PERSPECTIVE
https://doi.org/10.1038/s41558-021-01032-7

nature climate change

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

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

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 €800–1,200 per tCO_2. Large-scale deployment could reduce costs to €20–270 per tCO_2 until 2050, yet it is unlikely that e-fuels will 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-fuel 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.

E-fuels (that is, electrofuels, powerfuels or electricity-based synthetic fuels) are hydrocarbon fuels synthesized from hydrogen and CO_2 (that is, carbon capture and utilization (CCU)), where hydrogen is produced from electricity and water (via electrolysis), and CO_2 is captured from either fossil sources (for example, industrial plants) or the atmosphere (biomass or direct air capture (DAC)) (Fig. 1)[1–3]. E-fuels can thereby tap into the low-cost and vast global potentials of low-carbon wind and solar photovoltaic (PV) power. The resulting gaseous and liquid fuels feature characteristics that make them perfect substitutes for 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].

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 on which they should be targeted, which predetermines the future market volumes of hydrogen and e-fuels.

Some studies consider 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.[10] present scenarios in which a pivotal role of electrification allows for a cross-sectoral 80% reduction (with reference to 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 emission reductions. Jacobson et al.[14] argue for an all-electric energy system (excluding chemical feedstocks) allowing energy-related GHG emissions to be fully abated by an almost complete phase-out of combustion technologies, although 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 the 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 (for instance, 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 substantially 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 (for example, the European Union (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 modelling 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 (for example, through import) and use[37–39].

This Perspective aims to reconcile different views on the potential role of e-fuels. On the basis of literature and our own analyses, we synthesize knowledge on their technoeconomic 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

---

[1]Potsdam Institute for Climate Impact Research, Potsdam, Germany. [2]Technology Assessment Group, Paul Scherrer Institute, Villigen, Switzerland. [3]Wegener Centre for Climate and Global Change (WEGC), Universität Graz, Graz, Austria. [4]Global Energy Systems Analysis, Technische Universität Berlin, Berlin, Germany. ✉e-mail: falko.ueckerdt@pik-potsdam.de

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 northwestern 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 and 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 (Fig. 2) and combined efficiencies. We seek to demonstrate the relevant orders of magnitude. Exact values vary for specific types of electrolysis, synthesis (and their degree of integration) or fuel type (for example, 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, such as the losses from potential liquefaction and regasification, long-distance transport and distribution of hydrogen[41], are neglected for the efficiency analysis.

Depending on the application and respective technologies, overall efficiencies of e-fuels—that is, converting electricity to useful energy—range from roughly 10% to 35%. This translates into (renewable) electricity generation requirements that are 2–14 times higher than for direct electrification alternatives. These losses outstrip by far the efficiency gains of using electricity from renewable-rich countries (for example, Chile or North Africa) and exporting them as e-fuels.

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 60%. 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 (1,500 kwh per tCO_2, ref. [44]), comprising ~15–20% of total 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-fuel energy content is lost when combusting e-fuels for mechanical work (for example, combustion engines for transport services or re-electrification applications such as renewable gas turbines), resulting in 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 retain 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 could 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 direct 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 (refs. [12,47]). This leads to energy efficiencies that are 6–14 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 vehicles (easy to abate), heavy-duty trucks (hard to abate) and long-distance aviation (hard to abate and inaccessible to electrification) (Fig. 3).

GHG emissions for these transportation modes from a full cradle-to-grave life-cycle assessment (Supplementary Information 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) (Fig. 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 manufacture 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 Fig. 5 shows results for 2050).

Across transport applications, 90–100% renewable electricity shares are required for e-fuel use to reduce GHG emissions compared with their fossil alternatives. With the 2018 German electricity mix (carbon intensity of 542 g $CO_2e\,kWh^{-1}$)[50], 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 light-duty vehicles 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, electrolysers, DAC plants and hydrogen, as well as CO_2 storage and transport infrastructure.

Battery-electric alternatives for light-duty vehicles, by contrast, have GHG emissions that are already comparable to or lower than those of diesel, gasoline or natural gas vehicles with today's electricity mixes for many countries (for example, Germany), as has been shown before[51,52]. The performance of battery-electric trucks strongly 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 a range autonomy of 800 km (requiring larger batteries and reducing the maximum payload) reduce the per-tonne-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 Fig. 5). The main reason is non-CO_2 impacts, which account for about two-thirds of the total net radiative forcing due to aviation[53]. Aviation thus is a truly hard-to-abate sector, where

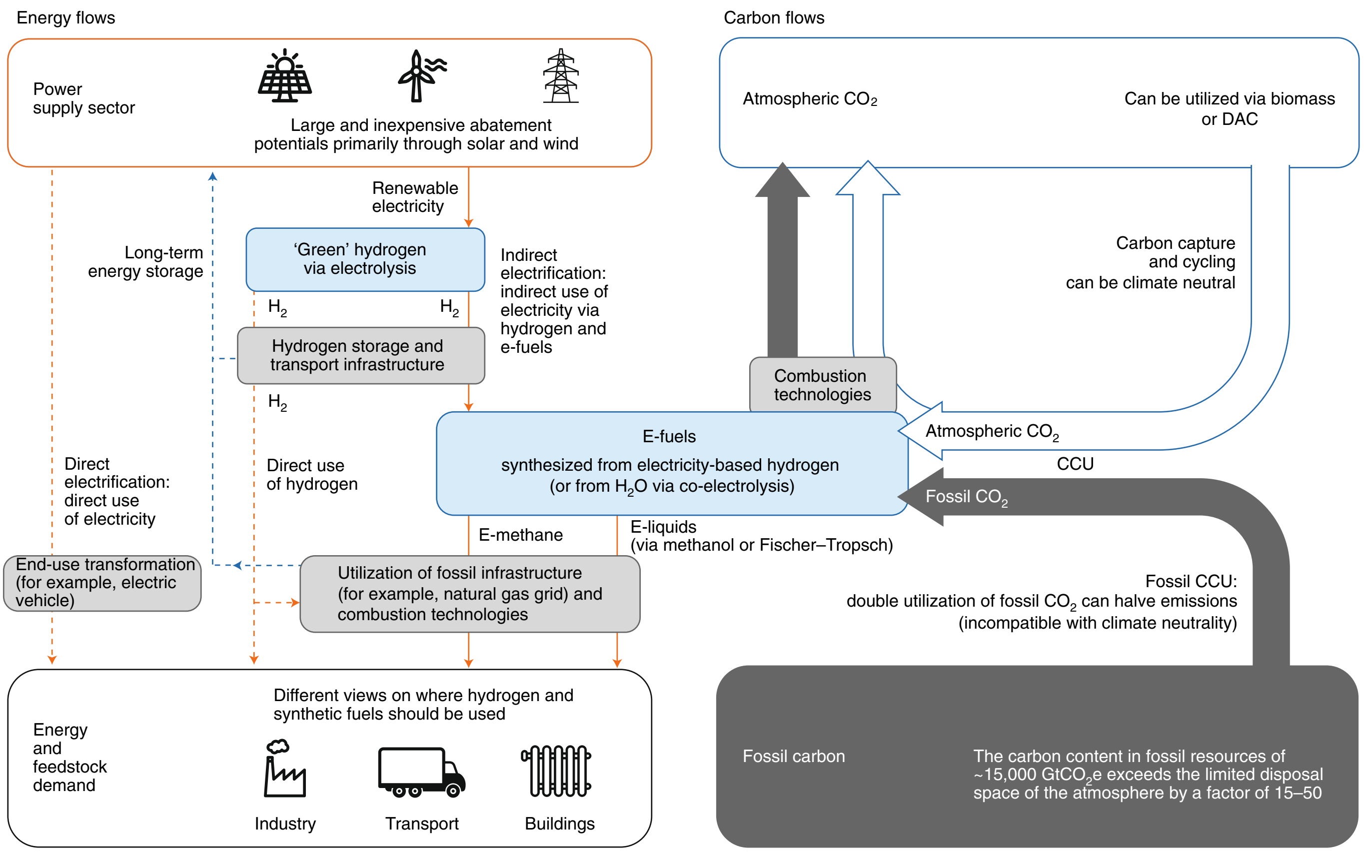


Fig. 1 | Basic principle of e-fuels in an energy system. Left: energy flows. E-fuels and hydrogen are forms of indirect electrification in which (renewable) electricity can be used via electrolysis and e-fuel synthesis to meet energy demands that rely on gaseous and liquid fuels. A competing option is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

even e-fuels are only an incomplete backstop. E-kerosene alone does not allow mankind to fully buy itself out of GHG emissions.

