Potential and risks of hydrogen-based e-fuels in climate change mitigation

Falko Ueckerdt[1*], Christian Bauer[2], Alois Dirnaichner[1], Jordan Everall[1,4], Romain Sacchi[2], Gunnar Luderer[1,3]

[1]Potsdam Institute for Climate Impact Research, Telegrafenberg, 14473 Potsdam, Germany.

[2]Technology Assessment group, Paul Scherrer Institute, Forschungsstrasse 111, CH-5232 Villigen PSI, Switzerland

[3]Chair of Global Energy Systems, Technische Universität Berlin, Straße des 17. Juni 135, 10623 Berlin, Germany.

[4]Wegener Centre for Climate and Global Change (WEGC), Universität Graz, Brandhofgasse 5, 8010, Graz, Austria.

*corresponding author

This is a post-print (i.e. the accepted manuscript). The final paper in journal layout can be found here:

Ueckerdt, F., Bauer, C., Dirnaichner, A., Everall, J., Sacchi, R., Luderer, G. (2021): Potential and risks of hydrogen-based e-fuels in climate change mitigation. Nature Climate Change. https://dx.doi.org/10.1038/s41558-021-01032-7

Abstract

E-fuels promise to replace fossil fuels with renewable electricity without the demand-side transformations required for a direct electrification. However, e-fuels' versatility is counterbalanced by their fragile climate effectiveness, high costs and uncertain availability. E-fuel mitigation costs are 800–1200 €/tCO_2. Large-scale deployment could reduce costs to 20–270 €/tCO_2 until 2050, yet it is unlikely that e-fuels become cheap and abundant early enough. Neglecting demand-side transformations threatens to lock in a fossil fuel dependency if e-fuels fall short of expectations. Sensible climate policy supports e-fuels deployment, while hedging against the risk of their unavailability at large scale. Policies should be guided by a "merit order of end uses" that prioritizes hydrogen and e-fuels for sectors that are inaccessible to direct electrification.

Editor summary: E-fuels – hydrocarbon fuels synthesized from green hydrogen – can replace fossil fuels. This Perspective highlights the opportunities and risks of e-fuels, and concludes that hydrogen and e-fuels should be prioritized for sectors inaccessible to direct electrification.

Main

E-fuels (i.e. electrofuels, powerfuels, or electricity-based synthetic fuels) are hydrocarbon fuels synthesized from hydrogen and CO_2 (i.e. carbon capture and utilization, CCU), where hydrogen is produced from electricity and water (via electrolysis), and CO_2 is captured from either fossil sources (e.g., industrial plants) or the atmosphere (biomass or direct air capture, DAC) (Figure 1)[1–3]. E-fuels can thereby tap into the low-cost and vast global potentials of low-carbon wind and solar PV power. The resulting gaseous and liquid fuels feature characteristics that make them perfect substitutes to their fossil counterparts: a high energy density, storability, transportability and combustibility. While these characteristics already improve in the conversion of electricity to hydrogen, adding carbon in a second step also circumvents the challenges of handling hydrogen[4].

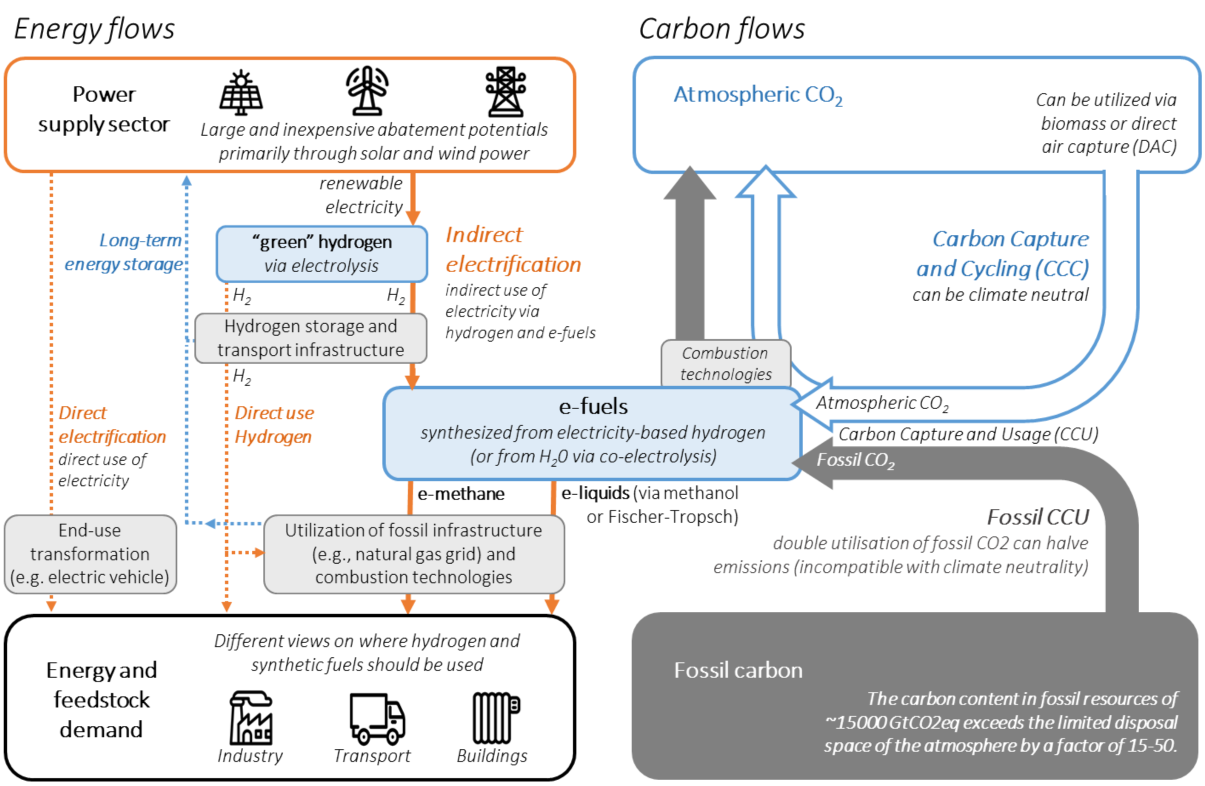


Figure 1 | Basic principle of e-fuels in an energy system. Energy flows (left): E-fuel and hydrogen are forms of indirect electrification, in which (renewable) electricity can be used via electrolysis and e-fuel synthesis to meet energy demands that rely on gaseous and liquid fuels. A competing option is direct electrification, which requires an end-use transformation to electric applications. **Carbon flows (right)** associated with e-fuels when using CO_2 from atmospheric or fossil sources. Only utilizing atmospheric CO_2 (through biomass or direct air capture, DAC) creates a carbon cycle that is compatible with carbon neutrality.

Due to their versatility, e-fuels could extend the reach of wind and solar electricity to potentially *all* end-use sectors. This is increasingly important as the large-scale deployment of biofuels, carbon capture and storage (CCS) and CO_2 removal (CDR), which are prominent mitigation options for non-electric energy demand, are limited by sustainability and acceptance concerns[5–9]. However, there are contrasting views on the role of e-fuels and the range of applications they should be targeted on, which predetermines the future market volumes of hydrogen and e-fuels.

Some studies show a minimal or no e-fuel use and instead suggest a deep[10–13] or full[14,15] *direct* electrification of one or all end-use sectors. For example, Williams et al. (2012) present scenarios in which a pivotal role of electrification allows for a cross-sectoral 80% reduction (wrt. 1990 levels) of greenhouse-gas (GHG) emissions in California. Biofuels have a complementary role for long-haul freight trucking and air travel and hereby contribute 6% to 2050 emissions reductions. Jacobson et al. (2015) argue for an all-electric energy system (excluding chemical feedstocks) allowing to fully abate energy-related GHG emissions by an almost complete phase-out of combustion technologies, while the study's framing has been criticized for an ex-ante exclusion of other mitigation options[16].

Recent reports[17–19] point to the potential value of e-fuels and hydrogen in overcoming the limitations of other mitigation options in difficult-to-decarbonize sectors[20]. The requirement of carbon neutrality creates increasing awareness of residual hydrocarbon demands[21] as bottlenecks for climate stabilization. E-fuels could help out in sectors and applications such as long-distance aviation[22,23], shipping, feedstocks in chemical industry[24], high-temperature industrial processes, long-haul heavy-duty road transport and long-term energy storage[25].

In the current public policy debate, particularly in Europe, some (mostly incumbent) industry stakeholders, policy makers and researchers argue for applying e-fuels beyond difficult-to-decarbonize sectors. They call for a wider replacement of natural gas and petroleum with e-fuels, for example for heating and cooking in buildings (e.g., by blending hydrogen and e-fuels into gas grids)[26–28] or for light-duty vehicles[29–31]. Such a hydrogen[32,33], renewable methane, or methanol economy[1] would significantly reduce the demand-side transformation requirements and partly maintain existing fossil-fuel infrastructure. In this spirit, e-fuels could build a bridge between technologies of the past and future. Combustion technologies, for example, the internal combustion engine, can be regarded as an integral part of the climate problem. E-fuels promise to break this link by allowing combustion technologies and fossil infrastructures to become part of the climate solution. For densely populated countries (e.g., EU countries or Japan) with limited wind and solar resources, this vision relies on the import of hydrogen and e-fuels from abundant global resources[34–36].

Finally, recent scenario modeling studies, often conducted for the EU or Germany, move towards offering a range of scenarios that explicitly differ in assumptions made about hydrogen and e-fuel availability (e.g., through import) and use[37–39].

This Perspective aims at reconciling different views on the potential role of e-fuels. Based on literature and own analyses, we synthesize knowledge on their techno-economic characteristics, life-cycle GHG emissions (full cradle-to-grave) and system-level implications. We draw conclusions; for example, thoughts towards an e-fuel merit order that prioritizes the end uses of scarce e-fuels. Most of the conclusions also hold for the direct use of hydrogen, yet, exploring the balance of direct use of hydrogen and e-fuels is out of the scope of this paper. While our cost analysis is based on e-fuels that are shipped from Northern Africa to North-western European ports, we seek to derive generic insights that are valid for most countries.

Energy conversion efficiency

E-fuels and hydrogen are not a primary energy source, but a secondary energy carrier. As an *indirect* electrification pathway, they are subject to additional conversion losses during both their supply-side production as well as their demand-side utilization. E-fuels compete with *direct* electrification alternatives, which are more energy efficient.

Across a range of energy services in buildings (low temperature heat), industry (high temperature heat) and transport (light-duty vehicles), we show individual conversion steps (Figure 2), and combined efficiencies. We seek to demonstrate the relevant orders of magnitudes. Exact values vary for specific types of electrolysis, synthesis (and their degree of integration) or fuel type (e.g., gaseous or liquid). Waste heat recovery in an integrated system of electrolysis and hydrocarbon synthesis can improve the overall supply side efficiency[40]. Additional losses from energy transport and storage are neglected for the efficiency analysis such as the losses from a potential liquefaction and, regasification long-distance transport and distribution of hydrogen[41].

Depending on the application and respective technologies, overall efficiencies of e-fuels, i.e. converting electricity to useful energy, range from roughly 10% to 35%. This translates into (renewable) electricity generation requirements that are two to fourteen times higher than for direct electrification alternatives. These losses outstrip by far the efficiency gains of using electricity from renewable-rich countries (in e.g. Chile or North Africa) and exporting them as e-fuels.

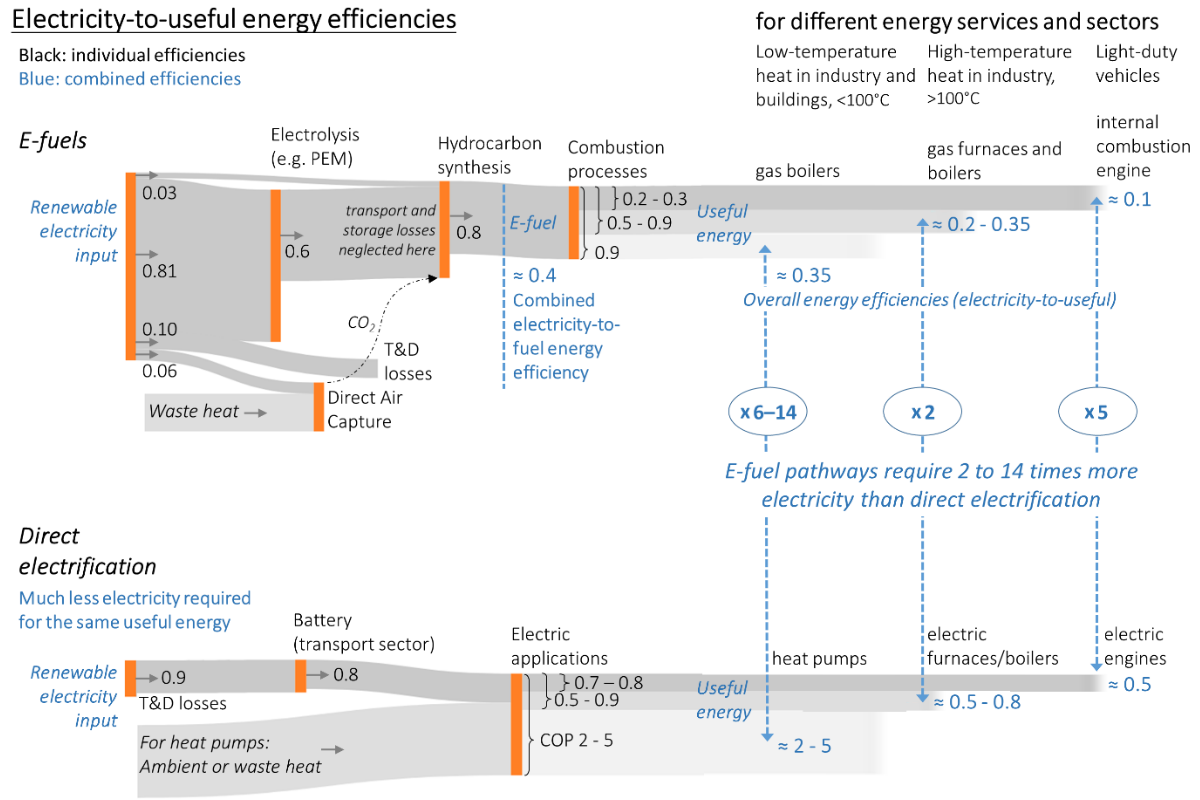


Figure 2 | **Energy efficiencies for major conversion steps from electricity input to useful energy.** This is considered across sectors for e-fuel applications (top) and direct electrification applications (bottom) and shows individual conversion efficiencies (black) and combined efficiencies (blue). The overall electricity-to-useful energy efficiencies of e-fuels range from roughly 10% (e-gasoline in a light-duty vehicle) to 35% (e-methane boiler), which translates into (renewable) electricity generation requirements that are two to fourteen times higher than for direct electrification alternatives. The underlying data comes from LCA inventories (supplement S1) and additional literature (references in the main text and in supplement S2).

On the e-fuel supply side, generating hydrocarbon fuels from electricity currently requires at least two conversion steps, electrolysis and hydrocarbon synthesis, with electricity-to-fuel efficiency losses of about 40%. This figure also includes electricity requirements of ~6% (of total electricity input) when capturing CO_2 from the air (DAC)[42,43]. We optimistically assume that the heat demand of DAC (1500 kwh/t CO_2 [44]), comprising ~15-20% of overall energy input, is met by waste heat from other processes and thus excluded from the calculation.

On the e-fuel demand side, roughly 70% of the remaining e-fuels energy content is lost when combusting e-fuels for mechanical work (e.g., combustion engine for transport services or re-electrification applications such as renewable gas turbines) resulting in the electricity-to-useful energy efficiencies for transport of about 10%. Using e-fuels in an internal combustion engine of a passenger car thus requires about five times more (renewable) electricity than directly using electricity in an equivalent battery electric vehicle, where conversion chains are shorter and keep most of the electricity's exergy as they do not rely on combustion.

When using e-fuels for low-temperature (<100°C) heating in buildings and industry, the efficiency disadvantage reduces to the losses from the e-fuel production on account of highly efficient gas boilers. If, in addition, the waste heat from the supply side can be utilized on the demand side, efficiencies could be increased. This would require a system that integrates electrolysis and hydrocarbon synthesis with buildings, district heating systems or industrial facilities. Supplying high-temperature heat (>100°C) for industrial applications is contingent on gas boilers and furnaces with efficiencies of about 50-90% (dependent on the temperature and industrial process)[45,46]. Heat pumps, by contrast, can make very efficient use of electricity by transferring energy from ambient or waste heat, reaching a coefficient of performance (COP: ratio of heat output and electricity input) above 2 [12,47]. This leads to energy efficiencies that are six to fourteen times higher than using e-fuels. For high-temperature heat (>100°C), demand-side efficiencies of electric boilers and furnaces compare with their gas counterparts (50-90%) such that the electricity-to-useful energy efficiency comparison is determined by losses in the e-fuel supply chain [12,48,49].

Climate mitigation effectiveness of e-fuels

E-fuels can be low-emission alternatives to fossil fuels. However, their climate mitigation effectiveness critically depends upon the carbon intensity of the input electricity and the source of CO_2. We demonstrate this here for a range of applications in the transport sector: light-duty vehicle, LDV, (easy-to-abate), heavy-duty trucks (hard-to-abate) and long-distance aviation (hard-to-abate and inaccessible to electrification) (Figure 3).

GHG emissions for these transportation modes from a full cradle-to-grave life cycle assessment (supplement S1) are shown as a function of the life-cycle carbon intensity of electricity used for battery charging, hydrogen production (electrolysis) and e-fuel production as well as for two different sources of CO_2 (DAC and fossil CCU) (Figure 3).

The slope of the GHG intensity lines reflects the amounts of required electricity input for each conversion pathway. The lines are flat for the fossil reference technologies (negligible electricity input), and steepest for e-fuel vehicles due to their low overall energy efficiencies and thus high electricity input. Residual emissions at a 100% renewable electricity share are mainly determined by embodied life-cycle energy requirements for construction and manufacturing of wind and solar PV plants, vehicle gliders, or batteries. These floor emissions could approach levels close to zero in the long term if a transformation towards a net-zero industry sector can be achieved (Extended Data Figure 5 shows results for 2050).

