Energy Conversion and Management 372 (2027) 122422

Contents lists available at ScienceDirect

Energy Conversion and Management

journal homepage: www.elsevier.com/locate/enconman

Research Paper

Techno-economic and environmental investigation of Power-to-X at various greenfield and brownfield levels – A structured multi-level infrastructure access framework for PtX

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ARTICLE INFO

Keywords:
Power-to-X
Life cycle assessment
Techno-economic analyses
Greenfield
Brownfield

ABSTRACT

Existing infrastructure can have a significant impact on the production costs and emissions of Power-to-X (PtX) processes. This paper presents a new structured multi-level infrastructure access framework for PtX. The framework was applied to a techno-economic and environmental analysis of the production of ammonia, methanol, methane and kerosene in Chile, Germany and South Africa. Various infrastructural conditions were systematically examined, including grid connection, access to CO_2, N_2 and H_2 supply and existing synthesis plants. Chile achieved the lowest production costs and emissions due to the significant number of wind full-load hours. In contrast, production in South Africa is dominated by low electricity procurement costs from coal, resulting in high emissions. The impact of existing infrastructure can be so significant that PtX production can be more economical and have a lower global warming potential in locations that are less favourable for renewable energy. The largest cost reduction of 8–34% can be achieved through an additional grid connection. Switching from direct air capture to a site with CO_2 from biogas results in a 14–23% cost reduction. Notably, purchasing renewably produced hydrogen in Germany and Chile can offset the environmental drawbacks of grid electricity and lead to lower-emission production than a greenfield scenario based solely on wind and PV electricity. This creates an interesting scenario when comparing structurally weak sites in Chile with highly developed sites in Germany, where the production costs and emissions are very similar.

1. Introduction

Direct electrification is a beneficial approach for the transition of various sectors. Nevertheless, not all industries can be fully electrified [1]. The defossilisation of energy-intensive sectors such as aviation, shipping, and chemical production requires energy carriers beyond direct electrification. Power-to-X (PtX) pathways, including ammonia, methanol, synthetic methane, and Fischer-Tropsch-based products like kerosene (sustainable aviation fuel, SAF), have therefore emerged as key options for integrating renewable electricity into these hard-to-abate sectors [2]. Despite rapid technological progress in electrolysis, synthesis processes and carbon capture, the overall feasibility and competitiveness of PtX systems remain dependent on many factors.

One factor is the availability of critical infrastructure - such as access to renewable energy (RE), carbon and nitrogen supply, hydrogen sourcing options, and existing synthesis infrastructure. These factors can play a decisive role in determining both the economic viability and environmental performance of PtX value chains [3].

However, most existing studies either assume fixed system configurations or treat infrastructure availability in a binary manner, typically distinguishing between greenfield and one specific brownfield setup. In their review article on the environmental impacts of PtX systems, Koj et al. [4] demonstrate that the scientific community has placed a strong focus on Power-to-Gas and Power-to-Transport. Although greenfield and

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https://doi.org/10.1016/j.enconman.2026.122422
Received 12 August 2026; Received in revised form 4 November 2026; Accepted 16 November 2026
Available online 21 November 2026
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Open access funding enabled and organized by Projekt DEAL.

brownfield approaches are being implemented in some cases, they have not been systematically investigated. Of the PtX technologies examined, ammonia, methanol, methane, and SAF appear repeatedly. These have already been studied individually to varying degrees.

Goffart De Roeck et al. [5] examined the environmental differences between chemical and biological methanation. They noted that only minor differences could be identified between the two technologies. Nevertheless, biological methanation can offer certain benefits over chemical methanation, particularly in brownfield applications, since the necessary feed gases require less purification [6,7]. Biological methanation has already been studied from both techno-economic [8] and ecological [9,10] perspective. Minardi et al. [11] conducted a techno-economic and ecological analysis of a brownfield system consisting of a wastewater treatment plant (WWTP) and chemical methanation.

The techno-economic and environmental aspects of producing sustainable methanol using CO_2 from a direct air capture (DAC) were evaluated by Sollai et al. [12] and Badger et al. [13], respectively. The latter considered various electricity sources for the system. Pratschner et al. [14,15] presented an innovative process for producing methanol from biomass and conducted a techno-economic analysis (TEA) which estimated that production costs would be 44% higher than the price of methanol in Germany. Sankaran [16] conducted a TEA of a brownfield approach with scenario variations, examining the production of methanol from industrial exhaust gases.

In the field of ammonia production, Cameli et al. [17] conducted a TEA of a greenfield approach consisting of green hydrogen and an air separation unit (ASU) coupled with the Haber-Bosch process. In addition to a TEA, Mayer et al. [18] performed a LCA and examined green and blue ammonia production. Sabra et al. [19] addressed various gradations between green and blue ammonia, although existing infrastructure played no explicit role in either case. Musa et al. [20] present an approach in retrofitting existing ammonia plants.

Rojas-Michaga et al. [21] conducted a TEA and LCA of SAF production. The system comprises a DAC, an offshore wind farm, an alkaline electrolyser and a refinery plant incorporating a reverse water-gas shift coupled with a Fischer-Tropsch reactor. Brandt et al. [22] examined a brownfield approach in which biogenic-based SAF is produced in combination with pulp and paper facilities and conducted a comparison of repurposed facilities with greenfield. In addition, Uddin and Wang [23] compiled numerous publications on SAF production in a review article. Identified research gaps include the lack of analysis of hourly energy supply fluctuations and under-explored system dependencies, such as DAC capital costs.

Overall, most publications in the field of PtX focus on greenfield approaches, even though the barrier for investment decisions may be lower in brownfield projects [24]. Studies that take the use of existing infrastructure into account are based on specific use cases. Such simplification limits the ability to systematically evaluate the impact of stepwise changes in infrastructure accessibility on cost structures and life cycle emissions of PtX products.

To address this research gap, this study introduces a structured multi-level infrastructure access framework for PtX systems, enabling a stepwise hierarchy of key resource and technology constraints in five reasonable levels. Rather than relying on binary greenfield or brownfield assumptions, the proposed approach defines a hierarchy of system increments that explicitly represent increasing levels of infrastructure accessibility. These levels range from fully isolated greenfield systems to systems with access to external electricity supply, biogenic CO_2 or nitrogen sources, market-based green hydrogen procurement, and finally the availability of existing synthesis infrastructure (methanation, methanol synthesis, Haber-Bosch and Fischer-Tropsch reactors).

We implemented this approach using a coupled modelling method comprising the open energy system modelling framework oemof [25,26] for techno-economic optimisation, and openLCA for environmental impact assessment. The linkage between the two modelling layers enables a harmonised evaluation of system costs and greenhouse gas emissions based on identical structural conditions. We applied this methodological framework to exemplary PtX products (ammonia, methanol, methane, and SAF) and to representative locations in Chile, Germany, and South Africa. This covers a broad spectrum of renewable resource availability, infrastructure conditions, and regional energy system characteristics.

The results provide a comparative assessment of PtX cost structures and life cycle emissions at different levels of infrastructure accessibility and in different geographic contexts. Our study highlights the extent to which infrastructure availability influences the feasibility and sustainability of PtX pathways, and it quantifies to what extent the individual infrastructure options can be assessed independently of one another.

While further location-specific factors such as transport logistics, water availability, port access, grid capacity, land use and regulatory requirements also play a decisive role in real-world site selection and are not explicitly modelled here, the proposed framework offers a systematic basis for comparing the techno-economic and environmental effects of staged infrastructure access that can complement such site-specific assessments.

2. Materials and Methods

To determine the impact of infrastructure on PtX production costs and emissions, we introduce a transferable framework consisting of various levels between greenfield and brownfield sites (Section 2.1). These levels are examined using example sites in Chile, Germany, and South Africa, for which the selection criteria and local conditions for photovoltaic (PV) and wind power are outlined (Section 2.2). Levels and time series for PV and wind power are then implemented in oemof in combination with technology-specific data for ammonia, methanol, methane, and SAF value chains. This enables optimisation of plant sizing and calculation of production costs (Section 2.3). The specific plant dimensions are then transferred to openLCA, where LCA models are constructed to determine the environmental impact of PtX production (Section 2.4).

2.1. Greenfield - Brownfield Levels

A greenfield site is defined as an area lacking any existing infrastructure [27]. By contrast, a brownfield site refers to an area that has already been used for other purposes and may therefore offer infrastructure that could be reused [28]. In practice, brownfield sites can vary considerably, ranging from decommissioned industrial facilities to fully operational industrial complexes. For PtX production, factors such as access to the power grid, feedstock supply, and the availability of reactors are particularly relevant. To systematically evaluate the influence of existing infrastructure on PtX deployment, we defined five infrastructure levels to represent realistic stages between greenfield and highly integrated brownfield sites:

1. Greenfield site
2. Level 1 + grid connection
3. Level 2 + access to CO_2 or N_2 supply
4. Level 3 + access to H_2 supply
5. Level 4 + existing synthesis step

The sequence of levels is cumulative, progressing from greenfield, through the grid connection and the supply of reactants, to complete syntheses.

To produce PtX products, a Level 1 site would require RE sources, such as wind and PV systems, CO_2 via DAC or N_2 via an ASU, and hydrogen from a newly built electrolyser (shown in Fig. 1a). A new plant would also need to be installed for the final synthesis. At a Level 2 site, electricity can also be obtained from the grid, although expansion of wind and solar power remains possible. At Level 3, it is additionally possible to source CO_2 from a biogas plant, or purchase N_2, depending

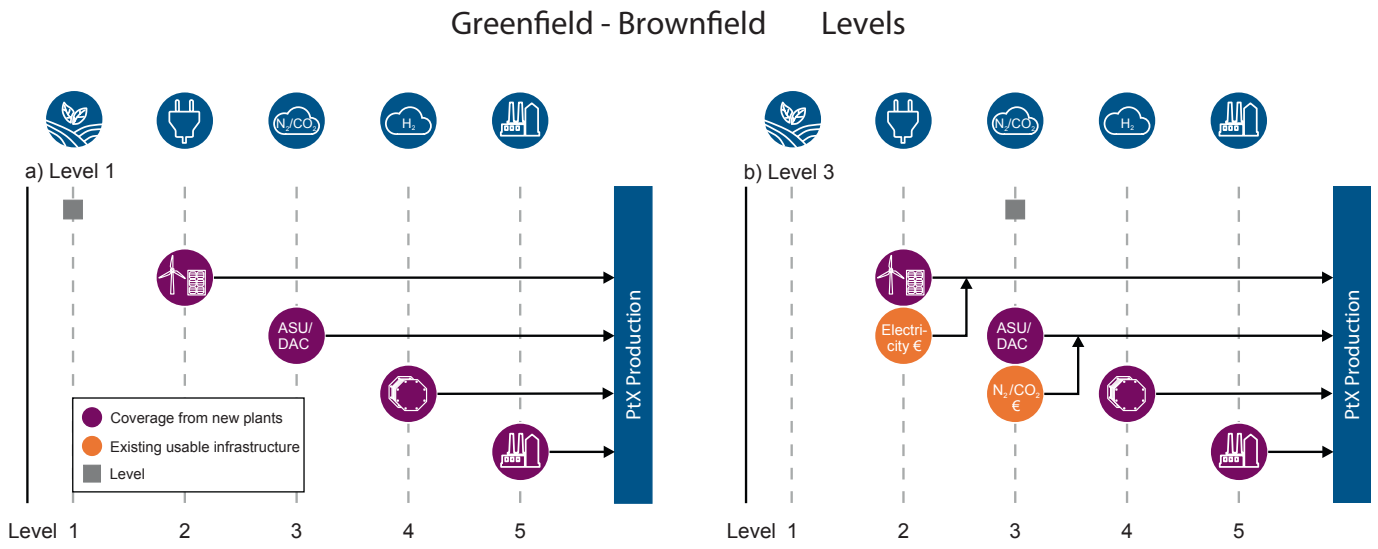


Fig. 1. Illustration of the greenfield-brownfield spectrum. a) shows a Level 1 site, where all necessary facilities must be newly constructed. b) shows a Level 3 site, where electricity and either N_2 or CO_2 can be sourced externally depending on the selected PtX pathway.

on the selected PtX pathway (shown in Fig. 1b). At Level 4, hydrogen can be supplied both by a newly built electrolyser and through market-based procurement. At Level 5, it is assumed that the necessary production reactors are available.

