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Bento Lira Vital Pereira
Federal University of Rio de Janeiro https://orcid.org/0009-0003-1004-0129
Caio Teixeira de Carvalho
Federal University of Rio de Janeiro https://orcid.org/0009-0004-1975-9073
Maria Eduarda Monteiro Madeira Cerqueira dos Santos
Federal University of Rio de Janeiro https://orcid.org/0009-0008-5450-8949
Andrea Lucchesi
Universidade de São Paulo https://orcid.org/0000-0002-0813-245X
Luiz Felipe Assis
Federal University of Rio de Janeiro https://orcid.org/0000-0001-5602-3779
Crístofer Hood Marques
Federal University of Rio de Janeiro https://orcid.org/0000-0003-0178-5666
Paula Carvalho Pereda
Universidade de São Paulo https://orcid.org/0000-0002-6717-9522
Jean-David Caprace
jdcaprace@oceanica.ufrj.br
Federal University of Rio de Janeiro https://orcid.org/0000-0002-1014-9357

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Article

Marine Fuel Pathways under Uncertainty

Bento Lira Vital Pereira [1], Caio Teixeira de Carvalho [1], Maria Eduarda Monteiro Madeira Cerqueira dos Santos [1], Andrea Lucchesi[2], Luiz Felipe Assis [1], Crístofer Hood Marques [1], Paula Carvalho Pereda[3] and Jean-David Caprace [1,*]

[1] Ocean Engineering Department, Federal University of Rio de Janeiro (UFRJ), Rio de Janeiro, 21941-611, Brazil; bentolirapereira.20231@poli.ufrj.br (B.L.P.); caiotc16.20231@poli.ufrj.br (C.T.C.); memonteiro.20232@poli.ufrj.br (M.M.M.); felipe@oceanica.ufrj.br (L.F.A.); cristoferhood@oceanica.ufrj.br (C.H.M.); jdcaprace@oceanica.ufrj.br (J.-D.C.)
[2] School of Arts, Sciences and Humanities (EACH), University of São Paulo (USP), São Paulo, 03828-000, Brazil; andrea.lucchesi@usp.br (A.L.)
[3] Department of Economics, University of São Paulo (USP), São Paulo, 05508-010, Brazil; pereda@usp.br (P.P.)
* Correspondence: jdcaprace@oceanica.ufrj.br;

Abstract

Maritime decarbonization assessments commonly rely on point estimates for fuel properties, lifecycle emissions, and costs, despite the substantial variability associated with production pathways, feedstocks, geographical regions, technologies, and future market conditions. This study develops a harmonized database of physical, environmental, and economic parameters for conventional and alternative marine fuels, focusing on well-to-wake (WTW) greenhouse gas intensities, fuel prices, lower heating values, and volumetric energy densities. Data are compiled from scientific literature, technical reports, institutional sources, and sector-specific cost tools, standardized into common units, and classified by fuel molecule and production pathway. Particular attention is given to the temporal evolution of fuel prices: the dataset spans 2020–2050, combining historical and contemporary estimates with long-term forecasts under different technological and market scenarios. For each parameter and fuel pathway, the first quartile, median, and third quartile are derived to characterize low, central, and high estimates and support uncertainty-aware maritime modelling. The results indicate that fossil fuels generally exhibit narrower parameter ranges, whereas biofuels, electrofuels, hydrogen, ammonia, and synthetic methane pathways display substantially greater dispersion. This variability primarily reflects differences in feedstocks, electricity sources, carbon origins, production technologies, geographical contexts, and underlying scenario assumptions. By quantifying how these ranges—and the projected evolution of fuel prices through 2050—affect estimated emissions and energy costs, this study demonstrates the limitations of deterministic fuel comparisons and provides transparent, harmonized inputs for lifecycle assessment, fuel-selection models, and maritime energy-transition scenarios.

Keywords: maritime decarbonization; alternative marine fuels; well-to-wake emissions; data harmonization; fuel selection

1. Introduction

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Maritime shipping carries approximately 80%–90% of global cargo and is therefore essential to international trade and economic activity. This strategic role is accompanied by a substantial environmental footprint: shipping emits approximately one billion tonnes of carbon dioxide (CO_2) annually, representing around 2.5% to 3% of global CO_2 emissions, and consumes nearly 300 million tonnes of predominantly carbon-intensive fossil fuels each year. Without additional mitigation measures, continued growth in seaborne trade and transport demand may significantly increase sectoral greenhouse gas (GHG) emissions, which include heat-trapping gases such as CO_2, methane, and nitrous oxide, by 2050. This prospect reinforces the need for a rapid transition toward lower-carbon energy systems [1].

In response, the International Maritime Organization (IMO), the United Nations agency responsible for regulating international shipping, has progressively strengthened the regulatory framework governing energy efficiency and GHG emissions from the sector. Measures introduced under Annex VI of the MARPOL Convention [2], the international convention for preventing pollution from ships, include the Energy Efficiency Design Index (EEDI), which establishes minimum efficiency requirements for new ships; the Ship Energy Efficiency Management Plan (SEEMP), which supports the improvement of operational energy performance; the Energy Efficiency Existing Ship Index (EEXI) [3], which applies technical efficiency requirements to existing vessels; and the Carbon Intensity Indicator (CII), which evaluates a ship's annual carbon emissions relative to its transport activity.

More recently, the 2023 IMO Strategy on Reduction of GHG Emissions from Ships established the ambition of reaching net-zero GHG emissions from international shipping by or around 2050, meaning that any remaining emissions should be balanced by equivalent removals or reductions. This ambition is supported by indicative checkpoints for reducing total annual emissions by at least 20% by 2030 and at least 70% by 2040 relative to 2008 levels. The strategy also calls for a reduction of at least 40% in carbon intensity, defined as the amount of carbon emitted per unit of transport activity, by 2030 and emphasizes the adoption of zero- and near-zero-GHG fuels, technologies, and energy sources. Importantly, it reinforces the need to assess emissions across the complete fuel lifecycle through a Well-to-Wake (WTW) approach, which covers all stages from energy-source extraction and fuel production to its final use onboard the vessel, rather than considering onboard emissions alone [4,5].

Meeting these objectives will require the deployment of a diverse portfolio of conventional, bio-based, renewable, synthetic, and low-carbon marine fuel pathways [6]. A fuel pathway comprises the feedstock, production process, energy source, transport, distribution, and final use associated with a particular fuel. Bio-based fuels, or biofuels, are produced from biological materials such as crops, residues, waste, and other forms of organic matter, while synthetic fuels are manufactured through chemical processes using inputs such as hydrogen and captured carbon. Carbon capture refers to the separation and collection of CO_2 from engine exhaust gases before its release into the atmosphere. Alternatively, when CO_2 is removed directly from ambient air, the process is known as direct air capture (DAC).

The suitability of these pathways for maritime applications, however, cannot be determined solely from the chemical identity of the fuel. The environmental performance of hydrogen, ammonia, methane, methanol, biofuels, and synthetic hydrocarbons depends strongly on their feedstocks, meaning the raw materials used in their production, as well as on production technologies, electricity sources, carbon origins, transport chains, and carbon-capture assumptions. The operational feasibility of the different fuel production pathways is also influenced by metrics like lower heating value, gravimetric and volumetric energy density, storage conditions, engine compatibility, bunkering infrastructure, and technological maturity. These characteristics directly affect vessel autonomy, onboard tank capacity, cargo-space utilization, propulsion-system design, and overall operational efficiency, particularly in long-distance maritime transport [7]. Consider that lower heating value represents the useful heat released during combustion without recovering the energy contained in the resulting water vapor; gravimetric and volumetric energy densities describe the energy stored per unit of mass and volume, respectively; bunkering infrastructure includes the facilities and systems required to supply fuel to ships, while technological maturity indicates how developed, tested, and commercially available a technology is.

Economic performance is subject to an equally broad range of assumptions. Fuel prices depend on production scale, regional energy markets, feedstock availability, electricity costs, infrastructure development, technological learning, policy incentives, and future carbon-pricing mechanisms, which assign a monetary cost to GHG emissions through instruments such as carbon taxes or emissions-trading systems. Consequently, values reported for the same fuel pathway can vary substantially among scientific studies, technical reports, institutional publications, and sectoral databases. Part

of this dispersion reflects genuine differences among technologies, regions, reference years, and production configurations, while another part arises from methodological choices, including lifecycle boundaries, Global Warming Potential (GWP) horizons, allocation procedures, treatment of biogenic carbon, methane leakage and slip assumptions, and price-conversion methods. Lifecycle boundaries determine which production, transport, distribution, and use stages are included in the analysis. GWP expresses the heat-trapping effect of a GHG relative to CO_2 over a specified period, commonly 20 or 100 years. Allocation procedures distribute environmental impacts among products generated by the same process, while biogenic carbon refers to carbon originating from biological materials. Methane leakage describes unintended releases throughout the fuel supply chain, whereas methane slip refers mainly to unburned methane released during engine operation.

Nevertheless, many environmental, economic, fleet-transition, and fuel-selection models continue to represent these parameters through single deterministic values, meaning fixed inputs that do not explicitly account for variability or uncertainty. Such simplification can obscure the range of outcomes supported by the available evidence and may substantially affect conclusions regarding the relative performance of alternative marine fuels [7].

This study addresses this limitation by developing a structured and harmonized database of physical, environmental, and economic parameters for marine fuel pathways. Harmonization consists of converting data from different sources into consistent units, definitions, reference conditions, and methodological boundaries. The database integrates information from scientific articles, technical reports, institutional publications, regulatory sources, and specialized sectoral tools. The collected parameters include mass density, lower heating value, gravimetric and volumetric energy density, Well-to-Tank (WTT) and WTW GHG intensity, GWP assumptions, fuel prices, reference years, and production-pathway characteristics. WTT represents the portion of the lifecycle extending from the extraction or production of the primary energy source to the delivery of the fuel into the vessel's storage system, while GHG intensity expresses the amount of emissions generated per unit of energy or transport work. Cost projections are additionally obtained from the Fuel Cost Calculator developed by the Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping [8].

Rather than reducing the collected evidence to a single representative value, the study characterizes the empirical dispersion of the available data through the first quartile (Q_1), median (Q_2), and third quartile (Q_3), corresponding to the values below which 25%, 50%, and 75% of the observations are found, respectively. These measures provide transparent low, central, and high estimates for uncertainty-aware modeling. The principal contribution, therefore, lies not in data collection alone, but in transforming heterogeneous literature evidence into harmonized parameter ranges that can be incorporated into maritime emissions, cost, fuel selection, and decarbonization models to evaluate how uncertainty in their inputs influences the resulting conclusions.

2. Methodology

The methodology was designed to systematically collect, classify, and harmonize quantitative information on marine fuels and energy carriers. Particular attention was given to the fact that the environmental, energetic, and economic performance of a fuel cannot be characterized independently of its production pathway. Therefore, the database was structured to distinguish the final fuel from the feedstock, production route, energy source, carbon origin, and other relevant pathway characteristics.

The methodological procedure comprised four main stages: (i) definition of the study scope and fuel pathway classification; (ii) identification and collection of data from the selected sources; (iii) automated extraction and organization of fuel cost projections; and (iv) harmonization and quality control of the collected data. The resulting dataset preserves the variability reported across different sources rather than reducing each parameter to a single representative value.

2.1. Study scope and fuel pathway classification

The methodological framework was developed to compile, harmonize, and characterize physical, environmental, and economic data for conventional and alternative marine fuel pathways. The

analysis was organized according to the four groups defined in Table 1: fossil fuels, biofuels, e-fuels and renewable fuels, and other blue or gray fuel pathways. In this context, blue fuels are produced mainly from fossil feedstocks with the associated carbon dioxide emissions being partially captured and stored, whereas gray fuels are also fossil-based but are produced without carbon capture, resulting in higher lifecycle GHG emissions. This classification supports consistent database management while recognizing that the environmental and economic performance of a fuel depends not only on its chemical composition but also on its feedstock, production technology, energy source, carbon origin, carbon capture configuration, and supply-chain characteristics.[9–11].

The fossil-fuel group comprises the petroleum-derived fuels currently used as conventional references in maritime transport: High Sulfur Fuel Oil (CHSFO) [12–14], Very Low Sulfur Fuel Oil (VLSFO) [12,13,15], Marine Diesel Oil (CFMDO) [12,16,17], and Marine Gas Oil (CFMGO) [13,15,18]. These pathways were retained as baseline alternatives because of their established use, mature supply chains, compatibility with existing marine engines, and comparatively high gravimetric and volumetric energy densities. Despite differences in sulfur content, refining processes, and fuel specifications, all four pathways remain fossil-derived and are therefore associated with substantial lifecycle GHG emissions [9,19].

The biofuel group includes Fatty Acid Methyl Ester (BIFAME) [6,20,21], Straight Vegetable Oil (BISVO) [21–23], Hydrotreated Vegetable Oil (BIHVO) [6,21,24], Hydrotreated Pyrolysis Oil (BIHPO) [18,23,25], Dimethyl Ether produced from biomass-derived routes (BIDME) [6,21,26], bioethanol (BIETH) [20,24,27], biomethane (BICH4) [24,26], biomethanol (BICH3) [6,24,28], and bio-LNG (BILNG) [12,20,29]. These fuels are produced from biological feedstocks such as vegetable oils, waste oils, agricultural residues, forest residues, sugars, organic waste, and other biomass resources. Their lifecycle performance is highly pathway-dependent because feedstock origin, land-use assumptions, conversion technology, allocation method, and supply-chain configuration can substantially influence both GHG intensity and production cost. Biofuels were therefore treated as distinct production pathways rather than as a homogeneous fuel category [9,30,31].

The e-fuel and renewable-fuel group comprises e-methanol (ECFCH3) [6,12,28], e-LNG (ELNG), electricity-based hydrogen (EH2) [12,32,33], e-ammonia (ECFNH3) [12,28,29], e-methane (ECH4) [26,33], e-diesel (EDIE) [12,24,28], renewable ammonia (RENH3) [26,34,35], and renewable hydrogen (REEH2) [21,26,36]. These pathways rely primarily on electricity-based conversion processes, including water electrolysis and the subsequent synthesis of hydrogen-derived energy carriers. Their environmental performance depends strongly on the carbon intensity of the electricity supply, process efficiency, carbon source, synthesis route, and transport and storage requirements. Although these fuels may achieve low lifecycle GHG intensities when produced using renewable electricity, their costs and emissions may increase considerably when grid electricity, energy-intensive conversion processes, or carbon-intensive upstream inputs are considered [10,11].

The final database group comprises blue hydrogen (BLSH2), blue ammonia (BLNH3), gray LNG (CFLNG) [13,15,37], liquefied petroleum gas (CFLPG), gray methanol (CFCH3), gray ammonia (CFNH3), and gray hydrogen (CFSH2) [23,36,38]. Blue and gray pathways were treated separately from conventional petroleum fuels because their production chains, physical properties, propulsion applications, and lifecycle GHG profiles differ substantially. In particular, the performance of blue hydrogen and blue ammonia depends on upstream methane emissions, conversion efficiency, carbon capture rate, and residual emissions, while the performance of gray methane-, methanol-, ammonia-, and hydrogen-based pathways remains closely linked to the carbon intensity of fossil feedstocks and production energy [10,38,39].

Each database observation was assigned a fuel code corresponding to the pathway definitions presented in Table 1. Whenever available, additional metadata were retained to describe the feedstock, electricity source, conversion route, carbon source, carbon capture condition, engine technology, geographical scope, reference year, and lifecycle boundary. This additional classification was necessary because observations assigned to the same broad fuel code may represent different technological

Table 1. Fuel codes and corresponding fuel pathways adopted in the database.

Fuel code	Description
Fossil fuels	
CHSFO	HSFO - High Sulfur Fuel Oil, max 3.50%S (requires scrubber)
VLSFO	VLSFO - Very Low Sulfur Fuel Oil ($\leq$ 0.5%)
CFMDO	MDO - Marine Diesel Oil
CFMGO	MGO - Marine Gas Oil
Biofuels	
BIFAME	FAME - Biodiesel - Fatty Acid Methyl Esters
BISVO	SVO - Straight Vegetable Oil
BIHVO	HVO - Hydrotreated Vegetable Oil
BIHPO	HPO - Hydrotreated Pyrolysis Oil
BIDME	DME - Dimethyl Ether
BIETH	ETH - Ethanol LHV
BICH4	Biomethane
BICH3	CH_3OH - BioMethanol - Biomass Gasification
BILNG	LNG - Green - Bio-LNG from Biomass Degradation
E-fuels / Refuels	
ECFCH3	E-Methanol - Synthetic methanol produced using renewable electricity
ELNG	E-LNG - Synthetic LNG produced from renewable electricity pathways
EH2[†]	E-H_2 - Hydrogen produced via electricity-based processes
ECFNH3[†]	E-Ammonia - Synthetic ammonia produced using renewable electricity
ECH4	E-Methane - Synthetic methane from renewable electricity and CO_2
EDIE	E-Diesel - Synthetic diesel produced from renewable electricity
RENH3	NH_3 - Green Ammonia from H_2, N_2 and Renewable Electricity
REEH2	H_2 - Green Hydrogen - Electrolysis with Renewable Energy (Liquid H_2)
Blue or gray fuels	
BLSH2	Blue Hydrogen - Hydrogen produced with carbon capture technologies
BLNH3	Blue Ammonia - Ammonia produced from blue hydrogen pathways
CFLNG	LNG - Gray LNG - Liquefied Natural Gas
CFLPG[‡]	LPG - Gray LPG - Liquefied Petroleum Gas
CFCH3	CH_3OH - Gray Methanol - Steam Reforming from Natural Gas
CFNH3	NH_3 - Gray Ammonia from Natural Gas
CFSH2	H_2 - Gray Hydrogen - Steam Reforming from Natural Gas (Liquid H_2)

[†] Included in the initial pathway list but excluded from the quantitative analysis, as no usable records were obtained; entries were consistently reported under the renewable-electricity designations REEH2 and RENH3, respectively.

[‡] Included in the initial pathway list but excluded from the quantitative analysis due to insufficient data coverage across the physical, environmental, and economic parameters.

or geographical configurations. The resulting database therefore preserves both the standardized pathway code required for comparative analysis and the source-specific information required to interpret the observed parameter dispersion.

