Supplementary material of "Absolute environmental sustainability

assessment of renewable dimethyl ether fuelled heavy-duty trucks"

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Contents

1	Alte	rnative scenarios	3
2	Sim	ulations	4
	2.1	DME simulation	4
	2.2	Methanol from coal gasification	5
	2.3	Post-combustion capture on the biomass to methanol plant	6
3	Envi	ronmental Assessment	8
	3.1	Scenarios detailed description	8
	3.2	Methodological assumptions and limitations	9
4	Inve	ntories used in the life cycle assessment	13
	4.1	DME production inventories1	13
	4.2	Methanol production inventories	4
	4.3	H ₂ inventories1	8
	4.4	CO ₂ inventories	22
	4.5	Electricity mix	24
	4.6	Cooling water energy	24
5	Sup	plementary results	25
	5.1	Breakdown on the Planetary Boundaries2	25
	5.2	Main impact contributions2	27
	5.3	Global warming	28
	5.4	Hydrogen from wind breakdown2	28
	5.5	Biosphere integrity stressors	29
6	Ecoi	nomic Assessment	31

	6.1	References	31
	6.2	Additional results	32
7	Refe	erences	32

This document is divided into six sections. The first explains all the alternative scenarios, giving more detailed information on the abbreviations used. Then, in the second section, the flowsheet of DME production from methanol and methanol production from coal gasification are presented. In section 3, all the information required for the environmental analysis is included, together with a further description of all the scenarios and the assumptions and limitations of the work. Section 4, includes the life-cycle inventories (LCI) used for the LCA. Section 5, includes all the extracted supplementary results. Lastly, the references used for the economic analysis and the costs of the alternative fuels per MJ are provided in section 6.

1 Alternative scenarios

Our work assesses the global environmental implications of replacing the current diesel-fueled heavyduty (HD) trucking sector with a DME-powered sector. DME would be relying on differing captured CO_2 and H₂ sources. A detailed description of all the scenarios is described in Section 2, while Table S 1 provides the acronyms for each scenario. Lastly, in Table S 2, the main features of each scenario are listed.

Scenarios acronym	Scenario description
BAU	Current diesel-powered HD trucking sector
coalDME	Conventional fossil DME scenario. DME originates from coal gasification to
	syngas, syngas to methanol, and methanol to DME.
NGDME	Conventional fossil DME scenario. DME originates from NG steam
	reforming to syngas, syngas to methanol, and methanol to DME.
DAC/Wind	CO ₂ -based alternative scenario based on CO ₂ captured using direct air
	capture and H ₂ from wind-powered electrolysis.
DAC/BECCS	CO_2 -based and bio-alternative scenario based on CO_2 captured using direct air capture and H_2 from water electrolysis powered with bioenergy with carbon capture and storage (CCS). The biomass feedstock used for
	bioenergy generation is woodchips from hardwood and softwood forestry
	species from sustainable forestry management.
DAC/BIH	direct air capture and H_2 from biomass gasification with carbon capture and storage. The biomass feedstock used for bioenergy generation is poplar trees from short-rotation plantations.
Coal/Wind	CO_2 -based alternative scenario based on CO_2 captured at a coal power
	plant and H_2 from wind-powered electrolysis.
NG/Wind	CO_2 -based alternative scenario based on CO_2 captured at a natural gas power plant and H_2 from wind-powered electrolysis.
BtDME	Bio-based alternative scenario based on DME production from catalytic
	conversion of syngas produced from biomass gasification. First, methanol
	is produced and then converted to DME. The biomass feedstock used is
	the straw of cotton plants.
BtDME CCS	Based on the BtDME scenario with additional post-combustion capture.
	Post-combustion captures all the CO ₂ from the purges. First, all the purges
	are combusted with air so that all the carbonaceous emissions are
	converted to CO ₂ , and then 91% of the CO ₂ is capture using
	monoethanolamine (MEA).

Table S 1: Acronyms and description of the scenarios included in the study

 Table S 2: The main features (feedstock, energy source, co-product) for the different DME alternatives under analysis. The scenario names are given in abbreviations used throughout the paper.

Scenario name	Feedstock	Energy source	Co-product
coalDME	Coal	Electricity mix 2019	
NGDME	Natural gas	Electricity mix 2019	
Coal / Wind	CO ₂ (coal PP) + Water	Wind	Electricity
NG / Wind	CO ₂ (NG PP)+ Water	Wind	Electricity

DAC / Wind DAC / BECCS	CO_2 (air) + Water CO_2 (air) + Water + woodchips	Electricity mix 2019 + Wind Electricity mix 2019 + BECCS	Electricity
DAC / BTH	CO ₂ (air) + poplar	Electricity mix 2019	
BtDME	cotton straw	Electricity mix 2019	
BtDME CCS	cotton straw + MEA	Electricity mix 2019	CO ₂

2 Simulations

2.1 DME simulation

The production of DME was based on the indirect process where methanol was produced first and then converted into DME via methanol dehydration. We created a simulation in Aspen HYSYS v.11 based on Bildea et al. for the methanol to DME process.¹ The process is shown in Figure S 1.



Figure S 1: DME process flowsheet for the production of 10^6 tDME·y⁻¹.

The operating conditions of the main equipment and streams are presented in Table S 3 and Table S 4.

Table S 3: Operating conditions of equipment for the production of DME.

Units	DME reactor	DME column	Methanol column
Inlet Temperature [°C]	275–395	153	88.2
Pressure [bar]	1.00	10.0	1.20
Reflux ratio	-	3.94	1.37
Reboiler duty [MW]	-	1.30	1.60
Distillate rate [kmol/h]	-	272	94.3
Number of stages	-	12.0	30.0
Distillate rate [kmol/h] Number of stages	- -	1.30 272 12.0	94.3 30.0

Table S 4: Conditions of most important streams extracted from the DME simulation.

Units	Methanol feed	Reactor out	Methanol recycle	W.W	DME
Temperature [°C]	35.0	395	68.4	106	45.0
Pressure [bar]	1.00	11.5	1.20	1.29	10.0
Mass flow [kg/h]	1.74·10 ⁵	2.04·10 ⁵	2.92·10 ⁴	$4.94 \cdot 10^4$	1.25·10 ⁵

2.2 Methanol from coal gasification

For the production of conventional DME from coal gasification, we created a simulation in Aspen PLUS v.11 based on the proximate and ultimate analysis of sub-bituminous coal, as presented in Li et al.² The gasification process is shown in Figure S 2.



Figure S 2: Coal gasification to methanol process flowsheet.

First, coal is mixed with water to create a coal slurry that enters the gasification process, which comprises various steps modelled separately. First, we have the drying with hot air, then the decomposition of coal – or, in other words, the pyrolysis process –followed by the gasification, which converts carbon into syngas using steam and oxygen at high temperatures of 1400K. During the

pyrolysis process, coal is converted into substituent components such as carbon, hydrogen, oxygen, sulfur, tar, char and ash. Char and ash are removed from the gasification process without reacting. Both are sent to a furnace where they combust to produce energy used to cover the energy required in the gasifier. The combustion of char is the 4th step of the gasification process. The whole gasification process is simulated as an entrained flow gasifier. The tars are the organic fraction of coal that can be reformed to produce syngas. The tars of coal are mainly benzene, toluene and naphthalene. After the tars are converted to syngas, a quench tower is needed to decrease the temperature of syngas from 1400K to 900K. After the whole gasification process, the syngas we get is raw and needs further cleaning. A two-step cleaning process is performed to remove HCL and H₂S.

The cleaned syngas passes through high temperature and low temperature water gas shift reactors to increase the hydrogen in syngas and achieve the optimal fraction of $2.05 (H_2/CO/CO_2 = 9.8/3.3/1)$. This is the optimal fraction of syngas required for the methanol reactor.

The following process steps are modelled in Aspen HYSYS v.11. The methanol reactor is an ideal fixedbed plug-flow reactor (PFR). The kinetics are taken from González-Garay et al.³ based on a commercial Cu-ZnO-Al₂O₃ catalyst modelled by Vanden Bussche and Froment.⁴ After the reaction, we apply a purification section to remove all the gases and water and produce methanol with 99.9% mol. All the flue gases are fed into a furnace where they combust and are converted to CO_2 while producing energy, which is integrated in the process.

