DTU Library

MarE-Fuel: ROADMAP for sustainable maritime fuels

Franz, Sebastian Marco; Shapiro-Bengtsen, Sara; Campion, Nicolas Jean Bernard; Backer, Martijn; Münster, Marie

Publication date:
2021

Document Version
Publisher's PDF, also known as Version of record

Citation (APA):
Franz, S. M., Shapiro-Bengtsen, S., Campion, N. J. B., Backer, M., & Münster, M. (2021). *MarE-Fuel: ROADMAP for sustainable maritime fuels*. Technical University of Denmark.

MarE-Fuel: ROADMAP for sustainable maritime fuels

Authors:

Sebastian Franz

Sara Shapiro-Bengtsen

Nicolas Campion

Martijn Backer

Marie Münster

October 31th, 2021

Technical University of Denmark

Contents

List of Figures

List of Tables

Abbreviations

α	Average utilization factor [%]
β	Fuel share [%]
C	Set of ship capacity bins *c*
CapEx	Capital Expenditures
d	Distance [nautical miles]
FC	Fuel Consumption
gt	Giga-tonne
HFO	Heavy Fuel Oil
IMO	International Maritime Organization
kW	Kilo-Watt
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
MGO	Marine Gas Oil
MW	Mega-watt
nm	Nautical mile
P	Engine power
PJ	Peta-Joule
Q	Number of actual ships
q	Number of average ships
S	Set of ship types *s*
SFC	Specific Fuel Consumption
t	Time [international days]
TW	Transport Work [gt*nm]
u	Speed [knots]
UNCTAD	United Nations Conference on Trade and Development
Y	Set of years *y*

Introduction

This report is a background report to the MarE-Fuel project financed by the Maritime Fund and the Lauritzen Fund. Partners of the project has been DTU, Anker Invest, Mærsk Line, Copenhagen Economics, OMT and DFDS.

In the report, potential decarbonization roadmaps or pathways for the maritime industry are presented, as well as the methodology of deriving them. Different future fuels and their emissions are highlighted. In addition, biomass availability plays an essential role in climate mitigation efforts towards net-zero by 2050, and thus we examined different biomass availability scenarios alongside greenhouse-gas emissions cap scenarios. The assumptions related to the underlying emissions can be found in the first chapter of the report.

Besides the underlying emissions for a decarbonized maritime industry, the ship stock and the underlying transport demand play an essential role for a future decarbonized maritime industry. In the second chapter of the report, we address this issue by explaining how ship stock and shipping demand have been incorporated into the model.

Finally, we present the optimization ship stock model developed to generate roadmap scenarios. We show the objective function and the underlying constraints of the model. The results of this work are presented and discussed. We also show some sensitivity analysis, which will shed light on the relevant parameters for the future of the maritime industry. Our main findings can be found in the end of the report.

1. Fuel price, emissions, availability, and emissions cap scenarios

Authors

Sara Shapiro-Bengtsen

Nicolas Campion

1.1 Introduction

This chapter provides an overview of the assumptions regarding fuel price, fuel availability, emissions associated with fuel use, and emission reduction scenarios. These is input data are used to develop the MarE-fuel Roadmaps for the transition of the shipping sector to green fuels.

An overview of fuels assessed in this report is listed in table 1.Other pathways for methanol production include methanol from coal, which is disregarded due to the high related greenhouse gas (GHG) emissions. Methanol can also be produced from biomass through gasification without hydrogen input, but this pathway is disregarded due to its low carbon efficiency. Biodiesel from algae was considered but not included due to sustainability concerns[1]. The fuels using electrolysis to produce H_2 as input to the fuel synthesis are characterized as e-fuels. In this note, these are; MET-e-bio, MET-DAC, MET-PS, and AMM-green.

Abbreviation	Name	Description
HFO	Heavy Fuel Oil	Conventional fossil fuel.
VLSFO	Low Sulphur Fuel Oil	Conventional fossil fuel. Sulphur content ≤0.5%
MDO	Marine Diesel Oil	Conventional fossil fuel.
MGO	Marine Gasoline Oil	Conventional fossil fuel.
LNG	Liquefied Natural Gas	Conventional fossil fuel.
LPG	Liquefied Petroleum Gas	Conventional fossil fuel.
MET-Grey	Methanol (grey)	Conventional methanol produced from fossil natural gas.
MET-e-bio	Methanol (e-bio)	Methanol produced from gasification of residual biomass and hydrogen from water electrolysis.
MET-PS	Methanol (PS)	Methanol produced from point source (PS) carbon bio energy carbon capture and utilization (BECCU), and hydrogen from water electrolysis.
MET-DAC	Methanol (DAC)	Methanol produced from carbon from direct air capture (DAC) and hydrogen from water electrolysis.
AMM-grey	Ammonia (grey)	Conventional ammonia produced from fossil natural gas.
AMM-blue	Ammonia (blue)	Ammonia produced from fossil natural gas with carbon capture.
AMM-green	Ammonia (green)	Ammonia produced from water electrolysis.
Refined-PO	Refined pyrolysis oil	Oil from pyrolysis of residual biomass refined to a quality enabling drop-in use in HFO/VLSFO engines.
LBG	Liquefied Biogas	Liquefied biogas generated from manure or organic waste.

Table 1: Overview of assessed fuels.

The fuels presented cannot all be used as such in a vessel engine and need to be used together with a pilot fuel to allow fuel ignition. The pilot fuel is also accounted for in the fuel emissions and price. This is done by modeling a virtual “blended fuel” having the total price/emissions of the original fuel plus the price/emission of pilot fuel. In reality, main fuel and pilot fuel may be physically separated in the vessel, but modeling a blended fuel will give the same results in terms of total price and emissions. It is assumed that pilot fuel is changing from fossil to e-fuel (DME) after 2040. For simplification, DME (Dimethyl Ether) is assumed to have the same price and emissions as methanol. The price of DME is equal to the cheapest option between Bio-eMethanol, Methanol from

[1] If algae cultivation is placed in seawater close to known industrial CO_2 sources with food competition and biodiversity taken into account, the potential is 6 EJ [1]. If this were to be limited to biogenic CO_2 sources, the potential would be reduced further. The environmentally sustainable potential of biodiesel from Algae is limited to ~1.4 EJ when atmospheric CO_2 is used. This is deemed not to be economically feasible [2].

point source, and methanol from Direct Air Capture. Considered emissions for DME correspond to the ones associated with the cheapest fuel among the three "green" methanol (Met-e-bio, Met-PS, Met-DAC).

The type and share pilot fuel considered for the assessed fuel in this study is presented in table 2.

Main fuel	Pilot fuel used 2020	2030	2040	2050	Share of pilot oil (energy share)
LNG	VLSFO	VLSFO	DME	DME	1.5%
LPG	VLSFO	VLSFO	DME	DME	3.5%
Methanol	VLSFO	VLSFO	DME	DME	5%
Ammonia	VLSFO	VLSFO	DME	DME	5%
LBG	VLSFO	VLSFO	DME	DME	1.5%

Table 2: Type and share of pilot fuel used with the main fuel

1.2 Fuel prices

Fuel prices are determined with two different methods:

- If the fuel market price is available (e.g., for fossil fuels), the price is derived from real market data and IEA predictions. The assumptions and methodology used to derive fossil fuel prices are presented in "FUEL PRICES AND LEARNING RATES Contribution" by Copenhagen Economics and biofuels (pyrolysis oil and LBG) in the report "MarE-Fuel: Energy efficiencies in synthesizing green fuels and their expected cost". By convention, prices are taken in Rotterdam.
- If the fuel is not on the market already (e.g., electro-fuels), the price is derived from the estimated fuel production cost using the method presented in Figure 1: Fuel price derivation process when the fuel market price is unknown. Figure 1. The assumptions and methodology used to estimate the fuel production cost are presented in the "Energy efficiencies in synthesizing green fuels and their expected cost" report.

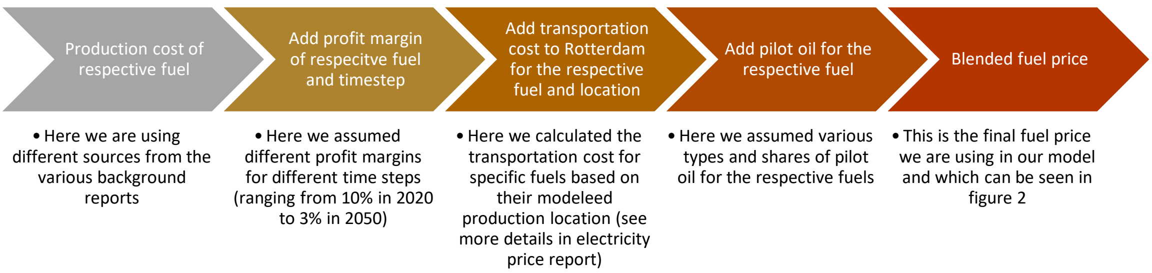


Figure 1: Fuel price derivation process when the fuel market price is unknown.

1.2.1 Blended fuel prices derived from market

Fuel market prices in Rotterdam are used as references. On top of that, the price of pilot fuel is added to the main fuel. Pilot fuel price is either market price (for VLSFO) or is calculated from production cost adding profit margin and transport cost to Rotterdam (for DME). Table 3 summarizes the final blended fuel price used as input in the roadmap model.

	Source	Original fuel price[1] [€2019/GJ] 2020	2030	2040	2050	Blended fuel price if different from original [€2019/GJ] 2020	2030	2040	2050
HFOsc/ VLSFO[2]	**CE Economics[1]**	10.2	9.0	8.6	8.1	-	-	-	-
MDO[3]	**CE Economics[1]**	10.9	9.6	9.2	8.7	-	-	-	-
MGO	**CE Economics[1]**	10.9	9.6	9.2	8.7	-	-	-	-

LNG	**CE Economics**[1]	4.3	3.1	3.1	3.2	4.4	3.2	3.5	3.5
LPG	**CE Economics**[1]	8.0	7.1	6.7	6.4	8.1	7.1	7.5	7.0
MET-Grey	**CE Economics**[1]	9.7	7.4	7.5	7.6	9.7	7.5	8.5	8.4
AMM-grey	**CE Economics**[1]	10.7	8.2	8.2	8.3	10.7	8.2	9.2	9.1
AMM-blue	**DTU Energy**[4]	30.0	24.0	22.6	21.1	29.0	23.3	22.9	21.2
Refined-PO	**DTU Energy**[4]	24.0	32.9	40.3	54.9	-	-	-	-
LBG	**DTU Energy**[4]	20.3	28.2	34.2	46.6	20.1	27.9	34.1	46.2

[1] Market price in Rotterdam. Future price estimated using the Sustainable Development Scenario from IEA [see *MarE-Fuel: CO2-Taxes, Fuel Prices and Learning Rates*, 9/9 -2021, Copenhagen Economics]

[2] To simplify the problem, it is assumed that HFO and scrubber has the same price as Very Low Sulphur Oil

[3] Not found on market data assumed equal to be equal to MGO price

[4] *MarE-fuel: Energy efficiencies in synthesising green fuels and their expected cost,* 9/9-2021, DTU Energy

Table 3: Blended fuel prices derived from market prices

1.2.2 Fuel prices derived from production cost

The price of fuels that cannot be derived from existing market prices and are thus calculated by adding production cost, transport cost to Rotterdam (reference price location), and profit margin. Fuel prices refer to the blended fuel included in the price of pilot fuel. The price of pilot fuel is either market price for VLSFO or calculated price for DME (including profit margin, production cost, and transport cost to Rotterdam). Fuels concerned by this price calculation method are MET-e-bio, MET-PS, MET-DAC, and AMM-green.

Production cost

As presented in the report: "**MarE-Fuel: Energy efficiencies in synthesizing green fuels and their expected cost"**, selected production costs are the ones estimated in the cheapest configuration (depending on weather profile, power supply type, and fuel transport cost). The cheapest way of producing electro fuel is to mix local renewable power production with electricity from the grid (behind the meter with grid). As it is difficult to track the origin of the electricity when it comes from the grid and assess its "greenness," we assume that the second cheapest location is used when the use of local renewable power is higher and the cost difference small (see the reports: "MarE-Fuel: Energy efficiencies in synthesizing green fuels and their expected cost" and "MarE-Fuel: LCOE and optimal electricity supply strategies for P2X plants" for more details)

Summary of the production cost of e-fuels used in the model is shown in Table 4:

	Selected production site				**Production cost [€2019/GJ fuel]**			
	2020	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
MET-e-bio	Dakhla	Arica	Arica	Dakhla	36.4	28.6	25.7	22.8
MET-PS	Dakhla	Arica	Arica	Arica	44.9	33.4	28.5	23.5
MET-DAC	Dakhla	Arica	Arica	Arica	52.9	40.7	34.4	28.0
AMM-green	Dakhla	Dakhla	Dakhla	Arica	38.5	28.8	23.9	19.1

Table 4: Selected production sites and associated cost behind meter with grid configuration [see the report "MarE-Fuel: Energy efficiencies in synthesizing green fuels and their expected cost" for more details]. Dakhla: West Sahara, perfect wind and solar potential. Arica: North Chile, excellent solar potential, low wind potential.

When the fuel producer is concerned about the sustainability of the fuel or the technical feasibility of accessing the grid, it may choose to produce the fuel off-grid, meaning only with local renewable power production and storage systems. However, producing off-grid leads to higher costs due to oversizing the infrastructures and investing in intermediate storage (batteries and/or hydrogen tanks). The cheapest fuel production site may also change, and access to the grid is not granted.

Table 5 summarizes the production cost and selected production sites in the off-grid (behind the meter) set-up:

	Selected production site				Production cost [€2019/GJ fuel]			
	2020	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
MET-e-bio	Dakhla	Dakhla	Dakhla	Dakhla	38.4	30.8	28.3	25.7
MET-PS	Dakhla	Dakhla	Dakhla	Arica	48.5	38.7	33.4	28.0
MET-DAC	Dakhla	Dakhla	Dakhla	Arica	57.8	46.4	39.8	33.2
AMM-green	Dakhla	Dakhla	Dakhla	Arica	42.7	33.6	28.1	22.6

Table 5: Selected production sites and associated cost in the behind the meter configuration [see the report "MarE-Fuel: Energy efficiencies in synthesizing green fuels and their expected cost" for more details]. Dakhla: West Sahara, very good wind and solar potential. Arica: North Chile, excellent solar potential, low wind potential.

Transportation cost

In order to compare all the fuels on a similar basis, it has been decided that all fuels will be shipped to Rotterdam. The production cost between the production location of the respective fuel and Rotterdam has been calculated by the following simple equation:

$$Transport\ cost_{s,f}[€2019/GJ] = \frac{cargo - cost\ per\ tonne_{s}\ (based\ on\ rotation\ duration\ between\ O\&Ds)}{calorific\ value\ of\ fuel_{s,f}}$$

Where:

s= production site (in our approach Dakhla, Arica, Esbjerg, and Ceduna, for more details see the report "MarE-fuel: LCOE and optimal electricity supply strategies for P2X plants")

f= type of fuel (we only calculated transport cost for electro-fuels as the other fuels are already market price based fuels

The variable "cargo-cost per tonne" for the respective production site is based on the assumed rotation duration, consistent of loading, transit, off-load and transit back. This rotation duration of the different Origin and Destinations (O & O&Ds) are then linked to average monthly cost of vessels (this data is based on one of our industry partners).

Obtained transport costs applied to the original fuel cost are presented in Table 6.

Transportation cost to Rotterdam [€2019/GJ fuel]	Arica	Dakhla	Ceduna	Esbjerg
Methanol	0.76	0.29	1.09	0.06
Ammonia	1.08	0.31	1.54	0.01

Table 6: Transportation cost to Rotterdam

Profit margin

The profit margin added to the fuel production cost is assumed to be relatively high in 2020 and decreasing over time due to increasing competition. Values used in the price calculation are presented in table 7. Profit margin is applied before including the transportation cost.

	2020	2030	2040	2050
Profit margin on fuel production cost	10%	7%	5%	3%

Table 7: Profit margin added to the fuel production cost

Blended fuel prices

The resulting blended electro fuel prices, including transport from selected production site to Rotterdam, can be found in table 8.

	"Blended" fuel price Bhm with grid [€2019/GJ fuel]				"Blended" fuel price Behind meter [€2019/GJ fuel]			
	2020	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
MET-e-bio	39.2	30.4	27.8	23.8	41.3	32.6	30.5	26.8
MET-PS	48.2	35.3	30.6	24.9	52.0	40.7	35.6	29.5
MET-DAC	56.6	42.8	36.5	29.4	61.8	48.6	42.0	34.5
AMM-green	41.5	30.2	25.6	20.9	45.9	35.0	29.9	24.5

Table 8: Blended electro-fuel price in Rotterdam when produced off-grid and partially on-grid

1.2.3 Summary

Figure 2 and Figure 3 show the final fuel price used in the 2020-2050 periods for all assessed fuels. The prices are interpolated linearly between the years. These fuel prices are used as such in the baseline scenario. Still, it has to be kept in mind that these prices come with high uncertainty and will have to be adjusted regularly depending on technology evolution.

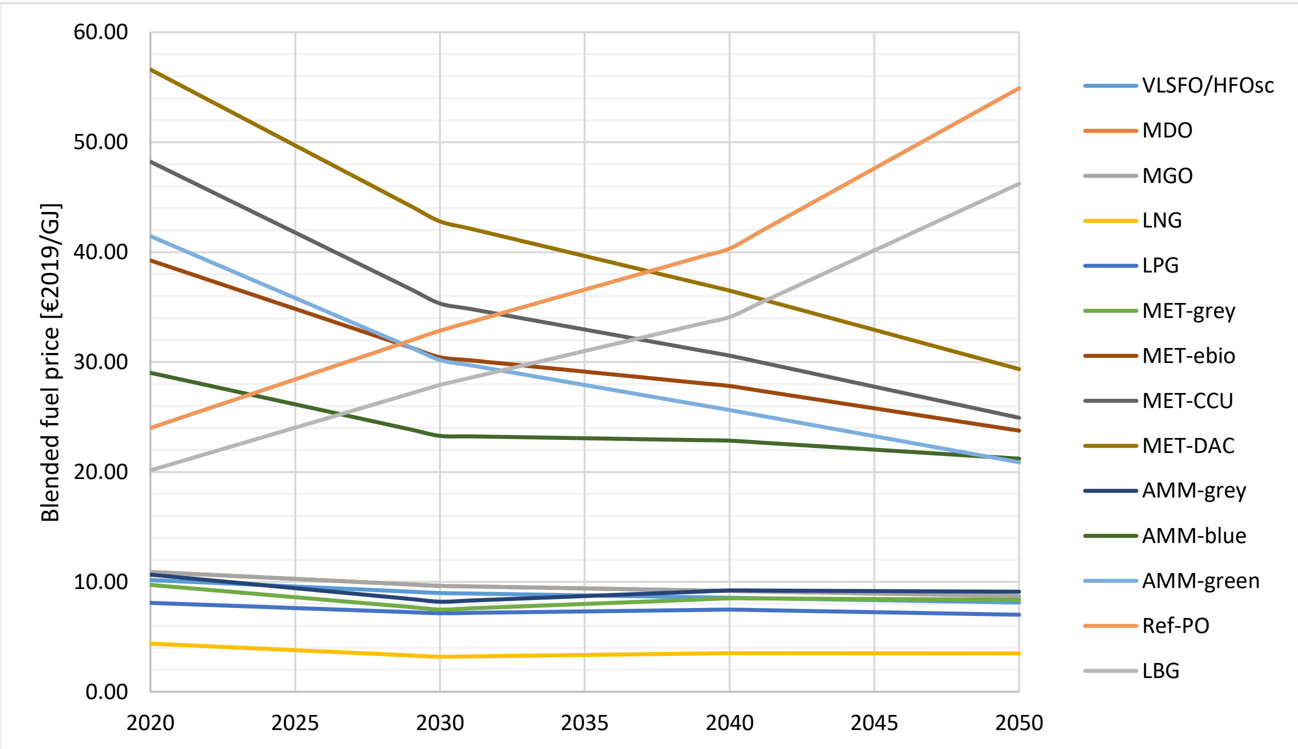


Figure 2: Blended fuel prices with electro-fuels powered using grid electricity and local renewable production (Bhm-grid)

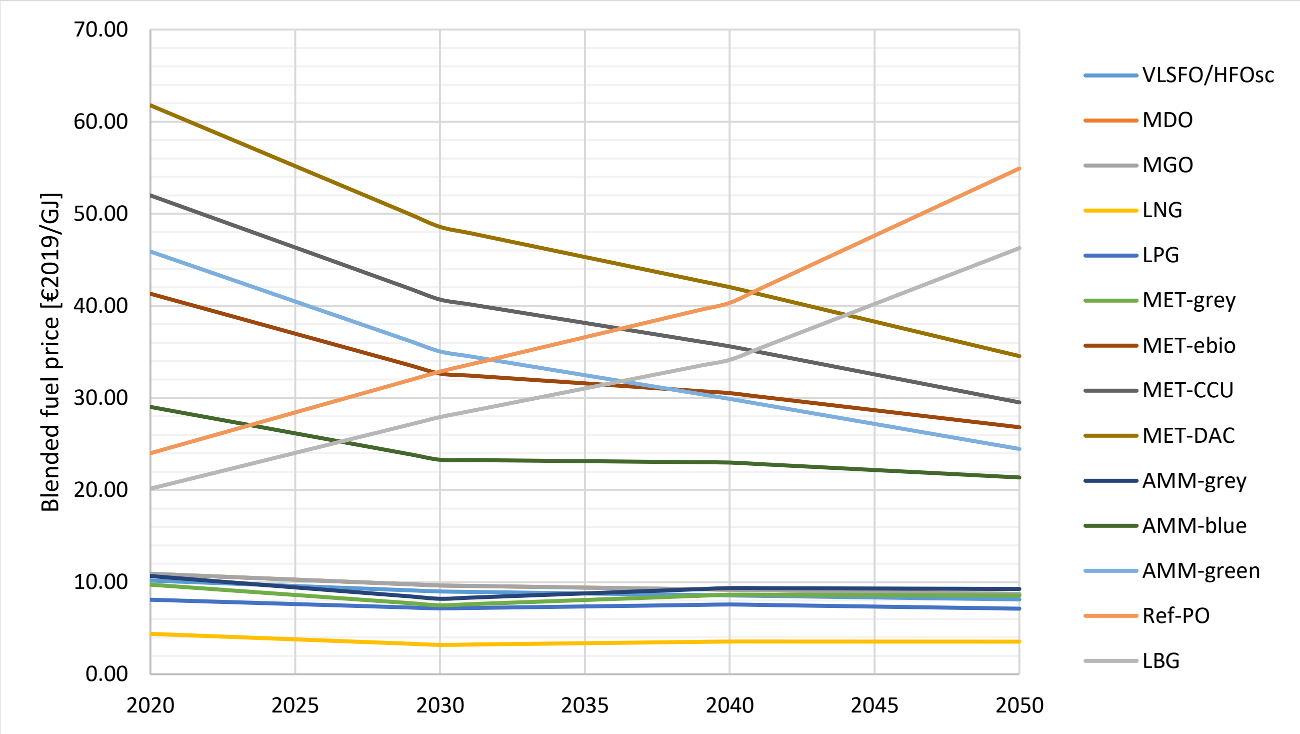


Figure 3: Blended fuel prices with electro-fuels produced off-grid (BHM)

1.3 Fuel emissions

1.3.1 Well-to-Tank and Tank-to-Wake

Greenhouse gas emissions (GHG) from production and use of fuels are divided into Well-to-Tank (WTT), covering the fuel production, and Tank-to-Wake (TTW), covering the combustion of the fuel. The sum of WTT and TTW emissions are the Well-to-Wake (WTW) emissions. See Figure 4: Overview of elements in well-to-wake GHG emissions. The WTW emissions covered here are limited to GHG emissions from fuel production and use. The production of the engines, ships, or needed infrastructure to produce these are disregarded as they are assumed to be similar for different types of fuels. For a complete lifecycle analysis, upstream and downstream emissions for ships using other fuels should be included. The upstream emissions from fuel production are made up of emissions from extracting raw materials for building infrastructure and the fuel itself. For e-fuels, there is a significant input of electricity in fuel production, which is why this is shown separately. For fossil-based electricity, most emissions stem from the operational stage of electricity generation, which is associated with extracting and combusting fossil fuels. Still, for renewables, the majority of emissions are in the upstream stage. For example, emissions from wind electricity are minimal, but they are not zero as they include upstream emissions primarily from steel production for building wind turbines (see Figure 5). Some studies are limited to operational WTT emissions, where non-fossil electricity emissions are zero [3,4]. This means that the contribution to the WTT emissions of e-fuels can vary significantly in different studies, which makes them difficult to compare. Comparable assumptions of emissions related to electricity use for e-fuels are therefore given focus in section 0. This does not make a big difference when comparing fossil fuels, as the major part of WTT emissions is in the operational stage. However, when looking at e-fuels, the electricity input is substantial and should therefore be taken into account.

$$WTW = WTT_{upstream} + WTT_{operational} + TTW_{operational}$$

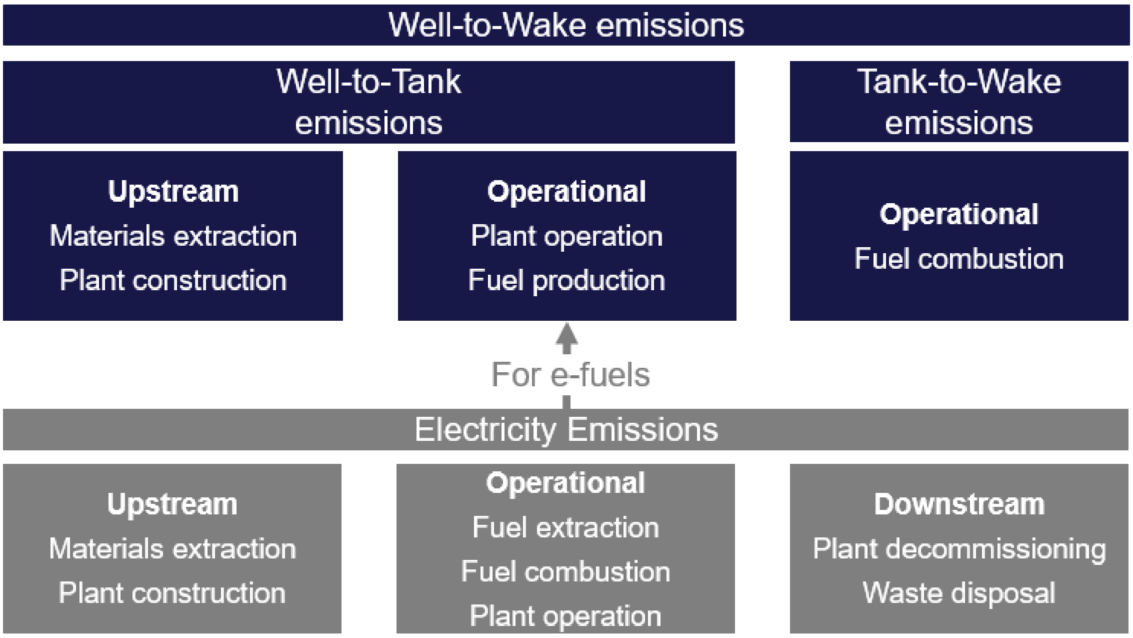


Figure 4: Overview of elements in well-to-wake GHG emissions.

Different targets can be applied for WTT and TTW emissions. Current International Maritime Organisation (IMO) targets for emission reductions are restricted to TTW emissions.There are no IMO guidelines for defining WTT emissions, something the EU, among others, is pushing for [5].

1.3.2 Global Warming Potential

The three main GHGs, CO_2, CH_4, and N_2O, are included in this assessment and converted to CO_{2e} using global warming potential (GWP) conversion factors for a set time frame. It is common to use a time period of 100 years. However, a shorter timeframe might be relevant due to the urgency of climate change. As CH_4 has an atmospheric lifetime of 12 years, the GWP for CH_4 in a 20-year perspective is significantly higher than when using a 100-year perspective, see Table 99. Impacts from black carbon or hydrogen as indirect greenhouse gasses are not included in this study. As the biomass resources used for fuels in this study are limited to residuals (see section 0), these are in themselves considered to be neutral in terms of CO_2 emissions and uptake.

	GWP 20 years	GWP 100 years	Lifetime (years)
CH_4	87	36	12
N_2O	268	298	121

Table 9: Overview of GWP factors and atmospheric lifetime of CH_4 and N_2O [6].

1.3.3 Grid electricity emissions

For e-fuels, the GHG emission intensity of the electricity used can be decisive for the WTT emissions of the fuel. For electricity from the grid, the electricity mix is based on the IEA Net-Zero by 2050 report, which includes a scenario for developing the global electricity mix [7]. This scenario consists of some carbon capture, listed as carbon capture utilization and storage (CCUS). However, it is not specified whether the captured CO_2 from fossil and bioenergy is utilized or stored. This study assumes that all captured CO_2 in the IEA scenario, listed as CCUS, is stored. The lifecycle GHG emissions for electricity production are calculated as a weighted average based on the generation mix, as it is unknown where the fuels will be produced in the world. Using operational WTT data, where emissions from wind and solar PV and fuel production are zero, the emissions from e-fuel production are limited to the intensity of the grid mix electricity used.

Life cycle emission factors for electricity production without carbon capture and storage (CCS) are extracted from the Ecoinvent consequential database version 3.7.1 using the climate change impact IPCC 2013 method for climate change impact with 100 year GWP. As these emissions in some cases are country-specific, a simple average from the four locations used in this study, Australia, Chile, Denmark, and Morocco,[2] is used, assuming these places are representative. It is believed that lifecycle emissions from wind and solar will decline to zero[3] by 2050 as infrastructure production is expected to become green over time. For electricity generation-inducing CCS, an average of values found in literature is used. See Appendix B (Chapter 1) for details. For the average grid mix, the resulting emission intensity is shown in Figure 5. These have been compared to the operational emissions factors found in the EU joint research center well-to-wheel study, which is limited to the operational emissions [3]. Using these factors would result in a slightly lower GHG grid intensity, primarily due to wind and solar being zero throughout the time period.

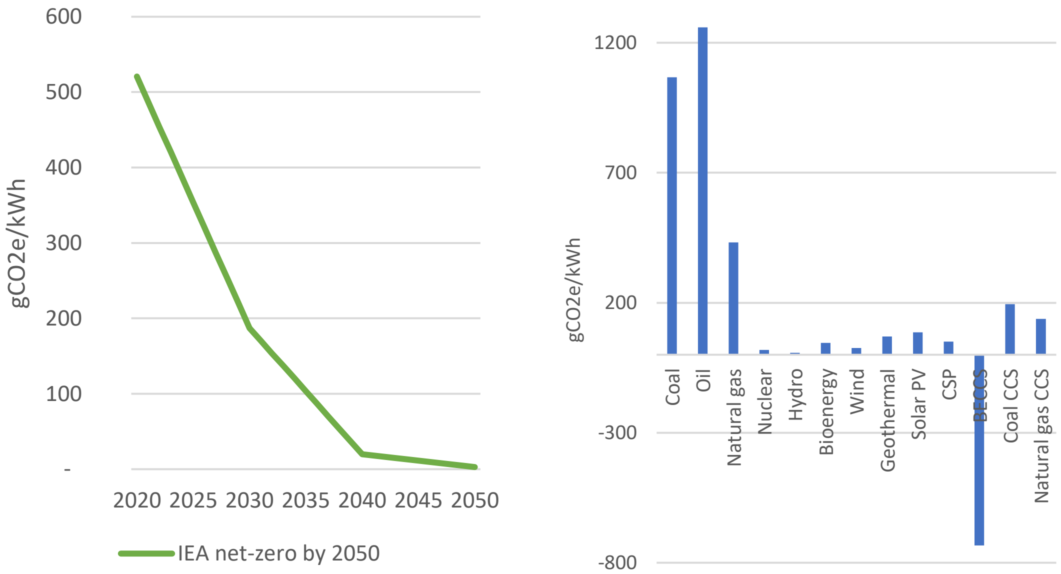


Figure 5: GHG intensity used for grid electricity (left), emission factors for electricity produced from different energy sources used for the year 2020 (right).

