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# Life cycle assessment of e-/bio- methanol and e-/grey-/blue- ammonia for maritime transport



Conducted by IFP Energies Nouvelles,  
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<b>Title</b>	<b>Life Cycle Assessment of E-/Bio- Methanol and E-/Grey-/Blue- Ammonia for Maritime Transport</b>
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### Executive Summary

In response to the increasing need for maritime decarbonisation illustrated by the ambitious 2050 net-zero greenhouse gases (GHG) emissions targets set by the International Maritime Organization (IMO) and EU regulations, this Life Cycle Assessment (LCA), commissioned by CMA CGM, evaluates the greenhouse gas emissions of alternative marine fuels, focusing on methanol and ammonia. These fuels are assessed across multiple production pathways as follows, to determine real-world emissions performance and compliance with regulatory frameworks:

- E-methanol: Produced from renewable hydrogen (electrolysis) and captured CO<sub>2</sub> (from flue gases or direct air capture).
- Bio-methanol: Derived from biomass gasification, using waste wood or cultivated wood as feedstock.
- E-ammonia: Synthesized from renewable hydrogen (electrolysis) and nitrogen from the air via the Haber-Bosch process.
- Blue ammonia: Produced using hydrogen from natural gas reforming (SMR or ATR), with carbon capture and storage (CCS) applied.
- And VLSFO (Very Low Sulphur Fuel Oil), for the sake of having a comparison with a fossil-based fuel.

### Methodology and Scope

This study provides a comprehensive assessment of alternative marine fuels, focusing on the role of electricity source variations, transport distances, and regulatory frameworks in determining their true decarbonization potential. The LCA assesses 17 production regions, each with different electricity grid intensities, transport distances to bunkering ports, and fuel conditioning requirements. It also includes prospective analyses for 2035 and 2050, incorporating global energy decarbonization trends and evolving regulatory landscapes. This provides a robust, data-driven evaluation of the decarbonisation potential of methanol and ammonia-based fuels for maritime transport. The study evaluates:

- Variations in local electricity grid mix, reflecting the carbon intensity of national energy grids and their impact on fuel production emissions.
- Renewable electricity following the RED methodology, which assumes zero emissions from renewable sources, aligning with regulatory accounting methodologies.
- Full cradle-to-grave (CTG) accounting, incorporating the emissions from renewable energy infrastructure, offering a more comprehensive decarbonisation assessment.
- Carbon capture processes, including flue gas capture (industrial sources) and Direct Air Capture (DAC), which has higher energy demands.

### From Fuel Unit to Container Transportation Unit Life Cycle Assessment: A Holistic approach from Busan to Rotterdam

To ensure a realistic evaluation of emissions performance in container transport operations, the study employs a state-of-the-art LCA methodology that goes beyond the traditional per-MJ Fuel Well-to-Wake (WtW) assessment to a per-TEU.km (Twenty-Foot-Equivalent = 1 (small) container) approach. This enables a more accurate comparison between fuels by incorporating real-world vessel performance metrics.

The analysis considers two primary functional units:

- Well-to-Wake (WtW) emissions per unit of fuel energy (gCO<sub>2</sub>eq/MJ), both with and without renewable energy infrastructure emissions.
- Well-to-Wake (WtW) emissions per container transport work (gCO<sub>2</sub>eq/TEU.km), accounting for engine efficiency, pilot fuel requirements, and cargo capacity constraints, to ensure a realistic representation of the energy conversion efficiency of these fuels.
- To reflect real-world deep-sea shipping conditions, the study models a 23,000 TEU CMA CGM container vessel operating on a typical trade route between Busan (South Korea) and Rotterdam (Netherlands). The fuel pathways are evaluated using:
  - Engine data from test bed results for methanol engines, which are already operational, and therefore with a good level of certainty.
  - Manufacturer simulations for ammonia engines, still under development, and therefore with relatively higher level of uncertainty.

## Key Findings

### E-Methanol

- Average fuel WtW emissions per MJ for e-methanol across 17 locations, *assuming fully powered by renewable energy with cradle-to-grave emissions, carbon captured from flue gases in up to 2035 and from Direct Air Capture in 2050*, are  $16 \pm 4$  gCO<sub>2</sub>eq/MJ (2025),  $12 \pm 3$  gCO<sub>2</sub>eq/MJ (2035) and  $5 \pm 1$  (2050) [with  $\pm$  values representing mean absolute deviation]. (Figure 1)
- Average fuel WtW emissions per MJ for e-methanol across 17 locations, *assuming carbon capture is powered by natural gas and auxiliary processes are powered by local electricity*, are  $26 \pm 7$  gCO<sub>2</sub>eq/MJ (2025),  $14 \pm 4$  gCO<sub>2</sub>eq/MJ (2035) and  $7 \pm 1$  (2050). Under this configuration, these emissions meet the 70% reduction threshold for RFNBO compliance under RED only from 2035 onwards. (Figure 1)
- In container unit transportation WtW GHG emissions (gCO<sub>2</sub>eq/TEU.km), e-methanol is fit for decarbonisation, achieving an average 70% reduction (range 60-80%) compared to VLSFO. However, it relies on the availability of biogenic CO<sub>2</sub> and its capture, which may present logistical and scalability challenges.

### Bio-methanol

- Supply chain for waste wood and gasification efficiency losses are the most important contributors.
- RED compliance is met in all regions reaching (~95% GHG reduction)
- In container unit transportation WtW GHG emissions (gCO<sub>2</sub>eq/TEU.km), bio-methanol is fit for decarbonisation and offers the highest reduction potential. It achieves on average 80% lower WtW emissions (range 75-85%) compared to VLSFO, provided that sustainable biomass feedstocks are used. Transporting finished bio-methanol rather than raw biomass significantly reduces emissions. (Figure 3)

### E-Ammonia

- Average WtW emissions per MJ for e-ammonia across 17 locations, *assuming fully powered by renewable electricity with cradle-to-grave emissions*, are  $17 \pm 4$  gCO<sub>2</sub>eq/MJ (2025),  $12 \pm 3$  gCO<sub>2</sub>eq/MJ (2035) and  $5 \pm 1$  (2050). These emissions meet the 70% reduction threshold for RFNBO compliance under RED from 2025 onwards. (Figure 2)
- In container unit transportation WtW GHG emissions (gCO<sub>2</sub>eq/TEU.km), e-ammonia achieves an average 50% reduction (range 35-85%) compared to VLSFO. While fit for decarbonization, its effectiveness is currently constrained by lower engine efficiency, high pilot fuel needs, and N<sub>2</sub>O emissions. As this technology is still in its early stages and rapidly evolving, these findings are subject to significant uncertainties, therefore conclusions should be considered with caution and not considered as definitive.

Further research and vessel design optimization are required to improve performance and reduce uncertainties. (Figure 3)

### Blue Ammonia

- Average WtW emissions per MJ for blue-ammonia across 17 locations, *assuming a natural gas-powered Steam Methane Reforming unit with MEA carbon capture and storage up to 2035, and a natural gas-powered Auto Thermal Reforming Unit with VPSA carbon capture and storage in 2050*, are  $83 \pm 12$  gCO<sub>2</sub>eq/MJ (2025),  $61 \pm 6$  gCO<sub>2</sub>eq/MJ (2035) and  $29 \pm 4$  (2050). These emission levels fail to meet the 70% reduction threshold for LCF (Low-Carbon Fuels) compliance under the Gas Directive in both 2025 and 2035, mainly due to methane and CO<sub>2</sub> emissions associated with the natural gas supply chain and the process used to produce blue hydrogen. Even under optimistic scenarios with reduced upstream blue hydrogen emissions, it only meets the 70% reduction threshold in 6 out of 17 regions by 2050. (Figure 2)
- In container unit transportation WtW GHG emissions (gCO<sub>2</sub>eq/TEU.km), blue ammonia achieves on average slightly higher emissions than those of VLSFO. Hence, blue ammonia is not currently a viable decarbonisation option. (Figure 3). However, under specific conditions—such as optimized upstream blue hydrogen production using ATR technology—it may serve as a transitional solution until e-ammonia production scales up. However, such conditions were only considered to become widely adopted in 2050 for this study.

### Impact of Production Region and Transport

- The proximity of fuel production to the bunkering location significantly affects total emissions. Transporting fuels over long distances (e.g., from remote renewable energy hubs to Europe) adds substantial emissions that can impact RFNBO / LCF / biofuels compliance.
- Electricity grid mix is a critical factor for both e-methanol and e-ammonia. Countries with high shares of renewables or low-carbon power (e.g., France, Canada) obtain significantly lower WtW emissions compared to regions reliant on fossil-fuel-based electricity (e.g., India, South Africa).
- The use of e-ammonia and e- or bio-methanol as fuel for their own transport (expected by 2050) will reduce transport-related emissions, making geographical differences in emissions less pronounced over time.

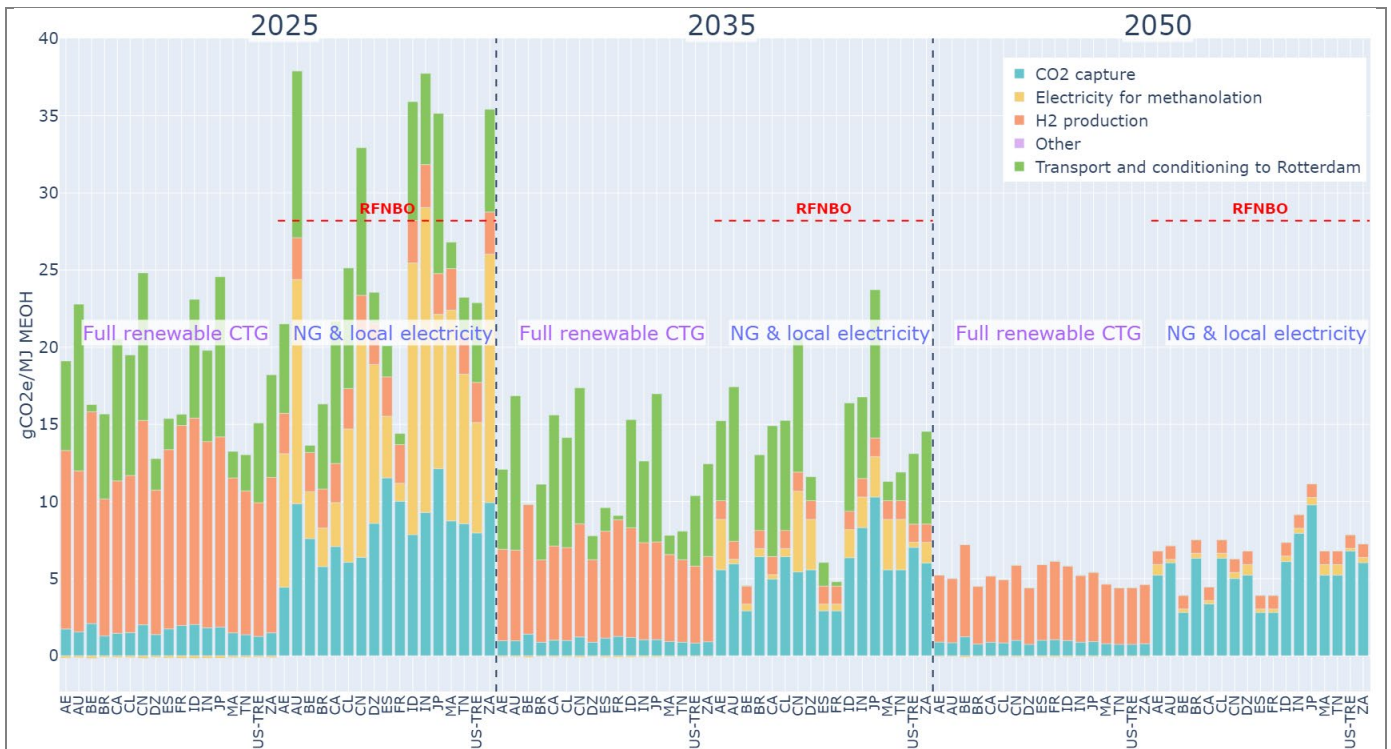
### Regulatory and Prospective Insights

- Using the RED-compliant methodology, e-fuels derived from green hydrogen show a ~90% GHG reduction potential compared to the fossil reference. However, this approach does not account for emissions from renewable energy infrastructure, leading to over-optimistic estimates.
- Under full cradle-to-gate accounting, including emissions from renewable energy infrastructure, e-fuels can still achieve ~80% reduction. While the 70% RFNBO threshold does not technically account for these emissions, the results demonstrate that the assessed e-fuels remain compliant even when they are considered.
- GHG emissions are projected to decline further due to global grids decarbonization, improved electrolyser efficiency, and better transport logistics.

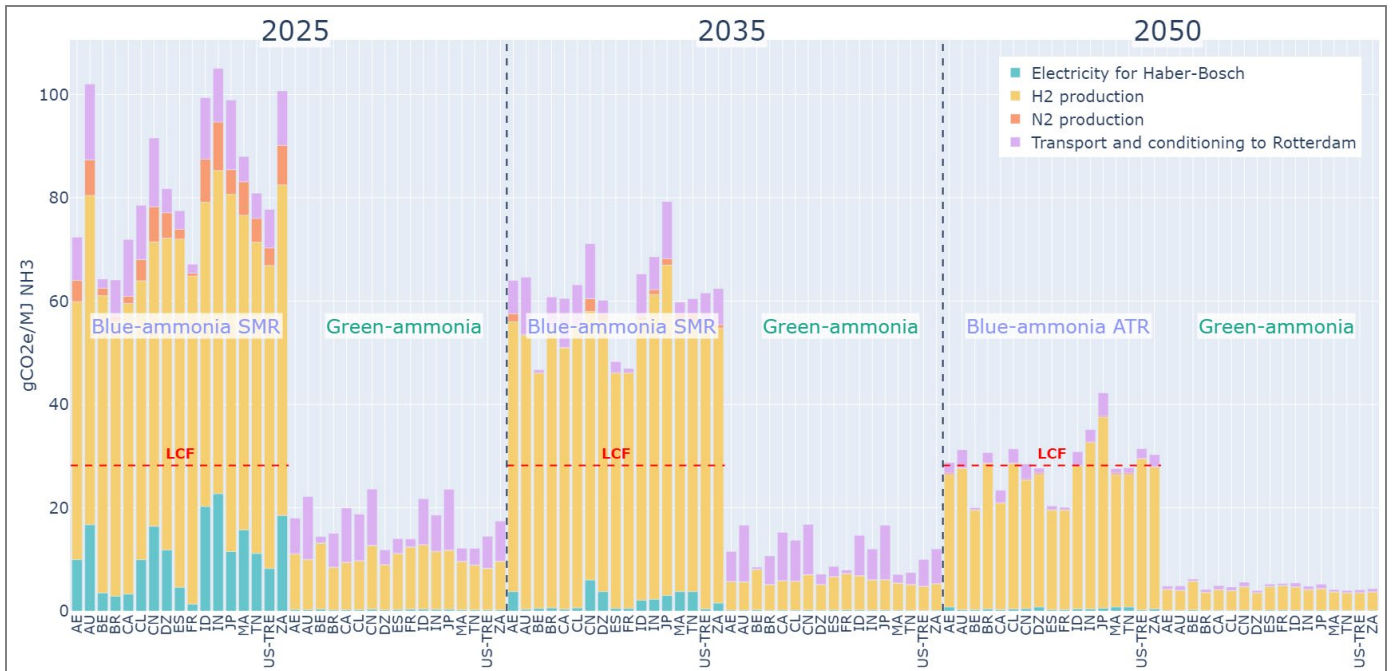
### Final considerations

This LCA provides an advanced and comprehensive assessment of the decarbonization potential of methanol and ammonia for maritime transport. While e-methanol and bio-methanol offer the highest reduction potential, e-ammonia offers decarbonization benefits but requires further technological development to address efficiency, pilot fuel use, and N<sub>2</sub>O emissions. Blue ammonia remains unsuitable for deep decarbonization unless substantial improvements in methane emissions control and carbon capture technology are realized. Strategic decisions in the broader shipping industry must account not only for regulatory compliance but also for the full life-cycle emissions and the feasibility of adopting alternative fuels.

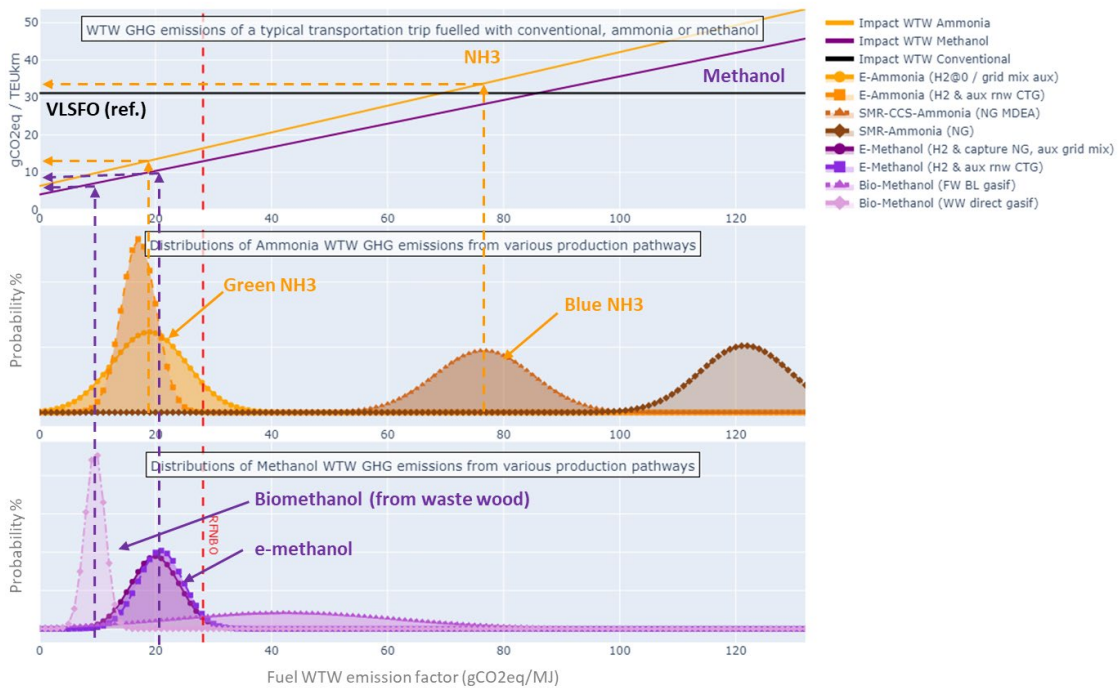




**Figure 1:** Projected Greenhouse Gas Fuel Emissions for E-Methanol (Well-to-Wake, g CO<sub>2</sub>-eq/MJ) in 2025, 2035, and 2050 under the “REMIND - SSP2 – NDC” scenario configuration. The graph compares the GHG emissions (y-axis) from Well-to-Wake in different production regions (x-axis) of different e-methanol production scenarios: “Full renewable CTG” e-methanol, a scenario where renewable energy, accounted for from a cradle-to-grave (CTG) emissions scope, is used to power both hydrogen production and carbon capture processes. And “NG & local electricity” e-methanol: a scenario where renewable electricity is used for hydrogen production and accounted for from a “Operation & Maintenance” scope of accounting (following EU Renewable Energy Directive methodology), with carbon capture powered by natural gas and auxiliary processes powered by local electricity grid mix. Both scenarios include a transport and conditioning step to Rotterdam. Only the second scenario “NG & local electricity” e-methanol is comparable to the RFNBO reference since the “Full renewable CTG” e-methanol accounts for a broader scope than the one defined in the EU RED methodology.



**Figure 2:** Projected Greenhouse Gas Fuel Emissions for E-Ammonia and Blue Ammonia (Well-to-Wake, g CO<sub>2</sub>-eq/MJ) in 2025, 2035, and 2050 under the “REMIND - SSP2 – NDC” scenario configuration. The graph compares the GHG emissions (y-axis) from Well-to-Wake in different production regions (x-axis) of different ammonia production scenarios: “Green-ammonia”, a scenario where renewable energy, accounted from a cradle-to-grave (CTG) emissions scope, is used for hydrogen and N<sub>2</sub> production and auxiliary consumptions. And “Blue Ammonia SMR/ATR”, a scenario where ammonia is synthesised from hydrogen from natural gas methane reforming using carbon capture technology and N<sub>2</sub> production and auxiliary consumptions are powered by local electricity grid mix. Both scenarios include a transport and conditioning step to Rotterdam. The “Blue ammonia” scenario is comparable to the LCF reference. The “Green-ammonia” scenario cannot be compared to the RFNBO reference since it is calculated accounting the CTG scope of emissions, a broader scope than the one defined in the EU RED methodology.



**Figure 3:** GHG Emissions from Transport Using Methanol or Ammonia – Relationship Between Fuel Well-to-Wake (WtW) GHG Intensity and Container Unit Transportation WtW GHG Intensity. The first graph presents fuel GHG intensity versus transportation work associated emissions, while the second and third graphs illustrate scenario sensitivity distributions for ammonia (NH<sub>3</sub>) and methanol (MeOH), respectively. These distribution curves are derived from a global sensitivity analysis conducted using Monte Carlo simulations. The results are approximated as normal distributions, using mean values and standard deviations, to represent the most probable range of GHG emissions for each assessed fuel based on the defined parameter variations.

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## Glossary

Abbreviation	Full name
LCA	Life Cycle Assessment
CII	Carbon Intensity Indicator
CO <sub>2</sub> (eq)	CO <sub>2</sub> equivalent unit, also noted CO <sub>2</sub> eq
CTG	Cradle-to-Grave scope
DAC	Direct Air Capture
ETS	Emissions Trading System
GSA	Global Sensitivity Analysis
GHG	Greenhouse Gases
IMO	International Maritime Organization
NG	Natural gas
OM	Operation and Maintenance scope
RED	Renewable Energy Directive
RFNBO	Renewable Fuel of Non-Biological Origin
MDO	Marine Diesel Oil
TEU	TEU means Twenty-foot Equivalent Unit in English. Its equivalent in French is EVP, Equivalent Vingt Pieds, 1 EVP corresponds to 1 container of 20 feet long (approximately 6.096 meters), 8 feet wide (2.438 m) and 9.5 feet high (approximately 2.7 m).
VSLFO	Very Low Sulphur Fuel Oil, ISO 8217
HFO	Heavy Fuel Oil
MDO	Marine Diesel Oil, ISO 8217
WtT	Well-to-Tank, also noted WTT
TtW	Tank-to-Wake, also noted TTW
WtW	Well-to-Wake, also noted WTW
SOEC	Solid Oxide Electrolyzer Cell: stack of electrochemical cells in ceramic, site of the reaction producing hydrogen and oxygen from steam, operating at 700°C.
VPSA	Vacuum Pressure Swing Adsorption
MDEA	Methyldiethanolamine
GT	Gross Tonnage, ship transportation capacity measure



# 1 Introduction

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Following the commitments made at COP21 to limit global warming to below 2°C, most countries are tightening their positions on CO<sub>2</sub> emissions and implementing proactive policies to reduce greenhouse gas (GHG) emissions despite a continuously increasing global energy demand. The European Union, through its "Green Deal," aims to make Europe the first carbon-neutral continent by 2050. In France, the Climate Plan also aims to develop a green economy without fossil energy to achieve carbon neutrality by 2050. In this context, the transport sector, a significant contributor to greenhouse gas emissions, must significantly reduce its CO<sub>2</sub> emissions and improve its energy efficiency while continuing efforts on local pollutant emissions, primarily in urban areas for road transport.

Maritime transport faces the same challenges as road transport, although it emits less per tonne.km or per passenger.km transported. Regulations on atmospheric pollutant emissions are tightening, and GHG emission reduction targets are also being set. As in other sectors, the two levers to achieve these objectives are (1) improving the energy efficiency of ship propulsion technologies and (2) using low-carbon fuels while respecting the economic constraints specific to maritime transport.

More specifically, this study is set in the context of new requirements regarding GHG emissions from ships, which came into effect on January 1, 2023, with the application of the International Maritime Organisation (IMO) 2023 standard, as well as new European regulations such as Fuel EU Maritime, which will begin to apply in 2025, and the inclusion of shipping in the EU Emissions Trading System (EU ETS). The IMO stipulates that ships must implement new equipment to immediately reduce their carbon intensity by 2023. This includes, for example, power limiters. From an "operational" perspective, each ship will be assigned an individual carbon intensity rating (CII, for Carbon Intensity Indicator) each year. This rating will be calculated on the basis of the previous year's performance and against thresholds that will be further lowered each year. The first rating will therefore arrive in 2024. Ships with the lowest rating will have to implement a corrective action plan. These measures may involve adjusting the ship's speed or changing fuels.

In response to the significant environmental challenges facing the shipping industry, CMA CGM has commissioned this Life Cycle Assessment (LCA) study to assess the environmental impact of alternative fuels and develop a forward-looking strategy for decarbonizing its container fleet. The study evaluates the life cycle emissions of two promising alternative fuels—methanol and ammonia—as potential substitutes for conventional fossil fuels.

Methanol (CH<sub>3</sub>OH) is a well-known industrial fuel with a relatively high energy density, remaining liquid at room temperature, which simplifies storage and handling. It can be blended into gasoline for existing automotive engines and is already used in dual fuel maritime engines, potentially enabling relatively rapid adoption in the shipping industry. Ammonia (NH<sub>3</sub>), another promising alternative, contains no carbon and thus has the potential to eliminate direct CO<sub>2</sub> emissions. It is already widely produced and transported globally, making it a potentially scalable solution for maritime decarbonisation.

This report is structured as follows: the first section reviews the Regulatory Aspects of alternative marine fuels. The subsequent sections outline the Objectives, Scope, and Methodology of the Life Cycle Assessment (LCA), detailing the full Well-to-Wake (WTW) inventories and results for fossil fuel references, e-methanol, bio-methanol, e-ammonia from hydrogen electrolysis and e-ammonia from hydrogen via natural gas reforming with carbon capture and storage. These results are then applied to a typical CMA CGM shipping route, using modelled consumption data to estimate potential GHG reductions. Finally, prospective projections provide an outlook on expected emissions reductions for the years 2035 and 2050.

## 2 Regulatory Aspects

---

The year 2023 was marked by significant regulatory developments regarding the reduction of greenhouse gases (GHG) for maritime transport, both at the international level, with the revised International Maritime Organisation (IMO) strategy aiming for carbon neutrality by 2050, and at the European Union level with two main measures from the Fit-for-55 package having a direct impact on maritime transport (inclusion of maritime transport in the EU Emissions Trading System (ETS), [Fuel EU Maritime](#) coming into force in 2025). Three other texts from the Fit-for-55 also affect the maritime environment ([RED III](#), the [AFIR regulation](#), and the [Energy Taxation Directive ETD](#)). These various regulations are briefly summarised in Table 1 below and discussed in further detail in this chapter.

At the European level, the conditions for considering fuels in the renewable energy objectives of the member states are defined within a rapidly evolving EU regulatory framework. In particular, two delegated acts submitted by the Commission on 13 February, 2023, are currently being used to implement the requirements of [Art. 27 \(3\)](#) and Art. 25 (2), [28 \(5\)](#) of the 2018/2001 Renewable Energy Directive (RED II). An important consideration in the production of RFNBOs (Renewable Fuels of Non-Biological Origin) from renewable hydrogen is the classification of the CO<sub>2</sub> used in the process. The annex of the second delegated act regulates the conditions under which captured CO<sub>2</sub> can be considered as an avoided greenhouse gas emission, allowing its use in the production of RFNBO.

The deliverable of this phase will consist of an analysis of the European regulation on renewable energy with a specific focus on the definitions of renewable hydrogen, renewable electricity and CO<sub>2</sub> used to produce RFNBO.

**Table 1 : Summary and key targets of the different regulations**

Regulation/Directive	Scope	Targets and main requirements	Sustainability and GHG savings criteria
<b>EU GHG regulatory framework</b>			
<b>EU Renewable Energy Directive (REDIII) DIRECTIVE (EU) 2023/2413</b>	WtT	<ul style="list-style-type: none"> <li>• <b>Overall binding RES target:</b> at least 42,5% by 2030 in               <ul style="list-style-type: none"> <li>• <b>Advanced biofuels (AB) and RFNBOs:</b> Combined 5.5% Advanced biofuels and RFNBO (min. 1%) target in 2030. Incentive for AB and RFNBOs (double counting) and their use in aviation and maritime (1,2 x for AB and x1,5 for RFNBOs). Indicative target of 1.2% for RFNBOs in shipping</li> <li>• <b>Waste &amp; Residues:</b> Capped to 1,7%</li> <li>• <b>Food and feed crops:</b> capped to 7% or 2020 share +1% (all transport), limit to high-ILUC risk except if certified Low-ILUC risk biomass</li> </ul> </li> </ul>	Defines sustainability criteria and minimum GHG savings for renewables fuels brought to EU market and sets a GHG emissions reduction threshold compared to reference fossil (94 gCO <sub>2</sub> eq/MJ): <ul style="list-style-type: none"> <li>• <b>biofuels</b> requiring at least <b>50-65%</b> (depending on the date of facility installation)</li> <li>• <b>RFNBO and RCFs</b> at least <b>70%</b></li> </ul>
<b>RFNBO Delegated act under Art.27(3) of the 2018/2001 directive (REDII) - (EU) 2023/1184</b> <b>RFNBO Delegated act under Art.28(5) of the 2018/2001 directive (REDII) - (EU) 2023/1185</b>		<ul style="list-style-type: none"> <li>• Requirements have been set out for when hydrogen produced from electricity can be considered zero-emission, and how to account for captured carbon reused in the fuel.</li> <li>• Methodology for determining GHG emissions of RFNBOs</li> </ul>	Defines the conditions under which the <b>electricity</b> used for hydrogen production is considered <b>fully renewable: temporal correlation, geographical correlation and additionality.</b>
<b>FuelEU Maritime Régulation (EU) 2024/2031</b>	WtW	<ul style="list-style-type: none"> <li>• Aims to increase demand for renewable and low-carbon fuels by establishing limits on the annual average GHG intensity of the energy used on-board (reference value 91.16 g CO<sub>2</sub>eq/MJ) every 5 years starting in 2025: -2%; -6%; -14.5%; -31%; -62%; -80%</li> <li>• Ships above 5000 GT, cover 100% of energy used on intra-EU voyages and 50% of the energy on extra-EU voyages.</li> </ul>	<b>Refers to RED II Directive:</b> <ul style="list-style-type: none"> <li>• RED compliant : use actual certified GHG intensity values for well-to-tank emissions</li> <li>• RED compliant : considered as having GHG emissions equal to the least favourable fossil</li> </ul>
<b>EU Emissions Trading System Directive (EU ETS) 2003/87/EC consolidated text</b>	TtW	Since 2024, the EU ETS has been extended to cover the maritime sector. Regulate GHG emissions in the EU/EEA through cap and trade of emission allowances. Ships of 5000 GT and above to be included in the EU ETS from 2023. Applicable to all intra-EEA voyages and 50% of voyages to/from countries outside the EEA.	EU-ETS allows for a zero CO <sub>2</sub> emissions factor for biofuels, RFNBOs and RCFs that meet specific sustainability and GHG savings criteria defined by the RED.
<b>Alternative Fuels Infrastructure Regulation (AFIR) (EU) 2023/1804</b>		Main EU ports are required to provide a minimum shore power supply for container ships and passenger ships over 5,000 GT by 2030. Mandates LNG refueling infrastructure at major ports by 2025.	
<b>Revision of Energy Taxation Directive (ETD) 2003/96/EC</b>		Aims to modify the way energy products are taxed in EU. The proposal introduces a new structure of tax rates based on energy content and environmental performance of the fuels and electricity. Removes tax exemptions for conventional maritime fuels; introduces €10.75/GJ tax for fossil fuels while advanced biofuels, biogas, and RFNBOs have a reduced rate of €0.15/GJ.	

IMO GHG regulatory framework			
<b>2023 IMO GHG Strategy</b>		<p>The 2023 revised IMO GHG Strategy strengthens the ambitions for international shipping to achieve net zero emissions by 2050:</p> <ul style="list-style-type: none"> <li>• Reduce CO2 emissions per transport work by at least 40% by 2030 (baseline 2008).</li> <li>• Reduce total annual GHG emissions by at least 20%, striving for 30%, by 2030 and by 70% (striving for 80%) in 2040 (baseline 2008).</li> <li>• The uptake of zero or near-zero GHG emission fuels and/or energy sources that should represent at least 5 % of the energy used in shipping in 2030.</li> <li>• Life cycle GHG assessment guidelines (LCA Guidelines) adopte using a well-to-wake GHG emissions approach</li> <li>• Interim guidance on the use of biofuels under DCS and CII</li> </ul>	
<b>EEDI &amp; EEXI (Energy Efficiency Design/Existing Ship Index)</b>	TtW	EEDI (2013) applies to new ships, mandating design efficiency improvements; EEXI (2023) extends efficiency standards to existing ships, requiring compliance by 2023.	
<b>CII (Carbon Intensity Indicator)</b>	TtW	<ul style="list-style-type: none"> <li>• Carbon Intensity Indicator (starting 2023), vessels must collect emissions and be rated A-E for annual efficiency of all ships above 5000 GT</li> <li>• The use of biofuels under IMO DCS and CII regulations</li> </ul>	<ul style="list-style-type: none"> <li>• Biofuels that have been certified as sustainable through an international certification system (ISCC, RSB, etc.) should be promoted.</li> <li>• Biofuels that are not certified as sustainable or do not meet the emissions reduction criterion will be assigned a Cf equal to that of the equivalent fossil fuel type</li> </ul>

## 2.1 International Decarbonisation Objectives

The International Maritime Organization (IMO) is the global regulatory body for maritime transport, aiming for net-zero GHG emissions by 2050. Through its technical body, the Marine Environment Protection Committee (MEPC), has been developing a set of technical and operational measures since 2011 regarding the energy efficiency of ships to decarbonize international shipping. The first binding measures, added to Annex VI of the MARPOL convention, aim to improve the energy efficiency of both new and existing ships:

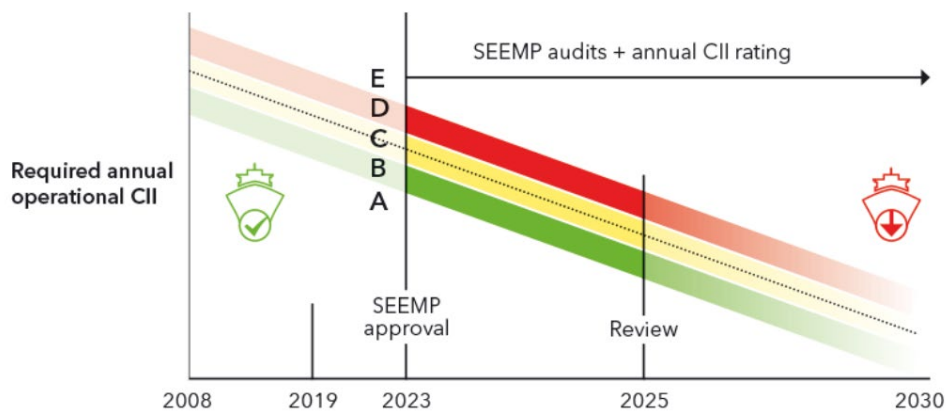
- Implementation in 2013 of an Energy Efficiency Design Index (EEDI) for design: since 2015, all newly delivered ships must meet a minimum design energy efficiency standard based on their type and size, and a mechanism to improve the efficiency of ships in operation (Ship Energy Efficiency Management Plan or SEEMP).

- Implementation in 2016 of a system for collecting data on fuel consumption from ships with a gross tonnage of 5,000 or more (representing around 85% of total GHG emissions from international shipping). These data collected since 2019 are submitted annually to the state in which the ship is registered.

In 2018, the IMO adopted the Initial Strategy for reducing GHG emissions from ships to reduce the carbon intensity of all ships by 40% by 2030 compared to 2008. It introduces two new mandatory short-term measures aimed at measuring the energy performance of existing ships. Since January 1, 2023, it has been mandatory for all ships to

calculate the Energy Efficiency Existing Ship Index (EEXI), which was previously reserved for new constructions (EEDI), and to collect data for the declaration of their Carbon Intensity Indicator (CII):

- The Energy Efficiency Existing Ship Index (EEXI) is a technical requirement aimed at improving the energy efficiency of existing ships in service. It applies to ships with a gross tonnage of 400 or more. The calculated value of the EEXI obtained for each ship must be lower than the required EEXI to ensure that the ship meets a minimum energy efficiency standard. The ships concerned must comply by December 31, 2023, at the latest. Several technical possibilities are available to achieve this, including limiting engine power, optimizing propulsion, recovering heat, optimizing propellers, installing wind-assisted propulsion systems, etc.
- The Carbon Intensity Indicator (CII) is an operational component that enables the assessment of ships with a gross tonnage of 5,000 or more based on their operational carbon intensity (emissions relative to activity). The rating scale ranges from A to E, with A being the best rating and E the highest CO<sub>2</sub> emitter. If a ship is rated D or E for three consecutive years, a corrective action plan must be implemented to achieve a minimum rating of C. The first year of CII verification is 2024 based on data collected in 2023. This index is measured annually and takes into account the annual fuel consumption multiplied by a CO<sub>2</sub> emission factor, all divided by the distance travelled over the year and the ship's carrying capacity. Its goal is to ensure that the global fleet meets the target of a 40% reduction in its carbon intensity by 2030 compared to 2008. To achieve this, each ship is imposed carbon intensity reduction targets relative to a reference calculated based on the carbon intensity of its category in 2019: -5% in 2023, -7% in 2024, -9% in 2025, and -11% in 2026 (Figure 1).



**Figure 1 : Stricter CII rating thresholds by 2030 (source DNV)**

Furthermore, to improve the CII, the IMO also agreed in July 2023 that certified sustainable biofuels with at least 65% GHG emissions reduction from well-to-wake compared to fossil fuels (94 gCO<sub>2</sub>e/MJ) can use a reduced CO<sub>2</sub> emission factor within the data collection system (DCS) and the CII.

*2 Pending the development of the comprehensive method to account for well-to-wake GHG emissions and removals based on the Guidelines on life cycle GHG intensity of marine fuels (LCA Guidelines) (resolution MEPC 376(80)), biofuels that have been certified by an international certification scheme,\* meeting its sustainability criteria, and that provide a well-to-wake GHG emissions reduction of at least 65% compared to the well-to-wake emissions of fossil MGO of 94 gCO<sub>2</sub>e/MJ (i.e. achieving an emissions intensity not exceeding 33 gCO<sub>2</sub>e/MJ) according to that certification, may be assigned a Cf equal to the value of the well-to-wake GHG emissions of the fuel according to the certificate (expressed in gCO<sub>2</sub>e/MJ) multiplied by its lower calorific value (LCV, expressed in MJ/g) for the purpose of regulations 26, 27 and 28 of MARPOL Annex VI for the corresponding amount of fuels consumed by the ship. In any case, the Cf value of a biofuel*



cannot be less than 0. For blends, the Cf should be based on the weighted average of the Cf for the respective amount of fuels by energy

**Interim guidance on the use of biofuels under regulations 26, 27 and 28 of MARPOL Annex VI(DCS and CII), July 2023**

Finally, since July 2023, the IMO has reinforced its initial strategy from 2018 to adopt a "net zero" ambition for GHG emissions from international shipping by 2050 ([IMO 2023 strategy](#)). Figure 2 presents this strategy, which translates into:

- An intermediate target for absolute GHG emissions reduction from ships of 20%, striving to reach 30% by 2030 and 70%, striving to reach 80% by 2040 compared to 2008, and net zero by 2050.
- The share of zero-emission energies and fuels must account for 5% of the total used by international maritime transport by 2030, striving to reach 10% of this total.
- A Well-to-Wake approach for GHG emissions from marine fuels: from the well during the energy production phase to the wake during the energy combustion phase on board.

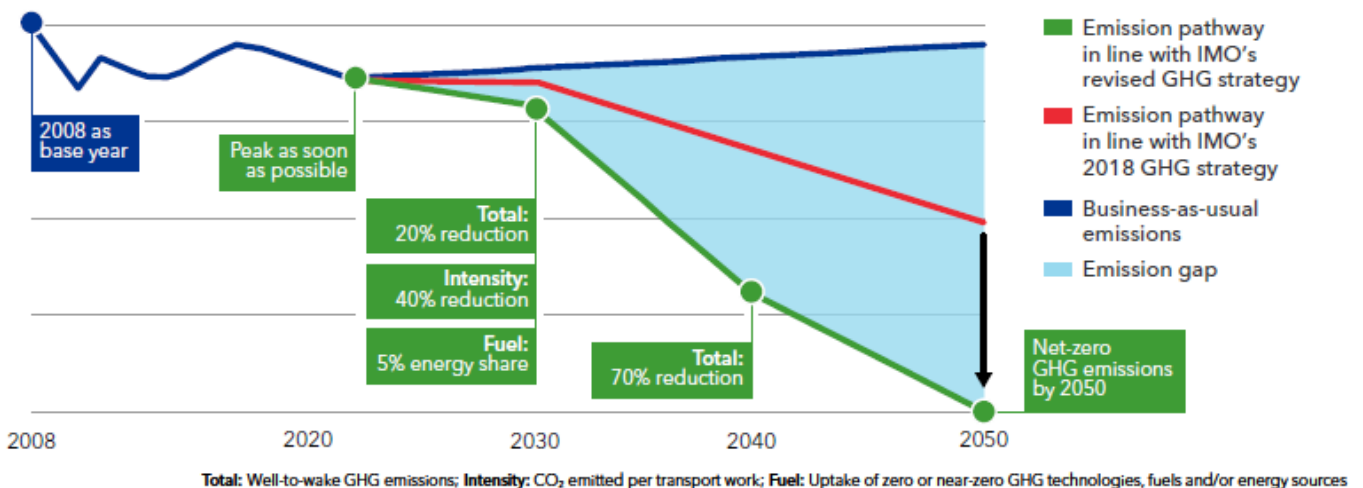
To achieve these new objectives, short-term measures to improve the energy efficiency of new and existing ships (EEXI and CII) have been in effect since January 2023.

In discussions at the IMO, the full set of medium-term measures should be finalized and approved by the Committee by 2025, for entry into force in mid-2027. It would include 2 components:

- A technical standard on the intensity of GHG emissions from marine fuels.
- An economic mechanism for pricing GHG emissions in the maritime sector, such as a carbon tax on ship emissions.

**Outline of ambitions and minimum indicative checkpoints in the revised IMO GHG strategy**

Units: GHG emissions



**Figure 2 : Revised IMO decarbonization strategy (source DNV)**

## 2.2 GHG Reduction Objectives and Measures at the European Level

At the EU level, maritime transport accounted for 3 to 4% of total CO<sub>2</sub> emissions, or more than 124 Mt of CO<sub>2</sub> in 2021. As part of the Green Deal, the European Commission proposed, in July 2021, the Fit-for-55 package, aiming to adapt EU policies to reduce GHG emissions by at least 55% by 2030 compared to 1990, and to achieve carbon neutrality by 2050.