2.3 Post-combustion capture on the biomass-to-methanol plant

For the BtDME CCS scenario, we created a simulation in Aspen HYSYS v.11 for the carbon capture part. As feedstock to the carbon capture plant, we considered the emissions reported in the life cycle inventory of Liu et al., which is the same for the BtDME scenario.⁵

In Figure S 3, an overview of the simulation of the biomass-to-methanol plant with carbon capture is presented. For this case, we consider a CO₂ capture process using a 30% wt. aqueous solution of MEA. Notably, other CO₂ capture technologies are commercially available; however, this technology is very mature with a technology readiness level (TRL) of 9, as reported by Bui and co-authors.⁶ Moreover, its easy installation and high efficiency are some of the main reasons we chose to use it.

First, all the purges are combusted in the furnace with air to convert all carbonaceous emissions to CO_2 . The exhaust stream of the furnace is compressed and cooled down to condense the water produced during the combustion. The water is removed in a flash (V-100), and then the stream is conditioned to 40 °C and 2 bar and sent to the absorber column (T-101). The 30% wt. aqueous MEA solution enters at the top of the absorber column and comes in contact with the gaseous stream from the bottom. It leaves at the bottom of the column rich in CO_2 . Then it is sent to the desorber column (T-102) at 90 °C where the CO_2 -rich solution is stripped of CO_2 using heat provided by the reboiler. The CO_2 stream leaves at the top of the desorber column and the regenerated MEA at the bottom. MEA is recycled back to the absorber with additional make-up water and make-up MEA, while the CO_2 is compressed to 110 bar and stored. Heat integration of the carbon capture plant section of the biomass-to methanol-plant is performed using Aspen Energy Analyzer v.11. The overall capture achieved here was 91%.



Figure S 3: Post-combustion capture with MEA for the BtDME scenario

3 Environmental Assessment

This section gives a detailed description of the scenarios considered in the study (3.1), and list all the methodological assumptions and limitations (3.2).

3.1 Scenarios detailed description

Here we provide a detailed description of all the scenarios considered in the study. All the references used to extract the life cycle inventories are included in section 2.2 (ii) of the main manuscript.

For the conventional scenarios, we consider DME from natural gas and coal. Currently, DME has been produced from these fossil resources following the indirect route – first, methanol production and then DME production. The steam reforming of natural gas to syngas and then the catalytic conversion to methanol is modelled based on Ecoinvent v3.5.⁵ The coal gasification to syngas and then the catalytic conversion to methanol were modelled in Aspen PLUS v.11 and Aspen HYSYS v.11, as shown in Figure S 2 and Section 2.

For the CCU routes, the Coal scenario considers post-combustion capture at a coal-fired power plant based on chemical absorption with monoethanolamine (MEA) solvent. Post-combustion capture takes place after the combustion of fossil fuels and considers an absorber operating at atmospheric pressures and 50 °C. 30% MEA ag. w/w is fed at the top of the absorber and captures CO_2 from cleaned flue gases, leaving at the bottom of the column as a rich-CO₂ stream. The rich-CO₂ stream is then heated and fed to the stripper, where the solvent is removed from CO₂.⁶ The NG scenario considers pre-combustion capture of CO₂ at the exit of an auto-thermal reformer in a conventional combinedcycle natural-gas-fired (NGCC) power plant. Combustion of the fuel occurs in a methane auto-thermal reformer where a mixture of gases is converted to CO₂ and H₂. The CO₂ capture is performed with MEA absorption while at the same time generating H_2 that is fed to the combustion chamber, drastically reducing the emissions. Between the two capture technologies, the NG is more efficient and emits less due to the gas turbine and steam turbine implemented in the design; however, it implies a higher complexity.⁷ Finally, in the DAC scenarios, CO₂ is directly captured from the air following an industrial Direct Air Capture system developed by Carbon Engineering. The technology uses a process based on an aqueous KOH sorbent coupled to a calcium caustic recovery loop. For these scenarios, the outlet pressure of the CO₂ product was adjusted accordingly to comply with the input requirements of the methanol plant. Moreover, no additional compression was considered for transporting the CO₂ from the point sources to the chemical plants due to the assumption that the methanol plant is located near the CO₂ source.⁸

For the H₂ production routes, the thermochemical scenario (*BTH*) is regarded as one of the most environmentally promising scenarios for hydrogen production, especially when combined with CCS. Biomass gasification with CCS can produce carbon-negative H₂. Here we consider gasification of shortrotation poplar biomass⁹ coupled with CO₂ capture based on membranes. During this endothermic process, dried biomass acts as the hydrogen carrier and is converted into syngas in an indirect gasifier coupled with a char combustor. After conditioning and cleaning the syngas, hydrogen is separated from the rest of the compounds in a pressure swing adsorption (PSA) unit. The CO₂ from the flue gases is captured through membranes, transported and stored in an aquifer.¹⁰ In contrast, the electrochemical scenarios (*Wind, BECCS*) focus on polymer electrolyte membrane water electrolysis (PEMWE)¹¹ powered either with onshore wind or BECCS electricity.¹² PEMWE electrochemically splits water into H₂ (cathode) and O₂ (anode) at their respective electrodes. Water is pumped to the anode of the electrochemical cell, where it is catalytically split into O₂, protons and electrons on an Ir-based catalyst. Protons pass to the cathode side through a membrane electrode assembly (MEA–perfluorosulfonic acid polymeric membrane) and re-combine with electrons that pass to the cathode through an external power circuit on a Pt-based catalyst to produce H₂.¹³ Finally, the scenario based on electricity supplied by *BECCS* uses the gasification of woodchips in a combined heat and power plant while capturing, transporting and geologically storing the CO₂ in an aquifer.¹⁴ At this point, it is important to mention that directly converting biomass to hydrogen is more efficient than converting biomass to electricity to power the electrolyser later. BECCS is a carbon-negative technology with a great prospect as a future power source that will undoubtedly play a role in the hydrogen economy of some countries.

Further adjustments to the inventory were required for compressing H_2 gas from 30 bar to 200 bar to ensure the continuous operation of the methanol plant that consumes H_2 produced from intermittent wind power. Notably, when hydrogen is produced in the PEM electrolyser, it leaves the cell at 30 bar and then is compressed in a 3-stage compressor with intermediate cooling to 200 bar appropriate for storage in steel tanks as a compressed gas. All the compression steps were modelled with Aspen HYSYS v.11. Lastly, in order to calculate the amount of H_2 produced from wind power, we use the typical capacity factor of wind turbines, 0.34.¹⁵

Lastly, the *BtDME* scenario uses direct methanol production from biomass-based syngas using cotton straw from agricultural activities as feedstock. Methanol is converted in a second step into DME via a dehydration step. Biomass, in this scenario, acts as both hydrogen and carbon source. First, it is pre-treated (drying and pelleting), then converted to raw syngas through the gasification process, which takes place under high pressure. Raw syngas is then conditioned and fed to the methanol reactor and purification unit.

It is essential to point out that the CO_2 feedstock originating from biogenic or atmospheric sources used in the scenarios is modelled as a negative output in the LCA to portray the removal of atmospheric CO_2 . These technologies have the potential to generate a negative carbon footprint. In the transportation sector, the CO_2 captured is converted into a carbon-based fuel, so the CO_2 stored in the biomass is released back in the atmosphere during the combustion phase.

3.2 Methodological assumptions and limitations

The main assumptions and limitations of our study are discussed below:

i. We consider a cradle-to-wheel scope covering all the activities from the procurement of raw materials and utilities generation to the production of DME, and lastly, the use of it in HD trucks. This scope is motivated by the fact that the true potential of each alternative can only be quantified when the entire life cycle of the studied system is considered. Based on a cradle-to-gate scope, some scenarios may yield negative values since biogenic sources or CO₂ from the air (DAC) are used. CO₂ from those sources is modelled as a negative flow (to provide credits for the avoided burden) since it is removed from the atmosphere or through photosynthesis during biomass growth. However, the end-use of the fuel will determine its

actual environmental benefits since the combustion of the fuel will return the CO_2 to the atmosphere.