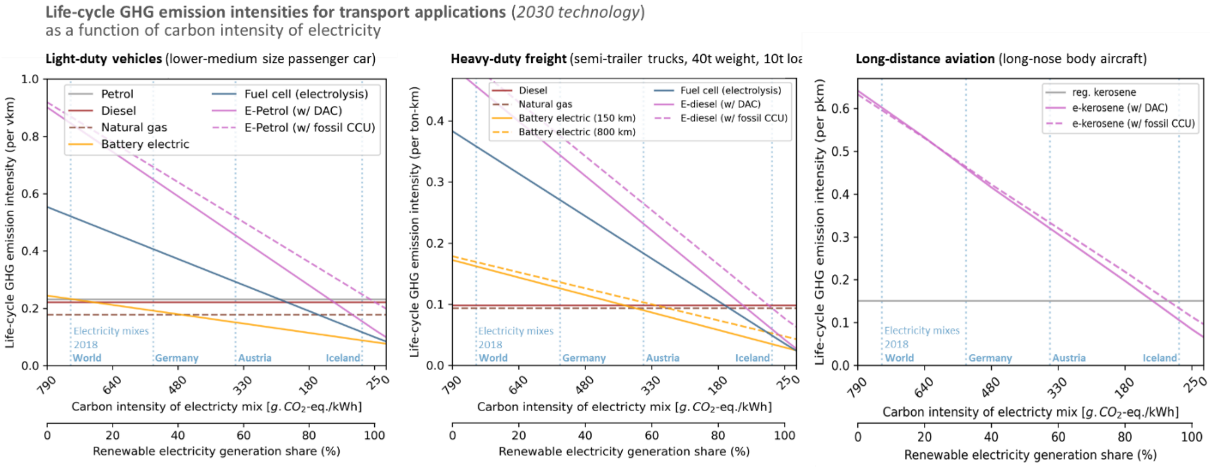


Figure 3 | Life-cycle GHG emissions for different fuels and transport applications, as a function of the life-cycle carbon intensities of electricity used for battery charging, hydrogen and e-fuel production. Note different functional units on y-axis across light-duty vehicles (left), heavy-duty trucks (middle), and planes (right). Comparing e-fuel options (CO2 from DAC or fossil CCU), hydrogen fuel cells (H2 from electrolysis), direct electrification with batteries and fossil options, all of which is based on anticipated technological progress in 2030 using the life cycle assessment model carculator[50] and carculator_truck[51]. Vertical lines show life-cycle carbon intensities of electricity for selected geographies for 2018. The secondary x-axis (bottom) translates the carbon intensity of electricity into an equivalent share of renewable electricity generation (equal shares of wind and solar PV electricity, where the remaining non-renewable generation is natural gas and coal electricity in equal shares). For a breakdown of life-cycle GHG emissions see Extended Data Figures 6-8.

Across transport applications, 90–100% renewable electricity shares are required for e-fuel use to reduce GHG emissions compared to their fossil alternatives. With the 2018 German electricity mix (carbon intensity of 542 g CO_2-eq./kWh)[52], using e-fuel in cars, trucks or planes would produce about three to four times more GHG emissions than using fossil fuel. Direct use of hydrogen (for LDVs or trucks) performs slightly better. Hence, only for truly renewable-based power systems do e-fuels or hydrogen become an effective mitigation option. This suggests that for most countries and power systems no mitigation contribution can be expected from e-fuels or hydrogen before 2030, unless they are imported from countries that build up the required *additional* renewable capacity, electrolyzers, DAC plants, hydrogen as well as CO_2 storage and transport infrastructure.

Battery electric alternatives for LDVs, by contrast, have GHG emissions that are comparable to or lower than those of diesel, gasoline or natural gas vehicles already with today's electricity mixes for many countries (e.g., Germany), which has been shown before[50,53]. The performance of battery-electric trucks highly depends on the progress of battery technology, in particular energy densities. Both battery trucks with a range autonomy of 150 km (mainly for inner-city transport with potential charging breaks) and long-distance trucks with range autonomy of 800 km (requiring larger batteries and reducing the maximum payload) reduce the per-ton-km GHG emissions at renewable electricity shares above ~60–65%, which is the current 2030 target for renewable electricity shares in Germany. The direct electrification option of long-distance overhead cables (not analysed here) might further improve the GHG performance of electric trucks that can run on their electric motor while simultaneously charging a smaller battery.

For long-distance aviation there is no direct electric or hydrogen option. E-kerosene can reduce GHG emissions by about one third at 100% renewable electricity input. This does not substantially improve with anticipated technological progress until 2050 (Extended Data Figure 5). The main reason are non-CO_2 impacts of aviation, which account for about two thirds of the total net radiative forcing due to aviation[54]. Aviation thus is a truly hard-to-abate sector where even e-fuels are only an incomplete backstop. E-kerosene alone does not allow mankind to fully buy itself out of GHG emissions.

Re-utilizing CO_2 from a fossil source (e.g., CO_2 from a traditional coke-based steel plant) for the production of e-fuels still results in a net flow of fossil CO_2 from geological reservoirs to the atmosphere (illustrated in Figure 1). On the system level, such double-utilization of CO_2 can at best yield a rough halving of emissions, even if additional emission-free electricity is available and any CO_2 leakage is ignored[55,56]. Fossil CCU is thus not compatible with the long-term climate neutrality requirement prescribed by the Paris climate targets (nor with less-ambitious climate stabilization targets).

The evaluation of the short-term climate-effectiveness of fossil CCU depends on the attribution of the remaining fossil emissions between the process that provides the fossil CO_2 and the e-fuel application, which is emitting the fossil CO_2. We assume that the remaining emissions are distributed equally between both processes. As a result, GHG emissions of a fossil CCU pathway lead to no or only a minor reduction of GHG emissions compared to fossil vehicles even at a 100% renewable electricity share.

One could argue that as long as there are large fossil CO_2 sources, fossil emissions should not be attributed to the re-utilizing e-fuel application (Extended Data Figure 4 shows a sensitivity analysis on this attribution). However, if source applications have to carry the full carbon costs (e.g., via CO_2 pricing), the industry will increasingly consider alternatives to a re-utilization such as low-carbon industrial processes or CCS.

Fossil CCU and atmospheric CCC require infrastructures with very different spatial topography. For fossil CCU, point sources of CO_2 such as large steel or power plants would need to be connected to hydrogen import or domestic hydrogen production. For the energy-intensive DAC option, capture plants would ideally be placed close to electrolysis plants - both using abundant renewable energy in sunny and windy countries with sufficiently available land. Synthesizing hydrocarbons directly in the exporting countries (e.g., in Northern Africa) improves transportability and thus reduces costs and energy losses, but can lead to very different infrastructure than utilizing CO_2 in the importing countries (e.g., in the EU). These structural differences in long-lived infrastructure suggest that fossil CCU not only misses the mark on the carbon neutrality requirement, but is also unsuitable as a bridge to the sustainable circular option.

If CO_2 from sustainably grown biomass or DAC is used instead, e-fuels GHG emissions can approach very low levels, this however relies on low-carbon electricity production, and a reduction of life-cycle GHG emissions from equipment construction[57]. When combusting e-fuels, CO_2 of atmospheric origin is emitted back into the atmosphere, giving rise to a huge anthropogenic carbon cycle (illustrated in Figure 1). Such full recycling of CO_2 could become a pillar of a circular climate-neutral economy. However, capturing atmospheric carbon requires either significant land (in case of using biogenic CO_2) or energy resources (in case of DAC), which have to be low carbon to minimize indirect GHG emissions[44]. E-fuels cannot reduce emissions, if the heat supply of DAC is met by natural gas or an average mix of heat sources used by the petro-chemical industry in the EU today (Extended Data Figure 4 shows a sensitivity analysis on heat supply assumptions). Low-carbon heat supply is thus just as crucial as a 100% low-carbon (e.g., renewable) electricity supply. If CO_2 is instead sourced from biomass, this would require an accurate accounting of associated emissions including those from indirect land-use changes [58,59].

Climate economics of e-fuels

E-fuels compete in two directions: with conventional fossil fuels (gaseous and liquid fuels) and with other mitigation options, mostly direct electrification alternatives.

Competition with fossil fuels

We estimate levelized costs of e-fuels for 2020-2050 (Figure 4, a, b) for a case in which hydrogen is produced in a renewable-rich country and shipped ~4000 km, which represents the distance between Northwest Africa (e.g., Morocco) and North-western European ports (e.g., Rotterdam or Hamburg). E-methane or e-gasoline are either synthesized in the exporting country with DAC-based CO_2, or at the European port from fossil CO_2 utilizing imported liquefied hydrogen, which increases transport costs. We neither include potential taxes and levies nor further domestic transport or distribution costs. The resulting levelized e-fuel costs are consequently compared with fossil fuel whole-sale market prices.

The bottom-up analysis for the several e-fuel cost components is based on a literature review, LCA inventory data, empirical hourly electricity prices and an optimization of electrolysis operation (Table 1 shows a selection of crucial and uncertain parameters. Supplement S2 shows all underlying assumptions and crucial techno-economic parameters for all cost components. Extended Data Figure 9 shows life-cycle emissions of all fuels.). The extensive electrolysis cost data collected is available in Everall and Ueckerdt (2021)[60] and visualized in an interactive dashboard [https://h2.pik-potsdam.de/H2Dash/] and Extended Data Figure 10.

Table 1. Most important parameter for e-fuel cost estimation and sensitivity analysis (see the full table and references in supplement S2)

	2020-25	2030	2050
Annual average electricity price (EUR/MWh)	50 +/-10	50 +/-10	30 +/-10
Electrolysis CAPEX (€/kW, median of AEC/PEMEC literature review)	1100 +/-389	625 +/-258	334 +/-189
Direct-air capture (€/t CO_2 captured)	460 +/-90	150 +150/-50	50 +50/-10

Calculating production costs of hydrogen and e-fuels faces several parameter uncertainty especially for 2030 and 2050 estimates. The data and literature that we rely on typically show substantial cost reductions due to technological progress and large-scale production. Our analysis thus represents a scenario in which e-fuels and their components (renewable electricity, electrolysis, DAC, hydrocarbon synthesis, liquefaction, storage and long-distance shipping) are scaled up substantially in the coming years and decades, which requires significant and continuous policy support (e.g., subsidies) as we argue below. We focus on large-scale average production costs (plants with >100m kg/a), not niche markets, and draw on *median* values where parameter variability or uncertainty occurs. To develop a sense of how the underlying uncertainties impact costs, we conduct a sensitivity analysis in which we vary several crucial parameters based on the ranges in literature and own judgement (see supplement S2). The largest uncertainties are associated with DAC, electrolysis and costs of transporting hydrogen (for which only little detailed work has been published). Mid-term cost estimates for 2030 highly depend on the technology deployments in the next years, which crucially depends on governmental support for the scale-up of electrolysis, the general role of e-fuels and the extent to which CO_2 is fossil-based or DAC-based in the near term. Our hydrogen cost estimates are similar to those derived for 2030 in Glenk and Reichelstein (2019)[61]. Our e-fuel cost estimates are similar for those derived for 2030 to 2050 in Ram et al. (2020)[36] and slightly lower (10-20%) than 2030 estimates derived in Hank et al. (2020)[62].

Our estimation of hydrogen production costs considers synergies of integrating electrolysers into power systems with high wind and solar PV shares (supplement S2). Increasing shares of variable renewables increase price variability such that - through a flexible operation - electrolysers can profit from low electricity price hours such that the average electricity costs for producing hydrogen can be substantially reduced. Note that these synergies gradually vanish if annual hydrogen export amounts exceed domestic electricity demand of the exporting country.

As an indicator of the competitiveness with fossil fuels, we calculate the fuel switching CO_2 prices (Figure 4, a, b, right axis) such that e-fuel costs break even with natural gas prices (whole-sale spot market price benchmarks for Europe) and global gasoline prices. These CO_2 prices also represent CO_2 abatement costs of e-fuels that can be compared with those of other mitigation options (next section). Note that we assume 100% additional renewable electricity input here.

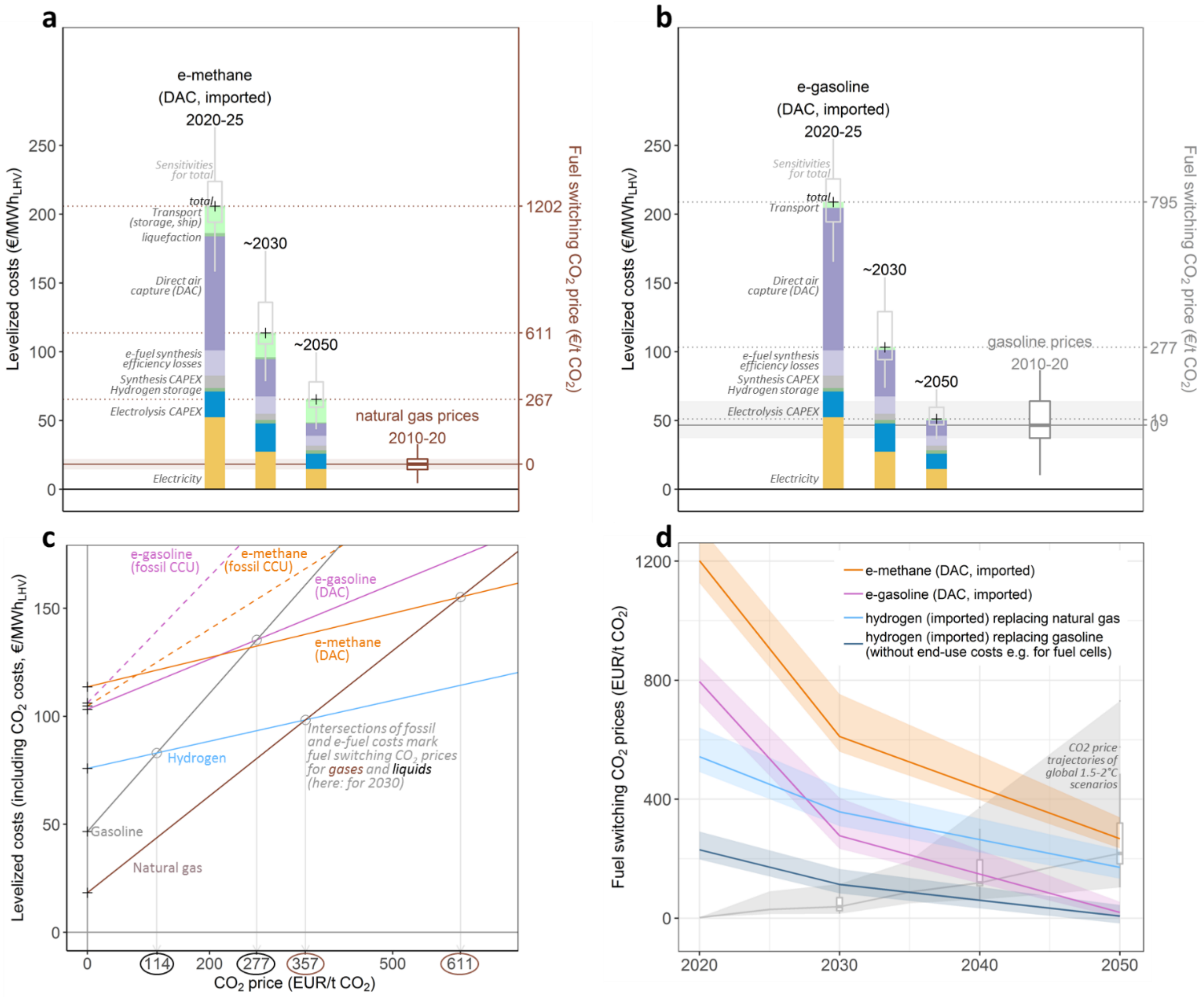


Figure 4 | Levelized cost and fuel switching CO2 prices of e-fuels. a, Levelized cost (and its components) and fuel switching CO_2 prices for e-methane (shipped from Northwest Africa to North-western European ports, based on DAC) for 2020-25, 2030 and 2050, in comparison to European whole-sale market natural gas prices for 2010-20. The + shows total costs. The box plots indicate uncertainties based on a sensitivity study (see supplement S2). **b**, same as 'a', but for e-gasoline compared to wholesale gasoline prices. Also compare an analogue Extended Data Figure 1, in which life-cycle emissions of e-fuels are neglected, and Extended Data Figure 2 for liquefied hydrogen and fossil-CCU based e-fuels. **c**, Levelized costs (including CO_2 costs) of e-fuels and fossil fuels for 2030 as a function of CO2 prices. The + on y-axis are the direct costs (without CO2) shown in panel a and b. The slopes represent the life-cycle carbon intensities of the respective fuels. The circles mark the intersections of fossil and e-fuel costs, which are the break-even points that determine fuel switching CO_2 prices (shown on the 2nd y-axis in a and b). See an analogue Supplement Figure S1 for all years and fuels. **d**, Fuel switching CO_2 prices in time, for e-fuels and hydrogen, in comparison to CO_2 price trajectories of global 1.5-2°C climate mitigation scenarios[63]. Uncertainty ribbons of the e-fuels lines represent 25th-75th percentiles.

For 2020-25, we estimate e-fuel production costs of 194–226 €/MWh (25th-75th percentile), which translates into roughly 3.20 €/l (without taxes) in the case of gasoline. These estimates assume a large-scale application of today's technology; yet, as only a few pilot and demonstration e-fuel projects exist, this short-term, large-scale production estimate is somewhat hypothetical and shall solely indicate the potential competitiveness and required policy support. Given historic natural gas and gasoline prices (mean of 2010-2020 values), this translates into fuel switching CO_2 prices of 800 €/tCO_2 for e-gasoline and 1200 €/tCO_2 for e-methane. Abatement costs for replacing natural gas are higher because both natural gas prices and per-energy emissions savings (carbon intensities) are lower than for gasoline (Figure 4c). As a result, power-to-liquid (PtL) applications are less uncompetitive than power-to-gas (PtG).

Hydrogen and e-fuel costs are anticipated to reduce significantly due to continued technological progress if substantial cumulative investments can be achieved. Decreasing capacity costs of electrolysis, hydrocarbon synthesis and DAC, slight improvements in electrolysis efficiency, as well as lower generation costs and increasing shares of wind and solar PV (supplement S2) can lead to 2050 e-fuel cost estimates of 47-51 €/MWh for e-gasoline and 60-65 €/MWh for e-methane, which faces higher transport costs (due to liquefaction and on-ship cryogenic storage). This translates into 2050 fuel switching CO_2 prices of ~20 €/tCO_2 for e-gasoline and ~270 €/tCO_2 for e-methane.

If fossil CO_2 were utilized instead of DAC, the direct 2020 e-fuel production costs can be reduced by roughly one quarter (Extended Data Figure 2). The low-cost provision of fossil CO_2 in Europe is partly counteracted by an increase of transport costs of liquid hydrogen from Northwest Africa. Despite the net cost savings, the high carbon intensity of fossil CCU leads to very high fuel switching CO_2 prices of >2500 €/tCO_2 in 2020 and ~2000 €/tCO_2 in 2030.

While CO_2 prices required to make e-fuels competitive in 2020-2030 (280-1200 €/tCO_2) are unrealistically high for most countries (including the EU ETS trading scheme), the CO_2 prices required in 2050 (20-270 €/tCO_2) can fall within or below the range seen in climate change mitigation scenarios[63] (Figure 4d) or those likely realized in regional and potentially global carbon markets by that time. Despite the uncertainty about future cost developments, this general result is likely robust and offers two key insights.

1. E-fuels have the potential to become a backstop technology around 2040-2050, widely replacing remaining fossil fuels and feedstocks. Hence, future e-fuel costs indicate an upper limit of long-term marginal abatement costs and thus future carbon prices. In addition, a new generation of mitigation scenario models are likely to calculate long-term carbon prices that are lower than those shown in Figure

4d, once the models fully consider e-fuel pathways - including their potential cost reduction, broad end-use applicability and potential long-term abundance through global trade.

2. However, the realization and timing of this long-term vision hinges on substantial large-scale policy support schemes, which have not been implemented anywhere on the planet. Continuous policy support is required for about two decades before business cases might be secured solely by carbon pricing. Global hydrogen and e-fuel markets have to be facilitated by the international coordination of policy makers. The enormous gap between abatement costs and carbon prices illustrates the magnitude of required subsidies. This adds significant uncertainty to the large-scale availability of hydrogen and e-fuels especially within the next two decades.