Reutilizing CO_2 from a fossil source (for example, 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 Fig. 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[54,55]. 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 the two processes. As a result, GHG emissions of a fossil-CCU pathway lead to no or only a minor reduction of GHG emissions compared with fossil-fuel 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 reutilizing e-fuel application (Extended Data Fig. 4 shows a sensitivity analysis of this attribution). However, if source applications have to carry the full carbon costs (for example, via CO_2 pricing), the industry will increasingly consider alternatives to a reutilization, such as low-carbon industrial processes or CCS.

Fossil CCU and atmospheric carbon capture and cycling require infrastructures with very different spatial topographies. 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 (for example, 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 (for example, 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-fuel 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[56]. 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 Fig. 1). Such full recycling of CO_2 could become a pillar of a circular climate-neutral economy. However, capturing atmospheric carbon requires either substantial land (in the case of biogenic CO_2) or energy resources (in the 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 petrochemical industry in the EU today (Extended Data Fig. 4 shows a sensitivity analysis of heat supply assumptions). Low-carbon heat supply is thus just as crucial as a 100% low-carbon (for example, renewable) electricity supply. If CO_2 is instead sourced from biomass,

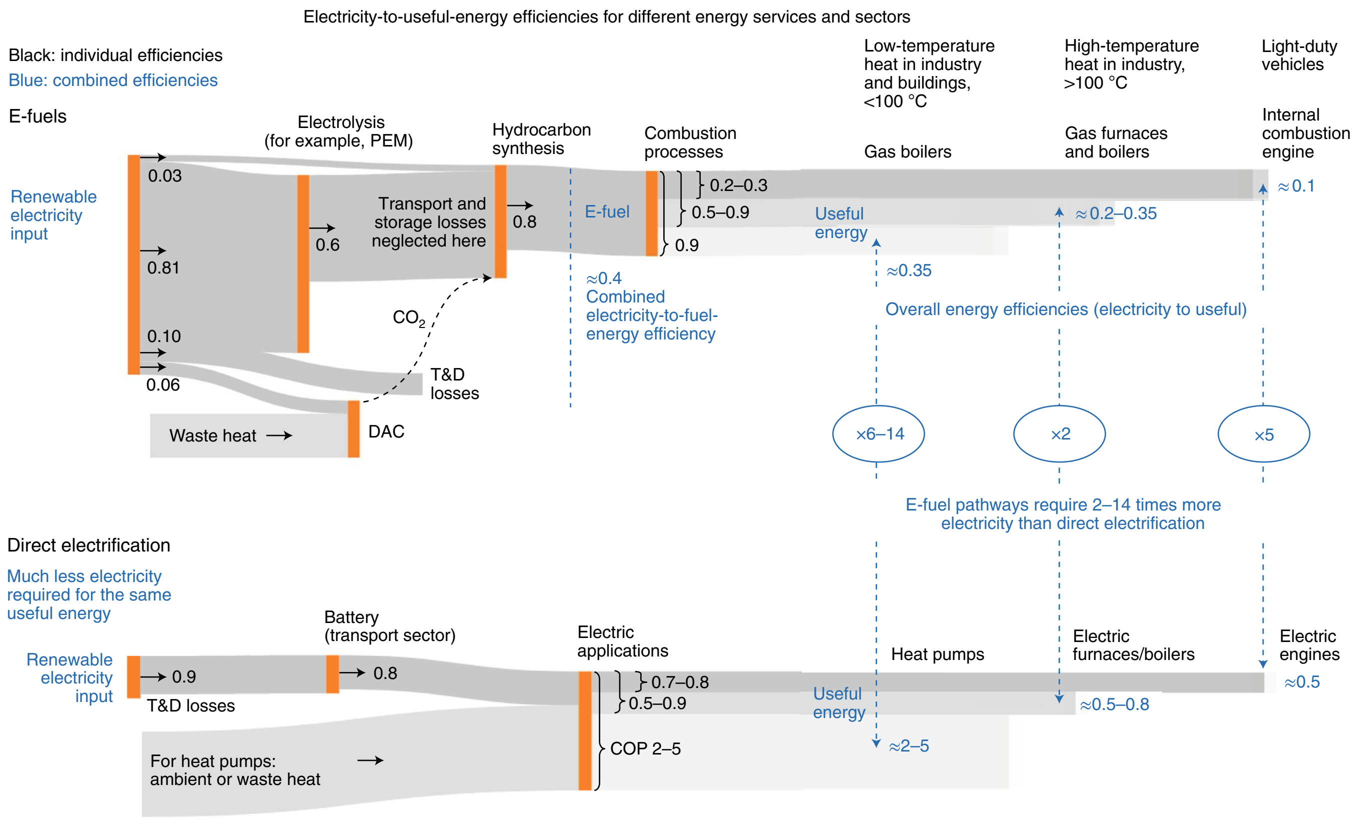


Fig. 2 | Energy efficiencies for major conversion steps from electricity input to useful energy. These are considered across sectors for e-fuel applications (top) and direct electrification applications (bottom); individual conversion efficiencies (black) and combined efficiencies (blue) are shown. The 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 2–14 times higher than for direct electrification alternatives. The underlying data originate from life-cycle assessment inventories (Supplementary Information S1) and additional literature (references in the main text and in Supplementary Information S2). PEM, proton-exchange membrane; T&D, transmission and distribution.

this would require an accurate accounting of associated emissions, including those from indirect land-use changes[57,58].

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 (Fig. 4a,b) for a case in which hydrogen is produced in a renewable-rich country and shipped ~4,000 km, which represents the distance between Northwest Africa (for example, Morocco) and northwestern European ports (for example, 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 do not include either potential taxes and levies or further domestic transport or distribution costs. The resulting levelized e-fuel costs are consequently compared with fossil-fuel wholesale market prices.

The bottom-up analysis for the several e-fuel cost components is based on a literature review, life-cycle assessment inventory data, empirical hourly electricity prices and optimization of electrolysis operation (Table 1 shows a selection of crucial and uncertain parameters, Supplementary Information S2 shows all underlying assumptions and crucial technoeconomic parameters for all cost components, and Extended Data Fig. 9 shows life-cycle emissions of all fuels). The extensive electrolysis cost data collected are available in ref. [59] and visualized in an interactive dashboard (https://h2.pik-potsdam.de/H2Dash/) and Extended Data Fig. 10.

Calculating production costs of hydrogen and e-fuels faces several parameter uncertainties, especially for 2030 and 2050 estimates. The data and literature on which we rely 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 immense and continuous policy support (for example, subsidies), as we argue below. We focus on large-scale average production costs (plants with >100 $\mathrm{m\,kg^{-1}\,yr^{-1}}$), 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 on the basis of the ranges in literature and our own judgement (Supplementary Information S2). The largest uncertainties are associated with DAC, electrolysis and costs of transporting hydrogen (for which little detailed work has been published). Mid-term cost estimates for 2030 strongly depend on the technology deployments in the next years, which crucially depend 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