- ii. The allocation factors used in this study are based on an economic allocation that considers the multiple co-products at the coal power plant, NG power plant and BECCS power plant. Generally, allocation methods are subject to debate, and up to now, there is no clear winner on which one should be used for each system. For our case, economic allocation is considered since the by-products have lower costs than the main products.¹⁶ The electricity production from those plants is considered relatively cheap compared to the CO₂ capture part. In this case, it is recommended in LCA practice to use economic allocation.
- iii. We applied the allocation at point of substitution (APOS) to include wastewater treatment and recycling impacts.
- iv. Our environmental assessment quantifies the performance of DME based on the feedstock requirements and utility consumption for each scenario. Therefore, we omit the infrastructure of the chemical plants, but we include the infrastructure of the electrolyser unit and the HD truck.
- v. The LCI for the HD truck, for both powertrains, is taken from Ecoinvent v3.5. It corresponds to the activity with a FU of 1 tonne·km labelled as: "Lorry 16-32 metric ton, EURO6 {RER}". In reality, the change in fuel will impose changes on the infrastructure. In the case of DME, the basic infrastructure of the engine will remain the same as in diesel; however, it has been reported that additional parts dedicated to DME for the fuel injection system (based on a common rail concept) are often added to the basic design to accommodate for the higher injection pressures (up to 30 bar). A standard liquid petroleum gas (LPG) tank under low pressures is used to transport and store DME in liquid form; however, the size of the tank needs to be 1.5 fold bigger than the equivalent for diesel due to the lower specific energy (kJ/kg) of DME. Regarding the emissions, since DME contains 35% oxygen in its molecular structure, it can be combusted in a clean way and produce hardly any soot (PM), which means that the powertrain will no longer need a particulate filter in the after-treatment system.
- vi. Furthermore, NO_x emissions are also drastically reduced, making the need for selective catalytic reduction (SCR) redundant, while allowing the use of exhaust gas recirculation (EGR) a methanol that decreases NO_x by lowering the combustion temperature –, resulting in lower NO_x emissions. We assume that these changes will result in the same amount of mass for the truck compared to the diesel truck. Thus the infrastructure for both powertrains is considered the same in the LCI of truck manufacturing.
- vii. The DME consumption was calculated by considering the LHV of the fuel and the same power output as the diesel counterpart. The emissions originating from the DME engine assume complete combustion. The reason for this assumption is two-fold:
 - There is limited data availability from field measurements.
 - The life cycle impact assessment method (LCIA-PB) used does not include characterisation factors for all the emissions. This is more pronounced in the environmental performance of the diesel HD truck. At this point, it is essential to mention that all the emissions included in the LCI are provided from the HBEFA database, which considers field measurements for all the driving cycles of the trucks. Nevertheless, the environmental performance of the diesel HD truck impacts only the GHG-related planetary boundaries (CO₂ concentration CC-CO₂ –, Energy Imbalance CC-EI –, Ocean acidification OA –), and the stratospheric

ozone depletion – O_3D – PB. In Table S 5, we present the impacts of the combustion emissions in the PBs mentioned above per tkm.

Combustion emissions	CO ₂ concentration (CC-CO ₂) [ppm]	Energy Imbalance (CC-EI) [W·m ²]	Stratospheric ozone depletion (O₃D) [DU]	Ocean acidification (OA) [Ω _{arag}]
CO ₂	3.09·10 ⁻¹²	4.05·10 ⁻¹⁴	-	9.44·10 ⁻¹⁵
СО	4.77·10 ⁻¹⁵	3.09·10 ⁻¹⁷	-	1.05·10 ⁻¹⁷
CH₄	7.00·10 ⁻¹⁸	1.00·10 ⁻¹⁹	-	3.72·10 ⁻²⁰
N ₂ O	-	2.85·10 ⁻¹⁶	8.66·10 ⁻¹⁶	-
NMVOC	$5.70 \cdot 10^{-16}$	$1.00 \cdot 10^{-18}$	-	1.23·10 ⁻¹⁹

Table S 5: Impacts caused by the combustion emissions of the diesel HD truck on the CO₂, EI, O₃D and OA PBs.

Based on Table S 5, carbon dioxide from combustion emissions causes more than 99% of the impacts on CC-CO₂, EI and OA PBs. However, dinitrogen monoxide (N_2O) is the only compound that impacts the O_3D .

Focusing on O_3D , Figure 2 of the main manuscript shows that the impacts relative to the SOS are <1% for O_3D for diesel HD trucks. N_2O emissions balance N_2O formation and destruction within the after-treatment system. Since the after-treatment processes are not required in the DME truck, instead of the EGR, the N_2O emissions are expected to decrease relatively to NO_x and consequently result in much lower impacts on the O_3D .

- viii. Our biomass-based scenarios, i.e., BECCS, BTH, and the BtDME scenario, consider different second-generation biomass sources (non-food crops) from forestry and agricultural residues and from dedicated energy crops process data are available. These include wood chips from forestry residues (BECCS scenario), poplar short rotation coppice (BTH scenario) and cotton straw residues (BtDME scenario). Other biomass feedstocks could also be considered (e.g., willow, *Miscanthus*, wheat straw), leading to different PBs performance and cost. Ultimately, the choice of a specific biomass type should consider the regional availability of resources (i.e., marginal land for growing crops or availability of residues, depending on the case), as well as the associated economic and environmental performance of the biomass source.
- ix. The electricity mix included in the LCI is modelled based on data sourced from the World Energy Outlook.¹⁷
- x. The cooling water activity (FU = 1 MJ) includes only the electricity needed to pump the water in the cooling tower. Pumping of water is considered from 1 bar to 2.5 bar. -up water was calculated based on an open recirculated system with evaporation losses of 2.59% of the total circulating water. The activity includes the amount of make-up water required for 1 MJ of cooling energy, plus the losses to evaporation and wastewater.
- xi. Environmental data of the background system are taken from Ecoinvent v.3.5⁵ assessed via SimaPro¹⁸. We chose the most appropriate activities, focusing on global datasets ([GLO]) to be consistent with the global scope of our study. When global datasets were not available, the European ([RER]) or the Rest of the World ([RoW]) datasets were used instead.
- xii. Life cycle impact assessment methodology:

- Due to methodological gaps in the PBs framework, we omitted two Earth system processes in the analysis: the aerosol loading defined only for the South Asian region and the novel entities PB, which has not been quantified yet.
- Our work considers the control variables defined at the global level. This is due to the unavailability of specific regional data regarding the location of fuel production plants or the accumulation of emissions from the HD trucks. Also, the original method of Ryberg et al.¹⁹ does not cover regional boundaries, while the updated version focuses on the regionalisation of the Nitrogen flows and Freshwater use PBs. The global scope of this work calls for global characterisation factors; however, the geographically resolved characterisation factors would still be required for a more accurate assessment of the interventions across the life cycle. At this point, operating under the global PBs is a necessary condition but still insufficient for being absolute environmentally sustainable; thus, regional environmental impacts would lead to a more accurate assessment.
- The Nitrogen biogeochemical flow PB, as initially defined by Steffen et al.²⁰ and suggested by De Vries et al.²¹, only considers the intended biological and chemical nitrogen fixation in agriculture. The characterisation factor from Ryberg et al.²² includes the N-compounds to freshwater because it is thought to be the most dominant route for intended agricultural activities. Unfortunately, the characterisation factor does not consider emissions to air like NO_x or N₂O, emissions released mostly through fuel combustion. However, it has been observed that 64% of the current global nitrogen fixation is associated with chemical fertilisers. The biomass scenarios should be considered, depending on the biomass we use, and fertilisers applied.

xiii. Life cycle interpretation:

The results shown in this work reflect the global annual tkm (33 trillion tkm per year) for the HD trucking sector. Each scenario replaces the current diesel fuel HD trucks, with no restriction on the technical feasibility. For example, the DME produced from electrolytic hydrogen powered by BECCS will require the removal of around 50 Gt of CO₂ per year to satisfy the annual demand for DME. This high CO₂ removal from BECCS has not been proved as technically feasible, with the maximum being around 10 Gt CO₂ removed per year.²³ This limitation, however, does not hinder the ultimate goal of this work to prove that DME from different educts can potentially decrease the current stresses in the PBs.

4 Inventories used in the life cycle assessment

This section presents the inventories created for the life cycle assessment. SimaPro v9.2.0.2 was used to implement them and calculate all the impacts. The inputs depicted with an asterisk "*" represent activities that we constructed and the inventories of their production are presented further in the section.

