Life Cycle Assessment of Greenhouse Gas and Criteria Air Pollutant Emissions from Conventional and Biobased Marine Fuels

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Introduction

Marine fuels are a major source of pollutant emissions. Global shipping contributes 13% of human-caused emissions of sulfur oxides (Sofiev 2018) and 2.6% of human-caused carbon dioxide emissions (Olmer 2017). The marine shipping sector is responsible for transporting 90% of world's goods and is one of the largest consumers of petroleum fuels. Global marine fuel consumption is estimated to be around 330 million metric tons (87 billion gallons) annually and is expected to double in the next 20 years. The fuel used by the marine shipping sector is primarily heavy fuel oil (HFO), which is a residual of the refinery process which contains many of the undesirable impurities separated from other refinery products. The International Maritime Organization (IMO) has set emission targets to reduce global marine fuel sulfur content from current 3.5% to 0.5% by weight in 2020. In addition, in the U.S., the California Air Resources Board (CARB) and other state agencies have established regulations limiting the sulfur content of fuel used in coastal regions to 0.1%. These regulations will require shipowners to find alternative fuel pathways. The options include low-sulfur HFO, low-sulfur marine gas oil, installing sulfur scrubbers, or other alternative fuels/powertrains. Biofuels offer a possible alternative. The expected higher costs for low-sulfur marine fuels, other forthcoming emission regulations, and the additional processing associated with HFO, could provide a new market opportunity for biofuels, which have inherently low sulfur content and potential to reduce particulate matter emissions. In addition, biofuels offer the potential to reduce net carbon dioxide emissions due to the uptake of carbon from the atmosphere during biomass growth.

The objective of this study is to estimate the life-cycle greenhouse gas (GHG) and criteria air pollutant (CAP) emissions of conventional and biobased marine fuels. This study is performed in parallel with efforts at the National Renewable Energy Laboratory and Pacific Northwest National Laboratory to estimate the potential costs of biofuel options via techno-economic analysis. The fuel options considered in the report include conventional HFO and marine gas oil as well as low sulfur versions of HFO and marine gas oil, several biofuel pathways, and natural gas. The biofuels considered in this report are considered to be potential drop in fuels compatible for use in marine engines, however further work is needed to confirm compatibility and to address any potential issues which could be caused by differences in their properties.

These pathways are evaluated using a new version of the GREET marine fuels module developed for this project. This new module includes several new marine biofuel pathways as well as updated pathways for conventional marine fuels and natural gas as a marine fuel. We updated the combustion emission factors using the best available data.

The scope of this study includes the well-to-hull emissions of each fuel option. Supply chain emissions are included for petroleum extraction and refining, biofuel feedstock growth, harvesting, and conversion, as well as natural gas extraction and liquefaction. Use phase emissions are based on the best available emissions factors, however in several cases conventional diesel emissions are used as a proxy for emissions from biobased diesel. The infrastructure associated with fuel production and distribution as well as fuel-specific handling requirements are outside the scope of this study. The findings of this study are meant to gauge the potential emissions benefits associated with the use of biofuels for marine transportation and to identify tradeoffs amongst fuel options.

Method

LCA System Boundary

In this study, a total of nine fuel types is considered (Table 1). For heavy fuel oil (HFO) that is the most typical marine fuel, we considered two additional HFO with low sulfur contents (0.5% and 0.1%) along with conventional HFO with a sulfur content of 2.7%. Marine gas oil (MGO), a distillate fuel, which has relatively lower sulfur content (1.0%) than the baseline HFO is considered with two additional MGOs with low sulfur contents (0.5% and 0.1%). Marine diesel oil is considered as a mixture of HFO and MGO, which generate three types of MDO with different sulfur contents. By default, we assume to mix 50% HFO and 50% MGO by weight. Liquefied natural gas (LNG) has emerged to comply with regulations by IMO and MARPOL because of its clean combustion profile and recent competitive LNG price. Other than these conventional fossil-based marine fuels, we analyzed alternative fuel production pathways. National Renewable Energy Laboratory (NREL) provided process engineering datasets for FTD using four different feedstocks (natural gas [NG], biomass, biomass/NG, and biomass/coal), and Pacific Northwest National Laboratory (PNNL) provided process engineering datasets for pyrolysis oil from woody biomass and renewable diesel using yellow grease with and without HFO. We also include straight vegetable oil (soy oil) and biodiesel as alternative marine fuels.

