Ueckerdt, F., Bauer, C., Dirnaichner, A., Everall, J., Sacchi, R., Luderer, G. (2021 online): Potential and risks of hydrogen-based e-fuels in climate change mitigation. - Nature Climate Change.

DOI: 10.1038/s41558-021-01032-7

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

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Please note that this is a preprint version that has been revised and updated in a review process. The final paper 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 are unique in that they can tap into low-cost renewable electricity, while directly replacing fossil fuels in transport, industry and buildings, which would minimize transformation requirements on the energy demand side. However, there are contrasting views on the future role of e-fuels. In this Perspective, we examine their potential and limitations by synthesizing knowledge on their techno-economic characteristics, life-cycle greenhouse gas emissions and system-level implications. E-fuels' versatility is counterbalanced by their fragile climate effectiveness, high mitigation costs and uncertain large-scale availability. We calculate current e-fuel mitigation costs to be ~690 €/tCO_2 for liquids and ~920 €/tCO_2 for gases, while technological learning could reduce costs to ~30–200 €/tCO_2 until 2050. E-fuels may develop to a backstop technology in the long term, yet we deem it unlikely that they become cheap and abundant early enough to broadly substitute fossil fuels. Hence, a merit order that prioritizes where to establish hydrogen and e-fuels end-uses can guide policy decisions. From a carbon-neutrality perspective, e-fuels should be targeted on sectors that are inaccessible to direct electrification (aviation, shipping, primary steel, chemical industry feedstocks). Neglecting end-use transformation instead threatens to lock in a fossil fuel dependency if the envisaged widespread availability if e-fuels fails to materialize. Sensible climate policy supports the market introduction of e-fuels, and steers e-fuel flows towards no regret applications, while hedging against the risk of their unavailability at large scale.

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 allows to overcome the challenges of handling hydrogen[4].

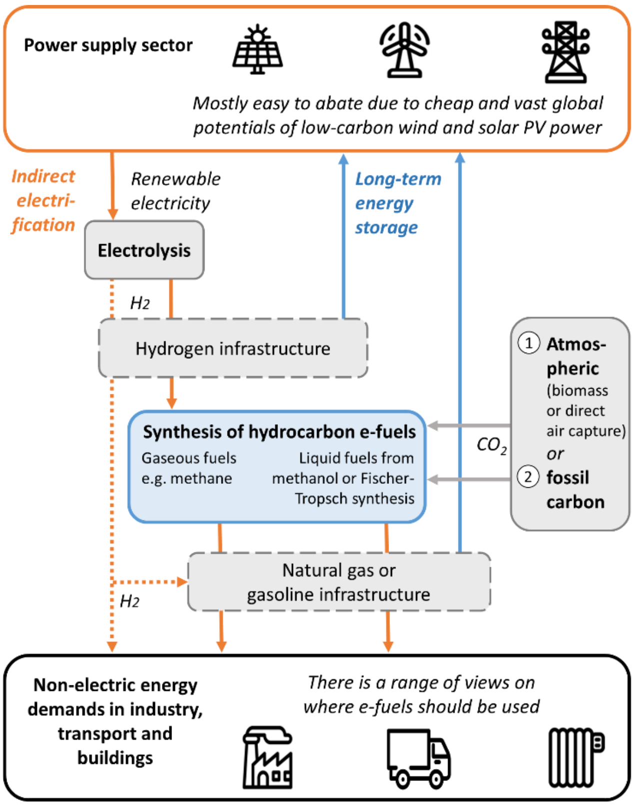

Figure 1 | Basic principle of how e-fuels can reduce CO_2 emissions in difficult-to-decarbonize sectors (through indirect electrification) and serve as a long-term energy storage.

Due to their versatility, e-fuels could extend the reach of wind and solar electricity to potentially *all* end-use sectors. 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 e-fuels.

Some studies show a minimal or no e-fuel use and instead suggest a deep[5–8] or full[9,10] *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 emissions (GHG) 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[11].

Recent reports[12–14] point to the potential value of e-fuels and hydrogen in overcoming the limitations of other mitigation options in difficult-to-decarbonize sectors[15]. The requirement of carbon neutrality creates increasing awareness of residual hydrocarbon demands[16] as bottlenecks for climate stabilization. E-fuels could help out in sectors and applications such as long-distance aviation[17,18], shipping, feedstocks in chemical industry[19], high-temperature industrial processes, long-haul heavy-duty road transport and long-term energy storage[20].