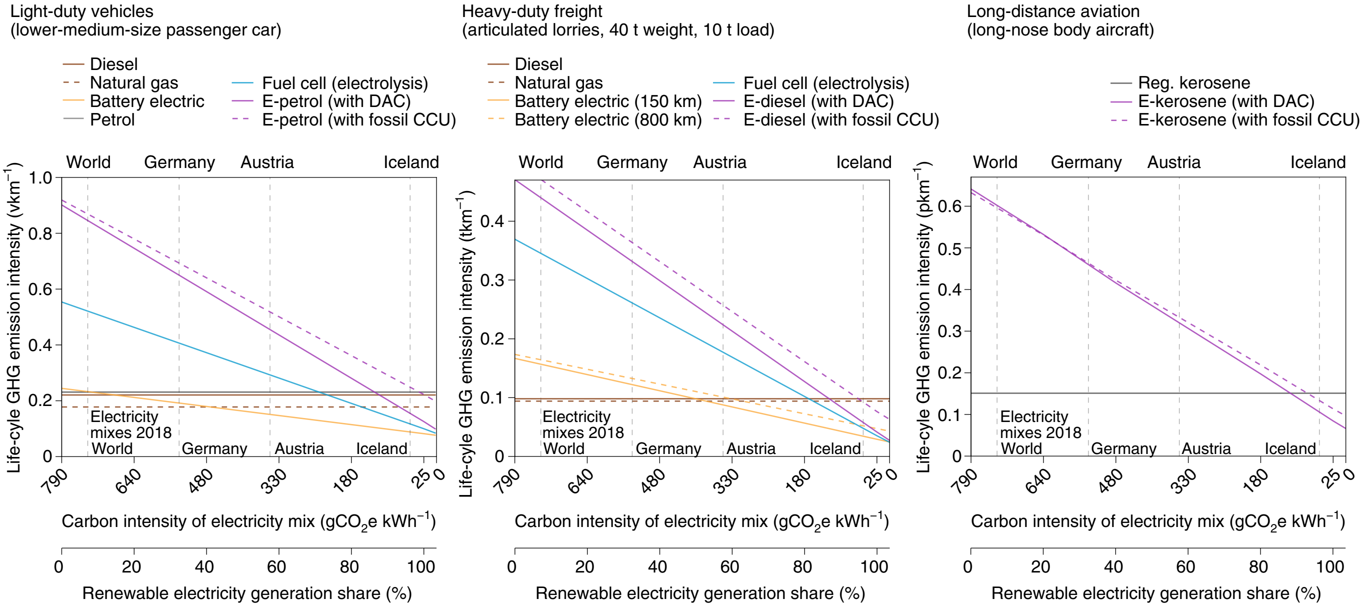


Fig. 3 | Life-cycle GHG emissions for different fuels and transport applications as a function of the life-cycle carbon intensities of electricity used for battery charging, hydrogen and e-fuel production. Note different functional units on the *y* axis across light-duty vehicles (left), heavy-duty trucks (middle) and aeroplanes (right). Comparison of 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 are based on anticipated technological progress in 2030 using the life-cycle assessment model carculator[51] and carculator_truck[68]. 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 Figs. 6–8.

DAC-based in the near-term. Our hydrogen cost estimates are similar to those derived for 2030 by Glenk and Reichelstein[60]. Our e-fuel cost estimates are similar for those derived for 2030–2050 by Ram et al.[36] and slightly lower (10–20%) than 2030 estimates derived by Hank et al.[61].

Our estimation of hydrogen production costs considers synergies of integrating electrolysers into power systems with high wind and solar PV shares (Supplementary Information 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 the domestic electricity demand of the exporting country.

As an indicator of the competitiveness with fossil fuels, we calculate the fuel-switching CO_2 prices (Fig. 4a,b, right axis) such that e-fuel costs break even with natural gas prices (wholesale 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.

For 2020–2025, we estimate e-fuel production costs of €194–226 MWh^{-1} (25th–75th percentile), which translates into roughly €3.20l^{-1} (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 will 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 per tCO_2 for e-gasoline and €1,200 per tCO_2 for e-methane. Abatement costs for replacing natural gas are higher because both natural-gas prices and per-energy emission savings (carbon intensities) are lower than for gasoline (Fig. 4c). As a result, power-to-liquid applications are less uncompetitive than power to gas.

Hydrogen and e-fuel costs are anticipated to reduce substantially due to continued technological progress if substantial cumulative investments can be achieved. Decreasing capacity costs of electrolysis, hydrocarbon synthesis and DAC, and slight improvements in electrolysis efficiency as well as lower generation costs and increasing shares of wind and solar PV (Supplementary Information S2), can lead to 2050 e-fuel cost estimates of €47–51 MWh^{-1} for e-gasoline and €60–65 MWh^{-1} for e-methane, which face higher transport costs (due to liquefaction and on-ship cryogenic storage). This translates into 2050 fuel-switching CO_2 prices of ~€20 per tCO_2 for e-gasoline and ~€270 per tCO_2 for e-methane.

If fossil CO_2 were utilized instead of DAC, the direct 2020 e-fuel production costs could be reduced by roughly one-quarter (Extended Data Fig. 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 >€2,500 per tCO_2 in 2020 and ~€2,000 per tCO_2 in 2030.

While CO_2 prices required to make e-fuels competitive in 2020–2030 (€280–1200 per tCO_2) are unrealistically high for most countries (including the EU Emissions Trading System (ETS)), the CO_2 prices required in 2050 (€20–270 per tCO_2) can fall within or below the range seen in climate change mitigation scenarios[62] (Fig. 4d) or those likely to be realized in regional and potentially global carbon markets by that time. Despite the uncertainty about future cost developments, this general result is probably 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

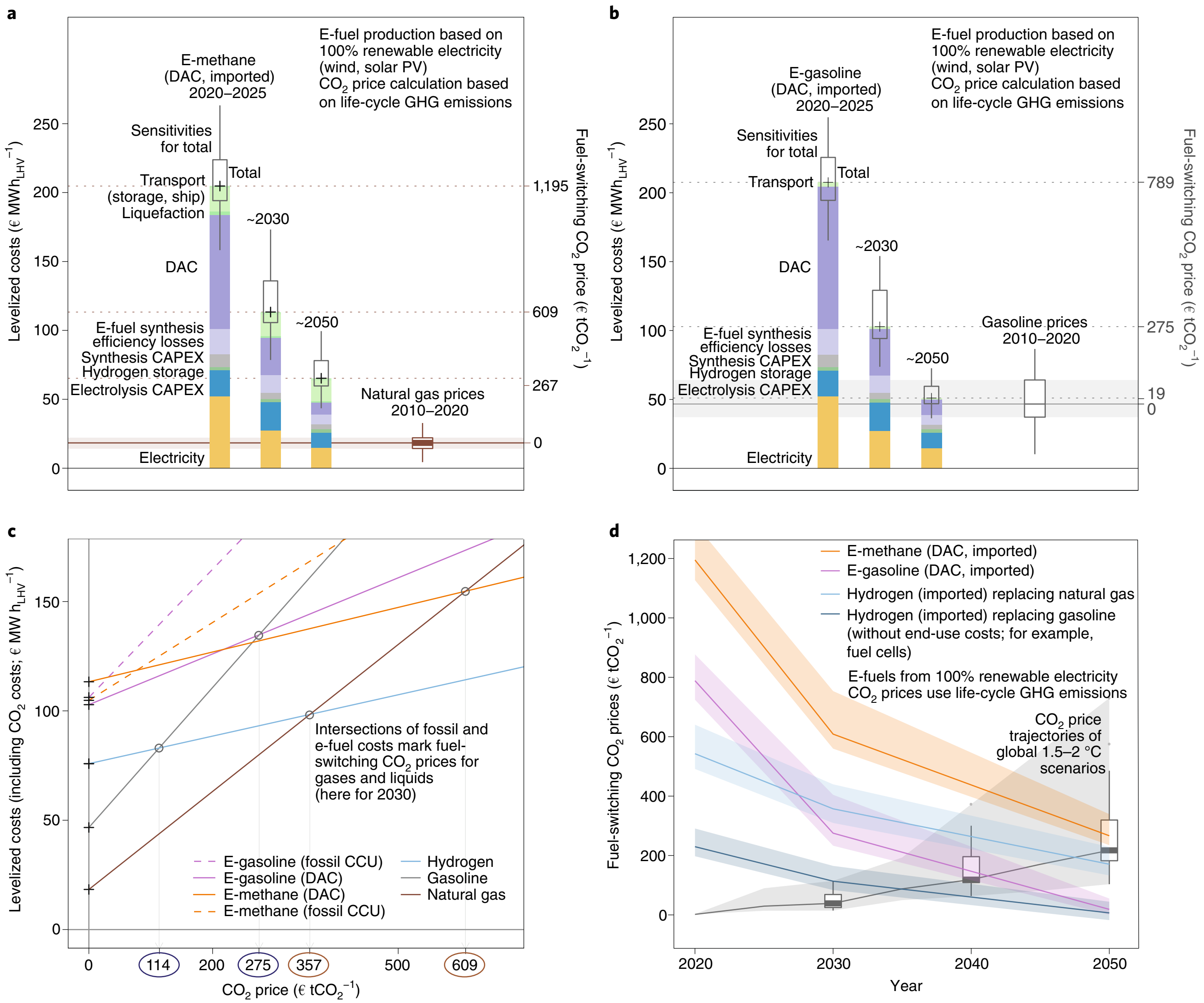


Fig. 4 | Levelized cost and fuel-switching CO_2 prices of e-fuels. a, Levelized cost (and its components) and fuel-switching CO_2 prices for e-methane (shipped from Northwest Africa to northwestern European ports, based on DAC) for 2020–2025, 2030 and 2050, in comparison with European wholesale market natural gas prices for 2010–2020. +, total costs. The box plots indicate uncertainties based on a sensitivity study (Supplementary Information S2). Boxes indicate the 25th–75th percentiles; whiskers indicate the full uncertainty range. CAPEX, capital expenditure. **b**, The same as **a** but for e-gasoline compared with wholesale gasoline prices. Also compare the analogous Extended Data Fig. 1, in which life-cycle emissions of e-fuels are neglected, and Extended Data Fig. 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 CO_2 prices. + (*y* axis), direct costs (without CO_2) shown in **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 right-hand *y* axis in **a** and **b**). See the analogous Supplementary Fig. 1 for all years and fuels. **d**, Fuel-switching CO_2 prices over time for e-fuels and hydrogen in comparison with CO_2 price trajectories of global 1.5–2 °C climate mitigation scenarios[62]. Uncertainty ribbons of the e-fuel lines represent 25th–75th percentiles.