Table 1. Fuel production pathways evaluated in this study

Pathways	Note
HFO (2.7% sulfur)	Residual oil in GREET
HFO (0.5% sulfur)	Residual oil in GREET + Desulfurization
HFO (0.1% sulfur)	Residual oil in GREET + Desulfurization
MGO (1.0% sulfur)	Unfinished oil in GREET
MGO (0.5 % sulfur)	Unfinished oil in GREET+ Desulfurization
MGO (0.1 % sulfur)	Unfinished oil in GREET+ Desulfurization
MDO (1.92% sulfur)	Mixture of HFO 2.7%S and MGO 1.0%S
MDO (0.5% sulfur)	Mixture of HFO 0.5%S and MGO 0.5%S
MDO (0.1% sulfur)	Mixture of HFO 0.1%S and MGO 0.1%S
LNG	LNG in GREET
FT-Diesel (NG)	Newly added; data provided by NREL
FT-Diesel (biomass)	Newly added; data provided by NREL
FT-Diesel (biomass/NG)	Newly added; data provided by NREL
FT-Diesel (biomass/coal)	Newly added; data provided by NREL
Pyrolysis oil (woody biomass)	Newly added; data provided by PNNL
Renewable diesel (yellow grease/HFO)	Newly added; data provided by PNNL
Renewable diesel (yellow grease)	Newly added; data provided by PNNL
Straight Vegetable Oil (SVO)	Soy oil in GREET
Biodiesel	Biodiesel in GREET

In order to compare the life-cycle GHG and CAP emissions for these marine fuels, it is essential to have a consistent system boundary with reliable datasets. The Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET®) model [1] is a tool with significant datasets enabling a systematic LCA of various transportation fuels. This model includes all processes associated with feedstock recovery, feedstock transportation, fuel production, fuel transportation, and fuel combustion. Since the analysis covers from feedstock recovery (well) to pump (WTP) and pump-to-hull (fuel combustion) (PTH), we call life-cycle of marine fuels as well-to-hull (WTH) [2]. WTP of petroleum products (HFO, MGO, and MDO) include crude oil recovery, crude oil transportation, crude oil refining for HFO and MGO production, and fuel transportation. All the parameters for these processes are from GREET [1] which are mainly based on the studies by Elgowainy et al. [3] and Forman et al. [4]. For LNG production, WTP covers both conventional NG and shale gas recovery, NG processing, transportation, and liquefaction which are documented in the earlier papers [5–7]. For the parameters of the new fuel production processes (FTD, pyrolysis oil, and renewable diesel), we documented inputs and outputs of the processes in the following sections. For SVO, we used parameters of soy oil production in GREET, and biodiesel is assumed to be 100% from soybean via transesterification. In case there are products other than marine fuels, energy allocation is used. For global warming potential (GWP) values, the Fifth Assessment Report (AR5) of the Intergovernmental Panel on Climate Change (IPCC) was used [8]. All fuel specifications are presented in Table A1.

Production of HFO and MGO with Low Sulfur Content

Residual oil and unfinished oil in GREET are used for HFO (2.7% sulfur) and MGO (1.0% sulfur), respectively. In order for production of low sulfur marine fuels via desulfurization, additional processes with hydrogen inputs are required. Due to limited information to perform simulations to estimate additional inputs and allocated emissions, we used a regression equation to estimate hydrogen inputs. McKetta [9] summarized hydrogen requirements for desulfurization of atmospheric tower bottoms, which shows desulfurizing 3.8% sulfur feed to 1.0%, 0.3%, and 0.1% require 497, 650, 725 scf/bbl, respectively. These can be converted into 0.245, 0.320, and 0.357 MJ H_2 for MJ of fuel production. With these and the baseline 3.8% sulfur fuel, we generated a regression equation (2nd order polynomial) among sulfur input, sulfur output, and hydrogen requirement (Figure 1). Estimated additional hydrogen requirements for HFO from 2.7% sulfur to 0.5% sulfur and 0.1% sulfur become 15,664 and 19,448 J H_2/MJ of fuel, respectively. Similarly, for MGO from 1.0% sulfur to 0.5% sulfur and 0.1% sulfur, hydrogen requirements are estimated at 4,325 and 8,109 J H_2/MJ of fuel, respectively. These hydrogen inputs were added along with other inputs for fuel production to estimate all upstream energy use and emissions. For MDO, we assumed it is a mixture of 50 vol.% HFO and 50 vol.% MGO; all related parameters were averaged between HFO and MGO on an energy input basis.

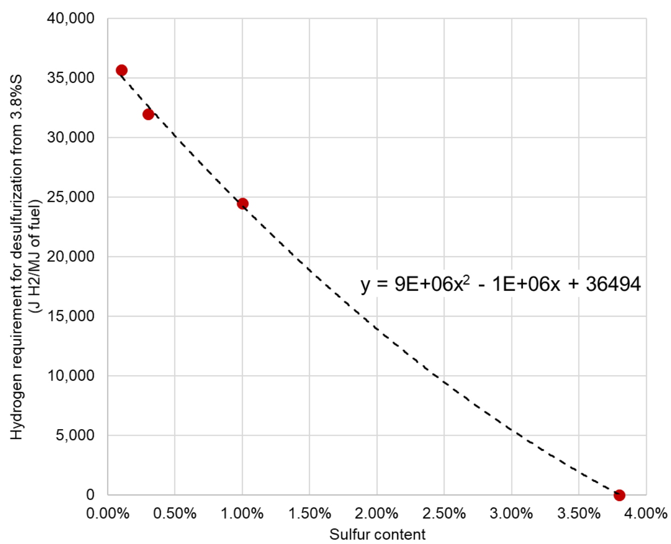


Figure 1. Hydrogen requirement for desulfurization from atmospheric tower bottoms with a sulfur content of 3.8%.