4.1 DME production inventories

DME truck inventory: The activity of the DME truck is presented in Table S6. It is based on the business as usual (fossil diesel fueled HD truck) taken from Ecoinvent v3.5. The name of the activity in Ecoinvent is *"Transport, freight lorry 16–32 metric ton, euro6"*. In order to adjust this activity for DME, we replaced the fuel and the combustion emissions, as mentioned in the main manuscript. The fuel consumption and emissions are shown in Table S 6.

Table S 6: Life cycle inventory for 1 tkm of DME truck.	

Products	Value	Units
DME truck, freight lorry 16-32 metric ton, Euro 6 {GLO}	1.00	tkm
Technosphere flows		
DME ¹	0.05	kg
Biosphere flows		
Carbon dioxide	0.10	kg
Dinitrogen monoxide	0.52	kg

DME production inventory: For the DME activity (production of DME), we used the mass and energy flow from the simulation (Figure S 1). This simulation is the same in all the scenarios that were developed, representing the second step of the indirect process of DME production. We will need methanol, the raw material for the dehydration step and utilities for the indirect process. The inventory of producing 1 kg of DME through the dehydration of methanol is shown in Table S 7. "Methanol*" is produced either from biomass or CO_2 hydrogenation for the low-carbon DME scenarios and from coal for the conventional scenario (*coalDME*). The LCIs of methanol production are presented in Table S 9 — Table S 11.

Table S 7: Life cycle inventory for the production of 1 kg of DME from methanol.

Products	Value	Units
DME	1.00	kg
Technosphere flows		
Methanol ²	1.40	kg
Heat, from steam, in chemical industry {RoW} market for heat, from steam, in	0.66	MJ
chemical industry APOS, U		
Heat, central or small-scale, natural gas {GLO} market group for APOS, U	1.90	MJ

¹ Details on DME are provided in Table S 7.

 $^{^{\}rm 2}$ Details on Methanol are provided in Table S 9, Table S 10, Table S 12.

DME from coal gasification: For the production of DME from coal, a simulation was developed in Aspen PLUS v.11. The flowsheet of the simulation is shown in Figure S 2. Table S 8 shows the life cycle inventory of producing 1 kg of DME from coal gasification. All the mass and energy flows shown were taken from the simulation.

Products	Value	Units
DME from coal	1.00	kg
Technosphere flows		
Hard coal {RoW} market for APOS, U	0.44	kg
Oxygen, via cryogenic air separation, production mix at the plant,	0.44	kg
gaseous EU-27		
Steam, in chemical industry {RoW} production APOS, U	1.07	kg
Global electricity mix from 2019 ³	0.93	kWh
Heat, from steam, in chemical industry {RoW} market for heat,	3.18	MJ
from steam, in chemical industry APOS, U		
Cooling water energy ⁴	13.6	MJ
Hard coal ash {RoW} market for hard coal ash APOS, U	-0.10	kg
Biosphere flows		
Carbon dioxide, fossil	0.18	kg
Nitrogen, atmospheric	2.49	kg
Sulfur	17.0·10 ⁻³	kg
Hydrogen sulphide	17.0·10 ⁻³	kg
Docosane	1.00·10 ⁻³	kg
Carbon	2.30·10 ⁻²⁴	kg
Dinitrogen monoxide	7.58·10 ⁻¹²	kg
Oxygen	5.80·10 ⁻¹⁷	kg
Nitrogen dioxide	1.14·10 ⁻²¹	kg
Water	1.70·10 ⁻⁶	kg

Table S 8: Life cycle inventory for the production of 1 kg of DME from coal gasification.

4.2 Methanol production inventories

For this study, we considered scenarios that include methanol produced from either biomass or CO_2 hydrogenation starting from CO_2 and H_2 .

Methanol from CO₂ and H₂: The LCI for producing methanol from CO₂ and H₂ was taken from Pérez-Fortes et al.²⁴

Products	Value	Unit
Methanol	1.00	kg
Technosphere flows		
CO ₂	1.46	kg
H ₂	0.19	kg
Global electricity mix from 2019 ³	0.16	kWh

Table S 9: Life cycle inventory for 1 kg of methanol from CO_2 and $\mathsf{H}_2.$

³ Details on Global electricity mix from 2019 are provided in Table S 26.

⁴ Details on Cooling water energy are provided in Table S 27.

Methanol from biomass: The LCI of the methanol production is taken from Liu et al. ²⁵

Products	Value	Unit
Methanol from Biomass	1.00	kg
Technosphere flows		
cotton straw ⁵	1.74	kg
Global electricity mix from 2019 ³	8.57·10 ⁻²	kWh
Global electricity mix from 2019 ³	4.89·10 ⁻³	kWh
Heat, from steam, in chemical industry {RoW} market for heat,	1.69	MJ
from steam, in chemical industry APOS, U		
Global electricity mix from 2019 ³	9.89·10 ⁻³	kWh
Heat, from steam, in chemical industry {RoW} market for heat,	5.51	MJ
from steam, in chemical industry APOS, U		
Wood ash mixture, pure {RoW} treatment of wood ash mixture,	-4.88·10 ⁻²	kg
pure, land farming APOS, U		
Coal tar {GLO} treatment of, in industrial furnace 1MW APOS, U	-1.68·10 ⁻²	kg
Wastewater from vegetable oil refinery {GLO} treatment of	-6.59·10 ⁻⁵	m ³
APOS, U		
Biosphere flows		
Carbon dioxide, fossil	1.16	kg
Nitrogen, atmospheric	0.30	kg
Carbon dioxide, fossil	3.32·10 ⁻³	kg
Carbon monoxide	6.19·10 ⁻⁴	kg
VOC, volatile organic compounds, unspecified origin	9.86·10 ⁻³	kg
Methane	0.12	kg

Table S 10: Life cycle inventory for 1 kg methanol from cotton straw biomass.

Cotton straw: The LCI for the production of cotton straw was taken from Bai et al.²⁶

Table S 11: Life cycle inventory for the production of 1 kg of cotton straw.

Products	Value	Unit
Cotton straw	1.00	kg
Technosphere flows		
Diesel, low-sulfur {GLO} market group for APOS, U	4.09·10 ⁻³	kg
Petrol, 5% ethanol by volume from biomass {GLO} market for APOS, U	1.82·10 ⁻³	kg
Nitrogen fertiliser, as N {GLO} nutrient supply from compost APOS, U	0.01	kg
Phosphate fertiliser, as P2O5 {GLO} nutrient supply from compost APOS, U	3.00·10 ⁻³	kg
Potassium fertiliser, as K2O {GLO} nutrient supply from compost APOS, U	3·10 ⁻³	kg
Transport, freight lorry unspecified {GLO} market group for transport	0.10	tkm
APOS, U		
Transport, freight train {GLO} market group for APOS, U	0.50	tkm

⁵ Details on cotton straw are provided in Table S 11.

Global electricity mix from 2019 ³	2.27·10 ⁻⁴		
Biosphere flows			
Carbon dioxide, fossil	-1.65	kg	
Occupation, annual crop	0.42	m²a	
Transformation from annual crop	0.42	m²	
Transformation to annual crop	0.42	m²	

Methanol from biomass with carbon capture and storage: The LCI of the methanol production from biomass with CCS is taken from Liu et al.,²⁵ and the simulation of the carbon capture as explained in section 2.3.

Table S 12: Life cycle inventory for the production of 1 kg methanol from cotton straw biomass with CCS.