The parameters were organized into three principal groups. Physical parameters include mass density, lower calorific value, gravimetric energy density, and volumetric energy density. Environmental parameters include greenhouse gas (GHG) intensities evaluated under three lifecycle boundaries: Well-to-Tank (WTT), which covers emissions from fuel production, processing, and distribution up to delivery onboard the vessel; Tank-to-Wake (TTW), which covers emissions generated during onboard fuel use; and WTW, which represents the complete fuel lifecycle and combines the WTT and TTW stages. The analysis also considers the Global Warming Potential (GWP), a metric used to express the climate impact of different greenhouse gases relative to CO_2 over a specified time horizon, together with the lifecycle assumptions reported by the original source. Economic parameters include historical and projected fuel prices, reference year, geographical region, cost basis, electricity-price assumption, carbon-price assumption, and individual cost components whenever available. These parameters were selected because they represent relevant inputs for maritime lifecycle assessment, fuel-cost modelling, fuel-selection studies, and fleet-decarbonization scenarios.

2.2. Data sources and collection

The database was compiled from a heterogeneous set of sources reflecting the multidisciplinary and rapidly evolving nature of the marine-fuel literature. These comprised peer-reviewed scientific articles, specialized sector databases, technical and industry reports, commercial maritime databases, regulatory and institutional publications, complemented by university reports and master's theses. Peer-reviewed studies were used primarily to obtain physical properties, lifecycle GHG intensities, production-pathway characteristics, propulsion-system assumptions, and techno-economic estimates. Regulatory and institutional documents were included because they provide standardized lifecycle definitions, default emission factors, sustainability criteria, and reference values frequently adopted in maritime fuel assessments [6,9,12,21,40]. Technical reports and industry studies were used to complement the scientific literature for emerging fuel pathways for which peer-reviewed evidence remains limited, particularly renewable hydrogen, ammonia, methanol, synthetic fuels, and advanced biofuels [10,11,28,31].

The literature collection followed a structured evidence-identification and screening procedure. Candidate sources were identified through bibliographic database searches, backward and forward citation tracking, and targeted searches of relevant institutional and industrial repositories. Sources were considered eligible when they reported quantitative information for at least one of the parameters included in the study and provided sufficient methodological context to identify the fuel molecule, production pathway, functional unit, lifecycle boundary, reference year, or technological scenario. Sources reporting only qualitative comparisons, values without identifiable units or provenance, or results that could not be assigned to a defined fuel pathway were excluded from the quantitative analysis. The final manuscript should report the bibliographic databases, search strings, screening period, and date of the last search to ensure full reproducibility.

For each eligible source, numerical observations were extracted together with the metadata required to interpret and harmonize the reported values. The recorded fields included bibliographic reference, fuel code, fuel molecule, production route, feedstock or primary energy source, electricity source, carbon source, carbon capture condition, geographical scope, reference year, engine or propulsion technology, lifecycle boundary, GWP horizon, original value, original unit, and scenario description. The complete set of recorded fields, grouped by category, is presented in Table A7 in the Section A.1. For environmental observations, the database also recorded whether the reported intensity corresponded to WTT, TTW, or WTW emissions and whether relevant factors such as methane leakage, methane slip, pilot-fuel consumption, biogenic carbon, land-use change, or carbon capture were included. For economic observations, the recorded metadata included the cost year, currency, geographical region, price basis, and electricity-cost assumption

Each numerical value was treated as an individual observation while retaining its association with the original source and scenario. When a publication reported several pathways, years, regions, or sensitivity cases, these values were entered separately and identified through the corresponding metadata. Exact duplicates reproduced from secondary publications were removed whenever the original source could be identified, while distinct scenarios reported by the same study were retained. The database preserved both the value as originally reported and the subsequently standardized value, allowing every transformation to be traced back to the source data.

The complete data-management workflow is summarized in Figure 1 and was organized into four sequential stages: source identification, data extraction, computational processing, and preparation of the output database. The scientific articles, technical and industry reports, institutional and regulatory publications, and commercial maritime databases described above formed the initial source base. During the data-extraction stage, the scope and scenario conditions were first defined, after which the identified sources were screened according to the selected fuel, geographical region, and reference period. Each eligible observation was then assigned to its corresponding production pathway, and the relevant physical, economic, and environmental parameters were extracted. The extracted observations and their associated metadata were organized in structured CSV files, preserving the relationship between each numerical value, its source, and the scenario under which it was reported.

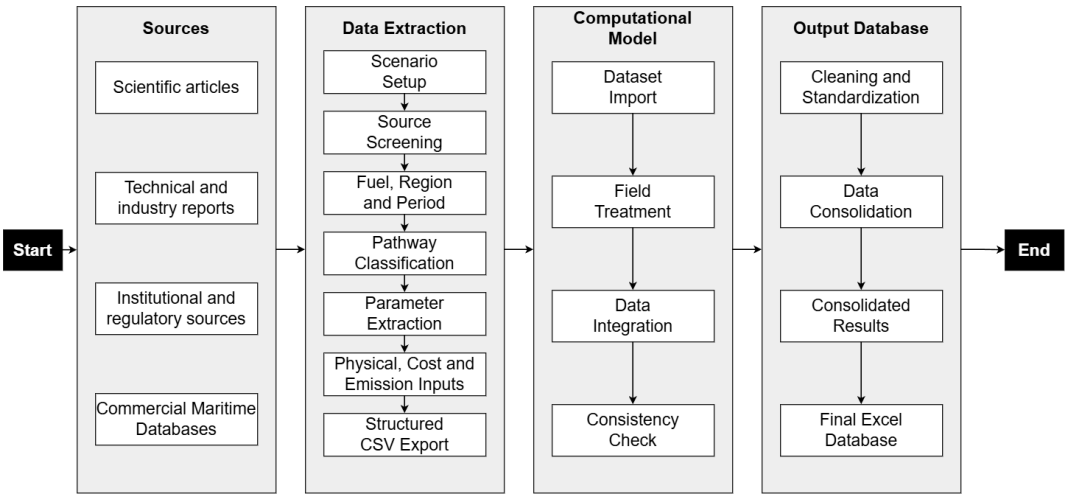


Figure 1. Data collection, harmonization and consolidation workflow.

During the computational-processing stage, the individual datasets were imported into a common data structure, and their fields were treated to harmonize variable names, formats, categories, units, fuel codes, and pathway classifications. The treated datasets were subsequently integrated, and consistency checks were performed to identify duplicated observations, incompatible units, incomplete metadata, inconsistent classifications, and values requiring further verification. In the final stage, the integrated dataset underwent additional cleaning and standardization before the records were consolidated. The consolidated results were exported to a final Excel database containing the original observations, standardized values, scenario identifiers, and source metadata. This workflow provided a consistent and traceable structure for statistical analysis, graphical visualization, scenario evaluation, and comparison among the different marine-fuel pathways.

Fuel cost information from the literature was complemented using the Fuel Cost Calculator developed by the Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping [8]. This source was incorporated because it provides internally consistent cost projections across multiple fuels, years, geographical regions, emission scopes, carbon-price assumptions, and electricity-cost scenarios. Data obtained from the calculator were stored separately from literature-derived observations during the extraction stage and were merged only after the relevant scenario variables and units had been identified and standardized.

A complete source-to-observation mapping was maintained throughout the data-collection process. The detailed production pathways, engine configurations, extracted variables, and corresponding references are provided in the Supplementary Material, together with the complete database and data dictionary. This structure preserves the traceability of the collected evidence while allowing the main manuscript to focus on data harmonization, uncertainty characterization, and the implications of parameter variability for maritime fuel assessment.

2.3. Automated extraction of fuel cost projections

The computational modeling stage was developed to automate the collection, organization, and consolidation of fuel cost data obtained from the Fuel Cost Calculator provided by the Mærsk McKinney Møller Center for Zero Carbon Shipping [8]. Automation was adopted because the calculator returns distinct results for each combination of input parameters, making manual extraction time-consuming and susceptible to transcription errors or inconsistencies. By using a programmed routine, all scenarios were queried under the same request protocol and the outputs were stored in a uniform format, ensuring that subsequent comparisons among fuel pathways reflected differences between scenarios rather than artifacts of the collection process.

A Python script was implemented to interact with the calculator and retrieve the results corresponding to the different combinations of parameters considered in the study, including region, year, and electricity cost level. Only the WTW scope was adopted, so that costs are accounted for across the entire fuel life cycle, from the production stage to onboard use. This choice is decisive for the validity of the comparison, since bio-based and synthetic pathways concentrate a large share of their costs and environmental burden in the stages preceding bunkering, whereas fossil pathways exhibit the inverse distribution; restricting the analysis to the Tank-to-Wake scope would artificially favour alternative fuels and compromise the equity of the assessment. The extracted results were stored in CSV files, each associated with its corresponding scenario conditions, preserving traceability between the consolidated data and its origin.

In the implemented routine, the selected years covered the period from 2023 to 2050, following the main horizon of maritime decarbonization targets and allowing projected fuel cost trajectories to be observed over the coming decades. Two electricity cost levels, classified as high and low, were also considered, in order to capture the sensitivity of electricity-intensive pathways, particularly those based on renewable hydrogen, ammonia, and methanol — to the price of the electricity used in their production. The WTW scope was maintained across all extractions, ensuring that the variation observed between scenarios is attributable solely to the parameters effectively manipulated and not to changes in the adopted system boundary.

The extracted files were subsequently processed in KNIME, where the data were imported, organized, standardized, and integrated into a single structured dataset. At this stage, scenario identifiers and fuel cost components were normalized with respect to nomenclature and units, so as to allow consistent comparison among the evaluated alternatives and to avoid duplication arising from labelling variations between files. The implemented workflow further includes integrity checks intended to identify missing or inconsistent records prior to final consolidation. The consolidated results were then exported to an Excel database containing the main cost components and total cost indicators for each fuel and scenario.

Overall, this computational workflow converted the results obtained from multiple scenarios into a structured, traceable, and internally consistent database, suitable both for statistical analysis and for graphical visualization and systematic comparison among the different marine fuel pathways. The standardization adopted allows new scenarios to be incorporated later without requiring full reprocessing of the base, which lends the procedure a reproducible and extensible character. This feature is particularly relevant in a context where cost projections are frequently revised as new information on feedstock availability, technological maturity, and the regulatory framework becomes available.

2.4. Data harmonization and quality control

Following the independent collection of literature-based data and fuel cost projections from the Fuel Cost Calculator [8], both datasets were integrated into a single consolidated database. The literature dataset contained physical properties, lifecycle emission indicators, production pathways, and economic values reported in scientific articles, technical reports, institutional publications, and sectoral databases. The computationally extracted dataset contained fuel cost projections organized according to fuel type, production pathway, reference year, region, and scenario.

To enable the integration of these datasets, the fuel names and production pathways reported by the different sources were reviewed and mapped to a standardized nomenclature. A unique fuel code was assigned to each pathway and used as the primary identification field during the consolidation process. This procedure reduced inconsistencies caused by variations in terminology, abbreviations, feedstock descriptions, and pathway classifications among the consulted sources and the Fuel Cost Calculator.

The consolidated database was structured to preserve the original source, reference year, geographical scope, production pathway, scenario assumptions, and system boundaries associated with each observation. Values referring to different years, regions, lifecycle boundaries, or GWP horizons were maintained as separate records rather than treated as directly equivalent. This distinction was particularly important for environmental indicators reported according to WTT, TTW, or WTW boundaries and for economic projections associated with different technological and market scenarios.

Data harmonization was subsequently performed to ensure consistency among physical, environmental, and economic parameters reported in different formats. All numerical parameters were converted into common reference units. Fuel properties were standardized in MJ/kg for lower calorific value and MJ/m^3 for volumetric energy density; lifecycle greenhouse gas emissions were expressed in gCO_2eq/MJ, and fuel prices were harmonized in USD/ton. When energy-normalized cost indicators were required, fuel prices were also converted to USD/GJ using the corresponding lower calorific value, allowing comparison among fuels with different energy contents.

For each converted parameter, the database retained the original value, original unit, conversion factor, and standardized value, ensuring traceability and enabling verification of the harmonization procedure. This structure allowed values extracted from literature sources and cost projections obtained from the Fuel Cost Calculator to be stored within the same database framework while preserving their methodological differences. Therefore, harmonization did not imply treating all observations as equivalent; instead, it ensured that records could be compared only when their units, system boundaries, reference years, regions, and scenario assumptions were compatible.

Quality control included the identification of duplicate records, incomplete entries, inconsistent units, incompatible reference conditions, and discrepancies in fuel or pathway classification. When multiple values were available for the same parameter, the observations were initially preserved as separate records together with their respective sources and methodological conditions. Statistical summaries, such as ranges or median values, were calculated only after records with compatible system boundaries, units, reference years, and pathway definitions had been grouped. An exception concerns indirect land-use change (ILUC) in biofuel pathways: GHG intensities were recorded as reported by each source, whether or not ILUC was included in the original figure. Because sources differ in this treatment, the resulting quartile ranges for feedstock-dependent biofuels—notably FAME, HVO, and SVO—partly reflect this methodological heterogeneity in addition to genuine differences in feedstock and production route. The ILUC-specific fields retained in the database, Table A7, preserve this distinction for future separation.

The resulting database therefore combined the broader physical, environmental, and economic information obtained from the literature with the structured temporal fuel cost projections extracted from the Fuel Cost Calculator. The final distribution of the consolidated records according to fuel pathway, parameter category, and data source is summarized in Table 2. The table also indicates the number of observations available for physical properties, lifecycle emissions, and fuel prices, providing

an overview of the coverage and composition of the database used in the subsequent comparative analyses.

Table 2. Record coverage by fuel code, source category, and parameter family.

	All records			Parameter coverage		Price coverage		
Fuel code	**Literature**	**MAERSK**	**Clarksons/IEA**	**Physical**	**Emissions**	**Literature**	**MAERSK**	**Clarksons/IEA**
Fossil fuels								
CHSFO	82	0	6	17	54	35	0	6
VLSFO	37	0	20	4	27	15	0	20
CFMDO	38	0	6	11	20	20	0	6
CFMGO	67	0	6	15	50	12	0	6
Biofuels								
BIFAME	77	0	0	24	30	46	0	0
BISVO	17	0	0	5	16	0	0	0
BIHVO	71	0	0	17	31	42	0	0
BIHPO	16	18	0	0	2	14	18	0
BIDME	17	0	0	6	12	3	0	0
BIETH	109	0	0	18	20	87	0	0
BICH4	66	0	0	1	14	60	0	0
BICH3	263	24	0	22	85	162	24	0
BILNG	26	24	0	2	16	12	24	0
E-fuels / renewable-electricity fuels								
ECFCH3	74	24	0	7	23	59	24	0
ELNG	22	24	0	3	5	17	24	0
ECH4	20	0	0	0	8	17	0	0
EDIE	22	24	0	1	8	16	24	0
RENH3	109	24	0	18	37	79	24	0
REEH2	102	24	0	7	39	71	24	0
Blue or gray fuels								
CFLNG	149	24	0	26	112	44	24	0
CFLPG	24	0	0	8	9	13	0	0
CFCH3	66	0	0	24	40	30	0	0
CFNH3	86	0	0	36	35	58	0	0
CFSH2	63	0	0	24	27	33	0	0
BLSH2	51	0	0	2	38	16	0	0
BLNH3	12	24	0	0	12	3	24	0
Additional labels	42	0	0	17	13	23	0	0
Subtotal by source	**1728**	**234**	**38**	**315**	**783**	**987**	**234**	**38**
Total		**2000**		**315**	**783**		**1259**	

Note: Source categories reproduce the labels in the *Source* field. Literature includes scientific publications and technical, institutional, and industry sources. MAERSK denotes the Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping [8]. Clarksons/IEA denotes the combined category for Clarksons and International Energy Agency data [41,42].
Physical-property coverage considers numerical values in *VolDen*, *EnergDen*, *EnergDen_MJ/L*, *LCV/LHV*, or *LCV_MJ/kg*. Emission coverage considers original or standardized WTT, TTW, or WTW values, including ILUC-related fields. Price coverage considers *Price*, *PRICE_USD/ton*, or *PRICE_USD/GJ*. Unit fields, conversion factors, and contextual metadata alone do not establish parameter coverage. Numerical zeros are retained. Each record is counted at most once per parameter family; families may overlap. Coverage indicates numerical availability, not methodological comparability or suitability for aggregation.

2.5. Fuel pathways and production routes

The following subsections describe the fuel pathways compiled in the database, organized according to the four groups defined in Table 1: conventional fossil fuels, bio-based fuels, e-fuels and renewable fuels, and blue and gray fuel pathways. The purpose is to document the production routes underlying each fuel code, since observations assigned to the same code may originate from substantially different feedstocks, conversion technologies, and energy inputs[43].

This documentation is a methodological requirement rather than a review exercise. The dispersion characterized by the quartiles reported in Section 3 is not measurement noise: it reflects genuine differences among the production configurations behind each pathway [18]. Interpreting a quartile range therefore requires knowing which routes it aggregates, and the tables accompanying each subsection map every fuel code to the specific production routes and, where relevant, engine technologies identified in the consulted sources.

Each subsection follows the same structure: the rationale for including the group in a maritime assessment, the fuel codes covered, the production routes associated with each fuel and their operational implications, and the factors governing the observed variability. Fuels are discussed by pathway

rather than by molecule, since the same molecule may appear in more than one group depending on how it is produced.

2.5.1. Conventional fossil fuels

Conventional fossil fuels remain the baseline for marine fuel comparison due to their extensive use in commercial shipping, high energy density, mature supply chains, and compatibility with existing propulsion systems. Within the scope of this study, the fossil fuel pathways considered are High Sulfur Fuel Oil (HSFO), Very Low Sulfur Fuel Oil (VLSFO), Marine Diesel Oil (MDO), and Marine Gas Oil (MGO). These fuels represent the conventional energy pathways against which alternative fuels can be evaluated in terms of physical properties, emissions, costs, and operational feasibility.

HSFO and MDO have historically supported maritime propulsion because of their availability, cost-effectiveness, and high energy density. HSFO, as a residual product of crude oil refining, has been widely used in large vessels due to its low cost. MDO, a blend of distillate and residual fractions, and MGO, a pure distillate, are generally preferred in smaller vessels and within emission control areas because of their lower sulfur content and improved combustion characteristics. However, all conventional fossil fuels remain major contributors to carbon dioxide (CO_2), sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulate matter emissions, reinforcing the need for alternative pathways in the context of maritime decarbonization [9].