Production of Fischer-Tropsch Diesel

NREL developed FT-marine diesel production pathways using four feedstocks (biomass, NG, biomass/NG, and biomass/coal) through process models; life-cycle inventory (LCI) data is presented in Table 2 [10]. For two co-feeding pathways, biomass and fossil feedstocks are assumed to be fed 50%/50% by weight. Feedstocks are converted into syngas in a gasifier, which is then synthesized through FT catalytic conversion processes. Detailed process descriptions can be found in [10,11]. Through condensation and separation, various types of hydrocarbon fuels can be generated including marine/diesel fuels. In particular, FT hydrocarbon fuels have no sulfur content since fuel products are generated from syngas.

Table 2. Inputs and outputs of Fischer-Tropsch diesel production

		Feedstock			
	Units	Biomass	NG	Biomass +NG	Biomass +Coal
Energy inputs					
Woody residue	MJ	1.97	0	0.434	0.644
	dry g	108	0	23.8	35.3
Natural Gas	MJ	0.00	1.52	1.24	0
Coal	MJ	0.00	0	0	0.836
Diesel	J	1,528	924	1,245	1,535
Natural Gas (process fuel)	J	0.00	0.00	0.00	0.00
Hydrogen	J	0.00	0	0	563,589
Electricity	J	0.00	0	7	1
Water	L	0.173	0.058	0.055	0.348
Chemicals/Catalysts					
Magnesium Oxide (MgO)	mg	13.35	0.00	2.94	4.36
Olivine	mg	306.49	0.00	67.51	0.00
Tar Reformer Catalyst	mg	13.20	4.97	5.57	14.40
Zinc Oxide (ZnO) Catalyst	mg	3.44	1.96	2.24	1.92
FT Synthesis Catalyst (Co based)	mg	2.51	0.87	1.34	1.36
Hydrotreating Catalyst (sulfided CoMo or NiMo)	mg	3.24	1.84	2.58	2.65
LO-CAT Chemicals	mg	74.34	0.00	16.24	728.42
Amine Make-Up	mg	0.02	3.72	5.35	53.19
Boiler Chemicals	mg	0.41	0.24	0.11	2.74
Cooling Tower Chems	mg	2.49	0.97	1.12	1.59
Products					
Marine/Diesel	MJ	0.18	0.11	0.14	0.18
Jet	MJ	0.40	0.23	0.31	0.38
Naphtha	MJ	0.31	0.20	0.27	0.33
Wax	MJ	0.12	0.07	0.09	0.11
Hydrogen	MJ	0.00	0.40	0.19	0.00
Mass ratio					
Fossil	%	0%	100%	51%	51%
Biomass	%	100%	0%	49%	49%

Production of Pyrolysis Oil

LCI data for bio-oil production via fast pyrolysis process are estimated based on the process modeling and simulation performed at PNNL [12]. The bio-oil production is designed as a standalone process with a capacity of 2,000 dry metric tons per day. Woody biomass is sent to a dryer to reduce its moisture content from 30% to 10% before it is fed to a circulating fluidized bed pyrolyzer where hot sand is used as a heat carrier for endothermic fast pyrolysis reaction. Biomass is converted into a mixture of vapors and char within less than two seconds. The sand and char are subsequently separated from the vapors by a series of cyclones. The hot vapors are rapidly quenched in a two-stage system with previously condensed and cooled bio-oil and non-condensable gases are separated from the condensed bio-oil. In the first stage, most of the condensable products are removed using recirculated and indirect air-cooled bio-oil. The second stage operates at a lower temperature by indirect water cooling of the recirculating bio-oil. Most of the gases are recycled back to the pyrolysis reactor to assist fluidization. Char and a small portion of non-condensable gas are burned to heat the circulating sand. Hot flue gas from the char and gas burner is used to dry wet biomass. Two sets of LCI data are generated based on ash content (0.9% and 1.9% by weight) of the feedstock. The assumptions of this process design, product compositions, and product yields can be found in the previous study [12].

Table 3. Inputs and outputs of pyrolysis oil production using woody biomass

	Units	Low ash-feedstock case	High ash-feedstock case
Inputs			
Feedstock (Woody biomass)	MJ	1.49	1.61
	g	80.7	88.0
Electricity	J	31,062	42,788
Cooling tower chemicals	mg	0.128	0.137
Product			
Pyrolysis oil	MJ	1.00	1.00

Production of Renewable Diesel

Table 4 presents the LCI of renewable diesel production via hydroprocessed esters and fatty acids (HEFA) using yellow grease with and without HFO co-feed developed by NREL [10]. HEFA processes can generate diesel-like fuels from various types of oil feedstocks. Oil feedstocks are processed through hydrogenation, hydrocracking, and product separation processes. Hydrogen is mainly used for both hydrogenation and hydrocracking processes. Detailed process information can be found in the previous NREL studies [10,13].