This cumulative order reflects a dependency commonly observed at real industrial sites: an operating synthesis process is highly likely to already have secured the feedstock and utility access required to run it, and feedstock-specific supply (CO_2/N_2) in turn typically presupposes basic grid access, since establishing dedicated feedstock infrastructure is usually a more specialised step than securing a grid connection. Alternative sequences remain conceivable at individual sites - for instance, an existing, originally fossil-fed synthesis plant repurposed for PtX production would already possess Level 5 infrastructure (an operating synthesis reactor) and plausibly also grid access (Level 2) but may lack the biogenic CO_2/N_2 and green hydrogen supply chains specifically assumed at Levels 3 and 4, since its original feedstock (e.g., natural-gas-derived syngas) typically differs from these pathways. Our modelling approach remains applicable in such cases, provided the set of infrastructure options assumed already available is adapted to the site's actual starting point.

2.2. Locations and Time Series

There are numerous potential sites for PtX production. As part of the Kopernikus P2X-III project, an interdisciplinary consortium identified relevant sites and made a selection based on technical, economic, social and political considerations [29]. Three of those locations were selected for this work:

- Patagonia (Chile)
- Industrial park Frankfurt-Höchst (Germany)
- Gqeberha (South Africa)

Patagonia was selected because of its high wind full load hours (FLH), which offer considerable potential for generating low-cost electricity and subsequently PtX products [30].

The industrial park in Frankfurt-Höchst was selected because it is a well-fitting brownfield site, as necessary infrastructure like energy and media supply are already in place. Hydrogen can be obtained locally from chlor-alkali electrolysis, CO_2 from a WWTP and nitrogen from the industrial park operator [31].

Gqeberha has high wind and PV FLH. In addition, the selected location is close to the port of Ngqura, which is advantageous for potential exports of PtX products. The site has already been selected for a real-world project by Hive Hydrogen and Linde to produce green ammonia (780,000 t/year capacity planned) [32,33].

Level and location are crossed in a full factorial design, regardless of the actual equipment at site. The CO_2-source in Level 3 is biogas or sewage gas, which have similar and thus comparable parameters. Table 1 lists the selected sites and their respective FLH for PV and wind power plants with a hub height of 150 m. The corresponding profiles of the energy sources were taken from Pfenninger and Staffell [34] based on the methods in [35,36] and converted into annual load curves.

2.3. Techno-economic modelling

Oemof, which was presented in detail by Krien et al. [25] and Hilpert et al. [26], was used for TEA. This open-source tool was developed for modelling and analysing energy systems based on the widely used programming language Python. Oemof models were solved as a deterministic linear optimisation problem under perfect foresight. Fig. 2 illustrates the structure of oemof classes using ammonia production at a greenfield site (Level 1) as an example. All models are published on GitHub [37].

As the law of conservation of energy applies to the buses, sinks must be installed at various points. The electric bus has an implemented sink, which correspond to curtailing RE. Hydrogen can be sold within the system at a price of 1.50 €/kg, based on the price of comparable fossil fuel products [38,39].

No sinks were integrated for the nitrogen or CO_2 bus, since these are used entirely within the system as feed gas. A heat sink was integrated for excess heat. However, due to the significant infrastructure requirements for a potential sale of the heat, it was implemented without a sale price. The by-product naphtha generated during Fischer-Tropsch synthesis is sold within the system at 550 €/t [40]. All revenue from

Table 1
Selected locations with resulting FLH for the respective energy source, FLH data taken from [34].

Country	Location	Latitude	Longitude	FLH PV	FLH Wind
DE: Germany	Höchst	50.085534	8.516610	1,289 h	3,365 h
ZA: South Africa	Gqeberha	-33.777298	25.692481	1,756 h	4,678 h
CL: Chile	Patagonia	-53.206663	-68.943440	1,095 h	6,537 h

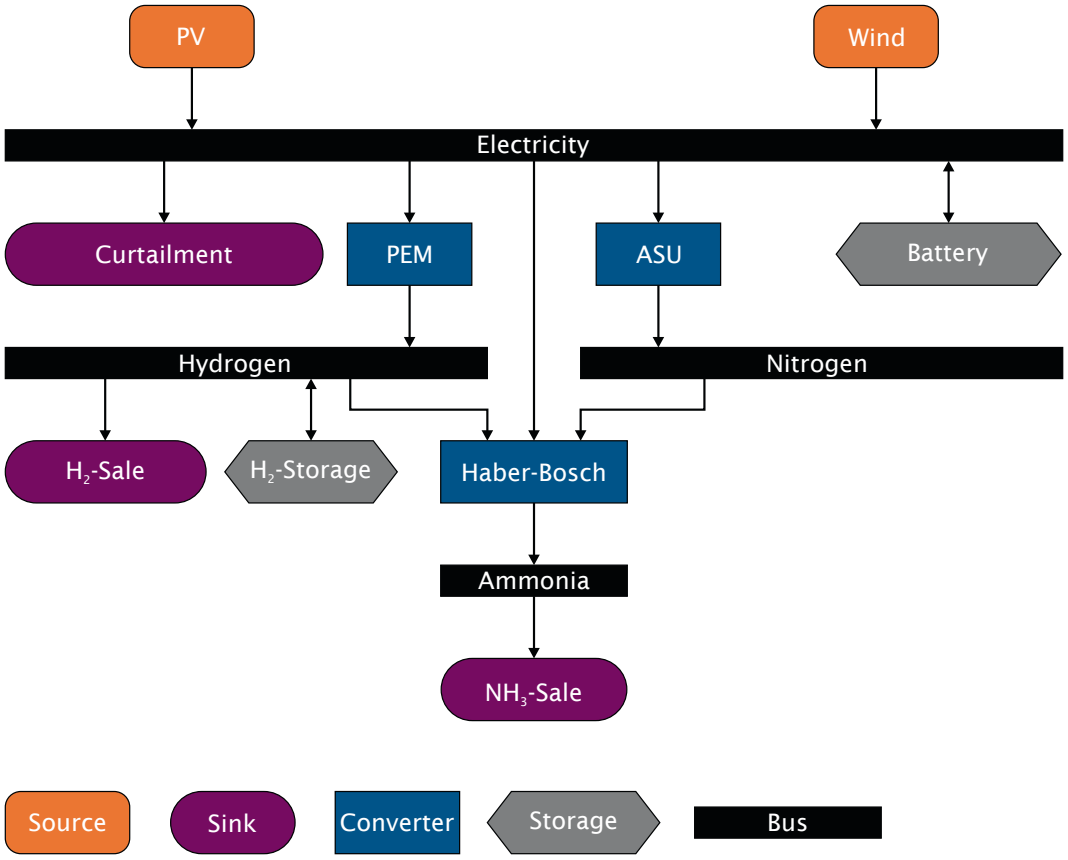


Fig. 2. Exemplary block diagram of ammonia production (greenfield – Level 1) as the basis for oemof modelling.

the sale of intermediate products was taken into account when calculating the levelised cost of PtX products (LCOP).

An annual production target of 2,500 t of PtX product was set, corresponding to INERATEC's ERA ONE e-Fuel pilot plant in Frankfurt-Höchst [41]. The size of the plants used in the final synthesis processes is therefore specified exogenously in all models. It is assumed that these plants operate continuously to maximise capacity utilisation, thereby boosting economic performance [15]. The sizing of other performance parameters and storage capacities, however, is optimised freely. The modelling runs on an hourly basis over the course of a whole year. Time series for PV and wind, as described in Section 2.2, are used as inputs. The Gurobi mixed integer linear programming solver was used for this optimisation with the aim of producing 2,500 t of PtX product in the most cost-effective way possible. This reflects a deliberate scope choice: we evaluate the environmental performance of economically optimal configurations, since these are the ones most likely to be implemented in practice, rather than searching for a theoretical environmentally optimal configuration that may not be economically viable.

In accordance with the levels defined in 2.1, five individual models were constructed for each location and product (60 models in total). The additional infrastructure requirements for stages 2-4 were implemented as sources, providing additional procurement options.

Electricity can be procured at the country-specific industrial electricity price (Germany: 16.99 €-ct/kWh [42,43], Chile 11.73 €-ct/kWh [44], South Africa 9.3 €-ct/kWh [45,46]). A time-of-use price is tested for South Africa in Section 3.4.2. Despite the relatively low purchase price of 0.2 €/kg [47] for nitrogen, on-site nitrogen production was more cost-effective in all scenarios examined. For green hydrogen, a uniform delivered purchase price of 5 €/kg [48,49] was implemented for all sites. As there is no established international hydrogen market and thus no country-specific price data, hydrogen is treated like the other traded commodities in the models (nitrogen purchase, hydrogen and naphtha sales), which are likewise priced uniformly across countries. This way, the results reflect the influence of infrastructure access rather than of country-specific hydrogen costs; the implications and limitations are discussed in Section 3.5. Hydrogen procurement is modelled as a source with a constant delivered price and no quantity limit, so availability enters the models as an assumption rather than as a constraint.

When considering the supply of CO_2, it was assumed that a sufficiently sized biogas plant was available. The CO_2 (40% of the plant's product gas [50,51]) is then separated from CH_4 using monoethanolamine (MEA) scrubbing, after which it can be fed into the PtX process. The construction and operation of the MEA are fully allocated to the PtX process. Biological methanation is a special case, as it can process the biogas directly and no MEA is required [52].

A notable exception is modelling of Level 5 with the existing final synthesis. Unlike Levels 2-4, no additional option for the construction of a new plant has been specified here. For Level 5, it is assumed that the necessary infrastructure for synthesis of PtX products is in place and has already been fully financed. Consequently, only the operating costs of the relevant reactors need to be covered. As retrofit costs have not been taken into account, the results therefore represent an upper limit on the potential savings of this level. An indicative retrofit cost case is discussed in Section 3.1. Fig. 3 shows a schematic representation of all the process components included in the models for PtX production, as well as the additional options for the greenfield-brownfield levels.

Another difference between the examined scenarios derives from the selected countries and their associated investment risk. When calculating the Weighted Average Cost of Capital (WACC), the country-specific investment risks in Germany, Chile and South Africa were considered based on data from Damodaran [53]. This results in country- and technology-specific WACCs, which are integrated into oemof models. The exact WACC calculation can be found in the corresponding Zenodo dataset in the 'WACC' worksheet [54].

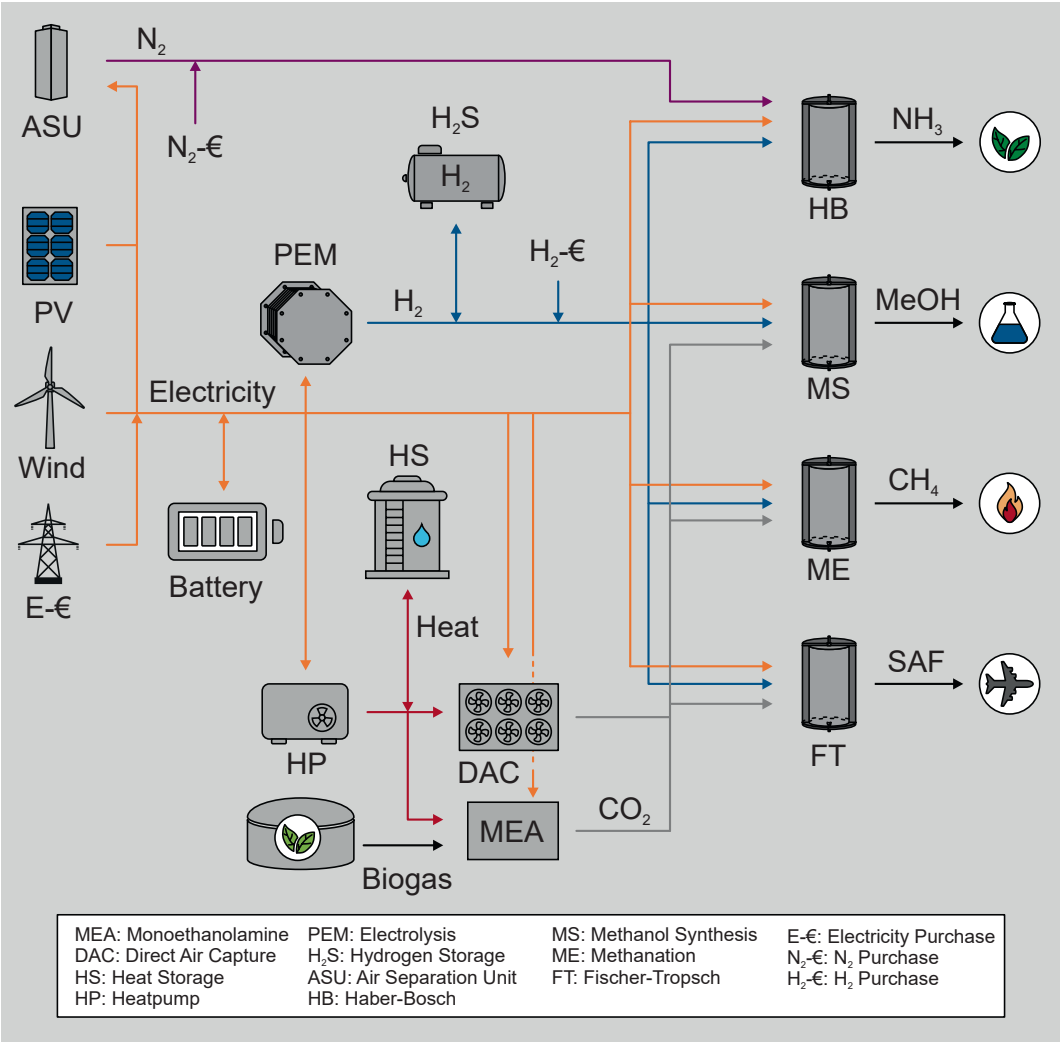


Fig. 3. Overview of the process components included in the models for PtX production.