VLSFO emerged as one of the main compliance options after the IMO 2020 sulfur regulation, which limited the sulfur content of marine bunker fuels to 0.50% m/m. In this context, ships may comply either by using lower-sulfur fuels or by installing exhaust gas cleaning systems, commonly referred to as scrubbers. Although VLSFO allows vessels to reduce sulfur oxide emissions without necessarily requiring scrubber systems, it remains a fossil-derived fuel and therefore does not eliminate greenhouse gas emissions from maritime transport. Moreover, treated or blended VLSFO may present operational challenges related to lubricity, pour point, wax formation, and fuel compatibility, especially when residual and distillate components are mixed [19].

Gas-based fossil pathways, such as gray LNG and LPG, are also derived from fossil sources but are addressed separately in Section 2.5.4, together with other blue and gray pathways, since their production routes, storage requirements, and lifecycle emission profiles differ substantially from oil-based bunker fuels.

Tables 3 and 4 include all sources considered in this study, along with a description of the engine type addressed in the present work, together with their respective production pathways. For each fuel, the corresponding pathway specifies the primary feedstock, the conversion process, and the main assumptions adopted in this study. This information ensures consistency and traceability across the different fuel categories considered, providing the basis for the subsequent lifecycle analysis.

Table 3. Fossil marine fuels (HSFO, MDO and MGO) and engine technologies identified in the literature.

Fuel	Engine type	References
CHSFO	Diesel engines (two- and four-stroke; slow- and medium-speed; compression-ignition)	[13,14,17,24,44–46]
CHSFO	All internal combustion engines	[12]
CHSFO	Gas turbine	[12,36]
CHSFO	Steam turbines and boilers	[12]
CHSFO	Auxiliary engines	[12]
CHSFO	Not specified	[14,15,17,20,23,26,27,29, 40,47–53]
CFMDO	Diesel engines (two- and four-stroke; compression-ignition; with or without SCR)	[16,17]
CFMDO	All internal combustion engines	[12]
CFMDO	Dual fuel (LNG/LBG with MDO pilot fuel)	[54]
CFMDO	Gas turbine	[36]
CFMDO	Not specified	[15–18,20,22,23,26,28,35, 40,47,51,55,56]
CFMGO	Diesel engines (two- and four-stroke; slow- and medium-speed)	[13,37,45,57]
CFMGO	Not specified	[14,15,18,27,29,48–50,52,53,58–61]

Table 4. Fossil marine fuels (VLSFO and LNG) and engine technologies identified in the literature.

Fuel	Engine type	References
VLSFO	Diesel engines (slow- and medium-speed)	[13]
VLSFO	Dual-fuel engines (two- and four-stroke)	[62]
VLSFO	All internal combustion engines	[12]
VLSFO	Not specified	[15,49,50,53,57,63]

2.5.2. Bio-based fuels

Biofuels are considered relevant alternatives for maritime decarbonization because they can be produced from renewable biological feedstocks, including vegetable oils, waste oils, agricultural residues, forest residues, and sugars. Their potential contribution to the maritime energy transition is associated with the possibility of reducing fossil fuel dependence and lowering GHG emissions [30]. Unlike fossil fuels, the CO_2 released during biofuel combustion was previously absorbed from the atmosphere through photosynthesis during biomass growth, partially closing the carbon cycle. Consequently, when produced sustainably and accounting for emissions throughout cultivation, processing, transportation, and distribution, biofuels can achieve substantially lower well-to-wake GHG emissions than conventional marine fuels. However, their environmental performance depends strongly on the feedstock, production route, land-use effects, supply-chain configuration, and lifecycle assessment boundaries.

Within the scope of this study, the biofuel pathways included in the database are Fatty Acid Methyl Ester (FAME), Straight Vegetable Oil (SVO), Hydrotreated Vegetable Oil (HVO), Hydrotreated Pyrolysis Oil (HPO), Dimethyl Ether (DME) from forest residues, ethanol from sugar cane, biomethane, and biomethanol from biomass gasification. These fuels differ significantly in terms of chemical composition, production process, energy density, engine compatibility, storage requirements, and lifecycle emission performance [20]. Therefore, biofuels should not be evaluated as a single homogeneous category, since each pathway presents specific advantages and limitations for maritime applications.

Biomethane (BICH4) and bio-LNG (BILNG) deserve particular attention, since both consist essentially of biogenic methane and yet are treated as separate pathways in this database. The distinction is not molecular but physical and logistical. Biomethane refers to the purified gas obtained mainly from the anaerobic digestion of waste and biomass feedstocks, typically upgraded to pipeline quality and used in gaseous form [26], whereas bio-LNG denotes the same biogenic methane after cryogenic liquefaction, which enables onboard storage at the energy densities required for maritime use. This additional liquefaction step is the reason the two are kept apart: although they share an almost identical lower calorific value and combustion behaviour, bio-LNG carries the extra energy demand, boil-off management, and cryogenic storage requirements associated with liquefaction, while its lifecycle performance remains governed by the same methane slip and upstream leakage that affect any methane-based fuel [24]. Their environmental profiles may therefore diverge despite the shared molecule, depending on feedstock origin, the energy source used in upgrading and liquefaction, and the extent of methane losses along the chain.

From an operational perspective, some biofuels may be compatible with existing marine engines and fuel infrastructure, especially when used as blends or drop-in alternatives. Biodiesel blends, SVO, and hydrotreated biofuels such as HVO are frequently discussed as technically attractive options because they may reduce the need for extensive modifications to propulsion systems and supply chains [31]. In particular, low-percentage biodiesel blends with MDO or MGO and the replacement of HSFO by SVO have been identified as promising options from a technical integration perspective. Nevertheless, issues such as fuel quality, viscosity, cold-flow properties, storage stability, filter clogging, and long-term engine operation must be considered before large-scale adoption.

Advanced biofuel pathways, including HPO, DME from forest residues, ethanol from sugar cane, and biomethanol, may contribute to long-term maritime decarbonization by using biomass residues or renewable feedstocks [25]. However, these fuels often require further technological development, dedicated storage or handling systems, and adaptations in engines or bunkering infrastructure. Alcohol-based fuels, such as ethanol and biomethanol, also tend to present lower energy density than conventional marine fuels, which can increase onboard storage volume requirements and affect vessel autonomy. Therefore, the large-scale adoption of biofuels depends not only on their renewable origin but also on sustainable feedstock supply, production scalability, cost competitiveness, fuel quality standards, and consistent lifecycle emission reductions [1].

Tables 5, 6 and 7 list the biofuels addressed in the present work, together with their respective production pathways. For each fuel, the corresponding pathway specifies the primary feedstock, the conversion process, and the main assumptions adopted in this study. This information ensures consistency and traceability across the different fuel categories considered, providing the basis for the subsequent lifecycle analysis.

Table 5. Biofuel production pathways identified in the literature (BIETH and BIFAME).

Fuel	Production pathway	References
BIETH	First-generation crop-based fermentation (corn/maize, wheat, barley, sugarcane, sugar beet and cassava)	[15,20,21,23,24,27,64]
BIETH	Second-generation lignocellulosic biomass fermentation	[24,33,64]
BIFAME	Virgin vegetable oil transesterification (palm, rapeseed, soybean and sunflower oils; incl. cases excluding ILUC)	[6,20–23,29,36]
BIFAME	Waste- and residue-based transesterification (used cooking oil, waste oils, tallow and forest residues)	[6,15,17,24,64]
BIFAME	Mixed or second-generation feedstocks	[12,20,21,28,40]
BIFAME	Not specified	[43,47,65–69]

Note: Indirect Land-Use Change (ILUC) refers to indirect land-use changes that occur when farmland is shifted from food production to biofuel crops, potentially leading to agricultural expansion into forests or other carbon-rich areas. "Not specified" lists only references that do not identify any production pathway for the fuel; a reference that specifies at least one pathway appears solely in the corresponding row(s).

Table 6. Biofuel production pathways identified in the literature (BIHVO and BISVO).

Fuel	Production pathway	References
BIHVO	Virgin vegetable oil hydroprocessing (palm, rapeseed, soybean and sunflower oils)	[6,21,26]
BIHVO	Waste- and residue-based hydroprocessing (used cooking oil, used oils and rendered animal fats)	[6,21,24,29,33,64]
BIHVO	Mixed or second-generation feedstocks	[12,40,70]
BIHVO	Not specified	[20,47]
BISVO	Pure/straight vegetable oils from oil crops (palm, soybean, sunflower and rapeseed; incl. cases excluding ILUC)	[21–23]
BISVO	Pure oil from used cooking oil	[21]
BISVO	Not specified	[47]

Note: "Not specified" lists only references that do not identify any production pathway for the fuel; a reference that specifies at least one pathway appears solely in the corresponding row(s).

Table 7. Biofuel production pathways identified in the literature (BICH3, BICH4, BILNG, BIDME and BIHPO).

Fuel	Production pathway	References
BICH3	Lignocellulosic and woody biomass (forest residues, wood, wheat straw, corn stover and miscanthus)	[6,17,24,25,28,29,36,71,72]
BICH3	First-generation crop feedstocks (sugar beet and wheat)	[36]
BICH3	Waste-derived feedstocks (incl. cow manure)	[24,28]
BICH3	Not specified	[20,21,23,26,58,63,73]
BICH4	Anaerobic digestion of waste and biomass feedstocks (municipal solid waste, waste-derived feedstocks and lignocellulosic biomass)	[24,26]
BILNG	Mixed and waste-derived feedstocks	[12,15,29]
BILNG	Not specified	[20,22,58,63]
BIDME	Ethanol-derived pathways (corn and non-maize cereals, using forest residues as process fuel)	[21]
BIDME	Lignocellulosic biomass (corn stover and miscanthus)	[6,26]
BIDME	Fossil natural gas pathway	[6]
BIDME	Not specified	[20,23,55]
BIHPO	Forest residue pyrolysis, co-processing and standalone upgrading	[18,25]
BIHPO	Not specified	[23]

Note: "Not specified" lists only references that do not identify any production pathway for the fuel; a reference that specifies at least one pathway appears solely in the corresponding row(s).

2.5.3. E-fuels and renewable fuels

Low-carbon and renewable fuel pathways have gained relevance in maritime decarbonization because their environmental performance depends not only on the fuel molecule itself but also on the production route, energy source, and lifecycle boundaries [1]. In this context, the term green generally refers to renewable-based routes, in which the energy input originates from renewable electricity. This distinction is particularly important for hydrogen, ammonia, and methanol, since the same fuel can present substantially different environmental impacts depending on how it is produced.

Within the scope of this study, the renewable and electrofuel pathways included in the database are mainly associated with hydrogen, ammonia, and methanol. These fuels are frequently discussed as potential alternatives for fossil-free or low-emission shipping, especially when produced from

renewable electricity as electrofuels. Electrolytic hydrogen, electro-ammonia, and electro-methanol can contribute to reducing maritime greenhouse gas emissions when low-carbon electricity is used in their production. However, life-cycle assessment and cost analyses indicate that these options still involve relevant trade-offs, including high carbon abatement costs, increased energy demand, and possible shifts toward other environmental impact categories [10]. Therefore, their evaluation requires a Well-to-Wake or life-cycle perspective rather than an analysis limited to onboard emissions.

Hydrogen is one of the most discussed renewable fuel pathways because it can be produced through water electrolysis using renewable electricity and can be used either directly as a fuel or as an intermediate energy carrier for other fuels. Its main advantage is the possibility of near-zero emissions during use, particularly in fuel cells. However, hydrogen presents important limitations for maritime applications, mainly due to its low volumetric energy density, which increases onboard storage volume requirements and creates challenges related to compression, liquefaction, safety, and fuel handling [11]. These limitations are especially relevant for long-distance shipping, where vessel autonomy and cargo space utilization are critical operational factors.

Ammonia is also considered a promising marine fuel pathway, especially when produced from green hydrogen and nitrogen through a renewable-based Haber-Bosch process [74]. Since ammonia does not contain carbon in its molecular structure, it can eliminate direct carbon dioxide emissions during use. Compared with hydrogen, ammonia offers practical advantages for onboard storage and transport. Ammonia liquefies at $-33\,^{\circ}\mathrm{C}$ under atmospheric pressure, or at approximately 8–10 bar at ambient temperature [34], whereas hydrogen has a critical temperature of 33 K [75] and therefore cannot be liquefied by compression alone, requiring cryogenic storage at 20 K or compression to 350–700 bar [76]. As a result, liquid ammonia also presents a higher volumetric energy density ($\approx 13578\,\mathrm{MJ\,m^{-3}}$) than liquid hydrogen ($\approx 8500\,\mathrm{MJ\,m^{-3}}$) [46]. Nevertheless, its adoption as a marine fuel remains associated with significant challenges, including toxicity, corrosiveness, combustion difficulties, possible nitrogen oxide and nitrous oxide emissions, safety requirements, and the need for further development of engines and fuel systems [77].

E-methanol represents another relevant pathway, synthesized from green hydrogen and captured carbon dioxide. From an operational perspective, methanol has the advantage of being liquid at ambient conditions, which facilitates storage, handling, and compatibility with existing fuel infrastructure when compared with hydrogen and ammonia [48]. However, its lower energy density relative to conventional marine fuels can increase storage volume requirements, and its lifecycle performance depends strongly on the origin of the hydrogen and carbon dioxide used in its production.

Therefore, renewable and electrofuel pathways must be compared through lifecycle and economic perspectives, considering production, storage, distribution, onboard use, infrastructure requirements, and cost competitiveness. Although they represent some of the most promising long-term alternatives for maritime decarbonization, their large-scale adoption still depends on renewable electricity availability, electrolyzer capacity, fuel production infrastructure, safety regulation, technological maturity, and policy incentives [51].

Tables 8 and 9 list the renewable fuels addressed in the present work, together with their respective production pathways. For each fuel, the corresponding pathway specifies the primary feedstock, the conversion process, and the main assumptions adopted in this study. This information ensures consistency and traceability across the different fuel categories considered, providing the basis for the subsequent lifecycle analysis.

Table 8. Renewable fuel production pathways identified in the literature (REEH2, RENH3, CFSH2, EDIE and ECH4).

Fuel	Production pathway	References
REEH2	Water electrolysis using renewable electricity (wind, solar,unspecified renewable sources)	[12,14,21,23,26,28,36,78]
REEH2	Hydrogen production from biomass or fossil feedstock (biomass gasification, coal gasification, natural gas and vegetable steam reforming)	[32]
REEH2	Thermochemical Cu-Cl water-splitting cycle	[32]
REEH2	Not specified	[15,16,22,46,60,67,68,72, 79–81]
RENH3	Ammonia produced from green hydrogen and nitrogen via water electrolysis and Haber-Bosch synthesis using renewable electricity sources (wind, solar or unspecified)	[6,12,14,17,26,28,29,34, 35,82]
RENH3	Not specified	[15,29,39,46,58,63,77,79, 81]
EDIE	Synthetic diesel produced with unspecified renewable electricity source	[12,28]
EDIE	Wood residues	[24]
EDIE	Not specified	[15,24,67,68]
ECH4	Green hydrogen and captured CO_2 using renewable electricity (wind or solar)	[26,33]
ECH4	Unspecified electricity mix	[26]
ECH4	Not specified	[24,61,73]

Note: "Unspecified" qualifiers within a production pathway (e.g. "unspecified renewable sources", "unspecified electricity mix") indicate that the reference defines the pathway but assumes electricity drawn from a blend of renewable sources without identifying the individual generation technologies or their shares. This differs from "Not specified", which lists references that do not identify any production pathway for the fuel; a reference that specifies at least one pathway appears solely in the corresponding row(s).

Table 9. Renewable fuel production pathways identified in the literature (ECFCH3, ECFNH3).

Fuel	Production pathway	References
ECFCH3	Green hydrogen and captured CO_2 using renewable electricity (wind, solar or unspecified renewable sources)	[6,12,26,28,29,58]
ECFCH3	Biomass-based synthesis (lignocellulosic biomass, willow gasification and cow manure)	[24,70]
ECFCH3	Unspecified electricity mix	[58]
ECFCH3	Not specified	[15,24,33,63,72]

Green ammonia (RENH3) and renewable hydrogen from electrolysis (REEH2) are the most prominent pathways within this group, consistent with their central role in long-term maritime decarbonization strategies [6]. Nevertheless, both still face important barriers related to production costs, storage requirements, safety, infrastructure availability, and technological maturity.

E-methanol (ECFCH3) also stands out, associated with the growing interest in synthetic methanol as a marine fuel, since it can be produced using renewable electricity, green hydrogen, and captured carbon [60].

Other electrofuel pathways, such as e-LNG (ELNG), e-diesel (EDIE), and e-methane (ECH4), remain less represented, which may reflect more limited data availability, more recent technological development, or greater uncertainty regarding their large-scale application in maritime transport [33]. Two pathways, e-hydrogen (EH2) and e-ammonia (ECFNH3), yielded no usable records and

were therefore excluded from the analysis, as their entries were consistently reported under the renewable-electricity designations REEH2 and RENH3.

2.5.4. Blue and gray fuel pathways

Blue and gray pathways occupy an intermediate position in the database, since they share the fossil feedstock base of conventional marine fuels but differ from them in molecular composition, production chain, and storage requirements. The distinction between the two rests on carbon capture: gray pathways release the carbon dioxide generated during production to the atmosphere, whereas blue pathways route a fraction of it to permanent storage [83]. Because the molecule delivered to the vessel is identical in both cases, their lifecycle performance is determined entirely upstream, which is why they are treated here as distinct pathways rather than as variants of a single fuel.

Within the scope of this study, the gray pathways included in the database are gray LNG (CFLNG), liquefied petroleum gas (CFLPG), gray methanol (CFCH3), gray ammonia (CFNH3), and gray hydrogen (CFSH2), while the blue pathways comprise blue hydrogen (BLSH2) and blue ammonia (BLNH3).

Gray LNG and LPG differ from oil-based bunker fuels because they consist mainly of light hydrocarbons. LNG contains virtually no sulfur, which reduces sulfur oxide emissions to near zero and almost eliminates particulate matter, while its higher hydrogen-to-carbon ratio yields lower direct carbon dioxide emissions during combustion than conventional fuel oils [24]. For this reason, LNG is frequently discussed as a transitional marine fuel and is already supported by an established bunkering infrastructure. Its lifecycle climate performance, however, remains governed by methane slip and upstream leakage, since unburned methane released during engine operation or along the supply chain can offset a substantial share of the expected reduction. LPG shares the low-sulfur advantage and the benefit of storage at moderate pressure rather than cryogenic conditions, but is considerably less represented in the maritime literature.