The Fit-for-55 legislative package mainly includes two texts that set specific requirements for ships: the EU ETS and the FuelEU Maritime regulation. However, three other texts from the Fit-for-55 also affect the landscape in which maritime transport operates: the promotion of alternative fuels through the revision of the Renewable Energy Directive RED III, the availability of infrastructure with the revision of the Alternative Fuels infrastructure Regulation (AFIR), and the costs associated with GHG emissions through the revision of the current Energy Taxation Directive (ETD).

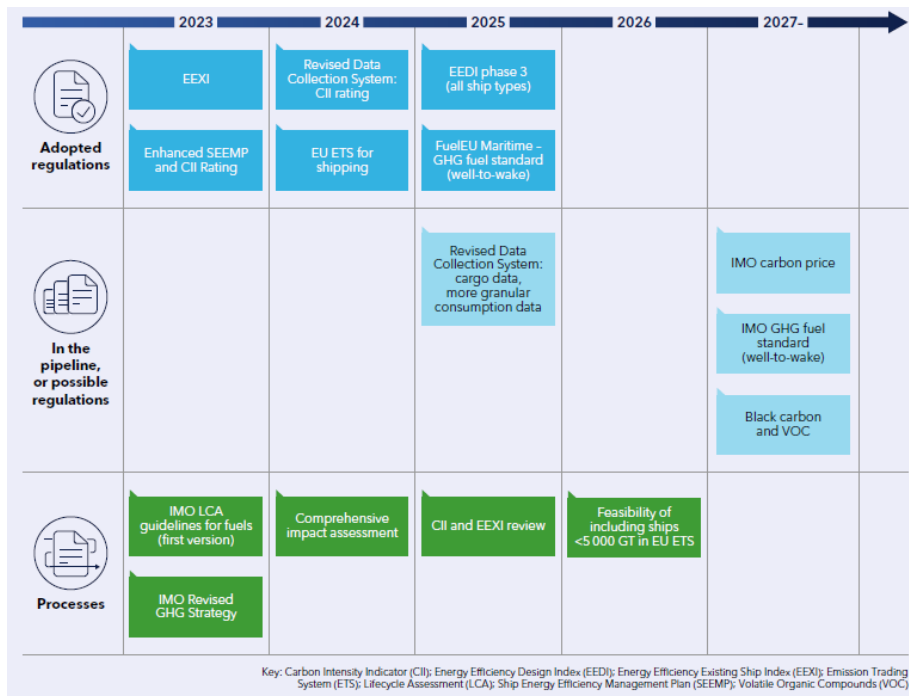


Figure 3 : IMO GHG reduction regulatory measures until 2030 (source DNV)

### 2.2.1 EU Emissions Trading System (ETS)

Since January 1, 2024, maritime emissions are subject to the EU Emissions Trading System (ETS), also known as the "polluter pays" principle. Each year, the European Commission sets a cap on the total amount of GHG emissions (CO<sub>2</sub> from 2024, then methane and nitrous oxide from 2026) that can be emitted by shipping companies within the European zone, in the form of tradable quotas. A cap is set for each shipping company that must purchase quotas to cover its CO<sub>2</sub> emissions. One tonne of CO<sub>2</sub> equals one ETS quota.

The implementation will be gradual over the period 2024-2026 (Figure 4), during which shipping companies only need to return quotas for a portion of their emissions:

- In 2025, shipping companies will need to return quotas for 40% of their emissions declared in 2024.
- In 2026, the percentage will rise to 70% for emissions declared in 2025.
- From 2027, ship operators will need to return quotas for 100% of their emissions declared in 2026.

The regulation applies to ships over 5,000 GT from 2024. Offshore ships over 5,000 GT will be subject to the ETS from 2027.

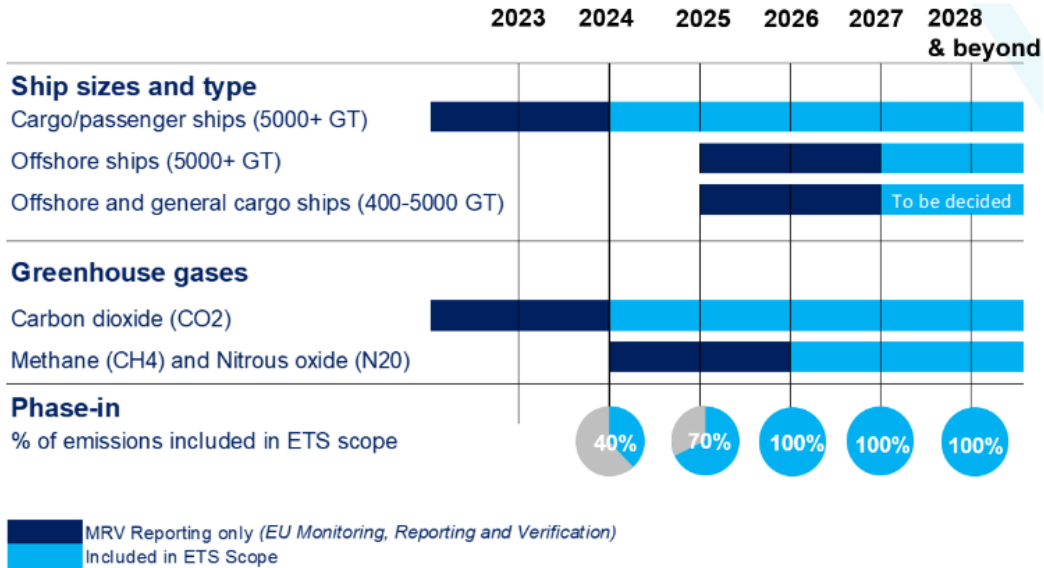


Figure 4 : EU ETS deployment schedule

This measure will be applied to routes within the EU as well as departing from and/or arriving at a European port. From 2024, ships located in EU ports navigating in this area will therefore have to pay for 100% of their emissions. Ships traveling to or from the EU will have to pay for 50% of the emissions of the journey (Figure 5).

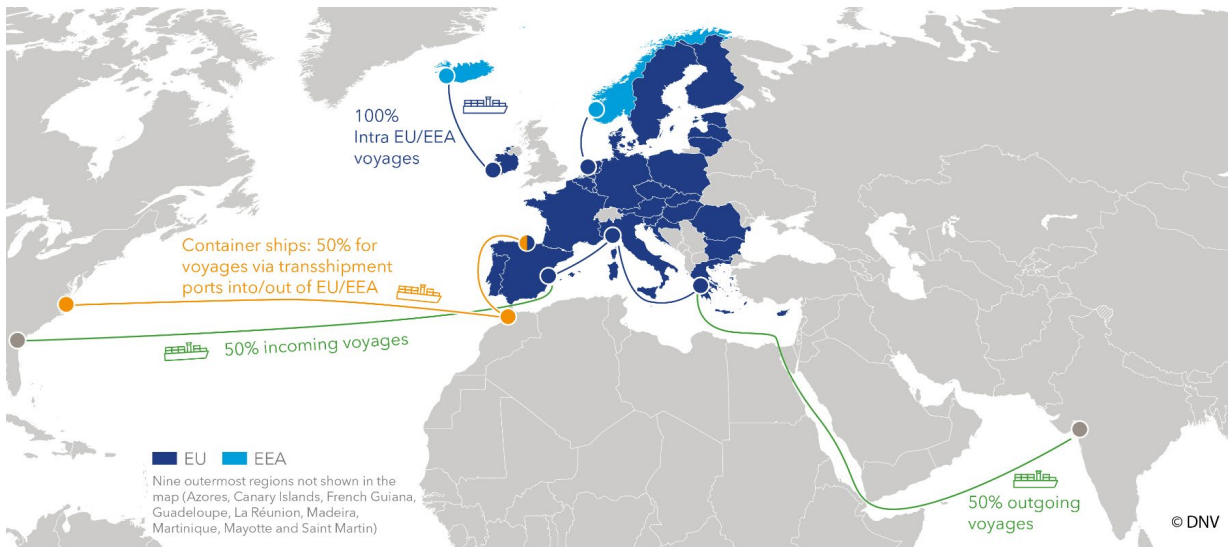


Figure 5 : Scope of the EU ETS (source DNV)

## 2.2.2 FuelEU Maritime Regulation

The new FuelEU Maritime regulation, definitively adopted in July 2023 by the EU Council, aims to increase the demand and consistent use of renewable and low-carbon fuels and reduce greenhouse gas emissions from the maritime sector. It complements the EU emissions trading system, CII ratings, and other decarbonisation initiatives. The regulation applies from January 1, 2025 to commercial ships over 5,000 GT used for the transport of goods or passengers, regardless of the flag.

FuelEU Maritime sets requirements for GHG emissions intensity from well to wake for energy used on board ships operating in the EU from 2025. The average annual GHG intensity of all energy used on board, measured in GHG emissions per unit of energy (gCO<sub>2</sub>e/MJ), must be below the required level. GHG emissions are calculated from a well-to-wake perspective, including emissions related to extraction, cultivation, production, and transport of the fuel, in addition to emissions from the energy used on board the ship.

The GHG emissions intensity limits for energy used on board ships operating in the EU from 2025 are set as a percentage reduction from the average GHG intensity of the fleet in 2020 (91.16 gCO<sub>2</sub>e/MJ). Ships must progressively reduce their GHG emissions as follows: 2% in 2025, 6% in 2030, 14.5% in 2035, 31% in 2040, 62% in 2045, and 80% in 2050 (Table 2).

**Table 2: GHG emissions intensity schedule for energy used on board ships operating in the EU according to the FuelEU Maritime regulation (EU) 2024/2031**

Reduction	2025	2030	2035	2040	2045	2050
GHG emissions reduction target (%)	2	6	14,5	31	62	80
Required GHG intensity (gCO <sub>2</sub> e/MJ)	89,3	85,7	77,9	62,9	34,6	18,2

The regulation includes a special incentive scheme to support the adoption of renewable fuels of non-biological origin (RFNBO) with high decarbonization potential. The use of RFNBO is encouraged by a multiplier of 2 for their uses from January 1, 2025, to December 31, 2033, meaning that each tonne of RFNBO will count twice towards achieving the overall GHG intensity targets used on board, as well as by establishing a sub-target of 2% RFNBOs from 2034 if the share of RFNBOs is below 1% in 2031 in the energy mix.

The FuelEU Maritime regulation requires renewable marine fuels to comply with the same sustainability criteria as those defined in the RED II directive. Thus, biofuels, biogas, RFNBO, and recycled carbon fuels (RCF) meeting sustainability and GHG emission reduction criteria (50-70% reduction compared to current fossil fuels) from the European RED directive can use certified well-to-tank and tank-to-wake real values.

Fuels that do not meet the GHG reduction criteria, unsustainable biofuels, and biofuels derived from crops intended for human or animal consumption are considered fossil fuels and must use the default factors for the same type of fossil fuel.

*1. Where biofuels, biogas, renewable fuels of non-biological origin and recycled carbon fuels, as defined in Directive (EU) 2018/2001, are to be taken into account for the purposes referred to in Articles 4(1) of this Regulation, the following rules apply:*

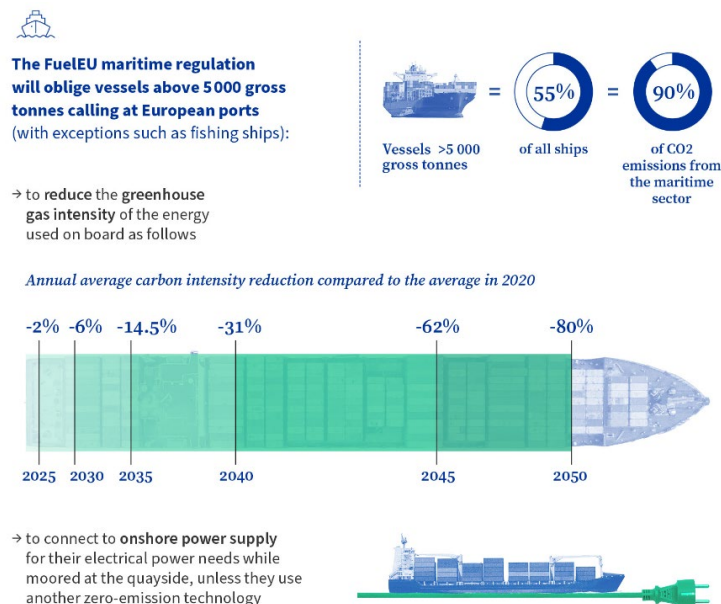
*(a) greenhouse gas emission factors of biofuels and biogas that comply with the sustainability and greenhouse gas saving criteria set out in Article 29 of Directive (EU) 2018/2001 shall be determined according to the methodologies set out in that Directive;*

*(b) greenhouse gas emissions factors of renewable fuels of non-biological origin and recycled carbon fuel that comply with the greenhouse gas emission savings thresholds set out in Article 27(3) of Directive (EU) 2018/2001 shall be determined according to the methodologies set out in that Directive;*

(c) biofuels and biogas that do not comply with point (a) or that are produced from food and feed crops shall be considered to have the same emission factors as the least favourable fossil fuel pathway for this type of fuel;

(d) renewable fuels of non-biological origin and recycled carbon fuels that do not comply with point (b) shall be considered to have the same emission factors as the least favourable fossil fuel pathway for this type of fuels.

Finally, from January 1, 2030, the text also requires container ships and passenger ships over 5,000 GT to connect to onshore power supply (OPS) when they are securely moored at the dock, in all ports covered by the Alternative Fuel Infrastructure Regulation (AFIR). The same will apply to all non-AFIR ports from January 1, 2035, to all ports that develop OPS capabilities. This measure will help reduce air pollution in ports. Other mechanisms are proposed to facilitate compliance with the regulation (pooling of emissions, banking operations, etc.). A graphical summary of the FuelEU Maritime objectives is presented in Figure 6.



**Figure 6 : FuelEU Maritime (EU) 2024/2031 objectives**

### 2.2.3 The revised Renewable Energy Directive (RED III)

The Renewable Energy Directive RED aims to promote renewable energies across all sectors of the EU, particularly in the transport and industry sectors. Established in 2009 (RED, 2009/28/EC), it was updated in 2018 (RED II, Directive EU/2018/2001). To achieve the Fit-for-55 objectives, the directive was revised again in 2021 ([RED III, EU/2023/2413](#)) and came into force in November 2023. Member States have until May 2025 to transpose it. RED III particularly promotes the increased production and use of renewable non-biological origin fuels (RFNBO) and recycled carbon fuels (RCF).



The revised RED III introduces the following changes (Table 3):

- The share of renewable energy in the EU's final energy consumption is raised to at least 42.5% (with a target of 45%) by 2030.
- Acceleration of authorisation procedures for renewable energy projects, with the creation of acceleration zones.
- For the transport sector, the text imposes:
  - A 14.5% reduction in carbon intensity by 2030 OR a share of at least 29% of renewable energy in the total energy consumption of the transport sector by 2030. Member States with maritime ports must also ensure that the share of RFNBO in maritime transport energy consumption is equal to 1.2% by 2030.
  - The cumulative share of advanced biofuels, biogas, and RFNBO is at least 1% in 2025 and 5.5% in 2030 in the final sector consumption, with at least 1% coming from RFNBO.
  - For the calculation of the overall incorporation of renewable energy in transport (at least 29%) or the reduction of GHG emission intensity related to the use of renewable energy (14.5%) (Article 27):
    - The share of biofuels and biogas produced from raw materials listed in Annex IX and the share of non-biological origin renewable fuels are considered as equivalent to twice their energy content; A multiplier factor of 1.2 is applied for advanced biofuels and biogas used in maritime and air transport, and a multiplier factor of 1.5 is applied for RFNBOs used in maritime and air transport

*‘Article 27 : Calculation rules in the transport sector and with regard to renewable fuels of non-biological origin regardless of their end use*

*2. For the calculation of the minimum shares referred to in Article 25(1), first subparagraph, point (a)(i) and point (b), the following rules shall apply:*

*(c) the share of biofuels and biogas produced from the feedstock listed in Annex IX and renewable fuels of non-biological origin shall be considered to be twice its energy content;*

*(e) the share of advanced biofuels and biogas produced from the feedstock listed in Part A of Annex IX supplied in the aviation and maritime transport modes shall be considered to be 1,2 times their energy content and the share of renewable fuels of non-biological origin supplied in the aviation and maritime transport modes shall be considered to be 1,5 times their energy content;*

**Table 3: Main RED updates for transportation sectors (source ICCT, 2023)**

	2018 RED II	2023 RED III
<b>Renewable energy in transport</b>	14% energy target (out of road and rail fuels)	14.5% GHG intensity reduction target or 29% renewable energy target (out of all energy supplied to transport)
<b>Advanced biofuels (Annex IX, part A)</b>	3.5% (out of road and rail fuels, with multiplier)	5.5% of a combination of both fuel types, with a 1% RFNBO minimum (out of all energy supplied to transport)
<b>Renewable fuels of nonbiological origin (RFNBOs)</b>	No target	
<b>Waste oils (Annex IX, part B)</b>	1.7% cap (out of all energy supplied to road and rail)	1.7% cap (out of all energy supplied to transport)
<b>Food- and feed-based biofuels</b>	Cap at whichever is lower: 7% or 2020 consumption in each member state + 1% (out of road and rail fuels)	Cap at whichever is lower: 7% or 2020 consumption in each member state + 1% (out of all transport energy consumption)
<b>Multipliers</b>	<ul style="list-style-type: none"> <li>• 2x for advanced biofuels and waste oils</li> <li>• 4x for renewable electricity used in vehicles</li> <li>• 1.5x for renewable electricity in rail</li> <li>• 1.2x for aviation and maritime fuels, except food- and feed-based biofuels</li> </ul>	Towards the overall 29% renewable energy target and all applicable subtargets for either an energy target or GHG target: <ul style="list-style-type: none"> <li>• 2x for advanced biofuels, RFNBOs, and waste oils</li> <li>• 4x for renewable electricity in vehicles</li> <li>• 1.5x for renewable electricity in rail</li> <li>• 1.2x for advanced biofuels and 1.5x for RFNBOs in aviation and maritime sectors</li> </ul>
<b>Fossil comparator</b>	<ul style="list-style-type: none"> <li>• 94 gCO<sub>2</sub>e/MJ for all transport energy</li> </ul>	<ul style="list-style-type: none"> <li>• 183 g CO<sub>2</sub>e/MJ for electricity used in vehicles</li> <li>• 94 g CO<sub>2</sub>e/MJ for all other energy used in transport</li> </ul>

- For the industrial sector:
  - 42% of the hydrogen used in the industry should come from RFNBOs (green H<sub>2</sub>) by 2030 and 60% by 2035.
  - An annual increase of 1.6% in the use of renewable energies.
  - Member States will have the option to reduce the share of green hydrogen by 20% provided that the share of grey H<sub>2</sub> consumed does not exceed 23% in 2030 and 20% in 2035 of their consumption (flexibility is granted to countries, like France, with a nuclear fleet to produce low-carbon hydrogen).

#### 2.2.4 Delegated Acts on RFNBO

The European Commission has adopted, in February 2023, two delegated acts under Articles 27(3) and 28(5) of the RED II directive - 2018/2001, to define RFNBO. The delegated acts define the conditions under which hydrogen, hydrogen-based fuels, or other energy carriers can be considered as renewable fuels of non-biological origin (RFNBO). A certification scheme will allow producers, whether national or from third countries, to demonstrate compliance with the EU framework and to market renewable hydrogen in the single market. The texts have been in force since July 10, 2023.

The delegated act under Article 27 (3) of the 2018/2001 directive (REDII): the first delegated act defines the conditions under which the electricity used for hydrogen production, hydrogen-based fuels, or other energy carriers is considered to be fully renewable. The delegated act defines four methods of connection to renewable energy (RE) assets to qualify the production of RFNBO.

Depending on the application case, requirements for additionality, temporal and geographical correlation are stipulated:

- Article 6 - Temporal correlation criterion: until December 2029, electricity production and consumption must be balanced on a monthly basis. From 2030, balance must even be proven on an hourly basis.
- Article 7 - Geographical correlation criterion: installations are located in the same bidding zone.
- Article 5 - Additionality criterion except for bidding zones with a carbon content of less than 18gCO<sub>2</sub>/MJ, only compliance with temporal and geographical correlation criteria is required. RE assets must be in service at least 36 months before the commissioning of the electrolyser and do not receive state aid.

These three criteria must be met if the electrolyser is connected to RE assets via Power Purchase Agreements (PPAs). These rules aim to ensure that hydrogen production genuinely contributes to increasing the share of renewable energy in the EU energy mix. RFNBO producers will have to demonstrate compliance with these rules in order for hydrogen to be considered as RFNBO.

The first delegated act also specifies the mode of connection of the electrolyser and what the RFNBO qualification criteria are (Table 4).

**Table 4: RFNBO qualification criteria according to the electrolyser connection mode**

Connection Methods	Requirements to Qualify as RFNBO
Direct Connection of the Electrolyser to a Renewable Energy Asset	<ul style="list-style-type: none"> <li>Electrolysers connected to these facilities must be commissioned no later than 36 months after the commissioning of the renewable energy assets → 100% of the production is counted as RFNBO.</li> <li>If the renewable energy asset is connected to the grid, the fuel producer must prove that no grid electricity was used for production, via a meter that certifies the electricity comes from the said renewable energy asset.</li> <li>Additionality of renewable energy assets with a temporary exemption for projects commissioned before January 1, 2028.</li> </ul>
Connection of the Electrolyser to a Decarbonized Electrical Grid	<ul style="list-style-type: none"> <li>The electrolyser is located in a bidding zone where the share of renewable energies is greater than 90% on the grid in year n-2: 100% of the production is qualified as RFNBO, provided that the electrolyser does not operate more hours in the year than the penetration rate of renewable energy in the mix.</li> <li>Exemption from the rules of additionality, temporal, and geographical correlation.</li> </ul>
Connection to Renewable Energy Assets via PPAs (French Case)	<ul style="list-style-type: none"> <li>The electrolyser is located in a bidding zone with a carbon content lower than 18gCO<sub>2</sub>/MJ in year n-2: the production is qualified as RFNBO up to the proportion of renewable energy in the national electricity mix in year n-2.</li> <li>Only compliance with temporal and geographical correlation criteria is required. Renewable energy assets connected to electrolysers via PPAs no longer need to be additional, nor should they be/have been supported by the State.</li> </ul>
Connection to Renewable Energy Assets via PPAs (General Case)	<ul style="list-style-type: none"> <li>The entire production from PPA electricity is qualified as RFNBO but must meet the criteria of additionality, temporal, and geographical correlation.</li> </ul>

- Delegated Act under Article 28 (5) of the 2018/2001 directive (REDII): The second delegated act defines a calculation methodology to determine compliance with the required 70% GHG emissions reduction for RFNBO production. The delegated act also stipulates the eligible CO<sub>2</sub> sources for e-fuel production.
- In terms of GHG emissions reduction threshold: RFNBO and RCF must achieve a GHG emissions reduction threshold of at least 70% compared to the fossil comparator of 94gCO<sub>2</sub>e/MJ, meaning lifecycle emissions below 28.2gCO<sub>2</sub>e/MJ or 3.38 kg CO<sub>2</sub>/kg H<sub>2</sub>.
- A methodology for calculating GHG emissions reductions for RFNBO or RCF is provided in Annex 1. The delegated act regulates the conditions under which captured CO<sub>2</sub> can be considered an avoided greenhouse gas emission, meaning its use in RFNBO production is possible (Table 5).

10. Emissions from existing use or fate include all emissions in the existing use or fate of the input that are avoided when the input is used for fuel production. These emissions shall include the CO<sub>2</sub> equivalent of the carbon incorporated in the chemical composition of the fuel that would have otherwise been emitted as CO<sub>2</sub> into the atmosphere. This includes CO<sub>2</sub> that was captured and incorporated into the fuel provided that at least one of the following conditions is fulfilled:

(a) the CO<sub>2</sub> has been captured from an activity listed under Annex I of Directive 2003/87/EC and has been taken into account upstream in an effective carbon pricing system and is incorporated in the chemical composition of the fuel before 2036. This date shall be extended to 2041 in other cases than CO<sub>2</sub> stemming from the combustion of fuels for electricity generation; or

(b) the CO<sub>2</sub> has been captured from the air; or











(c) the captured CO<sub>2</sub> stems from the production or the combustion of biofuels, bioliquids or biomass fuels complying with the sustainability and greenhouse gas saving criteria and the CO<sub>2</sub> capture did not receive credits for emission savings from CO<sub>2</sub> capture and replacement, set out in Annex V and VI of Directive (EU) 2018/2001; or  
(d) the captured CO<sub>2</sub> stems from the combustion of renewable liquid and gaseous transport fuels of non-biological origin or recycled carbon fuels complying with the greenhouse gas saving criteria, set out in Article 25(2) and Article 28(5) of Directive (EU) 2018/2001 and this Regulation; or

(e) the captured CO<sub>2</sub> stems from a geological source of CO<sub>2</sub> and the CO<sub>2</sub> was previously released naturally.

Captured CO<sub>2</sub> stemming from a fuel that is deliberately combusted for the specific purpose of producing the CO<sub>2</sub> and CO<sub>2</sub>, the capture of which has received an emissions credit under other provisions of the law shall not be included.

Emissions associated with the inputs like electricity and heat and consumable materials used in the capture process of CO<sub>2</sub> shall be included in the calculation of emissions attributed to inputs.

**Table 5: Validity of carbon sources for the production of RFNBO or RCF (source Arup, 2024)**

Valid Carbon Sources	Currently/Eventually Invalid Carbon Sources
 Captured CO <sub>2</sub> from an ETS-obligated facility that already paid for the ETS allowance (not indefinitely, see to the right) 	 From 2036 onwards, CO <sub>2</sub> captured from industrial activities for electricity production specifically  From 2041 onwards, CO <sub>2</sub> captured from any industrial activities in Dir. 2003/87/EC such as cement, oil or steel production
 Captured CO <sub>2</sub> from combustion of RED-compliant biofuels, RCFs or RFNBOs (that did not receive credits for carbon capture and replacement)	 CO <sub>2</sub> captured that has received emission credits under other provisions of the law (to avoid double counting)
 Direct air capture of CO <sub>2</sub>	 CO <sub>2</sub> captured from a fuel that is deliberately burned for producing the CO <sub>2</sub>
 Captured CO <sub>2</sub> from geological sources (where CO <sub>2</sub> was released naturally)	
 Biogenic CO <sub>2</sub> from sustainable biomass: the captured CO <sub>2</sub> stems from the production or the combustion of biofuels, bioliquids or biomass fuels complying with the sustainability and greenhouse gas saving criteria	

**Carbon sources valid for RFNBO and RCF production as indicated by the Methodology Delegated Act**

### **2.2.5 Revision of the Directive on the Deployment of an Infrastructure for Alternative Fuels (AFIR) (EU) 2023/1804**

The regulation on infrastructure for alternative fuels (AFIR) aims to increase the availability of charging and refuelling infrastructure for alternative fuels. Adopted in September 2023, it has been in force since October 2023. For maritime transport, the regulation sets mandatory targets for shore power supply in RTE-T ports for inland ports by the end of December 2024 and for maritime ports by the end of December 2029.

The main EU ports (RTE-T ports) are required to provide a minimum shore power supply for container ships and passenger ships over 5,000 GT starting January 2030.

RTE-T maritime ports should provide an appropriate number of LNG refuelling points by January 2025.

### **2.2.6 Revision of the Current Energy Taxation Directive (ETD) 2003/96/EC**

The Energy Taxation Directive (2003/96/EC) in force since 2003 sets minimum tax rates on energy products, fuels, and electricity. Since July 2021, the Commission has presented a proposal to revise the ETD as part of the Fit-for-55 package. Its goal is to align the taxation of energy products with the EU's climate change policy.

The main proposals for the overhaul of the ETD are:

- Indexing minimum tax rates (in €/GJ) on energy content and environmental performance (not on volume). The most polluting fuels are taxed the most. For example, conventional fossil fuels (diesel or gasoline) and non-sustainable biofuels will be subject to a rate of €10.75/GJ. For advanced biofuels, biogas, and RFNBO, the minimum rate would be €0.15/GJ.
- Removal of current tax exemptions for conventional marine fuels.

## 3 Goals, Scope and Modelling Approach

### 3.1 Goals

This report presents the results of the LCA of:

- E-methanol: synthesised via CO<sub>2</sub> hydrogenation using renewable hydrogen.
- Bio-methanol: synthesised via biomass gasification.
- E-ammonia: synthesised via the Haber-Bosch process, using renewable hydrogen.
- Blue ammonia: synthesised the Haber-Bosch process, using hydrogen from natural gas reforming with carbon capture.

The study is organized around two main objectives, each associated with two functional units.

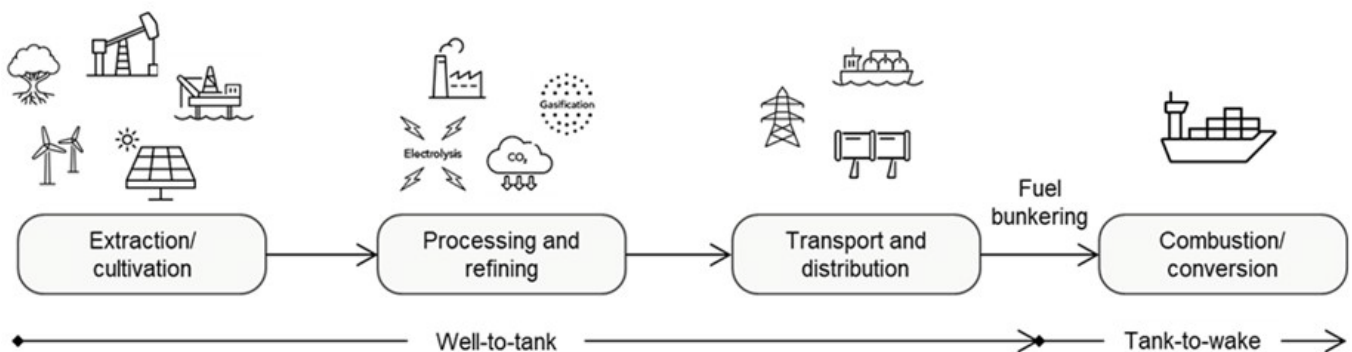
The first objective is to quantify the GHG impacts of the production and combustion (Well-To-Wake) of these fuels. These impacts are calculated for:

- Several producing countries to account for regional specificities (electricity mix, renewable energy potential, availability of water resources, etc.);
- Several technological scenarios (to understand the influence of the configuration of the production unit on GHG results) and regulatory scenarios (to understand how the applied GHG calculation rules impact results);
- Current and future horizons (2035 and 2050) to estimate the evolution of calculated impacts;
- Different distribution scenarios with either the Port of Singapore or the Port of Rotterdam as the bunkering location.

The second objective is to quantify the GHG impacts of a typical Busan – Rotterdam route for a container ship powered by: conventional fuel, methanol (e- or bio-) with pilot fuel, and ammonia (e- or blue) with pilot fuel. The potential reductions of replacing conventional fuel with the different derivatives of methanol or ammonia are assessed.

### 3.2 Scope

The scope will cover the Well-to-wake (WtW) steps (Figure 7). This is a combination of the well-to-tank (WtT) part (from primary production to the transport of fuel in the tank of a ship, also called upstream emissions) and the tank-to-wake (TtW) part (also called "from tank to propeller").



**Figure 7: Scope of the fuel Well-to-Wake assessment (from IMO LCA Guidelines (MEPC.376(80))**

The GHGs considered in our scope are carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), and nitrous oxide (N<sub>2</sub>O). Emissions from the cargo (e.g., volatile organic compounds (VOCs)) or the use of refrigerant gases are not included; other climate forcing and short-lived precursors are not taken into account. Other contributors to radiative forcing and



short-lived precursors such as non-methane volatile organic compounds (NMVOCs), sulfur oxides (SO<sub>x</sub>), and greenhouse gases (GHGs) such as carbon monoxide (CO), particulate matter (PM), and black carbon are excluded.

The "attributorial" method/scope is used, which aims at attributing impacts related to physical flows impacting the environment from and to a system and its environment is used.

The ex-ante study focuses on 17 regions for e-/bio-methanol production at current, 2035, and 2050 horizons. The regions of interest, as defined by CMA CGM, are: France (FR), China (CN), Australia (AU), Brazil (BR), Canada (CA-QC), Chile (CL), Spain (ES), Algeria (DZ), Morocco (MA), Tunisia (TN), Indonesia (ID), India (IN), Japan (JP), South Africa (ZA), Texas (US-TRE), Benelux (BE), and the United Arab Emirates (AE). The Quebec region was chosen for Canada and Belgium for Benelux.

### 3.3 Methodology

#### 3.3.1 IMO Methodological Guidance

The Life Cycle Assessment (LCA) is considered by the IMO as the methodological approach to comprehensively assess the environmental impact of an energy carrier for maritime transport, from its production phase to its end-of-life/combustion phase. This methodology is based on rigorous principles aimed at quantifying greenhouse gas emissions, resource and energy consumption, as well as other environmental impacts. According to the [recommendations adopted in July 2023 \(MEPC.376\(80\)\)](#) by the IMO, the calculation of GHG emissions from marine fuels is detailed below.

##### a Well-to-Tank

The Well-to-Tank (WtT) GHG emission factors (gCO<sub>2</sub>eq/MJ (LCV) of fuel or electricity) are calculated according to equations (1a) and (1b). The terms of equations (1a) and (1b) are presented in Table 6.

$$GHG_{WtT} = e_{fecu} + e_l + e_p + e_{td} - e_{sca} - e_{ccs} \quad \text{Equation (1a)}$$

Whereby

$$e_{ccs} = CCS - e_{cc} - e_t - e_{st} - e_x \quad \text{Equation (1b)}$$

**Table 6: Terms to consider according to IMO guidelines for calculating Well-to-Tank GHG emissions**

Term	Units	Explanation
$e_{fecu}$	gCO <sub>2</sub> eq/MJ(LCV)	Emissions associated with the extraction/cultivation/acquisition/recovery of raw materials
$e_l^*$	gCO <sub>2</sub> eq/MJ(LCV)	Annualized emissions (over 20 years) from changes in carbon stocks caused by direct land use (Direct Land Use Change - dLUC)
$e_p$	gCO <sub>2</sub> eq/MJ(LCV)	Emissions associated with the processing and/or transformation of the raw material at the source and its conversion into final fuel, including co-production of electricity
$e_{td}$	gCO <sub>2</sub> eq/MJ(LCV)	Emissions associated with the transport of the raw material to the conversion plant, and emissions associated with the transport and storage of the finished fuel, local distribution, conditioning, and bunkering
$e_{sca}^*$	gCO <sub>2</sub> eq/MJ(LCV)	Emissions (annualized emission savings (over 20 years) due to carbon accumulation in soils through the implementation of "sustainable" agricultural techniques)
$e_{ccs}$	gCO <sub>2</sub> eq/MJ(LCV)	Emissions credit from carbon capture and storage (e <sub>ccs</sub> ), that have not already been accounted for in e <sub>p</sub> . This should properly account the avoided emissions through the capture and sequestration of emitted CO <sub>2</sub> , related to the

		extraction, transport, processing and distribution of fuel (csc). From the above-mentioned emission credit, all the emissions resulting from the process of capturing (ecc) and transporting (et) the CO <sub>2</sub> up to the final storage (including the emissions related to the injection, etc.) need to be deducted. This element should be calculated with the following formula:
$C_{cs}$	gCO <sub>2</sub> stored/MJ(LCV)	Emissions credit equivalent to the net CO <sub>2</sub> captured and stored (long-term: 100 years)
$e_{cc}$	gCO <sub>2eq</sub> /MJ(LCV)	Emissions associated with the process of capturing, compression and/or cooling and temporary storage of the CO <sub>2</sub>
$e_t$	gCO <sub>2eq</sub> /MJ(LCV)	Emissions associated with transport to a long-term storage site
$e_{st}$	gCO <sub>2eq</sub> /MJ(LCV)	Any emissions associated with the process of storing (longterm: 100 years) the captured CO <sub>2</sub> (including fugitive emissions that may happen during long-term storage and/or the injection of CO <sub>2</sub> into the storage)
$e_x$	gCO <sub>2eq</sub> /MJ(LCV)	Any additional emissions related to the CCS

\*Pending further methodological guidance to be developed by OMI, the value of parameter should be set to 0.

## b Tank-to-Wake

The Tank-to-Wake (TtW) GHG emission factors are calculated using Equation (2). The terms of Equation 2 are presented in Table 7.

$$GHG_{TtW} = 1/LCV ((1 - 1/100 (C_{slip\_ship} + C_{fug})) \times (Cf_{CO_2} \times GWP_{CO_2} + Cf_{CH_4} \times GWP_{CH_4} + Cf_{N_2O} \times GWP_{N_2O}) + (1/100 (C_{slip\_ship} + C_{fug}) \times C_{sfx} \times GWP_{fuelx}) - SF_c \times e_c - SF_{ccu} \times e_{ccu} - e_{O_{CCS}}) \quad \text{Equation (2)}$$

**Table 7 : Terms to consider according to IMO guidelines for calculating Tank-to-Wake GHG emissions**

Term	Units	Explanation
$C_{slip\_ship}$	% of total fuel mass	Factor accounting for fuel (expressed in % of total fuel mass delivered to the ship) which escapes from the energy converter without being oxidized (including fuel that escapes from combustion chamber/oxidation process and from crankcase, as appropriate) $C_{slip\_ship} = C_{slip} * (1 - C_{fug}/100)$
$C_{slip}$	% of total fuel mass	Factor accounting for fuel (expressed in % of total fuel mass consumed in the energy converter) which escapes from the energy converter without being oxidized (including fuel that escapes from combustion chamber/oxidation process and from crankcase, as appropriate)
$C_{fug}$	% of fuel mass	Factor accounting for the fuel (expressed in % of mass of the fuel delivered to the ship) which escapes between the tanks up to the energy converter which is leaked, vented or otherwise lost in the system
$C_{sfx}$	gGHG/g fuel	Factor accounting for the share of GHG in the components of the fuel (expressed in g GHG/g fuel)
$Cf_{CO_2}$	gCO <sub>2</sub> /g fuel	CO <sub>2</sub> emission conversion factor (gCO <sub>2</sub> /g fuel completely combusted) for emissions of the combustion and/or oxidation process of the fuel used by the ship
$Cf_{CH_4}$	gCH <sub>4</sub> /g fuel	CH <sub>4</sub> emission conversion factor (gCH <sub>4</sub> /g fuel delivered to the ship) for emissions of the combustion and/or oxidation process of the fuel used by the ship

$Cf_{N_2O}$	gN <sub>2</sub> O/g fuel	N <sub>2</sub> O emission conversion factor (gN <sub>2</sub> O/g fuel delivered to the ship) for emissions of the combustion and/or oxidation process of the fuel used by the ship
$GWP_{CH_4}$	gCO <sub>2</sub> eq/g CH <sub>4</sub>	Global warming potential of CH <sub>4</sub> over 100 years (based on the fifth IPCC Assessment Report 5)
$GWP_{N_2O}$	gCO <sub>2</sub> eq/g N <sub>2</sub> O	Global warming potential of N <sub>2</sub> O over 100 years (based on the fifth IPCC Assessment Report 5)
$GWP_{fuelx}$	gCO <sub>2</sub> eq/g GHG	Global warming potential of GHG in the components of the fuel over 100 years (based on the fifth IPCC scientific Assessment Report)
$SF_c$	0 or 1	Carbon source factor to determine whether the emissions credits generated by biomass growth are accounted for in the calculation of the TtW value
$e_c$	gCO <sub>2</sub> eq/g fuel	Emissions credits generated by biomass growth
$e_{ccu}$	gCO <sub>2</sub> eq/g fuel	Emission credits from the used captured CO <sub>2</sub> as carbon stock to produce synthetic fuels in the fuel production process and utilization (that was not accounted under $e_{fecu}$ and $e_p$ )
$SF_{ccu}$	0 or 1	Carbon source factor to determine whether the emissions credits from the used captured CO <sub>2</sub> as carbon stock to produce synthetic fuels in the fuel production process are accounted for in the calculation of the TtW value
$e_{occu}$	gCO <sub>2</sub> eq / g fuel	Emission credit from carbon capture and storage ( $e_{occs}$ ), where capture of CO <sub>2</sub> occurs onboard. This should properly account for the emissions avoided through the capture and sequestration of emitted CO <sub>2</sub> , if CCS occurs on board. From the above-mentioned emission credit, all the emissions resulting from the process of capturing ( $e_{cc}$ ) and transporting ( $e_t$ ) the CO <sub>2</sub> up to the final storage (including the emissions related to the injection, etc.) need to be deducted. This element should be calculated with the following formula: $e_{occs} = C_{sc} - e_{cc} - e_t - e_{st} - e_x$
$C_{sc}$	gCO <sub>2</sub> / g fuel	Credit equivalent to the CO <sub>2</sub> captured and stored (long-term: 100 years)
$e_{cc}$	gCO <sub>2</sub> eq / g fuel	Any emission associated with the process of capturing, compress and temporarily store on board the CO <sub>2</sub>
$e_t$	gCO <sub>2</sub> eq / g fuel	Emissions associated with transport to long-term storage site
$e_{st}$	gCO <sub>2</sub> eq / g fuel	Any emission associated with the process of storing (long-term: 100 years) the captured CO <sub>2</sub> (including fugitive emissions that may happen during long-term storage and/or the injection of CO <sub>2</sub> into the storage)
$e_x$	gCO <sub>2</sub> eq / g fuel	Any additional emission related to the CCS
LCV	MJ/g	Lower Calorific Value is the amount of heat that would be released by the complete combustion of a specified fuel

\* Pending further methodological guidance to be developed by OMI, the value of " $e_{ccu} \times SF_{ccu}$ ", " $C_{fug}$ " as well as " $e_{occs}$ " should be set to 0.

IMO methodology allows to calculate two TtW values as follows:

- TtW GHG intensity value 1: calculated regardless of the carbon source, therefore the  $e_c$  and  $e_{ccu}$  parameters should not be taken into account and the  $SF_c$  and  $SF_{ccu}$  value should be always 0; and

- TtW GHG intensity value 2: calculated taking into account the carbon source for fuels of biogenic origins or made from captured carbon, therefore the ec and eccu parameters should be taken into account and the SFc and SFccu values should be always 1.

### c Fuel Well-to-Wake

The Fuel Well-to-Wake (WtW) GHG emission factor (gCO<sub>2</sub>e<sub>q</sub>/MJ<sub>LCV</sub> fuel or electricity) is calculated as the sum of the previously calculated terms, as follows:

$$GHG_{WtW} = GHG_{WtT} + GHG_{TtW} \quad \text{Equation (3)}$$

Where:

**Table 8: Terms to consider according to IMO guidelines for calculating Well-to-Wake GHG emissions**

Term	Units	Explanation
$GHG_{WtW}$	gCO <sub>2</sub> e <sub>q</sub> /MJ <sub>(LCV)</sub>	Total well-to-wake GHG emissions per energy unit from the use of the fuel or electricity in a consumer on board the ship
$GHG_{WtT}$	gCO <sub>2</sub> e <sub>q</sub> /MJ <sub>(LCV)</sub>	Total well-to-tank GHG upstream emissions per energy unit of the fuel provided to the ship
$GHG_{TtW}$	gCO <sub>2</sub> e <sub>q</sub> /MJ <sub>(LCV)</sub>	Total tank-to-wake GHG downstream emissions per energy unit from the use of the fuel or electricity in a consumer on board the ship

### d Container Unit Transportation Work Well-to-Wake

In the previous sections, it was detailed the Well-to-Wake methodology defined in IMO guidelines at fuel level - expressed in gCO<sub>2</sub>e per MJ of fuel. In this study, it is also expressed the Well-to-Wake lifecycle emissions in relation to freight transport, measured in gCO<sub>2</sub>e<sub>q</sub> per TEU-Nm or TEU-km (or t.Nm or t.km).