All other necessary modelling data, such as CAPEX, OPEX, efficiencies and lifetimes of the technologies are consistent across the models and are therefore not discussed in further detail here. The data used and the corresponding sources can be found in the Zenodo dataset under the 'oemof_data' worksheet. The optimised plant dimensions are generated based on the specified time series and selected data. LCOP are then determined, with capital expenditure allocated using the annuity method [30].

To assess the robustness of the results against uncertain input data, five parameters were varied one at a time between a lower and an upper bound: the CAPEX of PEM electrolysis (1,000-3,000 €/kW) and onshore wind (800-1,600 €/kW), the electricity price (±30%), the hydrogen purchase price (3-8 €/kg) and the WACC (±2 percentage points for all technologies). The variations were carried out for methanol at the three sites and Levels 1-4, and the model was re-optimised for each variation so that the plant design adapts to the changed parameter. Each parameter was varied at all levels where it is relevant (electricity price from Level 2, hydrogen price at Level 4). This allows the cost reduction of each infrastructure level to be recalculated with identical parameter values at both levels. Level 5 differs from Level 4 only by the annuity of the existing synthesis and was therefore not varied separately. The results refer to the LCOP; bounds, sources and results are provided in the Zenodo dataset (worksheets 'Tornado_parameter' and 'Tornado_results').

2.4. Life Cycle Analysis

Life cycle analysis (LCA) carried out in this work is based on the standards ISO 14040/14044 [55,56]. The ReCiPe method (Midpoint (H) V1.13) was selected as the life cycle impact assessment method [57,58]. It is used in many publications with PtX context, such as Otero et al. [59], Motevali et al. [60] and Sabra et al. [19]. We selected midpoint indicators, as they enable a more targeted analysis of the ecological impact than endpoint indicators. This paper focuses on the global warming potential (GWP). The results for the other indicators can be found in the Zenodo dataset in Worksheet 'Results_LCA'.

The system boundaries were defined as a cradle-to-gate approach. For the inputs and outputs to the system boundaries, cut-off processes of the life cycle inventory (LCI) database ecoinvent were used [61]. The allocation of emissions to products and by-products was carried out on a physical basis. This choice follows the ISO 14044 allocation hierarchy, which recommends avoiding economic allocation where a physical relationship between inputs and outputs can be established. It is independent of the market-price-based treatment of by-product revenues in the techno-economic analysis (Section 2.3), which serves a different purpose (cost accounting rather than burden distribution).

As far as possible global market processes were used for the construction effort of the system components. Country-specific processes were used for the electricity production upstream chains. As there is no country-specific process for electricity generation from PV in Chile, the

corresponding process from Argentina was used. Global processes were used for the biofuel and PV components of the South African electricity mix, since there are no country-specific alternatives here. The production of 1 t of PtX product was used as functional unit in all models. The investigations were carried out with the software openLCA 2.5.0 and the database ecoinvent 3.12.

The dimensioning of the technologies as well as the specific energy and material flows are based on our oemof results and have been integrated into openLCA. This ensures that construction efforts and operational data are both taken into account in the LCA in a manner consistent with the TEA assumptions and results.

For grid procurement, the country-specific annual-average composition of the electricity was replicated. For CO_2 procurement in Level 3, it was assumed that CO_2 itself was burden-free. Any associated emissions stem solely from the construction and operation of the necessary MEA scrubbing, as, in our case, it was installed solely for CO_2 capture. This treatment follows directly from the cut-off system model applied consistently throughout our life cycle inventory: under this convention, the burden of producing a co-product or waste-derived stream remains with the originating process, and only the effort required to make the stream usable is allocated to the receiving system.

For the procurement of green hydrogen in Level 4, it was assumed that it is produced near the selected site via Proton Exchange Membrane (PEM) electrolysis (50 kWh/kg H_2, 4,000 full-load hours [62], including the construction of the electrolyser) and delivered to the plant. Potentially required transport and compression were neglected, as even compression to 350 bar requires only about 2 kWh/kg H_2, i.e. less than 5% of the electrolysis demand [63]. The electricity is supplied by renewable generation technologies of the national electricity mix in their respective proportions (inventory in the Zenodo dataset, worksheet 'LCA_assumptions_H2 purchase'). To assess this assumption, we additionally calculated a case in which hydrogen is produced with the full national electricity mix used for grid procurement (Section 3.2). The GWP of the purchased hydrogen then increases from 3.7 to 21.1 kg CO_2-eq/kg H_2 in Germany and from 1.3 to 15.9 kg CO_2-eq/kg H_2 in Chile. For SAF, the resulting additional burden is allocated between SAF and naphtha on a mass basis (70.9% and 29.1%). South Africa is not affected, as no hydrogen is purchased in the South African models (Section 3.1).

The LCI, including the processes used in ecoinvent and data sources, can be found in the Zenodo dataset in the 'LCI' worksheets for each technology. As demonstrated in Heberl et al. [64], scaling effects have a small impact on the necessary construction work and the associated PtX emissions. Therefore, these effects were not considered in this study.

3. Results and discussion

As the aim of the optimisation in oemof is the cost-effective production of PtX products, the technical and economic results are

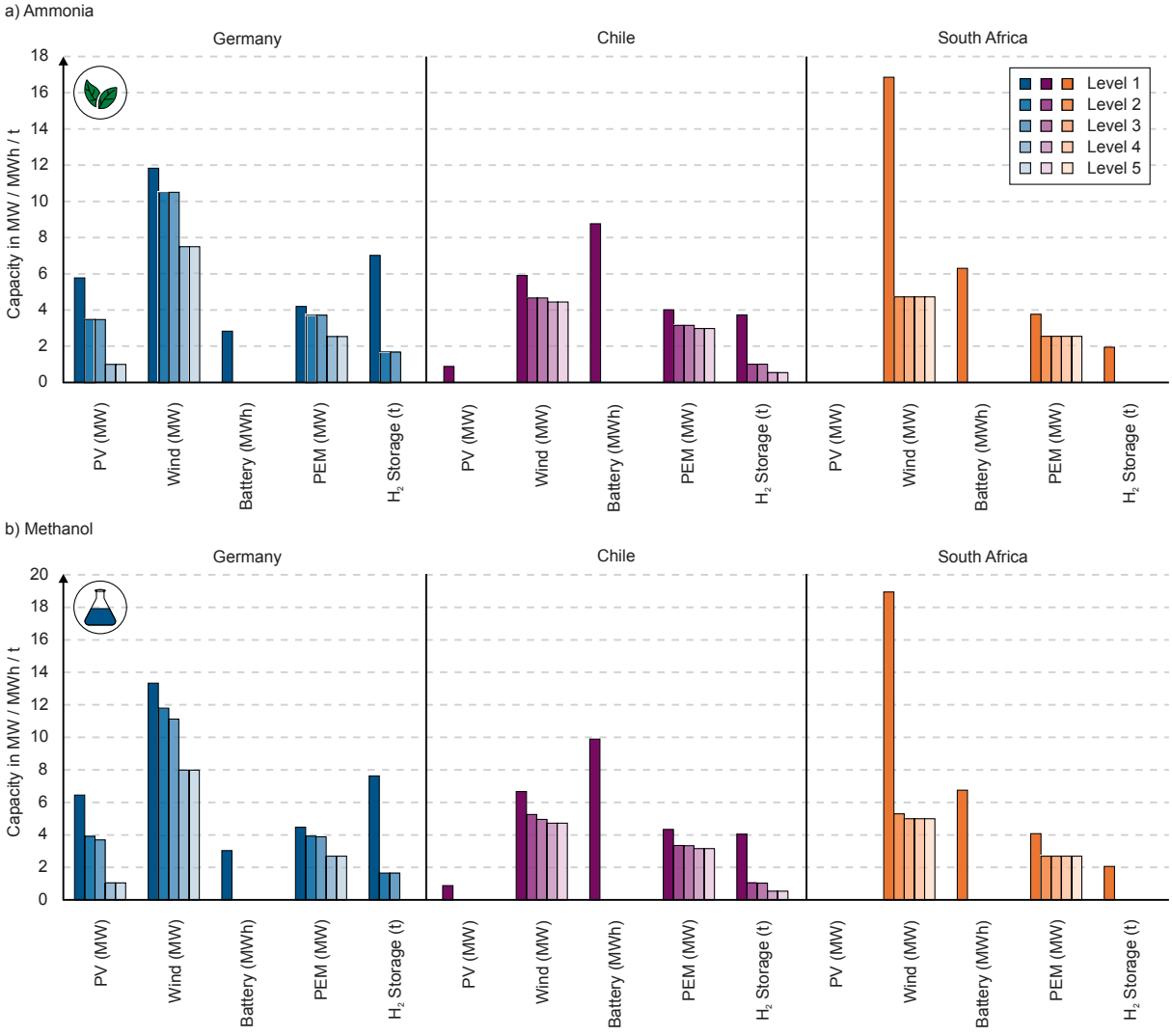


Fig. 4. Overview of installed capacities of the key components of a) ammonia and b) methanol production at the sites and levels examined.

discussed together in section 3.1, followed by the environmental results of the LCA in section 3.2. The GWP is then considered in relation to the resulting LCOP (section 3.3). We then assess the robustness of key modelling assumptions in a sensitivity analysis (section 3.4). Finally, we outline the limitations of our work (section 3.5). All results can also be found in the Zenodo dataset under 'Results_oemof' and 'Results_LCA".

3.1. Techno-economic results and discussion

Fig. 4 shows the optimised plant dimensions for producing ammonia and methanol at the three investigated sites. These cover PV, wind, electrolysis, battery and H_2 storage components. The capacities of DAC/MEA and ASU are effectively fixed due to the external specification of the final synthesis capacity and the absence of CO_2/N_2 storage. While the size of the heat pump is variable due to existing heat storage, this is only required for DAC/MEA. The resulting capacities are therefore very low and not included in Fig. 4.

Ammonia and methanol show similar capacity requirements at a single site: 5.8 MW PV / 11.8 MW wind for ammonia (Germany, Level 1), versus 6.5 MW PV / 13.3 MW wind for methanol. Kerosene requires substantially more - 20.6 MW PV / 42.0 MW wind - due to higher energy content of the final product and lower system efficiency.

There is a significant difference between carbon-based products and ammonia at levels 2 and 3 (see Fig. 4 a), as there are no changes for ammonia production as sourcing nitrogen externally (for 0.2 €/kg N_2) is not selected in any scenario due to the lower cost of in-house production via ASU (production costs of 0.04-0.06 €/kg N_2). For carbon-based products, switching from DAC to CO_2 from biogas offers the advantage of smaller plant sizes (see Fig. 4 b). As soon as this option becomes available, it is selected in all models instead of DAC.

