs of the end user. The diesel-like compounds produced by the FT process are typically of two types: one with a moderate CN (approximately 60), low aromatic content (less than 15 percent) product; and a second product with a high CN (greater than 74) and zero aromatic content.

The low CN products have cold-flow properties (pourpoint, cloudpoint) similar to those of petroleum diesel. However, the lubricity properties on both types are poor and require additives before they can be used in engines. Given their similar physical and chemical properties to diesel, FT synthetic diesels can be used neat or in blends with petroleum diesel without any modifications to the engines and fuel supply systems.

Chemical composition	GTL/BTL	Diesel
Density at 20° C (kg/m^3)	770–785	825
LHV (MJ/kg)	43.0	43.1
Viscosity at 40° C (mm^2/s)	3.2–4.5	3.5
Cetane Number (CN)	~60, > 74	40–50
Aromatics Content (% vol.)	< 15, 0	~30
Oxygen Content (% vol.)	0	0
Sulfur Content (ppm)	< 10	< 10

Table 5: Properties of GTL/BTL renewable diesel.

Synthetic diesel has been experimentally tested on a variety of automotive heavy-duty engines, and all data have consistently shown reductions in regulated emissions compared to baseline diesel operation[29]. The absence or aromatics reduces soot emissions and enables the use of modern emissions control systems. The high CN makes the mixture more prone to autoignition thus reduces the ignition delay, noise, and NO_x formation. In addition, synthetic diesel was found to promote combustion efficiency and reduce CO emissions.

Based on the above, synthetic diesel can be a viable solution for future marine vessels with strong potential to reduce the carbon footprint of shipping. From an economic perspective, biofuels produced through gasification feature high energy and refining costs because they are high quality, clean fuels. Therefore, their price is expected to be higher than FAME or HVO and will rely on economies of scale to become competitive.

From an environmental-sustainability perspective, the production of synthetic diesel from biomass has the potential to reduce the overall carbon footprint of the vessel. However, the synthesis of diesel from syngas creates opportunities for further reductions using renewable energy (electro-fuels).

Figure 3 shows a potential production pathway of synthetic diesel that combines renewable energy and carbon capture. The renewable energy is used to produce hydrogen from water electrolysis; the hydrogen is then used along with CO_2 captured from the atmosphere to produce syngas, which can be further processed to produce liquid fuels.

Low-Carbon Synthetic Liquid Fuels Production (Power-to-Liquids)

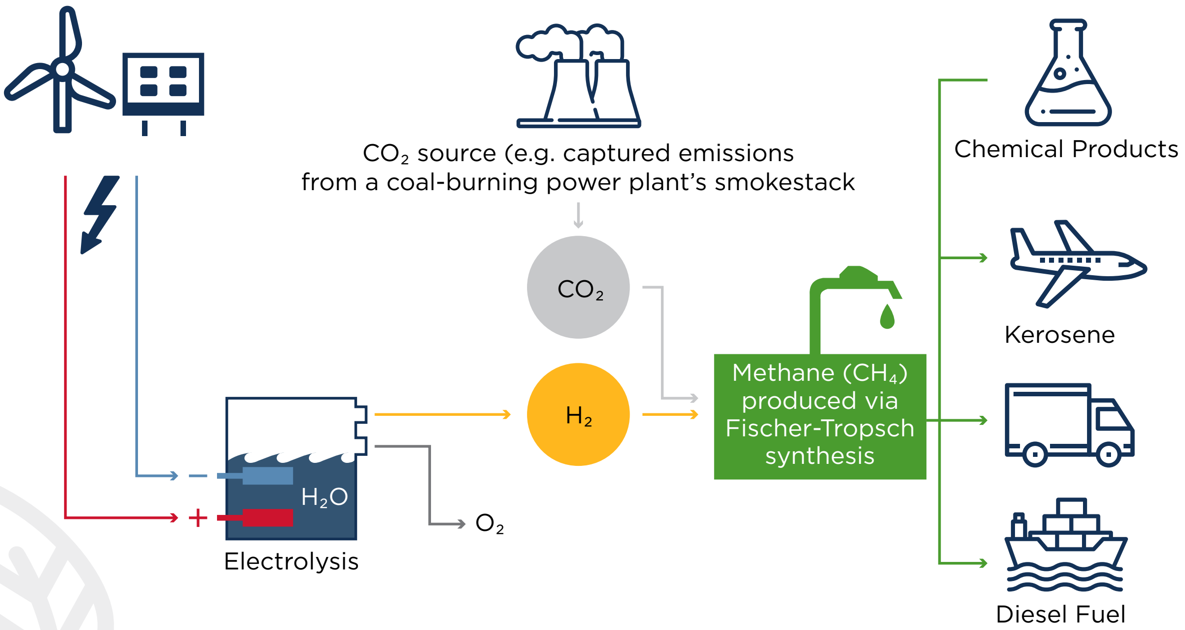

Figure 3: Schematic representation of GTL fuel production using renewable energy for water electrolysis and CO_2 capture.

Chemical composition	DME	Diesel
Density at 20° C (kg/m^3)	668	825
LHV (MJ/kg)	28.4	43.1
Boiling point (° C)	-25	3.5
Cetane Number (CN)	55-60	40-50
Aromatics Content (% vol.)	0	~30
Sulfur Content (ppm)	0	< 10

Table 6: Properties of DME.

As an alternative to synthetic diesel, the syngas produced during gasification can be converted to dimethyl ether (DME) via methanol dehydration or methane using the Sabatier process[23]. DME is a colorless, non-toxic gas, which is easy to liquefy and transport. It is comprised of smaller molecules than those present in LPG and can be an alternative fuel to diesel. The low-carbon content of DME enables significant reductions in CO_2 emissions and the absence of carbon bonds in the molecule eliminates soot formation during combustion.

Combustion with DME has been experimentally tested on automotive heavy-duty diesel engines and by manufacturers such as AB Volvo, Isuzu Trucks, Shanghai Diesel and Nissan. The results verified that the absence of carbon bonds and the presence of oxygen in the fuel eliminates soot formation and enables engine optimization for minimizing NO_x formation and fuel consumption[30].

Its higher CN than diesel decreases the ignition delay, the pressure rise during combustion (noise) and NO_x formation[31]. The latter is further supported by DME's lower adiabatic flame temperature than diesel and its higher tolerance to exhaust gas recirculation. The engine fuel conversion efficiencies reported when using DME were similar to that of baseline diesel operation[32].

The disadvantages of DME are its lower energy content than diesel, which necessitates larger storage tanks on board marine vessels, and its low viscosity and lubricity, which requires the use of additives to avoid supply line leakages and surface wear of moving parts.

Production of DME has been rapidly growing in recent years, primarily because it is used as a substitute and supplement for propane in China. Over 5 million tons of DME per year are currently produced by means of methanol dehydration and production is expected to grow rapidly.

Several countries have installed significant new DME-production facilities (e.g. Japan, Korea, Brazil) and others have plans for major capacity additions (e.g. Egypt, India, Indonesia). In Sweden, waste streams from pulping are used to produce BioDME, which is expected to grow in demand by 2030.

DME can be produced in a distributed fashion using small-scale facilities. Figure 4 shows a small-scale production unit by Oberon Fuels, which has been used to produce DME to fuel prototype heavy-duty diesel engines.

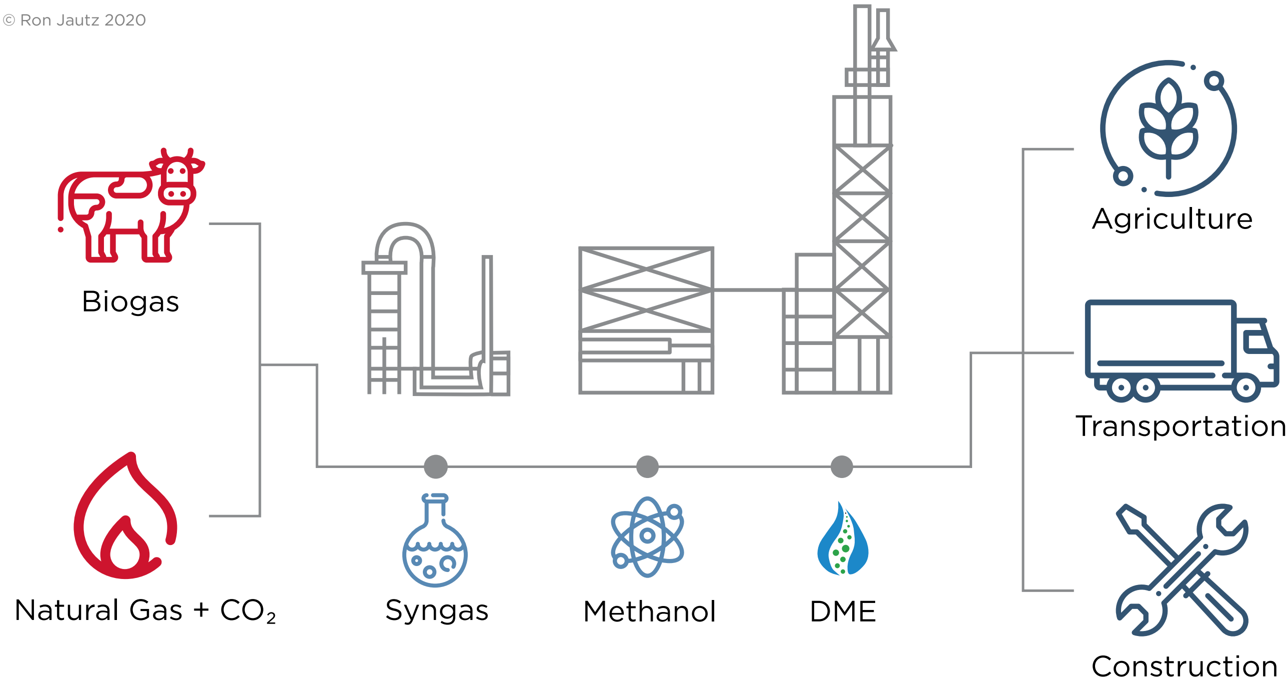

Figure 4: Schematic representation of DME production.

CARBON CAPTURE AND SEQUESTRATION

The effort to reduce the carbon footprint from shipping has led the industry to explore alternative low- and zero-carbon fuels, technologies and methods to increase vessel efficiency. Exhaust gas aftertreatment systems are among the technologies that can contribute to the reduction of greenhouse gases (GHG) and other regulated emissions.

Carbon Capture and Sequestration (CCS) refers to a set of technologies that can be used to remove carbon dioxide (CO_2) from vessel exhaust gas or the atmosphere and store it for subsequent use.

Combustion of zero-carbon fuels, such as ammonia and hydrogen, would result in zero CO_2 formation; however, in all other cases of fuels presented in this report – liquefied natural gas (LNG), liquefied petroleum gas (LPG), methanol, bio or renewable diesel and dimethyl ether (DME), – CO_2 will form as a complete combustion product in proportion to the carbon content of the fuel.

Therefore, with all but the zero-carbon fuels, CCS technology could be used on board ships to further reduce their carbon emissions.

CO_2 can be removed either from the exhaust gas of marine engines or directly from the atmosphere, a method often referred to as "direct air capture." Both technologies are based on the same fundamental principles, but removing CO_2 from the exhaust gas requires less energy because of its higher CO_2 concentration compared to air.

The separation of CO_2 from any stream requires two steps: capture and desorption/regeneration.

During capture, the CO_2 is absorbed into a solid or liquid by contacting the CO_2 source with the absorber. In the desorption/regeneration step, CO_2 is selectively desorbed from the absorber, resulting in a flow of pure CO_2 gas, and the original capture absorber is regenerated for further use[33].

Over the last 20 years, many research groups around the world have explored CCS technologies to increase the efficiency of the capture and reduce the volume and cost of the systems.

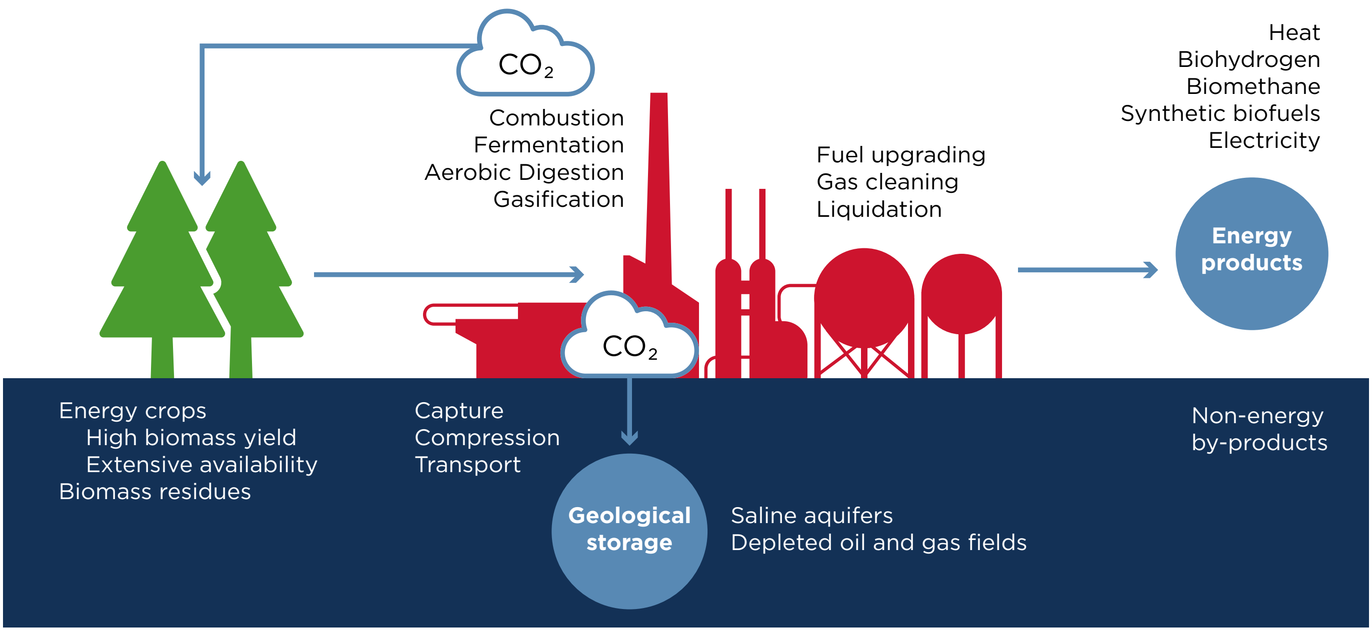

Figure 1: Schematic representation of carbon capture and sequestration technology.

Due to their present size, the majority of CCS systems have been designed and demonstrated in electric power plants. However, a recent concept study by Mitsubishi Heavy Industries (MHI) focused on installing a marine carbon capture and storage unit on a very large crude carrier (VLCC).

The system comprised four towers for cooling the exhaust, absorbing CO_2, treating the exhaust and regenerating the CO_2, in addition to the required liquefaction and storage facilities. The objective of the project was to investigate onboard production of methane or methanol by combining hydrogen from water electrolysis with the captured CO_2.

MHI reported a CO_2 capture rate of about 86 percent, which is expected to improve with further advances of this technology. However, the capital cost required for the CCS system was about $30M, and the cost for the methane or methanol production system was an additional $15M.

This level of investment would require 20 years to recover, making current CCS technology challenging from an economic perspective. In addition to the economic challenge, MHI reported that the size and weight of the system requires the vessel to be redesigned. Each of the four towers of the system is roughly the same size as a scrubber unit, and the weight of the total system exceeds 4,500 tonnes, or nearly two percent of the vessel's deadweight.

Despite these technical and economic challenges, carbon capture technology still can be an effective way to reduce the GHG emissions of future vessels, especially in combination with low-carbon fuels. Further technical advances are expected to reduce the scale, cost and complexity of CCS technology.

HYBRID ELECTRIC POWER

The International Maritime Organization's (IMO) efforts to decarbonize international shipping are expected to accelerate the electrification of power generation and propulsion systems, which offer the potential for operational flexibility, optimized power consumption, efficiency improvements and lower emissions from ships.

Hybrid-electric propulsion systems currently are used in the maritime industry and are increasing in popularity; their adoption is being led by offshore support vessels and harbor tugs, where the systems readily provide additional energy on demand.

Vessels and offshore installations require electric power for a wide range of components, from those that support communications and navigation systems to crew comfort and reliable propulsion systems.

These systems have the potential to improve reliability, operational efficiency, fuel consumption rates, environmental footprints and maintenance costs when compared to traditional electric power systems. A fully integrated hybrid system may include the energy storage system (ESS), power generation, and power management systems.

Hybrid-electric power systems combine engines, batteries or supercapacitors, fuel cells, and electric motors to form the power generation and propulsion system of the vessel. The architecture of a hybrid system can be designed specifically for the requirements of each vessel and thus optimize the use of each component for maximum efficiency (see Figure 1).

OPERATIONAL FLEXIBILITY

Hybrid-electric power systems also offer the flexibility to use a variety of energy storage and power generation components. Lithium-ion (Li-ion) batteries, supercapacitors, flywheel energy storage, fuel cells, solar and wind power can be used to supplement, or in some cases replace, traditional gen-sets during varying operational scenarios, such as those at sea, during maneuvering and while docking. (See Figure 1)

This diversity of electric power sources helps to improve the operational flexibility and reliability by selectively using generators as needed and operating them at their efficient load points.

For example, vessels engaged in long, low power transits such as a river or a canal passage require multiple generators to run in parallel for reliability purposes. The use of the appropriate energy storage system can decrease generator use by using the battery to prevent a loss of power.

Energy storage technologies can offer similar functions during dynamic positioning operations, cable/pipe laying, etc. Other uses include load leveling, such as with the active heave compensation required by drilling derricks and crane systems.

OPTIMIZATION OF POWER CONSUMPTION

When alternate power generation and energy storage technologies are used on a vessel, they can minimize the number of generators that are required, potentially optimizing their number and the operating points during different operating scenarios. Maintenance costs can be reduced in proporation to the operating hours of the equipment and by limiting the start/stop cycles of certain components.

Additionally, energy storage devices can offer purely electric power generation and propulsion to the vessel, which results in zero emissions operation in ports and other environmentally sensitive areas.

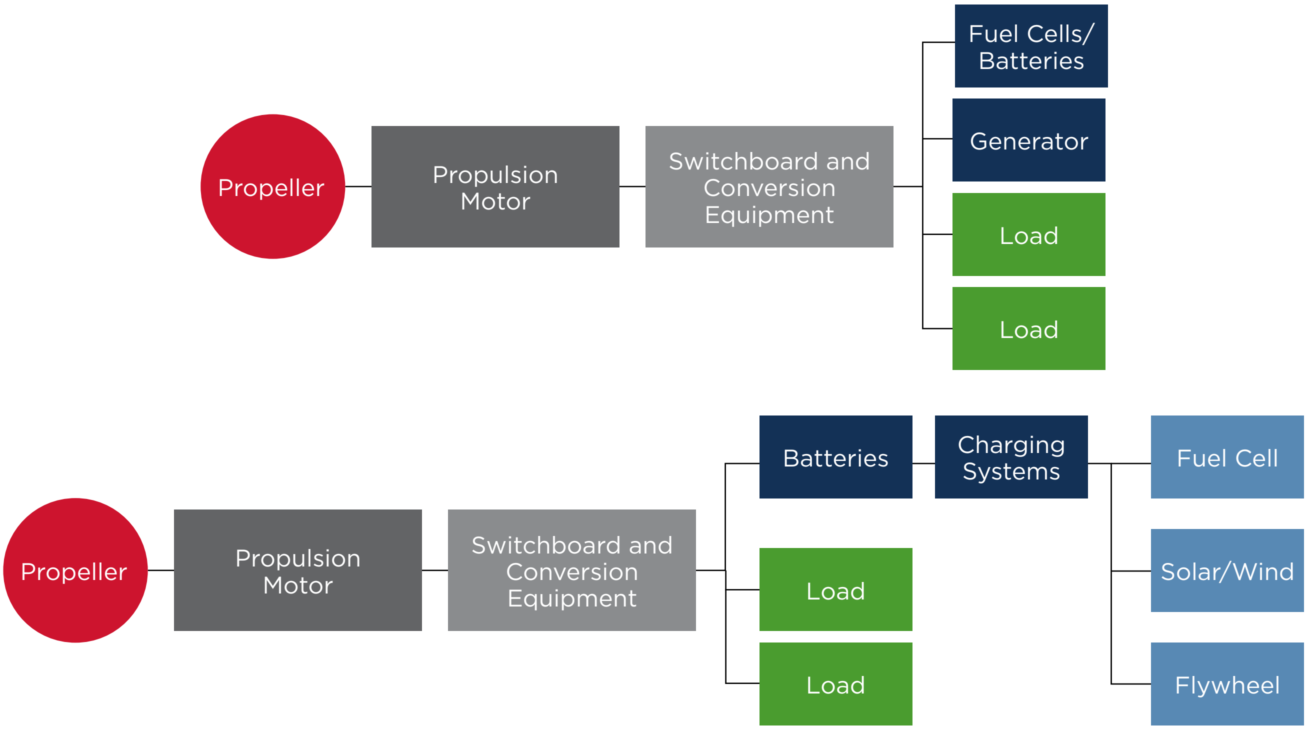

Figure 1: Example architectures of hybrid electric systems.

BATTERIES

The energy storage component is the central point of a hybrid-power generation system and, as such, battery technology is an enabler for electrification of modern vessels. Batteries store and convert electrochemical energy into electrical energy and they can be designed and optimized for any specific application. Common chemistry types include lead-acid (PbA), nickel-metal hydride (NiMH), and Li-ion.

A battery cell is the basic battery unit, and a battery pack comprises multiple cells. Multiple cells may be required to increase the energy storage, the pack voltage or the pack power.

Many electrical devices require higher voltage than the basic cell voltage for operation. For example, the speed of a DC electric motor, powered directly by a battery, is approximately proportional to the battery voltage.

Many electronic devices require battery voltages in excess of certain minimum values for the electronics to function. Cells can be arranged in series in order to generate higher voltage and higher power, as the battery pack voltage is simply the sum of individual cell voltages. Cells can also be arranged in parallel, in order to generate higher current and power.

The stored energy, voltage and lifetime of a battery are dependent on the current or power extracted from the battery. Adding more cells in parallel increases the energy, voltage and lifetime for a given power output.

The batteries used in hybrid propulsion systems are typically arranged in a combined series-parallel configuration in order to obtain higher voltage, current, power, energy and lifetime.

Batteries can be optimized for a particular application as the usage can dictate the material selection. For example, the battery used for a purely electric propulsion system is optimized for a wide operating range, while the battery used for a hybrid system is optimized for a narrow operating range in order to maximize the number of discharge cycles.

The recent advances in Li-ion batteries have created the basis for the development of modern hybrid and electric propulsion systems. Lithium is the lightest metal, and the Li-ion battery has many advantages over the other technologies, such as a higher energy density, higher cell voltage and longer life.

A number of variations of Li-ion chemistry have been developed by manufacturers and used in commercial products. Early Li-ion chemistry types feature cobalt and manganese as the main metals; the choice and mix of materials can significantly influence the energy density, lifetime, safety and cost.

Manufacturers such as Panasonic, Corvus, LG Chem and AESC among others, are offering a wide range of batteries that have been used primarily in electric and hybrid propulsion systems for automotive applications.

Performance parameters: The critical parameters when selecting a battery for marine applications are:

- Cell voltage
- Specific energy
- Cycle life
- Specific power
- Self-discharge

The cell voltage is a function of the chemical reaction within the battery and can vary significantly with the State of Charge (SOC), age, temperature, and charge or discharge rate. The rated voltage of a battery cell is the average voltage over a full discharge cycle. Operation at high voltage can result in significantly reduced battery lifetime, while, operation at a low voltage can result in cell failure.

The specific energy of a battery is a measure of the stored energy per unit weight. Li-ion has the highest energy density among different chemistry types. The specific energy of the Li-ion battery is approximately three to five times higher than that of the lead-acid battery.

Cycle life is a measure of the number of times a battery can be charged or discharged before it reaches the end of its life. Electrochemical batteries degrade with time and usage. Factors such as temperature and cell voltage also play a critical role. Li-ion has the highest cycle life and NiMH is similar. Lead-acid batteries have a significantly lower lifetime than the other two.

Lithium-titanate (LiT) is a variation of lithium battery that eliminates the important aging problem of Li-ion. Although LiT has a lower cell voltage and specific energy, the considerable increase in cycle life makes this chemistry type an attractive option for electric and hybrid propulsion systems.

Specific power is a measure of the discharge power available from a battery pack per unit weight. Lead-acid traditionally has had a high specific power and is used as the starter battery for different applications. Newer batteries, such as the Li-ion and NiMH have comparable specific power ratings.

Electrochemical cells consume energy even when they are not being charged or discharged. This energy use is a parasitic loss of stored energy and is known as "self-discharge." Self-discharge rates can increase significantly with temperature; the self-discharge for Li-ion batteries is less than two percent, but the overall self-discharge of a battery pack can be closer to five percent due to the electronic system and circuits managing the pack.

LIFETIME AND SIZING CONSIDERATIONS

Unlike many electrical and electronic devices, an electrochemical battery can have a relatively short lifetime depending on its chemistry. Marine batteries are currently designed for a 7-10 year lifetime, but this should be extended to over 15 years in order to match the lifespan of a vessel, can which be a challenge for manufacturers.

Electrochemical devices, such as batteries, fuel cells and electrolytic capacitors can degrade relatively fast as they age, especially with increased usage. In recent years, the market has shifted from relatively short-life lead-acid batteries to longer-life NiMH and Li-ion batteries.

Predicting the lifespan of a battery is a complex task, but the key factors affecting it are the (i) voltage, (ii) temperature, (iii) time and (iv) cycling.

High voltage can result in breakdown of the electrolyte, increased effects of impurities, and accelerated loss of lithium from the electrodes, all of which increase the resistance, reduce the storage capacity and consequently reduce the lifetime. Lower cell voltage can increase the battery lifetime, but it also reduces the energy storage within the cell, which creates a trade-off for optimum battery use.

Operation at high temperatures can significantly reduce the lifetime and reliability of a battery, therefore it is important to implement thermal-management techniques for preserving the battery packs. Operation at very low temperatures can also be a problem for some battery technologies, because the electrolyte can become more viscous and have decreased conductivity.

Freezing of Li-ion cells at temperatures less than -10° C (14° F) reduces the amount of power and stored energy available from a battery. For this reason, manufacturers offer battery heaters for colder climates in order to ensure adequate performance. Ideally, the battery is heated when charged from the grid so that energy is saved for vessel propulsion at sea.

One of the biggest challenges for every manufacturer is to develop batteries with lifetime comparable to that of a vessel. Factors such as voltage, temperature and cycles affect its lifetime as discussed above. As the battery ages, there is also a reduction in the lithium available as the active materials. A lower SOC results in lower cell voltage, which slows the degradation of the electrolyte and the loss of active lithium.

FAILURE AND PROTECTION

Batteries can be a source of catastrophic failure resulting in dangerous and possibly life-threatening consequences. Battery packs must undergo rigorous testing in order to ensure benign failure modes. As general guidelines, the battery should not emit particles, or any toxic and hazardous gases. Care must also be taken in manufacturing, transporting, using and recycling of batteries. Many safety standards exist to define the level of danger from batteries; safety tests include penetration, crash, thermal stability, overcharge/discharge, and externals short.

BATTERY MANAGEMENT

A battery pack is a complex energy storage system, which requires robust control to ensure its safe operation. A typical battery management system performs the following tasks, it:

- Monitors the voltage, current, power and temperature
- Estimates the SOC
- Maintains the health of the battery and conducts diagnostics
- Protects against fault conditions such as overcurrent, overcharge, undercharge, short circuit, and excessively high or low temperatures

In contrast to batteries, supercapacitors have so far found limited use in marine applications. Proving their viability will require more research and development in capacitor elements, modules, packs, ancillary functions, capacitor management systems, cooling arrangements, and safety functions.

CURRENT DEVELOPMENTS AND APPLICATIONS

As marine technology evolves and regulatory requirements increase, the industry is faced with the challenge of simultaneously trying to comply with environmental requirements and meet operational demands.

In this commercial environment, owners and operators are increasingly compelled to turn to non-conventional sources of energy to power and propel vessels; hybrid-electric power systems can play a key role in meeting the demand for more efficient, low-carbon propulsion options.

Classification societies such as ABS are helping the industry to adopt hybrid systems by developing guidelines and rules. A chronology and sample of ABS' focus for guidelines and rules for marine and offshore applications is shown in Figure 2.

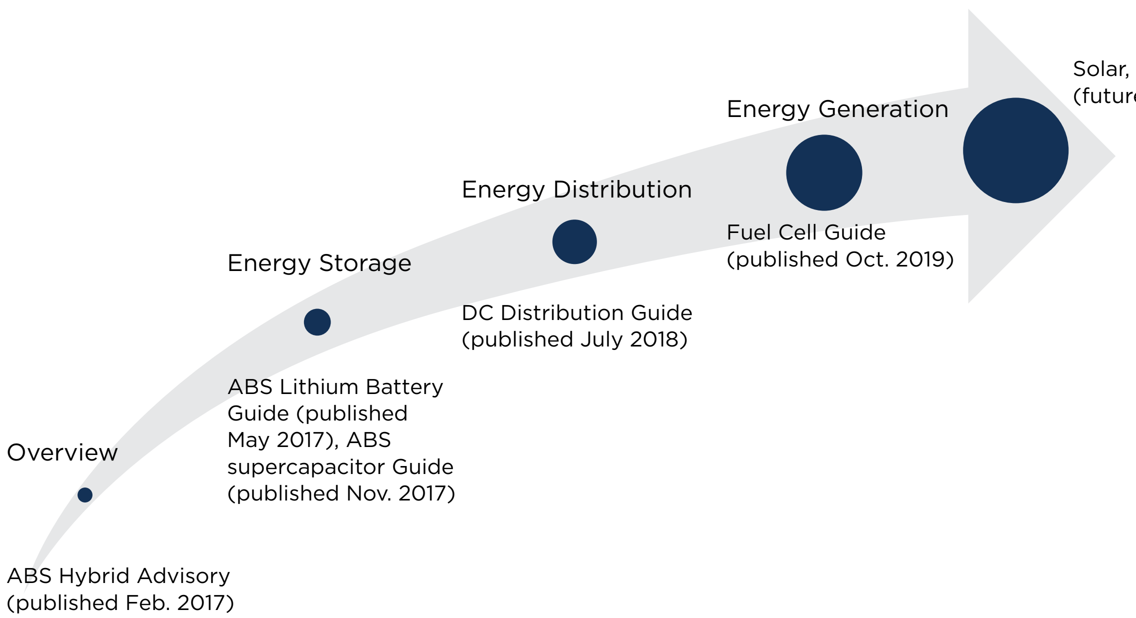

Figure 2: ABS publications on hybrid electric systems and components

© Seacor Marine

Figure 3: ABS/SEACOR Marine AIP.