The calculation methodology for transportation work Well-to-Wake is not defined in [\(MEPC.376\(80\)\)](#) but interpreted from [\(MEPC.278\(70\)\)](#) amendments to MARPOL Annex VI to introduce the data collection system for fuel oil consumption of ships.

The Transportation work Well-to-Wake (WtW) GHG emission factor (gCO<sub>2</sub>e<sub>q</sub>/TEU - km) is calculated in this study as defined in (Equation (4)). It accounts for the sum of the GHG intensity of different types of fuels used onboard, including ignition fuels and others, in both the Main Engine (ME) and the Auxiliary Engines (AE).

$$Transportation\ Work_{GHG_{WtW}} = \frac{\sum(Fuel_{ME} \times GHG_{WtW,ME}) + \sum(Fuel_{AE} \times GHG_{WtW,AE})}{C \times D} \quad \text{Equation (4)}$$

Where:

**Table 9: Terms considered in this study for calculating Transportation Work Well-to-Wake GHG emissions**

Term	Units	Explanation
$Transportation\ Work_{GHG_{WtW}}$	gCO <sub>2</sub> e <sub>q</sub> /TEU-km	Total well-to-wake GHG emissions per transportation work from the use of the fuel or electricity in a consumer on board the ship.
$Fuel_{ME}$	MJ <sub>(LCV)</sub>	Amount of fuel consumed by the Main Engine (ME)
$GHG_{WtW,ME}$	gCO <sub>2</sub> e <sub>q</sub> /MJ <sub>(LCV)</sub>	Well-to-Wake GHG emissions per energy unit of a fuel provided to the ME.
$Fuel_{AE}$	MJ <sub>(LCV)</sub>	Amount of fuel consumed by the Auxiliaries Engines (AE)
$GHG_{WtW,AE}$	gCO <sub>2</sub> e <sub>q</sub> /MJ <sub>(LCV)</sub>	Well-to-Wake GHG emissions per energy unit of a fuel provided to the AE.
$C$	TEU	Container capacity
$D$	Km	Distance of the trip

### 3.3.2 LCA Approach

The methodology adopted in the study is primarily based on the IMO’s LCA recommendations for maritime fuel, as outlined in MEPC.376(80), adopted in July 2023. These recommendations aim to comply with ISO 14040 and 14044 standards for assessing the life cycle impacts of fuels. However, the followed LCA approach differs from IMO’s LCA guidelines in several points:

- While IMO’s LCA guidelines allows for calculating two TtW values (see details above), it is used in our followed approach, only the second IMO TtW value. This approach accounts for carbon credits from biomass growth or captured CO<sub>2</sub> as carbon stock to produce synthetic fuels. The recommendations of the second delegated act of RED II defining the methodology for calculating greenhouse gas emissions for RFNBO are applied in this study. This methodology clearly defines the rules for allocating emission credits to capture to offset emissions at the combustion of the finished product: the emissions considered as avoided, either captured in combustion fumes in the case of e-methanol or through biomass growth for bio-methanol, allow for offsetting combustion emissions under the conditions defined by the delegated act (i.e., that the captured CO<sub>2</sub> is of biogenic or atmospheric origin from 2036 on electricity generation plants and from 2041 for companies subject to the ETS). However, for the sake of clarity, the CO<sub>2</sub> combustion emissions and the compensating associated credits do not appear in this study’s figures.
- CH<sub>4</sub> and N<sub>2</sub>O combustion emissions from methanol and ammonia are not accounted as they are yet to be measured (source [Fuel EU Maritime](#)). Consequently, emissions in WTW for ammonia and methanol products assessed in this study are equal to WTT emissions since:
  - TTW CO<sub>2</sub> emissions are compensated by carbon capture for methanol and null for ammonia and
  - CH<sub>4</sub> and N<sub>2</sub>O TTW emissions are not included.
- However, it was provided N<sub>2</sub>O combustion emissions simulated data from a hypothetical CMA CGM ammonia transportation trip. Those N<sub>2</sub>O emissions are only accounted in the section “7 Container Unit Transportation Work Well-to-Wake Results”.
- Latest values from [IPCC AR6](#) are used instead of [AR5](#) values recommended in IMO’s guidelines to calculate CO<sub>2</sub>eq emissions. Table 10 presents the Global Warming Potential over a 100-year period (GWP 100) from AR6 and AR5 emissions metrics for the selected species.

**Table 10: Global Warming Potential over a 100-year period (GWP 100) emissions metrics for the selected species (source IPCC AR6 and AR5)**

	AR6 GWP 100	AR5 GWP 100
Carbon dioxide (CO <sub>2</sub> )	1	1
Methane (CH <sub>4</sub> ) – non-fossil	27	28
Methane (CH <sub>4</sub> ) – fossil	29.8	30
Nitrous oxide (N <sub>2</sub> O)	273	265

### 3.4 Functional Units

To meet the study's objectives, two functional units are defined:

- **The production, transport, conditioning, and combustion of 1 MJ of e-/bio-methanol or e-/blue ammonia.**  
*The results are expressed in gCO<sub>2</sub>eq/MJ of methanol or ammonia in Well-to-Wake. In the case of e-methanol and bio-methanol, the Tank-to-Wake impacts related to combustion are offset by previously captured CO<sub>2</sub> and thus counted as null (see Methodology). In the case of e-ammonia, Tank-to-wake greenhouse gas (GHG) emissions from e-ammonia mainly depend on nitrous oxide (N<sub>2</sub>O) emissions as e-ammonia does not contain carbon and therefore does not emit CO<sub>2</sub> during combustion. Those emissions are however only included in the next functional unit.*

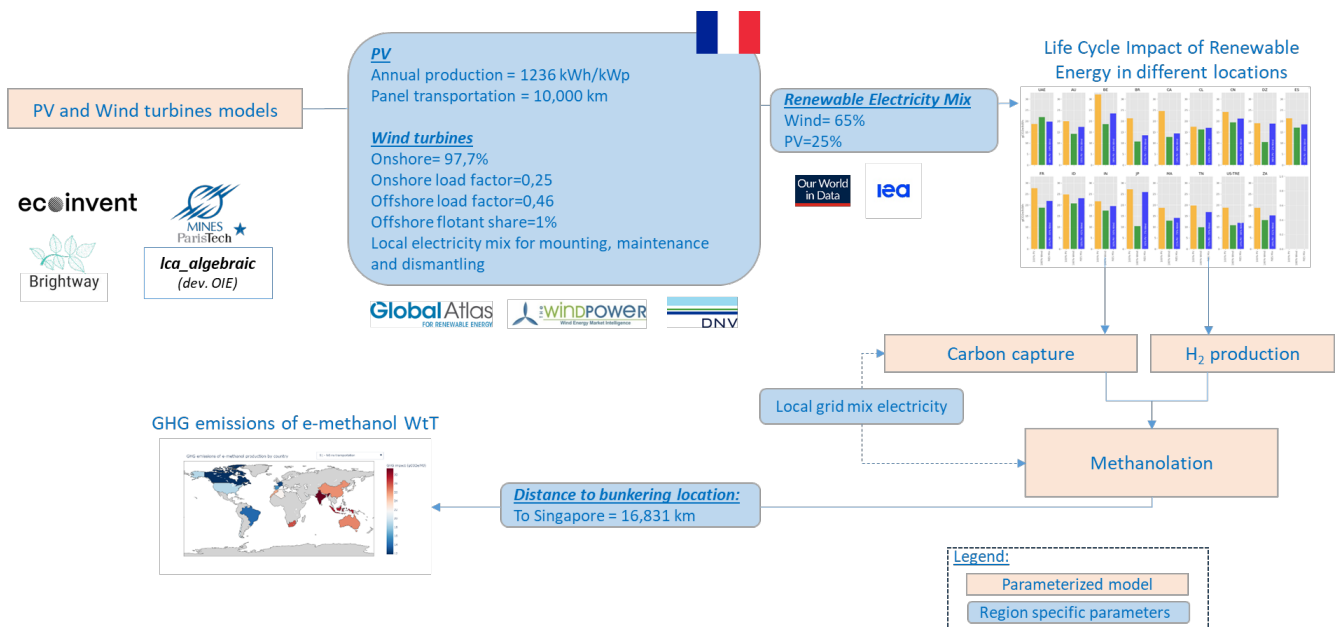
- **The transport of goods in TEU.km or t.km according to a typical route.**  
*For this second functional unit, the consumption data of methanol or ammonia (and conventional fuel for comparison) as well as the cargo capacity data of the ships are provided by CMA CGM.*

### 3.5 Data and Tools

The modelling is based on the Ecoinvent3.9.1 database (FitzGerald 2022) and the chosen method is cut-off, simple. The Python library “Brightway2” (Mutel 2017) and package “LCA algebraic” (Jolivet et al. 2021) are used to perform the LCA calculations. Simapro, another LCA calculation software, is used in addition to calculate the regionalised water use impacts using the AWARE method (Boulay et al. 2018). The use of Brightway2 and LCA algebraic overlayer allows for sensitivity analyses and the processing of a significant number of scenarios, using parameterised models, which is a major asset in our methodological approach.

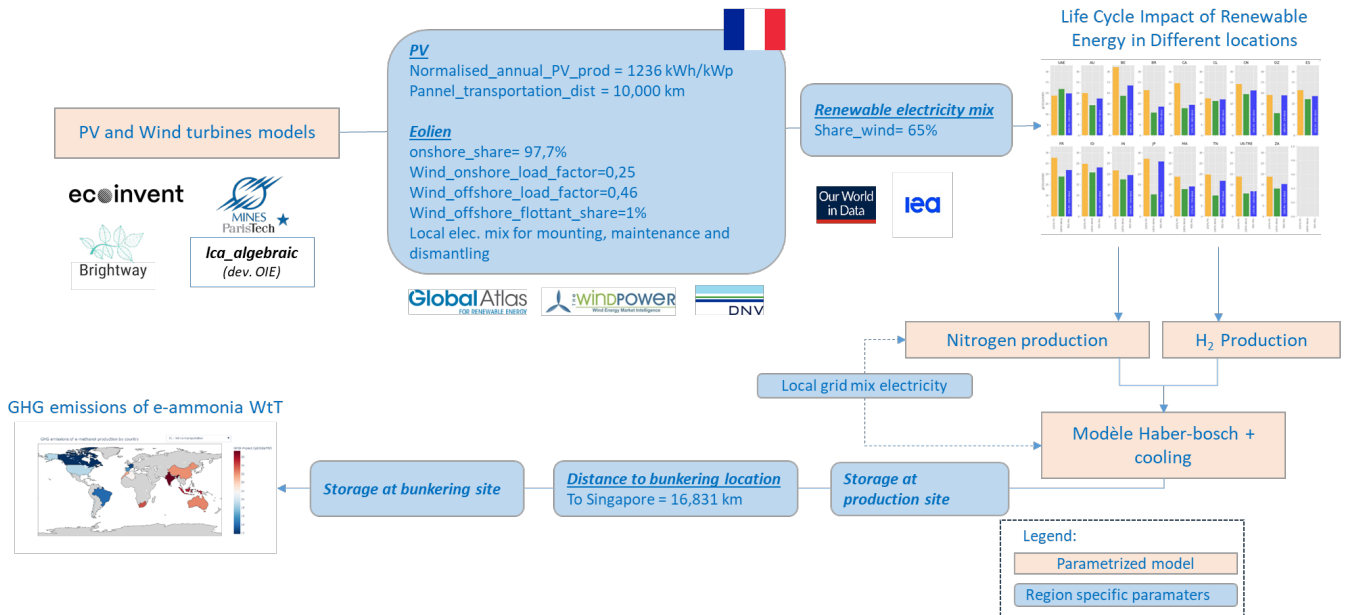
### 3.6 Modelling Chain

The parameterised modelling in Brightway2 consists of parameterised blocks. For each region and scenario studied, different parameters are applied to these blocks. Particularly, the parameters modified for each region (hereafter referred to as differentiating parameters) are presented in blue in Figure 8 and Figure 9 for the example of France. In Figure 8, the modelling chain of e-methanol is presented. It consists of the following four blocks: (1) Renewable electricity production models; (2) Carbon capture technology models; (3) Green hydrogen production technology models; (4) Methanol synthesis. In Figure 9, the modelling chain of e-ammonia is presented, consisting of the following four blocks: (1) Renewable electricity production models; (2) Nitrogen production; (3) Green hydrogen production technology models; (4) Ammonia synthesis (Haber-Bosch). This approach enables the calculation of the impact of fuel production, distribution, and conditioning specific to each region.



**Figure 8: Modelling chain, main data sources used, and differentiating parameters (here, the example of parameters for e-methanol synthesis in France) of the LCA model**





**Figure 9 Modelling chain, main data sources used, and differentiating parameters (here, the example of parameters for e-ammonia synthesis in France) of the LCA model**

## 4 Life Cycle Inventories

### 4.1 Fossil References

#### 4.1.1 Methanol

An additional objective of the study is to compare the environmental impact results, particularly the GHG emissions of bio-methanol and e-methanol to fossil references to quantify their potential to reduce emissions for the maritime sector. The conventional fuels currently used in the maritime sector are HFO (heavy fuel oil), VLSFO (Very Low Sulphur Fuel Oil), and MDO (marine diesel oil). We also compare the results of e-methanol and bio-methanol with the GHG emissions of grey methanol (derived from natural gas) and black methanol (derived from coal) sourced from recognised sources in the literature.

To obtain the GHG emissions of conventional fuels, data was sourced from [FuelEU Maritime Regulation](#). The results are presented in Table 11. For each fuel, the lower heating value, the WtT impact, TtW impact, and the total WTW emissions are presented.

**Table 11: GHG intensity and LHV of fossil references**

Fuel	Lower Heating Value (MJ/kg)	Well-to-Tank (g CO <sub>2eq</sub> /MJ)	Tank-to-Wake (g CO <sub>2eq</sub> /MJ)	Well-to-Wake (g CO <sub>2eq</sub> /MJ)
HFO <sup>1</sup>	40.5	13.5	76.9	90.4
VLSFO <sup>1</sup>	41	13.2	78.2	91.4
MDO <sup>1</sup>	42.7	14.4	75.1	89.5
Methanol from Natural Gas	19.9	31.3 <sup>1</sup> - 40 <sup>2</sup>	69.1	100.4 <sup>1</sup> - 110 <sup>2</sup>

<sup>1</sup>Source: [FuelEU Maritime Regulation](#)

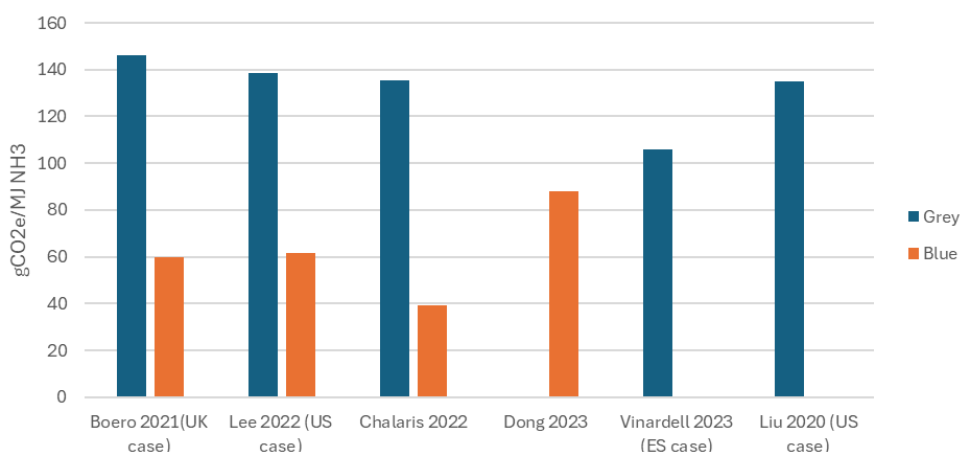
<sup>2</sup>Source: [Methanol Institute](#)

For methanol production from natural gas, we were able to compare this result with those from other sources such as the Methanol Institute (Carlo Hamelinck and Mark Bunse 2022) and the JECv5 study (PRUSSI et al. 2020). The Methanol Institute reports a value of 40 gCO<sub>2eq</sub>/MJ (WtT) and 110 gCO<sub>2eq</sub>/MJ (WtW) for grey methanol.

- The JECv5 study reports 31.6 gCO<sub>2eq</sub>/MJ (WtT) and 100.6 gCO<sub>2eq</sub>/MJ (WtW) for grey methanol.
- The Methanol Institute also reports Well-to-Wake data for black methanol from coal, reaching nearly 300 gCO<sub>2eq</sub>/MJ.
- The Ecoinventdata "Methanol {GLO} | market for methanol | Cut-off, U" provides a grey methanol result of 41 gCO<sub>2eq</sub>/MJ (WtT).

#### 4.1.2 Ammonia

An additional objective of the study is to compare the environmental impact results, particularly the GHG emissions, of e-ammonia with conventional grey ammonia (derived from natural gas) and also blue NH<sub>3</sub> (derived from natural gas with carbon capture and storage). In this section, greenhouse gas (GHG) emission values for grey and blue NH<sub>3</sub> are sourced from the literature are sourced and presented in Figure 10. In this study, grey and blue NH<sub>3</sub> will be modelled from other LCA inventories. The results are presented in the results section.



**Figure 10 Average of GWP contribution for grey- and blue-NH<sub>3</sub> production derived from literature.**

This bar chart presents the average Global Warming Potential (GWP) contribution for grey and blue ammonia (NH<sub>3</sub>) production based on existing literature results. The GWP is measured in gCO<sub>2</sub>eq/MJ.

- Grey ammonia (dark blue bars) consistently shows a much higher GWP across all sources, ranging approximately between 110 and 145 gCO<sub>2</sub>eq/MJ NH<sub>3</sub>.
- Blue ammonia (orange bars) shows significantly lower GWP values compared to grey ammonia, indicating that carbon capture and storage (CCS) significantly reduces emissions.
- Comparative differences among studies:
  - The highest grey ammonia GWP is reported in (Boero et al. 2021)(UK case), at approximately 145 gCO<sub>2</sub>e/MJ NH<sub>3</sub>.
  - The lowest grey ammonia GWP appears in (Vinardell et al. 2023)(ES case), around 100 gCO<sub>2</sub>eq/MJ NH<sub>3</sub>.
  - For blue ammonia, the lowest reported value is in (Chalaris et al. 2022), while (Duc Tuan Dong 2023) presents a higher GWP for blue ammonia, which could indicate variability in CCS efficiency or other process differences.
- Regional variations: The chart includes results from different geographical cases (UK, US, ES), which may influence the data due to differences in energy sources, CCS implementation, and ammonia production methods.

From the literature values found for fossil (grey and blue) ammonia, it can be stated that:

- Grey ammonia production remains a highly carbon-intensive process (higher emissions than RED fossil reference).
- Blue ammonia offers between 5% (Duc Tuan Dong 2023) and 40% (Chalaris et al. 2022) GHG reductions compared to fossil reference, there is variability depending on the study and region.
- The effectiveness of carbon capture technology and the energy sources used play a crucial role in determining the sustainability of blue ammonia.

These values for fossil fuels sources from the literature are given for informative purpose. Indeed, the fossil ammonia pathways have been specifically modelled for various production regions of interest.

## 4.2 Electricity

### 4.2.1 Local Grid Mix Electricity (Not fully Renewable)

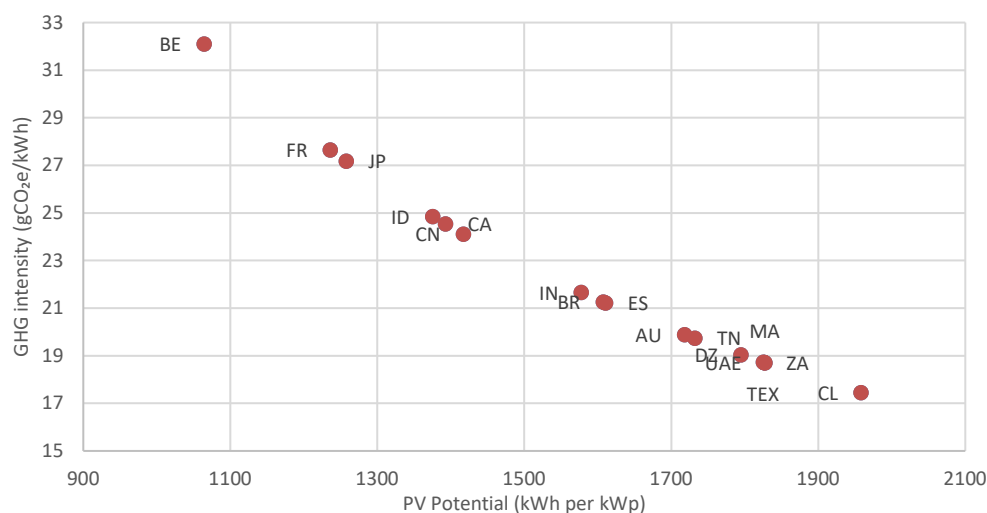
Depending on the configuration scenarios, electricity from the local regional electric mix may be used for the production of e-methanol and e-ammonia. The data used are from the Ecoinvent3.9.1 database and corresponds to the locally consumed electric mix (including electricity imports) calculated from statistical data for the year 2021. It should be noted that the carbon intensity for each country can vary significantly between regions of the same country: for example, in China, the carbon intensity can vary from 308 gCO<sub>2</sub>eq/kg for the grid of the southwest region (State Grid Southwest China Branch) containing a significant share of hydropower to over 1400 gCO<sub>2</sub>eq/kg for the northwest region, which has a significant share of low-energy coal. In this case, a "market" mix is used, averaging according to the quantities of electricity consumed.

### 4.2.2 Photovoltaic Electricity

For renewable production equipment, although the production of electricity does not directly generate GHGs, the stages of manufacturing, transport, maintenance, replacement, and end-of-life phases of the equipment do generate GHG emissions.

For this purpose, the work of (Besseau et al. 2023) is used, which - based on Ecoinvent data for photovoltaic production – allows to parameterise existing models in order to (i) update them according to technological advancements (Ecoinvent data dates back to 2009 for some and is no longer representative of progress made in the field) and (ii) vary several parameters to best represent the regional specificities of our study.

The differentiating parameters retained can be seen in Annex 2; the only differentiating parameters between regions are the photovoltaic production potential (which depends on the local annual irradiation) and the transport distance between the production region (China) and the e-methanol production region. The available data on photovoltaic potential are presented in Annex 1. The annual irradiation data are averaged over the area of the region considered. 3 presents all parameters value common to all production regions. The result of the GHG emissions for the regional photovoltaic production is presented in Figure 11:



**Figure 11: GHG emissions for electricity production from photovoltaic equipment from cradle-to-grave**

Note: The carbon intensity calculated from the parameterised model is much lower than that of Ecoinvent (~60 gCO<sub>2</sub>eq/kWh in France, for example) and similar to other values available in current literature. The impact per kWh produced can vary by a factor of one to two times for Chile and Belgium due to the different regional photovoltaic potential and thus the distribution over the considered lifespan of the photovoltaic equipment (30 years).

### 4.2.3 Wind Electricity

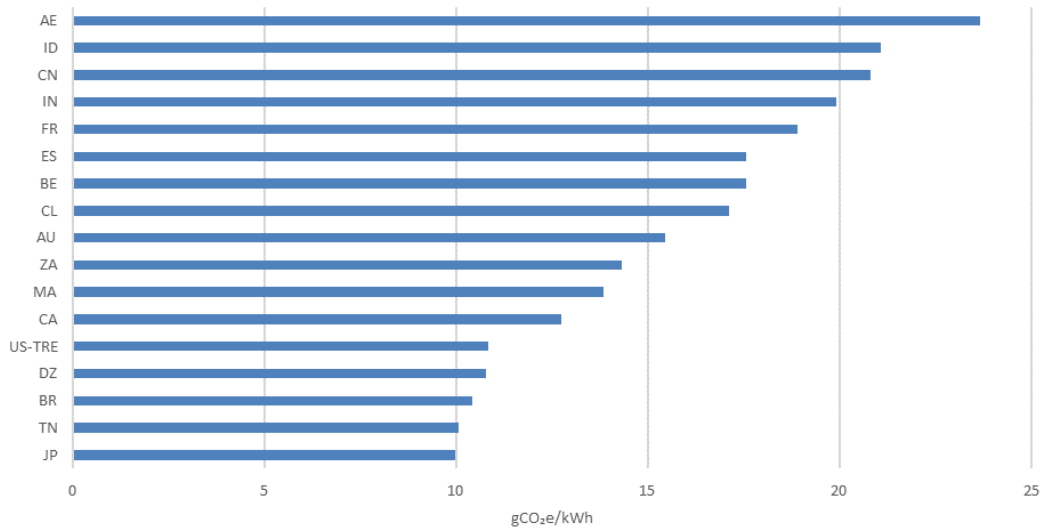
Similarly, the models developed by (Besseau et al. 2019) for wind turbines were used to reflect regional specificities. These models are constructed by extrapolation from Ecoinvent data for wind power production (obsolete as they are no longer representative of the sizes and powers of current wind turbines) and manufacturer data.

The differentiating parameters used can be seen in Annex 2 and all common parameters in 3. The source of each differentiating parameter for each region is presented in Table 12.

**Table 12: Data sources used for differentiating parameters for wind power production**

Differentiating Parameter	Parameter Name in Appendix	Source Used	Note
Onshore/offshore proportion	onshore_share	<a href="#">Global Wind Report 2022</a>	The offshore share is $1 - \text{onshore\_share}$
Onshore capacity factors	Wind_onshore_load_factor	<a href="#">The Wind Power database &amp; renewables.ninja</a> tool ((Pfenninger and Staffell 2016), (Staffell and Pfenninger 2016)) at the location of the largest operating onshore or offshore farm.	As the capacity factor is highly dependent on local conditions and difficult to represent for an entire country or region, it was chosen to use capacity factors at specific points: where there is already a wind farm.
Offshore capacity factors	Wind_offshore_load_factor		
Use of local electricity for assembly, maintenance, and decommissioning of the wind turbine	Wind_elec_switch_param_XX	Electricity from local electricity mix Ecoinvent 3.9.1	
Proportion between fixed-bottom and floating offshore	Wind_offshore_floatant_share	<a href="#">DNV energy transition outlook</a>	The fixed-bottom offshore share is $1 - \text{Wind\_offshore\_flottant\_share}$

The load factors for floating and fixed offshore wind are considered identical due to a lack of data. The type of fixation and the associated GHG emissions vary depending on the model used, floating or fixed. The results for wind power production are presented in Figure 12. These results are obtained from the model parameterised for each region considered in the study using the input data in Table 12 for each region.



**Figure 12: GHG emissions for electricity production from a wind energy mix from cradle-to-grave**

Note: The calculated emissions are heavily impacted by the considered onshore load factor (see Annex 2). These results are therefore difficult to represent the wind production potential at the scale of the region/country.

#### 4.2.4 Local Renewable Electricity Mix

To represent the use of renewable electricity for each region, a local renewable electricity mix is proposed based on the distribution of photovoltaic and wind productions. The differentiating parameter "share\_wind" is available for each region in Annex 2. The data used for this parameter comes from the [World Energy Outlook IEA 2022](#). The summary of the results obtained for electricity production for each region is presented in Table 13. This table also shows the GHG emissions from the local electricity mix in each region studied (Ecoinvent data). The results for electricity production from wind or photovoltaics come from the parameterised models presented in the previous sections.

**Table 13: GHG emissions related to local electricity consumption and electricity production from photovoltaic, wind, and renewable electric mix (gCO<sub>2</sub>eq/kWh)**

	MIX	100% PV	100% WIND	%PV	%WIND	ENR MIX (2022)
UAE	567,8	18,7	23,7	66%	34%	20,4
AU	958,7	19,9	15,5	55%	45%	17,9
BE	203,4	32,1	17,6	36%	64%	22,8
BR	167,3	21,3	10,4	27%	73%	13,4
CA-QC	24,6	24,5	12,7	14%	86%	14,4
CL	571,9	17,5	17,1	61%	39%	17,3
CN	940,8	24,1	20,8	36%	64%	22,0
DZ	669,4	19,0	10,8	98%	2%	18,8
ES	259,6	21,2	17,6	35%	65%	18,8
FR	74,2	27,6	18,9	35%	65%	21,9
ID	1160,0	24,9	21,1	58%	42%	23,2
IN	1363,4	21,7	19,9	50%	50%	20,8
JP	673,9	27,2	10,0	93%	7%	25,9
MA	885,6	18,7	12,9	21%	79%	14,1
TN	626,0	19,7	10,1	70%	30%	16,8
US-TRE	470,1	18,7	10,9	14%	86%	11,9
ZA	1056,7	18,7	14,3	39%	61%	16,0



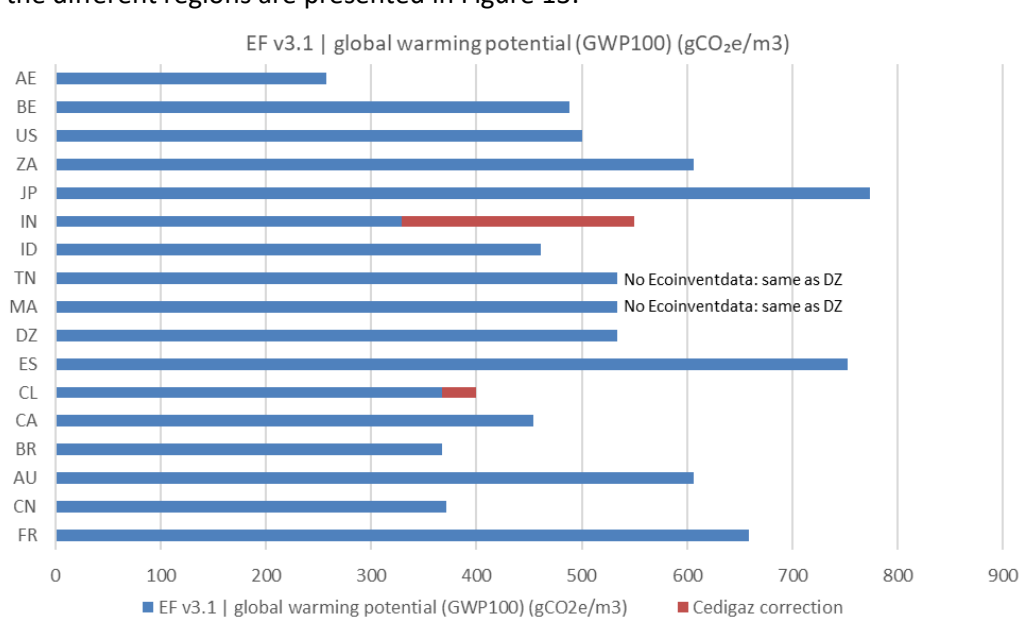
These different electricity mixes have been used in the modelling of e-methanol and e-ammonia production at the electrolyser level for hydrogen production as well as for CO<sub>2</sub> capture for heat production and auxiliaries' consumptions.

### 4.3 Natural Gas

Natural gas is used both for hydrogen production from methane reforming (Section 4.5.2. Methane Reforming) and for CO<sub>2</sub> capture (Section 4.4. CO<sub>2</sub> capture). The Ecoinvent 3.9.1 database is used to best represent the associated impacts of the region-specific natural gas use. Particularly, the data “market for natural gas, high pressure” represents the consumption mix of natural gas in a given geographical location, including imports, transportation to the consumer and losses during that process. In other words, the values used take into account supply chain steps including liquefaction/gasification/methane leaks etc. The regionalised supply of natural gas market data is based on either one of the following: (i) [statistics from BP 2020](#), (ii) gas trade data from [EuroStat 2022](#), (iii) based on national production mixes (considering no importation).

Natural gas flaring data are based on data from the [Global Gas Flaring Reduction Partnership \(GGFR\)](#) of the World Bank. Data on methane emissions from gas venting and fugitive emission sources come from the [International Energy Agency’s Methane Tracker 2022](#).

Some of the Ecoinvent data have been modified or added based on input from consulted experts: Morocco (MA) and Tunisia (TN) are assumed to have the same value as Algeria (DZ) due to lack of data. The values for India (IN) and Chile (CL) have been adjusted. The adjusted GWP100 results of market-based consumption of high-pressure natural gas in the different regions are presented in Figure 13:



**Figure 13: Adjusted GWP100 results of market-based consumption of high-pressure natural gas in the different regions (based on based on input from consulted experts )**

### 4.4 Carbon Dioxide Capture

According to the RED II delegated act methodology, the origin of the captured carbon - whether fossil or biogenic - is not relevant for determining the GHG emissions of the e-fuel (at least until 2035). Only the emissions associated with the energy needed to capture the CO<sub>2</sub> appear in the calculations. The inventories and sources of the various carbon capture technologies modelled are presented in Table 14:

**Table 14: Inventory data for modelling carbon capture technologies**

CO <sub>2</sub> stream source	Flue gas from natural gas power plants (NGPP) <sup>1</sup>		Direct Air Capture (DAC) <sup>2</sup>
Configuration	Electric calciner	Gas calciner	Configuration
Electricity requirements [MJ/kgCO <sub>2</sub> ]	4.3332	0.0334	Electricity requirements [MJ/kgCO <sub>2</sub> ]
Gas requirements [MJ/kgCO <sub>2</sub> ]	0	4.2998	Gas requirements [MJ/kgCO <sub>2</sub> ]
CO <sub>2</sub> volumetric concentration [%vol]	~12		0.04
Cooling water requirements [kg/kgCO <sub>2</sub> ]	2.15		0
Infrastructure & inputs data	Monoethanolamine, steel, etc. data from (Chisalita et al. 2019)		Data from (Keith et al. 2018)

<sup>1</sup> (Socolow, 2011) Heat requirements for solvent regeneration are considered in the electric configuration case as met by electric heating with 100% efficiency from electricity to heat.

<sup>2</sup> (Keith et al. 2018)

Assumptions related to the carbon capture from methane reforming hydrogen are detailed in the next section 4.5.2.

## 4.5 Hydrogen

### 4.5.1 From Water Electrolysis

#### a Production

Two hydrogen production technologies are modelled: alkaline electrolyser and reversible high-temperature solid oxide electrolysis (SOEC). Consumption and infrastructure data come from the literature and are summarised in Table 15. In this study, hydrogen storage to compensate for fluctuations in hydrogen production and allow continuous supply to the methanol synthesis process is not considered, however, hydrogen storage to maintain a minimum production threshold is considered and detailed in the next subsection.

**Table 15: Inventory data for modelling hydrogen production technologies**

Electrolysis Technology	Alkaline <sup>1,2</sup>	SOEC <sup>3</sup>
Efficiency [MJ <sub>electric</sub> /LHV <sub>hydrogen</sub> ]	62.5%	80%
Heat requirements [MJ/MJ <sub>H<sub>2</sub></sub> ]	0	0.246
Infrastructure	(Zhao 2018)	(Häfele 2016)

<sup>1</sup> Efficiency values for alkaline technology vary in the literature from 58% to 66% according to Eifer, CEA, and McPhy in (ADEME 2020). An average value of 62.5% was chosen, which is also used in (NREL-Norsk hydro 2004)

<sup>2</sup> Infrastructure data for the electrolyser comes from (Zhao 2018) with: 1MW installation size for H<sub>2</sub> production of 200Nm<sup>3</sup>/h, 6000h/year operation, stack (electrolyser) lifetime = 20000h, auxiliary equipment (Balance Of Plant or BoP) lifetime = 20 years, H<sub>2</sub> output pressure = 1 bar (equivalent to H<sub>2</sub> production of 16.8 kg H<sub>2</sub>/h).

#### b Storage

To ensure continuous operation of methanol and ammonia synthesis plants, a hydrogen storage step is required to maintain production above the minimum flexibility threshold. This storage impacts the LCA models in two ways: Infrastructure Impact – The environmental footprint of the storage tank is accounted for, with its impact distributed over its lifetime and the total hydrogen production.

- Energy Consumption – Local energy demand is considered for hydrogen compression:

- From the electrolyser output pressure (1 bar) to storage tank pressure (10 bar).
- Specifically for ammonia synthesis, an additional compression step from the storage tank (10 bar) to the Haber-Bosch reactor (20 bar).

At 10 bar, hydrogen remains in a gaseous state, eliminating the need for refrigeration or liquefaction during storage. The storage capacity required depends on the local intermittency of renewable energy. However, to simplify and ensure a conservative approach, this study assumes a storage reservoir capable of sustaining a Haber-Bosch plant for seven days, maintaining a minimum of 80% capacity.

The amount of steel required for the storage infrastructure is based on cylindrical tank modelling with a 4.0 cm wall thickness (Bionaz et al. 2022). A summary of the assumptions and calculated values for storage dimensioning is presented in Table 16.

**Table 16: Summary of the storage design model assumptions**

	Parameter	Value	Unit	Source
<b>Sizing the H2 tank</b>	H-B capacity	1,000,000	kgNH3/day	
	Flexibility	80%		
	Storage Days	7	days	
	Maximum electrolytic H2 production	142 400	kg H2/d	
	H2 tank reservoir @10bar	35 315	m3	Ideal gas law calculation
	Mass reservoir	1 662	t of reservoir	Austenitic SS type 316 (EN 1.4401). Thickness of the tank (4.0 cm). SS density (8.0 g/cm3). (Bionaz et al. 2022)
	Reservoir lifetime	10	years	
	Reservoir per kg H2	0,0032	kg of reservoir/kg H2	
<b>Energy for compression</b>	Compression energy (atm to 10bar)	0,0217	kWh/kWhH2	(Schmidt et al. 2022)

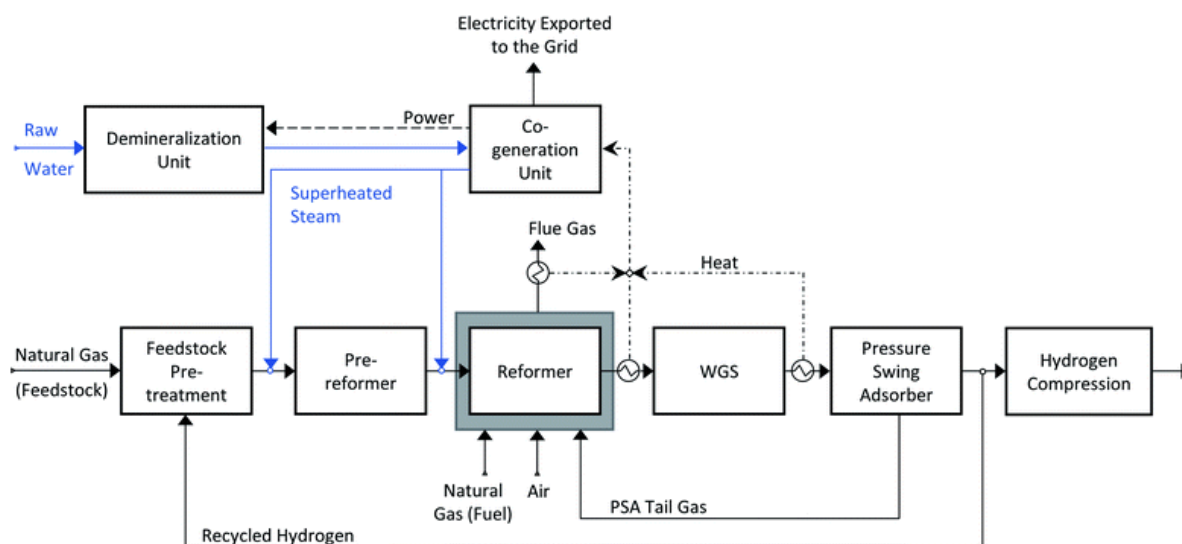
From the sensitivity analysis conducted on e-derived methanol and ammonia (Sections 6.1.1e and 6.2.1c Sensitivity analysis), it can be stated that the H2 storage phase has relatively low impacts on GHG emissions.

#### 4.5.2 From Methane Reforming

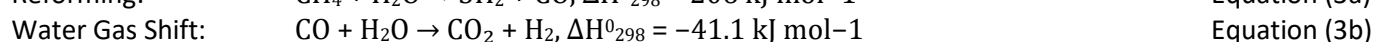
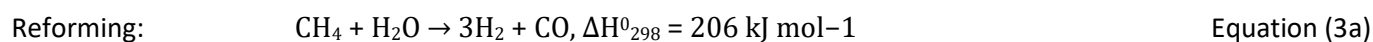
##### a SMR

Currently, hydrogen is produced on a large scale *via* natural gas reforming. The state-of-the-art technology is steam methane reforming (SMR), where methane reacts with steam to produce a hydrogen-rich syngas. A schematic representation of the production process is shown in Figure 14. First, the feedstock is desulfurized in a pre-treatment section and then pre-reformed with some steam, to break down the long-chain hydrocarbons into methane and syngas. Inside the main reforming reactor, the methane is converted to hydrogen and carbon monoxide (Equation (3a) – Reforming reaction). The reforming reaction is endothermic and therefore requires a

heat source. In an SMR production plant, the heat is provided by an external furnace (the grey box surrounding the reformer in Figure 14). The hydrogen yield is further increased in the water gas shift section (WGS), where part of the carbon monoxide reacts with water to produce hydrogen and carbon dioxide (Equation (3b) – WGS reaction).



**Figure 14: Process diagram of Steam Methane Reforming (SMR) from Natural Gas (from (Antonini et al. 2020))**



Multiple configurations exist for the WGS section, where here the choice is mostly between one or two reactors. A high temperature water-gas shift reactor is commonly included, and after that a low temperature water-gas shift reactor (LT WGS) can be added. The addition of the LT WGS allows to reach higher CO conversion, increasing hydrogen yield. Once the hydrogen-rich syngas leaves the WGS section, it requires an additional purification step.

Inventories used in this study for SMR/ATR are sourced from (Antonini et al. 2020). The inventories provided in the (Antonini et al. 2020) supplementary materials include a compression of the purified H<sub>2</sub> stream to 200 bar (following (Valente et al. 2017)). For the sake of our study, this compression energy consumption has been removed in the modelling of the study as H<sub>2</sub> should enter the Haber-Bosch at 20 bar.