However, if a distinction is made between locations within a single product, country-specific differences in the FLH of RE sources and the WACC result in greater variations. In Patagonia, for instance, the high number of full-load hours means that only 5.9 MW of wind and 0.9 MW of PV capacity are required for ammonia production at Level 1. It is interesting to note that in Chile, it is more cost-effective to build a large 8.8 MWh battery (compared to 2.8 MWh in Germany) than to cover the required electricity through additional PV capacity. Contrary to expectations, no PV capacity is being expanded in South Africa; instead, there is a significant overbuilding of wind power with 16.8 MW due to the assumptions on the continuous plant operation. This is also reflected in the necessary curtailment of RE at 44.9 GWh, which, by contrast, is at a significantly lower level in Germany (9.4 GWh) and Chile (4.3 GWh). The reason for this is the comparatively high levelised cost of electricity (LCOE) for PV. While the combination of wind and battery in South Africa results in a Level 1 LCOE of 7.7 €-ct/kWh, the lowest LCOE for PV in all examined scenarios is also 7.7 €-ct/kWh in Germany. Considering the higher WACCs in combination with high wind FLH in South Africa, electricity from PV is not competitive there.

It is noteworthy that there have been no changes in South Africa from Level 2 (ammonia) and level 3 (carbon-based products) onwards. As electricity purchase is very cheap there, any potential for optimisation has already been realised. The only remaining impact on the dimensions is the switch from DAC to MEA. No further battery or hydrogen storage systems are being built there.

Batteries are generally phased out of the systems at all sites with the option of grid connection from Level 2 onwards. The situation is different for H_2 storage. In Germany, it is required up to the point where an external H_2 supply becomes an option. In Chile, operating at least a small H_2 storage facility with a capacity of 0.55 t H_2 is most cost-effective up to Level 5. The electrolysis systems are comparable in size at all levels.

Fig. 5 shows LCOP for all analysed scenarios by product and location. Comparable trends can be seen for all products across the different stages.

Remarkably, the LCOP in Level 1 is highest in South Africa. The lack of infrastructure requires significant investment in the construction of plants, thus leading to higher LCOP in South Africa due to the increased investment risk in South Africa. As soon as electricity can be obtained from the grid at Level 2, the LCOP in South Africa decreases by 32-34%,

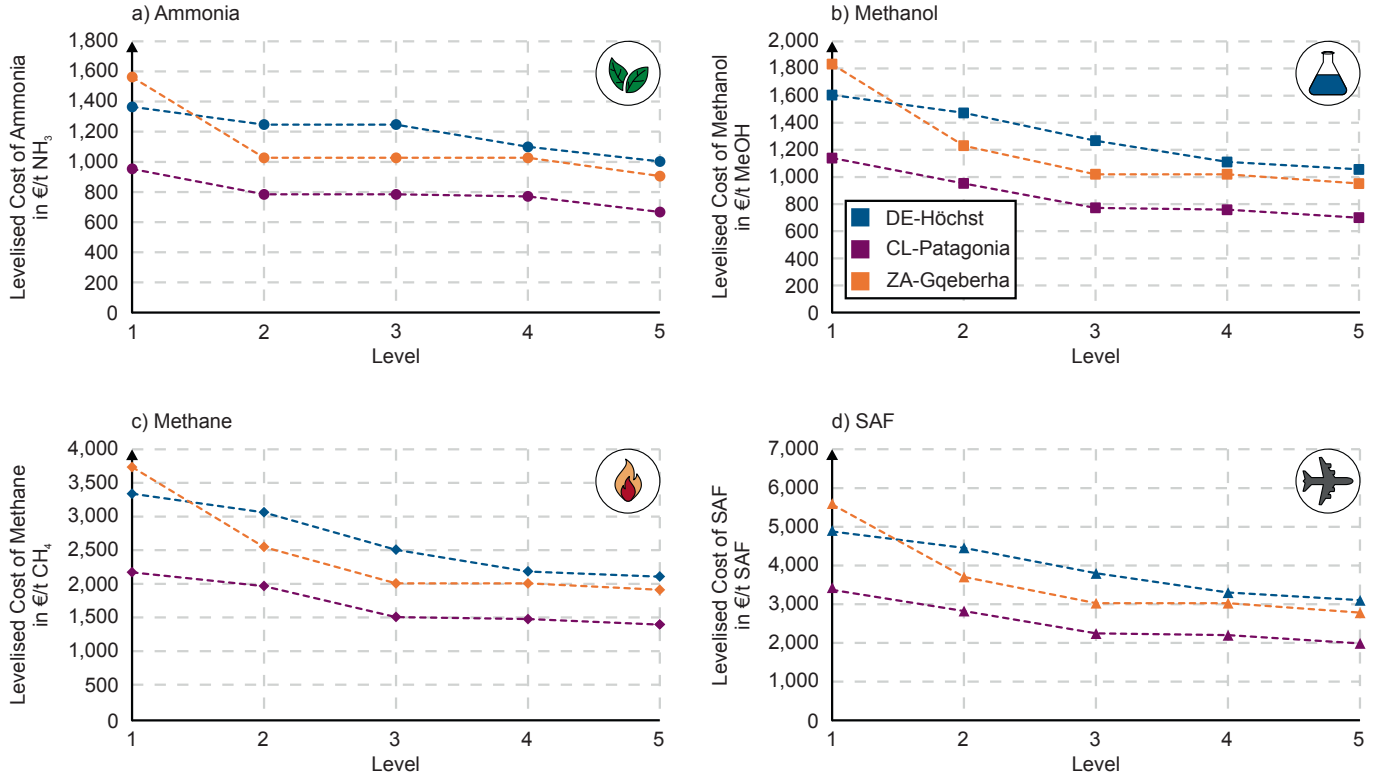


Fig. 5. LCOP broken down by PtX products, locations, and greenfield-brownfield levels.

which is the greatest cost reduction at any level. The reduction in Chile and Germany ranges from 8-18% at this level. From Level 2 onwards, the German site generates the highest LCOP due to the lower FLH of RE. The Chilean site, on the other hand, has the lowest LCOP at every stage. Its high wind FLH, combined with the comparatively low investment risk, results in the lowest LCOE of all the sites examined: 2.3-3.2 €-ct/kWh. LCOE are decisive for the entire production chain and consequently lead to the lowest LCOP.

Once again, there are no differences between Levels 2 and 3 in the case of ammonia. However, significant cost savings of 14-23% compared to Level 2 can be achieved by switching from DAC to MEA for the other products.

The impact of hydrogen procurement depends heavily on local conditions, the assumed hydrogen price (Section 3.4.4) and, consequently, on industrial electricity prices. While the cost of production in Germany can be reduced by 12-13% through H_2 procurement, in Chile this has a minimal impact of just 2%. An extreme example is South Africa, where it is cheaper to purchase grid electricity to power the newly built electrolysis plant, which is why no hydrogen is purchased there, and thus no change can be seen from Level 3 to 4.

Level 5 has a positive impact of 4-10% on the LCOP for carbon-based pathways and 9-13% for ammonia under the ideal assumption of no additional retrofit costs. Assuming retrofit costs of 10% of the new-build CAPEX of the synthesis unit, which is the upper end of the 5-10% estimated by Mingolla et al. [63] for the modifications needed to operate an existing ammonia plant with electrolytic hydrogen, these benefits decrease to 3-9% and 8-12%. As there are no technology-specific estimates available for methanol synthesis, methanation or Fischer-Tropsch processes, the same share was applied to all synthesis units. The Level 5 benefit declines proportionally with this share. At 25% of the new-build CAPEX, it amounts to 3-7% for carbon-based pathways and 7-10% for ammonia. At 50%, it amounts to 2-5% and 4-7%, respectively. The benefit would only be eliminated if the retrofit cost reached the synthesis unit's full new-build CAPEX (see Zenodo dataset, worksheet 'Retrofit Costs').

Overall, the LCOP can be significantly reduced by utilising existing infrastructure. For ammonia, LCOA fall from 953-1,563 €/t NH_3 to 667-1,003 €/t NH_3, representing an overall cost reduction of 27-42%. For carbon-based products such as methanol (1,140-1,832 to 701-1,056 €/t MeOH), methane (2,171-3,735 to 1,394-2,106 €/t CH_4) and SAF (3,365-5,578 to 1,985-3,096 €/t SAF), the LCOPs can even be reduced by 34-50%.

To assess the competitiveness of LCOP, market prices for fossil-based alternatives can be used as a benchmark. However, when making this comparison, it is important to bear in mind that the pure production costs calculated represent a lower limit. This is because additional costs for transport, taxes and trade margins must also be considered. In 2025, the price of ammonia in Europe ranged from 470 to 610 €/t NH_3 [65], whilst the price of methanol ranged from 535 to 700 €/t MeOH [66]. The modelled production costs for the corresponding PtX products are, on average, considerably higher than these fossil-based benchmarks (approximately 30-65% for ammonia and 31-51% for methanol). Notably, however, at our most favourable site (Chile), the modelled Level 5 LCOP already approaches the upper end of the current fossil price range (667 €/t NH_3 vs. 470-610 €/t NH_3; 701 €/t MeOH vs. 535-700 €/t MeOH), illustrating that specific location-product combinations can already be near cost-competitive with fossil alternatives today. According to the European Commission, the average price of methane in 2025 was 500 €/t CH_4 [67], whilst the price range for kerosene was 560 to 690 €/t [68]. For these two products, the discrepancy between the current situation and our modelled sustainable routes remains substantial. However, as the cost of fossil fuels is heavily dependent on political crises and current regulatory discourse, such as the future trajectory of the carbon price, the situation could develop in any direction.

3.2. Ecological results and discussion

Like the LCOP presentation in Fig. 5, Fig. 6 shows the resulting GWP by country, product, and level. At Level 1, the GWP is very similar in Germany and South Africa across all products (e. g. 0.68 t CO_2-eq/t NH_3 in Germany vs. 0.65 t CO_2-eq/t NH_3 in South Africa), while Chile has the lowest emissions in each case (0.38 t CO_2-eq/t NH_3). This is primarily due to emissions from the upstream electricity generation chain. While wind power in Chile amounts to 0.025 kg CO_2-eq/kWh, in South Africa it stands at 0.052 kg CO_2-eq/kWh. Although wind power in Germany achieves values between the other two countries at 0.033 kg CO_2-eq/kWh, the significant share of PV power at the German site, which has considerably higher emissions at 0.101 kg CO_2-eq/kWh, means that average emissions rise to merits comparable to those in South Africa. The required size of the hydrogen storage is also a factor. As Fig. 4 shows, Germany requires a significantly larger storage capacity, particularly at Level 1. In the case of ammonia production, this accounts for 21% of total emissions.

From Level 2 onwards, the gap between Chile/Germany and South Africa increases significantly. The prevalence of electricity purchases in South Africa has enormous consequences for the GWP, as the electricity mix consists of over 80% coal-fired power [69]. The GWP increases to around six times that of Level 1 up to 4.09 t CO_2-eq/t NH_3. From an emissions perspective, such a system in international comparison is not viable, given that the GWP of fossil-based ammonia production is 2.4 t CO_2-eq/t NH_3 [70]. In Chile and Germany, electricity procurement from the grid also leads to an increase in the GWP. However, due to significantly higher shares of RE (71% in Chile and 62% in Germany [71,72]), this increase is limited to around 30%.

There are hardly any further changes in South Africa from Level 2 onwards. For ammonia production, emissions remain at the same level; for carbon-based products, a small reduction can be achieved by switching to MEA at Level 3, before emissions remain constant.

On the other hand, for Germany and Chile, the impacts of the various greenfield-brownfield levels are comparable. Switching to MEA for carbon-based products reduces GWP for all products by 7-13% in both countries. The hydrogen procurement option has the greatest positive impact with a GWP reduction of 35-38% compared to Level 3. Procuring green hydrogen enables the energy system to be designed more efficiently, resulting in smaller wind, PV and electrolysis capacities, as well as lower H_2 storage capacities (see Fig. 4). Additionally, the amount of electricity purchased is reduced. Notably, the advantage of procuring green hydrogen from national renewable power is substantial enough to offset grid electricity purchases in both countries, leading to GWPs that are lower than those of the Level 1 Greenfield scenario (0.32 instead of 0.38 t CO_2-eq/t NH_3 in Chile and 0.57 instead of 0.68 t CO_2-eq/t NH_3 in Germany).

This result assumes that the purchased hydrogen is produced using only renewable electricity (see Section 2.4), whereas the on-site electrolysis at Levels 2-4 is partly supplied by the full national grid electricity mix. If the purchased hydrogen had also been produced using the full national mix, the GWP of Level 4 would have been 145-213% higher in Germany and 54-84% higher in Chile. In this case, purchasing hydrogen would no longer reduce the GWP compared with Level 3; in fact, it would clearly increase it in Germany. Therefore, the environmental benefit of Level 4 depends on the hydrogen being produced from renewable electricity.