Gray hydrogen, gray ammonia, and gray methanol are produced predominantly through steam methane reforming of natural gas, with gray methanol requiring a subsequent synthesis step and gray ammonia a Haber-Bosch step [39]. Coal-based routes are also reported for gray hydrogen, associated with higher lifecycle emissions than the natural gas alternative. These pathways are relevant to the present assessment for two reasons. First, they represent the current industrial baseline: the large majority of hydrogen, ammonia, and methanol produced worldwide today follows an unabated fossil route, and their costs therefore reflect mature technology rather than projected learning effects. Second, they demonstrate that the fuel molecule alone carries no environmental guarantee, since a carbon-free molecule such as ammonia may be associated with lifecycle emissions exceeding those of conventional fuel oils when its hydrogen input is unabated and fossil-derived.

Blue hydrogen is produced from natural gas through steam methane reforming, autothermal reforming, partial oxidation, or natural gas decomposition, in each case combined with carbon capture and storage; blue ammonia follows the same route with a subsequent Haber-Bosch synthesis step [84]. Their lifecycle emission performance is highly sensitive to three factors: the capture rate achieved by the process, which is bounded well below unity in practice; upstream methane leakage along the natural gas supply chain, which is unaffected by carbon capture; and the energy source powering the capture and compression stages. Because these factors vary widely among the reported configurations, blue pathways are best understood as a range of outcomes rather than as a single intermediate position between gray and green routes [38].

Consequently, the classification of a pathway as blue or gray should be read as a description of the production route and its carbon capture configuration, not as a direct ranking of environmental performance. The same molecule may correspond to a high-emission, moderate-emission, or low-emission pathway depending on the feedstock, the capture rate, the upstream methane balance, and the energy used throughout the chain [1]. Their assessment therefore requires the same Well-to-Wake perspective applied to the renewable pathways in Section 2.5.3, with the additional consideration that

blue routes remain dependent on natural gas supply chains and on the long-term availability and integrity of carbon storage capacity.

Tables 10 and 11 list the blue and gray fuels addressed in the present work, together with their respective production pathways. For each fuel, the corresponding pathway specifies the primary feedstock, the conversion process, and the main assumptions adopted in this study. This information ensures consistency and traceability across the different fuel categories considered, providing the basis for the subsequent lifecycle analysis.

Table 10. Gray fuel production pathways identified in the literature (CFLNG, CFCH3 and CFNH3).

Fuel	Production pathways	References
CFLNG	Not specified	[14,17,20,22,23,26,27,39,43,47,51,52,55–58,63,67–69,81,85–88]
CFCH3	All internal combustion engines	[12]
CFCH3	Diesel engines (two- and four-stroke and compression-ignition)	[17,37]
CFCH3	Not specified	[6,14,17,26,27,29,58,69]
CFNH3	Not specified	[6,14,15,17,26,28,34,35,40,55,58,69,71–73,89]
CFLPG	Not specified	[14,15,18,40,47,50,55,56,67,68]
CFSH2	Natural gas-based production (incl. steam methane reforming without CCS, with onsite combustion or grid electricity)	[23,36,38,72]
CFSH2	Coal-based hydrogen production	[36]
CFSH2	Not specified	[12,14,22,26,28,29,46,55,69,79,86–90]

Table 11. Blue fuel production pathways identified in the literature (BLSH2 and BLNH3).

Fuel	Production pathway	References
BLSH2	Fossil-based hydrogen production with CCS (steam methane reforming, autothermal reforming, partial oxidation and natural gas decomposition)	[38,78,83,84]
BLSH2	Liquid blue hydrogen production with CCS (incl. pipeline and LNG-based supply configurations)	[22,78,84]
BLSH2	Not specified	[60,61,73]
BLNH3	SMR	[39,91]
BLNH3	Not specified	[16,73]

3. Results

Based on the developed database, the fuels were evaluated according to three main aspects: physical, environmental, and economic properties. The fuels were then compared with one another by a multicriteria analysis. The physical assessment (Section 3.3) considered parameters related to fuel energy performance, particularly the lower calorific value (LCV). The environmental assessment (Section 3.1) focused on greenhouse gas (GHG) emissions, enabling a comparison of the lifecycle environmental impacts associated with each fuel. Finally, the economic assessment (Section 3.2) evaluated projected fuel prices across different decades, providing insights into future market trends

and the economic competitiveness of each fuel pathway. The combination of these three aspects (Section 3.4) allows for a comprehensive evaluation of alternative fuels for the maritime sector.

3.1. Emissions Assessment

Figure 2 presents the median greenhouse gas emissions of the evaluated fuels under a WTW approach. For this assessment, only the 100-year Global Warming Potential (GWP100) was considered, as it remains the most widely adopted metric in lifecycle assessment studies and greenhouse gas inventories. The choice of GWP100 is conservative for methane-based pathways. Under a GWP20 horizon, methane's warming effect is roughly 2.5–3 times higher, which would substantially worsen the lifecycle position of LNG-based fuels (CFLNG, BILNG, ELNG, ECH4) relative to liquid alternatives, given their exposure to upstream leakage and engine methane slip. The rankings reported here should therefore be read as horizon-dependent, particularly for the methane group. The fuels were organized into four groups: e-fuels/refuels, biofuels, other non-fossil fuels, and fossil fuels. Each boxplot represents the dispersion of the WTW emission values obtained for the different production routes of a given fuel, while the red line connects the medians of each pathway.

The most striking aspect of the figure is the difference in dispersion among the groups. Fossil fuels (VLSFO, CHSFO, CFMGO, and CFMDO) present the lowest variation, with medians concentrated around 93 gCO_2eq/MJ and narrow interquartile ranges. This behavior stems from the homogeneity of their production chains: the production routes and energy sources used in extraction and refining are essentially the same, resulting in a stable and predictable carbon footprint. As mature and highly standardized technologies, there is little room for lifecycle emissions to deviate from the central value.

In contrast, e-fuels and biofuels exhibit much wider interquartile ranges, showing that their emissions are strongly dependent on the energy source and feedstock used in production. The most expressive cases are those of hydrogen and ammonia. The CFNH3 (ammonia) and CFSH2 (hydrogen) pathways, for example, display a very broad dispersion because, even as fossil-based routes, the carbon intensity of the energy used at each stage of the process- extraction, reforming, and synthesis- can vary considerably depending on the energy mix and the technology adopted. This sensitivity drives the CFNH3 median above 120 gCO_2eq/MJ, placing it among the highest emitters in the figure. In other words, even within a fossil route, the lifecycle carbon footprint is far from a fixed value: it responds directly to the energy sources that power the production process.

This contrast becomes even clearer when comparing pathways of different origins for the same fuel. In the case of hydrogen, renewable electrolytic pathways (such as REEH2) rank among the lowest emitters in the figure, while fossil-based routes, such as CFSH2 itself, are positioned in substantially higher ranges. The same reasoning applies to ammonia, whose environmental performance is directly tied to how the hydrogen it contains was produced. Biofuels (such as BICH4, BICH3, and BIHVO), in turn, tend to occupy the lower range of the chart, although they also show relevant dispersion due to the diversity of feedstocks and conversion processes associated with each route. Part of the dispersion observed for FAME and SVO, however, stems from whether the underlying sources accounted for ILUC, rather than from feedstock or conversion differences alone.

The blue pathways, CFNH3 and CFSH2, show how conditional the benefit of carbon capture can be. Both display the widest dispersions of their group, and their medians remain only modestly below those of conventional fossil fuels. This spread reflects the dependence of blue routes on the capture rate actually achieved and on methane leakage upstream: when both are favorable, blue hydrogen and ammonia approach low-carbon performance; when either fails, their advantage over the corresponding gray routes largely disappears. The gray pathways not yet discussed, CFLNG and CFCH3, behave more predictably, with narrower dispersions typical of well-established natural gas conversion chains. Their position is nonetheless revealing: neither offers a meaningful reduction relative to conventional marine fuels, despite the additional processing they require. Taken together, the group reinforces the point made above for hydrogen and ammonia: without decarbonizing the upstream chain, molecular substitution may displace emissions rather than reduce them.

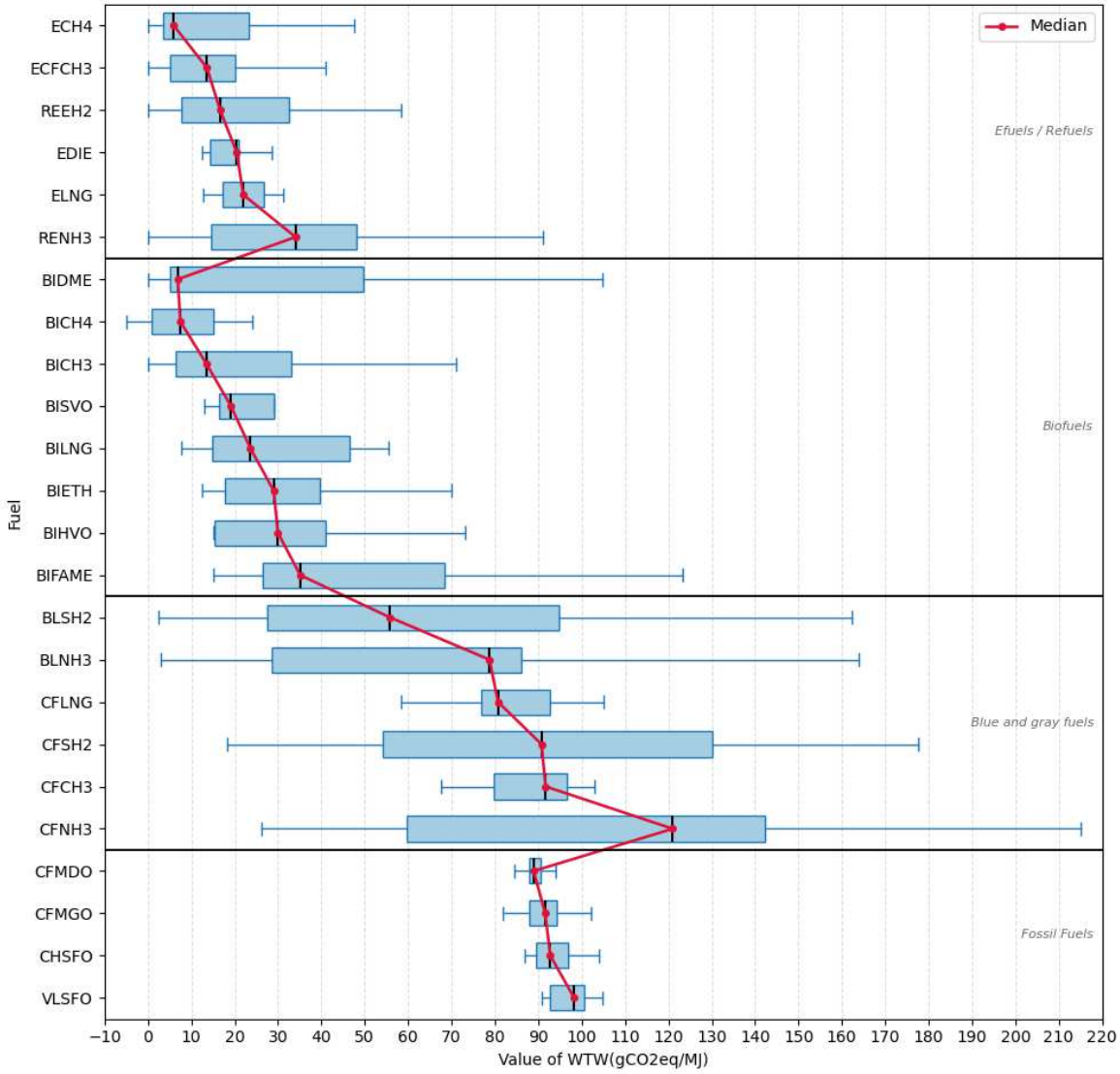


Figure 2. Well-to-wake greenhouse gas emissions of the evaluated marine fuels.

In summary, the figure demonstrates that the variability of a fuel's emissions largely reflects the flexibility of its production chain. Fuels with rigid and homogeneous routes — such as fossil fuels — present stable performance but no decarbonization potential. Alternative fuels, particularly hydrogen and ammonia, offer high emission-reduction potential, but this potential only materializes when the energy and feedstocks used in their production are low-carbon. This result reinforces the importance of evaluating fuels from a lifecycle perspective, since environmental performance cannot be inferred solely from onboard combustion but depends on the entire chain that precedes final use.

3.2. Economic Assessment

The economic assessment was performed considering four distinct time horizons (2020, 2030, 2040, and 2050), allowing the evaluation of projected fuel price evolution over time. This approach provides insights into the long-term competitiveness of alternative marine fuels and enables the identification of market trends associated with the energy transition of the maritime sector. The selected years are particularly relevant because they encompass the main milestones established by the International Maritime Organization (IMO) for greenhouse gas emission reduction and the progressive decarbonization of international shipping.

Figures 3, 4, 5 and 6 present the projected fuel prices for all evaluated fuel pathways across the analyzed time horizons, organized into four groups: e-fuels/refuels, biofuels, blue and gray fuels,

and fossil fuels. Each boxplot represents the dispersion of the price values reported for the different production routes of a given fuel, while the red line connects the medians of each pathway. The results indicate significant differences in fuel costs, reflecting the maturity level of each technology, feedstock availability, production complexity, and infrastructure requirements. Conventional fossil fuels such as CHSFO, VLSFO, CFMDO, and CFMGO generally exhibit the lowest prices and the narrowest dispersions, benefiting from established supply chains and mature production systems. The corresponding descriptive statistics, the number of data points, and the first, second, and third quartiles for each pathway are reported in Table A2 and A3 which allow the values discussed in this section to be inspected directly.

It should be noted that the number of data points varies considerably across pathways and time horizons, and that some pathways are not represented in every decade. This uneven coverage is a direct consequence of the availability of price data in the consulted sources: for certain fuels, no projected values were reported for particular decades, and no estimation or interpolation was applied to fill these gaps.

Among the alternative fuels, ammonia-based pathways generally present lower costs than hydrogen-based pathways throughout the analyzed period. In contrast, renewable and low-carbon hydrogen routes remain among the most expensive alternatives, with prices frequently exceeding 3000 USD/ton and displaying wide dispersions that reflect the diversity of production routes and energy sources considered. These results are associated with the high energy requirements of hydrogen production, storage, transportation, and distribution, as well as the relatively low technological maturity of some production pathways.

Biofuels occupy an intermediate position between conventional fossil fuels and hydrogen-based alternatives. Depending on the feedstock and production route, some biofuels exhibit prices that approach those of conventional marine fuels, while others remain significantly more expensive. This behavior suggests that biofuels may represent a transitional solution for maritime decarbonization, combining relatively low lifecycle emissions with a level of economic competitiveness that is more favorable than several emerging fuel technologies.

In the 2020 horizon (Figure 3), REEH2 stands out with the highest median price and a particularly broad dispersion, followed by EDIE and ECH4, confirming the elevated costs associated with hydrogen-based and synthetic fuels at the beginning of the analyzed period. Conventional fossil fuels, in contrast, remain concentrated at the lower end of the price range. Over the subsequent horizons (Figures 4, 5, and 6), a gradual redistribution of the medians can be observed, with hydrogen-based pathways such as BLSH2 and CFSH2 consistently occupying the upper range, while EDIE remains among the most expensive alternatives throughout the entire period.

The results also indicate that conventional fossil fuels remain among the most economically competitive alternatives throughout much of the analyzed period. Among the alternative fuels, ammonia-based pathways demonstrate particularly favorable economic performance, especially CFNH3, which maintains prices comparable to several conventional fuels throughout the entire time horizon. Some biofuel pathways, including BIETH, BICH4, and BIHVO, also exhibit declining or relatively stable cost trajectories, suggesting benefits associated with technological maturation and increased production scale.

A general trend observed throughout the analyzed period is the gradual reduction in the cost of several renewable fuel pathways. This behavior can be attributed to technological learning effects, production scale expansion, and the expected development of supporting infrastructure. Nevertheless, significant cost differences persist among the evaluated technologies, indicating that economic considerations will remain a key factor influencing the adoption of alternative fuels and the achievement of IMO decarbonization targets by 2050.