For the EU, recent ambitions of increasing the 2030 emission reduction target from 40 % to 55-60 % might lead to higher 2030 CO_2 prices than the global CO_2 prices shown in Figure 4d. This is true for both the EU-ETS as well for the non-EU ETS sectors transport and buildings that are not subject to explicit carbon pricing at the EU level yet. High EU carbon prices can create a global demand pull for hydrogen and e-fuels with far-reaching effects on potential export countries that may not have comparable carbon pricing.

Competition with direct electrification

Against the backdrop of high e-fuel costs until ~2040, uncertainty of their large-scale availability and urgent emission reductions in non-electric energy demand sectors, it is worthwhile to understand the cost comparison with other mitigation options; most importantly direct electrification. In Figure 2, we show marginal abatement cost curves (MACCs) for 2020-25 for liquid and gaseous e-fuels (blue, from the calculations presented in Figure 4) and direct electrification alternatives (green, schematic curve) across non-electric energy and industrial sectors in the OECD (energy end-use data from IEA ETP 2017 (ref[64])). The four categories of energy end-uses are sorted according to the anticipated costs of directly electrifying the respective applications (horizontal sorting from low to high costs of direct electrification). Within each of the four categories, the sectors are sorted according to their size.

E-fuel MACCs are flat because e-fuels are perfect substitutes to their fossil counterparts. Abatement costs are high due to conversion losses and investment costs, and mainly depend on the type of fossil fuel that is to be substituted. In contrast, electricity is relatively cheap, but an imperfect substitute to fossil fuels. Its application in (currently non-electric) energy services requires an end-use transformation from combustion technologies to electric devices and processes. The associated feasibility and costs depend on the specific circumstances and vary across energy demand sectors. The respective MACC is highly uncertain. We therefore show an illustrative curve progression here to provide a qualitative illustration of the competitiveness of e-fuels vis-à-vis direct electrification (Figure 5).

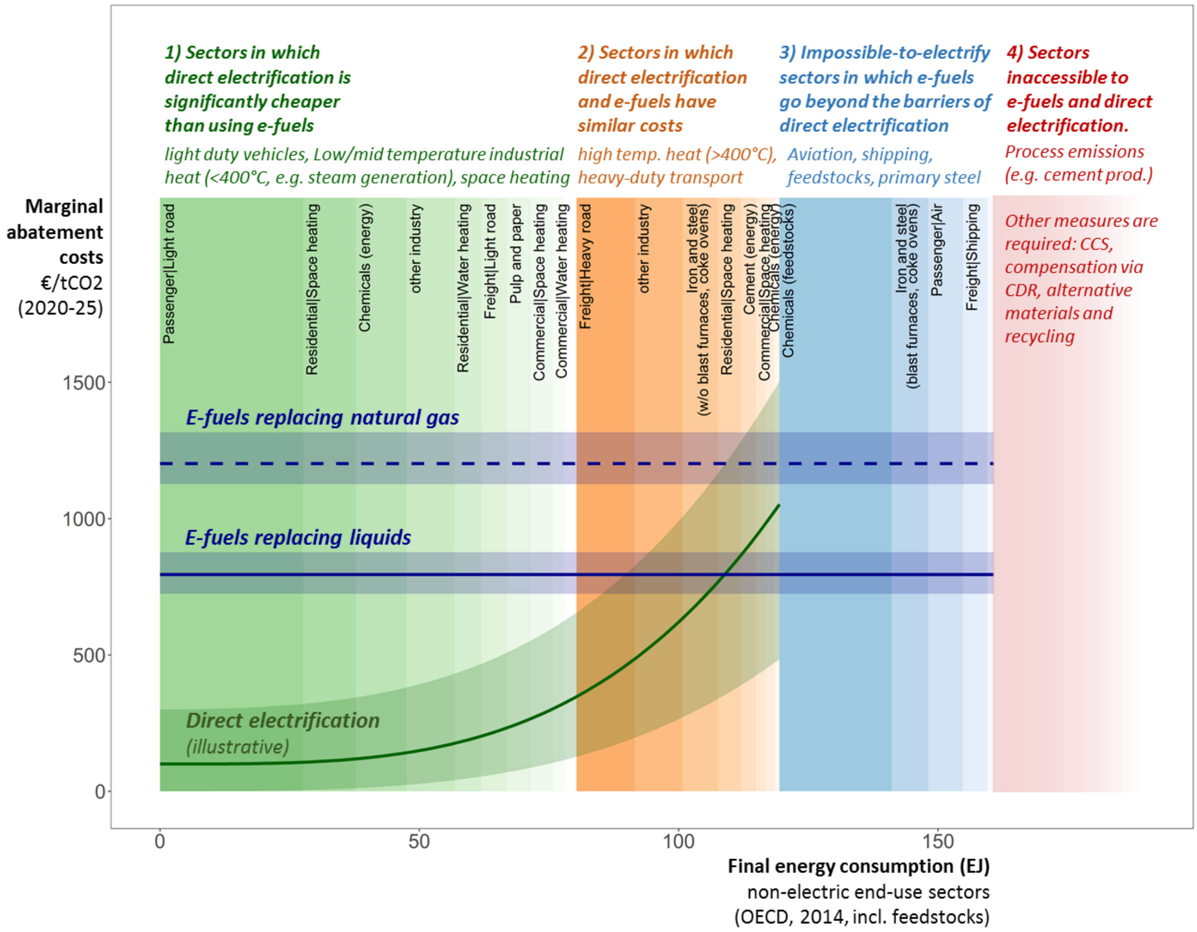


Figure 2 | Marginal abatement cost curves (i.e., fuel switching CO_2 prices). In 2020-25 and for e-methane (replacing natural gas) and liquid e-fuels (replacing fossil liquids) from the cost calculations shown in Figure 4, and direct electrification alternatives (green, illustrative curve) across non-electric energy and industrial sectors in the OECD (2014 energy end-use data from IEA ETP 2017[64]). The four categories of energy end-uses are sorted according to the costs of directly electrifying the respective applications (horizontal sorting from low to high costs of direct electrification). Within each of the four categories, the sectors are sorted according to their size. An analogue Extended Data Figure S3 also includes the direct use of hydrogen.

Based on the relation of both curves, we broadly group end-use sectors into four categories (corresponding to the four background colors) reflecting the competitiveness of e-fuels and direct electrification.

Firstly, there are sectors and applications for which direct electrification is significantly cheaper than using e-fuels. The corresponding technologies include battery-electric light-duty vehicles, heat pumps and electric boilers (low- to mid-temperature heat in buildings and industry), as well as secondary steel production in electric arc furnaces. The direct electrification cost advantage increases if the electricity input is not fully decarbonized due to the efficiency disadvantage of hydrogen and e-fuels.

Secondly, there are sectors in which direct electrification and e-fuels have similar costs, or in which high uncertainty or potential other barriers to a direct electrification leave the cost comparison ambiguous. This includes high-temperature heat in industry (>400°C), for example for large-scale glass, ceramics, or cement plants, as well as long-haul heavy-duty road transport, and space heating in those existing buildings that are not easily accessible for heat pumps, district, or electric central heating. These sectors could be approached with technology-neutral climate policies and broad R&D funding with the aim of quickly reducing costs and uncertainties. A coordinated decision needs to be made in the coming years given the urgency of climate mitigation and different infrastructure requirements. Since the large-scale availability of green hydrogen is uncertain and direct electrification is more efficient, an optimal allocation of scarce domestic renewable electricity could imply a priorization of direct electrification.

Thirdly, there are sectors and applications for which direct electrification faces limits that can be overcome by hydrogen and e-fuels (e.g., long-distance aviation and shipping, feedstock demand in the chemical industry, and primary steel). These can be regarded as "no-regret" sectors and targets for hydrogen and e-fuels. However, as abatement costs of e-fuels are high, alternative options should be considered as well (biofuels, CCS, alternative materials or industrial goods, and recycling). Final energy in these sectors amounts to ~40 EJ across the OECD (12500 TWh, in 2014). Meeting this with e-fuels would require additional solar and wind power capacity of about 5000 GW with roughly the same magnitude for electrolysis capacity, while global 2019 addition of renewable power capacity amounted to ~200 GW/y [65]. This points to the need for a prioritization even within impossible-to-electrify sectors.

Fourthly, there are some emissions that can neither be avoided by electrification nor by e-fuels, such as process emissions from cement manufacturing. Additional alternative options should primarily be used here, such as CCS, compensation with CDR, alternative materials, and recycling. Note that CDR and CCS also compete with e-fuels for the best use of captured carbon. If carbon storage is available (and socially accepted), permanent CO_2 storage may be more cost-efficient than CO_2 utilization and re-emission as e-fuels[66].

A holistic approach should not only consider the costs of hydrogen and e-fuels, but rather the two-fold opportunity costs: first, the next best mitigation alternative for a sector (often direct electrification), and second, the next best alternative use of scarce hydrogen and e-fuels. From a carbon neutrality perspective, e-fuels should be targeted on sectors inaccessible to direct electrification (category 3), even if competitiveness may be more in reach (i.e. would require less subsidies) in some of the category 1 applications, and even if removing barriers to electrification in category 2 requires major efforts. By contrast, policies that foster hydrogen and e-fuel use in category 1 applications can significantly increase overall costs of climate change mitigation, while even increasing GHG emission compared to using electricity directly, which risks public acceptance of the energy transition as a whole.

Conclusions and policy recommendations

The versatility of e-fuels gives rise to the vision of a wide-scale replacement of fossil fuels without the transformational burden on the demand side. However, this versatility comes at significant costs. Depending on the e-fuel application, electricity-to-useful energy efficiencies range from roughly 10% to 35%, which translates into renewable electricity generation requirements that are two to fourteen times higher than for direct electrification alternatives. As a result, the e-fuel climate effectiveness critically hinges on very high renewable electricity shares as well as renewability of the carbon source. Multifold supply side investments translate into high e-fuel mitigation costs: ~800 €/tCO_2 for e-gasoline and ~1200 €/tCO_2 for e-methane in 2020-25. Technological progress could reduce the abatement cost vis-à-vis fossil alternatives significantly to ~20 €/tCO_2 for e-gasoline and ~270 €/tCO_2 for e-methane in the long term (~2050).

From a system perspective, we can draw six main conclusions that should guide climate and energy policy decisions:

1. It is unlikely that hydrogen and e-fuels become cheap and abundant early enough to widely substitute fossil fuels. Their expansion critically depends on significant and continuous hydrogen- or e-fuel- specific policy support to bridge the gap between very high initial mitigation costs and the level of actual carbon pricing applied. Carbon prices anticipated until at least 2030 (e.g., in the EU-ETS) are too low to make e-fuels competitive. The scale of future e-fuel markets thus remains highly uncertain.

2. Given the short-term scarcity and long-term uncertainty of e-fuels, a merit order should prioritize hydrogen and e-fuel use for specific no-regret sectors. No-regret application are not only hard-to-abate, but also impossible-to-electrify such as chemical feedstocks (ammonia, olefins), primary steel making, long-distance aviation and shipping. In the OECD, these no-regret sectors amount to about one quarter of all final energy (including feedstock use), which demonstrates that these are hydrogen and e-fuel markets of significant size, which might require a further prioritization within this selection.

3. Betting on the future large-scale availability of hydrogen and e-fuels risks a lock-in of fossil fuel dependency if their upscaling falls short of expectations. Hydrogen and e-fuels are a potential distraction from the urgent need for an end-use transformation towards wide-scale direct electrification, which is cheaper, more efficient and widely on well-advanced available technology in many sectors such as light-duty vehicles or low-temperature heating in buildings and industry.

4. E-fuels are unlikely to provide substantial contributions to 2030 climate targets; not least because their climate effectiveness hinges on a very advanced power transition (e.g. a >90% renewable electricity share for transport applications), and low-carbon electricity can more efficiently reduce emissions via direct electrification. In the mid to long term, based on a large-scale production and technological progress (renewable electricity, electrolysis, DAC), e-fuel costs can become competitive solely based on carbon prices. E-fuels can then evolve to a long-term backstop technology: above a certain carbon price, e-fuels could replace all residual fossil fuels, thus reducing the reliance on less-sustainable options such as biofuels, CCS, and CDR mitigation options.

5. E-fuels can help addressing renewable resource limits in densely populated countries such as Japan, Germany or South Korea. Further, they create an export opportunity for renewable-rich regions, such as MENA, Iceland, Latin America, and Australia [34,67]. Tapping into the huge wind and solar PV potentials of the global sun belts, e-fuels can be globally traded ("shipping the sun"), and thus resolve the geographical discrepancy between renewable supply and energy demand patterns. However, developing a global e-fuel market is a tremendous challenge that relies on policy support, and an internationally coordinated ramp-up of e-fuel supply and demand technologies, together with the associated hydrogen and CO_2 infrastructure.

6. Finally, the hydrogen and e-fuel option should be embedded in an overall policy and transformation strategy that includes infrastructure roadmaps. The global sources for electricity and CO_2, future global patterns of renewable energy trade, and the extent to which hydrogen is directly used will determine the additional long-term infrastructure needs. Fossil CCU and atmospheric CCC require CO_2 and hydrogen infrastructure with different spatial topography, which suggests that utilizing fossil CO_2 is not a sensible bridge to the sustainable circular option due to the longevity of infrastructure investments.

Many of these conclusions also hold for the direct use of hydrogen. However, avoiding the additional conversion step of a hydrocarbon synthesis reduces the supply-side cost and efficiency penalties, while losing some of the versatility advantage of e-fuels on the demand side. Handling hydrogen (e.g., storage and transportation) is more challenging, requires additional infrastructure (potentially a hydrogen grid), and partially additional transformation on the demand side (e.g., fuel cells for heavy-duty road transport). Further research should explore a sensible balance of hydrogen and e-fuels in light of these tradeoffs.

Developing the potential of e-fuels requires policies that support research, demonstration and most importantly market introduction. Demand-side policies that complement supply-side instruments can steer e-fuel flows towards no regret applications and would thereby implement an e-fuel merit order. For example, a carbon contract for differences (CCfD) scheme that subsidizes the use of hydrogen in energy-intensive industries and e-fuel quotas for aviation fuels are currently debated in Germany and mentioned as an option in the EU hydrogen strategy[68].

Direct use of hydrogen for ammonia or primary steel production could become cost-competitive with the help of 2030 EU-ETS carbon prices, which would push the scale-up of hydrogen supply-chains before its usage for e-fuels. CCfDs, border tax adjustments and increasing EU carbon prices can create a global demand pull for hydrogen and e-fuels, which could even incentivize export from countries that do not have carbon pricing (e.g., Australia) or e-fuel policy support. Complementing bilateral cooperation projects and public-private partnerships can support the coordination of an international supply and demand scale-up towards a global e-fuel market.

Despite the good reasons for e-fuel policies, they should not crowd out more efficient and mature options such as direct electrification, renewable capacity and transmission grid expansion. Sensible climate and energy policy must not regard e-fuels as a full-scale substitute to fossil fuels or other mitigation technologies, but rather as a potential complement where other mitigation options face insurmountable barriers.

An overall policy strategy should rest on two pillars: First, broad technology support to foster innovation and initial scale-up across options until they are mature enough. Second, significant carbon pricing across sectors and an energy tax reform that together create a level-playing field for all technologies and thus a sensible balance between direct and indirect electrification.

Data availability

The life-cycle analysis for passenger cars and trucks can be reproduced with the open-source tools life cycle assessment model carculator[50] and carculator_truck[51]. The electrolysis cost and efficiency data is available in Everall and Ueckerdt (2021)[60]. All other data are available from the corresponding author on request.

Acknowledgements

We want to thank Jonas Knapp, Stephen Bi, Felix Schreyer, Falk Benke, Adrian Odenweller, Benjamin Pfluger, Jessica Strefler, Fabian Stöckl and Silvia Madeddu for their critical reviews, valuable discussion and comments, and Changlong Wang for sharing Australian electricity price data. We gratefully acknowledge funding from the START project (FKZ03EK3046A), the Kopernikus-Ariadne project (FKZ 03SFK5A) by the German Federal Ministry of Education and Research and from PSI's ESI platform.

Corresponding author

Correspondence and requests for materials should be addressed to FU (falko.ueckerdt@pik-potsdam.de).

Author Contributions

FU and GL designed the study and derived the main conclusions. FU coordinated the work, conducted the cost calculations and efficiency comparisons, derived the main figures and did most of the writing. GL significantly contributed to the writing. RS, CB and AD did the life-cycle greenhouse gas analysis and associated figures. JE conducted the majority of the literature review, and contributed to the data curation and code development. All co-authors reviewed and edited the text.

References

1. Olah, G. A., Goeppert, A. & Prakash, G. K. S. Chemical Recycling of Carbon Dioxide to Methanol and Dimethyl Ether: From Greenhouse Gas to Renewable, Environmentally Carbon Neutral Fuels and Synthetic Hydrocarbons. *J. Org. Chem.* **74**, 487–498 (2009).

2. Sterner, M. *Bioenergy and renewable power methane in integrated 100% renewable energy systems: Limiting global warming by transforming energy systems*. vol. 14 (Kassel University Press GmbH, 2009).
3. Zeman, F. S. & Keith, D. W. Carbon neutral hydrocarbons. *Phil. Trans. R. Soc. A.* **366**, 3901–3918 (2008).
4. He, T., Pachfule, P., Wu, H., Xu, Q. & Chen, P. Hydrogen carriers. *Nat Rev Mater* **1**, 16059 (2016).
5. Creutzig, F. *et al.* Bioenergy and climate change mitigation: an assessment. *GCB Bioenergy* n/a-n/a (2014) doi:10.1111/gcbb.12205.
6. Whitmarsh, L., Xenias, D. & Jones, C. R. Framing effects on public support for carbon capture and storage. *Palgrave Commun* **5**, 17 (2019).
7. Minx, J. C. *et al.* Negative emissions—Part 1: Research landscape and synthesis. *Environ. Res. Lett.* **13**, 063001 (2018).
8. Smith, P. *et al.* Biophysical and economic limits to negative CO2 emissions. *Nature Climate Change* **6**, 42–50 (2015).
9. Luderer, G. *et al.* Environmental co-benefits and adverse side-effects of alternative power sector decarbonization strategies. *Nat Commun* **10**, 5229 (2019).
10. Williams, J. H. *et al.* The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity. *Science* **335**, 53–59 (2012).
11. Needell, Z. A., McNerney, J., Chang, M. T. & Trancik, J. E. Potential for widespread electrification of personal vehicle travel in the United States. *Nat Energy* **1**, 16112 (2016).
12. Madeddu, S. *et al.* The CO_2 reduction potential for the European industry via direct electrification of heat supply (power-to-heat). *Environ. Res. Lett.* (2020) doi:10.1088/1748-9326/abbd02.
13. Mai, T. *et al. Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*. (NREL, 2018). doi:10.2172/1459351.