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 Fig. 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 immense 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 2030 CO_2 prices higher than the global CO_2 prices shown in Fig. 4d. This is true for both the EU ETS as well for the non-EU ETS sectors of transport and buildings that are not subject to explicit carbon pricing at the

Table 1 | Most important parameters for e-fuel cost estimation and sensitivity analysis

	2020–2025	2030	2050
Annual average electricity price (€ MWh^{-1})	50 ± 10	50 ± 10	30 ± 10
Electrolysis CAPEX (€ kW^{-1}, median of AEC/PEMEC literature review)	1,100 ± 389	625 ± 258	334 ± 189
DAC (€ per tCO$_2$ captured)	460 ± 90	150 + 150/− 50	50 + 50/− 10

For the full table and references, see Supplementary Information S2.

EU level yet. High EU carbon prices could 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 about 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 Fig. 5, we show marginal abatement cost curves for 2020–2025 for liquid and gaseous e-fuels (blue, from the calculations presented in Fig. 4) and direct electrification alternatives (green, schematic curve) across non-electric energy and industrial sectors in the Organisation for Economic Co-operation and Development (OECD; energy end-use data from IEA ETP 2017 (ref. [63])). 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 marginal abatement cost curves 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 is an imperfect substitute for 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 marginal abatement cost curve 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 (Fig. 5).

On the basis of the relation of the two curves, we broadly group end-use sectors into four categories (corresponding to the four background colours) reflecting the competitiveness of e-fuels and direct electrification.

First, there are sectors and applications for which direct electrification is substantially 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.

Second, there are sectors in which direct electrification and e-fuels have similar costs, or in which high uncertainty or other potential 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 or 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 prioritization of direct electrification.

Third, there are sectors and applications for which direct electrification faces limits that can be overcome by hydrogen and e-fuels (for example, 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 (12,500 TWh in 2014). Meeting this with e-fuels would require additional solar and wind power capacity of about 5,000 GW with roughly the same magnitude for electrolysis capacity, while global 2019 addition of renewable power capacity amounted to ~200 GW yr^{-1} (ref. [64]). This points to the need for a prioritization even within impossible-to-electrify sectors.

Fourth, there are some emissions that cannot be avoided either by electrification or 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[65].

A holistic approach should consider not only the costs of hydrogen and e-fuels but rather the twofold 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 is more within reach (that is, would require less subsidy) 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 substantially increase overall costs of climate change mitigation while even increasing GHG emission compared with 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 huge 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 2–14 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 per tCO$_2$ for e-gasoline and ~€1,200 per tCO$_2$ for e-methane in 2020–2025. Technological progress could reduce the abatement cost vis-à-vis fossil alternatives substantially to ~€20 per tCO$_2$ for e-gasoline and ~€270 per 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:

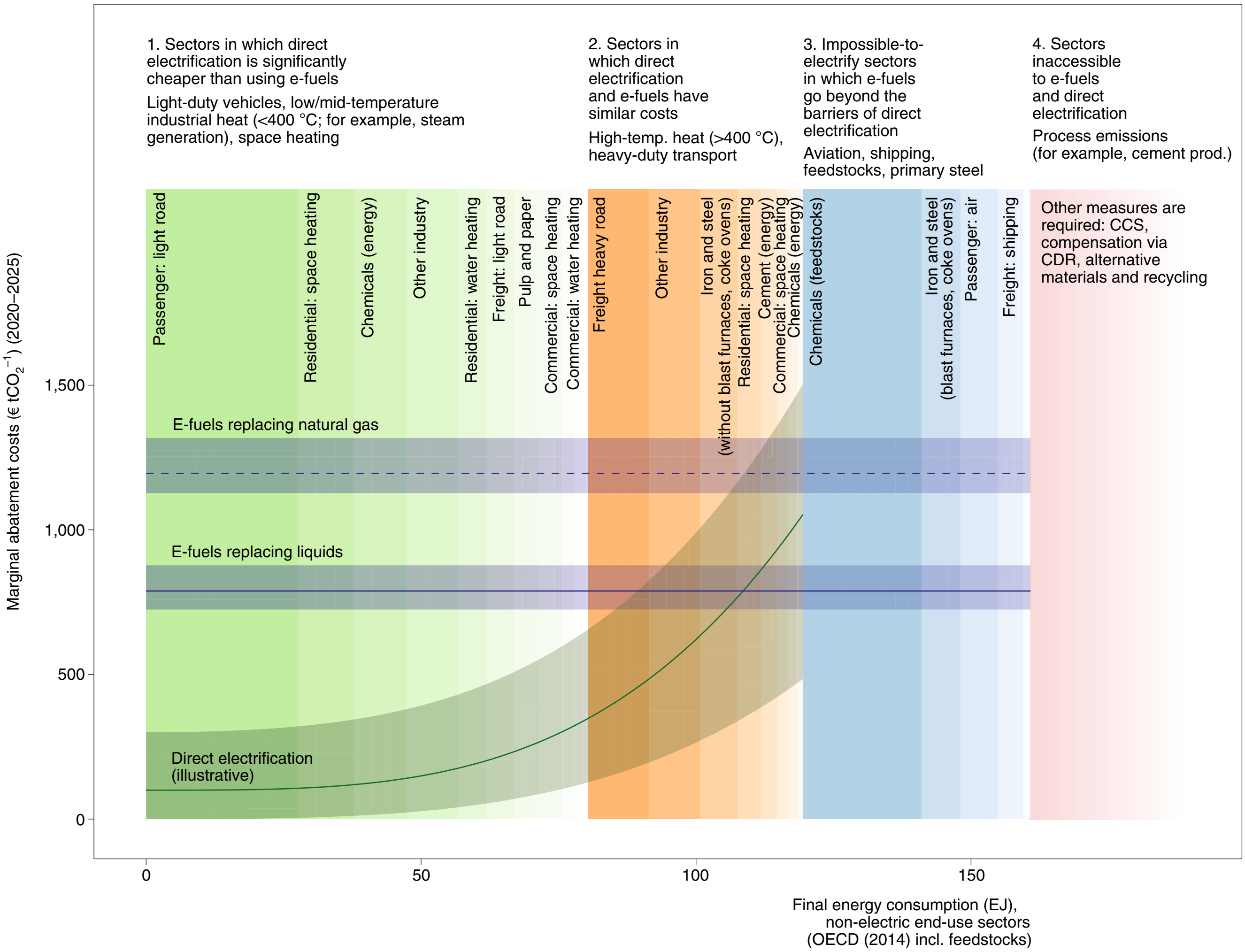


Fig. 5 | Marginal abatement cost curves (that is, fuel-switching CO_2 prices). Data in 2020–2025 for e-methane (replacing natural gas) and liquid e-fuels (replacing fossil liquids) from the cost calculations shown in Fig. 4, and direct electrification alternatives (green, illustrative curve) across non-electric energy and industrial sectors in the OECD (2014 energy end-use data from IEA ETP 2017 (ref. [63])). 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. The analogous Extended Data Fig. 3 also includes the direct use of hydrogen.

1. It is unlikely that hydrogen and e-fuels will become cheap and abundant early enough to widely substitute fossil fuels. Their expansion critically depends on immense 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 (for example, 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 applications 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 substantial 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 generally part of 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 (for example, 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, for a large-scale production and technological progress (renewable electricity, electrolysis, DAC), e-fuel costs can become competitive solely on the basis of 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 address 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 Middle East and North Africa (MENA), Iceland, Latin America and Australia[34,66]. 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 carbon capture and cycling require CO_2 and hydrogen infrastructures with different spatial topographies, 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 (for example, storage and transportation) is more challenging and requires additional infrastructure (potentially a hydrogen grid) and partial additional transformation on the demand side (for example, 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 scheme that subsidizes the use of hydrogen in energy-intensive industries and e-fuel quotas for aviation fuels are currently being debated in Germany and were mentioned as an option in the EU hydrogen strategy[67].