1.3.4 E-fuel emissions

As presented in the "MarE-fuel: LCOE and optimal electricity supply strategies for P2X plants" report, e-fuels can be produced using power from a different source:

- Exclusively from the grid (on-grid)
- Exclusively from local renewable power production (off-grid/behind the meter)
- A mix of power from the grid and local renewable power production (mixed/behind the meter with grid)

Embedded Well To Tank (WTT) fuel emissions will differ enormously depending on the power supply and are addressed separately.

<u>On-grid e-fuel production (grid exclusively)</u>

Emissions in the on-grid e-fuel production case includes:

- The emissions related to the embedded grid GHGs emissions (WTT operational)

[2] Rest of World was used for Morocco as there was no country specific data available.

[3] For modelling purposes 0.1% of current emissions is used for 2050 to avoid multiple optimal solutions.

- The Tank to Wake emissions (TTW)

Producing e-fuels exclusively from the grid (on-grid), using an average grid mix for producing e-fuels results in indirect emissions higher than that of VLSFO today. This changes over time as the electricity grid mix is assumed to become greener and e-fuel production more efficient, see Figure 6, where MET-e-bio has fewer emissions associated with it already shortly after 2025 and the rest around 2030 or shortly after.

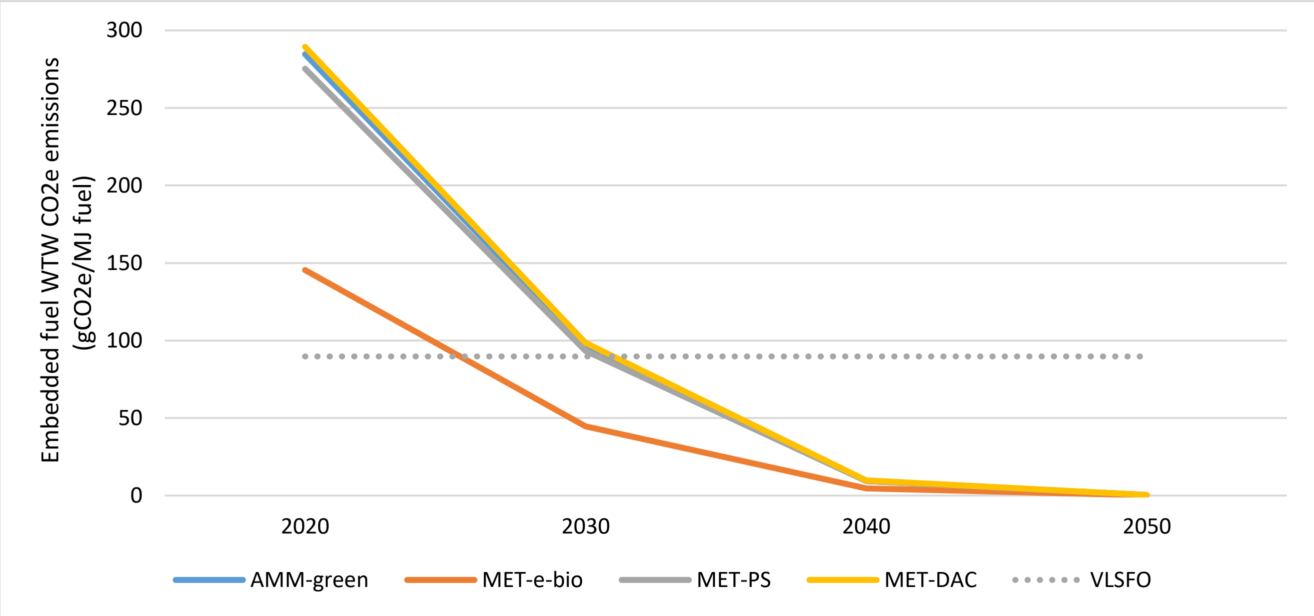


Figure 6: Emission intensity of producing e-fuels on-grid using average grid electricity compared to WTW emissions from VLSFO.

Plant owners could invest in their own electricity production to address the issue with high emissions from average grid electricity. In this case, there can go completely off-grid or combine grid power and local renewable output. If the grid infrastructure is already available and the connection cost is low, the cheapest option is to use a combination of grid power and local renewable production.

<u>Off-grid e-fuel production (using local renewable power: Solar PV and/or wind)</u>

This configuration adds up:

- The carbon emissions related to building the infrastructure such as fuel plant, batteries, solar PV and wind turbines (WTT upstream)
- The Tank to Wake emissions (TTW).

The WTT upstream emissions are calculated based on the optimal capacity installations presented in the report “MarE-Fuel: LCOE and optimal electricity supply strategies for P2X plants”. As the full load hours assumed in the Ecoinvent database, this is far from the modeled scenarios described in the “MarE-Fuel: LCOE and optimal electricity supply strategies for P2X plants” report. For wind and solar PV installations, the surrounding infrastructure is disregarded, and the infrastructure emissions are limited to the construction of the wind turbines and photovoltaic plants, see table 10.

Table 10: Emissions from wind and solar PV installations.

Technology	kg CO2e/kW/year	Source	Note
Onshore wind	55	Ecoinvent[a]	Data from 2008. Reference for wind turbines with a capacity of larger than 3 MW
Solar PV	91	Ecoinvent[b]	

All Ecoinvent processes taken from the consequential database v. 3.7.1. , specific processes as follows: [a]wind turbine construction, 4.5MW, onshore - GLO, [b]photovoltaic plant construction, 570kWp, multi-Si, on open ground - GLO.

Apart from electricity, the upstream emissions from fuel infrastructure are included, see assumptions in table 11. These are all assumed to decline linearly over time to reach zero in 2050.

Table 11: Overview of assumptions for GHG emissions associated with infrastructure for e-fuels.

Process	Value	Unit	Source	Note
Methanol plant	18.5	$kgCO_{2e}$/(kg MeOH/h)/year	Ecoinvent[a]	Plant capacity 2700 t/day. 30 year lifetime.
H_2 storage	0.006	$kgCO_{2e}$/kg H2/year	8	Compressed hydrogen storage 330 m3/tank. Ecoinvent processes for material use. Assumed lifetime 30 years.
Electrolyser AEC	2.29	$kgCO_{2e}$/kW/ year	9	Assumed 8000 load hours per year.
Electrolyser SOEC	2.73	$kgCO_{2e}$/kW/ year	9	Assumed 8000 load hours per year.
Battery	1.57	$kgCO_{2e}$/kWh/ year	Ecoinvent[b]	Assumed specific energy density: 0.265 kWh/kg
Ammonia plant	18.5	$kgCO_{2e}$/(kg NH_3/h)/year	Ecoinvent[a]	As no data was found on ammonia plants the same data is used as for methanol plant infrastructure.
Air separation unit	4.81	$kgCO_{2e}$/kg N_2/h/year	Ecoinvent[c]	Cryogenic air separation.
Gasifier	4.09	$kgCO_{2e}$/(kg syngas/h)/year	Ecoinvent[d]	Synthetic gas production from wood. Fluidized bed gasifier.
Carbon capture	5.68	gCO_{2e}/ kg CO_2 captured	10	Captured from ambient CO_2. Emissions for building point source CO_2 capture are assumed to be 5% of that of building infrastructure for capturing ambient CO_2 (own assumption)

All Ecoinvent processes taken from the consequential database v. 3.7.1. , specific processes as follows: [a]methanol factory construction – GLO, [b]battery cell production, Li-ion - RoW, [c]air separation, cryogenic - RER/RoW, [d]synthetic gas production, from wood, at fluidized bed gasifier – RoW.

By convention, WTT upstream emissions are usually not accounted. To align with "usual" carbon accounting methods, the baseline scenario used in the roadmap model does not count for WTT upstream emissions bringing off-grid electro-fuel WTT emissions to zero.

Figure 7 shows the difference in emissions from e-fuel production with or without including upstream emissions ("up + op" and "up" respectively, "up" standing for upstream and "op" for operational). The only resulting emissions when upstream emissions are not counted come from the pilot fuel.

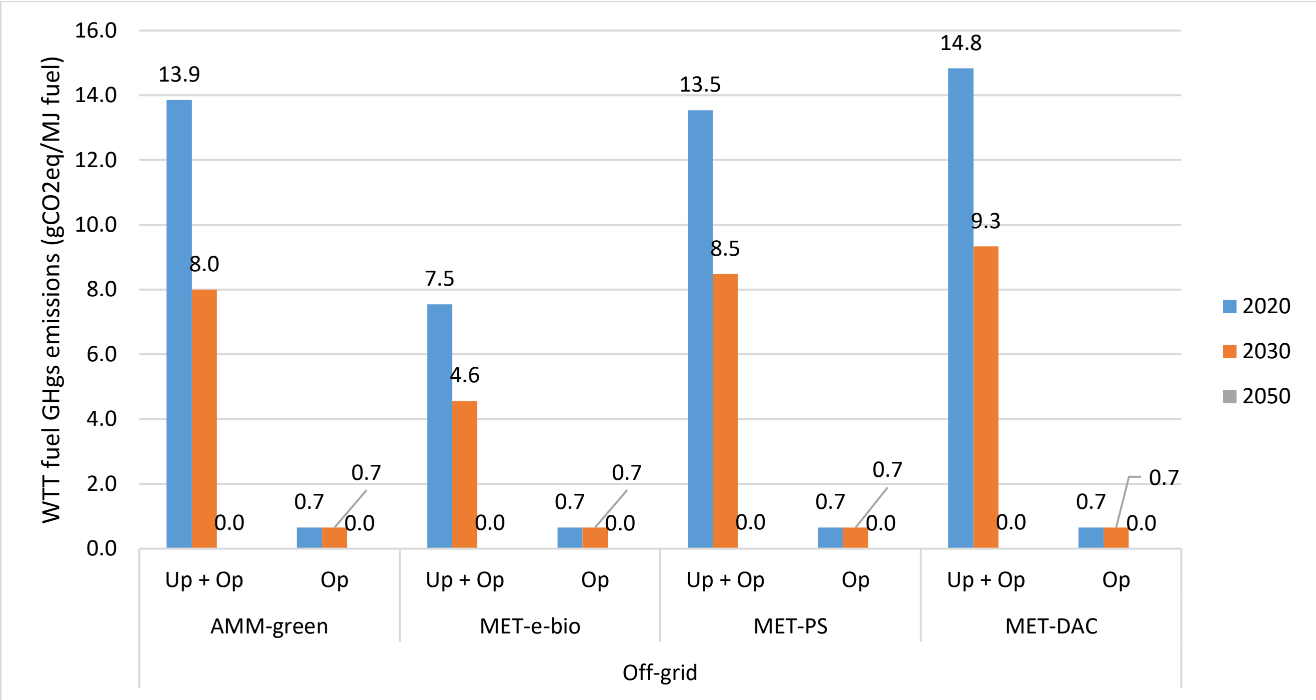


Figure 7: WTT fuel emissions counting upstream and operational emissions (up+op) or only operational emissions (op) in the selected sites (see section Fuel Prices) without grid for 2020, 2030, and 2050 (including pilot fuel).

Differences in upstream emissions between the different fuels originate from the optimal size of the power supply needed to produce the fuel. For example, MeOH-DAC has more significant upstream emissions than other fuels due to its higher electricity consumption. Indeed, more solar PV or wind turbines need to be built to produce the same amount of fuel. Therefore infrastructure-related emissions get higher. Infrastructures emissions are assumed to go down to zero in 2050. This is a strong assumption that considers that all the infrastructures production processes (e.g., mining activity) will be CO2 neutral in 2050.

Behind the meter with grid e-fuel production (mix of grid electricity and renewables)

In this configuration, the different emissions account:

- The carbon emissions are related to building the infrastructure such as fuel plants, batteries, tanks, solar PV, or wind turbines (WTT upstream).
- The emissions related to the embedded grid GHGs emissions (WTT operational). If the fuel is produced off-grid, these emissions are null.
- The Tank to Wake emissions (TTW).

As stated in the off-grid case, the baseline scenario used in the roadmap model does not count for WTT upstream emissions to align with the standard GHGs emissions accounting methods.

The behind-meter with grid case is an interesting case. It turns out to be the cheapest way of producing electro-fuels when the grid infrastructure is available without a significant extra cost supported by the fuel plant itself. Different shares of grid electricity are used in the fuel plant power mix depending on the weather profile type and the electricity price (See the reports “MarE-Fuel: LCOE and optimal electricity supply strategies for P2X plants” and “MarE-Fuel: Energy efficiencies in synthesizing green fuels and their expected cost” for further details).

The share of grid-power used to reach the least cost optimum in the selected cites is presented in table 12 (for the cheapest or second cheapest see the report “MarE-Fuel: Energy efficiencies in synthesizing green fuels and their expected cost” and section on Fuel prices). Results are presented for methanol production from a point source but would be similar for other fuels.

Fuels	2020	2030	2050
MET-e-Bio	19% (West Sahara)	50% (North Chile)	52% (West Sahara)
MET-PS	18% (West Sahara)	48% (North Chile)	53% (North Chile)
MET-DAC	18% (West Sahara)	48% (North Chile)	52% (North Chile)
AMM-Green	19% (West Sahara)	48% (West Sahara)	54% (North Chile)

Table 12: Share of grid electricity used in the least cost fuel production strategy in the behind the meter with grid configuration (example of methanol production)

Figure 8 shows the WTT emissions from e-fuel production with or without upstream emissions given the grid usage presented in table 12. WTT emissions coming from the use of pilot fuel are accounted for.

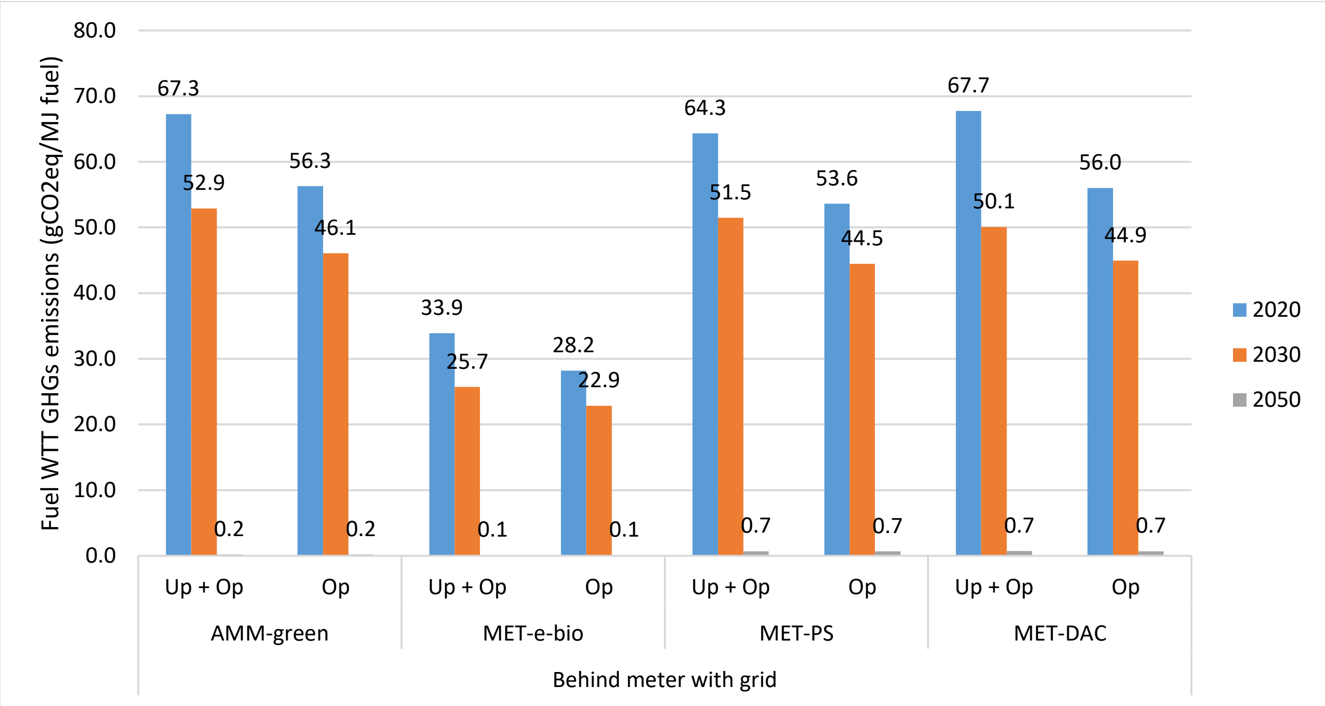


Figure 8: WTT fuel emissions counting upstream and operational emissions (up+op) or only operational emissions (op) in the selected sites (see section Fuel Prices) in the behind meter with grid case for 2020, 2030, and 2050 (including pilot fuel).

Figure 9 shows the WTT emissions share per source accounting for upstream (infrastructure emissions) and operational emissions (related to the grid usage). Green ammonia and bio-e-methanol have been selected for the example.

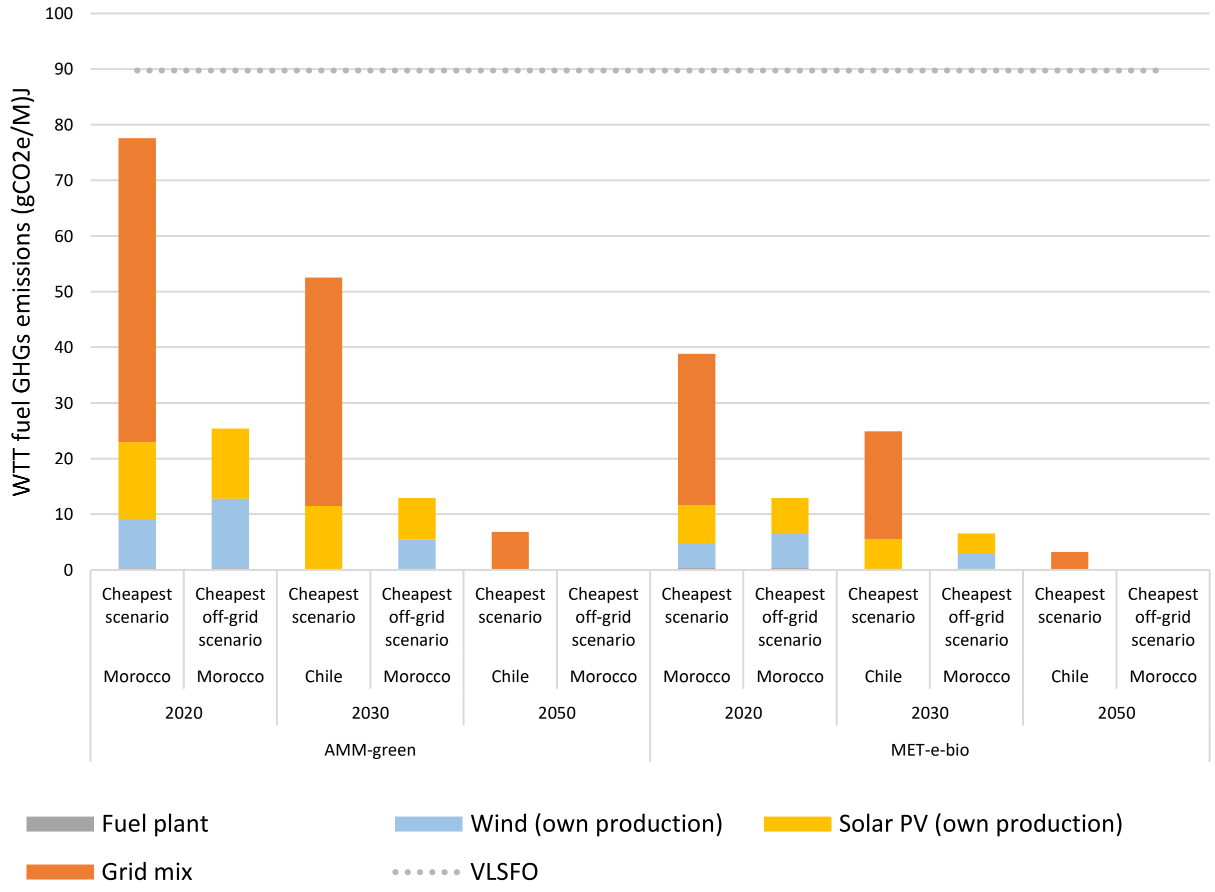
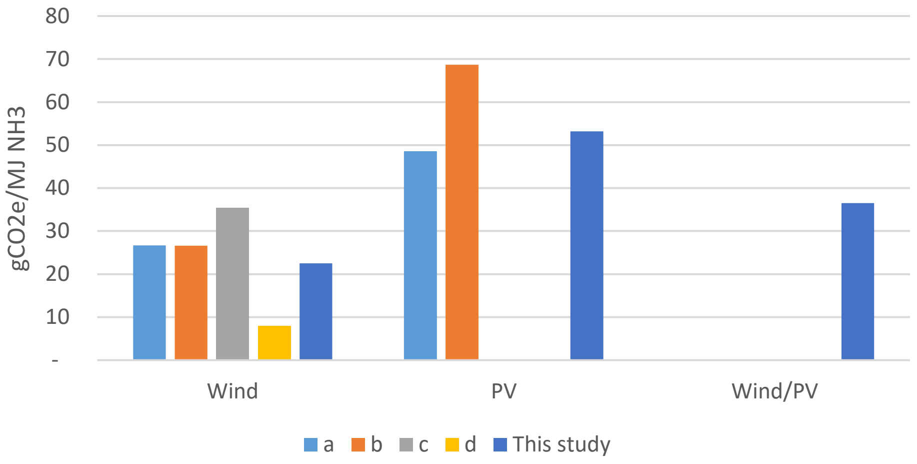


Figure 9: Well-to-tank emissions from AMM-green (left) and MET-e-bio production (right) for years 2020, 2030, and 2050.

Looking at the cheapest options for producing AMM-green and MET-e-bio, we see there is a significant difference in emissions impact between the off-grid scenarios and the scenarios where own production with wind and solar power is combined with 18-54% average grid electricity. The infrastructure emissions increase when the grid is not used due to the need to oversize the renewable power plant to compensate. With the data used, the infrastructures emissions related to the fuel plant or storage systems (batteries and hydrogen tank) are not significant compared to those related to power generations. However, other impacts not addressed here could be raised. For example, the extended use of batteries could increase metal resource depletion and soil pollution due to increased lithium extraction. A full Life Cycle Analysis could be done in future research to address other impacts than GHGs emissions.

Comparing the calculated emissions from AMM-green to other studies shows that our assessment is in the range of values found in the literature, see Figure 10. No studies have been found assessing emissions from the MET-e-bio process used in this study, where hydrogen is used to boost the syngas from gasification, with a combined emission factor of 19 gCO_{2e}/MJ in 2020. When methanol is produced without hydrogen, the assessed emissions range from 6.0 to 18.6 gCO_{2e}/MJ with an average of 12.2 gCO_{2e}/MJ [11–14].



The values used in this study are a mixture of 67% wind and 33% solar PV (right). The pure wind and PV values for this study are shown to compare with other studies. a [15], b [16], c [17], d [18].

Figure 10: Comparison of emission factors for AMM-green from literature and this study.

1.3.5 Grey and blue ammonia

A large number of studies estimating GHGs emissions from grey and blue ammonia have been conducted. However, these studies usually use different assumptions, and aligning assumptions for blue and grey ammonia GHGs accounting is challenging while using a large span of literature materials. To make a fair comparison between blue and grey ammonia, emissions are calculated using the same input data (as it was done for the cost estimate: see the report "MarE-Fuel: Energy efficiencies in synthesizing green fuels and their expected cost").

Grey ammonia emissions include emissions related to the production process and the methane leaks occurring during the transport and extraction of natural gas (upstream emissions). Upstream emissions are hard to quantify, and the uncertainty range is extensive and strongly depends on where the gas is extracted. The committee on climate change reported the range of natural gas upstream emissions between 15 and 70 kg of CO2e /MWh of gas (LNG) [19]. Natural gas consumption in the ammonia production process is 0.71 kg gas/kg NH3 [20], and process emissions used are 2.4 kg CO2/kg NH3 produced (values ranging between 1.6 to 2.7 for main regions, up to 4 kg CO2/kg NH3 when ammonia is produced from coal) [21].

Blue ammonia emissions are estimated using the grey ammonia emissions with the use of Carbon Capture and Storage (CCS) technology on the ammonia production site. The upstream emissions due to methane leakage during natural gas production are unchanged. CCS system applied on the ammonia plant is assumed to have an (optimistic) efficiency of 90% of CO2 captured [22], meaning that process emissions are reduced to 0.24 kg CO2/kg NH3.

Calculations and assumptions used to estimate blue and grey ammonia emissions are summarized in table 13:

GHGs emissions	Minimal	Base case	Maximal
Grey ammonia			
Natural gas consumption ammonia process [t gas/tNH3]	0.72	0.72	0.72
Grey ammonia upstream emissions (from natural gas) [tCO2e/tNH3]	0.15	0.425	0.70
Grey ammonia process emissions [tCO2/tNH3]	1.6	2.4	2.7
Total grey ammonia emissions [kg CO2e / GJ NH3]	**94.0**	**151.8**	**182.6**
Blue ammonia			
Carbon Capture efficiency [% CO2 captured]	90%	90%	90%
Blue ammonia process emissions [tCO2/tNH3]	0.16	0.24	0.27
Blue ammonia upstream emissions (from natural gas) [t CO2e/t NH3]	0.15	0.42	0.7
Total blue ammonia emissions [kg CO2e/GJ NH3]	**16.6**	**35.6**	**52.0**

Using the LHV of 18.6 MJ/kg for NH3 and 50MJ/kg for LNG

Table 13: Summary table of blue and grey ammonia emissions calculations

1.3.6 All fuels: summary

Figure 11 shows the average values used and the number of studies included (see appendices for more details). For ammonia, the reported TTW emissions are from evaporated gas on the ship, boil-off gas [23]. The average values for a 100 year GWP are compared to those found when using a 20-year time horizon for GWP for fuels where GHG species are specified. As data on GHG species was unavailable for AMM-grey, AMM-blue, it was impossible to assess the GWP in a 20 year perspective for these fuels (see Appendix A (Chapter 1). Production of these fuels involves methane use, which means that slips are possible and would mean higher emissions in a GWP 20-year timeframe. LNG and LBG are the fuels associated with the highest CH4 leakage for the fuels with GHG species-specific data, so LNG and LBG are most sensitive to the GWP timeframe used. HFO must be used with scrubbers to meet IMO requirements, but HFO is expected to be phased out, so the same emission factors are used for VLSFO and HFO.

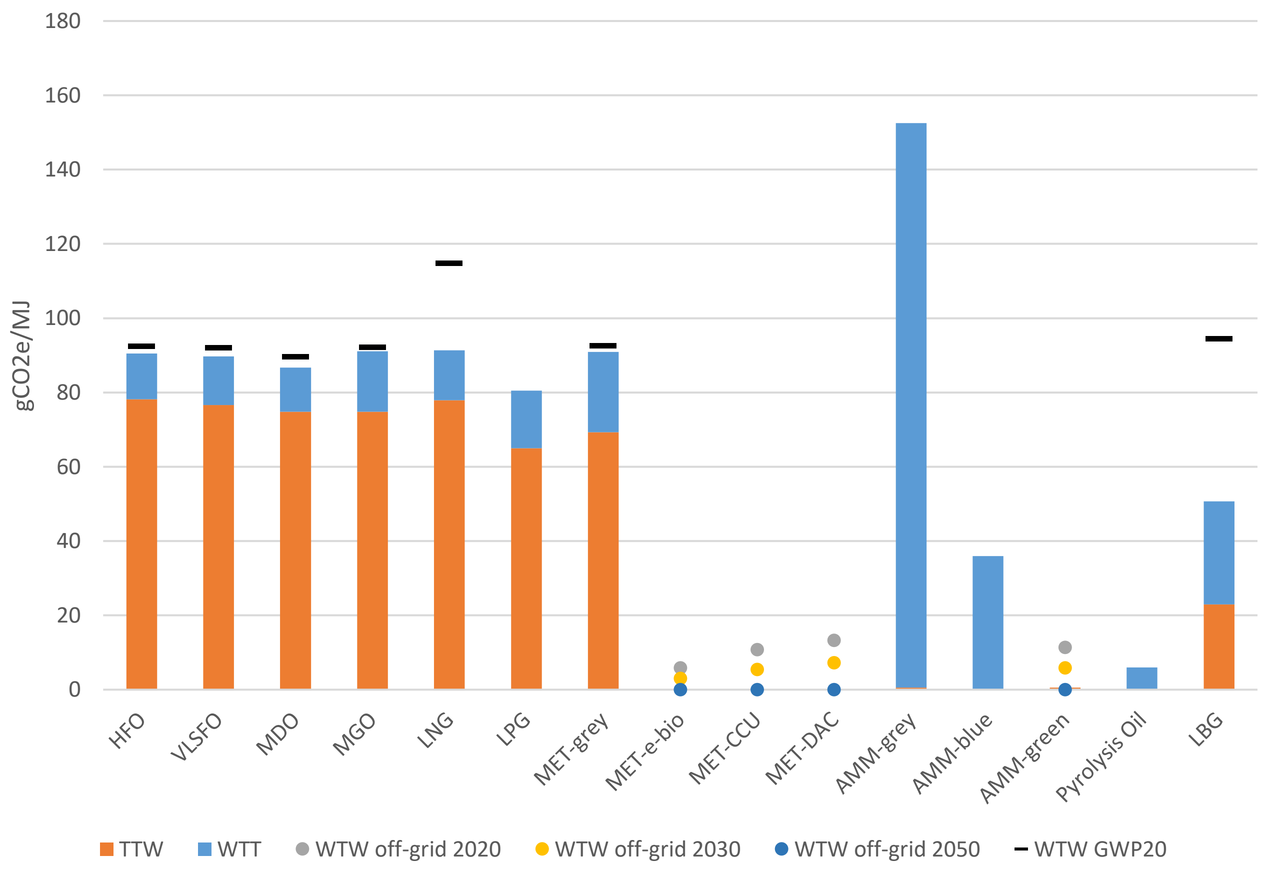


Figure 11: Overview of WTW emissions per fuel type.

Table 14 presents an overview of the emission factors used in the MarE-fuel project for 2020, including the pilot fuel emissions.