14. Jacobson, M. Z., Delucchi, M. A., Cameron, M. A. & Frew, B. A. Low-cost solution to the grid reliability problem with 100% penetration of intermittent wind, water, and solar for all purposes. *PNAS* **112**, 15060–15065 (2015).
15. Lu, B., Blakers, A., Stocks, M., Cheng, C. & Nadolny, A. A zero-carbon, reliable and affordable energy future in Australia. *arXiv:2007.09586 [physics]* (2020).
16. Bistline, J. E. & Blanford, G. J. More than one arrow in the quiver: Why "100% renewables" misses the mark. *Proc Natl Acad Sci USA* **113**, E3988–E3988 (2016).
17. Royal Society (Great Britain). *Sustainable synthetic carbon based fuels for transport*. (2019).
18. International Energy Agency. *The Future of Hydrogen: Seizing today's opportunities*. (OECD, 2019). doi:10.1787/1e0514c4-en.
19. Bloomberg Finance L.P. *Hydrogen Economy Outlook: Key Messages*. (2020).
20. Davis, S. J. *et al.* Net-zero emissions energy systems. *Science* **360**, (2018).
21. Luderer, G. *et al.* Residual fossil CO2 emissions in 1.5–2 °C pathways. *Nature Climate Change* **8**, 626–633 (2018).
22. Bruce, S. *et al.* Opportunities for hydrogen in commercial aviation. *CSIRO* 94 (2020).
23. World Economic Forum. Clean Skies for Tomorrow Sustainable Aviation Fuels as a Pathway to Net-Zero Aviation. (2020).
24. Geres, R. *et al. Roadmap Chemie 2050 auf dem Weg zu einer treibhausgasneutralen chemischen Industrie in Deutschland: eine Studie von DECHEMA und FutureCamp für den VCI*. (2019).
25. Blanco, H. & Faaij, A. A review at the role of storage in energy systems with a focus on Power to Gas and long-term storage. *Renewable and Sustainable Energy Reviews* **81**, 1049–1086 (2018).
26. Peters, D. *et al. Gas Decarbonisation Pathways 2020–2050 - Gas for Climate*. (2020).
27. van Renssen, S. The hydrogen solution? *Nat. Clim. Chang.* **10**, 799–801 (2020).

28. Blanco, H., Nijs, W., Ruf, J. & Faaij, A. Potential of Power-to-Methane in the EU energy transition to a low carbon system using cost optimization. *Applied Energy* **232**, 323–340 (2018).
29. dena. *The potential of electricity based fuels (e-fuels) for low emission transport in the EU*. (2017).
30. German Association of the Automotive Industry - VDA. VDA President Müller: Hydrogen and e-fuels are important elements in climate-neutral transport. (2020).
31. Clean Energy Wire. 'Tomorrow's oil': Germany seeks hydrogen export deal with West African states. (2020).
32. Barreto, L., Makihira, A. & Riahi, K. The hydrogen economy in the 21st century: a sustainable development scenario. *International Journal of Hydrogen Energy* **28**, 267–284 (2003).
33. Abe, J. O., Popoola, A. P. I., Ajenifuja, E. & Popoola, O. M. Hydrogen energy, economy and storage: Review and recommendation. *International Journal of Hydrogen Energy* **44**, 15072–15086 (2019).
34. Fasihi, M., Bogdanov, D. & Breyer, C. Techno-Economic Assessment of Power-to-Liquids (PtL) Fuels Production and Global Trading Based on Hybrid PV-Wind Power Plants. *Energy Procedia* **99**, 243–268 (2016).
35. Deutsch, M. *The Future Cost of Electricity-Based Synthetic Fuels*. https://www.renewableh2.org/wp-content/uploads/2018/11/2018-09-Agora_SynKost_Study_EN_WEB.pdf (2018).
36. Ram, M. *et al.* Powerfuels in a Renewable Energy World - Global volumes, costs, and trading 2030 to 2050. *LUT University and Deutsche Energie-Agentur GmbH (dena). Lappeenranta, Berlin.* 98 (2020).
37. Brown, T., Schlachtberger, D., Kies, A., Schramm, S. & Greiner, M. Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European energy system. *Energy* **160**, 720–739 (2018).

38. Stephanos, C., Rolle, C. & Seidl, H. Essential findings of the three baseline studies into the feasibility of the energy transition by 2050 in Germany. (2019).
39. Capros, P. *et al.* Energy-system modelling of the EU strategy towards climate-neutrality. *Energy Policy* **134**, 110960 (2019).
40. Bos, M. J., Kersten, S. R. A. & Brilman, D. W. F. Wind power to methanol: Renewable methanol production using electricity, electrolysis of water and CO2 air capture. *Applied Energy* **264**, 114672 (2020).
41. Stockl, F., Schill, W.-P. & Zerrahn, A. Green hydrogen: optimal supply chains and power sector benefits. *arXiv:2005.03464 [physics, q-fin]* (2020).
42. Milanzi, S. *et al. Technischer Stand und Flexibilität des Power-to-Gas-Verfahrens*. https://www.er.tu-berlin.de/fileadmin/a38331300/Dateien/Technischer_Stand_und_Flexibilit%C3%A4t_des_Power-to-Gas-Verfahrens.pdf (2018).
43. Beuttler, C., Charles, L. & Wurzbacher, J. The Role of Direct Air Capture in Mitigation of Anthropogenic Greenhouse Gas Emissions. *Front. Clim.* **1**, 10 (2019).
44. Deutz, S. & Bardow, A. *How (Carbon) Negative Is Direct Air Capture? Life Cycle Assessment of an Industrial Temperature-Vacuum Swing Adsorption Process*. https://chemrxiv.org/articles/preprint/How_Carbon_Negative_Is_Direct_Air_Capture_Life_Cycle_Assessment_of_an_Industrial_Temperature-Vacuum_Swing_Adsorption_Process/12833747/1 (2020) doi:10.26434/chemrxiv.12833747.v1.
45. European Commission. *Integrated Pollution Prevention and Control (IPPC) Reference Document on the application of Best Available Techniques to Industrial Cooling Systems (European Commission, 2001)*.
46. Cusano, G. *et al. Best Available Techniques (BAT) Reference Document for the Non-Ferrous Metals Industries - Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control)*. (Joint Research Centre, 2017).

47. Arpagaus, C., Bless, F., Uhlmann, M., Schiffmann, J. & Bertsch, S. S. High temperature heat pumps: Market overview, state of the art, research status, refrigerants, and application potentials. *Energy* **152**, 985–1010 (2018).
48. *Electrification in the Dutch process industry, In-depth study of promising transition pathways and innovation opportunities for electrification in the Dutch process industry*. (Berenschot, CE Delft, Industrial Energy Experts, Energy Matters, 2017).
49. Yilmaz, H. Ü., Keles, D., Chiodi, A., Hartel, R. & Mikulić, M. Analysis of the power-to-heat potential in the European energy system. *Energy Strategy Reviews* **20**, 6–19 (2018).
50. Sacchi, R., Bauer, C., Cox, B. & Mutel, C. Carculator: An Open-Source Tool for Prospective Environmental and Economic Life Cycle Assessment of Vehicles. When, Where and How Can Battery-Electric Vehicles Help Reduce Greenhouse Gas Emissions? *Renew. Sustain. Energy Rev.* (2020).
51. Sacchi, R., Bauer, C. & Cox, B. Does size matter? The influence of size, load factor, range autonomy and application type on the Life Cycle Assessment of current and future trucks. *Environmental Science and Technology* (2020).
52. Ecoinvent. *Life cycle inventory database v3.7*. www.ecoinvent.org (2020).
53. Knobloch, F. *et al.* Net emission reductions from electric cars and heat pumps in 59 world regions over time. *Nature Sustainability* **3**, 437–447 (2020).
54. Lee, D. S. *et al.* The contribution of global aviation to anthropogenic climate forcing for 2000 to 2018. *Atmospheric Environment* **244**, 117834 (2021).
55. Abanades, J. C., Rubin, E. S., Mazzotti, M. & Herzog, H. J. On the climate change mitigation potential of CO2 conversion to fuels. *Energy Environ. Sci.* **10**, 2491–2499 (2017).
56. von der Assen, N., Jung, J. & Bardow, A. Life-cycle assessment of carbon dioxide capture and utilization: avoiding the pitfalls. *Energy Environ. Sci.* **6**, 2721 (2013).
57. Zhang, X., Bauer, C., Mutel, C. L. & Volkart, K. Life Cycle Assessment of Power-to-Gas: Approaches, system variations and their environmental implications. *Applied Energy* **190**, 326–338 (2017).

58. Harper, A. B. *et al.* Land-use emissions play a critical role in land-based mitigation for Paris climate targets. *Nat Commun* **9**, 2938 (2018).

59. Cherubini, F., Peters, G. P., Berntsen, T., Strømman, A. H. & Hertwich, E. CO2 emissions from biomass combustion for bioenergy: atmospheric decay and contribution to global warming: GLOBAL WARMING POTENTIAL OF CO2 FROM BIOENERGY. *GCB Bioenergy* **3**, 413–426 (2011).

60. Everall, J. & Ueckerdt, F. Electrolyser CAPEX and efficiency data for: Potential and risks of hydrogen-based e-fuels in climate change mitigation. (2021) doi:10.5281/ZENODO.4619892.

61. Glenk, G. & Reichelstein, S. Economics of converting renewable power to hydrogen. *Nat Energy* **4**, 216–222 (2019).

62. Hank, C. *et al.* Energy efficiency and economic assessment of imported energy carriers based on renewable electricity. *Sustainable Energy Fuels* **4**, 2256–2273 (2020).

63. Huppmann, D., Rogelj, J., Krey, V., Kriegler, E. & Riahi, K. A new scenario resource for integrated 1.5 °C research. *Nature Climate Change* (2018) doi:10.1038/s41558-018-0317-4.

64. International Energy Agency. *Energy Technology Perspectives 2017: Catalyzing Energy Technology Transformations*. https://www.iea.org/etp2017/ (2017).

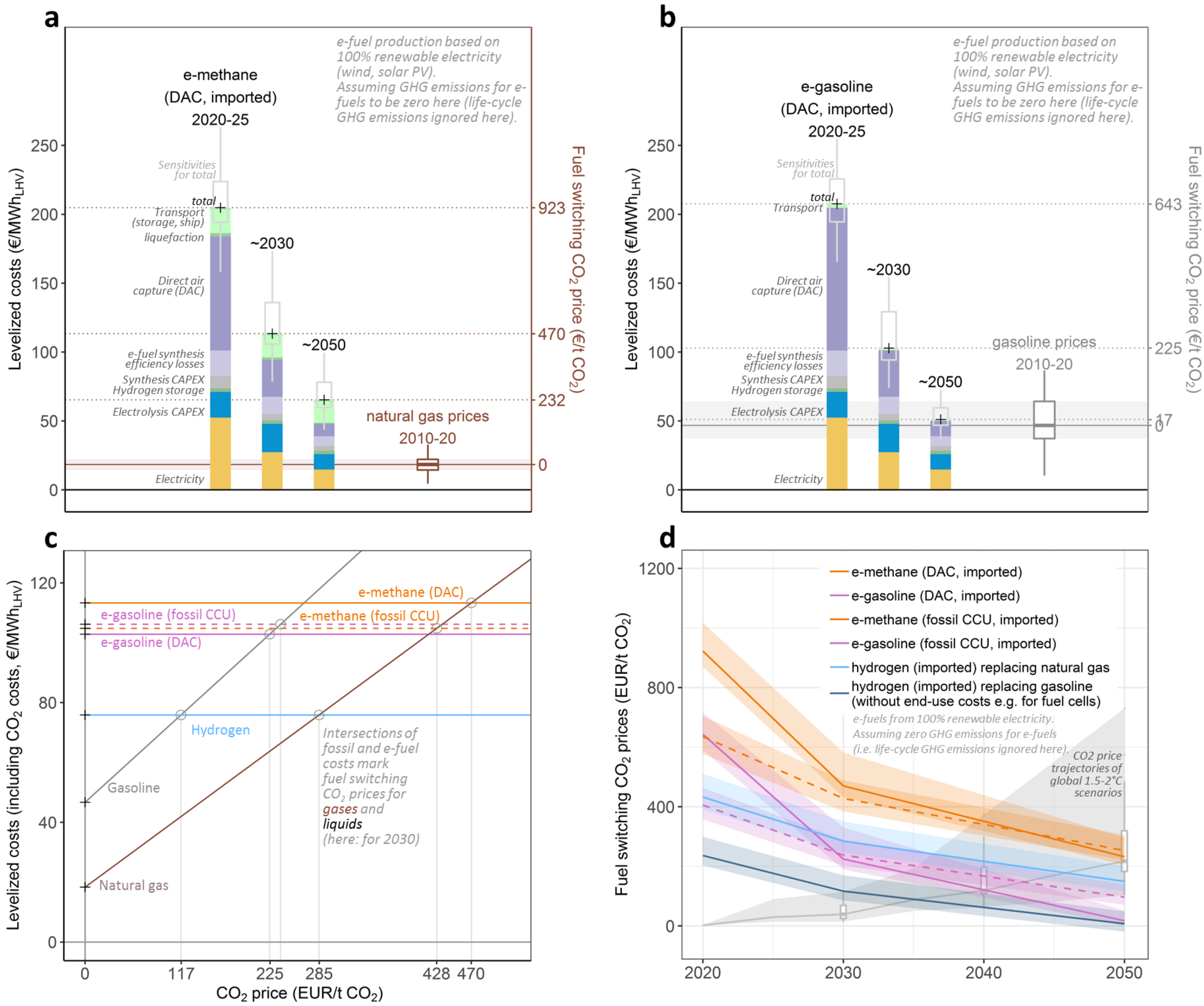
65. REN21. Renewables 2020 Global Status Report. (2020).

66. Lehtveer, M., Brynolf, S. & Grahn, M. What Future for Electrofuels in Transport? Analysis of Cost Competitiveness in Global Climate Mitigation. *Environmental Science & Technology* **53**, 1690–1697 (2019).

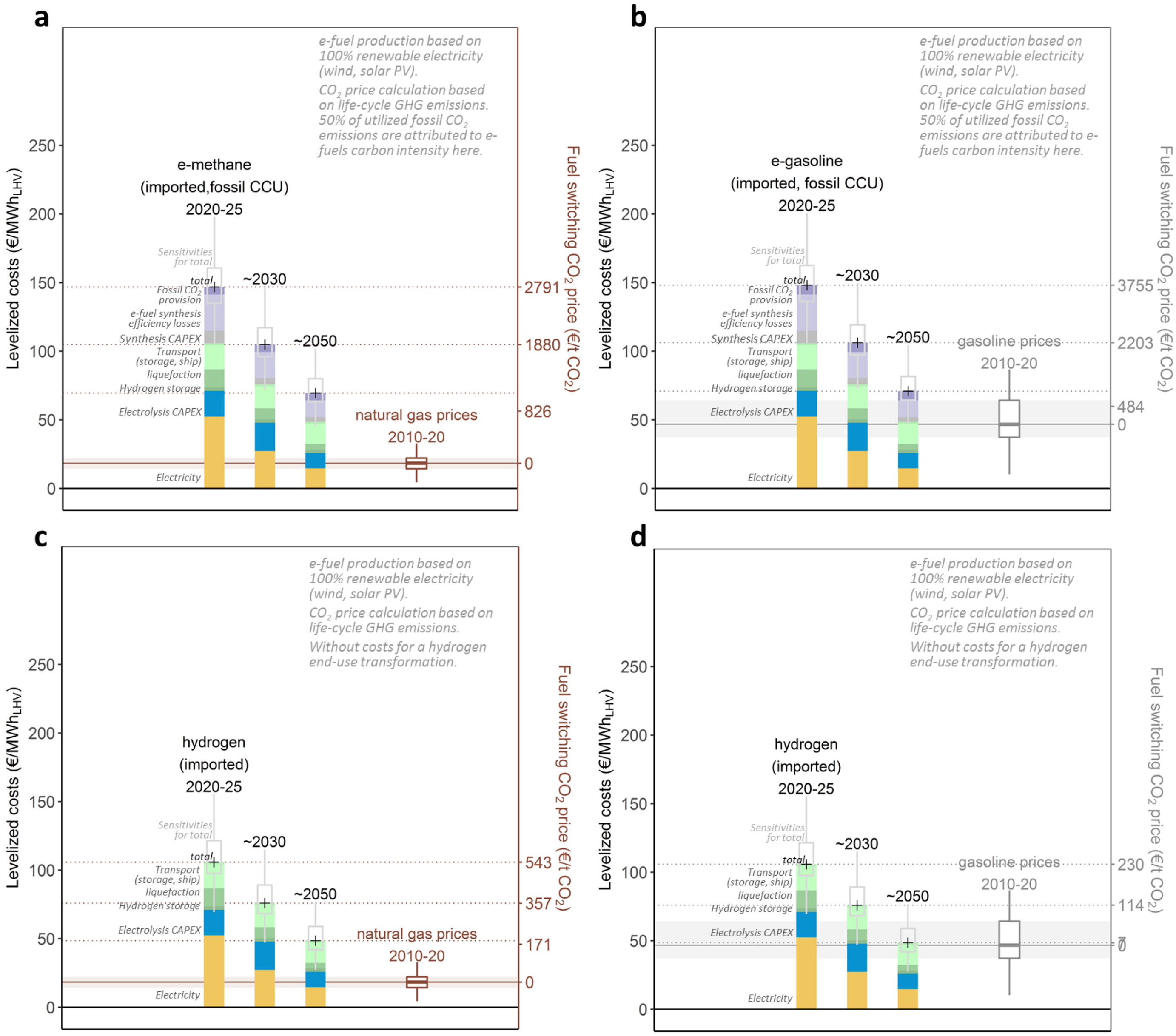
67. Fasihi, M., Bogdanov, D. & Breyer, C. Long-Term Hydrocarbon Trade Options for the Maghreb Region and Europe—Renewable Energy Based Synthetic Fuels for a Net Zero Emissions World. *Sustainability* **9**, 306 (2017).