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. Carbon contracts for differences, border tax adjustments and increasing EU carbon prices could create a global demand pull for hydrogen and e-fuels, which could even incentivize export from countries that do not have carbon pricing (for example, Australia) or e-fuel policy support. Complementing bilateral cooperation projects and public–private partnerships could 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 regard e-fuels not as a full-scale substitute for 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, substantial 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 carculator[51] and carculator_truck[68]. The electrolysis cost and efficiency data are available in ref. [59]. All other data are available from the corresponding author on request.

Code availability

The modified version of ecoinvent used in this analysis is generated from ecoinvent 3.7.1, which is available at https://github.com/romainsacchi/premise. The modified version is available from the authors on reasonable request.

Received: 20 November 2020; Accepted: 24 March 2021;

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* Renewable Energies and Energy Efficiency Vol. 14 (Kassel Univ. Press, 2009).
3. Zeman, F. S. & Keith, D. W. Carbon neutral hydrocarbons. *Philos. 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* **7**, 916–944 (2015).
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 CO_2 emissions. *Nat. Clim. 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.* **15**, 124004 (2020).
13. Mai, T. et al. *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States* (NREL, 2018); https://doi.org/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. *Proc. Natl Acad. Sci. USA* **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. *Energy* **220**, 119678 (2021).
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 *Sustainable Synthetic Carbon Based Fuels for Transport* (2019).
18. International Energy Agency *The Future of Hydrogen: Seizing Today's Opportunities* (OECD, 2019); https://doi.org/10.1787/1e0514c4-en
19. *Hydrogen Economy Outlook: Key Messages* (Bloomberg Finance, 2020).
20. Davis, S. J. et al. Net-zero emissions energy systems. *Science* **360**, eaas9793 (2018).
21. Luderer, G. et al. Residual fossil CO_2 emissions in 1.5–2 °C pathways. *Nat. Clim. Change* **8**, 626–633 (2018).
22. Bruce, S. et al. *Opportunities for Hydrogen in Commercial Aviation* (CSIRO, 2020).
23. *Clean Skies for Tomorrow: Sustainable Aviation Fuels as a Pathway to Net-Zero Aviation* (World Economic Forum, 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* (Verband der Chemischen Industrie, 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. *Renew. Sustain. Energy Rev.* **81**, 1049–1086 (2018).
26. Peters, D. et al. *Gas Decarbonisation Pathways 2020–2050—Gas for Climate* (Guidehouse, 2020).
27. van Renssen, S. The hydrogen solution? *Nat. Clim. Change* **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. *Appl. Energy* **232**, 323–340 (2018).
29. Siegemund, S. et al. *The Potential of Electricity Based Fuels for Low Emission Transport in the EU* (dena, 2017).
30. *VDA President Müller: Hydrogen and E-Fuels are Important Elements in Climate-Neutral Transport* (German Association of the Automotive Industry—VDA, 2020).
31. Wehrmann, B. *'Tomorrow's Oil': Germany Seeks Hydrogen Export Deal with West African States* (Clean Energy Wire, 2020).
32. Barreto, L., Makihira, A. & Riahi, K. The hydrogen economy in the 21st century: a sustainable development scenario. *Int. J. Hydrog. 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. *Int. J. Hydrog. 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. *The Future Cost of Electricity-Based Synthetic Fuels* (Agora Verkehrswende, Agora Energiewende and Frontier Economics, 2018); https://www.renewableh2.org/wp-content/uploads/2018/11/2018-09-Agora_SynKost_Study_EN_WEB.pdf
36. Ram, M. et al. *Powerfuels in a Renewable Energy World—Global Volumes, Costs, and Trading 2030 to 2050* (dena, 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. ESYS, BDI & dena. *Focusing Expertise, Shaping Policy—Energy Transition Now! Essential Findings of the Three Baseline Studies into the Feasibility of the Energy Transition by 2050 in Germany* (Energy Systems of the Future, 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 CO_2 air capture. *Appl. Energy* **264**, 114672 (2020).
41. Stockl, F., Schill, W.-P. & Zerrahn, A. Green hydrogen: optimal supply chains and power sector benefits. Preprint at https://arxiv.org/abs/2005.03464 (2020).
42. Milanzi, S. et al. *Technischer Stand und Flexibilität des Power-to-Gas-Verfahrens* (2018); https://www.er.tu-berlin.de/fileadmin/a38331300/Dateien/Technischer_Stand_und_Flexibilit%C3%A4t_des_Power-to-Gas-Verfahrens.pdf
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. Life-cycle assessment of an industrial direct air capture process based on temperature-vacuum swing adsorption. *Nat. Energy* **6**, 203–213 (2021).
45. *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 Rev.* **20**, 6–19 (2018).
50. *Life Cycle Inventory Database v3.7* www.ecoinvent.org (Ecoinvent, 2020).
51. PSI team develops web tool for consumers to compare environmental impact of passenger cars in detail. *Green Car Congress* https://www.greencarcongress.com/2020/05/20200517-psi.html (2020).
52. Knobloch, F. et al. Net emission reductions from electric cars and heat pumps in 59 world regions over time. *Nat. Sustain.* **3**, 437–447 (2020).
53. Lee, D. S. et al. The contribution of global aviation to anthropogenic climate forcing for 2000 to 2018. *Atmos. Environ.* **244**, 117834 (2021).
54. Abanades, J. C., Rubin, E. S., Mazzotti, M. & Herzog, H. J. On the climate change mitigation potential of CO_2 conversion to fuels. *Energy Environ. Sci.* **10**, 2491–2499 (2017).
55. 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).
56. Zhang, X., Bauer, C., Mutel, C. L. & Volkart, K. Life cycle assessment of power-to-gas: approaches, system variations and their environmental implications. *Appl. Energy* **190**, 326–338 (2017).
57. 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).
58. Cherubini, F., Peters, G. P., Berntsen, T., Strømman, A. H. & Hertwich, E. CO_2 emissions from biomass combustion for bioenergy: atmospheric decay and contribution to global warming. *GCB Bioenergy* **3**, 413–426 (2011).
59. Everall, J. & Ueckerdt, F. Electrolyser CAPEX and efficiency data for: potential and risks of hydrogen-based e-fuels in climate change mitigation. Version 1 (Zenodo, 2021); https://doi.org/10.5281/ZENODO.4619892
60. Glenk, G. & Reichelstein, S. Economics of converting renewable power to hydrogen. *Nat. Energy* **4**, 216–222 (2019).
61. Hank, C. et al. Energy efficiency and economic assessment of imported energy carriers based on renewable electricity. *Sustain. Energy Fuels* **4**, 2256–2273 (2020).
62. Huppmann, D., Rogelj, J., Krey, V., Kriegler, E. & Riahi, K. A new scenario resource for integrated 1.5 °C research. *Nat. Clim. Change* **8**, 1027–1030 (2018).
63. *Energy Technology Perspectives 2017: Catalyzing Energy Technology Transformations* (International Energy Agency, 2017); https://www.iea.org/etp2017/
64. *Renewables 2020 Global Status Report* (REN21, 2020).
65. Lehtveer, M., Brynolf, S. & Grahn, M. What future for electrofuels in transport? Analysis of cost competitiveness in global climate mitigation. *Environ. Sci. Technol.* **53**, 1690–1697 (2019).
66. 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).
67. *A Hydrogen Strategy for a Climate-Neutral Europe* (European Commission, 2020).
68. 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 medium- and heavy-duty vehicles. *Environ. Sci. Technol.* **55**, 5224–5235 (2021).

Acknowledgements

We thank J. Knapp, S. Bi, F. Schreyer, F. Benke, A. Odenweller, B. Pfluger, J. Strefler, F. Stöckl and S. Madeddu for their critical reviews, valuable discussion and comments, and C. Wang for sharing Australian electricity price data. We gratefully acknowledge funding from the START project (FKZ03EK3046A), from the Kopernikus-Ariadne project (FKZ 03SFK5A) by the German Federal Ministry of Education and Research and from PSI's ESI platform.