Level 5 does not offer any additional environmental benefits. While companies can ultimately write off the financial cost of synthesis, meaning that only OPEX needs to be paid, construction efforts are usually spread over the entire lifetime of a plant. Therefore, based on our assumptions, there is no environmental difference between existing and newly built synthesis facilities.

Fig. 7 shows the breakdown of the GWP for methanol production in the countries studied. The GWP is divided into four components: hydrogen production via PEM; purchased hydrogen; CO_2 supply from

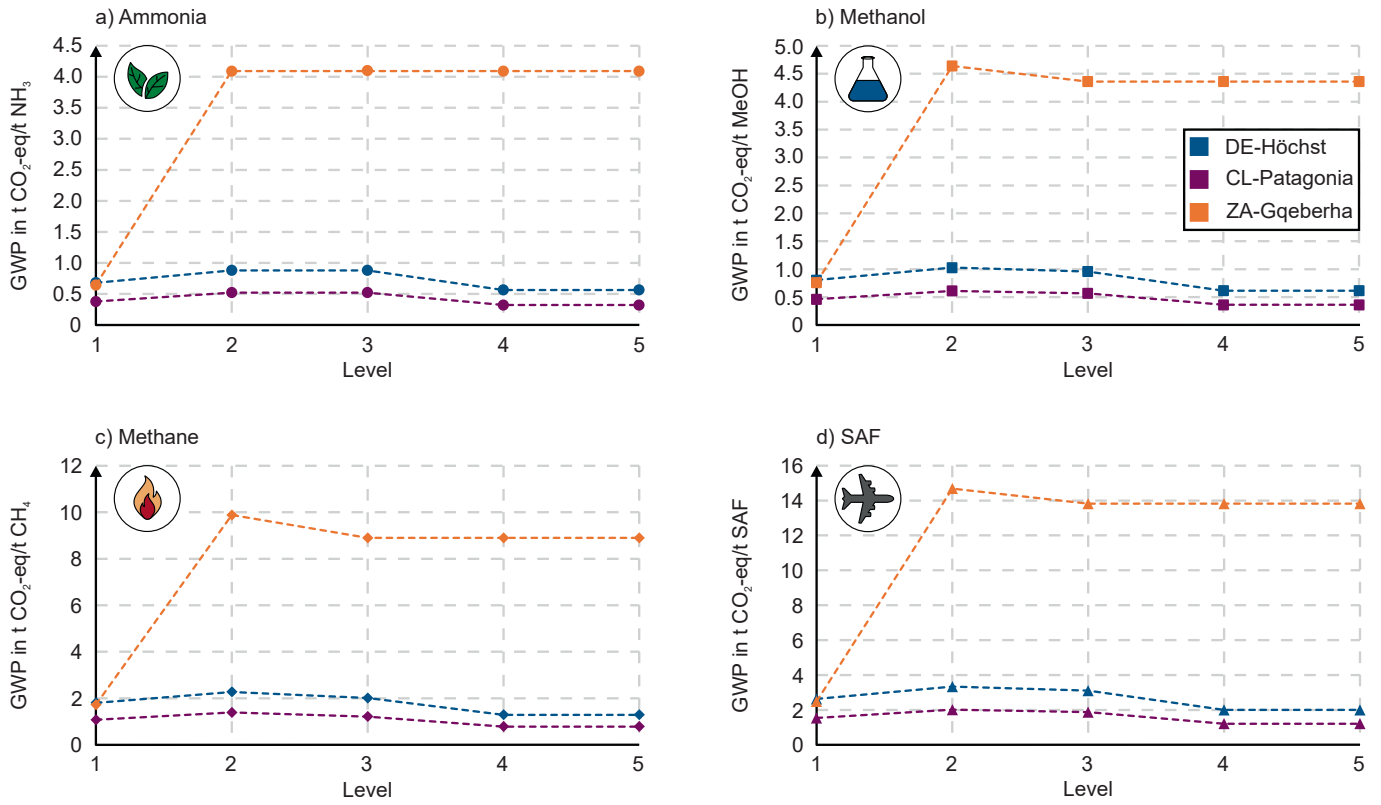


Fig. 6. GWP broken down by PtX products, locations, and greenfield-brownfield levels.

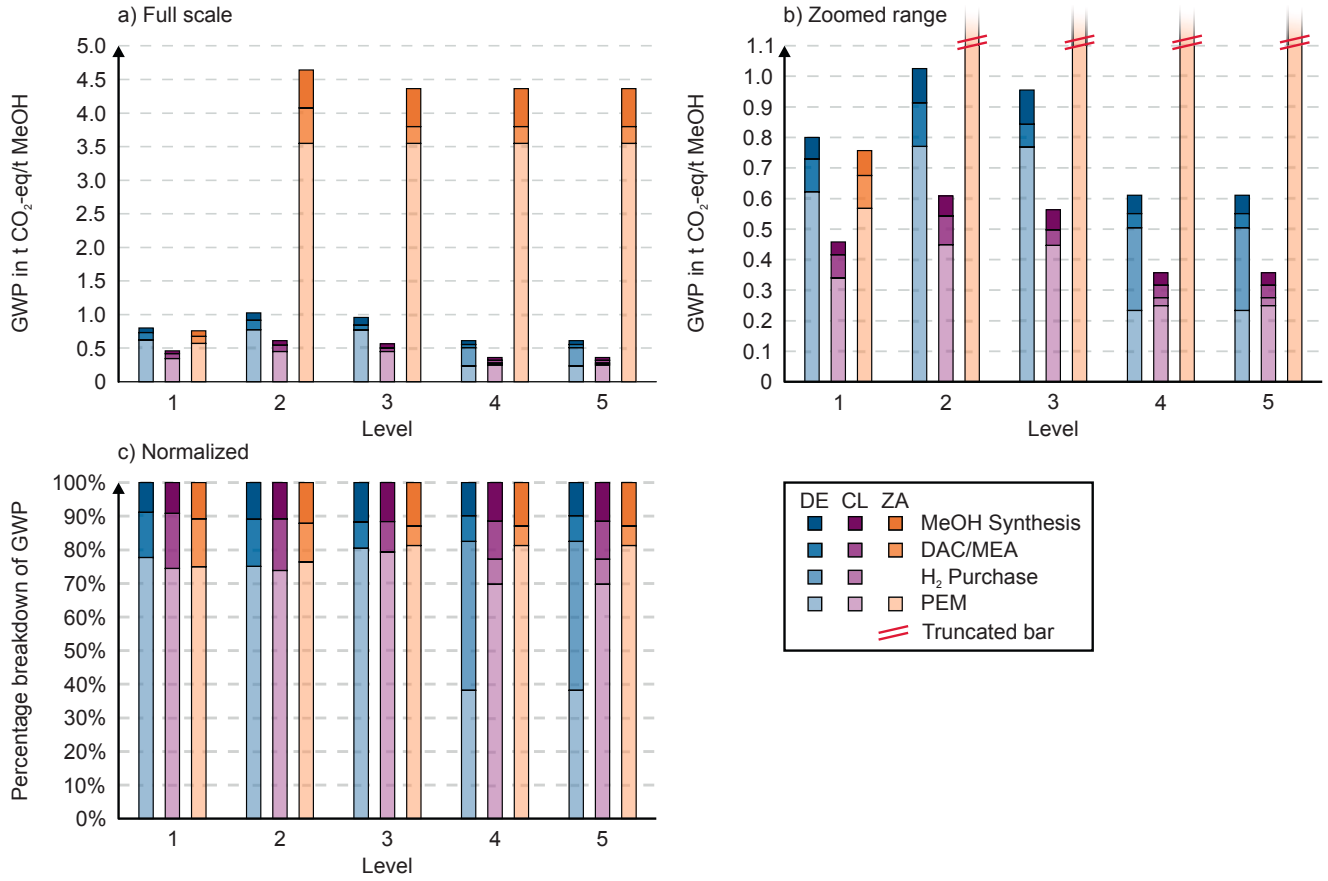


Fig. 7. Breakdown of the GWP across the components PEM, H_2 purchase, DAC/MEA and the synthesis stage in methanol production at a) Full scale, b) a zoomed-in section with truncated bars and c) a normalized diagram. As the H_2 Purchase is not used in South Africa, there is no corresponding bar.

DAC/MEA; and the synthesis process itself. These components contain the electricity demand required for each process step, as well as construction efforts including those for storage facilities. Once again, the significant influence of South Africa's electricity mix is immediately apparent (Fig. 7a). This effect is so strong that the comparatively low emissions from the synthesis step (0.08 t CO_2-eq/t MeOH at Level 1; Fig. 7b) rise to 0.56 t CO_2-eq/t MeOH at Level 2 (Fig. 7a), thereby exceeding the total emissions from methanol production in Chile. The contribution of DAC/MEA (max. 16%) and the synthesis process (max. 13%) to overall emissions is relatively low, accounting for no more than 26% of total emissions (Fig. 7c).

The main contributor to GWP is clearly hydrogen production accounting for up to 81% of total emissions. The construction effort of the PEM, for example in Germany at Level 1 with the highest electrolysis capacity among the methanol scenarios at 4.7 MW, has only a minor impact on total emissions, amounting to 0.01 t CO_2-eq/t MeOH. In contrast, the required H_2 storage system has an impact of 0.15 t CO_2-eq/t MeOH and the electricity generation process of 0.45 t CO_2-eq/t MeOH. The storage system is an exceptional case here, as in all other scenarios it is significantly smaller in scale, with a maximum GWP share of 0.07 t CO_2-eq/t MeOH.

The differences between Levels 3 and 4 in Germany and Chile are particularly interesting. Although the GWP decreases by a similar percentage in both countries (-36% in Germany and -37% in Chile), the composition of the emissions differs. H_2 procurement accounts for 44% of emissions in Germany but only 7% in Chile. This is partly because the volume purchased in Germany is significantly higher at 183 t of H_2, compared to 50 t in Chile. Furthermore, these volumes are produced in Chile using electricity with lower CO_2 emissions, which boosts this difference.

A direct comparison of LCA results with values from literature is often difficult, as the life cycle impact assessment method must be identical. For ammonia, Boero et al. [73] report a range of 0.3-0.7 t CO_2-eq/t NH_3 for power-to-ammonia systems. Hank et al. [74] report 0.5 t CO_2-eq/t MeOH for a system consisting of a wind-powered PEM and CO_2 from biogas. Elhaus et al. [10] investigated the emissions from biological methanation in Germany and found values of 2.1-2.3 t CO_2-eq/t CH_4. For kerosene, Ordóñez et al. [75] report a range of 1.8-4.0 t CO_2-eq/t SAF, depending on the country and hydrogen storage technology. All of these values align well with the GWPs we calculated, particularly in Level 1, which is the system setup most comparable to the approaches described in the literature.

The detailed LCA results can be found in the Zenodo dataset under 'Results_LCA". Similar observations to those described for GWP can be found for other indicators at the sites, as well as between ammonia and carbon-based products.

3.3. Overarching discussion of the results

The objective of PtX production is to achieve lowest production costs while minimising emissions. To enable a more comprehensive comparison of the selected sites, Fig. 8 plots the LCOP from the cost-optimised oemof simulations against the GWP derived from the downstream assessment in openLCA.

It becomes apparent that PtX production in Chile has the lowest production costs and emissions. In terms of costs, brownfield sites (Levels 3-5) in Germany and South Africa can compete with less developed sites in Chile (Levels 1-2). In terms of GWP, this is primarily possible in Germany for fully developed brownfield sites (Levels 4-5), while in South Africa it is only possible at pure greenfield site (Level 1). If the composition of South Africa's electricity mix changes, or if purely green electricity is purchased, production would become significantly more environmentally competitive, though at a higher cost.