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)[21–23] or for light-duty vehicles[24–26]. Such a hydrogen[27,28], 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 with limited wind and solar resources, this vision relies on the import of hydrogen and e-fuels from abundant global resources[29,30].

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[31–33].

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 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.

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 (Figure 2). For many energy services they compete with *direct* electrification alternatives, which are typically more energy efficient. Depending on the application and respective technologies, electricity-to-useful energy efficiencies of e-fuels range from roughly 16% to 48%, which translates into (renewable) electricity generation requirements that are two to ten times higher than for direct electrification alternatives. These losses likely outstrip the efficiency gains of using electricity from renewable-rich countries and exporting them as e-fuels.

The energy conversion losses shown in Fig. 2 are indicative of relevant orders of magnitude – 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[34]. Additional losses from energy transport and storage are neglected, such as the losses from a potential liquefaction and regasification of hydrogen[35].

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 50%. This figure also includes electricity requirements of ~5% (of total electricity input) when capturing CO_2 from the air (DAC)[36,37]. We optimistically assume that the heat demand of DAC, comprising ~20% of overall electricity 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 of less than 20%. 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) [38,39]. 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 [7,40]. This leads to energy efficiencies that are four to ten 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 [7,41,42].

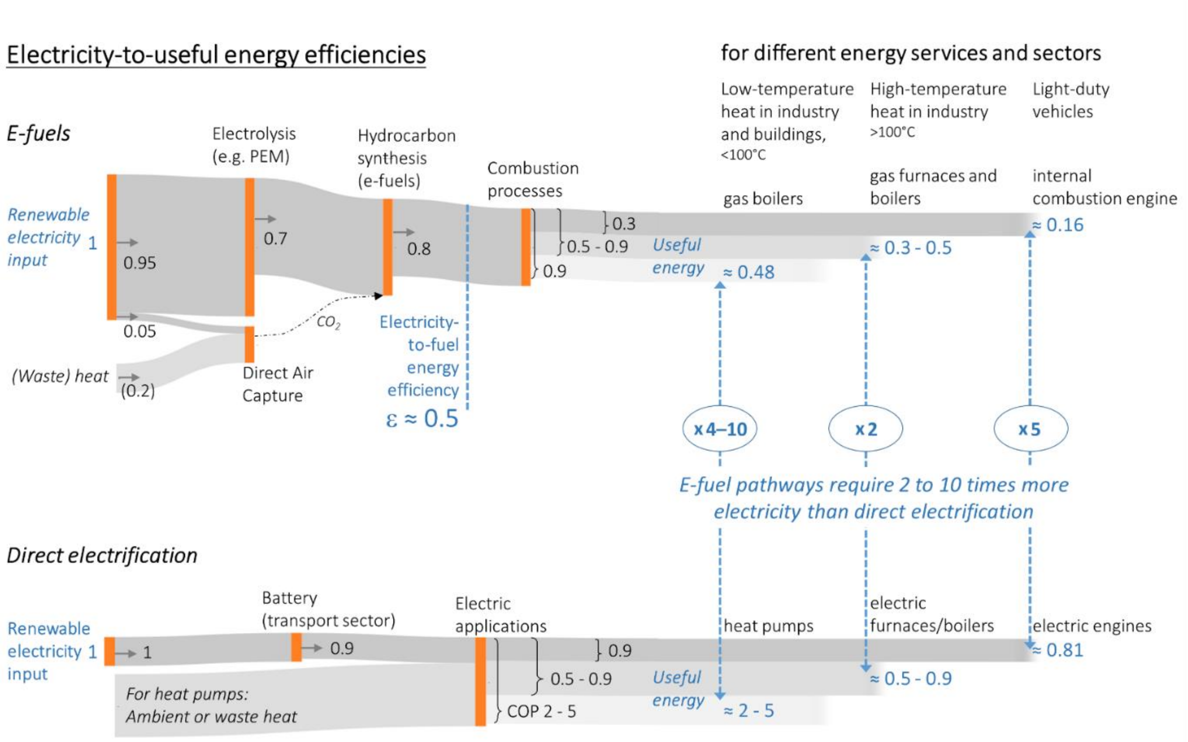

Figure 2 | Energy efficiencies for major conversion steps from electricity input to useful energy across sectors for e-fuel routes (top) and direct electrification routes (bottom). The overall e-fuel efficiencies range from roughly 16% to 48%, which translates into (renewable) electricity generation requirements that is two to ten times higher than for direct electrification alternatives.