Fuels	WTT (op+up)	WTT (op)	TTW	WTW (op+up)	WTW base case (op)
VLSFO/HFO	13	13	77	90	**90**
MDO	12	12	75	87	**87**
MGO	16	16	75	91	**91**
LNG	14	14	78	92	**92**
LPG	16	16	65	81	**81**
MET-Grey	22	22	70	92	**92**
MET-e-bio	7-32*	0-26*	4	11-36*	**4-30***
MET-PS	14-64*	0-54*	4	18-68*	**4-58***
MET-DAC	15-68*	0-56*	4	19-72*	**4-60***
AMM-grey	136	136	4	141	**141**
AMM-blue	35	35	4	39	**39**
AMM-green	14-52*	0-40*	4	18-56*	**4-44***
PO	6	6	0	6	**6**
LBG	28	28	24	52	**52**

*Value on the left: behind the meter set up. On the right behind the meter with grid using the electricity mix presented in the electro fuel emission section.

Table 14: Average values of emissions by fuel (include pilot fuel) in kg CO_{2e}/GJ in 2020 using GWP 100. ("op" stands for operational and "up" for upstream emissions)

1.4 Fuel availability

Biofuel production for the shipping sector must be based on low-cost sustainable resources. The biomass considered is limited to residual biomass. These residuals are waste streams from activities in primarily the agriculture and forestry sectors. A radical change in, for example, global diets would drastically alter the availability of these resources, but this has not been taken into account. The annual technical resource potential, where ecological sustainability concerns are taken into account, is listed in table 15 and is assumed not to change over time. For manure and organic waste, this data is calculated based on current data. This is associated with high degrees of uncertainty, so the availability is set to zero in the low availability scenario.

Resource	Low	High	Source
Crop residues	15 EJ	70 EJ	[24]
Forestry residues	13 EJ	15 EJ	[25]
Black liquor	2 EJ	2 EJ	[26]
Manure	0 EJ*	13 EJ**	[27,28]
Organic waste	0 EJ*	2 EJ**	[27,28]

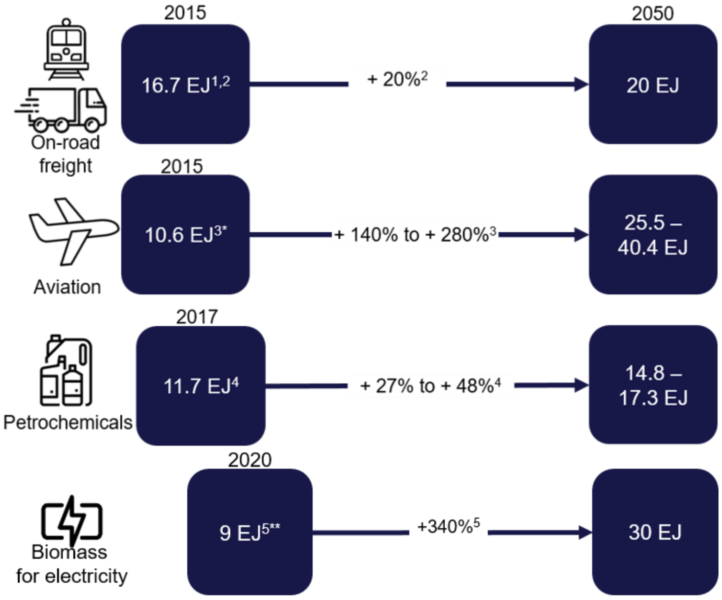
*Assumed to be zero in the low availability scenario

**listed as biogas potential

Table 15: Overview of annual technical resource availability.

1.4.2 Competing demand

Biogenic carbon is in high demand for energy and non-energy uses. Here the competing demand has been limited to electricity generation, aviation and road freight, as well as petrochemicals (plastics), see figure 12. Additional competing demands could be from, for example, the construction sector, but this has not been considered. It is assumed that competing uses for electricity generation, aviation, and road freight fuel, as well as petrochemicals, are served first. Thus the expected demand for these sectors is subtracted from what is available for producing shipping fuels.



Own calculation using data from [129 230 331 432 57] *using conversion factor for jet kerosene 43.15 MJ/kg. **efficiency going from 30% in 2020 to 40% in 2050.

Figure 12: Competing transport fuel and petrochemical demand.

1.4.3 Biomass for electricity

Bioenergy is expected to play an increasingly important role in the electricity sector. Following the IEA Net-Zero by 2050 scenario, bioenergy supplies 3% to 5% of increasing electricity demand. With a 30% conversion efficiency in 2020, rising to 40% by 2050[4], the biomass demand and electricity generated from biomass is shown in Figure 13. This is assumed to be covered by a mix of biomass resources with a distribution listed in table 15.

[4] By 2030 typical electrical conversion efficiencies for bioenergy power plants are expected to 16-20% for small scale (<10 MW), 23-38% for medium scale (10-50 MW), and 33-45% for large scale (>50 MW) [33].

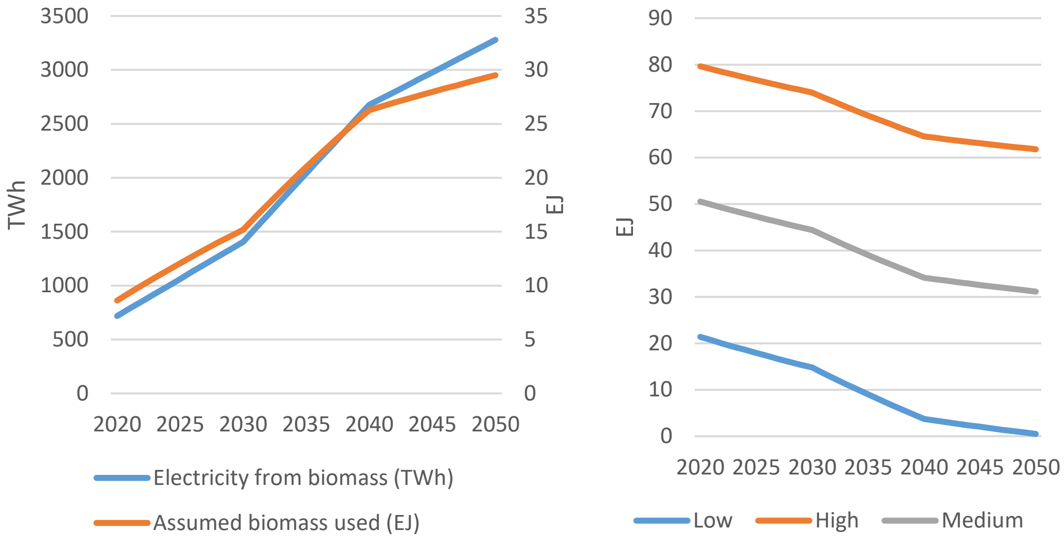


Figure 13: Produced electricity from biomass and resources used (left). Low and high availability scenarios with demand for electricity generation extracted (right).

When the electricity demand is deducted from biomass availability, the remaining quantities left for other sectors are shown in figure 13. The range between low and high availability is substantial, with no availability in the low scenario by 2050. This is why a medium scenario is added, the midpoint between the low and the high availability scenario.

1.4.4 Carbon conversion

Crop and forestry residues can be used for MET-e-bio or PO. The PO pathway means a low carbon efficiency as a large share of the carbon ends up as biochar, allowing for carbon sequestration in the soil. When used for MET-e-bio production, additional hydrogen from electrolysis is used, and 90% of the carbon ends up in the fuel compared to pyrolysis, where 30% of the carbon ends up in the PO.

1.4.5 Competing transport fuel and petrochemical demand

As MET-e-bio is the most carbon-efficient pathway, this is assumed to be used to cover competing transport fuel and petrochemical demand. If crop and forestry residues and black liquor are treated using the MET-e-bio pathway, the resulting fuel availability is shown in figure 14. MET-PS covers the remaining demand.

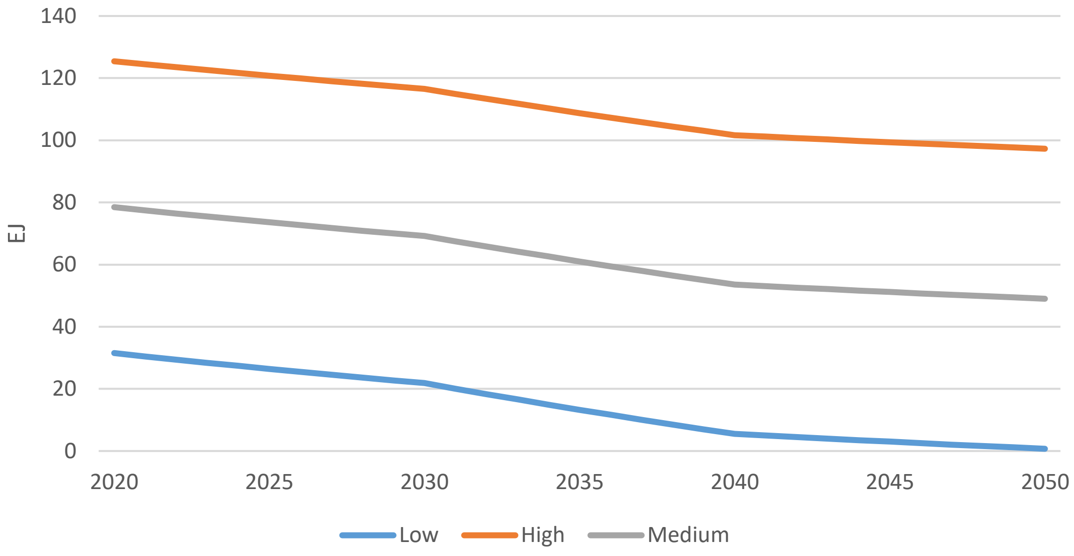


Figure 14: Potential MET-e-bio production with different biomass availability scenarios.

The competing demand from aviation, on-road freight, and petrochemicals are projected to 2050, and two scenarios are used, high and low competing demand. The projected demand for on-road freight and the high range for aviation shown in figure 15 is used for competing transport fuel demand in the high-demand scenario. In the low-demand scenario, all freight is assumed to be electrified, and the low demand for aviation fuel is used. For petrochemicals, the combined demand for ethane, naphtha, and other oil products for the petrochemical industry is used [32]. The low range is used in the low competing demand scenario, and the high range is used in the high competing demand scenario. Here again, a medium scenario is the mid-point between the two.

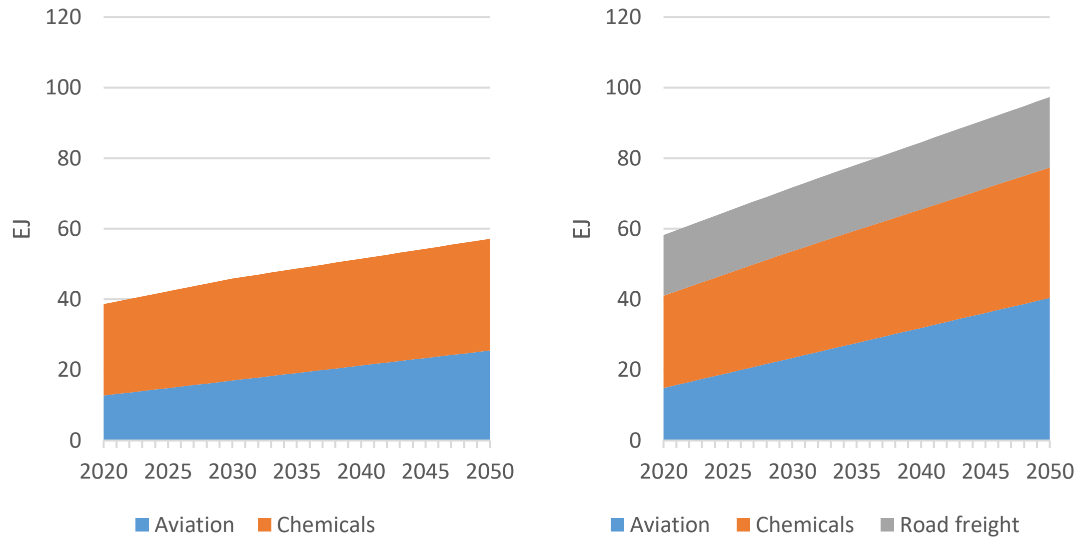


Figure 15: Projected low (left) and high (right) competing demand from 2020 to 2050.

1.4.6 Fuel availability scenarios

After the demand for electricity generation is taken into account, figure 13, the fuel availability scenarios are combined with scenarios for competing demand, Figure 15. This results in different configurations with or without biofuel availability to the shipping sector. In the scenarios with high biofuel availability, it could be relevant to produce PO instead of MET-e-bio. Figure 16 shows the different outputs in the different scenarios if crop and forestry residues and black liquor are converted to MET-e-bio, and figure 17, PO.

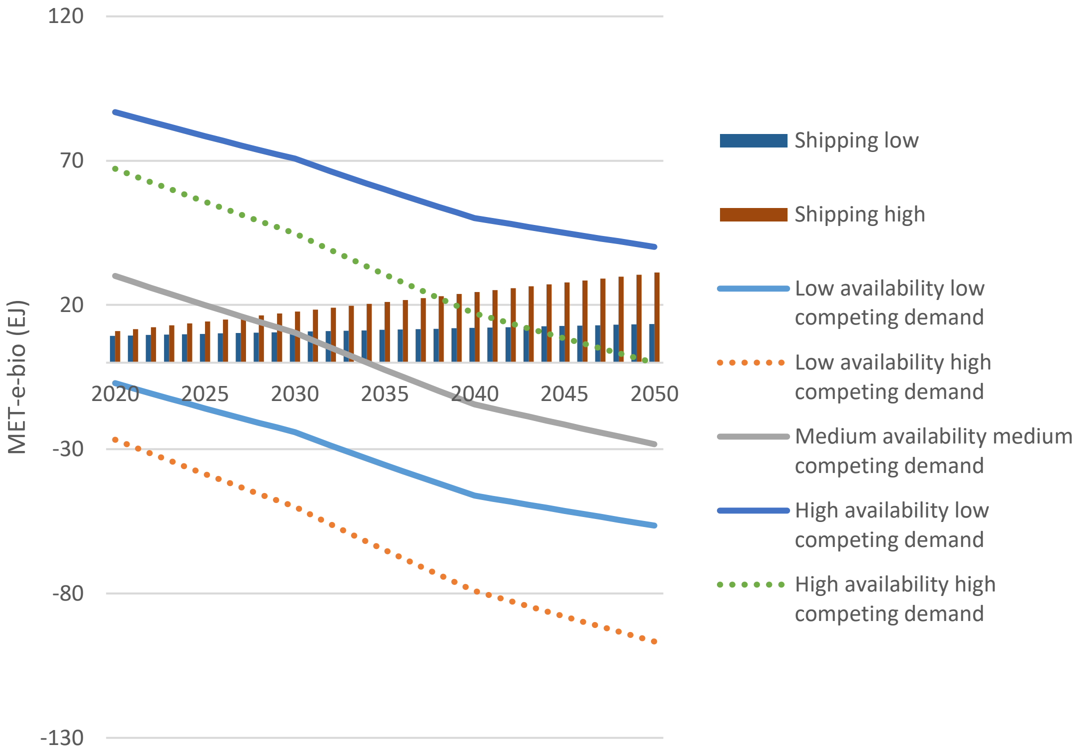


Figure 16: Biofuel potential compared to expected shipping demand using MET-e-bio pathway. Solid lines are for scenarios assessed in the MarE-fuel Roadmaps.

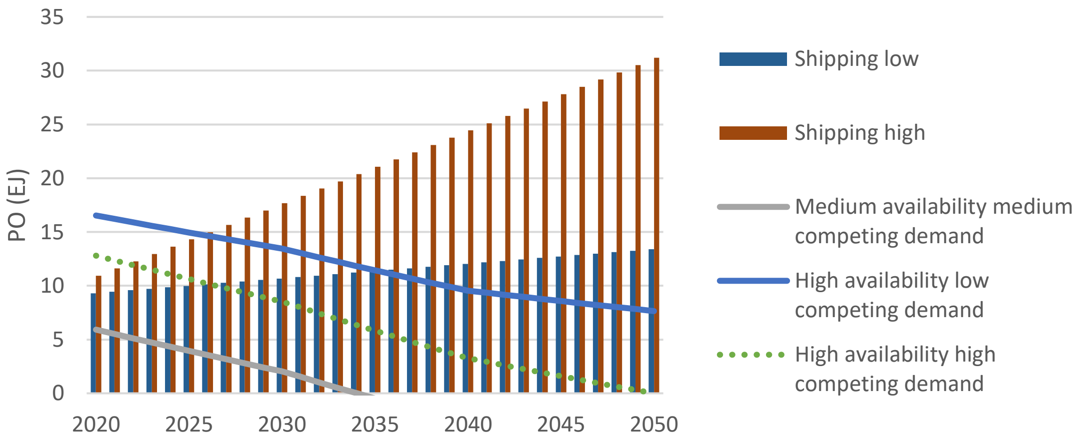


Figure 17: Biofuel potential compared to expected shipping demand using pyrolysis pathway. Solid lines are for scenarios assessed in the MarE-fuel Roadmaps.

The MET-PS availability is based on the electricity generation from biomass. When this biomass is used for electricity production 0.5 to 1 ton of CO_2 could potentially be captured per MWh of electricity [34]. The CO_2 not stored for negative emissions could be used for production MET-PS (or MET-PS) from a biogenic point source, see figure 18. It is assumed that competing demand not covered by Bio-e-MET is covered by MET-PS, leading to differences in MET-PS availability to the shipping sector in the different biomass availability scenarios.

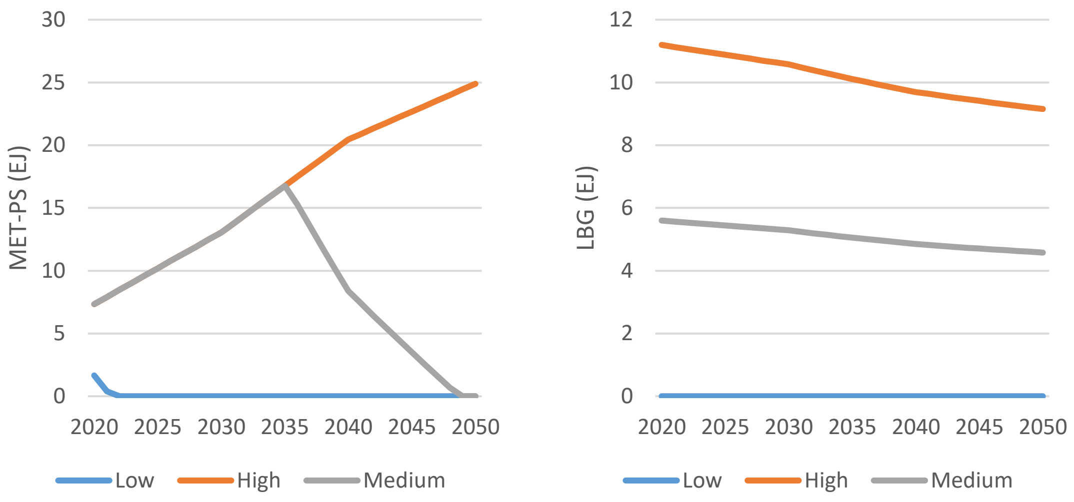


Figure 18: Potential for Methanol production from BECCU (left) and LBG potential in the different biomass availability scenarios (right).

The biogas potential is calculated using the volatile solids content from manure and organic waste and methane losses [27]. This is then upgraded to LBG using an average efficiency of 84% [35]. The resulting LBG potential is shown in Figure 18.

1.2.6 Fuel availability results

Three biofuel availability scenarios are modeled in the MarE-fuel Roadmaps:

- High biomass availability and low competing fuel demand. A very optimistic scenario with room for producing low carbon efficient fuels, see figure 19.
- Medium biomass availability and medium competing fuel demand. An optimistic scenario with some availability in the short term, but these are very limited if the PO route is chosen, see figure 20.
- Low biomass availability. There is essentially no biofuel availability to the shipping sector with low biomass availability even with low competing demand, see figure 21.

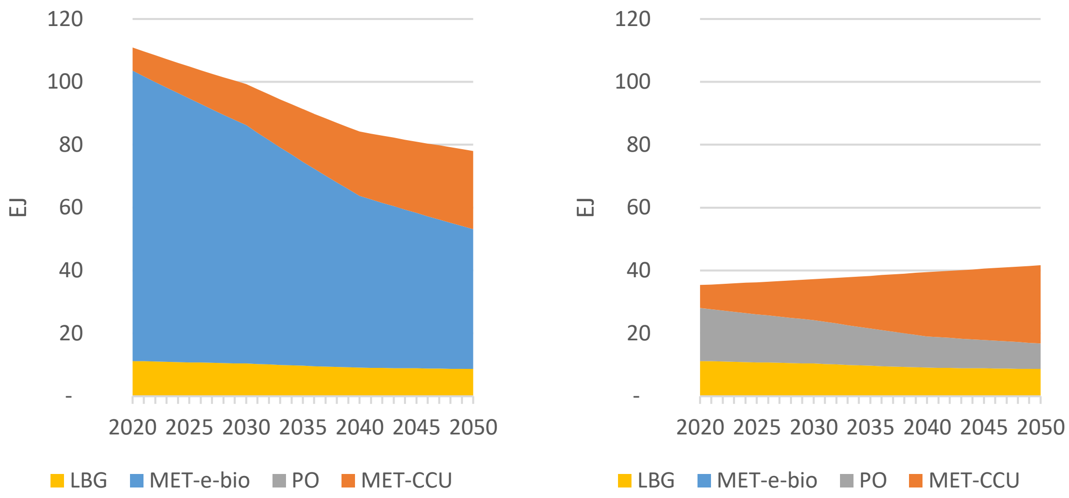


Figure 19: High biomass availability low competing demand, MET-e-bio (left) or PO (right)

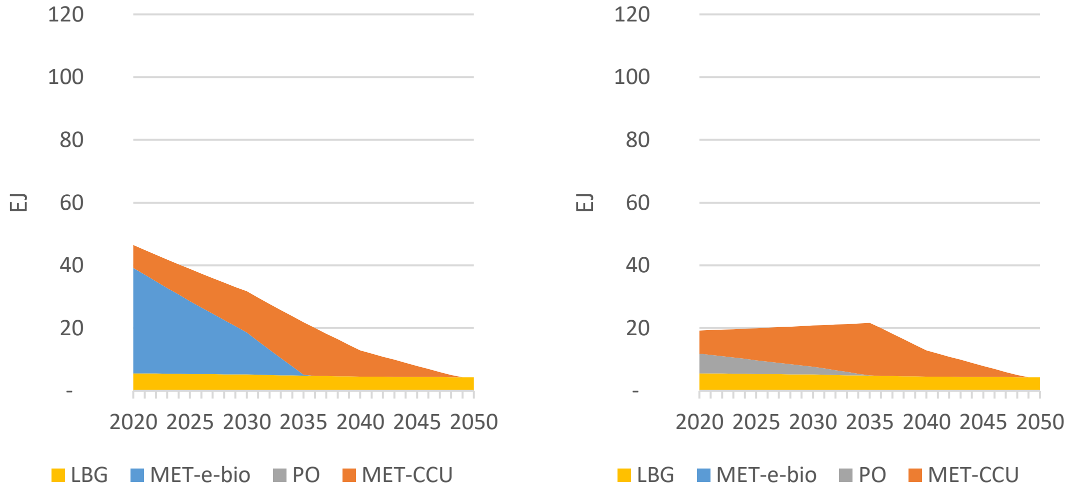


Figure 20: Medium biomass availability medium competing demand, MET-e-bio (left) or PO (right)

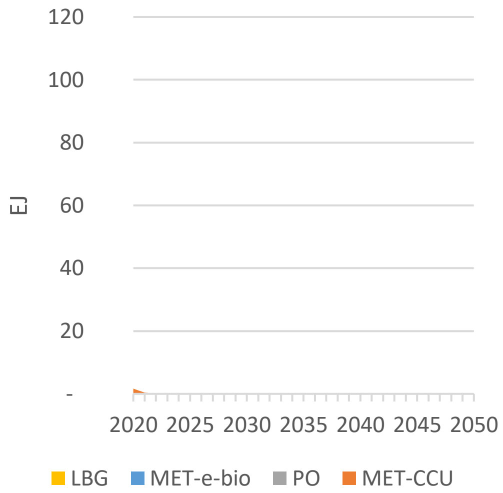


Figure 21: Low biomass availability low competing demand.

1.2.7 Emissions caps

The scenarios used for emissions caps are based on the IMO target to reduce GHGs from international shipping by at least 50% by 2050 compared to 2008 [36]. This target is limited to TTW emissions. However, the main GHG emissions impact from new fuels stem from WTT emissions, which is why these emissions are included in the WTW emission reduction scenarios. Different levels of ambition are used for WTW emission reduction scenarios, 50%, and 70% reduction compared to 2008 as well as a zero[5] emission scenario, all projected linearly from the latest data point in 2017.

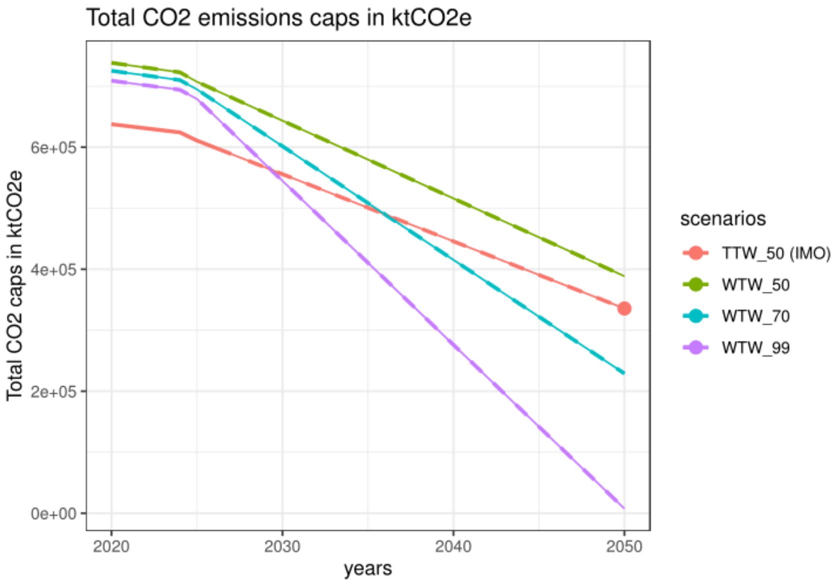


Figure 22: Emission cap reduction scenarios.

The historical emissions are found using the top-down ship fuel consumption data reported in the fourth IMO GHG study multiplied by the TTW and WTW emission factors by fuel listed in table 16. Apart from emissions related to the fuel, there are emissions from on-ship refrigerants and air conditioning. The fluorinated gasses (F-gasses), R-22, R404, and R134a are accounted for in the IMO fourth GHG study [36]. R-22 is assumed to be used in old ships built before 2000, and is being phased out as it is an ozone-depleting substance. On newer ships, R134a is used for air conditioning and R404 for cooling purposes. Using data from the IMO fourth GHG study, an average value of CO_{2e} emissions from F-gasses per gigatonne nautical mile for year 2018 is calculated, see table 16. For the year 2008, this amounts to 653 Mt CO_{2e} TTW and 753 Mt CO_{2e} WTW. The F-gasses are projected as a function of shipping demand by ship type, and the emission intensity is assumed to be reduced to zero in 2050, see figure 23. In all emission reduction scenario cases, the same level of F-gasses, where the emission intensity is reduced to zero, are subtracted from the emissions cap that is used in the roadmaps.

CO_{2e}/GT nautical miles	Oil tankers	Bulk carriers	General cargo	Container ships	Other types of ships
	34	125	78	42	1 549

Table 16: F-gasses per ship type in 2018

[5] The emission cap is set to 0.1% of 2008 emissions for modelling purposes.

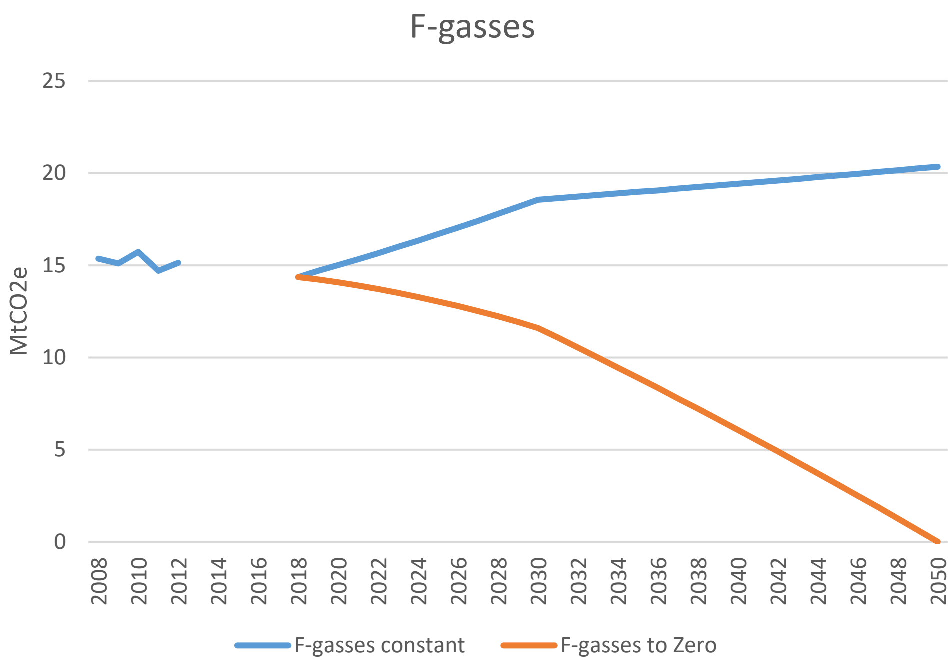


Figure 23: F-gasses as a function of projected shipping demand per ship type when the emission intensity per GT nautical mile is kept constant or linear reducing to zero from year 2018 to 2050.

1.3 Conclusion

Emission intensity for fossil fuels is most dominant in the on-board TTW emissions, whereas most emissions from production and use of alternative fuels are in the WTT step. For e-fuels, the source of electricity has a major impact on the emission factors of the fuels. Using electricity from low-emitting electricity production is paramount. Due to the potential high emission from WTT of alternative fuels, it is of great importance to include these emissions to ensure a real reduction of GHG from the shipping sector. The biomass demand is assessed using technically available resources and limited competing demand, which is why both scenarios with biomass available to the shipping sector can be seen as optimistic cases.

2 Modeling of the current and future shipping fleet

Author

Martijn Backer

Nicolas Campion

Sebastian Franz

2.1 Introduction

Most of the data throughout this work are retrieved from IMO's Fourth Greenhouse Gas Study[38].The 19 ship categories that are used in this source are grouped into five ship categories, following UNCTAD's convention[39]: tankers, bulk carriers, general cargo ships, container vessels, and other ships. Table 8 shows the categorization of the ships.

Ship type	Ships included
Tanker	Oil tankers (only crude oil)
Bulk	Bulk carriers, combination carriers, refrigerated bulk carriers
General Cargo	General cargo ships, roll-on roll-off cargo ships, vehicle ships
Container	Fully cellular container ships
Other	LPG carriers, LNG carriers, chemical tankers, specialized tankers, refrigerated container ships, offshore supply vessels , tugs, cruise ships, ferries, other non-cargo ships

Table 17: Classification of the ship types, according to UNCTAD's categories[39].

