

Navigating the Maritime **Fuel Transition**

How fuel economics, regulations,
and fleet decisions shape the future
bunkering landscape



Contents

List of abbreviations	4
List of figures	5
Executive summary	6
1. Navigating an uncertain maritime fuel transition	8
1.1 Transition is necessary, but its pace and shape remain uncertain	8
1.1.1 The regulatory landscape is evolving, and clarity remains elusive	8
1.1.2 Fuel cost gaps remain wide, and the pace of convergence is uncertain	9
1.2 Identifying the driving forces and signposts of the maritime fuel transition	10
1.3 Purpose of this study	10
2. Modelling future fuel adoption scenarios	11
2.1 A three-stage model architecture to forecast new fuel adoption scenarios	11
2.2 Fuels and engine technologies assessed	12
2.2.1 Fuel options assessed	12
2.2.2 Engine configurations assessed	13
2.2.2.1 Treatment of methanol and ethanol dual-fuel engines	13
2.2.2.2 Treatment of onboard carbon capture and storage (OCCS)-equipped conventional engines	14
2.3 Policy scenarios	14
2.4 Key fuel sensitivities	16
3. The role of regulation: How policy scenarios shape fuel competitiveness and fleet outcomes	17
3.1 Outcomes under the base scenario	17
3.1.1 The current Net-Zero Framework (NZF) Tier-2 remedial unit (RU) penalty narrows, but does not close the cost gap	17
3.1.2 The fleet remains dominated by fossil fuels	18
3.1.3 E-methanol and e-ammonia's levelised cost of fuel use are near parity	19
3.2 Outcomes under the International Maritime Organization (IMO) high penalty scenario	20
3.2.1 A higher penalty closes the cost gap and shifts the fleet towards new fuels	20
3.3 Outcomes under the European Union (EU) regulations scenario	21
3.3.1 Regional regulations alone are insufficient to drive a global fuel transition	21

4. Four key uncertainties that materially shape fuel pathways' competitiveness	23
4.1 Sensitivity 1: A lower levelised cost of hydrogen (LCOH) expands e-fuel adoption	24
4.2 Sensitivity 2: Biogenic CO ₂ costs determine the split between e-methanol and e-ammonia	25
4.2.1 Biogenic CO ₂ adds a distinct cost component to e-methanol	25
4.2.2 Impact of biogenic CO ₂ costs on cost comparison between e-fuels	25
4.2.3 Impact of biogenic CO ₂ costs on fuel uptake	26
4.3 Sensitivity 3: Bio-methanol cost trajectory determines whether the methanol pathway scales	27
4.3.1 Constant bio-methanol costs limit methanol uptake	28
4.3.2 Declining bio-methanol costs unlock methanol as a bridge fuel, lifting uptake from 2% to 19%	28
4.3.3 Aggregated methanol feedstock availability	29
4.4 Sensitivity 4: Regulatory recognition is the critical swing variable for the ethanol pathway	29
4.5 Early cost competitiveness determines which engines enter the orderbook	30
4.5.1 Near-term affordability shapes the future fleet	30
5. How the bunkering landscape could evolve	32
5.1 The current bunkering landscape and why it may change	32
5.1.1 Fuel economics, vessel traffic, and policy are likely to shape future bunkering hubs	32
5.1.2 Net voyage economics play a central role in bunkering decisions	33
5.1.3 Incumbent hubs have an advantage, but new entrants can still compete	33
5.1.4 Liner networks are well suited for early adoption of methanol and ammonia	33
5.2 Methanol and ethanol may reinforce existing bunkering hubs	34
5.3 Ammonia could reshape the bunkering landscape	34
5.3.1 Production-linked hubs	34
5.3.2 Import-aggregation hubs	35
6. Conclusions: Implications and key signposts to watch	36
6.1 Build fleet strategy around optionality, not a single fuel commitment	36
6.2 Regional fuel economics should inform engine choice	36
6.3 Cross-sector synergies can de-risk bunkering infrastructure investments	37
6.4 Infrastructure investment priority hinges on which penalty trajectory materialises	37
6.5 A global pricing mechanism remains the most powerful lever available to policymakers	38
References	39
Acknowledgements	40
About Global Centre for Maritime Decarbonisation (GCMD)	41
About Boston Consulting Group (BCG)	42

List of abbreviations

ARA	Amsterdam-Rotterdam-Antwerp
BCG	Boston Consulting Group
CAPEX	Capital Expenditure
DAC	Direct Air Capture
DWT	Deadweight Tonnage
ETS	Emissions Trading Scheme
EU	European Union
EU ETS	European Union Emissions Trading System
GCMD	Global Centre for Maritime Decarbonisation
GJ	Gigajoule
GHG	Greenhouse Gas
HSFO	High Sulphur Fuel Oil
HVO	Hydrotreated Vegetable Oil
IMO	International Maritime Organization
LCOH	Levelised Cost of Hydrogen
LNG	Liquefied Natural Gas
MEPC	Marine Environment Protection Committee
NZF	Net-Zero Framework
OCCS	Onboard Carbon Capture and Storage
OPEX	Operating Expenditure
PP	Percentage Point
RU	Remedial Unit
SAF	Sustainable Aviation Fuel
SU	Surplus Unit
UK ETS	United Kingdom Emissions Trading Scheme
VLSFO	Very Low Sulphur Fuel Oil
ZNZ	Zero or Near-Zero

List of figures

Figure 1:	Constituents of levelised cost of fuel use	9
Figure 2:	A three-stage framework to forecast new fuel adoption scenarios	12
Figure 3:	The three scenarios explored in this study	15
Figure 4:	Key parameters tested in this study	15
Figure 5:	Key fuel sensitivities	16
Figure 6:	Levelised cost of fuel use for twelve fuel options along with regulatory penalties, in 2050 (USD/GJ)	18
Figure 7:	Policy scenario comparison of fleet engine mix and energy consumption in 2050	19
Figure 8:	Cost breakdown of e-methanol versus e-ammonia	20
Figure 9:	Outcomes in the three scenarios	22
Figure 10:	2050 energy consumption mix for fuel sensitivities (% of total fleet energy demand)	23
Figure 11:	Sensitivity of the levelised cost of fuel use comparison to biogenic CO ₂ cost (USD/GJ)	27
Figure 12:	Four key uncertainties shaping fuel pathways' competitiveness	31
Figure 13:	Domestic e-ammonia and blue ammonia production cost vs total ship arrivals	35

Executive summary

This study identifies the principal drivers that determine how different fuel pathways become competitive, how the economics of fuel influences engine ordering decisions, and how those decisions shape future energy consumption and the global bunkering landscape.

To examine how these drivers interrelate, the Global Centre for Maritime Decarbonisation (GCMD) and Boston Consulting Group (BCG) jointly developed an integrated model that links policy and cost assumptions to engine adoption and fuel-mix outcomes, and traces the resulting implications for the global bunkering landscape.

This model assesses conventional fuels—very low sulphur fuel oil (VLSFO) and fossil liquefied natural gas (LNG)—alongside new fuels: first- and second-generation biodiesel, hydrotreated vegetable oil (HVO), bio-LNG, bio-methanol, first- and second-generation bio-ethanol, blue ammonia, e-methanol and e-ammonia. While these fuel pathways are not entirely independent—for example, bio-methanol adoption can help ease the pathway to eventual e-methanol adoption—capturing the full range of fuel options matters because fleet renewal takes time. With vessels lasting 25 to 30 years and only around 4% of the fleet is renewed each year, the engines ordered in the coming decade will shape the fuels shipping can consume in 2050.

Five key findings emerge from the analysis:

1. A global pricing mechanism is among the most critical levers for driving the transition at scale, but the carbon price will need to be high enough to close the cost gap.

Under our base scenario, new fuels are not cost-competitive through 2050. Rather, they become cost-competitive with conventional fuels when the International Maritime Organization (IMO)'s Net-Zero Framework's (NZF) Tier-2 remedial unit (RU) penalty rises to USD 700/tCO₂e, as captured in our high penalty scenario.

At the time of this analysis, the NZF agreed at the 83rd session of the Marine Environment Protection Committee (MEPC 83) was the only concrete regulatory proposal available to model, and our base scenario therefore assumes its adoption as proposed. Since then, the regulatory landscape has grown more fluid, with alternative proposals now under discussion ahead of MEPC 85 in December 2026.

Whether the NZF is ultimately adopted as proposed, revised, or superseded by an alternative mechanism, the underlying takeaway is that the effective carbon price needs to be sufficiently high to close the cost gap between new and conventional fuels. Achieving a price signal of this magnitude will be challenging, but without it, the economics are unlikely to support the transition to new fuels at scale.

2. E-methanol and e-ammonia are near parity in levelised cost of fuel use (per unit of energy).

Ammonia's production cost advantage is largely offset by its higher logistics and bunkering costs through 2050. For both fuels, the levelised cost of hydrogen (LCOH) is the primary cost driver, accounting for 54–60% of levelised cost of fuel use for e-methanol and e-ammonia over this same period.

3. The near-term affordability of new fuels relative to conventional fuels influences the engine types that shipowners order today.

Engine choices will establish the energy consumption base and the supporting infrastructure needed to enable further cost reductions over time. Although owning a dual-fuel fleet offers strategic optionality, engine orders alone do not guarantee fuel uptake. The rate at which individual fuel cost curves decline determines when dual-fuel vessels consume the compatible new fuel.

4. Ethanol, methanol, and ammonia each exhibit different sensitivities, providing signposts for the industry on how their competitiveness could evolve.

For e-methanol and e-ammonia, LCOH is a key sensitivity, while e-methanol is additionally sensitive to biogenic CO₂ costs. Both are directly related to feedstock cost and availability, and therefore affect fuel production costs. Bio-methanol cost trajectories, on the other hand, could influence near-term uptake of methanol dual-fuel engines, with implications for longer-term technology lock-in. Ethanol adoption is sensitive to the regulatory treatment of food-crop biofuels.

5. Future bunkering hubs will evolve into distinct archetypes.

As liquid fuels, bunkering methanol and ethanol require incremental structural and logistical changes compared to current operations. Ammonia's complex handling requirements and transport costs stemming from its toxicity and low boiling temperature give rise to two bunkering hub archetypes: production-linked hubs that compete on fuel cost, and import-aggregation hubs that compete on scale. Converting high vessel traffic and ammonia demand from adjacent industrial or power sectors are key considerations to justify import terminal investment.

1. Navigating an uncertain maritime fuel transition

The maritime fuel transition faces uncertainty on two fronts: regulations and fuel economics. These uncertainties slow investment decisions across the value chain.

1.1 Transition is necessary, but its pace and shape remain uncertain

1.1.1 The regulatory landscape is evolving, and clarity remains elusive

The maritime industry is entering a period of fuel transition, but the course forward remains far from settled.

Vessels capable of operating on new fuels are beginning to enter the global fleet, policies to reduce greenhouse gas (GHG) emissions from shipping are being introduced, and supply chains for new fuels are emerging. Yet the deployment of new fuels remains nascent. Most of the global fleet continues to operate on conventional fuels as the availability of new fuels remains limited and the costs high, and significant uncertainty remains on which fuel(s) will ultimately achieve widespread adoption.

One source of this uncertainty is the evolving regulatory landscape. International shipping emits approximately 800 million tonnes of CO₂ annually, and the 2023 IMO GHG Strategy, adopted by member states, targets net-zero GHG emissions from international shipping by or around 2050.

To support this transition, the IMO NZF introduced the sector's first globally binding emissions-pricing mechanism, comprising Tier-1 and Tier-2 RUs, a surplus unit (SU) trading mechanism, and a zero or near-zero (ZNZ) reward mechanism. Although the framework was agreed in principle at MEPC 83 in April 2025, member states voted to delay its formal adoption at an extraordinary session of MEPC in October 2025. Since then, several member states have submitted alternative proposals that will be considered alongside the original NZF ahead of MEPC 85, in December 2026. The next decision point will be at that meeting, leaving uncertainty not only over the framework's technical and operational details, but also over which version, if any, will ultimately be adopted.