68. EU Commission. A hydrogen strategy for a climate-neutral Europe. (2020).

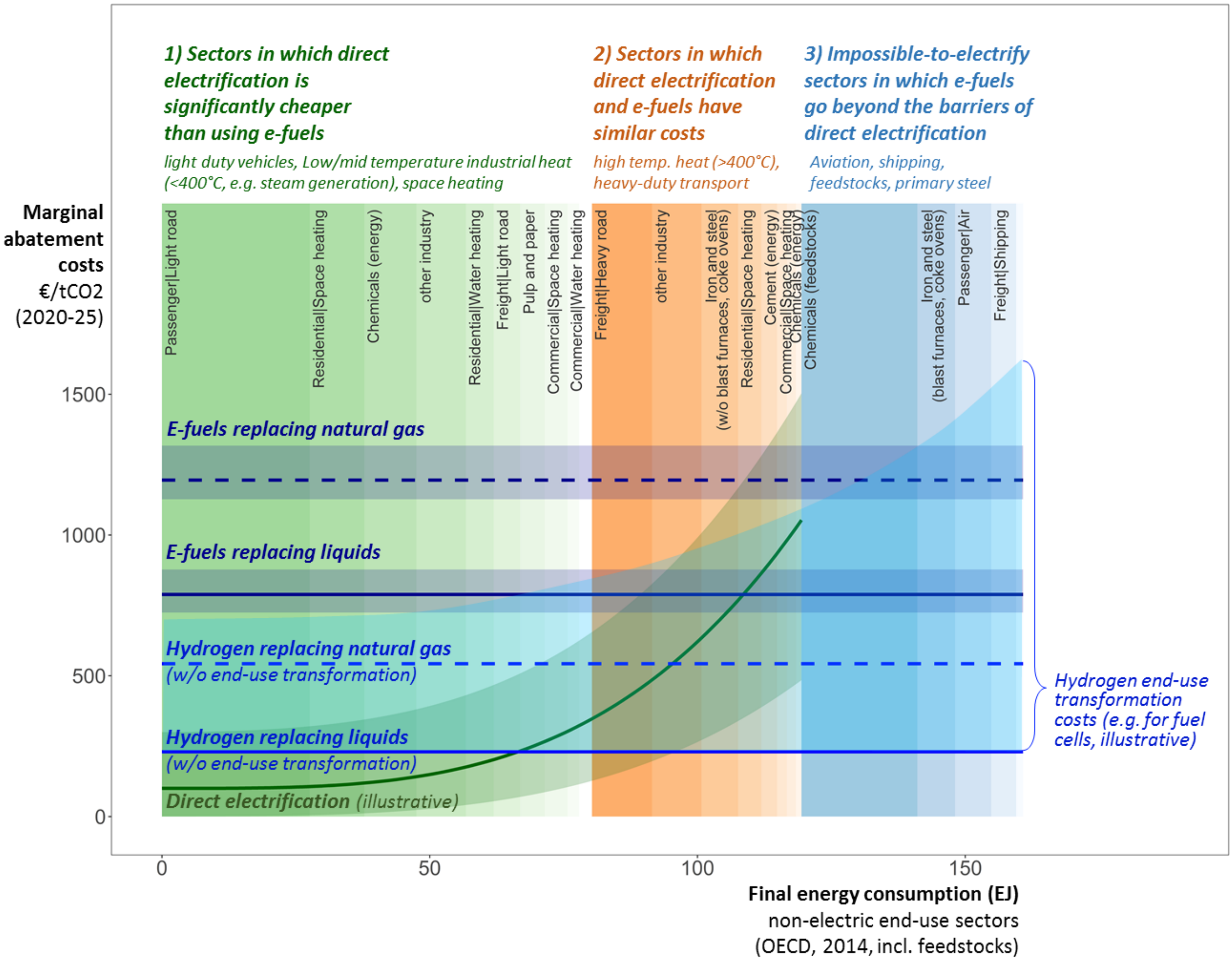
Extended data figures



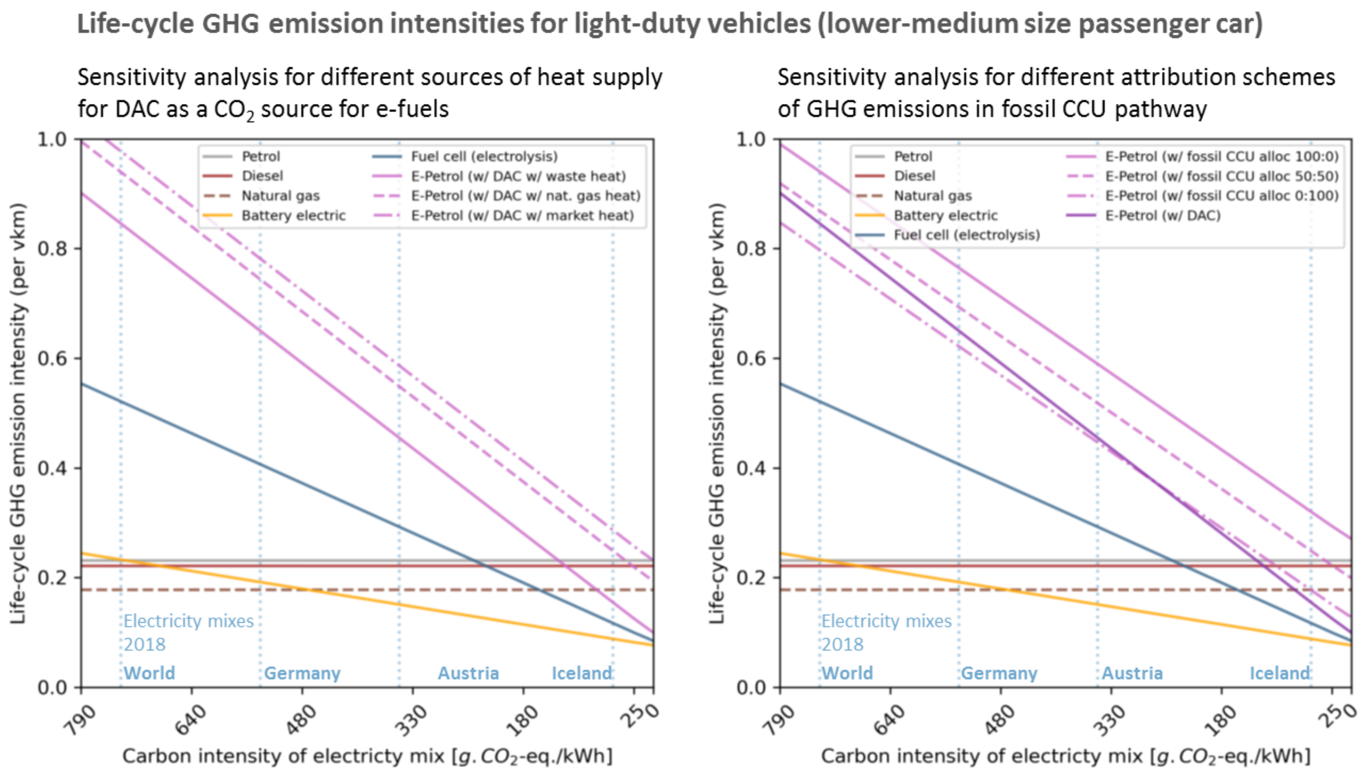
Extended Data Figure 1| Levelized cost and fuel switching CO_2 prices of e-fuels. Same as Figure 4, but here based on the assumption that e-fuels (including those that are fossil CCU based) are evaluated as if they would not cause GHG emissions. a, Levelized cost (and its components) and fuel switching CO2 prices for e-methane (shipped from Northwest Africa to North-western European ports, based on DAC) for 2020-25, 2030 and 2050, in comparison to European whole-sale market natural gas prices for 2010-20. The + shows total costs. The box plots indicate uncertainties based on a sensitivity study (see supplement S2). **b**, same as 'a', but for e-gasoline compared to wholesale gasoline prices. **c**, Levelized costs (including CO2 costs) of e-fuels and fossil fuels for 2030 as a function of CO2 prices. The + on y-axis are the direct costs (without CO2) shown in panel a and b. The slopes represent the life-cycle carbon intensities of the respective fuels. The circles mark the intersections of fossil and e-fuel costs, which are the break-even points that determine fuel switching CO2 prices (shown on the 2nd y-axis in a and b). **d**, Fuel switching CO2 prices in time, for e-fuels and hydrogen, in comparison to CO2 price trajectories of global 1.5-2°C climate mitigation scenarios[64]. Uncertainty ribbons of the e-fuels lines represent 25th-75th percentiles. Note that when calculating fuel switching CO_2 prices we compare costs (for e-fuels) with whole-sale prices (for fossil fuels). We hereby take a system planner perspective on climate mitigation seeking for a cost-efficient energy transformation. The extent to which e-fuel *costs* translate into e-fuel *prices* depend on competition, structure and regulation of future e-fuel markets.



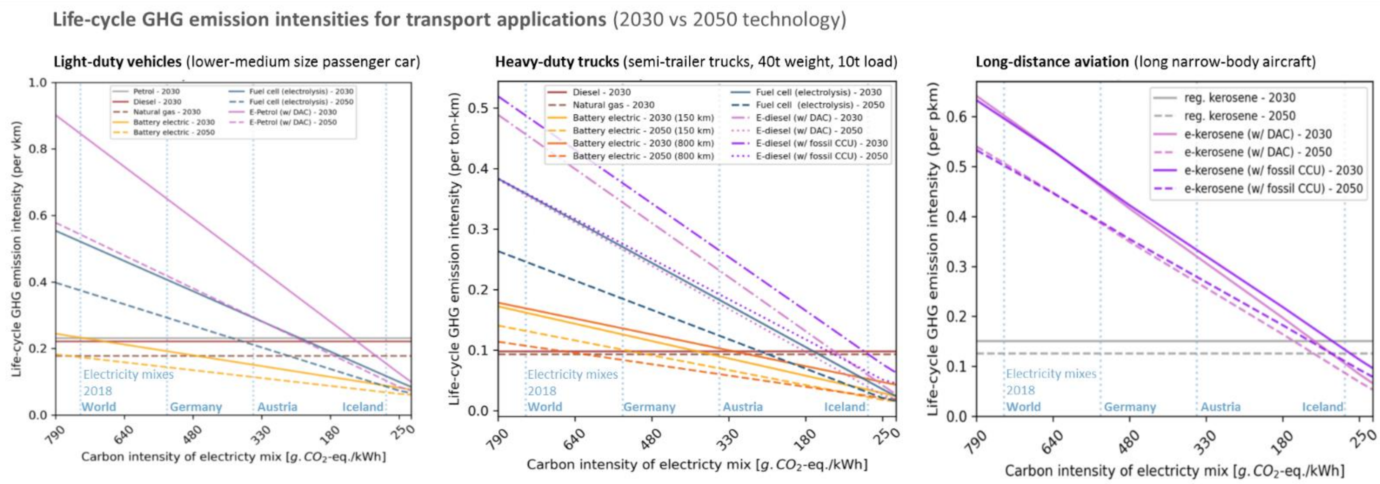
Extended Data Figure 2 | Levelized cost (and its components) and fuel switching CO_2 prices. a, for e-methane (hydrogen shipped from Northwest Africa to North-western European ports, based on fossil CCU) for 2020-25, 2030 and 2050, in comparison to European whole-sale market natural gas prices for 2010-20. The + shows total costs. The box plots indicate uncertainties based on a sensitivity study (see S5). **b**, same as 'a', but for e-gasoline compared to whole-sale gasoline prices. **c**, same as 'a', but for liquefied hydrogen compared to natural gas and **d,** to gasoline. Hydrogen is no perfect substitute to fossil fuels and thus requires additional costs for an end-use transformation, which are not reflected in the cost bars and fuel switching CO_2 prices.



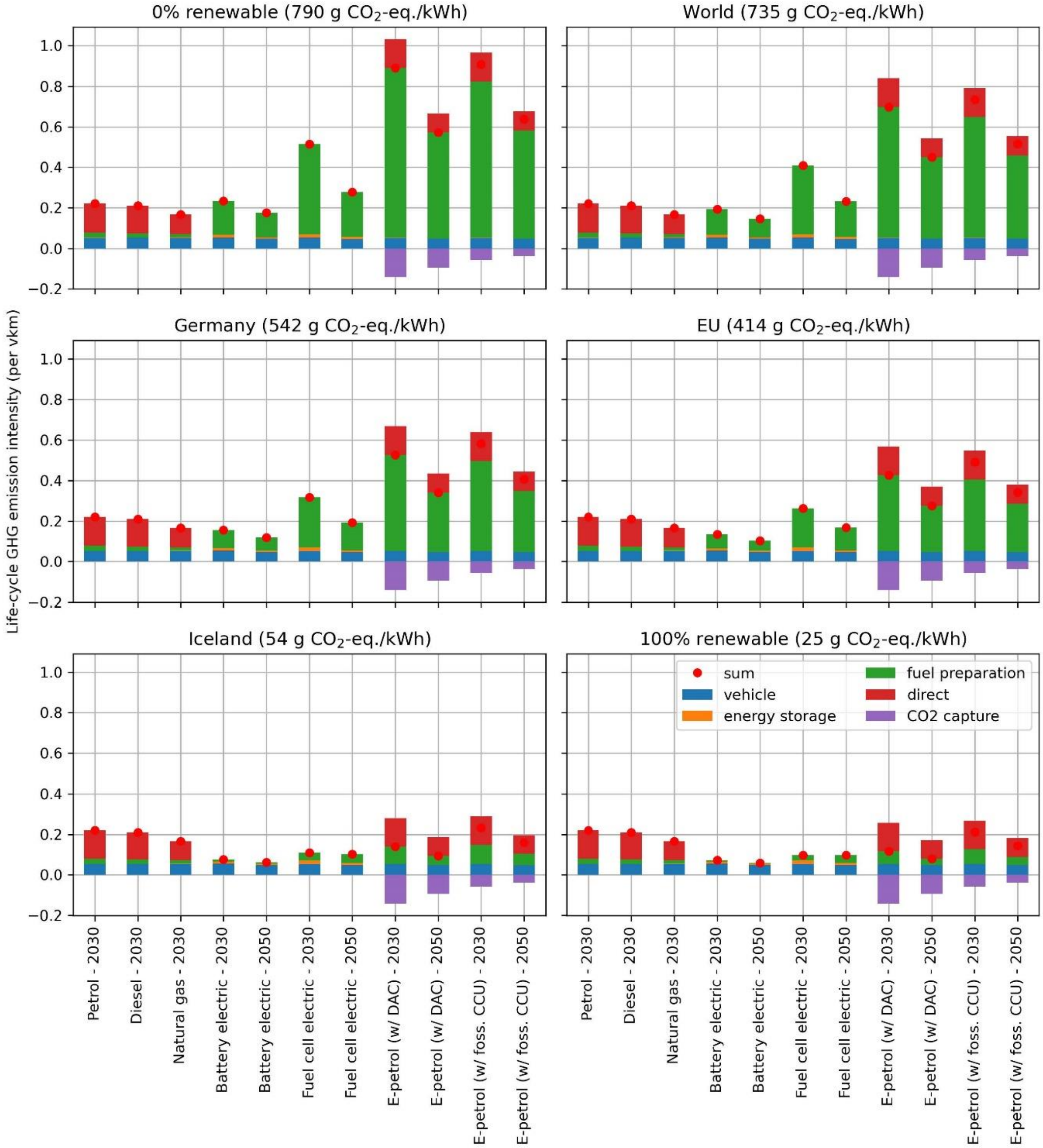
Extended Data Figure 3 | Marginal abatement cost curves (i.e., fuel switching CO_2 prices). Same as main figure 5, but here also including direct use of hydrogen. In 2020-25 and for e-methane (replacing natural gas), liquid e-fuels (replacing fossil liquids) and hydrogen (replacing liquids or gases) from the cost calculations shown in Figure 4 and Extended Data Figure 2, as well as direct electrification alternatives (green, illustrative curve) across non-electric energy and industrial sectors in the OECD (2014 energy end-use data from IEA ETP 2017[65]). The additional end-use transformation costs of using hydrogen are illustrative only. Shaded areas represent uncertainty ranges. The three categories of energy end-uses are sorted according to the costs of directly electrifying the respective applications (horizontal sorting from low to high costs of direct electrification). Within each of the four categories, the sectors are sorted according to their size.



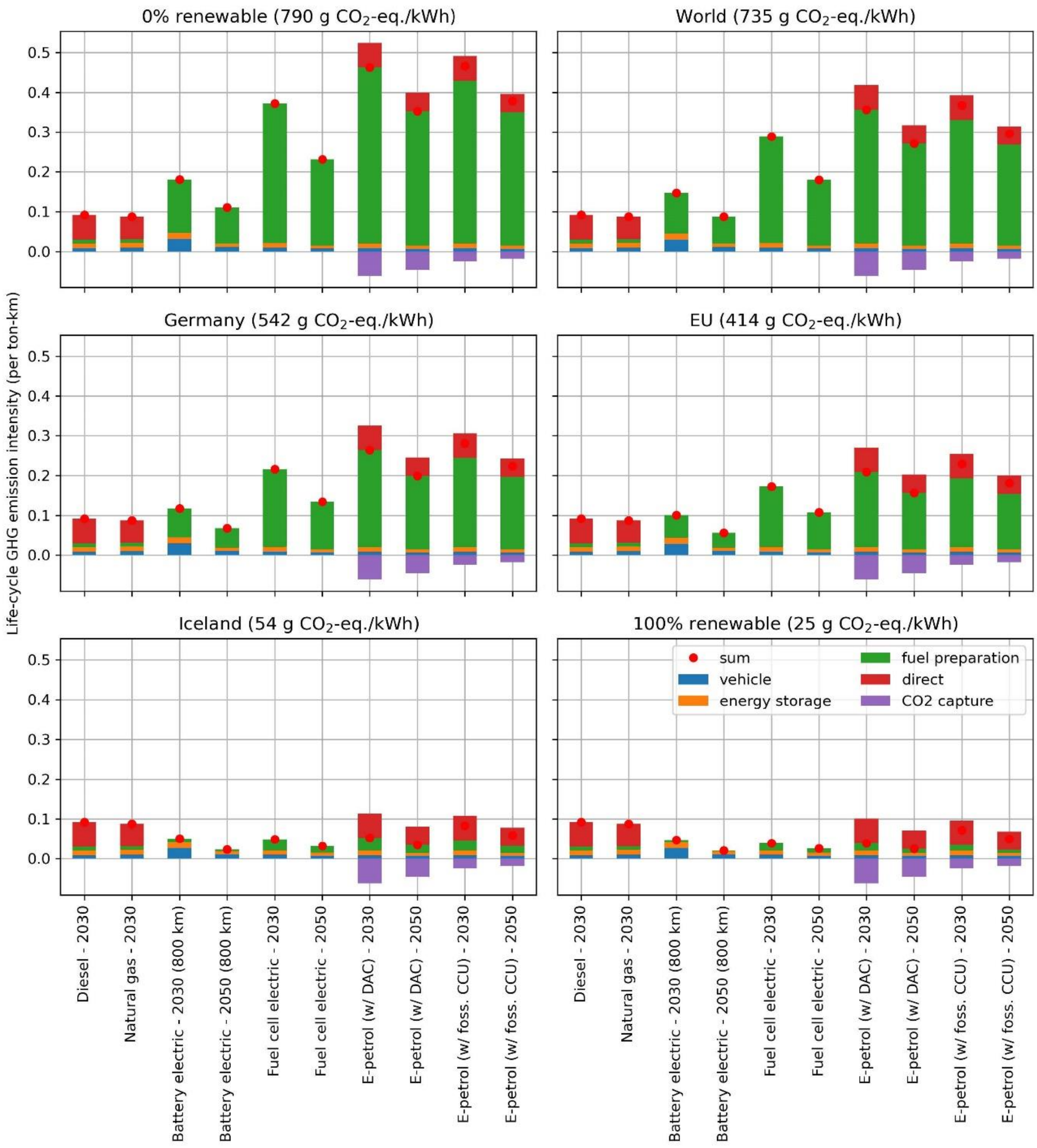
Extended Data Figure 4 | Same as main Figure 3 (left), but for two sensitivity analyses on CO_2 sources. Left, different assumptions for heat supply for DAC. Waste heat (e.g. from an integration with a renewable-based hydrocarbon synthesis) is GHG emission free. Market heat refers to an average mix of heat sources used by the petro-chemical industry in the EU. Natural gas heat is heat only provided by natural gas boilers. **Right,** different assumptions for fossil CCU pathways on the attribution of direct exhaust of fossil CO_2 emissions between the e-fuel application and the fossil CO_2 source application where CO_2 is captured. For example, "alloc 0:100" refers to 0 % allocated to the e-fuel application and 100 % to the fossil CO_2 source application. The rest of the figure is the same as main Figure 3: Life-cycle GHG emissions for light-duty vehicles (left), heavy-duty trucks (middle), and planes (right), as a function of the carbon intensity of electricity used for battery charging, hydrogen and e-fuel production. Comparing e-fuel options (CO_2 from DAC or fossil CCU), hydrogen fuel cells (H_2 from electrolysis), direct electrification with batteries and fossil options, all of which is based on anticipated technological progress in 2030 and 2050 using the life cycle assessment model carculator[50]. Vertical lines show carbon intensities of electricity for selected geographies (for 2017-18). The secondary x-axis (bottom) translates the carbon intensity of electricity into an equivalent share of renewable electricity generation (equal shares of wind and solar PV electricity, where the remaining non-renewable generation is natural gas and coal electricity in equal shares).



