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Electrofuels from excess renewable electricity at high variable renewable shares: cost, greenhouse gas abatement, carbon use and competition†

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Increasing shares of variable renewable electricity (VRE) generation are necessary for achieving high renewable shares in all energy sectors. This results in increased excess renewable electricity (ERE) at times when supply exceeds demand. ERE can be utilized as a low-emission energy source for sector coupling through hydrogen production *via* electrolysis, which can be used directly or combined with a carbon source to produce electrofuels. Such fuels are crucial for the transport sector, where renewable alternatives are scarce. However, while ERE increases with raising VRE shares, carbon emissions decrease and may become a limited resource with several usage options, including carbon storage (CCS). Here we perform a model based analysis for the German case until 2050, with a general analysis for regions with a high VRE reliance. Results indicate that ERE-based electrofuels could achieve a greenhouse gas (GHG) abatement of 74 $MtCO_2eq$ yearly (46% of current German transport emissions) by displacing fossil fuels, at high fuel-cell electric vehicle (FCEV) shares, at a cost of 250–320 € per tCO_2eq. The capital expenditure of electrolysers was found not to be crucial for the cost, despite low capacity factors due to variable ERE patterns. Carbon will likely become a limiting factor when aiming for stringent climate targets and renewable electricity-based hydrocarbon electrofuels replacing fossil fuels achieve up to 70% more GHG abatement than CCS. Given (1) an unsaturated demand for renewable hydrocarbon fuels, (2) a saturated renewable hydrogen demand and (3) unused ERE capacities which would otherwise be curtailed, we find that carbon is better used for renewable fuel production than being stored in terms of overall GHG abatement.

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1 Introduction

To achieve climate targets of well below 2 °C compared to pre-industrial levels,[1] a global switch to renewable energy and especially the variable renewable energy (VRE) options wind and solar photovoltaic power is necessary.[2] VRE is in most world regions necessary to decarbonise electricity generation and also to supply other sectors, such as the transport sector, through sector coupling.[2,3] The transport share of global greenhouse gas (GHG) emissions is at 25% and increasing,[4] and the sector shows large challenges for a renewable transition compared to other sectors.[2]

Electrification of transport is a key element for reaching climate targets.[2,5] Direct electrification and battery electric vehicles (BEV) are important in some transport sectors such as in road passenger transport, with renewable gaseous and liquid fuels serving as bridging and complementary solutions.[6,7] In heavy freight[8] and maritime[9] transport as well as aviation,[10] full electrification is challenging and thus combustion engines requiring fuels are still considered as long-term options.

Two main renewable fuel options exist: biofuels and electrofuels. Biofuels are produced from agricultural crops or biomass residues and are the most common option today. However, the resource base is limited[11,12] and, if produced from energy crops, there is concern for potential negative environmental effects[13,14] and competition for arable land with food production.[15,16] This limits biomass potentials for energetic use[17,18] and complicates the sustainability assessment with substantial uncertainty and risk.[19,20]

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Electrofuels are derived from hydrogen produced through electrolysis. The hydrogen can be used directly as a fuel or optionally be combined with a carbon source to produce hydrocarbon fuels (also called Power-to-Gas, PtG, or Power-to-Liquid, PtL[21]), which can be used in present internal combustion engine vehicles (ICEV). Electrofuels based on VRE do not necessarily rely on arable land, and if the carbon source is also renewable they are largely GHG neutral.

With increasing VRE shares in the power grid, the potential supply will at times exceed demand (and therefore be curtailed unless the demand adapts), thus making increasing amounts of low cost and low emission excess renewable electricity (ERE) available. However, many studies come to the conclusion that this may happen only at very high VRE shares.[22–24] At the same time, anthropogenic CO_2 emissions have to decrease in order to fulfill climate targets, thus reducing the resource base of the CO_2 required to produce hydrocarbon fuels. These two counteracting effects limit the potential for hydrocarbon electrofuels, unless carbon captured from the atmosphere is used.