Table 4. Inputs and outputs of renewable diesel production using yellow grease with and without HFO co-feed

	Units	Yellow grease	Yellow grease with HFO
Energy Inputs			
Feedstock (Yellow Grease)	MJ	1.21	0.51
	g	30.4	12.9
HFO (co-feed)	MJ	0.00	0.51
Hydrogen	J	77,146	50,835
Natural Gas	J	79,109	85,602
Electricity	J	11,193	8,467
Catalysts			
Hydrotreating catalyst	mg	3.17	2.97
Isomerization/Hydrocracking catalyst	mg	0.52	0.53
Water	L	0.21	0.20
Products			
Marine/Diesel	MJ	0.01	0.18
Jet	MJ	0.69	0.48
Gasoline	MJ	0.22	0.26
Propane	MJ	0.08	0.08

Emissions from Fuel Use

Among the fuel supply chain stages, combustion emissions contribute the most life-cycle emissions. Combustion emissions are dependent on fuel properties, engine characteristics, and control technologies [Billings personal communication][14][15]. Table 5 summarizes the emission factors used in this study and the corresponding data sources. It shows emission factors vary by engine types as well as fuel types. We include five major engine types (Slow-Speed Diesel [SSD], Medium-Speed Diesel [MSD], Steam Turbine [ST], Gas Turbine [GT], and LNG) and thee auxiliary engine types (MSD, High-Speed Diesel [HSD], and LNG). Due to strict regulations on NOx, the emission factors of NOx are highly dependent on regulations. SOx emissions are estimated based on sulfur content of fuels assuming 97.75% of sulfur is emitted as SOx and the rest (2.247%) becomes sulfate in PM10 emissions. The emission factors of PM10 in Table 5 represent base PM without considering PM from sulfur in marine fuels. Note that the emission factors of PM2.5 are calculated as 92% of those of PM10 [16]. CO_2 emissions are estimated based on carbon balance assuming all carbon in fuels are emitted as VOC, CO, CH_4, and CO_2. Due to limited information for the emission factors of other fuels (diesel, SVO, and pyrolysis oil), we used the same emission factors of MGO/MDO. The emission factors of LNG show that overall LNG vessels would generate lower CAP emissions compared to petroleum-based fuels except for CH_4 emissions (CH_4 slip) [15].

Table 5. Emission factors (g/kWh operation)

<table>
<tr><th colspan="2" rowspan="2"></th><th rowspan="2">Emission Regulation Tier</th><th colspan="5">Main engine</th><th colspan="3">Aux. engine</th></tr>
<tr><th>SSD</th><th>MSD</th><th>ST</th><th>GT</th><th>LNG</th><th>MSD</th><th>HSD</th><th>LNG</th></tr>
<tr><td colspan="2">VOC (HC)[a]</td><td>-</td><td>0.6</td><td>0.5</td><td>0.1</td><td>0.1</td><td>0.5</td><td>0.4</td><td>0.4</td><td>0</td></tr>
<tr><td colspan="2">CO[a]</td><td>-</td><td>1.4</td><td>1.1</td><td>0.2</td><td>0.2</td><td>1.30</td><td>1.1</td><td>0.9</td><td>1.3</td></tr>
<tr><td rowspan="9">NOx</td><td rowspan="4">HFO[a]</td><td>0</td><td>18.1</td><td>14</td><td rowspan="4">2.1</td><td rowspan="4">6.1</td><td rowspan="8">-</td><td>14.7</td><td>11.6</td><td rowspan="8">-</td></tr>
<tr><td>1</td><td>17</td><td>13</td><td>13</td><td>10.4</td></tr>
<tr><td>2</td><td>15.3</td><td>11.2</td><td>11.2</td><td>8.2</td></tr>
<tr><td>3</td><td>3.4</td><td>2.6</td><td>2</td><td>2.6</td></tr>
<tr><td rowspan="4">MGO/MDO[a]</td><td>0</td><td>17</td><td>13.2</td><td rowspan="4">2.0</td><td rowspan="4">5.7</td><td>10.9</td><td>13.8</td></tr>
<tr><td>1</td><td>16</td><td>12.2</td><td>9.8</td><td>12.2</td></tr>
<tr><td>2</td><td>14.4</td><td>10.5</td><td>7.7</td><td>10.5</td></tr>
<tr><td>3</td><td>3.4</td><td>2.6</td><td>2</td><td>2.6</td></tr>
<tr><td>LNG[c]</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>1.82</td><td>-</td><td>-</td><td>1.82</td></tr>
<tr><td rowspan="3">PM10 *</td><td>HFO[a]</td><td>-</td><td>0.576</td><td>0.576</td><td>0.93</td><td>0.06</td><td>-</td><td>0.576</td><td>0.576</td><td>-</td></tr>
<tr><td>MGO/MDO[a]</td><td>-</td><td>0.155</td><td>0.155</td><td>0.16</td><td>0.01</td><td>-</td><td>0.155</td><td>0.155</td><td>-</td></tr>
<tr><td>LNG[c]</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>0.04</td><td>-</td><td>-</td><td>0.04</td></tr>
<tr><td rowspan="2">CH_4</td><td>HFO/MDO [b]</td><td>-</td><td>0.012</td><td>0.01</td><td>0.002</td><td>0.002</td><td>-</td><td>0.008</td><td>0.008</td><td></td></tr>
<tr><td>LNG[c]</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>5.05</td><td>0.008</td><td>0.008</td><td>5.05</td></tr>
<tr><td rowspan="2">N_2O[b]</td><td>HFO/MDO [b]</td><td>-</td><td>0.031</td><td>0.034</td><td>0.049</td><td>0.049</td><td></td><td>0.036</td><td>0.036</td><td>-</td></tr>
<tr><td>LNG[c]</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>0.015</td><td>-</td><td>-</td><td>0.015</td></tr>
</table>

SSD: Slow-Speed Diesel, MSD: Medium-Speed Diesel, ST: Steam Turbine, GT: Gas Turbine, HSD: High-Speed Diesel

* PM10 does not include PM converted from sulfur. It is estimated that 2.247% of sulfur in fuels is converted into additional PM10.