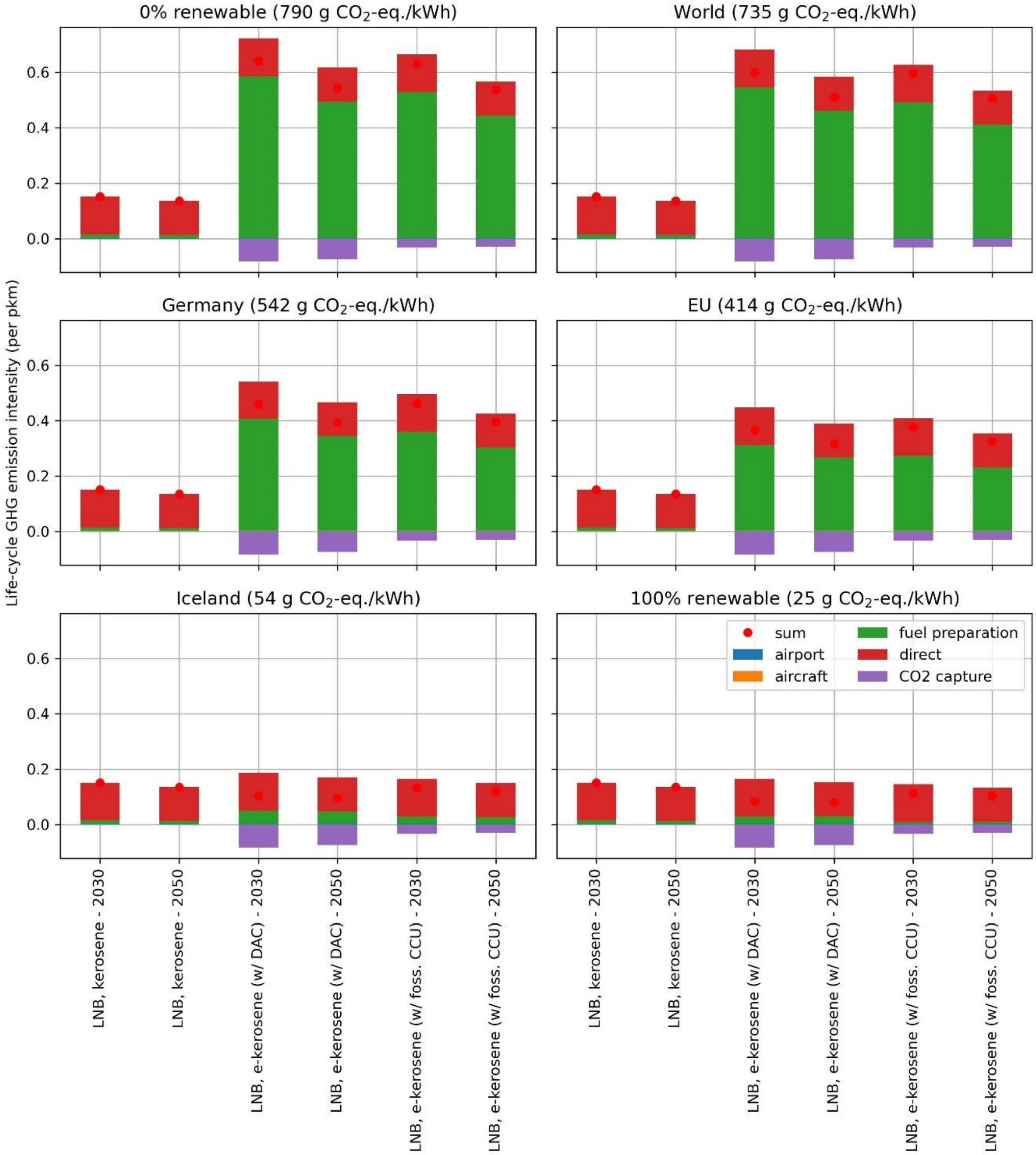
Extended Data Figure 5 | Same as main Figure 3, but for 2030 and 2050 technology: Life-cycle GHG emissions for light-duty vehicles (left), heavy-duty trucks (middle), and planes (right), as a function of the carbon intensity of electricity used for battery charging, hydrogen and e-fuel production. Comparing e-fuel options (CO_2 from DAC or fossil CCU), hydrogen fuel cells (H_2 from electrolysis), direct electrification with batteries and fossil options, all of which is based on anticipated technological progress in 2030 and 2050 using the life cycle assessment model carculator[50] and carculator_truck[51]. Vertical lines show carbon intensities of electricity for selected geographies (for 2017-18). The secondary x-axis (bottom) translates the carbon intensity of electricity into an equivalent share of renewable electricity generation (equal shares of wind and solar PV electricity, where the remaining non-renewable generation is natural gas and coal electricity in equal shares).



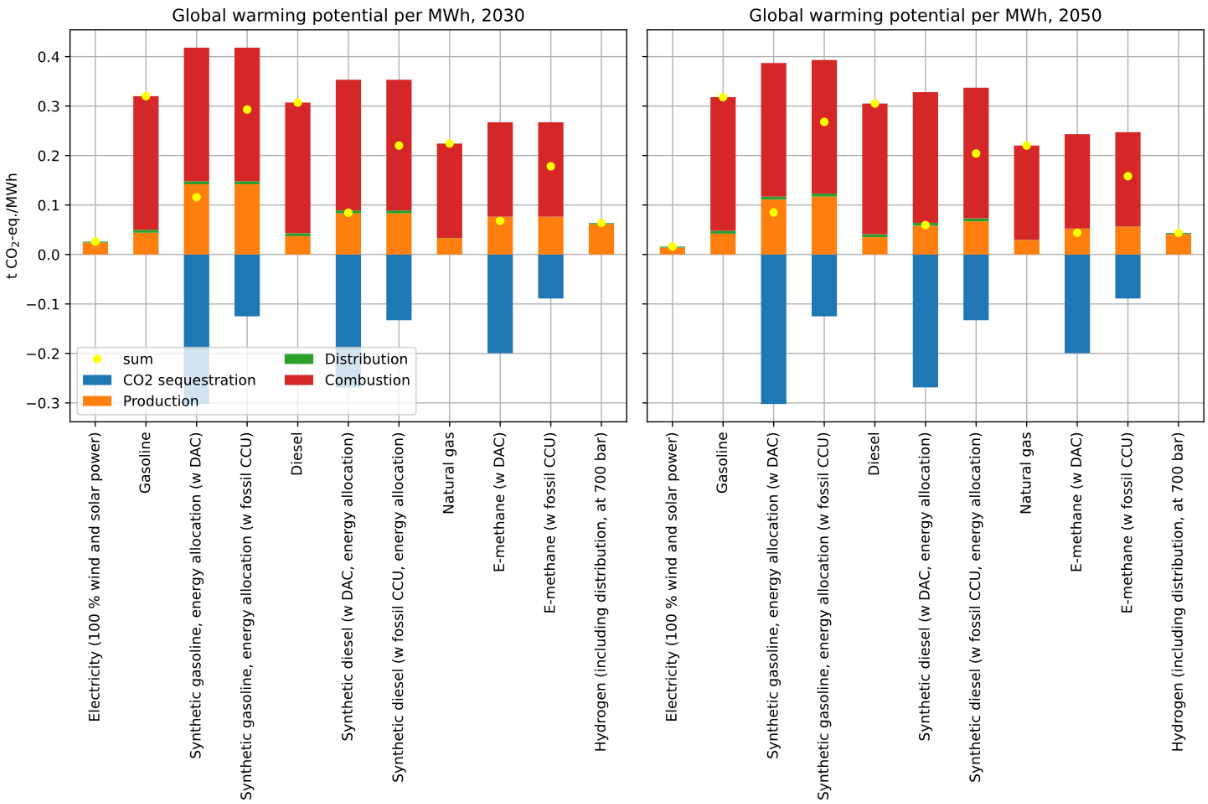
Extended Data Figure 6 | Breakdown of overall life-cycle GHG emissions of 2030 and 2050 medium-sized passenger vehicles for carbon intensities of electricity for several regions, quantified using the LCA model presented in Sacchi et al. 2020[50]. Numbers in each panel title are the GHG intensity of average electricity supply mixes (for 2017-18)[52]. In the legend, "EoL": End-of-life (of vehicles); "energy chain" represents net emissions associated with fuel supply. CO_2 for e-fuels is supplied via DAC or fossil CCU.



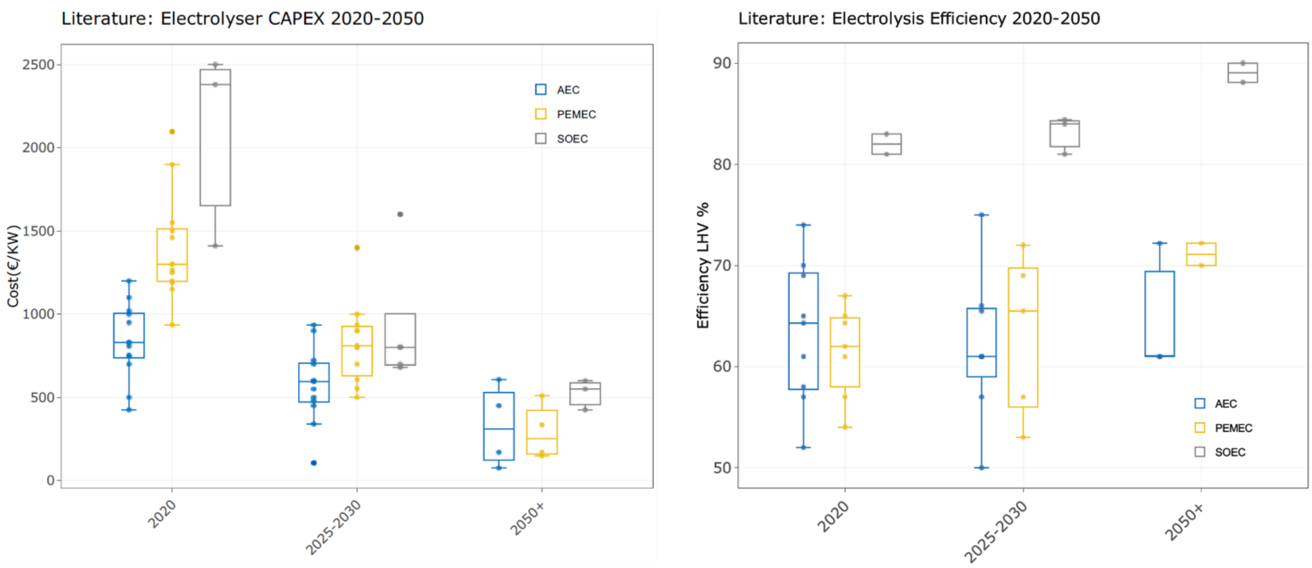
Extended Data Figure 7 | Breakdown of overall life-cycle GHG emissions of 2030 and 2050 heavy-duty trucks for carbon intensities of electricity for several regions, quantified using the LCA model presented in Sacchi et al. 2020[50]. Numbers in each panel title are the GHG intensity of average electricity supply mixes (for 2017-18)[52]. In the legend, "EoL": End-of-life (of vehicles); "energy chain" represents net emissions associated with fuel supply. CO_2 for e-fuels is supplied via DAC or fossil CCU.



Extended Data Figure 8 | Breakdown of overall life-cycle GHG emissions of 2030 and 2050 long-distance planes for carbon intensities of electricity for several regions, quantified using the LCA model presented in Sacchi et al. 2020[50]. Numbers in each panel title are the GHG intensity of average electricity supply mixes (for 2017-18)[52]. In the legend, "EoL": End-of-life (of vehicles); "energy chain" represents net emissions associated with fuel supply. CO_2 for e-fuels is supplied via DAC or fossil CCU. "LNB": Long-Nose Body.



Extended Data Figure 9 | GHG emissions (t CO2-eq./MWh) of all fuels from our life-cycle analysis for 2030 and 2050. This includes all upstream as well as combustion related (direct) emissions without specifying the end-use application or energy service. These values are the basis for the main specification of calculating fuel-switching CO_2 prices presented in figures 4, 5 and Extended Data Figures 2 and 3.



Extended Data Figure 10 | Specific capacity costs (left) and efficiencies (right) of electrolysis (PEMEC, AEC, SOEC) based on a literature review[61].

Potential and risks of hydrogen-based e-fuels in climate change mitigation

Falko Ueckerdt[1*], Christian Bauer[2], Alois Dirnaichner[1], Jordan Everall[1,4], Romain Sacchi[2], Gunnar Luderer[1,3]

[1]Potsdam Institute for Climate Impact Research, Telegrafenberg, 14473 Potsdam, Germany.

[2]Technology Assessment group, Paul Scherrer Institute, Forschungsstrasse 111, CH-5232 Villigen PSI, Switzerland

[3]Chair of Global Energy Systems, Technische Universität Berlin, Straße des 17. Juni 135, 10623 Berlin, Germany.

[4]Wegener Centre for Climate and Global Change (WEGC), Universität Graz, Brandhofgasse 5, 8010, Graz, Austria.

*corresponding author

Supplementary information

S1 Methodology life-cycle GHG emission assessment

Life-cycle GHG emission for passenger cars, heavy duty trucks and long-distance planes for different years, with different fuel types and carbon intensities for the electricity supply, are shown in Figure 3 and Extended Data Figures S6-8. Life-cycle emissions for passenger cars and trucks are produced using *carculator*[1] and *carculator_truck*[2], two open-source life cycle assessment tools for prospective analysis, using the inventory database ecoinvent 3.7.1 [3]. Life-cycle emissions for the aircrafts are adapted from the study of Cox et al. (2018)[4], where the input of conventional kerosene has been replaced by Fischer-Tropsch-based synthetic kerosene from the work of Hank et al. (2016)[5]. Impacts of aircrafts on climate change due to cloud formation and non-GHG emissions are also quantified according to Cox et al. (2018)[4].

The life-cycle boundaries for the three vehicles are cradle-to-grave. This includes the extraction and transformation of raw materials and energy directly and indirectly involved in the manufacture, delivery, use, maintenance and disposal phases of their life-cycle. The emissions regarding the fuel and electricity supply have well-to-wheel boundaries, where losses during distribution (or voltage transformation) and filling at the station (or battery charging) are accounted for, but also losses due to inefficiency along the drivetrain of the vehicles (i.e., transmission and engine inefficiency, rolling friction, etc.).

For passenger cars and trucks, an energy model calculates the tank-to-wheel energy consumption of the vehicles, given a driving cycle as well as a number of other specifications for the vehicles: their driving mass, their coefficient of aerodynamic drag and rolling friction, the road gradient, etc. For passenger cars, the WLTP driving cycle is used. For the trucks, vehicles have a range autonomy of 800 km and follow a long-haul driving cycle with rather constant speed levels (which also offers less opportunities for energy recuperation on electric powertrains). For battery-electric trucks, emissions are also calculated for vehicles with a range autonomy of 150 km that follow an “urban delivery” driving cycle, which is marked by frequent stops and transient loads.

An important assumption for electric trucks is the energy density of the battery cells. It is assumed to be 0.3 and 0.5 kWh/kg of battery cell in 2030 and 2050, respectively. The energy density of battery cell is the driver for the overall mass of the battery, which is responsible for a large share of the motive energy consumed in 2030.

Finally, the life-cycle models for passenger cars and trucks use a prospective version of ecoinvent 3.7.1 in the background. This modified version of ecoinvent is generated by the open-source library premise (https://github.com/romainsacchi/premise), where a few activities have been modified to reflect the expected technological progress in 2030 and 2050, according to an energy scenario provided by the Integrated Assessment Model (IAM) REMIND. Notably:

- the electricity sector: the electricity markets, including the share of renewable, as well as the efficiency of power plants and photovoltaic panels are adjusted.
- the cement sector: efficiencies for clinker production and fuel mix are adjusted.
- the transport sector: vehicles for fleet average passenger and lorry transport are adjusted

Vehicle specifications are listed in Table 1-3.

Table 1. Vehicle specifications for lower-medium size passenger cars

powertrain	year	Range	Power	Tank-to-wheel efficiency	Curb mass	Driving mass	Battery charge efficiency	Battery discharge efficiency	Battery mass	Fuel cell system efficiency	Battery lifetime replacements	Battery cel energy density	Fuel cell lifetime replacements	Electric energy stored	Oxidation energy stored
		km	*kW*	*%*	*kg*	*kg*			*kg*	*%*		*kWh/kg*		*kWh*	*kWh*
Electric	2030	219	99	66%	1410	1550	86%	89%	249		0	0.30		49	
	2050	323	88	69%	1259	1399	87%	89%	171		0	0.50		56	
Fuel cell	2030	473	97	38%	1381	1521				52%			0.12		150
	2050	634	88	42%	1251	1391				55%					150
Gas	2030	404	92	24%	1311	1451									217
	2050	354	86	31%	1225	1365									123
Gasoline	2030	806	91	24%	1295	1435									423
	2050	745	85	30%	1208	1348									260

Table 2. Vehicle specifications for heavy duty 40-ton semi-trailer trucks

powertrain	year	Range autonomy	Power	Tank-to-Wheel efficiency	Curb mass	Driving mass	Cargo mass	Battery charge efficiency	Battery discharge efficiency	Battery mass	Fuel cell system efficiency	Battery lifetime replacements	Battery cell energy density	Fuel cell lifetime replacements	Electric energy stored	Oxidation energy stored
		km	*kW*	*%*	*kg*	*kg*	*kg*	*%*	*%*	*kg*			*kWh/kg cell*		*kWh*	*kWh*
Electric	2030	150	293	89%	13117	23200	10083	85%	88%	1800		2	0.3		324	
	2050	150	224	91%	10036	20200	10164	86%	89%	690		1	0.5		241	
Electric	2030	800	435	80%	19410	29742	10333	85%	88%	7728		2	0.3		1391	
	2050	800	271	82%	12085	22127	10042	86%	89%	2675		1	0.5		936	
Fuel cell	2030	800	334	38%	11943	22036	10092				40%			2		1871
	2050	800	276	46%	9839	20100	10261				47%			2		1272
Diesel	2030	800	340	39%	12157	22173	10016									1834
	2050	800	283	40%	10100	20200	10100									1472
Gas	2030	800	360	34%	12852	22900	10048									2166
	2050	800	298	38%	10647	21204	10556									1547

Table 3. Vehicle specifications for long-nose body aircraft

powertrain	year	Range autonomy	Type	Lifetime	Lifetime	Operating empty mass	Operating mass	Seating capacity	Passenger occupancy rate	Freight occupancy rate
		km		*Years*	*Million Km*	*Kg*	*Kg*	*Passengers*	*%*	*%*
Jet engine	2030	2000	Long nose body	22	50	56253	74097	215	73%	2%
	2050	2000	Long nose body	22	50	60485	80983	238	76%	2%

DAC systems are usually based either on aqueous solutions with High Temperature regeneration (HT DAC), or on solid sorbents with Low Temperature regeneration (LT DAC)[6]. We use the latter in our analysis. Determining factors for the life-cycle GHG emissions of such DAC systems are the amount of energy required for the capture process and the sources of heat and electricity supply. Our inventory data includes heat demands of 1500 kWh and electricity demand of 578 kWh_el per ton of CO_2 captured[7].