Products	Value	Unit
Methanol from Biomass with CCS	1.00	kg
Technosphere flows		
cotton straw ⁵	1.74	kg
Global electricity mix from 20193	8.57·10 ⁻²	kWh
Global electricity mix from 2019 ³	4.89·10 ⁻³	kWh
Heat, from steam, in chemical industry {RoW} market for heat, from	1.69	MJ
steam, in chemical industry APOS, U		
Global electricity mix from 2019 ³	9.89·10 ⁻³	kWh
Heat, from steam, in chemical industry {RoW} market for heat, from	5.51	MJ
steam, in chemical industry APOS, U		
Wood ash mixture, pure {RoW} treatment of wood ash mixture,	-4.88·10 ⁻²	kg
pure, land farming APOS, U		
Coal tar {GLO} treatment of, in industrial furnace 1MW APOS, U	-1.68·10 ⁻²	kg
Wastewater from vegetable oil refinery {GLO} treatment of APOS,	-6.59·10 ⁻⁵	m³
U		
CO ₂ from biomass to methanol plant with CCS ⁶	1.36	Kg
CO_2 stored in aquifer at 200 km distance from emission source and	1.36	kg
transported by pipeline ⁷		
Biosphere flows		
Carbon dioxide, fossil	0.13	kg
Nitrogen, atmospheric	0.30	kg
Carbon dioxide, fossil	3.32·10 ⁻⁴	kg
VOC, volatile organic compounds, unspecified origin	9.86·10 ⁻³	kg

Carbon capture from a biomass to methanol plant: The LCI of the capture of 1 kg CO_2 from a biomass to methanol plant with CCS. The inventory is taken from a simulation as explained in section 2.3.

Table S 13: Life cycle inventory for the capture of 1 kg CO_2 from a biomass to methanol plant

Products	Value	Unit
CO_2 from biomass to methanol plant with CCS	1.00	kg

⁶ Details for CO₂ from biomass to methanol plant with CCS is provided in Table S 13.

⁷ Details for CO₂ stored in aquifer at 200 km distance from emission source and transported by pipeline are provided in Table S 14.

Technosphere flows		
Monoethanolamine {GLO} market for APOS, U	7.66 ·10 ⁻³	kg
Cooling water energy ⁴	3.20	MJ
Global electricity mix from 2019 ³	0.04	kWh

 CO_2 stored in aquifer at 200 km distance from emission source and transported by pipeline: The LCI of the storage of 1 kg CO₂ in aquifer at 200 km distance and transported by pipeline. The inventory is taken from Wildbolz el al.²⁷

Products	Value	Unit
CO ₂ stored in aquifer at 200 km distance and transported by pipeline	1.00	kg
Technosphere flows		
Diesel, burned in building machine {GLO} APOS, U	$4.20 \cdot 10^{-3}$	MJ
Steel, low-alloyed {GLO} market for steel, low-alloyed APOS, U	3.42 ·10 ⁻⁴	kg
Drawing of pipe, steel {RoW} drawing of pipe, steel APOS, U	3.42 ·10 ⁻⁴	kg
Stone wool, packed {GLO} market for stone wool, packed APOS, U	$6.49 \cdot 10^{-6}$	kg
Transport, helicopter {GLO} market for transport, helicopter APOS, U	$3.30 \cdot 10^{-8}$	hr
Transport, helicopter, LTO cycle {GLO} market for transport, helicopter LTO cycle APOS, U	1.32 ·10 ⁻⁸	hr
Transport, freight, lorry 16-32 metric ton, EURO 6 {RoW} market for transport, freight, lorry 16-32 metric ton, EURO 6 APOS, U	3.99 ·10 ⁻⁴	tkm
Transport, freight, train {GLO} market group for transport, freight, train APOS, U	6.99 ·10 ⁻⁵	tkm
Inert waste, for final disposal {RoW} treatment of inert waste, inert material landfill APOS, U	-5.58 ·10 ⁻³	kg
Scrap steel {RoW} treatment of scrap steel, inert material landfill APOS, U	-1.71 ·10 ⁻⁴	kg
Waste mineral wool, for final disposal {RoW} treatment of waste mineral wool, inert material landfill APOS, U	-6.49 ·10 ⁻⁶	kg
Deep well, drilled, for geothermal power {GLO} market for deep well, drilled, for geothermal power APOS, U	9.14 ·10 ⁻⁸	m
Cement, unspecified {GLO} market group for cement, unspecified APOS, U	3.20 ·10 ⁻⁶	kg
Gravel, crushed {RoW} market for gravel, crushed APOS, U	3.35 ·10 ⁻⁵	kg
Transport, freight, lorry 16-32 metric ton, EURO 6 {RoW} market for transport, , freight, lorry 16-32 metric ton, EURO 6 APOS, U	7.34 ·10 ⁻⁷	tkm
Transport, freight, train {GLO} market group for transport, freight, train APOS, U	3.20 ·10 ⁻⁷	tkm
Sand {GLO} zinc mine operation APOS, U	$5.58 \cdot 10^{-3}$	kg
Biosphere flows		
Occupation, construction site	4.22 ·10 ⁻⁶	m²a
Transformation, from forest, unspecified	2.54 ·10 ⁻⁶	m²
Transformation, to heterogeneous, agricultural	2.54 ·10 ⁻⁶	m²

Table S 14: Life cycle inventory for the storage of 1 kg of CO_2 in aquifer at 200 km distance

Carbon dioxide, fossil	5.20 ·10 ⁻⁵	kg
Water, unspecified natural origin	2.37 ·10 ⁻⁷	m³
Occupation, industrial area	2.29 ·10 ⁻⁷	m²a
Transformation, from grassland, natural, for livestock grazing	1.52 ·10 ⁻⁸	m²
Transformation, to industrial area	1.52 ·10 ⁻⁷	m²

4.3 H₂ inventories

For the production of H_{2} , an electrolytic and a thermochemical route are considered. The electrolytic route follows the production of H_2 from polymer electrolyte water electrolysis (PEMWE) using different electricity sources, and the thermochemical route is biomass gasification.

Hydrogen from PEMWE electrolysis: The LCI for producing H_2 from PEMWE is presented in Table S 15. Data were taken from Bareiß et al.,¹¹ based on water electrolysis in a 1 MW polymer electrolyte membrane (PEM) electrolyser. The electricity sources considered were wind electricity with above 3 MW turbines and electricity from BECCS power. Wind electricity is taken from Ecoinvent v3.5, whereas electricity from BECCS was modelled. As explained in Section 3, the intermittency of wind energy is considered.

Table S 15: Life cycle inventory for the production of 1 kg hydrogen from polymer electrolyte water

Products	Value	Units
Hydrogen from PEMWE	1.00	kg
Technosphere flows		
Water, deionised, from tap water, at user {RoW} market for water APOS, U	11.0	kg
PEM electrolyser construction _for 1 kg of H ₂ ⁸	1.00	kg
Electricity, high voltage {RoW} electricity production, wind, >3MW turbine,	63.9	kWh
onshore APOS, U		
Electricity from BECCS ⁹	63.4	kWh

PEM electrolyser construction for 1 kg of H_2: The inventory of the PEM electrolyser is taken from Bareiß et al.¹¹

Table S 16: Life cycle inventory for the production of a polymer electrolyte stack that will be used for 1 kg of H₂.

Products	Value	Units	Comment
PEM electrolyser construction for 1 kg of H ₂	1.00	kg	
Technosphere flows			
Copper {GLO} market for APOS, U	4.17·10 ⁻⁶	kg	PEMWE stack
Steel, unalloyed {GLO} market for APOS, U	9.26·10 ⁻⁵	kg	PEMWE stack
Titanium, primary {GLO} production APOS, U	4.89·10 ⁻⁴	kg	PEMWE stack
Aluminium, primary, ingot {RoW} production APOS, U	0.25·10 ⁻⁴	kg	PEMWE stack
Activated carbon, granular {GLO} market for activated	8.33·10 ⁻⁶	kg	PEMWE stack
carbon, granular APOS, U			
gasket for H ₂ (PEMWE cell stack) ¹⁰	$1.13 \cdot 10^{-4}$	kg	PEMWE stack
Nafion cast membrane ¹¹	1.48·10 ⁻⁵	kg	PEMWE stack

⁸ Details on PEM electrolyser construction_for 1kg of H₂ are provided in Table S 16.

⁹ Details on Electricity from BECCS are provided in Table S 20.

¹⁰ Details on gaskets for H₂ (PEMWE stack) are provided in Table S 17.

¹¹ Details on Nafion cast membrane are provided in Table S 18.