Thus, both biofuels and electrofuels are limited in scope and their respective roles within a renewable transition is yet unclear. For both fuel types, the analysis is rather complex with many factors involved, requiring a systems perspective and modelling.[25,26]

For biofuels, the information on biomass usage options in systems-modelling studies is often highly aggregated.[27] For Germany, these aspects have been analysed with the BENSIM[28] and BENOPT[29] models, with detailed questions on the competition between biofuels assessed. One finding from the models is that the merit order of the fuels changes over time and strongly depends on the functional unit (*e.g.* costs per energy unit,[30,31] costs per GHG reduction unit[32] or GHG reduction per agricultural land unit[7]), so that a methodological breadth of approaches is required to investigate the complexities.[33]

For electrofuels, the field of systems assessment is relatively new,[21] but growing. There are scientific studies on electrofuels regarding potential,[34] costs,[35–37] GHG emissions[38] and technical comparisons with fossil fuels.[39] Only a few system studies have been published so far,[6,40] whereby a new challenge in this area is to couple the previously separate electricity and transport sectors.[41–43]

Analyses for Germany containing both biofuels and electrofuels have been performed for singular years by Hansen *et al.*[44] However, extensive system modelling studies focusing on a transport *transition* over time with a high level of detail on both biofuels and electrofuels as well as including both GHG emissions and costs are not known to exist to the authors.

In this paper, scenarios of parameters affecting electrofuel and biofuel usage in transport are assessed, in order to answer the research questions:

• How may VRE generation and carbon availability limit the production of electrofuels?

• What is the cost and GHG abatement potential of electrofuels in transport under high VRE expansion scenarios?

The assessment is performed under German conditions, with the analysis applicable to regions with a high VRE reliance.

2 Materials and methods

In this section, the modelling framework is first introduced, followed by the data and assumptions. Finally the assessed scenarios are described.

2.1 Modelling

VRE and ERE developments and subsequent resource allocation modelling is presented here, in the given order.

2.1.1 Variable renewable energy developments. For the VRE generation, *i.e.* on- and offshore wind and solar photovoltaic (PV), hourly generation time series as well power load for Germany for the years 2016–18 were used.[45] The hourly resolution ensures that the diurnal pattern of PV generation is depicted in sufficient detail, so that for example mid-day peaks in power demand and power production from solar PV are sufficiently captured.

The future development of (a) power demand as well as (b) on- and offshore wind and solar PV capacities, and (c) capacity factors (C_f, the ratio of actual output to the maximum possible output of a power plant, over a period of time) were assumed for 5 year time steps from 2020 until 2050 according to the defined scenario conditions (Section 2.3).

The generation time series data were normalized and scaled[23,46] according to the assumed capacity expansions and their capacity factor developments. The power load time series were likewise scaled to comply with the assumed development of total annual power demand.

Electricity generation from river hydro power was modelled as a fixed feed-in to the production time series, with an invariable electricity generation (MW) totalling the projected energy generation volume (TWh) in the respective year.

The resulting time series for VRE and hydro power production were then subtracted from the power load time series on an hourly basis for each 5 year time step from 2020 until 2050, resulting in hourly time series for the residual load that model the development of electricity generation and consumption from 2020 until 2050. Power storage was assumed according to Section 2.2.3 and used to redistribute power from times of VRE oversupply to times of VRE undersupply (technical dispatch).

The residual load data was then sorted, resulting in residual load duration curves (RLDC) for every 5 years. These were then interpolated to obtain RLDCs for each year between 2020–2050.

2.1.2 Renewable energy carrier allocation in transport. The modelling of biomass and power based motorised transport is performed with the open source BioENergy OPTimisation model (BENOPT).[29,47,48]

BENOPT is a fully deterministic, bottom-up, perfect foresight, linear optimisation model for modelling cost-optimal and/or GHG abatement optimal allocation of renewable energy carriers and materials across power, heat and transport sectors. The sectors are further divided into sub-sectors. The model has an up to hourly resolution, which can be aggregated depending on the task.