In the meantime, several regulatory frameworks are already in force or advancing. The European Union Emissions Trading System (EU ETS) and FuelEU Maritime Regulation apply to voyages within, entering, or leaving European Union (EU) waters, covering approximately 20%

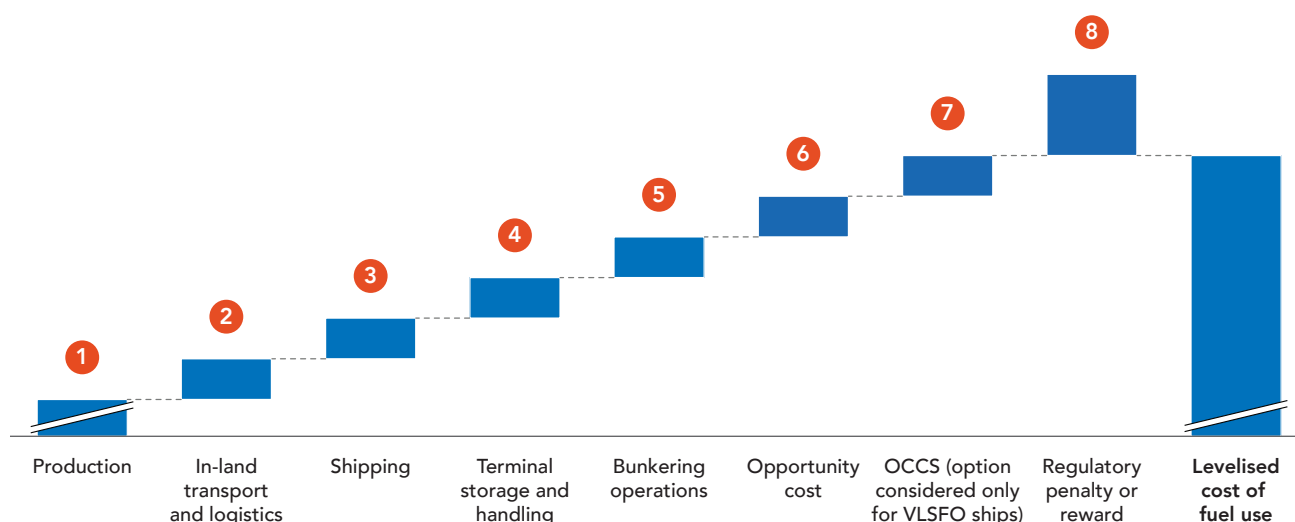
of international shipping energy consumption in 2025. This is creating compliance obligations that are reshaping fuel economics for impacted vessels. That landscape continues to evolve: on 17 July 2026, the European Commission proposed a new mechanism, funded by EU ETS allowance revenue, that subsidises the cost of green shipping fuels, lowering the cost of complying with the FuelEU Maritime obligation (European Commission, 2026).

The United Kingdom Emissions Trading Scheme (UK ETS) was expanded to cover domestic shipping emissions from 1 July 2026. At the same time, China continues to expand its national emissions trading scheme (ETS)—already the world's largest by volume of covered emissions—to industries like steel, cement, and aluminium. Cities such as Shanghai have piloted an ETS that cover domestic shipping. While international shipping is not yet included in China's national ETS, it is plausible that coverage could be extended to the sector over time as governments seek to broaden carbon pricing across hard-to-abate industries.

Taken together, these evolving regulatory regimes make it hard for shipowners and operators to underwrite the long-term capital commitments required for the fuel transition.

1.1.2 Fuel cost gaps remain wide, and the pace of convergence is uncertain

A second source of uncertainty is fuel economics. New fuels are expected to remain up to two times more expensive to produce in 2050 than the conventional fuels they would replace (IMO, 2023), and production cost only represents one of several components of the levelised cost of fuel use (Figure 1). Once transport, terminal storage, and bunkering costs are included, the cost gap widens further. These uncertainties differ across fuel pathways and regions, making it difficult for shipowners to develop commercial strategies and take investment decisions.



Note: OCCS - Onboard Carbon Capture and Storage

Source: GCMD and BCG analysis

Figure 1: Constituents of levelised cost of fuel use

1.2 Identifying the driving forces and signposts of the maritime fuel transition

The maritime fuel transition is shaped by a network of interdependent decisions. Decisions about fuel production influence fuel availability and cost; these affect engine ordering decisions, which in turn determine the fuels that vessels are capable of consuming over the following decades. The resulting fleet composition shapes future fuel demand and, ultimately, the commercial case for bunkering infrastructure. At the same time, expectations about future regulation, fuel availability, and bunkering infrastructure influence investment decisions today.

These decisions cannot be deferred until the uncertainty is resolved. With vessels having a lifespan of 25 to 30 years and only around 4% of the fleet renewed annually, the engines ordered in the coming years play a big role in determining the fuels shipping consumes in 2050. Understanding what determines fuel competitiveness is therefore not a far-out question but an imminent one.

1.3 Purpose of this study

Specifically, the study addresses four questions:

1. Under what conditions do new fuels become economically competitive with conventional fuels?
2. Which factors strongly influence the adoption of different fuel pathways?
3. How do fuel economics influence engine ordering decisions and the long-term evolution of the fleet?
4. How might these developments reshape the future global bunkering landscape?

To address these questions, GCMD and BCG have jointly developed an integrated model that combines policy scenarios, fuel economics, fleet evolution, and port-level analysis. The objective is not to predict a single transition pathway. Rather, it is to identify the economic and regulatory conditions under which different fuel pathways become competitive, the resulting implications for fleet and bunkering development, and the signposts that will determine how the maritime fuel transition ultimately unfolds.

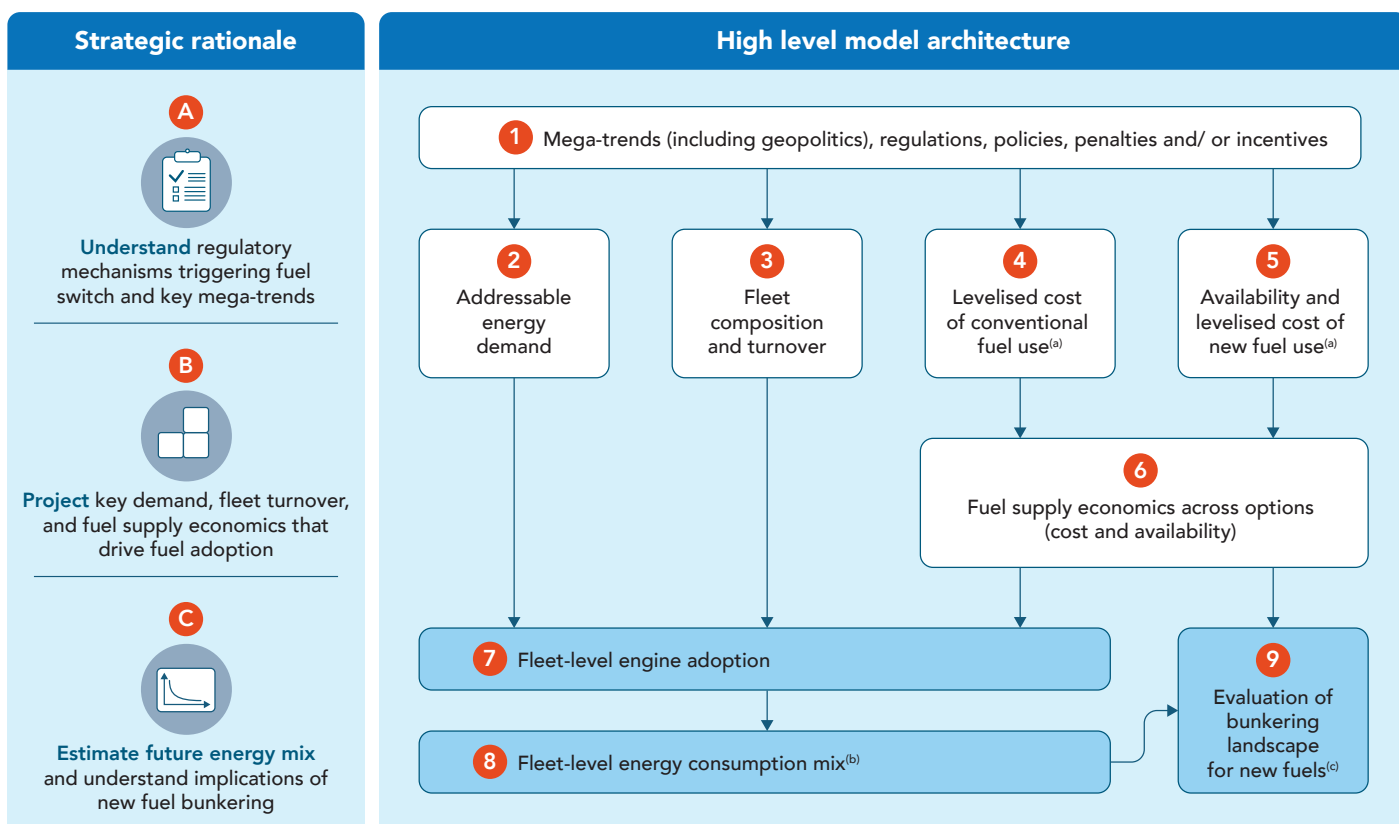
2. Modelling future fuel adoption scenarios

Because no single transition pathway can be confidently predicted, this study takes a scenario-based approach. A three-stage model forms the analytical backbone, mapping different regulatory and cost assumptions to engine adoption and energy consumption mix outcomes through 2050.

2.1 A three-stage model architecture to forecast new fuel adoption scenarios

The analytical framework comprises three connected stages, with one feeding into the next (Figure 2):

- **Stage A – External drivers:** This stage evaluates key policy drivers, such as the IMO NZF, the EU ETS, and the FuelEU Maritime Regulation, alongside trade routes and trade volume changes driven by geopolitical developments including shifting trade patterns, protectionism, and the fragmentation of global trade corridors. It also incorporates global decarbonisation trends, including the structural decline in fossil fuel trade and the availability of regional feedstocks for new fuels. Together, these factors establish the conditions for downstream analysis of energy demand and fuel economics.
- **Stage B – Fuel competitiveness:** Analyses from Stage A are fed into this stage to project addressable international shipping energy demand through 2050 and construct full-spectrum levelised cost of fuel use for both conventional and new fuel options. Addressable energy demand is estimated from projected international maritime transport work and average fleet energy intensity and is limited to international shipping vessels of 5,000 gross tonnage and above. Transport-work growth varies across global decarbonisation pathways as commodity trade patterns change. The levelised cost of fuel use incorporates seven cost components: production, inland transport, shipping, terminal storage and handling, bunkering operations, opportunity cost, and OCCS cost for the VLSFO pathway (Figure 1). Regulatory penalties and incentives are assessed separately and combined with these costs when evaluating fuel competitiveness under each policy scenario. Opportunity cost refers to additional newbuild capital expenditure (CAPEX), additional non-fuel operating expenditure (OPEX) including crew training, maintenance and insurance, and lost cargo revenue arising from reduced cargo capacity.
- **Stage C – Industry outcomes:** Building on Stages A and B, this stage translates fuel and engine economics into newbuild engine adoption rates and fleet-level energy consumption, accounting for dual-fuel vessels' ability to switch between fuel types based on prevailing economics. Port-level bunkering analysis is then derived from the regional fuel supply landscape and resulting fuel demand.



Notes:

^(a) Levelised cost of fuel use include opportunity costs (for new fuels), OCCS cost (for conventional fuels), etc.

^(b) E.g., dual-fuel vessels may operate on conventional fuel when economics are favourable

^(c) Identified based on proximity to regions with new fuel production and major trade routes

New fuels refer to biodiesel (1G)/ (2G), HVO, bio-methanol, bio-ethanol (1G)/ (2G), bio-LNG, e-ammonia, e-methanol, blue ammonia; conventional fuels refer to VLSFO and fossil LNG

Source: BCG case experience, GCMD and BCG analysis

Figure 2: A three-stage framework to forecast new fuel adoption scenarios

2.2 Fuels and engine technologies assessed

2.2.1 Fuel options assessed

The model assessed twelve fuel options across two broad categories.

Conventional fuels include VLSFO and fossil LNG. As a pathway for decarbonisation, the model also explored an option in which OCCS capability is introduced to VLSFO-fuelled vessels. OCCS is not considered for LNG vessels primarily because the technology remains insufficiently mature.

New fuels comprise bio-based fuels—first- and second-generation biodiesel, HVO, bio-LNG, bio-methanol, and first- and second-generation bio-ethanol—alongside blue ammonia and e-fuels, specifically e-methanol and e-ammonia. Synthetic fuels such as e-LNG and e-diesel were not included as these fuels are not sufficiently developed and the costs remain high.

Throughout this report, drop-in fuels refer to first- and second-generation biodiesel and HVO, which the model assumes are compatible with conventional fuels and can be used in existing engines.