## b ATR

The other commercialized hydrogen production technology analysed here is autothermal reforming (ATR). A schematic representation of an ATR plant is shown in Figure 15. Unlike an SMR plant, the reaction heat is provided within the reaction vessel and therefore no external furnace is required. In the reforming reactor, methane is partially oxidized by oxygen and the heat generated drives the endothermic steam reforming reaction. In principle, air could be used as oxygen source, but to avoid the contamination of the hydrogen with nitrogen, pure oxygen is used, requiring an air separation unit (ASU) unit. As for the SMR process, the syngas is shifted with steam and then the raw hydrogen is purified in a PSA unit. The PSA tail gas is burned in a small, fired heater. The generated heat is used to pre-heat the feed streams and to provide some additional heat to the co-generation section. Similar catalysts as for steam methane reforming are used. In this study, we do not consider the option of burning additional natural gas together with the PSA tail gas.

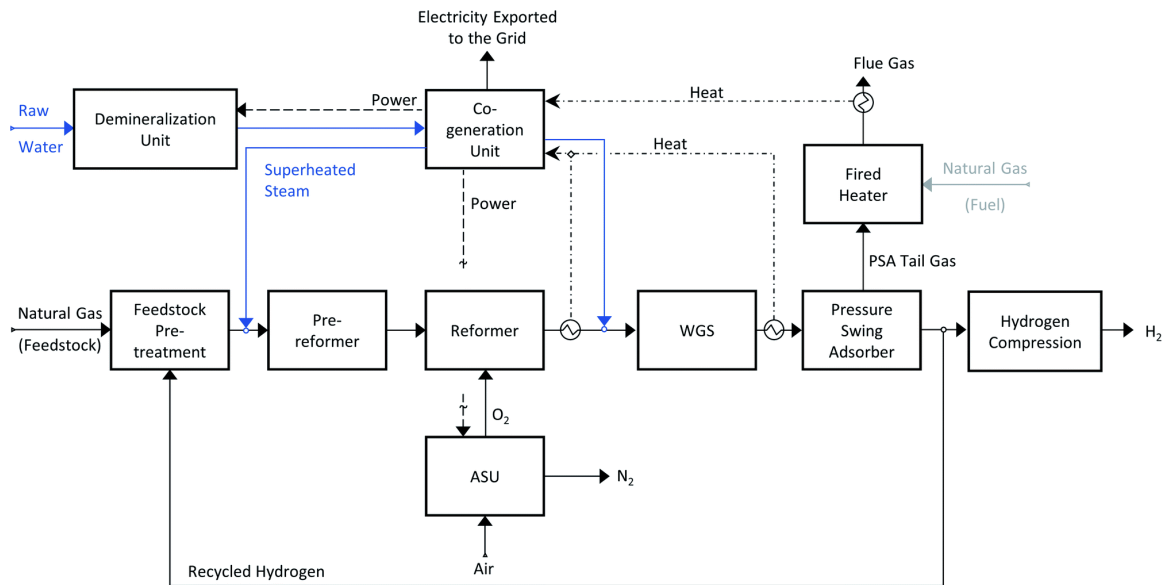


Figure 15: Process diagram of Auto Thermal Methane Reforming (ATR) from Natural Gas (from (Antonini et al. 2020))

### c SMR/ATR with Carbon Capture and Storage

In an SMR plant, there are two sources of carbon dioxide: first (~60%) from the oxidation of the carbon atoms present in the feedstock during reforming and shifting, and second (~40%) from the combustion occurring in the reformer furnace. Therefore, pre-combustion capture can only capture the CO<sub>2</sub> present in the syngas, whereas a post-combustion plant would be needed to capture all the CO<sub>2</sub> in the flue gas. In an ATR plant, the only source of direct CO<sub>2</sub> emissions is the combustion of the PSA-tail gas in the fired heater. Therefore, by adding a pre-combustion capture plant to recover the CO<sub>2</sub> from the syngas, most of the direct CO<sub>2</sub> emissions could be avoided.

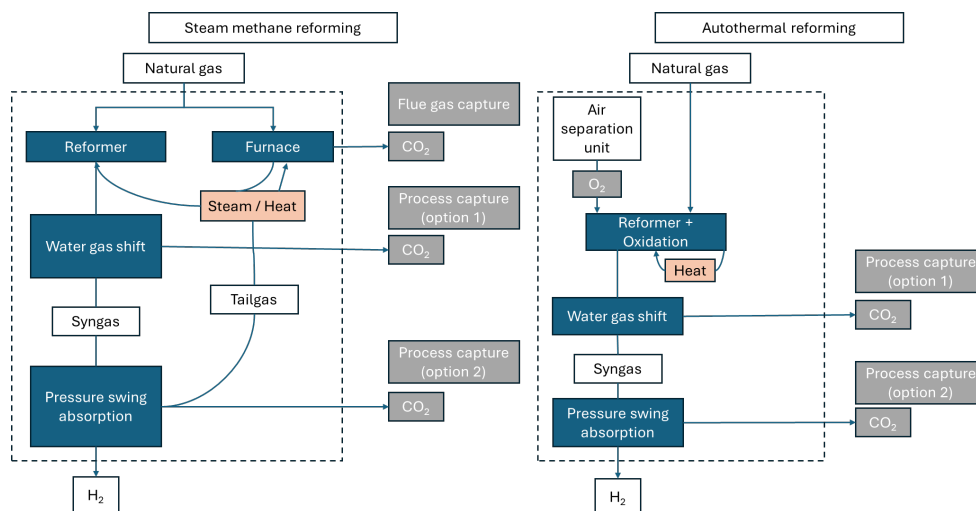


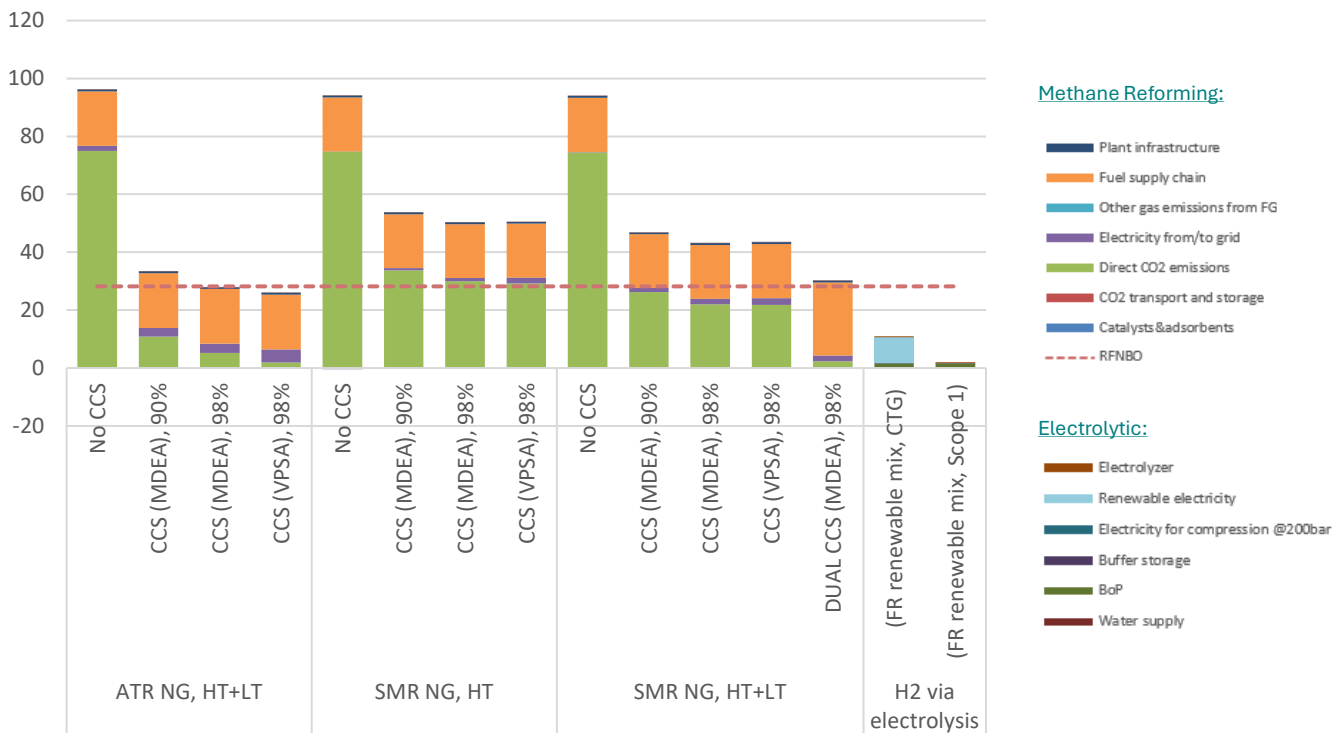
Figure 16: Potential capture block options on SMR and ATR processes (adapted from (Riemer and Duscha 2023))

As investigated in (IEAGHG 2017) report by the International Energy Agency Greenhouse Gas program (IEAGHG), many different SMR processes with CCS options are available; this report showed that classical CO<sub>2</sub> pre-combustion capture from the syngas is the most economic option. Therefore, in (Antonini et al. 2020) only pre-combustion CO<sub>2</sub> capture is considered. In our study, we also evaluate a case of Steam Methane Reforming (SMR) with carbon capture, where CO<sub>2</sub> is captured both, from the Pressure Swing Adsorption (PSA) unit (syngas), and from the flue gas

generated by methane combustion in the furnace, using the flue gas capture inventory defined in section 4.4 (CO<sub>2</sub> capture). This scenario as well as all other scenarios considered is presented in Figure 17 as “Dual CCS capture”.

State-of-the-art amine-based absorption capture technologies (MEA) is considered. Instead of using the carbon capture "block" inventories from section 4.4 on CO<sub>2</sub> capture, our study relies on the integrated inventories from (Antonini et al. 2020) These inventories are derived from process simulations that incorporate MDEA carbon capture directly into the SMR/ATR plant.

Inventories for transport and geological storage of CO<sub>2</sub> (over 200 km per pipeline and in a saline aquifer at a depth of 800 m, respectively) are from (Volkart et al. 2013) Where CO<sub>2</sub> transportation is assumed in a supercritical state without the need of recompression, with 0.00026kg CO<sub>2</sub>/tkm leaks over the pipeline transportation, but no leaking once geologically stored.



**Figure 17: GHG emissions for the production (Well-to-Tank) of 1 MJ of H<sub>2</sub> @ 200 bar via various production pathways (e-, grey-, -blue) in France**

Figure 17 presents the GHG emissions associated with the production of 1 MJ of hydrogen at 200 bar for different production pathways in France. Results show that conventional natural gas-based ATR and SMR exhibit similar GHG intensities, with most emissions stemming from direct CO<sub>2</sub> emissions (green bars) and the natural gas supply chain (orange bars).

Introducing carbon capture to SMR syngas significantly reduces emissions, but the remaining direct CO<sub>2</sub> emissions from furnace combustion remain too high to meet the RFNBO threshold. Even in an optimized SMR configuration, which includes High and Low-Temperature Water Gas Shift (HT+LT) to improve hydrogen yield and a dual carbon capture system (98% capture on syngas + additional capture on furnace flue gases), the resulting hydrogen still slightly exceeds the RFNBO threshold in France.



By contrast, ATR with carbon capture achieves greater GHG reductions than SMR. When equipped with an optimized configuration and state-of-the-art VPSA carbon capture, ATR has the potential to meet the RFNBO criteria.

For this study, we have selected the following life cycle inventories for methane reforming:

- SMR NG, HT (No CCS)
- SMR NG, HT (CCS MDEA 90%)
- ATR NG, HT+LT (CCS VPSA 98%) (For the prospective assessment in 2050)

## 4.6 Nitrogen

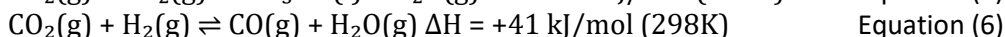
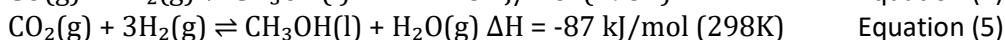
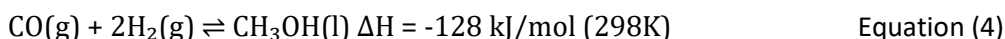
Production of nitrogen (N<sub>2</sub>) at 8 bar (pressure requirements for Haber-Bosch) is modelled in this study for the ammonia synthesis model. There are three main methods for separating N<sub>2</sub> from air: cryogenic distillation, pressure swing adsorption (PSA), and membrane separation. For this study, cryogenic distillation was chosen as cryogenic distillation accounts for more than 90% of the global production of N<sub>2</sub>. Compared to other air separation methods, cryogenic distillation produces the purest N<sub>2</sub> and requires the smallest power input (Liu et al. 2020). The electricity consumption for this distillation comes from (Liu et al. 2020). A total of 162 kWh of electricity is consumed per metric ton of N<sub>2</sub> produced (at 8 bar). Additionally, air separation facility infrastructures from Ecoinvent have been added to the N<sub>2</sub> production model.

## 4.7 Synthesis of Molecules

### 4.7.1 Methanol Synthesis

#### a Methanolation (H<sub>2</sub>+CO<sub>2</sub>)

The inventory data for e-methanol synthesis is sourced from (Van-Dal 2013). Another inventory is available in the literature by (Schmidt et al. 2022), presenting very similar data. Both inventories are presented in Annex 3. Regarding synthesis, the inventory data from (Schmidt et al. 2022) is also very similar to those of JECv5 (Prussi et al. 2020). The synthesis of e-methanol requires hydrogen, carbon dioxide, and electricity consumption (for utilities and equipment supplies). Pure water and a surplus of steam are produced during synthesis. Indeed, methanol is produced from exothermic reactions (Equations (4) and (5)). A Reverse Water Gas Shift (RWGS) reaction occurs in parallel Equation (6):



However, this surplus energy in the form of steam does not fully meet the heat needs for CO<sub>2</sub> capture. This is generally the case for a Fischer-Tropsch (FT) process for e-diesel production, for example, as the reaction during FT is more exothermic.

#### b Direct gasification of biomass

The life cycle inventory of bio-methanol is less complex than that of e-methanol. Nevertheless, it is possible to produce bio-methanol from various resources. In our study, we focus on the production of bio-methanol from cultivated wood or wood waste. The bio-methanol synthesis process generally involves a series of steps, including the gasification of biomass to produce a synthesis gas mixture containing carbon monoxide and hydrogen. Then, the synthesis gas is converted into methanol through catalytic reactions, such as the methanol synthesis reaction (CO + 2H<sub>2</sub> -> CH<sub>3</sub>OH). This methanol can then be purified and used as a fuel. The inventories from JECv5 (Prussi et al. 2020) are used to model these two types of bio-methanol. These inventories can be found in (Prussi et al. 2020) appendices.

It is used for the "Production & conditioning at source" inventories for farmed wood or waste wood. Those include a 500 km biomass transportation scenario. As well as the "transformation near market" inventories. However, several scenarios for the bio-methanol distribution have been considered based on the production countries and supply ports. Similarly, a sensitivity analysis is conducted on the transport of wood to the bio-methanol production site. Regarding the biomass (wood) transformation step into bio-methanol through gasification and then synthesis, the inventory from the JECv5 table is based on a publication from (IEA/AMF 1999). This publication estimates an energy conversion yield of 51.1%. This means that it takes almost twice as many megajoules of biomass to produce one megajoule of biomethanol. to produce one megajoule of bio-methanol, nearly double the megajoules of biomass are required.

### c Black Liquor gasification

The inventory for black liquor gasification to produce methanol is sourced from (Lundgren et al 2017) to produce crude methanol. As a basis, 174 tonnes of black liquor (DM) is considered as an input to the system presented in Table 17.

**Table 17: Mass and energy balance for gasification of black liquor (from (Lundgren et al 2017))**

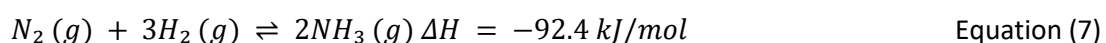
	Units	Crude MeOH
Flows going IN		
Pulp wood	[t/h]	107
	[MJ/kg]	
	ds [%]	
Bark	[t/h]db	16
	[MJ/kg]db	19.56
	ds [%]	
Fuel biomass	[t/h]	21
	[MJ/kg]ds	18.97
	ds [%]	
Electricity	[MW]el	74
Flows going OUT		
Electricity	[MW]el	0
Pulp	[Adt/h]	82
Crude MeOH	[t/h]	42
	[MJ/kg]	21
Hot water	[t/h]	867
	[°C]	95

Pulp wood, Bark and Fuel biomass for the selected inventory is replaced by the previously modelled Wood (Farmed or Waste), adjusted to the reported LHV. Hot water output is modelled as a substitution of hot water production (average of solar + gas and solar + electric) based on the energy content of the water at 95°C. This inventory accounts for the electricity consumption resulting from utilising black liquor for crude methanol production, rather than for electricity generation within the paper mill.

### 4.7.2 Ammonia Synthesis (Haber-Bosch)

#### The Haber-Bosch Process for Ammonia Synthesis

The Haber-Bosch process is an industrial method for synthesizing ammonia (NH<sub>3</sub>) from nitrogen (N<sub>2</sub>) and hydrogen (H<sub>2</sub>) gases. The chemical reaction is represented as follows in Equation (7):



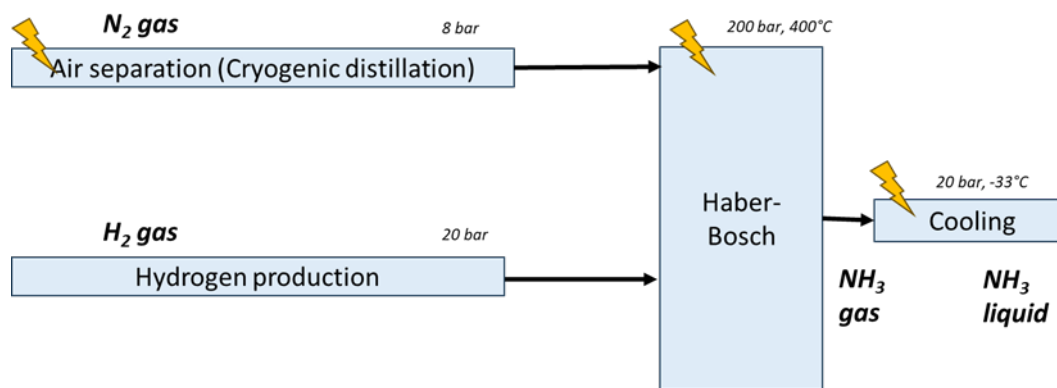
This reaction is exothermic, meaning it releases energy in the form of heat. Since the formation of ammonia results in a decrease in the number of gaseous molecules (from 4 moles of reactants to 2 moles of products), the reaction is favoured by high pressure according to Le Chatelier’s principle.

### Operating Conditions

To achieve a high yield of ammonia while maintaining an economically viable reaction rate, the Haber-Bosch process operates under the following conditions:

- Temperature: 400 – 500 °C (a compromise between equilibrium yield and reaction kinetics)
- Pressure: 150 – 300 bar (to shift equilibrium toward ammonia formation)
- Catalyst: Iron-based catalyst (Fe) promoted with small amounts of Al<sub>2</sub>O<sub>3</sub> (alumina) and K<sub>2</sub>O (potassium oxide) to enhance reaction efficiency.

The gaseous mixture containing stoichiometric N<sub>2</sub> and H<sub>2</sub> is compressed to the operating pressure of the Haber-Bosch (HB) reactor (assumed to be 200 bar in this analysis) and enters the HB synthesis loop, which is powered by electricity, as shown in the Figure 18. The electrical energy required for compressing the synthesis gas in the HB loop is 0.324 kWh per kilogram of NH<sub>3</sub> (Liu et al. 2020). After cooling, the NH<sub>3</sub> is in liquid form at 20 bar and -33°C.



**Figure 18 Haber-Bosch process diagram**

The inventory data for Haber-Bosch and for nitrogen production come from Table 18.

**Table 18 : Inventory data for Electric-based Haber-Bosch (Liu, 2020)**

	Electricity (GJ)	N <sub>2</sub> 8 bar (metric ton)	H <sub>2</sub> 20 bar (metric ton)
Electric-based Haber-Bosch	1,165	0,822	0,178

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## 4.8 Transport, Storage and Bunkering

### 4.8.1 Methanol Transportation, Storage and Bunkering

In addition to the synthesis of e-methanol, it is necessary to model the distribution and conditioning phase of the fuel to determine its GHG emissions. Based on their significance as the two central international bunkering hubs, Rotterdam and Singapore were selected as the reference ports for this study. From the production countries considered in the study, e-methanol is then shipped by boat to one of these two ports, with land transport also considered for France and Spain to Rotterdam.

#### a Transportation by boat

For the port of Singapore, the production countries and the distances between these countries and the port of Singapore by ship are estimated using the [ship traffic sea distances calculator](#). Values are reported in Table 12.

**Table 19: Transport distances from the production region to the bunkering port (Singapore)**

Country of production of e-methanol	Port of departure	Distance (Nautical Miles)	Distance (kilometers)
China	Shanghai	2691	4984
EAU	Dubai (Mina Rashid)	3971	7354
Australia	Sydney	4791	8873

For the port of Rotterdam, the producing countries and the distances separating these countries from the port of Rotterdam by boat are shown in Table 20.

**Table 20: Transport distances from the production region to the bunkering port (Rotterdam)**

Country of production of e-methanol	Port of departure	Distance (Nautical Miles)	Distance (kilometers)
US Texas	Houston	6190	11464
France	Le Havre	335	620
Spain	Valencia	2042	3782
EAU	Dubai (Mina Rashid)	7029	13018
Morocco	Tanger	1651	3058
South Africa	Durban	8157	15107

In the case of transporting methanol by boat at the current horizon, the following Ecoinvent data was used: "Transport, freight, sea, tanker for liquid goods other than petroleum and liquefied natural gas {GLO}| Cut-off, U".

With this data, the GHG emissions for the distribution of methanol are 8.15 gCO<sub>2</sub>eq/tkm. For information, transporting methanol over 1000 km by boat would result in an impact of 0.41 gCO<sub>2</sub>eq/MJ to be added to the emissions from e-methanol production.

#### b Transportation by land

For the case of the port of Rotterdam, two production countries (France and Spain) are considered for which transport can also be done by train or truck. The distances by truck and train are shown in Table 21.

**Table 21: Transport distances from the production region to the bunkering port (Rotterdam) by land routes (train and road)**

Country of production of e-methanol	Distance by train (kilometers)	Distance by Truck (kilometers)
France (Paris)	372	443
Spain (Madrid)	1423	1715

In the case of transporting methanol by train at the current horizon, the following Ecoinvent data was used: "Transport, freight train {RER}| market group for transport, freight train | Cut-off, U". With this data, the GHG emissions for the distribution of methanol are 45.7 gCO<sub>2</sub>eq/tkm. For information, transporting methanol over 1000 km by train would result in an impact of 2.3 gCO<sub>2</sub>eq/MJ to be added to the emissions from e-methanol production. Emissions related to train transport are six times higher than those related to boat transport.

In the case of transporting methanol by truck at the current horizon, the following Ecoinvent data was used: "Transport, freight, lorry >32 metric ton, EURO6 {RER}| market for transport, freight, lorry >32 metric ton, EURO6 | Cut-off, U". With this data, the GHG emissions for the distribution of methanol are 100 gCO<sub>2</sub>eq/tkm. For information, transporting methanol over 1000 km by truck would result in an impact of 5.03 gCO<sub>2</sub>eq/MJ to be added to the emissions from e-methanol production. Emissions related to truck transport are twice as high as those related to train transport (and twelve times higher than those from boat transport).

#### **c Dispensing at Bunkering site**

The distribution of methanol at retail sites requires energy, primarily in the form of electricity, for lighting, pumping, etc. In the JECv5 inventories, there is a value of electricity consumption of 0.0034 MJ/MJ methanol. For large volume bunkering, one might expect lower energy consumption. It is nevertheless chosen to use this value from JEVv5 due to the lack of literature data and for the sake of a conservative approach. The electricity mix of Rotterdam or Singapore depending on the selected bunkering port is used.

#### **d Prospective horizons**

For prospective horizons other assumptions are made. For 2035, only an evolution of the background data, i.e. the Ecoinvent database, is considered. the Ecoinvent database is modified according to the projections of the IAM and the chosen socio-economic scenario (section 8.3). By 2050, fuel is assumed to be auto-consumed for its own transportation, lowering greenhouse gas emissions.

### **4.8.2 Ammonia Transportation, Storage and Bunkering**

In addition to the synthesis of e-ammonia, it is necessary to model the distribution and conditioning phase of the fuel to determine its GHG emissions. This section outlines the processes involved in transporting and storing liquid ammonia (NH<sub>3</sub>) for bunkering purposes, alongside the associated assumptions regarding electricity consumption, leakage rates, and fugitive emissions.

#### **a Storage at the Production Site**

Liquid ammonia is stored at the production site for five days. During this period, electricity consumption amounts to 9.4 kWh per day per tonne of liquid NH<sub>3</sub> (Boero et al. 2021). A 0.02% leakage of the stored ammonia is assumed to occur over these five days (Boero et al. 2021). According to [IPCC guidelines](#), 1% of ammonia slip is assumed to convert to nitrous oxide (N<sub>2</sub>O) emissions.

#### **b Transportation**

Transport scenario and distances from the production regions to bunkering ports (Rotterdam and Singapore) are the same as those presented in the e-methanol transport section. Transportation from the production site to the bunkering site is carried out by sea freight, using tankers designed for liquid goods other than petroleum and

liquefied natural gas. The relevant transportation data are taken from the Ecoinvent dataset “Transport, freight, sea, tanker for liquid goods other than petroleum and liquefied natural gas {GLO}” (Boero et al. 2021). Transport distances from production regions to bunkering ports are those presented in the e-methanol transport section. The Ecoinvent data used are the same as for methanol transport as, according to consulted experts, there is no active refrigeration and instead ammonia is transported in a cold state in insulated tanks with boil off gas management and compressors. However, in this study, BOG management is not included as the associated GHG emissions are considered negligible.

**c Prospective horizons**

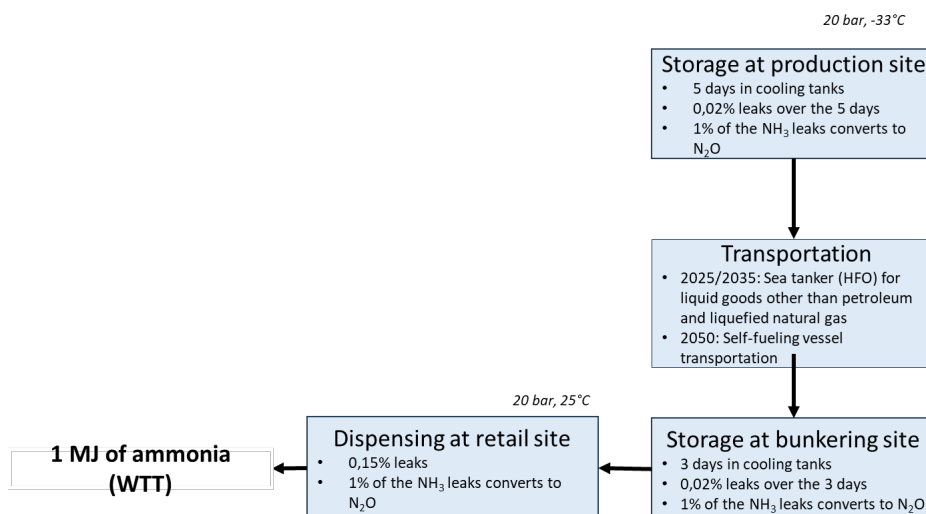
For prospective horizons other assumptions are made. For 2035, only an evolution of the background data, i.e. the Ecoinvent database, is considered. The Ecoinvent database is modified according to the projections of the IAM and the chosen socio-economic scenario (section 8.3). By 2050, the fuel is assumed to be auto-consumed for its own transportation, lowering greenhouse gas emissions.

**d Storage at the Bunkering Site**

Upon arrival at the bunkering site, the ammonia is stored for an additional three days. Similar to the production site, electricity consumption during this period is 9.4 kWh per day per tonne of liquid NH<sub>3</sub> (Boero et al. 2021), and a 0.02% leakage rate is assumed over the three days (Boero et al. 2021). According to [IPCC guidelines](#), 1% of ammonia slip is assumed to convert to nitrous oxide (N<sub>2</sub>O) emissions.

**e Dispensing at the Bunkering Site**

Fugitive emissions may occur during the dispensing process at the bunkering site. According to (Bertagni et al. 2023), the ammonia slip can be as high as 0.3%. However, consulted experts report effectively 0% under optimal conditions. Consequently, an intermediate assumption of a 0.15% ammonia slip is used. According to [IPCC guidelines](#), 1% of ammonia slip is assumed to convert to nitrous oxide (N<sub>2</sub>O) emissions. Finally, no relevant data was found for the energy required for bunkering ammonia into vessels. As a conservative approach, the same electricity consumption for road transport fuel retail is used: of 0.0008 MJ per MJ of NH<sub>3</sub> (PRUSSI et al. 2020). The distribution of ammonia at bunkering sites requires energy, primarily in the form of electricity, for lighting, pumping, etc. The electricity mix of Rotterdam or Singapore is used, depending on the selected bunkering port. The storage, transport and bunkering assumptions are summarized in Figure 19.



**Figure 19 Ammonia storage, transport and bunkering assumptions**

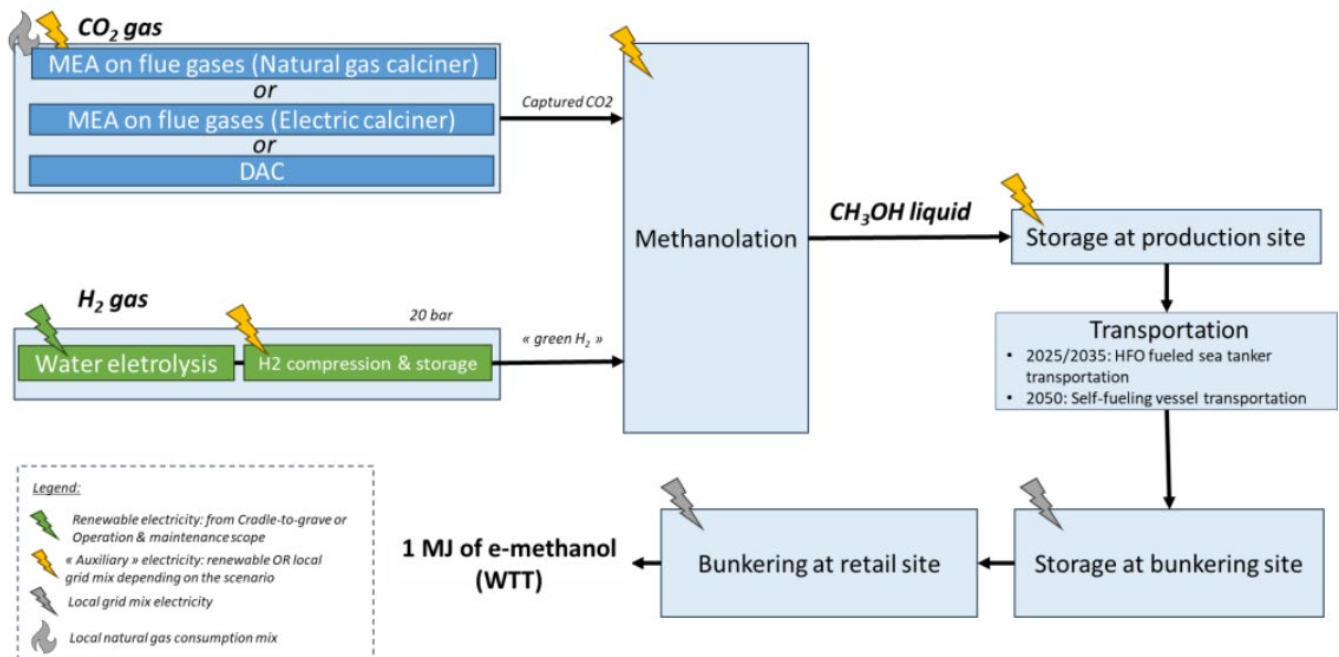


## 5 Assessed Process and Electricity Source Configurations

### 5.1 Methanol

#### 5.1.1 Hydrogen from Electrolysis

Figure 20 is a process diagram of the methanol with electrolytic hydrogen (e-methanol) from well to wake. It presents the different technological options assessed as well as the different type of energetic flows considered in the configuration scenario below.

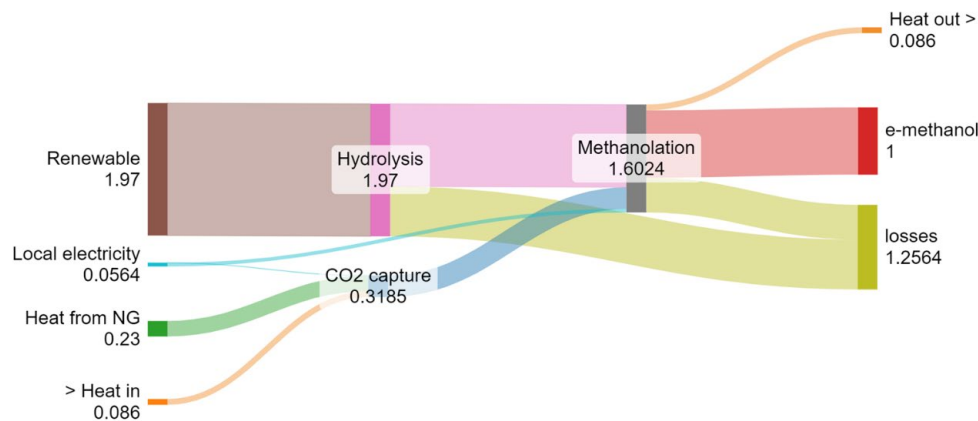


**Figure 20** Process diagram of methanol with electrolytic hydrogen (e-methanol) from well to tank

To be recognized as RFNBO, the hydrogen for e-methanol synthesis must be produced from renewable electricity. However, no indication is given in the delegated act or in the IMO recommendations on the energy to be used for the carbon capture and methanol synthesis steps. As explained in the previous section, the energy surplus from synthesis is insufficient to cover the energy needs for CO<sub>2</sub> capture. It is therefore necessary to study different integration scenarios and energy sources for capture needs.

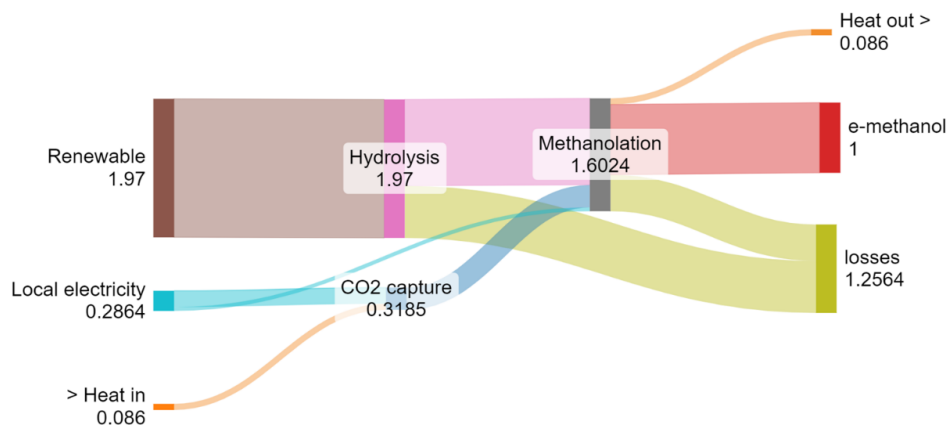
Four configuration scenarios have been retained:

**Scenario 1:** In the first scenario, it is considered that the heat needed for CO<sub>2</sub> capture is obtained from natural gas ("Heat from NG" in green on the left of Figure 21):



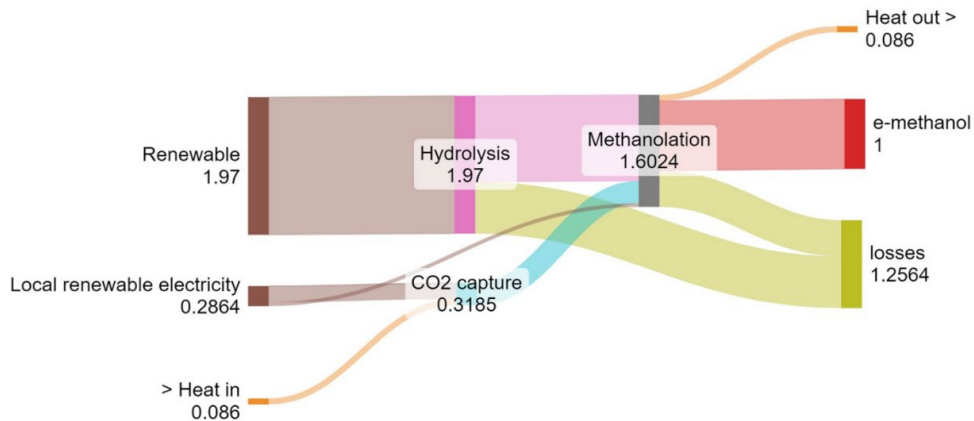
**Figure 21: Sankey diagram of the energy flows related to the production of 1 MJ e-methanol for Scenario 1 (Renewable electricity set to 0 gCO<sub>2</sub>e for H<sub>2</sub> production, Natural gas for Carbon capture and local electricity grid mix for auxiliaries' consumptions)**

**Scenario 2:** In the second scenario, it is considered that the heat needed for CO<sub>2</sub> capture is obtained from electricity from the local mix of the studied countries ("Local electricity" in blue in Figure 22:



**Figure 22: Sankey diagram of the energy flows related to the production of 1 MJ e-methanol for Scenario 2 (Renewable electricity set to 0 gCO<sub>2</sub>e for H<sub>2</sub> production, local electricity grid mix for carbon capture and auxiliaries' consumptions)**

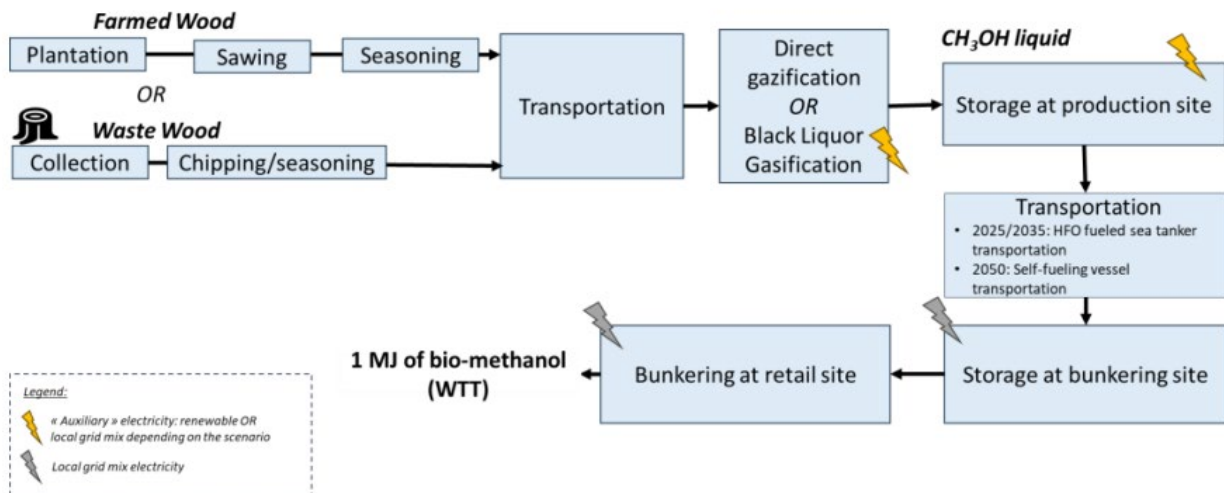
**Scenarios 3 & 4:** In the third and fourth scenarios, it is considered that the heat needed for CO<sub>2</sub> capture is obtained from electricity from the renewable local mix ("Local renewable electricity" in brown in Figure 23 of the studied countries). The configuration is the same for Scenarios 3 and 4, only the way of accounting for green hydrogen differs. Indeed, in the first three scenarios, the GHG emissions from the production of renewable electricity for electrolysis are not accounted for in accordance with current recommendations: the [methodology proposed by the International Partnership for Hydrogen and Fuel Cells in the Economy \(IPHE\)](#) includes "only" emissions from scope 1 and 2 for hydrogen production (i.e., direct and indirect emissions related to energy use). This scope can also be called the "Operation & Maintenance" (OM) scope of accounting. They are therefore considered null for green hydrogen. This recommendation is followed by the IEA, the RED, and will likely be followed by the future IMO regulation. Nevertheless, these emissions are not null in the life cycle of green hydrogen. Indeed, the renewable electricity production equipment embody grey emissions due to their manufacturing and end of life treatment - this scope can be referred as scope 3. This is why a fourth scenario is considered. Identical to the third scenario, except that in this one, the GHG emissions from the production of renewable electricity for hydrogen production are accounted for in cradle-to-grave (scopes 1, 2, and 3).



**Figure 23: Sankey diagram of the energy flows related to the production of 1 MJ e-methanol for Scenario 3 (Renewable electricity set to 0 gCO<sub>2</sub>e for H<sub>2</sub> production, renewable electricity grid mix for carbon capture and auxiliaries' consumptions) and Scenario 4 (Renewable electricity from cradle to grave for H<sub>2</sub> production, renewable electricity grid mix for carbon capture and auxiliaries' consumptions)**

### 5.1.2 Biomass-based Methanol

The bio-methanol process diagram in Figure 24 synthesises the different feedstock options (farmed or waste wood) and synthesis processes (direct gasification or black liquor gasification) explored in this study. The supply chain after methanol synthesis remains the same as for e-methanol.



**Figure 24 Process diagram of methanol biomass based (bio-methanol) from Well to Wake**

The energy flow analysis presented in Figure 25 illustrates the energy losses at each process stages of the bio-methanol from direct gasification of waste wood. The main losses appear at the gasification stage due to the conversion efficiency.

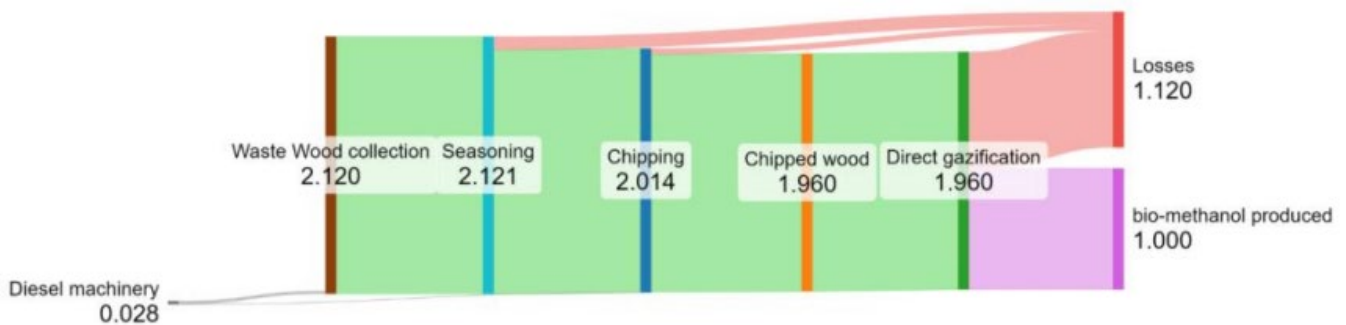


Figure 25 Bio-methanol from direct gasification of waste wood energy flow analysis

## 5.2 Ammonia

Figure 26 summarises the different H<sub>2</sub> production pathways used for ammonia synthesis assessed in this study. The classification of ammonia is based on the H<sub>2</sub> production method, which determines its “colour” designation. This study evaluates green ammonia or e-ammonia, produced from electrolytic hydrogen using renewable electricity; grey ammonia, derived from Steam Methane Reforming (SMR) or Auto-Thermal Reforming (ATR) of natural gas; and blue ammonia, which is similar to grey ammonia but includes Carbon Capture and Storage (CCS) to reduce emissions. Additionally, the temperature and pressure conditions for synthesised ammonia are presented in the process diagram.