Fig. 8 also illustrates the configurations that offer the best balance between cost and emissions. A level is considered efficient at each site if no other level achieves a lower LCOP at an equal or lower GWP, or a lower GWP at an equal or lower LCOP. In Germany and Chile, only Level 5 meets this condition for all four products, as the configuration that

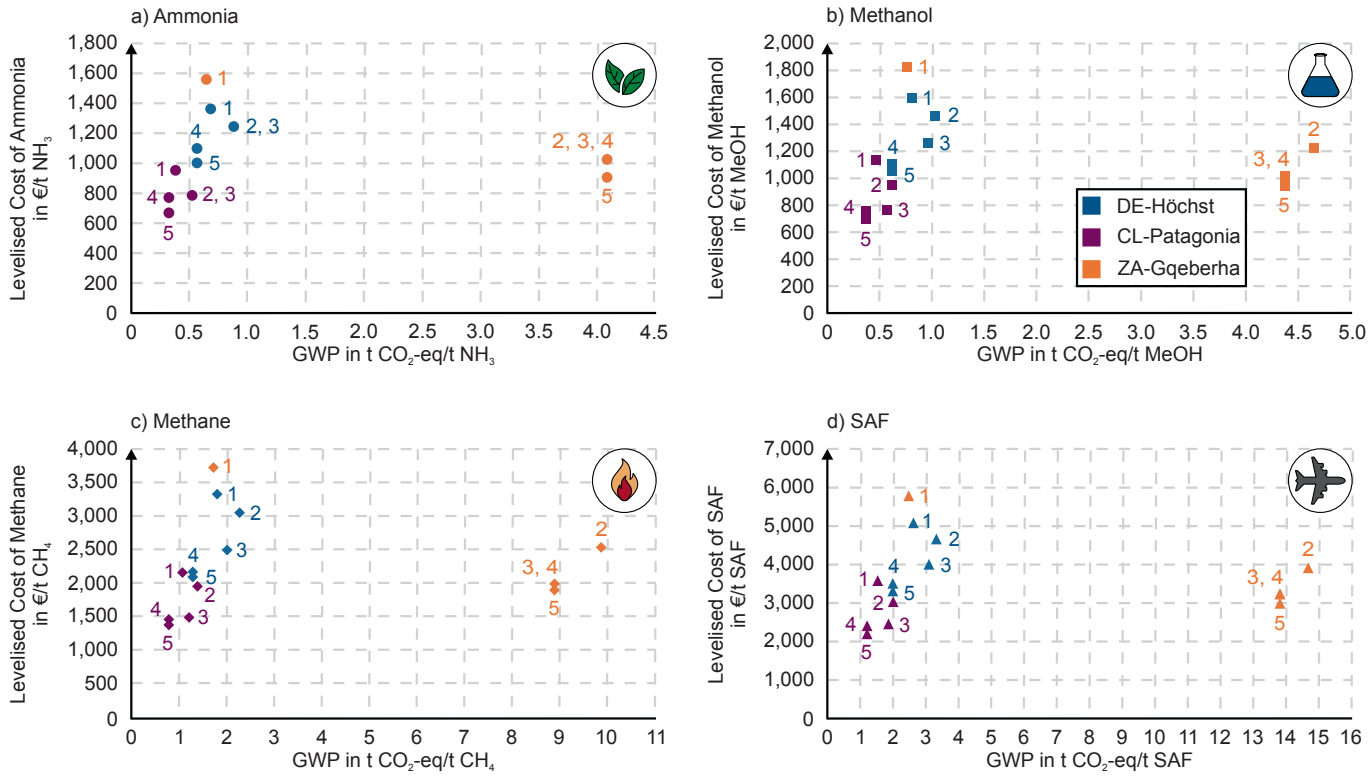


Fig. 8. LCOP plotted against the corresponding GWP values. The greenfield-brownfield levels are displayed as color-coded labels associated with the respective markers.

minimises costs also minimises emissions, so no trade-off arises. South Africa is the exception. Here, Levels 1 and 5 are both efficient, while Levels 2 to 4 are outperformed by Level 5. The lower emissions of the greenfield site come at a cost of 191 €/t CO_2-eq for ammonia, 243 €/t CO_2-eq for methanol, 246 €/t CO_2-eq for kerosene, and 254 €/t CO_2-eq for methane. Section 3.4.5 examines how this trade-off changes when grid electricity procurement at Level 5 is restricted.

Current political and social debates surrounding the energy transition in Europe, and in Germany in particular, often focus on the future origin of energy carriers. The pros and cons of domestic production versus imports from regions with greater RE potential, such as Chile, are frequently discussed. Based on our findings, an interesting comparison can be drawn between Chile (Levels 1-2) and Germany (Levels 4-5). The two countries reflect the current debate between setting up greenfield sites and domestic production at sites with a high level of infrastructure. In these scenarios, both LCOP and GWP are very close to one another. However, if the focus is on the use of these energy carriers in Europe, transport must also be considered to ensure a fair comparison of the alternatives. This increases the LCOP and GWP of PtX products in Chile, potentially making production at German or European brownfield sites more economical and lower in GWP.

This political and economic debate can be made more concrete by considering carbon pricing as a policy lever: we estimated the carbon price at which the LCOP of each product would reach parity with its fossil-based market price. This requires accounting for the distinct carbon origin of fossil and PtX-based carbon-containing fuels. While our system boundary excludes the combustion stage, fossil methane, methanol and kerosene release previously sequestered fossil carbon upon combustion, whereas the carbon in our products originates from biogenic or atmospheric sources and is therefore climate-neutral at the point of use. The detailed calculation, including all fossil benchmark data and combustion emission factors, is provided in the supplementary Zenodo dataset in the 'CO2_price_parity' worksheet [54]. We therefore compared our cradle-to-gate LCOP and GWP results (Level 5, Fig. 5 and Fig. 6) against a combustion-inclusive fossil benchmark (production emissions from ecoinvent 3.12 plus stoichiometric combustion emissions: 2.44 t CO_2-eq/t NH_3, 2.11 t CO_2-eq/t MeOH, 3.62 t CO_2-eq/t CH_4 and 4.05 t CO_2-eq/t kerosene, respectively) and the market prices given in 3.1. Table 2 summarises the resulting carbon price for parity in Chile and Germany. In South Africa, parity is not achievable for any product at Level 5, as the GWP of grid-electricity-based production exceeds even this combustion-inclusive fossil benchmark.

Depending on the fossil price within the observed range, ammonia and methanol in Chile reach parity at 27-93 €/t CO_2 and 1-95 €/t CO_2, respectively. This is close to the current EU ETS price of approximately 85 €/t CO_2 in September 2026 [76], so that these products require no or only a modest carbon price, provided that a comparable carbon price is applied to the fossil alternatives. Substantially higher carbon prices are required for methane production in Chile and for both ammonia and methanol production in Germany, which are several times higher than current EU ETS levels. While considerably higher than today's market, these are not entirely outside plausible long-term carbon pricing trajectories. For the remaining combinations - kerosene at both sites and methane in Germany - the required carbon prices (456-1,238 €/t CO_2) far exceed any current or foreseeable policy trajectory, suggesting that carbon pricing alone is unlikely to close the cost gap for these products and that additional cost-reduction measures would be necessary.

Table 2
CO_2 prices needed in Germany and Chile to enable PtX products to compete economically with fossil fuel market prices.

Product	Carbon price for parity in Chile in €/t CO_2	Carbon price for parity in Germany in €/t CO_2
Ammonia	27–93	210–285
Methanol	1–95	238–348
Methane	316	690
Kerosene/ SAF	456–502	1,174–1,238

3.4. Sensitivity analysis

3.4.1. Cumulative level structure

The five-level framework presented in Section 2.1 has a cumulative structure. This means that the effect attributed to each level (see Section 3.1) depends on all the infrastructure introduced at the preceding levels. To assess whether this results in strong interdependence between levels, i.e. whether the effect of a given infrastructure option would differ substantially if it were the only one available, we modelled each of the three 'add-on' options in isolation from a greenfield baseline, in addition to the cumulative chain presented in Section 3.1. We present methanol production in Germany in detail, as it exhibits the most pronounced level effects in our dataset. Table 3 compares the effect of each option in isolation with its effect as the corresponding incremental step in the cumulative chain.

For three of the four infrastructure options - grid connection, CO_2 access and existing synthesis - the isolated and cumulative effects are closely aligned (within 2 percentage points) for both LCOP and GWP. This suggests that these effects are largely additive and not significantly influenced by the existing infrastructure. However, hydrogen procurement is the exception, with its isolated effect exceeding its cumulative increment for both LCOP (17% vs. 12%) and GWP (50% vs. 36%). This is consistent with the following plausible mechanism: without grid access, a greenfield system must rely entirely on self-built renewable generation and storage. This requires larger capacities, as well as a correspondingly higher cost and embodied emissions, both of which are substantially reduced once hydrogen is purchased externally. Once grid access is established, as in the cumulative chain, the system is smaller to begin with, leaving less potential for hydrogen procurement to further reduce LCOP and GWP.

The same analysis was carried out for methanol at the Chilean and South African sites and for ammonia in Germany, covering both the site and the product dimension (see 'Sensitivities' in the supplementary Zenodo dataset [54]). Grid connection, CO_2 or N_2 access and the existing synthesis unit behave as in the German methanol case. Their isolated effects correspond closely to the incremental steps of the cumulative chain for both the LCOP and the GWP. However, hydrogen procurement remains the exception, with its isolated and cumulative effects differing substantially. Within the cumulative chain, purchased hydrogen replaces electrolysis operated using grid electricity. In isolation, it replaces hydrogen produced from the plant's own renewable generation. Therefore, the deviation varies with the site. For the GWP, the isolated reduction is 50% in Germany, compared to 36% in the cumulative chain. However, in Chile, where own generation is considerably more efficient, the isolated reduction is only 14%, compared to 37% across the entire chain. South Africa is an extreme case. The inexpensive but carbon-intensive grid means that purchased hydrogen becomes uncompetitive once grid access is factored in. This means that the cumulative step yields no reduction at all, whereas the same option lowers the LCOP by 29% in isolation. A comparable, albeit much smaller, effect is observed for nitrogen. Although nitrogen is never purchased within the cumulative chain, it covers 3.9% of demand in isolation. This reduces the LCOP by 0.6% and the GWP by 1.2%. Summing the four isolated effects would overstate the cumulative reduction in LCOP from Level 1 to Level 5 by 99 €/t to 119 €/t in Germany and Chile, and by 572 €/t in South Africa. Such an estimate is unreliable for the GWP in either direction and would even indicate an increase for Chile, where the cumulative chain results in a reduction.

While this analysis does not replace a full factorial design across all levels, products and locations, it suggests that the effects attributed to individual infrastructure levels in our framework are additive for most options rather than being artefacts of the specific cumulative sequence.

Table 3
Isolated vs. cumulative effect of individual infrastructure options on a) LCOP and b) GWP for methanol production in Germany. Negative values indicate an increase.

a) LCOP

Infrastructureoption	LCOP isolatedin €/t MeOH	Reduction vs. Greenfield	LCOP cumulativein €/t MeOH	Reduction vs. Previous level
Greenfield	1,605		1,605 (Level 1)	
+ grid connection	1,473	8 %	1,473 (Level 2)	8 %
+ access to CO_2	1,392	13 %	1,268 (Level 3)	14 %
+ access to H_2	1,337	17 %	1,111 (Level 4)	12 %
+ existing synthesis	1,550	3 %	1,056 (Level 5)	5 %

b) GWP

Infrastructureoption	GWP isolated in kg CO_2-eq/t MeOH	Reduction vs. Greenfield	GWP cumulative in kg CO_2-eq/t MeOH	Reduction vs. Previous level
Greenfield	800		800 (Level 1)	
+ grid connection	1,025	−28 %	1,025 (Level 2)	−28 %
+ access to CO_2	745	7 %	955 (Level 3)	7 %
+ access to H_2	400	50 %	611 (Level 4)	36 %
+ existing synthesis	800	0 %	611 (Level 5)	0 %

3.4.2. Time-varying electricity price

Grid access is the largest single cost lever in our results, particularly in South Africa (Section 3.1), while the model operates hourly on a constant price. To test whether this simplification drives the results, we re-ran the ammonia case for South Africa at Level 2 with a time-of-use price instead of the constant 9.3 €-ct/kWh. As no market-based hourly prices exist yet for South Africa, we used the seasonal and time-of-use active energy charges of Eskom's Megaflex tariff [77] ($\geq$ 500 V and $<$ 66 kV; transmission zone $>$ 600 km and $\leq$ 900 km; including VAT), converted at the ECB reference rate of 18.7839 ZAR/EUR (2nd October 2026)) [78]. The resulting hourly price series ranges from 7.5 to 45.0 €-ct/kWh (mean 11.4 €-ct/kWh, Zenodo dataset). All other assumptions remain unchanged.