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 source of CO_2 and the carbon intensity of the input electricity.

Source of CO_2

Re-utilization of CO_2 of fossil origin (Figure 3a, pathway 2), 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. 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[43,44]. Fossil-based carbon capture and utilization (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).

If CO_2 from sustainably grown biomass or DAC is used instead (Figure 3a, pathway 1), e-fuels can become (almost) carbon neutral[3], if produced from low-carbon electricity, and if life-cycle GHG emissions from the construction of equipment are small[45]. When combusting e-fuels, CO_2 of atmospheric origin is emitted back into the atmosphere, giving rise to a closed carbon cycle: carbon capture and cycling (CCC). Such full recycling of CO_2 could become a pillar of a circular climate-neutral economy. However, these processes require 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[46]. Note that biomass use requires an accurate accounting of associated emissions [47,48].

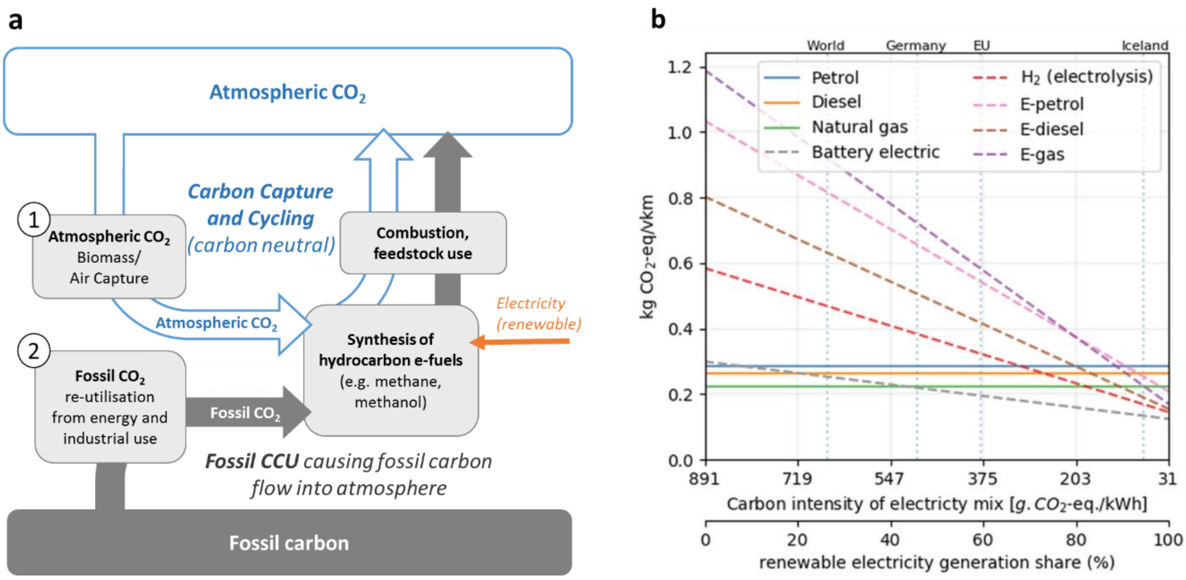

Figure 3 | *CO_2* and electricity sources. a, Carbon flows associated with e-fuels when using *CO_2* from atmospheric (1) and fossil (2) sources. Only utilizing atmospheric *CO_2* (through biomass or DAC) creates a carbon cycle that is compatible with carbon neutrality. **b,** Life-cycle GHG intensity of light-duty vehicles (LDVs) as a function of GHG intensity of input electricity generation. This compares several e-fuel options (e-petrol, e-diesel, e-gas, all using DAC *CO_2*) with fossil, fuel-cell (H_2 from electrolysis) and battery electric alternatives. Vertical lines show life cycle GHG intensities of electricity for selected geographies (for 2017-18). The secondary x axis (bottom) translates GHG intensity of electricity into an equivalent share of renewable electricity generation (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 of light-duty vehicles see SI Figure S1.

Fossil CCU and atmospheric CCC require CO_2 and hydrogen infrastructure with 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 sufficient land available. 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.