All fuel costs in this study are compared on a per-gigajoule (GJ) basis to keep fuels with different energy densities directly comparable.

2.2.2 Engine configurations assessed

The model covers six engine configurations: conventional engines, conventional engines with OCCS installed, LNG dual-fuel engines, methanol dual-fuel engines, ammonia dual-fuel engines, and ethanol dual-fuel engines.

Conventional engines can burn either VLSFO or high sulphur fuel oil (HSFO) with a scrubber. The model uses VLSFO as the representative fuel, given its dominance following the IMO 2020 Sulphur Cap. HSFO with a scrubber is not modelled separately.

Dual-fuel engines retain the flexibility for switching between their designated new fuel and VLSFO or drop-in fuels (e.g., biodiesel and HVO) in any given year based on fuel economics. As a result, the engine mix and the energy consumption mix can diverge significantly depending on prevailing fuel economics.

2.2.2.1 Treatment of methanol and ethanol dual-fuel engines

The model treats methanol and ethanol dual-fuel engines as separate configurations. Ethanol use has been demonstrated on some methanol engine platforms: Maersk has used ethanol and its blends with methanol in its methanol dual-fuel vessel, the *Laura Maersk*, confirming that ethanol can be burned without compromising engine performance (Engine, 2026). However, its broad compatibility across the fleet remains unproven.

In current practice, engines are configured and certified for a designated primary fuel, and operating on a derivative fuel (i.e., ethanol instead of methanol, which comprises an additional methylene unit) may require adaptation of the fuel supply system and renewed engine certification.

Fuel choice is further constrained by long-term offtake agreements and route-specific bunkering availability, particularly for emerging fuels. Separate treatment is therefore a conservative modelling choice that reflects distinct methanol and ethanol markets, although wider adoption of alcohol-flexible engines could soften this distinction over time.

2.2.2.2 Treatment of OCCS-equipped conventional engines

The OCCS analysis assumes a 60% gross capture rate, mature capture technology, and an uptake that is unconstrained by the availability of downstream CO₂ offloading infrastructure. The model only assessed OCCS on VLSFO-fuelled conventional engines.

LNG dual-fuel vessels with OCCS were excluded primarily because the technology remains insufficiently mature and there are too few reliable technical and cost benchmarks to support defensible modelling even though cold energy from LNG regasification could plausibly lower OCCS's energy penalty on this fleet. OCCS is therefore represented as a standalone decarbonisation pathway for the conventional fleet, rather than in combination with other engine types.

2.3 Policy scenarios

Given the uncertainty surrounding future regulations, three policy scenarios were modelled (Figure 3):

1. **Base scenario:** The base scenario assumes that the proposed IMO NZF, as agreed at MEPC 83, is adopted, with Tier-2 RU penalty held at USD 380/tCO₂e through 2050. ZNZ rewards are assumed to lapse after 2044, when the Direct Compliance Target becomes more stringent than the ZNZ reward threshold. The scenario also assumes that food-crop biofuels receive neutral regulatory treatment because the NZF's sustainability and certification criteria—which determine the eligibility of these fuels—have not yet been finalised. Other key assumptions include bio-methanol production costs remaining constant at USD 43/GJ, renewable hydrogen reaching around USD 3/kg H₂ by 2050, and biogenic CO₂ costs of USD 150/t. These values also serve as the reference point for the policy scenarios and fuel sensitivities that follow (Figure 4).
2. **IMO high penalty scenario:** This scenario assumes the proposed IMO NZF is adopted, with the Tier-2 RU penalty held at USD 380/tCO₂e from 2028 to 2030 and rising linearly thereafter to USD 700/tCO₂e by 2050. This scenario examines the effect of a stronger global carbon pricing signal on fuel adoption.
3. **EU regulations scenario:** The scenario assumes no global framework in place, but considers EU ETS and FuelEU Maritime Regulation to be fully implemented through 2050. This scenario examines how the transition would evolve in the absence of a globally harmonised framework.

	Policy scenarios		
	Base scenario	IMO high penalty scenario	EU regulations scenario
IMO penalty level	Constant USD 380/tCO ₂ e	USD 700/tCO ₂ e by 2050	Non applicable
Regulatory treatment of food-crop biofuels	Neutral		Unfavourable
Bio-methanol cost trajectory	Constant USD 43/GJ		
LCOH pathway	Base ~USD 3/kg H ₂ in 2050		
Biogenic CO ₂ costs	USD 150/t		

Figure 3: The three scenarios explored in this study

Parameters tested	Options				Description
Regulatory regime	IMO		EU ETS and FuelEU Maritime Regulation		Refers to the regulatory regime selected in the model - IMO: Penalties apply to all vessels >5,000 gross tonnage across global voyages - EU ETS and FuelEU Maritime Regulation: Penalties apply to voyages within, entering, or leaving EU waters, covering approximately 20% of international shipping energy consumption
Penalty level	USD 380/t CO ₂ e constant	USD 700/t CO ₂ e			Refers to the penalty rates in 2050 for non-compliance with GHG intensity targets - USD 380/tCO₂e is kept constant from 2028-2050 based on IMO NZF's Tier-2 RU penalty - USD 700/tCO₂e is the "tipping point" penalty rate in 2050 for conventional fuels to be more expensive than most new fuels
Bio-methanol cost trajectory	Constant		Declining		- Constant: Bio-methanol costs held at USD 43/GJ from 2025-2050 - Declining: Costs fall to USD 33/GJ by 2050, driven by maturation of gasification pathway
LCOH	Base		Low		Assumes different steepness of learning and scale curves for the cost of renewable electricity and electrolyzers by 2050 - Base LCOH costs: ~USD 3/kg H₂ by 2050 - Low LCOH costs: ~USD 2/kg H₂ by 2050
Biogenic CO ₂ cost	USD 50/t	USD 100/t	USD 150/t	USD 200/t	Refers to the biogenic CO ₂ costs held constant from 2025-2050
Food-crop biofuel treatment	Neutral		Unfavourable		Biofuels (1G) are considered food-crop biofuels, and are explicitly excluded under the FuelEU Maritime Regulation. This toggle allows biodiesel (1G) and bio-ethanol (1G) to be recognised or excluded in different regimes - Neutral: Biodiesel (1G) and bio-ethanol (1G) included - Unfavourable: Biodiesel (1G) and bio-ethanol (1G) are assigned an emission factor that is comparable to that of the least favourable fossil fuel pathway.

Source: GCMD and BCG analysis

Figure 4: Key parameters tested in this study

2.4 Key fuel sensitivities

Relative to the base scenario, the model tests a series of fuel sensitivity cases that vary renewable hydrogen costs (LCOH), biogenic CO₂ costs, bio-methanol cost trajectories, and the regulatory treatment of food-crop biofuels, each of which materially influences the competitiveness of individual fuel pathways (Figure 4).

Each sensitivity case changes only one or two parameters relative to the base scenario, while all others remain invariant in order to understand how the significance of the manipulated parameters on fuel economics and engine adoption (Figure 5).

	Fuel sensitivities						
	Base scenario	Unfavourable food-crop biofuels	Bio-methanol cost declining	Low LCOH with USD 50/t of biogenic CO ₂	Low LCOH with USD 100/t of biogenic CO ₂	Low LCOH with USD 150/t of biogenic CO ₂	Low LCOH with USD 200/t of biogenic CO ₂
IMO penalty level	Constant USD 380/tCO ₂ e						
Regulatory treatment of food-crop biofuels	Neutral	Unfavourable					
Bio-methanol cost trajectory	Constant USD 43/GJ		Declining From USD 43/GJ to USD 33/GJ by 2050				
LCOH pathway	Base ~USD 3/kg H ₂ in 2050			Low ~USD 2/kg H ₂ in 2050			
Biogenic CO ₂ costs	USD 150/t			USD 50/t	USD 100/t	USD 150/t	USD 200/t

Source: GCMD and BCG analysis

Figure 5: Key fuel sensitivities

3. The role of regulation: How policy scenarios shape fuel competitiveness and fleet outcomes

A global carbon pricing mechanism remains the most powerful lever for accelerating the transition to new fuels. However, a global mechanism alone is insufficient: the carbon price must be high enough to close the cost gap with conventional fuels over the full transition horizon. Although the temporary ZNZ reward mechanism under the base scenario encourages investment in dual-fuel vessels, conventional fuels remain more economical for much of the transition through 2050, resulting in a fleet that continues to be dominated by fossil-fuel use.

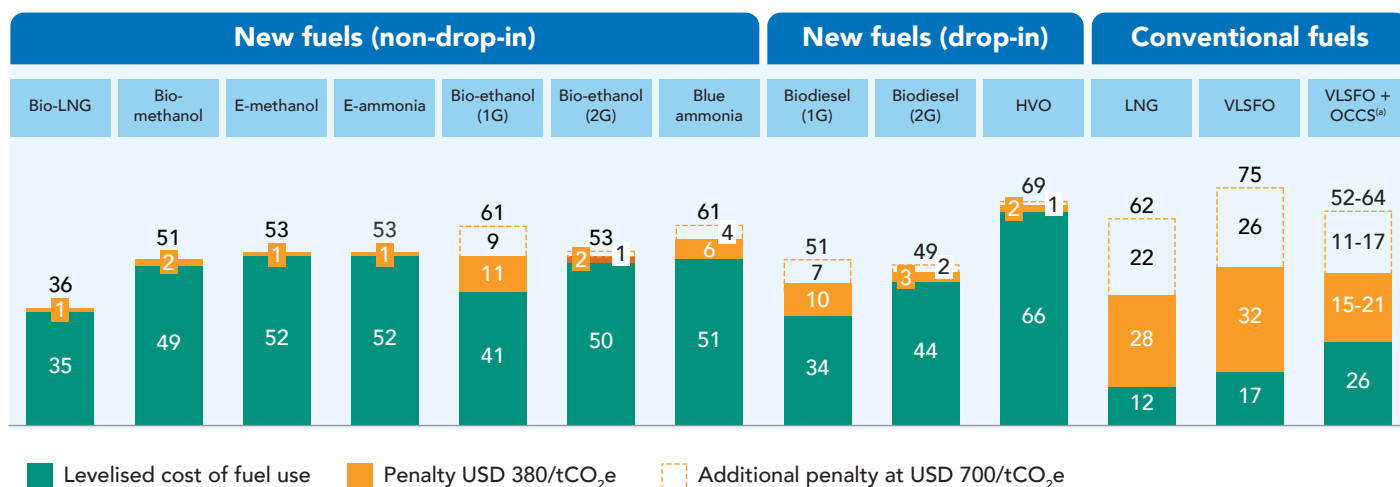
3.1 Outcomes under the base scenario

3.1.1 The current NZF Tier-2 RU penalty narrows, but does not close the cost gap

The penalty level required for new fuels to achieve cost parity with conventional fuels is not fixed. It depends on how the gap in levelised cost of fuel use evolves over time. This gap is the difference in levelised cost of fuel use between a new fuel and its conventional counterpart, before regulatory penalties and rewards are applied. Cost parity is reached when regulatory penalties and rewards are sufficient to offset this underlying cost gap.

Under the base scenario, the temporary ZNZ fuel reward mechanism narrows the cost gap through the 2030s and into the early 2040s, briefly bringing some new fuels close to parity with conventional fuels during the critical early adoption window. However, as these rewards taper beyond the early 2040s, conventional fuels once again become economically attractive (Figure 6).

As highlighted in Figure 5, this scenario considers an LCOH of USD 3/kg H₂ by 2050 and biogenic CO₂ cost of USD 150/t.