The LCOP changes by only +0.7% (Table 4), and the cost reduction relative to greenfield remains about 34% (33.8% vs. 34.3%). The model adapts by installing a battery and hydrogen storage, a larger electrolyser and more wind capacity, and shifts consumption into cheaper hours (average price paid: 8.8 €-ct/kWh). GWP decreases by 19%, as grid purchases fall by 22%, but remains above the fossil benchmark (2.4 t CO_2-eq/t NH_3). The cost advantage of grid access in South Africa is therefore robust against the time structure of the electricity price.

3.4.3. Biogenic CO_2 allocation

We also examine the sensitivity of a specific environmental modelling assumption. To illustrate the sensitivity of the burden-free biogenic CO_2 assumption (Section 2.4), we evaluated an alternative with an upper bound, in which CO_2 is sourced from a non-waste, energy crop-based biogas process (i.e. biogas production from grass with an emission factor of 0.098 kg CO_2-eq/m^3 biogas). We allocated the resulting upstream burden to the CO_2 fraction on a mass basis (i.e. 64.7%, based on the molar composition of biogas). For methanol production in Germany at Level 3, this increases the GWP by around 12% (from 0.955 to 1.066 t CO_2-eq/t MeOH), which is a moderate shift compared to the differences already observed between levels and locations in this study.

Table 4
Ammonia production in South Africa at Level 2 with a constant electricity purchase price and with a time-of-use price.

	Unit	Constant electricity purchase price	Time-of-use electricity purchase price
Grid electricity price	€-ct/kWh	9.3	7.5–45.0
Average price paid	€-ct/kWh	9.3	8.8
Grid electricity	GWh/a	8.6	6.7
Wind / electrolysis	MW	4.7 / 2.5	5.3 / 3.0
Battery / H_2 storage	MWh or t	– / –	0.67 MWh / 0.45 t
LCOP	€/t NH_3	1,027	1,034
LCOP reduction vs. greenfield		34.3 %	33.8 %
GWP	kg CO_2-eq/t NH_3	4,092	3,329

3.4.4. Tornado analysis

To test how the results depend on uncertain input data, we varied the parameters described in Section 2.3 one at a time for methanol at Level 4. Fig. 9 shows the change in LCOP relative to the baseline.

The most influential parameter differs between the sites. In Germany, the hydrogen price has the largest effect (-22% to +13%), as 33% of the costs arise from the purchased hydrogen. The effect is limited upwards: if hydrogen becomes more expensive, the plant switches to its own electrolysis, and at 8 €/kg the LCOP approaches that of Level 3. In Chile and South Africa, the CAPEX of the PEM electrolyser dominates (-13% to +30% and -9% to +18%). In Chile, own hydrogen production (about 3 €/kg) is much cheaper than purchased hydrogen in the base scenario (5 €/kg), so that higher electrolyser costs can hardly be offset by buying hydrogen. In Germany and South Africa, the purchase option dampens this effect. The WACC (±8-10%) and the CAPEX of wind turbines (-6% to +10%) have a comparable influence at all sites. The electricity price has almost no effect in Germany (±0.2%), because hardly any grid electricity is used at Level 4. In South Africa, where a third of costs are related to grid electricity, the effect is the largest (-11% to +3%). In Chile, the lower electricity price (-3%) makes grid-based electrolytic hydrogen cheaper than purchased hydrogen.

To assess whether the benefits of the infrastructure levels depend on these parameters, the cost reductions were recalculated for each variation with identical parameter values at both levels (Table 5). The ranking of the sites does not change in any of the parameter variations (32 comparisons at Levels 1-4). At Level 1, Chile has the lowest LCOP, followed by Germany and South Africa; at Levels 2-4, the order is Chile, South Africa and Germany. The cost reductions of the individual levels are also stable. For grid connection and CO_2 from biogas, the limits of the ranges deviate from the baseline values by up to 7 percentage points. The exception is hydrogen procurement, whose benefit reaches 32% in Germany and 19% in South Africa (10% in Chile) at a hydrogen price of 3 €/kg. This benefit depends on the difference between the purchase price and the cost of own hydrogen production, which amounts to 5.3 €/kg in Germany, 4.0 €/kg in South Africa and 3.0 €/kg in Chile at Level 3. At the baseline price of 5 €/kg, purchasing hydrogen pays off mainly in Germany (12%), hardly in Chile (2%) and not at all in South Africa (0%). At 3 €/kg, purchased hydrogen is cheaper than own production in Germany and South Africa and largely replaces the electrolyser (261 kW instead of 2,697 kW in Germany, none instead of 2,697 kW in South Africa), which explains the high reductions. At 8 €/kg, the benefit disappears (0-1%), as the plants return to their own hydrogen production.

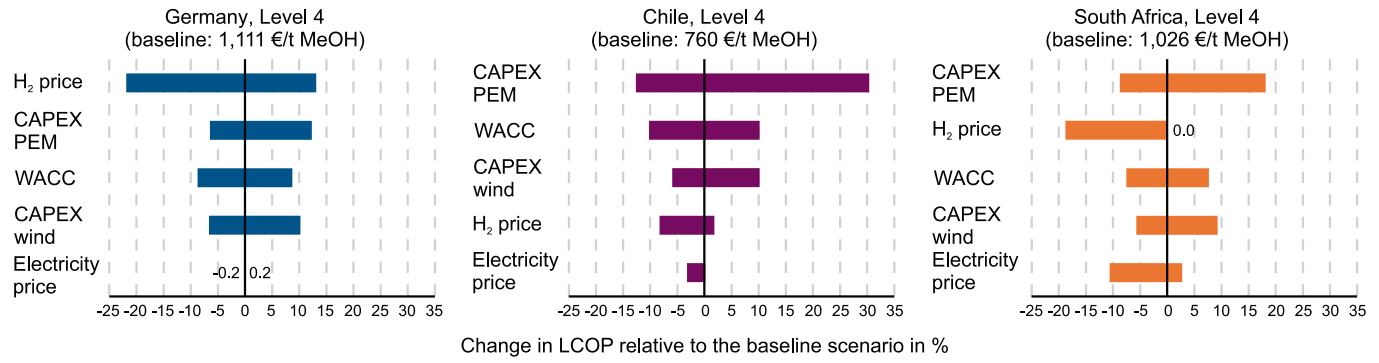


Fig. 9. Sensitivity of the LCOP of methanol at Level 4 to individual parameter variations at the three sites. Bars to the left show the lower, bars to the right the upper parameter bound. Parameter ranges: CAPEX PEM 1,000–3,000 €/kW; CAPEX wind 800–1,600 €/kW; electricity price ± 30 %; H_2 price 3–8 €/kg; WACC ± 2 percentage points. Parameters are sorted by total bar length per site. In South Africa no hydrogen is purchased in the baseline, so higher H_2 prices have no effect.

Table 5
Reduction by infrastructure level for methanol of the LCOP relative to the preceding level. Values: reduction in the base case, followed by the range over all parameter variations (in brackets).

	Germany	Chile	South Africa
Grid connection (Level 1 →2)	8 % (6–14 %)	16 % (15–20 %)	33 % (28–40 %)
MEA (Level 2 →3)	14 % (12–15 %)	19 % (15–21 %)	17 % (14–18 %)
H_2 procurement (Level 3 →4)	12 % (1–32 %)	2 % (0–10 %)	0 % (0–19 %)
All levels (Level 1 →4)	31 % (22–46 %)	33 % (31–39 %)	44 % (40–55 %)

The hydrogen price also causes the upper limits of the cumulative reduction (46%, 39% and 55%) and its lower limit in Germany (22%).

The parameters were also varied simultaneously to examine their combined effect, again for methanol at Level 4. Setting all five parameters to their lower and to their upper bound at the same time, the LCOP ranges from -33% to +62% of the baseline in Germany, from -31% to +66% in Chile and from -31% to +56% in South Africa (see 'Sensitivities' in the supplementary Zenodo dataset [54]). These bounds lie well beyond the individual effects, with the difference being largest upwards. In Germany, the strongest single parameter increases the LCOP by 13%, whereas the combined effect of all five parameters increases it by 62%. This is because the mechanisms that limit the individual effects depend on the other parameters remaining at baseline values. A plant can only switch from purchased hydrogen to its own electrolysis if the electrolyser is affordable, and it can only avoid a costly electrolyser if purchased hydrogen is affordable. When the parameters move together, these options are no longer available.

The configurations change accordingly. At the lower bound, cheap hydrogen becomes the preferred supply route where own production is expensive. South Africa, which currently purchases no hydrogen, buys 180 t/a and reduces its grid electricity consumption from 9,131 MWh/a to 472 MWh/a. Conversely, Chile increases its electrolyser capacity by 28%, as a cheaper electrolyser makes its own production more attractive than purchasing hydrogen. At the upper bound, each site falls back on the supply route least affected. Chile stops purchasing hydrogen entirely, while Germany installs 3,365 kW of photovoltaics instead of the 1,042 kW seen in the baseline scenario. South Africa has no alternative route as it does not purchase hydrogen in the baseline either. This is why the individual effects accumulate almost in full there, even though they are the smallest of the three sites. Nevertheless, the ranking of the sites is preserved at both bounds, with Chile ahead of South Africa and Germany. These combinations should be interpreted as bounding envelopes rather than scenarios, as they assume all parameters deviate in the same direction simultaneously.

Overall, the parameter variation confirms the main results of the techno-economic analysis. Although the absolute LCOP changes by up to +30% (CAPEX of PEM electrolysis in Chile) and -22% (hydrogen price in Germany) in the individual variations, and considerably more when the parameters are combined, the ranking of the sites and the cost reductions through grid access and CO_2 from biogas change only moderately. Hydrogen procurement is the only lever whose cost basis cannot yet be derived from an established market. Its baseline benefit (12% in Germany, 2% in Chile, none in South Africa) should therefore be read as a value for the assumed purchase price of 5 €/kg.

3.4.5. *Restricted grid electricity procurement*

Section 3.3 shows that the only trade-off between cost and emissions occurs in South Africa. There, the carbon intensity of the grid results in the cost-optimal Level 5 configuration being the most CO_2-intensive option. To quantify the impact of reducing grid electricity on this trade-off, we repeated the Level 5 model for methanol in South Africa with an upper bound on annual grid procurement. This was set at 50%, 25%, and 0% of the 9,131 MWh/a drawn in the Level 5 scenario in Section 3.1. All other assumptions remained unchanged.

The LCOP increases from 957 €/t in the Level 5 scenario to 970 €/t, 976 €/t and 1,018 €/t for the 50%, 25% and 0% bounds, while the GWP decreases from 4,362 kg CO_2-eq/t to 2,493 kg CO_2-eq/t, 1,558 kg CO_2-eq/t and 655 kg CO_2-eq/t (see also 'Sensitivities' in the supplementary Zenodo dataset [54]). These three steps correspond to abatement costs of 6.6 €/t CO_2-eq, 6.8 €/t CO_2-eq and 46.8 €/t CO_2-eq. The system responds in two distinct ways. While some grid procurement remains, the installed capacities do not change, and the system simply replaces grid electricity with purchased hydrogen. Between the 50% and 25% bounds, 2,283 MWh/a of grid electricity are replaced by an additional 45.7 t/a of purchased hydrogen. However, only when grid procurement is excluded entirely does the capacity mix change. In this case, 661 kW of photovoltaics, a 5.7 MWh battery and a 9.8 MWh heat storage unit are added to cover the hours previously bridged by the grid. The additional investment required for these components is why the abatement cost of the final step is an order of magnitude higher than the preceding steps.

Without grid electricity, the Level 5 configuration is cheaper and has a lower GWP than the greenfield site at Level 1 (1,018 €/t compared to 1,833 €/t and 655 kg CO_2-eq/t compared to 757 kg CO_2-eq/t). Therefore, the trade-off identified in Section 3.3 disappears under this sensitivity analysis: restricting grid procurement at the developed brownfield site is preferable to greenfield development in both dimensions, at a cost penalty of around 6% of the LCOP. This quantifies the expectation in Section 3.3 that production in South Africa would be considerably more environmentally competitive if green electricity were used. However, the result depends on the availability of purchased hydrogen, which rises to 136 t/a in the fully restricted case, as well as on the renewable electricity mix assumed for its production (see Section 2.4).