Resulting GHG emissions of e-fuels and fossil fuels

In the economics section of the main paper we calculate fuel switching CO_2 prices (Figure 4) based on the lower heating values of e-fuels and fossil fuels (irrespective of specific end-use applications). For this purpose, we extract GHG emissions (t CO_2-eq./MWh) of all fuels from our life-cycle analysis. These include all upstream as well as combustion related (direct) emissions without specifying the end-use application or energy service for 2030 and 2050:

Electricity (100 % wind and solar power): 0.026, 0.016
Gasoline: 0.32, 0.318
Synthetic gasoline, energy allocation* (w DAC): 0.116, 0.085
Synthetic gasoline, energy allocation* (w fossil CCU): 0.293, 0.268
Diesel: 0.307, 0.305
Synthetic diesel (w DAC, energy allocation*): 0.084, 0.059
Synthetic diesel (w fossil CCU, energy allocation*): 0.22, 0.204
Natural gas: 0.224, 0.22
E-methane (w DAC): 0.068, 0.044
E-methane (w fossil CCU): 0.178, 0.158
Hydrogen (including distribution, at 700 bar): 0.063, 0.043

*The synthesis processes for synthetic liquid fuel production generate multiple (by-)products. The term "energy allocation" refers to the way how environmental burdens of this process as well as upstream processes are assigned to the multiple co-products, which is done according to their energy content.

The breakdown of these aggregate emissions are shown in Extended Data Figure 9.

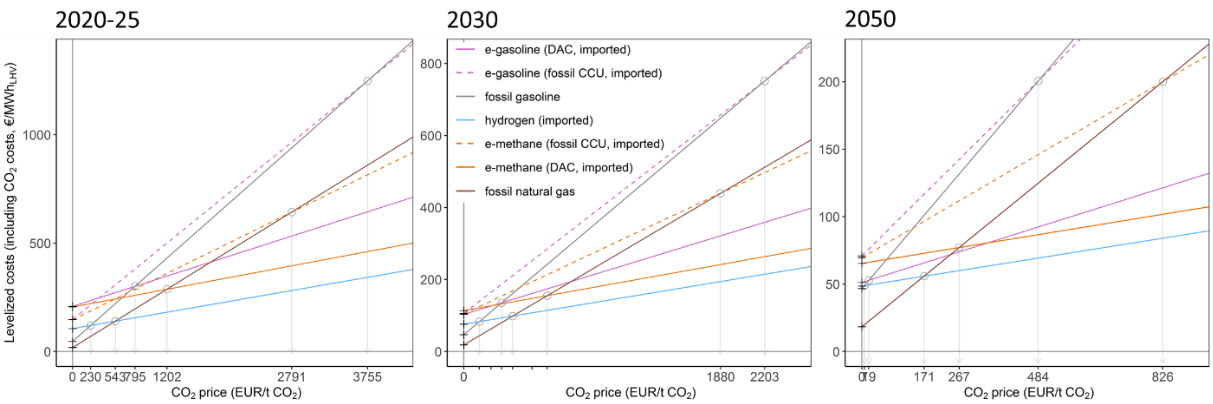


Figure S1 | Levelized costs (including CO_2 costs) of e-fuels and fossil fuels as a function of CO_2 prices. Same as figure 4c, but for 2020-25 (left), 2030 (middle), and 2050 (right) and with an expanded x-axis limit to also include fuel switching CO_2 prices for fossil CCU pathways. The + on y-axis are the direct costs (without CO_2 price related costs). The circles mark the intersections of fossil and e-fuel costs, which are the break-even points that determine fuel switching CO_2 prices (shown on the 2nd y-axis in a and b).

S2 Data for the e-fuel cost estimation

Here we present the data, assumptions and some calculations underlying the e-fuel cost estimation shown in main figure 4 and Extended Data Figure 1 and 2, which also builds the foundation of estimating fuel switching CO_2 prices. These bottom-up estimations for the several e-fuel cost components are based on a literature review, empirical data on temporal electricity price distribution due to wind and solar PV generation, and a cost-optimization of electrolysis operation that gives endogenous electricity costs for hydrogen production. The extensive electrolysis cost data collected is available in Everall and Ueckerdt (2021)[8] and visualized in an interactive dashboard [https://h2.pik-potsdam.de/H2Dash/] and Extended Data Figure 10.

The scope of this cost analysis are levelized costs of e-fuels for 2020-2050 for a case in which hydrogen is produced in a renewable-rich country and shipped ~4000 km, which represents the distance between Northwest Africa (e.g., Morocco) and North-western European ports (e.g., Rotterdam or Hamburg). E-methane or e-gasoline are either synthesized in the exporting country with DAC-based CO_2, or at the European port from fossil CO_2 utilizing imported liquefied hydrogen, which increases transport costs. We neither include potential taxes and levies nor further domestic transport or distribution costs. Costs do not include potential taxes and levies.

Table 1 gives an overview, while the next subsections are dedicated to the specific cost components. Note that the underlying literature is based on a scenario in which all components of the e-fuel value chains are scaled up significantly such that cost reductions based on scale effects and technological learning can be achieved. Under this premise we include uncertainty ranges for the most important and uncertain cost parameters (electricity, electrolysis, DAC, fossil CO_2 capture, transport and liquefaction costs). In a sensitivity analysis we independently combine all these parameter ranges resulting in >200 variations of each aggregated cost value (for each e-fuel). We add the 25th-75th percentile and full range of this distribution to the cost bar figures presented in main figure 4a,b and Extended Data Figures 1 and 2. In addition, we use the 25th-75th percentile to calculate uncertainty ranges for fuel switching CO_2 prices shown in Figure 4d.

Table 4. Parameter and sources for e-fuel cost estimation and sensitivity analysis

	2020-25	2030	2050
Annual average electricity price (EUR/MWh)	50 +/-10	50 +/-10	30 +/-10
Empirical source for electricity price variability	National Electricity Market (NEM) Australia (2019)	South Australia (2019) (w/o negative prices)	South Australia (2019) (w/o negative prices)
Electrolysis CAPEX (€/kW, median of AEC/PEMEC literature review)	1100 +/-389 [9–21]	625 +/-258 [10–12,17,18,20–22]	334 +/-189 [11,17,18,20,21]

Electrolysis efficiency (median of AEC/PEMEC literature review)	0.642 +/-0.057 [10,11,13–17,20,21,23]	0.655 +/-0.072 [11,17,18,20,21]	0.722 +/-0.069 [11,17,18,20,21]
Full-load hours electrolysis	4730 (endogenous calculation)	2444 (endogenous calculation)	2410 (endogenous calculation)
Liquefaction €/MWh_{LHV} calculated based on [24,25]	Hydrogen: 13 e-methane: 2.4	Hydrogen: 8 e-methane: 1.6	Hydrogen: 4 e-methane: 0.8
International transport (shipping, 4000km) €/MWh_{LHV} calculated based on [24,25,17,18]	Liquefied hydrogen: 18 e-methane: 17 e-methanol: 3	Liquefied hydrogen: 16 e-methane: 16 e-methanol: 2	Liquefied hydrogen: 15 e-methane: 15 e-methanol: 1
Regasification €/MWh_{LHV}	1.5 [26]	1.5 [26]	1.5 [26]
Cavern storage hydrogen €/kWh	0.24 € per hydrogen storage reservoir in kWh, 40 days average storage duration, lifetime: 30y [18]	0.24 €/kWh h2 stored, 40 days average storage duration, lifetime: 30y [18]	0.24 €/kWh h2 stored, 40 days average storage duration, lifetime: 30y [18]
CAPEX hydrocarbon synthesis (€/kW)	800[23]	400[23]	300[23]
Efficiency, lifetime hydrocarbon synthesis	0.8[23]	0.8[23]	0.8[23]
Direct-air capture (€/t CO_2 captured)	460 [27] +/-90	150 [27–29] +150/-50	50 [28,29] +50/-10
Fossil CCU Capture costs (€/t CO_2 provided)	30 [30] +30/-10	30 [30] +30/-10	30 [30] +30/-10
Attribution (%) of fossil CCU CO_2 emissions to e-fuel	50	50	50
WACC (%)	5	5	5
Attribution (%) of fossil CCU CO_2 emissions to e-fuel	50	50	50

Electrolysis

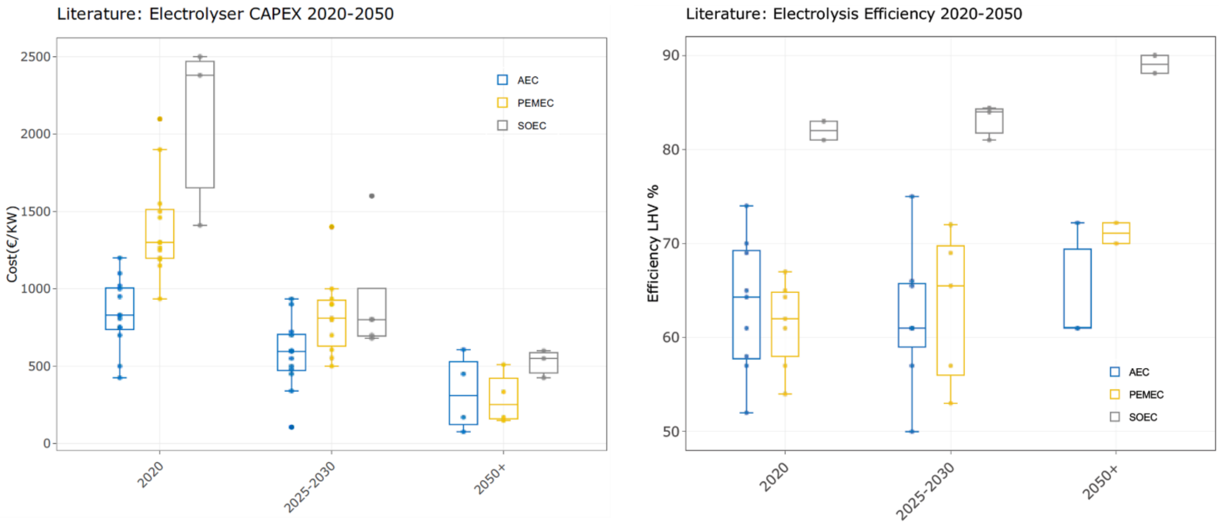


Figure S2 | Specific capacity costs (left) and efficiencies (right) of electrolysis (PEMEC, AEC, SOEC) based on a literature review

While there are currently three predominant electrolysis methods (PEMEC: Proton Exchange Membrane Electrolysis, AEC: Alkaline Electrolysis Cell, and SOEC: Solid Oxide Electrolyzer Cell), we focus on PEMEC and AEC for the evaluation in this paper as their cost and technical parameters show less uncertainty due to a higher TRL and more data from literature and projects.

There is a range of estimates for current and 2030 capacity costs (CAPEX) of PEMEC and AEC electrolysis (2020: n=24[9–21], 2030: n=18[10–14,17,18]); however, there are substantially less that give estimates for long-term capacity costs (2050: n=7[11,17,18,20,21]). Some costs, such as those reported by Agora[17], are categorized by temperature (low vs high) rather than technology, which precludes technology-specific cost estimates. Additional assumptions made in this paper are the lifetime of an electrolysis (20 years) and a WACC of 5%, which significantly shapes the CAPEX shares in the levelized cost estimates.

CAPEX estimates are frequently based on aged or recycled data, which is not immediately obvious through the use of secondary sources. For example, several studies published in the last year still cite or rely on Bertuccioli's collaborative work from 2014[19]. A number thereof having cited this work through a secondary source. We therefore removed duplicates in the literature review and classified according to type of analysis (original analysis, original review, secondary source). Additionally, CAPEX is referenced to the year of the oldest used data source cited in the respective literature (effective year), and not the publication date of the secondary source.

The parameters and literature from this review can be found in an online cost dashboard developed alongside this analysis [*https://h2.pik-potsdam.de/H2Dash/*], which interactively allows exploration of the effect of parameter currency on CAPEX cost projections[31] and which offers an open literature database [*doi will be added and linked to this manuscript*]. Our electrolysis capacity cost review and the resulting 2030 overall hydrogen costs estimates are very similar to results of an analysis by Glenk and Reichelstein, 2019[9].

Reflecting on electrolysis technologies, picking a winner at this current stage would be premature both due to uncertainty in learning-associated cost reductions and potential technological advances. In the case of AEC this relates to developments such as "no-gap" technology which reduces cell electrode spacing leading to increased efficiencies[32]. With respect to PEMEC, this involves advances in earth-abundant electrocatlysts[33]. Lastly, SOEC development is focused on stack durability and operational longevity improvements[12]. Despite potential technical leaps, reduction of future costs across technologies are largely attributed to economies of scale, with efficiency improvements expected to play a smaller role [12]. Aside from its high current density and capacity for high-pressure operation, literature and project data suggests that PEMEC is more flexible than AEC and SOEC. PEMEC achieves the quickest current and projected warm standby and cold start up times (15 seconds, 2 minutes respectively)[11], has the smallest minimal load requirement (5% vs 18% for AEC)[11], and maintains the highest ramping rate (~40-50 %/s vs ~25%/s for AEC)[23]. AEC on the other hand is more mature, is low cost and does not require rare-earth elements such as Iridium or Platinum unlike PEMEC. AEC, however, faces problems during flexible operation, affecting efficiency, gas purity and longevity[12]. SOEC, while commercially unavailable, shows high efficiencies, with low material costs, and can also operate in reverse mode, acting as a fuel cell. Currently however, SOEC systems face rapid degradation due to high operational temperatures, show limited flexibility, and are still expensive to produce, ruling out commercial feasibility for the time being[10,34]. SOECs are not included in the cost and efficiency analysis.

Electricity costs and flexible electrolysis operation

Levelized costs of hydrogen are mainly determined by specific capacity costs for electrolysis and electricity costs. We assume annual time-weighted mean electricity prices of 50 EUR/kWh in 2020 and 2030 and 30 EUR/kWh in 2050. The latter reflects the average costs of electricity supply of a wind and solar PV heavy power system, for example in Australia[35], which has been selected because it is one of likely future hydrogen export countries.

Electricity costs are calculated without taxes and levies and based on cost developments for wind and solar PV, combined with empirical data on hourly price variability (e.g., electricity price data for South Australia, which sees >50% wind and solar generation). In addition to the decrease of average electricity costs (table 4), there are reduction potentials from integrating electrolysis in power systems with high wind and solar PV shares. Higher shares of variable renewables increase price variability, where reducing electrolyser full-loud hours (FLH) and profiting from periods with low electricity prices reduces electricity costs for the electrolysis operator. As a result, electricity costs not only depend on the average electricity price of a power supply system, but also of the hourly price distribution and the electrolysis operation.[9]

A flexible operation of electrolysis can focus on low-electricity-price hours at the expense of capacity utilization (i.e. annual full-load hours, FLH), which would thus increase specific capacity costs. As a result, specific per-unit-hydrogen CAPEX and electricity costs are interdepend and their optimal balance depends on the electrolysis capacity costs and electricity price distribution. The more wind and solar PV are in a system, the more the price duration is skewed such that the benefit of reducing FLH and focusing on low prices increases. The additional specific capacity cost at lower FLH decreases with decreasing electrolysis' capacity costs. Hence, as wind and solar PV shares increase and as electrolysis capex decrease the optimal FLH will also likely decrease.

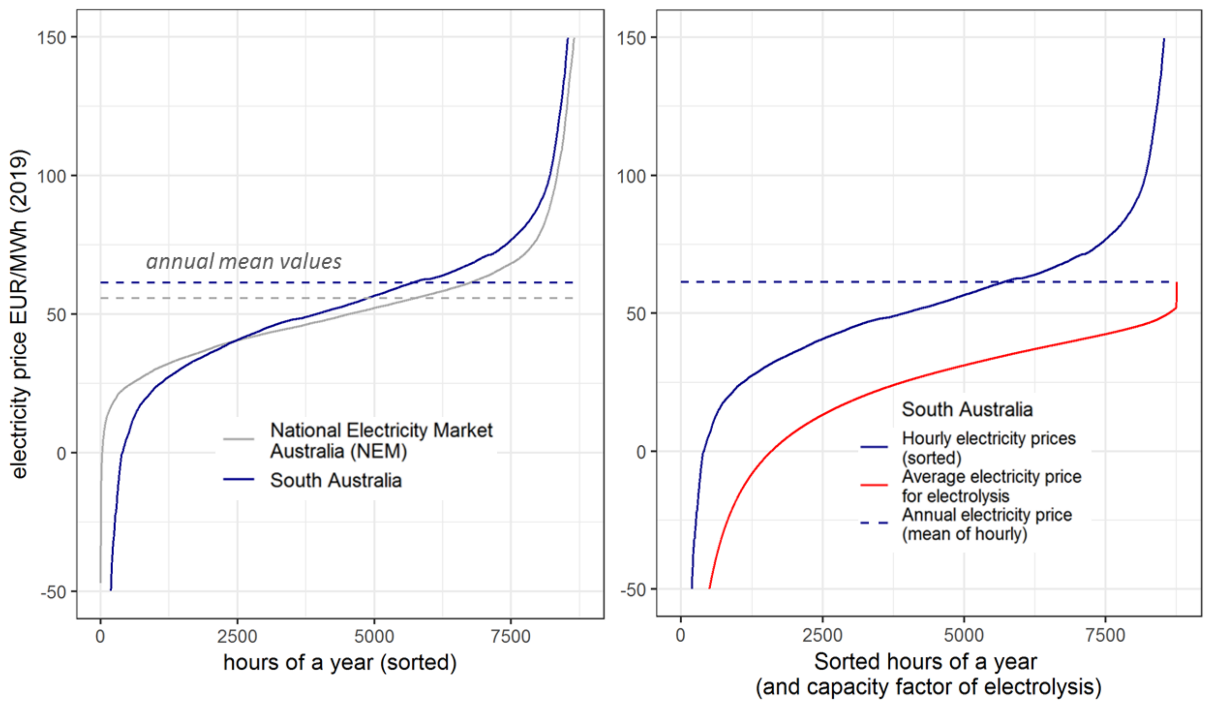


Figure S3 | Hourly electricity prices, annual averages (left) and average electricity price paid by an electrolysis as a function of full-load hours (right).