SEACOR Marine recently installed a hybrid system using Li-ion batteries on the *SEACOR Maya*. With the design and components tested and approved for hybrid power integration, the vessel was converted at Bollinger Shipyards in Morgan City, Louisiana, and sent for sea trials in May 2018.

The integration of the Li-ion battery system was completed and operational within 90 days, a transition that the owner says reduced the vessel's average fuel consumption by 20 percent. As a result of this performance, SEACOR adapted three more vessels for service and has plans for six more. ABS provided an initial Approval in Principle (AIP) for the design, as well as classification.

Wärtsilä recently introduced a hybrid propulsion system (HY) that combines a diesel engine, with batteries, a generator, and DC power electronics; it can be configured in a series or parallel architecture (Figure 4). In the parallel configuration, the engine and shaft generator are connected to the propeller through a gearbox; in the series configuration, the diesel engine is only coupled to a generator to produce electric power, without driving the propeller, which is electrically driven.

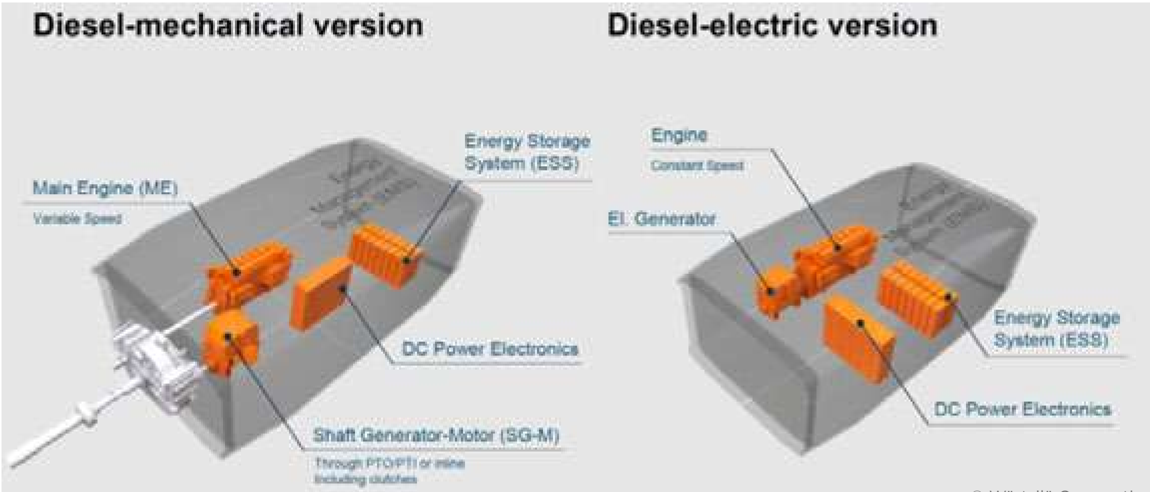

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Figure 4: Wärtsilä HY system in parallel and series configurations.

This hybrid system was installed into a 90-tbp harbor tug in 2018 that is used for ice breaking operations at the northern end of the Baltic Sea (Figure 5). Wärtsilä reported that each component of the system was designed to be hybridized, and the entire system is controlled to maximize energy efficiency, performance, lifetime, and safety, while minimizing emissions and smoke levels.

Figure 5: Wärtsilä HY system installed in a harbor tug vessel.

IMPACT

As the industry prepares to shift to low- and zero-emissions propulsion, hybrid solutions will play an important role in maximizing vessel efficiency. In order to meet the IMO's decarbonization goal for 2050, owners will need to commit to a solution long before the deadline, given that the lifespan of some vessels can exceed 30 years. Ongoing market applications of hybrid-electric power systems is providing valuable data and knowledge to expand the:

- Operational knowledge and experience of hybrid technologies
- Competence training for crew and operational personnel
- Methods for thermal management of battery systems
- Use of data analytics and its impact on ESS modeling
- Control software products and cyber security as hybrid-electric systems become more integrated in the primary functions of a vessel

Today, the vast majority of vessels are powered by conventional electric power plants, diesel, gas, or dual-fuel engine-generator sets; however, hybrid electric and electric-drive vessels are expected to gain market share in commercial ships, with initial applications to feature in small- and medium-sized vessels.

The rate at which hybrid systems are adopted has the potential to be impacted by conventional fuel supply and price trends. Significant changes in the way supply chains are managed have the potential to increase fuel costs against a backdrop of rising oil prices. To alleviate the fuel costs and maximize the efficiency of onboard power, shipowners may accelerate the adoption of hybrid systems, especially if the economic benefits over conventional propulsion systems become more apparent.

For example, in the offshore arena, prominent European drilling companies have already committed to hybrid, low-emission rigs. Service providers, integrators and vendors are also upgrading well intervention vessels and drilling platforms with battery solutions, often combined with conventional electric power generators.

On the safety front, regulations are responding to the electrification of the wider marine industry, with the short-term emphasis on batteries, fuel cells, and setting new standards and best practice for fire protection, installation, and operation. Industry practitioners are driving efforts to design and build safer solutions (containerized solutions, self-cooled modular systems, etc.) dedicated to the expanding array of hybrid-electric power systems.

These efforts will be supported by the industry's transition to "smart" technologies – the enhanced diagnostic and asset-monitoring capabilities that are at the center of current conditioned-based, or predictive, maintenance trends.

CHALLENGES

The growing availability of alternative energy storage and power generation technologies provides more options and benefits to designers of vessels and offshore installations. These options can be combined in different and imaginative ways, and this has led to the advent of more complex electrical systems. This in turn has influenced the entire vessel design concept.

The proper selection of the most appropriate combination of technologies is crucial and can have an important impact on the desired benefits, such as reduction of capital expenditures (capex), operational expenditures (opex), the environmental footprint and increased safety. The weight and size of the associated technologies are also critical design factors, and necessary for risk assessment. It is important to note that these factors may compete against each other.

New, more complex designs are more difficult and impractical to assess using traditional discrete electrical design tools such as a load analysis, short-circuit analysis, coordination study and harmonic analysis. Limiting common mode voltages and currents must also be considered in contrast to traditional alternating current power.

As technology progresses, the means of addressing this increased complexity is being developed with the advent of new modeling and simulation tools and techniques. The more these simulation techniques are used to assess the electrical aspects of the design, the more the designer is able to consider other variables, including non-technical considerations such as capex, opex and specific regulatory requirements.

When a preliminary decision is made on a design, it can be reviewed for practical aspects such as layout, failure modes and effects analysis, response in a blackout, operation and maintenance aspects. It can also be reviewed for compliance with class rules, other regulatory aspects and owner requirements.

FUEL CELLS

Fuel cells are electrochemical devices that convert the chemical energy of a fuel to electrical energy and heat through an electrochemical reaction.

Similar to an electrochemical battery, the electrical energy is output in the form of DC power. Unlike a battery however, the fuel and the oxidant are stored outside of the cell and are transferred into the cell as the reactants are consumed. The fuel cell converts energy rather than storing it and can provide continuous power, as long as fuel is supplied.

The technology of fuel cells is established, with the first application recorded by William Grove, in England, in 1838. However, the first commercial use of fuel cells was in the 1950s by NASA. Fuel cells are now regularly used for primary power production on spacecrafts, such as the International Space Station. Given that hydrogen is the fuel used for rocket propulsion, it is also convenient to use it for onboard power generation.

Fuel cells vary in type, structure, and performance characteristics. The proton-exchange membrane or polymer electrolyte membrane (PEM) fuel cell, which is of interest for marine applications, was originally invented by General Electric in the 1950s. Solid-oxide fuel cells (SOFC) have also become commercial products for stationary power generation, while alkaline fuel cells have been commonly used for spacecrafts. All types can use hydrogen as the fuel.

PEM fuel cells can be an attractive technology for use in marine applications due to its low operating temperature range (less than 100° C), small size, high efficiency, and wide operating range. Challenges for the fuel cells have been the costs of platinum for the electrodes, lifetime, sensitivity to impurities, and the significant accessory system required to operate the fuel cell, known as "balance of plant."

The voltage of the PEM fuel cell is quite low, in the range of 0.5 to one volts over the load range. Marine fuel cells are typically arranged in stacks with hundreds of cells in series. Stacks also can be configured in parallel to increase the power output.

Fuel cells are of particular interest for marine applications due to the high energy density of hydrogen and its potential for fast refueling, both of which are major challenges for batteries. Fuel cells are often seen as a competing technology to internal combustion engines; however, their operational characteristics are quite different, in a way that can make them complimentary technologies in a hybrid system.

OPERATIONAL FLEXIBILITY

FUNDAMENTAL OPERATION

The basis of operation of an electrochemical fuel cell and also of the battery cell is an oxidation-reduction reaction, commonly known as "redox reaction."

As with a battery, a simple electrochemical fuel cell comprises two electrodes and an electrolyte. The fuel cell is composed of two half-cells; one is the site of the oxidation reaction and the other is the site of the reduction reaction.

The anode is the solid metal connection or electrode within the fuel cell at which oxidation occurs. It is at the negative terminal of the fuel cell.

The cathode is the solid metal connection or electrode within the fuel cell at which reduction occurs. It is the positive terminal of the fuel cell.

An electrolyte is a substance which contains ions and allows the flow of ionic charge. PEM fuel cells feature a polymer electrolyte, which is designed to conduct the positive charge and insulate the electrodes.

Platinum is typically included as a catalyst for both the anode and cathode in order to split the hydrogen molecules into ions and electrons at the anode and facilitate the combination of the hydrogen and oxygen at the cathode. Figure 1 shows a schematic representation of a PEM fuel cell, showing the anode, cathode, polymer electrolyte, the flows of air and fuel, as well as the electric current.

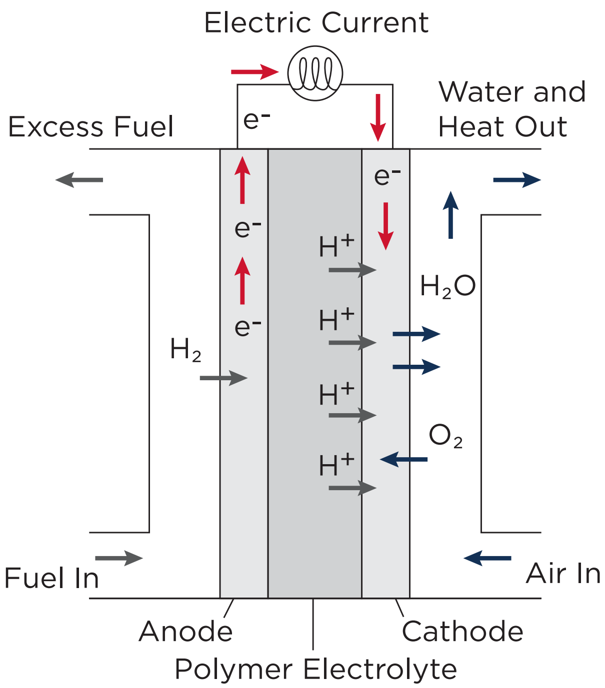

Figure 1: Typical Proton Exchange Membrane (PEM) Fuel Cell.

Electricity is generated from hydrogen and oxygen in a PEM fuel cell through the following process:

1. Hydrogen is supplied to the anode side (negative electrode).
2. Hydrogen molecules are activated when the anode catalysts release their electrons.
3. The released electrons travel from the anode to the cathode, creating an electrical current.
4. The hydrogen molecules that release electrons become hydrogen ions and move through the polymer-electrolyte membrane to the cathode side.
5. The hydrogen ions then bond with airborne oxygen and electrons on the cathode catalyst to form water (a positive electrode) and heat.

The hydrogen and oxygen are absorbed in the gas-diffusion layer (GDL), which acts as an electrode and enables the reactants to diffuse among the membrane, and also helps to remove the water. The full assembly of the electrodes and membrane is known as the membrane-electrode assembly.

Because the main difference between fuel-cell types is the electrolyte, they are classified by the type of electrolyte they use. The startup time can vary drastically between different fuel cell types and can range from one second for PEM fuel cells to 10 minutes for SOFC (see table below).

Type	Mobile Ion	Operating Temperature	Applications and Notes
Proton Exchange Membrane (PEM)	H+	30–120° C	Vehicles and mobile applications, and for lower power "combined heat and power" (CHP) systems
Alkaline (AFC)	OH-	100–250° C	Used in space vehicles, (e.g., Apollo, Shuttle)
Phosphoric Acid (PAFC)	H+	150–220° C	Large numbers of 200 kW CHP systems in use
Molten Carbonate (MCFC)	CO32+	600–700° C	Suitable for medium- to large-scale CHP systems, up to MW capacity
Solid Oxide (SOFC)	O2-	650–1000° C	Suitable for all sizes of CHP systems, 2 kW to multi-MW

Table 1: Fuel Cell Types

BALANCE OF PLANT

Fuel cell power generation systems require significant support components and ancillary equipment to produce power. These additional balance-of-plant components perform the following functions: (i) fuel processing; (ii) air processing; (iii) thermal and water management; (iv) electrical controls; (v) protection; and (vi) AC-DC conversion. The energy requirement for the balance of plant can be quite high, typically consuming about 20 percent of the fuel cell output at full load for high-pressure systems and about 10 percent or less for low-pressure systems, in order to drive the fans, pumps and compressors.

AGING

The performance of fuel cells decays with time as the GDLs and membrane degrade. Endurance was a significant challenge for the earlier generations of fuel cells; however, the latest generations have demonstrated lifetime and operating hours that can meet or exceed the stringent marine requirements.

ENERGY EFFICIENCY

Fuel cells generate energy electrochemically, do not burn fuel and can be more efficient than internal combustion engines. The waste heat from fuel cells can be captured for combined heat and power – a process known as cogeneration – which can reduce energy costs. Using this waste heat can bring the system efficiency up to 85 percent, compared with other types of electrical-generating devices. Table 2 (below) presents a comparison between different power generation systems and their respective energy efficiencies.

Electrical Generating Device	Conversion Type	Energy Efficiency
Diesel Engine-Generator	Diesel Fuel (Chemical) to Electrical	Between 30% and 55% (combined)
Gas Turbine	Chemical to Electrical	Up to 40% (primary)
Gas Turbine and Steam Turbine	Chemical/Thermal to Electrical	Up to 60% (combined)
Wind Turbine	Kinetic to Electrical	Up to 59% (primary, theoretical limit)
Solar Cell	Radiative to Electrical	Up to 6–40% (primary, technology-dependent, 15–20% most often, 85–90% theoretical limit)
Fuel Cell	Chemical to Electrical	Up to 85%

Table 2: Comparison of power generation systems.

Since fuel cells are increasingly being used for medium-to-large power generation in the marine and offshore installations, ABS has developed the *Guide for Fuel Cell Power Systems for Marine and Offshore Applications*. The Guide is applicable to marine and offshore assets designed, constructed or retrofitted with a fuel cell using either gaseous or liquid fuels. It is also applicable to the fuel-cell power systems used for auxiliary and main electric power systems on board vessels, offshore floating production installations, etc.

In publishing and updating the Guide, ABS continues to support the design, evaluation and construction of fuel cell systems for marine assets. The Guide, which covers all types of fuel cells, focuses on the use of their systems and arrangements for propulsion and auxiliary systems on new and retrofitted ships, while maintaining safety principles.

CURRENT DEVELOPMENT AND APPLICATIONS

Fuel-cell technology has been implemented in commercial products (i.e., forklifts, vehicles), naval submarines, commercial ferries and offshore support vessels. It is being deployed as fuel cell power systems for cruise ships, while other marine applications are in the planning stages.

In 2015, ABS, in collaboration with industry partners initiated the *SF-BREEZE* project, in which the goal was to design and build a high-speed passenger ferry with hydrogen-fueled PEM fuel cells for operation in the San Francisco Bay area (right, below). The *SF-BREEZE* received Approval in Principle (AIP) from ABS in 2016.

ABS is also involved in developing a prototype hydrogen fuel-cell unit to power onboard refrigerated containers. This unit fits into a standard 20-foot container (left, below) to replace diesel generators which power refrigerated containers in port and while being transported by barge. ABS also issued an AIP for this containerized hydrogen fuel cell generator unit.

© Sandia National Laboratories, Elliott Bay Design Group

Figure 2: H_2 Containerized Fuel Cell Unit (left) and the SF-BREEZE (right).

In 2019, ABS collaborated with Daewoo Shipbuilding & Marine Engineering to examine the viability of hybrid SOFC and gas turbine generator technology for future generations of liquefied natural gas (LNG) carriers. This theoretical work demonstrated the high efficiency of electricity and heat co-generation.

The Oslo-listed Havyard Group is working with other Norwegian companies to design, certify and deliver a large-scale hydrogen power solution that can be retrofitted onto ro/pax vessels (Figure 3). The project is focusing on developing safe storage solutions for cryogenic hydrogen on board vessels and in other unregulated areas related to hydrogen.

© Havyard Group

Figure 3: Conceptual design of the FreeCO$_2$ast project.

Another Norwegian firm, NCE Maritime CleanTech, is working on a project that involves retrofitting the *Viking Energy,* an offshore support vessel, with a 2-MW fuel cell using ammonia. Scheduled for completion in 2023, the project will test the feasibility of using sustainably sourced, ammonia in a SOFC system on a commercial ship.

In Japan, Tokyo Kisen Co. and e5 Lab Inc. are working with several groups to develop the design and regulatory baseline for a hydrogen fuel-cell powered tugboat. e5 Lab is a joint venture group tasked with designing the electric vessel and to share the information with all stakeholders in the shipping industry. The targeted launch year for the commercial operation of the tug is 2022.

Canada's Ballard Power Systems recently presented its modular, 100 kW PEM fuel cell stack (Figure 4) that can be used in various combinations in parallel to provide the power and redundancy needed by a vessel, from 100 kW to 1 MW or more. These PEM stacks can be used as the main propulsion system for small vessels, such as ferries and river boats, for auxiliary power on larger vessels, such as cruise ships, or for providing shore power to vessels when they are docked.

The PEM fuel cells are a source of DC power that is compatible with battery hybrid electric architectures and can be deployed in parallel configurations to meet the power requirements of hybrid-electric propulsion and auxiliary power systems. They also can be optimized for given power, fuel storage and fuel consumption.

© Ballard Power Systems Inc.

Figure 4: 100 kW marine PEM fuel-cell module.

IMPACT

The ongoing development of fuel-cell power systems for marine use is expected to encourage more:

- Joint development projects to increase knowledge sharing among maritime stakeholders.
- Competence training for crew and operational personnel.
- Research on optimizing hydrogen fuel-cell arrangements on board vessels, including best practices for safe operation, handling, storage and the use of hydrogen and fuel cell technologies.

The broad diversity of the fuel-cell types and their application with different marine fuels, such as LNG, ammonia and hydrogen, has yet to lead to the identification of a single preferred arrangement. However, more feasibility studies and safety assessments of their operations are expected to provide a greater understanding of best practices.

Current fuel-cell technology can be used either with pure hydrogen or with other fuels that can be used to extract hydrogen. In the latter case, fuel reforming is needed to extract the hydrogen from the fuel, which increases the system complexity and cost. The following table summarizes the advantages and disadvantages and each option.

	Advantages	Disadvantages
Pure Hydrogen Fuel	• Does not require reforming • Zero-emission power source • Provides stable and reliable DC power distributed across the vessel • Offers a high level of energy efficiency • Can be stored in liquid storage facilities, hence enable refueling at docks	• Gaseous hydrogen fuel storage can be large and heavy (so, difficult to accommodate) • Liquid hydrogen fuel storage, although lighter, requires high pressure and cryogenic temperatures to maintain its effectiveness • Smaller hydrogen molecules can leak more easily than larger fuel molecules, resulting in complex fuel storage and supply systems, and the need for redundant compressors • Expensive to acquire from present infrastructure
Other low-flashpoint fuels (methanol, ethanol, methane, propane, butane and ammonia)	• Produce lower emissions than conventional internal combustion engines • More readily available for purchase, cheaper and safer as compared to pure hydrogen • Low flashpoint fuels that are liquid at ambient conditions, (i.e., methanol or ethanol, can be stored in conventional fuel tanks and can be simpler to apply.)	• Requires reforming (either internal or external) before ionizing in the fuel cell • If an external reformer is not available, high temperature fuel cell types need to be used, which could lead to larger and more complicated systems

In general, the availability of resources, including fuel-cell manufacturers and fuel infrastructure (storage, transportation, bunkering, etc.), is expected to grow as more vessels are equipped with fuel-cell power systems in pursuit of a cleaner fuel solution. As capabilities grow, the inherent longer voyage limits have the potential to expand the number of viable sailing routes for this technology.

At present, fuel cell technology supports small- to medium-sized marine applications. As vessel owners search for emissions-free power solutions for larger vessels such as ro/pax, cruise ships, containerships or tankers, scaling up fuel cell technology will become more critical.

While there are many questions to be answered about the viability and safety concerns of fuel-cell technology for larger ships, present levels of investment in related projects and research suggests that the industry believes they hold potential to provide solutions on the path to carbon-neutral shipping.

CHALLENGES

Fuel cells offer a few challenges that will need to be overcome as the industry evaluates the technology's potential for carbon reduction. The technology is new in the marine industry, so the complexity of a new system will need to be managed, including the need for crew training on operations and maintenance.

Additionally, there is the complex process of tying the fuel cell into the electrical-distribution system.

Fuel cells are currently more expensive that competing power generation technologies. Depending on the type of fuel cell, exotic materials are often used as catalysts for the reaction. These can increase unit costs by 10 times on average, compared to an equivalent internal combustion engine.

With limited full-scale marine applications, there is also limited history and operational experience to support investments and long-term expectations.

For many of the fuel cell technologies, hydrogen is a preferred fuel, which can be extracted from light gaseous and liquid fuels. The availability of such fuels, storage challenges and bunkering infrastructure poses many challenges to the uptake of fuel cells. Additionally, the alternative fuels required by some fuel cells raise concerns related to the safety hazards of handling gas.

These challenges are applicable across most types of fuel cells. Additional concerns may need to be addressed based on the chosen technology. Individual types of fuel cells can have requirements for fuel purity (Proton Exchange Membranes) or slow start-up times (molten carbon and solid oxide varieties, for example).

DC SYSTEMS

Direct current (DC) power distribution systems were first proposed for lighting purposes, and patented by Thomas Edison in 1883. However, due to limited advancements in DC technology at the time, they were thought to be inefficient and unsuitable for transmitting power over long distances.

After technological advancements, however, they have evolved and been proven to provide several advantages over their alternating current (AC) counterparts, including higher efficiency and reliability.

OPERATIONAL FLEXIBILITY

DC distribution has the potential to reduce the cost of onboard installation, as it requires fewer stages for power conversion, less copper and less floor space. It has a simpler integration process with renewable energy sources and energy storage systems (ESS). DC power distribution systems are simply alternatives to the AC variety that is typically used for ships with electric propulsion. They can be used for any electrical ship application with power demands in the tens of megawatts and can operate at voltages of around 1,000V DC. DC systems are also suitable for vessels with equipment that is used for essential and emergency services through a DC bus. The following figure shows a schematic of a typical DC system.

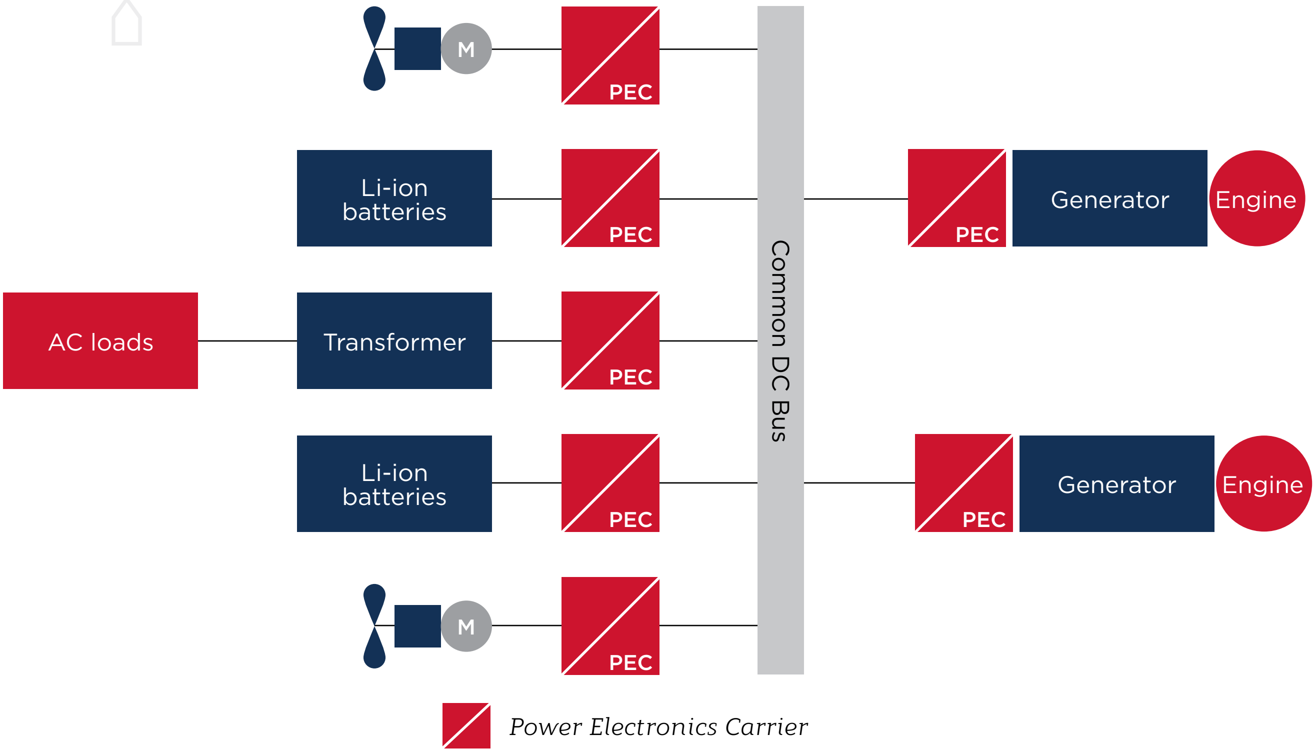

Figure 1: DC System.

The DC distribution system is simply an extension of the multiple DC links that exist in all propulsion and thruster drives, which can account for more than 80 percent of the power consumption on vessels that rely on electrical propulsion.

They offer comparative savings in space and weight and more flexibility in the placement of electrical equipment. This can result in a significant increase in cargo space and a more functional vessel layout, one that allows the electrical system to be designed to the functions of the vessel.

Of course, the reduced weight and on board footprint of the electrical equipment will vary according to the type of ship and its application.

The major components of DC systems include:

- Power electronics (i.e., inverters, rectifiers and filters)
- DC power control
- Protective devices (bus tie DC switches, DC circuit breakers, etc.)
- ESS
- Bus ducts

The comparative energy efficiency gains are being realized in part because the DC system does not need be locked to a specific frequency (traditionally, 60Hz on ships). The flexibility to control each power source has opened up new ways to optimize fuel consumption and new operational efficiencies, including the ability to vary generator speeds and voltage in line with demands for vessel services and the propulsion loads required for dynamic-response capabilities, such as in offshore support vessels and tugs.

DC distribution arrangements also feature comparatively lower noise from vibrations.

Different network topologies have been used in marine vessels, including:

- Multi-drives
  - Converter modules are arranged similarly to modern AC systems.
  - Each main consumer is fed by a separate inverter unit.
- Distributed
  - Each converter component is located as near as possible to the respective power source or load.
  - All generated electric power is fed directly or via a rectifier into a common DC bus.

Below are examples of a multi-drive (Figure 2) and distributed (Figure 3) topologies.

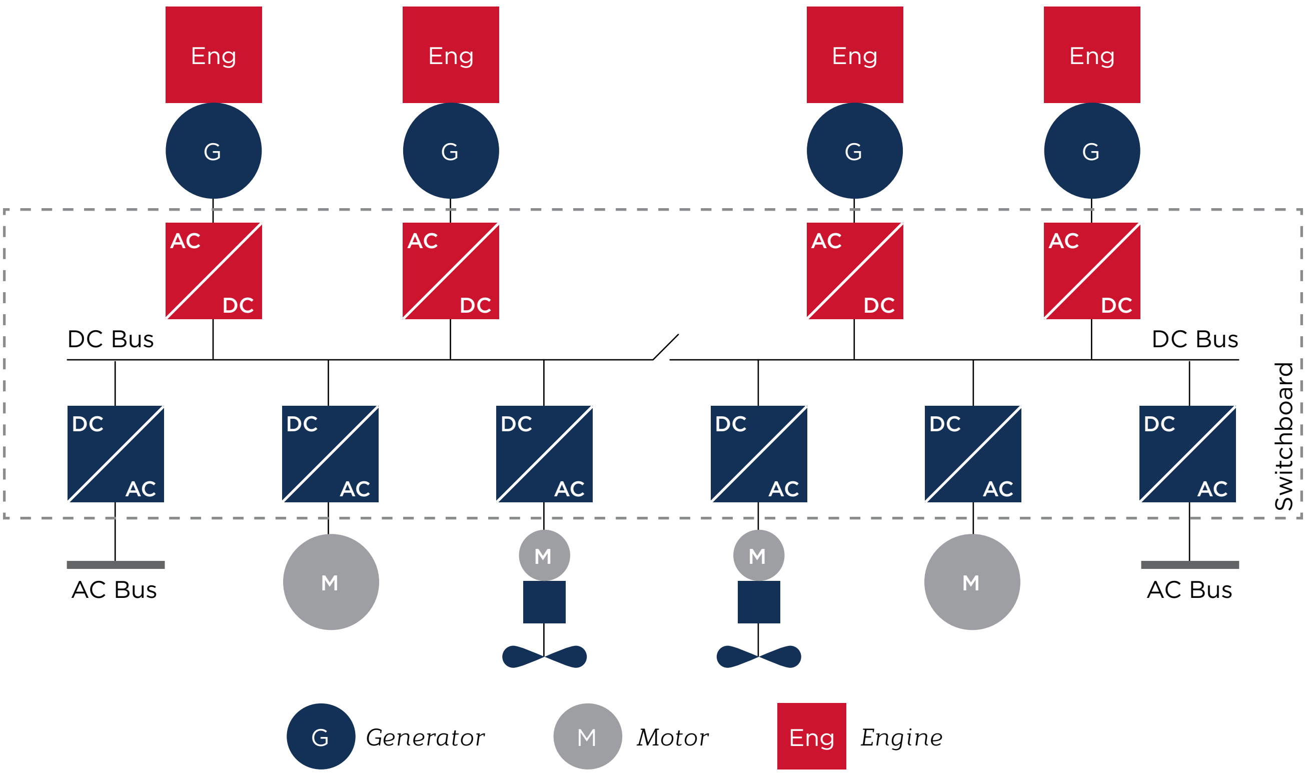

Figure 2: DC Multi-Drive Topology.