In this work, focus lies on the transport sectors in Germany. An optimal resource allocation without requiring sub-sectoral renewable fuel targets is enabled through a two-stage modelling. First, the total possible GHG abatement under the given restrictions is maximised (eqn (1)):

$$\varepsilon_{\max} = \sum_{i,t}(\varepsilon_{\mathrm{sub},t}\omega_i - \varepsilon_{i,t})\pi_{i,t} \tag{1}$$

with $\varepsilon_{\mathrm{tot}}$ being the total GHG abatement, given by the avoided reference fossil fuel emissions $\varepsilon_{\mathrm{sub},t}$ multiplied by the Tank-To-Wheel (TTW) relative fuel economy (compared to the sector specific reference vehicle) ω_i of the fuel type i, minus the production emissions $\varepsilon_{i,t}$, multiplied by the production of the renewable fuel $\pi_{i,t}$, at time point t. The factor ω_i ensures that the fuel economy for a given transport service is being compared, and thus a Well-To-Wheel (WTW) analysis is performed.

Second, the resulting maximal total GHG abatement is set as a boundary condition (eqn (2)), which can be step-wise reduced in runs where the costs are minimised (eqn (3)), with the total cost C_{tot} being the sum of the product of the endogenously installed capacities $\kappa_{i,t}^{\mathrm{endo}}$ and their investment costs $I_{i,t}^{+}$, and the production $\pi_{i,t}$ multiplied with marginal costs $\mathrm{mc}_{i,t}$, for each option at each time-point.

$$\varepsilon_{\mathrm{tot}} = a\varepsilon_{\max},\ a \in [0,1] \tag{2}$$

$$C_{\mathrm{tot}} = \sum_{i,t}\kappa_{i,t}^{\mathrm{endo}}I_{i,t}^{+} + \pi_{i,t}\mathrm{mc}_{i,t} \tag{3}$$

The temporally high resolution RLDC data are aggregated in order to reduce the computational time, and here divided into $\hat{j} = 50$ slices ($j \in \{1, 2, 3, \ldots, \hat{j}\}$) within each year, similar to methodologies described by Ueckerdt *et al.*[49] and Lehtveer *et al.*[50] Excess electrical energy (ERE) production (cumulated negative residual load) is assumed as an input for electrofuels.

Processes based on energy crops, biomass residues as well as electricity-based fuel options (electrofuels) are included. In order to capture the complexities involved in a sufficient detail, an intra-annual temporal resolution is required. The electrolyser capacities are endogenously adapted in order to capture the cost trade-off between electrolyser standing production capacity and their achievable capacity factor which is determined by the aggregated ERE curve:

$$\hat{E}_{j,t} \geqslant \sum_{i} E_{i,j,t} \tag{4}$$

where $\hat{E}_{j,t}$ is the ERE limit at slice j in year t, and $E_{i,j,t}$ is the ERE used by technology i at the same time point. The capacity restriction is given by:

$$\kappa_{i,t}\frac{8760}{\hat{j}}\frac{3.6}{1000} \geqslant \eta_{i,t}E_{i,j,t} \tag{5}$$

where the available production capacity $\kappa_{i,t}$ [GW] of technology i is multiplied by the hours per slice (hours per year divided by the set number of intra-year slices $\hat{j}$), which cannot be surpassed by the production at slice j, given by the conversion efficiency $\eta_{i,t}$ of technology i in year t, multiplied by the ERE used by technology i at the same time point, $E_{i,j,t}$ [PJ].

2.2 Data and assumptions

2.2.1 Renewable fuel options. The biofuel options included are biomethane (BME, based on anaerobic digestion), Synthetic Natural Gas (SNG, based on gasification and methanation), bioethanol (EtOH), biodiesel (fatty-acid methyl ester, FAME), Fischer–Tropsch-diesel (FT), and liquefied methane (LCH_4). For each process, one or several biomass types can be used, including both crops and residues. These are combined with different conversion efficiencies, as summarized in Table 1 in the ESI.† The biofuel options are further elaborated in Millinger *et al.*[30]

The electrofuel options included are Power-to-Gas (PtG-CH_4), Power-to-Liquid (PtL, diesel or otto fuel) and hydrogen (PtG-H_2). The basis for the options is water electrolysis with electricity as input, producing H_2. For PtG and PtL, the H_2 is combined with CO_2 to produce hydrocarbons. Cost and input data are assumed based on Meisel *et al.*[51] and Brynolf *et al.*,[35] where a thorough review and discussion of cost and conversion efficiency ranges of these options can be found.