Notes:

^(a) OCCS range indicates costs or penalties at a 40-60% gross capture rate

Average across all global data points available

Source: International Energy Agency, International Renewable Energy Agency, Argus, Expert interviews, BCG H₂ model, BCG biofuels model, GCMD and BCG analysis

Figure 6: Levelised cost of fuel use for twelve fuel options along with regulatory penalties, in 2050 (USD/GJ)

3.1.2 The fleet remains dominated by fossil fuels

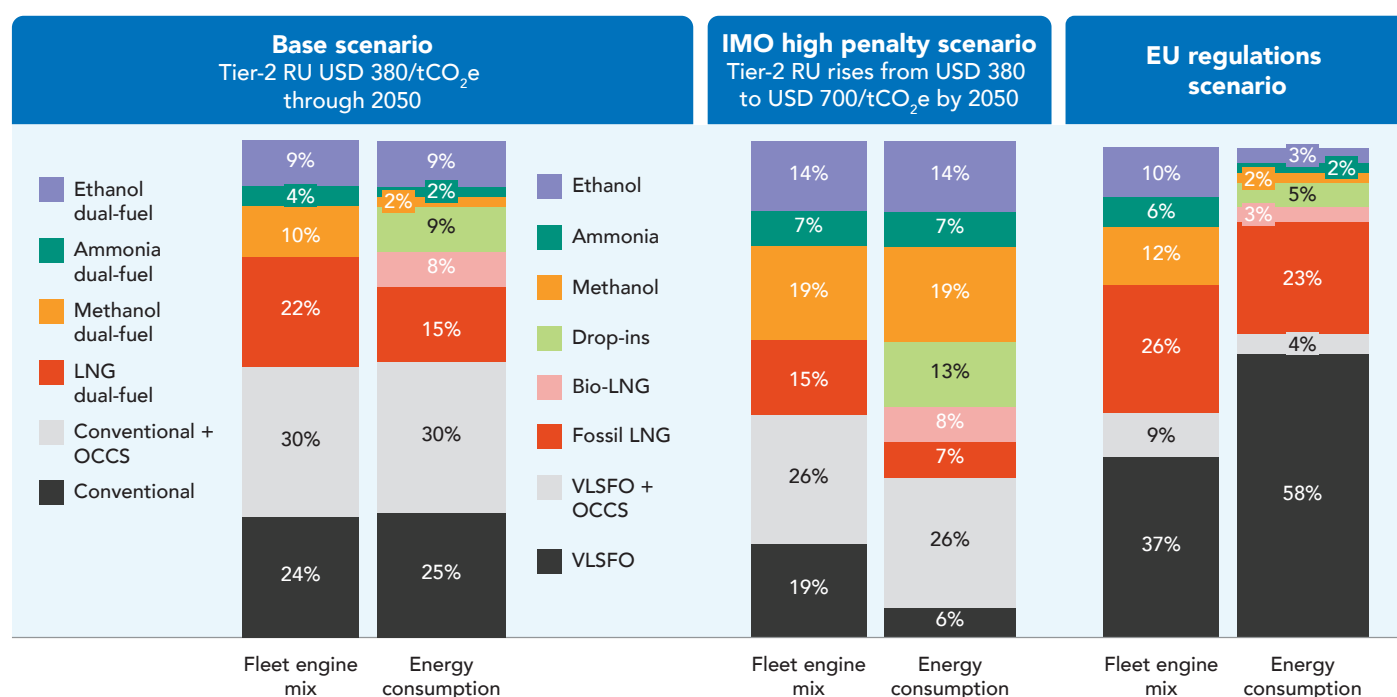
In the base scenario, conventional VLSFO and LNG dual-fuel vessels take up 24% and 22% of the engine mix, respectively, in 2050. OCCS-equipped VLSFO vessels take the largest single share of the engine mix at 30% (Figure 7).

Methanol (10%) and ethanol (9%) dual-fuel engines account for most of the new-fuel capacity in 2050, supported by the early, lower-cost bio-methanol and first-generation bio-ethanol alongside surplus unit (SU) sales and ZNZ rewards.

As these incentives taper towards 2050, paying the regulatory penalty while burning VLSFO remains cheaper than switching fuels in many cases, resulting in low uptake of new fuels. This leads to a gap between global fleet engine capacity and fuel use.

Methanol and ammonia dual-fuel engines reach 14% of fleet energy capacity by 2050. Yet, ammonia only supplies around 2% of total energy consumed by the global fleet in 2050 despite engine capacity of 4%. We see a similar trend with methanol; consumption is 2% despite an engine capacity of 10%. The apparent gap between engine capacity and energy consumption can be explained by the optionality in fuel choice with dual-fuel engines; they effectively allow the decoupling of the engine adoption decision from the fuel-use decision. This decoupling applies in every scenario; a gap between engine capacity and fuel use opens up whenever dual-fuel engines are in service, but the compatible new fuels remain the less economical choice. Section 4.5 examines the consequence of this optionality in detail.

The industry is projected to see the delivery of a wave of ammonia and methanol dual-fuel newbuilds through the 2030s, when ZNZ rewards temporarily improve the economics of new fuels. As these rewards taper off beyond 2040, the same vessels are likely to switch to either VLSFO or introduce drop-in biofuels as needed.



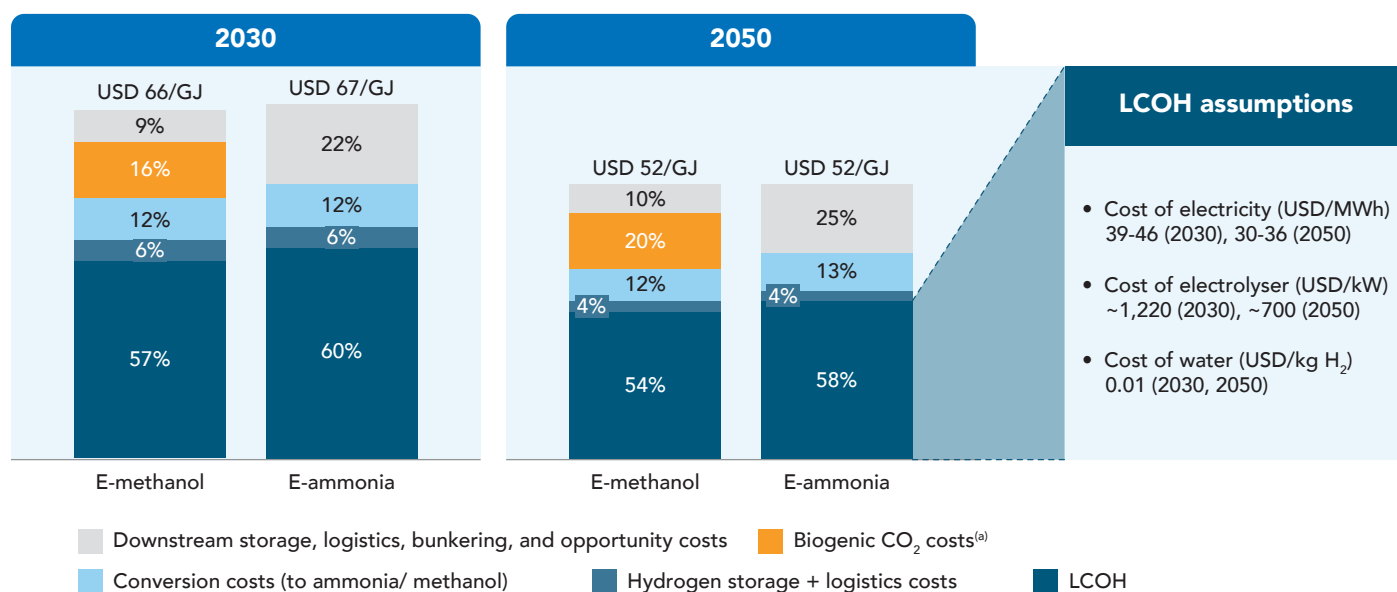
Source: GCMD and BCG analysis

Figure 7: Policy scenario comparison of fleet engine mix and energy consumption in 2050

3.1.3 E-methanol and e-ammonia's levelised cost of fuel use are near parity

Despite e-ammonia's lower production cost compared with e-methanol, the two fuels yield similar levelised cost of fuel use in the base scenario (Figure 8). This is because e-ammonia's production cost advantage is offset by higher downstream costs. These include specialised storage requirements and higher operational costs stemming from its toxicity, such as additional crew training, larger exclusion zones, and more complex bunkering operations. E-ammonia also has higher opportunity costs, including newbuild CAPEX, when levelised, the difference is only around USD 1/GJ relative to e-methanol. By contrast, e-methanol benefits from simpler handling and logistics across the supply chain.

As a result, neither fuel holds a decisive advantage in terms of levelised cost of fuel use under the base scenario. Their relative competitiveness is sensitive to changes in LCOH and biogenic CO₂ costs, which are examined in Sections 4.1 and 4.2. Bio-methanol uptake also plays a role: where low-cost bio-methanol drives early adoption of methanol dual-fuel engines, that installed capacity lowers the barrier for e-methanol to enter the energy consumption mix once its own costs decline, since no new engine technology or crew retraining is required, as discussed further in Section 4.3.

**Notes:**

^(a) USD 150/tCO₂ assumption used for e-methanol

Illustration of cost buckets performed with a simple average across all available data points

Source: GCMD and BCG analysis

Figure 8: Cost breakdown of e-methanol versus e-ammonia

3.2 Outcomes under the IMO high penalty scenario

3.2.1 A higher penalty closes the cost gap and shifts the fleet towards new fuels

In the IMO high penalty scenario, new fuels become economically attractive compared to fossil fuels when the Tier-2 RU penalty rises to USD 700/tCO₂e (Figure 6).

Relative to the base scenario, the fossil-based engine share compresses: the share of conventional engines fall by 5 percentage points (pp), OCCS-equipped conventional engines by 4 pp, and LNG dual-fuel engines by 7 pp. Methanol dual-fuel engine share rises by 9 pp, ethanol dual-fuel by 5 pp, and ammonia dual-fuel by 3 pp (Figure 7).

The growth in methanol dual-fuel engines reflects the cost competitiveness of bio-methanol and the relative maturity of methanol dual-fuel engine technology. The growth in ethanol dual-fuel engines is driven by the lower cost of first-generation bio-ethanol and high fuel supply availability. By contrast, ammonia dual-fuel engine uptake remains small because blue ammonia lacks sufficient cost advantages relative to bio-methanol to drive the adoption of ammonia dual-fuel engines, limiting its near-term share despite strong long-term potential.

In the resulting energy consumption mix, new fuels, including drop-in fuels, account for approximately 61% of energy consumption; VLSFO with OCCS contributes 26%, with fossil fuels (VLSFO and fossil LNG) around 13% (Figure 7).

For both the base case and IMO high penalty scenarios, installing OCCS on conventional-engine vessels can be an economical abatement option. Projections estimate the volume of onboard captured CO₂ to be an order of magnitude smaller than that captured on land (DNV, 2025). The model thus assumes that the investments for infrastructure to accommodate landside carbon capture and storage are borne by other sectors, such as cement, steel, and power generation, and offloaded CO₂ from OCCS activities can leverage the build-out of this infrastructure.

The significance of this finding extends beyond the NZF in its current form. Whether the NZF is adopted as proposed, revised, or replaced by an alternative pricing mechanism, the model highlights the importance of a sufficiently strong carbon price in narrowing the cost gap between new and conventional fuels.