Carbon intensity of electricity input

Due to their low energy efficiency, climate effectiveness of e-fuels is sensitive to the carbon intensity of the input electricity. For the case of light-duty vehicles (LDVs), the life cycle assessment model *carculator*[49] is used to estimate GHG emissions per vehicle-km for several power trains with a current technology level for lower-medium size cars. Figure 3b shows such life-cycle GHG emissions as a function of the carbon intensity of electricity used for battery charging and fuel production (including hydrogen production and DAC).

With the current German electricity mix (which has a carbon intensity of 542 g CO_2-eq./kWh)[50], e-fuels produce between 1.8 to 2.6 times more GHG than the equivalent amount of conventional petrol. Liquid e-fuels only match petrol vehicle CO_2 emissions at a carbon-intensity of ~100 g CO_2-eq. per kWh – corresponding to an electricity supply system with at least 90 % low-carbon generation (see 2nd x-axis in Figure 3b, which assumes an equal share of wind and solar PV electricity and residual fossil electricity from natural gas and coal). Only for truly renewable-based power supplies do e-fuels become an effective mitigation option. This suggests that, for many countries and power systems, hardly any mitigation contribution can be expected from e-fuels before 2030. Battery electric vehicles, by contrast, have GHG emissions that are comparable to or lower than those of diesel cars already at today's electricity mixes for most countries[49,51].

For e-fuels to yield a climate benefit their electricity demand needs to be met from *additional* low-carbon electricity sources. This limitation is particular relevant (a) in the near- to mid-term, during which the growing renewable electricity share is needed to replace fossil fuels for already existing electricity demand, and (b) in densely populated countries with limited resource potential and social acceptance of renewable capacity expansion, such as Japan or many EU member states. Under such circumstances the inefficient use of limited renewable electricity in e-fuel applications might crowd out more efficient direct electrification alternatives and can thus be counterproductive for emission reductions.

Given resource limitations in some countries, the more sensible way of reaching a climate benefit from e-fuels seems to be importing them from countries with the capacity to build significant *additional* renewable capacity, electrolyzers, DAC plants, hydrogen as well as CO_2 storage and transport infrastructure.

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 derive levelized costs of e-fuels for a case in which hydrogen is produced in a renewable-rich country, stored and synthesized with DAC-based CO_2, liquefied (in the case of methane) and shipped 3500 km to an importing country's harbor where it is fed into the existing fossil fuel infrastructure (without additional costs). The estimates are based on a literature review, empirical hourly electricity prices and an optimization of electrolysis operation (Figure 4, supplement S3 and SI table 1 for more detail, underlying data is public [*doi will be added and linked to this manuscript*] and visualized in an interactive dashboard [*this will be made publicly available. private link:* https://h2foroveralls.shinyapps.io/H2Dash/#section-visualisations]).

As an indicator of the competitiveness with fossil fuels, we calculate the breakeven CO_2 prices that make e-fuel costs equal to empirical natural gas (whole-sale spot market price benchmarks for the US and Europe) and global gasoline prices. This indicates competitiveness as well as CO_2 abatement costs of e-fuels that can be compared with those of other mitigation options (next section). Supplement S2 presents an analogous figure for hydrogen. Note that here we assume fossil fuel prices to remain in roughly the same order of magnitude in the future.

Calculating production costs of hydrogen and e-fuels faces several parameter uncertainties and system-level interactions (e.g., with respect to hourly electricity prices). Since our analysis focusses on large-scale average production costs (plants with >100m kg/a), we draw on *median* values where parameter variability or uncertainty occurs. The largest uncertainty is associated with the costs of DAC (see supplement S3). Additional cost for storing, transporting and distributing hydrogen, CO_2 and e-fuels, can change depending on the supply chain and infrastructure configurations[35].

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). Large cost reduction potentials may be seized by integrating electrolysis in power systems with high wind and solar PV shares (supplement S3). 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. As a result, per-MWh-hydrogen electrolysis costs increase in 2030 (compared to 2020), while per-GW electrolysis costs are set to decrease due to technological learning (see supplement S3). Blue 'x' in Figure 4 mark the specific electrolysis costs, if full-load hours were constant. The resulting 2030 levelized-costs of hydrogen are very similar to estimates in Glenk and Reichelstein, 2019[52]. The main specification in Figure 4 represents low-carbon e-fuels, building on DAC as a carbon source and renewable electricity as an input.