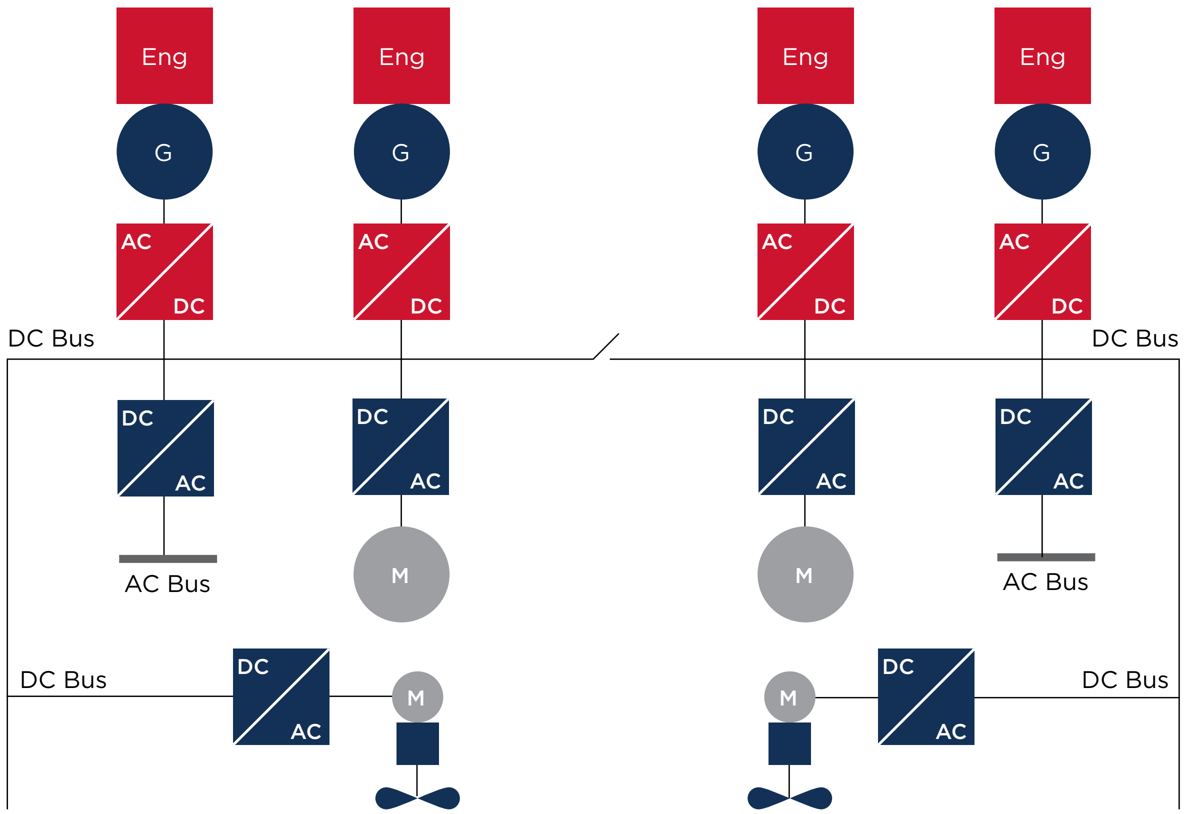

Figure 3: DC Distributed Topology.

CURRENT DEVELOPMENTS AND APPLICATIONS

New hybrid systems offer opportunities in renewable energy that could support a more environmentally friendly approach to power distribution.

The ABS *Guide for Direct Current Power Distribution Systems (DC) for Marine and Offshore Applications* provides practical steps to safer installation and integration of DC-power systems. It lays out the requirements for their design, installation, testing and survey.

The Guide's design requirements cover all major areas, including functionality, voltage variances, computer-based systems, power quality, earthing, materials, clearance and creeping distances, and enclosures.

Integrating new technology with DC systems requires thorough risk assessments that identify technical risks and the uncertainties associated with incorporation of power distribution and control system designs on a vessel. Assessments should also demonstrate safe practice and the continuity of power supply if systems fail.

Growing demand for DC generation and power loads, new DC technology and the integration of AC and DC distribution networks, is driving many projects to explore more efficient distribution systems.

Leading maritime players have received Approval in Principle (AIP) from ABS for new and innovative DC power distribution systems, including the ABB-designed Onboard DC Grid.

IMPACT

With the IMO's Energy Efficiency Design Index (EEDI) mandating incremental improvements in the fuel efficiency of ships to 2025, shipowners are exploring a wide range of technologies that will help them to comply with the targets for each stage.

When integrated with new technologies such as ESS, fuel cells and dual-fuel electric power generators, DC distribution has the potential to improve fuel efficiency and cost effectiveness and reduce emissions. These benefits will reveal themselves in the operators' key performance indicators and in any performance-monitoring and data-collection systems they install in their fleets as the industry moves towards "smart" technology.

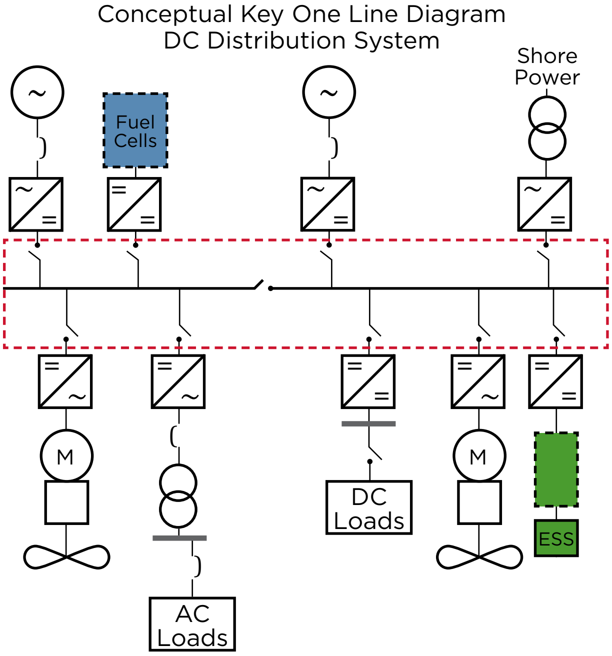

Figure 4: DC system on board a vessel

DC energy sources, including fuel cells and batteries, can also be connected directly into the ship's electrical systems via power-electronic converters (PEC), producing additional fuel savings.

There are several functional areas that can positively influence the development and deployment of DC power distribution systems and new technologies, including:

EQUIPMENT DESIGNS

It is theoretically possible to design a PEC to withstand abnormal conditions (i.e., transient overvoltage and overcurrent) from the DC bus without changes in its characteristics and functionalities.

PROTECTION SCHEMES AND FAST-PROTECTIVE DEVICES

To verify the integrity, reliability and dependability of DC systems and their components, research and development is likely to mature to accommodate short-circuit protection, as well "selective" and "fast-protection" schemes.

MATURITY OF ONSHORE POWER

Portable equipment and alternative energy sources can be improved and leveraged to improve the reliability of systems and their connections to onshore power.

DEVELOPMENTS FOR MARINE RULES, REGULATIONS, STANDARDS

Due to the different converter configurations used in DC distribution systems, the calculation methods for short-circuits (e.g. simulations) are expected to continue to evolve and contribute to a deeper understanding of their benefits.

Standards and guidelines, such as the Institute of Electrical and Electronic Engineers' Recommended Practice for 1kV to 35kV Medium-Voltage DC Power Systems on Ships, the International Electrotechnical Commission's Draft Technical Specification NP 63108, and the ABS *Guide for Direct Current (DC) Power Distribution Systems for Marine and Offshore Applications* will continue to mature and be updated.

As the industry's understanding of the technical, economic and environmental advantages that marine applications of DC power distribution systems have over their AC counterparts grows, they are expected to play significant role in helping owners to meet their emission-reduction goals.

CHALLENGES

The many advantages of DC systems have been discussed in this section. However, even though DC was the first application of electricity, the return to DC applications and distribution is not without challenges.

DC systems have been used for many years in small applications (e.g. control and instrumentation systems) and in high voltage transmission systems. However, the application of DC systems in power-distribution systems for the marine industry is new; it is only in the past few years that full DC networks have been used in small vessels. New systems require crew training, awareness, and familiarity. Also, the supporting components do not have a long history of operations in marine environments.

These new systems also are being supported by relatively new components. This is the case for protective devices such as fast DC-breakers, solid-state switches, etc. Operability, reliability and historic data for failure rates may not be available for some of the technologies.

Additionally, the requirements and international standards are in development for marine use. Many are the result of the transition from land-based standards and guidelines with adaptations for marine and offshore applications.

GLOBAL TRADE AND ITS EFFECT ON DECARBONIZATION OF SHIPPING

The adoption of the alternative fuels and novel power generation systems discussed in the previous sections is expected to contribute significantly to the reduction of greenhouse gas (GHG) emissions from shipping and promote the sustainability of the marine environment. However, the composition of the future fleet and by extension the fuels and technologies used in vessels will be shaped by the evolution of global trade.

ABS has collaborated with Maritime Strategies International (MSI) to model and investigate the evolution of global trade until 2050, to understand future ship demand for different commodities, and to calculate the future fuel consumption and CO_2 emissions from vessels.

This study is focused on five key vessel types that comprise the majority of the deep-sea fleet: (i) dry bulk carriers, (ii) oil and chemical tankers, (iii) containerships, (iv) liquefied natural gas (LNG) carriers, and (v) liquefied petroleum gas (LPG) carriers. The results presented and conclusions drawn are based on calculations for the selected fleet.

Ship Type	Size Ranges/Ship Class							Total Mn gt	Total vessels	Typical Emissions (gCO_2/dwt/nm)
Dry Bulk Carrier										
(k dwt)	10-40	40-65	65-120	120+				482	11,536	3-9
Oil and Chemical Tanker (k dwt)	10-70	70-125	120-200	200+				352	8,681	2.5-7.5
Containerships										
(k TEU)	0.1-1.3	1.3-2.9	2.9-3.9	3.9-5.2	5.2-7.6	7.6-12	12+	246	5170	6-19
LNG Carriers	Steam Turbine	D/TFDE	Motor Diesel	Gas Injection				58	518	6-11
LPG Carriers										
(k M^3)	6-22	22-40	40+					21	779	7-15
Other Ship Types (gt)	100+							221	40,620	N/A

Table 1: Key ship types and their size ranges, number of vessels, and typical CO_2 emissions.

CARGO DEMAND AND FLEET EMISSIONS

To calculate future emissions from shipping in conjunction with cargo demand, this study incorporates a potential change to the marine fuels used to achieve the International Maritime Organization's (IMO) goals by 2050 of a 50 percent reduction in absolute CO_2 emissions and a 70 percent reduction in CO_2 per transport work done (a measure of carbon intensity).

For both targets, the reference point for the reduction has been set as 2008. In that year, total emissions were estimated in the third International Maritime Organization (IMO) GHG study at 921 MnT from all international shipping. An estimate of transport work done does not appear to have been officially adopted, but a figure for the global fleet of 22 gCO2/dwt-nm has been quoted in the Poseidon Principles documents, which are being used to create a framework for responsible ship financing. This appears to be derived from the total CO_2 emissions and data for total cargo tonne nautical miles published by the United Nations Conference on Trade and Development (UNCTAD).

Two cases were considered: (i) a base scenario that follows the International Energy Agency's (IEA) stated policies, and (ii) an Accelerated Climate Action (ACA) scenario that follows the IEA Sustainable Development actions. Both cases are informed by projections made or commissioned by the Intergovernmental Panel on Climate Change (IPCC) and have been projected to 2050.

These scenarios consider how the supply and demand for key commodities (iron ore, coal, minor bulks, crude oil, refined products, chemicals, edible oils, LPG and LNG) and containerized goods will drive global trade until 2050. The forecasts incorporate explicit views on global economic growth, demographics, social factors, and energy intensity.

The following sections focus on the five key ship types that account for the majority of commodity and manufactured goods shipments (Table 1). According to the third IMO GHG study these ship types accounted for 623 MnT (68 percent of total global emissions) in 2008; it is estimated that this proportion remained the same in 2020.

BULK CARRIERS

Although global steel production is projected to be at or near its peak, the seaborne trade of iron ore is not expected to peak until 2022-2023, as imports continue to displace lower grade domestic ore in China. However, a number of structural changes are foreseen in the global iron ore market, primarily related to China's economy.

First, the substitution of Chinese domestic ore with imports is projected to be approaching a peak, limiting the potential growth for iron ore imports. Second, China's steel consumption is reaching maturity, and a gradual decline in the country's steel output is forecast as the economy evolves further.

Third, the use of steel scrap in electric arc furnace (EAF) steel production is expected to increase, partially displacing iron ore and imports of coking coal. Since its ascension to the World Trade Organization (WTO) in late 2001, China has seen a fivefold increase in steel consumption as consumer demand for white goods and vehicles increased rapidly. For example, between 2002 and 2019, over 280 million light vehicles were sold in China. This has led to the systematic collection and recycling of steel in recent years.

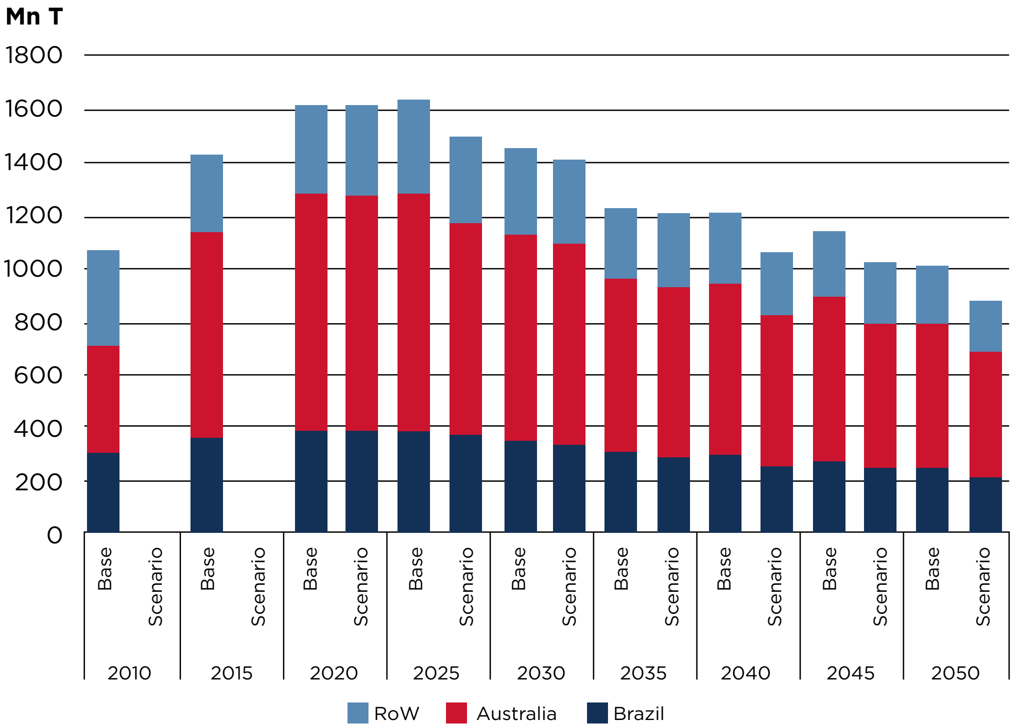

Figure 1: Iron ore exports from Australia, Brazil, and the rest of the world (RoW).

As a consequence, the global seaborne trade in iron ore is forecast to fall to 900 MnT per annum by 2050, from a peak of 1,600 MnT in 2022-2023.

Under the ACA scenario, the combination of lower steel consumption and greater use of EAF in the steel-production process will further impact the seaborne ore trade, which is expected to decline by an additional 115 MnT by 2050, relative to the base case.

The main influence on the performance of the capesize sector is expected to come from the decline in ore shipments to 2050; this is reflected in the CO_2 emissions of this segment.

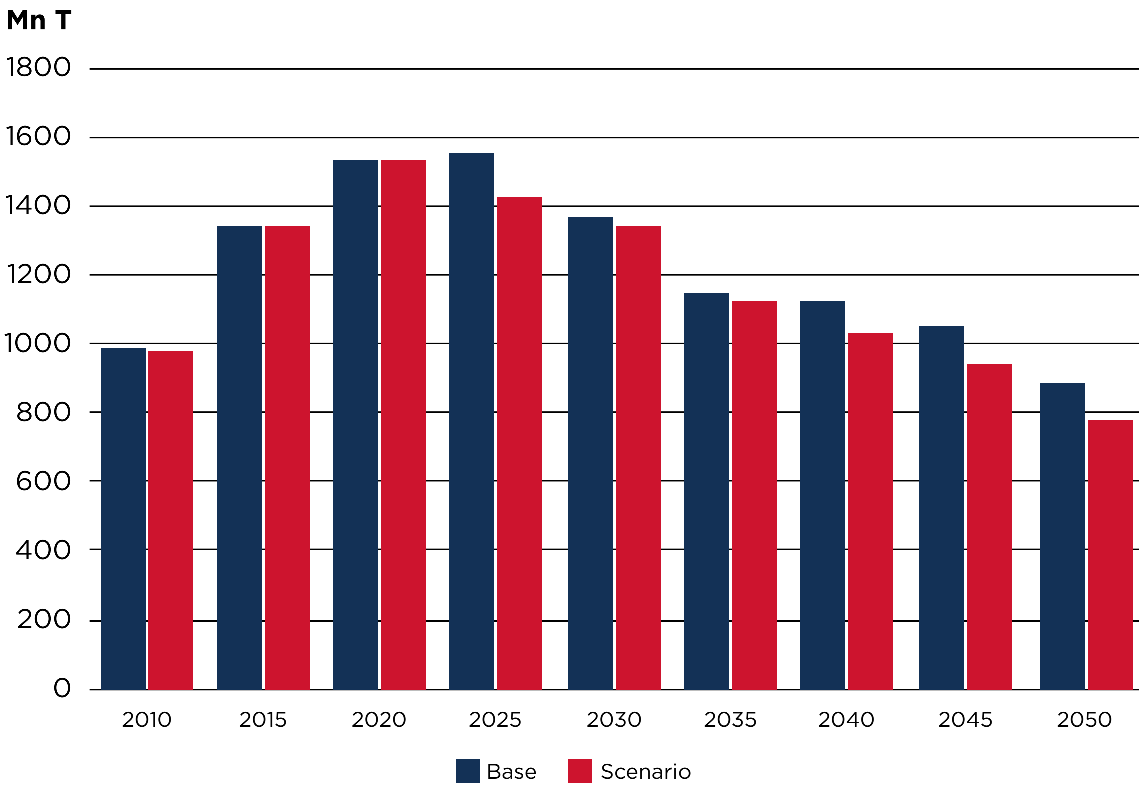

Figure 2: Iron ore seaborne trade.

In contrast to the gradual decline in iron ore shipments that underpins the long-term forecast, the seaborne trade of coal is forecast to continue to expand until 2050 supported by Asian growth in coal-fired power-generating capacity. Australia and Indonesia currently account for approximately 60 percent of global exports and are expected to maintain a leading position in the Pacific basin coal market.

However, as highlighted in the preceding section, coal is the power source most at risk from heightened action on climate change, as countries switch away from coal-fired power to reduce emissions and improve air quality. The use of coking coal in steel production is also threatened by greater use of EAF in the production process, in addition to declines in steel output.

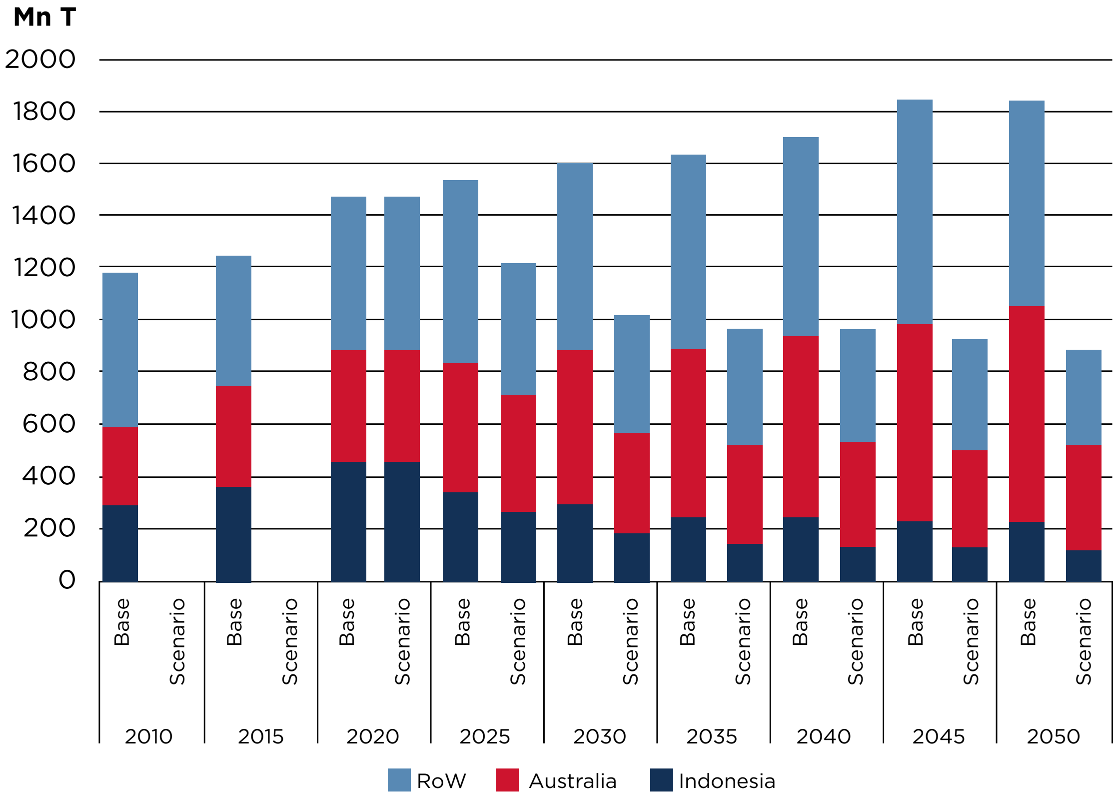

Figure 3: Coal ore exports from Australia, Indonesia and the RoW.

Under the ACA scenario, by 2050 the seaborne trade in coal is expected to have declined by almost 50 percent relative to the base case forecast. Whereas China is already targeting reductions in coal use to improve air quality, the transition will be slower in other parts of Asia (such as India), where long-term commitments to coal-fired power will support continued imports.

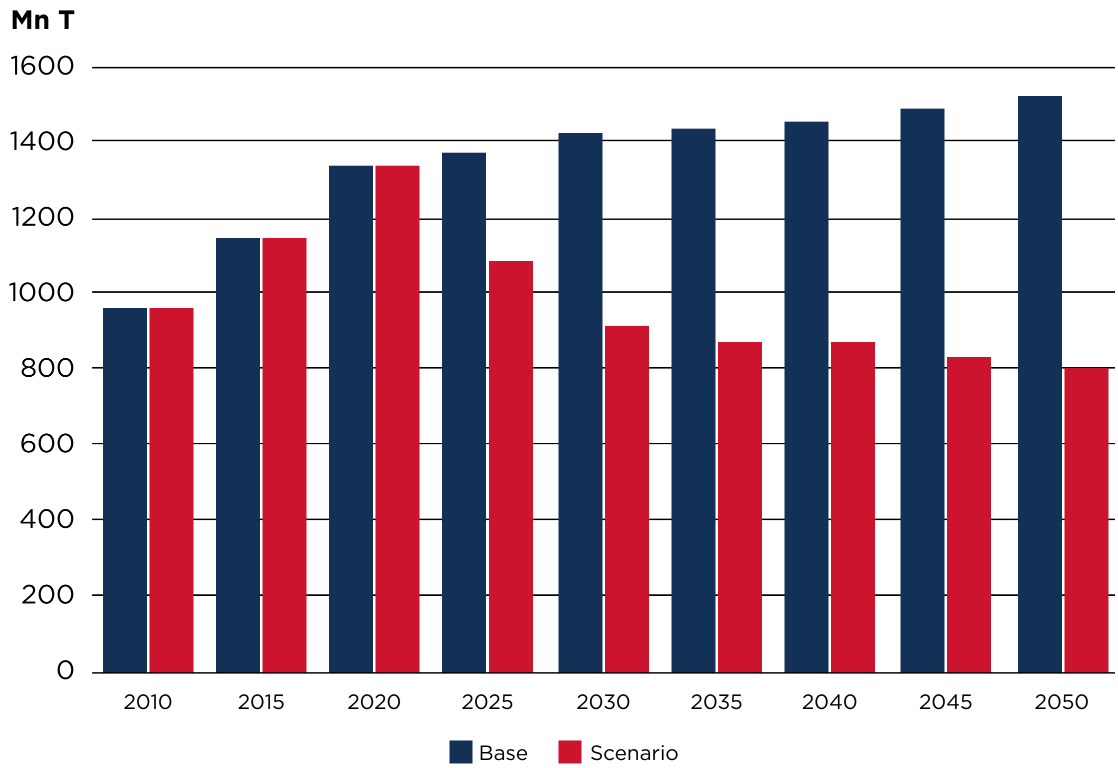

Figure 4: Coal seaborne trade.

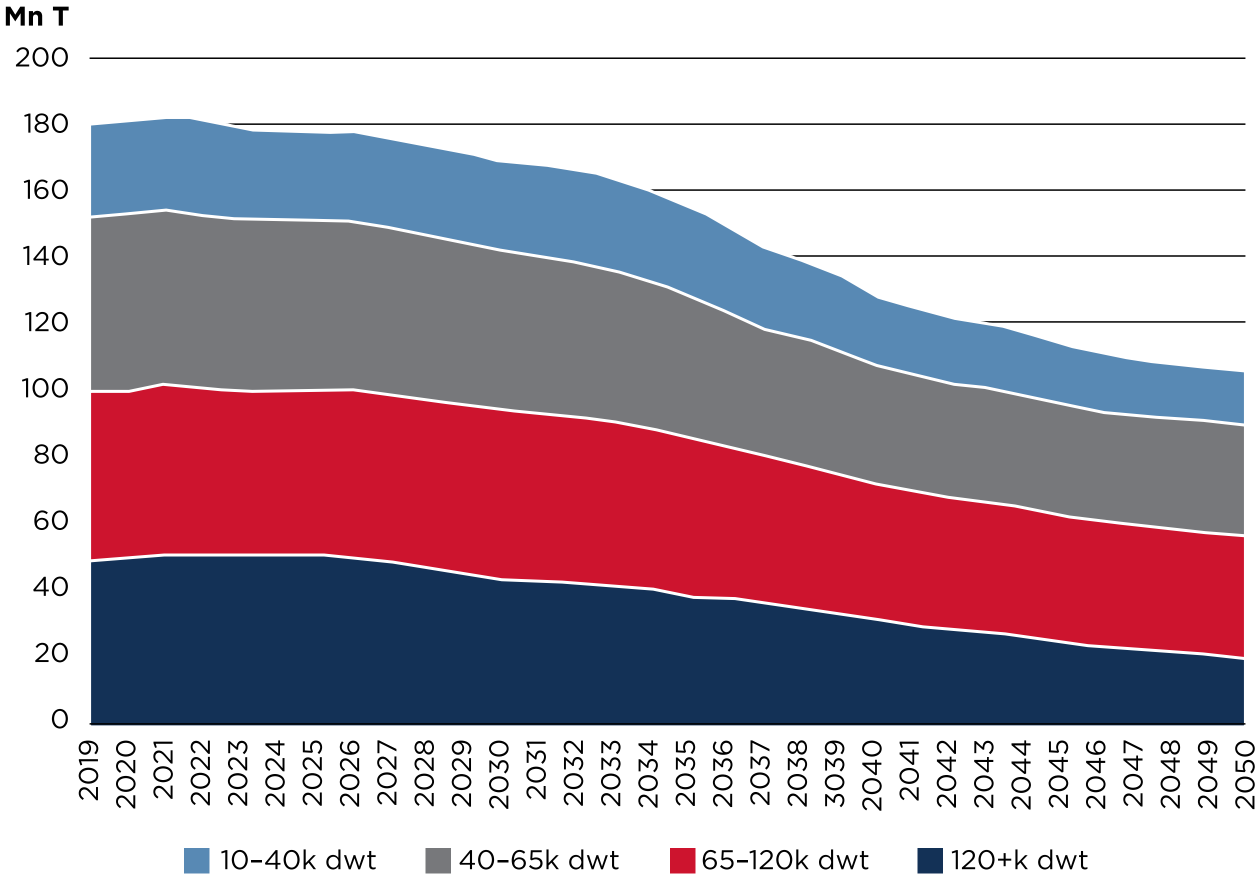

Figure 5: Bulk carrier CO_2 emissions by vessel size (base case).

The bulk carrier fleet (10k dwt and above) emitted just over 180 MnT of CO_2 in 2019. As shown in Figure 6, if the fuel mix remains unchanged from 2019 (when it was dominated by HFO/MGO/MDO), there will be a marginal reduction in CO_2 emissions by 2050. However, a gradual transition to lower carbon fuels (such as LNG, LPG, methanol and biofuels) and zero-carbon fuels (ammonia and hydrogen) underpins the projection of a 41 percent reduction in CO_2 emissions to 107 MnT by 2050, compared to 2019 levels.

The biggest reductions are forecast for the capesize segment, where structural changes to the iron-ore market are expected to drive an overall decline in trade, thus negatively impacting the size of the required fleet.

In addition, more negative adjustments to the dry bulk trades are expected if actions geared towards reducing global carbon emissions continue to gain momentum. Under the ACA scenario, downward adjustments to the seaborne trade of coal, and to a lesser extent iron ore, will further reduce the size of the required bulk carrier fleet. These changes result in additional savings of 16 MnT of CO_2, with emissions falling to 91 MnT by 2050, or 50 percent below 2019 levels.