Electronics, for control units {GLO} market for APOS, U	1.02·10 ⁻⁶	kg	ВоР
Concrete block {GLO} market for APOS, U	5.19·10 ⁻⁶	kg	ВоР
Plaster mixing {GLO} market for APOS, U	2.78·10 ⁻⁷	kg	BoP
Steel, low-alloyed {RoW} steel production, electric, low-	2.12·10 ⁻⁶	kg	BoP
alloyed APOS, U			
Aluminium, primary, ingot {RoW} production APOS, U	3.17·10 ⁻⁸	kg	BoP
Lubricating oil {GLO} market for APOS, U	1.85·10 ⁻⁷	kg	BoP
Copper {GLO} market for APOS, U	3.17·10 ⁻⁸	kg	BoP
Biosphere flows			
Iridium	6.94·10 ⁻⁷	kg	PEMWE stack
Platinum	6.94·10 ⁻⁷	kg	PEMWE stack

Gaskets for PEMWE stack: The LCI for the construction of the gaskets that are used in the electrolyser stack was taken from Koj et al.²⁸

Table S 17: Life cycle inventory for the production of gaskets that will be used for 1 kg polymer electrolytewater electrolyser stack.

Products	Value	Units
gasket for H ₂ (PEMWE cell stack)	1.00	kg
Technosphere flows		
Tetrafluoroethylene {GLO} market for APOS, U	0.07	kg
Acrylonitrile-butadiene-styrene copolymer {GLO} market for APOS, U	0.15	kg
Aniline {RER} market for aniline APOS, U	0.04	kg
Acetic anhydride {RER} production, ketene route APOS, U	0.05	kg
Purified terephthalic acid {GLO} market for APOS, U	0.08	kg
Nitric acid, without water, in 50% solution state {GLO} market for APOS, U	0.03	kg
Hydrochloric acid, without water, in 30% solution state {RER} market for	0.13	kg
APOS, U		
Graphite {GLO} market for APOS, U	0.42	kg
Lubricating oil {GLO} market for APOS, U	0.47·10 ⁻³	kg

Nafion cast membrane: The LCI for the construction of the gaskets that are used in the electrolyser stack was taken from Evangelisti et al.²⁹

Table S 18: Life cycle inventory for the production of 1 kg Nafion cast membrane.

Products	Value	Units
Nafion cast membrane	1.00	kg
Technosphere flows		
Isopropanol {RER} production APOS, U	0.07	kg
Water, deionised, from tap water, at user {RoW} production APOS, U	0.15	kg
Polyethylene terephthalate, granulate, amorphous {RER} production	0.04	kg
APOS, U		
Heat, from steam, in chemical industry {RoW} market for heat APOS, U	0.05	kg
Polypropylene, granulate {RER} production APOS, U	0.08	kg
Sulphuric acid {RER} market for sulphuric acid APOS, U	0.03	kg
PTFE ¹²	0.85	kg
Global electricity mix from 2019 ³	1.15	MJ
Nafion cast membrane	1.00	kg

¹² Details on PTFE are provided in Table S 19.

PTFE: The LCI for the production of polytetrafluoroethylene (PTFE) that are used for the construction of nafion cast membrane was taken from Evangelisti et al.²⁹

Products	Value	Units
PTFE	1.00	kg
Technosphere flows		
Market for wáter, deionised {ROW} APOS, U	0.03	kg
Tetrafluoroethylene {RER} production APOS, U	0.09	kg
Ammonium sulfate {RER} production APOS, U	0.57·10 ⁻³	kg
Boric oxide {RoW} market for boric oxide APOS, U	4.26·10 ⁻⁵	kg

Table S 19: Life cycle inventory for the production of 1 kg PTFE

Electricity from BECCS: The data for the construction of the LCI for the production of electricity from bioenergy with carbon capture and storage (BECCS) was taken from Oreggioni et al. ³⁰

 Table S 20: Life cycle inventory for the production of 1 kWh of electricity from bioenergy with carbon capture and CCS (BECCS).

Products	Value	Units	Comment
Electricity from BECCS	1.00	kWh	
Technosphere flows			
Metal working, average for steel product manufacturing	5.32·10 ⁻⁶	kg	MEA unit
{GLO} market for APOS, U			
Concrete, normal {ROW} market for APOS, U	4.05·10 ⁻⁸	m³	MEA unit
Copper {GLO} market for APOS, U	1.89·10 ⁻⁷	kg	MEA unit
Polyethylene, low density, granulate {GLO} market for APOS, U	5.41·10 ⁻⁷	kg	MEA unit
Monoethanolamine {GLO} market for APOS, U	6.77·10 ⁻³	m³	MEA unit
Concrete, normal {RoW} market for APOS, U	1.75·10 ⁻⁹	m³	
Metal working, average for steel product manufacturing	1.75·10 ⁻⁶	kg	CO ₂
{GLO} market for APOS, U			compression
Copper {GLO} market for APOS, U	1.89·10 ⁻⁷	kg	CO ₂
			compression
Polyethylene, low density, granulate {GLO} market for	$5.41 \cdot 10^{-7}$	kg	CO ₂
APOS, U			compression
CO ₂ stored in aquifer at 200 km distance from emission	1.69	kg	
source and transported by pipeline'			
Electricity, high voltage {RoW} heat and power co-	1.23	kWh	
generation, woodchips, 667 kW, state-of-the-art 2014			
APOS, U			
Diesel, burned in building machine {GLO} market for	5.35.10-3	MJ	MEA unit
APUS, U Clabal ale stribits units for an 20103			
Global electricity mix from 2019 ³	1.65.10 °	KVVN	MEA unit
Diesel, burned in building machine (GLO) market for	5.35.10 °	IVIJ	
APUS, U Clabal electricity mix from 2010 ³	1 CF 10 ⁻⁶		compression
GIODAI Electricity mix from 2019-	1.02.10 °	KVVN	
Spand columnt mixture (DoW() treatment of basedous	6 70 10 ⁻³	ka	compression
waste incineration APOS, U	-0.70.10	кд	
Biosphere flows			

Carbon dioxide fossil	-1.69	kg	
Hydrogen sulphide	2.02·10 ⁻⁵	kg	MEA unit
Hydrogen chloride	1.85·10 ⁻⁵	kg	MEA unit
Ammonia	9.65·10 ⁻⁵	kg	MEA unit
Particulate, <2.5 um	2.87·10 ⁻⁵	kg	MEA unit
Nitrogen oxides	2.02·10 ⁻⁵	kg	MEA unit
Sulfur oxides	9.48·10 ⁻⁴	kg	MEA unit
Methylamine	$1.80 \cdot 10^{-8}$	kg	MEA unit
Dimethylamine	1.31·10 ⁻⁸	kg	MEA unit
Ethylamine	1.31·10 ⁻⁸	kg	MEA unit
Diethylamine	6.40·10 ⁻⁹	kg	MEA unit
Monoethanolamine	8.92·10 ⁻⁸	kg	MEA unit
Diethanolamine	6.15·10 ⁻⁹	kg	MEA unit
Morpholine	2.55·10 ⁻⁸	kg	MEA unit
Formaldehyde	3.90·10 ⁻⁷	kg	MEA unit
Acetaldehyde	6.00·10 ⁻⁶	kg	MEA unit
Acetone	1.52·10 ⁻⁶	kg	MEA unit
Acetic acid	2.14·10 ⁻⁷	kg	MEA unit
Formamide	1.75·10 ⁻⁷	kg	MEA unit
Acetamide	2.48·10 ⁻⁷	kg	MEA unit
Carbon dioxide, biogenic	4.90·10 ⁻⁴	kg	

Hydrogen from biomass: The LCI for the production of H_2 from biomass is presented in Table S 21. Data for constructing the inventory were taken from Susmozas et al.³¹

Table S 21: Life cycle inventory for the production of 1 kg H_2 from poplar biomass with CCS.

Products	Value	Unit	Comment
Hydrogen from biomass with CCS	1.00	kg	
Technosphere flows			
Wet poplar ¹³	0.07	kg	
Water, decarbonised at user {GLO} market for APOS, U	0.15	kg	
Transport, freight lorry {GLO} market for APOS, U	0.04	kg	
Magnesium oxide {GLO} market for APOS, U	0.05	kg	
Iron-nickel-chromium alloy {GLO} market for APOS, U	0.08	kg	
Copper oxide {GLO} market for APOS, U	0.03	kg	
CO ₂ stored in aquifer at 200 km distance from emission	0.85	kg	
source and transported by pipeline ⁷			
Global electricity mix from 2019 ³	1.15	MJ	
Hard coal ash {RoW} treatment of, residual material landfill	-4.95·10 ⁻¹	kg	
APOS, U			
Spend catalyst base from ethylene oxide production {RoW}	-6.06·10 ⁻³	kg	
treatment of, residual material landfill APOS, U			
Wastewater from vegetable oil refinery {GLO} treatment of	-4.00·10 ⁻³	m³	
APOS, U			
Biosphere flows			
Carbon dioxide fossil	33.5	kg	CO ₂ in
			biomass

¹³ Details on wet poplar are provided in Table S20.