For 2020, we estimate production costs for liquid e-fuels to reach ~220 €/MWh, based on *green* hydrogen (~80 €/MWh, ~2.7 €/kg) and DAC. These estimates are based on today's technology; yet, as only few demonstration and pilot PtL plants exist, our large-scale production assumptions are hypothetical and shall solely indicate the potential competitiveness and required policy support. Methane can be produced slightly cheaper than liquid efuels as it requires ~20% less CO_2 per energy, while long-distance transport costs are higher. Given historic natural gas and gasoline prices (mean of 2010-2020 values), this translates into a breakeven CO_2 price of ~690 €/tCO_2 for liquids and ~920 €/tCO_2 for gases. 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. This divergence increases for fossil CCU e-fuels due to residual carbon emissions. Note that 2020 fossil fuel prices are well below their mean of 2010-2020 mainly due to energy demand reductions during the COVID-19 pandemic. Accordingly, required CO_2 prices would increase, thereby exacerbating competitiveness challenges and requiring intensified policy support for e-fuels.

Hydrogen and e-fuel costs are anticipated to reduce significantly due to continued technological progress if significant 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 (see literature review in supplement S3) would lead to 2050 e-fuel cost estimates of ~50 €/MWh. This translates into a breakeven CO_2 price of ~30 €/tCO_2 for liquids and ~200 €/tCO_2 for gases. Power-to-liquid (PtL) is more competitive than power-to-gas (PtG) as gasoline prices are much higher than natural gas prices.

If fossil CO_2 were utilized instead of DAC, the direct e-fuel production costs roughly half (cost bars up to efficiency loss of e-fuel synthesis in Figure 4), while the breakeven CO_2 prices remain in the same magnitude (see square marker in Figure 4) due to the residual carbon emissions that we equally attribute to the industrial CO_2 source and the utilizing e-fuel.