3.3 Outcomes under the EU regulations scenario

3.3.1 Regional regulations alone are insufficient to drive a global fuel transition

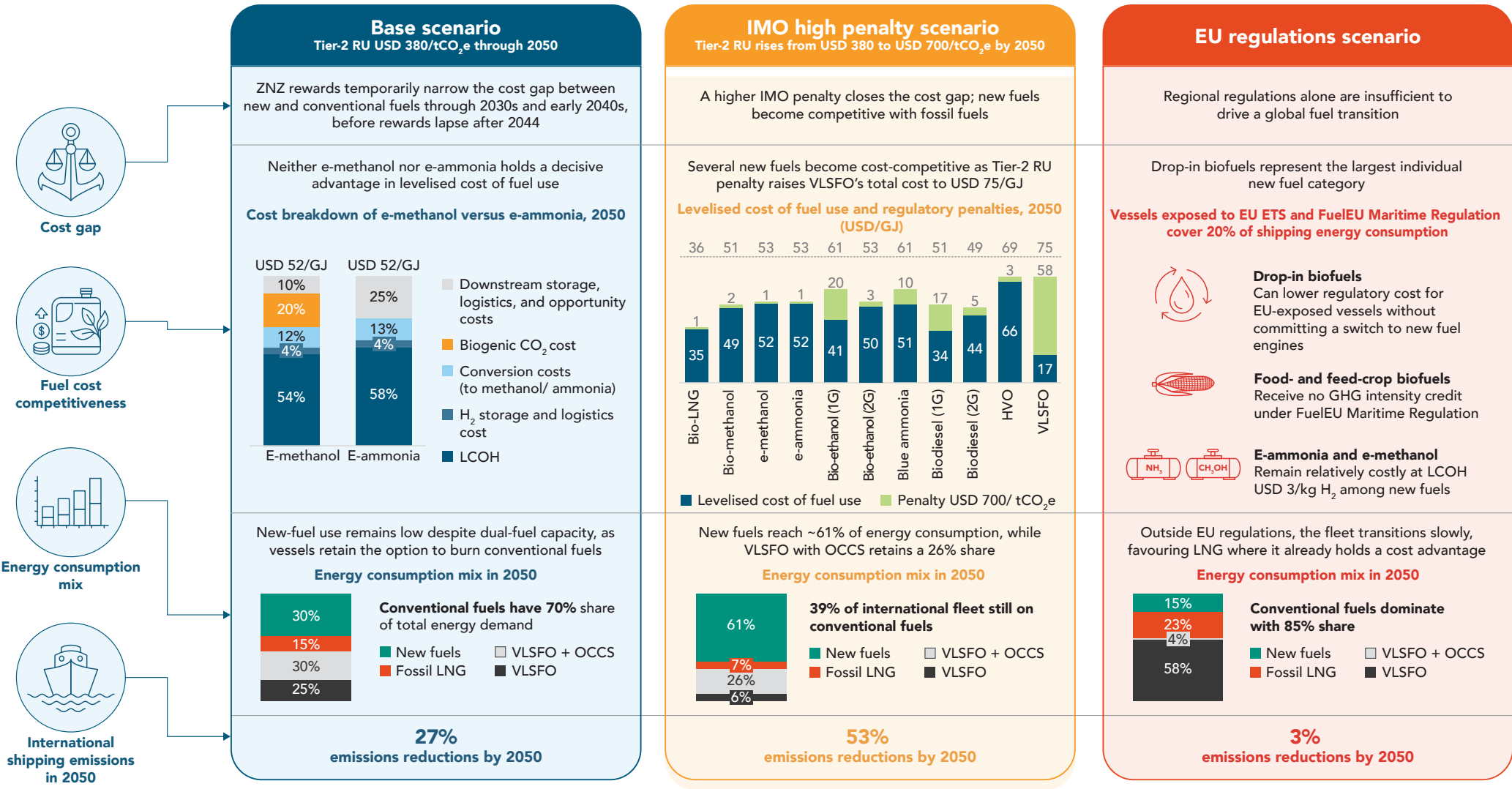
The EU ETS and FuelEU Maritime Regulation cover around 20% of international shipping energy consumption (voyages within, entering, or leaving EU waters).

Within the EU-exposed pool, the increasingly stringent FuelEU Maritime target pushes vessels towards lower-GHG pathways, but no single new fuel dominates. Drop-in biofuels represent the largest individual new-fuel category at around 5% of the energy consumption mix, but methanol and ammonia together contribute a comparable 4%, alongside bio-LNG (3%) and ethanol (3%) (Figure 7). At an LCOH of USD 3/kg H₂, e-methanol and e-ammonia remain relatively costly compared with certain biofuel pathways, thereby limiting their uptake.

At a capture rate of 60% assumed by the model, OCCS is also less favoured in this scenario when penalties are high because the solution does not achieve sufficiently low emissions to comply with increasingly stringent FuelEU Maritime GHG targets.

Outside EU regulations, vessels responsible for the remaining 80% of energy demand transition slowly, favouring LNG where it already holds a cost advantage in certain vessel segments.

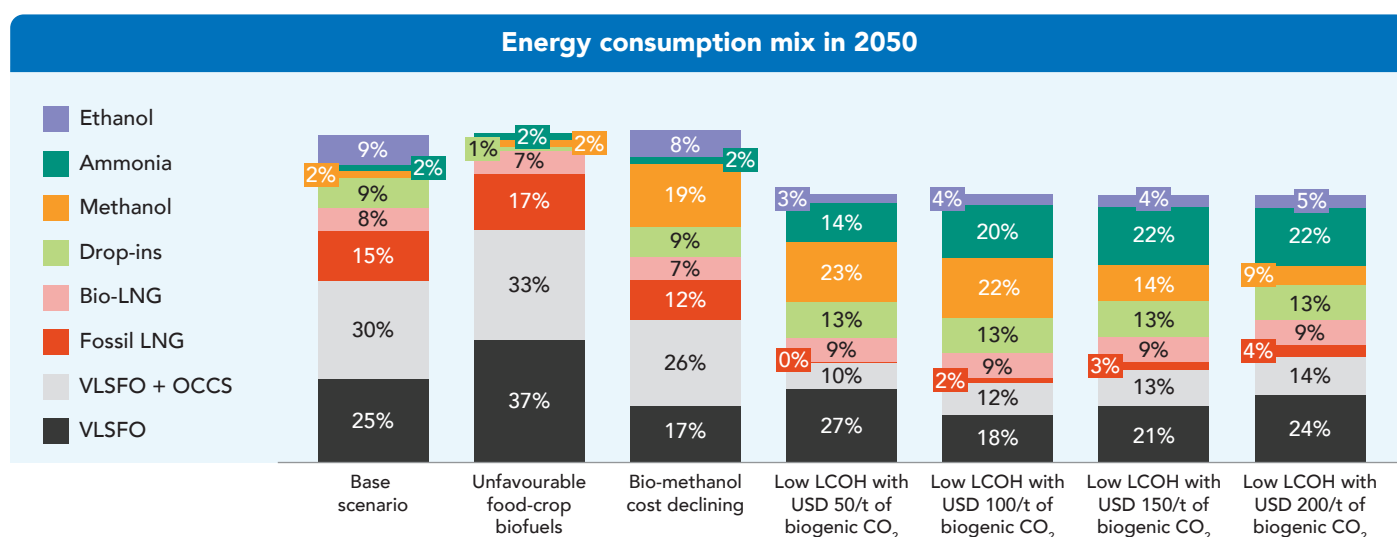
Figure 9 summarises these outcomes across the base, IMO high penalty, and EU regulations-only scenarios.



4. Four key uncertainties that materially shape fuel pathways' competitiveness

This chapter examines four key sensitivities in the base scenario, each providing a signpost for how fuel competitiveness and adoption could evolve. Two relate directly to feedstock inputs and therefore production costs: LCOH, the primary cost driver for all e-fuels; and biogenic CO₂ cost, which influences the relative competitiveness of e-methanol versus e-ammonia. A third, the bio-methanol cost trajectory, governs the near-term affordability of the methanol pathway and could influence technology choices today and potential technology lock-in tomorrow. The fourth, the regulatory treatment of food-crop biofuels, acts as a binary switch for the ethanol pathway.

Together, these sensitivities provide a strong sense of the key drivers that shape new fuels' share of fleet energy by 2050.



Notes:

Total addressable energy demand is lower under the faster global decarbonisation considered for low LCOH (7.1 EJ) than under the base decarbonisation speed (8.6 EJ), primarily reflecting a faster structural decline in seaborne fossil fuel trade—particularly coal and crude oil cargo volumes—as the global energy transition accelerates. All fuel shares are presented as a percentage of each scenario's respective total fleet energy demand.

Source: GCMD and BCG analysis

Figure 10: 2050 energy consumption mix for fuel sensitivities (% of total fleet energy demand)

4.1 Sensitivity 1: A lower LCOH expands e-fuel adoption

For both e-methanol and e-ammonia, the LCOH is the primary cost driver, accounting for 54-60% of the levelised cost of fuel use.

In 2030, levelised cost of fuel use for e-methanol and e-ammonia are estimated at around USD 66-67/GJ, reflecting first-mover risk premiums, early-stage infrastructure requirements, and integration risks, of which production costs make up USD 60/GJ for e-methanol and USD 52/GJ for e-ammonia.

By 2050, as hydrogen production scales and renewable electricity and electrolyser costs decline, production costs for e-methanol and e-ammonia are projected to fall to USD 47/GJ and USD 39/GJ, respectively, bringing levelised cost of fuel use for both fuels down by around 20%, reaching USD 52/GJ. For e-ammonia, this cost reduction also includes lower newbuild CAPEX and declining logistics and bunkering costs as the industry matures through learning and scale.

Given LCOH's dominant contribution to e-fuels' levelised cost of fuel use, the rate at which renewable hydrogen costs decline is a critical determinant of when and how broadly e-fuels become competitive.

The base scenario assumes an LCOH of around USD 3/kg H₂ by 2050. To examine a what-if pathway of lower-cost e-fuel, the model assumes LCOH falls to around USD 2/kg H₂ by 2050, reflecting faster deployment of renewable electricity and steeper reductions in electrolyser costs. This low-LCOH case is paired with a faster global decarbonisation pathway, under which broader electrification and substitution away from fossil fuels reduce seaborne conventional-fuel trade and slow the growth of maritime transport work. Addressable international-shipping energy demand consequently falls to 7.1 EJ by 2050, compared with 8.6 EJ in the base scenario. Biogenic CO₂ at a cost of USD 150/t is considered in this case.

One recent data point is broadly consistent with this sensitivity: in early 2026, e-ammonia for maritime bunkering was reportedly quoted at prices as low as USD 710/t (WinGD and Envision Energy, 2026), implying a near-term hydrogen cost consistent with the low-LCOH trajectory reaching around USD 2/kg by 2050.

Under this pathway, methanol and ammonia together account for 36% of the global fleet's total energy demand by 2050 (Figure 10), representing a 32 pp increase relative to the base scenario which assumes an LCOH of USD 3/kg H₂.

4.2 Sensitivity 2: Biogenic CO₂ costs determine the split between e-methanol and e-ammonia

4.2.1 Biogenic CO₂ adds a distinct cost component to e-methanol

Unlike ammonia, e-methanol requires a sustainable carbon source, making sourcing CO₂ an additional cost driver for its production. Sensitivity 2 assumes e-methanol production relies on biogenic CO₂ rather than on direct air capture (DAC), as DAC-derived CO₂ remains technologically immature and significantly more expensive. Only CO₂ from biogenic sources is considered because sustainable use of carbon-containing e-fuels requires a CO₂ feedstock that can be accounted for as carbon removal; biogenic CO₂ is one of the most straightforward and lowest-cost sources that meet this bar (Maersk Mc-Kinney Møller Center for Zero Carbon Shipping, 2024).

In this study, biogenic CO₂ refers to CO₂ released from the combustion, digestion, fermentation, decomposition, or processing of biologically based material (United States Environmental Protection Agency, 2014). Biogenic CO₂ is a byproduct of several industries, including pulp and paper, bio-ethanol production, biogas refinement, biomass power generation, and waste-to-energy conversion, making it one of the more available renewable carbon sources for e-fuels. Its delivered cost, however, is uncertain: aggregating dispersed point sources, transport and storage add to the underlying capture cost, and demand from sustainable aviation fuel (SAF) mandates and power-to-liquid pathways could further add pressure as those pathways scale.

Under the base scenario assumption of USD 150/tCO₂, biogenic CO₂ contributes approximately 16–20% of e-methanol's levelised cost of fuel use over 2030-2050 (Figure 8).

To assess the impact of biogenic CO₂ cost on the uptake of e-methanol, we varied it from USD 50/tCO₂ to USD 200/tCO₂. These pathways simulate a range of situations, from low-cost co-located supply on the one end to a constrained market in which aggregation costs of biogenic CO₂ and cross-sector demand raise delivered costs on the other end.

4.2.2 Impact of biogenic CO₂ costs on cost comparison between e-fuels

Production costs are largely driven by feedstock costs: for e-ammonia, this is LCOH alone; for e-methanol, it is both LCOH and the cost of biogenic CO₂. The relative competitiveness of the two fuels therefore depends on this combination.

Under the base scenario in which we assumed an LCOH of USD 3/kg H₂ in 2050, e-methanol has a lower levelised cost of fuel use than e-ammonia when biogenic CO₂ costs are below USD 150/t. However, if LCOH drops to USD 2/kg H₂, e-methanol has a lower levelised cost of fuel use than e-ammonia when biogenic CO₂ is USD 50/tCO₂.

Accordingly, if biogenic CO₂ costs rise higher than USD 50/t, their share of e-methanol's

levelised cost of fuel use increases from approximately 8–10% to 25–31% (Figure 11), with the higher percentage in each range corresponding to LCOH USD 2/kg H₂, as lower hydrogen costs increase the relative contribution of biogenic CO₂ cost to the levelised cost of fuel use.

Biogenic CO₂ costs are therefore an important determinant of the relative levelised cost of fuel use of e-methanol and e-ammonia, and should be closely monitored.

4.2.3 Impact of biogenic CO₂ costs on fuel uptake

The shift in relative levelised cost of fuel use for e-methanol and e-ammonia translates directly into fuel adoption outcomes.