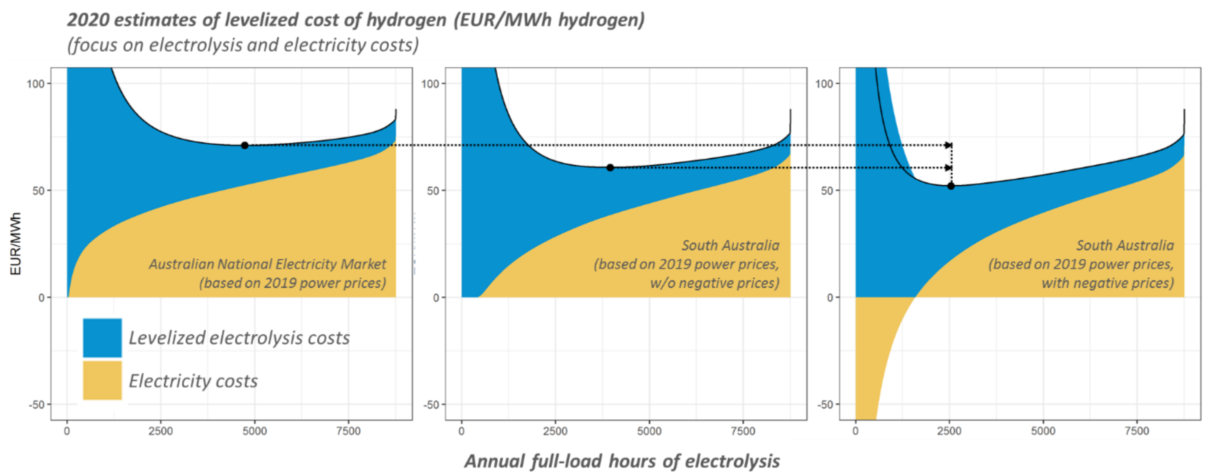


Figure S4 | electricity and specific electrolysis costs of hydrogen production as a function of annual full-load hours of electrolysis. Dots mark the minimum combined costs used for 2020 estimates for levelized cost of hydrogen.

For each of the focus years, we determine the cost-optimal electrolysis FLH based on electricity price variability of whole-sale market data for Australia because the high wind and solar PV shares in South Australia provide a glimpse into future high variable renewable power systems. For current 2020 cost estimates we use 2019 prices for the Australia's national electricity market (NEM) with ~20% of wind and solar PV generation. We avoid using

2020 price data as it is distorted by demand reductions induced by the Covid19 pandemic. For 2030 and 2050 we use 2019 price data for South Australia, which had reached ~50% wind and solar generation by that time.

Figure S3 (left) illustrates the differences in the price variability for NEM and South Australia and the relation of price variability, and electricity prices that an electrolysis sees depending on its FLH (right). If an electrolysis runs throughout the year, it pays the average electricity price, while in the case of South Australia it could also flexibly operate and pay a negative or zero average up to ~1500 FLH.

Figure S4 demonstrates how the cost-minimizing FLH (black dots) shift to lower values when using NEM prices (left), South Australian prices without negative prices (middle) and with negative prices (right). At the same time, levelized costs of hydrogen decrease. Negative prices are mostly indicating a lack of flexibility in a power system. At small amounts of hydrogen production it can be assumed that electrolysers are solely a price taker, while at high amounts of flexible hydrogen generation, negative prices vanish and increase to at least zero. This is the standard assumption in our cost estimation.

The impact of a flexible electrolysis operation is the main reason why our e-fuel cost estimates are slightly lower than those of a review[10] by Brynolf et al. 2018, where the electrolysis pays an average electricity price of 50 €/MWh_el resulting in e-fuel cost ranges of 160–210 €/MWh in 2030. Our analysis assumes an energy-only whole-sale electricity market. Additional regulation, i.e. taxes and levies, change the electricity prices that an electrolysis „sees". The regulator tax away hydrogen cost benefits and re-distribute them to other electricity consumers. However, from an economic perspective, price signals should remain undistorted to incentivize a system-friendly flexible operation.

Note that there are some world regions in which hydrogen and e-fuel projects can draw on continuously low power prices from reservoir-hydro or geo-thermal power, which leads to a different electrolysis operation. For example, the planned Norsk e-Fuel project in Norway uses highly efficient but more expensive solid oxide electrolysis cells, which benefit from high full-load hours and Norwegian power prices.

CO_2 costs: DAC and fossil CCU

CO_2 from atmospheric origin via DAC. The cost estimates for DAC are uncertain and based on only scarce and diverse scientific and industrial data for different DAC approaches[27,28,36–38]. This results in a high range for short- to mid-term cost assumptions, while the literature agrees on significant long-term cost reduction potentials when scaling up global DAC capacity. Optimistic current cost estimates of ~200 €/t CO_2 have been calculated based on data from comparably small market actors[28,36]; yet, the global market leader Climeworks reported their current capture costs as 600 USD/t CO_2 in 2017/18 [27] with the expectation to push costs to around 100 USD/t CO_2 within a decade[38].

For 2020, we assume 90% of the value communicated by Climeworks 2-3 years ago, which results in 460 €/t CO_2. For 2050, we use cost estimates of ~50 €/t CO_2[28,29], which assumes further cost decreases at a learning rate of 15 % and a significant scale-up of cumulative capacity up to 8-15 Gt CO_2 removed per year in 2050. For the in-between value of 2030, cost estimates highly depend on the very uncertain speed of deployment in the next years, which depends on the scale-up of electrolysis, the general role of e-fuels and the extent to which CO_2 is fossil-based in the near term. We stay on the conservative side here by expecting a high DAC expansion only after 2030. We assume DAC costs in 2030 of 150€/tCO_2 (i.e., a third of our 2020 estimate), which is higher than Climeworks cost target of 100 USD/t CO_2 (=85 €/t CO_2) at high DAC capacity scale and higher than the 2030 estimate of 105€/tCO_2 in Fasihi et al. 2019, which is derived from DAC CAPEX in 2020 that is much lower than those communicated by Climeworks.

For the costs associated with utilizing CO_2 of fossil origin, we assume CO_2 capture and provision costs of 30 €/t CO_2, which is at the optimistic end of this review of capture costs across major industrial point sources[30].

Hydrocarbon synthesis

For the conversion from hydrogen and CO_2 to a synthetic hydrocarbon there are several pathways resulting in different gaseous or liquid fuels. First, liquid fuels can be synthesized via a Fischer-Tropsch synthesis (creating a crude PTL) and requiring a reverse water gas shift reaction (RWGS) for producing a syngas. The RWGS can be integrated in a co-electrolysis set-up with solid oxide electrolysis cells (SOEC). The crude PtL requires an additional upgrading step. Second, liquid fuels can be synthesized via a methanol synthesis, which does not require the RWGS but a more fundamental upgrading step to produce PtL from methanol. Third, synthesizing methane from hydrogen and CO_2 can be done in a methanation based on the Sabatier process.

These processes are rooted in standard organic chemical processing, for which specific cost reductions scale with the size of the production facility. In general, the more innovative pathways such as using a co-electrolysis feature higher current costs, higher project development times and potentially higher cost reductions. We are interested in generic large-scale production costs (from sites >100m kg/a), where the specific cost contributions from the synthesis processes are rather small. We thus abstract from current development differences and assume roughly similar costs across PtL and PtG pathways with CAPEX costs close to those for methanation[23]. For all synthesis plants we assume efficiencies of 80%[23] and high annual capacity factors of roughly 80%, which reduces specific CAPEX, but requires additional hydrogen storage capacity. Specific costs are calculated based on 20 year lifetime, while industrial actors and investors might require shorter amortization periods.

E-fuel liquefaction, international transport and storage costs

For transport, liquefaction and storage costs, data is scarce and we rely on only a few references [24,25,17,18]. The resulting data is summarized in per-MWh terms for the different e-fuels in table 4. For the sensitivity analysis, we assume a doubling (and halving) of transport and liquefaction costs as upper and lower limits.

Hydrogen is produced in a renewable-rich country and shipped ~4000 km, which represents the distance between Northwest Africa (e.g., Morocco) and North-western European ports (e.g., Rotterdam or Hamburg). E-methane or e-gasoline are either synthesized in the exporting country with DAC-based CO_2, or at the European port from fossil CO_2 utilizing imported liquefied hydrogen, which increases overall costs of fossil CCU pathways. For on-land storage costs, we assume that low-cost geological caverns for gaseous hydrogen are available in the exporting country[18].

The main cost components are liquefaction (for transporting hydrogen in the fossil CCU pathways and for DAC-based e-methane) and transport costs associated with on-ship product storage, boil-off, ship investment and shipping fuel costs. For the calculations, we build on input parameters from mainly Hank et al. 2020[24] and Matthes et al. 2020[25]. The most important drivers are:

- electricity input for liquefaction for hydrogen (0.24 MWh_el/MWh_h2 in 2020, and 0.18 MWh_el/MWh_h2 in 2030-50) and for e-methane (0.036 MWh_el/MWh_CH4 in 2020, and 0.018 MWh_el/MWh_CH4 in 2030-50)
- cryogenic on-ship storage costs for hydrogen (11 EUR/MWh_h2) and e-methane (14 EUR/MWh_CH4). The requirements for storing e-methane are assumed higher to minimize boil-off due to the global warming potential of methane, while for hydrogen a continuous boil-off is allowed (resulting in ~4% over 4000km)

As this has not been done before, large-scale shipping of hydrogen might be associated with additional fundamental uncertainties that are not represented in the data. In addition, there are additional hydrogen distribution costs that highly depend on the underlying infrastructure and supply chain configurations, which depend on the overall e-fuel quantities and end-uses. A detailed analysis[39] considering different infrastructure configurations for Germany shows associated cost contributions of ~1-3 €/kg hydrogen. The specific costs of distributing small amounts of hydrogen at a very early stage of infrastructure build-up could be significantly higher than what we assume here focusing on large-scale quantities, which is particularly relevant for the 2020 cost estimates shown here.

Fossil fuel prices and costs

The competitiveness of e-fuels is analysed based on empirical fossil fuel prices. For natural gas, we use monthly prices from two whole-sale spot market price benchmarks for the US and Europe from the last decade. The first benchmark are the settlement prices at Henry Hub[40] that are representative for the entire North American natural gas market and parts of the global liquid natural gas (LNG) market. The second benchmark are day-ahead gas prices at Great Britain's gas hub (the National Balancing Point, NBP)[41]. As the main point of comparison we use the median prices for the 2010–2020 period, which results in ~18 €/MWh and ~9 €/MWh in Europe and the US, respectively.

As a representative for liquid fossil fuels, we use the New York harbor conventional gasoline regular spot price[42]. As gasoline spot prices across the world are closely linked, using only one spot price seems enough. As the main point of comparison we use the median price for the 2010–2020 period: ~47 €/MWh.

For fossil hydrogen from steam methane reforming (SMR) we use 2018 IEA data (without CCS) for production costs in USA, Europe, Russia, China, Middle East and Platts 2020 data for Japan. The regional median is ~36 €/MWh.

Scenario data for CO_2 prices

In Figure 4d we compare abatement costs of e-fuels with global carbon prices from long-term scenarios calculated with the Integrated Assessment Model (IAM) REMIND. The scenarios are published in the IPCCSR15 Scenario Database [43]. We chose all 2° C and "well-below 2° C" scenarios from the projects ADVANCE, CD-LINKS, PEP1p5 and CEMICS, which resulted in 13 scenarios.

References

1. Sacchi, R., Bauer, C., Cox, B. & Mutel, C. Carculator: An Open-Source Tool for Prospective Environmental and Economic Life Cycle Assessment of Vehicles. When, Where and How Can Battery-Electric Vehicles Help Reduce Greenhouse Gas Emissions? *Renew. Sustain. Energy Rev.* (2020).
2. Sacchi, R., Bauer, C. & Cox, B. Does size matter? The influence of size, load factor, range autonomy and application type on the Life Cycle Assessment of current and future trucks. *Environmental Science and Technology* (2020).
3. Wernet, G. *et al.* The ecoinvent database version 3 (part I): overview and methodology. *Int J Life Cycle Assess* **21**, 1218–1230 (2016).
4. Cox, B., Jemiolo, W. & Mutel, C. Life cycle assessment of air transportation and the Swiss commercial air transport fleet. *Transportation Research Part D: Transport and Environment* **58**, 1–13 (2018).
5. Hank, C. *et al.* Comparative well-to-wheel life cycle assessment of OME3–5 synfuel production via the power-to-liquid pathway. *Sustainable Energy Fuels* **3**, 3219–3233 (2019).
6. *Negative emissions technologies and reliable sequestration: a research agenda*. (The National Academies Press, 2019).
7. Deutz, S. & Bardow, A. Life-cycle assessment of an industrial direct air capture process based on temperature–vacuum swing adsorption. *Nat Energy* (2021) doi:10.1038/s41560-020-00771-9.
8. Everall, J. & Ueckerdt, F. Electrolyser CAPEX and efficiency data for: Potential and risks of hydrogen-based e-fuels in climate change mitigation. (2021) doi:10.5281/ZENODO.4619892.
9. Glenk, G. & Reichelstein, S. Economics of converting renewable power to hydrogen. *Nat Energy* **4**, 216–222 (2019).

10. Brynolf, S., Taljegard, M., Grahn, M. & Hansson, J. Electrofuels for the transport sector: A review of production costs. *Renewable and Sustainable Energy Reviews* **81**, 1887–1905 (2018).
11. Smolinka, T. *et al.* Studie IndWEDe Industrialisierung der Wasser-elektrolyse in -Deutschland: -Chancen und -Herausforderungen für nachhaltigen Wasserstoff für Verkehr, Strom und -Wärme. 201 (2018).
12. Schmidt, O. *et al.* Future cost and performance of water electrolysis: An expert elicitation study. *International Journal of Hydrogen Energy* **42**, 30470–30492 (2017).
13. Tractabel engie & Hinicio. *STUDY ON EARLY BUSINESS CASES FOR H2 IN ENERGY STORAGE AND MORE BROADLY POWER TO H2 APPLICATIONS*. https://www.fch.europa.eu/sites/default/files/P2H_Full_Study_FCHJU.pdf (2017).
14. Matute, G., Yusta, J. M. & Correas, L. C. Techno-economic modelling of water electrolysers in the range of several MW to provide grid services while generating hydrogen for different applications: A case study in Spain applied to mobility with FCEVs. *International Journal of Hydrogen Energy* **44**, 17431–17442 (2019).
15. Proost, J. State-of-the art CAPEX data for water electrolysers, and their impact on renewable hydrogen price settings. *International Journal of Hydrogen Energy* **44**, 4406–4413 (2019).
16. Bruce, S. *et al. National Hydrogen Roadmap*. 115 https://doi.org/10.25919/5b8055bc08acb (2018).
17. Agora Energiewendge, Agora Verkehrswende & Frontier Economics. *The Future Cost of Electricity-Based Synthetic Fuels*. https://www.agora-energiewende.de/fileadmin2/Projekte/2017/SynKost_2050/Agora_SynKost_Study_EN_WEB.pdf (2018).
18. Michalski, J. *et al.* Hydrogen generation by electrolysis and storage in salt caverns: Potentials, economics and systems aspects with regard to the German energy transition. *International Journal of Hydrogen Energy* **42**, 13427–13443 (2017).

19. Bertuccioli, L. *et al.* Development of water electrolysis in the European Union. *Fuel cells and hydrogen joint undertaking* **83**, (2014).
20. Bloomberg. *Hydrogen: The Economics of Production From Renewables*. (2019).
21. IEA. *The Future of Hydrogen*. https://www.iea.org/reports/the-future-of-hydrogen (2019).
22. Glenk, G. & Reichelstein, S. Economics of converting renewable power to hydrogen. *Nat Energy* **4**, 216–222 (2019).
23. Milanzi, S. *et al. Technischer Stand und Flexibilität des Power-to-Gas-Verfahrens*. https://www.er.tu-berlin.de/fileadmin/a38331300/Dateien/Technischer_Stand_und_Flexibilit%C3%A4t_des_Power-to-Gas-Verfahrens.pdf (2018).
24. Hank, C. *et al.* Energy efficiency and economic assessment of imported energy carriers based on renewable electricity. *Sustainable Energy Fuels* **4**, 2256–2273 (2020).
25. Matthes, D. F. C. *et al.* Wasserstoff sowie wasserstoffbasierte Energieträger und Rohstoffe. *Ökoinstitut e.V.* 145 (2020).
26. Henderson, J. *Gazprom - Is 2016 the Year for a Change of Pricing Strategy in Europe?* https://www.oxfordenergy.org/wpcms/wp-content/uploads/2016/02/Gazprom-Is-2016-the-Year-for-a-Change-of-Pricing-Strategy-in-Europe.pdf (2016).
27. Tollefson, J. Sucking carbon dioxide from air is cheaper than scientists thought. *Nature* **558**, 173–173 (2018).
28. Fasihi, M., Efimova, O. & Breyer, C. Techno-economic assessment of CO2 direct air capture plants. *Journal of Cleaner Production* **224**, 957–980 (2019).
29. Breyer, C., Fasihi, M. & Aghahosseini, A. Carbon dioxide direct air capture for effective climate change mitigation based on renewable electricity: a new type of energy system sector coupling. *Mitig Adapt Strateg Glob Change* **25**, 43–65 (2020).
30. Leeson, D., Mac Dowell, N., Shah, N., Petit, C. & Fennell, P. S. A Techno-economic analysis and systematic review of carbon capture and storage (CCS) applied to the iron and steel, cement, oil refining and pulp and paper industries, as well as other high purity sources. *International Journal of Greenhouse Gas Control* **61**, 71–84 (2017).

31. Everall, J. Price of Hydrogen: CAPEX Data. https://h2foroveralls.shinyapps.io/H2Dash/ (2020).
32. Phillips, R. & Dunnill, C. W. Zero gap alkaline electrolysis cell design for renewable energy storage as hydrogen gas. *RSC Adv.* **6**, 100643–100651 (2016).
33. Sun, X. *et al.* Earth-Abundant Electrocatalysts in Proton Exchange Membrane Electrolyzers. *Catalysts* **8**, 657 (2018).
34. Anghilante, R., Colomar, D., Brisse, A. & Marrony, M. Bottom-up cost evaluation of SOEC systems in the range of 10–100 MW. *International Journal of Hydrogen Energy* **43**, 20309–20322 (2018).
35. Ueckerdt, F. *et al.* Australia's power advantage. Energy transition and hydrogen export scenarios. (2019).
36. Keith, D. W., Holmes, G., St. Angelo, D. & Heidel, K. A Process for Capturing CO2 from the Atmosphere. *Joule* **2**, 1573–1594 (2018).
37. Broehm, M., Strefler, J. & Bauer, N. Techno-Economic Review of Direct Air Capture Systems for Large Scale Mitigation of Atmospheric CO2. *SSRN Journal* (2015) doi:10.2139/ssrn.2665702.
38. Beuttler, C., Charles, L. & Wurzbacher, J. The Role of Direct Air Capture in Mitigation of Anthropogenic Greenhouse Gas Emissions. *Front. Clim.* **1**, 10 (2019).
39. Stockl, F., Schill, W.-P. & Zerrahn, A. Green hydrogen: optimal supply chains and power sector benefits. *arXiv:2005.03464 [physics, q-fin]* (2020).
40. EIA. Historic Henry Hub spot market prices.
41. ofgem. Historic gas market prices - Great Britain's National Balancing Pointspot.
42. EIA. Historic gasoline spot market prices New York Habor.
43. Huppmann, D., Rogelj, J., Krey, V., Kriegler, E. & Riahi, K. A new scenario resource for integrated 1.5 °C research. *Nature Climate Change* (2018) doi:10.1038/s41558-018-0317-4.