3.3. Physical Assessment

The physical assessment was based on the lower calorific value (LCV) of each evaluated fuel, expressed in MJ/kg, and on the volumetric energy density (ED), expressed in MJ/m^3, as presented in

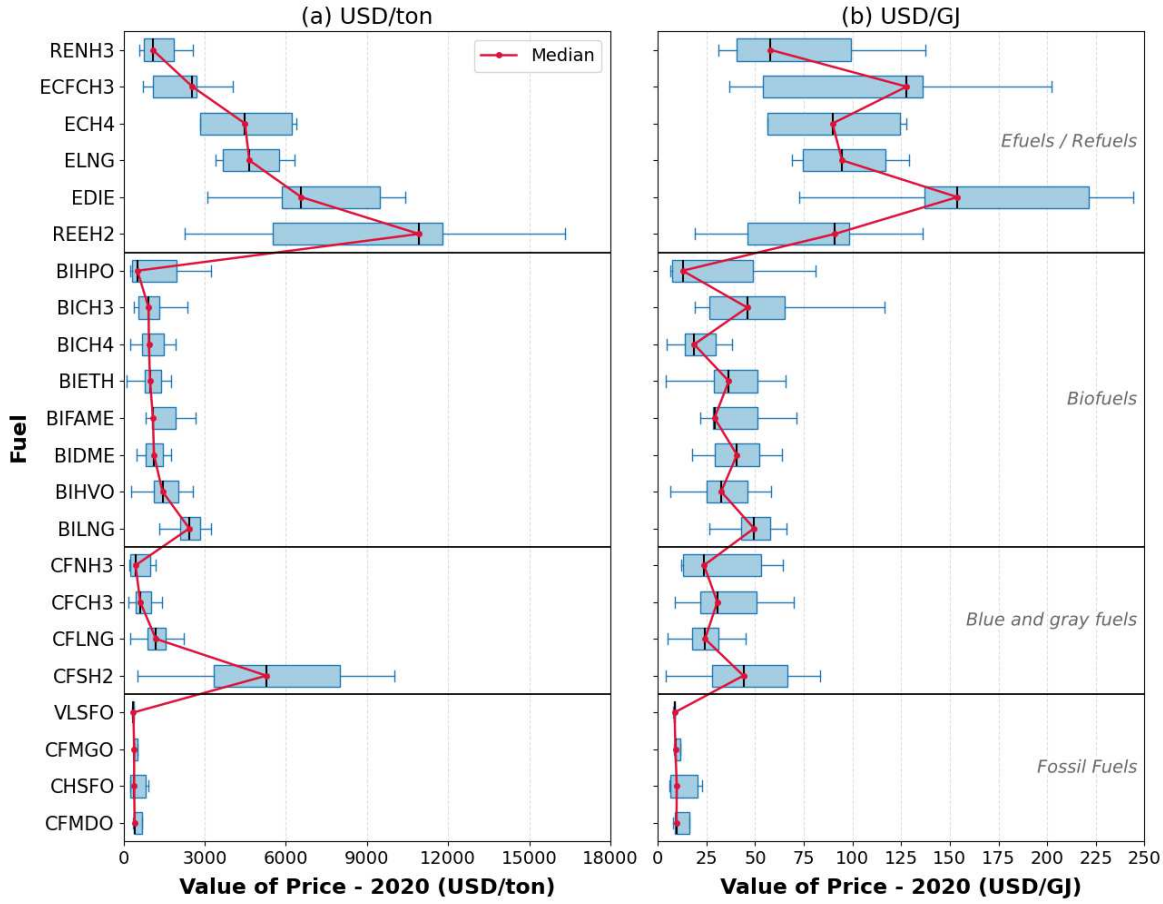


Figure 3. Price distribution of the evaluated marine fuel pathways in 2020: (a) in USD/ton and (b) in USD/GJ.

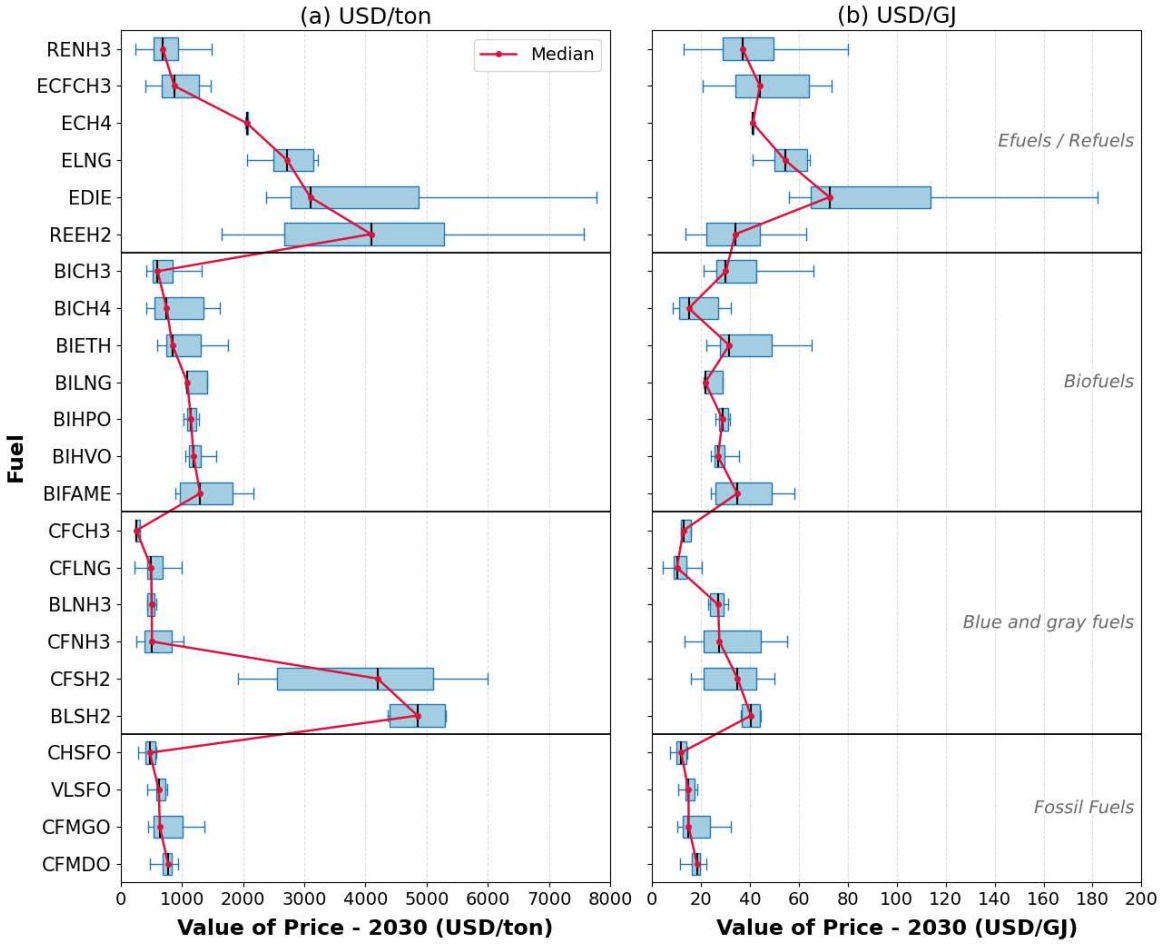


Figure 4. Price distribution of the evaluated marine fuel pathways in 2030: (a) in USD/ton and (b) in USD/GJ.

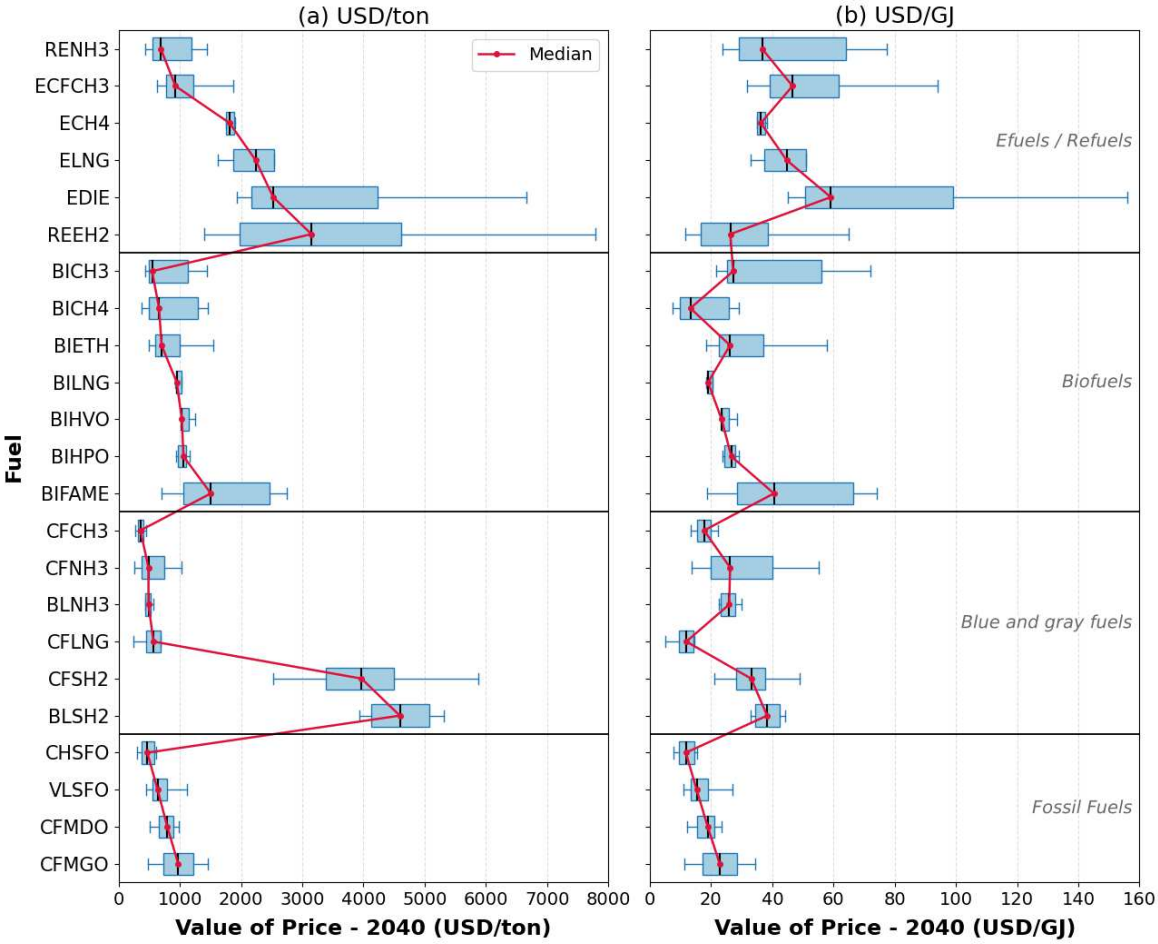


Figure 5. Price distribution of the evaluated marine fuel pathways in 2040: (a) in USD/ton and (b) in USD/GJ.

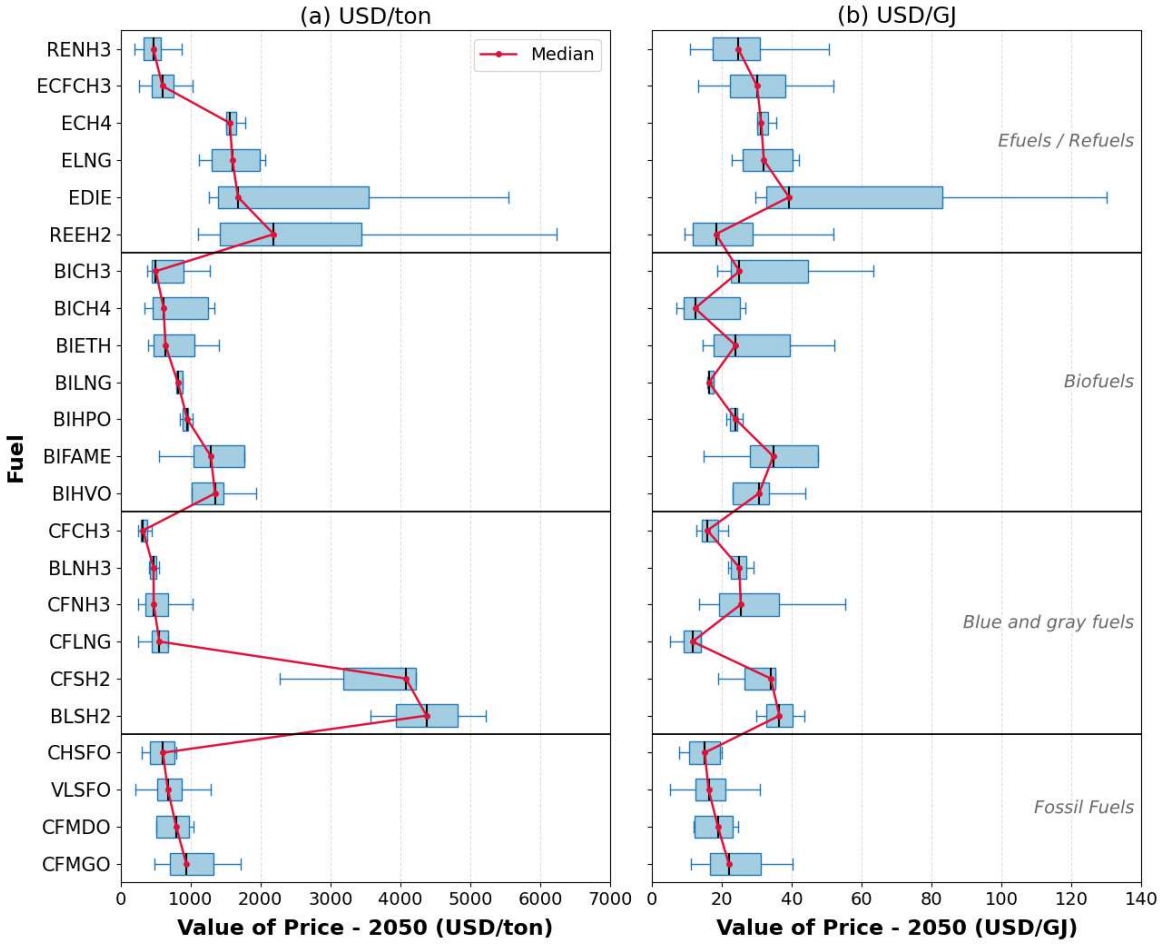


Figure 6. Price distribution of the evaluated marine fuel pathways in 2050: (a) in USD/ton and (b) in USD/GJ.

Table 12. To facilitate comparison among the different fuel pathways, both metrics were also expressed as a percentage relative to VLSFO, which was adopted as the reference fuel due to its widespread use in current maritime operations. The joint use of the two metrics is essential, since a fuel may perform well on a mass basis and poorly on a volume basis, a distinction that has direct consequences for tank sizing and vessel autonomy.

Unlike the environmental and economic parameters reported in Sections 3.1 and 3.2, which are characterized through quartiles, the physical properties are presented as single representative values. This choice reflects the nature of the underlying data: LCV and ED are intrinsic properties of the fuel molecule and its physical state, and the dispersion observed across sources arises predominantly from rounding conventions, reference conditions, and measurement precision rather than from genuine differences among production configurations. The values reported in Table 12 correspond to the median of the observations compiled for each pathway.

The results indicate substantial differences in energy density among the evaluated fuels, which are directly associated with their chemical composition and production pathway. Conventional fossil fuels, including CHSFO, VLSFO, CFMDO, and CFMGO, present LCV values ranging from approximately 39.96 to 42.70 MJ/kg, remaining close to the VLSFO reference (95.8% to 102.4%). On a volumetric basis, the same fuels range from 36,534.12 to 41,500.00 MJ/m^3 (88.03% to 100.00%), and it is worth noting that CFMDO and CFMGO, which slightly exceed VLSFO in gravimetric terms, fall below it volumetrically due to their lower density. Even so, the deviations remain modest. This similarity reflects the comparable hydrocarbon-based composition of these fuels and explains their established compatibility with existing marine engines and fuel storage systems.

Methane-based pathways, including CFLNG, ELNG, BILNG, BICH4, and ECH4, exhibit slightly higher LCV values, between 49.10 and 50.00 MJ/kg, corresponding to 117.7% and 119.9% of the VLSFO reference. This behavior is consistent with the higher hydrogen-to-carbon ratio of methane-based fuels, which generally results in greater energy content per unit mass when compared with conventional liquid fuels. This advantage, however, is reversed when volume is considered: at 20,965.70 MJ/m^3, methane-based fuels retain only 50.52% of the VLSFO reference, since liquefaction at cryogenic temperatures still yields a much lower density than that of liquid hydrocarbons. In practice, roughly twice the tank volume would be required to store the same amount of energy.

In contrast, alcohol-based and nitrogen-based fuels present considerably lower energy density. Ethanol (BIETH) shows an LCV of 26.80 MJ/kg (64.3% relative to VLSFO), while methanol-based pathways (BICH3 and ECFCH3) present even lower values, between 19.90 and 20.10 MJ/kg (47.7% to 48.2%). Ammonia-based fuels (CFNH3, ECFNH3, RENH3, and BLNH3) present the lowest LCV among all evaluated pathways, at 18.60 MJ/kg, corresponding to only 44.6% of the VLSFO reference. Volumetrically, ethanol reaches 21,198.80 MJ/m^3 (51.08%), methanol 16,039.00 MJ/m^3 (38.65%), and ammonia 13,578.00 MJ/m^3 (32.72%). It is worth noting that alcohols, being liquids at ambient conditions, lose comparatively less when moving from the mass basis to the volume basis than cryogenic fuels do, which partly offsets their poor gravimetric performance. These results highlight a key operational limitation of alcohol- and ammonia-based fuels: their reduced gravimetric energy density implies that a substantially larger fuel mass and storage volume would be required to deliver the same amount of energy as conventional marine fuels, directly affecting vessel autonomy and cargo space availability.

Hydrogen-based pathways (CFSH2, REEH2, and BLSH2) present the highest LCV among all evaluated fuels, reaching 119.97 MJ/kg, equivalent to 287.7% of the VLSFO reference. The volumetric metric, however, reverses this picture entirely: at 8,500.00 MJ/m^3, liquid hydrogen retains only 20.48% of the VLSFO reference, the lowest value in the entire table. In other words, the fuel that carries nearly three times more energy per kilogram carries almost five times less per cubic metre, a consequence of the extremely low density of hydrogen even in its liquid state. This divergence between the two metrics is the most pronounced in the dataset and confirms that gravimetric performance alone offers

a misleading picture of hydrogen's viability, reinforcing the storage and tank capacity challenges discussed in Section 2.5.3.

Overall, the physical assessment indicates that the two metrics tell partly opposing stories, and that volumetric energy density is the more restrictive criterion for maritime application. Only hydrocarbon-based pathways remain close to the operational profile of conventional marine fuels under both metrics; methane-, ammonia-, alcohol-, and hydrogen-based alternatives all fall to between 20% and 51% of the VLSFO reference volumetrically, implying tank volumes two to five times larger for equivalent autonomy. This trade-off between gravimetric energy content, volumetric storage requirements, and vessel design constraints must therefore be weighed alongside the environmental and economic criteria addressed in the following sections.

Table 12. Lower calorific value (LCV) and energy density (ED) of the evaluated fuels compared with VLSFO.