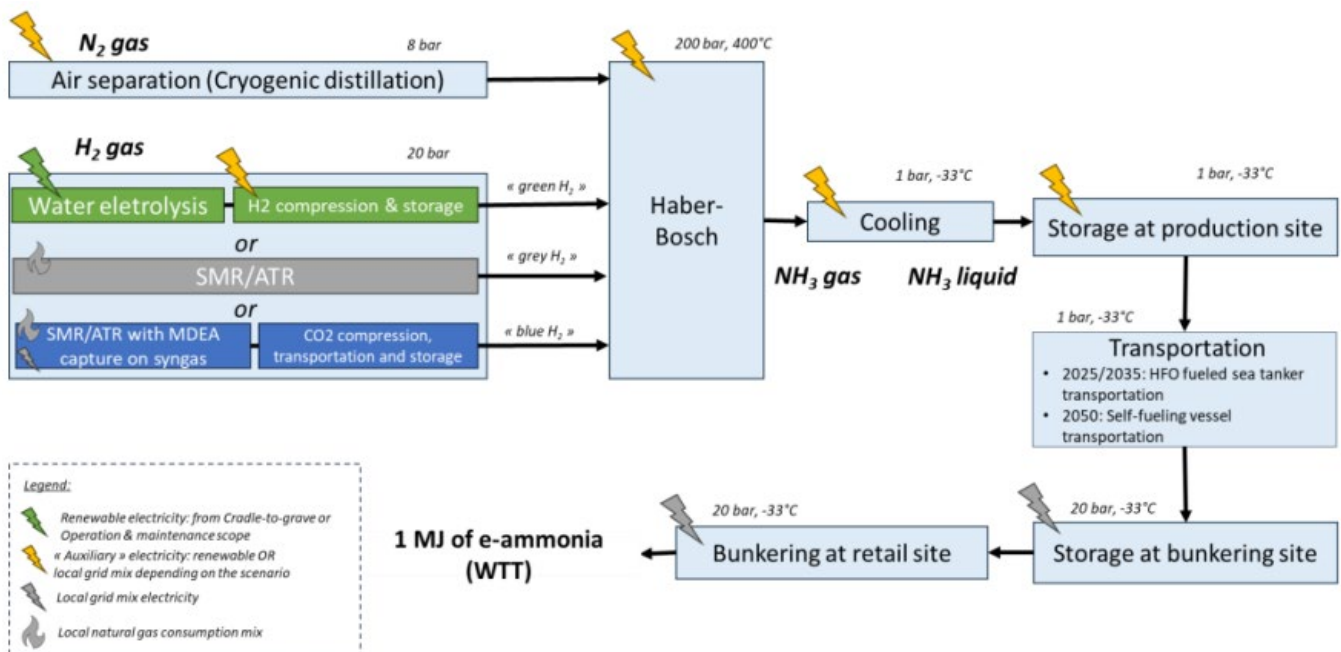


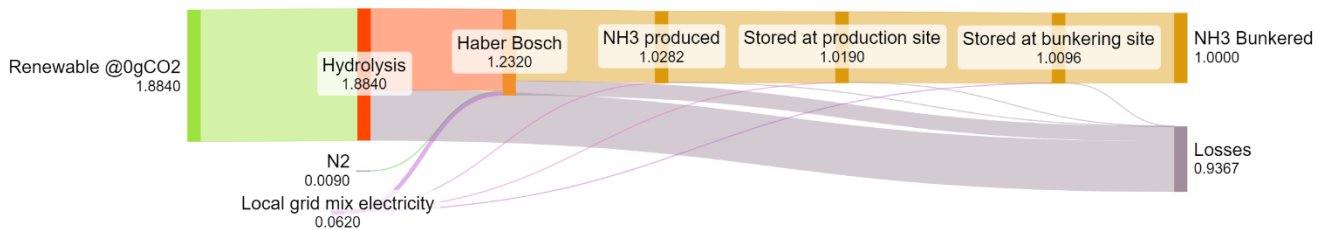
Figure 26 Process diagram of ammonia from well to wake

### 5.2.1 Hydrogen from Electrolysis

As with methanol production, evaluating various e-ammonia production configurations is essential, as they significantly influence the GHG emission results. In this study, we analyse three e-ammonia production scenarios, all of which rely on renewable electricity for hydrogen production via electrolysis. The key differences between

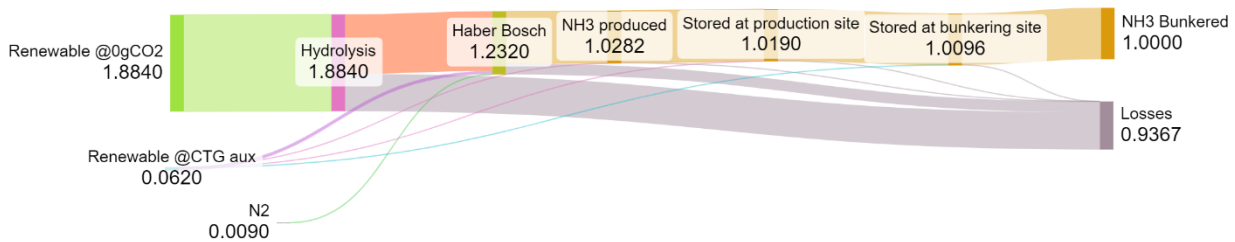
these configurations lie in the handling of auxiliary power sources (i.e., electricity required for nitrogen production, Haber-Bosch utilities, and refrigeration during ammonia storage phases):

**Scenario A:** Considers IPHE methodology for electrolytic H<sub>2</sub> production (renewable electricity is GHG emissions free) and uses local grid mix electricity to power auxiliaries (Figure 27).



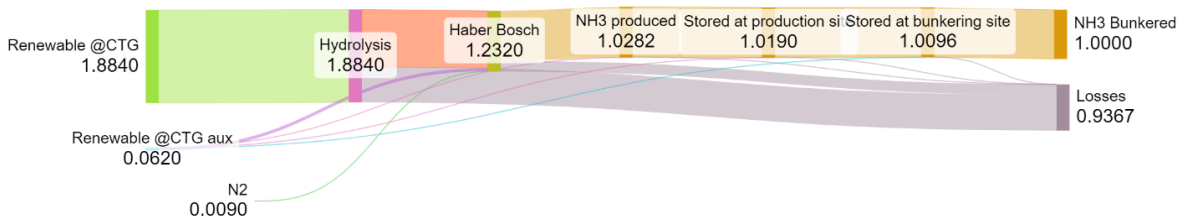
**Figure 27 NH<sub>3</sub> energy flow analysis in Scenario A: RED & local grid mix auxiliaries**

**Scenario B:** Considers IPHE methodology for electrolytic H<sub>2</sub> production (renewable electricity is assumed to have no GHG emissions) and renewable electricity for auxiliaries' consumptions. However, as per IPHE's methodology, only renewable electricity used for hydrogen production itself is considered to have a 0 g CO<sub>2</sub> impact, meaning that the renewable electricity used for auxiliaries is assessed on a cradle-to-gate (CTG) basis (Figure 28).



**Figure 28 NH<sub>3</sub> energy flow analysis in Scenario B: RED & CTG renewable electricity for auxiliaries**

**Scenario C:** Investigates the GHG impact of a fully renewable configuration (like Scenario 2) but assesses renewable electricity for H<sub>2</sub> production on a CTG basis, rather than assuming it has zero emissions (Figure 29).



**Figure 29 NH<sub>3</sub> energy flow analysis in Scenario C: CTG renewable electricity for H<sub>2</sub> electrolysis and auxiliaries**

## 5.2.2 Hydrogen from Methane Reforming

It is assumed the electricity for auxiliaries' consumptions (including N<sub>2</sub> production) for the ammonia synthesised from H<sub>2</sub> from SMR/ATR is sourced from local grid mix electricity. Figure 30 presents the energy flow analysis of the ammonia synthesised out of H<sub>2</sub> from SMR with CCS.

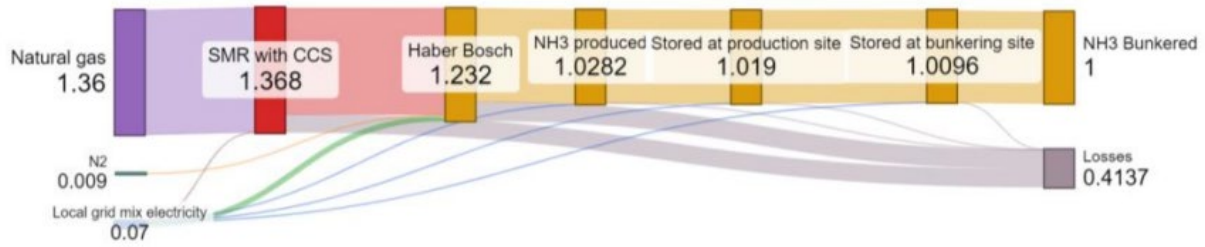


Figure 30 NH3 from SMR with CCS hydrogen (“blue-H2”) energy flow analysis

Blue ammonia synthesis is significantly more efficient than green ammonia due to the higher conversion efficiency of Steam Methane Reforming (SMR) and the significant energy losses associated with electrolysis in green ammonia production.

### 5.3 Summary of Assessed Configurations

The different configurations assessed and presented in this report are summarized in the Table 22 below. However, additional configurations can be calculated using the dedicated dashboard in the Appendix of this report. For example, it is possible to evaluate methanol production using grey or blue H2 instead of the electrolytic H2 or biomass-based hydrogen pathways presented in this report.

Table 22: Summary of all the assessed production configurations

Molecule	Feedstock type	H2 scope of emissions accounting	Auxiliaries	CO2 capture (as feedstock)	CO2 capture and storage (on methane reforming unit)	Scenario code
Methanol	e-H2	OM	Local grid mix	NG with local grid mix	-	1
				Electrical with local grid mix	-	2
			Renewable electricity (CTG)	Electrical with renewable electricity	-	3
		CTG	Renewable electricity (CTG)	Electrical with renewable electricity	-	4
	Biomass	-	Local grid mix	-	-	-
Ammonia	e-H2	OM	Local grid mix	-	-	A
			Renewable electricity (CTG)	-	-	B
		CTG	Renewable electricity (CTG)	-	-	C
		Grey-/blue-H2	CTG	Local grid mix electricity	-	NG with local grid mix electricity

OM: Operation & Maintenance scope (0gCO<sub>2</sub>e for renewable electricity powered electrolysis as per IPHE methodology). CTG: Cradle-to-Grave scope.

The different assessed energetic configurations of e-methanol Scenarios 1 and 2 are comparable to the e-ammonia Scenario A. E-methanol Scenario 3 is comparable to e-ammonia Scenario B. E-methanol Scenario 4 is comparable to e-ammonia Scenario C.



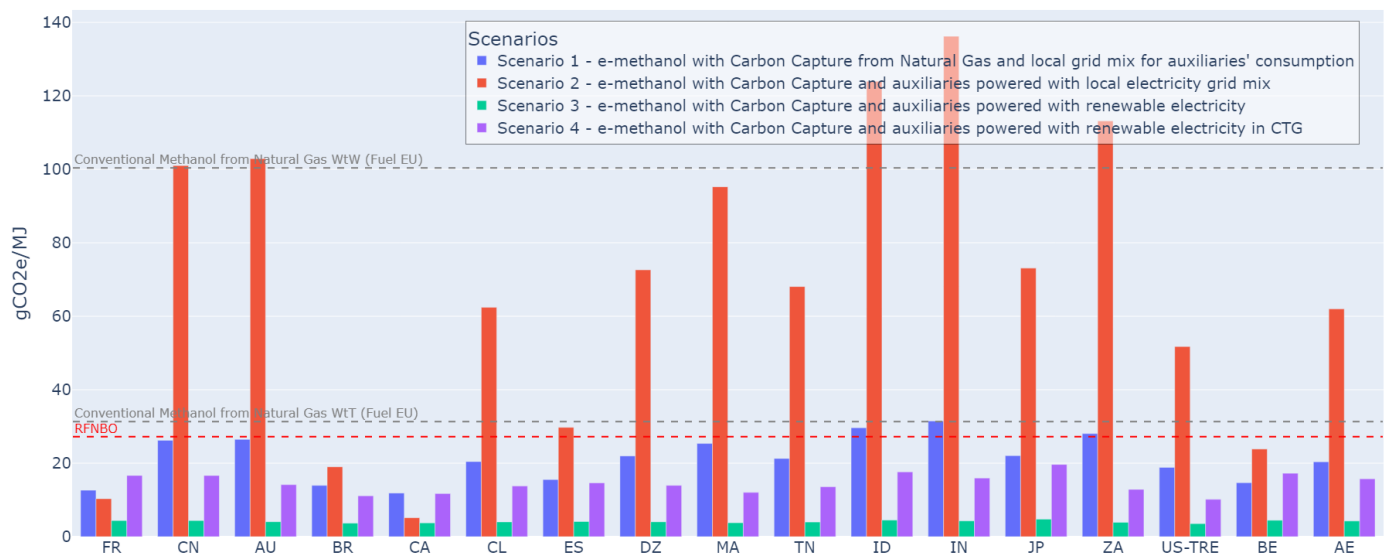
## 6 Fuel Well-to-Wake Results

### 6.1 Methanol

#### 6.1.1 Methanol from Electrolytic Hydrogen

##### a Without Transport & Conditioning

Initially, the results of the production of e-methanol by region and configuration scenario for carbon capture are presented in Figure 31. ISO alpha-2 codes are used for region names (see Section 3.2 Scope).



**Figure 31: GHG emissions (gCO<sub>2</sub>e/MJ) of e-methanol in WtW without transport and conditioning by region and configuration scenario**

The energy required for CO<sub>2</sub> capture is not fully covered by the excess heat from the methanol synthesis (unlike FT for e-diesel). Thus, the GHG emissions related to e-methanol production strongly depend on the configuration of the production unit and the source of electricity for auxiliary energy consumption (different scenarios are summarised in Section 5.3). The configuration using natural gas for capture (Scenario 1) has a lower impact on GHG emissions in all countries, except for two countries/regions with a low carbon intensity electricity mix (FR and CA-QC). Using the local grid configuration for carbon capture (Scenario 2) has a detrimental effect for locations with a high carbon intensity grid. So much so that for some countries with a very carbon-intensive mix such as India or Indonesia, the e-methanol produced, although still from green H<sub>2</sub>, may be more carbon-intensive than fossil methanol produced from natural gas. The exclusive use of renewable energy (Scenario 3 & Scenario 4) allows for a reduction of greenhouse gas emissions by an average of 95% compared to conventional natural gas-based methanol.

Scenario 3 considers only emissions related to production infrastructures (electrolyser, balance of plant, carbon capture columns, etc.) and cradle-to-grave impacts of local renewable electricity for capture and synthesis. Scenario 4 additionally accounts for the cradle-to-grave impact of green H<sub>2</sub>. The total impact is about three times higher in Scenario 4 than in Scenario 3 (~15gCO<sub>2</sub>e/MJ vs ~5gCO<sub>2</sub>e/MJ). It should be noted that even when accounting for the "real" impacts of H<sub>2</sub> production (Scenario 4), the e-methanol produced is still below the threshold of 70% GHG reduction compared to the fossil reference, thus allowing it to be classified as RFNBO according to RED.

## **b With Transport & Conditioning**

Two transport and conditioning scenarios for e-methanol are explored: the finished product is transported by ship to Singapore or Rotterdam and distributed on-site (Section 4.7.1). The results are presented for each scenario in the form of choropleth maps.

### **To the Port of Singapore:**

The results with transport by ship to the port of Singapore are presented for the four scenarios in Figure 32. The analysis of this figure allows for distinguishing two cases:

- (1) For Scenarios 1 and 2, the transport of e-methanol does not significantly impact the GHG footprint.
  - a. In Scenario 1, most of the carbon capture needs are met using natural gas; however, low local electricity consumption can still significantly contribute to GHG emissions. As a result, the transport distance from the production region to Singapore does not solely determine the best production location. For example, producing e-methanol in France under Scenario 1 and transporting it to Singapore results in a lower GHG footprint than producing and transporting it from India.
  - b. As in Scenario 1, the transport distance from the production region to Singapore is not a determining factor for selecting a region for decarbonised e-methanol production in Scenario 2. However, the GHG intensity of the electricity mix is a key criterion. For example, France, Quebec, and Brazil have low-carbon electricity grids, making them more favourable production locations, even if the e-methanol must be transported over long distances to Singapore. In contrast, producing e-methanol in regions closer to Singapore but with a more carbon-intensive electricity mix would result in higher overall GHG emissions.
- (2) For Scenarios 3 and 4, the transport of e-methanol can significantly impact the GHG footprint.
  - a. In the case of a 100% renewable electricity configuration (Scenarios 3 & 4), the differences in GHG emissions between regions are less significant. The impact related to transport appears more significantly in the results. Methanol produced in regions close to the supply point has a lower GHG impact than that produced in distant regions. For these two scenarios, the GHG emissions related to the transport & conditioning of the final product are not negligible and can be a decisive criterion in the choice of the production region.

### **To the Port of Rotterdam:**

The results with transport by ship to the port of Rotterdam are presented for the four scenarios in Figure 32.

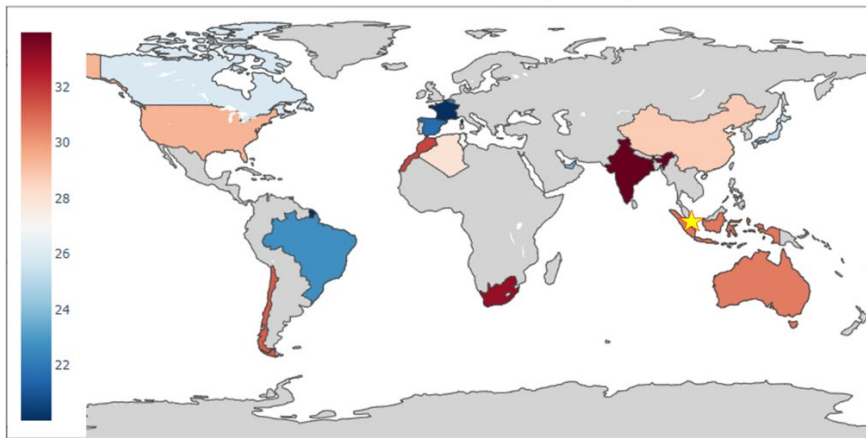
The GHG discrepancies in Scenarios 1 and 2 with transport to Rotterdam are greater than in the same scenario with transport to Singapore; because the countries with decarbonized mixes have the additional advantage of being at a shorter distance from Rotterdam than the countries in Southeast Asia, for example.

The impact of transport and conditioning in Scenarios 3 and 4 is clearly visible (Figure 33). Indeed, the GHG results and discrepancies between regions for these scenarios are relatively low. Therefore, when considering bunkering in Rotterdam, the results with transport and conditioning are therefore strongly influenced by the impact of transport.

Scenario 1

GHG emissions of e-methanol (gCO<sub>2</sub>e/MJ) from Well-to-Wake, by country

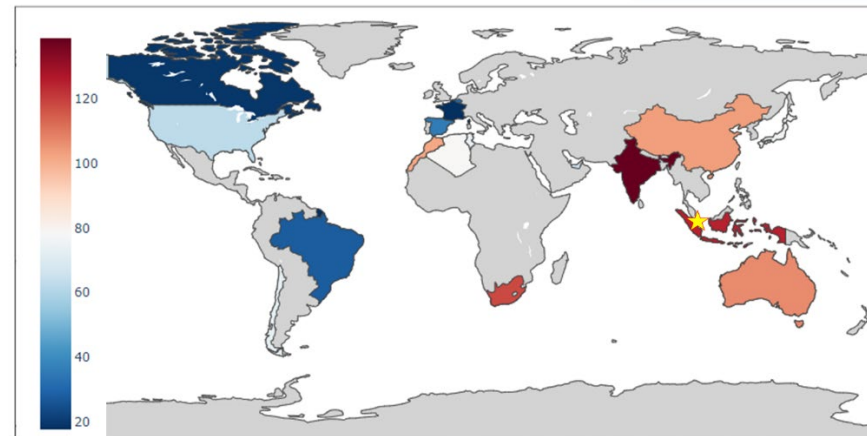
S1 - NG - T&C to SG



Scenario 2

GHG emissions of e-methanol (gCO<sub>2</sub>e/MJ) from Well-to-Wake, by country

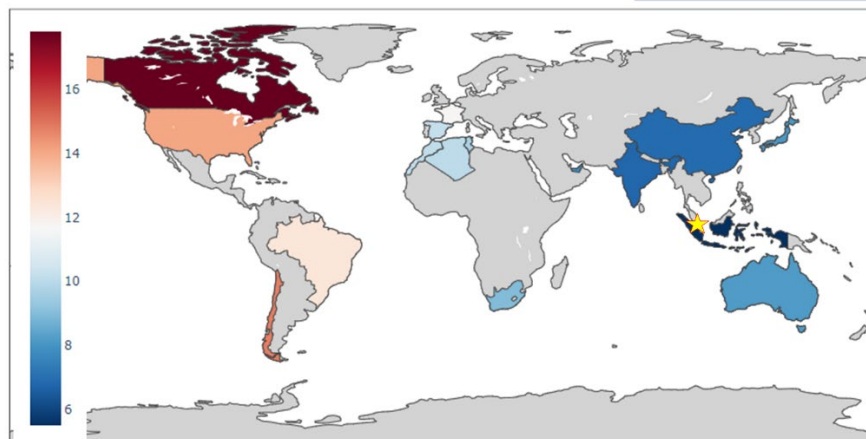
S2 - Local mix - T&C to SG



Scenario 3

GHG emissions of e-methanol (gCO<sub>2</sub>e/MJ) from Well-to-Wake, by country

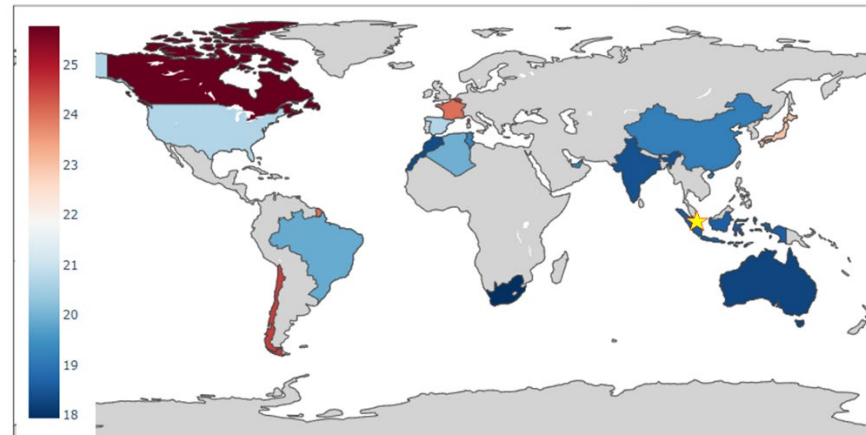
S3 - Full renewable - T&C to SG



Scenario 4

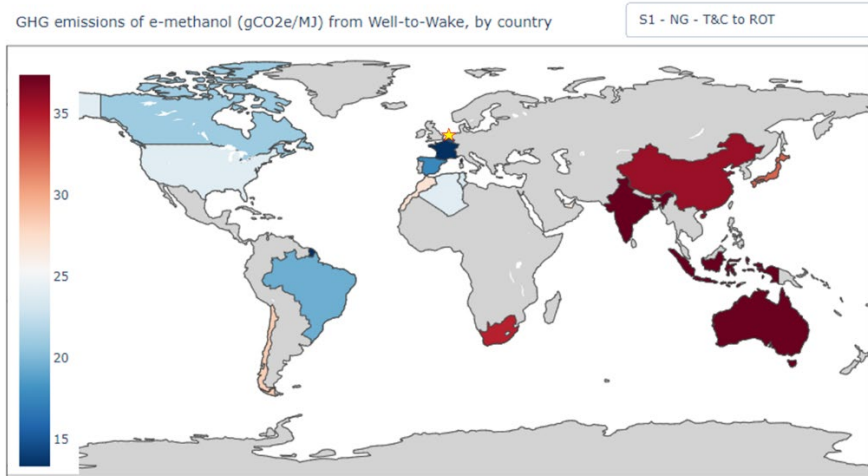
GHG emissions of e-methanol (gCO<sub>2</sub>e/MJ) from Well-to-Wake, by country

S4 - Full renewable CTG - T&C to SG

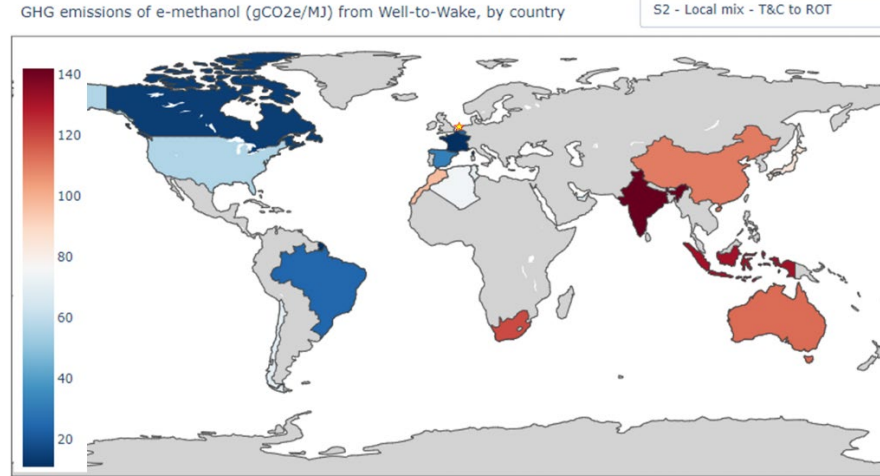


**Figure 32 : GHG emissions of e-methanol (gCO<sub>2</sub>eq/MJ), WtW scope by region with transport and conditioning from the production region to the port of Singapore (yellow star); the four prospective scenarios are represented; readers are advised to pay attention to the colour scales that vary according to the map.**

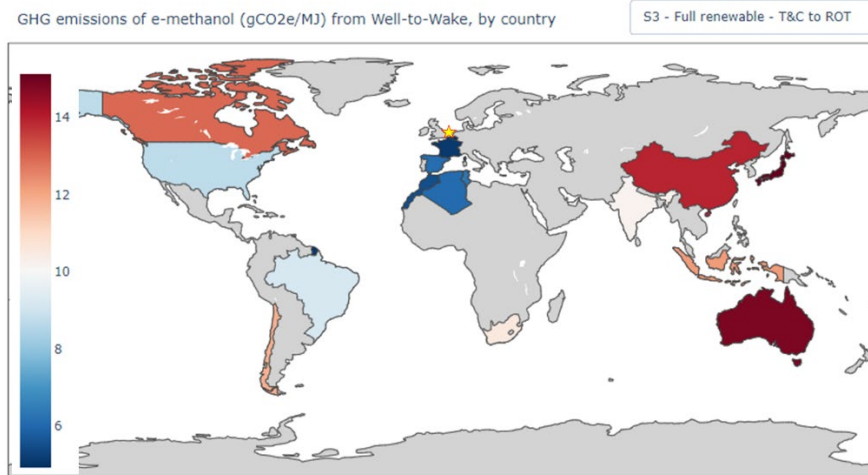
Scenario 1



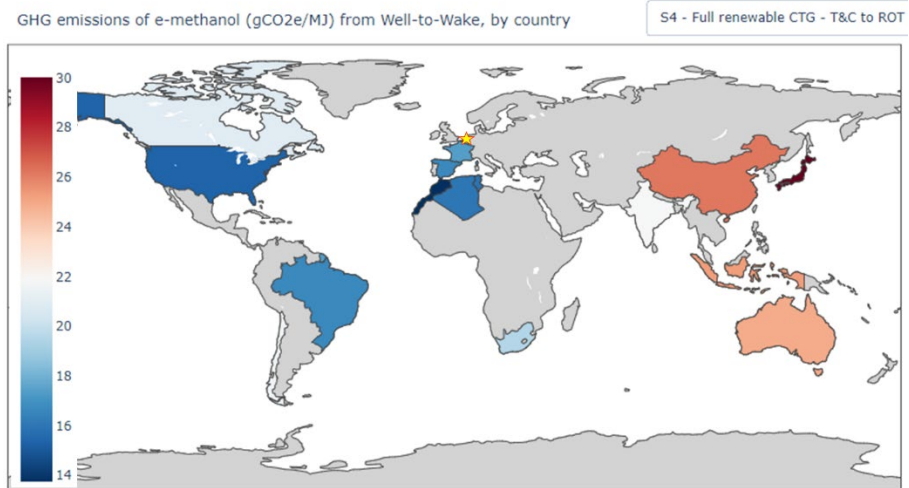
Scenario 2



Scenario 3

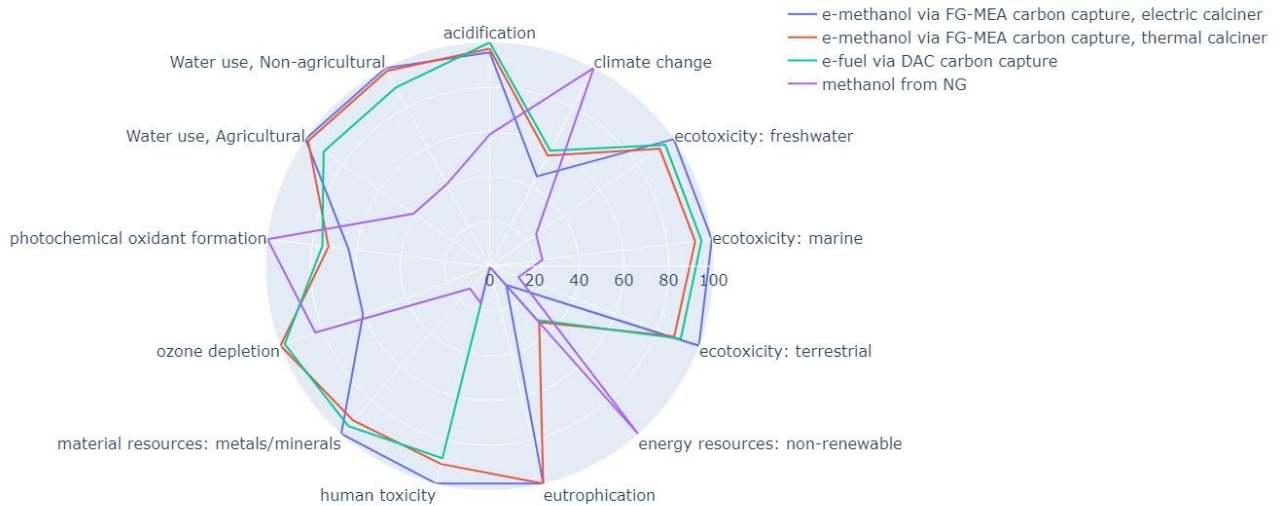


Scenario 4



**Figure 33 : GHG emissions of e-methanol (gCO<sub>2</sub>eq/MJ), WtW scope by region with transport and conditioning from the production region to the port of Rotterdam (yellow star); the four prospective scenarios are represented; readers are advised to pay attention to the colour scales that vary according to the map.**

### c Results of Other Indicators



**Figure 34: Normalised WtT environmental impacts of fossil methanol (purple), e-methanol produced from French renewable electricity mix (65% wind – 35% photovoltaic) (S4 in blue), renewable with natural gas (S1 in red), and renewable with DAC (in green). Alkaline electrolysis. CML v4.8 2016 and AWARE methods.**

Results for other environmental impact categories (CML v4.8 2016 and AWARE for water) are also calculated. They provide a comparative overview against the impacts of grey methanol production. The maturity levels of the two pathways are not the same, so caution should be exercised when interpreting these results. Importantly, the radar chart presentation is not intended to calculate and compare the areas between each pathway (which would mean weighting all impact categories in the same way). The pathway with the highest impact in a specific category is the one at the periphery of the radar and has a value of 100.

Considering WtT, there is a reduction in GHG emissions (category "climate change"). The reduction is even more significant for WtW. E-methanol has a significant impact on the categories of ecotoxicity, human toxicity, and the use of metallic and mineral resources. This is mainly due to the renewable production equipment used to generate renewable electricity, which mobilises large amounts of copper, steel, and rare earths for wind turbine magnets or silicon in photovoltaic panels. Monoethanolamine used as a solvent for capture also impacts the eutrophication category, common to all e-methanol pathways. Platinum group metals in electrolyzers contribute significantly to the acidification category.

### d Focus on the Water Indicator

The water use indicator has been calculated regionally using the AWARE method (Boulay et al. 2018). This method is recognized and recommended by the UNEP-SETAC Life Cycle Initiative, the PEF of the European Commission, and the international EPD system.

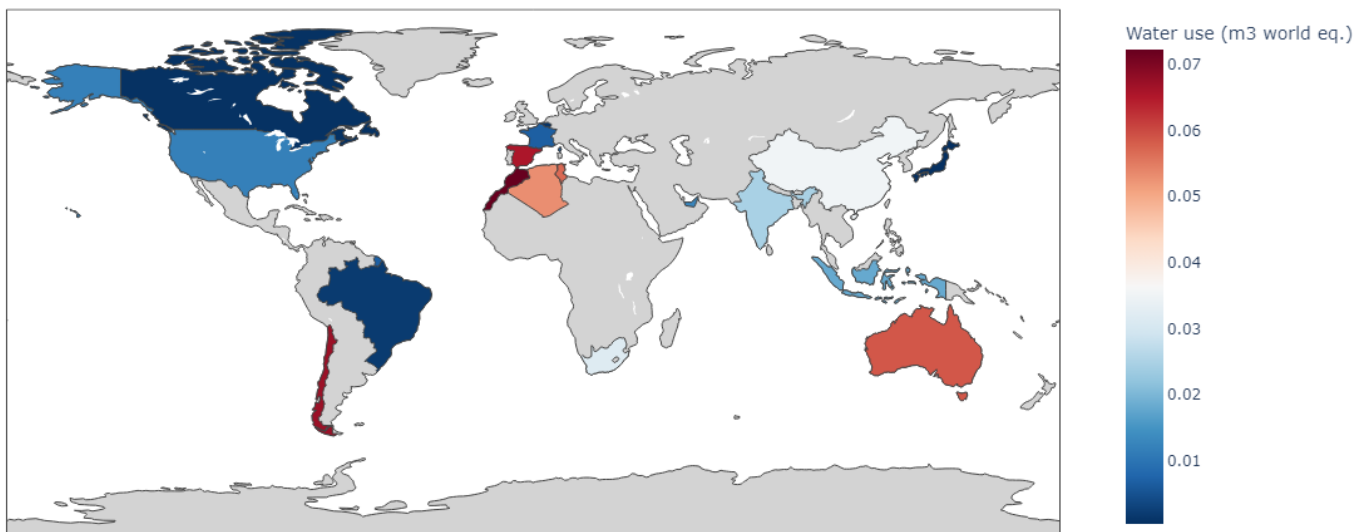
AWARE is an indicator of the remaining available water in a watershed, once the demand from humans and aquatic ecosystems have been met. It assesses the risk of water deprivation, either for humans or for ecosystems, based on the premise that the less water remaining per area, the more likely it is that another user will be deprived of water. It is first calculated as the availability of water minus the demand (AMD) from humans and aquatic ecosystems at a monthly frequency and is reported per watershed area ( $\text{m}^3 \text{m}^{-2} \text{month}^{-1}$ ). Secondly, the value is normalized against the global average result ( $\text{AMD} = 0.0136 \text{m}^3 \text{m}^{-2} \text{month}^{-1}$ ) and inverted, thus representing the relative value compared to the average  $\text{m}^3$  consumed worldwide (the global average is calculated as an average of



all watersheds weighted by consumption). Once inverted, 1/AMD can be interpreted as a surface time equivalent to generate unused water in that region. The indicator is limited to a range of 0.1 to 100, with a value of 1 corresponding to the global average and a value of 10, for example, representing a region where there is 10 times less available water per area than the global average.

These characterization factors (Annex 4) are multiplied by the demand for e-methanol production. It is assumed that this demand is the same regardless of the production region. Based on this, the water needs for carbon capture and electrolysis are 0.16 L/MJ and 0.092 L/MJ, respectively, totalling 0.25 L/MJ (which corresponds to 3.8 L of water for 1 L of e-methanol).

Water use for e-methanol production by country



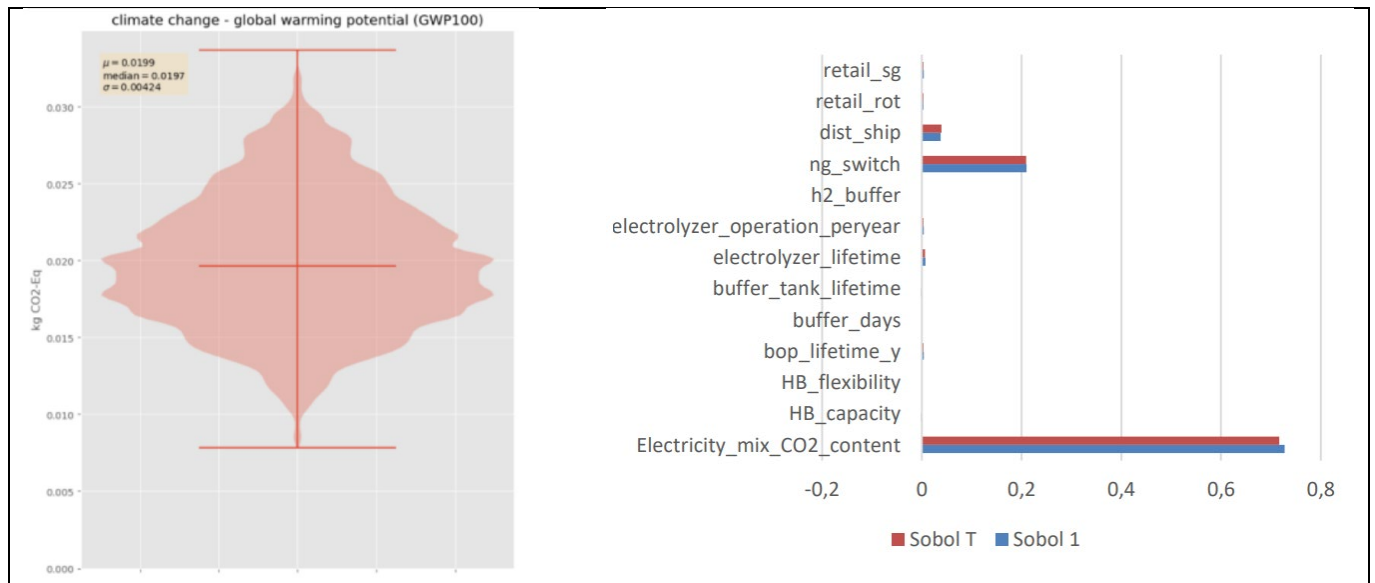
**Figure 35: Water use impacts (m<sup>3</sup> world eq.) for e-methanol production by region using the AWARE method**

Note: Some countries/regions such as Spain, Sub-Saharan Africa, Australia, and Chile stand out particularly due to AWARE factors that reflect the risk of water stress (availability minus demand) in the region. To fully exploit this indicator, it would be necessary to study more specific projects with a precise geographical location, which would allow for calculating the impact at the scale of a regional watershed.

#### e Sensitivity analysis

This study conducts a Global Sensitivity Analysis (GSA) using Monte Carlo simulations to identify the most influential parameters affecting GHG emissions per MJ of fuel produced. The simulation is applied only to foreground parameters, though it could also be extended to the Ecoinvent database and characterisation factors. Each parameter requires a default value, as well as minimum and maximum values, which are sourced from peer-reviewed literature and assigned an appropriate probability distribution – summarised in Annex 3.





**Figure 36: GSA results (probabilistic distribution of impacts left and Sobol indices right) for e-methanol with renewable H<sub>2</sub> production set to 0 gCO<sub>2</sub>e, carbon capture with natural gas-powered regeneration of MEA, and local electricity grid mix for auxiliaries' consumptions (Scenario 1)**

The GSA indicates a median of around 20 gCO<sub>2</sub>e/MJ of e-methanol (Scenario 1) including transport and distribution (the ship transportation distance ranges from 0 to 10 000km with a default value of 4 000 km and a triangular distribution). The Monte Carlo simulations also enable to draw Sobol indices. These are powerful indices to understand which parameters have the greatest impact on the results. Only the parameters that have an impact on the results (i.e. Sobol indices not null) are presented in Figure 36. As renewables for hydrogen production are considered at Scope 1 with an emission factor of 0 gCO<sub>2</sub>e, it is expected that parameters related to renewable electricity production or electrolyser efficiency are null and do not appear in the Sobol indices. However, even though electrolytic hydrogen from renewables is set at 0 gCO<sub>2</sub>e, the infrastructure associated with hydrogen production is included in the models. Some parameters used to determine hydrogen production and storage infrastructure allocation, such as electrolyser lifetime or buffer days, have non-null but relatively low Sobol indices, indicating that they are less sensitive compared to the GHG intensity of the local electricity grid mix.

The Sobol indices are classified as follows:

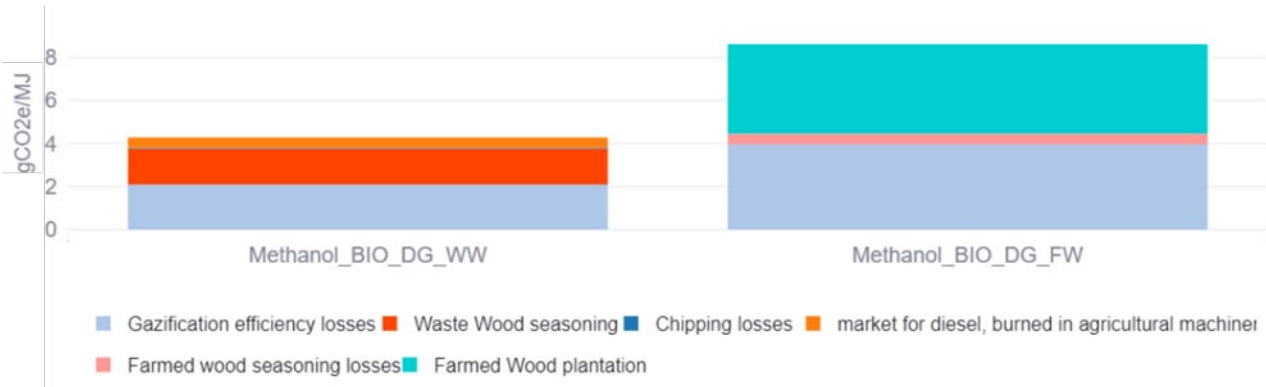
- $S_1$  (First-order Sobol index): Measures the direct effect of a parameter on the output, ignoring interactions. A high  $S_1$  (close to 1) indicates that the parameter alone contributes significantly to output variability.
- ST (Total-order Sobol index): Accounts for both the direct effect and interactions with other parameters. A high ST (close to 1) suggests a strong overall influence, including interaction effects.
- If ST is significantly higher than  $S_1$ , it means interactions between parameters are important, amplifying their impact on GHG emissions.