At a biogenic CO₂ cost of USD 50/t, methanol accounts for 23% of total energy consumption mix, ahead of ammonia at 14%; at USD 100/t, methanol falls to 22% while ammonia rises to 20% (Figure 10).

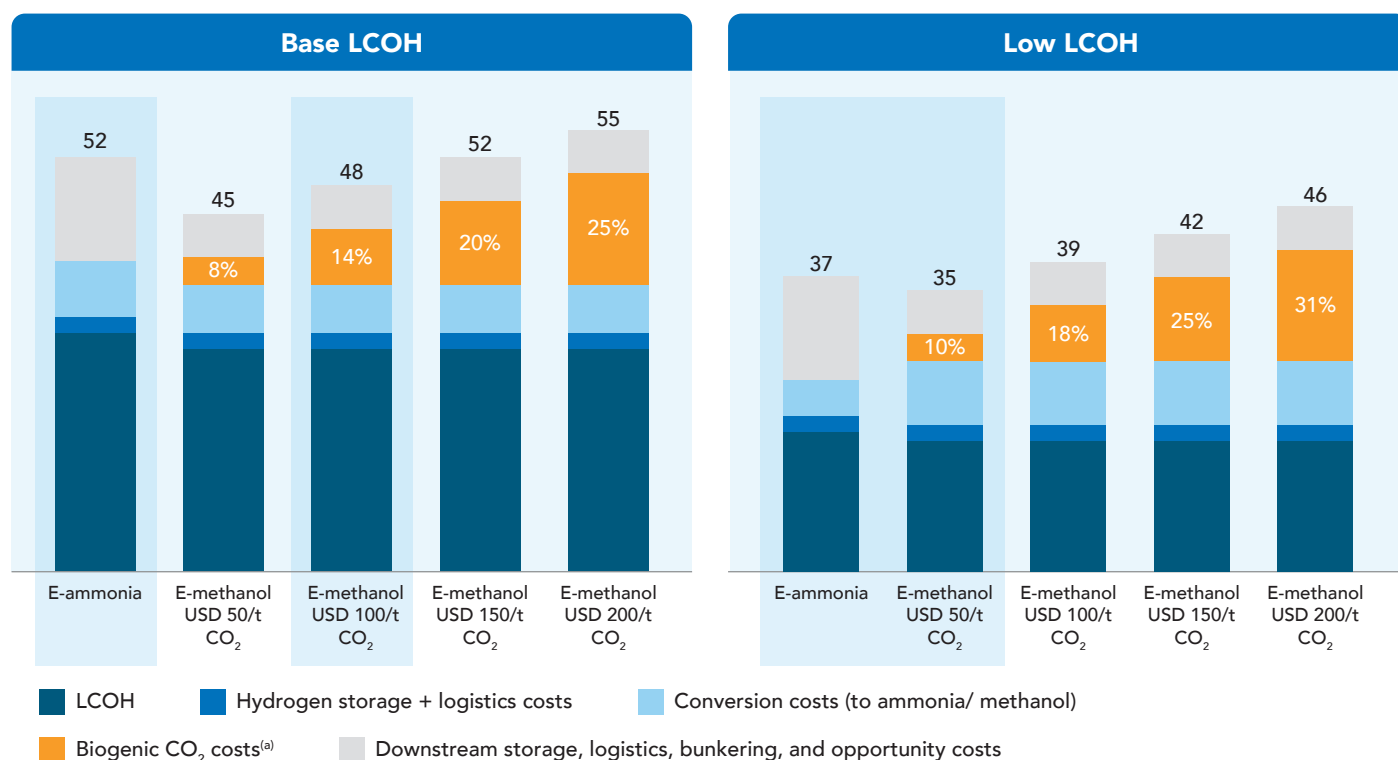
At higher biogenic CO₂ costs, new fuels uptake shifts towards ammonia. With biogenic CO₂ at USD 150/t, ammonia's share of uptake supersedes that of methanol, accounting for 22% of global energy consumption versus 14% for methanol in 2050.

At USD 200/tCO₂, methanol's share of global energy consumption falls to 9%, as e-methanol loses its cost competitiveness not only against e-ammonia but also against other fuels.

Taken together, while LCOH is the primary lever that determines whether e-fuels can achieve mainstream adoption, biogenic CO₂ cost is the key variable that determines the split between e-methanol and e-ammonia consumption in 2050. At the highest point of demand in this range—USD 50/tCO₂—the biogenic CO₂ required for e-methanol is approximately 112 million tonnes per year, representing 30–35% of point-source supply estimated as suitable for e-fuel production (Maersk Mc-Kinney Møller Center for Zero Carbon Shipping, 2024).

As such, the practical constraints are access, aggregation, transport, certification and cross-sector competition. These enter the model not as a supply limit but as the delivered cost of biogenic CO₂.

Methanol's overall adoption, however, is also influenced by a separate and independent variable: the cost trajectory of bio-methanol. Because bio- and e-methanol can use the same engines, early uptake of bio-methanol could create technological lock-in, biasing future fuel demand towards e-methanol as the lower-carbon drop-in successor down the road.



Notes:

^(a) USD 150/tCO₂ assumption used in the base scenario, other CO₂ costs tested between USD 50/t to USD 200/t

Illustration of cost buckets performed with a simple average across all available data points

Source: GCMD and BCG analysis

Figure 11: Sensitivity of the levelised cost of fuel use comparison to biogenic CO₂ cost (USD/GJ)

4.3 Sensitivity 3: Bio-methanol cost trajectory determines whether the methanol pathway scales

Bio-methanol is unique among the fuel pathways because its uptake has an outsized effect on the longer-term adoption of methanol: it provides a lower-carbon fuel in the near term while driving investment in methanol dual-fuel engines that can later transition to lower-carbon e-methanol without requiring a change in onboard hardware.

Two bio-methanol production cost trajectories were modelled: a constant-cost trajectory and a declining-cost trajectory for gasification-based bio-methanol.

4.3.1 Constant bio-methanol costs limit methanol uptake

In the base scenario, bio-methanol production costs are held constant at USD 43/GJ (USD 850/t) through 2050, reflecting a pathway in which potential savings from scaling-up are offset by feedstock and supply-chain constraints. Feedstock alone accounts for up to 50% of total bio-methanol production costs (International Renewable Energy Agency and Methanol Institute, 2021), and as production scales, supply chain costs can also increase as demand mandates aggregation and transport of distributed biomass and/ or waste streams over wider catchment areas.

Under this trajectory, methanol accounts for approximately 2% of total fleet energy demand, despite methanol dual-fuel engines representing around 10% of the fleet's installed engine capacity (Figure 7). This gap arises because both bio-methanol and e-methanol cost more than fossil fuels, even with penalties, which in turn leads dual-fuel vessels to consume conventional fuels despite having the capability to consume methanol.

4.3.2 Declining bio-methanol costs unlock methanol as a bridge fuel, lifting uptake from 2% to 19%

As a counterpoint, the model tested a declining bio-methanol cost option in which its production costs decline from USD 43/GJ (USD 850/t) in 2025 to USD 33/GJ (USD 650/t) by 2050. This assumes that gasification costs, which are largely CAPEX-driven, would decline along a learning-curve dynamic as plants reach commercial scale. It also assumes that gasification feedstock faces limited competition from other uses. This is plausible because key alternative pathways today, including converting these feedstocks to SAF or biomass power—are not yet commercially mature (International Renewable Energy Agency and Methanol Institute, 2021). No equivalent SAF-style policy mandate redirects bio-methanol's feedstock away from shipping today (Rystad, 2026).

In this declining cost trajectory, methanol consumption increases from 2% to 19% of total fleet energy demand in 2050 (Figure 10). This cost reduction nearly doubles the share of methanol dual-fuel engines in the fleet before 2035, stimulating orderbook commitments ahead of e-methanol becoming cost-competitive. Low-cost bio-methanol thus serves as a bridge to e-methanol and encourages dual-fuel engine adoption. As production costs decline over time, e-methanol faces a lower barrier in entering the energy consumption mix given engine technology and crew competence lock-ins.

The 17 pp difference between the two cost trajectories hinges on two signposts: whether bio-methanol gasification can reach commercial scale sufficiently quickly to drive cost reductions, and whether competing end-uses, particularly SAF and biomass power, mature sufficiently to begin competing for the same feedstock.

However, these signposts relate primarily to the timing and cost of scalable bio-methanol supply rather than to its availability. The next question is therefore whether the level of bio-methanol implied by the 2050 energy consumption mix is plausible from an aggregated supply perspective.

4.3.3 Aggregated methanol feedstock availability

At the levels of uptake implied by a declining bio-methanol production cost, the availability of bio-methanol does not appear to be the binding constraint. The required 70 million tonnes per year of bio-methanol is well below the 135 million tonnes per year that is projected to be available in 2050 by the International Renewable Energy Agency and the Methanol Institute (2021).

4.4 Sensitivity 4: Regulatory recognition is the critical swing variable for the ethanol pathway

In the base scenario, ethanol accounts for approximately 9% of energy consumption in 2050 (Figure 10), supported by the cost competitiveness and availability of first-generation bio-ethanol and its neutral treatment under the IMO NZF.

However, this outcome is highly sensitive to the regulatory classification of ethanol. Under the FuelEU Maritime Regulation, biofuels produced from food and feed crops are assigned the emission factor of the least-favourable fossil-fuel pathway for that fuel type, regardless of their actual lifecycle emissions. This stipulation is accounted for in the model's EU regulations scenario, under which ethanol only makes up 3% of total energy consumption in 2050 (Figure 7), supplied entirely by more costly second-generation bio-ethanol. The model assumes that first-generation bio-ethanol and first-generation biodiesel are produced from food-crop feedstocks.

The model finds that this impact extends across both the ethanol and drop-in fuel pathways. In both cases, the model projects negligible uptake of ethanol and drop-in biofuels: uptake of both falls from 9% each, under neutral treatment of food-crop-based fuels, to negligible levels once these fuels instead receive unfavourable treatment. This is because removing cost-competitive first-generation biodiesel and bio-ethanol leaves only higher-cost second-generation biodiesel, bio-ethanol, and HVO, the consumption of which no longer closes the cost gap compared to conventional fuels. The effect compounds over time: without the early cost advantage of first-generation fuels, ethanol never gains the orderbook share needed to scale (Section 4.5).

The displaced demand is absorbed by VLSFO (+12 pp), OCCS (+3 pp), and fossil LNG (+2 pp) (Figure 10). There is no meaningful spillover benefit to other new fuels, as long as the cost gaps of new fuels remain high.

Ethanol's role in the future maritime energy consumption mix is therefore essentially binary and largely determined by regulatory specification. The treatment of food-crop-based biofuels in regulatory frameworks remains a key signpost to track for ethanol.

4.5 Early cost competitiveness determines which engines enter the orderbook

As examined, changes in LCOH, biogenic CO₂ costs, bio-methanol cost trajectories, and regulatory treatment can materially shift the competitiveness of new fuels (Figure 12). But fuel economics alone do not determine how much of a fuel is actually consumed. Adoption depends on a prior condition: whether sufficient engine capacity compatible with that fuel has already been built into the fleet.

Two distinct factors therefore shape the energy consumption mix in any given year. The first is the total engine capacity of ships compatible with each fuel type, determined by newbuild decisions made over the preceding 20–25 years. This defines the upper bound of potential consumption of each fuel type. The second is fuel economics, including regulatory costs and incentives, which determine which fuels are used and in what proportion. Dual-fuel vessels have the option to switch to the cheaper fuel in any given year.

Successfully scaling the adoption of any new fuel must therefore clear two hurdles. There must first be sufficient engine capacity through newbuild orders. The fuel must then be cost-competitive, year after year, once the vessels are in service. In the base scenario, for example, around 10% of the fleet has methanol dual-fuel engine capacity. Yet, methanol accounts for only 2% of actual energy consumption, because conventional fuel remains the more economical option in 2050, even with a USD 380/tCO₂e penalty (Figure 7).

4.5.1 Near-term affordability shapes the future fleet

Our model also highlights that a fuel's current cost is at least as consequential as its 2050 endpoint, as near-term fuel affordability shapes shipowner decisions on which engine types to order now. This establishes the consumption base and infrastructure that enable further cost reductions over time. The economic life of vessels is about 25–30 years, and around 4% of the fleet is renewed annually. Also, considering the lead time for delivery, more than half of the vessels operating in 2050 will come from orders placed before 2035. Therefore, fuels that remain expensive through the 2030s risk missing this critical orderbook window, even if their long-run economics are favourable.