Carbon dioxide fossil	12.7	kg	Pre-treatment and gasification
Nitrogen dioxide	5.42·10 ⁻⁵	kg	Pre-treatment and gasification
Carbon dioxide fossil	4.07	kg	capture
Nitrogen dioxide	7.69·10 ⁻³	kg	capture
Wastewater	14.9	kg	

Poplar biomass inventory: Table S 22 shows the LCI for producing 1 kg of poplar biomass. The data were taken from Gasol et al.³²

Table S 22: Life cycle inventory for the production of 1 kg wet poplar biomass.

Products	Value	Units
Wet poplar	1.00	kg
Technosphere flows		
Diesel, low-sulfur {GLO} market group for APOS, U	2.00·10 ⁻³	kg
Glyphosate {GLO} market for APOS, U	4.64·10 ⁻⁶	kg
Ammonium nitrate, as N {GLO} market for APOS, U	1.00·10 ⁻³	kg
Phosphate fertiliser, as P ₂ O ₅ {GLO} market for APOS, U	1.00·10 ⁻³	kg
[thio]carbamate-compound {GLO} market for APOS, U	7.10·10 ⁻⁶	kg
Biosphere flows		
Occupation, permanent crop, non-irrigated, intensive	0.37	m²a
Transformation, from arable	0.02	m²
Transformation, to permanent crop, non-irrigated, intensive	0.02	m ²

4.4 CO₂ inventories

For the production of CO_2 we consider that CO_2 is captured either from point sources at coal or natural gas³³ plants or directly from air (*Coal, NG* and *DAC* scenarios, respectively).

CO₂ capture from a coal PP: Table S 23 shows the LCI for producing 1 kg of CO_2 from a coal power plant. The data were taken from Iribarren et al.⁶

Table S 23: Life cycle inventory for the production of 1 kg CO_2 from a coal power plant with post-combustion capture.

Products	Value	Units	Allocation
CO ₂	1.00	kg	57.49%
Electricity from coal PP	0.88	kWh	42.51%
Technosphere flows			
Hard coal {RoW} market for APOS, U	0.52	kg	
Natural gas liquids {GLO} market for APOS, U	8.20·10 ⁻⁴	kg	
Ammonia, liquid {RoW} market for APOS, U	$1.15 \cdot 10^{-4}$	kg	
Limestone, crushed, washed {RoW} market for limestone	0.04	kg	
APOS, U			
Sodium hydroxide, without water, in 50% solution state {GLO}	$1.20 \cdot 10^{-4}$	kg	
market for APOS, U			
Monoethanolamine {GLO} market for APOS, U	1.54·10 ⁻³	kg	
Light fuel oil {RoW} market for APOS, U	6.22·10 ⁻³	kg	

Hazardous waste, for underground deposit {RoW} treatment of	-2.27·10 ⁻³	kg
hazardous waste, underground deposit APOS, U		
Municipal solid waste {GLO} treatment of municipal solid waste,	-1.81·10 ⁻³	kg
open dump, moist infiltration class (300 mm) APOS, U		
Biosphere flows		
Sulfur dioxide	6.90·10 ⁻⁵	kg
Carbon dioxide, fossil	0.05	kg
Nitrogen oxides	1.06·10 ⁻³	kg
Ammonia	2.71·10 ⁻⁴	kg
Particulates, <2.5 um	$1.08 \cdot 10^{-4}$	kg
Monoethanolamine	0.85·10 ⁻⁴	kg

CO₂ capture from a NG PP: The LCI for the production of CO_2 from a natural gas power plant is presented in Table S 24. Data for constructing the inventory were taken from Petrakopoulou et al.⁷

Table S 24: Life cycle inventory for the production of 1 kg CO₂ from a natural gas power plant with postcombustion capture.

Products	Value	Units	Allocation
CO ₂	1.00	kg	18.33%
Electricity from NG PP	3.34	kWh	81.66%
Technosphere flows			
Natural gas liquids {GLO} market for APOS, U	0.47	kg	
Tap water {GLO} market group for APOS, U	1.06	kg	
Rhodium {GLO} market for APOS, U	1.48·10 ⁻⁷	kg	
Aluminium oxide {GLO} market for APOS, U	2.82·10 ⁻⁶	kg	
Monoethanolamine {GLO } market for APOS, U	8.00·10 ⁻³	kg	
Spent catalyst base from ethylene oxide production {RoW}	-2.97·10 ⁻⁶	kg	
treatment of, residual material landfill APOS, U			
Wastewater, average {RoW} market for wastewater, average	-1.00·10 ⁻³	kg	
APOS, U			
Biosphere flows			
Water	1.64	kg	
Carbon dioxide, fossil	0.32	kg	
Nitrogen oxides	$1.00 \cdot 10^{-3}$	kg	
Monoethanolamine	3.00·10 ⁻³	kg	

CO₂ capture from direct air capture: The LCI for the production of CO_2 from direct air capture is presented in Table S 25. Data for constructing the inventory were taken from Keith et al.⁸

Table S 25: Life cycle inventory for the production of 1 kg CO_2 from direct air capture.

Products	Value	Units
CO ₂	1.00	kg
Technosphere flows		
Natural gas liquids {GLO} market for APOS, U	0.09	kg
Tap water {GLO} market group for APOS, U	3.10	kg
Calcium carbonate, precipitated {RoW} market for calcium carbonate APOS, U	0.02	kg
Global electricity mix from 2019 ³	0.14	kWh
Biosphere flows		
Carbon dioxide, fossil	-0.74	kg

4.5 Electricity mix

The LCI for the production of 1 kWh of electricity from the global electricity mic of 2019 is presented in Table S 26.

Table S 26: Life cycle inventory for the production of 1 kWh from the current electricity mix taken from the World Energy Outlook of 2019.¹⁷

Droducts	Value	Unite
	value	Units
Global electricity mix from 2019	1.00	kWh
Technosphere flows		
Electricity, high voltage {RoW} electricity production, hard coal APOS, U	0.38	kWh
Electricity, high voltage {RoW} electricity production, natural gas,	0.23	kWh
combined cycle power plant APOS, U		
Electricity, high voltage {RoW} electricity production, oil APOS, U	0.03	kWh
Electricity, high voltage {RoW} electricity production, nuclear, pressure	0.10	kWh
water reactor APOS, U		
Electricity, high voltage {RoW} electricity production, hydro, reservoir,	0.15	kWh
non–alpine region APOS, U		
Electricity, high voltage {RoW} heat and power co-generation, woodchips,	0.02	kWh
667 kW, state-of-the-art 2014 APOS, U		
Electricity, high voltage {RoW} electricity production, wind, >3MW turbine,	0.04	kWh
onshore APOS, U		
Electricity, high voltage {RoW} electricity production,	0.02	kWh
photovoltaic,570kWp open ground installation, multi-Si APOS, U		
Electricity, high voltage {RoW} electricity production, deep geothermal	3.00·10 ⁻³	kWh
APOS, U		
Electricity, high voltage {RoW} electricity production, solar thermal	4.00·10 ⁻⁴	kWh
parabolic trough, 50 MW APOS, U		

4.6 Cooling water energy

The activity considers an open recirculating cooling tower system. Evaporation and spray losses were calculated to be 3.87% of the circulating water. Make-up water is added to compensate for the losses. The electricity to pump the circulating water to the cooling tower is also included.

Table S 27: LCI for 1 MJ cooling energy provided by cooling water recirculating in an open cooling tower system.

Products	Value	Units
Cooling water energy	1.00	MJ
Technosphere flows		
Global electricity mix from 2019 ³ (for pumping)	5.94·10 ⁻⁷	kWh
Biosphere flows		
Water, to air	0.41	kg
Water, to water	0.20	Kg
Water, natural resource	0.62	kg

5 Supplementary results

5.1 Breakdown on the Planetary Boundaries

In Figure S 3 and Figure S 4, the PBs of energy imbalance (CC-EI), stratospheric ozone depletion (O_3D), ocean acidification (OA), phosphorus biogeochemical flows (BGC-P), land system change (LSC), and lastly, freshwater use (FWU) are presented for the BAU and DME scenarios.