References: [a] Billings [personal communication], [b] IMO 2014 [14], [c] Thomson et al. [15]

Fuel Consumption

Marine fuel consumption presented as brake-specific fuel consumption (BSFC) or specific fuel oil consumption (SFOC) also varies by fuel and engine types. The information is important to estimate the energy use for a trip. Additionally, since SOx and CO_2 emissions are estimated based on sulfur and carbon balances, respectively, fuel consumption values are used to estimate SOx and CO_2 emissions. We used SFOC data from the IMO 2014 report [14] (Table 6). The fuel consumption values (g fuel/kWh operation) of MGO/MDO were converted into energy consumption (Btu/kWh operation); the same energy consumption values are used for diesel fuels.

Table 6. Specific fuel oil consumption by engine and fuel types (g fuels/kWh operation) [14]

Main engine		HFO	MGO/MDO	LNG
	SSD	195.0	185.0	
	MSD	215.0	205.0	
	ST	305.0	300.0	
	GT	305.0	300.0	
	LNG			166.0
Aux engine		HFO	MGO/MDO	
	HSD	227.0	217.0	
	MSD	227.0	217.0	
	LNG			166.0

Trip Characteristics

Various marine vessels are operated to serve different purposes, which incurs different trip profiles. In order to evaluate the WTH emissions of trips, vessel types and corresponding trip characteristics should be defined. Adom et al. [2] characterized trips for three vessel types (bulk, container-large, and tanker VLCC [Very Large Crude Carriers]) in different regions (Pacific, Atlantic, Gulf of Mexico, Great Lakes, and California waters). The trips consist of several segments (hotel, reduced-speed zones [RSZ], cruise), and trip information such as distance, speed, time in mode, load factor, and payload for each segment were characterized [2]. In this study, we used the trip information by Adom et al. [2] to evaluate the WTH GHG and CAP emissions for each trip. Note that we can select different fuels for each trip segment in GREET, which is useful to manage emission profiles.

Results and Discussion

Life-cycle GHG and CAP Emissions

Figure 2 presents life-cycle GHG emissions of 19 cases, which include feedstock production and transportation (feedstock), fuel production and fuel transportation (conversion), and fuel use (combustion); for biomass-derived fuels, biogenic carbon uptake emissions are considered as emission credits. The sum of these stages becomes WTH GHG emissions. The functional unit is MJ of marine fuel produced and utilized, and the values in Figure 2 present relative differences compared to the baseline HFO (2.7% sulfur). All diesel results are based on emission factors of MSD with NOx regulations for Tier 3, while results can be generated using emission factors of other engine types.