The bio-methanol case in Section 4.3 shows the window's leverage. A declining cost of bio-methanol can nearly double the share of methanol dual-fuel engines in the fleet by 2035, compared to the base scenario, stimulating orderbook commitments ahead of e-methanol becoming cost-competitive. In this specific example, early cost levels would stimulate engine adoption, while the long-run economics of e-methanol would only impact consumption once the engines are adopted.

Because dual-fuel vessels can switch between the compatible new fuel, VLSFO, and drop-in as market prices evolve, owning a dual-fuel fleet offers strategic optionality. The same optionality cuts both ways: it lowers the risk of ordering a new-fuel engine, but it also means engine orders alone do not guarantee fuel uptake. The orderbook, however, is decided early. The absolute cost of new fuels today drives near-term newbuild engine decisions, while the rate at which individual fuel cost curves decline determines when dual-fuel vessels start consuming new fuels.

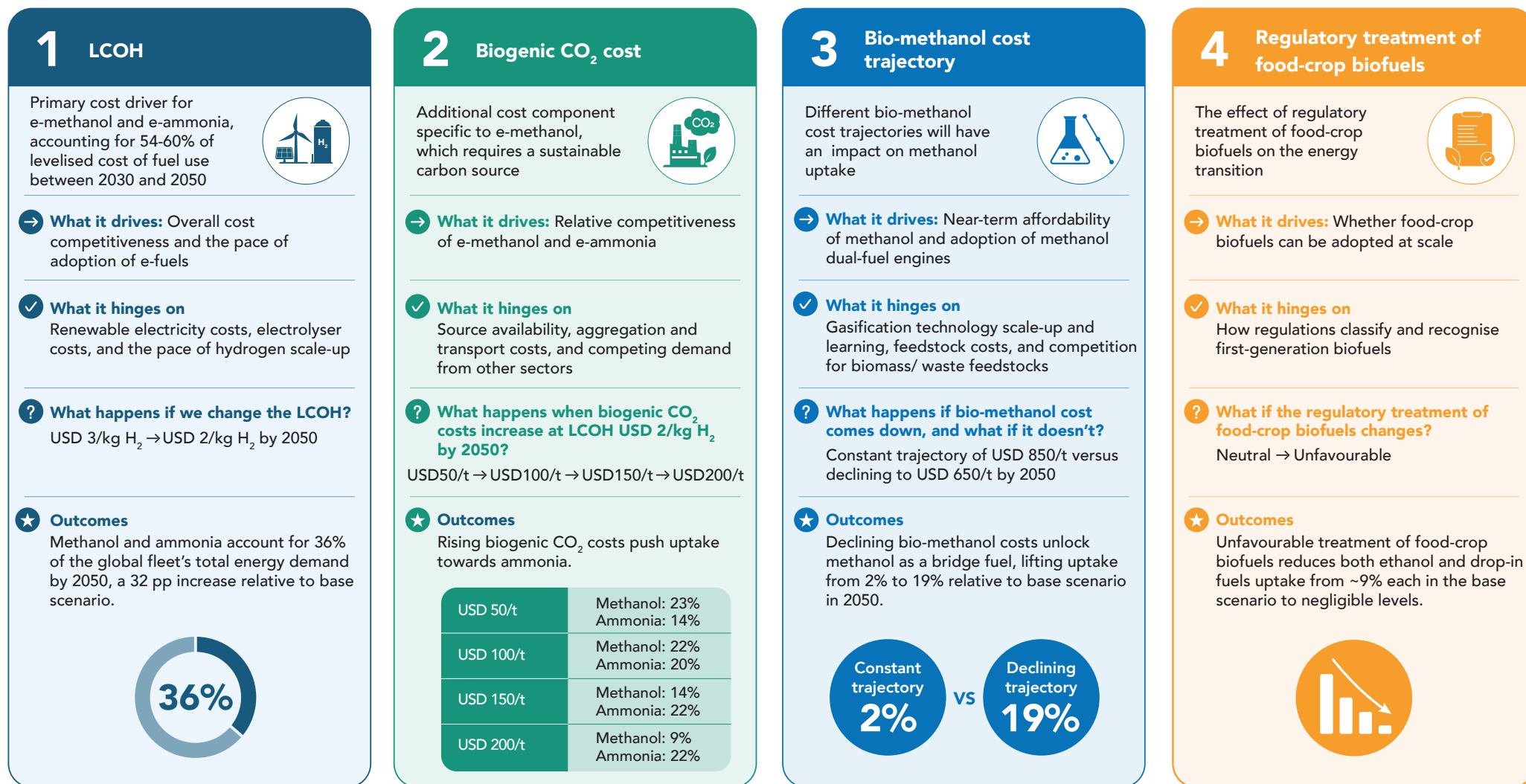


Figure 12: Four key uncertainties shaping fuel pathways' competitiveness

5. How the bunkering landscape could evolve

Liquid fuels, such as methanol and ethanol, are relatively straightforward to transport, store and bunker. As a result, their availability at ports is less dependent on proximity to production. Their adoption by shipowners is unlikely to significantly alter the competitive positioning of established bunkering hubs. By contrast, ammonia's storage and handling requirements as a refrigerated and toxic fuel introduce additional logistical complexity. Its use as a marine fuel could thus give rise to two distinct port archetypes offering ammonia bunker: production-linked hubs that compete on fuel cost, and import-aggregation hubs that compete on demand aggregation.

5.1 The current bunkering landscape and why it may change

5.1.1 Fuel economics, vessel traffic, and policy are likely to shape future bunkering hubs

Traditionally, bunkering activity has been concentrated in regions that combine dense vessel traffic with competitive fuel supply. For example, Singapore benefits from the large volume of vessels passing through the Strait of Malacca and access to competitively priced fuel oil. The Amsterdam-Rotterdam-Antwerp (ARA) region similarly combines access to low-cost fuel supply with significant container and bulk operations. These dynamics—traffic density and supply competitiveness—have historically determined which ports capture bunkering demand.

Our analysis suggests that favourable fuel economics and strong vessel traffic are two factors that can increase a port's likelihood of emerging as a future new-fuel bunkering hub. The presence of either can potentially improve a port's prospects for developing into a bunkering hub.

Fuel economics: the ability to source price-competitive new fuels at scale, whether through co-located domestic production, advantaged imports, or aggregated supply from nearby production centres.

Vessel traffic: the ability to convert existing port calls, conventional bunkering demand, or predictable route-based traffic into demand for new fuels.

Policy on its own is not a third determining factor. Strong fuel transition policies, however, can help reinforce a port's positioning as a bunkering hub provided that it already meets one of

the two factors above. Supply-creation policies, such as hydrogen hub strategies, can improve fuel availability and costs. Demand-creation policies, such as ammonia co-firing, can anchor early offtake and support bulk procurement. Enabling policies, including safety, handling, and bunkering standards, reduce operational risk and facilitate infrastructure build-out. This is particularly important for new fuels, where suppliers and shipowners will need regulatory certainty, safe operations, and reliable infrastructure before committing to a fuel switch.

5.1.2 Net voyage economics play a central role in bunkering decisions

Bunkering decisions are fundamentally route- and operations-led. Ships typically bunker at mandatory cargo call ports. While lower fuel prices can attract demand, deviation to a cheaper bunkering port is assessed based on net voyage economics, including fuel price savings, additional fuel burned, waiting time, voyage disruption, and off-hire exposure. For liner services or those trading from point-to-point on voyage or time charters, these costs can also include missed berth windows, disrupted feeder connections, and downstream network impacts. In other words, fuel availability alone may be insufficient; reliability, safety, and operational efficiency are also likely to influence bunkering decisions.

5.1.3 Incumbent hubs have an advantage, but new entrants can still compete

Existing large bunkering hubs may be well-positioned to leverage their high traffic density, established storage and trading ecosystems, regulatory capabilities, and supplier networks to expand their new-fuel offerings. However, ports may still compete as a new bunkering hub if they offer clear advantages in fuel cost or captive demand.

Production-linked ports with access to low-cost fuel may attract incremental bunker calls if the price advantage is large enough. Conversely, high-traffic ports without low-cost domestic fuel production may still become viable hubs if they can import new fuels at scale, aggregate demand across sectors, and offer reliable bunkering to vessels already calling at the ports.

5.1.4 Liner networks are well suited for early adoption of methanol and ammonia

Vessels on predictable and fixed schedules may be better positioned to anchor initial bunkering demand for new fuels: repeated port calls enable long-term fuel offtake agreements and provide the demand certainty needed to justify new infrastructure investments. Since ships typically bunker at ports where they already have a mandatory call, liner networks are particularly well-suited to the early adoption of non-drop-in fuels, such as methanol and ammonia. In contrast, tramp bulkers, tankers and general cargo vessels operate on less predictable routes, making it more difficult for them to commit to fixed bunkering locations or long-term fuel offtake contracts. Some bulk carriers operate on a fixed route, such as those on the iron ore corridor between China and Australia, and may therefore support targeted adoption. However, the

broader segment is less likely to provide the anchor demand needed for early infrastructure build-out.

5.2 Methanol and ethanol may reinforce existing bunkering hubs

For liquid new fuels, such as methanol and ethanol, existing bunkering patterns are more likely to persist. Liquid fuels are relatively straightforward to transport, meaning import-led bunkering models remain viable. These fuels may be produced in cost-advantaged regions and then moved to demand centres, allowing existing bunkering hubs to remain relevant even where local production is not the most competitive.

Asia is expected to produce the lowest-cost bio-methanol; the US holds a structural cost advantage in bio-ethanol supply; and China is emerging as a leader in e-methanol production.

5.3 Ammonia could reshape the bunkering landscape

Ammonia has greater potential to reshape the bunkering landscape, as high logistics costs associated with shipping a refrigerated and toxic fuel are expected to restrict the radius of potential ammonia sourcing and lead to more regionalised ammonia bunkering activities. As such, ammonia bunkering is expected to be more dependent on either proximity to low-cost production or the ability to aggregate large-scale demand.

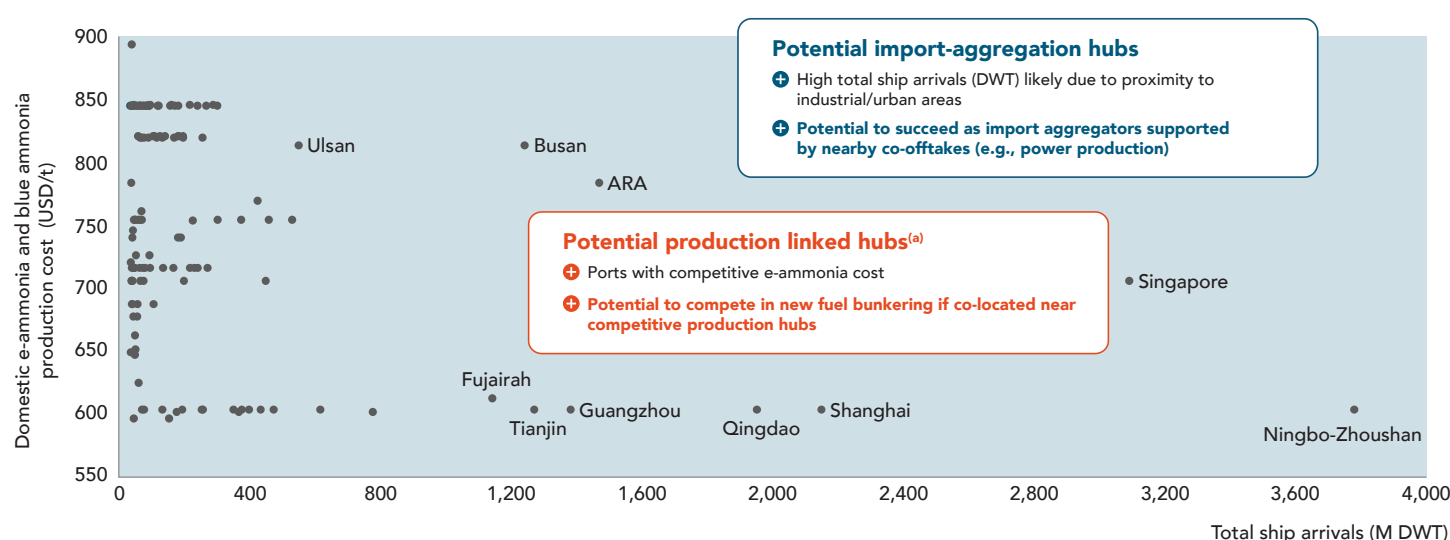
As shown in Figure 13, the analysis points to two distinct port archetypes when domestic ammonia production costs are plotted against total vessel arrivals (measured in deadweight tonnage).