3.5. Limitations of the work and further discussion

The results of energy system models depend heavily on the data used. Our data is primarily based on scientific literature but has been verified by industry-related representatives to ensure a high degree of accuracy. However, shifts in market conditions can lead to price fluctuations, particularly affecting energy procurement prices and CAPEX, resulting in different model outcomes. The influence of the most important cost parameters was tested in a one-at-a-time variation and in a combined variation of all parameters (Section 3.4.4). This was only done for methanol and the LCOP. The main drivers of the GWP were tested separately (Sections 2.4, 3.2 and 3.4).

As a fully developed international hydrogen market has yet to be established, we have assumed a standard purchase price of 5 €/kg for green hydrogen. This standardised H_2 price favours locations with high electricity prices, thereby reinforcing the Level 4 effect in Germany. Currently, it is not possible to predict whether such a scenario will occur or if there will be country-specific hydrogen prices, driven by local RE conditions. The influence of the hydrogen price is quantified in Section 3.4.4: for prices between 3 €/kg and 8 €/kg, the benefit of hydrogen procurement ranges from 0% to 32%. This relates to the cumulative level structure (Section 2.1): while a site with existing synthesis infrastructure is likely to have an established hydrogen supply chain, this does not guarantee that the available hydrogen is low-carbon. This is because it may originate from a fossil-based legacy source, such as steam methane reforming or chlor-alkali electrolysis (as is the case at our Höchst site). This represents a limitation of the strict nesting assumption, specifically for Level 4.

We also assume that the required hydrogen is available in unlimited quantities and without interruption to the supply. The volumes involved are small: no hydrogen is purchased at the South African site and, where hydrogen is purchased elsewhere, the volumes range from 46 t/a (ammonia in Chile) to 588 t/a (kerosene in Germany). This corresponds to a dedicated electrolysis capacity of roughly 0.6-7.0MW under the supply assumptions of Section 2.4. At this scale, Level 4 presupposes not a developed hydrogen market, but rather a single local supplier. The Höchst site illustrates that an established hydrogen supply may already exist at an industrial location, albeit not necessarily from a low-carbon source. Nevertheless, a real project would depend on a contracted supplier. Where no local supply exists, the Level 4 configuration is unavailable, and the results are the same as for Level 3.

We have calculated purely LCOP to keep the locations as comparable as possible, which means that our values represent a lower limit. In a real-world system, location- and application-specific transportation costs, taxes, and trade margins are added to this.

For modelling purposes, we assumed a fixed target of 2,500 t of PtX product per year to create a consistent framework for analysis and comparison. We tested the influence of this target by repeating the methanol models for Germany at Levels 4 and 5 with annual production targets of 1,250 t and 5,000 t. The LCOP is unchanged in both cases, and all capacities, energy flows and the curtailment of renewable electricity scale proportionally with the target (see 'Sensitivities' in the supplementary Zenodo dataset [54]). However, it is expected that PtX projects will be implemented on a larger scale in the coming years, which may result in economies of scale that have not been considered in this study. Furthermore, it is conceivable that the synthesis processes could be operated on a more variable basis, in contrast to the fixed load we have assumed. This would make it possible to reduce the overcapacity in renewable energy generation, as is the case in South Africa, for example. It would not change the minimum electrolyser capacity, which follows from the annual hydrogen requirement and the maximum of 8,760 FLH rather than from the operating mode of the synthesis. Consequently, our results refer to the plant scale and the continuous operation studied here. Economies of scale primarily lower specific CAPEX, and the infrastructure effects remained robust against variations in CAPEX and financing conditions (see Section 3.4.4). Therefore, we do not expect their relative benefit to change fundamentally at other production scales. More flexible operating strategies were not investigated and could have a stronger impact. Regarding revenues from sales of intermediate products, modelled volumes remain modest (up to 514 t/year of excess hydrogen and 1,025 t/year of naphtha), which is negligible relative to established global markets for these commodities. We therefore do not expect market size to have a significant impact on our results.

Surplus hydrogen is sold at a price of 1.50 €/kg (see Section 2.3). We tested the impact of this assumption by repeating the methanol model at Level 3 for Chile and Germany, using sale prices of 0 €/kg, 2.5 €/kg and 5.0 €/kg. Without any revenue, the LCOP increases by 8 €/t in Chile and by 13 €/t in Germany, around 1% in both cases, and the sale of surplus hydrogen ceases. Above a price of around 2.5 €/kg, the system begins to build renewable and electrolysis capacity for hydrogen export. At this price, the Chilean model sells 1,102 t/a of hydrogen, compared to 24 t/a in the base case. At a price of 5.0 €/kg, the renewable capacity reaches the exogenous expansion limit. This means that the plant effectively becomes a hydrogen producer, with methanol as a by-product. This threshold lies below the levelised cost of own hydrogen production because the marginal cost of additional production is lower. Therefore, the assumed price keeps the system within its intended purpose and the contribution of by-product revenues to the LCOP remains small (see 'Sensitivities' in the supplementary Zenodo dataset [54]).

The results in oemof are based on the perfect foresight principle and represent a theoretical optimum. In reality, the dimensions of the plants should be slightly larger. As the weather varies from year to year, greater storage capacities might be necessary.

In the retrofit case at Level 5, a single share of the new-build CAPEX is applied to all four synthesis units. Mingolla et al. [63] provide the only quantified estimate, which refers to ammonia plants. We are not aware of comparable figures for the other pathways. The actual effort is likely to differ between them. Converting a Haber-Bosch plant primarily impacts the units upstream of the synthesis loop, as the loop itself is indifferent to the source of the hydrogen [63]. The stoichiometry and water load of methanol synthesis using captured CO_2 rather than fossil syngas are different, which could impact the selection of catalysts and affect the condensation and recycling processes [79]. For Fischer-Tropsch, the reactor itself is comparatively insensitive to the origin of the syngas, and studies of retrofitted gas-to-liquid plants accordingly leave the synthesis and refining sections unchanged and concentrate the conversion effort on the upstream reforming and energy supply [80]. This is consistent with our Level 5 definition, in which only the synthesis section is assumed to be available while all upstream supply is costed as new-build. However, biological methanation is not affected in the same way, as it processes biogas directly. Additionally, the remaining service life of an existing plant may be shorter than the 20 to 25 years assumed for a new unit. Furthermore, integration work such as piping and control systems is not resolved at the level of detail of our models. For these reasons, we report Level 5 as a bounded range rather than a specific value. Section 3.1 quantifies how the benefit changes if the retrofit effort is considerably higher than assumed.

When assessing the environmental impact of existing synthesis infrastructure at Level 5, we decided to spread the construction effort over their entire service life, as is standard practice in LCAs, whilst keeping all other operating parameters constant. As a result, our analysis shows that, there is no environmental difference compared with the construction of a new plant; there is merely a financial advantage. In reality, differences may arise between a plant that has been in operation for decades and a newly built one, for example in the form of slightly more efficient operation.

We focus our environmental discussion on GWP, as it is the most widely reported and compared indicator in the PtX literature. A comprehensive discussion of all ReCiPe midpoint categories would exceed the scope of this paper. Claims of environmental benefit should accordingly be understood as referring specifically to climate-change

performance. Results for the additional ReCiPe midpoint impact categories are provided in the supplementary Zenodo dataset for readers interested in a broader environmental assessment.

Cost and emissions are assessed sequentially rather than being optimised simultaneously. A multi-objective formulation with an emission constraint would require a separate life cycle model for each configuration resulting from this, which was beyond the scope of this work. However, Sections 3.3 and 3.4.5 address this issue within the configurations examined here.

It should also be noted that not all levels are equally impactful for every product. For ammonia, Levels 2 and 3 yield identical results in every scenario studied, since in-house nitrogen production via ASU is cost-optimal over external N_2 procurement at the prices considered. This reflects a genuine techno-economic characteristic of the ammonia pathway rather than a shortcoming of the framework, and it illustrates that the relative importance of each infrastructure level is product-specific.

4. Conclusion

We present a multi-level approach to the structured assessment of PtX under various infrastructure conditions. These levels range from a greenfield to highly developed industrial sites. This approach thus enables systematic analysis of the influence of different site conditions on various PtX products. We have demonstrated this from a techno-economic and environmental perspective using the examples of ammonia, methanol, methane and kerosene in Chile, Germany and South Africa. The framework is intended as a structured basis for comparing infrastructure conditions, not as a substitute for a site-specific feasibility assessment.

Our results show:

- PtX production in Chile has the lowest GWPs and LCOPs due to excellent wind power conditions and low investment risk.
- Investment risk significantly influences the achievable LCOP, particularly at greenfield sites. In fact, this effect is so substantial that sites with considerably poorer RE conditions can still produce more cost-effectively due to lower country-specific investment risk.
- The option of purchasing electricity has the greatest influence on LCOP, with cost reductions of 8-34% depending on the purchase price. However, the effect on the GWP depends heavily on the electricity mix. With a high share of fossil fuels, it may result in higher emissions than those associated with current fossil-fuel-based processes.
- Switching from DAC to MEA reduces LCOP by 14-23% while reducing the GWP simultaneously.
- Sourcing green hydrogen can reduce costs by up to 13%. If produced using renewable electricity, the GWP can be lowered to a level below that of a greenfield site, offsetting the use of grid electricity. However, with hydrogen produced from the national grid mix, this advantage would be lost.
- Without a carbon price, PtX products do not yet reach parity with fossil benchmarks. In Chile, ammonia and methanol require a carbon price of around 95 €/t CO_2 at Level 5, which is close to current EU ETS levels. However, methane and kerosene in Chile, as well as all products in Germany, require a carbon price of between 210 and 1,238 €/t CO_2. In South Africa, on the contrary, parity is unachievable due to the emissions associated with grid-based production.
- Variations in the CAPEX of PEM electrolysis and wind turbines, electricity prices, hydrogen prices and the WACC do not change the ranking of the sites and only moderately shift the cost reductions through grid access and CO_2 from biogas. The only factor that varies strongly is the benefit of hydrogen procurement (0-32%), as there is no established hydrogen market yet that can provide a reliable price basis.
- Assessing the infrastructure options in isolation confirms the level effects for grid connection, CO_2 or N_2 access and existing synthesis units. Hydrogen procurement is the exception, as its benefit depends on which infrastructure is already available and ranges from no effect at all to a 29% cost reduction.
- The locational advantages offered by the existing infrastructure can enable PtX production to be carried out more economically and with a lower GWP at sites that are significantly less favourable for RE. At comparable-level sites Chile remains superior. The advantage arises only where infrastructure levels differ substantially.

This last point highlights a high degree of social relevance, as it is precisely this situation that arises between locations in the South of Chile with structurally weak conditions and highly developed locations in Germany. In this regard, project developers should carry out extensive preliminary investigations when selecting a location, prior to making a final investment decision.

Further research could address other cost-relevant factors, such as country-specific taxes and levies, the impact of funding instruments and transport, as well as qualitative, location-specific siting factors (e.g., water availability, port access, grid capacity, land use and regulatory requirements) not captured by the present framework, building on our work. The isolated assessment could also be extended to all products and locations in order to quantify the interactions between infrastructure options more completely.

Data and Code availability

The data used in this work is available on Zenodo: Dataset. The code to reproduce the experiments is available on GitHub: Repository.

Declaration of generative AI and AI-assisted technologies in the manuscript preparation process

During the preparation of this work the author(s) used AI-Tools like DeepL, Claude and Copilot in order to improve language. Claude was additionally used to check the consistency of numerical results and formatting. After using these tools, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

CRediT authorship contribution statement

Michael Heberl: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Project administration, Methodology, Investigation, Conceptualization. **Timon Geiss:** Writing – review & editing, Visualization, Software. **Daniel Rank:** Writing – review & editing, Visualization, Validation, Methodology. **Andreas Hofrichter:** Writing – review & editing, Validation, Methodology. **Dinh Du Tran:** Writing – review & editing, Validation. **Michael Sterner:** Writing – review & editing, Visualization, Validation, Supervision, Project administration, Funding acquisition.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Michael Heberl reports financial support was provided by German Federal Ministry of Research, Technology and Space. Daniel Rank reports financial support was provided by German Federal Ministry of Research, Technology and Space. Dinh Du Tran reports financial support was provided by German Federal Ministry of Research, Technology and Space. Andreas Hofrichter reports financial support was provided by German Federal Ministry for Economic Affairs and Energy. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence

the work reported in this paper.

Acknowledgements of funding sources

This research was funded by the German Federal Ministry for Economic Affairs and Energy [BMWE, grant numbers 03EI1078-C]; the German Federal Ministry of Research, Technology and Space [BMFTR, grant numbers 03SFK2T1-3, 03SFK2W0-3].

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