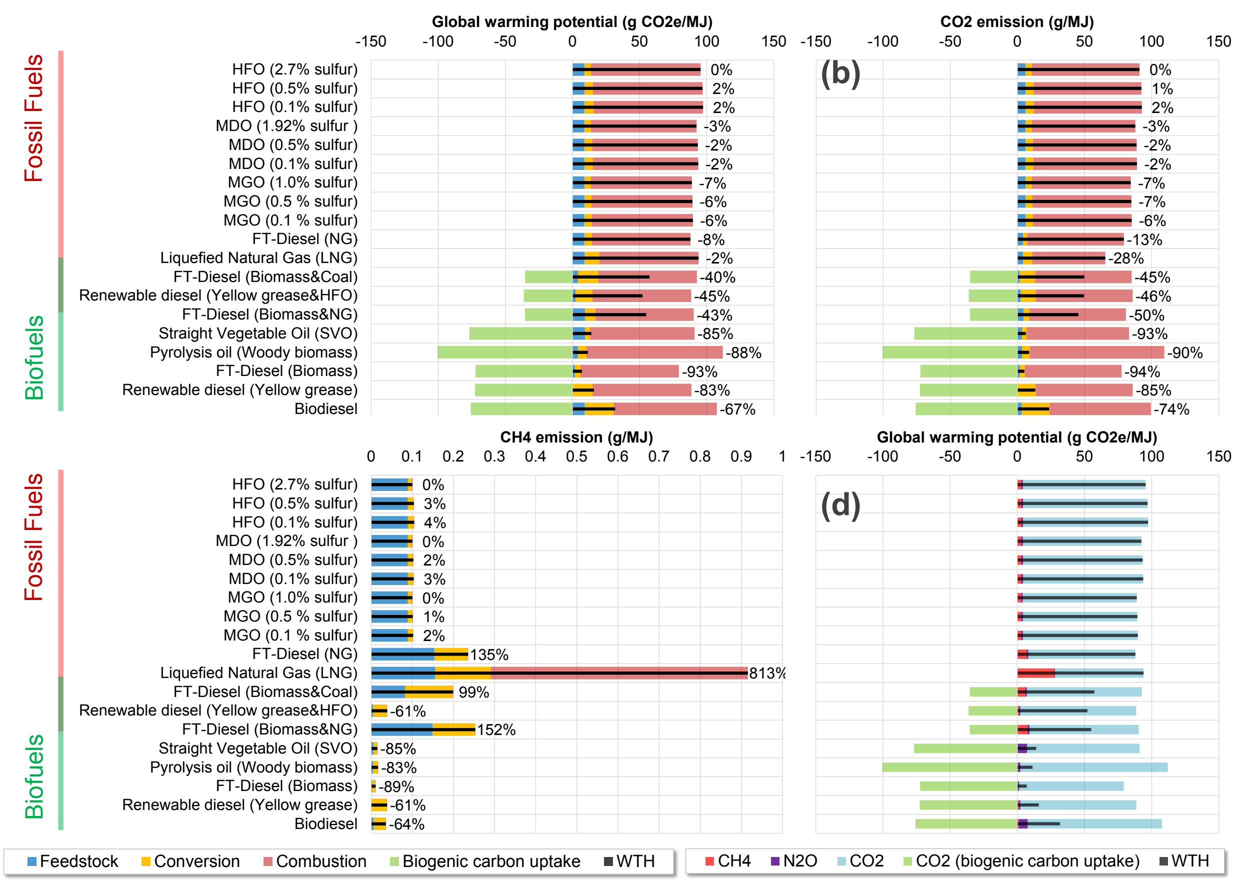


Figure 2. WTH GHG emissions of marine fuels pathways. The numbers present emissions relative to baseline (HFO 2.7% sulfur) emissions. MSD engines. MSD engines under IMO emission regulation tier of three are assumed to be used.

First, WTH GHG emissions of the baseline HFO (2.7% sulfur) and MGO (1.0% sulfur) are estimated at 95.5 and 88.9 gCO_2/MJ, respectively, and combustion emissions take around 85% of total WTH GHG emissions. Low sulfur petroleum-derived marine fuels have slightly higher WTH GHG emissions due to additional hydrogen inputs. HFO (1.0% sulfur) and MGO (1.0% sulfur) have WTH GHG emissions of 97.3 and 89.7 gCO_2e/MJ, respectively, which are 1.9% and 0.9% higher compared to those of HFO (2.7% sulfur) and MGO (1.0% sulfur).

Fuel combustion emissions are dependent on carbon contents which do not show significant variations (except for pyrolysis oil with very low heating value [Table A1]); main differences in WTH emissions are from other factors such as emissions during fuel production, biogenic carbon contents, and CH_4 leakages. For NG uses, Figure 2c shows corresponding pathways (LNG and FTD using NG) involve significantly higher CH_4 emissions compared to other pathways. Due to CH_4's high GWP, CH_4 emissions magnify the overall WTH GHG emissions. In particular, LNG involves significantly high CH_4 emissions throughout its supply chain. While WTH CO_2 emissions of the LNG pathway is estimated at 65.4 g/MJ, which is 28.0% lower than HFO (2.7% sulfur), WTH GHG emissions are 94.0 gCO_2e/MJ, similar to those of HFO (2.7% sulfur) due to contribution of CH_4 emissions (Figure 2d); only 0.916 g CH_4/MJ contributes 29.2% of its WTH GHG emissions. In particular, CH_4 slip during downstream combustion significantly influences LNG's WTH GHG emissions [15].

Fuels from biomass have significantly lower WTH GHG emissions mainly due to their biogenic carbon credits. Depending on the share of biogenic carbon, emission reduction rates vary. For example, marine fuel production using both fossil and biomass feedstocks (50% and 50% by weight), WTH GHG emission reductions in GHG emissions compared to HFO (2.7% sulfur) are estimated at 40–45%. Biofuels produced from 100% biomass have much higher reductions in GHG emissions (67–93%).

Figure 3 presents major WTH CAP emissions (SOx, NOx, $PM_{2.5}$, and CO), which shows that the combustion stage is dominant for CAP emissions. SOx emissions are dependent on sulfur contents in marine fuels; thus, desulfurization reduces life-cycle SOx emissions significantly (Figure 3a) while slightly increases WTH GHG emissions (Figure 2a). The baseline HFO (2.7% sulfur) has WTH SOx emissions of 1.35 g/MJ, and low sulfur HFOs with 0.5% and 0.1% have WTH SOx emissions of 0.26 and 0.06 g/MJ, respectively, which are 81% and 95% lower than the baseline HFO, respectively. MGO (1.0% sulfur) has SOx emissions of 0.47 g/MJ, and this can be reduced to 0.24 and 0.06 g/MJ through desulfurization to 0.5% and 0.1%, respectively. Biomass-derived fuels are mostly free of sulfur leading to significant reductions in SOx emissions (97–100%) except for renewable diesel from yellow grease with HFO inputs (1.51% sulfur) because of sulfur from HFO. PM emissions mainly consist of base PM and PM derived from sulfur. For NOx and CO emissions, all fuels are within a relatively narrow boundary, except for LNG. LNG shows 25% lower NOx emissions and 28% higher CO emissions. Note that the results may vary depending on the types of engines and emission regulation tiers.