Additionally, three mixed options, using both biomass and renewable hydrogen are included from Thrän *et al.*,[52] and here denoted electrobiofuels. Power-to-Biomass-to-Liquid (PBtL) is an option where additional hydrogen is added to the FT process, increasing the conversion rate of carbon to diesel and thus the overall output. In the power-to-methane *via* biological methanation (PBME) option, hydrogen is added to the anaerobic digestion process, likewise increasing carbon conversion. In Hydrotreated Vegetable Oil (HVO), hydrogen is added to vegetable oils and fats to produce a high quality diesel fuel.

Stoichiometric theoretical limits for the CO_2 input requirement were derived based on formulae (6) (Sabatier reaction to produce CH_4) and (7) (stylized reaction for producing –CH_2–chains such as diesel) and Table 1:

$$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O \tag{6}$$

Table 1 Molar masses, energy densities and theoretical CO_2 and H_2 input for producing CH_4 and CH_2-chains (equivalent to liquid hydrocarbon fuels)

	Molar mass (g mol^{-1})	Energy density (GJ t^{-1})	CO_2 input per mol (nCO_2 n^{-1})	H_2 input per mol (nH_2 n^{-1})	CO_2 input per GJ (kg CO_2 per GJ)	H_2 input per GJ (kg H_2 per GJ)
CO_2	44	0	—	—	—	—
H_2	2	120	—	—	—	—
CH_4	16	50	44/16	8/16	55	10
CH_2	14	44	44/14	6/14	71	10

Table 2 Transport and storage & fuelling costs for the different fuel types ethanol (EtOH), diesel, methane (CH_4) and hydrogen (H_2)

€ per GJ	EtOH	Diesel	CH_4	H_2
Transport	2.9	1.4	1.2–1.9	0
Storage & fuelling	0.1	0.1	1.1–1.2	6.5–12.1

$$CO_2 + 3H_2 \rightarrow -CH_2- + 2H_2O \quad (7)$$

CO_2 capture costs differ between sources, of below 20 € per tCO_2 for bioethanol production and biogas upgrading, 10–150 € per tCO_2 for industrial point sources and 20–950 € per tCO_2 for direct air capture.[35] Here, a gate price of 50 € per tCO_2 is assumed. The CO_2 usage is discussed and compared to potentials of possible sources ex-post.

For hydrogen fuelling stations, an infrastructure CAPEX of 4000 € per kW with $C_f = 0.74$ (*i.e.* 74% of the maximal *daily* capacity is used) was assumed for 2020, linearly decreasing to 2300 € per kW with $C_f = 0.8$ (calculated based on Melaina and Penev,[53] summarized under FCEV in Table 3 in the ESI†), which with a 5% discount rate translates into 6.5–12.1 € per GJ. For the other fuels, data from Cazzola *et al.*[54] for transport and logistics were adopted (Table 2). In the table, the lower bound for CH_4 are data for mature technology and the upper bound is the average of current and mature technology according to Cazzola *et al.*[54] For hydrogen, the cost was derived based on Melaina and Penev[53] for early commercial and larger stations with a discount rate of 5% and life-time of 25 years. The lower bound applies for the start year and the upper bound for the end year, with a linear interpolation in-between.