Fuel	LCV MJ/kg	VLSFO %	ED MJ/m^3	VLSFO %
Fossil fuels				
CHSFO	39.96	95.8	39600.00	95.42
VLSFO	41.70	100.0	41500.00	100.00
CFMDO	42.10	101.0	37486.00	90.33
CFMGO	42.70	102.4	36534.12	88.03
Biofuels				
BIFAME	37.20	89.2	32736.00	78.88
BICH4	50.00	119.9	20965.70	50.52
BIHVO	44.10	105.8	34398.00	82.89
BIETH	26.80	64.3	21198.80	51.08
BICH3	20.10	48.2	16039.00	38.65
BILNG	49.10	117.7	20965.70	50.52
E-fuels / Refuels				
ECFCH3	19.90	47.7	16039.00	38.65
ECH4	50.00	119.9	20965.70	50.52
ELNG	49.10	117.7	20965.70	50.52
EDIE	42.70	102.4	37486.00	90.33
RENH3	18.60	44.6	13578.00	32.72
REEH2	119.97	287.7	8500.00	20.48
Blue or gray fuels				
CFLNG	49.10	117.7	20965.70	50.52
CFNH3	18.60	44.6	13578.00	32.72
CFSH2	119.97	287.7	8500.00	20.48
CFCH3	19.90	47.7	16039.00	38.65
BLNH3	18.60	44.6	13578.00	32.72
BLSH2	119.97	287.7	8500.00	20.48

3.4. Comparative Fuel Assessment

While individual assessments of environmental performance, fuel properties, and economic competitiveness provide valuable insights, decision-making in maritime decarbonization requires the simultaneous consideration of multiple criteria. A fuel exhibiting excellent environmental performance may present significant economic barriers, whereas economically attractive fuels may offer limited emission reduction potential. Therefore, a Comparative Fuel Assessment was performed to identify fuel pathways that provide the best overall balance among environmental, physical, and economic aspects [70].

Three evaluation criteria were considered in the analysis: lifecycle greenhouse gas emissions (WTW GWP100), physical fuel properties, and projected fuel price. The environmental criterion was represented by the median WTW GHG emissions calculated previously. The physical criterion was represented by the combination of two properties, the lower calorific value (LCV) and the energy density (ED) of each fuel, in order to capture both the gravimetric and volumetric dimensions of

onboard energy storage. The economic criterion was determined using the average projected fuel price across the analyzed time horizon (2020-2050).

The average fuel price was calculated according to Equation 1, where $Price_i$ represents the projected fuel price for each evaluated year and N corresponds to the number of available price projections for each fuel pathway. To enable a direct comparison between criteria with different units and magnitudes, all variables were normalized on a scale ranging from 0 to 10.

$$Price_{avg} = \frac{\sum_{i=1}^{N} Price_i}{N} \tag{1}$$

$$Score_{GHG} = 10\left(\frac{GHG_{max} - GHG_i}{GHG_{max} - GHG_{min}}\right) \tag{2}$$

$$Score_{LCV} = 10\left(\frac{LCV_i - LCV_{min}}{LCV_{max} - LCV_{min}}\right) \tag{3}$$

$$Score_{ED} = 10\left(\frac{ED_i - ED_{min}}{ED_{max} - ED_{min}}\right) \tag{4}$$

$$Score_{Phys} = \frac{Score_{LCV} + Score_{ED}}{2} \tag{5}$$

$$Score_{Cost} = 10\left(\frac{Cost_{max} - Cost_i}{Cost_{max} - Cost_{min}}\right) \tag{6}$$

$$Score_{Final} = w_{GHG} \cdot Score_{GHG} + w_{Cost} \cdot Score_{Cost} + w_{Phys} \cdot Score_{Phys} \tag{7}$$

$$Score_{Final} = 0.50\, Score_{GHG} + 0.30\, Score_{Cost} + 0.20\, Score_{Phys} \tag{8}$$

The resulting ranking provides an integrated perspective of fuel performance and highlights the trade-offs associated with each technological pathway. Fuels achieving high scores demonstrate a favorable balance between emissions reduction, energy performance, and economic viability, whereas fuels with lower scores generally exhibit weaknesses in one or more of the evaluated dimensions. The Comparative Fuel Assessment (CFA) framework allows a more comprehensive comparison than isolated analyses and supports the identification of fuel pathways that may represent the most promising alternatives for achieving the International Maritime Organization (IMO) decarbonization targets. Furthermore, the methodology facilitates the evaluation of how improvements in technology maturity, production scale, and market conditions may affect the overall competitiveness of alternative marine fuels over time.

The results of the CFA are summarized in Figure 7, which presents the normalized scores for the GHG, Cost, and Physical criteria as bar series, together with the resulting Final Score displayed as a line on a secondary axis. This visualization allows the simultaneous interpretation of how each individual criterion contributes to the overall ranking of each fuel pathway, while keeping the aggregated Final Score visually distinguishable from the individual normalized scores.

The ranking reveals a clear separation between the highest-performing alternative pathways and the conventional, gray, and blue pathways concentrated in the lower portion of the Final Score ranking. Conventional fossil fuels such as CHSFO, CFMDO, CFMGO, and VLSFO benefit from high Cost scores and relatively favorable physical properties, but their poor GHG performance substantially limits their overall competitiveness under the adopted weighting scheme. A similar trade-off is observed for several gray and blue pathways, although the relative contribution of each criterion varies considerably among fuels.

The lowest Final score is obtained by CFSH2, reflecting the combined effect of poor lifecycle GHG performance and a very low Cost score associated with its high projected fuel price. CFNH3

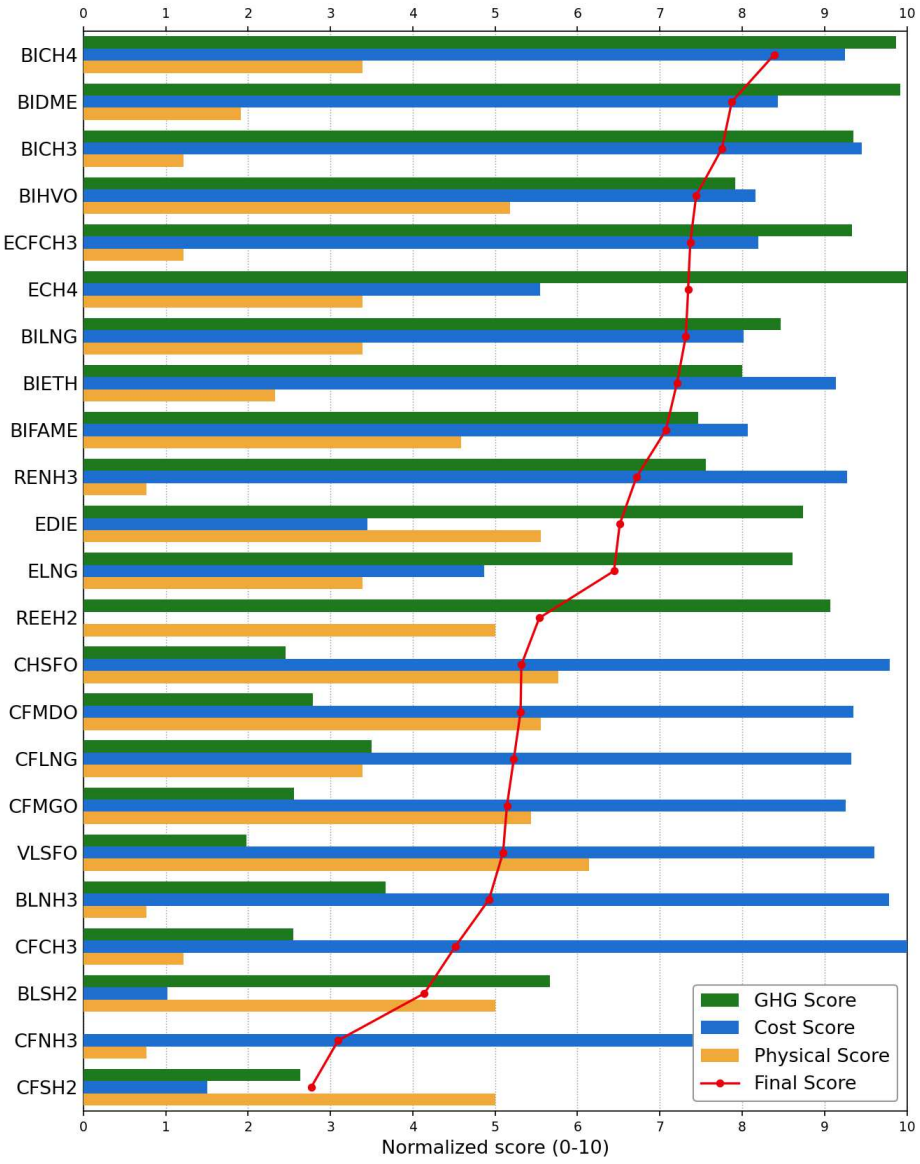


Figure 7. Comparative assessment of the evaluated marine fuels, showing the normalized scores for each criterion and the aggregated Final Score.

also occupies one of the lowest positions in the ranking, but for a different reason, despite its highly favorable Cost score, it presents the lowest GHG score of all evaluated pathways and a very low Physical score due to the limited gravimetric and volumetric energy performance of ammonia. Blue pathways also remain in the lower portion of the ranking, BLSH2 is strongly penalized by its low Cost score, whereas BLNH3 combines favorable economic performance with comparatively poor GHG and Physical scores.

Intermediate positions are occupied primarily by EDIE, ELNG and REEH2.These pathways illustrate the trade-offs inherent in emerging electrofuels and renewable fuels. EDIE and REEH2 achieve favorable GHG scores but are penalized by their comparatively low Cost scores, reflecting high projected fuel prices. ELNG presents a more balanced performance among the three criteria, although its economic and physical advantages are not sufficient to place it among the highest-ranked pathways.

The highest Final Scores are achieved by BICH4, BIDME, BICH3, BIHVO, ECFCH3, and ECH4, which occupy the upper portion of the ranking. BICH4 obtains the highest overall score, combining an excellent GHG performance with a highly favorable Cost score, despite a comparatively moderate Physical score. Biofuel pathways are particularly prominent among the highest-ranked alternatives, with BICH4, BIDME, BICH3, and BIHVO occupying four of the six leading positions. ECFCH3 and ECH4 also achieve high Final Scores because their strong lifecycle GHG performance compensates for limitations in their physical or economic performance.

These results demonstrate that, under the adopted weighting scheme, strong lifecycle environmental performance has a decisive influence on the overall ranking. Since the GHG criterion accounts for 50% of the Final Score, pathways with low lifecycle emissions can remain highly competitive even when their cost or physical performance is less favorable. Conversely, fuels with mature supply chains and low projected costs may occupy lower positions when their lifecycle GHG performance is poor. This outcome is consistent with the weighting structure defined in Equation 8, which assigns the environmental criterion twice the relative importance of the physical criterion and approximately 1.67 times the importance of the economic criterion.

Consequently, the CFA framework adopted in this study reflects a decarbonization-oriented prioritization, in which pathways capable of substantially reducing lifecycle GHG emissions are favored over alternatives whose main advantages are limited to cost competitiveness or energy density. The resulting ranking should therefore be interpreted as a consequence of the selected weighting structure rather than as an absolute measure of fuel superiority, while remaining consistent with the IMO's long-term objective of reducing lifecycle GHG emissions from international shipping.

3.5. Group-level analysis of cost and Well-to-Wake emissions

While the previous sections examined each fuel individually, this subsection aggregates the selected fuels into three families: conventional fuels, biodiesel, and Zero- and Near-Zero-emission fuels (ZNZ). The grouping mirrors the categories in which the sector's regulatory instruments treat marine fuels, and allows the results to be read against targets defined at family level rather than per individual pathway.

The conventional group comprises CHSFO, VLSFO and CFMDO; the biodiesel group is represented by BIFAME; and the ZNZ group comprises BIETH, RENH3 and REEH2. For each group and year, the first, second and third quartiles (Q_1, Q_2, Q_3) were computed separately for each pathway from its own observations, and then combined across the pathways of the group by arithmetic averaging at each quantile level. Pathway-level empirical quantiles were estimated by linear interpolation between order statistics at plotting positions $p_k = (k-1)/(n-1)$, corresponding to the type 7 estimator in the typology of Hyndman and Fan [92], the definition adopted throughout this work.

$$F^{-1}(\alpha) \;=\; \sum_{i=1}^{G} w_i \, F_i^{-1}(\alpha), \qquad 0 < \alpha \leq 1. \tag{9}$$

Since a convex combination of non-decreasing functions is itself non-decreasing, Equation 9 defines a valid quantile function, which guarantees $Q_1 \leq Q_2 \leq Q_3$ at group level by construction. It is the quantile function of the weighted average of pathway values under comonotonicity, which admits a direct reading: it is the value of a basket holding a fixed share of each pathway in the group. Equal weights were adopted, so that each pathway contributes identically regardless of how many observations the literature reports for it.

The choice of this aggregation follows from the question this section poses. A fuel group, here, is not a sample of the literature: it is a set of technological pathways across which a shipowner may distribute demand. The relevant statistic is therefore that of a basket holding a defined share of each pathway. Three properties support the choice. The first is invariance to bibliographic coverage: the weights w_i are fixed by the analyst and do not change when new studies on a particular pathway are published. The second is representativeness: every pathway in the group influences the group value at any quantile level, in exact proportion to the weight assigned to it. The third is auditability, since the group value is the mean of individually verifiable pathway-level statistics, which makes the contribution of each technology explicit. For single-pathway groups such as biodiesel, the Vincent average coincides exactly with the sample quantile of the pooled set, so that the dispersion observed there is entirely within-pathway.

Two alternative specifications were evaluated to test the sensitivity of this choice. The first pools all observations assigned to a group and computes the quantiles of the pooled set; this weights each pathway by the number of observations available for it, a property of the coverage of the compiled literature rather than of the technologies themselves. The second computes the quantiles of the mixture distribution in which each pathway carries equal weight, equivalent to assigning weight $1/n_i$ to each observation of pathway i. Both answer a question distinct from the one posed here, namely what value would be observed when drawing an estimate at random from the compiled body of work. Results are reported in Table 13. The ordering of the three groups is preserved under every specification, for both price and carbon intensity, but the margin separating ZNZ from biodiesel under the two quantile-based specifications is only 2.4 % and 0.3 %, that is, of the order of rounding.

Table 13. Group medians for 2029 under the three aggregation specifications, for the quantities analysed. The mean of quartiles is the specification adopted throughout. Interpolation applies to price only, the carbon-intensity data having no temporal dimension.

Group	Mean of quartiles	Pooled	Equal pathway weight
WTW carbon intensity (gCO_2eq/MJ)			
Conventional	93.6	92.8	92.2
Biodiesel	35.1	35.1	35.1
ZNZ	26.6	21.1	24.1
Price, mass basis (USD/ton)			
Conventional	601	554	584
Biodiesel	1276	1276	1276
ZNZ	2120	1306	1280
Price, energy basis (USD/GJ)			
Conventional	15	14	14
Biodiesel	34	34	34
ZNZ	37	37	37

The divergence between specifications is concentrated in the ZNZ group and has an identifiable cause. The price medians of its three pathways differ by a factor of 5.9 on a mass basis, and Figures 3 and 4 show that the renewable hydrogen distribution lies above those of ethanol and ammonia over its entire extent, lower quartile included. Consequently the REEH2 observations influence only the count that fixes the position of the pooled median, never the value it takes. The pooled ZNZ median is, in that sense, the median of a subset from which one of the three technologies has been silently excluded,

whereas the Vincent average assigns each of them the one-third weight declared for it. The difference between specifications therefore measures how much the quantile-based aggregation discards, not how much the Vincent average distorts. In numerical terms, the 2029 median of the ZNZ group is 2120 USD/ton under the Vincent average, against 1306 and 1280 under the pooled and equal-weight specifications, a difference of 65.6 %; the conventional group, whose pathways have similar price levels, varies by only 8.5 % across the three, and biodiesel does not vary. That this divergence is a property of the mass basis rather than of the estimator is shown by repeating the comparison per unit of delivered energy, where the three specifications return the same 37 USD/GJ for the ZNZ group and the same 34 for biodiesel, and differ only for the conventional group, by 15 against 14 USD/GJ (Table 13). Once hydrogen is measured by the energy it carries rather than by its mass, it ceases to be an outlier within its group, and the choice of aggregation rule stops mattering.

A further objection deserves examination. The interquartile range produced by the Vincent average is narrower than that of the pooled specification, since $\sum_i w_i Q_{3,i} - \sum_i w_i Q_{1,i} = \sum_i w_i (Q_{3,i} - Q_{1,i})$, that is, the weighted mean of within-pathway ranges, whereas the pooled range also incorporates between-pathway dispersion. This narrowing is not an understatement but the diversification effect proper to a fixed-composition basket, whose dispersion is necessarily lower than that of a draw across pathways at different levels. It should be added that, among all copulas compatible with given marginals, the comonotonic one maximises the dispersion of the sum; the range of Equation 9 is therefore an upper bound on the dispersion of any basket formed from these pathways, not a lower one.

Finally, the scope of a known result should be delimited: quantile averaging reproduces the shape of the component distributions exactly only when these belong to a common location–scale family [93,94]. That restriction applies to the inferential use of the procedure, that is, to the recovery of a latent distribution common to the pathways, which is not the purpose adopted here. The target of this section is descriptive and defined directly by Equation 9, the quantiles of a basket of known composition, an object that remains well defined whatever the family of the component distributions.

Group prices are reported in USD per tonne of fuel, the unit in which the original sources express them and in which marine fuel is contracted, delivered and invoiced, mass being the quantity recorded on the bunker delivery note. Reporting in this unit avoids introducing calorific-value assumptions into the price data, so that the uncertainty shown is that of the sources themselves, and preserves comparability with panel (a) of Figures 3 and 4. Since the pathways considered span lower calorific values from 18.6 MJ/kg for ammonia to 120 MJ/kg for hydrogen [95], one tonne of one pathway does not deliver the same energy as one tonne of another; energy-basis values, in USD per gigajoule of delivered energy, are therefore reported alongside in panel (b) of Figure 8, and it is on those that the abatement costs below are computed.

Since the comparison year adopted is 2029, group quartiles for that year were obtained by linear interpolation between the two decades that bracket it, 2020 and 2030. No model was fitted to the four-decade series and no extrapolation was performed: the interpolated value is a weighted average of two reported quartiles, with 2029 lying at 90 % of the interval. Since the Vincent average and linear interpolation are both linear operations, the two commute, so that the result does not depend on whether pathways are aggregated first and interpolation applied afterwards, or the reverse. Sensitivity to the rule is correspondingly small, since 2029 lies at nine tenths of the interval, where the two rules nearly coincide: log-linear interpolation over the same interval shifts the group medians by a few per cent at most. Interpolation was used exclusively to align the comparison year, and was not applied to fill missing observations in the original dataset.