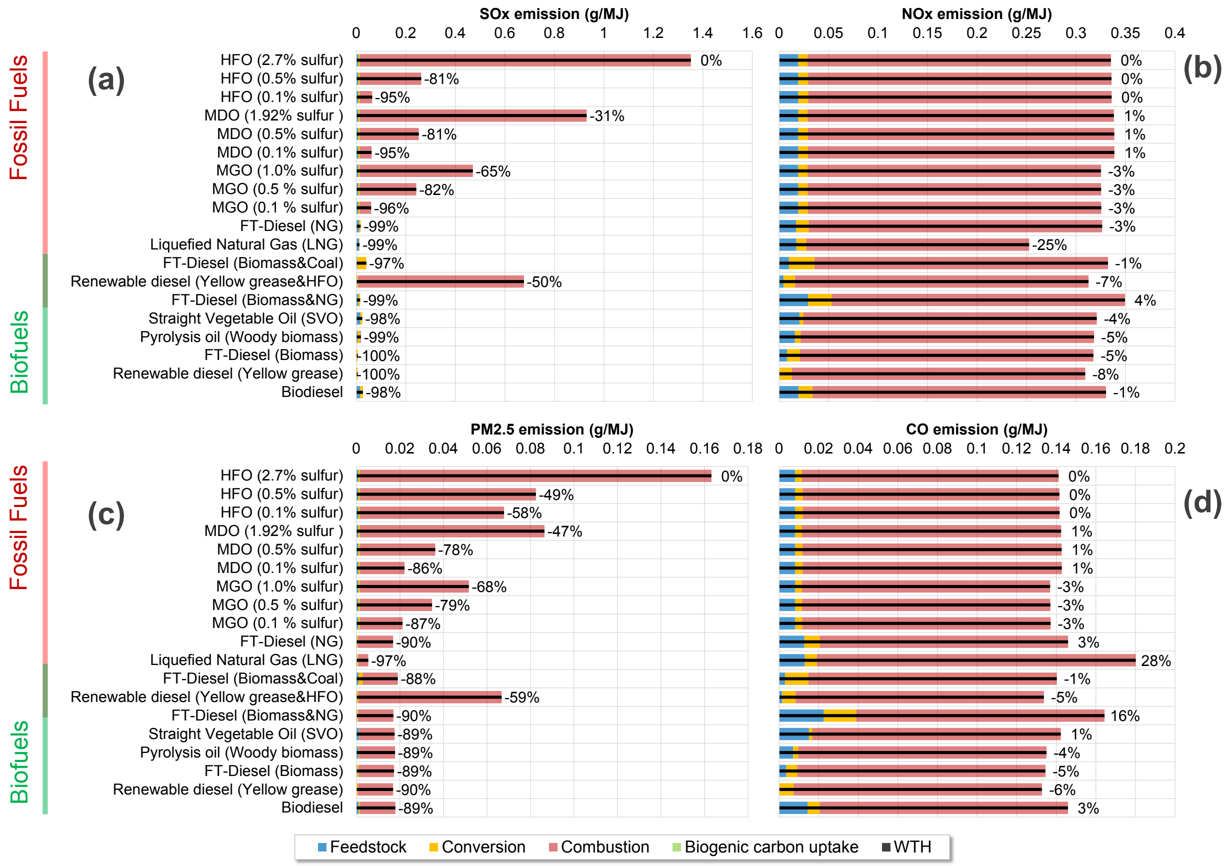
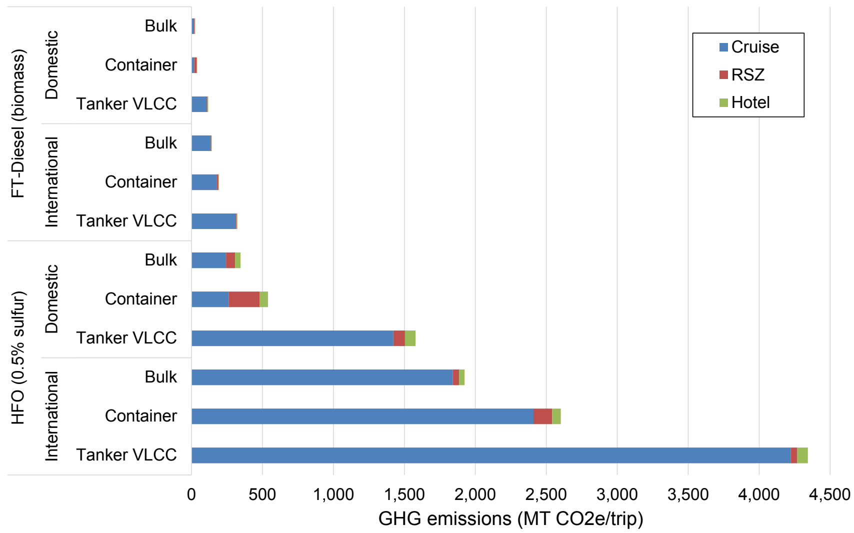
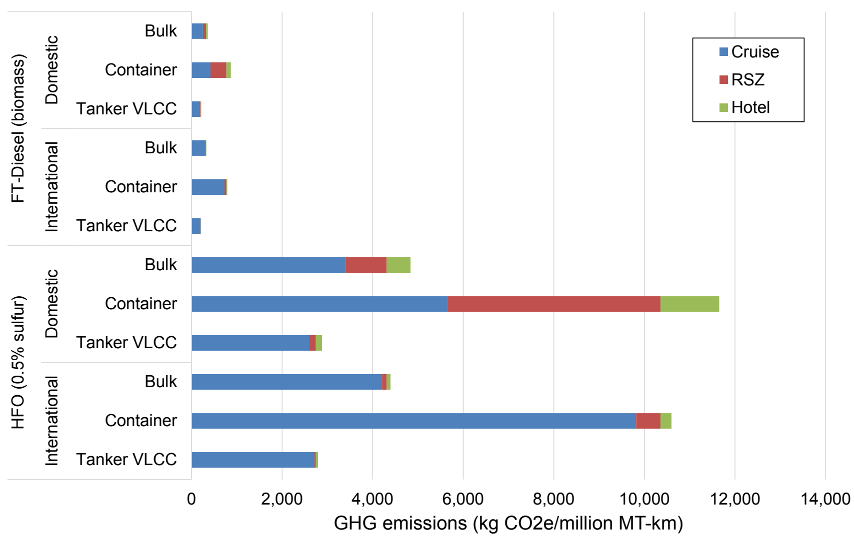