Author contributions

F.U. and G.L. designed the study and derived the main conclusions. F.U. coordinated the work, conducted the cost calculations and efficiency comparisons, derived the main figures and did most of the writing. G.L. substantially contributed to the writing. R.S., C.B. and A.D. carried out the life-cycle GHG analysis and produced the associated figures. J.E. conducted the majority of the literature review and contributed to the data curation and code development. All coauthors reviewed and edited the text.

Competing interests

The authors declare no competing interests.

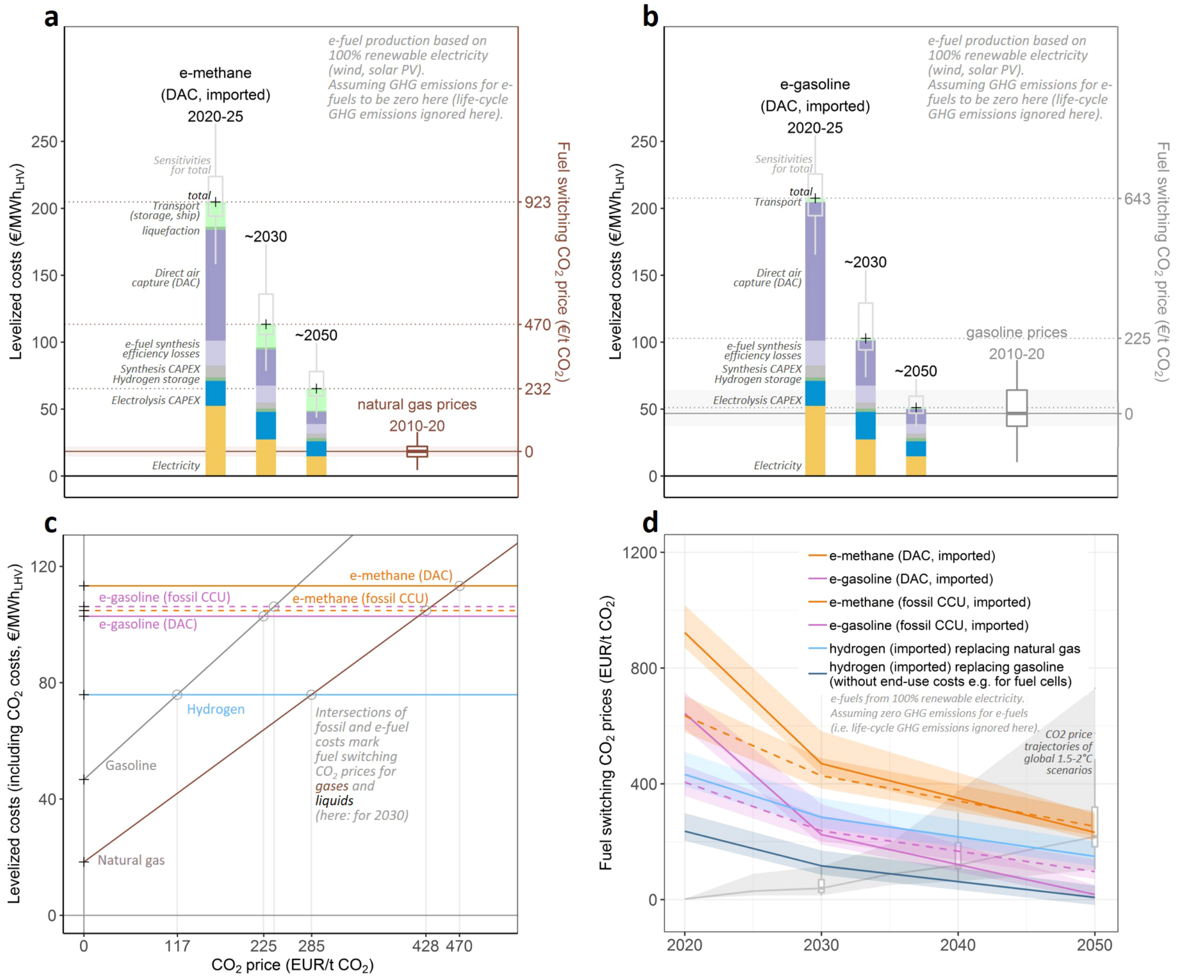
Additional information

Extended data is available for this paper at https://doi.org/10.1038/s41558-021-01032-7.

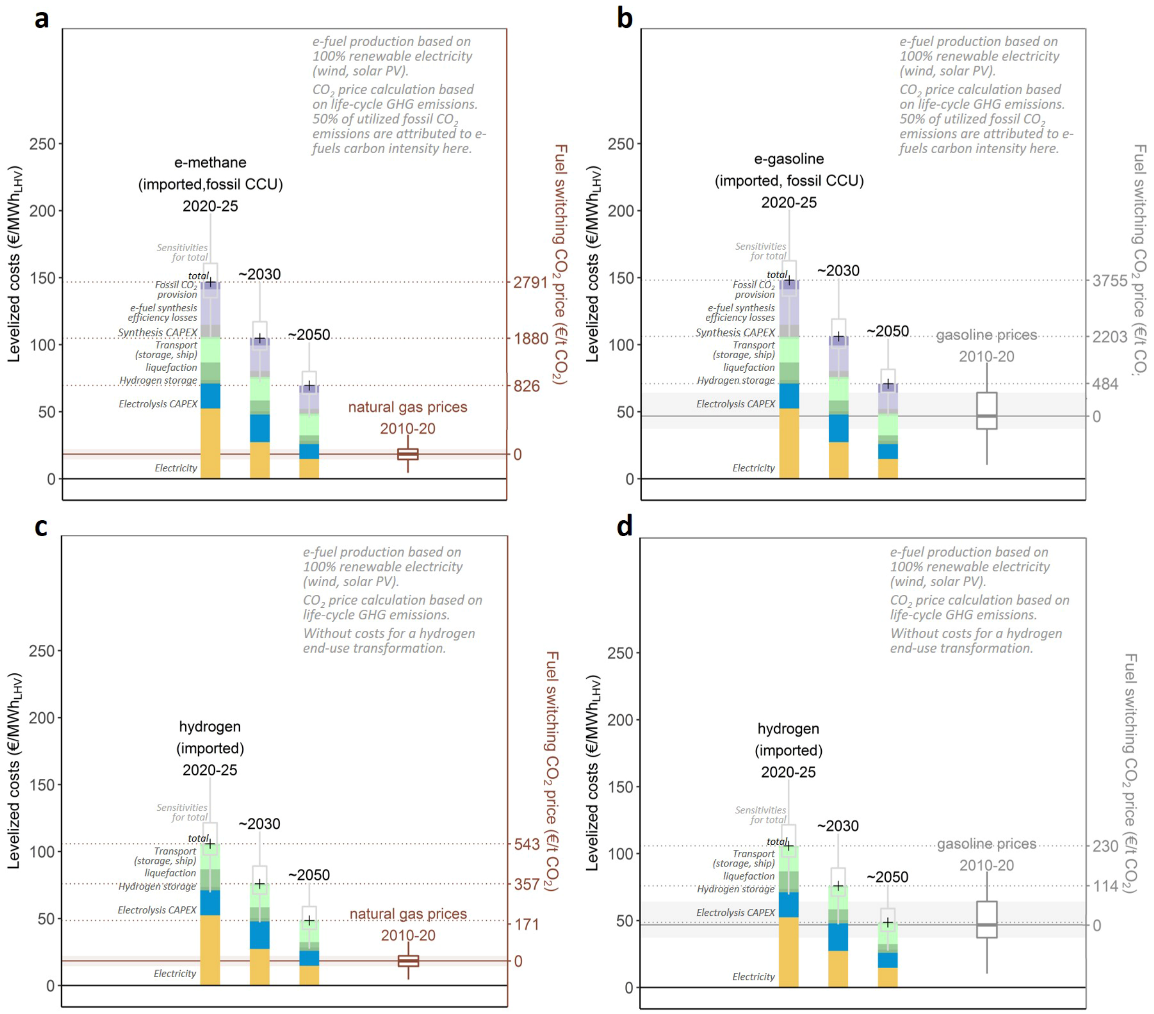
Supplementary information The online version contains supplementary material available at https://doi.org/10.1038/s41558-021-01032-7.

Correspondence should be addressed to F.U.