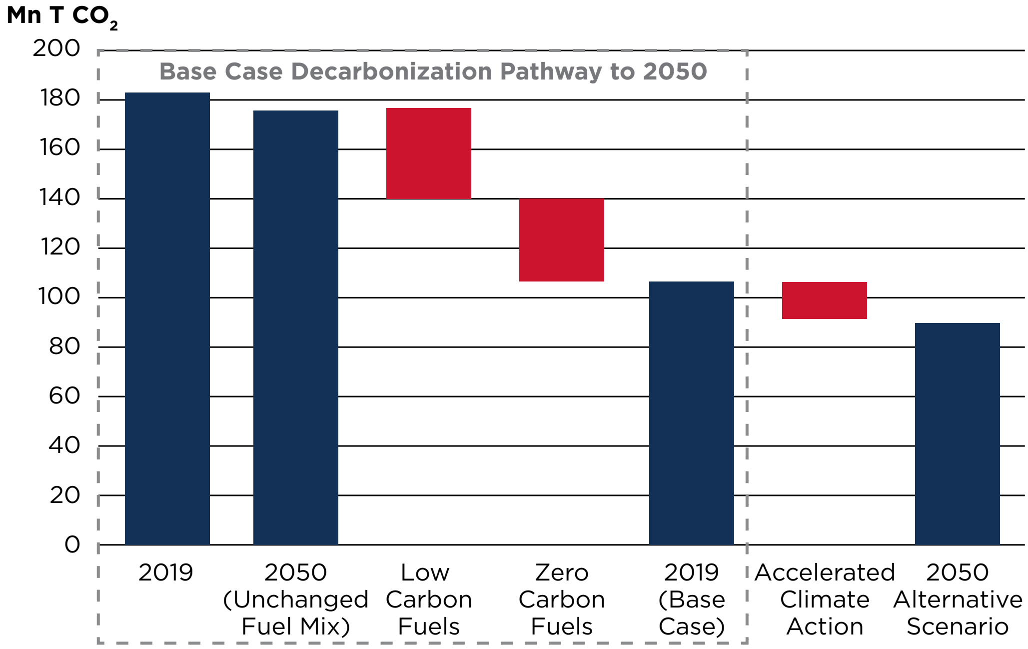

Figure 6: Bulk carrier pathway to decarbonization.

OIL AND CHEMICAL TANKERS

Long-term demand for oil is dependent on the evolution of transportation technology, predominantly with regard to road transport. Assuming demand for transportation continues to grow with demographic and economic expansion, oil demand will be mostly determined by the increase in efficiency of the global vehicle fleet – using either internal combustion engines or hybrid technology – and the pace of the transition towards electrification.

Global oil consumption is expected to peak in the next 15–20 years, and to gradually decrease thereafter. Any growth in consumption will continue to be driven by non-OECD regions, in particular Asia, where economic growth rates have been high and vehicle ownership rates are low.

In contrast, oil demand in Europe and North America is projected to decline over the next 10 years. As the electrification of the personal vehicle fleet grows, the proportion of oil demand driven by freight transport, aviation and petrochemicals is expected to increase.

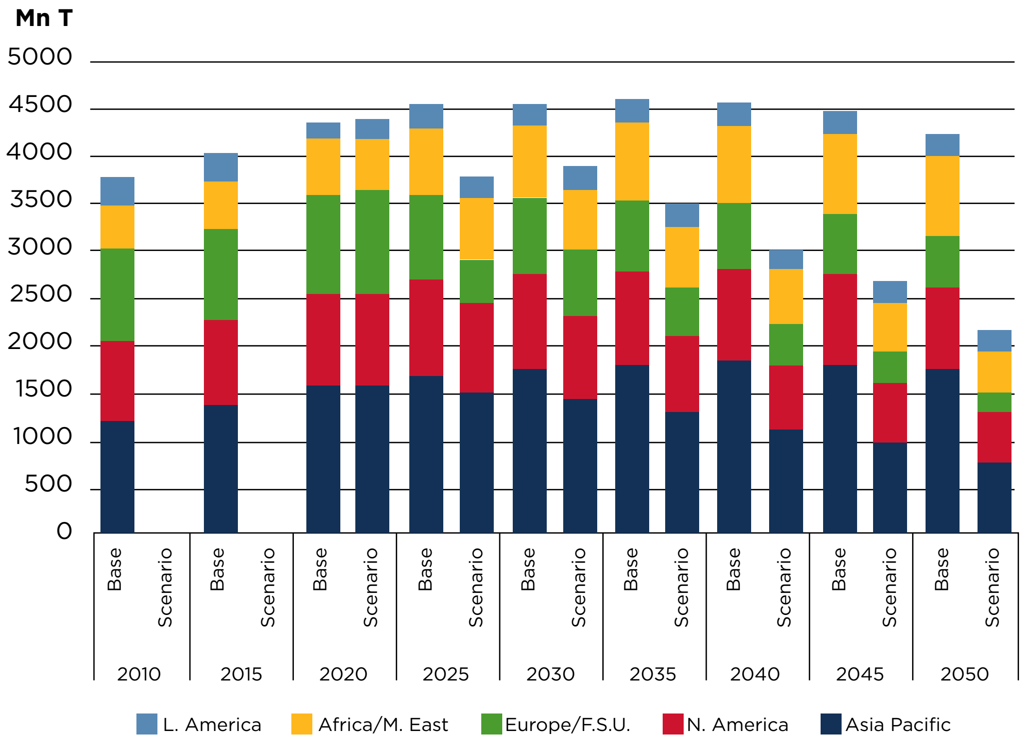

Figure 7: Oil refinery throughput by region.

Although the seaborne trade of crude oil is forecast to remain comfortably above 2 BnT per annum over the forecast horizon, the ACA scenario envisions that oil consumption will fall by almost 50 percent between 2020 and 2050.

Global refining capacity is expected to lag behind the slowdown in demand, due to the long lead times for new projects coming onstream in the Middle East and Asia, and the long-term economic considerations that influence decisions to reduce capacity. Non-energy demand – petrochemical feedstocks, for example – will also support refining activity. As the decline in oil demand becomes entrenched, the deteriorating commercial viability of refining is expected to drive a rapid consolidation of capacity in this sector.

Refining capacity is expected to see the largest decline in regions with older infrastructure and lower oil production bases, notably Europe, which will support product imports. The dislocation between points of refining supply and demand is likely to increase as refining capacity is retained in areas with easily accessible local crude production, and/or more resilient oil demand.

Exports of oil products from Europe will fall significantly as its refining capacity declines. The Middle East and North America are expected to have an increasing proportion of the trade moving out as refined products.

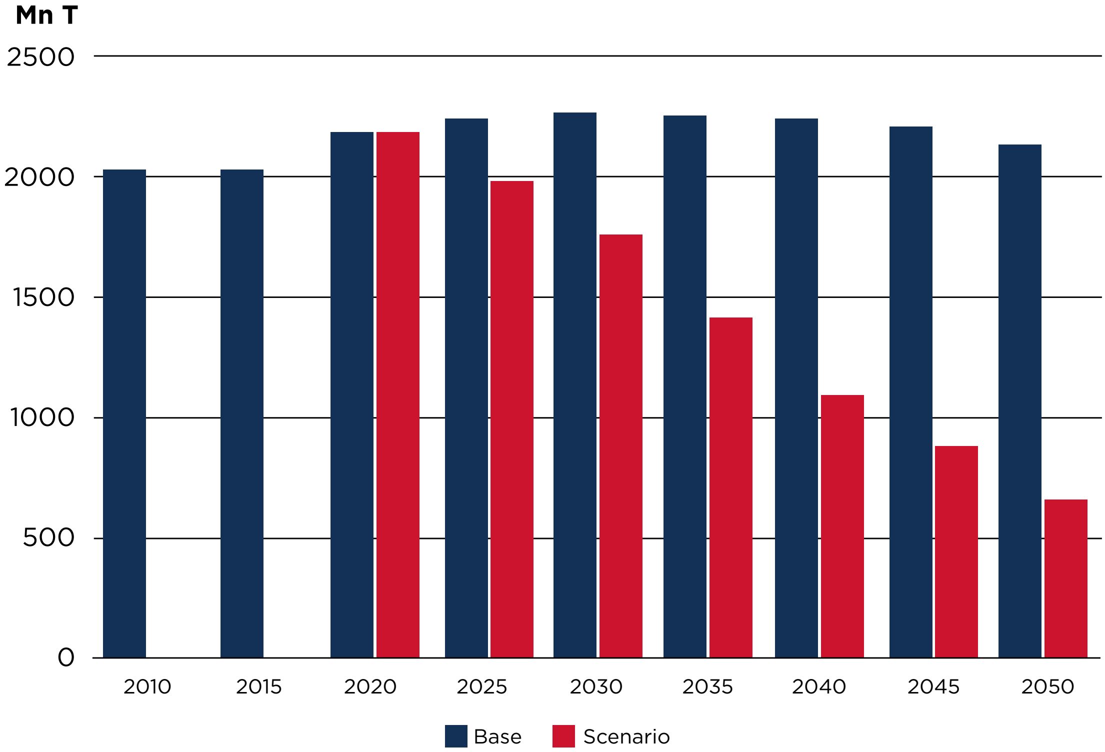

Figure 8: Crude oil seaborne trade.

Under the ACA scenario, the seaborne trade of oil products is expected to decline by just under 40 percent between 2020 and 2050. In contrast to the crude market, oil products may be partially protected from the downturn by the ongoing trend for traditional crude oil exporters such as the Middle East to invest in refining capacity. This would help them to diversify away from crude exports towards higher value, refined petroleum products and petrochemicals.

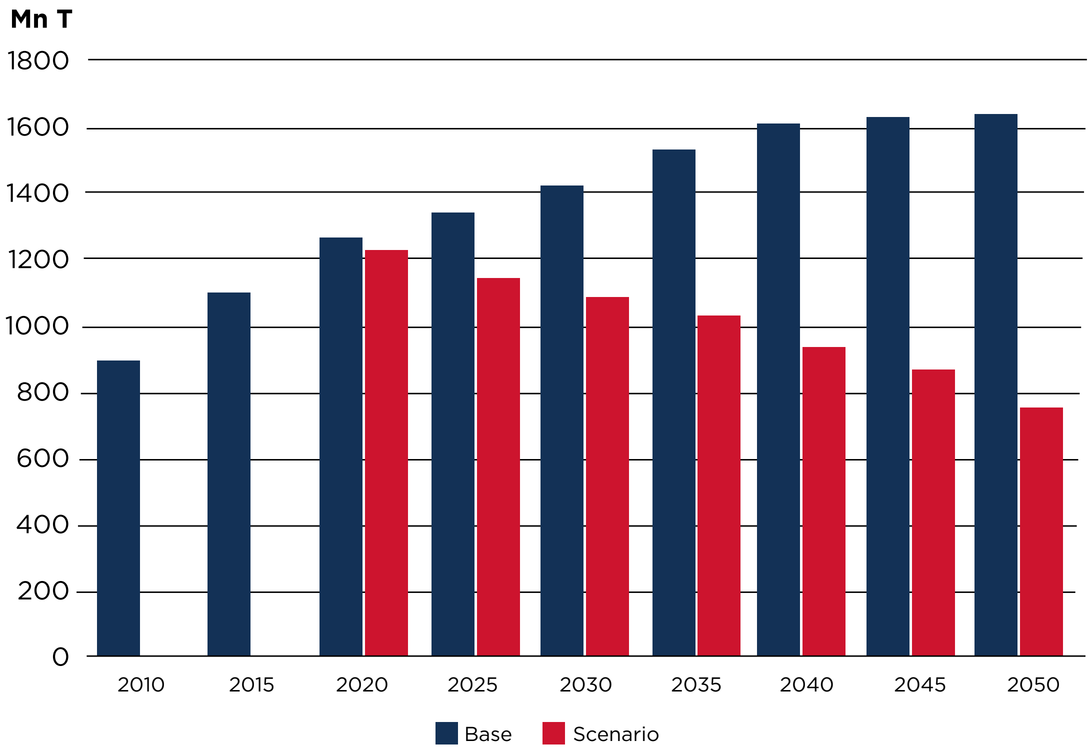

Figure 9: Oil products seaborne trade.

The base case shows a long-term decline in growth as an increase in Chinese chemical capacity reduces imports of organic chemicals, which in turn will decrease the related traded in the next 10 years. After that, increased demand for organic chemicals in developing countries is expected to expand the trade in the longer term.

After a surge in edible oil imports in the last 10 years, long-term growth is expected to remain fairly slow as countries within Europe, for example, investigate alternative sources for biofuel, one of edible oil's biggest uses. Furthermore, key producers of edible oils, such as Indonesia, Malaysia and Brazil, are making efforts to increase local demand by increasing the bio-derived content in the fuel, thus further limiting the growth. However, growth is expected to continue, as it remains a key product for other industries such as pharmaceuticals, cosmetics and food.

Demand for inorganic chemicals is expected to remain strong in the long term, as they will continue to be used in mining, metal processing and other key industries where production benefits from growing populations and economies. However, this is not expected to cause significant growth in demand for chemical tankers in the long-term.

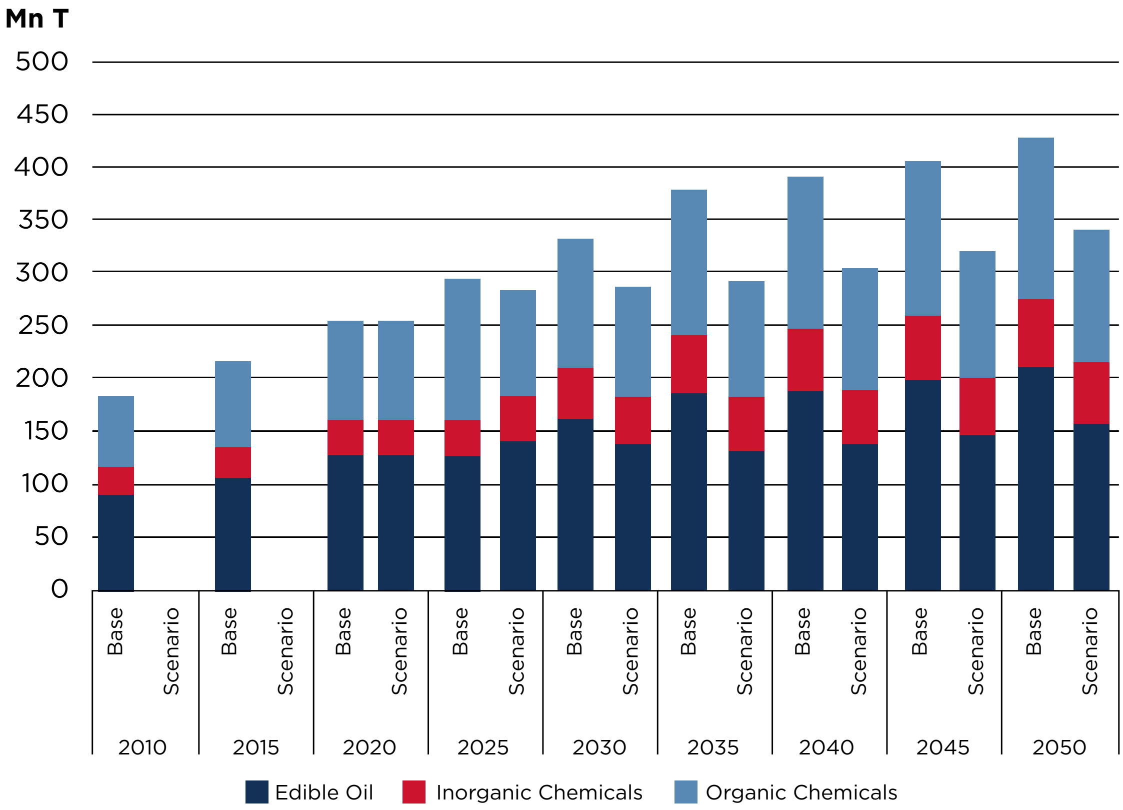

Figure 10: Chemical products seaborne trade.

The combined oil and chemical tanker fleet (10k dwt and above) emitted 114 MnT of CO_2 in 2019. If the fuel mix remains unchanged from 2019 (dominated by HFO/MGO/MDO), CO_2 emissions will increase by 25 percent to 143 MnT by 2050. However, a gradual transition to low-carbon fuels (such as LNG, LPG, methanol and biofuels) and zero-carbon fuels (ammonia and hydrogen) could reduce CO_2 emissions by 25 percent to 86 MnT by 2050, compared to 2019 levels.

Given the more favorable outlook for the trade in refined oil products, product tankers are expected to have the lowest reduction in CO_2. However, further negative adjustments to the tanker trade are expected if actions geared towards reducing global carbon emissions continue to gain momentum.

Under the ACA scenario, downward adjustments to the seaborne trade of crude oil and refined oil products could further reduce the size of the tanker fleet. These changes could result in additional savings of 35 MnT of CO_2 with emissions being reduced to 50 MnT by 2050, or 56 percent below 2019 levels.

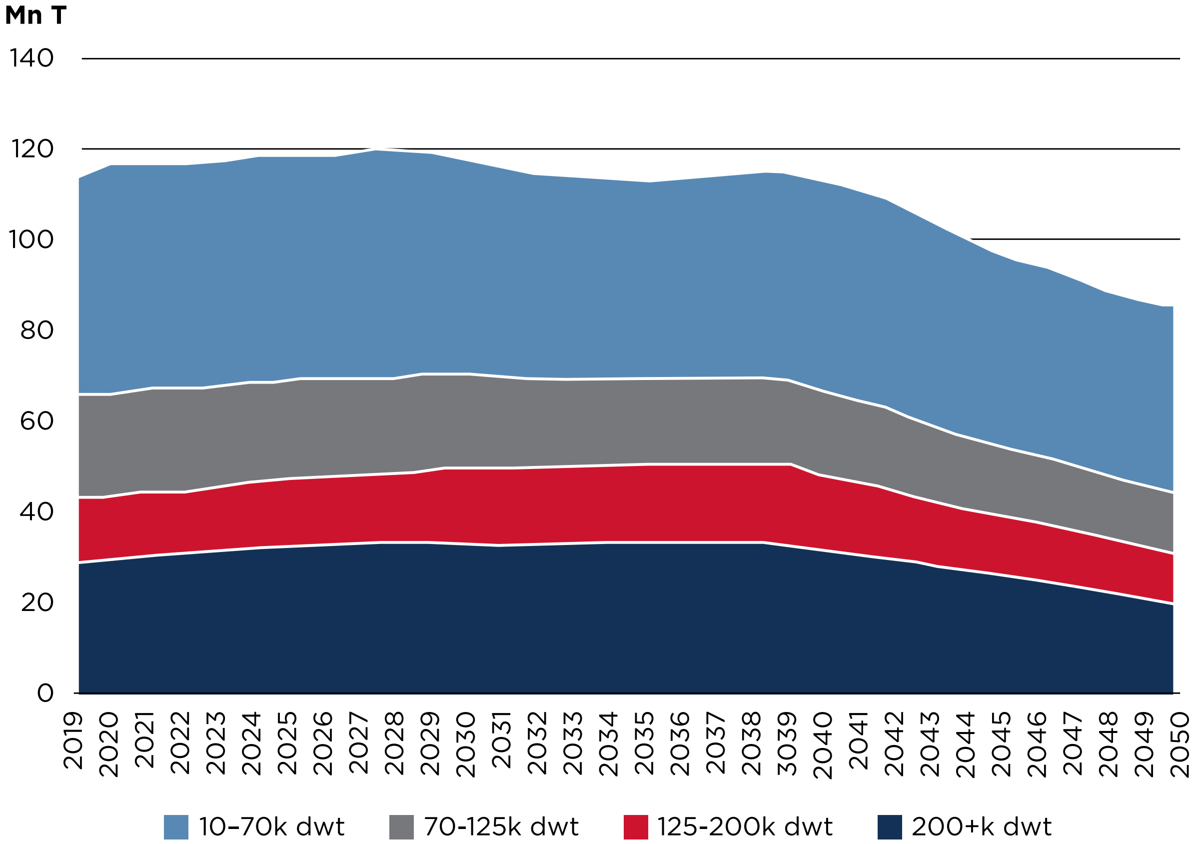

Figure 11: Tanker CO_2 emissions by vessel size (base case).

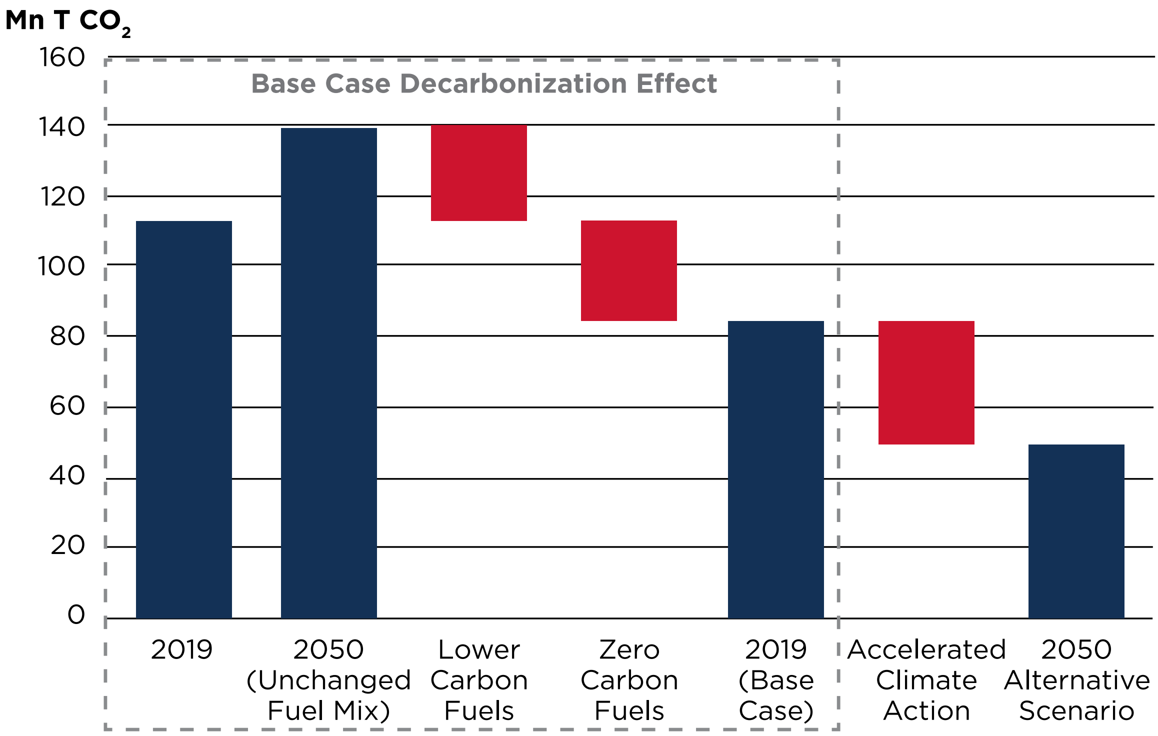

Figure 12: Tanker pathways to decarbonization.

CONTAINERSHIPS

Increasingly, the sources of growth in the container trades will come from emerging economies, predominantly in East Asia, as China becomes a larger importer of consumer goods. Given the geography of global manufacturing, these new sources of demand will offer lower "TEU miles" than the current long-haul trades that connect the Far East with Europe and North America.

Under the base case, containerized trade is expected to see a compound annual growth rate of 3.4 percent until 2050. In contrast to the bulk carrier and tanker sectors, the role of containerships in transporting energy-related commodities is small; tank containers account for a minor share of containerized trade.

However, as the primary mode of transport for finished and semi-finished manufactured goods, the containership sector is the trade most directly exposed to consumer behavior.

The ACA scenario assumes that climate-conscious consumers will move away from today's disposable single-use model towards a more sustainable behavior. As radical changes in consumer technology become less frequent, the technology replacement cycle is expected to increase, thus slowing containerized trade from 2030 onwards.

This trend may be reinforced by increased consumer pressure on manufacturers to reduce their carbon footprints, thus driving the development of greener supply chains and a partial reshoring of manufacturing.

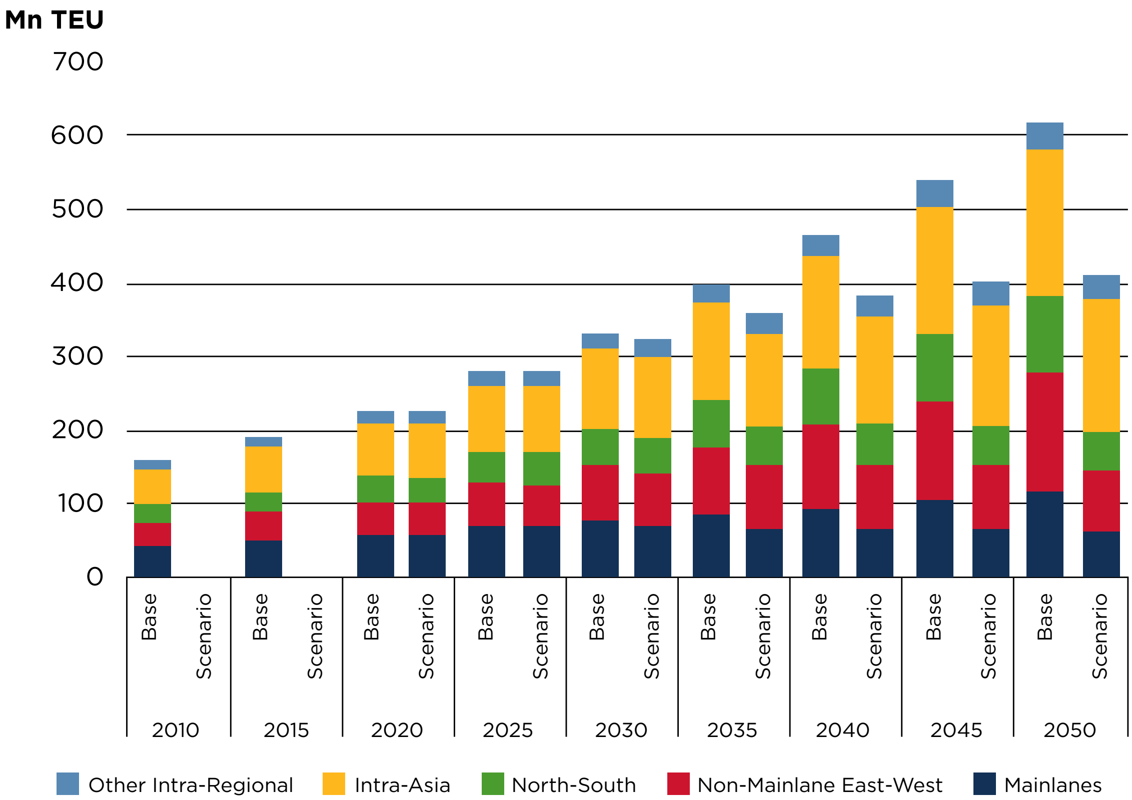

Figure 13: Global container trade evolution.

The containership fleet (100 TEU and above) emitted 215 MnT of CO_2 in 2019. If the fuel mix remains unchanged from 2019 (dominated by HFO/MGO/MDO), CO_2 emissions will increase by 63 percent to over 350 MnT by 2050. However, a gradual transition to low-carbon and zero-carbon fuels is expected to reduce CO_2 emissions by six percent, to 202 MnT, by 2050, compared to 2019 levels.

With fleet expansion firmly focused on very large containerships, this is the sector that exhibits the fastest growth in emissions under the base case.

Under the ACA scenario, there is slower growth in containerized trade, particularly from 2030 onwards, which is expected to yield additional savings in CO_2 emissions. These savings forecast an additional reduction of 76 MnT of CO_2 to 126 MnT by 2050, or 42 percent below 2019 levels.

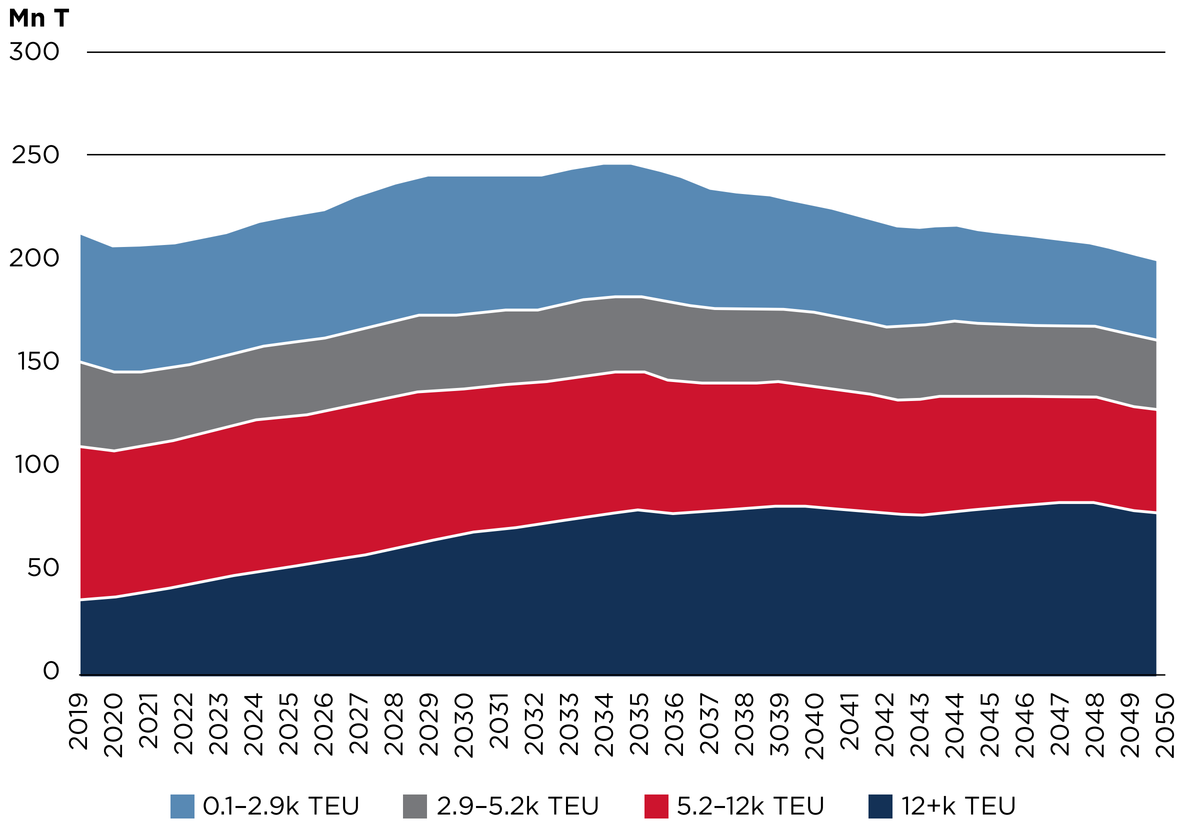

Figure 14: Containership CO_2 emissions by vessel size (base case).