In this configuration, although the energy consumption of auxiliaries is relatively low at 0.056 MJ of electricity per MJ of e-methanol produced (see Section 5.2.1 Hydrogen from electrolysis), the Sobol indices for the parameter "Electricity\_mix\_CO<sub>2</sub>\_content", which represents the GHG intensity of the local electricity grid, are the highest. This indicates that it is the most influential parameter. The electricity parameter is defined within a range of 0 gCO<sub>2</sub>e/kWh to 1 kgCO<sub>2</sub>e/kWh, following a triangular distribution centred around a default value of 500 gCO<sub>2</sub>e/kWh. The second most significant parameter is the GHG intensity of the natural gas supply chain ("ng\_switch" parameter), which varies based on the values assigned to different natural gas supply chains across regions (see Section 4.3 Natural Gas).

### 6.1.2 Biomass-based Methanol

Via direct gasification

#### a Without Transport & Conditioning



**Figure 37 : GHG contributions of bio-methanol from direct gasification of waste wood (Methanol\_BIO\_DG\_WW), and bio-methanol from direct gasification of farmed wood (Methanol\_BIO\_DG\_FW) without transport and conditioning of the finished product**

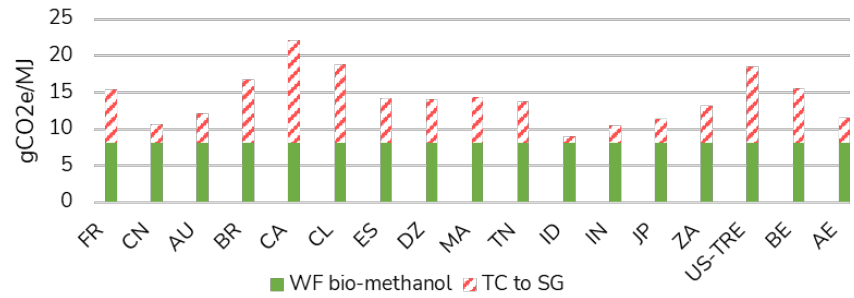
Figure 37 presents the GHG results for bio-methanol production via the direct gasification of biomass, specifically bio-methanol from the direct gasification of waste wood (Methanol\_BIO\_DG\_WW) and bio-methanol from the direct gasification of farmed wood (Methanol\_BIO\_DG\_FW). In our model, which is based on JECv5 inventories, there are no region-specific parameters. As a result, the GHG emissions for bio-methanol production, excluding transport and conditioning, remain consistent across the assessed production regions, with values of 4.3 gCO<sub>2e</sub>/MJ for waste wood methanol and 8.1 gCO<sub>2e</sub>/MJ for farmed wood methanol.

The figure details the contribution of different factors to the overall emissions. Although both pathways have the same process efficiency, the efficiency losses appear to be higher for the farmed wood pathway. However, this is primarily due to the higher emissions contribution per MJ of farmed wood feedstock, which results from the use of fertilisers, pesticides, and field emissions. In contrast, the impacts associated with waste wood are limited to collection and storage.

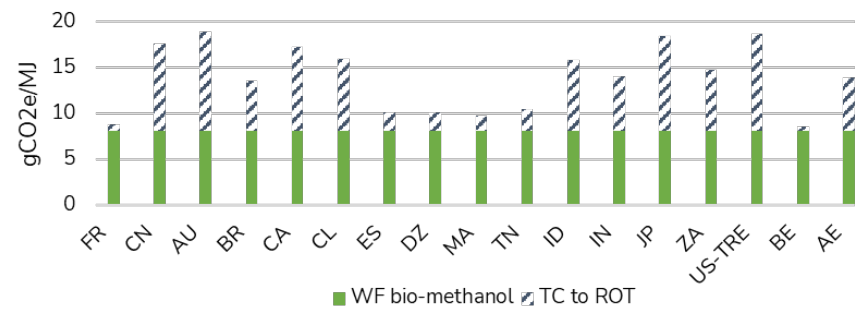
#### b With Transport & Conditioning

While the biomass transport assumptions are the same as in JECv5, the finished fuel transportation is adapted to this study (similar assumptions as for e-methanol). Figure 38 and Figure 39 show the GHG emission results for bio-methanol from cultivated wood and wood waste, respectively. Each figure considers the distribution of bio-methanol to either the bunkering port of Singapore or Rotterdam from the various locations detailed in Section 2.3 Scope. It can be seen that for the current horizon the share of GHG emissions linked to transport is very significant and, in several cases, larger than that of the production of bio-methanol. As the GHG emissions from the production of bio-methanol are very low (in particular with waste wood as a resource), the addition of transport, however important, does not allow the RFNBO threshold to be exceeded.

GHG emissions (gCO<sub>2</sub>e/MJ) for **Farmed Wood** bio-methanol production, transportation and conditioning to **Singapore**

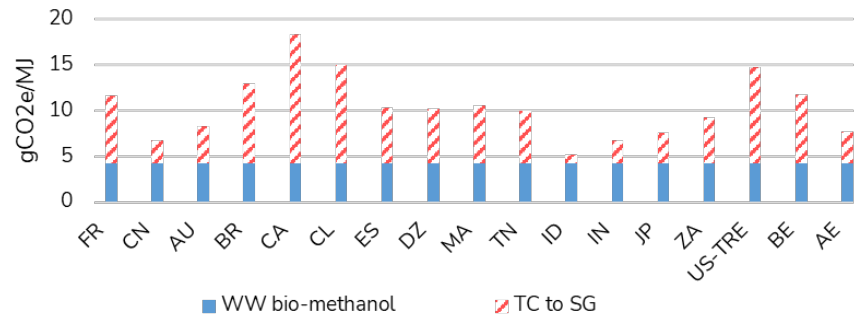


GHG emissions (gCO<sub>2</sub>e/MJ) for **Farmed Wood** bio-methanol production, transportation and conditioning to **Rotterdam**

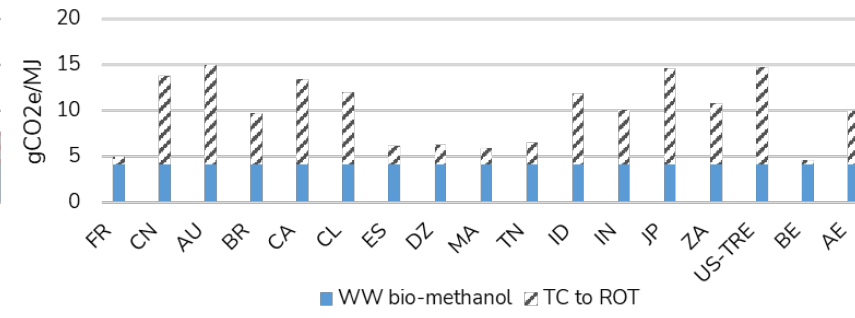


**Figure 38 GHG Emissions of Bio-methanol from Cultivated Wood with Transport to Singapore/Rotterdam; the emissions related to the transport of methanol correspond to the hatched areas.**

GHG emissions (gCO<sub>2</sub>e/MJ) for **Waste Wood** bio-methanol production, transportation and conditioning to **Singapore**



GHG emissions (gCO<sub>2</sub>e/MJ) for **Waste Wood** bio-methanol production, transportation and conditioning to **Rotterdam**

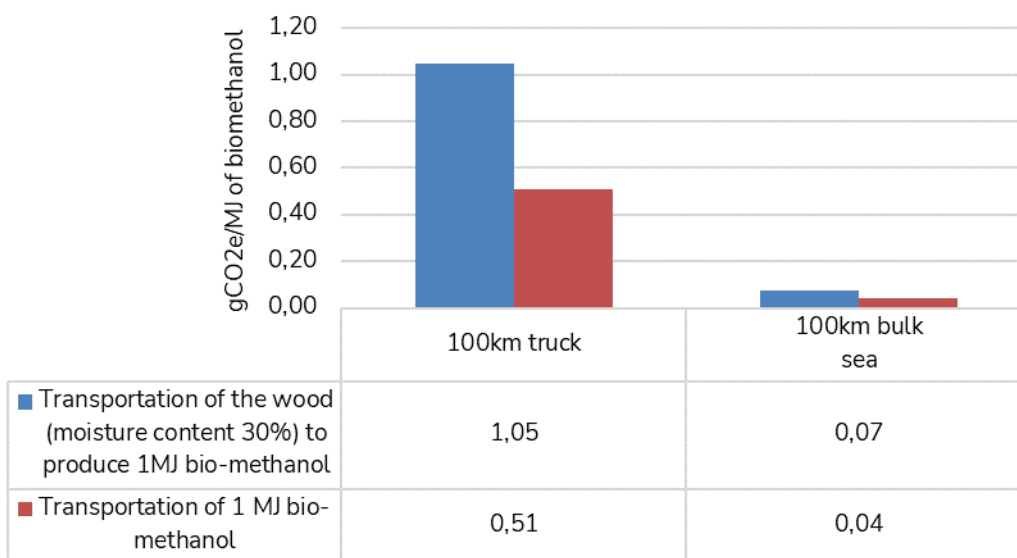


**Figure 39 GHG Emissions of Bio-methanol from Wood Waste with Transport to Singapore/Rotterdam; the emissions related to the transport of methanol correspond to the hatched areas.**

### c Sensitivity Analysis

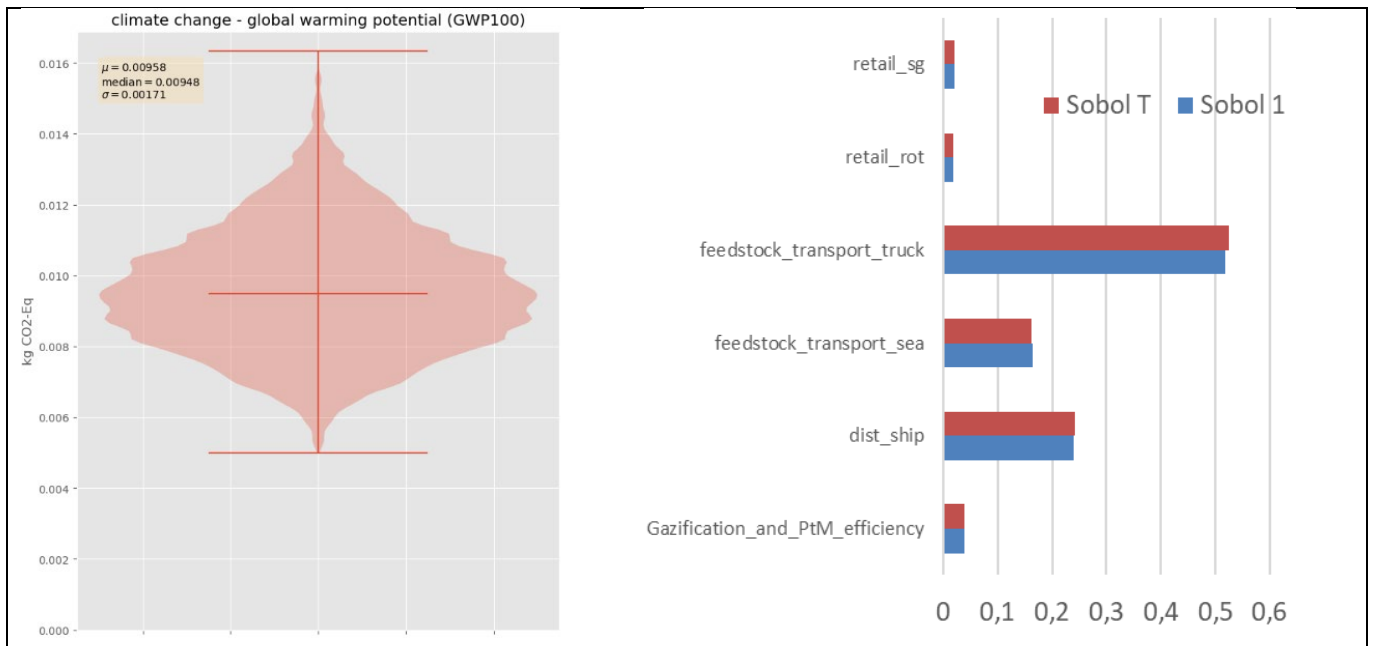
A local sensitivity analysis on the transport of wood to the bio-methanol production site, as well as on the transport of bio-methanol to the supply ports, has been conducted in this study. Initially, the objective was to compare the transport impacts of wood with those of the synthesised bio-methanol, considering two modes of transport: truck transport and ship.

The emissions from transporting the wood required to produce 1 MJ of bio-methanol over 100 km and the emissions from transporting 1 MJ of bio-methanol over 100 km, either by truck or by train, are presented in Figure 40. It appears that the transport of biomass is about twice as emissions-intensive as the transport of bio-methanol. Knowing that the lower heating values (LHV) of wood and methanol are close, this result is explained by the energy yield of 51.1% for converting wood to bio-methanol (during gasification and synthesis). In other words, it is necessary to transport twice as much wood (or wood waste) by mass as bio-methanol. These results demonstrate that the transport of both biomass and produced bio-methanol is a significant contributor to the GHG emissions impact of bio-methanol.



**Figure 40 : GHG emissions values to be added to the final results according to the transportation scenario**

In addition to the local sensitivity analysis on transport of wood or bio-methanol via truck or train, a Global Sensitivity Analysis (GSA) was performed using Monte Carlo simulations to identify the most influential parameters affecting GHG emissions per MJ of fuel produced. The simulation was applied to the foreground parameters of the bio-methanol model. Minimum and maximum values for each parameter were sourced from peer-reviewed literature and assigned an appropriate probability distribution – summarised in Annex 3. All transportation stages were included in the GSA, with the bio-methanol transportation distance via ship defined as a minimum of 0 kilometres, a default of 4,000 kilometres, and a maximum of 10,000 kilometres, following a triangular distribution.



**Figure 41 : GSA results (probabilistic distribution of impacts left and Sobol indices right) for biomethanol via direct gasification of waste wood**

The GSA results indicate a median GHG value of 9.1 gCO<sub>2</sub>e/MJ for bio-methanol produced via the direct gasification of waste wood, with a standard deviation of 1.7 gCO<sub>2</sub>e/MJ. The Sobol indices confirm the findings of the local sensitivity analysis, highlighting feedstock transportation by truck as the most influential parameter, as it has the highest Sobol indices. This is followed by the transportation of the finished product, represented by the ‘dist\_ship’ parameter.

These results suggest that to minimise the GHG impact of waste wood bio-methanol, it is preferable to prioritise local and short-distance waste wood feedstock collection to produce bio-methanol, even if this results in longer transport distances for the finished product. This approach is more beneficial than transporting wood biomass over long distances while keeping finished bio-methanol product transport minimal. It should be noted that the ‘Gasification\_and\_PtM\_efficiency’ parameter has a relatively low Sobol index due to the narrow range of efficiencies selected from the literature, with a default efficiency of 51.1 percent, a minimum of 42.82 percent, and a maximum of 52.78 percent, following a triangular distribution (El Koitsoumpa, 2020).

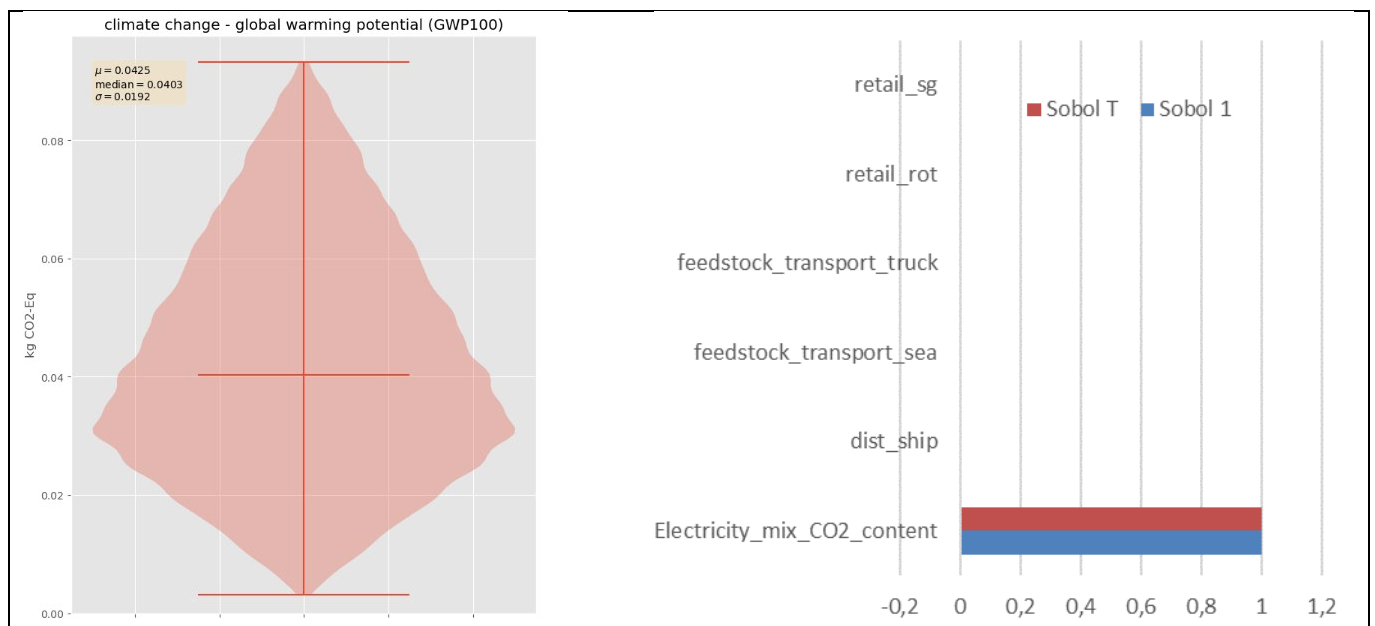
*Via Black Liquor gasification of Farmed Wood*



**Figure 42 GHG results of bio-methanol production from black liquor gasification of farmed wood, without transport and conditioning of the fuel**

Figure 42 presents the GHG results for bio-methanol production from the black liquor gasification of farmed wood. Unlike direct gasification, where results remain relatively stable across regions, the GHG emissions for black liquor bio-methanol production without transport and conditioning show significant variation. Values range from 6 gCO<sub>2</sub>e/MJ in France to 111 gCO<sub>2</sub>e/MJ in Indonesia, exceeding fossil reference levels in some cases. This variation is primarily due to the electricity input requirements, which are the dominant contributor to GHG emissions (see Section 4.6.1.c Black Liquor Gasification).

This conclusion is reinforced by the Global Sensitivity Analysis (GSA), which indicates that black liquor methanol results are almost entirely sensitive to the electricity mix used, as shown in Figure 43 below. The mean GHG value is 40 gCO<sub>2</sub>e/MJ, but the standard deviation is relatively high at 19 gCO<sub>2</sub>e/MJ, reflecting the wide variation in CO<sub>2</sub> intensity across different regional electricity grids.



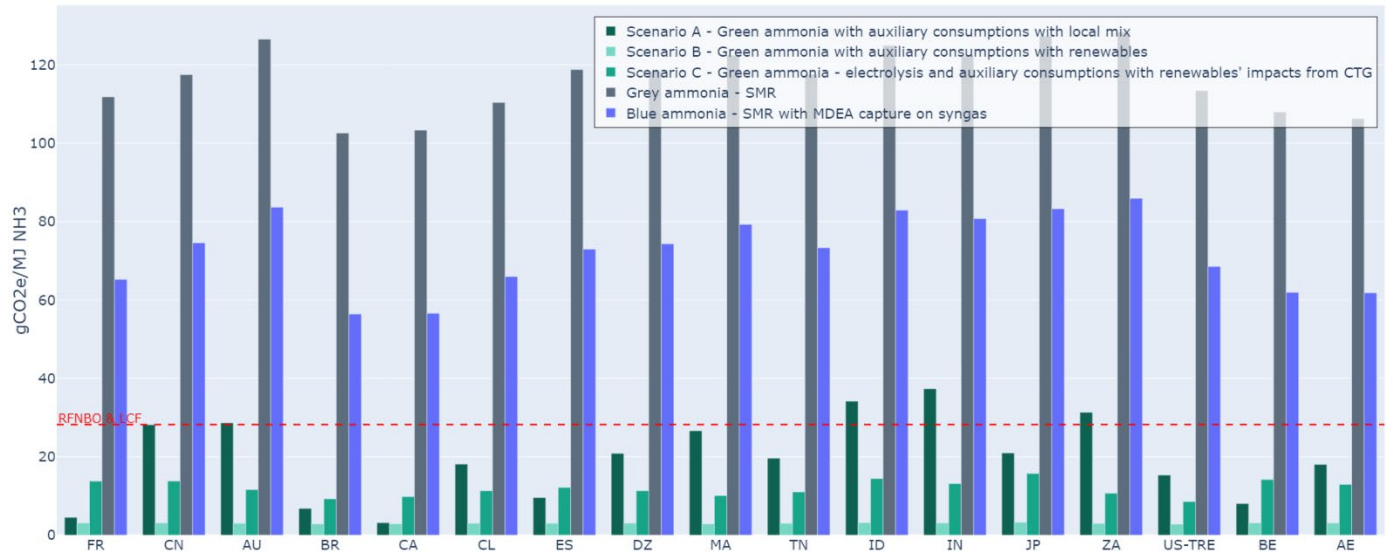
**Figure 43 GSA results (probabilistic distribution of impacts left and Sobol indices right) for bio-methanol via black liquor gasification of farmed wood**



## 6.2 Ammonia

### 6.2.1 Ammonia from Electrolytic Hydrogen

#### a Without Transport & Conditioning



**Figure 44: GHG emissions of Ammonia WTW without T&C, by region and configuration scenario**

Figure 44 presents the GHG emissions of the three green ammonia configurations summarised in Section 5.3, alongside grey and blue ammonia, excluding transport and conditioning.

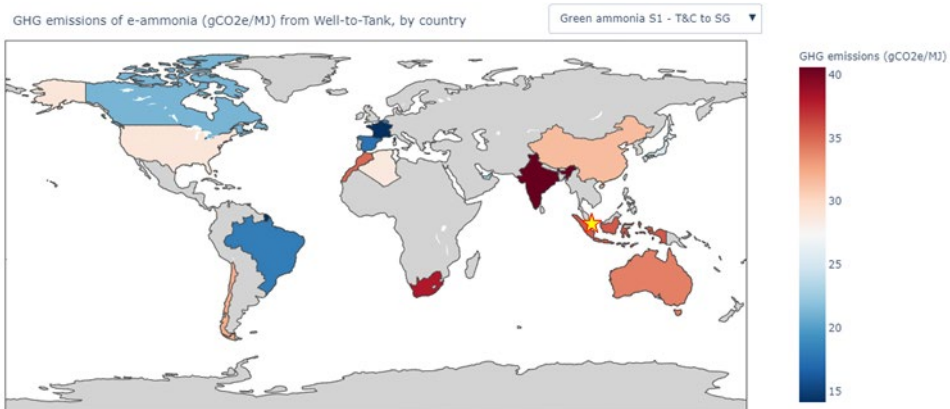
The results for Scenario A for green ammonia, where auxiliary electricity consumption (including Haber-Bosch utilities, nitrogen production, and refrigeration during storage) is powered by the local grid mix, indicate that auxiliaries can significantly contribute to overall GHG emissions, particularly in regions with a high-carbon electricity mix. In contrast, in Scenario B, where auxiliary consumption is powered by renewable electricity, green ammonia meets the RFNBO 70% reduction threshold, whether assessed under the RED methodology (assuming zero emissions) or on a cradle-to-gate basis. However, grey and blue ammonia do not achieve RFNBO compliance in any of the assessed production regions. Even the capture of CO<sub>2</sub> on syngas for SMR hydrogen (Blue ammonia) does not sufficiently reduce grey ammonia emissions. This is due to the H<sub>2</sub> production emissions (see the yellow contribution in Figure 65), particularly, the natural gas supply chain and furnace direct CO<sub>2</sub> and CH<sub>4</sub> emissions.

#### b With Transport & Conditioning

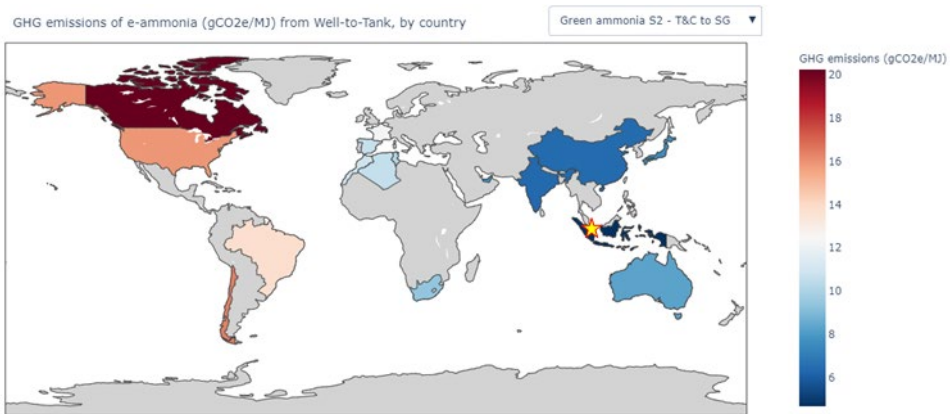
##### To the port of Singapore:

A similar pattern observed for e-methanol can also be seen with e-ammonia:

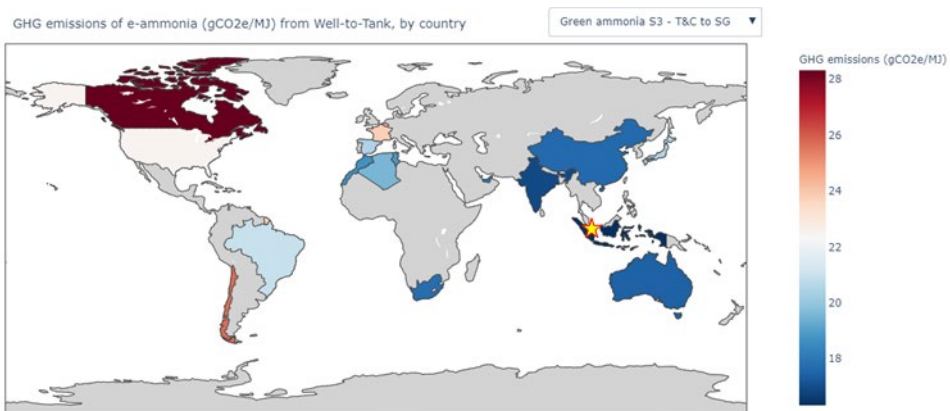
- In the first scenario, where auxiliary electricity is sourced from the local grid mix, producing e-ammonia in regions with a lower GHG-intensity electricity grid, such as France, Canada, or Brazil, can result in lower overall GHG emissions, even when transported over long distances to Singapore for bunkering (Figure 45).
- When renewable electricity is used for auxiliary consumption, transport distance becomes the primary factor influencing GHG emissions (Figure 46).
- Under a full renewable cradle-to-gate (CTG) configuration in Scenario C, the results are similar to those in Scenario 2. However, there is a wider variation in emissions, as a greater share of renewable electricity is used, leading to higher GHG emissions overall (Figure 47).



**Figure 45: GHG emissions of e-ammonia (gCO<sub>2</sub>eq/MJ), WtW scope by region with transport and conditioning from the production region to the port of Singapore; for Scenario A with local grid mix electricity for auxiliaries; readers are advised to pay attention to the colour scales that vary according to the map.**



**Figure 46: GHG emissions of e-ammonia (gCO<sub>2</sub>eq/MJ), WtW scope by region with transport and conditioning from the production region to the port of Singapore; for Scenario B with renewable electricity for auxiliaries; readers are advised to pay attention to the colour scales that vary according to the map.**

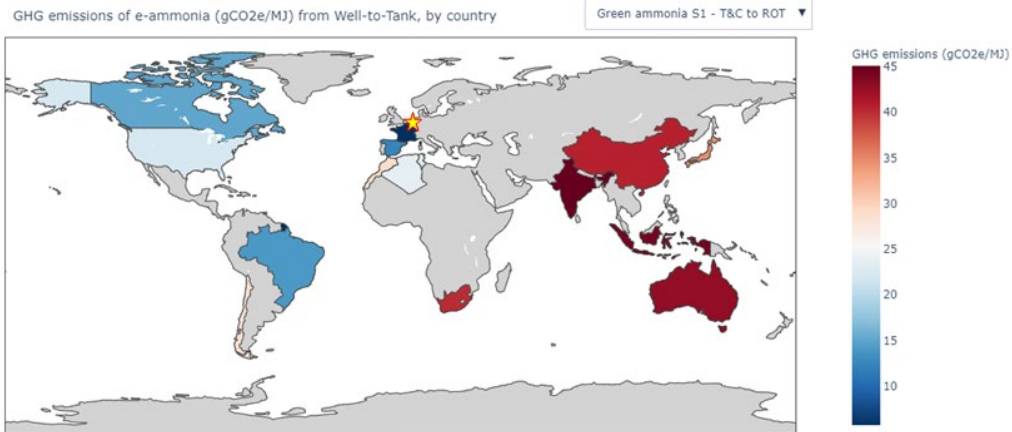


**Figure 47: GHG emissions of e-ammonia (gCO<sub>2</sub>eq/MJ), WtW scope by region with transport and conditioning from the production region to the port of Singapore; for Scenario C with renewable electricity from cradle-to-grave for H<sub>2</sub> production and for auxiliaries; readers are advised to pay attention to the colour scales that vary according to the map.**

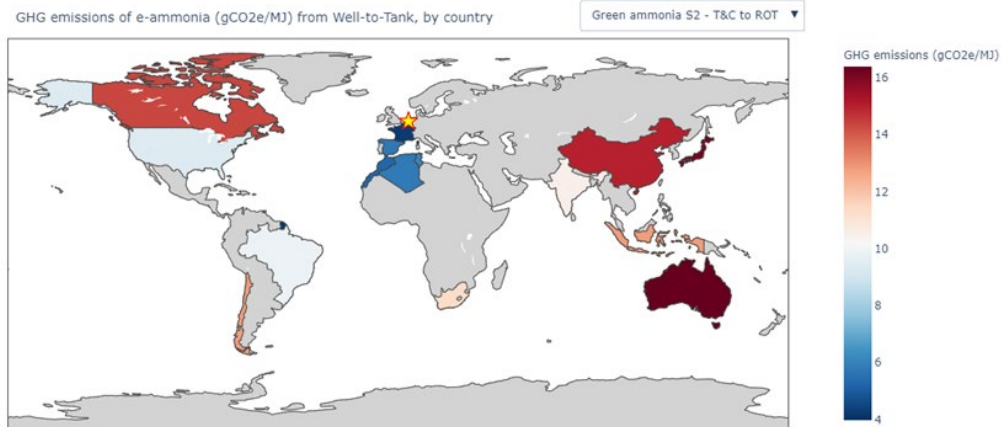
### **To the port of Rotterdam:**

Similar conclusions apply when considering Rotterdam as the bunkering site.

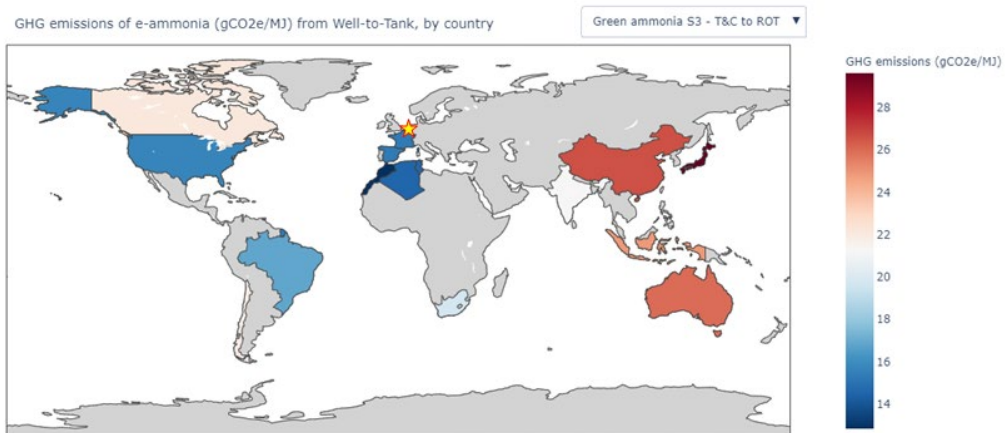
- In the Scenario A, where auxiliary electricity is sourced from the local grid mix, producing e-ammonia in regions with a lower GHG-intensity electricity grid, such as France, Canada, or Brazil, can result in lower overall GHG emissions, even when transported over long distances to Rotterdam for bunkering (Figure 48).
- The interest of producing fuel close to the bunkering location is more pronounced, as regions near Rotterdam often have a lower GHG-intensity electricity grid (e.g., France) compared to more distant production regions (Figure 48).
- When renewable electricity is used for auxiliary consumption, transport distance becomes the primary factor influencing GHG emissions (Figure 49).
- Under a full renewable cradle-to-gate (CTG) configuration in Scenario C, the results are similar to those in Scenario B. However, there is a wider variation in emissions, as a greater share of renewable electricity is used, leading to higher GHG emissions overall (Figure 50).



**Figure 48: GHG emissions of e-ammonia (gCO<sub>2</sub>eq/MJ), WtW scope by region with transport and conditioning from the production region to the port of Rotterdam; for the Scenario A with local grid mix electricity for auxiliaries; readers are advised to pay attention to the colour scales that vary according to the map.**



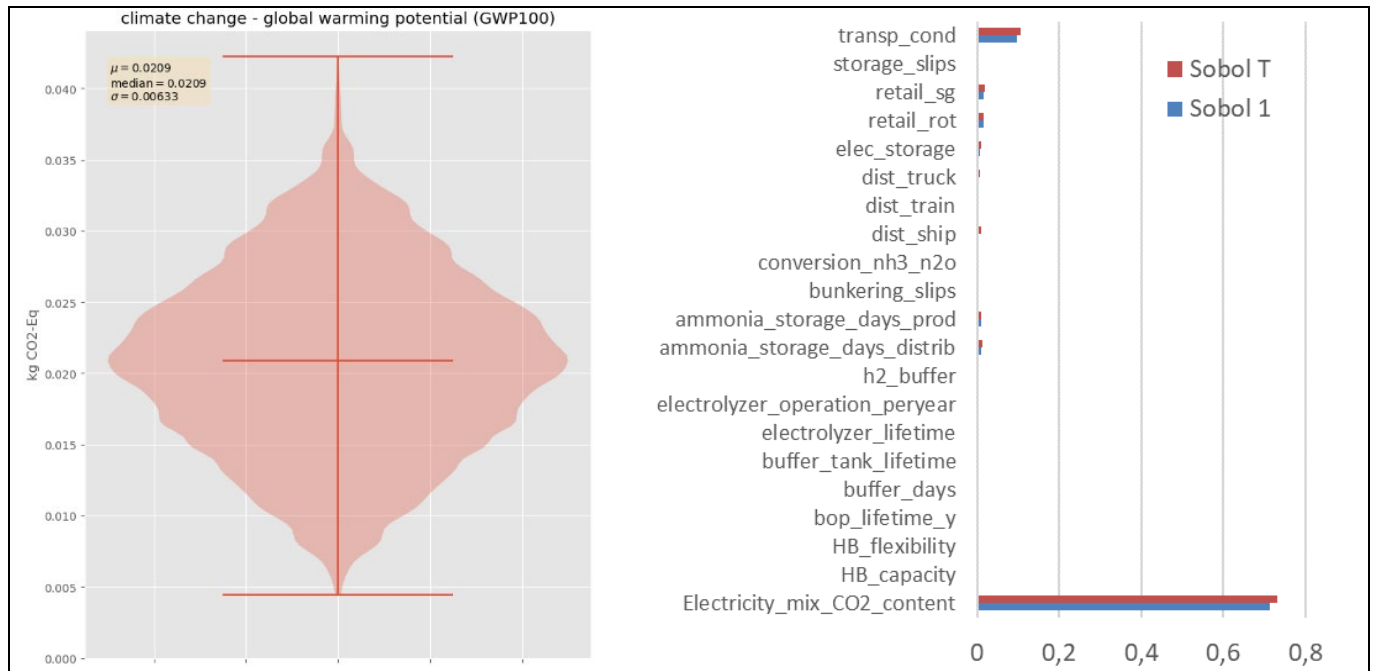
**Figure 49: GHG emissions of e-ammonia (gCO<sub>2</sub>eq/MJ), WtW scope by region with transport and conditioning from the production region to the port of Rotterdam; for Scenario B with renewable electricity for auxiliaries; readers are advised to pay attention to the colour scales that vary according to the map.**



**Figure 50: GHG emissions of e-ammonia (gCO<sub>2</sub>eq/MJ), WtW scope by region with transport and conditioning from the production region to the port of Rotterdam; for the Scenario C with renewable electricity from cradle-to-grave for H<sub>2</sub> production and for auxiliaries; readers are advised to pay attention to the colour scales that vary according to the map.**

### c Sensitivity analysis

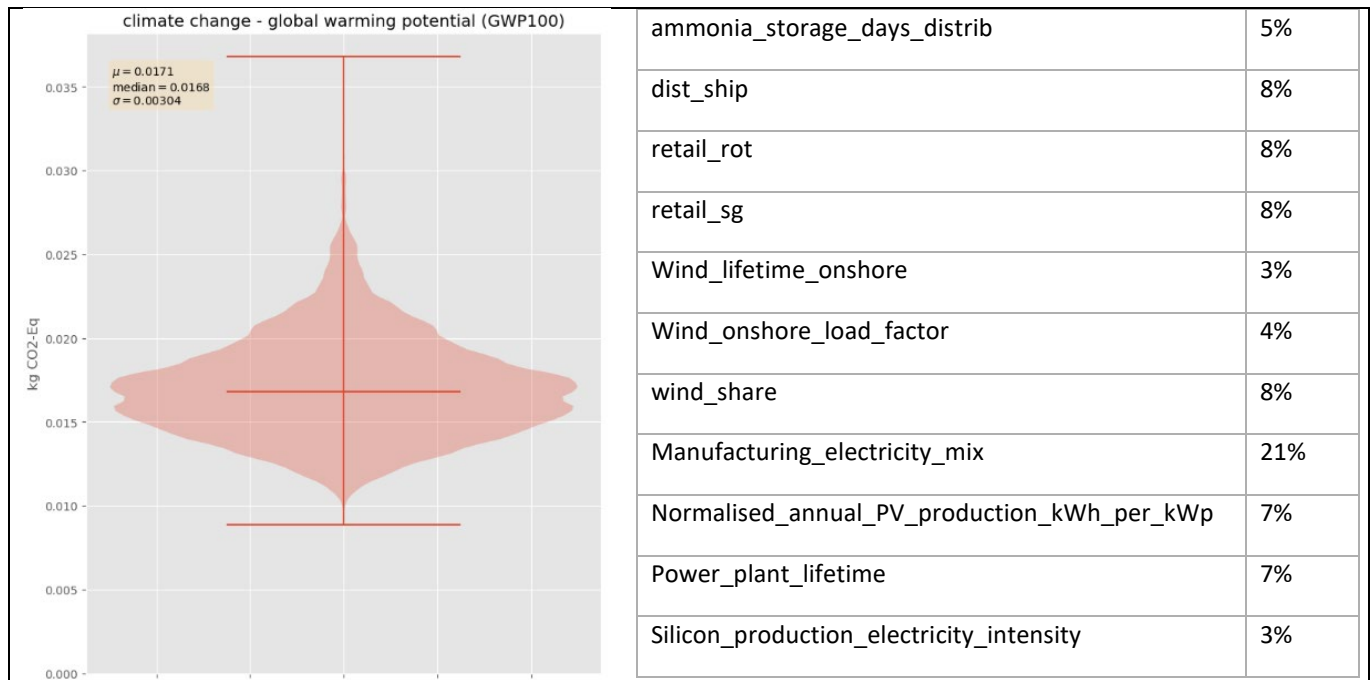
A Global Sensitivity Analysis (GSA) was performed using Monte Carlo simulations to identify the most influential parameters affecting GHG emissions per MJ of fuel produced. The simulation was applied to the foreground parameters of e-ammonia under Scenario A ( $H_2 = 0 \text{ gCO}_2\text{e}$ , auxiliary electricity from local grid mix). Minimum and maximum values for each parameter were sourced from peer-reviewed literature and assigned an appropriate probability distribution – summarised in Annex 3. Results are presented in Figure 51:



**Figure 51 : GSA results (probabilistic distribution of impacts left and Sobol indices right) for e-ammonia Scenario A (electricity for  $H_2$  production =  $0 \text{ gCO}_2\text{e}$ , auxiliary electricity from local grid mix)**

The electricity grid mix  $\text{CO}_2$  content parameter has the highest Sobol index, making it the most influential factor in the results. It is defined within a range of  $0 \text{ gCO}_2\text{e/kWh}$  to  $1 \text{ kgCO}_2\text{e/kWh}$ , following a triangular distribution. Its significance is such that it shapes the ammonia distribution curve, centring around  $20 \text{ gCO}_2\text{e/MJ}$  in a triangular pattern. The "transp\_cond" parameter is a boolean variable that determines whether the transport and conditioning stages of ammonia are included in the assessment. In this specific scenario, all parameters related to renewable electricity production are absent, as electricity is set to  $0 \text{ gCO}_2\text{e/kWh}$ .

The sensitivity analysis for e-ammonia under Scenario C (where both hydrogen production and auxiliaries are powered by renewable electricity within the cradle-to-gate (CTG) scope) includes a greater number of parameters related to renewable electricity production models. Figure 52 presents only the parameters with Sobol T indices exceeding 3%.



**Figure 52: GSA results (probabilistic distribution of impacts left and sobol indices right) for e-ammonia Scenario C (H<sub>2</sub> and auxiliaries' consumptions from CTG renewable electricity)**

The median GHG emissions for this scenario are approximately 17 gCO<sub>2</sub>e/MJ, which is lower than the previously assessed e-ammonia scenario where auxiliaries were powered by the local grid mix and hydrogen production relied on renewable electricity. The standard deviation is also reduced to 3 gCO<sub>2</sub>e/MJ, compared to 6.3 gCO<sub>2</sub>e/MJ in the previous scenario. This is because the GHG intensity of cradle-to-gate (CTG) renewable electricity impacts shows less variation across production regions compared to the GHG intensity of local grid mixes.