Figure 8 presents the expected price distribution of each group in 2029 on both unit bases. In panel (a), per tonne of fuel, the conventional group shows the lowest and by far the most concentrated range (Q_1–Q_3: 532–699 USD/ton, median 601, with an interquartile range equal to 28 % of the median), biodiesel occupies an intermediate position (972–1831, median 1276), and ZNZ the highest (1424–2758, median 2120). The conventional group overlaps neither of the other two, and is separated

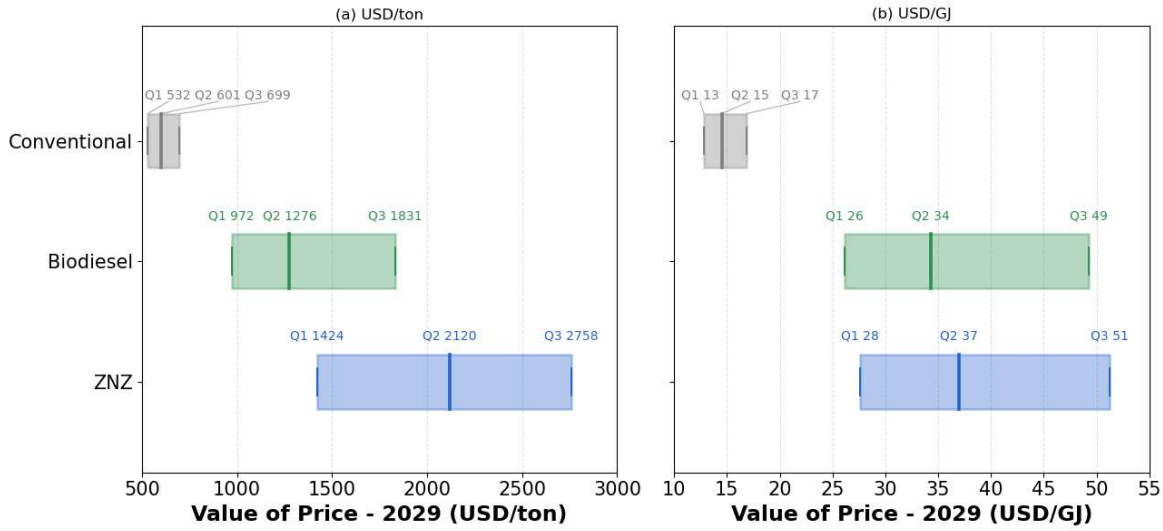


Figure 8. Price distribution by fuel group in 2029, on two unit bases: (a) per tonne of fuel and (b) per gigajoule of delivered energy. Boxes span the interquartile range (Q_1 to Q_3) and the internal line marks the median (Q_2); whiskers and outliers are not shown. Quartiles were computed per pathway and combined across the pathways of each group by arithmetic averaging at each quantile level (Vincent average), with 2029 values linearly interpolated between the 2020 and 2030 decades. The conversion to an energy basis was applied to each observation before aggregation, using the lower calorific values of Annex II of the FuelEU Maritime Regulation [95].

from biodiesel by a gap of 273 USD/ton. Between the two low-carbon families, the medians are 66 % apart, but the interquartile boxes still intersect over 1424–1831 USD/ton, equivalent to 47 % of the biodiesel interquartile range, so that an expensive biodiesel pathway and a cheap ZNZ pathway are not distinguishable in cost per tonne.

That separation requires careful reading, since it is specific to the combination of the mass basis with the Vincent average, and has renewable hydrogen as its single origin. Panel (b) shows the same groups per gigajoule of delivered energy, where the 2029 medians are 15 USD/GJ for the conventional group, 34 for biodiesel and 37 for ZNZ. The distance between the two low-carbon families falls from 66 % to 8.8 %, because hydrogen carries per tonne about three times the energy of a tonne of fuel oil, and their boxes, at 26–49 and 28–51 USD/GJ, now overlap over 91 % of the biodiesel interquartile range. Keeping the mass basis but changing the aggregation, the distance falls likewise, to 2.4 % and 0.3 % (Table 13), now because hydrogen ceases to influence the value of the median. The 66 % therefore measure a precise quantity: the per-tonne premium of a basket containing one third hydrogen by mass, and not a generic premium of ZNZ pathways over biodiesel. What the change of basis does not alter is the relative dispersion of each group, whose interquartile range stays at 27 %, 68 % and 62 % of the respective medians against 28 %, 67 % and 63 % on the mass basis: the unit shifts the levels, not the spread. The two readings answer distinct questions and both are reported: the mass basis gives the cost of bunkering per tonne contracted, the energy basis the cost of the energy actually available on board.

Figure 9 presents the Well-to-Wake carbon intensity of the same groups, aggregated by the same procedure, with a well-to-wake system boundary following the IMO LCA Guidelines [40]. The ordering is exactly the inverse of the cost ordering: the conventional group shows the highest intensity (90.0–96.0, median 93.6), followed by biodiesel (26.5–68.4, median 35.1) and ZNZ (13.4–40.1, median 26.6). Relative to the conventional median, the biodiesel median corresponds to a 62 % reduction and the ZNZ median to 72 %.

Dispersion behaves in the opposite way to cost. The conventional group is extremely concentrated, with an interquartile range of only 6.0 gCO_2eq/MJ, or 6 % of its median, reflecting the maturity and homogeneity of fossil supply chains. The two low-carbon families are far more dispersed: 119 % of the median for biodiesel and 100 % for ZNZ. In the case of biodiesel, which contains a single pathway,

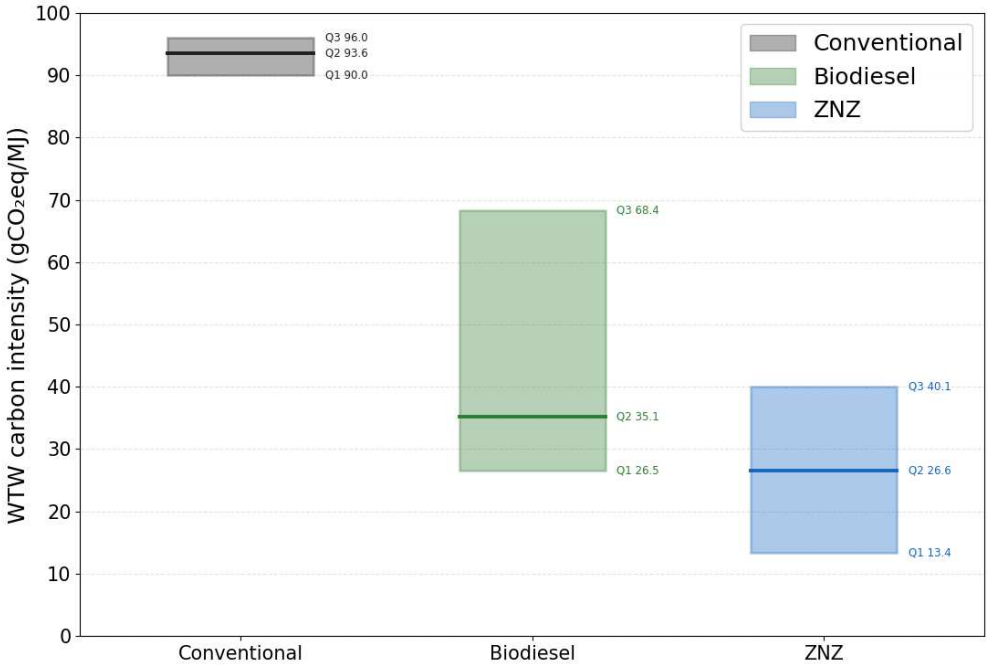


Figure 9. Well-to-Wake carbon intensity by fuel group, in gCO_2eq/MJ, with the system boundary following the IMO LCA Guidelines [40]. Boxes span the interquartile range (Q_1 to Q_3) and the internal line marks the median (Q_2); whiskers and outliers are not shown. Aggregation across pathways follows the same procedure as Figure 8.

this dispersion is entirely within-pathway and attributable to feedstock heterogeneity and upstream emission allocation rather than to group composition. Unlike the dispersion observed in prices, it does not arise from the basis of the comparison, since carbon intensity is expressed per unit of energy from the outset. As a result, the biodiesel and ZNZ boxes overlap widely, over 26.5–40.1 gCO_2eq/MJ, whereas the conventional group remains entirely separated from both by a gap of 21.6 gCO_2eq/MJ.

The conventional group result is checked against two regulatory reference values in the public domain. The intensity reference value adopted by the FuelEU Maritime Regulation, 91.16 gCO_2eq/MJ [95], and the value of 94 gCO_2eq/MJ assigned by the IMO to fossil MGO [40] both fall within the interquartile box of the conventional group, at 2.7 % and 0.4 % from the estimated median respectively. This agreement supports both the composition of the group and the aggregation procedure. The same comparison is informative as to compliance: the intensity limit applicable in 2029 under FuelEU, corresponding to a 2 % reduction relative to the reference value, is 89.34 gCO_2eq/MJ, which lies below the conventional first quartile, so that no part of the estimated conventional distribution meets it. It is further observed that the biodiesel median of 35.1 gCO_2eq/MJ corresponds to a 63 % reduction relative to the IMO value for fossil MGO, falling short of the 65 % threshold required for certified biofuels to have their carbon factor reduced; only the lower quartile of the group, at 26.5 gCO_2eq/MJ, exceeds that threshold, with a 72 % reduction.

Read together, the two figures make the cost–emissions trade-off explicit at the group level. Relative to conventional fuels, the biodiesel group reduces the median WTW carbon intensity from 93.6 to 35.1 gCO_2eq/MJ, a reduction of 62 %, while raising the median price from 15 to 34 USD/GJ, an increase of 127 %. The ZNZ group reduces the median intensity further, to 26.6 gCO_2eq/MJ, an overall reduction of 72 % relative to conventional fuels, at a median price of 37 USD/GJ, or 2.5 times the conventional value.

The marginal structure of this trade-off is the more informative result. The calculation is carried out on the energy basis of panel (b), the only one on which the ratio of cost to emissions avoided is dimensionally defined, since carbon intensity is expressed per unit of energy. Expressed per tonne of CO_2eq avoided, moving from conventional fuels to biodiesel costs approximately 325 USD/tCO_2eq, and moving from biodiesel to ZNZ approximately 350 USD/tCO_2eq. The two steps therefore cost

about the same, and the abatement supply implied by these three groups is close to linear rather than offering a cheaper second stage. The second figure is the less firmly determined of the two, since it rests on a price difference of some 3 USD/GJ between medians of 34 and 37; propagating the rounding of the reported medians places it between roughly 230 and 480 USD/tCO_2eq, against 316 to 334 for the first step. Even at the lower end of that interval, however, the conclusion holds: the additional abatement that ZNZ fuels offer over biodiesel is not obtained at a materially lower marginal cost than the move away from fossil fuels, so that the cost penalty of decarbonisation is not concentrated in a single step.

At the same time, the wider interquartile ranges observed for biodiesel and ZNZ indicate greater variability in both cost and WTW performance than for conventional fuels, and their distributions overlap in carbon intensity as well as in energy-basis cost, so that the choice between the two families is not settled by either dimension on its own. These results highlight that the choice among fuel families is governed not only by emissions performance, but also by the cost, the dispersion, and the unit basis on which the comparison is made.

4. Conclusion

This study set out to address a recurring limitation in maritime decarbonization assessments: the reliance on single deterministic values for fuel properties, lifecycle emissions, and costs, despite the substantial dispersion reported across production pathways, feedstocks, regions, and future scenarios. To this end, a harmonized database of physical, environmental, and economic parameters was compiled from scientific literature, technical and institutional reports, commercial maritime databases, and a sector-specific cost tool, and characterized through the first quartile, median, and third quartile of each pathway rather than through isolated point estimates.

The results confirm that parameter dispersion is not measurement noise but a genuine reflection of the flexibility of each production chain. Conventional fossil fuels exhibited narrow ranges across all three dimensions, consistent with their mature and homogeneous supply chains, whereas biofuels, electrofuels, hydrogen, ammonia, and synthetic methane pathways displayed markedly wider dispersions driven by differences in feedstock, electricity source, carbon origin, and conversion technology. The environmental assessment made this point explicit: the same molecule may correspond to a low- or high-emission pathway depending on how it is produced, as illustrated by the contrast between renewable and fossil-based hydrogen and ammonia routes, and by the conditional benefit of blue pathways, whose performance depends on capture rate and upstream methane leakage. A carbon-free fuel at the point of combustion, such as ammonia, may therefore carry lifecycle emissions exceeding those of conventional fuel oils when its hydrogen input is unabated and fossil-derived.

The physical assessment reinforced the importance of evaluating fuels on both a gravimetric and a volumetric basis, since the two metrics tell partly opposing stories. Volumetric energy density emerged as the more restrictive criterion for maritime application, with methane-, alcohol-, ammonia-, and hydrogen-based alternatives all falling well below the VLSFO reference and implying substantially larger tank volumes for equivalent autonomy. The economic assessment, in turn, showed that conventional fuels and several ammonia-based pathways remain the most cost-competitive across the analyzed horizons, while hydrogen- and synthetic-fuel routes remain the most expensive, albeit with a gradual cost reduction attributable to technological learning and production scale-up. It also highlighted that the availability of price data is itself uneven across pathways and decades, a limitation preserved transparently in the database rather than masked by interpolation.

Integrating these dimensions, the Comparative Fuel Assessment revealed clear trade-offs: no single pathway simultaneously optimizes emissions, energy density, and cost. Under a decarbonization-oriented weighting scheme, biofuel pathways occupied the upper portion of the ranking, combining low-to-moderate lifecycle emissions with comparatively favorable costs, while fossil and gray pathways, despite their economic advantage, ranked lowest owing to their poor environmental performance. This outcome should be read not as a definitive endorsement of any specific fuel, but

as a demonstration of how the choice of weighting and of central-versus-range inputs shapes the conclusions.

The principal contribution of this work therefore lies less in the specific values reported than in the transformation of heterogeneous literature evidence into harmonized parameter ranges suitable for uncertainty-aware modelling. By exposing the dispersion behind each pathway, the database supports more robust lifecycle assessments, fuel-selection studies, and fleet-transition scenarios, and cautions against conclusions drawn from deterministic comparisons. Future work may extend the database as new evidence becomes available, refine the treatment of methane leakage and carbon-capture assumptions, incorporate additional pathways currently limited by data scarcity, and couple these ranges with vessel-level operational models to translate parameter uncertainty into uncertainty in emissions and cost outcomes at the fleet scale.

Author Contributions: Bento Lira Vital Pereira (B.L.P.): Conceptualization; Software; Formal analysis; Investigation; Data curation; Writing—original draft preparation; Writing—review and editing; Visualization. Caio Teixeira de Carvalho (C.T.C.): Conceptualization; Software; Formal analysis; Investigation; Data curation; Writing—original draft preparation; Writing—review and editing; Visualization. Maria Eduarda Monteiro Madeira Cerqueira dos Santos (M.M.M.): Conceptualization; Software; Formal analysis; Investigation; Data curation; Writing—original draft preparation; Writing—review and editing; Visualization. Andrea Lucchesi (A.L.): Conceptualization; Methodology; Validation; Formal analysis; Investigation; Data curation; Writing—review and editing; Project administration; Funding acquisition. Luiz Felipe Assis (L.F.A.): Conceptualization; Methodology; Validation; Formal analysis; Investigation; Data curation; Writing—review and editing; Supervision. Crístofer Hood Marques (C.H.M.): Conceptualization; Methodology; Validation; Formal analysis; Investigation; Data curation; Writing—original draft preparation; Writing—review and editing; Supervision. Paula Carvalho Pereda (P.P.): Conceptualization; Methodology; Validation; Formal analysis; Investigation; Data curation; Writing—review and editing; Project administration; Funding acquisition. Jean-David Caprace (J.-D.C.): Conceptualization; Methodology; Validation; Formal analysis; Investigation; Data curation; Writing—original draft preparation; Writing—review and editing; Supervision; Project administration; Funding acquisition.

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Data Availability Statement: The dataset supporting this study, including the CSV data file and accompanying documentation, is available through Mendeley Data [96].

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Abbreviations

The following abbreviations are used in this manuscript:

MDPI	Multidisciplinary Digital Publishing Institute
DOAJ	Directory of open access journals
TLA	Three-letter acronym
LD	Linear dichroism
CFA	Comparative Fuel Assessment
CII	Carbon Intensity Indicator
CO_2	Carbon Dioxide
DME	Dimethyl Ether
ED	Energy Density
EEDI	Energy Efficiency Design Index
EEXI	Energy Efficiency Existing Ship Index
FAME	Fatty Acid Methyl Esters
GHG	Greenhouse Gas
GWP	Global Warming Potential
GWP20	Global Warming Potential over a 20-year time horizon
GWP100	Global Warming Potential over a 100-year time horizon
HPO	Hydrotreated Pyrolysis Oil
HSFO	High Sulfur Fuel Oil
HVO	Hydrotreated Vegetable Oil
ILUC	Indirect Land-Use Change
IMO	International Maritime Organization
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MDO	Marine Diesel Oil
MGO	Marine Gas Oil
NO_x	Nitrogen Oxides
Q1	First Quartile
Q2	Second Quartile (Median)
Q3	Third Quartile
SEEMP	Ship Energy Efficiency Management Plan
SO_x	Sulfur Oxides
SVO	Straight Vegetable Oil
TTW	Tank-to-Wake
VLSFO	Very Low Sulfur Fuel Oil
WTT	Well-to-Tank
WTW	Well-to-Wake

Appendix A

Appendix A.1

This section brings together the main quantitative data obtained throughout the study, referring to the greenhouse gas emissions and the price projections of the different marine fuel pathways evaluated. The objective is to provide, in a centralized and organized manner, the reference values that supported the comparative analyses presented in the previous sections.

Both the environmental and economic data are presented through descriptive statistics in tables A1 and A2, including the first quartile (Q1), the median (Q2), and the third quartile (Q3) of each fuel. This structure highlights not only the central value of each parameter but also the dispersion of the values reported in the literature, reflecting the influence of the energy source, feedstock, and production route on each fuel pathway.

Emissions are expressed according to the WTW approach, in gCO_2eq/MJ, while the price projections are presented in USD/ton. In this way, the data compiled in this annex serves as a reference base for the detailed consultation of the results discussed throughout the report.