2.2 Description of current and future fleet

2.2.1 Total transport demand - today and future

Data for the total transport demand for each ship type are retrieved from tables 19 and 21 of IMO's Fourth Greenhouse Gas Study[38]. The transport demand is described in the unit of gigatonne-nautical miles (gt*nm), with one gt*nm meaning the transport of 1 gigatonne load over one nautical mile (1.852 kilometers). This study includes prognoses regarding shipping demand for two combinations of long-term socioeconomic scenarios and long-term emission scenarios.

For the first combination, **Shared Socioeconomic Pathway 1 (SSP1)** – "Sustainability: Taking the Green Road" – was selected as socioeconomic scenario and **Representative Concentration Pathway 2.6 (RCP2.6)** as emission scenario.

SSP1 scenario assumes an inclusive development where environmental boundaries are respected, and human well-being is more important than the size of the economy, and where consumption has a low material intensity and energy intensity[40]. Average population growth is 0.5% per year and GDP growth per capita 2.8% per year[38].

RCP2.6 represents an emission pathway limiting the mean increase in global temperature to 2 °C[41]. For this, the scenario shows sharp reductions in global greenhouse gas emissions[42]. This affects the international energy mix, and thereby also the shipping demand. In particular, the demand for transport of energy products by, for example, oil tankers, gas tankers, and coal carriersis much lower in the RCP2.6 scenarios than in higher-emission scenarios[38].

The expected shipping demand under the combined scenario SSP1-RCP2.6 is displayed in figure 24.

Values for 2018 and expectations for 2050 are taken from IMO's 4th greenhouse gas study[38], and values between 2018 and 2050 are based on linear interpolation. Under SSP1-RCP2.6, demand declines towards 2050 for the high-carbon energy carriers oil (transported by tankers) and coal (bulk carriers).In contrast, demand for natural gas (other) and non-energy products (bulk, general cargo, container) increases in this scenario.

The second scenario combines SSP5 with RCP2.6. In SSP5 – "Fossil-fueled Development - Taking the Highway" –, global markets are increasingly integrated and competitive. Economic and social development is pursued by further exploitation of fossil fuel resources and adopting resource and energy-intensive lifestyles worldwide[42]. This results in an average annual GDP per capita growth of 3.2%, while population growth equals 0.5% per year[38]. Much faith is put in technological solutions to manage social and ecological system[38].

The expected shipping demand under SSP5-RCP2.6, according to IMO[38], is displayed in figure 25. In contrast with SSP1-RCP2.6, demand for oil tankers will increase towards 2050. The more energy- and material-intensive lifestyles of the SSP5-RCP2.6 also translate to higher demands for the other ship types. The only significant demand reduction is for coal carriers (part of bulk), with a 95% decrease in demand[38].

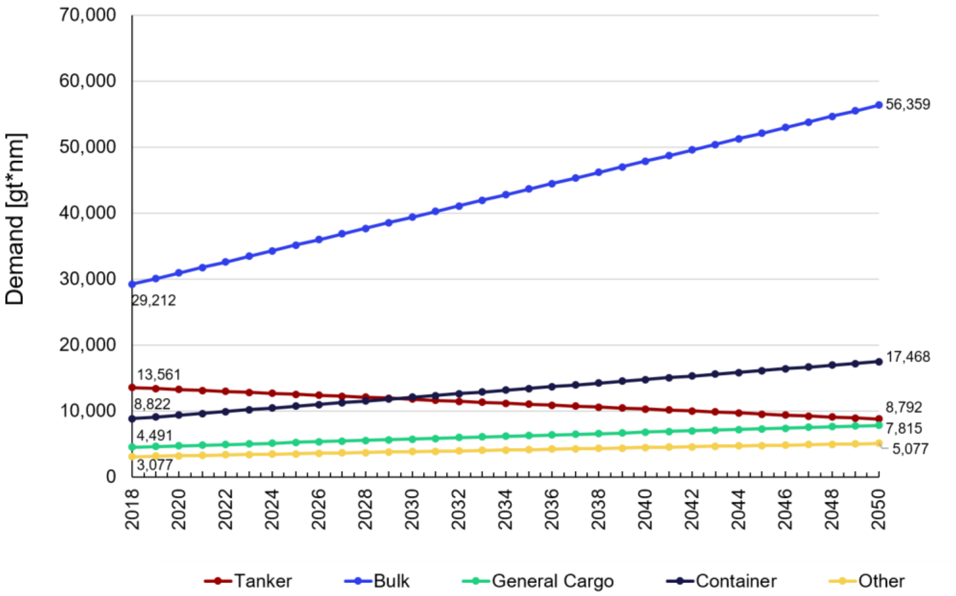


Figure 24 Shipping demand under scenario SSP1-RCP2.6 (linear inter- polation between 2018 and 2050)[38].

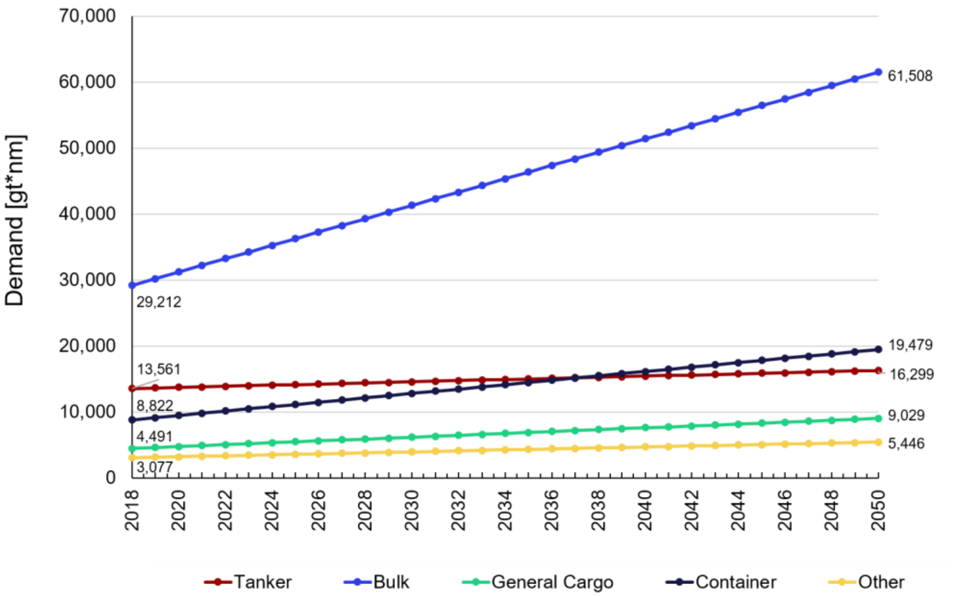


Figure 25: Shipping demand under scenario SSP5-RCP2.6 (linear interpolation between 2018 and 2050)

It should be remarked that the classification method of ship types used by IMO[38] in their demand statistics and projections is slightly different than the one used elsewhere. The most notable deviation is that the "Other" category was split up into gas and chemical tankers, including no non-energy products. Furthermore, fishing is allocated to container ships. Finally, no personal transport is included, and general cargo only consists of Ro-Ro ships.

2.2.2 Existing fleet

The values for the existing number of ships in 2018 are retrieved from IMO's Fourth Greenhouse Gas Study[38]. The age distribution of the global ships is presented in table 18[43]. It can be seen that the age distributions vary between ship types. For example, the number of ships older than 25 years is much higher for general cargo ships than for bulk or container vessels.

Age [years]	Tankers	Bulk	General Cargo	Container	Other
0-4	14 %	16 %	6 %	13 %	8 %
5 - 14	41 %	59 %	27 %	53 %	25 %
15 - 24	20 %	16 %	19 %	29 %	16 %
+25	25 %	8 %	49 %	6 %	50 %
Average lifetime [years]	25	28	35	25	33

Table 18: Age distribution of the global fleet[43].

Table 18 also displays the average lifetimes (scrapping ages) of the ship types. It is assumed that after a period equal to the stated lifetime, 0% of the existing ships remain. For example, if the model started in 2018, all the existing bulk carriers will be decommissioned by 2018 + 28 = 2046. Since 16%of the bulk carriers is 0–4 years old (and thus has a minimum remaining lifetime of 28-4 = 24 years), it is assumed that 16% of the existing bulk carriers is still active in 2018 + 24 = 2042. Between 2042 and 2046, the existing bulk carrier fleet is assumed to decline linearly from 16% to 0%. The same method is applied to the other age bins and ship types.

It is challenging to handle the distribution of ship sizes in the optimization model. Therefore, instead of *actual* ships, the model uses *average* ships for each ship type. Based on the distribution of the carrying capacities of each ship type, an average ship was defined (figure 26).

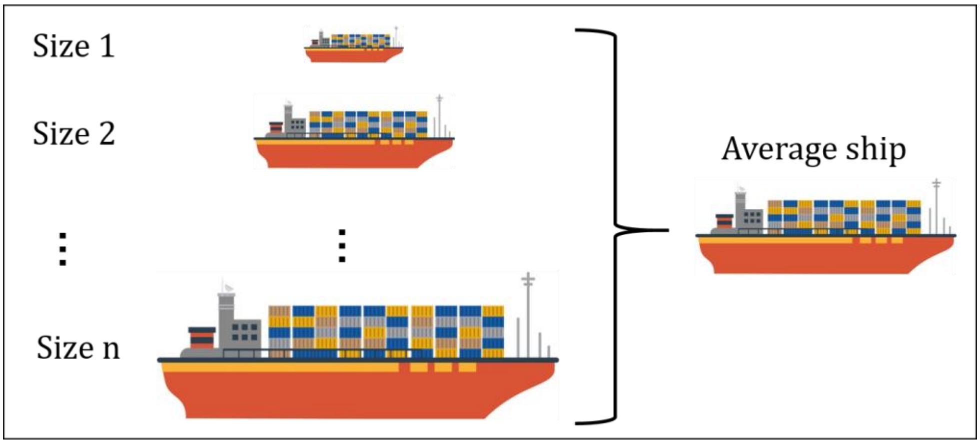


Figure 26: The existing fleet, consisting of ships of various sizes, is aggregated into an equivalent fleet of 'average-sized ships' per ship type.

2.2.3 Ordered ships

From a report by Danish Ship Finance[43], it was found that the order book (i.e., ordered ships as a percentage of the total existing fleet) is currently equal to 7% of the global fleet. For the different types, the order book amounts to the following shares of total capacity of these ships: tankers - 7%, bulk - 3%, general cargo - 7%, container ships - 9%, other - 23%[6]. These ships are added to the existing fleet.

2.3 Representation of current and future fleet using average

For each ship type, a capacity-weighted average-sized ship was determined to use in the optimization model (figure 26). This section describes the methodology to define the average ships. The average ships are representative of the whole fleet and are sorted into the five different types presented in the introduction (Containers, Bulk carriers, Cargos, Tanker, and Others).

All input data required for the equations in this section are retrieved from IMO's Fourth Greenhouse Gas Study[38]. This source provides data per 'size bin' $c \in C$, based on capacity. For example, for bulk carriers size, bin c_1 contains all ships with a deadweight tonnage in the range 0 - 9,999, size bin c_2 in the range 10,000 - 34,999, etc.

The *averaged ships* will be characterized by their:

- Average transport work
- Engine specification (fuel accepted, power, fuel consumption)
- CAPEX and OPEX

2.3.1 Average transport work

The average transport work per ship category s in year y (in gt*nm), $TW_{s,y}^{avg}$, is defined as the capacity-weighted average transport work of all ships of that category:

$$TW_{s,y}^{avg} = \sum_{c \in C}(d_{s,y}^{avg} * C_{s,y}^{avg} * \frac{Q_{s,y,c}}{\sum_{c \in C} Q_{s,y,c}}) \quad (1)$$

$d_{s,c}^{avg}$(in nm) indicates the average yearly traveled distance for each ship and size bin and is calculatedfrom the average speed $u^{avg.}$(in knots) and number of international days at sea $t_{s,c}^{avg}$

$$d_{s,c}^{avg} = u_{s,c}^{avg} * t_{s,v}^{avg} \quad (2)$$

The deadweight tonnage capacity of the ship, $C_{s,c}^{cap}$ is defined as the mass of the cargo that the shipcan carry (excluding its own mass). In order to find the average deadweight tonnage carried by ship type s of a size bin c, $C_{s,c}^{avg.}$, the capacity is multiplied by the average utilization factor α (in %):

$$C_{s,c}^{avg} = C_{s,c}^{cap} * \alpha \quad (3)$$

The resulting average transport work values are displayed in table 19. Values for average transport work between the years 2018 and 2050 result from linear interpolation. .

		Tanker	Bulk	General Cargo	Container	Other
Average transport work [gt*nm]	**2018**	1.94	3.14	0.24	5.47	0.08
	2050	1.94	3.64	0.24	7.60	0.08

Table 19: Average transport work per ship type in 2018 and projected average transport work per ship type in 2050. Projections show the same values for the SSP1-RCP2.6 and SSP5-RCP2.6 scenarios[38]

2.3.2 Number of average ships

For modelling purposes, the number of existing ships need to be converted into a number of *average* ships $q_{s,f,y}$ of ship type s using fuel $f \in F$ in year y (not to be confused with actual number of real ships, $Q_{s,y}$).

$$q_{s,f,y} = \beta_{s,f} * \frac{TW_{s,y}^{demand}}{TW_{s,y}^{avg}} \quad (4)$$

where $\beta_{s,f}$ refers to the fraction of ships of type s that use fuel f (figure 27).

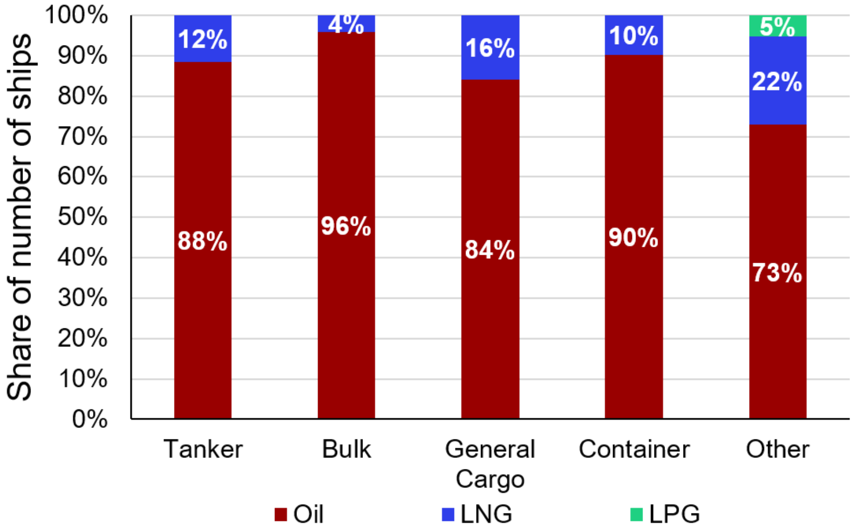


Figure 27: Fuel types as a percentage of the total number of ships.

The resulting number of (average-sized) ships is displayed in figure 28.

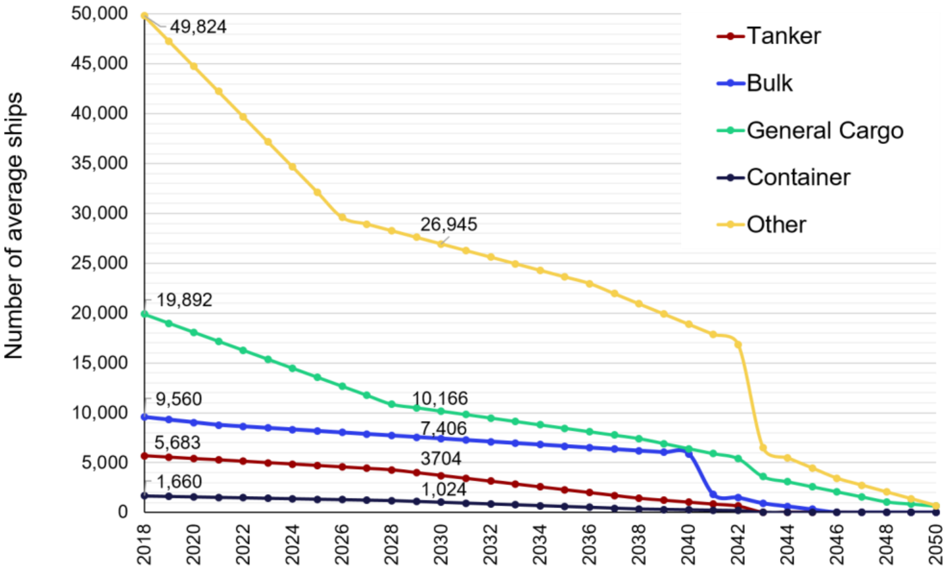


Figure 28: Equivalent of existing fleet (including orders) in average-sized ships. Values are highlighted for 2018 and 2030.

2.4 Ship engine specifications

Ship engines specifications include:

- The type of fuels that can be used in the same engine without retrofitting.
- The engine power.

The engine fuel consumption.

All values are calculated for the *average* ships representing the whole fleet.

2.4.1 Engine type and fuels handled

Based on a recommendation from external industry partners, the following engines have been selected for this study. The brief description of the engines is based on discussions with external partners and data publicly available from MAN Energy Solutions:

- **ME-C:** Two-stroke fuel oil engine installed on most of the current vessel.

- **ME-GI:** Two-stroke dual-fuel engine using fuel oil or LNG with the same thermal efficiency no matter the fuel used. Already commercially available.

- **ME-LGIp:** Liquid gas injection dual-fuel two-stroke engine allowing to switch between VLSFO, MGO, and LPG with no efficiency loss. Newly available commercially.

- **ME-LGIm:** Liquid gas injection dual-fuel two-stroke engine allowing to switch between VLSFO, MGO, and methanol. The switch is assumed to be possible without efficiency loss. Newly available commercially.

- **ME-LGIa:** Liquid gas injection dual fuel two-stroke engine. It is assumed to switch between VLSFO, MGO, LPG, and ammonia with no efficiency loss. First engine delivery to yard announced for 2024.

- **ME-LGImulti:** Hypothetic liquid gas injection multi-fuel engine with the possibility to switch between all fuels except LNG without efficiency loss. If demand for such an engine exists, it is assumed to be commercially available after 2030.

- **ME-GImulti:** Hypothetic multi fuel engine able to switch between all fuels without efficiency loss. Similarly to the ME-LGImulti engine, it is assumed to be commercially available after 2030.

Table 20 summarizes the different years of availability and fuels handled by the selected engines. In all cases, it is assumed no thermal efficiency losses between the different fuels (as it is for existing dual fuels engines).

		Fuels handled without additional retrofitting cost						
Engine type	**First year available**	**VLSFO/HFOsc**	**MDO/MGO**	**Refined PO**	**LNG/LBG**	**LPG**	**MeOH**	**NH3**
ME-C	2020	✓	✓	✓	✗	✗	✗	✗
ME-GI	2020	✓	✓	✓	✓	✗	✗	✗
ME-LGIp	2020	✓	✓	✓	✗	✓	✗	✗
ME-LGIm	2020	✓	✓	✓	✗	✗	✓	✗
ME-LGIa	2025	✓	✓	✓	✗	✓	✗	✓
ME-LGImulti	2031	✓	✓	✓	✗	✓	✓	✓
ME-GImulti	2031	✓	✓	✓	✓	✓	✓	✓

Table 20: Different Engine Types and Fuel usage.

After the first year available, it is assumed that ships using these engines can be produced at a large scale to the rate of **600 ships per year**. The production capacity can **increase by 200 ships every year** and can reach a **maximum limit of 2000 ships produced per year**. These production capacities are however uncertain, but in this way, the model will have more freedom to solve.

2.4.2 Engines fuel consumption

As explained in section 2.4.1, the fuel consumption is assumed to be the same no matter the fuel type as the engine are designed to switch fuel without thermal losses. However, the fuel consumption depends on the ship type.

The fuel efficiency of the ships is indicated by the specific fuel consumption $SFC_{f,s}$ of fuel f by ship s. (in gt*nm / PJfuel). This is defined as the quotient of total transport work TW^{tot} and total fuel consumption FC^{tot} for each ship type s and fuel f:

$$SFC_{f,s} = \frac{TW_s^{tot}}{FC_s^{tot}} \tag{6}$$

The resulting specific fuel consumption rates per ship type are displayed in table 21 (based on data from figure 28 of IMO's Fourth Greenhouse Gas Study[1]). The fuel consumption includes the auxiliary engines and boilers.

	Tanker	Bulk	General Cargo	Container	Other
Specific fuel consumption [gt*nm/PJ]	8.57	11.76	4.52	3.23	1.29

Table 21: Specific fuel consumption for average ships of each ship type, using 2018 data[38]. Values are in gigatonne-nautical mile per peta Joule fuel (gt*nm/PJ)

2.4.2 Average ships engine power

The average engine power size per ship type, $P_{s,y}^{avg}$, is defined as the sum of the product of average power per size bin c and the fraction of ships of size bin c:

$$P_{s,y}^{avg} = \sum_{c \in C} \left(P_{s,y,c}^{avg} * \frac{Q_{s,y,c}}{\sum_{c \in C} Q_{s,y,c}}\right) \tag{5}$$

The resulting engine power of the average ship is displayed in table 22.

	Tanker	Bulk	General Cargo	Container	Other
Main engine power [MW]	4.80	7.99	5.14	28.24	1.59

Table 22: Main engine power of average ships of each ship type, using 2018 data[38].

2.5 Ships CAPEX and OPEX

CapEx and OpEx used in this model are derivated from the TCO model and underlying assumptions can be found in the report "MarE-Fuel: Total Cost of Ownership"

2.5.1 CapEx

The CapEx of the average ships used in the model is calculated using cost estimates for existing fuel oil ships and expected added cost to handle a new type of fuel.

From the TCO, we get the cost estimates for existing oil ships (see table 23).

Engine size [MW]	6	14	50
Ship size [TEU]	1200	2500	24000
Vessel CapEx [MUSD]	**18**	**28**	**150**

Table 23: Input data for CapEx calculations (see the report "MarE-Fuel: Total Cost of Ownership" for more details)

Costs are then converted to €2019 and linearly interpolated to fit the engine power of the averaged ships used in the model (see table 21). Data used in the model are presented in table 25.

Extra costs are added depending on the engine type and fuel handling. These costs include the need for different fuel supply systems, engines, tanks depending on the type of fuel. Ships using ammonia also need to be equipped with water curtain systems and collectors to handle leaks.

The additional CapEx estimates extracted from TCO are presented in table 24.

Main fuel	**Engine type**	**6 MW engine**	**14 MW engine**	**50 MW engine**
Fuel oil	**ME-C**	0	0	0
LNG	**ME-GI**	5	8	13
LPG	**ME-LGIp**	4	5.5	8.5
Methanol	**ME-LGIm**	3	4.5	8
Ammonia	**ME-LGIa**	4	6	10

Table 24: Additional vessel CapEx estimates depending on the engine type and size in MUSD (see the report "MarE-Fuel: Total Cost of Ownership" for more details)

These additional costs are also converted in €2019 and linearly interpolated to fit the engine power of the averaged ships used in the model (see table 21). Data used in the model are presented in table 25.

Multi-fuels engines have not been considered in the TCO model. Using inputs from external partners, the additional cost (compared to a fuel oil engine) considered is calculated using the ammonia vessel as a reference. Multi-fuels vessel tanks are sized for ammonia which has the lowest calorific value among the possible fuels.

Vessels equipped with ME-LGImulti engines (all fuels but LNG) are designed the same way as an ammonia ship, but additional costs need to be added to include tank coating to allow the use of methanol. The extra cost is then increased by 5% compared to ammonia vessels.

Vessels able to handle all fuels, including LNG (ME-GImulti engine), need a more expensive fuel supply system (x 1.9) and tanks system (x 2) compared to an ammonia vessel. The resulting additional cost has been estimated to be 70% more on top of the ammonia vessel extra cost.

Table 25 summarizes all the vessel CapEx assumptions used in the model.

Ship category		**Other**	**Tanker**	**General Cargo**	**Bulk**	**Container**
Average engine power [MW]		2	5	5	8	28
Main fuel	**Engine type**	**Total CapEx new built vessel used in the model [M€2019]**				
Fuel oil	**ME-C**	5.6	15.0	15.0	18.8	70.3
LNG	**ME-GI**	7.5	18.9	18.9	24.4	79.7
LPG	**ME-LGIp**	6.9	18.3	18.3	23.1	76.6
Methanol	**ME-LGIm**	6.7	17.4	17.4	22.2	75.8
Ammonia	**ME-LGIa**	6.9	18.4	18.4	23.3	77.4
All fuels but LNG	**ME-LGImulti**	7.0	18.5	18.5	23.5	77.9
All fuels	**ME-GImulti**	8.0	21.0	21.0	26.8	83.2

Table 25: Additional vessel CapEx estimates depending on the engine type and size in M€2019

2.5.2 OpEx

Underlying assumptions about O&M cost derivation can be found in the report „MarE-Fuel: Total Cost of Ownership” for more details.Operation and maintenance costs include crew salaries, stores, maintenance, insurance, administrative fees, dry docking, and port taxes. Cost is assumed to be similar for all types of fuels and differs only depending on ship size.

The O&M cost data per ship type and engine used in the model can be found in table 26.

Ship category	**Other**	**Tanker**	**General Cargo**	**Bulk**	**Container**
Average engine power [MW]	2	5	5	8	28
O&M cost [M€2019/y]	**0.9**	**2.1**	**2.1**	**2.5**	**3.3**

Table 26: O&M cost per ship type and engine type in M€2019

3 ROADMAP Methodology and Results

Authors:

Sebastian Franz

Nicolas Campion

Marie Münster

3.1 Introduction

The shipping industry is a significant source of GHG emissions. These emissions come mainly from the use of fossil fuels such as VLSFO or HFO. It is now clear that climate change must be stopped to provide a liveable future for future generations. Therefore, the decarbonization of the maritime industry is an essential part of a decarbonization pathway, which should include all emitting sectors.

In this context, the question of alternative energy sources for the shipping industry arises. Various technologies are conceivable and already in use. These technologies range from hydrogen technologies to biomass-based fuels. In this work, the least-cost fueling options for the maritime industry are analyzed. All future conceivable fuels for the marine industry are compared and studied under certain constraints, such as biomass availability and GHG emission targets.

An optimization model based on many different inputs will be used to calculate an optimized future fuel mix. The results of this work can be analyzed in a later step to identify possible decarbonization pathways for the maritime industry and at the same time to show policymakers ways to solid climate change mitigation efforts.

3.2 Methodology – ROADMAP model

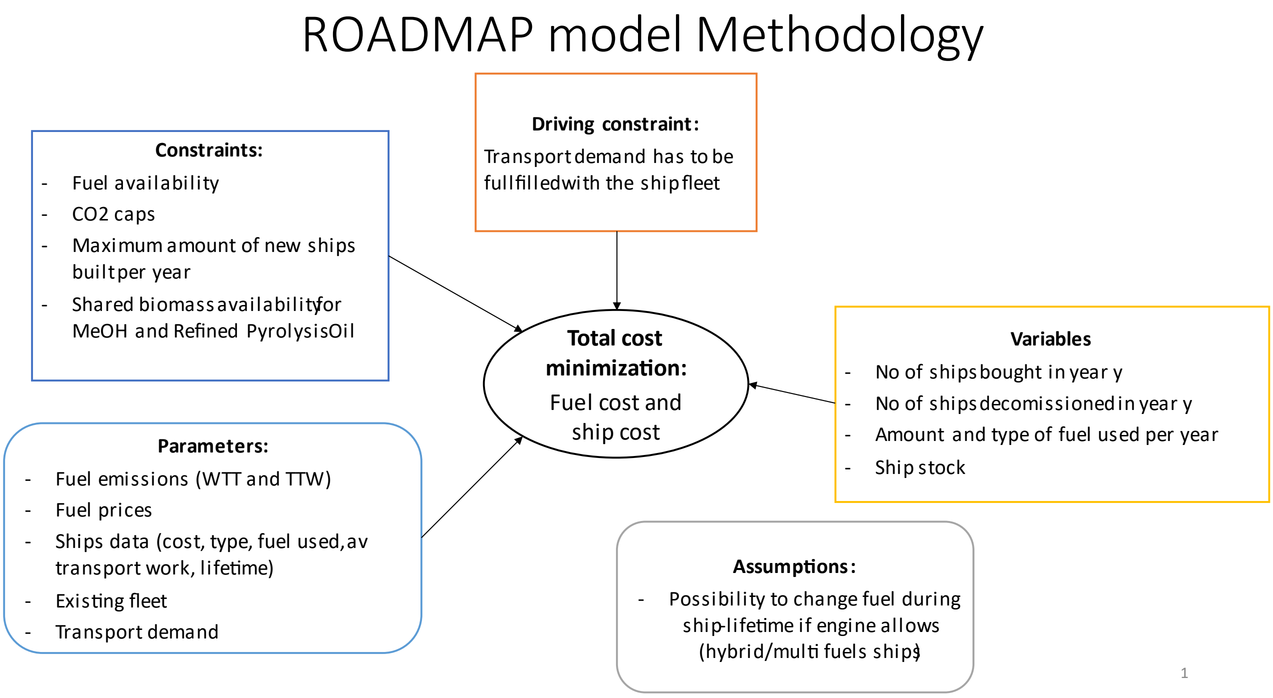


Figure 29: Overview of the ROADMAP model methodology

The ROADMAP model uses various input data, which have been derived in many processes before and are essential for the model. The relevant constraints, assumptions, variables, and parameters are illustrated in figure 29.

Once all the necessary input data has been derived and put into a suitable form, the roadmap model starts the optimization process. A cost optimization function is used as the objective function. The overall goal is to obtain the least cost fuelling options for the maritime industry. To achieve this, the objective function, which is a cost function, is minimized. The components of the objective function can be divided into two main parts. One of them concerns all costs related to the fleet itself, including investment costs for additional vessels, operations, and maintenance costs of the entire fleet. To avoid the decommissioning of the existing fleet at no cost, discarding an existing ship before its lifetime costs half of the original investment. The second cost block is limited to fuel costs. The consumption of each ship in the fleet is multiplied by the fuel costs (including fuel taxes if there is any). The objective function looks as follows:

$$min_{x,q,z,d^{EF}} \sum_{s,y} SI_s * NewBuildShip_{s,y} + SOM_s * ShipStock_{s,y} + SI_s * Decom_{val} * Decomissioned_{s,y}^{EF} + \sum_{s,f,y} FuelUsed_{f,s,y} * (FC_{f,y} + FT_{f,y})$$

Where SI_s is the investment expenditure for a new build (average) vessel of type s, SOM_s is the operation and maintenance cost for vessel of type s, $Decom_{val}$ is the decommission value factor for discarding an existing ship (equal to 0.5), $FC_{f,y}$ is the fuel cost per fuel type and year, $FT_{f,y}$ is the fuel tax added on top of fuel cost (fuel tax is zero in the base case). $NewBuildShip_{s,y}$ is a variable representing the number of new ships of type s bought in year y. $ShipStock_{s,y}$ is a variable representing the total ship stock of ship of type s at year y (variable). $FuelUsed_{f,s,y}$ is a variable representing the amount of fuel bought per fuel type, ship type and year.