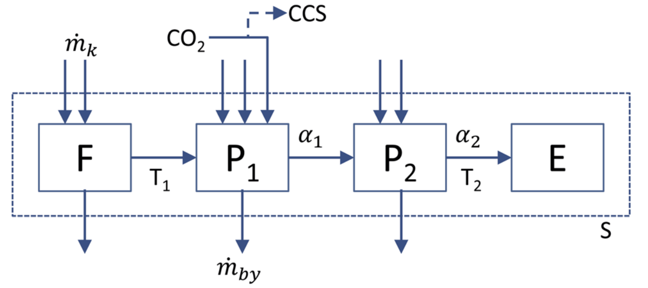

Fig. 2 System boundaries of the WTW assessment from feedstock to transport service for each pathway, shown by the dashed line S. F = feedstock (ERE, biomass residues or crop cultivation); T = transport; P_1 = process one; P_2 = process two; E = end use; $\dot{m}_k$ = process inputs (including *e.g.* electricity, heat and input CO_2); $\dot{m}_{by}$ = process by-products; α = allocation factor, based on which the preceding greenhouse gas emissions are allocated to the main product, weighted based on the energy content of the different process outputs. Carbon capture and storage (CCS) is not within the system boundary and is treated as a reference case for the process input CO_2 in some scenarios.

For transport costs to the fuelling station, either the hydrogen is produced centrally and delivered by truck or pipeline, or the hydrogen is produced on-site by electrolysis.[55] Here, the latter is assumed and transport costs are therefore omitted.

The process options are shown in Fig. 1, with key data summarised in Table 3 in the ESI.†

2.2.2 Life-cycle GHG emissions. A WTW life cycle assessment (LCA) of the energy carriers used in transport is performed. The main contributing parameters are included, whereas parameters contributing little to the overall GHG

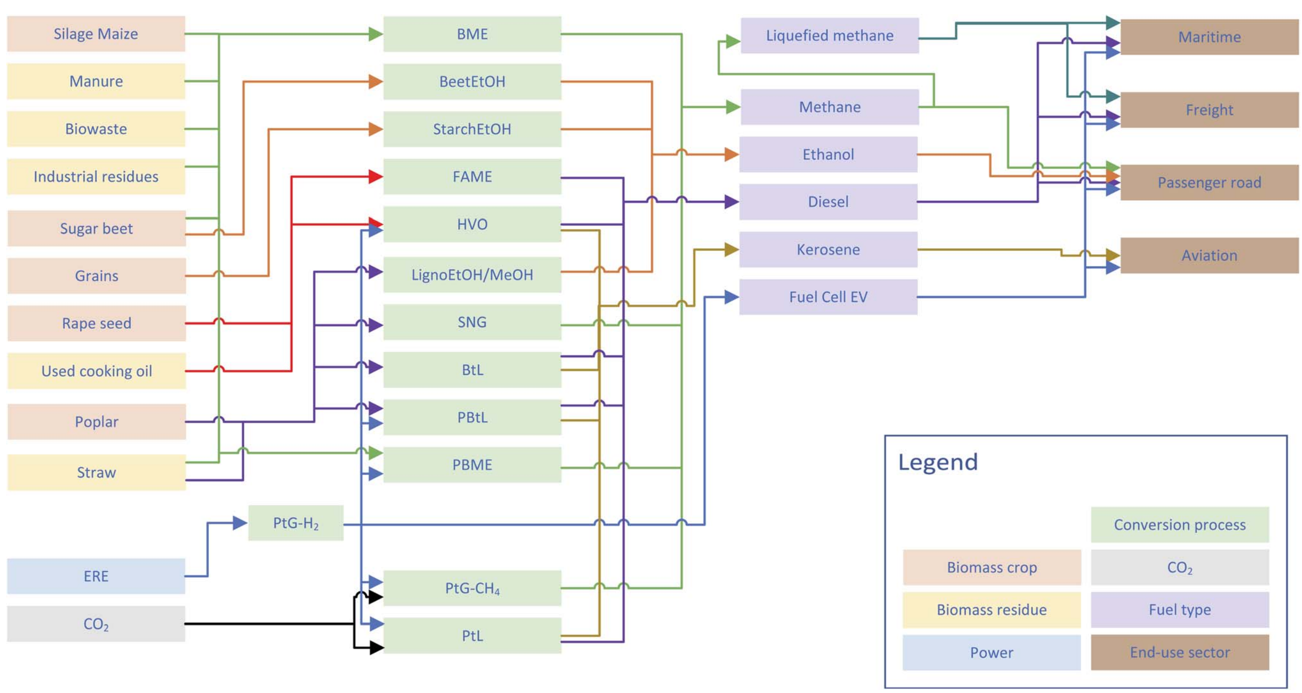

Fig. 1 Fuel and feedstock combinations considered in this paper.

emissions,[32] as well as emissions from vehicle manufacturing and infrastructure are not included. The fuel combustion is assumed to be carbon neutral, as the carbon absorbed during plant growth or carbon capture is emitted, thus closing the short life-cycle.