In terms of sensitivity, many parameters influence the model results. For better readability, it is only presented in Figure 52 the parameters with a larger than 3% total Sobol indice. Annex 6 presents the Sobol indices for each of the parameters influencing the e-ammonia Scenario C results. This analysis identifies the GHG intensity of electricity used in PV panel manufacturing as the most influential parameter, with a Sobol Total Index of 21%. The distribution of this parameter is centred around the high GHG intensity of China, the world's largest PV panel producer. Other key factors include transportation distance by ship (8%) and the share of wind and PV electricity in the hypothetical renewable mix.

For an e-ammonia producer operating under this energy configuration, reducing fuel production GHG intensity would require maximising wind electricity use over PV and/or sourcing PV panels manufactured using low-carbon electricity.

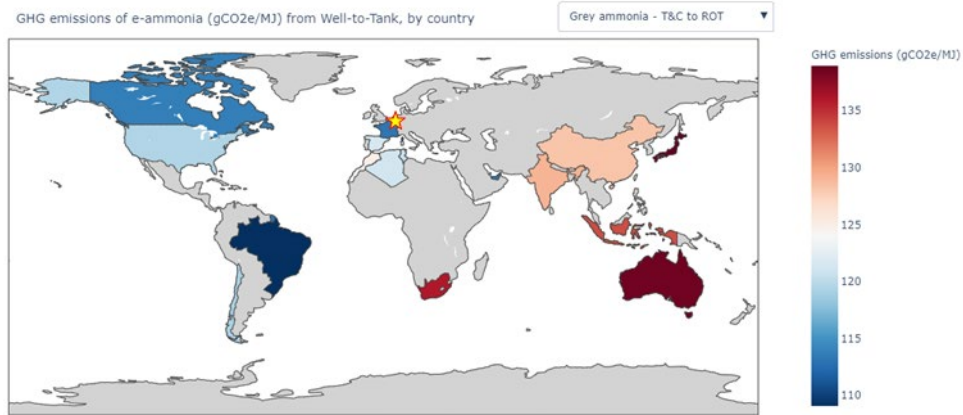
## 6.2.2 Ammonia from Methane Reforming Hydrogen

### a Without Transport & Conditioning

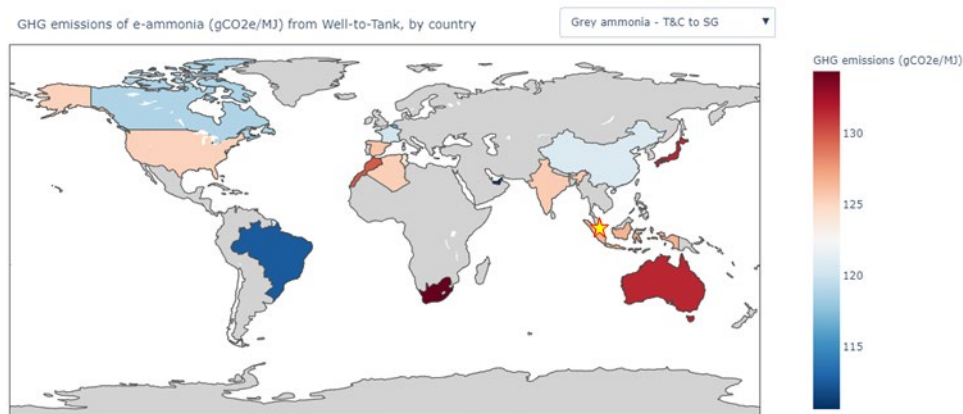
GHG emissions for grey and blue ammonia produced via conventional hydrogen production using SMR and SMR with CCS are presented in 6.2.1a Figure 31. In all production regions, the grey ammonia do not pass the RFNBO threshold ranging 100 to 120 gCO<sub>2</sub>e/MJ. In all production regions, grey ammonia fails to meet the RFNBO threshold, with emissions ranging from 100 to 120 gCO<sub>2</sub>e/MJ. Similarly, blue ammonia does not achieve RFNBO compliance in any of the assessed regions, with emissions ranging from 57 to 85 gCO<sub>2</sub>e/MJ NH<sub>3</sub>. A clear trend emerges where the regions with lower GHG emissions from natural gas consumption, such as Brazil, Canada, and the United Arab Emirates, also have the lowest overall GHG emissions for ammonia production.



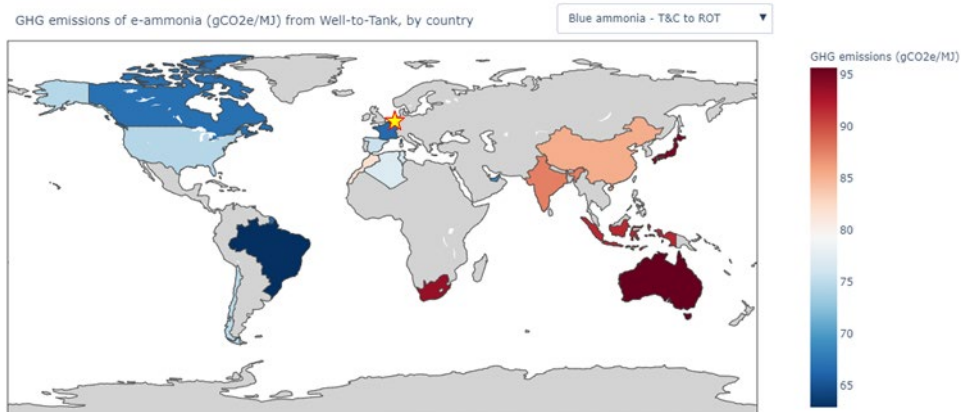
**b With Transport & Conditioning**



**Figure 53: GHG emissions of grey ammonia (gCO<sub>2</sub>eq/MJ), WtW scope by region with transport and conditioning from the production region to the port of Rotterdam; with local grid mix electricity for auxiliaries; readers are advised to pay attention to the colour scales that vary according to the map.**

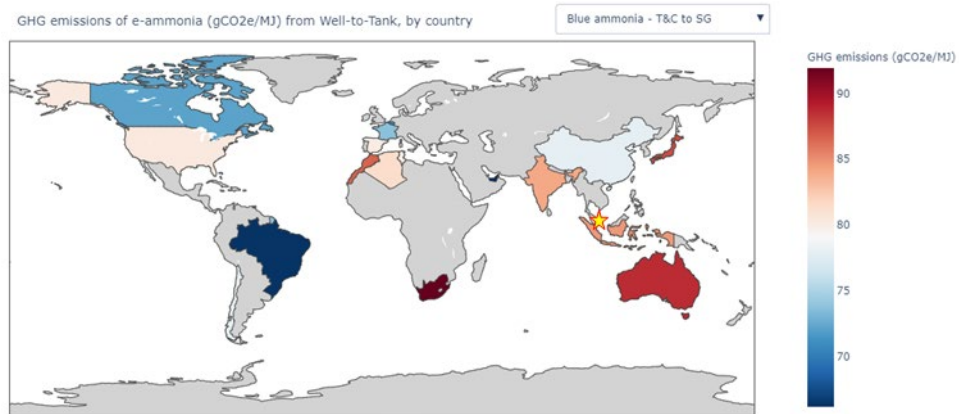


**Figure 54: GHG emissions of grey ammonia (gCO<sub>2</sub>eq/MJ), WtW scope by region with transport and conditioning from the production region to the port of Singapore; with local grid mix electricity for auxiliaries; readers are advised to pay attention to the colour scales that vary according to the map.**



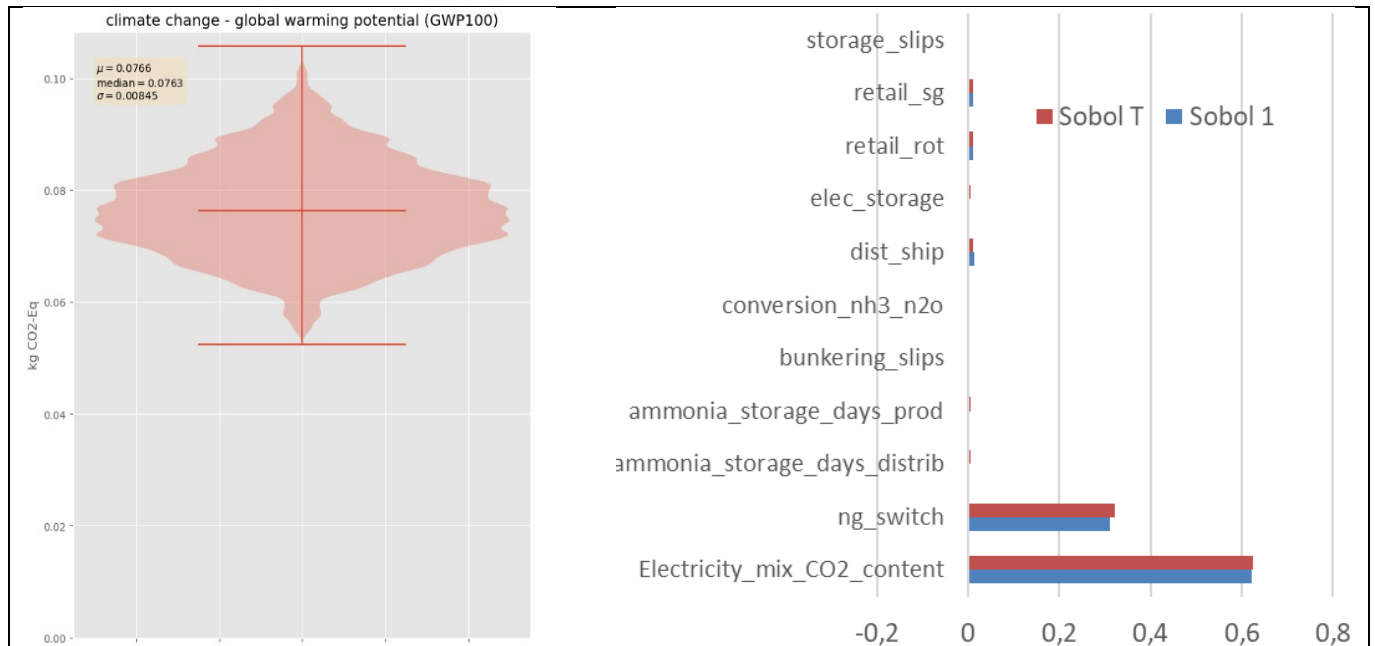
**Figure 55: Figure 56: GHG emissions of blue-ammonia (gCO<sub>2</sub>eq/MJ), WtW scope by region with transport and conditioning from the production region to the port of Rotterdam; with local grid mix electricity for auxiliaries; readers are advised to pay attention to the colour scales that vary according to the map.**





**Figure 57: GHG emissions of blue-ammonia (gCO<sub>2</sub>eq/MJ), WtW scope by region with transport and conditioning from the production region to the port of Singapore; with local grid mix electricity for auxiliaries; readers are advised to pay attention to the colour scales that vary according to the map.**

**c Sensitivity analysis**



**Figure 58 : GSA results (probabilistic distribution of impacts left and sobol indices right) for ammonia from SMR with CCS with MDEA hydrogen**

A Global Sensitivity Analysis (GSA) was conducted using Monte Carlo simulations to identify the most influential parameters affecting GHG emissions per MJ of fuel produced, presented in Figure 58. Minimum and maximum values for each parameter were sourced from peer-reviewed literature and assigned an appropriate probability distribution – summarised in Annex 3. The median GHG emissions for blue ammonia are approximately 76 gCO<sub>2</sub>e/MJ, with a standard deviation of 8.45 gCO<sub>2</sub>e/MJ.

Among the most sensitive parameters, the Sobol index for "Electricity\_mix\_CO<sub>2</sub>\_content", which represents the GHG intensity of the local electricity grid mix, is the highest, indicating it has the most significant impact on results. This parameter follows a triangular distribution, ranging from 0 gCO<sub>2</sub>e/kWh to 1 kgCO<sub>2</sub>e/kWh, with a default value of 500 gCO<sub>2</sub>e/kWh. The local electricity grid mix is used for nitrogen (N<sub>2</sub>) production and ammonia storage (see Ammonia Transportation, Storage, and Bunkering and H<sub>2</sub> from Methane Reforming).

The second most influential parameter is the GHG intensity of the natural gas supply chain, represented by the "ng\_switch" parameter, which varies based on the range of natural gas supply chain emissions across different regions (see Section 4.3 Natural Gas).

## 7 Container Unit Transportation Work Well-to-Wake Results

### 7.1.1 Modelled Engine Data and Scenarios for Typical Ship Route

In the previous sections, Well-to-Wake results were presented per one megajoule of methanol or ammonia in gCO<sub>2</sub>e per MJ of fuel. In this section, the objective is to express Well-to-Wake lifecycle emissions in relation to freight transport, measured in gCO<sub>2</sub>eq per TEU-km (or t.km). For a typical CMA CGM route from Busan, South Korea, to Rotterdam, Netherlands, the aim is to calculate the emissions associated with methanol or ammonia and compare them with emissions from reference, conventional fuels. In each case, The data provided by CMA CGM, which forms the basis for these calculations, can be found in Figure 59, Table 23, Table 24 and Table 25.

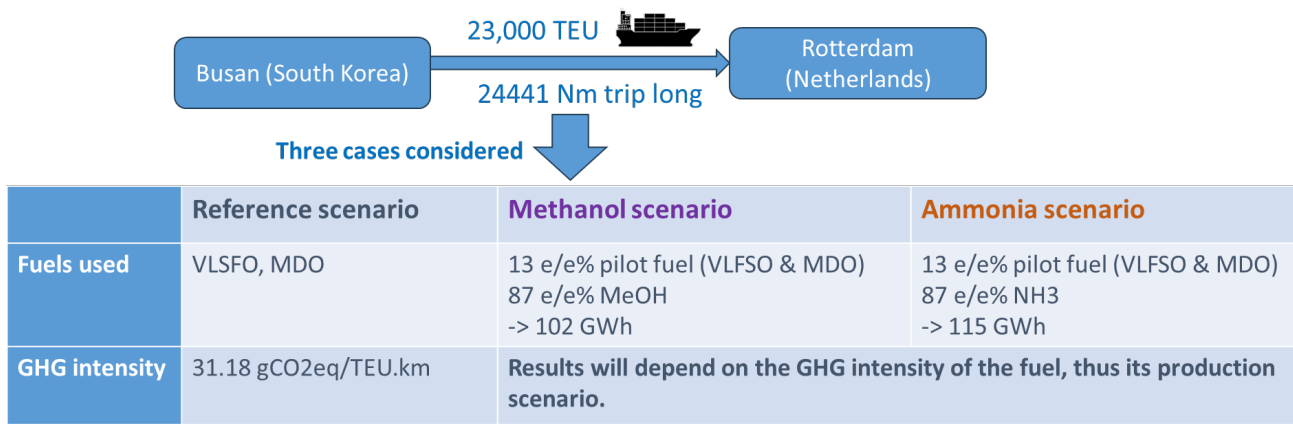


Figure 59 : Summary of Well-to-Wake analysis scenarios (data provided by CMA CGM)

Table 23 : Fuel consumption values for the typical route.

Configuration	23K Conventionnal Fuel	23K Methanol	23K NH3	23K Conventionnal Fuel [GWh]	23K Methanol [GWh]	23K NH3 [GWh]
TOTAL: VLSFO (t)	7261 tns	82 tns	82 tns	84.10	0.95	0.95
TOTAL: MDO (only) (t)	1254 tns	1005 tns	1149 tns	14.87	11.93	13.63
TOTAL: Methanol (t)	0 tns	16223 tns	0 tns		89.68	
TOTAL: Ammonia (t)	0 tns	0 tns	19465 tns			100.57
TOTAL ENERGY				98.98	102.56	115.16

Table 24: Data on the typical route related to the functional unit

	23K Conventionnal Fuel	23K Methanol	23K NH3
TOTAL ENERGY PRODUCED (GWh)	47.53	48.39	49.70
MAIN ENGINE (ME) ENERGY PRODUCED (GWh)	35.67	35.67	35.67
AUX. ENGINE (AE) ENERGY PRODUCED (GWh)	11.86	12.72	14.02
TEU CAPACITY	23000	22600	22350
Distance (Nm)	24441	24441	24441
Total Transport efficiency (Wh/TEU.Nm)	84.56	87.61	90.98
Main engine Transport efficiency (Wh/TEU.Nm)	63.46	64.58	65.31
Aux Engine Transport efficiency (Wh/TEU.Nm)	21.10	23.03	25.67

**Table 25: N<sub>2</sub>O tank-to-wake emissions**

	<b>23K NH3</b>
<b>ME N2O hypothesis (g N2O/kWh energy produced)</b>	0.06
<b>AE N2O hypothesis (g N2O/kWh energy produced)</b>	0.30
<b>ME N2O hypothesis (g N2O/GWh energy produced)</b>	60000
<b>AE N2O hypothesis (g N2O/GWh energy produced)</b>	300000
<b>ME N2O TTW emissions (g N2O)</b>	28313
<b>AE N2O TTW emissions (g N2O)</b>	10702345
<b>ME N2O TTW emissions (tonnes N2O)</b>	0.03
<b>AE N2O TTW emissions (tonnes N2O)</b>	10.70

Table 23, presents fuel consumption for three scenarios: a reference scenario using only conventional fuels (VLSFO and MDO) and two alternative scenarios, one primarily based on methanol and the other on ammonia, each supplemented by a small share of conventional fuels. In the methanol scenario, total fuel consumption is slightly higher than in the reference case, reaching 102.56 GWh compared to 98.98 GWh. In the ammonia scenario, fuel consumption is even greater, with a total of 115.16 GWh compared to 98.98 GWh in the reference case.

It is important to note that 23,000 TEU methanol and ammonia-powered ships do not currently exist. The ship models used in this analysis are based on the most up-to-date engine model data, incorporating test bed results for methanol engines (already in operation) and manufacturer simulations for ammonia engines. However, for the sake of a baseline comparison, the same engine configuration (size and number) has been selected across all scenarios. This results in non-optimal emissions configurations, particularly for ammonia, where auxiliary systems contribute significantly to N<sub>2</sub>O emissions.

Table 24, presents information on the functional unit, including the distance travelled corresponding to the fuel consumption values and the maximum container capacity (expressed in TEU). These data enable the conversion of GHG emission results for methanol and ammonia into gCO<sub>2eq</sub>/TEU.km. It can be noted that in the case of methanol and ammonia, the transported cargo capacity is slightly lower compared to conventional fuel-powered transport. This reduction is due to the larger volume required for the propulsion system and, in the case of methanol, the space occupied by the additional fuel storage in the holds. Table 25 shows the tank-to-wake N<sub>2</sub>O emissions for the typical route in the ammonia scenario as the combustion of ammonia produces nitrous oxide (N<sub>2</sub>O), a potent greenhouse gas with a global warming potential significantly higher than that of CO<sub>2</sub>.

## 7.1.2 Well-to-Wake Emission Results for Typical Ship Route

### a Reference Scenario

In the reference scenario, the total energy consumption amounts to 84.10 GWh of VLSFO and 14.87 GWh of MDO. The well-to-wake GHG emission values for conventional fuels in Table 26 are used to assess the impact of transporting 23,000 TEU over a distance of 24,441 Nm. Total emissions for the entire journey amount to 32,463 tonnes of CO<sub>2eq</sub>, equivalent to 31.2 gCO<sub>2eq</sub>/TEUkm.

**Table 26: Reference values of GHG emissions from conventional marine fuels (source: FuelEU Maritime Regulation)**

<b>Fuel</b>	<b>LHV (MJ/g)</b>	<b>WtT (gCO<sub>2eq</sub>/MJ)</b>	<b>TtW (gCO<sub>2eq</sub>/MJ)</b>	<b>WtW (gCO<sub>2eq</sub>/MJ)</b>
VLSFO	0.041	13.2	78.2	91.4
MDO	0.0427	14.4	75.1	89.5

## **b Alternative Methanol Scenario**

In the alternative scenario with methanol, since two fossil fuels are used in addition to methanol, it is necessary to use the GHG emission values of methanol (e-methanol or bio-methanol) calculated in the study and the GHG emission values of conventional fuels to determine the total emissions.

In this scenario, total energy consumption amounts to 0.95 GWh of VLSFO, 11.93 GWh of MDO, and 89.68 GWh of methanol. Using the well-to-wake GHG emission values for conventional fuels from Table 26, the emissions from VLSFO and MDO amount to 4,156 tonnes of CO<sub>2</sub>eq for transporting 22,600 TEU over 24,441 Nm. For the methanol share, the well-to-wake emissions depend on whether e-methanol or bio-methanol is used. For example, assuming e-methanol with emissions of 16.0 gCO<sub>2</sub>eq/MJ, the associated impact is 5,166 tonnes of CO<sub>2</sub>eq for the same transport conditions. Summing the contributions from both conventional fuels and methanol, the total impact reaches 9.1 gCO<sub>2</sub>eq/TEUkm, with 4.1 gCO<sub>2</sub>eq/TEUkm attributed solely to conventional fuels.

In the previous calculation, the result was obtained using a predefined input value for the well-to-wake GHG emissions from methanol. Regardless of this value, the GHG emissions associated with the share of fossil fuels used alongside methanol remain constant. This implies that the total GHG emissions of the ship follow a linear relationship with the emissions from methanol. The ship's functional unit, expressed in gCO<sub>2</sub>eq/TEUkm and calculated based on the well-to-wake GHG emissions of methanol for all scenarios considered in the study, is presented in the first graph in Figure 60. For reference, the transport impact in the reference scenario, previously calculated as 31.2 gCO<sub>2</sub>eq/TEUkm, is also shown.

## **c Alternative Ammonia Scenario**

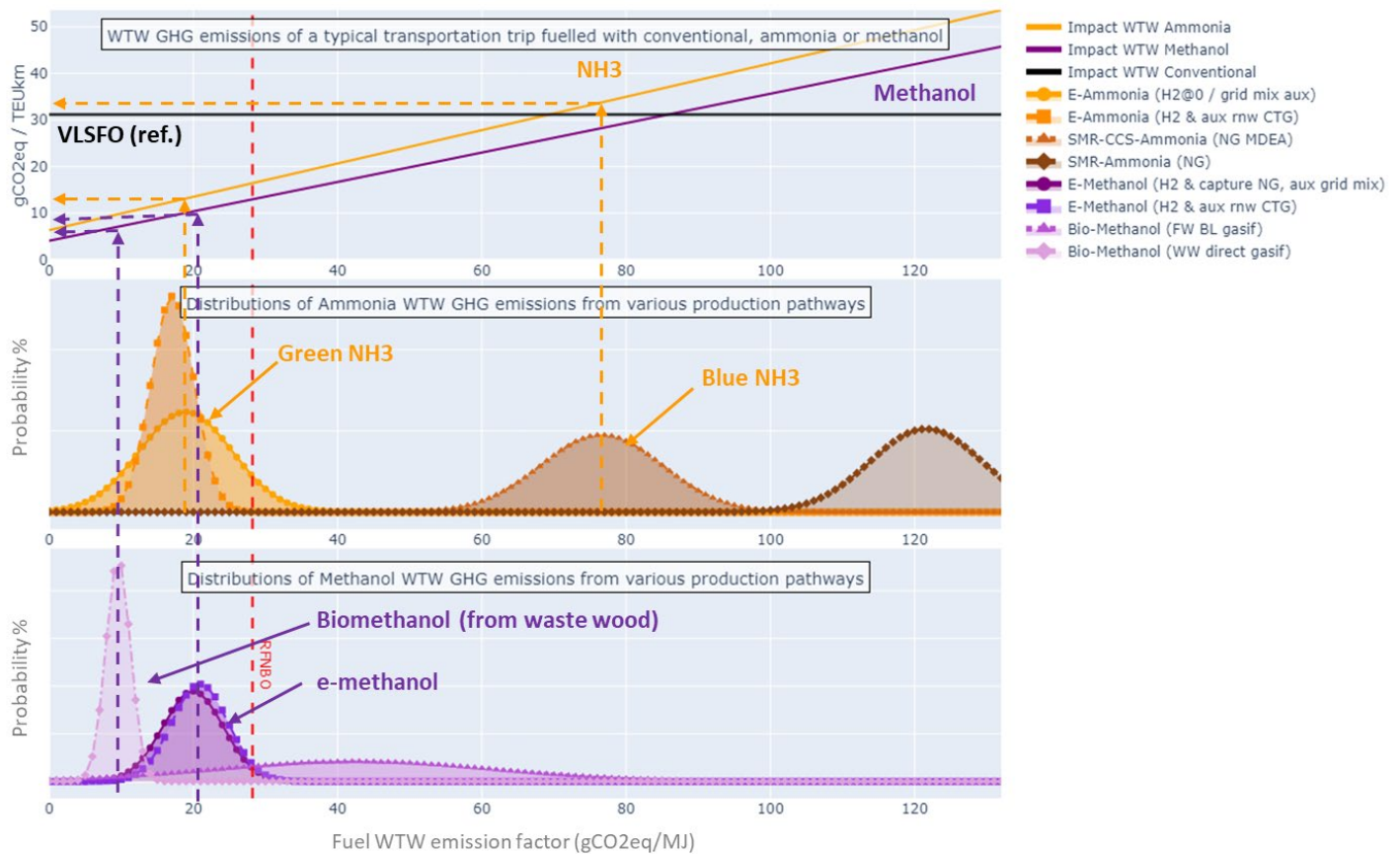
In the alternative scenario with ammonia, as with methanol, since two fossil fuels are used alongside ammonia, the total well-to-wake lifecycle GHG emissions must be determined using the well-to-wake emission values for ammonia (blue, grey, or green) calculated in this study, along with the GHG emissions of conventional pilot fuels.

Total energy consumption in this scenario amounts to 0.95 GWh of VLSFO, 13.6 GWh of MDO, and 100.6 GWh of ammonia. Using the well-to-wake GHG emission values for conventional fuels from Table 19, the emissions from VLSFO and MDO total 4,704 tonnes of CO<sub>2</sub>eq for transporting 22,350 TEU over 24,441 Nm. For the ammonia share, the well-to-wake GHG emissions depend on the specific ammonia type used. Assuming e-ammonia with 15.0 gCO<sub>2</sub>eq/MJ, the associated impact amounts to 5,431 tonnes of CO<sub>2</sub>eq for the same transport conditions. Additionally, ammonia tank-to-wake emissions must account for N<sub>2</sub>O emissions, calculated relative to the functional unit emissions. Using an N<sub>2</sub>O emission factor of 273 g CO<sub>2</sub>eq per g N<sub>2</sub>O, the resulting emissions total 1,733 tonnes of CO<sub>2</sub>eq. Summing the contributions from conventional fuels, ammonia, and N<sub>2</sub>O emissions, the total impact reaches 11.7 gCO<sub>2</sub>eq/TEUkm, with 4.65 gCO<sub>2</sub>eq/TEUkm attributed to conventional fuels and 1.71 gCO<sub>2</sub>eq/TEUkm from tank-to-wake N<sub>2</sub>O emissions.

In the previous calculation, the result was obtained using a predefined input value for the well-to-wake GHG emissions of ammonia. Regardless of this value, the emissions from fossil fuels used alongside ammonia and the tank-to-wake N<sub>2</sub>O emissions remain constant. Like methanol, this implies that the total GHG emissions of the ship follow a linear relationship with the emissions from ammonia.

## **d Comparison of Reference, Methanol and Ammonia Scenarios**

The ship's functional unit, expressed in gCO<sub>2</sub>eq/TEUkm, and calculated based on the well-to-wake GHG emissions of ammonia or methanol, is shown in the first graph in Figure 60. To enhance readability, the distribution curves from previous Monte Carlo simulations have been transformed into normal distributions using mean values and standard deviations. This provides an indication of the most probable range of GHG emissions for each assessed fuel, based on the defined parameter ranges.



**Figure 60 GHG Emissions from Transport Using Methanol or Ammonia – Relationship Between Fuel Well-to-Wake (WtW) GHG Intensity and Container Unit Transportation WtW GHG Intensity. The first graph presents fuel GHG intensity versus transportation work associated emissions, while the second and third graphs illustrate scenario sensitivity distributions for ammonia (NH<sub>3</sub>) and methanol (MeOH), respectively. These distribution curves are derived from a global sensitivity analysis conducted using Monte Carlo simulations. The results are approximated as normal distributions, using mean values and standard deviations, to represent the most probable range of GHG emissions for each assessed fuel based on the defined parameter variations.**

The analysis of the first graph in Figure 60 shows that, for a given fuel emission factor, the transportation work using ammonia (NH<sub>3</sub>) is more greenhouse gas (GHG) intensive compared to methanol. This is primarily due to the lower engine efficiency associated with ammonia, resulting in higher energy consumption per unit of output power. This inefficiency can be partly attributed to a non-optimised engine size and architecture tailored for ammonia combustion. Additionally, since ammonia engines consume a higher amount of pilot fuel, this contributes to increased CO<sub>2</sub> emissions. Furthermore, the combustion of ammonia produces nitrous oxide (N<sub>2</sub>O), a potent greenhouse gas with a global warming potential significantly higher than CO<sub>2</sub>.

To improve the environmental performance of ammonia as a marine fuel, advances in engine design and ship architecture are essential. Incorporating a Power Take-Off (PTO) system could improve energy recovery and reduce N<sub>2</sub>O emissions. Additionally, using cleaner pilot fuels could further decrease ammonia and methanol emissions. However, this solution may involve additional costs and compete with the decarbonisation efforts of the VLSFO.

The second graph in Figure 60 indicates that, on average, blue ammonia (NH<sub>3</sub>) is more GHG-intensive than Very Low Sulfur Fuel Oil (VLSFO), with emissions between ranging from 20% lower to 35% higher than VLSFO. In contrast, green ammonia achieves an average GHG reduction of approximately 50% compared to VLSFO, though the reduction range is broad, from 35% to 85%. These results highlight the need for continued research and



development on ammonia engine technology, along with vessel architecture optimisation to improve efficiency and emissions performance.

The third graph in Figure 60 shows that, on average, e-methanol results in lower well-to-wake (WTW) emissions, achieving a 70% reduction compared to VLSFO, with a range between 60% and 80%. Despite its slightly higher fuel well-to-wake footprint compared to green ammonia, e-methanol offers overall significant emissions savings when considering the well-to-wake footprint for container transport. Bio-methanol produced from waste wood has the lowest WTW GHG emissions, with an average reduction of 80%, ranging from 75% to 85% relative to VLSFO. These findings highlight the potential of methanol, particularly bio-methanol, as a low-emission alternative for marine fuels.

Overall, it is important to acknowledge that current regulatory accounting practices do not fully account for emissions associated with the development of renewable energy infrastructure for the production and distribution of e-fuel. As a result, the perceived environmental benefits may be more optimistic than the outcomes reflected in this analysis for methanol and ammonia, which considers a well-to-wake scope, and cradle-to-gate emissions associated with renewable energy infrastructure.

## 8 Prospective Life Cycle Assessments

### 8.1 Methodology

To assess the GHG impacts of the different production pathways for e- and bio-methanol in 2035 and 2050, the methodology presented in Figure 61 was applied. The foreground data, representing technological modelling assumptions, were defined in collaboration with CMA CGM and integrated into the parameterised model. The background data, sourced from Ecoinvent 3.9.1, reflect current economic and market flows. To extend the database to future scenarios, the PREMISE tool (Sacchi et al. 2022) was used. This tool enables the generation of prospective life cycle assessment (LCA) databases based on Integrated Assessment Models (IAMs).

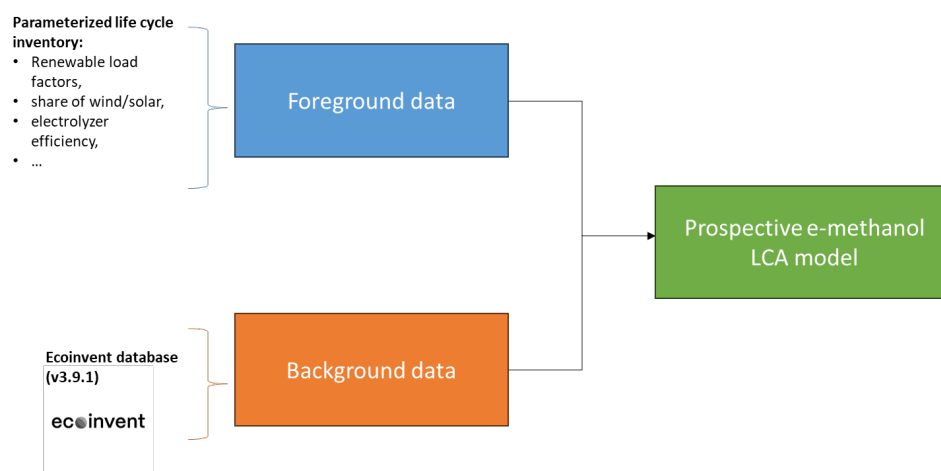


Figure 61: Methodological principle for prospective LCA

### 8.2 Foreground Assumptions

The technological evolution assumptions for 2035 and 2050 are presented in Table 27. Scenario 4 (considering all cradle-to-grave emissions) was chosen because the evolution of GHG emissions related to certain technological improvements would not be perceptible in the case of Scenario 3 (where green H<sub>2</sub> is assigned zero GHG emissions).

- **Wind Power Generation:**

The wind load factors are assumed to be equivalent to the current load factors (in other words, no significant climate evolution at the considered horizons), the distribution between onshore and offshore wind, as well as the distribution between fixed and floating offshore wind, will evolve in our analysis.

- **Photovoltaic Power Generation:**

Only an improvement in the efficiency of photovoltaic panels is considered. The efficiency of photovoltaic panels increases from 19% for the current horizon to 23% for the prospective horizons of 2035 and 2050.

- **Hydrogen Production by Electrolysis:**

Between today and 2035, the electrolyzers are of alkaline type, and by 2050, they will be of the ceramic electrochemical cell type (SOEC). The efficiency of electrolysis increases from 62.3% for the current horizon to 65% for 2035 and 80% in 2050 with SOEC technology.

- **Hydrogen Production by Methane Reforming:**

Between today and 2035, H<sub>2</sub> production from Methane Reforming with and without CCS is assumed via SMR with a 90% CO<sub>2</sub> capture rate on the syngas with MDEA state of the art technology. In 2050, it is assumed the use of ATR with VPSA capture at 98% capture rate.

- **Transport of produced fuels:**

The transport of the produced fuel is assumed to be carried out by an HFO-powered ship in 2024 and 2035. By 2050, it is assumed that HFO used for transport will be replaced by the fuel produced in the production region. The quantities consumed are calculated using proportionality rules based on the conversion yields provided by CMA CGM (Table 23).

- **CO<sub>2</sub> Capture:**

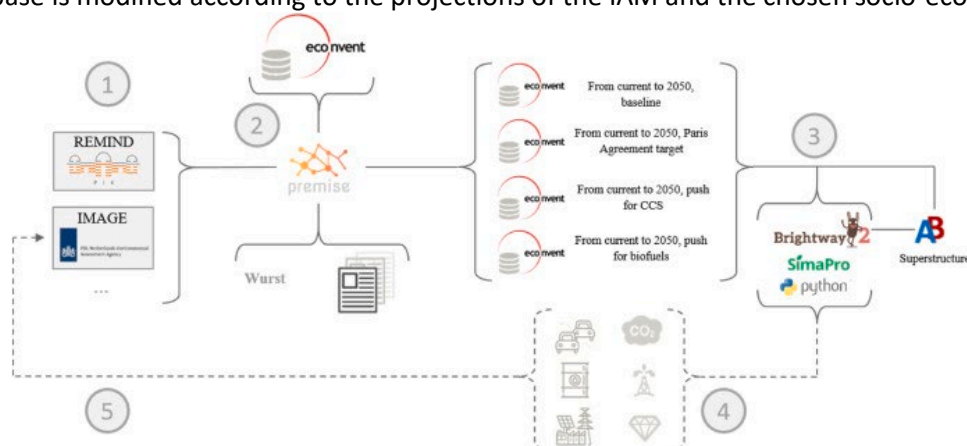
From factory flue gases by solvent (monoethanolamine) until 2035, then DAC in 2050.

**Table 27: Foreground assumptions table summary**

	Today	2035	2050
<b>Electricity</b>			
PV efficiency	19%	23%	23%
Share onshore/offshore	-	IEA forecasts	IEA forecasts
Share offshore fixed/floating	DNV forecasts	DNV forecasts	DNV forecasts
<b>H<sub>2</sub></b>			
Methane reforming technology	SMR (with or without MDEA CCS @90% capture rate)	SMR (with or without MDEA CCS @90% capture rate)	ATR (with or without VPSA CCS @98% capture rate)
Electrolysis technology	100% Alkaline	100% Alkaline	100% SOEC
Electrolysis efficiency	62.3%	65%	80%
<b>CO<sub>2</sub></b>			
Source	100% concentrated (Flue gases)	100% concentrated (Flue gases)	100% diluted (DAC)
Methanolation unit configuration	S4 (renewable CTG for H <sub>2</sub> & capture)	S4 (renewable CTG for H <sub>2</sub> & capture)	S4 (renewable CTG for H <sub>2</sub> & capture)
<b>Transportation &amp; conditioning</b>			
Type and source of energy for transportation	HFO (ship)	HFO (Ship)	E-methanol (Ship)

### 8.3 Background Scenario

PREMISE is implemented with Brightway2 according to the operational scheme presented in Figure 62. Thus, the Ecoinvent database is modified according to the projections of the IAM and the chosen socio-economic scenario.



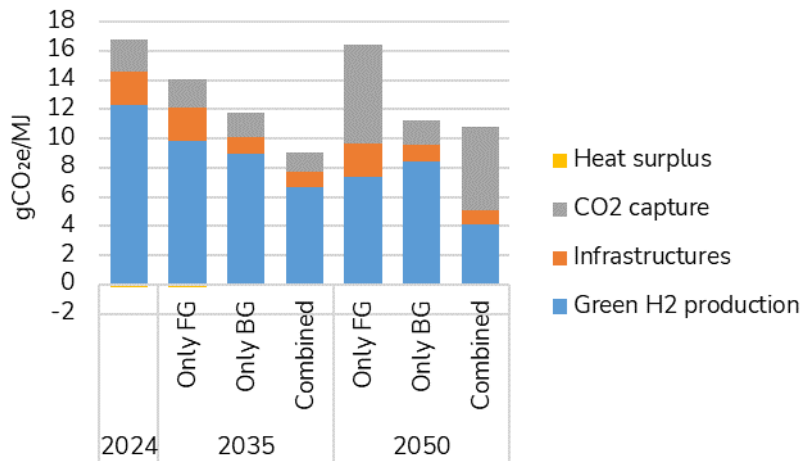
**Figure 62: PREMISE workflow (Sacchi et al. 2022)**

The IAM chosen for this study is the REMIND - SSP2-NDC scenario, which can be perceived as a middle ground between optimistic and pessimistic and approximately corresponds to the Announced Pledges Scenario (APS) of the IEA used for wind energy production projections (Table 27). The description of the scenario and the associated energy projections can be consulted at PREMISE Dashboard (Sacchi et al. 2022).

## 8.4 Prospective Results

### 8.4.1 Methanol

Figure 63 illustrates the emissions from e-methanol production in France under Scenario 4, as defined in Section 5.3 Table 22 along with the main contributors to GHG emissions. To assess the influence of assumptions and modelling choices, the figure presents three variations: results obtained by varying only the foreground data (denoted 'Only FG'), results obtained by varying only the background data (denoted 'Only BG'), and results obtained by varying both simultaneously (denoted 'Combined').



**Figure 63: Emissions and GHG Contributors from e-methanol Production: Influence of Prospective Scenarios on Results - The Case of Production in France, S4 - Full Renewable, No Transport and Conditioning**

At the current horizon, most of the impacts arise from hydrogen production (represented in blue in Figure 63) and the associated renewable energy sources. By varying only the technological scenario (foreground, denoted as 'Only FG'), a decrease in hydrogen production emissions is observed. However, this reduction is offset by an increase in CO<sub>2</sub> capture emissions by 2050, due to the transition from solvent-based capture from concentrated flue gases to the more energy-intensive direct air capture (DAC) method.

The background data ('Only BG') evolves according to the energy futures defined in the IAM scenario, incorporating factors such as global decarbonisation, changes in the electricity mixes, increased use of recycled metals, and improvements in transport efficiency. These background changes alone lead to a reduction in GHG emissions, with a significant decrease by 2035 and a more moderate decline by 2050. Combining the foreground and background assumptions gives the prospective results for 2035 and 2050 (denoted as 'Combined' in the figure).

Figure 64 presents the GHG emissions for e-methanol production across all countries for Scenario 4 (Full renewable CTG) under the 'Combined' assumption and Scenario 1 (Renewable hydrogen production set at 0 gCO<sub>2</sub>e/kWh, with natural gas used for MEA recovery and local electricity grid mix for auxiliaries), referred to as 'NG & local electricity'. This assessment includes fuel transport and conditioning to Rotterdam.

Based on the figure, the footprint of e-methanol produced using fully renewable electricity (Scenario 4) is below the RFNBO threshold across all locations from 2025 onwards (with an average value between production regions of  $16 \pm 4$  gCO<sub>2</sub>e/MJ) [with  $\pm$  values being mean absolute deviation], even when accounting for cradle-to-gate emissions associated with renewable energy infrastructure, which are technically excluded from the RFNBO target. The decarbonisation of the electricity grid mix and natural gas supply chain indicates that e-methanol using natural gas for carbon capture (Scenario 1) will achieve RFNBO compliance across all locations from 2035 onwards.

In Scenario 4, emissions are expected to decrease ( $12 \pm 3$  gCO<sub>2</sub>e/MJ on average in 2035 and  $5 \pm 1$  gCO<sub>2</sub>e/MJ in 2050) primarily due to a reduction in the GHG intensity of hydrogen production. This is driven by improvements in electrolyser efficiency, renewable electricity generation, and material decarbonisation. In Scenario 1, reductions are mainly attributed to a decline in emissions from electricity used for methanol synthesis, reflecting the impact of IAM scenarios aiming for carbon neutrality by 2050 (with an average value of  $26 \pm 7$  gCO<sub>2</sub>e/MJ in 2025 decreasing to  $14 \pm 4$  gCO<sub>2</sub>e/MJ in 2035 and  $7 \pm 1$  gCO<sub>2</sub>e/MJ in 2050). The emissions associated with CO<sub>2</sub> capture (indicated in the turquoise contribution bars) decrease between 2025 and 2035 but rise slightly again in 2050, as carbon capture technology shifts to the more energy-intensive DAC method.

In both scenarios, transport and conditioning have a significant impact (indicated in the green contribution bars) on the carbon footprint, potentially leading to non-compliance with RFNBO criteria. The proximity of production sites to bunkering locations is critical. Emissions from e-methanol transport decline slightly between 2025 and 2035, with a more substantial reduction in 2050. This is due to the assumption that e-methanol will be used as fuel for its own transport to the bunkering port. This explains why GHG emissions linked to transport (in green) no longer appear for 2050.