The objective function is used to find the optimal fuel mix of a fleet. Additional constraints are added to adapt the future fuel mix to the future challenges regarding climate protection, sustainability, and biomass availability. The most relevant constraints of the roadmap model are described in the following:

Transport demand:

This constraint limits the supply in the roadmap model to the exogenous demand projections of the IMO. This ensures that supply and demand are matched and that there is no excess demand or supply in the model that could distort the results. It is important to note that the IMO demand has a strong influence on the results of the future fuel mix, and this variable might have to be replaced by endogenous demand projections to create a more inherent modeling process

Ship stock

This constraint ensures the management of the total fleet used in the shipping stock within the model. It says that the ship stock (number of ships in the world fleet) is equal to the ship stock in the previous year plus the new bough ships in the current year minus the “retired ships” in the current year, which ran out of a lifetime, minus the decommissioned ships in the current year. The ship stock of year 1 includes the existing fleet.

Ship capacity production

The amount of bought ships of type s in year y cannot exceed the industry ship production capacity. The production capacity of ship s in year y is 0 when the engine is not available commercially yet.

Fuel consumption

The amount of fuel used by ships of type s in year y must be enough to satisfy the transport demand. The transport demand of the fleet of the ship of type s is equal to the ship stock of that type (the number of ships of type s in the fleet) multiplied by the average transport work. The fuel consumption is calculated using the specific fuel consumption per fuel type and ship (see the previous chapter for numerical values). Any fuel can be used to satisfy the demand, meaning that more than one fuel type can be used in the same year if the engine is a dual/multi-fuel engine.

Fuel availability

For all fuels and all years, the amount of fuel used for the whole shipping fleet cannot exceed the fuel available (see chapter 1 for more details).

CO2e emissions cap

With this constraint,a global CO_2 emissions cap have to be respected every year. To make the model able to solve this constraint can be broken at a very high cost. Fuel emissions can be TTW, WTT operational, and WTT upstream and operational. Different global CO2 caps can be applied, ranging from 99% to 50% reduction compared to 2008 emissions (see the first chapter for more details).

3.3 Results

Solving the optimization problem gives a unique solution which is the least cost option able to meet all the constraints. Potential alternatives that would still be acceptable (near-optimal solutions) in real life but not optimal are not chosen, meaning that the optimization model gives a rather "black or white" vision of the world. For this reason, the solutions presented should not be interpreted as a "must-do" but rather as one of the possible/acceptable options given the input data. The solution can also be very sensitive to specific parameters (e.g., fuel production cost) and provides a different picture depending on input data. Given the high uncertainty of some parameters, results have to be analyzed carefully. The results section must be interpreted as an ensemble to draw interesting conclusions, including all the different scenarios and sensitivities. There is not one good answer, but rather trends and statements that will be more robust than others.

This section does not aim to predict what is more likely to happen in the future but rather to show what would be needed to fulfil ambitious climate mitigation goals under the constraints presented in the previous sections. Some of real world constraints, such as limited capacity ramping for electro-fuel production, have not been considered due to the lack of data available and could be a topic for further research. However, there will always be a discrepancy between reality and modeling. According to the previous reports, this work keeps this gap as small as possible by modeling all future fuels bottom-up to maintain a high degree of realism.

The different scenarios considered and presented in the result sections are illustrated in Figure 30. The scenarios depend on the type of power supply used to produce the electro-fuel (Behind-the-meter, Behind-the-meter with grid), the electro-fuel carbon accounting method (with or without counting upstream emissions/ infrastructures), the biomass availability for shipping (Very large, large, limited) and the GHG emissions reduction target.

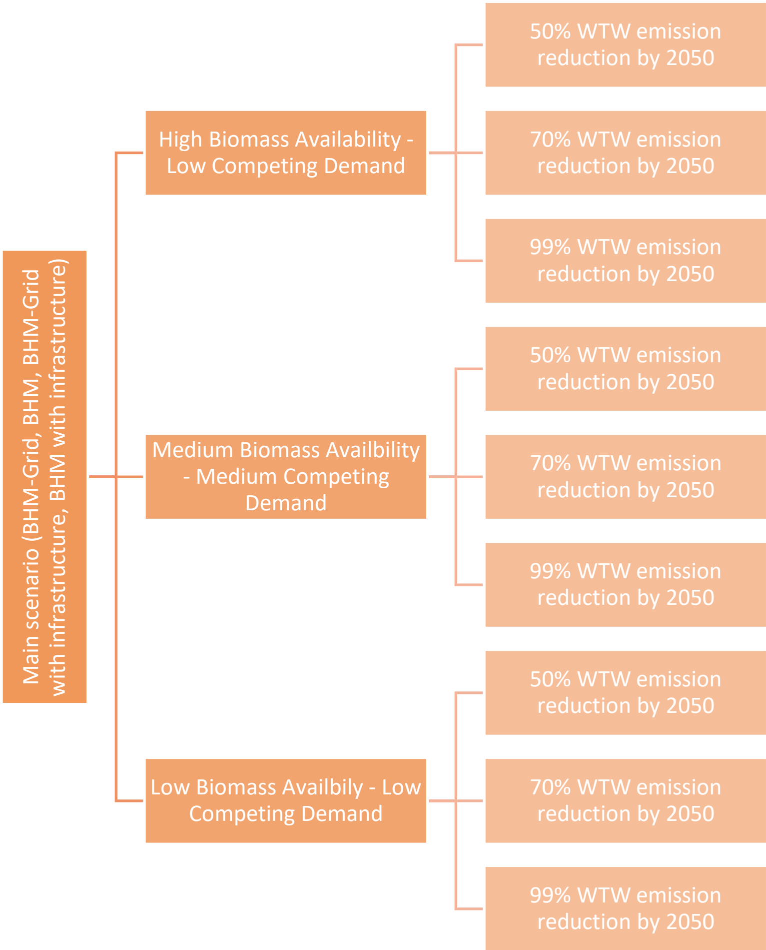


Figure 30: Scenarios considered. Emissions are compared to the 2008 reference year.

In the “baseline scenario,” electro-fuels are produced most cost-efficient and therefore combine the use of local renewable electricity and local renewable power ("BHM-Grid" scenario). Furthermore, we show a "BHM" scenario as well as the "BHM-Grid with infrastructure" emissions and a "BHM with infrastructure" emissions. All mentioned scenarios are then again subdivided into nine different scenarios. These are three emission cap scenarios (50%, 70%, 99% emission reductions by 2050) per biomass availability scenario. Low, medium and high biomass scenarios are considered in this work regarding the biomass availability scenarios. This means that we show a 3x3 sub-scenario matrix per main scenario.

In addition to the results, it is vital to perform sensitivity analysis which reveals the impact of possible uncertainties in the parameters used for the baseline scenarios. Therefore, it is advisable always to consider the sensitivity analysis and the results to know the possible dynamics in the future. It is important to note that all sensitivity analyses were performed only for our main scenario, "BHM-Grid."

3.3.1 Baseline Scenario

The future fuel mix will largely depend on the prevailing framework conditions concerning biomass availability and CO2 emissions reduction targets. It will differ depending on which framework scenario occurs. In the different columns in figure 31, the modeled GHG emissions caps can be seen. The number (e.g. xxxx_xxx_50, xxxx_xxx_70, xxxx_xxx_99) always represents the percentage of the reduction of GHG emissions from 2018 to 2050 going from left to right. The biomass availability is illustrated in the rows, going from high in the top, to low in the bottom. For example, in an "HBLD_WTW_99" scenario (top right), one recognizes the 99% reduction of all maritime GHG emissions by 2050 measured in a well-to-wake (WTW) perspective with high biomass availability.

In Figure 31, we show our baseline scenario, which is a behind-the-meter WTW pathway where usage of the electricity grid is also possible (BHM-Grid) (see table 12). In this scenario, at high biomass availability and low competing demand (HBLD), Refined Pyrolysis Oil, LNG, methanol produced from biomass and hydrogen (MeOH-ebio), and green ammonia are utilized as the primary fuels. The pyrolysis oil is assumed to be cheaper than MeOH-ebio, and it is assumed it can be used on existing ships. Since our assumptions on the Refined Pyrolysis Oil are not as detailed as the e-fuels, we decided to perform some sensitivity analysis on this fuel (see section 3.4.4).

In the case of medium biomass availability and low biomass availability, blue ammonia and green ammonia will play a significantly more significant role in the long term. The red color indicates a gap. i.e., we cannot reduce the WTW emissions sufficiently with the given biomass availability, and the assumed use of electricity from the grid is burdened with some emissions, albeit low. The gaps are also linked to the assumed availability of new ships being built each year, which can be seen in the first years of the low biomass scenarios. When gaps appear, use of methanol utilizing direct air capture (MeOH-DAC) appears.

The model does not include restrictions on ramping up of fuel production, as this is difficult to assess at a global level, and hence potentially unrealistic steep increases in the use of fuels can be seen. Such restrictions could be implemented if the required data was available.

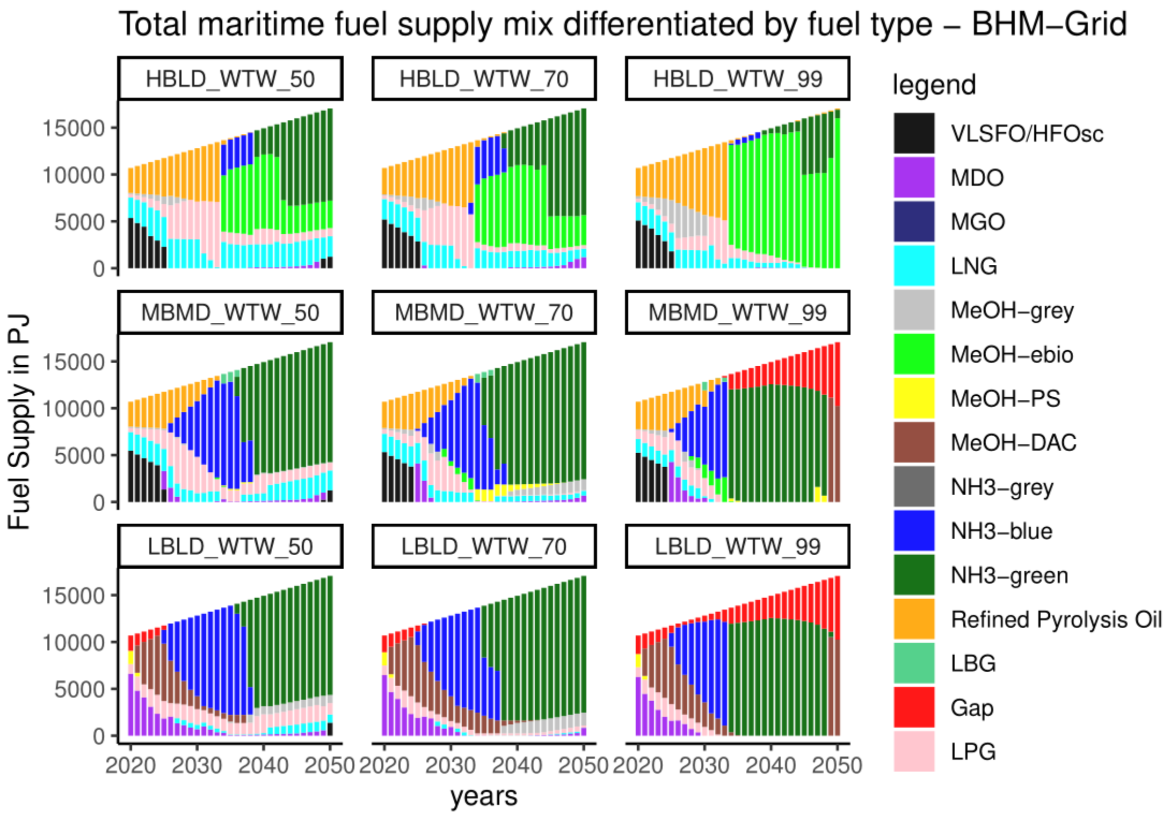


Figure 31: Future Fuel Mix for different biomass availability and GHG emission reductions scenarios in a BHM-grid world

These results illustrate the dependence on available biomass and climate mitigation efforts in the maritime industry in the future very well. It is essential to emphasize that these results are subject to assumptions and uncertainties in considering these results. The optimization model chooses among the available modeled fuels based on underlying cost and emissions data. Since these are future projections associated with significant uncertainties, these data may already look quite different in a few years, when more fuel production plants have been demonstrated at scale. To compensate for this, you will find sensitivity analyses in part 3.4. The critical use of this work is not to highlight a future fuel that will drive the decarbonization of the maritime sector but rather highlight possible pathways that all lead to the same decarbonization goal by 2050. We are particularly interested in highlighting the urgency of climate mitigation action in the maritime industry, which is apparent in all scenarios modeled. The maritime industry is at a crossroads. The baseline scenario and its projections for near-term fuel use are apparent. In all scenarios, a complete transformation of fuel usage away from VLSFO and HFO will take place in the short-term.

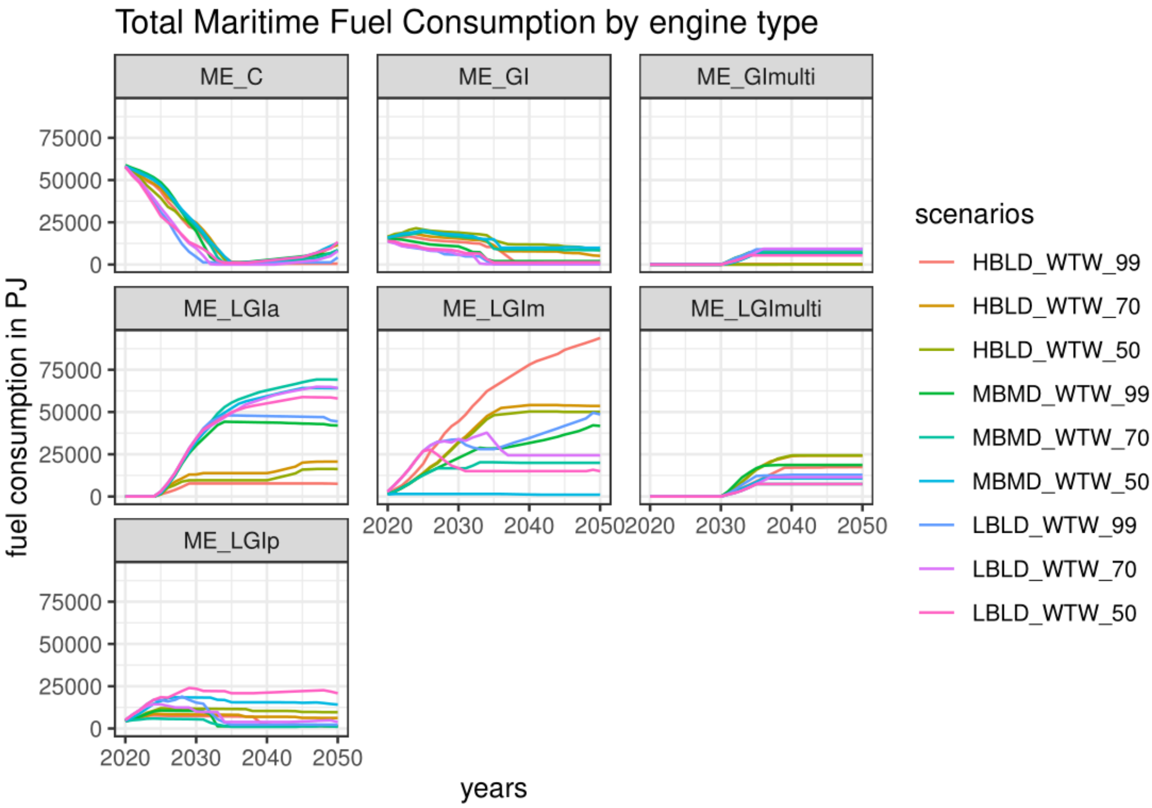


Figure 32: Maritime Fuel Consumption by engine type for different biomass availability and GHG emission reductions scenarios in our baseline scenario with some use of electricity from the grid

With the transformation of fuel usage, the engine type usage also changes. In figure 32, we show the future fuel consumption by engine type for our baseline scenario. It can clearly be seen that soon, in all modeled biomass and GHG emission sub-scenarios, the conventional oil engine will be discarded and replaced by novel engines such as ME_LGIa or ME_LGIm. The choice of engine will depend on the underlying projections of fuel usage. This can be seen particularly well in the total projected ship-stock per engine type, which is shown in figure 33.

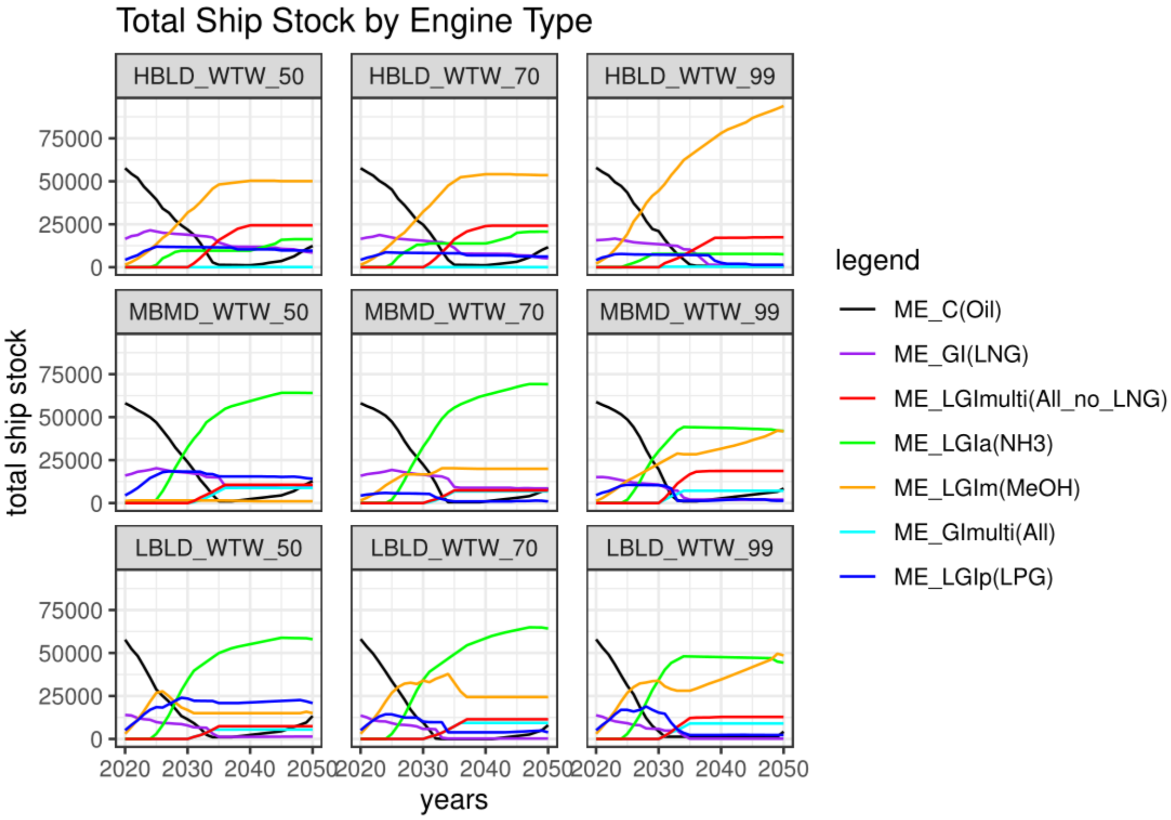


Figure 33: Projected Maritime Ship by engine type for different biomass availability and GHG emission reductions scenarios in our baseline scenario

Figure 33 shows the projected total maritime ship stock differentiated by engine type. Here, the trend already indicated by the fuel consumption in figure 32 can be clearly seen. In the short term, the classic oil engine will be discarded and, depending on biomass availability and the GHG emission sub-scenario, ME_LGIa or ME_LGIm will be used.

3.3.2 BHM Scenario

In addition to the baseline scenarios, other scenarios were examined. One of these is the behind-the-meter scenario without connection to the electricity grid. This scenario with its sub-scenarios regarding biomass availability and GHG emission reduction targets can be seen in figure 34.

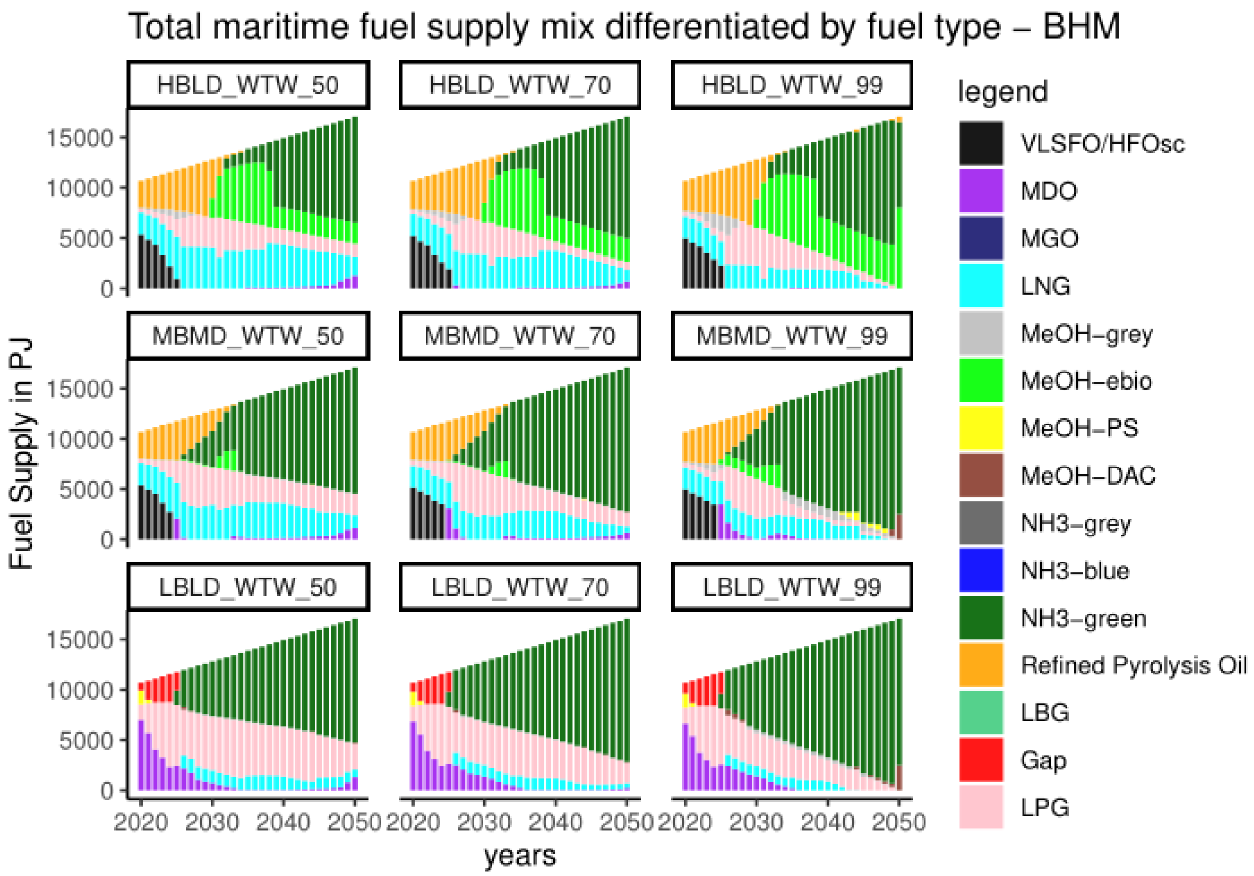


Figure 34: Future Fuel Mix for different biomass availability and GHG emission reductions scenarios in a BHM world

In figure 34, the different biomass availability scenarios and the different GHG emission scenarios can be recognized. In the case of high biomass availability (HBLD), again a lot of Refined Pyrolysis Oil, as well as MeOH-ebio, is seen. In contrast, in scenarios with significantly less available biomass (MBMD and LBLD), NH3-green appears to be the fuel of the future. This is mainly due to the green electricity, which is exclusively used in this scenario, as it does not rely on the (not so green) electricity grid. On the other hand, MeOH-DAC does not play a significant role in this scenario compared to our baseline scenario. Besides NH3-green, LPG and LNG seem to be feasible options for the future fuel supply. In contrast, MDO plays a role in the short term only if biomass availability is low and no pyrolysis oil is available.

3.3.3 Baseline scenario including infrastructure emissions

Another scenario we investigated is the baseline scenario, including upstream emissions from infrastructure such as wind turbines. This scenario with its sub-scenarios regarding biomass availability and GHG emission reduction targets can be seen in figure 35.

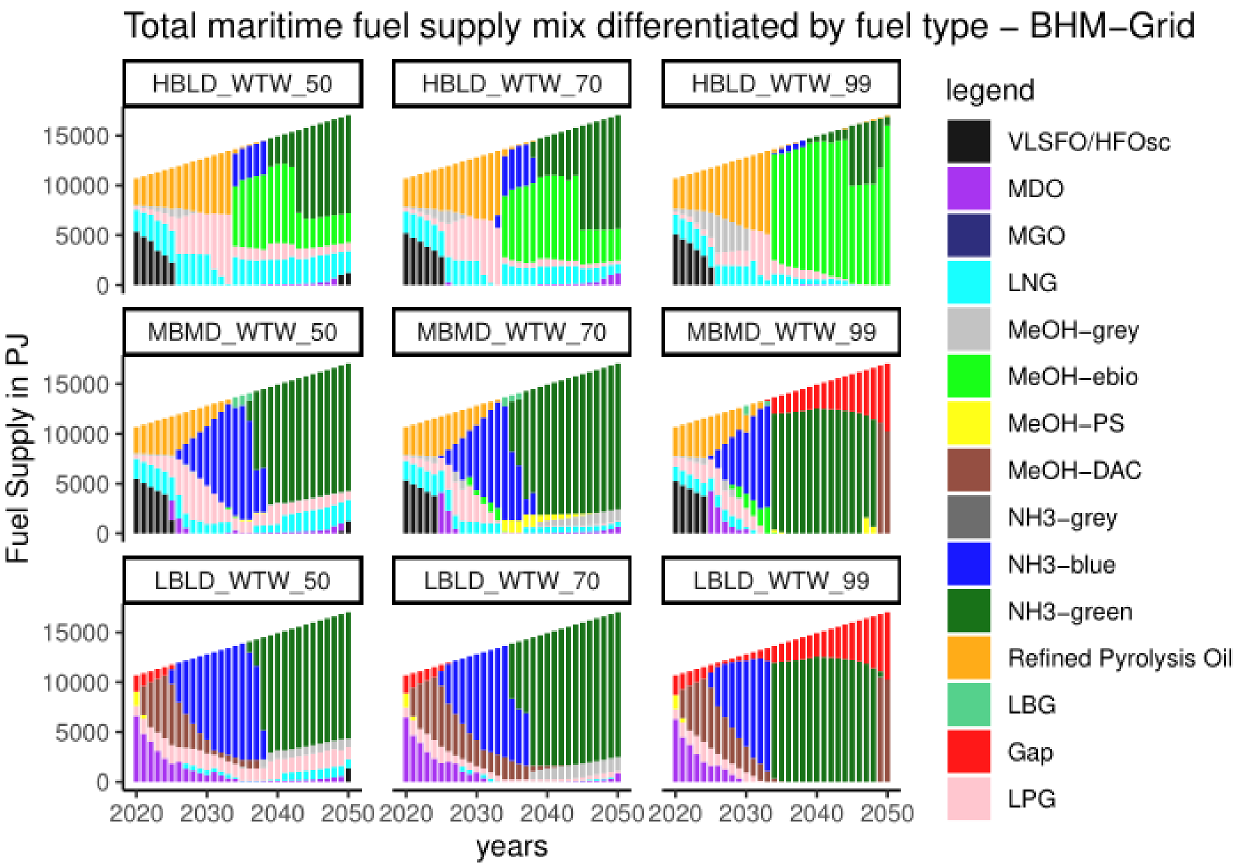


Figure 35: Future Fuel Mix for different biomass availability and GHG emission reductions scenarios in a BHM -grid world, including infrastructure emissions

In figure 35 again, the different biomass availability scenarios and the different GHG emission scenarios can be recognized. In the case of high biomass availability, a lot of Refined Pyrolysis Oil and MeOH-ebio can be identified. In contrast, in scenarios with significantly less available biomass (LBLD), NH3-green and MeOH-DAC appear to play a significant role in future fuel supply. Also, one can identify a higher gap, which illustrates an unfeasible solution for the model to satisfy the exogenous demand with the available fueling options. This again demonstrates the urgency for climate action. Taking this lifecycle-assessment approach towards WTW emissions, which is not currently the industry standard, yet essential to account for all related emissions, one can see enormous challenges towards decarbonization of the maritime sector.

3.3.4 BHM scenario including infrastructure emissions

Our last set of scenarios can be found in figure 36 and are defined as BHM, including infrastructure emissions.

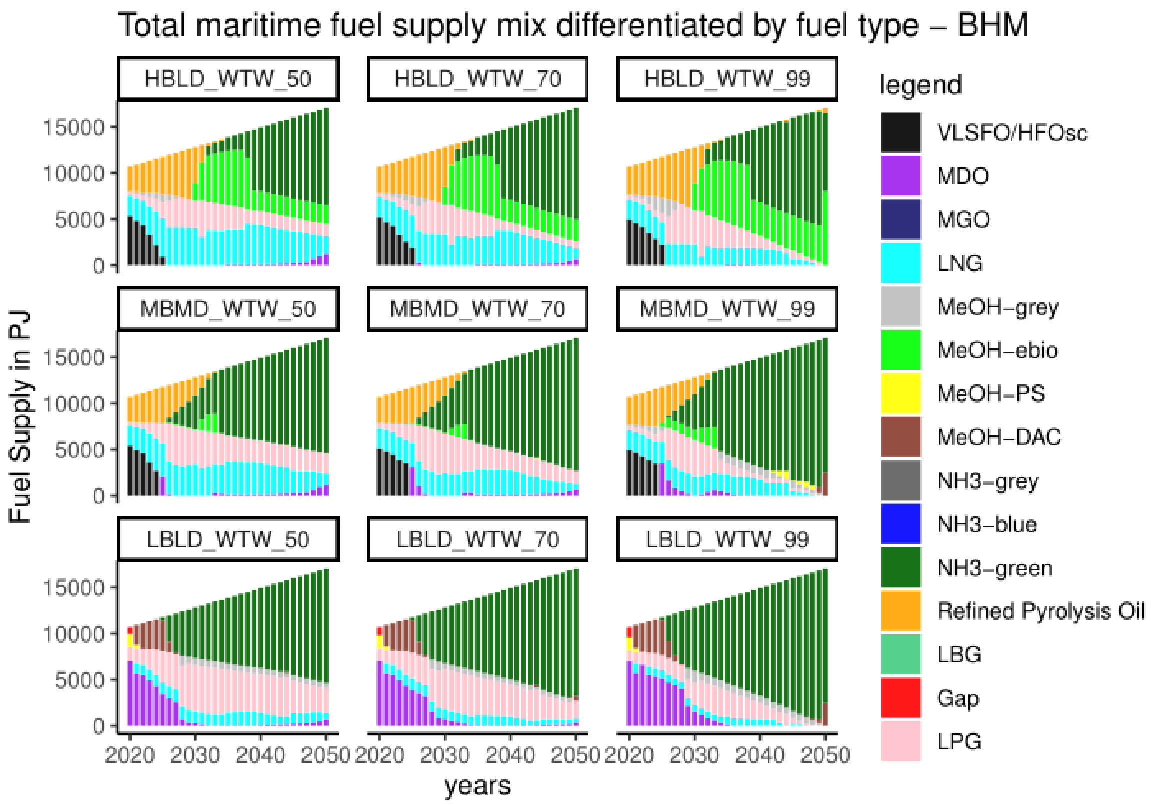


Figure 36: Future Fuel Mix for different biomass availability and GHG emission reductions scenarios in a BHM world, including infrastructure emissions

In figure 36, the different biomass availability scenarios and the different GHG emission scenarios, including the underlying emission for infrastructure, are illustrated. One cannot see a huge difference compared to our BHM scenario without the infrastructure emissions. This is because low emissions are associated with the construction of infrastructure. Hence, the green electricity we use to produce fuels, in this case, allows enough flexibility for the complete lifecycle assessment approach.