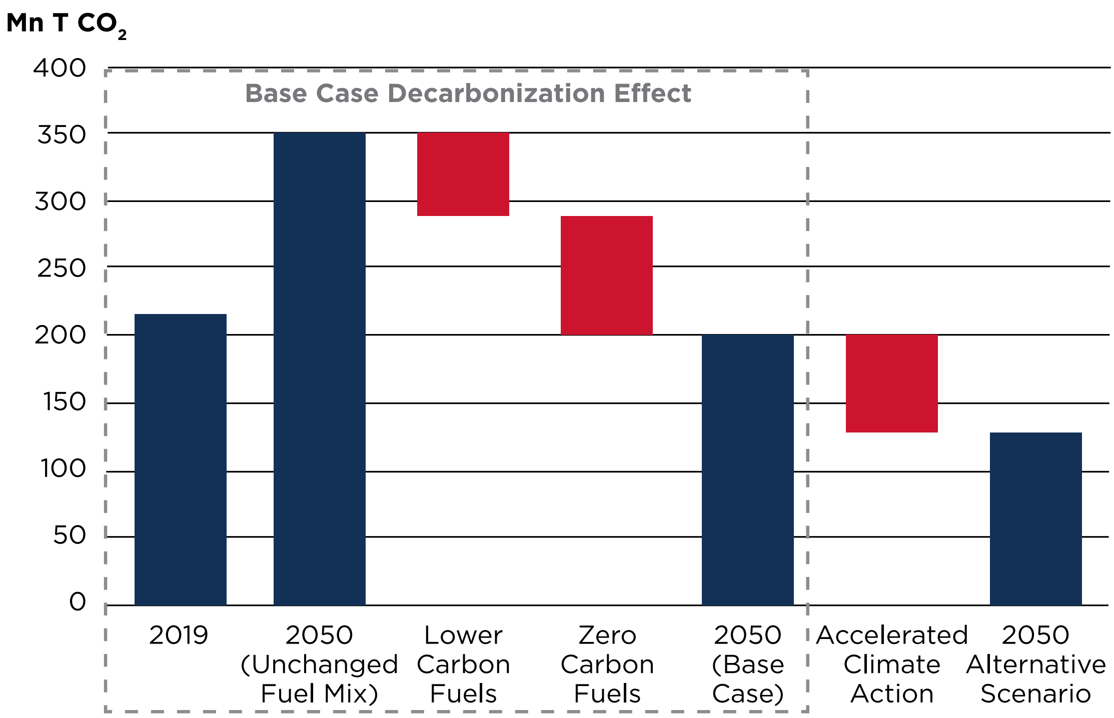

Figure 15: Containership pathways to decarbonization.

LNG CARRIERS

Natural gas is currently used as an alternative to coal and oil for electricity generation, distributed power, and transportation. The dislocation between the centers of supply and demand is expected to continue to boost the LNG trade and vessel requirements; pipelines are generally considered not to be economical over distances greater than 3,500 kilometers.

The largest gas-consuming markets are the U.S., Russia and China. All three have large-scale production volumes and pipeline networks to transport gas to the consuming regions. China is one of the fastest growing gas markets, as it turns to cleaner burning fuels reduce pollution and emissions within major urban centers. Demand for LNG is expected to be positive for most of the forecast period and China is expected to become the largest LNG importer.

The largest gas reserves are located within Russia, Iran and Qatar. The largest LNG producer is Qatar, followed by Australia and Malaysia. U.S. gas production is experiencing a significant increase as new extraction techniques (fracking) have enabled excess gas to be liquefied and exported as LNG.

Under the base case, global gas consumption is expected to peak in 2040 at just under 4 BnT, a gain of approximately 40 percent on 2019 levels, before gradually declining as the overall use of fossil fuels falls. LNG is expected to grow even faster over the period to 2040 (+86 percent), supported by strong demand and increased capacity to export it.

Under the ACA scenario, the gas market is expected to peak earlier, and at a lower level.

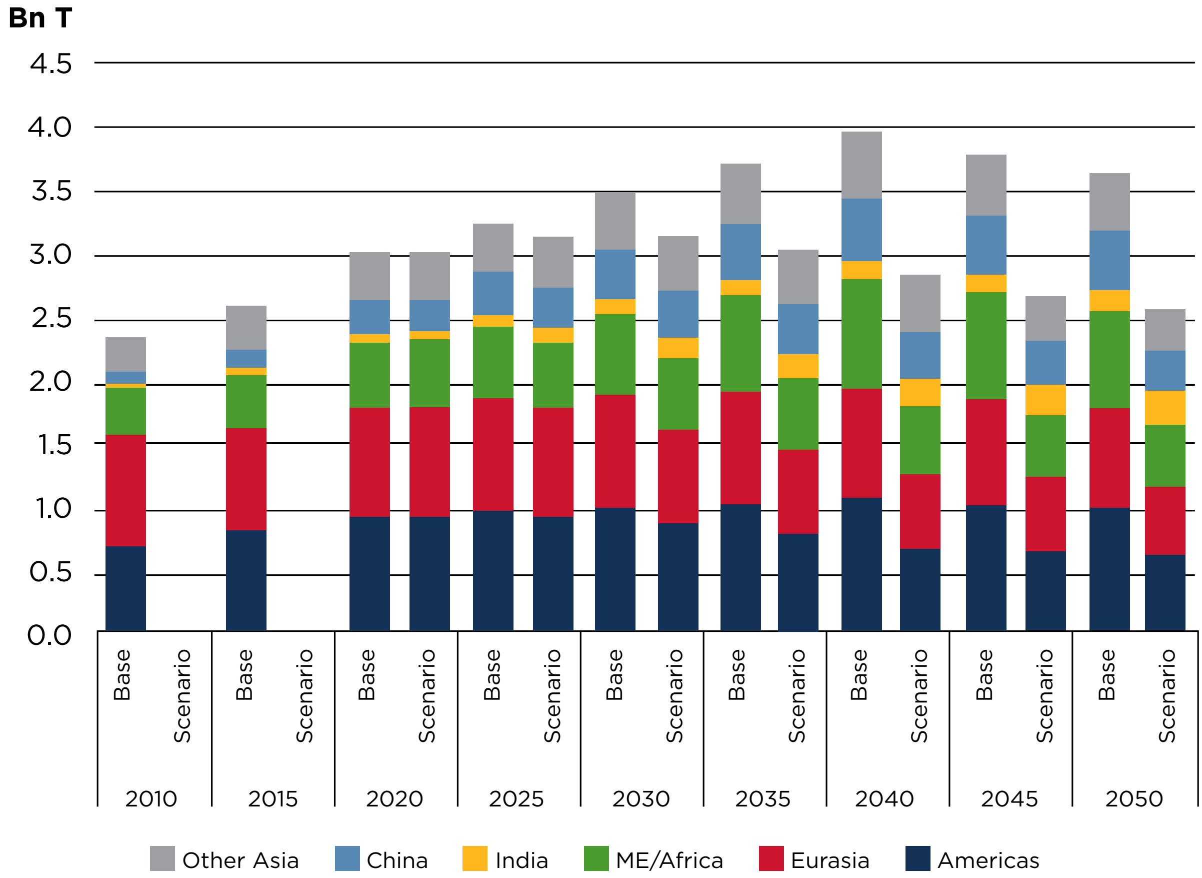

Figure 16: Natural gas consumption by region.

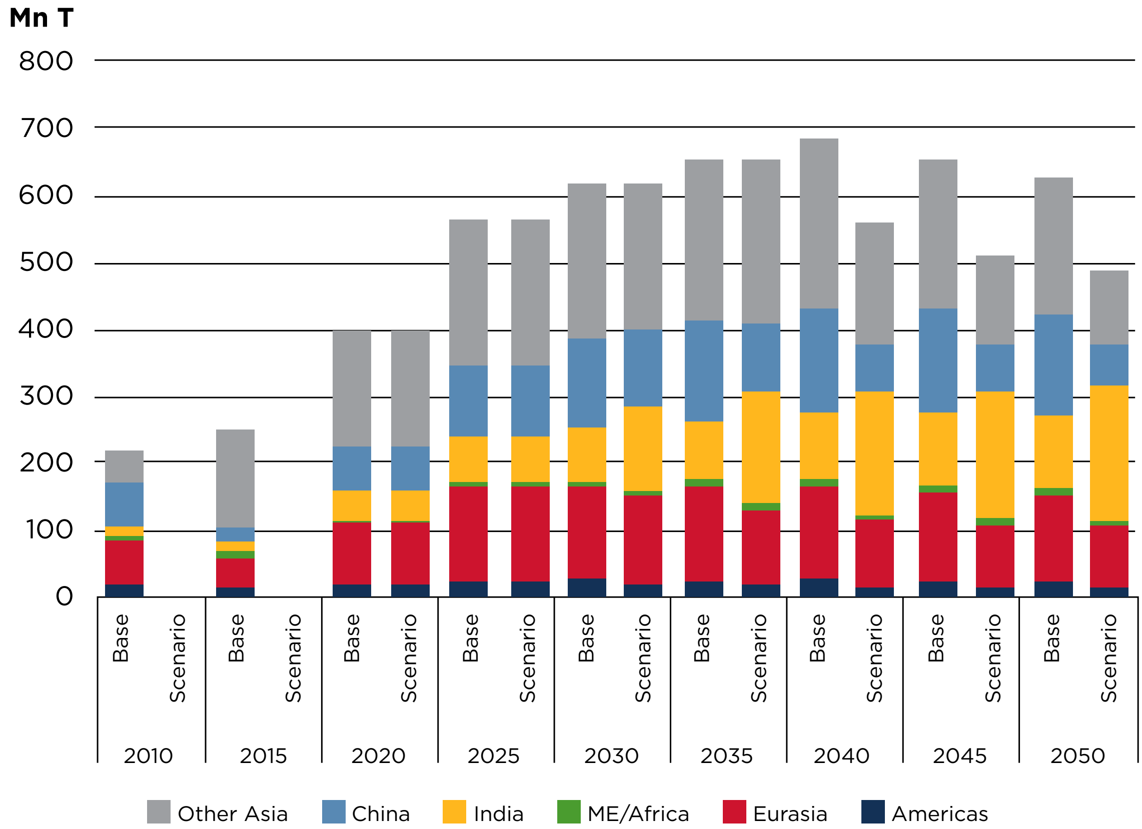

Figure 17: LNG imports by region.

The dedicated LNG-carrier fleet consumed far more LNG as fuel than all other ship types combined in 2019. The latter is currently estimated to have consumed less than one MnT, compared with the 15 MnT used in LNG carriers.

The LNG-carrier fleet accounts for five percent of the total fleet considered in this analysis in terms of aggregate gross tonnage. However, it accounts for approximately nine percent of current total fuel consumption in HFO-equivalent terms.

The LNG-carrier fleet (50k M^3 and above) emitted 40.3 MnT of CO_2 in 2019. If the fuel mix remains unchanged from 2019, CO_2 emissions will increase by 29 percent to 52 MnT by 2050. In contrast to other sectors, the fuel mix for the LNG-carrier fleet is already dominated by LNG. However, zero-carbon fuels (ammonia and hydrogen) are the most likely pathway to 2050 for the sector, potentially reducing CO_2 emissions by 16 percent to 34 MnT by 2050, compared to 2019 levels.

Under the ACA scenario, downward adjustments to LNG trade are expected to lower the size of the fleet of its dedicated carriers. These changes can result in additional savings of 7.3 MnT of CO_2 with emissions reduced to 26.6 MnT by 2050, 34 percent below 2019 levels.

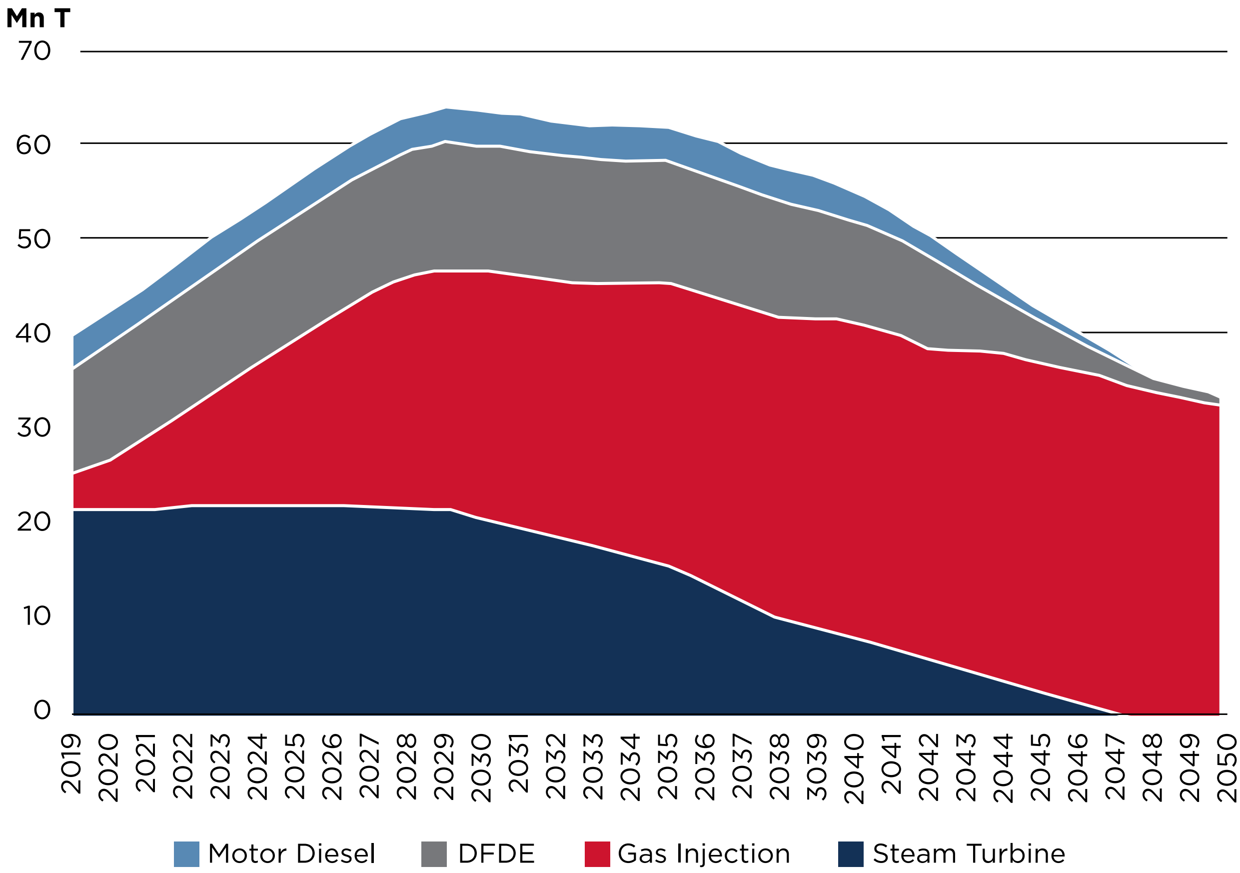

Figure 18: LNG-carrier CO_2 emissions by vessel type (base case).

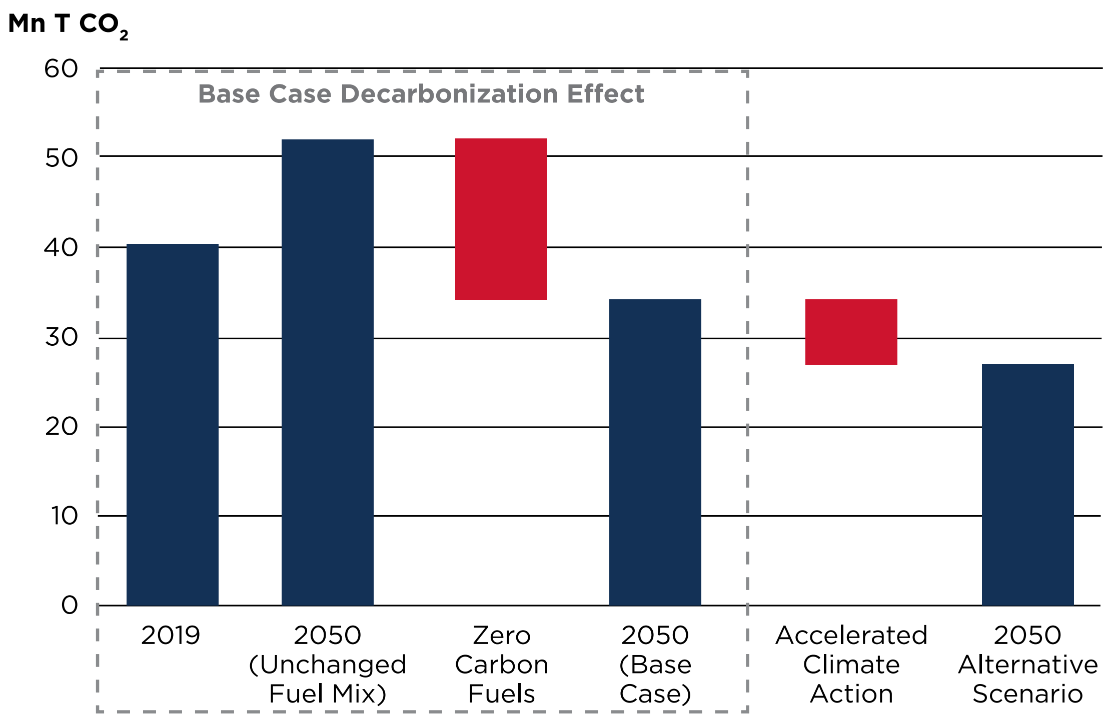

Figure 19: LNG-carrier pathways to decarbonization.

LPG CARRIERS

LPG is produced as a byproduct of oil and gas production, and oil refining. Therefore, production and consumption of LPG are ultimately constrained by activity in those sectors. In the absence of explicit forward views on LPG within the IPCC and IEA scenarios, the ACA scenario for LPG has been linked to the oil and gas scenarios outlined in the previous sections.

Exports of LPG are closely aligned with the regions that account for the majority share of oil and gas production. U.S. shale gas is currently driving a large increase in exports from North America, although this is expected to plateau towards 2035. The Middle East and Africa are likely to remain important suppliers of LPG, but output ultimately may decline in line with trends in oil and gas production. The pattern of importers is relatively diverse, with China being the dominant country.

Under the base case, LPG production and consumption are expected to peak around 2035, thereafter remaining relatively flat until 2040, before gradually declining in line with the projections for oil and gas markets.

Under the ACA scenario, the market is expected to peak 10 years earlier and at a lower level. In this case, the most significant reductions in LPG output would be in regions with limited oil and gas production and a greater focus on refinery output. This would impact Eurasian production the most, while high gas production would dampen the impact on the Middle East and North America.

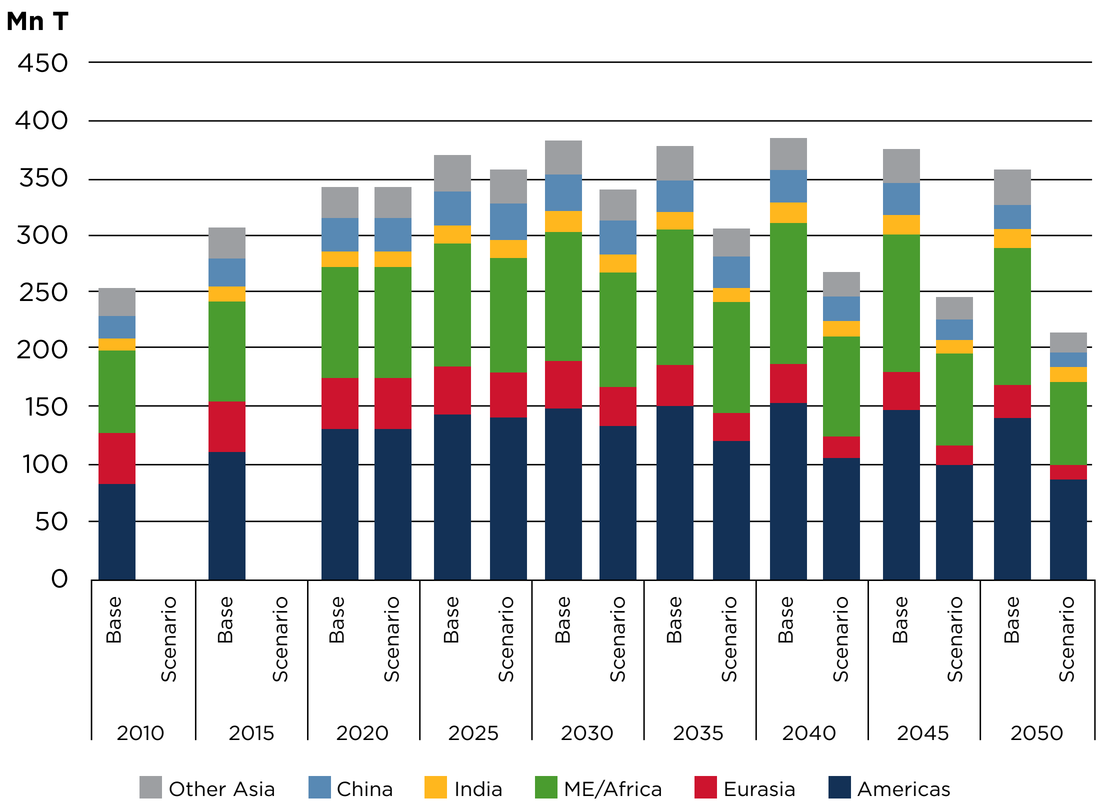

Figure 20: LPG production by region.

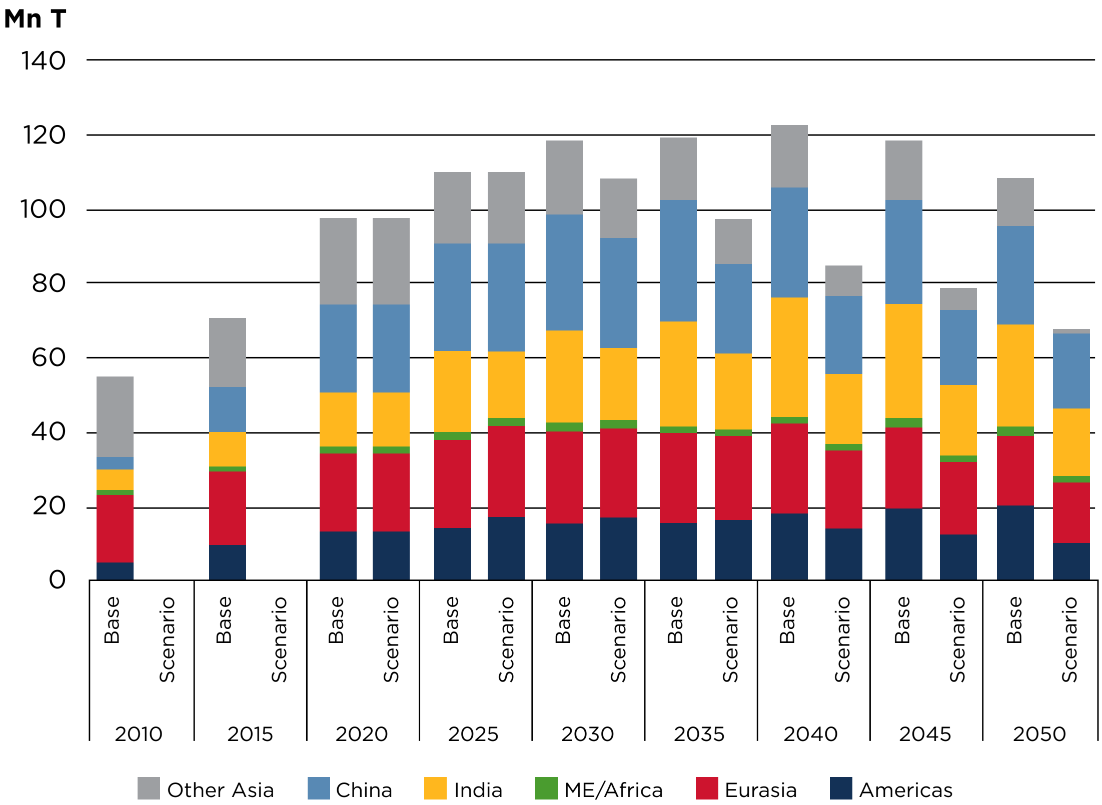

Figure 21: LPG imports by region.

The LPG-carrier fleet (6k M³ and above) emitted 14.6 MnT of CO_2 in 2019. If the fuel mix remains unchanged from 2019 (dominated by HFO/MGO/MDO), CO_2 emissions will increase by 12 percent to 16.4 MnT by 2050.

However, a gradual transition to zero-carbon fuels could see CO_2 emissions fall by 30 percent to 10.2 MnT by 2050, compared to 2019 levels. Because the prospects for the LPG sector are closely linked to those of the oil and natural gas sectors, lower consumption of fossil fuels will have a negative impact on the LPG market.

Under the ACA scenario, reductions to the seaborne trade of LPG are expected to lower the size of LPG-carrier fleet. These changes could result in additional savings of 3.8 MnT of CO_2 with emissions dropping to 6.4 MnT by 2050, 56 percent below 2019 levels.

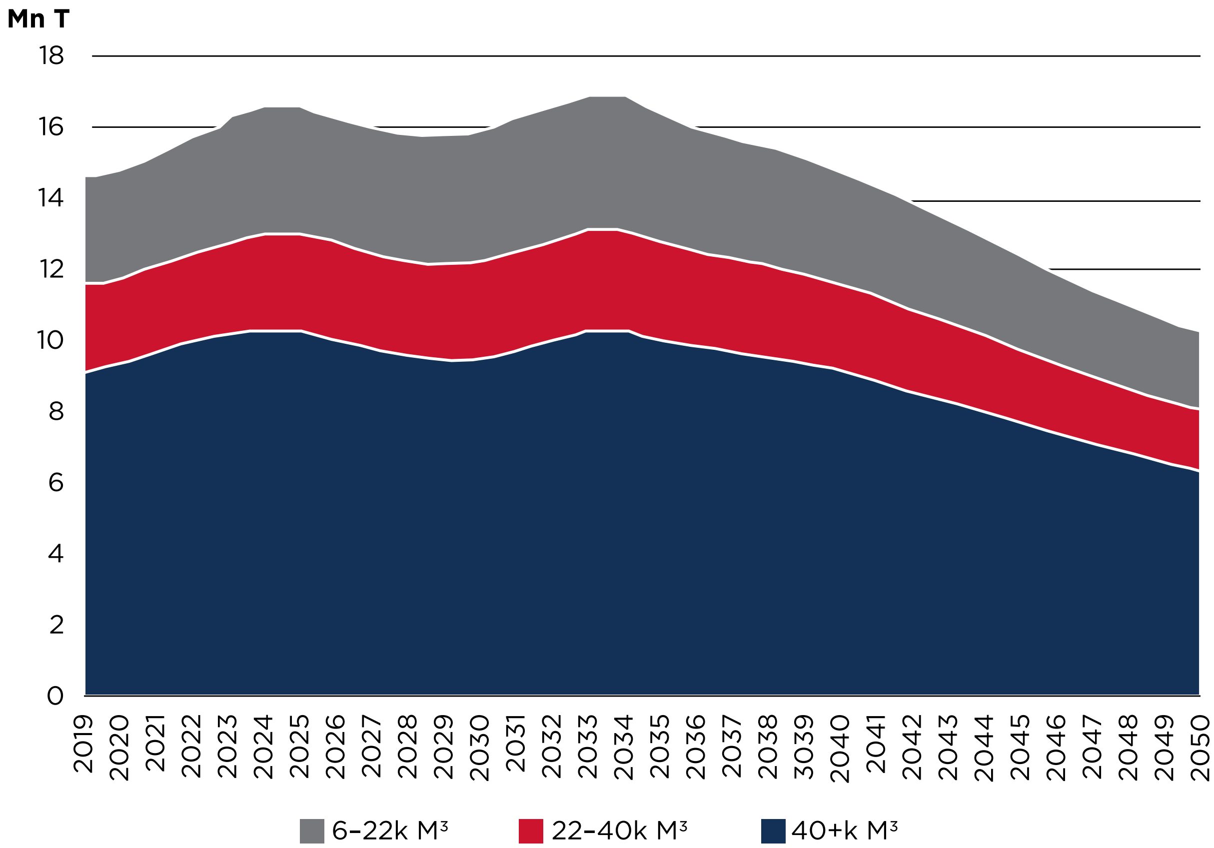

Figure 22: LPG carrier CO_2 emissions by vessel size (base case).

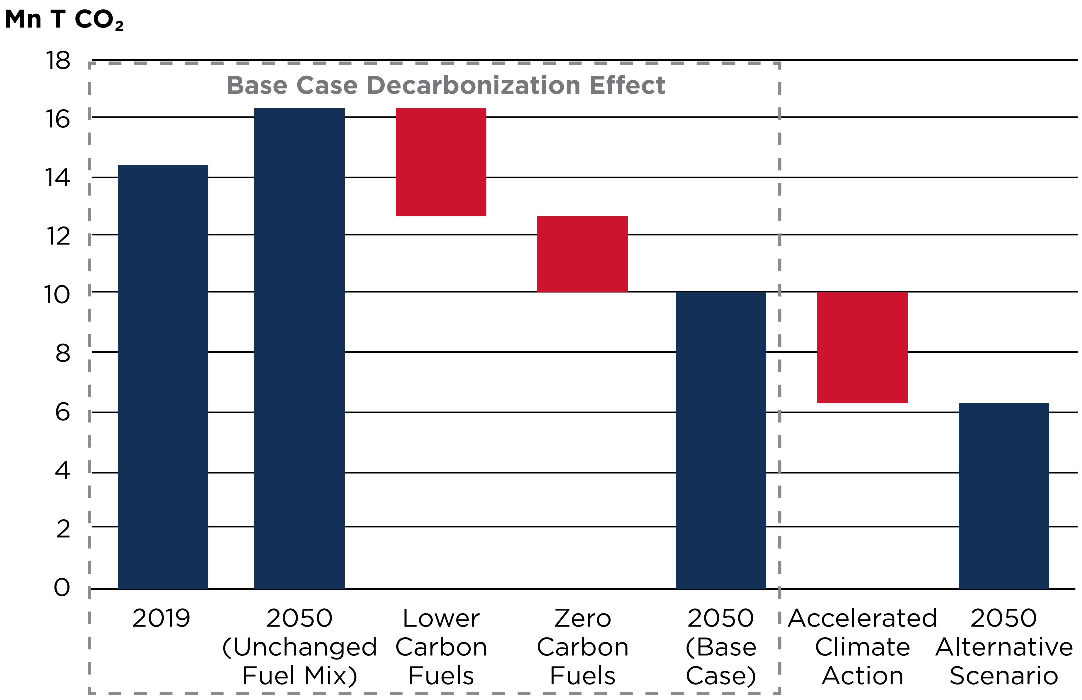

Figure 23: LPG carrier pathway to decarbonization.