Additionally, this annex also presents the results of the CFA analysis under three distinct scenarios: the first, Table A4 using the average prices, as depicted in Section 3.4; the second considering only the 2020 prices in Table A5; and the third employing the projected prices for 2050 in Table A6. This approach allows the sensitivity of the results to temporal variations in fuel prices to be assessed, highlighting how different cost assumptions influence the comparison among the evaluated pathways. Finally, a table is also presented detailing how the database was organized, explaining the structure adopted for the compilation and treatment of the parameters used throughout the study.

Table A1. Summary statistics of Well-to-Wake (WTW) emissions by fuel pathway.

Fuel	#	Q1	Q2	Q3
Fossil fuels				
CHSFO	25	89.44	92.78	97.00
VLSFO	13	92.60	98.28	100.50
CFMGO	25	87.80	91.60	94.32
CFMDO	10	87.80	88.95	90.53
Biofuels				
BIFAME	22	26.49	35.13	68.38
BISVO	4	16.56	19.17	29.04
BIHVO	13	15.50	30.00	41.00
BIDME	5	5.20	6.90	49.65
BIETH	14	17.65	29.00	39.60
BICH4	14	0.78	7.50	15.00
BICH3	83	6.45	13.50	33.05
BILNG	14	14.83	23.65	46.58
E-fuels / Refuels				
ECFCH3	18	5.13	13.64	20.00
ELNG	2	17.35	22.00	26.65
ECH4	8	3.45	6.00	23.28
EDIE	6	14.38	20.50	21.00
RENH3	29	14.60	34.04	47.96
REEH2	36	7.86	16.67	32.64
Blue or gray fuels				
CFNH3	25	59.62	121.00	142.36
CFCH3	31	79.80	91.70	96.55
CFLNG	52	76.94	80.74	92.58
CFSH2	18	54.18	90.75	130.00
BLSH2	35	27.59	55.85	94.73
BLNH3	10	28.50	78.76	86.02

Note: # denotes the number of data points representing the observations available for each fuel pathway. Q1, Q2, and Q3 denote the first quartile, median, and third quartile, respectively. WTW emissions are expressed in gCO_2eq/MJ.

Table A2. Summary statistics of fuel prices by fuel type and year.

	2020				2030				2040				2050			
Fuel	**#**	**Q1**	**Q2**	**Q3**	**#**	**Q1**	**Q2**	**Q3**	**#**	**Q1**	**Q2**	**Q3**	**#**	**Q1**	**Q2**	**Q3**
Fossil fuels																
CHSFO	6	260.6	390.2	817.1	10	399.6	476.3	563.3	6	373.1	469.2	581.3	9	423.6	603.3	775.8
VLSFO	5	342.0	360.4	371.1	6	576.5	623.9	727.3	4	556.5	636.8	792.8	7	522.4	676.2	875.6
CFMGO	4	382.7	389.0	503.2	3	542.3	640.5	1006.5	2	728.0	973.6	1219.1	3	708.8	939.4	1326.4
CFMDO	4	367.5	406.3	693.8	4	688.2	775.7	829.9	3	652.9	795.4	891.0	5	511.4	795.4	972.9
Biofuels																
BIHPO	14	297.9	509.2	1950.9	6	1087.6	1149.7	1241.8	6	974.6	1059.7	1106.6	6	886.8	954.8	968.0
BICH4	19	691.6	934.6	1490.6	13	557.1	751.5	1356.1	13	489.3	661.1	1288.3	13	455.4	615.9	1254.4
BIETH	30	777.5	978.7	1371.1	19	743.6	846.4	1315.5	16	601.5	701.8	994.2	19	475.8	640.8	1057.8
BICH3	16	533.4	924.0	1310.6	22	528.1	604.6	854.2	20	500.2	546.7	1124.5	23	447.5	502.9	899.4
BIFAME	11	1050.0	1083.3	1908.6	9	963.9	1297.9	1822.8	6	1064.3	1506.9	2466.0	9	1041.9	1290.8	1769.9
BIDME	2	802.4	1122.2	1442.0	–	–	–	–	–	–	–	–	–	–	–	–
BIHVO	20	1104.1	1436.9	2032.7	7	1120.0	1190.7	1312.9	3	1032.9	1032.9	1143.2	5	1021.6	1348.9	1474.3
BILNG	5	2097.7	2427.7	2828.7	9	1073.3	1090.4	1415.7	8	934.4	949.7	1023.6	8	801.8	816.6	881.8
E-fuels / Refuels																
RENH3	14	750.0	1076.0	1849.1	23	544.3	688.2	931.5	15	546.7	690.6	1193.3	25	329.3	466.7	572.9
ECFCH3	9	1072.4	2542.8	2706.4	22	677.5	878.1	1275.0	14	776.0	927.6	1226.1	22	445.0	598.7	759.0
ECH4	4	2825.3	4487.3	6209.2	4	2053.0	2059.0	2083.0	4	1750.5	1812.8	1883.8	4	1509.8	1562.4	1656.3
ELNG	4	3655.3	4646.4	5744.7	10	2490.5	2718.9	3152.8	10	1865.7	2237.9	2535.5	10	1299.8	1598.6	1988.4
EDIE	7	5844.6	6571.1	9458.1	9	2774.9	3098.1	4867.8	9	2172.0	2525.6	4227.3	9	1397.5	1677.5	3544.1
REEH2	10	5508.7	10917.4	11789.7	21	2675.7	4092.0	5278.8	16	1975.5	3149.8	4612.9	19	1413.4	2189.5	3443.2
Blue or gray fuels																
CFNH3	18	242.5	442.2	991.2	12	390.5	513.2	827.6	9	372.0	487.3	744.0	11	355.3	472.4	674.4
CFCH3	10	441.9	614.7	1015.8	4	241.2	259.3	316.7	2	310.5	355.8	401.0	3	286.1	319.0	379.7
CFLNG	9	872.9	1192.0	1541.2	15	436.7	500.5	689.1	11	454.9	568.9	683.3	13	439.5	554.3	672.7
CFSH2	7	3332.5	5278.8	7988.1	8	2549.4	4198.3	5104.3	6	3378.7	3969.1	4501.9	5	3183.3	4079.0	4223.0
BLNH3	–	–	–	–	7	439.9	508.0	547.3	7	435.3	488.4	528.7	7	421.5	471.2	510.8
BLSH2	–	–	–	–	4	4391.5	4851.2	5305.8	4	4123.7	4594.9	5080.8	4	3934.2	4373.0	4822.9

Note: Fuel prices are expressed in USD per tonne. The symbol # denotes the number of data points. Q1, Q2, and Q3 denote the first quartile, median, and third quartile, respectively. An em dash (–) indicates that no data were available for the corresponding fuel pathway and year.

Table A3. Summary statistics of fuel prices in USD/GJ by fuel type and year.

	2020				2030				2040				2050			
Fuel	**#**	**Q1**	**Q2**	**Q3**	**#**	**Q1**	**Q2**	**Q3**	**#**	**Q1**	**Q2**	**Q3**	**#**	**Q1**	**Q2**	**Q3**
Fossil fuels																
CHSFO	6	6.5	9.8	20.4	10	10.0	11.9	14.1	6	9.3	11.7	14.5	9	10.6	15.1	19.4
VLSFO	5	8.2	8.6	8.9	6	13.8	15.0	17.4	4	13.3	15.3	19.0	7	12.5	16.2	21.0
CFMGO	4	9.0	9.1	11.8	3	12.7	15.0	23.6	2	17.1	22.8	28.5	3	16.6	22.0	31.1
CFMDO	4	8.7	9.6	16.5	4	16.3	18.4	19.7	3	15.5	18.9	21.2	5	12.1	18.9	23.1
Biofuels																
BIHPO	14	7.5	12.8	49.0	6	27.3	28.9	31.2	6	24.5	26.6	27.8	6	22.3	24.0	24.3
BICH4	19	13.8	18.7	29.8	13	11.1	15.0	27.1	13	9.8	13.2	25.8	13	9.1	12.3	25.1
BIETH	30	29.0	36.5	51.2	19	27.7	31.6	49.1	16	22.4	26.2	37.1	19	17.8	23.9	39.5
BICH3	16	26.5	46.0	65.2	22	26.3	30.2	42.5	20	25.1	27.2	55.9	23	22.5	25.0	44.8
BIFAME	11	28.2	29.1	51.3	9	25.9	34.9	49.0	6	28.6	40.5	66.3	9	28.0	34.7	47.6
BIDME	2	29.1	40.7	52.3	–	–	–	–	–	–	–	–	–	–	–	–
BIHVO	20	25.0	32.6	46.1	7	25.4	27.0	29.8	3	23.4	23.4	25.9	5	23.2	30.6	33.4
BILNG	5	42.7	49.4	57.6	9	21.5	21.8	28.8	8	18.7	19.0	20.6	8	16.0	16.3	17.7
E-fuels / Refuels																
RENH3	14	40.3	57.8	99.4	23	29.1	37.0	49.8	15	29.0	36.7	64.2	25	17.5	24.7	30.8
ECFCH3	9	53.9	127.8	136.0	22	34.0	44.1	64.0	14	39.0	46.6	61.6	22	22.4	30.1	38.1
ECH4	4	56.5	89.7	124.2	4	41.1	41.2	41.7	4	35.0	36.3	37.7	4	30.2	31.2	33.1
ELNG	4	74.4	94.6	117.0	10	50.0	54.4	63.3	10	37.3	44.7	51.0	10	26.0	32.0	40.3
EDIE	7	136.9	153.9	221.5	9	64.9	72.5	114.0	9	50.8	59.1	99.0	9	32.7	39.2	83.0
REEH2	10	45.9	91.0	98.3	21	22.3	34.1	44.0	16	16.5	26.3	38.5	19	11.8	18.3	28.7
Blue or gray fuels																
CFNH3	18	13.0	23.8	53.3	12	21.0	27.6	44.5	9	20.0	26.2	40.0	11	19.1	25.4	36.3
CFCH3	10	22.0	30.6	50.5	4	12.0	12.9	15.8	2	15.5	17.7	20.0	3	14.2	15.9	18.9
CFLNG	9	17.8	24.3	31.4	15	9.0	10.2	14.2	11	9.5	11.9	14.3	13	9.2	11.6	13.9
CFSH2	7	27.8	44.0	66.6	8	21.3	35.0	42.5	6	28.2	33.1	37.5	5	26.5	34.0	35.2
BLNH3	–	–	–	–	7	23.6	27.0	29.1	7	23.2	25.9	28.0	7	22.5	25.0	27.1
BLSH2	–	–	–	–	4	36.6	40.4	44.2	4	34.4	38.3	42.4	4	32.8	36.5	40.2

Note: Fuel prices are expressed in USD per gigajoule (USD/GJ). The symbol # denotes the number of data points. Q1, Q2, and Q3 denote the first quartile, median, and third quartile, respectively. An em dash (–) indicates that no data were available for the corresponding fuel pathway and year.

Table A4. Overall ranking of alternative marine fuels based on the comparative fuel assessment.

Rank	Fuel	Avg. Price	GHG	Cost	Phys.	Final
1	BICH4	740.78	9.87	9.25	3.39	8.39
2	BIDME	1122.18	9.92	8.44	1.91	7.87
3	BICH3	644.55	9.35	9.45	1.22	7.75
4	BIHVO	1252.36	7.91	8.16	5.18	7.44
5	ECFCH3	1236.79	9.34	8.19	1.22	7.37
6	ECH4	2480.37	10.00	5.55	3.39	7.34
7	BILNG	1321.09	8.47	8.01	3.39	7.32
8	BIETH	791.92	8.00	9.14	2.33	7.21
9	BIFAME	1294.73	7.47	8.07	4.59	7.07
10	RENH3	730.37	7.56	9.27	0.77	6.72
11	EDIE	3468.06	8.74	3.45	5.55	6.51
12	ELNG	2800.41	8.61	4.87	3.39	6.44
13	REEH2	5087.17	9.07	0.00	5.00	5.54
14	CHSFO	484.73	2.45	9.79	5.77	5.32
15	CFMDO	693.21	2.79	9.35	5.55	5.31
16	CFLNG	703.93	3.50	9.33	3.39	5.23
17	CFMGO	735.62	2.56	9.26	5.44	5.14
18	VLSFO	574.35	1.98	9.60	6.14	5.10
19	BLNH3	489.20	3.67	9.78	0.77	4.93
20	CFCH3	387.17	2.55	10.00	1.22	4.52
21	BLSH2	4606.36	5.67	1.02	5.00	4.14
22	CFNH3	478.78	0.00	9.81	0.77	3.10
23	CFSH2	4381.30	2.63	1.50	5.00	2.77

Table A5. Comparative fuel assessment based on the 2020 cost scenario. Fuels are ranked by descending Final Score.

Ranking	Fuel	Cost_{2020}	GHG	Cost	Phys.	Final
1	BICH4	934.59	9.870	9.456	3.393	8.450
2	BIDME	1122.18	9.922	9.278	1.912	8.127
3	BICH3	924.00	9.348	9.466	1.216	7.757
4	BIHVO	1436.93	7.913	8.980	5.182	7.687
5	ECH4	4487.28	10.000	6.091	3.393	7.506
6	BIFAME	1083.30	7.467	9.315	4.590	7.446
7	BILNG	2427.72	8.465	8.042	3.393	7.324
8	ECFCH3	2542.78	9.336	7.933	1.216	7.291
9	BIETH	978.67	8.000	9.414	2.329	7.290
10	ELNG	4646.35	8.609	5.940	3.393	6.765
11	RENH3	1075.96	7.561	9.322	0.769	6.731
12	EDIE	6571.06	8.739	4.117	5.551	6.715
13	REEH2	10917.43	9.072	0.000	5.000	5.536
14	CFMDO	406.34	2.787	9.957	5.552	5.491
15	CHSFO	390.19	2.454	9.972	5.766	5.372
16	CFMGO	389.02	2.557	9.973	5.436	5.357
17	VLSFO	360.44	1.976	10.000	6.140	5.216
18	CFLNG	1192.04	3.501	9.212	3.393	5.193
19	CFCH3	614.69	2.548	9.759	1.216	4.445
20	CFSH2	5278.76	2.630	5.341	5.000	3.918
21	CFNH3	442.20	0.000	9.923	0.769	3.131

Table A6. Comparative fuel assessment based on the 2050 cost scenario. Fuels are ranked by descending Final Score.

Ranking	Fuel	$Cost_{2050}$	GHG	Cost	Phys.	Final
1	BICH4	615.90	9.870	9.268	3.393	8.394
2	BICH3	502.92	9.348	9.546	1.216	7.781
3	ECH4	1562.41	10.000	6.933	3.393	7.758
4	ECFCH3	598.70	9.336	9.310	1.216	7.704
5	BILNG	816.60	8.465	8.772	3.393	7.543
6	EDIE	1677.50	8.739	6.649	5.551	7.474
7	BIHVO	1348.91	7.913	7.459	5.182	7.231
8	BIETH	640.77	8.000	9.206	2.329	7.228
9	REEH2	2189.50	9.072	5.386	5.000	7.152
10	ELNG	1598.55	8.609	6.844	3.393	7.036
11	BIFAME	1290.84	7.467	7.603	4.590	6.932
12	RENH3	466.70	7.561	9.636	0.769	6.825
13	CFLNG	554.30	3.501	9.420	3.393	5.255
14	CHSFO	603.25	2.454	9.299	5.766	5.170
15	CFMDO	795.40	2.787	8.825	5.552	5.151
16	VLSFO	676.24	1.976	9.119	6.140	4.952
17	CFMGO	939.40	2.557	8.470	5.436	4.906
18	BLNH3	471.20	3.673	9.624	0.769	4.878
19	CFCH3	318.97	2.548	10.000	1.216	4.517
20	BLSH2	4372.97	5.666	0.000	5.000	3.833
21	CFNH3	472.44	0.000	9.621	0.769	3.040
22	CFSH2	4079.04	2.630	0.725	5.000	2.533

Table A7. Fields recorded in the marine-fuel database, grouped by category.

Field	Description
Identification and metadata	
Person	Team member responsible for extracting the observation.
MainRefID	Internal identifier of the source reference.
MainRefLink	Direct hyperlink to the source document.
BibTeX Key	BibTeX key used to cite the reference in the manuscript.
DOI/Council	Digital Object Identifier or issuing body/council of the source.
Where	Location of the value within the source (e.g. table, figure or page).
FuelCode	Standardized fuel-pathway code as defined in Table 1.
Country/year	Geographical scope and reference year of the observation.
Engine Type	Engine or propulsion technology associated with the observation.
State	Physical state of the fuel (e.g. liquid, gas, cryogenic).
Description	Free-text description of the pathway, scenario or assumptions.
Physical parameters	
VolDen	Volumetric density (mass density) as reported.
EnergDen	Volumetric energy density as reported; harmonized to MJ/L.
LCV/LHV	Lower calorific / lower heating value as reported; harmonized to MJ/kg.
Environmental parameters	
WTT	Well-to-Tank GHG intensity; harmonized to gCO_2eq/MJ.
WTT_ILUC	Well-to-Tank GHG intensity including Indirect Land-Use Change, in gCO_2eq/MJ.
TTW	Tank-to-Wake GHG intensity; harmonized to gCO_2eq/MJ.
WTW	Well-to-Wake GHG intensity; harmonized to gCO_2eq/MJ.
WTW_ILUC	Well-to-Wake GHG intensity including Indirect Land-Use Change, in gCO_2eq/MJ.
GWP	Global Warming Potential horizon adopted by the source (e.g. GWP100).
Economic parameters	
Price_Year	Reference year of the reported price.
Price_USD_ton	Fuel price as reported; harmonized to USD/ton.
Price_USD_GJ	Fuel price as reported; harmonized to USD/GJ.
General	
COMMENTS	Additional remarks, caveats or clarifications on the observation.

Note: Every quantitative parameter is stored together with three auxiliary fields following the pattern `<Parameter>`, `<Parameter>_UM`, `<Parameter>_Factor` and `<Parameter>_<reference unit>`. The base field holds the value exactly as reported by the source; `_UM` records its original unit of measurement; `_Factor` is the conversion factor applied to express the value in the reference unit; and the final field holds the harmonized value in the reference unit adopted throughout the study (MJ/L for volumetric energy density, MJ/kg for LCV/LHV, gCO_2eq/MJ for GHG intensities, and USD/ton, USD/GJ for prices). This structure preserves the original reported value and its provenance while ensuring comparability across heterogeneous sources.

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