3.3.5 Required CO2-tax

To meet the implemented global emission caps, strong policy measures need to be taken to make the electricity grid greener and improve future technologies and development. One way of a policy measure could be a CO2 tax. For this reason, we have calculated the required CO2-tax needed to meet the emission caps of 50,70 and 99% WTW GHG emission reductions. The results of this can be found in figure 37.

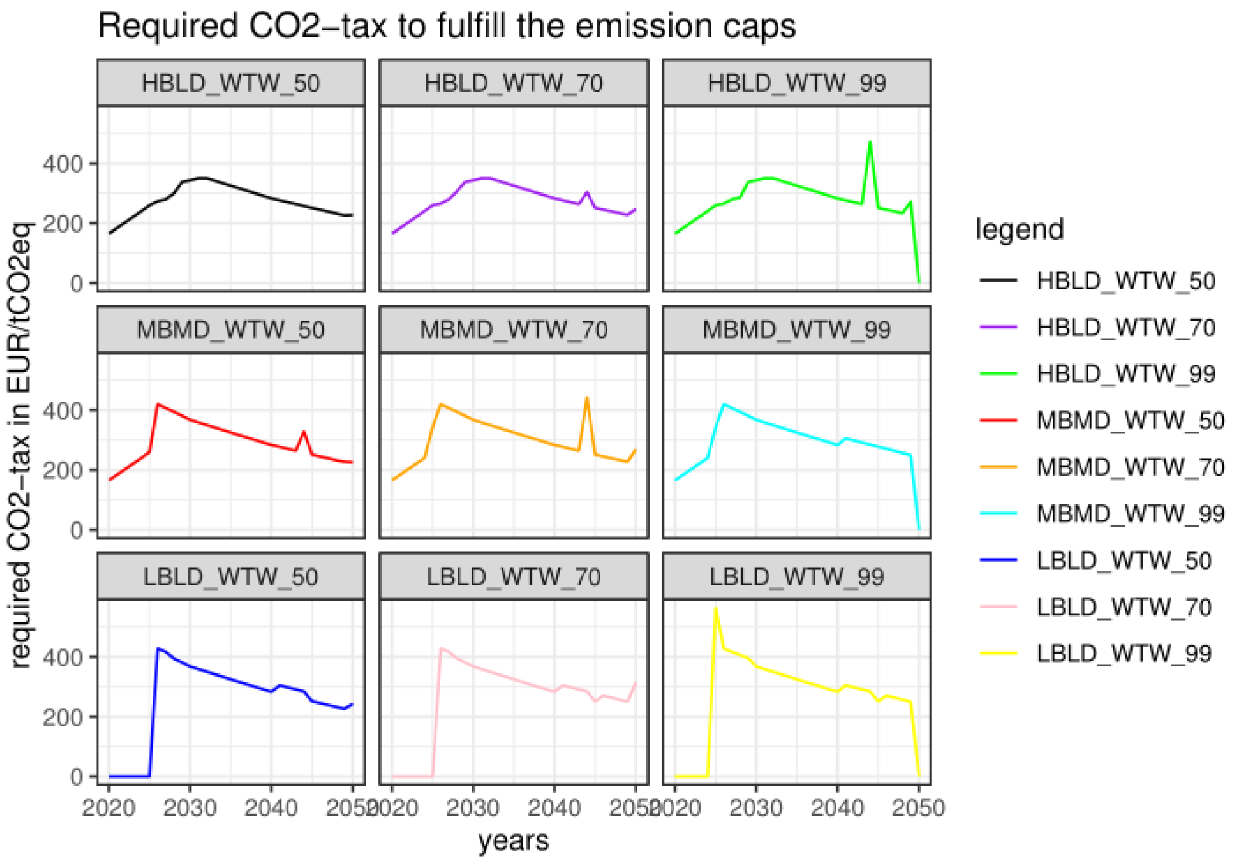


Figure 37: Projected Required CO2-tax to fulfill the emission caps for different biomass availability and WTW GHG emission reductions scenarios in our baseline scenario

Figure 37 shows the required CO2-tax (or marginal CO2 reduction costs) over the years to meet the modeled WTW GHG emissions caps of 50, 70, and 99%. These values can also be understood as required CO2-tax, including governmental subsidies for a green transition, which can significantly lower the challenges towards climate mitigation. If the CO2-tax in the graph is 0, this means that the optimization model could not find a solution except to increase the CO2-tax enormously. To show the results, nevertheless, we have ignored all values above 1000 EUR/tCO2eq for this plot and therefore set them to 0, such as in the first years in the low biomass scenarios and 2050 in the 99% GHG reduction scenario. It can be seen in figure 37 that we will expect a CO2-tax of up to 350 EUR/tCO2eq already in 2030 to meet even a 50% reduction of GHG emissions. The general decline after 2030 is due to the assumed improvements in green fuel costs, and the assumed decreasing emissions from the power sector.

These values show the urgency of political action. Climate mitigation efforts to bring the maritime industry on a sustainable decarbonization pathway are now more critical than ever. Governments and international organizations such as the IMO must urgently work together to develop international standards for carbon taxes and potentially other regulations to move the shipping industry forward on a global scale.

3.4 Sensitivity Analysis

3.4.1 Sensitivity Analysis NH3-blue

To get a complete overview of possible future decarbonization pathways for the maritime industry, it is necessary to analyze the results critically and to capture their sensitivity to possible deviating developments in the future. In this section, we focus on NH3-blue. This fuel is not currently commercially available. Its emissions and costs are highly dependent on future developments regarding the emission intensity of future technologies such as

CCS. For this reason, we prepared a sensitivity analysis in which we increased the emissions for NH3 blue to our upper bound value. This can be seen in figure 38.

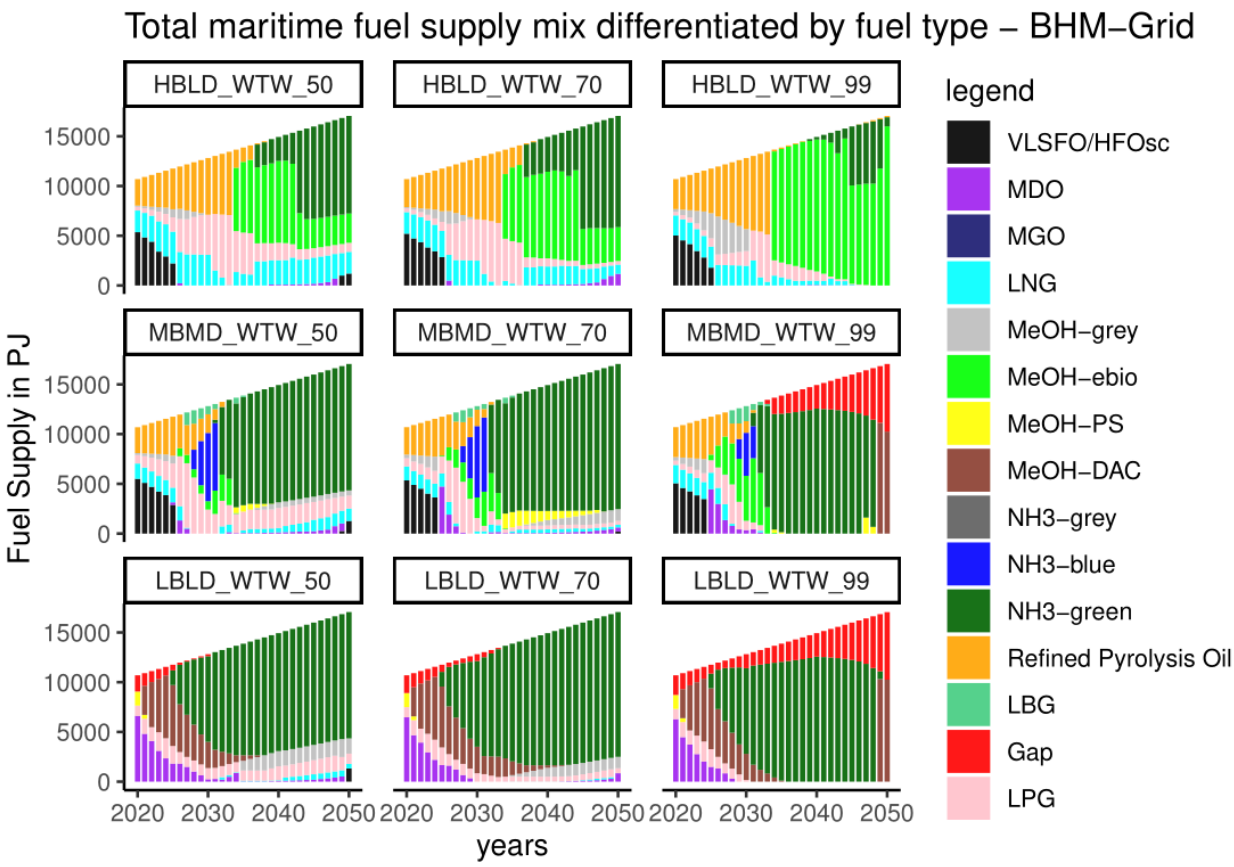


Figure 38: Baseline scenario upper bound (50[ktCO2eq/PJ] instead of 34 [ktCO2eq/PJ] in our baseline) blue-NH3 emission for different biomass availability and GHG emission reductions scenarios in our baseline scenario

Compared to our baseline scenario, NH3-green now takes over most of the previously covered part by NH-blue. This illustrates the considerable uncertainty we are facing regarding blue-NH3.

3.4.2 Sensitivity Analysis MeOH-DAC

Another significant uncertainty is the future development of MeOH-DAC. In our baseline scenario, the use of MeOH-DAC can be identified at the beginning and towards the end of the analysis. However, this is again a future fuel that is still subject to great uncertainties, both on the emissions and cost sides. Therefore, in the following, we have prepared a sensitivity analysis in which we have increased the emissions for MeOH-DAC over all time steps by 10% (see figure 39) and decreased them by 10% (see figure 40).

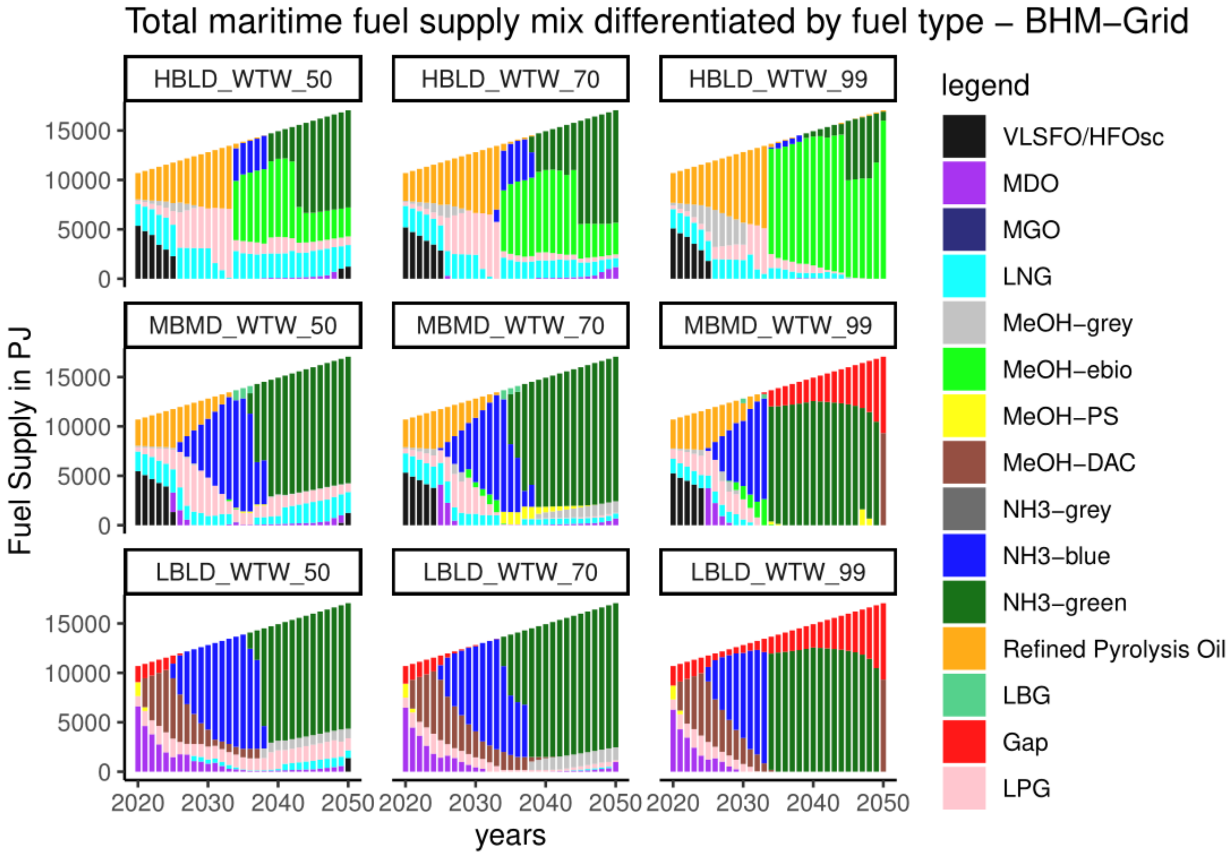


Figure 39: Baseline scenario with 10% higher MeOH-DAC emissions for different biomass availability and GHG emission reductions scenarios in our baseline scenario

In figure 39, we show our baseline scenario with 10% higher MeOH-DAC emission across all years. One can identify that MeOH-DAC is not utilized that strong in the later stage of our analysis (2045-2050). Yet, there is still some demand, especially in the Low-biomass availability scenario.

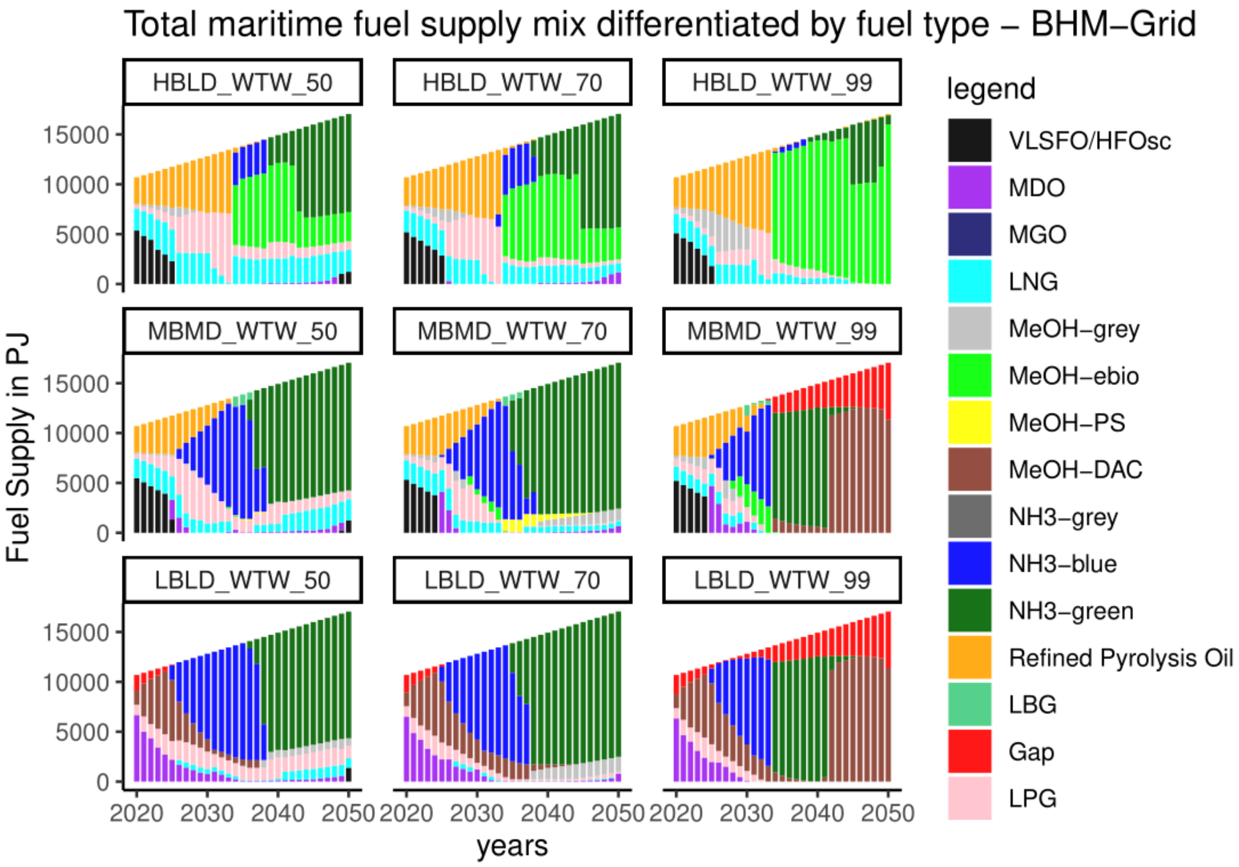


Figure 40: Baseline scenario with 10% lower MeOH-DAC emissions for different biomass availability and GHG emission reductions scenarios in our baseline scenario

Figure 40 shows our baseline scenario with 10% lower MeOH-DAC emissions than our initial baseline scenario. One can see that instead of NH-green, MeOH-DAC now becomes an essential fuel for the future maritime industry for the medium and low biomass. Then, of course, we must think about the question of whether this is feasible. Especially the fuel usage in the very short-term seems complicated to achieve with existing facilities. If one assumed today DAC efficiency as stated in the new plant in Iceland by the Swiss company "Climeworks" which can capture 4000tons of CO2 every year[44], one would roughly need 64.000 plants of this size to fulfill the fuel demand in our baseline scenario in the short-term (2022).

Thus, it can only be emphasized again that e-fuels are very sensitive to deviating future emission intensity and cost developments. Therefore, no fuel can now be stressed as the future fuel of the maritime industry. Instead, e-fuels will be necessary, particularly in low or medium biomass availability scenarios. There seem to be many different decarbonized fueling pathways for the maritime industry.

3.4.3 Sensitivity Analysis competition for carbon from a point source (MeOH-PS)

Another uncertainty is the competing demand for biomass. Point 1.4.2 of this report illustrates our approach towards biomass availability and competing demand from other industries. In our system for the baseline scenario, we assume that the maritime industry will be served as the very last industry well after the aviation and petrochemical industry. To show the significant impact of this approach, we prepared a sensitivity analysis in which we changed the order of prioritization towards biomass availability for competing industries.

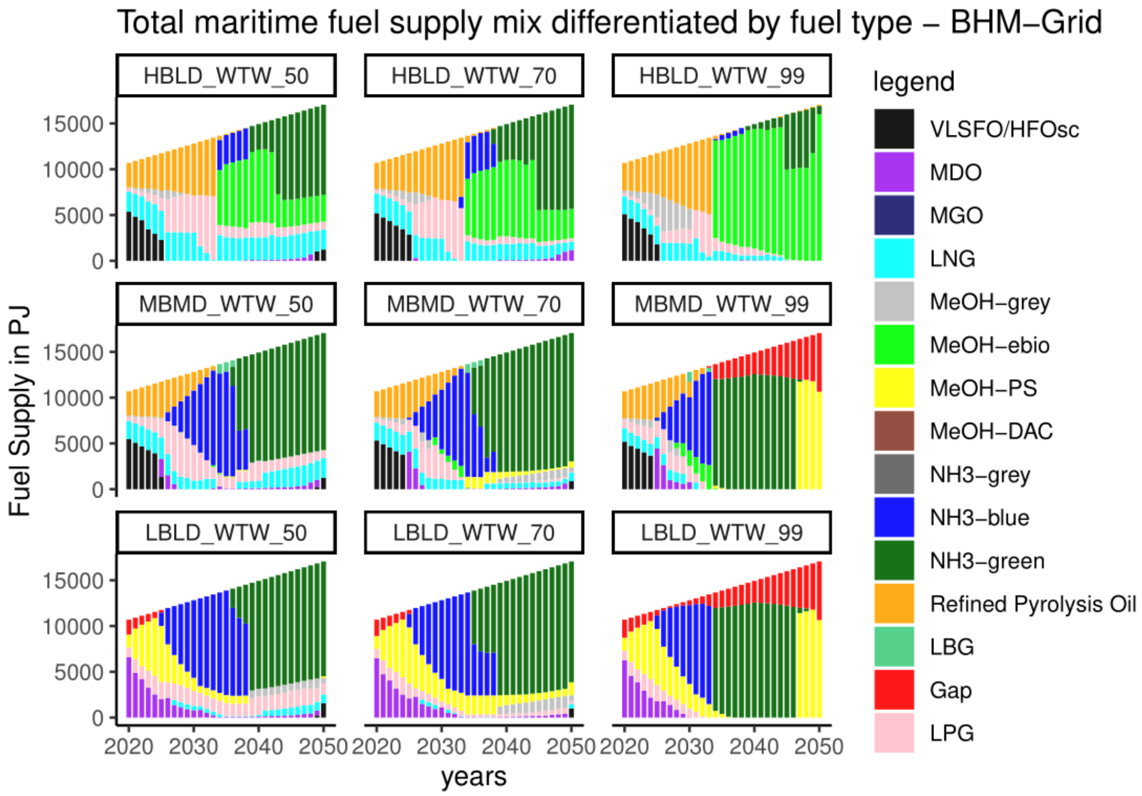


Figure 41: Baseline scenario with no competition for carbon from point source from other industries for different biomass availability and GHG emission reductions scenarios in our baseline scenario

Figure 41 shows our baseline scenario with no competition for carbon from point sources from other industries and thus full availability for producing MeOH-PS for the maritime industry. One can identify that MeOH-PS will take the place of MeOH-DAC as the emissions of MeOH-PS are slightly lower. So, this shows depending on the underlying assumptions towards available biomass, the entire fuel mix, especially in the longer term, could change dramatically.

3.4.4 Sensitivity Analysis Refined Pyrolysis Oil

As already mentioned, the level of detail in Refined Pyrolysis Oil is not as pronounced as for e-fuels or other fuels. For this reason, and because it plays a significant role in our baseline scenario, a sensitivity analysis of the cost of refined pyrolysis oil follows. We look at the upper bound and lower bound values available to us and consider the changes for the overall picture. The upper bound limit can be seen in figure 42.

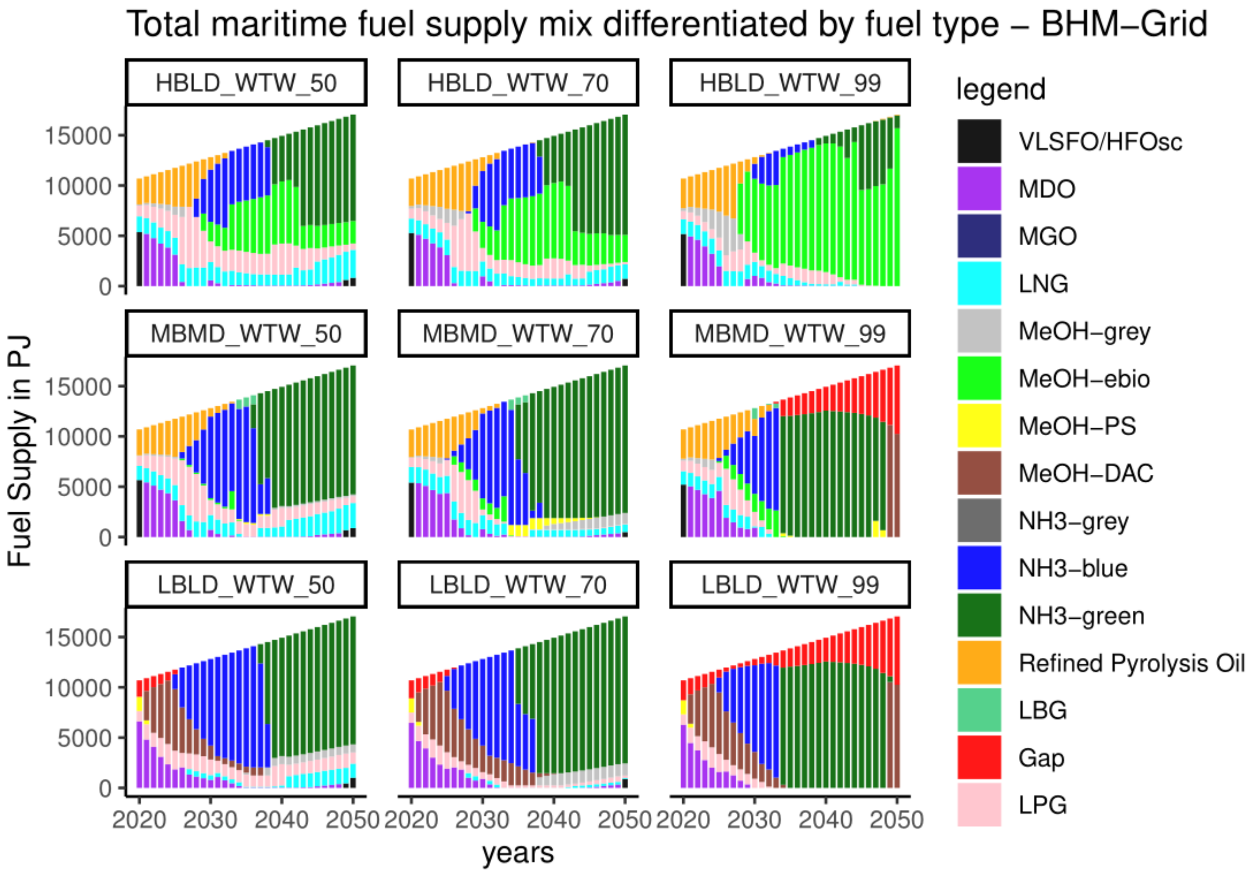


Figure 42: Baseline scenario with upper bound Refined Pyrolysis Oil cost (starting value in 2020: 30EUR/GJ) for different biomass availability and GHG emission reductions scenarios in our baseline scenario

Using the upper bound values for the costs of Refined Pyrolysis Oil leads to a drastic drop in the use of Refined Pyrolysis Oil, and instead, massive investments are made in NH3-blue and MeOH-ebio. This again illustrates the path dependency of this approach and the importance of sensitivity analysis. MeOH-ebio has an attractive conversion factor of biomass and is therefore used at rising costs of Refined Pyrolysis Oil.

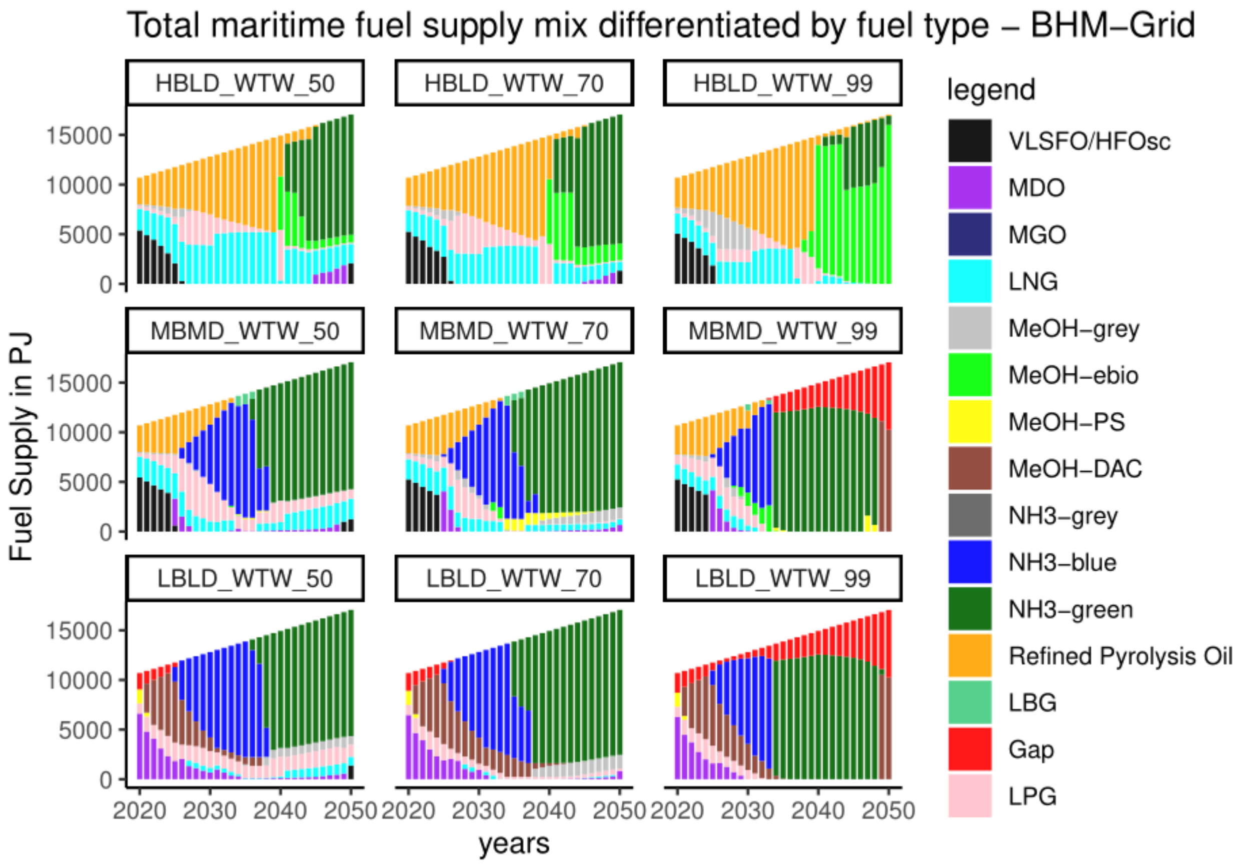


Figure 43: Baseline scenario with lower bound Refined Pyrolysis Oil cost (starting value in 2020: 30EUR/GJ) for different biomass availability and GHG emission reductions scenarios in our baseline scenario

However, if we analyze lower bound Refined Pyrolysis Oil cost, we can see a massive utilization of Refined Pyrolysis Oil compared to our baseline scenario (see figure 43). This highlights the great potential of Refined Pyrolysis Oil when it comes to utilization as a drop-in fuel. Especially very soon, it can serve as a good low emission intensity alternative to fossil fuels. In the longer term, even in a lower bound Refined Pyrolysis Oil cost scenario, we can see MeOH-ebio utilization. MeOHe-bio and Refined Pyrolysis Oil are competing for the very same source of biomass, which is why their utilization is correlated. However, the main price driver of Refined Pyrolysis Oil is the underlying biomass price, which accounts for approximately 50% of the total cost. The derivation of Refined Pyrolysis Oil cost can be found in the report "MarE-Fuel: Energy efficiencies in synthesizing green fuels and their expected cost ".