Detailed input–output data of all fuel production processes that are included in this study lay the foundation for calculating detailed cost and GHG emissions developments as well as for analysing uncertainties and sensitivities to important parameters. GHG emissions are calculated according to Millinger *et al.*,[32] with inputs multiplied by their respective emission factors (EF). For each process step along the pathway, emissions are allocated to main and by-products according to their relative energy content, if applicable. Biomass feedstock cultivation, transport, processing and vehicle fuel economy is included, and thus all energy carrier emissions and losses from well-to-wheel are considered (Fig. 2), while direct and indirect land use change emissions are not. Biomass residues are assumed to carry zero emissions in accordance with RED II,[56] while transport emissions are assumed according to Millinger *et al.*[32]

For the life-cycle analysis of the CO_2 inputs, two reference systems are assessed (Fig. 3):

(1) The status quo without the option of carbon capture and storage, *i.e.* the carbon dioxide would be directly emitted to the atmosphere instead of being emitted at combustion in the vehicle, and thus in this comparison the usage of the CO_2 can be seen as carbon neutral (0 kg CO_2eq per kg CO_2), regardless of the CO_2-source.

(2) Carbon capture and storage assumed as a reference usage of the input carbon. The carbon would in this case be assumed to be stored long-term if it is not used for fuel production, in which case the reference is −1 kg CO_2eq per kg CO_2.

Renewable fuels are assumed to replace fossil fuels, with an emission factor of 94.1 kg CO_2eq per GJ_{fuel}. Thus, in reference case (2), using the carbon for storage would mean that an equivalent amount of hydrocarbon electrofuels cannot be produced and instead fossil fuels would have to be deployed (unless other renewable fuels which do not require additional CO_2 suffice to completely displace fossil fuels). Hence, the optimal carbon usage comes down to which option results in the least total GHG emissions: CCS or electrofuels replacing

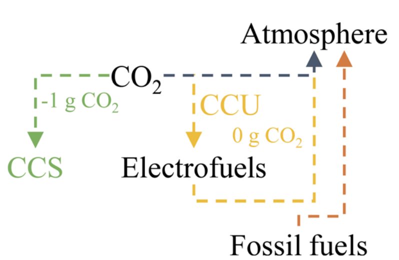

Fig. 3 For electrofuels, two reference cases are used: with or without carbon capture and storage (CCS). If CCS is assumed as the reference pathway of the carbon, a negative credit of −1 kg CO_2eq per kg CO_2 is given. If instead the reference carbon pathway is emission to the atmosphere (no carbon capture), the option carbon capture and usage can be seen as carbon neutral, *i.e.* the credit is 0 kg CO_2eq per kg CO_2.

Table 3 Solar photovoltaic[57] and wind[58,59] power plant installed capacities (GW = gigawatt) and full load hour (FLH, kWh kWp^{-1})[60] development assumptions for the start and end[61,62] years of this work

	Solar PV	Wind onshore	Wind offshore
GW_{2020}	49	54	7.5
GW_{2050}	200	170	54
FLH_{2020}	935	2000	4091
FLH_{2050}	951	2295	4290

fossil fuels. Carbon storage is not explicitly modelled, but only used as a reference for the LCA, and thus does not show up in the total GHG abatement results.

2.2.3 Power system assumptions. The VRE capacity and annual full-load hour (FLH) development assumptions are summarised in Table 3, with linear interpolation between 2020 and 2050. The capacity factor C_f is derived by dividing the FLH by the number of hours in a year.

The net power demand was assumed to increase linearly from 513 TWh in 2020 (ref. 63) to 700 TWh in 2050 (*cf.* Fraunhofer IWES[64]), thus allowing for increased power demand due to sector coupling.