Figure 3. WTH CAP emissions. The numbers present emissions relative to baseline (HFO 2.7% sulfur) emissions. MSD engines under IMO emission regulation tier of three are assumed to be used.

WTH GHG emissions of trips vary by the types of marine vessels and corresponding trip characteristics as well as fuel types (Figure 4). Here, domestic and international trips of three types of marine vessels in Pacific using two different fuels (FT-marine diesel [biomass] and HFO [0.5% sulfur]) are presented as an example. More detailed analyses are available using GREET by setting trip parameters and fuel types for each trip segment. Due to its low carbon intensity (g CO_2/MJ), FT-diesel (biomass) generates much lower GHG emissions for the same trip conditions as expected. However, trip characteristics results in significant differences in WTH GHG emission results mainly due to the differences in fuel consumption (operation hours). When it comes to million MT-km results, tanker VLCC emissions become smaller mainly due to its high payload and longer distance compared to others.



a)



b)

Figure 4. WTH GHG emissions (per trip and per million MT-km) for example trip conditions using FT-marine diesel (biomass) and HFO (0.5% sulfur). Three marine vessel types for domestic and international trips in Pacific are presented.

Variations in WTH CAP emissions depending on vessel types and trip characteristics are presented in Figure 5.

Figure 5. WTH GHG and CAP emissions for example trip conditions using FT-marine diesel. These are for three marine vessel types (bulk, tanker, and container) for two trip conditions in Pacific (domestic and international). The numbers presented right hand side of each chart represent total emissions during the trip.

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Appendix A

Table A1. Fuel Specifications

	Units	HFO (2.7% sulfur)	HFO (0.5% sulfur)	HFO (0.1% sulfur)	MDO (1.92% sulfur)	MDO (0.5% sulfur)	MDO (0.1% sulfur)	MGO (1.0% sulfur)	MGO (0.5 % sulfur)	MGO (0.1 % sulfur)
Lower heating value	MJ/kg	39.5	39.5	39.5	41.0	41.0	41.0	42.8	42.8	42.8
Density	kg/L	0.99	1.0	1.0	0.91	0.91	0.91	0.84	0.84	0.84
C ratio	% by wt.	87	90	90	87	87	87	87	87	87
S ratio	% by wt.	2.70	0.50	0.10	1.92	0.50	0.10	1.00	0.50	0.10
Biogenic carbon share	% by wt.	0%	0%	0%	0%	0%	0%	0%	0%	0%

	Units	FT-Diesel (NG)	Liquefied Natural Gas (LNG)	FT-Diesel (Biomass&Coal)	Renewable diesel (Yellow grease&HFO)	FT-Diesel (Biomass&NG)	Straight Vegetable Oil (SVO)	Pyrolysis oil (Woody biomass)	FT-Diesel (Biomass)	Renewable diesel (Yellow grease)	Biodiesel
Lower heating value	MJ/kg	43.2	48.63	43.2	44.0	43.2	37.2	15	43.2	44.0	37.5
Density	kg/L	0.8	0.43	0.8	0.78	0.8			0.80	0.78	0.89
C ratio	% by wt.	90	75	90	87	90	78	41	85	87	78
S ratio	% by wt.	0.00	0.00	0.00	1.51	0.00	0.00	0.00	0.00	0.00	0.00
Biogenic carbon share	% by wt.	0%	0%	49%	50%	49%	100%	100%	100%	100%	100%