3.4.5 Sensitivity Analysis Constant Demand Projections

Another critical input parameter is the demand for shipping. For this, we use exogenous demand projections by the IMO[38], as described in part 2.2.1 of the report. To critically examine this input parameter, we have prepared a sensitivity analysis in which we have kept the demand for maritime constant at the 2020 level. This could be done by increasing the efficiency of the marine sector significantly (e.g., through improving the fuel consumption and thus the demand for maritime fuels to facilitate the decarbonization of the marine industry. The results of this sensitivity analysis can be found in figure 44.

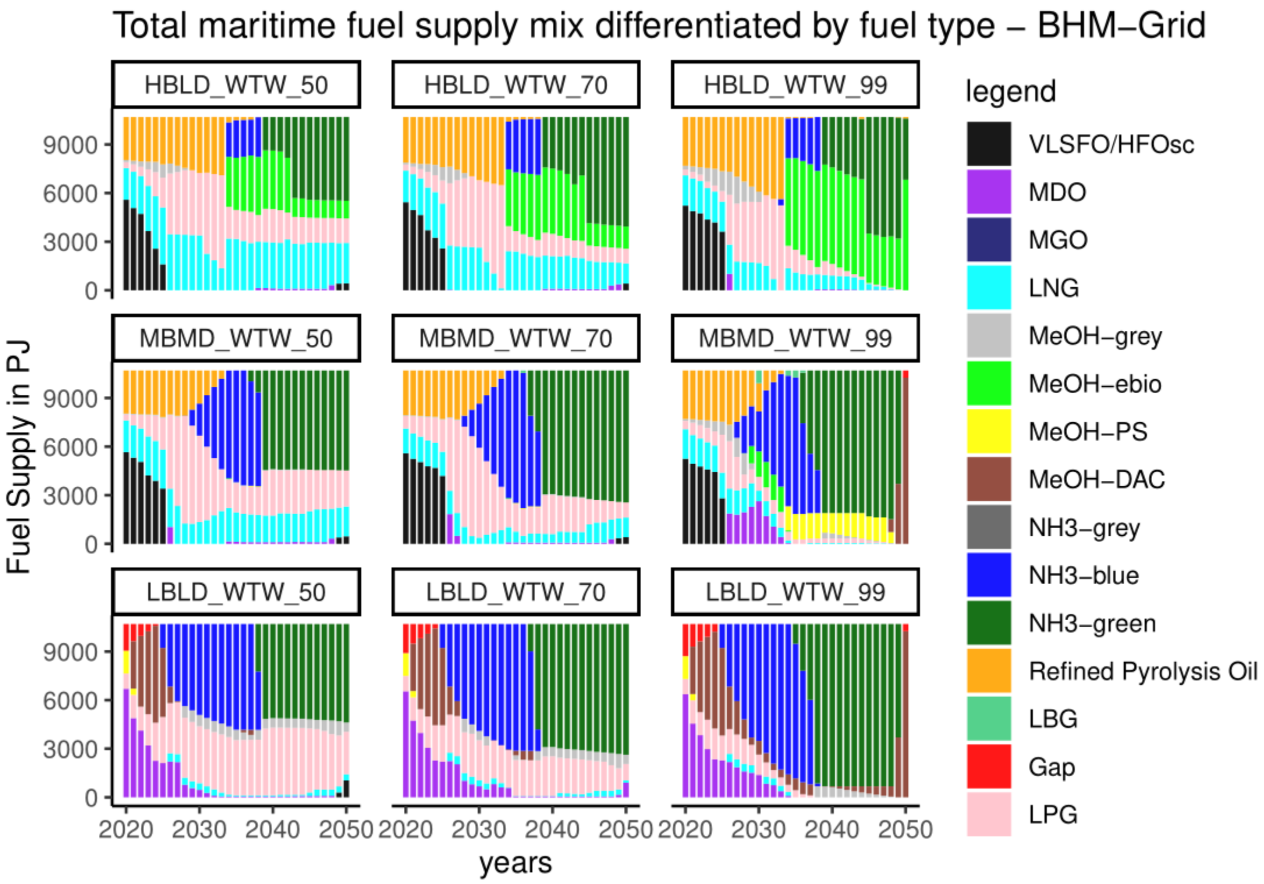


Figure 44: Baseline scenario with constant demand projections for different biomass availability and GHG emission reductions scenarios in our baseline scenario

Compared to our baseline scenario, where demand for shipping in general increases, the challenges for decarbonization of the maritime industry decrease significantly with constant demand projections. One can identify this by the absence of a gap in the longer term, which illustrates the infeasibility to solve when using electricity from the grid with associated emissions. This clearly shows the influence of the demand projections on the overall result and how important it is to have a relatively low demand for the future. This can be achieved either through radical fuel efficiency improvements or through lifestyle change and market based measures. The underlying demand projections used for this sensitivity can be seen in figure 45.

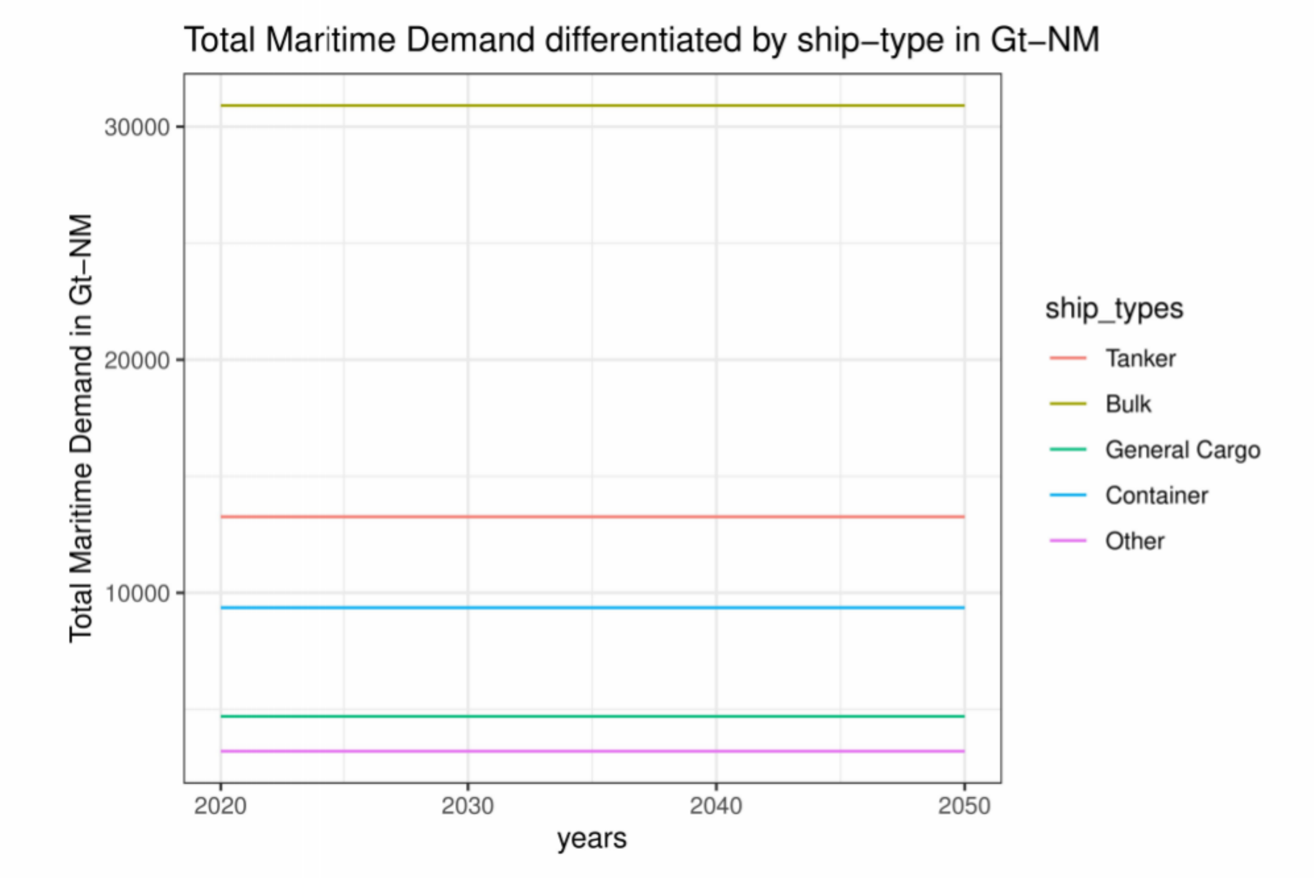


Figure 45: Constant demand projections differentiated by ship types in Gt-NM

3.4.6 Sensitivity Analysis No availability of multifuel engines

Another critical assumption in this work is the availability of multi-fuel engines in 2031. These types of engines can use many different fuels, which allows the maritime industry great flexibility in their fleet setup. To acknowledge the uncertainty in this framework, we have prepared a sensitivity analysis, illustrated in figure 46, that completely excludes the availability of multi-fuel engines.

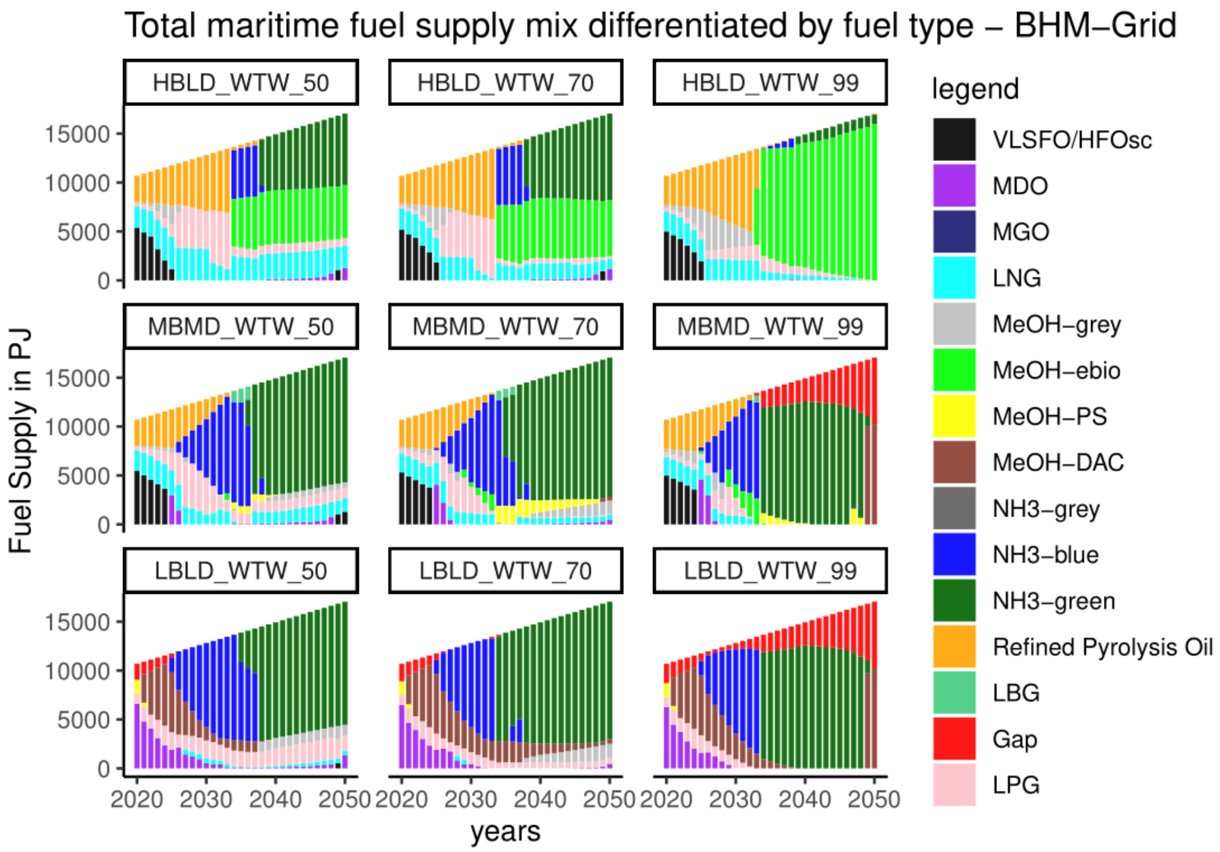


Figure 46: Baseline scenario with no multi-fuel availability for different biomass availability and GHG emission reductions scenarios in our baseline scenario

In this analysis, no significant difference can be detected compared to our baseline scenario. This means that our results are not particularly sensitive regarding the assumption of multi-fuel engine availability in the year 2031. This is because the respective specific engine types will already be available from 2025 onwards, and therefore, many ship-owners will probably already invest in these engine types before then. Only in the far future there might be some differences in the fuel supply compared to the baseline scenario, which is due to the lack of flexibility and, therefore, the lack of possibility to easily change the fleet's fuel. The underlying fuel consumption differentiated by the engine type can be seen in figure 47.

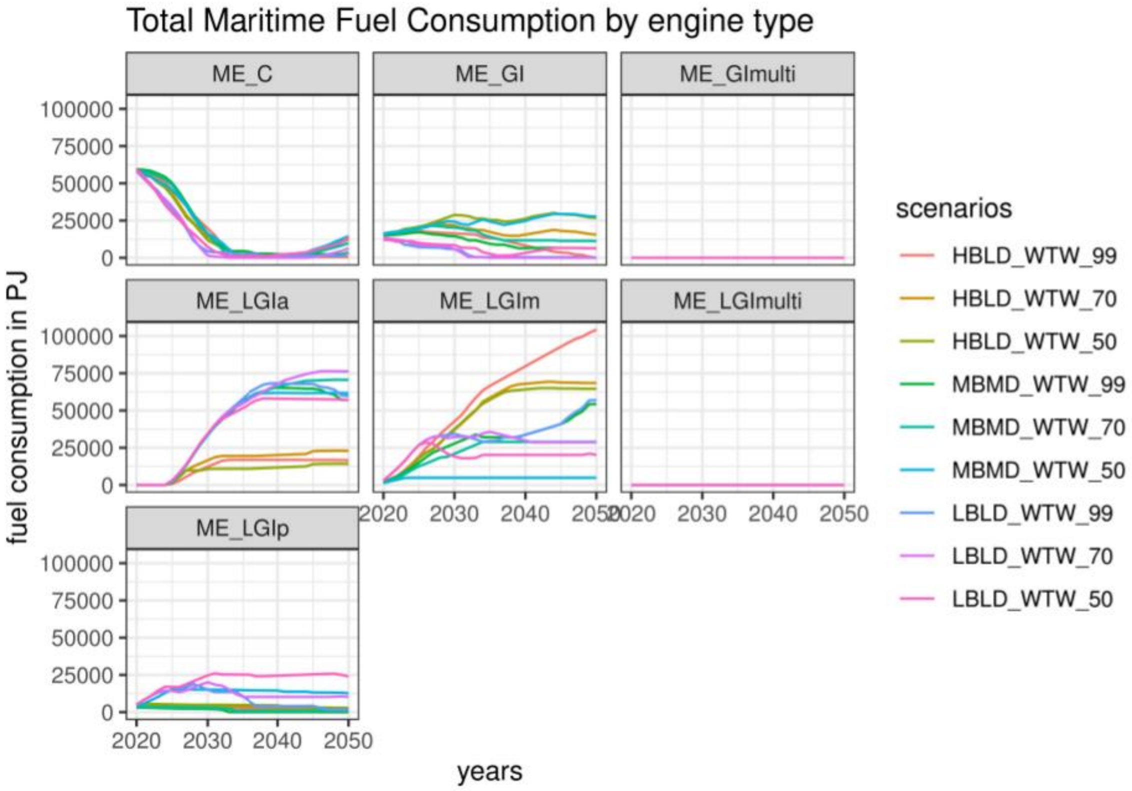


Figure 47: Fuel consumption per engine type with no multi-fuel availability for different biomass availability and GHG emission reductions scenarios in our baseline scenario

3.4.7 Sensitivity Analysis on 20-years Global Warming Potential horizon

Another critical assumption in this work is the perspective on global warming potential horizons. The usual perspective is the 100 years global warming potential. This is highly beneficial for fuels which are associated with Methane emissions (e.g., LNG). This is why in Figure 48 we show a sensitivity for a 20 year horizon for global warming potential.

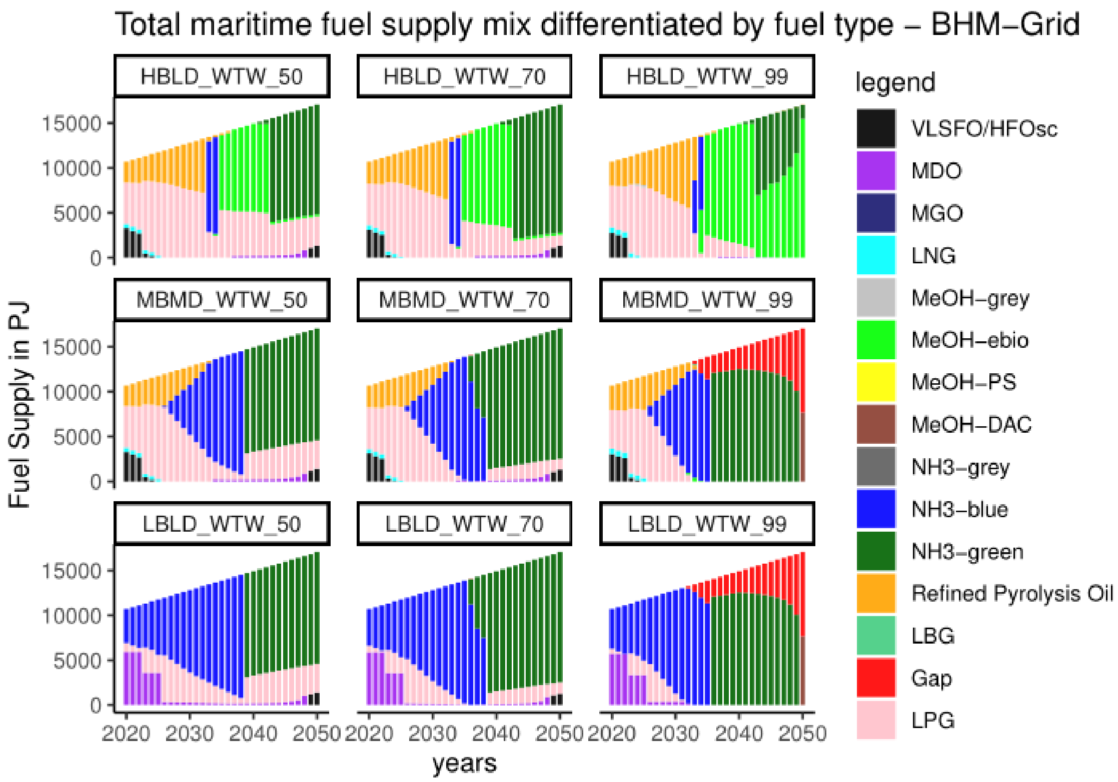


Figure 48: Fuel consumption per engine type with 20 year global warming potential for LNG for biomass availability and GHG emission reductions scenarios in our baseline scenario

With a 20 years global warming potential horizon for LNG we see that most of the LNG is being replaced by LPG. But it is important to note, that we only used the 20 years global warming potential horizon for LNG. So LPG and other fuels associated with methane emissions might also be affected by this change in perspective. These include HFO/VLSFO, MDO, MGO, LNG, LPG, MeOH-grey, NH3-grey, NH3-blue. We do not have enough data to do a detailed analysis for all these fuels and hence we illustrate the consequence just for LNG: namely that the use is highly reduced.

3.5 Conclusion

Based on the assumptions outlined at the beginning of this report and the supporting background reports several conclusions can be drawn:

- On the *pathway* towards decarbonisation of the maritime sector a number of fuels will be required, i.e. there is not one overall winner.
- In the beginning of a transition period, low emission fossil fuels such as LPG, LNG and MDO may play an important part. The feasibility of LNG use is however highly sensitive to assumptions on emissions, and is not used if a 20 year GHG perspective is applied.
- The availability of biomass for the maritime sector is heavily determining for the choice of fuels. If plenty of biomass is available, refined pyrolysis oil may be feasible in the short term (subject to some uncertainty) and e-bio-methanol in the longer term, supplemented with green ammonia. In this case the cheapest pathway therefore appears to include use of fuels based on biomass, given the biomass costs applied - and that the biomass used can be considered CO2 neutral. Thus, biomass availability deserves even more attention in future works.

- Availability of green power is also determining for the ability to achieve 99% reduction of GHG. With medium or low availability of biomass, electro fuels are required to fulfil the demands, with the cheapest alternatives using some share of electricity from the grid. It does however not seem possible to achieve the 99% reductions if using some electricity from the grid, although a strong decrease in emissions from power production is assumed. Hence, due to the high consumption of electricity to produce electro fuels, the electricity has to be completely green in order to produce fuels, which can contribute to ambitious decarbonisation pathways. Thus behind-the-meter solutions - or traceable trading of green power - appears to be highly necessary for the feasibility of a high decarbonisation with electro fuels.
- In order to produce electro fuels with own supply of power from variable renewable sources such as wind and solar, flexible production and energy storages will be required to avoid over-sizing. It is not enough to have cheap green power, it has to be available most of the time in order to avoid high fuel production capacities.
- With limited biomass availability, green ammonia appears to be feasible after 2035 in many scenarios, but as the costs and emissions are similar to other electro-fuels, methanol based on CCU from biogenic point sources or direct air capture could also be competitive depending on local conditions.
- Marginal CO2 reduction costs of around 350 EUR/t CO2e were found already by 2030, indicating a need for a high CO2 tax or similar/ supplementary regulation to motivate a shift. As the green fuels will have higher fuel prices, than the fossil alternatives, robust certification schemes for the green fuels will be required to avoid fraud.
- Important cost drivers for green fuels are electricity prices, CAPEX of fuel plant and electrolyser and biomass prices

Our analysis reveals the different decarbonization fuelling pathways for the maritime industry. We cannot identify a single fuel that can achieve decarbonization of the marine industry on its own. Instead, we see strong path dependencies concerning future emission intensities, especially for the power grid, and concerning costs of the different technologies in general. However, the maritime industry is at a crossroads. Immediate climate mitigation efforts towards net-zero by 2050 are needed. In all our findings, we find great transformation potentials that call for a sustainable transformation of the maritime industry.

References Chapter 1

[1] Prussi M, Yugo M, De Prada L, Padella M, Edwards R, Lonza L. JEC Well-to-Tank report v5. 2020. https://doi.org/10.2760/959137.

[2] Moro A, Lonza L. Electricity carbon intensity in European Member States: Impacts on GHG emissions of electric vehicles. Transp Res Part D Transp Environ 2018;64:5–14. https://doi.org/10.1016/j.trd.2017.07.012.

[3] European Parliament. Greenhouse gas emissions from shipping: waiting for concrete progress at IMO level committee EN 2020.

[4] UNEP/SETAC. Global Guidance for Life Cycle Impact Assessment Indicators Volume 1 2016;266:166.

[5] IEA. Net Zero by 2050. 2021.

[6] Neelis ML, Van der Kooi HJ, Geerlings JJC. Exergetic life cycle analysis of hydrogen production and storage systems for automotive applications. Int J Hydrogen Energy 2004;29:537–45. https://doi.org/10.1016/S0360-3199(03)00087-9.

[7] Zhao G, Kraglund MR, Frandsen HL, Wulff AC, Jensen SH, Chen M, et al. Life cycle assessment of H2O electrolysis technologies. Int J Hydrogen Energy 2020;45:23765–81. https://doi.org/10.1016/j.ijhydene.2020.05.282.

[8] Deutz S, Bardow A. Life-cycle assessment of an industrial direct air capture process based on temperature–vacuum swing adsorption. Nat Energy 2021;6:203–13. https://doi.org/10.1038/s41560-020-00771-9.

[9] Brynolf S, Kuvalekar S, Andersson K. Life cycle assessment of methanol and dimethyl ether (DME) as marine fuels. 2014.

[10] Brynolf S, Fridell E, Andersson K. Environmental assessment of marine fuels: Liquefied natural gas, liquefied biogas, methanol and bio-methanol. J Clean Prod 2014;74:86–95. https://doi.org/10.1016/j.jclepro.2014.03.052.

[11] Ellis J, Svanberg M. SUMMETH – D5.1: Expected benefits, strategies, and implementation of methanol as a marine fuel for the smaller vessel fleet 2018.

[12] IRENA and Methanol Institute. Innovation Outlook: Renewable Methanol. 2021.

[13] MITACS. Mitacs Accelerate Project Final Report Application Ref .: IT08015 Comprehensive Evaluation of NH 3 Production and Utilization Options for Clean Energy Applications Period : September 2016 - March 2017 Submission Date : Principal Investigator : Prof . Dr . 2017.

[14] Singh V, Dincer I, Rosen MA. Life Cycle Assessment of Ammonia Production Methods. Elsevier; 2018. https://doi.org/10.1016/B978-0-12-813734-5.00053-6.

[15] Al-Breiki M, Bicer Y. Comparative life cycle assessment of sustainable energy carriers including production, storage, overseas transport and utilization. J Clean Prod 2021;279:123481. https://doi.org/10.1016/j.jclepro.2020.123481.

[16] Chisalita DA, Petrescu L, Cormos CC. Environmental evaluation of european ammonia production considering various hydrogen supply chains. Renew Sustain Energy Rev 2020;130:109964. https://doi.org/10.1016/j.rser.2020.109964.

[17] Committe on Climate Change. Hydrogen in a low-carbon economy. 2018.

[18] Singh V, Dincer I, Rosen MA. Life Cycle Assessment of Ammonia Production Methods. Elsevier; 2018. https://doi.org/10.1016/B978-0-12-813734-5.00053-6.

[19] IEA. The future of hydrogen. vol. 2012. 2012. https://doi.org/10.1016/S1464-2859(12)70027-5.

[20] Bellotti D, Rivarolo M, Magistri L, Massardo AF. Feasibility study of methanol production plant from hydrogen and captured carbon dioxide. J CO2 Util 2017;21:132–8. https://doi.org/10.1016/j.jcou.2017.07.001.

[21] Al-Breiki M, Bicer Y. Investigating the technical feasibility of various energy carriers for alternative and sustainable overseas energy transport scenarios. Energy Convers Manag 2020;209:112652. https://doi.org/10.1016/j.enconman.2020.112652.

[22] Chum H, Faaij A, Moreira J, Berndes G, Dahmija P, Dong H, et al. Bioenergy. In: Edenhofer O, Pichs-Madruga R, Sokona Y, Seyboth K, Matschoss P, Kadner S, et al., editors. Renew. Energy Sources Clim. Chang. Mitig. Spec. Rep. Intergov. Panel Clim. Chang., Cambridge, United Kingdom and New York, NY, USA: Cambridge University Press; 2011, p. 209–331. https://doi.org/10.1017/CBO9781139151153.

[23] Daioglou V, Stehfest E, Wicke B, Faaij A, van Vuuren DP. Projections of the availability and cost of residues from agriculture and forestry. GCB Bioenergy 2016;8:456–70. https://doi.org/10.1111/gcbb.12285.

[24] IEA Bioenergy. Black Liquor Gasification. 2013.

[25] Gustafsson M, Svensson N. Cleaner heavy transports – Environmental and economic analysis of liquefied natural gas and biomethane. J Clean Prod 2021;278:123535. https://doi.org/10.1016/j.jclepro.2020.123535.

[26] Oosterkamp WJ. Use of volatile solids from biomass for energy production. BV; 2020. https://doi.org/10.1016/b978-0-12-819597-0.00006-4.

[27] IEA. Marine bunkers product demand, 2015-2024 2019.

[28] IRENA. Global Renewables Outlook: Energy transformation 2050. 2020.

[29] ICAO. Environmental Trends in Aviation to 2050. 2019.

[30] IEA. The Future of Petrochemicals 2018.

[31] Cumicheo C, Mac Dowell N, Shah N. Natural gas and BECCS: A comparative analysis of alternative configurations for negative emissions power generation. Int J Greenh Gas Control 2019;90. https://doi.org/10.1016/j.ijggc.2019.102798.

[32] Hashemi SE, Sarker S, Lien KM, Schnell SK, Austbø B. Cryogenic vs. absorption biogas upgrading in liquefied biomethane production – An energy efficiency analysis. Fuel 2019;245:294–304. https://doi.org/10.1016/j.fuel.2019.01.172.

[33] IMO. Fourth IMO GHG Study Final Report. vol. REDUCTION. 2020.

[34] Man Energy solution. Man energy solution 2021. https://www.man-es.com/marine/products/ (accessed September 20, 2021).

[35] Correa DF, Beyer HL, Possingham HP, Thomas-Hall SR, Schenk PM. Global mapping of cost-effective microalgal biofuel production areas with minimal environmental impact. GCB Bioenergy 2019;11:914–29. https://doi.org/10.1111/gcbb.12619.

[36] Somers MD, Quinn JC. Sustainability of carbon delivery to an algal biorefinery: A techno-economic and life-cycle assessment. J CO2 Util 2019;30:193–204. https://doi.org/10.1016/j.jcou.2019.01.007.

[37] IEA. Technology roadmap: bioenergy for heat and power. Manag Environ Qual An Int J 2012;24. https://doi.org/10.1108/meq.2013.08324aaa.005.

References Chapter 2

[38] International Maritime Organization. Fourth Greenhouse Gas Study. 2020. url: https://www.imo.org/en/OurWork/Environment/Pages/Fourth-IMO-Greenhouse-Gas-Study-2020.aspx.

[39] United Nations Conference on Trade and Development. Review of Maritime Transport 2020. 2020.

url: https://unctad.org/webflyer/review-maritime-transport-2020.

[40] Detlef P. van Vuuren et al. "Energy, land-use and greenhouse gas emissions trajectories under a green growth paradigm". In: Global Environmental Change 42 (2017), pp. 237–250. issn: 0959- 3780. doi: https :/ / doi . org / 10 . 1016 / j. gloenvcha . 2016 . 05 . 008. url: https :/ / www . sciencedirect.com/science/article/pii/S095937801630067X.

[41] Detlef P Van Vuuren et al. "RCP2. 6: exploring the possibility to keep global mean temperature increase below 2 C". In: Climatic change 109.1 (2011), pp. 95–116.

[42] Carbon Brief. Explainer: How 'Shared Socioeconomic Pathways' explore future climate change. 2018. url: https : / / www . carbonbrief . org / explainer - how - shared - socioeconomic - pathways-explore-future-climate-change.

[43] Danish Ship Finance. SHIPPING MARKET REVIEW – NOVEMBER 2020. 2020. url: https:

//www.shipfinance.dk/media/2054/shipping-market-review-november-2020.pdf.