FORECAST OF FLEET GROWTH AND ALTERNATIVE FUEL ADOPTION

The evolution of marine fuel use is dependent upon multiple factors associated with the fuels' carbon footprints, the technology of power generation and propulsion systems, the production, distribution, storage and bunkering infrastructure, regulatory frameworks, and the value proposition of each fuel.

The following figure shows the projected marine fuel use until 2050 as the industry strives to meet the GHG emissions-reduction targets mandated by the IMO.

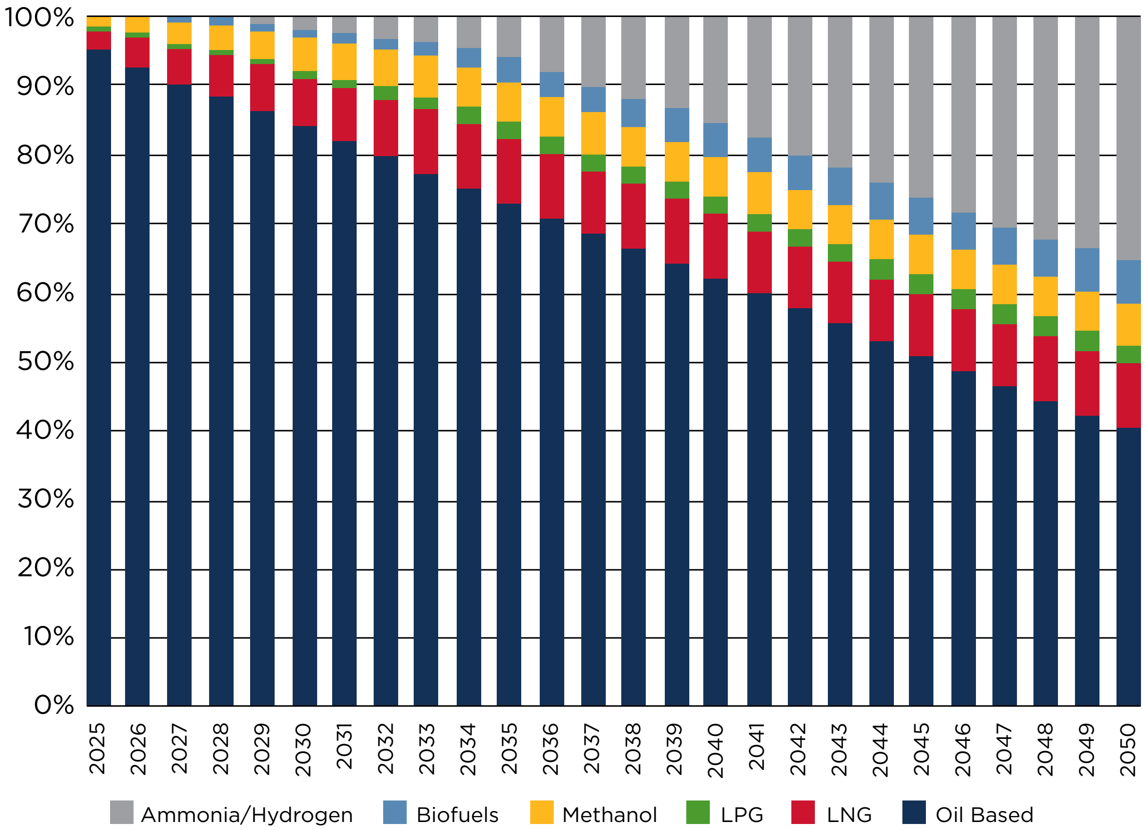

Figure 24: Projected marine fuel use to 2050.

Oil-based fuels currently dominate all other fuels used in vessels, but they are projected to decrease in fairly linear fashion until 2050. Current vessels retrofitted with scrubber systems are expected to phase out in 2040, considering a 20-year service lifetime, and end the use of HFO.

Beyond 2040, MGO/MDO are expected to be the only oil-based fuels used for propulsion. Along this path, the adoption of biodiesel or renewable diesel is expected to displace part of the HFO and MGO/MDO share.

The use of LNG is expected to increase until 2035, based on its expanding infrastructure, trade volumes and lower carbon intensity than oil-based fuels. However, the adoption of LNG is not sufficient to meet the long-term IMO targets, therefore it is expected that it will be replaced by bio-derived natural gas and, eventually, by hydrogen.

The use of LPG and methanol is supported by their use as cargo in tankers and the development of dedicated propulsion systems, such as the MAN ME-LGIP/M engines. It is expected that tankers carrying LPG and methanol as cargo will continue to use them as fuel for propulsion and power generation. Both are expected to continue to be used in the future, but methanol has greater potential to reduce the life-cycle carbon emissions from shipping because it can be produced renewably.

The use of ammonia as a fuel is expected to grow due to its zero-carbon content, easier distribution, storage and bunkering compared to hydrogen, and its suitability with existing and emerging technologies for propulsion and power generation.

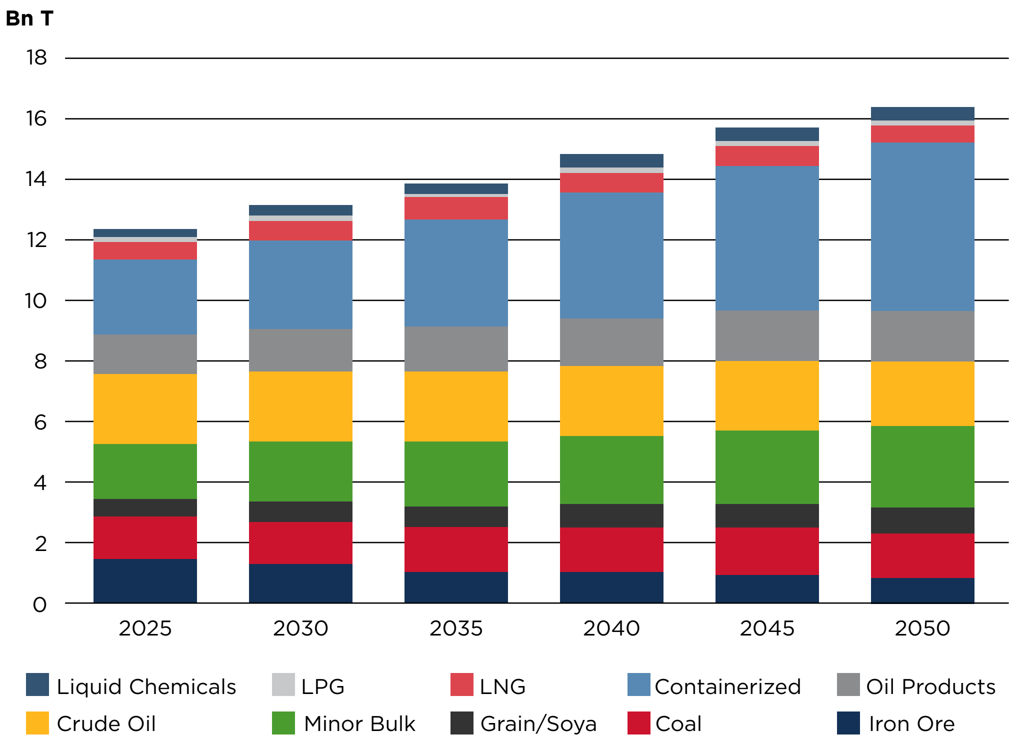

Figure 25: Trade growth by key commodity.

Based on the projections for trade growth presented in the previous sections, Figure 25 (above) shows the trade growth by key commodity until 2050, while Figure 26 (below) shows the corresponding fleet composition. It is interesting to note that containerized and minor bulk trade account for the strongest growth until 2050. Accordingly, containerships are expected to have the highest growth in the aggregate fleet size.

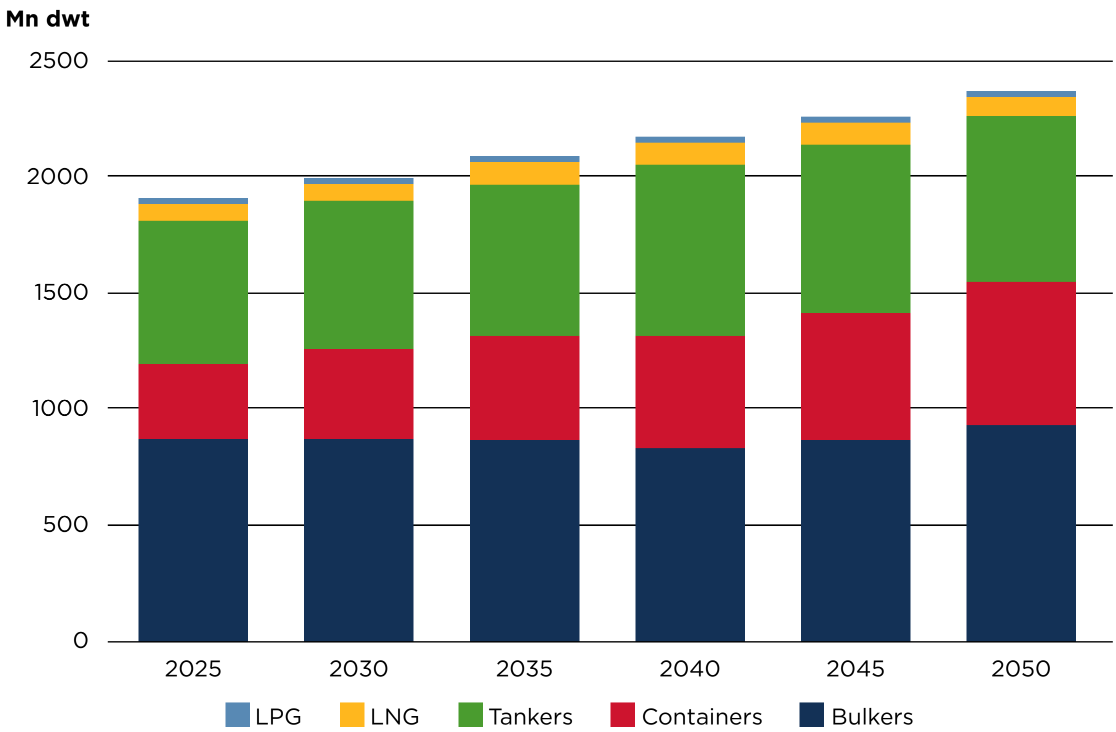

Figure 26: Projected fleet composition.

Based on the projected fleet, the fuel consumption by ship type was calculated and is shown in Figure 27 (below). The share of fuels in shipping is illustrated by restating energy consumed in terms of tonnes of HFO equivalent.

Under the base case, the total energy consumed by shipping is expected to continue to rise to 254 MnT HFO equivalent in 2050. This is driven by the containerships and, to a much lesser extent, LNG carriers.

The significant demand for LNG is largely provided by the use of the LNG cargo as a fuel on its dedicated carriers. Demand for LNG bunkers for other ship types is expected to rise from very low current levels to a peak of 25 MnT (approximately 10 percent of total demand). The share of ammonia and hydrogen is expected to increase, as they will largely contribute to the CO_2 reduction from shipping in the long term.

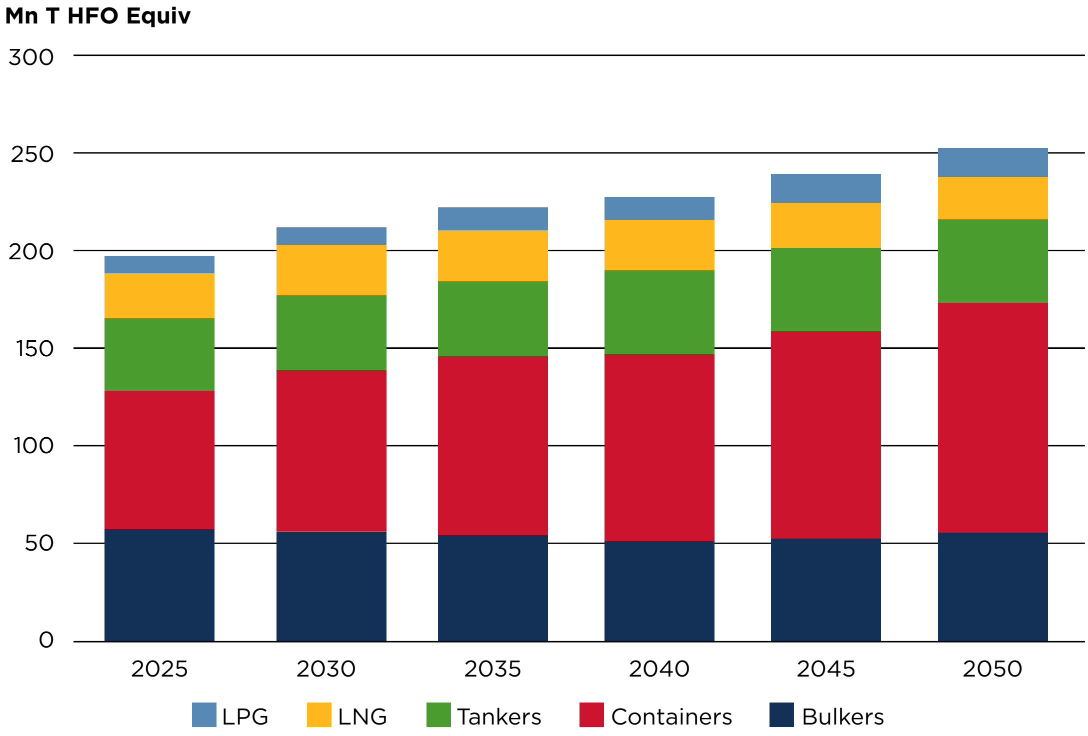

Figure 27: Fuel consumption by ship type.

According to the projected fuel consumption, the calculated CO_2 emissions are shown in the following figure. Under the base case, a marked reduction in CO_2 emissions is expected due to the increased share of zero-carbon fuels, more than offsetting the steady increase in the size of the fleet and rising energy consumption. This trend is most apparent for the containership sector.

Nevertheless, under the base case, by 2050 containerships are expected to account for 46 percent of all emissions for the five ship types included in this study, which is an increase of 38 percent compared to 2019.

However, under the ACA scenario, the relative share of the fleet by sector changes, thus the containerships share of emissions is lower (41 percent). In contrast, the share of emissions accounted for by dry bulk carriers is significantly higher at 30 percent, compared with 24 percent in the base case.

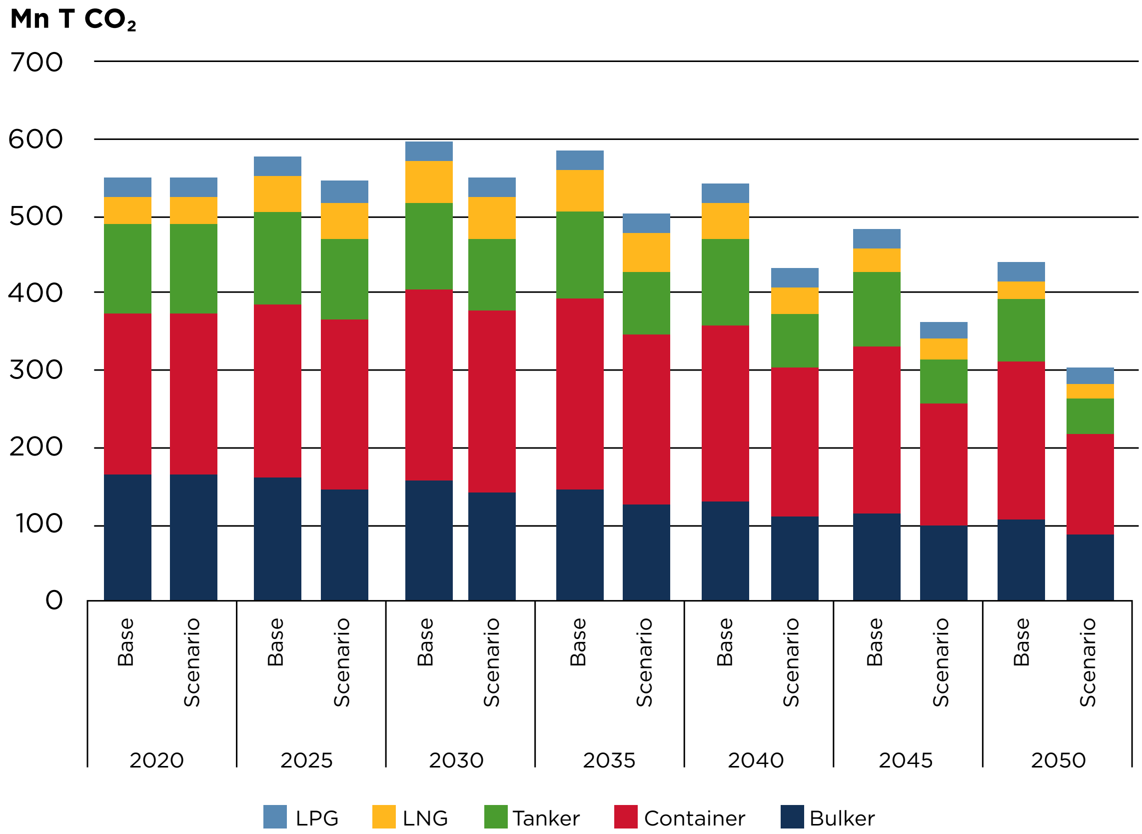

Figure 28: CO_2 emissions by ship type.

SECTION SUMMARY AND CONCLUSIONS

Based on the data presented above for each vessel segment, the following figure shows the aggregate CO_2 emissions for all five segments included in this study. The effect of adopting low- and zero-carbon fuels is shown, as is the impact of the ACA scenario.

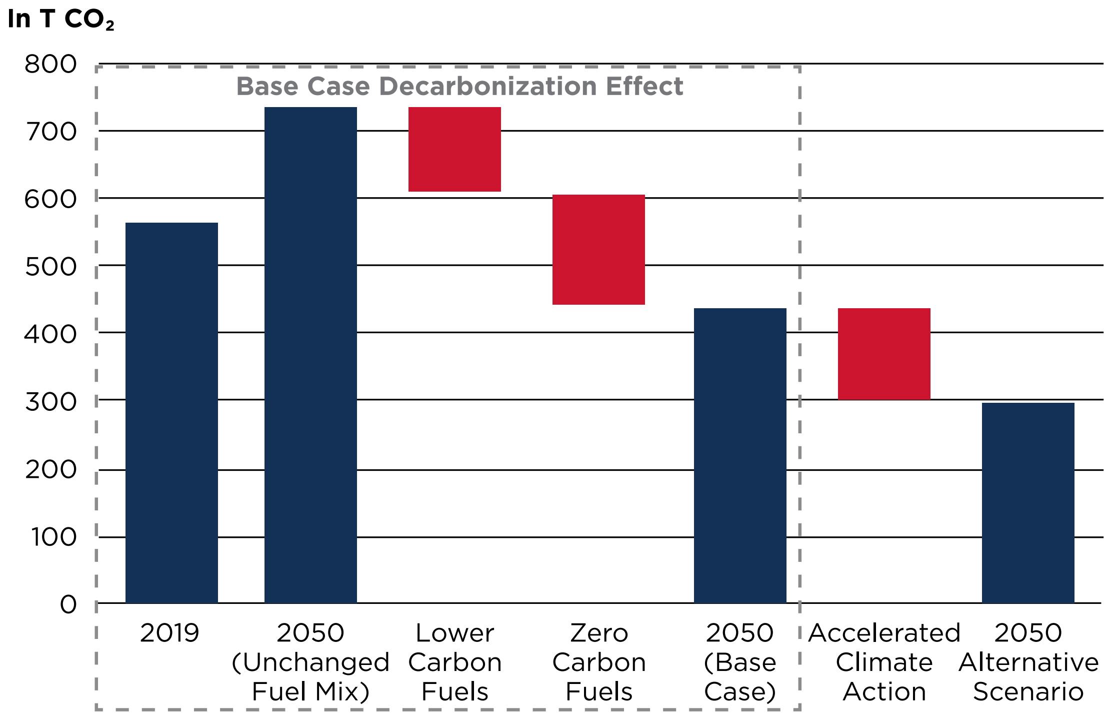

Figure 29: Key vessel segments pathways to decarbonization.

The following figure shows the trajectory for emissions in terms of grams of CO_2 emitted per dwt-tonne mile (g/dwt-nm) traveled. This is the measure of efficiency that the IMO will use to drive the target of a 50 percent reduction in absolute CO_2 emissions from shipping in the period to 2050, when compared to the reference year of 2008. To achieve this 50 percent reduction, it is assumed that emissions in g/dwt-nm will need to be reduced by 70 percent compared to 2008 levels.

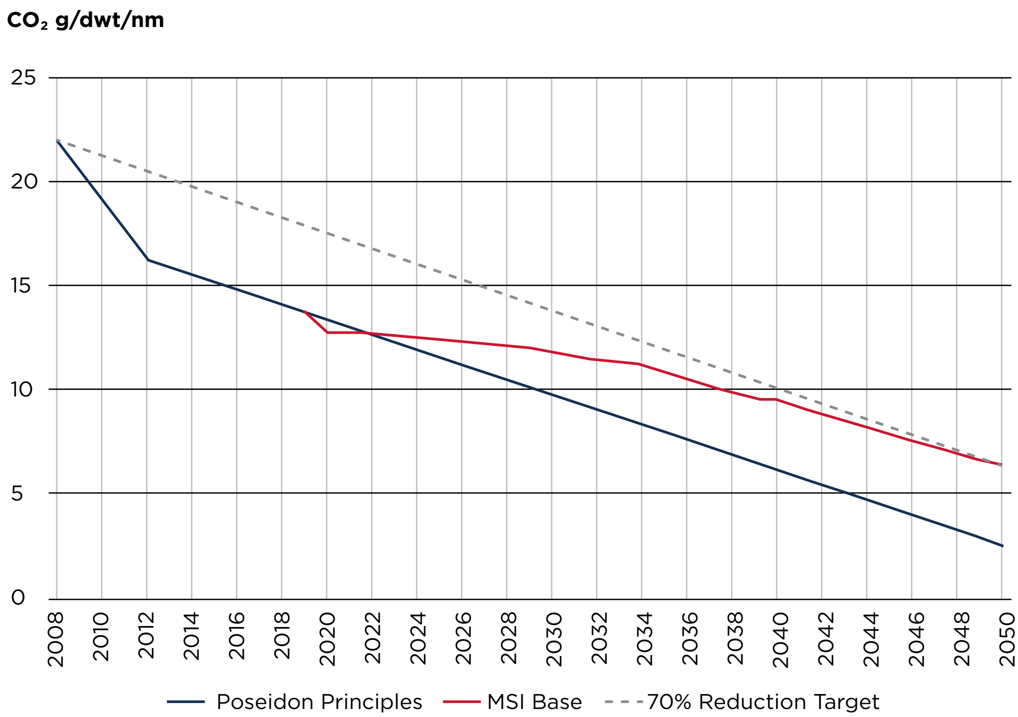

Figure 30: CO_2 emissions per transport work vs. IMO trajectory.

Decarbonization of the economy is likely to lead to profound changes in the volume and pattern of trade in the full range of commodities transported by sea over the next 30 years. These changes will affect the fleet evolution across the shipping spectrum, and reduce the aggregate fleet size in some sectors by 2050.

While low-carbon fuels (LNG, LPG, methanol) can assume a significant role in the near term, the adoption of zero-carbon fuels must begin in earnest before the end of the current decade. It has yet to become clear what the carbon footprint of biofuels and synthetic fuels will be, and how this could be measured in a standardized manner.

The projected marine fuel use could help the shipping industry meet the target to reduce by 70 percent CO_2 emissions per transport work (gCO_2/dwt/nm) by 2050.

However, the 50 percent absolute reduction in CO_2 emissions (ton) over the same timeframe will require additional measures, such as: (i) reducing the share of oil-based fuels by 2050 below the 40 percent level projected in this study through greater adoption of low and zero-carbon fuels; and (ii) the broader decarbonization of the global economy as captured by the ACA scenario.

The latter can contribute to the reduction in seaborne transportation of carbon-based fuels, by reducing the required fleet and by extension the absolute CO_2 emissions.

JUST-IN-TIME AND OPTIMUM SHIP ROUTING

Many options are available to the shipowner or operator for achieving compliance with the International Maritime Organization's (IMO) regulations, whether it is using low- and zero-carbon fuels or using innovative technologies for improving the energy efficiency of vessels. Other options, which can be combined with the above, are operational procedures such as speed optimization and just-in-time (JIT) scheduling[34].

THE CASE FOR JIT SHIPPING

The definition of JIT originates from the automotive industry. The concept originated in Japan, developed during the 1960s and 1970s, championed by Toyota and based on an inventory system that aligned orders of raw materials from suppliers directly with production schedules.

Companies employed this strategy to increase efficiency and decrease waste by receiving goods only as they need them for the production process, which reduced inventory and inventory-depreciation costs. It required producers to forecast demand accurately and modernized "just-in-case" strategies, wherein producers held sufficient inventories to absorb maximum market demand.

The aviation industry also adopted JIT, although its focus was on operational processes, rather than manufacturing. Today most airlines and airports are involved in a symbiotic collaboration that, through JIT, aims to minimize the time airplanes spend on land or waiting to land, thus avoiding passenger waiting times, maximizing the use of aviation assets, and lowering fuel consumption and emissions.

The shipping industry can significantly benefit from the efficiency of JIT. Recent reports by Marine Traffic, a leading provider of ship tracking and maritime intelligence services, indicate that ships spend roughly 50 percent of their time in berth, anchoring or maneuvering; this accounts for more than 15 percent of their annual fuel consumption.

Adoption of JIT operations would reduce the time spent waiting for berths or trade, maximize the utilization of ports and reduce the fuel costs and others associated with port stays. Moreover, it would substantially reduce the emissions of greenhouse gases (GHGs) and other gases.

Key agents of the shipping industry have identified JIT arrival as an operational improvement that could generate wide benefits by reducing the GHG emissions from vessels when they approach and berth at ports.

JIT operations limit the amount of time that ships spend idling outside the ports. This can be achieved by optimizing the vessel speed during the voyage to ensure that it arrives and departs without unnecessary delays.

Implementing the JIT arrival concept requires a holistic view of the voyage, including the port operations section of the voyage, because it may require occasional increases in vessel speed during the voyage (with the associated increase in fuel consumption). This negates enough of the waiting time at port that may result in lower overall fuel consumption.

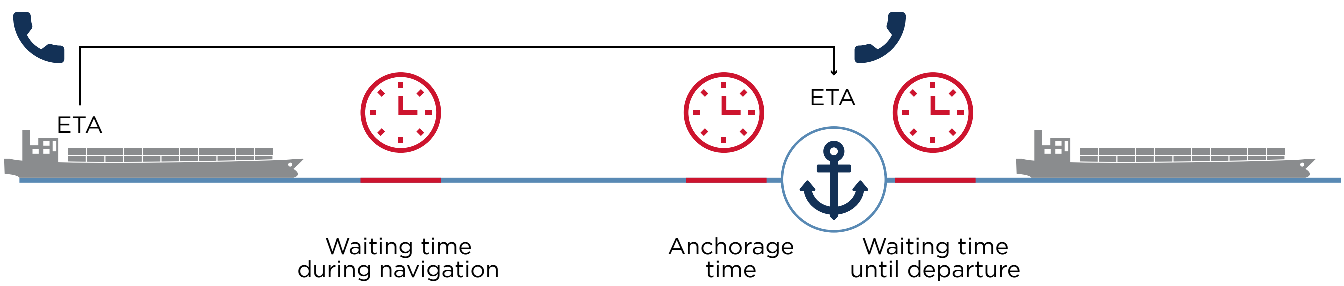

Figure 1: Normal arrival process.

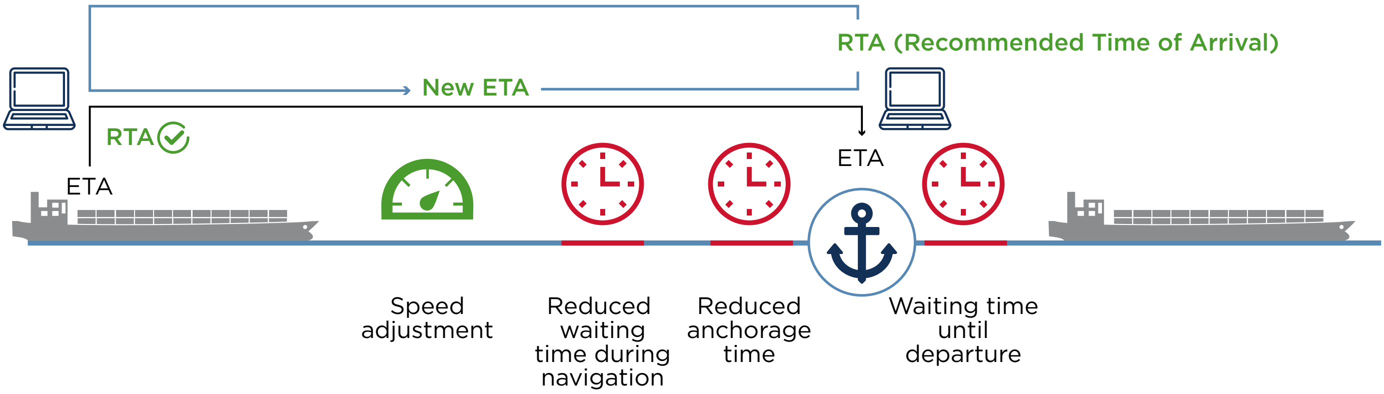

Figure 2: JIT arrival process.

BARRIERS AND CHALLENGES

Despite its theoretical benefits, JIT has yet to be widely adopted by shipping or the port sector. Their practitioners agree that JIT would lessen their businesses' impact on the environment and can reduce costs, but there are multiple operational and contractual barriers to overcome.