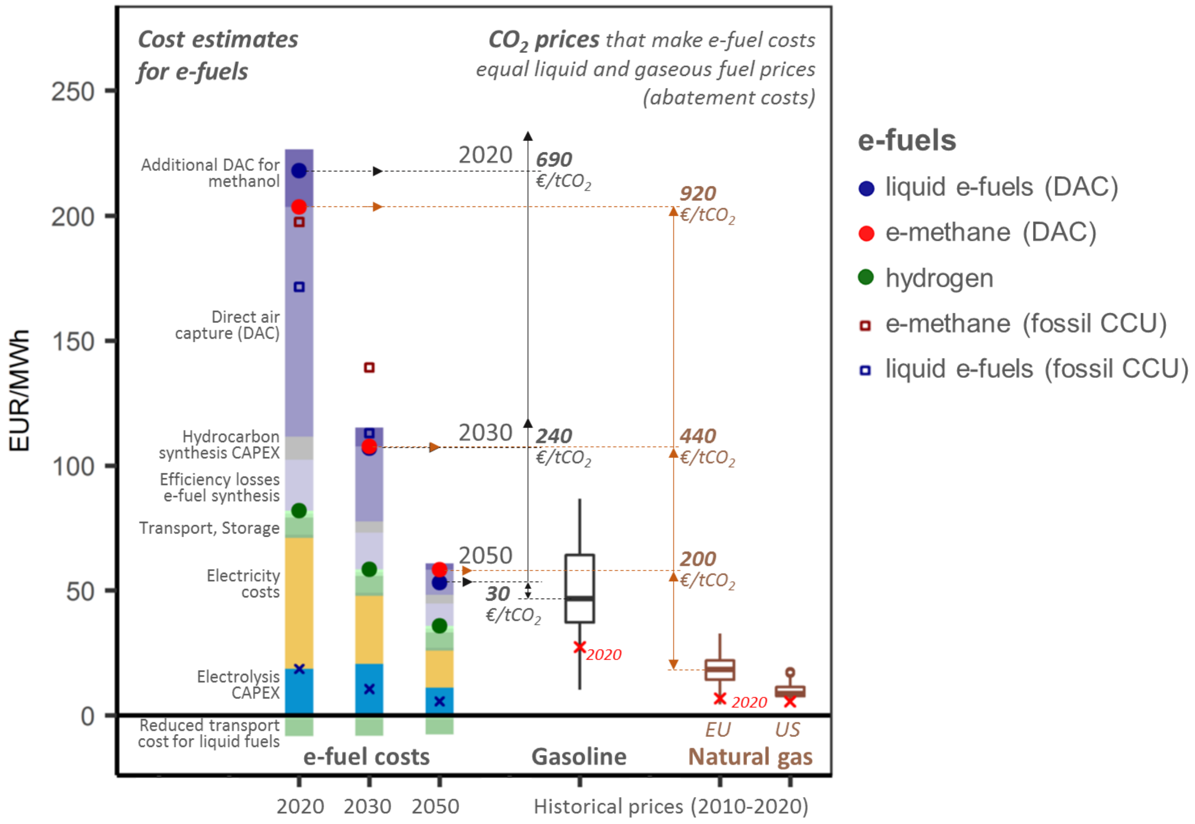

Figure 4 | Levelized cost of e-fuels (hydrogen, renewable methane and liquid e-fuels) compared with fossil fuel prices (natural gas, gasoline) for 2020, 2030, and 2050, and associated CO_2 prices that would equalize all costs. These breakeven CO_2 prices are estimates for e-fuel CO_2 abatement costs (if e-fuels can replace fossil fuels without any additional costs). Also compare an analogue figure for only hydrogen in the supplement S2.

While CO_2 prices required by e-fuels in 2020-2030 (240-920 €/tCO_2) are unrealistically high for most countries, the CO_2 prices required in 2050 (30-200 €/tCO_2) can fall in or below the range seen in climate change mitigation scenarios[53] (Figure 5), or those likely realized in regional and potentially global carbon markets by that time. Despite the significant uncertainty about future cost developments, this 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. Also, mitigation scenario models are likely to give reduced long-term carbon prices (compared to Figure 5) once they 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 the 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. All 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 Figure 5 shows. 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.

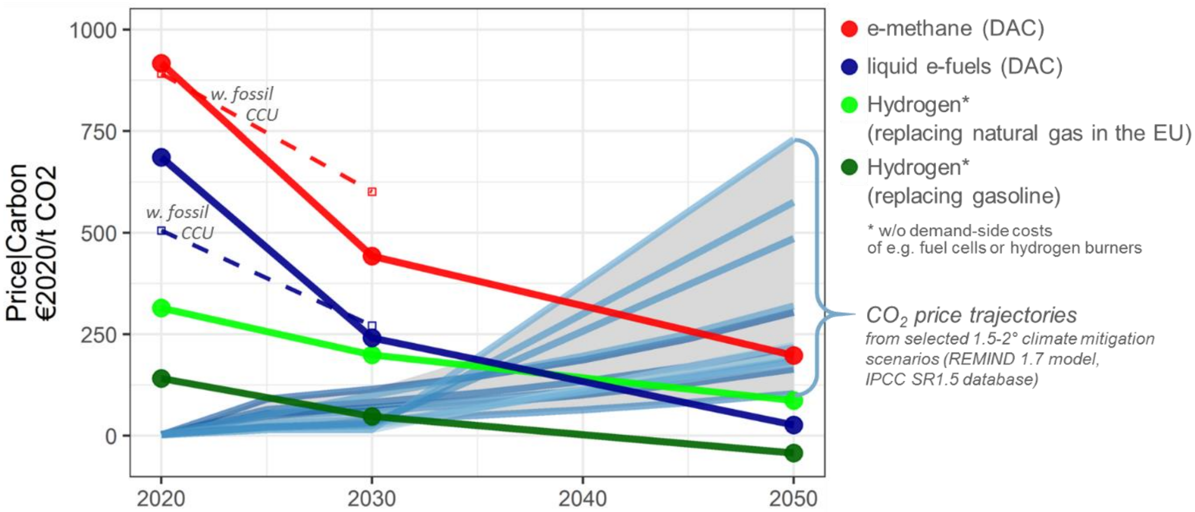

Figure 5 | Trajectories for required *CO_2* prices (from Figure 4) to make e-fuels competitive with fossil fuels compared to modeled *CO_2* prices from mitigation scenarios (selected *2° C and "well-below 2° C" scenarios from the REMIND model [53]*).

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 6, we show marginal abatement cost curves (MACCs) in 2020 for liquid and gaseous e-fuels (blue, from the calculations shown previously, uncertainty ranges are indicative) 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[54]).