A standing capacity of 9 GW electric energy storage in 2020 (storage capacity 66 GWh), increasing linearly to 30 GW (100 GWh) in 2050 (*cf.* Schill[22]), with a conversion efficiency of η_{el} = 0.9 was assumed. Through this option, some excess electricity is stored and fed back at times when demand exceeds supply, thus reducing the ERE that can be used for sector coupling.

For the power mix, average emission values are assumed for the future German power mix, starting from 474 gCO_2 per kWh in 2018,[65] decreasing linearly with a target of 175 $MtCO_2$eq in total for electricity generation in 2030 (ref. 66) and 575 TWh net power demand (Section 2.2.3), giving 304 gCO_2eq per kWh. For 2050, 10 gCO_2eq per kWh is set as an ambitious target.

The ERE is assumed to carry negligible GHG emissions and the price is assumed to be zero.

2.2.4 Biomass residues and crops. Biomass residues available for transport fuel production and corresponding conversion efficiencies as well as price assumptions are listed in ESI (Table 1).† The residue types are each sub-divided into three groups of equal potential amounts, with prices for each group in the low, medium and upper range, as described in Thrän *et al.*,[52] and increasing by 4% annually. GHG emissions are assumed to be zero for the biomass resource itself, whereas additions for transport, logistics and conversion are added according to Millinger *et al.*[32]

The biomass crop costs were calculated according to a method elaborated by Millinger and Thrän,[31] with an annual reference feedstock price increase of 4%. The available land is varied between 0-1 Mha (0–10 000 km^2) in the scenarios (Section 2.3), slightly less than what was used for German biofuels in recent years.[7] The crops grown on the available land is decided endogenously within the model.

There is substantial uncertainty with regard to present prices for biomass residues as well as future biomass prices in general. The benchmark 4% biomass price increase reflects scenarios where biomass demand for energy supply, materials and chemicals increases substantially, in line with achieving ambitious climate targets,[31] and should be considered a conservative high assumption.

2.2.5 Transport sector developments. Passenger road, freight land and maritime transport as well as aviation are included as separate sectors. The sectors differ in terms of demand developments and restrictions for eligible fuel types.

For the passenger road transport sector, extensive data on the historic vehicle park developments in Germany are available.[67] The historic development of vehicle types in the passenger vehicle sector is used as a basis for different fuel demands.

48 million passenger cars were registered as of 2020,[68] with 3.4 million new registrations in 2018.[67] A constant vehicle fleet is assumed, with a 14 year average vehicle life time. The total amount of person-kilometres was assumed to remain constant in this sector. The required vehicle-kilometres were derived with an average of 1.5 persons per vehicle and used as a constraint.

A baseline vehicle was assumed to increase its fuel economy by 40% in 2050 compared to today (through smaller average vehicles, as well as mass, rolling resistance and aerodynamic drag reduction[69]), *i.e.* the baseline vehicle would reduce its fuel economy from 6.1 to 3.7 l petrol 100 km^{-1}. Diesel engines were assumed to be 20% more efficient than spark-ignition Otto cycle engines, while FCEV were assumed to be twice as efficient (based on data for Toyota Mirai).

The historic BEV park increase was relatively constant at around 50% annually in Germany between 2014–2018, and even slightly higher in the EU (own calculation based on data from ICCT[67]). BEV developments for passenger vehicles are taken from Millinger *et al.*,[7] with an increase of the BEV stock of 50% each year until the number of sold vehicles each year is reached in 2030. From this point in time only BEVs are deployed as new vehicles in the passenger road transport sector.

The fuel demand of the freight land transport sector is assumed to decrease linearly to half of the demand in 2020 by 2050, through a combination of modal shift to rail transport, electrification and transport and logistics efficiency improvements, in line with IPCC.[70] Allowed fuels are diesel, liquefied methane and hydrogen, in line with expectations for heavy freight transport, which is more challenging to electrify than *e.g.* light-duty vehicles.[5] LCH_4 is assumed to be on par with diesel in terms of fuel efficiency,[71] while FCEV are assumed to be twice as efficient. The upper hydrogen and methane shares are set to linearly increase from zero in 2020 to the maximum values set in the scenarios (Section 2.3) in 2050, but do not have to be achieved.