A full implementation of JIT sailing implies a commitment between ships and ports, and the related agents (shipping companies, cargo owners, port authorities, terminal operators, nautical service providers, etc.). The ship must adhere to estimated times of arrival (ETA) and the port must ensure that the resources for the ship berth are available at that time.

Modern vessels use various services to estimate the time it will take to reach a destination, taking into account aspects such as weather conditions. These estimations are not without challenges.

Ship operators face problems such as the nondisclosure of information related to the vessel's construction or its engine performance that would improve the accuracy of estimations and any efforts to calculate and optimize the associated fuel consumption or GHG emissions.

Without this information, mathematical modeling or the creation of "digital twins" – virtual replicas of physical assets, processes and systems – for ships can be a challenge, thus complicating the task of providing an accurate ETA.

For some types of vessels – such as tankers and bulk carriers – contracts may be breached by reducing speed, which renders JIT arrivals impossible. Communication with charterers and a commitment to reducing GHG emissions from them is a prerequisite to JIT and optimum ship routing (OSR).

AT PORTS

The barriers to JIT at ports are equally numerous. Few ports have adequate management systems to estimate the resources (e.g. pilots, tugs or mooring) that will be available beyond a 24-48-hour horizon. A standardization of the format for the information is required for automation and further optimization to be possible.

In addition, the concept of JIT involves adapting the freight contract to allow the ship to reduce its speed on passage to meet the scheduled arrival time. JIT adoption requires cooperation between the shipowner/operator and the charterer to overcome third-party contractual obligations, and to provide benefits that go beyond emission reductions and fuel savings, and extend to voyage planning.

A commitment between ports, ships, manufacturers and other industry agents is required to make JIT sailing possible.

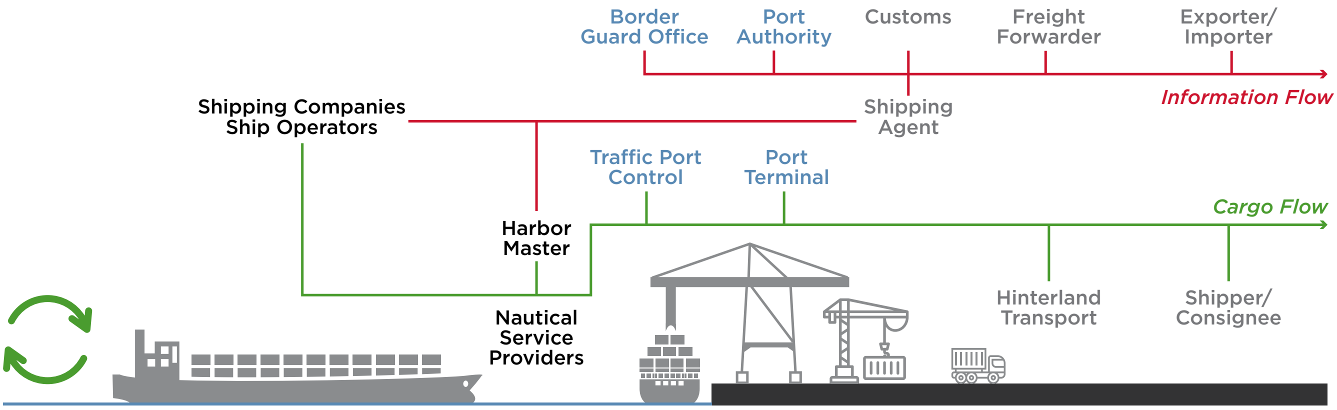

Figure 3: Different partners involved in a JIT operation.

CURRENT JIT INITIATIVES

The European Commission (EC) and the governments of South Korea – as well as several port authorities such as Rotterdam, Valencia and Algeciras – are funding initiatives to improve synchronization of port calls and voyage planning, the enablers for JIT in shipping.

These initiatives include the Sea Traffic Management (STM) Program and its related EU co-funded research and development projects (the STM Validation project, Efficient Flow and Real Time Ferries). There are also initiatives such as the PRONTO project promoted by the Port of Rotterdam and the Pit Stop Operations project developed by the Port of Algeciras.

The STM project is one of the largest e-navigation projects funded by the EC and it aims to validate the technical, environmental and financial feasibility of the concept by testing new navigation services on board 300 ships in collaboration with ECDIS3 suppliers.

The services allow digital transmission of voyage plans and connectivity between these ships, ports and shore centers through large-scale testbeds in the Baltic and Mediterranean Seas. More than 50 partners from 13 countries are participating.

For ports, the STM Validation initiative is working on an ambitious set of pilots involving several ports in Europe: Gothenburg, Valencia, Stavanger, Barcelona and Limassol, among others. The pilots are oriented to increase the efficiency of coordination of the agents involved in the port-call process by defining a common communication standard that allows them to exchange information in real time. This enables the agents to share the various stages and operations related to the port call and receive timestamps in real time.

JIT'S IMPACT ON THE INDUSTRY'S CARBON FOOTPRINT

ABS collaborated with Maritime Strategies International (MSI) to assess the potential impact of JIT on the industry's carbon footprint.

As a base case, MSI assumed the following compound annual growth rates for each of the major vessel types during the period 2019-2030:

- 0.9 percent for dry bulk
- 0.9 percent for oil tankers
- 3.9 percent for containerships

For several years, the use of data from automated identification systems has made it possible for the industry to operationally benefit from knowing details such as the ETA, the arrival port, draught and navigational speeds, etc.

These data points are being used today to track vessels and to support limited adjustments to voyage planning. However, deeper analyses of the data on vessel positions and berth availability are revealing the type of information that could make JIT shipping more probable.

More efficient communications between vessels and ports on the availability of berths and ancillary-service providers such as tug operators would optimize marine traffic, with all the commercial and environmental benefits.

MSI modeled the effect of potential improvements in efficiency created by JIT shipping by presuming an average five percent reduction in speed, assuming no impact on cargo-carrying capacity and no adjustment to the size of the fleet. Based on this analysis, the CO_2 emissions savings are around 10–11 percent annually.

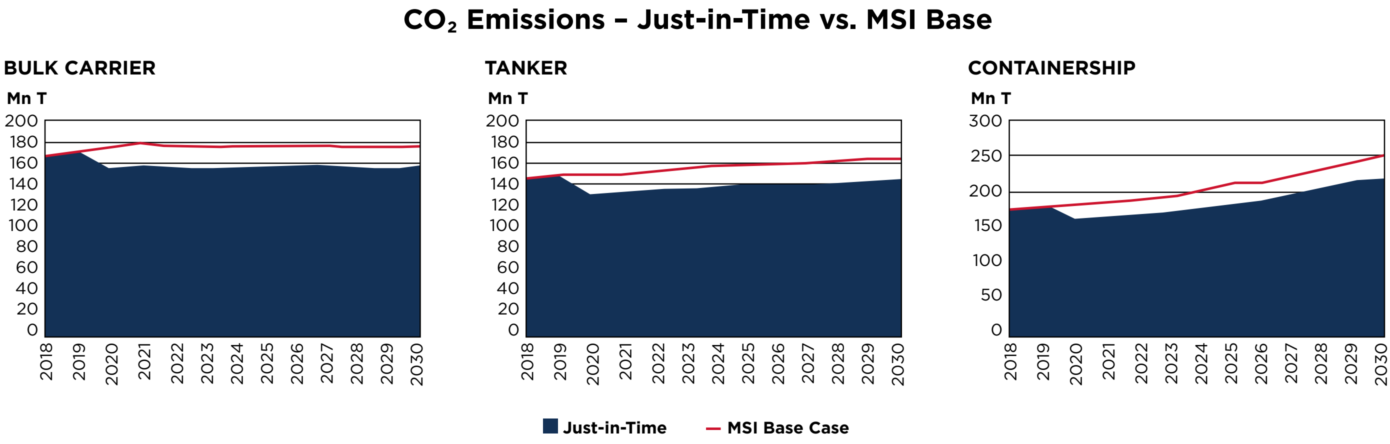

Figure 4: Potential reduction of emissions with JIT.

Speed optimization involves varying the vessel speed to arrive "just in time", thus avoiding idle time outside the terminals and minimizing overall fuel consumption. These are both used in OSR, the method of developing the "best route" for a ship based on weather forecasts, ship characteristics, and geographical data. Invariably, these are subjected to targets and constraints, such as:

- JIT arrival
- Minimum voyage fuel consumption
- Maximum daily fuel consumption
- Maximum time charter equivalent (TCE)
- Bathymetry
- Land proximity
- Maximum speed for safety and sickness motion
- Maximum and minimum speeds imposed by authorities
- Minimum speed for safety
- Slamming
- Operation outside the barred speed range
- Operation within the engine envelope
- Avoidance of specifics areas

THE CASE FOR OSR

With so many variables and constraints, it is reasonable to question what can be dependably achieved. The "best route" is selected based on time, fuel consumption, safety aspects, crew and passenger comfort, financial cost, or any combination of the above.

Fuel costs constitute a major part of the operating expenses of any voyage; in some cases, it comprises up to 80 percent. With an eye on the IMO's goals, minimizing fuel consumption also has a positive impact on the environment because GHG emissions are reduced proportionately to the reduction in fuel consumption.

METHODOLOGY FOR SELECTING THE OPTIMAL ROUTE

The most common route followed by vessels is the one that connects the departure and arrival points through a straight line (loxodrome). Under ideal conditions, this route would offer the shortest travel distance and time, with the lowest fuel consumption. However, weather conditions, geography and other factors may necessitate a different route to minimize fuel consumption. Identifying this route involves an optimization task using a numerical algorithm.

As a first step, the operator needs to provide a set of inputs to the algorithm: the departure and arrival points, the geographical data and the weather data. Based on these inputs, the algorithm approximates every possible route as a mathematical function, as well as the associated fuel consumption with every route.

JIT can be implemented on a single trip by changing the objective of this optimization task from the total fuel consumption to the total TCE for a voyage and then minimizing it.

CALM WATER ROUTING

The simplest case for applying this optimization method is a ship traveling at constant speed in calm water without any effects from waves. In this case, the water resistance remains constant and the route of minimum fuel consumption is equivalent to the shortest distance on the globe.

Figure 5 shows representative results from applying this method, where the numerical solution (shown in cross symbols) matches the geodesic (solid blue line, orthodrome). The loxodrome (white dashed line) is also shown as a reference for comparing the two solutions.

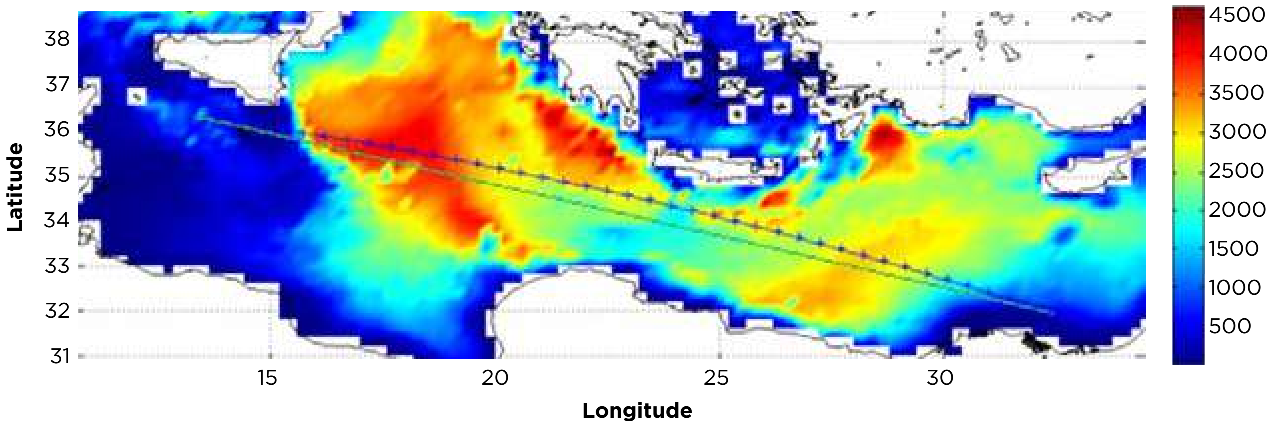

Figure 5: Application of the route optimization method on a clam water case. Bathymetric data are shown by the color contour.

APPLICATION TO AN AFRAMAX VOYAGE

Consider the case of a typical 105,000 dwt aframax tanker traveling in the eastern Mediterranean Sea, from Port Said to Marseille via Sicily in the presence of a storm. Data is available from seakeeping calculations for the hull, general arrangement, main engine, and ship performance at various speeds, drafts, and weather conditions.

The principal particulars of the vessel are LOA = 238.5 m (overall length), LPB = 234 m (length between perpendiculars), B = 42 m (max breadth) and Ts = 14.9 m (scantling draft). The vessel is equipped with one MAN B&W 6S60MC diesel engine directly coupled to the propeller.

The optimization objective is to minimize the vessel's fuel consumption as it travels through the storm and the results are shown in the following figures (Figure 6). The color contour in each plot shows the sea severity (wave height) and the cross symbols show the calculated optimum route as compared to the loxodrome (dashed line) and the orthodrome (solid line). In this case, using the optimized route results in the minimum fuel consumption; the calculated cost of this route is two percent lower than the orthodrome.

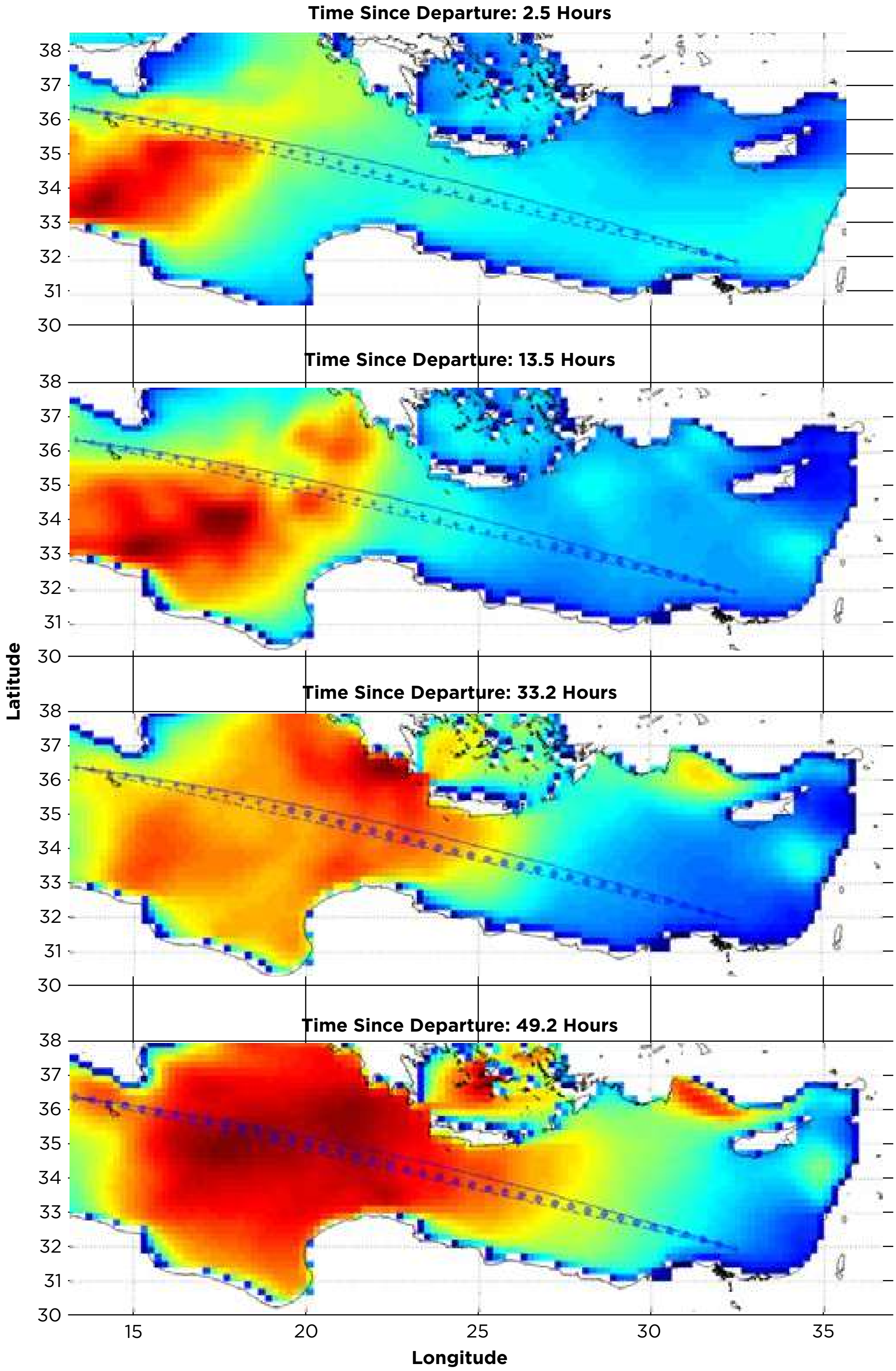

Figure 6: Calculation of optimal ship route in the case of a storm in the eastern Mediterranean Sea.

The application of JIT and OTR are two effective operational measures that can contribute significantly to the reduction of fuel consumption and carbon emissions from future vessels. Such operational measures combined with low- and zero-carbon fuels and technological advancements can provide cost-effective solutions that help vessels to meet the decarbonization target of IMO to 2030 and 2050.


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FINDING A COMPANY PATHWAY TOWARDS DECARBONIZATION

While the 2018 targets represented a broad IMO consensus of what was achievable and an effective way to lessen the industry's collective environmental footprint, how to achieve them was left up to individual owners, who are now faced with the extraordinarily complex task of decarbonizing their fleets, one ship at a time.

The present pathways towards the 2030 targets and beyond include operational measures, new technologies designed to improve energy efficiency, or alternative fuels. With so many combinations of options on the table — and more certain to emerge in the next few years — devising a sustainable fleet-wide decarbonization strategy that meets company goals is complex; more so, when each ship requires a bespoke solution that fits its age and operating profile, etc.

As with most efforts to improve technical and operational processes, it is important to establish a performance baseline for each specific ship and to benchmark that against the targets. Benchmarking is no longer seen by leading shipping companies as an optional management tool; it as an essential way to monitor competitiveness and evaluate progress in a dynamic environment.

As the deadlines for compliance with the IMO's emissions targets draw nearer, a key focus for benchmarking efforts will be carbon-intensity, the volume of CO_2 emissions per unit of transport work. Once the company ship/fleet benchmark is established, its trajectory under various scenarios can be compared to the trajectory established for the Poseidon Principles, a set of goals created to help financial institutions align their ship portfolios with responsible environmental behavior, and which are consistent with the policies and ambitions of the IMO.

The chart below shows how the projected performance of a theoretical fleet of 10 panamax bulk carriers built in 2010 (prior to agreement of the IMO's Energy Efficiency Design Index (EEDI)) and can be tracked against the IMO's 2030 GHG goal, as adopted by the Poseidon Principles. The effect of the fleet's dynamic operating conditions in the next decade on carbon intensity (taken as an average of the fleet, based on vessels' deadweight) is shown in terms of percentage to the baseline (2019) and is compared to the Poseidon Principles. The operating profile of these vessels has been considered constant, 50 percent at laden condition, 35 percent at ballast condition and 15 percent idle.

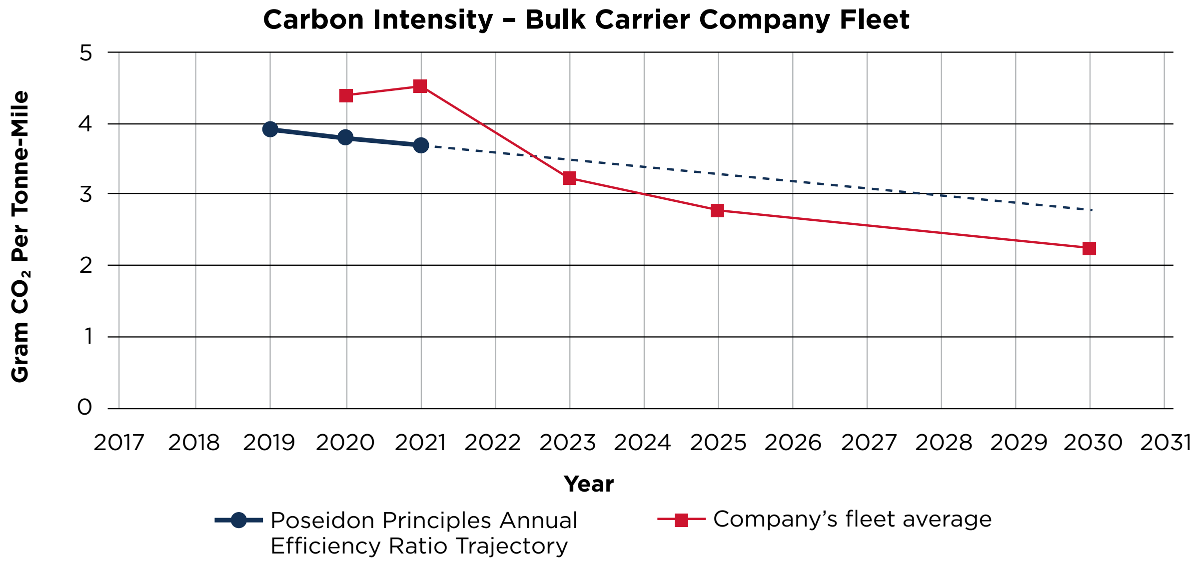


Figure 1. Carbon intensity as a function of time for a bulk carrier fleet.

The table below shows a combination of elements a shipowner may want to consider when benchmarking the carbon-intensity performance of their fleet against IMO targets, including past and future performance of the vessels, and forecasts for any newbuilds in the next decade.

The baseline year is 2019, prior to the 2020 sulfur cap, so the vessels are assumed to burn heavy fuel oil (HFO) for the main engine and marine diesel oils (MDO) for the auxiliaries. The assumption for 2020 is that the vessels switch to MDO, so the carbon intensity slightly increases by two percent.

In 2021, the vessel speed is decreased from 13 to 12 knots, and the carbon intensity is decreased by 27 percent compared to the baseline year. In 2025, three of the vessels are replaced by LNG fueled vessels of similar size (complying with EEDI phase III requirements). The fleet's speed remains at 12 knots, and the carbon intensity is reduced by 36 percent. In 2030, two other vessels are replaced, with the new units burning biofuels. All new vessels are assumed to have optimized design and negligible fouling, while existing vessels retain a fouling allowance.

The underlying calculations based on these parameters reflect that with the introduction of operational measures (e.g. speed reduction), new energy-efficiency technologies (including optimized hull designs) and LNG as fuel, the average energy-intensity of the fleet can result in compliance with the 2030 GHG targets, based on the Poseidon Principles trajectory.

However, achieving the IMO's 2050 goals will be considerably more challenging without the introduction of zero-carbon fuels.

Scenario Fleet of 10 bulk carriers: 10 x 80k dwt prior EEDI, built in 2010 Operating profile: • Laden 50% • Ballast 35% • Idle 15% *Note: Newbuildings are assumed with negligible fouling, whilst existing vessels with a fouling allowance.*		**Fuel for Main Engine**	**Fuel for Auxiliary Engines**	**Speed**	**Carbon Intensity** Calculation assumptions: 1. The carbon intensity has been calculated as an average of the fleet 2. The carbon intensity = CO_2 emissions per transport work 3. Transport work was calculated using nominal deadweight, not cargo carried	**Carbon Intensity Percentage Reduction from baseline**
2019: Bulk Carrier Fleet 10 vessels, prior the 2020 Sulfur cap	10 x 80k dwt	HFO	MDO	13 knots	4.4	0%, i.e. baseline
2020: Bulk Carrier Fleet 10 vessels, after the 2020 Sulfur cap	10 x 80k dwt	MDO	MDO	13 knots	4.5	+2%
2021: Slow steaming by 1 knot	10 x 80k dwt	MDO	MDO	12 knots	3.2	-27%
2025: Replacement of 3 vessels with Phase III vessels with LNG as fuel	7 x 80k dwt 3 x 85k dwt EEDI Phase III with LNG as fuel	MDO LNG	MDO LNG	12 knots	2.8 *Note: The newbuildings are assumed with a 20% gain in specific fuel oil consumption (SFOC), and a 5% gain in power from design optimization*	- 36%
2030: Replacement of 2 vessels with Phase III vessels with biofuel	5 x 80k dwt; 3 x 85k dwt EEDI Phase III with LNG; 2 x 85k dwt EEDI Phase III with biofuel	MDO LNG Biofuel	MDO LNG Biofuel	12 knots	2.2 *Note: The newbuildings are assumed with a 0% gain in SFOC and a 10% gain in Power from optimized design; For the biofuel, the carbon factor is assumed as 0.4*	- 49%

DESIGN STUDY OF FUTURE VESSELS

ABS has collaborated with Herbert Engineering Corp. (HEC) to develop a series of tanker, bulk carrier, and container ship design concepts to provide visual representations and specifications of practical options for meeting the International Maritime Organization's (IMO) greenhouse gas (GHG) goals for 2030 and beyond.

Some of the concepts are based on technologies that are currently available or are likely to be available in the 2030 time frame. Certain technologies considered are beyond the current state of the art. The concepts provide a window into what may be possible using current knowledge and technology and are extended to anticipate future development.

The schematics offer some insights into the limitations of current technology, future fuels (by current metrics) and how these designs can affect criteria such as on board arrangements, cargo capacity and the potential for propulsive power.

This study includes two baseline ship designs, a Suezmax tanker and a large bulk carrier, sailing on a global trade route with high requirements for endurance. Also included are additional liquefied natural gas (LNG) and ammonia fuel options for the 14,000-TEU containership that was first presented in ABS' 2019 Low Carbon Shipping Outlook.

The general specifications for existing ships in the tanker and bulk carrier categories are:

	Tanker	Bulk Carrier
Size Category	“Suezmax”	“Newcastlemax”
Deadweight	160k at design draft	200k at scantling draft
Length	About 275 m	Max. 300 m
Beam	About 48 m	Max. 50 m
Endurance	18,000 nm	25,000 nm
Service Speed at Design Draft	14.8 knots	14.5 knots

These performance requirements are generally consistent with typical ships currently being designed and built. For the low-carbon fuel alternatives, the requirements for endurance and service speed have been reduced (by about 0.5 knots) in light of the higher capital and fuel costs.

In consideration of the lower energy density of low-carbon fuels, the range was reduced to about half of the current standard.

For the tanker, the current 18,000 nm range reflects enough fuel and margin for about one and a half round-trip voyages between the Middle East and northern China. The proposed endurance of 9,000 nm reflects about a 50 percent margin over the longest Middle East to China one-way voyage.

For the bulk carrier, the current 25,000 nm range reflects sufficient fuel and margin for more than two round-trip voyages between Australia and northern China. The proposed endurance of 12,000 nm reflects fuel and margin for a full round-trip voyage on the longest eastern Australia to northern China route.

Having set the base cases, the study progresses to generally consider the following alternative future zero-carbon fuel systems for the subject ships, plus some alternatives for the containerships, all constructed around the 2030 timeframe:

- Biofuel internal combustion engine (ICE) (applied to the tanker)
- LNG/Bio-Natural Gas (BNG) internal combustion engine (bulker, containership, tanker)
- Hydrogen fuel cell (tanker)
- Ammonia fuel cells (tanker, containership)
- Ammonia internal combustion engine (bulker, containership)

The design concepts are verified at a conceptual level to meet the functional requirements stated above. They also include some efficiency improvement measures, including:

- Optimized hull forms, including principal particulars
- Leading-edge propeller and rudder enhancements, including contra-rotating propellers
- Advanced coatings and measures to reduce hull friction, including air lubrication
- Streamlining to minimize wind resistance
- Shore power supply
- Reduced design speeds

The fuel and power and propulsion system options were extrapolated from the current state-of-the-art to potential 2030 designs.

SHIP DESIGNS

The designs for the 2020 ships were based on conventional technology and are considered using low-sulfur heavy fuel oil (LSHFO).

One of the 2030 technology options is expected to include the combustion of liquid biofuel (bio-diesel or bio-gas oil). This concept ship will be largely similar to the base 2020 designs with a very modest adjustment in its fuel tanks, treatment and engine settings for the different fuel specifications.

The LNG/BNG ships in this study are also similar to the baseline 2020 designs, utilizing current technology in dual-fuel internal combustion engines (ICE) and current state-of-the-art LNG tank alternatives.

The liquefied hydrogen, combined with proton-exchange membrane (PEM) fuel cells, was included as one of the alternatives for the containership in ABS' 2019 Outlook, and a similar, but lower power version is included in this report for the tanker design.

A liquid ammonia design is featured in both internal combustion engine and fuel cell versions.

PRELIMINARY ASSESSMENT OF AMMONIA FUELED SHIPS

FUEL CHARACTERISTICS AND STORAGE

Ammonia (NH_3) is seen as an alternative carbon-free energy carrier to hydrogen. Unlike hydrogen, ammonia is easy to liquefy by bringing it to temperatures below -34° C. It can also be carried in liquid form at ambient temperature, typically compressed to around 18 bar.

These fuel characteristics enable the use of C-Type or prismatic tanks and require significantly lower re-liquefaction energy compared to hydrogen or LNG. NH_3 also has a narrow flammability range so it is not considered an explosion hazard.

However, ammonia is toxic and very reactive. For this reason, the International Gas Carrier Code (IGC Code) specifies strict requirements on the materials that can be used to contain ammonia, as well as on the design features that a plant needs in order to minimize the risk of exposing personnel to NH_3 poisoning.

Ammonia has a much better volumetric-energy density than hydrogen, close to that of methanol. For the same energy requirement, the volume of NH_3 storage tanks will be significantly less than of those for liquid hydrogen, even more so when considering the volume of insulation that is required.

Finally, like LNG, NH_3 tanks need to respect the requirements in the IGC Code on minimum distances from the hull's shell.

SHIPBOARD POWERING OPTIONS

Ammonia can be burned either in an ICE or used in fuel cells. Ammonia has high auto-ignition temperature, high heat of vaporization, and narrow flammability range. Due to these characteristics, ammonia typically requires a pilot fuel injection in order to be burned in two-stroke diesel cycle engines. High pressure injection systems can help to minimize ammonia slip, an important consideration given its stoxicity.

Combustion of ammonia results in NO_x formation and will require selective catalytic reduction (SCR) systems to reduce NO_x in the exhaust gas. It is assumed that the use of a SCR converter would enable ammonia engines to comply with present and future NO_x emissions regulations.