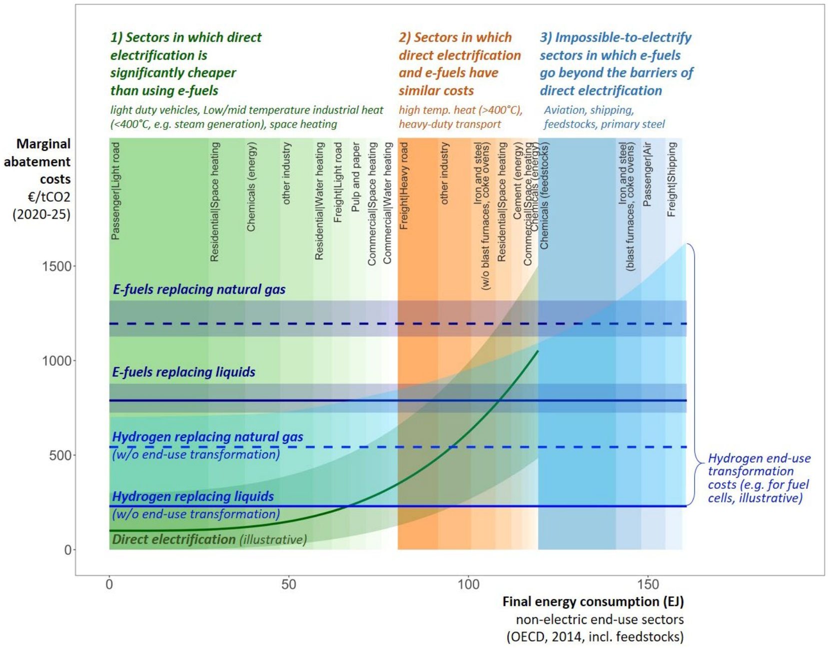
Peer review information *Nature Climate Change* thanks Pilar Lisbona and Yuanrong Zhou for their contribution to the peer review of this work.



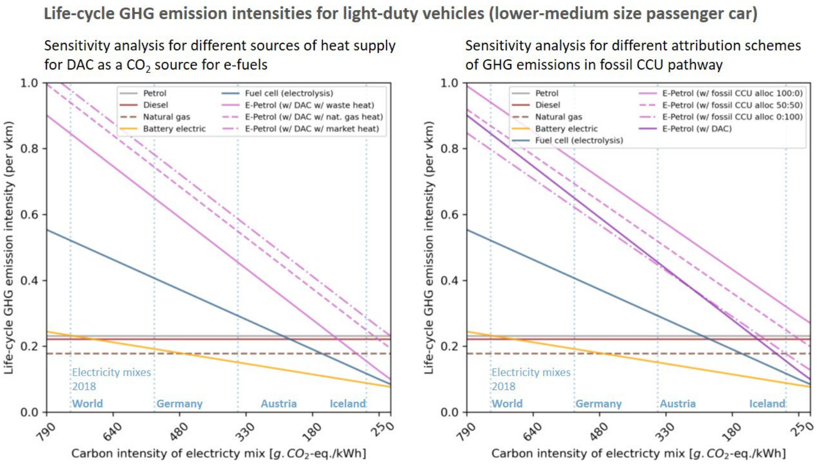
Extended Data Fig. 1 | Levelized cost and fuel-switching CO$_2$ prices of e-fuels with zero emissions approximation. Same as Fig. 4, but here based on the assumption that e-fuels (including those that are fossil CCU based) are evaluated as if they would not cause GHG emissions. **a**, Levelized cost (and its components) and fuel-switching CO$_2$ prices for e-methane (shipped from Northwest Africa to northwestern European ports, based on DAC) for 2020–25, 2030 and 2050, in comparison to European wholesale market natural gas prices for 2010–20. The + shows total costs. The box plots indicate uncertainties based on a sensitivity study (see Supplementary Information S2). **b**, same as 'a', but for e-gasoline compared to wholesale gasoline prices. **c**, Levelized costs (including CO$_2$ costs) of e-fuels and fossil fuels for 2030 as a function of CO$_2$ prices. The + on y axis are the direct costs (without CO$_2$) 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). **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[62]. 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 wholesale 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.



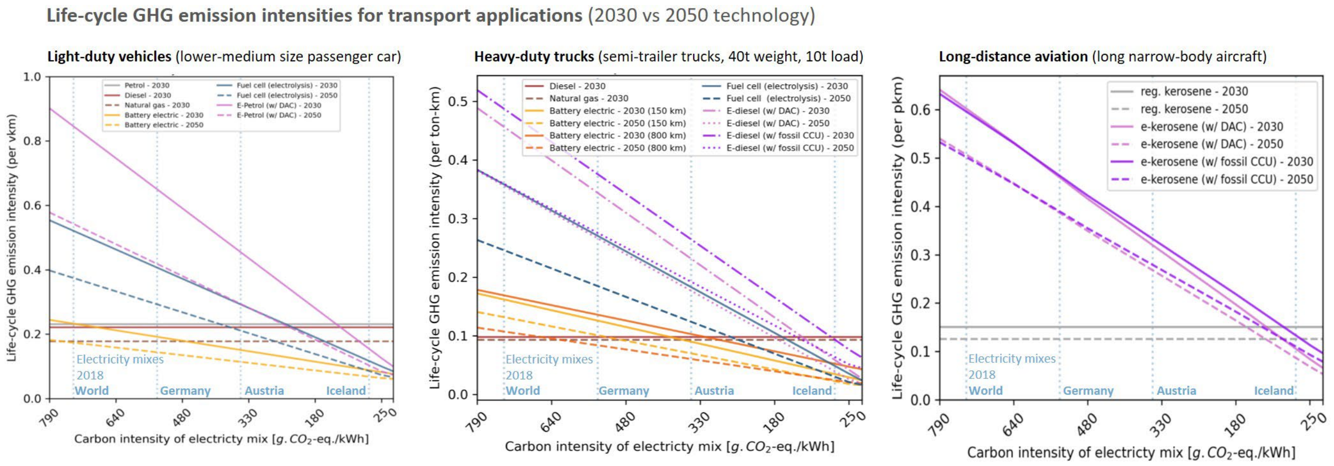
Extended Data Fig. 2 | Levelized cost and fuel-switching CO_2 prices. a, for e-methane (hydrogen shipped from Northwest Africa to northwestern European ports, based on fossil CCU) for 2020–25, 2030 and 2050, in comparison to European wholesale market natural gas prices for 2010–20. The + shows total costs. The box plots indicate uncertainties based on a sensitivity study (see S5). **b**, same as 'a', but for e-gasoline compared to wholesale 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.



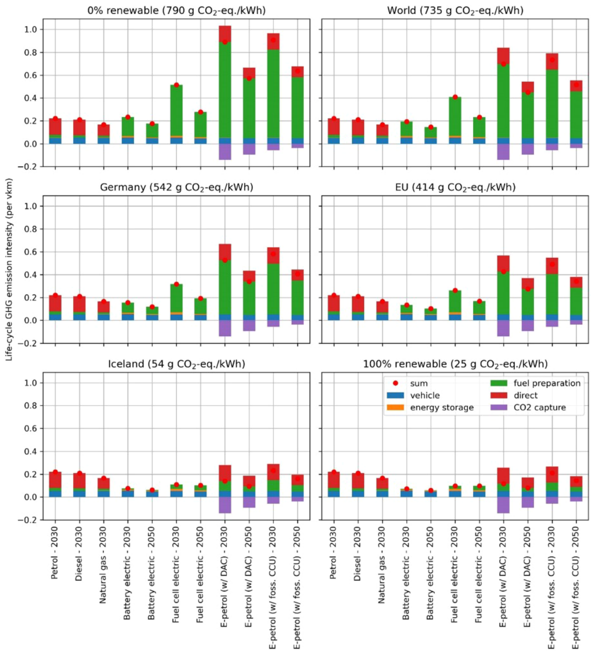
Extended Data Fig. 3 | Marginal abatement cost curves including hydrogen (that is, fuel-switching CO_2 prices). Same as main Fig. 5, but here also including direct use of hydrogen. In 2020–25 and for e-methane (replacing natural gas), liquid e-fuels (replacing fossil liquids) and hydrogen (replacing liquids or gases) from the cost calculations shown in Fig. 4 and Extended Data Fig. 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[63]). 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.