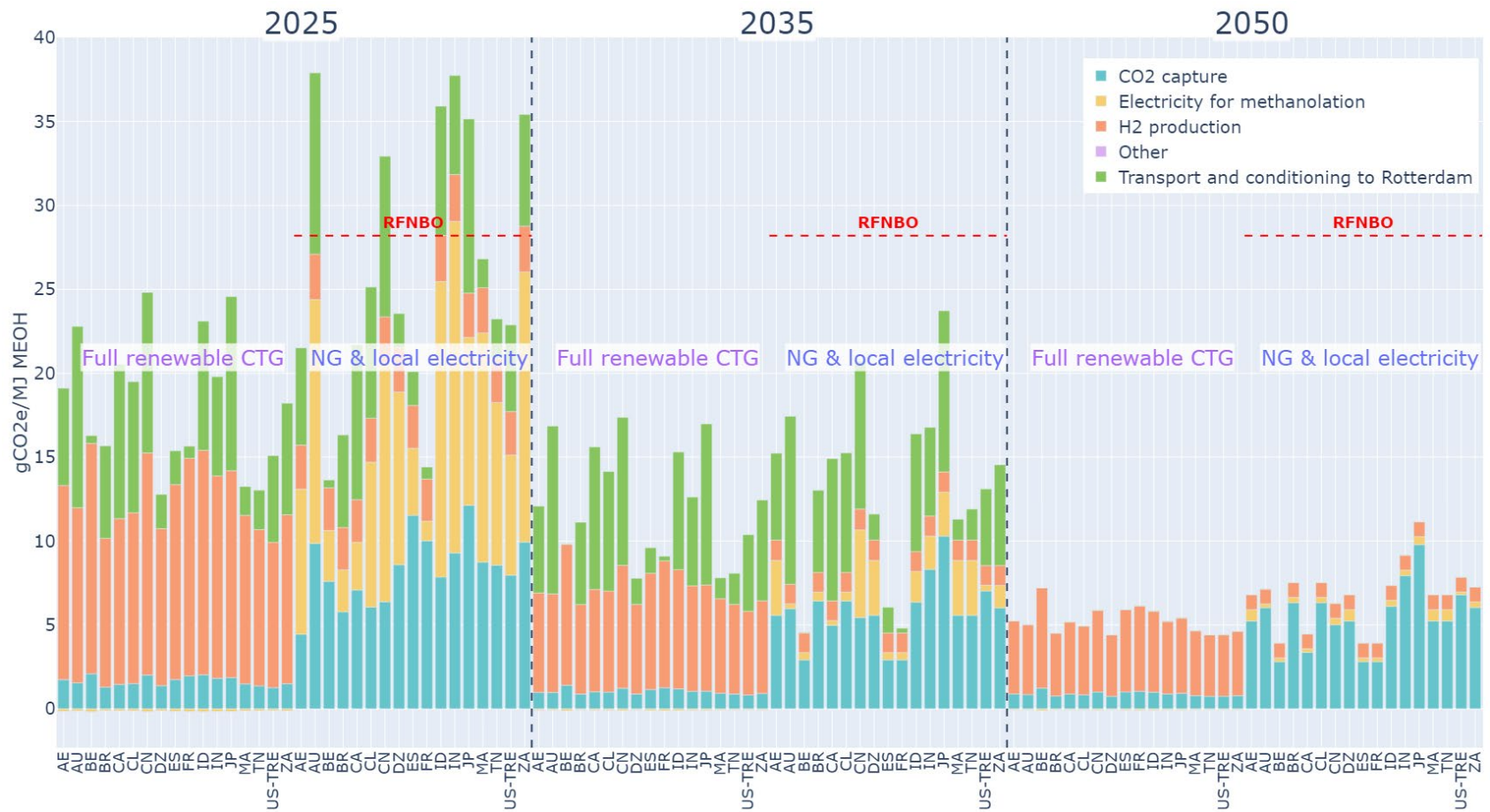


Figure 64: Projected Greenhouse Gas Fuel Emissions for E-Methanol (Well-to-Wake, g CO<sub>2</sub>-eq/MJ) in 2025, 2035, and 2050 under the “REMIND - SSP2 – NDC” scenario configuration. The graph compares the GHG emissions (y-axis) from Well-to-Wake in different production regions (x-axis) of different e-methanol production scenarios: “Full renewable CTG” e-methanol, a scenario where renewable energy, accounted for from a cradle-to-grave (CTG) emissions scope, is used to power both hydrogen production and carbon capture processes. And “NG & local electricity” e-methanol: a scenario where renewable electricity is used for hydrogen production and accounted for from a “Operation & Maintenance” scope of accounting (following EU Renewable Energy Directive methodology), with carbon capture powered by natural gas and auxiliary processes powered by local electricity grid mix. Both scenarios include a transport and conditioning step to Rotterdam. Only the second scenario “NG & local electricity” e-methanol is comparable to the RFNBO reference since the “Full renewable CTG” e-methanol accounts for a broader scope than the one defined in the EU RED methodology.



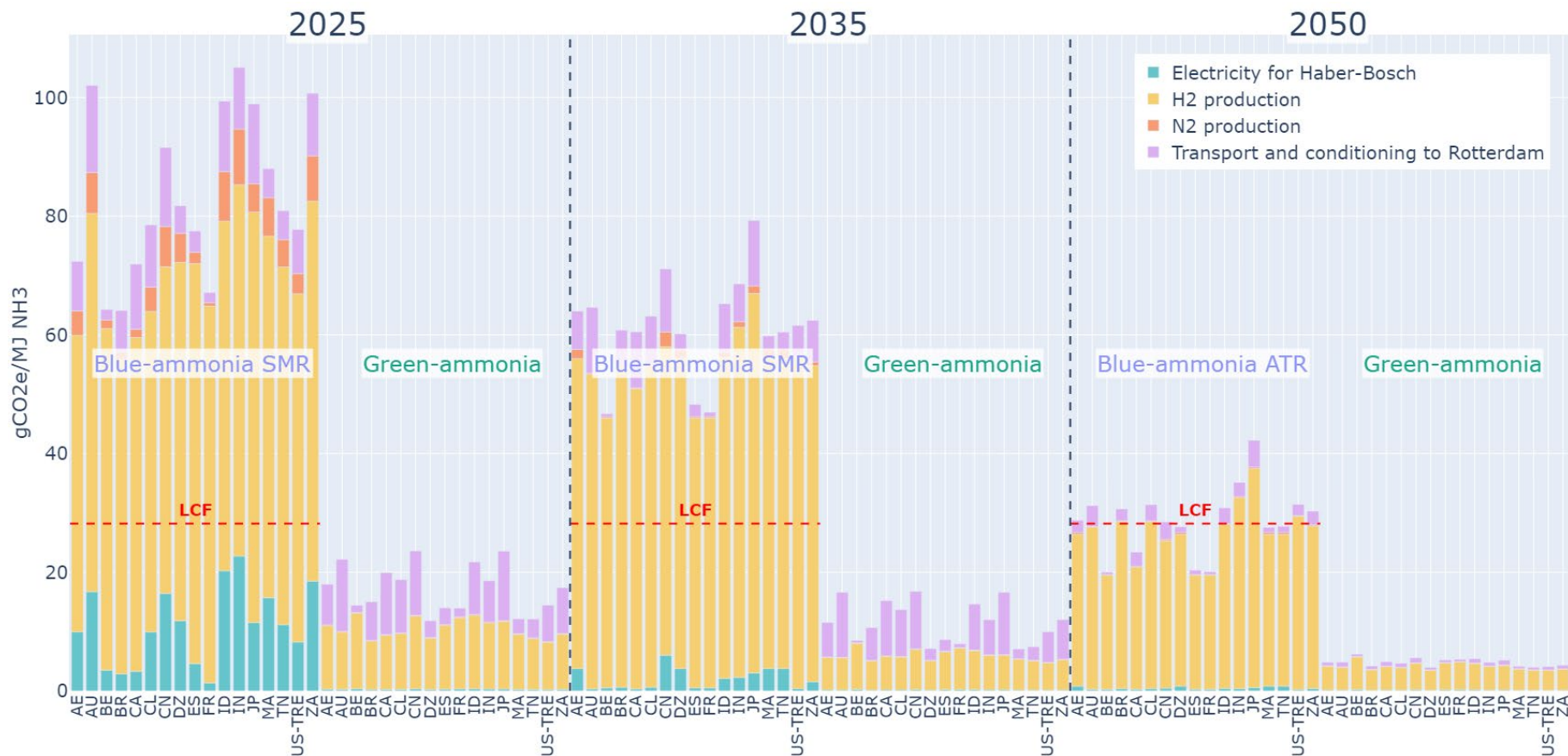
## 8.4.2 Ammonia

Similarly to methanol, the potential GHG emissions of future ammonia production are assessed under two scenarios as depicted in Figure 65: a blue ammonia scenario, where hydrogen is produced via SMR in 2025 and 2035 and ATR with CCS in 2050, with auxiliaries powered by the local grid mix; and a green ammonia scenario, where hydrogen production and auxiliary consumption are powered by renewable electricity under a cradle-to-gate (CTG) approach (Scenario C), as defined in Section 5.3 Table 22.

Blue-ammonia GHG emissions are expected to decrease from  $83 \pm 12$  gCO<sub>2</sub>e/MJ average value in 2025 to  $61 \pm 6$  gCO<sub>2</sub>e/MJ in 2035, and to  $29 \pm 4$  gCO<sub>2</sub>e/MJ in 2050. Hydrogen production from blue H<sub>2</sub> (represented by the yellow contribution bars) remains the primary source of emissions throughout the prospective results. A slight reduction is observed from blue H<sub>2</sub> production emissions in 2035 compared to 2025, reflecting anticipated improvements in natural gas supply chain efficiency and reductions in methane losses and leaks. By 2050, emissions from hydrogen production are expected to decline further as ATR with CCS replaces SMR. However, blue ammonia still only meets the 70% reduction threshold required by RED (<28 gCO<sub>2</sub>eq/MJ) in only six locations, largely due to the high emissions footprint associated with upstream methane extraction. As with e-methanol, emissions from e-ammonia are expected to decline over time, driven by improvements in electrolyser efficiency, renewable electricity production, and material decarbonisation. Only green ammonia meets the regulatory -70% emissions reduction threshold.

Green-ammonia (Scenario C: with CTG renewable electricity for hydrogen and auxiliaries' consumption) GHG emissions are also expected to decrease (from an average value of  $17 \pm 4$  gCO<sub>2</sub>e/MJ in 2025 to  $12 \pm 3$  g CO<sub>2</sub>e/MJ in 2035 and  $5 \pm 1$  gCO<sub>2</sub>e/MJ in 2050) for the same reasons than for e-methanol (i.e. increased electrolyser and renewable electricity generation efficiency, and material decarbonisation).

In both scenarios, emissions from ammonia transport to Rotterdam decrease between 2025 and 2035, with a more substantial reduction in 2050 due to the assumption that ammonia will be used as fuel for its own transport to the bunkering port, further reducing GHG impacts. The transport of ammonia to the bunkering location contributes significantly to its overall footprint, highlighting the importance of locating production near bunkering sites.



**Figure 65: Projected Greenhouse Gas Fuel Emissions for E-Ammonia and Blue Ammonia (Well-to-Wake, g CO<sub>2</sub>-eq/MJ) in 2025, 2035, and 2050 under the “REMIND - SSP2 – NDC” scenario configuration. The graph compares the GHG emissions (y-axis) from Well-to-Wake in different production regions (x-axis) of different ammonia production scenarios: “Green-ammonia”, a scenario where renewable energy, accounted from a cradle-to-grave (CTG) emissions scope, is used for hydrogen and N<sub>2</sub> production and auxiliary consumptions. And “Blue Ammonia SMR/ATR”, a scenario where ammonia is synthesised from hydrogen from natural gas methane reforming using carbon capture technology and N<sub>2</sub> production and auxiliary consumptions are powered by local electricity grid mix. Both scenarios include a transport and conditioning step to Rotterdam. The “Blue ammonia” scenario is comparable to the LCF reference. The “Green-ammonia” scenario cannot be compared to the RFNBO reference since it is calculated accounting the CTG scope of emissions, a broader scope than the one defined in the EU RED methodology.**

## 9 Conclusions

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### 9.1 Fuel Life Cycle Assessments Conclusions

The Life Cycle Assessment (LCA) conducted in this study has provided a comprehensive quantification of greenhouse gas (GHG) emissions for the evaluated fuel pathways: e-methanol, bio-methanol, and ammonia (e-ammonia, and blue and grey ammonia). The assessment considered both geographical variations in production conditions across 17 regions and a forward-looking perspective, projecting emissions reductions for 2035 and 2050.

Additionally, several production scenarios for e-methanol and e-ammonia were explored, evaluating different energy integration strategies, such as the energy sources used for CO<sub>2</sub> capture or auxiliary power consumption. These configurations provided a more detailed understanding of how different technological choices affect overall GHG performance. The key findings for the fuel life cycle assessments are as follows:

#### E-methanol

- E-methanol is an effective solution for reducing GHG emissions in maritime transport, provided that renewable electricity is used for water electrolysis and that CO<sub>2</sub> capture heat requirements are met using natural gas, low-carbon, or renewable electricity.
- The use of renewable electricity for hydrogen production is a necessary but insufficient condition to achieve the minimum 70% GHG reduction required for Renewable Fuels of Non-Biological Origin (RFNBO) compliance.
- The energy source used for CO<sub>2</sub> capture and methanation significantly impacts emissions. Using natural gas for CO<sub>2</sub> capture (Scenario 1) results in GHG emissions ranging from 11.9 gCO<sub>2</sub>eq/MJ (Canada) to 31.2 gCO<sub>2</sub>eq/MJ (India). The emissions are relatively uniform across regions and close to the RFNBO threshold.
- When local electricity grids power CO<sub>2</sub> capture (Scenario 2), results become more variable and less promising, with emissions ranging from 5.1 gCO<sub>2</sub>eq/MJ (Canada) to 136.2 gCO<sub>2</sub>eq/MJ (India), demonstrating the high sensitivity to grid carbon intensity, a factor clearly highlighted by the conducted sensitivity analysis.
- Using renewable electricity for CO<sub>2</sub> capture and methanol synthesis (Scenario 3) leads to ~95% GHG reduction compared to fossil methanol, with emissions ranging from 3.5 gCO<sub>2</sub>eq/MJ (Texas) to 4.8 gCO<sub>2</sub>eq/MJ (Japan).
- When including cradle-to-grave (CTG) emissions for renewable energy infrastructure (Scenario 4), reductions are slightly lower at ~80% compared to fossil methanol, with emissions between 10.2 gCO<sub>2</sub>eq/MJ (Texas) and 19.6 gCO<sub>2</sub>eq/MJ (Japan). Even considering the cradle-to-grave emissions of renewable energies, the results remain below the RFNBO threshold.
- Transport and storage of e-methanol significantly impacts the overall carbon footprint, highlighting the importance of locating production close to bunkering ports.

#### Bio-methanol

- Bio-methanol is an effective solution for reducing GHG emissions in maritime transport, provided that sufficient wood or wood waste resources are available, and biomass transportation distances are minimised.
- Bio-methanol from wood (either cultivated or waste) achieves at least a 70% GHG reduction compared to fossil methanol, with emissions ranging from 10 to 20 gCO<sub>2</sub>eq/MJ well-to-wake, depending on biomass feedstock and transport distances.
- Bio-methanol produced from waste wood results in lower GHG emissions than bio-methanol produced from cultivated wood due to the avoidance of emissions associated with fertilizers, pesticides, and land-use change.

- The transportation of biomass feedstock significantly contributes to total emissions, making it preferable to transport finished bio-methanol rather than raw biomass. Transporting wood generates approximately twice the emissions compared to transporting bio-methanol.
- With a conversion efficiency of 51.1% from wood to methanol, bio-methanol's emissions are largely influenced by transportation distances.
- Black liquor, an alternative feedstock for bio-methanol, exhibits a wide range of GHG emissions, depending on the electricity grid mix replacing the energy previously provided by black liquor. In high-carbon-intensity grids, black liquor methanol fails to meet the 70% GHG reduction threshold.

### **E-ammonia**

- E-ammonia is an effective solution for reducing GHG emissions in maritime transport, provided that auxiliary electricity consumption is covered by renewable sources, either following the RED methodology or on a cradle-to-grave basis.
- Similar to e-methanol, the energy configuration of e-ammonia production significantly impacts emissions.
- In Scenario 1, where auxiliary power is drawn from the local electricity grid, high-GHG-intensity regions (India, China, Australia, Indonesia, and South Africa) fail to meet RFNBO compliance due to elevated emissions from nitrogen production, refrigeration, and storage.
- In Scenario 2 and Scenario 3, where renewable electricity powers auxiliary consumption - either following the RED methodology or including cradle-to-grave infrastructure emissions - e-ammonia meets the RFNBO 70% reduction threshold in all assessed regions.
- Transporting ammonia from production sites to bunkering locations has a significant footprint, reinforcing the need for proximity to bunkering hubs to minimise transport-related emissions.

### **Grey and Blue Ammonia**

- Blue ammonia is not an effective solution for achieving RFNBO compliance, as it does not meet the 70% GHG reduction threshold in most of the assessed regions, even under optimistic 2050 projections.
- At present, neither grey nor blue ammonia meets RFNBO compliance in any of the assessed production regions.
- Blue ammonia produced from steam methane reforming (SMR) with carbon capture and storage (CCS) and bunkering in Rotterdam offers a maximum GHG reduction of 33%.
- By 2050, transitioning from SMR-CCS to auto-thermal reforming (ATR) with CCS results in lower emissions; but, blue ammonia still only meets the 70% reduction threshold in six out of the 17 sites considered, mainly due to the high GHG intensity of upstream methane extraction to produce blue hydrogen.
- The assumption that by 2050, fuel will be used for its own transport helps mitigate emissions but does not fully compensate for methane leakage and upstream supply chain emissions.

### **Overall Considerations**

- E-methanol and bio-methanol offer strong decarbonisation potential, with bio-methanol from waste wood achieving the lowest overall emissions.
- E-ammonia can meet RFNBO requirements if the auxiliaries are powered by renewable electricity, but its impact is highly sensitive to production energy sources and transport distances.
- Blue ammonia does not meet the 70% GHG reduction target in most regions, even under optimistic 2050 projections.
- Transport and storage contribute significantly to emissions, reinforcing the importance of locating production facilities close to bunkering hubs.
- Regulatory methodologies do not fully account for emissions from infrastructure, which may overestimate the environmental benefits of e-fuels.

This LCA underscores the importance of optimising fuel production configurations to achieve meaningful GHG reductions in maritime transport.

## 9.2 Container Unit Transportation Life Cycle Assessment Conclusions

### Assessing Decarbonisation Potential: Shifting from MJ to TEU.km for a Typical Ship Route

A functional unit shift from fuel Well-to-Wake emissions (gCO<sub>2</sub>eq per 1 MJ fuel) to transport emissions (gCO<sub>2</sub>eq per TEU.km) is critical for accurately evaluating the decarbonisation potential of alternative marine fuels. This approach accounts for onboard energy conversion efficiency, pilot fuel requirements, and the impact of propulsion systems and fuel storage on container capacity, which all significantly affect real-world emissions at the operational scale.

Based on simulated energy consumption data for a 23,000 TEU ship on a typical CMA CGM route from Busan to Rotterdam, the study found that while e-ammonia has a slightly higher GHG reduction potential per MJ compared to methanol, methanol achieves greater overall decarbonisation per TEU.km. This is due to methanol's higher engine efficiency considered for this study, lower pilot fuel consumption, and the absence of nitrous oxide (N<sub>2</sub>O) emissions from combustion. Therefore, the key findings for the container unit transportation life cycle assessments for the various fuels are as follows:

#### E-methanol

- E-methanol is an effective decarbonisation solution, achieving an average 70% reduction in container unit transportation WTW GHG emissions compared to VLSFO (ranging from 60% to 80%).
- Its feasibility is constrained by CO<sub>2</sub> supply challenges, as biogenic CO<sub>2</sub> capture is required for large-scale production.

#### Bio-methanol

- Bio-methanol is a highly effective decarbonisation solution, achieving an average 80% reduction in container unit transportation WTW GHG emissions compared to VLSFO (ranging from 75% to 85%).
- Availability of sustainable bio-feedstock is a key limitation, as large-scale production depends on wood or wood waste supply.

#### E-ammonia (Green ammonia)

- E-ammonia is a viable decarbonisation fuel, achieving an average 50% reduction in container unit transportation WTW GHG emissions compared to VLSFO (ranging from 35% to 85%).
- This underscores the need for further R&D on ammonia engine technology and vessel architecture optimisation to enhance efficiency and reduce emissions.

#### Blue Ammonia

- Blue ammonia is not a viable decarbonisation option, as on average its WTW container unit transportation GHG emissions (per TEU.km) slightly exceed those of VLSFO.
- Even under optimistic 2050 scenarios, only six of 17 production locations meet the 70% GHG reduction threshold, primarily due to methane extraction emissions. At present, neither grey nor blue ammonia meets RFNBO compliance in any region.

## 9.3 Prospective GHG Emission Trends

### E-methanol

- E-methanol's WTW emissions, averaged over all 17 considered locations in the scenario of fully renewable powered with cradle-to-grave scoping, are projected to decrease from  $16 \pm 4$  gCO<sub>2</sub>eq/MJ (2025) to  $12 \pm 3$  gCO<sub>2</sub>eq/MJ (2035) to  $5 \pm 1$  gCO<sub>2</sub>eq/MJ (2050).
- E-methanol's WTW emissions, averaged over all 17 considered locations in the scenario of renewable hydrogen production set at 0 gCO<sub>2</sub>e/kWh, with natural gas used for MEA recovery and local electricity grid mix for auxiliaries, are projected to decrease from  $26 \pm 7$  gCO<sub>2</sub>eq/MJ (2025) to  $14 \pm 4$  gCO<sub>2</sub>eq/MJ (2035) to  $7 \pm 1$  gCO<sub>2</sub>eq/MJ (2050).
- Scenario 4, which assumes renewable electricity for both DAC and methanol synthesis, is considered for these projections. If grid electricity is used instead, further decarbonisation of the electricity mix will be required, as DAC powered by a high-carbon grid mix leads to increased emissions by 2050.
- Variations in technology assumptions (foreground data) show that reductions in hydrogen production emissions are offset by an increase in CO<sub>2</sub> capture emissions by 2050 due to the shift to DAC.
- Background data evolution (including global decarbonisation, grid mix changes, increased use of recycled materials, and improved transport efficiency) leads to significant GHG reductions by 2035, though further reductions are less pronounced by 2050.
- The prospective evolution of GHG emissions for e-methanol transport shows a slight decrease between 2025 and 2034, followed by a significant reduction in 2050 due to the assumption that e-methanol will be used as fuel for its own transport to the bunkering port.
- By 2050, GHG emissions from transport become negligible, and regional discrepancies in emissions are significantly reduced, making production location less of a differentiating factor.

### E-ammonia

- Green ammonia's WTW emissions, averaged over all 17 considered locations, are projected to decrease from  $17 \pm 4$  gCO<sub>2</sub>eq/MJ (2025) to  $12 \pm 3$  gCO<sub>2</sub>eq/MJ (2035) to  $5 \pm 1$  gCO<sub>2</sub>eq/MJ (2050).
- Similar to e-methanol, WTW emissions from e-ammonia are projected to decrease steadily until 2050 due to a combination of global decarbonisation and technological advancements in renewable hydrogen production.
- The reduction is primarily driven by improvements in electrolysis efficiency and the continued expansion of low-carbon electricity sources.
- By 2050, emissions from transportation and conditioning for bunkering are expected to decrease significantly, assuming e-ammonia is used as fuel for its own transport.
- By 2050, e-ammonia across production regions is projected to achieve a 95% reduction in GHG emissions compared to the fossil fuel reference.
- While this reduction aligns with RFNBO compliance, there is a need for continued R&D on ammonia engines and vessel architecture to enhance the decarbonisation effectiveness of ammonia at the TEU.km scale.

### Blue Ammonia

- Blue ammonia's WTW emissions, averaged over all 17 considered locations, are projected to decrease from  $83 \pm 12$  gCO<sub>2</sub>eq/MJ (2025) to  $61 \pm 6$  gCO<sub>2</sub>eq/MJ (2035) to  $29 \pm 4$  gCO<sub>2</sub>eq/MJ (2050).
- Blue ammonia faces significant challenges in achieving RFNBO compliance, mainly due to the high GHG intensity of the natural gas supply chain.
- By 2050, under optimistic background scenarios that assume a switch to Auto-Thermal Reforming (ATR) with VPSA carbon capture technology, blue ammonia could achieve RFNBO compliance in six out of 17 assessed production regions.
- Blue ammonia's decarbonisation potential heavily depends on improvements in the natural gas supply chain, including:
  - Optimised methane extraction to reduce upstream emissions.
  - Enhanced liquefaction processes to improve energy efficiency.



- Reduced methane leakage across the supply chain.
- Blending blue ammonia with biomethane could further improve its GHG reduction potential, though this pathway was not assessed in this study.

## 9.4 Regulations Conclusions

The year 2023 marked a turning point in regulatory frameworks for maritime decarbonisation, with new international and European measures aimed at significantly reducing greenhouse gas (GHG) emissions from shipping.

### International Regulations

At the international level, the International Maritime Organization (IMO) adopted an updated decarbonisation strategy in July 2023, strengthening its 2018 targets and introducing a "net zero" ambition for GHG emissions from international maritime transport by 2050, with key intermediate milestones:

- A 20% GHG reduction by 2030, striving for 30%, and a 70% reduction by 2040, striving for 80%, compared to 2008 levels, and net zero by 2050.
- A target for the adoption of zero or near-zero GHG emissions fuels, which should account for 5 to 10% of total maritime fuel consumption by 2030.
- The introduction of a Well-to-Wake (WtW) approach for marine fuel GHG emissions, assessing emissions from production (well) to combustion on board (wake) in line with the IMO's LCA Guidelines.

To meet these objectives, binding medium-term measures are expected to be finalised by 2025. These include:

- A new standard regulating the progressive reduction of marine fuel GHG intensity.
- The implementation of a GHG pricing mechanism for the maritime sector.

Currently, the regulatory framework remains incomplete, as the specific mechanisms to enforce these targets have yet to be defined. To date, only short-term measures aimed at evaluating ship energy performance (EEDI/EEXI) and the Carbon Intensity Indicator (CII) have come into effect.

### Europe, Leader in Decarbonized Maritime Transport

At the European level, the Fit-for-55 package introduced new regulations reinforcing the EU's leadership in maritime decarbonisation. Two primary measures directly impact shipping:

- The extension of the EU Emissions Trading System (EU ETS) to maritime transport, requiring ships over 5000 GT operating in European ports to pay for their emissions starting January 2024. The system will be phased in between 2024 and 2027, progressively reducing the price gap between conventional and alternative fuels.
- The FuelEU Maritime regulation mandates a trajectory for reducing the carbon intensity of onboard energy and promotes renewable and low-carbon fuels. From 2030 onwards, the regulation will also require passenger ships and container vessels to connect to shore power in major European ports. Additionally, a dedicated incentive mechanism has been introduced to support the adoption of Renewable Fuels of Non-Biological Origin (RFNBOs), given their high decarbonisation potential.

Three additional Fit-for-55 legislative texts indirectly impact maritime transport:

- The revision of the Renewable Energy Directive (RED III), which sets binding targets for renewable energy integration in the transport sector.
- The two delegated acts of the RED III defining RFNBO production rules, ensuring that synthetic fuels derived from green hydrogen meet stringent sustainability and GHG reduction criteria.

With the RED methodology, fuels derived from green hydrogen can offer significant GHG reduction potential (~90% compared to the RED fossil reference). However, current loopholes in the methodology do not account for emissions associated with renewable energy infrastructure, leading to overestimated emissions savings for

e-fuels. When applying a Cradle-to-Grave (CTG) approach, GHG reduction potential falls to approximately 80%, which still meets RFNBO thresholds but presents a more realistic outlook on total lifecycle emissions.

While the regulatory landscape continues to evolve, the measures introduced in 2023 provide a clearer trajectory for maritime decarbonisation, with an emphasis on GHG pricing, fuel carbon intensity standards, and incentives for RFNBOs. However, further refinements will be necessary to align regulatory accounting with actual lifecycle emissions, as demonstrated by the life cycle assessments conducted in this study on e-methanol, e-ammonia and blue ammonia, to ensure that e-fuels deliver genuine climate benefits at scale.

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# 11 Annex

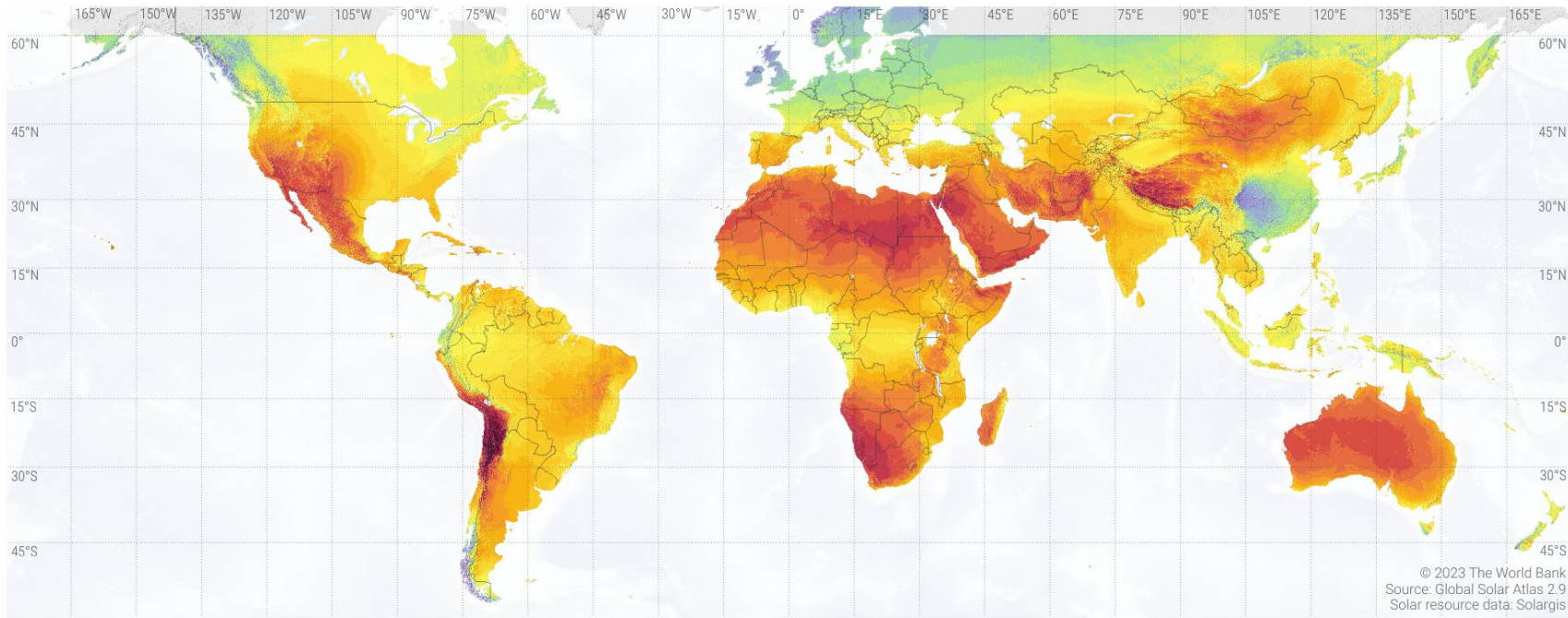
Annex 1: Photovoltaic potential by region available at (<https://datacatalog.worldbank.org/search/dataset/0038379>)

SOLAR RESOURCE MAP

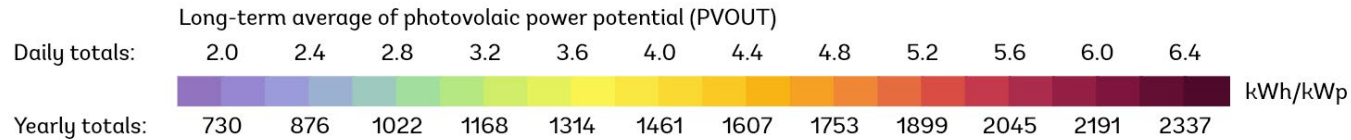
## PHOTOVOLTAIC POWER POTENTIAL



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Source: Global Solar Atlas 2.9  
Solar resource data: Solargis



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## Annex 2: Differentiating parameters for each region



Name	FR	CN	AU	BR	CA	CL	ES	DZ	MA	TN	ID	IN	JP	ZA	US-TRE	BE	AE
Solar energy																	
Transport_distance_boat (of manufactured PV panel to power plant)	18000	0	6500	2000 0	20000	20000	20000	20000	20000	20000	3000	300 0	2000	1300 0	110 00	18000	9000
Normalised_annual_PV_production_kWh_per_kWp	1235.9 265	1417.1 125	1718. 0915	1607 .533	1392. 6575	1958. 1155	1610. 6355	1794. 5955	1827. 3725	1731. 7425	1375 .101	157 7.53	1257.6 44	1826 .314	182 5	1064.4 86	1826. 5695
Wind energy																	
Wind_onshore_load_factor	0.25	0.24	0.337	0.46 2	0.379	0.293	0.277	0.471	0.374	0.502	0.22 5	0.27	0.478	0.36 7	0.4 58	0.2518	0.212
Wind_offshore_load_factor	0.46	0.432	0	0	0	0	0	0	0	0	0	0	0.374	0	0	0.3099	0
Wind_offshore_flottant_share	0.01	0.0001	0	0	0	0	0	0	0	0	0	0	0.01	0	0	0.01	0
onshore_share	0.9771 9423	0.9139 6125	1	1	1	1	1	1	1	1	1	1	0.9716 9026	1	1	0.6989 2187	1
Renewable electricity mix																	
share_wind	0.65	0.64	0.45	0.73	0.86	0.39	0.65	0.2	0.79	0.3	0.42	0.5	0.07	0.61	0.8 6	0.64	0.34
Transportation and conditioning																	
distance_ship_distribution (example for transportation to Singapore)	16831	4984	8873	2019 4	33167	25163	13677	13490	14297	12784	1305	4883	6963	1123 2	245 54	17134	7354

### Annex 3: Parameters default values, minimum, maximum values and distribution type used in the LCA models

Group	Label	Default	Min	Max	Distrib	Unit
PV	Aluminium frame surfacic weight	1.5	0.0	2.63	triangle	kg/m <sup>2</sup>
PV	Electrical installation specific weight	3.0	2.15	4.6	linear	kg/kW
PV	Electricity consumption for recycling	50	0.0	250.0	triangle	kWh/t
PV	Glass thickness	3.2	2.0	4.0	triangle	mm
PV	Ground coverage ratio	0.4	0.2	0.5	triangle	fraction
PV	Heat consumption for recycling	76	0.0	150.0	triangle	MJ/t
PV	Inverter lifetime	15	10.0	30.0	triangle	year
PV	Inverter weight per kW	2.0	1.0	6.0	linear	kg/kWp
PV	Kerf loss (silicon material lost in the wafering process)	0.44	0.4	0.5	triangle	fraction
PV	Manufacturing efficiency gains	0	0.0	1.0	triangle	fraction
PV	Manufacturing electricity mix	CN	0.0	2.0		
PV	Mounting system weight alu	2.4	0.67	2.4	triangle	kg/m <sup>2</sup>
PV	Mounting system weight total	3	2.0	11.5	triangle	kg/m <sup>2</sup>
PV	Mounting system weight wood	0	0.0	10.0	triangle	kg/m <sup>2</sup>
PV	Normalised annual PV production kWh per kWp	1226.4	900.0	1700.0	triangle	kWh/kWp/year
PV	PV module efficiency	0.19	0.15	0.228	triangle	kWp/m <sup>2</sup>
PV	Power plant capacity	500.0	3.0	10000.0	linear	kWc
PV	Power plant lifetime	30	20.0	40.0	triangle	year
PV	Recycling rate	0.9	0.0	1.0	linear	fraction
PV	Recycling rate Al	0.92	0.56	1.0	triangle	fraction
PV	Recycling rate Cu	0.75	0.44	0.96	triangle	fraction
PV	Recycling rate glass	0.9	0.6	1.0	triangle	fraction
PV	SiC recycled share	0.694	0.6	0.9	triangle	fraction
PV	Silicon casting electricity intensity	19.295	10.0	30.0	triangle	kWh/kg
PV	Silicon production electricity intensity	30	11.0	180.0	triangle	kWh/kg
PV	Silicon production heat intensity	185	0.0	185.0	triangle	MJ/kg
PV	Silver content	9.6	2.0	9.6	triangle	g/m <sup>2</sup>
PV	Transport distance boat	4000.0	2000.0	6000.0	linear	km
PV	Transport distance lorry	1020.0	40.0	2000.0	linear	km
PV	Transport distance train	350.0	100.0	600.0	linear	km
PV	Wafer thickness	190	128.0	190.0	triangle	µm
PV	roof vs ground ratio	0.5	0.0	1.0	linear	fraction
Wind	Wind elec switch param	FR	0.0	2.0		
Wind	Wind lifetime offshore	20	15.0	30.0	triangle	year
Wind	Wind lifetime onshore	20	15.0	30.0	triangle	year
Wind	Wind offshore flottant share	0.3	0.0	1.0	triangle	year
Wind	Wind offshore load factor	0.4	0.25	0.55	triangle	
Wind	Wind onshore load factor	0.25	0.15	0.35	triangle	
Wind	Wind ratio DD EESG	0.2	0.0	1.0	linear	fraction
Wind	Wind ratio DD PMSG	0.2	0.0	1.0	linear	fraction
Wind	Wind ratio cabling aluminium	0.0	0.0	1.0	linear	fraction
Wind	Wind steel ratio gravity based structure	0.1	0.02	0.12	triangle	fraction

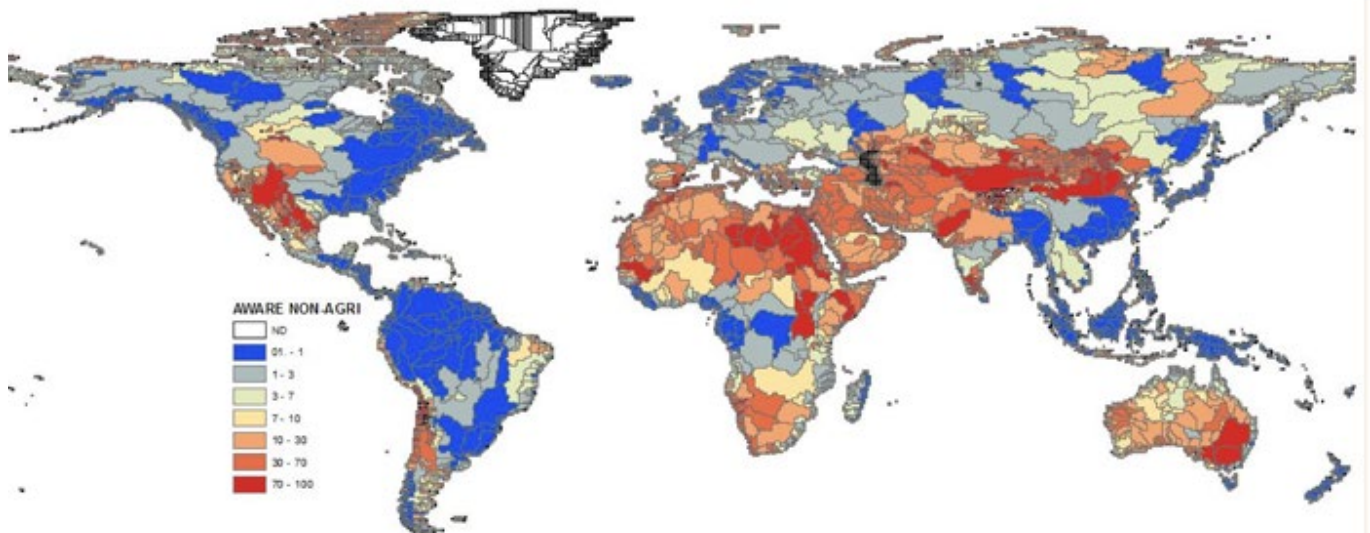
Wind	Wind steel ratio onshore foundation	0.04	0.03	0.05	triangle	fraction
Wind	Wind steel secondary share	0.3	0.0	1.0	triangle	fraction
Wind	onshore share	0.93	0.0	1.0	triangle	fraction
co2	DAC lifetime	20	10.0	30.0	triangle	year
elec	Electricity mix CO2 content	0.3	0.0	1.0	triangle	ratio or quasi-equivalent in kgCO <sub>2</sub> eq/kWh
elec	wind share	0.65	0.0	1.0	triangle	fraction
h2	Haber Bosch capacity	1000000	3000.0	1000000.0	triangle	kgNH <sub>3</sub> /day
h2	Haber Bosch flexibility	0.8	0.6	0.9	triangle	fraction
h2	Balance of Plant lifetime	20	5.0	20.0	triangle	year
h2	buffer days	7	0.0	7.0	triangle	day
h2	buffer tank lifetime	10	5.0	15.0	triangle	year
h2	eff alkaline	0.623	0.57	0.65	triangle	fraction
h2	electrolyzer lifetime	20000	20000.0	60000.0	triangle	hour
h2	electrolyzer operation peryear	6000	2000.0	8760.0	triangle	hour
syn	Gazification and PtM efficiency	0.511	0.4282	0.5278	triangle	%
syn	ttw methanol ch4	0	0.0	0.00251256	triangle	gCH <sub>4</sub> /MJ NH <sub>3</sub>
syn	ttw methanol n2o	0	0.0	0.00904523	triangle	gN <sub>2</sub> O/MJ NH <sub>3</sub>
tc	ammonia storage days distrib	3	0.0	10.0	triangle	day
tc	ammonia storage days prod	5	0.0	10.0	triangle	day
tc	bunkering slips	0.15	0.0	0.3	triangle	%
tc	conversion nh3 n2o	1	0.5	1.5	triangle	%
tc	dist ship	4000	0.0	10000.0	triangle	km
tc	dist train	0	0.0	500.0	triangle	km
tc	dist truck	0	0.0	500.0	triangle	km
tc	elec storage	9.4	5.0	15.0	triangle	kWh/day
tc	feedstock transport sea	0	0.0	4000.0	triangle	km
tc	feedstock transport truck	0	0.0	500.0	triangle	km
tc	storage slips	0.02	0.0	0.1	triangle	%

**Annex 4 : Inventory of the methanol synthesis of (Schmidt et al. 2022)**

**Table 3:** Mass and energy balance of the methanol synthesis process

H <sub>2</sub> consumption	0.193	kg/kg fuel
CO <sub>2</sub> consumption	1.40	kg/kg fuel
Methanol production	1.00	kg
Water production	0.59	kg/kg fuel
Power consumption	1.07	MJ/kg fuel
Heat production	1.72	MJ/kg fuel

**Annex 5: Map of AWARE factors for non-agricultural activities (normalised average over 12 months) - Spatio-temporal scale (source (Boulay et al. 2018))**



### Annex 6: Sobol indices from the Global Sensitivity Analysis of e-ammonia (Scenario C)