The use of ammonia in fuel cells is still relatively experimental. However, the current pace of development is accelerating, with large stationary plants currently under development.

In order to use NH_3 in fuel cells, the hydrogen (H_2) contained in the molecule needs to be extracted. Although it is possible to achieve this through an external reformer so that the H_2 can be used in low-temperature fuel cells such as a PEM, using ammonia directly in high-temperature fuel cells such as solid oxide (SOFC) can be a more efficient and compact solution.

There are also other advantages of using ammonia in SOFC, such as the high electrical efficiency achievable, the absence of NO_x production and the lack of vibration. However, SOFC currently have a relatively short development track compared to ICE, and a very high comparative cost. These factors are expected to show gradual improvement as research continues. An additional shortcoming of SOFC compared to PEM is the sensitivity of the solid oxide ceramic materials used to heat gradients, which cause relatively long and careful start up and shut down procedures, which often last for hours.

Ideally, SOFC plants should be run continuously to minimize the risk of permanent damage. This may require the use of batteries for energy storage in order to accommodate fluctuations in load demand.

THE 2020 BASELINE SHIPS

THE BASELINE SUEZMAX TANKER

This ship is a conventional Suezmax with 6x2 cargo tanks offering 172,000 m^3 in carrying capacity. It has a conventional arrangement with a single direct-connected ICE and conventional auxiliaries. It normally runs on LSHFO, without a scrubber, and marine diesel oil (MDO) in any emission control areas (ECA).

The speed at the design draft and 85 percent maximum continuous rating (MCR) power – assuming a 15 percent sea margin – is 15.8 knots. The ship employs current state-of-the-art hull and propeller optimization, meeting Phase Two of the IMO's Energy Efficiency Index (EEDI). The endurance range is about 18,000 nm, with fuel consumption about 70 tons per day.

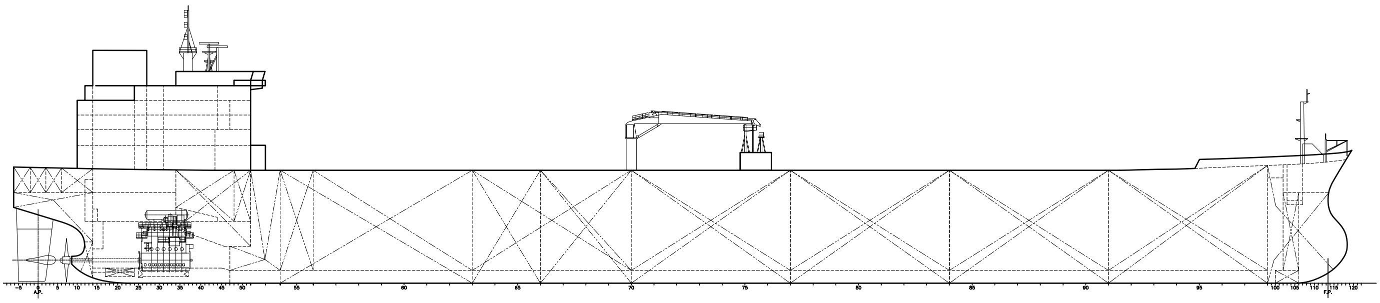
THE BASELINE BULK CARRIER

This ship has the nine conventional cargo holds of a newcastlemax large bulk carrier, and a cargo capacity of 255,000 m^3. It has a conventional arrangement with a single direct-connected ICE and conventional auxiliaries. The ship normally runs on LSHFO, without a scrubber, and MDO in any ECAs.

The speed at the design draft and 85 percent MCR power – assuming 15 percent sea margin – is 15.8 knots. The ship employs current state-of-the-art hull and propeller optimization, meeting EEDI Phase 2. The endurance range is about 24,000 nm, with fuel consumption at about 70 tons/day.

THE 2030 LIQUID BIOFUEL SHIPS

THE LIQUID BIOFUEL SUEZMAX TANKER



This ship has a conventional arrangement with a single direct-connected ICE with conventional auxiliaries.

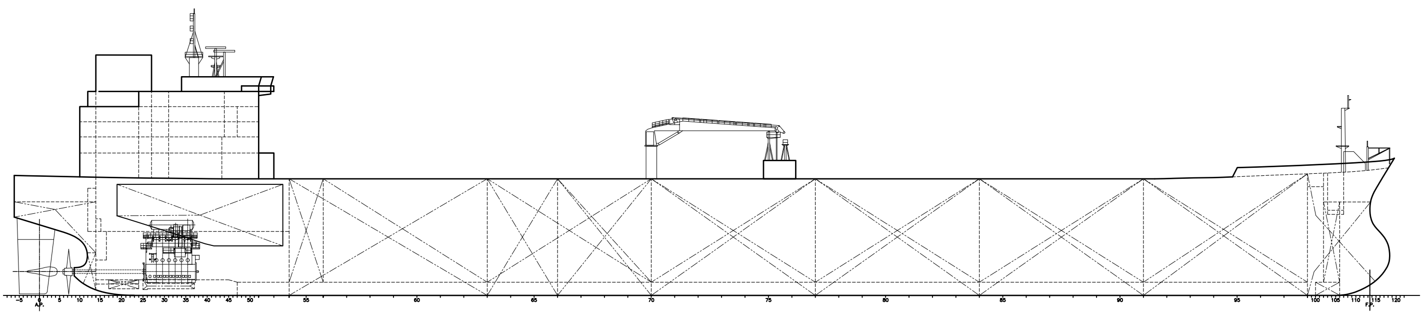
An overall four percent improvement in hull efficiency is assumed compared to the baseline ship by considering the benefits of optimum hull design, a larger slower turning, optimized propeller design based on a de-rated main engine, with minimal aerodynamic fairing.

The fuel storage and handling of liquid biofuels is similar to the current design practice. The design speed is 14.3 knots at the design draft and the ship has a corresponding overall propulsion power about 92 percent of the baseline design.

Engines operating on biofuels are assumed to have similar efficiencies to engines operating on fossil fuels. This example considers the use of FAME biodiesel, which typically has seven to eight percent lower heating value than HFO and about 10 percent lower density.

THE LNG SHIPS

THE LNG ICE TANKER

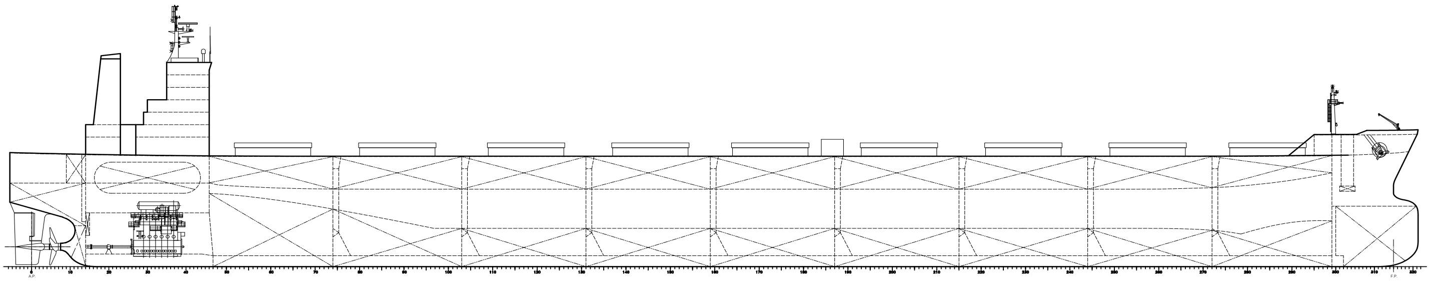


The LNG fueled ICE tanker is very similar to the biofuel ICE tanker; the major differences are the fuel storage tanks and some technical modifications to the engines.

All of the engine and fuel storage technology considered is the current state-of-the-art with overall efficiencies similar to fossil fuels. LNG has somewhat higher heating value per unit mass, but its liquid density is about 50 percent lower than HFO.

Fuel tanks can be cryogenic Type 3 or Type 2 prismatic or membrane.

THE LNG ICE BULK CARRIER



The LNG fueled bulk carrier is similarly configured to the baseline ship. An overall four percent improvement in hull efficiency is assumed compared to the baseline ship by considering the benefits of optimized hull design, and a larger slower turning, optimized propeller design based on a de-rated main engine, with minimal aerodynamic fairing.

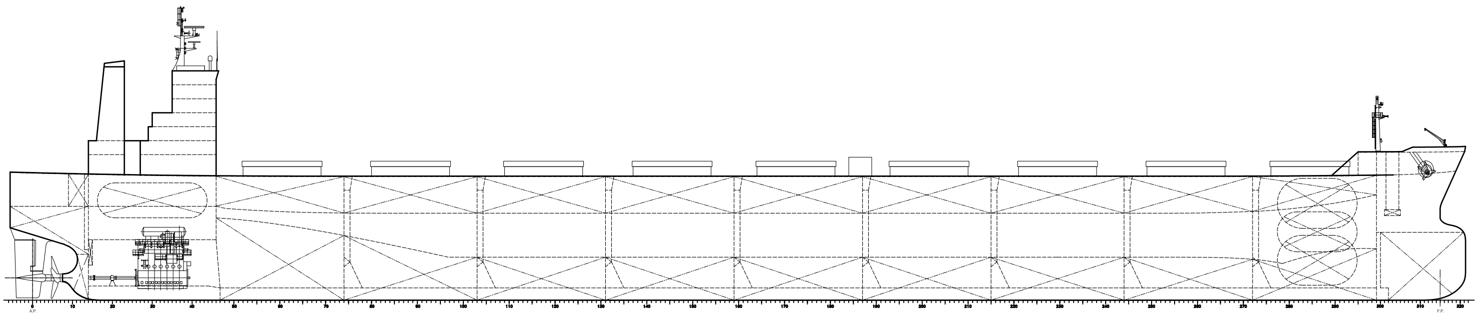
The design speed is 14.0 knots at the design draft, and the ship has corresponding overall propulsion power of about 92 percent of the baseline design.

All of the engine and fuel storage technology considered is the current state-of-the-art with overall efficiencies similar to fossil fuels. LNG has somewhat higher heating value per unit mass, but its liquid density is about 50 percent lower than HFO.

Fuel tanks can be cryogenic Type Three or Type Two prismatic or membrane.

THE 2030 AMMONIA SHIPS

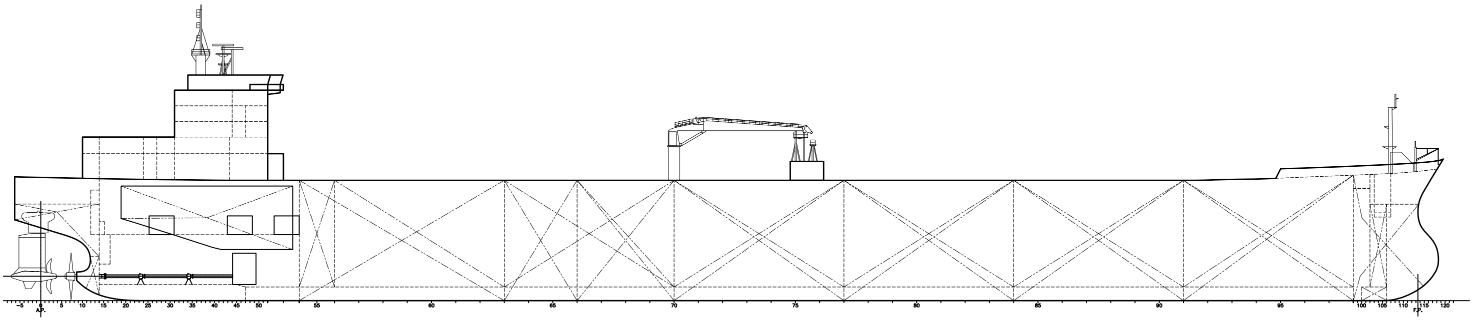
THE NH_3 ICE BULK CARRIER



The engine room arrangement is largely similar to the baseline ship arrangements. The lower heating value and density of ammonia compared to HFO contribute to the requirement for significantly larger fuel tank capacity than for HFO.

Unlike the tanker, where deck space is available for Type C tanks, fuel is stowed below deck in the available space in the engine room and in Hold One, decreasing the cargo volume by about five percent from 255,000 m^3 to 241,000 m^3.

THE NH_3 SOFC TANKER

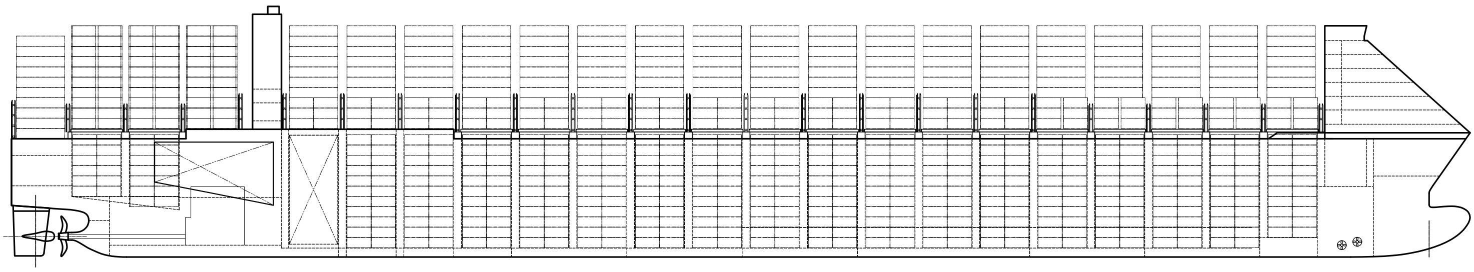


This design incorporates technologies which are beyond the current start of the art. The power generation and propulsion system is envisioned to be fully electric with all of its power generated by SOFC using ammonia. The assumed overall propulsive efficiency was 60 percent.

The fuel cells are sized to meet a maximum power capacity of 1.0 MW for auxiliaries, and 13.9 MW for propulsion. The propulsion power is provided by two contra-rotating propellers; one is a conventional shaft propeller driven by an 8.5 MW electric motor, and the other by a 5.4 MW steerable pod.

There is a minimum installed battery capacity of about 169 MWh, which is used for power conditioning, dynamic stability and hybrid operations. The ammonia is stored in a pair of prismatic Type B tanks in the engine room, but it could also be carried in Type C deck tanks.

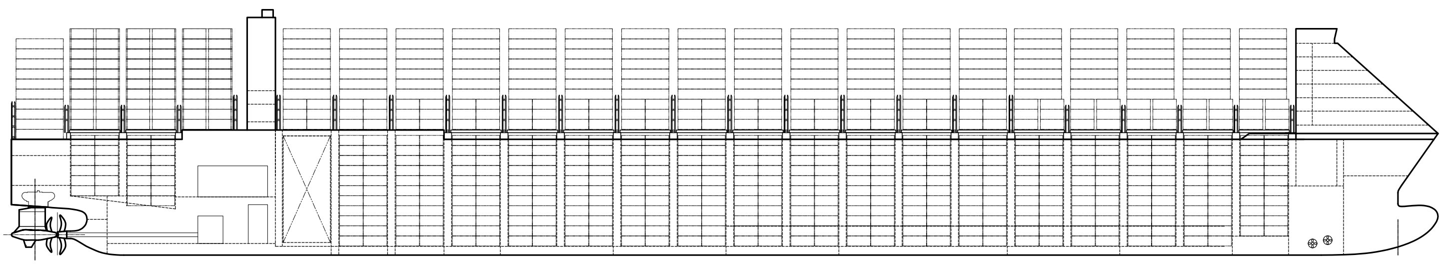
THE NH_3 ICE CONTAINERSHIP



The overall design of this ship is essentially unchanged from the current generation of new panamax 14,000 TEU carriers. It features a single direct-connected ICE with conventional auxiliaries. An overall five to six percent improvement in hull efficiency is assumed compared to the baseline ship, by considering the benefits of optimized hull design, and a larger slower turning, optimized propeller design based on a de-rated main engine, with modest aerodynamic fairing.

Ammonia is carried in a single Type B membrane tank forward of the engine room and two similar tanks on each side of the room. The design speed of 21.5 knots at the design draft is a full knot slower than the current generation of ultra-large container vessels, and the ship features an overall propulsion power less than 80 percent of the baseline design.

THE NH_3 SOFC CONTAINERSHIP



This ship's design is very similar to the hydrogen fuel cell ship described in ABS' 2019 Outlook, incorporating advanced technologies, several of which are beyond the current start of the art.

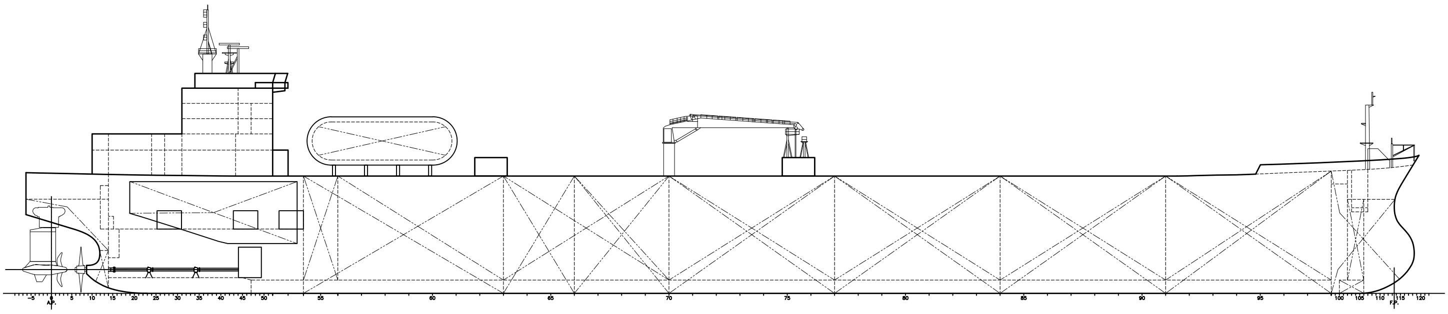
The ship is envisioned to be fully electric with all power provided by SOFC using ammonia. The fuel cells are sized to meet the maximum power capacity of 15 MW for auxiliary loads, and 43 MW for propulsion.

The propulsion is provided two contra-rotating propellers, one a conventional shaft propeller driven by a 26 MW electric motor, and the second by a 17 MW steerable pod.

Fuel storage is in a single Type B membrane tank, but alternate fuel tanks could also be the Type B prismatic variety. The volume of stored ammonia required for the 12,000 nm endurance is 11,500 m^3 .

THE 2030 HYDROGEN SHIPS

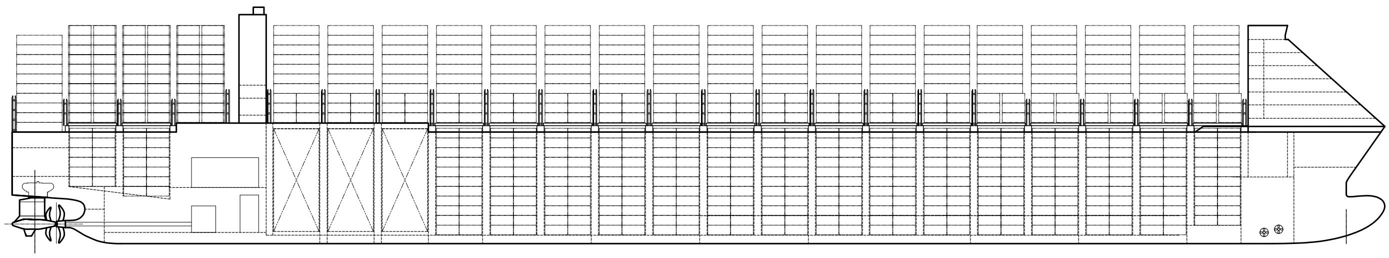
THE H_2 FUEL CELL TANKER



This ship is similar to the ammonia SOFC tanker. It can use either PEM or SOFC fuel cells for power generation and propulsion. The volume of fuel required for the 9,000 nm endurance is 8,820 m^3 for liquid hydrogen (versus 3,265 m^3 for ammonia).

A different type of containment system and a re-liquefaction plant is required for the hydrogen version to limit boil-off gas.

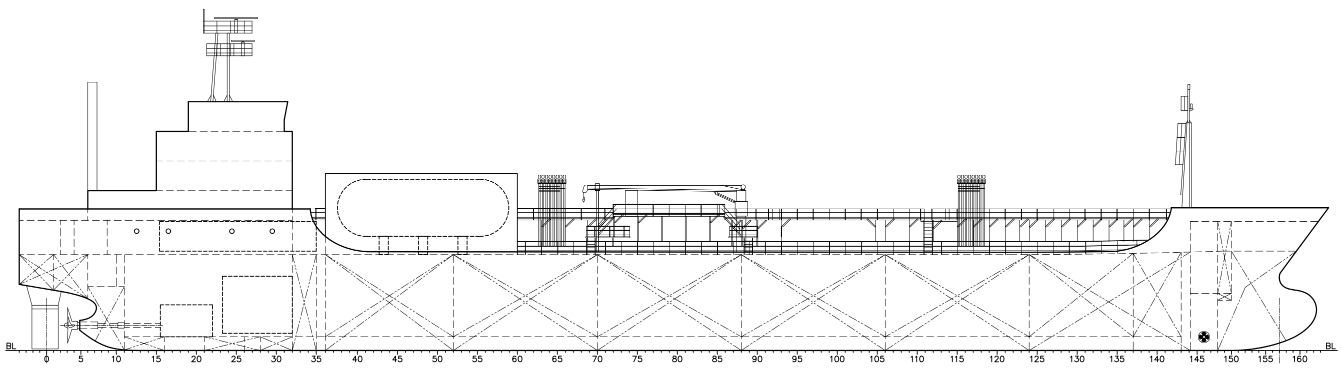
THE H_2 FUEL CELL CONTAINERSHIP



This ship is similar to the ammonia SOFC containership with the same power capacity for auxiliary loads and propulsion. It can use either PEM or SOFC fuel cells for power generation and propulsion.

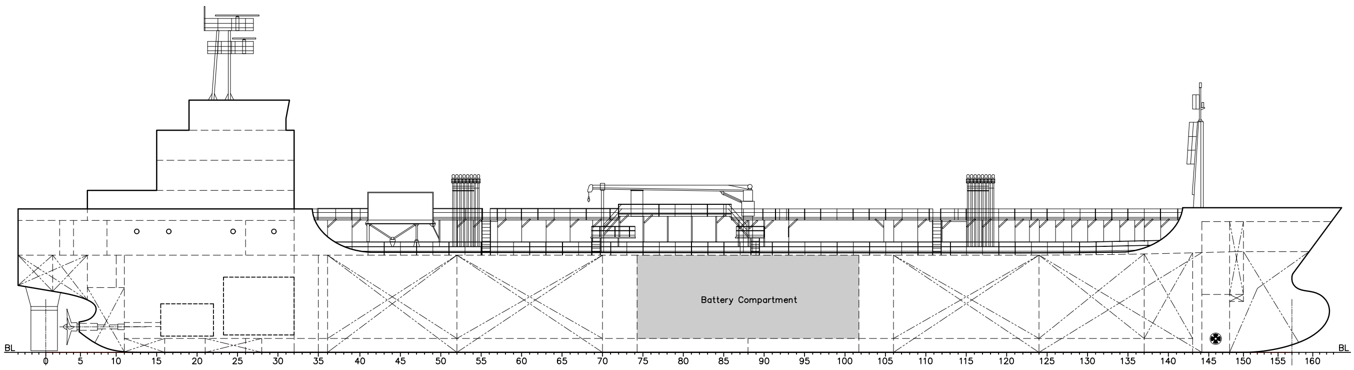
However, the amount of stored liquid hydrogen required is 31,000 m^3, which is about three times higher than the ammonia ship.

THE HYBRID NH_3 SOFC/BATTERIES CHEMICAL CARRIER



This design incorporates advanced future features and technologies similar to those of the NH3 SOFC tanker. The ship is fully electric with all power provided by NH3 solid oxide fuel cells. The fuel cells are sized to meet the maximum power capacity of 3.5 MW, 1.0 MW of which are for auxiliary loads. The propulsion power is provided to a single high-performance propeller matched to a rudder bulb by a 3.0 MW electric motor, assuming that the auxiliary power can be reduced to 0.5 MW while sailing. The minimum installed battery capacity is 15 MWh, which is used for power conditioning, dynamic energy stability, and hybrid operations. This battery set is sufficient to provide enough power to the motor to take the 20 percent sea margin for 1.5 days, even when the full auxiliary load of 1.0 MW power is required, possibly for cargo heating. The schematic shows the ammonia stored in a pair of C-Type tanks P/S on deck, ensuring a total range of 4,200 nm.

THE FULLY ELECTRIC CHEMICAL CARRIER



This ship is potentially small to consider the exploration of rechargeable Li-ion batteries for power. However, even at this size, this design shows the limitations imposed by this technology. The ship is fully electric with all power provided by two sets of Li-ion batteries that need to be recharged at the end of each trip. One set is installed forward of the main propulsion motor in the ER and provides 15 MWh of energy. The second set is hosted in a separate battery room at MS separated by the rest of the cargo block by two cofferdams forward and aft. This second set provides 200 MWh of energy and increases the lightship weight from 2,850 MT to 3,850 MT. The combination of the MS battery room and cofferdams reduce the cargo capacity from 7,700 m^3 to 4,950 m^3. Notwithstanding the loss in payload, the total maximum range provided by the batteries at 10 knots is only 72 hours or 720 nm. The batteries are sized to meet similar power requirements as the hybrid NH3 SOFC version shown above.

CONCLUSIONS

The design study presented in this section showed that future tankers, bulk carriers, and container vessels will require holistic designs based on the selected fuels and power generation and propulsion systems. Fuels with low energy content will require larger tanks for storage and their location on board will be a critical design factor.

Novel power generation systems such as fuel cells may also change the architecture of the current engine room. They may enable more efficient use of space as they allow distributed placement.

OUTLOOK CONCLUSIONS

ABS' 2020 Setting the Course to Low-Carbon Shipping – Pathways to Sustainable Shipping outlook presents a comprehensive description of the three potential fuel pathways for meeting the International Maritime Organization's (IMO) goals to decarbonize the global fleet.

It also offers key insights into: alternative power generation systems; the evolution of global trade and its effect on fleet size; fuel consumption and emissions; operational measures to optimize vessel usage and reduce greenhouse gas (GHG) emissions; and conceptual designs and specifications for vessels opting to use alternative fuels and power generation systems.

The key conclusions can be summarized as follows:

- The three fuel pathways are: (i) light gas, (ii) heavy gas-alcohol, and (iii) biofuel or synthetic fuels. All three pathways start with fuels that can be used in existing power generation and propulsion systems and have a proven potential to reduce or eliminate carbon dioxide (CO_2) and other regulated emissions.
- The use of low- and zero-carbon fuels is essential in the effort to reduce the carbon footprint of future vessels. The operational profile of each vessel will dictate the choice of fuel and propulsion system, based on requirements for bunkering and cargo capacity.
- Low- and zero-carbon fuels that have low volumetric energy content, such as methanol, ammonia or hydrogen, may require holistic redesigns of vessels to be used as primary fuels.
- Petroleum-based fuels are expected to have a considerable market share by 2050 (up to 40 percent), which makes the use of carbon capture and sequestration systems relevant not only for shore applications, but potentially on board marine vessels.
- Novel power generation systems such as hybrid diesel-electric or fuel cells have the potential to offer significant emissions benefits. The first applications of such systems are in specific vessel types, especially those that operate in environmentally sensitive areas such as ports. Their market penetration is increasing; however, wider adoption to larger vessels will require more technological innovation and the cost reductions associated with economies of scale.
- Decarbonization of the global economy is likely to lead to profound changes in trade volumes and patterns in the full range of commodities transported by sea over the next 30 years. These changes will affect the evolution of the fleet and reduce certain vessel segments over the period to 2050.
- The transition to low- and zero-carbon fuels is likely to increase the cost of vessels and their operation in the medium term, until the associated technologies for fuel production, distribution, bunkering and on board use become more cost effective.
- The anticipated alternative fuel and power generation technologies will require the adoption of new regulations, which in turn may affect cargo and trade volumes.
- New safety regulations also will be required to ensure the wide adoption of new technologies and operational frameworks that may not be covered by current standards.
- Based on the projected fuel mix for the five vessel segments analyzed in this study, shipping can meet the IMO's target to reduce CO_2 emissions per transport work (gCO_2/dwt/nm) by 70 percent by 2050, relative to 2008. However, to achieve a 50 percent reduction in absolute CO_2 emissions (ton), the market share of petroleum fuels will need to be further reduced by 2050 (below 40 percent).

ABS ACTIVITIES

The synchronized search for zero-carbon fuels and more fuel-efficient vessels is on course to make the business of transporting trade by sea cleaner, more efficient and more cost effective.

As with any large-scale industry transition, success will not come easily or without the significant disruptions that pose unique and unprecedented challenges and opportunities, especially for early adopters.

This document highlights the challenges associated with meeting the International Maritime Organization's (IMO) decarbonization targets and focuses on the ways the industry will be able to respond. The decarbonization challenge can be addressed by a combination of alternative fuel use, new technology application and operational efficiency measures.

The shipping industry is at a point where well-informed decisions are reducing its collective carbon footprint, while simultaneously meeting growing public demand to lessen its impact on the environment and adopt more sustainable business models.

ABS is committed to supporting the shipping industry by continuing to develop the tools and services that facilitate decision-making and help the operator to navigate the challenges addressed in this document.

Reaching the future milestones for decarbonization will require contributions from existing ships. Benchmarking greenhouse gas (GHG) output and investigating ways to reduce that at the vessel and fleet levels are at the core of this effort.

Building the decarbonization trajectory for a fleet requires a specific toolbox to address the complexities of decision-making. ABS has developed a set of tools and services to deliver a rapid response and decision support.

Utilizing digital tools and advanced visualization, ABS can create a bespoke dashboard for each ship which tracks the output of metrics related to performance and decarbonization indicators. The Sustainability Dashboard dynamically monitors the targets set by the operator to reach their sustainability goals.

Ship designs are already required to improve in order to comply with the next phase of the IMO’s Energy Efficiency Design Index; but that the contribution of this initiative to meeting the IMO’s ambitious GHG targets will be minimal.

New low- and zero-carbon energy sources will be needed to reach the 2050 targets. New, holistic vessel designs will be necessary to accommodate this change and address the complexity of available technical options.

With its state-of-the-art simulation tools, ABS can help operators to identify the optimum technology mix that is best suited for each ship and its operating profile. As a class society, ABS is focused on working with other industry stakeholders to maintain safety as new fuels and technologies are introduced.

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