5.3.1 Production-linked hubs

Existing and emerging production-linked exporters, such as those in China and India, can offer a lower-cost supply and potentially leverage their export infrastructure build-out to support bunkering at a lower incremental cost compared to ports developing infrastructure purely for bunkering. However, low-cost production alone does not guarantee bunkering demand. These ports would still have to sit on relevant trade routes, so that vessels do not incur significant deviations that could nullify their cost advantage, and demonstrate credible safety and bunkering operations. The commercial challenge for such emerging ports with ambitions for ammonia bunkering would depend on their ability to convert fuel-cost advantage into route-relevant demand.

5.3.2 Import-aggregation hubs

These are ports with significant vessel traffic and strong infrastructure capability, but without access to low domestic ammonia production costs (Figure 13). Their competitive advantage for becoming an ammonia bunkering hub lies in demand aggregation rather than fuel production. By combining maritime demand with demand from adjacent industrial or power sectors, such as ammonia co-firing or industrial fuel switching, these ports may be able to procure ammonia at scale, justify investments into the construction of import terminals, secure long-term offtake, and reduce delivered bunkering costs.



Notes:

^(a) For production hubs, the lowest cost of production is used for plants with a commercial operation date by 2035, and a 15% decline in costs due to scale/ learning effects by 2050 is assumed

Domestic e-ammonia and blue ammonia production cost (min, USD/t, 2050): The lower between e-ammonia and blue ammonia production cost in 2050 applied for ports based on countries where costs are available; For ports where country-specific data is unavailable, the closest proxy is used

Total ship arrivals (M DWT, 2023): Latest data available from 2023; For Busan, Ulsan, and Chinese ports, ship arrivals (DWT) was unavailable and estimated by taking the ratio between the specified port and other key port's total cargo throughput x ship arrivals (DWT).

Unlabelled dots indicate additional ports covered by the analysis, shown to illustrate its scope; the chart is not a comprehensive listing of all ports assessed.

Source: GlobalData, BCG H₂ model, Expert interviews, Institute of Shipping Economics and Logistics, GCMD and BCG analysis

Figure 13: Domestic e-ammonia and blue ammonia production cost vs total ship arrivals

6. Conclusions: Implications and key signposts to watch

Independent of policy scenarios, our model shows that no single fuel will dominate, and no single port will capture the transition alone. The structural forces shaping which fuel vessels bunker and where in 2050 are already emerging today. Four key signposts merit monitoring: policy developments at the IMO, bio-methanol cost trajectory, hydrogen and biogenic CO₂ costs, and the regulatory treatment of food-crop biofuels.

The study's key findings carry concrete and differentiated implications across the ecosystem:

6.1 Build fleet strategy around optionality, not a single fuel commitment

Shipowners and operators should build their fleet strategy around optionality, not early commitment to a single fuel pathway. No scenario in this analysis produces a single dominant fuel by 2050. Instead, the future fuel landscape remains fragmented across all fuel types and in bunkering locations. Shipowners that lock into a single fuel pathway today risk assets stranded by regulatory or cost outcomes. Dual-fuel optionality helps manage future regulatory risks, preserving the ability to switch between compatible new fuels and conventional fuels as economics shift.

At penalty levels of USD 380/tCO₂e, vessels consuming VLSFO equipped with OCCS remain cost-competitive, but should penalties escalate towards USD 700/tCO₂e, dual-fuel vessels are better positioned to pivot towards new fuels as the economics invert.

6.2 Regional fuel economics should inform engine choice

For vessels deployed on fixed routes or under long-term charter, route-specific bunkering availability should be factored into engine selection when ordering vessels, rather than treated as an operational consideration to be resolved post-delivery. This is because structural regional differences drive the economics of new fuel supply.

Bio-methanol supply will be the cheapest along global sea lanes, with Asia being the most cost-competitive. Ammonia bunkering is likely to favour Asia sea lanes, anchored by lower-cost e-ammonia production in China and India. Bio-ethanol will be predominantly sourced from the United States, where production costs are at least 10–15% lower than in other regions. Therefore, a vessel ordered today for trans-Pacific routes faces a materially different

future bunkering landscape than one deployed on Atlantic corridors—and that differentiation should inform engine configuration decisions now, while the orderbook window is still open.

6.3 Cross-sector synergies can de-risk bunkering infrastructure investments

Ports need to assess their competitive advantages in light of the evolving bunkering landscape, covering both new fuel demand and supply. Synergies with other sectors could potentially help de-risk bunkering infrastructure investments. For example, carbon offloading infrastructure could serve both OCCS and land-based carbon capture and storage demand from other industries. Similarly, aggregating low-carbon ammonia demand for adjacent sectors could help reduce ammonia sourcing and storage costs.

6.4 Infrastructure investment priority hinges on which penalty trajectory materialises

Investment cases for new fuel infrastructure are highly sensitive to the regulatory outcome and penalty level trajectory.

Under the base scenario (Tier-2 RU penalty of USD 380/tCO₂e), the most capital-efficient pathway remains OCCS on VLSFO vessels and LNG newbuilds, suggesting that new fuel infrastructure investment ahead of this penalty threshold risks being premature.

Under the IMO high penalty scenario, the economics invert: new fuels capture approximately 61% of fleet energy consumption, making methanol, ammonia, and ethanol bunkering infrastructure the more relevant investments. Given that the final penalty outcome remains unresolved, investment cases should be explicitly structured across both scenarios rather than underwritten on a single regulatory assumption.

Within the new fuels space, two technology cost trajectories should be closely monitored as they exert direct influence on which fuel infrastructure warrants priority investment.

First, the maturation of the bio-methanol production pathway, since the scale-up of biomass gasification has the greatest effect on methanol infrastructure bankability, where methanol's share of fleet energy increases from 2% to 19% in 2050 (Figure 10).

Second, LCOH trajectory (including the costs of renewable electricity and electrolyzers) and biogenic CO₂ costs, which jointly determine the relative priority between e-methanol and e-ammonia infrastructure.

6.5 A global pricing mechanism remains the most powerful lever available to policymakers

The maritime energy transition will be significantly accelerated by a global carbon pricing mechanism, provided that the carbon price is sufficiently high to close the cost gap between new and conventional fuels. While regional policies serve as valuable market-creation instruments and demand signals, they are unlikely to substitute for a functioning global carbon pricing mechanism. Given the importance of cost gaps and the rate at which they close, fiscal policies could be beneficial. For example, potential ZNZ reward mechanisms would incentivise new fuel adoption in the early years. Governments could also consider introducing policies to stimulate innovation and the scaling of new-fuel production technologies, reducing production costs and increasing their supply competitiveness.

References

DNV. (2025). Energy Transition Outlook: CCS to 2050. <https://www.dnv.com/energy-transition-outlook/carbon-capture-storage/>. Accessed on 20 August 2026.

Engine. (2026). Maersk completes 100% ethanol trials. <https://www.engine.online/news/maersk-completes-100-pc-ethanol-trials-7bba>. Accessed 25 July 2026.

European Commission. (2026). Reducing emissions from the shipping sector. https://climate.ec.europa.eu/eu-action/transport-decarbonisation/reducing-emissions-shipping-sector_en. Accessed 25 July 2026.

IMO. (2023). Reduction of GHG emissions from ships: Report on the study on the readiness and availability of low- and zero-carbon ship technology and marine fuels (MEPC 80/INF.10). <https://wwwcdn.imo.org/localresources/en/MediaCentre/WhatsNew/Documents/MEPC80.INF10.pdf>

International Renewable Energy Agency and Methanol Institute. (2021). Innovation Outlook: Renewable Methanol. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jan/IRENA_Innovation_Renewable_Methanol_2021.pdf. Accessed on 15 March 2026.

Maersk Mc-Kinney Møller Center for Zero Carbon Shipping. (2024). Global Availability of Biogenic Carbon Dioxide and Implications for Maritime Decarbonization. [https://www.zerocarbonshipping.com/publications/global-availability-of-biogenic-co₂-and-implications-for-maritime-decarbonization](https://www.zerocarbonshipping.com/publications/global-availability-of-biogenic-co2-and-implications-for-maritime-decarbonization). Accessed on 14 May 2026.

Rystad Energy. (2026). Clean Fuels in Transportation: Maritime, aviation, and road transport. New Energies Whitepaper. <https://pages.rystadenergy.com/Whitepaper-New-Energies-Clean-Fuels-Whitepaper-May-2026>. Accessed on 31 May 2026.

United States Environmental Protection Agency. (2014). Framework for Assessing Biogenic CO₂ Emissions from Stationary Sources. Office of Air and Radiation. [https://19january2017snapshot.epa.gov/sites/production/files/2016-08/documents/framework-for-assessing-biogenic-co₂-emissions.pdf](https://19january2017snapshot.epa.gov/sites/production/files/2016-08/documents/framework-for-assessing-biogenic-co2-emissions.pdf). Accessed on 19 August 2026.

WinGD and Envision Energy. (2026). WinGD-Envision Energy Renewable Fuel Economics Report. <https://wingd.com/news-media/brochures-papers/f23dp2re/wingd-envision-energy-renewable-fuel-economics-report.pdf>. Accessed on 20 March 2026.

Acknowledgements

Authors, GCMD

Dr Bhushan TASKAR, Director, Projects
Wee Meng TAN, Chief Projects Officer
Prof Lynn LOO, Chief Executive Officer

Authors, BCG

Anand VEERARAGHAVAN, Managing Director & Senior Partner
Christian XIA, Project Leader
Ronnie LYE, Consultant, Singapore
Angeline NEO, Senior Associate, Singapore

Editor

Xingt LIU, Director, Communications, GCMD

Report design

Image Diplomacy

The authors would also like to thank the following individuals for their assistance during the project: Rex LEE, Eng Kiong KOH, Shane BALANI, Prapisala THEPSITHAR, Christine KOK, Claudia TAN, Simin TAI, Wei Jie LAU, Grace LIAN, and Shi Xian SIM.

Citation: To cite this report, please use Global Centre for Maritime Decarbonisation-Boston Consulting Group (2026), "Navigating the maritime fuel transition: How fuel economics, regulations, and fleet decisions shape the future bunkering landscape".

About Global Centre for Maritime Decarbonisation (GCMD)

The Global Centre for Maritime Decarbonisation (GCMD) is an international, independent action tank, established on 1 August 2021 to help international shipping decarbonise through pilots and trials. Its mission is to support decarbonisation through four pillars: shaping standards, deploying solutions, financing projects, and fostering collaboration across sectors.

GCMD was founded with the support of industry partners, alongside funding from the Maritime and Port Authority of Singapore (MPA) for qualifying research and development programmes. Since its founding, GCMD has expanded its ecosystem to include more than 130 centre- and project-level partners contributing funds, expertise, and in-kind support to pilot, accelerate the deployment, and scale the adoption of decarbonisation solutions.

GCMD has launched four key initiatives to close technical and operational gaps in: enabling ammonia as a marine fuel, developing an assurance framework for drop-in green fuels, unlocking the carbon value chain through onboard carbon capture and articulating the value chain of captured carbon dioxide, as well as closing the data-financing gap to scale the adoption of energy efficiency technologies.

GCMD is strategically located in Singapore, the world's largest bunkering hub and busiest transshipment port. For more information, go to www.gcformd.org

CONTACT US

Email: projects@gcformd.org

LinkedIn: Global Centre for Maritime Decarbonisation (GCMD)

Website: www.gcformd.org

About Boston Consulting Group (BCG)

Boston Consulting Group bridges the gap between ambition and outcomes for the world's leading companies and organizations. We are built for this era of unprecedented change—bringing strategic clarity rooted in over 60 years of deep domain knowledge, combined with applied AI shaped by our practitioners. BCG works shoulder-to-shoulder with CEOs across industries and geographies to deliver transformative impact at scale: stronger returns, transferred capabilities, and change that sticks. For more information, visit bcg.com.

Disclaimer: This report presents findings from a project jointly conducted by BCG and GCMD. While all reasonable efforts have been made to ensure the accuracy of the information, BCG and GCMD make no warranties regarding the fitness of the information for a particular purpose. Users should exercise independent judgement before relying on any part of this publication.

CONTACT US

Email: projects@gcformd.org

LinkedIn: [Global Centre for Maritime Decarbonisation \(GCMD\)](#)

Website: www.gcformd.org