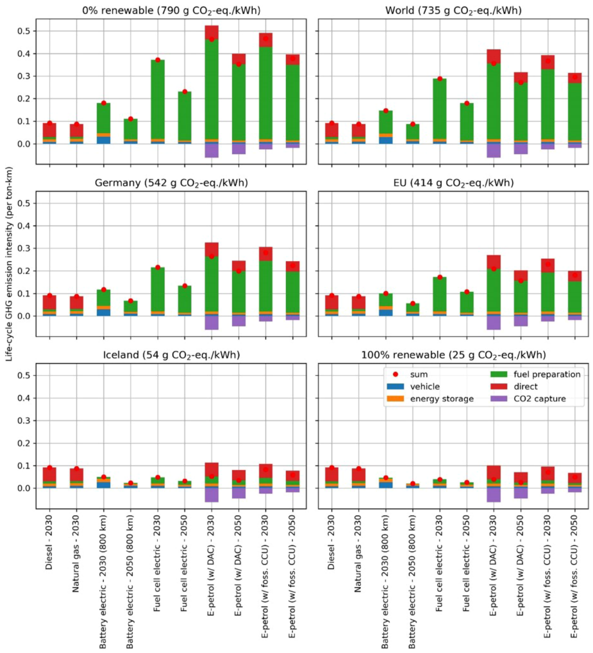
Extended Data Fig. 4 | *Life-cycle GHG emissions: Sensitivity analyses associated with* CO_2 sources. Left, different assumptions for heat supply for DAC. Waste heat (for example from an integration with a renewable-based hydrocarbon synthesis) is GHG emission free. Market heat refers to an average mix of heat sources used by the petrochemical 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 Fig. 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[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).



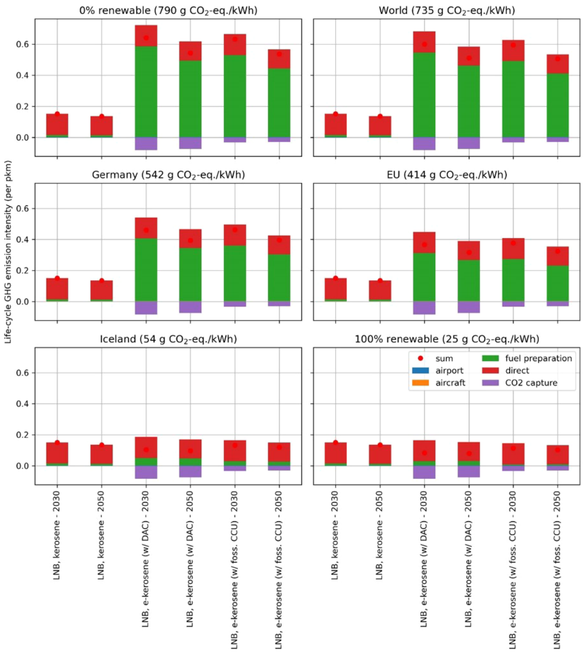
Extended Data Fig. 5 | Life-cycle GHG emissions: Sensitivity analyses for 2030 and 2050 technology. Life-cycle GHG emissions for light-duty vehicles (left), heavy-duty trucks (middle), and planes (right), as a function of the carbon intensity of electricity used for battery charging, hydrogen and e-fuel 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[51] and carculator_truck[68]. 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).



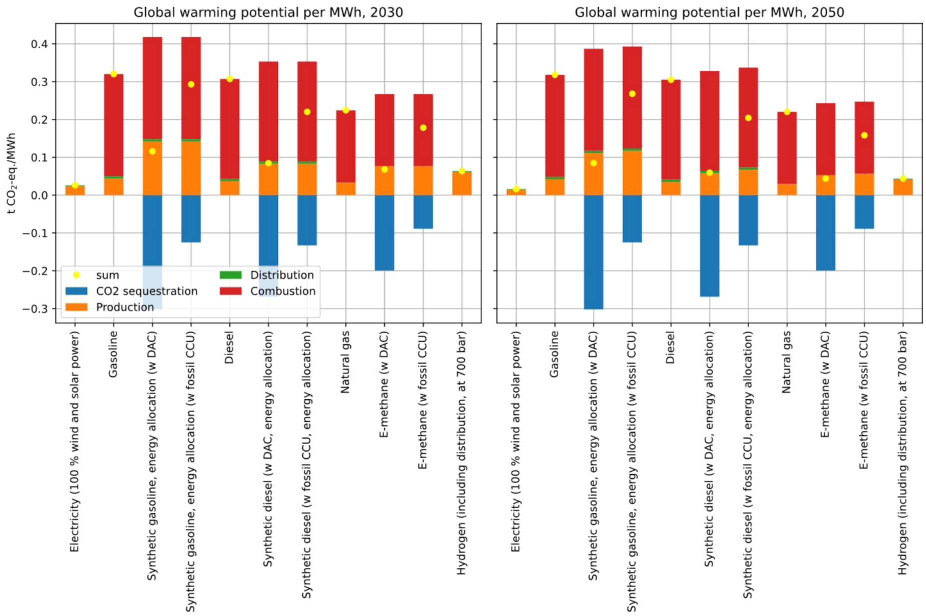
Extended Data Fig. 6 | Breakdown of overall life-cycle GHG emissions of 2030 and 2050 medium-sized passenger vehicles for carbon intensities of electricity for several regions, quantified using the LCA model presented in Sacchi et al.[51]. Numbers in each panel title are the GHG intensity of average electricity supply mixes (for 2017–18)[68]. 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.



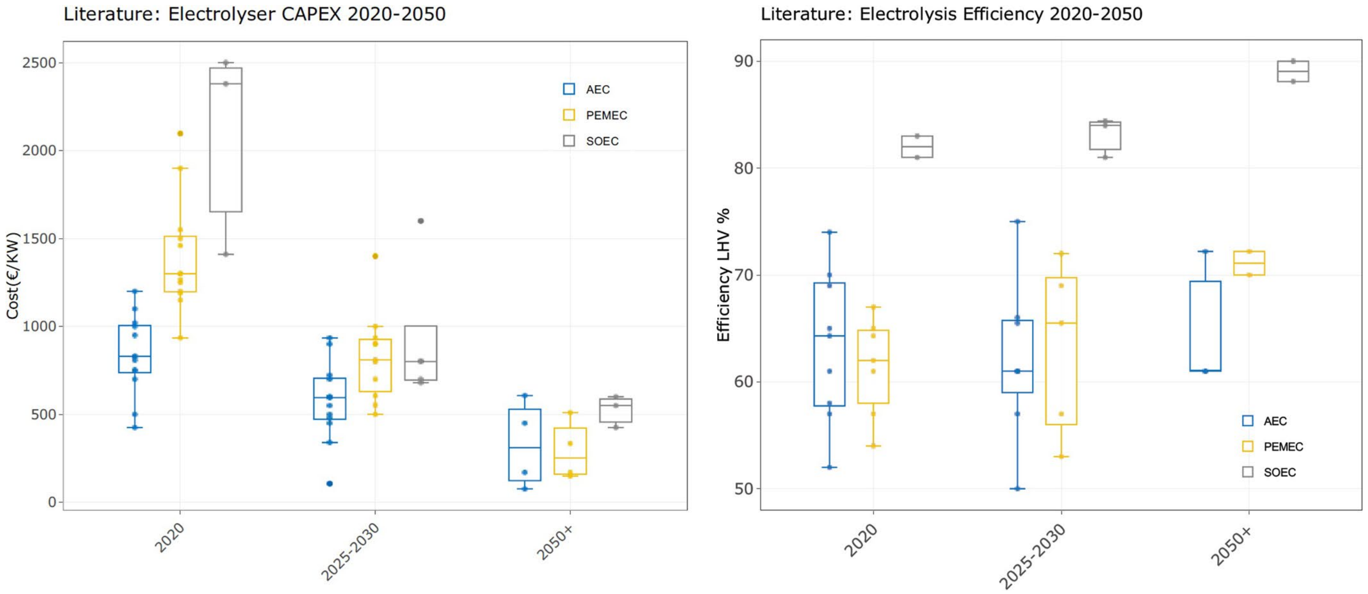
Extended Data Fig. 7 | Breakdown of overall life-cycle GHG emissions of 2030 and 2050 heavy-duty trucks for carbon intensities of electricity for several regions, quantified using the LCA model presented in Sacchi et al.[68]. Numbers in each panel title are the GHG intensity of average electricity supply mixes (for 2017–18)[50]. 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 Fig. 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.[51]. Numbers in each panel title are the GHG intensity of average electricity supply mixes (for 2017–18)[50]. 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 Fig. 9 | Life-cycle GHG emissions of fuels 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 Figs. 4, 5 and Extended Data Figs. 2 and 3.



Extended Data Fig. 10 | Literature review: electrolysis data. Specific capacity costs (left) and efficiencies (right) of electrolysis (PEMEC, AEC, SOEC) based on a literature review[59].