E-fuel MACCs are flat because e-fuels are a perfect substitute to fossil fuels (assuming roughly constant fossil fuel prices). 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 utility in (non-electric) energy end uses requires a transformation 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 and we only show a schematic curve progression here to assess the competitiveness of e-fuels vis-à-vis direct electrification qualitatively.

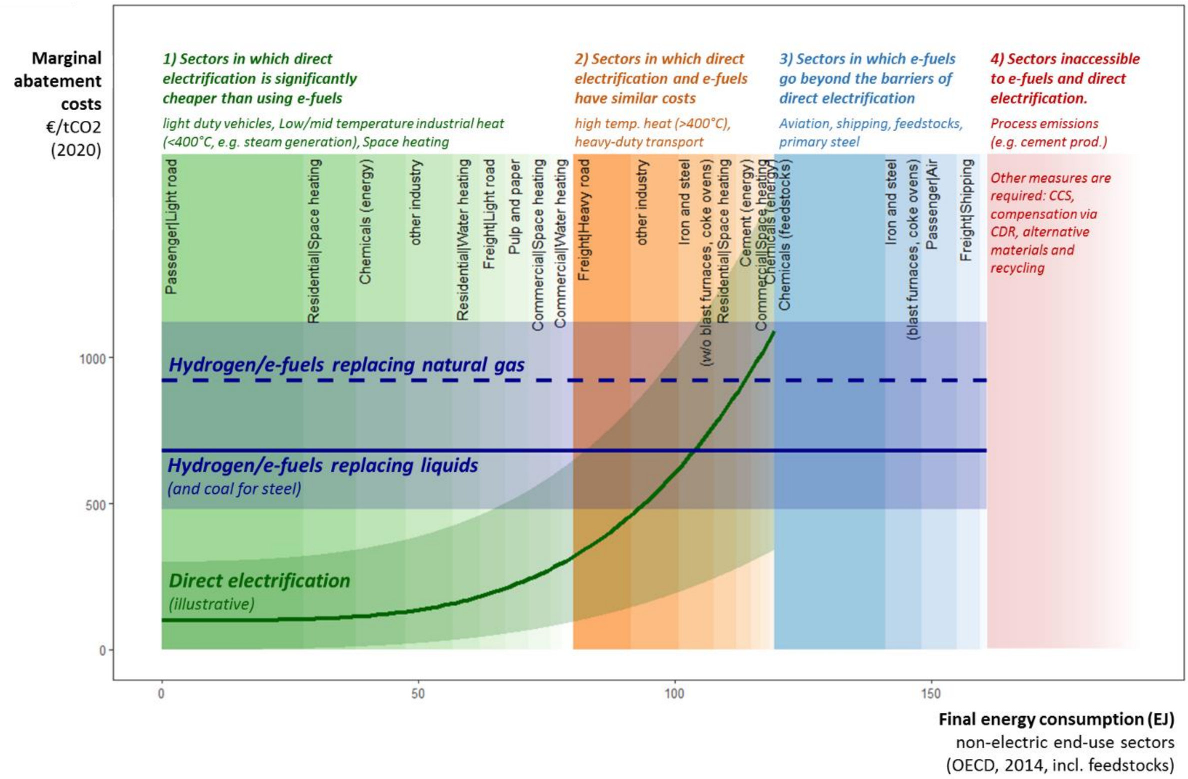

Figure 6 | Marginal abatement cost curves in 2020 for liquid and gaseous e-fuels (blue, from the calculations shown previously, uncertainty ranges are indicative) and direct electrification alternatives (green, schematic curve) across non-electric energy and industrial sectors in the OECD (energy end-use data from IEA ETP 2017[54]).

Based on the relation of both curves, we broadly group end-use sectors into four categories reflecting the competitiveness of e-fuels and direct electrification. Within each category, the sectors are sorted according to their size, such that the steep increase of direct electrification mitigation costs is not mapped onto specific sectors within category 2.

Firstly, there are sectors and applications for which direct electrification is significantly cheaper than using e-fuels mainly due to efficiency advantages and low capacity costs of mature electrifying technologies (compared to electrolysis and DAC costs). Such elements 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 addressed with a broad strategy of policy support and research, such that costs and uncertainties can be reduced, while neither excluding nor focusing on selected technological options. However, at the same time, a coordinated decision needs to be taken in the next years given the urgency of climate mitigation and different infrastructure requirements. Since direct electrification is more efficient, it is favored by an optimal allocation of scarce domestic renewable electricity.