Figure S 4: Breakdown of impacts on the control variables of energy imbalance (EI), stratospheric ozone depletion (O₃D), and ocean acidification (OA)



Figure S 5: Breakdown of impacts on the control variables of phosphorus biogeochemical flows (BGC-P), land system change (LSC), and freshwater use (FWU).

5.2 Main impact contributions



■ Combustion emissions ■ Fuel ■ ICE truck ■ Road



■Combustion emissions ■Fuel ■ICE truck ■Road



■ Combustion emissions ■ Fuel ■ ICE truck ■ Road



■ Combustion emissions ■ Fuel ■ ICE truck ■ Road



■ Combustion emissions ■ Fuel ■ ICE truck ■ Road



■ Combustion emissions ■ Fuel ■ ICE truck ■ Road



■ Combustion emissions ■ Fuel ■ ICE truck ■ Road



■ Combustion emissions ■ Fuel ■ ICE truck ■ Road

Figure S 6: Main impact contributions for the DME scenarios.

5.3 Global warming

Main impact contributions of the nine scenarios analysed in this work. The results are based on the IPCC 2013 100a method in SimaPro v9.2.



Figure S 7: Global warming potential in CO_{2-eq} for all the scenarios per global annual tkm (33 trillion tkm·y⁻¹).

The results of Figure S 7 show that combustion emissions cause the main impacts in global warming in most scenarios except for BtDME. This is due to the direct emissions during the methanol production from cotton straw and especially methane emissions. The results shown in Figure S 7 follow the findings from the "Well-to-Wheels report v5" of the Joint Research Institute of the European Commission, which shows that DME from coal and natural gas will increase GHG emissions, while when originating from biomass or renewable sources could provide substantial reductions.³⁴

5.4 Hydrogen from wind breakdown

The impact breakdown on the nitrogen biogeochemical flows from hydrogen production from wind electricity is shown in Figure S 7, while the percentage impact breakdown of BECCS, Coal and NG scenarios is displaced in Figure S 9.



Figure S 8: Impact breakdown on the N biogeochemical flows for the production of electrolytic hydrogen from wind electricity



Figure S 9: Percentage impact breakdown on the N biochemical flows for BECCS, Coal, NG scenarios

In Figure S 9, the impact breakdown in BGC-N PB in percentage of the three technologies that use post-combustion capture is presented. The three scenarios are electrolytic hydrogen powered with BECCS electricity (H₂-BECCS), carbon dioxide from coal power plant (CO₂-Coal), carbon dioxide from a natural gas power plant (CO₂-NG). MEA is the main source of impact in BGC-N PB in H₂-BECCS and CO₂-Coal systems. A small percentage is taken up from hard coal in CO₂-Coal, while wastewater in CO₂-NG takes up almost 25% of the impacts, mainly due to high nitrate emissions in wastewater.

5.5 Biosphere integrity stressors

As reported by H. Kim et al.,³⁵ and the recent study of P. Jaureguiberry et al.,³⁶ land-use and climate change are recognised as two of the main drivers of future biodiversity change. Notably, land use being the most important driver of biodiversity loss can cause devastating effects on habitat availability and species extinctions, while climate change as projected, could drive extinction up to 16% due to expected warming.³⁷ Due to these interactions, biodiversity models use harmonized land-use and climate scenarios.³⁵

On this note, the method used here to quantify the change in biosphere integrity PB is based on Galán Martín et al.,³⁸ who computes the biodiversity footprint based on two stressors; direct land use and GHG emissions.³⁵ Galán Martín et al.³⁸ considered the characterisation factors in Hanafiah et al. ³⁹ for the two stressors and normalized them against the total available surface of the planet. Thus, direct

land use represents the global area required to compensate for the mean species abundance (MSA) loss caused by direct land use for man-made purposes. Moreover, GHG emissions on the biodiversity footprint represent the global area required to compensate for the MSA loss caused by fossil-based GHG emissions. The change in biodiversity calculated here represents the functional response of the ecosystems that are significant for humanity, which is calculated based on the mean species abundance (MSA) loss. The control variable used is the biosphere intactness index (% BII loss), proposed as an interim control variable, and similarly to MSA it measures the abundance of original species relative to the original abundance since the Holocene period.⁴⁰ The BII indicates the average abundance of a large and diverse set of organisms relative to their reference populations in a given geographical area.⁴⁰

Furthermore, Hanafiah et al. found that GHG emissions dominate versus direct land use in most systems except for ones that make use of biomass, energy, and agricultural products.³⁹ In our case, as presented in Figure 3c of the main manuscript, we see that combustion emissions take up a big portion of the impacts in BAU, coalDME, NGDME, DAC/Wind, coal/Wind, NG/Wind, BtDME, and BtDME CCS. Regarding the BtDME scenario, the domination of the "direct land use" stressor due to the biomass source was expected; however, this is not the case. The high GHG emissions are embedded in the "Other" category and come from the direct emissions of the biomass-to-methanol plant, taking up 62% of the scenarios' impacts. Therefore, when the direct emissions of the biomass-to-methanol plant are captured in the BtDME CCS scenario, it is evident from Figure S 10 that the "direct land use" stressor dominates in contrast to the BtDME scenario.

The hydrogen part is dominant in the DAC/BTH and DAC/BECCS scenarios. The high impacts from BTH and BECCS are caused by biomass growth associated with the "direct land use" stressor.

Figure S 10 of the ESI presents the percentage contributions of the two stressors in the total impacts for each scenario analysed.



Figure S 10: Contribution of the environmental stressors to the PBs of change of biosphere integrity.

6 Economic Assessment

This section includes a detailed explanation of the economic assessment performed in this work, as well as, the literature sources for the cost of raw materials.

Environmental inventories were mostly based on literature sources. Due to data gaps, we carried out a simplified economic assessment that omits in some cases the CAPEX expenditures, wherever this assumption is not expected to affect the economic estimates significantly. Notably, the economic assessment of the DME scenarios produced via CO₂ hydrogenation (DAC/Wind, DAC/BTH, DAC/BECCS, coal/Wind, NG/Wind) consider only the OPEX cost, since it was shown that the CAPEX often represents a small percentage of the total cost. In contrast, for the scenarios involving gasification in a bio-refinery (BtDME and BtDME CCS), the CAPEX term was also considered, since it has been found to represent as much as 50% of the total costs.⁴¹ Moreover, the cost of hydrogen from BTH taken from Parkinson et al. also considers the CAPEX.⁴² This choice was hence based on the observation that bio-refineries are capital-intensive while CCU-plants (DME produced via CO₂ hydrogenation) are not.⁴³⁻⁴⁵

We next provide the primary data used in the economic calculations, along with the economic results provided per MJ of fuel.

6.1 References

For the cost of conventional DME from coal and natural gas, and fossil diesel we used values from the internet. All the sources are listed in Table S 28.

.	Price (\$/kg)			
Products	min	average	Max	- Source
Hydrogen				
Biomass gasification with CCS	3.52	3.29	3.77	42
 Electrolytic hydrogen powered from Wind 	3.72	5.48	11.3	42
 Electrolytic hydrogen powered from BECCS 	8.38	11.0	13.2	38
Carbon dioxide				
Coal PP	0.04	0.05	0.06	14
Natural gas PP	0.05	0.09	0.12	14
Direct Air Capture	0.09	0.16	0.23	46
Heating (\$/kJ)	11.6	14.6	17.0	47
Electricity grid (\$/MWh)	50.0	65.5	81.0	48
Biomass (cotton straw)	0.04	0.07	0.10	49
CCS (\$2019/tCO ₂)	22	71	120	50
Conventional DME from coal (\$/kg)	-	0.47	-	51
Conventional DME from natural gas (\$/kg)	-	1.09	-	52
Fossil diesel (\$/kg)	-	1.57	-	53

Table S 28: Prices considered for the cost calculations of raw materials and utilities.

6.2 Additional results

In Figure S 9, the unitary cost of DME per MJ of fuel is presented.



Figure S 11: Cost of DME per MJ of fuel.

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