References Chapter 3

[44] Climeworks, The world’s largest climate-positive direct air capture plant: Orca!, https://climeworks.com/orca

Appendices

Appendix A (Chapter 1)

	WTT emissions (kg/MJ)				TTW emissions (kg/MJ)				
Fuel	CO_{2e}	CO_2	CH_4	N_2O	CO_{2e}	CO_2	CH_4	N_2O	Reference
HFO	11	8	0.08	-	76	75	-	0.004	UMAS, 2019. Scenario Analysis: Take-up of Emissions Reduction Options and their Impacts on Emissions and Costs - Technical Annex. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/816019/scenario-analysis-take-up-of-emissions-reduction-options-impacts-on-emissions-costs-technical-annexes.pdf
HFO	10	10	-	-	76	76	-	-	DNVGL. Alternative Fuels Encyclopedia. Figure 3. https://afi.dnvgl.com/Content/images/Fig3.png
HFO	19	19	-	-	80	80	-	-	ALFA LAVAL, HAFNIA, HALDOR TOPSØE, VESTAS, SIEMENS GAMESA (2020). Ammonfuel – an industrial view of ammonia as a marine fuel.
HFO	-	-	-	-	78	78	-	-	Kristensen, H. O. (2015). Energy demand and exhaust Gas emissions of marine engines. Clean Shipping Currents, 1(2014), 18–26. http://www.skibstekniskselskab.dk/public/dokumenter/Skibsteknisk/Foraar 2013/25.02.2013/WP 2 - Report 5 - Energy demand and emissions of marine engines - December 2012.pdf
HFO	9	7	0.07	-	78	77	-	0.004	Brynolf, S., Fridell, E., & Andersson, K. (2014). Environmental assessment of marine fuels: Liquefied natural gas, liquefied biogas, methanol and bio-methanol. Journal of Cleaner Production, 74(X), 86–95. https://doi.org/10.1016/j.jclepro.2014.03.052
HFO	-	-	-	-	78	77	-	0.004	IMO Marine Environment Protection Committee. (2020). Fourth IMO Greenhouse Gas Study 2020. Mepc 75/7/15, 74.
HFO	14	14	-	-	79	78	-	0.004	Thinkstep. (2019). Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel.
HFO	14	11	0.10	-	81	80	-	0.004	Pavlenko, N., Comer, B., Zhou, Y., Clark, N., & Rutherford, D. (2020). The climate implications of using LNG as a marine fuel. In ICCT Working Paper 2020-02 (Issue January). www.theicct.org
HFO	11	11	-	-	80	80	-	-	Baresic, D., Smith T., Raucci, K., Rehmatulla, C., Narula, N. & Rojon, I. (2018). LNG as a marine fuel in the EU: Market, bunkering infrastructure investments and risks in the context of GHG reductions.
HFO	11	8	0.08	-	76	75	-	0.004	Lloyd's Register. (2019). Fuel production cost estimates and assumptions. 44. https://www.lr.org/en-gb/insights/global-marine-trends-2030/zero-emission-vessels-transition-pathways/
VLSFO	11	8	0.08	-	74	73	-	0.004	UMAS, 2019. Scenario Analysis: Take-up of Emissions Reduction Options and their Impacts on Emissions and Costs - Technical Annex. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/816019/scenario-analysis-take-up-of-emissions-reduction-options-impacts-on-emissions-costs-technical-annexes.pdf
VLSFO	23	23	-	-	77	77	-	-	ALFA LAVAL, HAFNIA, HALDOR TOPSØE, VESTAS, SIEMENS GAMESA (2020). Ammonfuel – an industrial view of ammonia as a marine fuel.
VLSFO	11	8	0.08	0.002	76	75	-	0.004	Gilbert, P., Walsh, C., Traut, M., Kesieme, U., Pazouki, K., & Murphy, A. (2018). Assessment of full life-cycle air emissions of alternative shipping fuels. Journal of Cleaner Production, 172(2018), 855–866. https://doi.org/10.1016/j.jclepro.2017.10.165
VLSFO	13	13	-	-	79	78	-	0.004	Thinkstep. (2019). Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel.
VLSFO	17	13	0.10	-	77	76	-	0.004	Pavlenko, N., Comer, B., Zhou, Y., Clark, N., & Rutherford, D. (2020). The climate implications of using LNG as a marine fuel. In ICCT Working Paper 2020-02 (Issue January). www.theicct.org
VLSFO	6	6	-	-	80	80	-	-	Baresic, D., Smith T., Raucci, K., Rehmatulla, C., Narula, N. & Rojon, I. (2018). LNG as a marine fuel in the EU: Market, bunkering infrastructure investments and risks in the context of GHG reductions.
VLSFO	11	8	0.08	-	74	73	-	0.004	Lloyd's Register. (2019). Fuel production cost estimates and assumptions. 44. https://www.lr.org/en-gb/insights/global-marine-trends-2030/zero-emission-vessels-transition-pathways/
MDO	11	8	0.08	-	73	72	-	0.004	UMAS, 2019. Scenario Analysis: Take-up of Emissions Reduction Options and their Impacts on Emissions and Costs - Technical Annex. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/816019/scenario-analysis-take-up-of-emissions-reduction-options-impacts-on-emissions-costs-technical-annexes.pdf

MDO	11	8	0.09	0.001	73	72	-	0.004	Gilbert, P., Walsh, C., Traut, M., Kesieme, U., Pazouki, K., & Murphy, A. (2018). Assessment of full life-cycle air emissions of alternative shipping fuels. Journal of Cleaner Production, 172(2018), 855–866. https://doi.org/10.1016/j.jclepro.2017.10.165
MDO	-	-	-	-	75	75	-	-	Kristensen, H. O. (2015). Energy demand and exhaust Gas emissions of marine engines. Clean Shipping Currents, 1(2014), 18–26. http://www.skibstekniskselskab.dk/public/dokumenter/Skibsteknisk/Foraar 2013/25.02.2013/WP 2 - Report 5 - Energy demand and emissions of marine engines - December 2012.pdf
MDO	-	-	-	-	77	75	-	0.004	IMO Marine Environment Protection Committee. (2020). Fourth IMO Greenhouse Gas Study 2020. Mepc 75/7/15, 74.
MDO	11	11	-	-	76	76	-	-	Baresic, D., Smith T., Raucci, K., Rehmatulla, C., Narula, N. & Rojon, I. (2018). LNG as a marine fuel in the EU: Market, bunkering infrastructure investments and risks in the context of GHG reductions.
MDO	15	15	0.02	-	76	75	-	0.004	Spoof-Tuomi, K., & Niemi, S. (2020). Environmental and Economic Evaluation of Fuel Choices for Short Sea Shipping. Clean Technologies, 2(1), 34–52. https://doi.org/10.3390/cleantechnol2010004
MDO	11	8	0.08	-	73	72	-	0.004	Lloyd's Register. (2019). Fuel production cost estimates and assumptions. 44. https://www.lr.org/en-gb/insights/global-marine-trends-2030/zero-emission-vessels-transition-pathways/
MGO	12	12	-	-	74	74	-	-	DNVGL. Alternative Fuels Encyclopedia. Figure 3. https://afi.dnvgl.com/Content/images/Fig3.png
MGO	22	22	-	-	75	75	-	-	ALFA LAVAL, HAFNIA, HALDOR TOPSØE, VESTAS, SIEMENS GAMESA (2020). Ammonfuel – an industrial view of ammonia as a marine fuel.
MGO	14	14	-	-	76	75	-	0.004	Thinkstep. (2019). Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel.
MGO	17	14	0.10	-	75	74	-	0.004	Pavlenko, N., Comer, B., Zhou, Y., Clark, N., & Rutherford, D. (2020). The climate implications of using LNG as a marine fuel. In ICCT Working Paper 2020-02 (Issue January). www.theicct.org
LNG	9	6	0.05	0.002	93	56	1.03	0.002	UMAS, 2019. Scenario Analysis: Take-up of Emissions Reduction Options and their Impacts on Emissions and Costs - Technical Annex. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/816019/scenario-analysis-take-up-of-emissions-reduction-options-impacts-on-emissions-costs-technical-annexes.pdf
LNG	8	8	-	-	56	56	-	-	DNVGL. Alternative Fuels Encyclopedia. Figure 3. https://afi.dnvgl.com/Content/images/Fig3.png
LNG	-	-	-	-	56	56	-	-	ALFA LAVAL, HAFNIA, HALDOR TOPSØE, VESTAS, SIEMENS GAMESA (2020). Ammonfuel – an industrial view of ammonia as a marine fuel.
LNG	9	6	0.05	0.003	72	57	0.41	0.002	Gilbert, P., Walsh, C., Traut, M., Kesieme, U., Pazouki, K., & Murphy, A. (2018). Assessment of full life-cycle air emissions of alternative shipping fuels. Journal of Cleaner Production, 172(2018), 855–866. https://doi.org/10.1016/j.jclepro.2017.10.165
LNG	-	-	-	-	76	54	0.63	-	Stenersen, D., & Thonstad, O. (2017). GHG and NOx emissions from gas fuelled engines. SINTEF Ocean Report OC2017 F-107.
LNG	17	10	0.20	-	42	38	0.07	0.002	Corbett, J. J., Thomson, H., & Winebrake, J. J. (2015). Methane Emissions from Natural Gas Bunkering Operations in the Marine Sector: A Total Fuel Cycle Approach. November, 38.
LNG	-	-	-	-	55	55	-	-	Kristensen, H. O. (2015). Energy demand and exhaust Gas emissions of marine engines. Clean Shipping Currents, 1(2014), 18–26. http://www.skibstekniskselskab.dk/public/dokumenter/Skibsteknisk/Foraar 2013/25.02.2013/WP 2 - Report 5 - Energy demand and emissions of marine engines - December 2012.pdf
LNG	10	8	0.03	-	80	54	0.71	-	Brynolf, S., Fridell, E., & Andersson, K. (2014). Environmental assessment of marine fuels: Liquefied natural gas, liquefied biogas, methanol and bio-methanol. Journal of Cleaner Production, 74(X), 86–95. https://doi.org/10.1016/j.jclepro.2014.03.052
LNG	-	-	-	-	62	56	0.17	0.002	IMO Marine Environment Protection Committee. (2020). Fourth IMO Greenhouse Gas Study 2020. Mepc 75/7/15, 74.
LNG	19	14	0.16	-	70	56	0.38	0.002	Thinkstep. (2019). Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel.
LNG	22	11	0.30	-	58	57	0.02	0.002	Pavlenko, N., Comer, B., Zhou, Y., Clark, N., & Rutherford, D. (2020). The climate implications of using LNG as a marine fuel. In ICCT Working Paper 2020-02 (Issue January). www.theicct.org
LNG	9	9	-	-	74	74	-	-	Baresic, D., Smith T., Raucci, K., Rehmatulla, C., Narula, N. & Rojon, I. (2018). LNG as a marine fuel in the EU: Market, bunkering infrastructure investments and risks in the context of GHG reductions.

LNG	10	10	-	-	58	58	-	-	Al-Breiki, M., & Bicer, Y. (2021). Comparative life cycle assessment of sustainable energy carriers including production, storage, overseas transport and utilization. Journal of Cleaner Production, 279, 123481. https://doi.org/10.1016/j.jclepro.2020.123481
LNG	17	11	0.18	-	71	56	0.41	0.002	Spoof-Tuomi, K., & Niemi, S. (2020). Environmental and Economic Evaluation of Fuel Choices for Short Sea Shipping. Clean Technologies, 2(1), 34–52. https://doi.org/10.3390/cleantechnol2010004
LPG	9	9	-	-	63	63	-	-	DNVGL. Alternative Fuels Encyclopedia. Figure 3. https://afi.dnvgl.com/Content/images/Fig3.png
LPG	-	-	-	-	60	60	-	-	ALFA LAVAL, HAFNIA, HALDOR TOPSØE, VESTAS, SIEMENS GAMESA (2020). Ammonfuel – an industrial view of ammonia as a marine fuel.
MET-grey	22	22	-	-	71	71	-	-	DNVGL. Alternative Fuels Encyclopedia. Figure 3. https://afi.dnvgl.com/Content/images/Fig3.png
MET-grey	-	-	-	-	70	70	-	-	ALFA LAVAL, HAFNIA, HALDOR TOPSØE, VESTAS, SIEMENS GAMESA (2020). Ammonfuel – an industrial view of ammonia as a marine fuel.
MET-grey	24	21	0.08	0.002	69	69	-	-	Gilbert, P., Walsh, C., Traut, M., Kesieme, U., Pazouki, K., & Murphy, A. (2018). Assessment of full life-cycle air emissions of alternative shipping fuels. Journal of Cleaner Production, 172(2018), 855–866. https://doi.org/10.1016/j.jclepro.2017.10.165
MET-grey	20	20	0.01	-	69	69	-	-	Brynolf, S., Fridell, E., & Andersson, K. (2014). Environmental assessment of marine fuels: Liquefied natural gas, liquefied biogas, methanol and bio-methanol. Journal of Cleaner Production, 74(X), 86–95. https://doi.org/10.1016/j.jclepro.2014.03.052
MET-grey	-	-	-	-	69	69	-	-	Thinkstep. (2019). Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel.
MET-grey	18	18	-	-	69	69	-	-	Collodi, G., Azzaro, G., Ferrari, N., & Santos, S. (2017). Demonstrating Large Scale Industrial CCS through CCU - A Case Study for Methanol Production. Energy Procedia, 114(November 2016), 122–138. https://doi.org/10.1016/j.egypro.2017.03.1155
MET-grey	25	21	0.12	-	69	69	-	-	Eggleston S, Leandro B, Kyoko M, Todd N, Tanabe K. 2006 IPCC Guidelines for National Greenhouse Gas Inventories - Volume 3: Industrial Processes and Product Use. 2006. https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_3_Ch3_Chemical_Industry.pdf
MET-grey	20	20	-	-	69	69	-	-	Al-Breiki, M., & Bicer, Y. (2021). Comparative life cycle assessment of sustainable energy carriers including production, storage, overseas transport and utilization. Journal of Cleaner Production, 279, 123481. https://doi.org/10.1016/j.jclepro.2020.123481
MET-blue	8	8	-	-	-	-	-	-	UMAS, 2019. Scenario Analysis: Take-up of Emissions Reduction Options and their Impacts on Emissions and Costs - Technical Annex. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/816019/scenario-analysis-take-up-of-emissions-reduction-options-impacts-on-emissions-costs-technical-annexes.pdf
MET-blue	-	-	-	-	70	70	-	-	ALFA LAVAL, HAFNIA, HALDOR TOPSØE, VESTAS, SIEMENS GAMESA (2020). Ammonfuel – an industrial view of ammonia as a marine fuel.
MET-blue	-	-	-	-	69	69	-	-	Thinkstep. (2019). Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel.
MET-blue	2	2	-	-	69	69	-	-	Collodi, G., Azzaro, G., Ferrari, N., & Santos, S. (2017). Demonstrating Large Scale Industrial CCS through CCU - A Case Study for Methanol Production. Energy Procedia, 114(November 2016), 122–138. https://doi.org/10.1016/j.egypro.2017.03.1155
AMM-blue	13	12	-	0.001	-	-	-	-	UMAS, 2019. Scenario Analysis: Take-up of Emissions Reduction Options and their Impacts on Emissions and Costs - Technical Annex. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/816019/scenario-analysis-take-up-of-emissions-reduction-options-impacts-on-emissions-costs-technical-annexes.pdf
AMM-blue	-	-	-	-	-	-	-	-	ALFA LAVAL, HAFNIA, HALDOR TOPSØE, VESTAS, SIEMENS GAMESA (2020). Ammonfuel – an industrial view of ammonia as a marine fuel.
AMM-blue	20	20	-	-	-	-	-	-	Chisalita, D. A., Petrescu, L., & Cormos, C. C. (2020). Environmental evaluation of european ammonia production considering various hydrogen supply chains. Renewable and Sustainable Energy Reviews, 130(June), 109964. https://doi.org/10.1016/j.rser.2020.109964

AMM-blue	-	-	-	-	1	1	-	-	Al-Breiki, M., & Bicer, Y. (2021). Comparative life cycle assessment of sustainable energy carriers including production, storage, overseas transport and utilization. Journal of Cleaner Production, 279, 123481. https://doi.org/10.1016/j.jclepro.2020.123481
PO	8	-	-	-	-	-	-	-	Spatari, S., Larnaudie, V., Mannoh, I., Wheeler, M.C., Macken, N.A., Mullen, C.A., Boateng, A.A., 2020. Environmental, exergetic and economic tradeoffs of catalytic- and fast pyrolysis-to-renewable diesel. Renew. Energy 162, 371–380. https://doi.org/10.1016/j.renene.2020.08.042
PO	3	-	-	-	-	-	-	-	Roberts, M., Marker, T.L., 2012. Biomass to Gasoline and Diesel Using Integrated Hydropyrolysis and Hydroconversion 1–123.
PO	6	-	-	-	-	-	-	-	Roberts, M., Marker, T.L., 2012. Biomass to Gasoline and Diesel Using Integrated Hydropyrolysis and Hydroconversion 1–123.
LBG	37	10	0.70	0.008	16	-	0.41	0.002	Gilbert, P., Walsh, C., Traut, M., Kesieme, U., Pazouki, K., & Murphy, A. (2018). Assessment of full life-cycle air emissions of alternative shipping fuels. Journal of Cleaner Production, 172(2018), 855–866. https://doi.org/10.1016/j.jclepro.2017.10.165
LBG	34	27	0.18	-	28	-	0.79	-	Brynolf, S., Fridell, E., & Andersson, K. (2014). Environmental assessment of marine fuels: Liquefied natural gas, liquefied biogas, methanol and bio-methanol. Journal of Cleaner Production, 74(X), 86–95. https://doi.org/10.1016/j.jclepro.2014.03.052
LBG	22	10	0.34	-	16	1	0.41	0.002	Spoof-Tuomi, K., & Niemi, S. (2020). Environmental and Economic Evaluation of Fuel Choices for Short Sea Shipping. Clean Technologies, 2(1), 34–52. https://doi.org/10.3390/cleantechnol2010004
AMM-green	9	9	-	0.001	-	-	-	-	UMAS, 2019. Scenario Analysis: Take-up of Emissions Reduction Options and their Impacts on Emissions and Costs - Technical Annex. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/816019/scenario-analysis-take-up-of-emissions-reduction-options-impacts-on-emissions-costs-technical-annexes.pdf
AMM-green	-	-	-	-	-	-	-	-	ALFA LAVAL, HAFNIA, HALDOR TOPSØE, VESTAS, SIEMENS GAMESA (2020). Ammonfuel – an industrial view of ammonia as a marine fuel.
AMM-green	8	8	-	-	-	-	-	-	Chisalita, D. A., Petrescu, L., & Cormos, C. C. (2020). Environmental evaluation of european ammonia production considering various hydrogen supply chains. Renewable and Sustainable Energy Reviews, 130(June), 109964. https://doi.org/10.1016/j.rser.2020.109964
AMM-green	35	35	-	-	1	1	-	-	Al-Breiki, M., & Bicer, Y. (2021). Comparative life cycle assessment of sustainable energy carriers including production, storage, overseas transport and utilization. Journal of Cleaner Production, 279, 123481. https://doi.org/10.1016/j.jclepro.2020.123481
AMM-green	22	22	-	-	-	-	-	-	Al-Breiki, M., & Bicer, Y. (2021). Comparative life cycle assessment of sustainable energy carriers including production, storage, overseas transport and utilization. Journal of Cleaner Production, 279, 123481. https://doi.org/10.1016/j.jclepro.2020.123481
AMM-green	48	48	-	-	-	-	-	-	Al-Breiki, M., & Bicer, Y. (2021). Comparative life cycle assessment of sustainable energy carriers including production, storage, overseas transport and utilization. Journal of Cleaner Production, 279, 123481. https://doi.org/10.1016/j.jclepro.2020.123481
AMM-green	69	69	-	-	-	-	-	-	Singh, V., Dincer, I., & Rosen, M. A. (2018). Life Cycle Assessment of Ammonia Production Methods. In Exergetic, Energetic and Environmental Dimensions. Elsevier. https://doi.org/10.1016/B978-0-12-813734-5.00053-6
AMM-green	27	27	-	-	-	-	-	-	Singh, V., Dincer, I., & Rosen, M. A. (2018). Life Cycle Assessment of Ammonia Production Methods. In Exergetic, Energetic and Environmental Dimensions. Elsevier. https://doi.org/10.1016/B978-0-12-813734-5.00053-6
AMM-green	27	27	-	-	-	-	-	-	MITACS. (2017). Mitacs Accelerate Project Final Report Application Ref .: IT08015 Comprehensive Evaluation of NH 3 Production and Utilization Options for Clean Energy Applications Period : September 2016 - March 2017 Submission Date : Principal Investigator : Prof . Dr .
AMM-green	49	49	-	-	-	-	-	-	MITACS. (2017). Mitacs Accelerate Project Final Report Application Ref .: IT08015 Comprehensive Evaluation of NH 3 Production and Utilization Options for Clean Energy Applications Period : September 2016 - March 2017 Submission Date : Principal Investigator : Prof . Dr .
AMM-green	12	12	-	-	-	-	-	-	Liu, X., Elgowainy, A., & Wang, M. (2020). Life cycle energy use and greenhouse gas emissions of ammonia production from renewable resources and industrial by-products. Green Chemistry, 22(17), 5751–5761. https://doi.org/10.1039/d0gc02301a
AMM-green	10	10	-	-	-	-	-	-	Liu, X., Elgowainy, A., & Wang, M. (2020). Life cycle energy use and greenhouse gas emissions of ammonia production from renewable resources and industrial by-products. Green Chemistry, 22(17), 5751–5761. https://doi.org/10.1039/d0gc02301a

AMM-green	11	11	-	0.001	-	-	-	-	Lloyd’s Register. (2019). Fuel production cost estimates and assumptions. 44. https://www.lr.org/en-gb/insights/global-marine-trends-2030/zero-emission-vessels-transition-pathways/

Appendix B (Chapter 1)

GHG emission factors for electricity from grid

	2020	2030	2040	2050
kg CO2e/kWh	0.521	0.187	0.019	0.001

GHG emission factors. From Ecoinvent Consequential Database 3.7.1 (except when noted)

kg CO2e/kWh	**2020**	**2030**	**2040**	**2050**	**Ecoinvent process**
Coal	1.067	1.067	1.067	1.067	electricity production, hard coal
Oil	1.260	1.260	1.260	1.260	electricity production, oil
Natural gas	0.432	0.432	0.432	0.432	electricity production, natural gas, combined cycle power plant
Nuclear	0.018	0.018	0.018	0.018	electricity production, nuclear, pressure water reactor
Hydro	0.007	0.007	0.007	0.007	electricity production, hydro, reservoir, alpine region
Bioenergy	0.046	0.046	0.046	0.046	electricity production, wood, future
Wind*	0.029	0.019	0.010	0.000	electricity production, wind, >3MW electricity production, wind, 1-3MW turbine, offshore 20%
Geothermal	0.071	0.071	0.071	0.071	electricity production, deep geothermal
Solar PV*	0.087	0.058	0.029	0.000	electricity production, photovoltaic, 3kWp slanted-roof installation, multi-Si, panel, mounted
CSP*	0.051	0.035	0.019	0.003	solar thermal parabolic trough/solar tower power plant
BECCS	-0.734	-0.734	-0.734	-0.734	Not from Ecoinvent, average from sources below
Coal CCUS	0.194	0.194	0.194	0.194	Not from Ecoinvent, average from sources below
NG CCUS	0.138	0.138	0.138	0.138	Not from Ecoinvent, average from sources below

*Assumed to reduce to 0.1% of 2020 value by 2050

GHG emission factors for BECCS, Coal CCUS and NG CCUS

Fuel	**Technology**	**gCO2/kWh**	**Source**
Coal CCS	Oxy-fuel combustion	200	a
Coal CCS	Post-conversion capture	220	a

Natural gas CCS	Oxy-fuel combustion	120	a
Natural gas CCS	Post-conversion capture	140	a
Coal CCS	Oxy-fuel combustion	154	b
Coal CCS	Post-conversion capture	203	b
Natural gas CCS	Oxy-fuel combustion	120	b
Natural gas CCS	Post-conversion capture	173	b
BECCS		-591	c
BECCS		-877	d

a Singh, B., Strømman, A.H., Hertwich, E.G., 2011. Comparative life cycle environmental assessment of CCS technologies. Int. J. Greenh. Gas Control 5, 911–921. https://doi.org/10.1016/j.ijggc.2011.03.012

b Cuéllar-Franca, R.M., Azapagic, A., 2015. Carbon capture, storage and utilisation technologies: A critical analysis and comparison of their life cycle environmental impacts. J. CO2 Util. 9, 82–102. https://doi.org/10.1016/j.jcou.2014.12.001

c Yan, L., Cao, Y., He, B., 2019. Energy, exergy and economic analyses of a novel biomass fueled power plant with carbon capture and sequestration. Sci. Total Environ. 690, 812–820. https://doi.org/10.1016/j.scitotenv.2019.07.015

d Yang, B., Wei, Y.M., Hou, Y., Li, H., Wang, P., 2019. Life cycle environmental impact assessment of fuel mix-based biomass co-firing plants with CO2 capture and storage. Appl. Energy 252. https://doi.org/10.1016/j.apenergy.2019.113483

		gCO2/kWh
BECCS	Average	-734
Coal CCS	Average	194
Natural gas CCS	Average	138

Global electricity generation — Source: IEA, 2021, Net Zero by 2050

Unit: TWh	**2020**	**2030**	**2040**	**2050**
Coal	9426	2947	0	0
Oil	756	189	6	6
Natural gas	6200	6222	626	253
Nuclear	2698	3777	4855	5497
Hydro	4418	5870	7445	8461
Bioenergy	718	1278	2003	2437
Wind	1592	8008	18787	24785
Geothermal	94	330	625	821
Solar PV	821	6970	17031	23469
CSP	14	204	880	1386
BECCS		129	673	842
Coal CCUS	4	289	966	663
NG CCUS		170	694	669

Appendix C (Chapter 2)

Table 6: Number of actual ships in 2018, from IMO Fourth Greenhouse Gas Study, table O.7 [1].For some ship types, capacity ranges were given in gross tonnage volume instead of deadweight tonnage. Based on data by Grimaldi Lines, it is assumed that every gross tonnage volume corresponds to one-third deadweight tonnage.

		Size		
Ship type	**Category**	**dwt min**	**dwt max**	**no. of ships total 2018**
Bulk carrier	Bulk	0	9999	1446
Bulk carrier	Bulk	10000	34999	2014
Bulk carrier	Bulk	35000	59999	3391
Bulk carrier	Bulk	60000	99999	3409
Bulk carrier	Bulk	100000	199999	1242
Bulk carrier	Bulk	200000		516
Refrigerated Bulk	Bulk	0	1999	1371
Refrigerated Bulk	Bulk	2000	5999	213
Refrigerated Bulk	Bulk	6000	9999	182
Refrigerated Bulk	Bulk	10000		157
				13941

Container	Container	0	999	1027
Container	Container	1000	1999	1271
Container	Container	2000	2999	668
Container	Container	3000	4999	815
Container	Container	5000	7999	561
Container	Container	8000	11999	623
Container	Container	12000	14499	227
Container	Container	14500	19999	101
Container	Container	20000		44
				5337

General Cargo	General Cargo	0	4999	13296
General Cargo	General Cargo	5000	9999	2245
General Cargo	General Cargo	10000	19999	1054
General Cargo	General Cargo	20000		793
Ro-Ro	General Cargo	0	4999	2174
Ro-Ro	General Cargo	5000	9999	200
Ro-Ro	General Cargo	10000	14999	135
Ro-Ro	General Cargo	15000		89
Vehicle	General Cargo	0	10000	175
Vehicle	General Cargo	10000	16666	189
Vehicle	General Cargo	16667		487

20837

Chemical tanker	Other	0	4999	6067
Chemical tanker	Other	5000	9999	862
Chemical tanker	Other	10000	19999	1088
Chemical tanker	Other	20000	39999	706
Chemical tanker	Other	40000		1289
Cruise	Other	0	1999	812
Cruise	Other	2000	9999	110
Cruise	Other	10000	59999	105
Cruise	Other	60000	99999	98
Cruise	Other	100000	149999	61
Cruise	Other	150000		21
Ferry-pax	Other	0	299	10680
Ferry-pax	Other	300	999	666
Ferry-pax	Other	1000	19999	51
Ferry-pax	Other	2000		55
Ferry-RoPax	Other	0	1999	2854
Ferry-RoPax	Other	2000	4999	400
Ferry-RoPax	Other	5000	9999	227
Ferry-RoPax	Other	10000	19999	231
Ferry-RoPax	Other	20000		282
LNG tanker	Other	0	91.57317	2685
LNG tanker	Other	91575	1831498	308
LNG tanker	Other	183150	366298.2	436
LNG tanker	Other	366300		46
Miscellaneous fishing	Other			36530
Miscellaneous other	Other			249
Offshore	Other			16893
Service	Other			76266
Service	Other			12419
Yacht	Other			15021
Other liquid tankers	Other	0	999	533
Other liquid tankers	Other	1000		106

188157

Oil tanker	Tanker	0	4999	9692
Oil tanker	Tanker	5000	9999	779
Oil tanker	Tanker	10000	19999	235
Oil tanker	Tanker	20000	59999	615
Oil tanker	Tanker	60000	79999	429
Oil tanker	Tanker	80000	119999	1029

Oil tanker	Tanker	120000	199999	597
Oil tanker	Tanker	200000		755
				14131

ID	Product	Ship type
1	Bulk Agriculture - High Added Value	Container Carrier
2	Bulk Agriculture - Low Added Value	Bulk Carrier
3	Chemical, rubber, plastic products - Bulk solid	Bulk Carrier
4	Chemical, rubber, plastic products - High Added Value	Container Carrier
5	Chemical, rubber, plastic products - High Added Value Solid	Container Carrier
6	Chemical, rubber, plastic products - Liquid	Chemical Tanker
7	Electronic equipment	Container Carrier
8	Ferrous metals - Bulk	Bulk Carrier
9	Ferrous metals - Semi-Finished	Container Carrier
10	Fishing	Container Carrier
11	Forestry	Bulk Carrier
12	Leather products	Container Carrier
13	LNG	LNG Tanker
14	LPG	LPG Tanker
15	Machinery and equipment nec	Container Carrier
16	Manufactures nec	Container Carrier
17	Metal products - Large	Bulk Carrier
18	Metal products - Small	Container Carrier
19	Metals nec - Bulk	Bulk Carrier
20	Metals nec - High Added Value	Container Carrier
21	Mineral products nec - Bulk	Bulk Carrier
22	Mineral products nec - High Added Value	Container Carrier
23	Minerals - Bulk	Bulk Carrier
24	Minerals - High Added Value	Container Carrier
25	Motor vehicles and parts - Parts	Container Carrier
26	Motor vehicles and parts - Vehicles	RoRo
27	Oil	Oil Tanker
28	Paper products, publishing - Bulk	Bulk Carrier
29	Paper products, publishing - High Added Value	Container Carrier
30	Petroleum, coal products - Liquid	Oil Tanker
31	Petroleum, coal products - Solid	Bulk Carrier
32	Processed Agriculture - High Added Value	Container Carrier
33	Processed Agriculture - Live animals	Container Carrier
34	Textiles	Container Carrier
35	Transport equipment nec	Container Carrier
36	Wearing apparel	Container Carrier
37	Wood products	Container Carrier

Figure 6: Alternative classification used by IMO for demand per ship type, table 17 of IMO'sFourth Greenhouse Gas Study [1]