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 additions of renewable power capacity amounted to ~200 GW/y [55]. 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[56].

Figure 6 illustrates the need for a systems perspective in deriving a merit-order curve for hydrogen and e-fuel demand. 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 impossible-to-electrify sectors (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 increase overall costs of climate change mitigation and might be even counterproductive in terms of cross-sectoral emissions reductions, which risks public acceptance for the energy transition.

Conclusions and policy recommendations

The versatility of e-fuels gives rise to the vision of a wide-scale replacement for fossil fuels without the transformational burden on the demand side. However, this versatility of e-fuels comes at significant costs. Depending on the e-fuel application, electricity-to-useful energy efficiencies range from roughly 16% to 48%, which translates into renewable electricity generation requirements that are two to ten 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: ~690 €/tCO_2 for liquids and ~920 €/tCO_2 for gases in 2020. Technological progress could reduce the abatement cost vis-à-vis fossil alternatives significantly to ~30 €/tCO_2 and ~200 €/tCO_2, respectively, in the long term (~2050).

From a system perspective, we can draw seven main conclusions:

1. It is unlikely that e-fuels become cheap and abundant early enough to widely substitute fossil fuels. Their expansion critically depends on significant and continuous e-fuel- or hydrogen-specific policy support to bridge the gap between initially very high mitigation costs and the level of actual carbon pricing applied. Today, there is no such large-scale support scheme implemented, while 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 scarcity of e-fuels, a merit order that prioritizes where to establish hydrogen and e-fuels end-uses can guide climate and energy policy decisions. Regulation and policies that steer specific e-fuel end-uses should take a systems perspective that accounts for opportunity costs of using e-fuels and electricity somewhere else. Against the backdrop of urgent emission reductions towards carbon neutrality, scarce e-fuels should be prioritized for no regret sectors, for which direct electrification and other options are unavailable or impractical. These are not necessarily the sectors in which e-fuels are most competitive and also do not include those difficult-to-decarbonize sectors where direct electrification alternatives exist (see category 2 in Figure 6). In the OECD, e-fuel no-regret sectors amount to about one quarter of all final energy (including feedstock use), which points to the need for a prioritization even within this category. Second order criteria comprise country-specific circumstances, fossil lock-in risks due to re-investment cycles, or sectoral emission reduction targets.

3. E-fuels do not eliminate the urgent need for a broad direct electrification, which makes more efficient use of renewable electricity. This is particularly relevant in the near to medium term as wind and solar power capacities are being upscaled and therefore limited in supply. Instead, betting on the future large-scale availability of e-fuels and neglecting end-use transformation processes (e.g., for light-duty vehicles or space heating), risks a lock-in of fossil fuel dependency, if e-fuels fall short of expectations.

4. E-fuels are unlikely to contribute to reaching 2030 climate targets; not least because their climate effectiveness hinges on a very advanced power transition (e.g. a >90% renewable electricity share in case of LDVs), and low-carbon electricity can more efficiently reduce emissions via direct electrification.

5. In the mid to long term, e-fuels could become competitive solely based on carbon prices due to (i) technological learning in electrolysis and DAC, (ii) reduction of electricity costs through flexible electrolysis operation in future high wind and solar PV power systems, and (iii) optimizing renewable

potentials through an internationalization of supply chains. E-fuels can then evolve to a 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.

6. In the long term, e-fuels can help addressing renewable resource limits in densely populated countries with limited domestic renewable resource potential, 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 [29,57]. 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.

7. E-fuel use should be embedded in an overall transformation strategy that includes infrastructure roadmaps. The global sources for electricity and CO_2 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 might not be 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 sectors. For example, a carbon contract for differences (CCfD) scheme that potentially subsidizes the use of hydrogen in energy-intensive industries is currently debated in Germany and mentioned as an option in the EU hydrogen strategy[58].

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 or e-fuel policy support. Complementing bilateral cooperation projects, this can support coordination of an international supply and demand scale-up to develop an 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.

Acknowledgements

We want to thank Jonas Knapp, Stephen Bi, Felix Schreyer, Falk Benke, Adrian Odenweller, Fabian Stöckl and Silvia Madeddu for their critical reviews, valuable discussion and comments, and Changlong Wang for sharing Australian electricity price data.

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 major part of the literature review. All co-authors reviewed and edited the text.

The authors declare no competing interests

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