The German share of total international maritime fuel demand was estimated by weighting the global maritime fuel demand with the gross domestic product (GDP). Germany has a share of global GDP of 4.6% (own calculation based on data from The World Bank[72] for 2018). The annual total global maritime fuel consumption has been estimated at 298 Mt.[73] Weighting by GDP results in 13.7 Mt_{fuel} for Germany, with a lower heating value (LHV) for diesel fuel of 43 MJ kg_{fuel}^{-1} resulting in a current annual demand of 589 PJ. This demand is assumed to decrease linearly to 70% of current demand by 2050, through partial electrification and modal shift. Allowed biofuels are diesel, liquefied methane and hydrogen. FCEV vessels were assumed to be twice as efficient as diesel and LCH_4 driven vessels.

The fuel demand for the aviation sector is expected to increase considerably or at best remain at the same level, despite efficiency improvements,[10,70,74] and is here conservatively assumed to increase by a third until 2050. The initial fuel demand is based on an estimated 22.2 $MtCO_2$ emissions for flights departing in Germany, with 3.16 tCO_2 t_{fuel}^{-1} (ref. 75) and an energy density of 42.8 GJ t_{fuel}^{-1}, resulting in a fuel demand of 300 PJ. FCEV were assumed to be as efficient as kerosene propelled aircraft, due to counteracting effects of hydrogen aircraft.[76]

Vehicle costs for passenger vehicles are assumed to decline with increasing economies of scale and the total cost of ownership for different drivelines is expected to converge.[76] Quantifying the costs of vehicles using alternative fuels in aviation and maritime transport is challenging and out of the scope of this work. As a consistent data basis for all vehicle types would be necessary for an overall analysis, vehicle costs are omitted for all sectors in this paper.

2.3 Scenarios

In the scenarios, three main parameters are varied: the upper demand limit for hydrogen demand, the availability of arable land for producing biofuels, and the CO_2 reference. These variations highlight important and mutually independent boundary conditions with an impact on the achievable renewable shares in transport. Six scenarios are assessed. In all scenarios, the same progressive VRE generation development is assumed, as stated in Section 2.2.3.

In the base scenario, the conditions stated thus far apply. The hydrogen upper demand limit in the maritime and freight sectors is increased in scenarios 2 and 5. The stated limits apply for the year 2050, with a linear increase from 0 in 2020 in each case. The arable land available for biofuel production is decreased to 0 Mha in 2050 in scenarios 3 and 6, with a linear decrease from 1 Mha in 2020. Two sets of LCA CO_2 references are applied (Section 2.2.2): either CO_2 neutral (scenarios 1–3) or with a CCS reference (scenarios 4–6). The variations are summarised in Table 4.

In the scenarios, a neutral CO_2 reference means that the carbon would be emitted to the atmosphere in the reference case as well, and a carbon capture and storage (CCS) reference means that the carbon would be stored and thus not emitted to the atmosphere in the reference case (*i.e.* −1 kg CO_2eq per kg CO_2). The hydrogen (H_2) demands are upper energetic shares of the total fuel demand in the respective sectors, which cannot be surpassed but do not have to be met.

As CCS is not explicitly included as an option in this work, the overall resulting CO_2 emissions differ between the scenarios. The results shown are the cost-optimal developments at 99% of the maximal GHG abatement, as over-capacities which tweak the costs are reduced compared to the GHG abatement maximal case.

Table 4 Scenarios assessed in this work

Scenario	Name	H_2 demand		Arable land	CO_2 reference
1	Base	Maritime Freight	<10% <30%	1 Mha	Neutral
2	MoreH2	Maritime Freight	<30% <50%	1 Mha	Neutral
3	NoLand	Maritime Freight	<10% <30%	0 Mha	Neutral
4	CCSBase	Maritime Freight	<10% <30%	1 Mha	CCS
5	CCSMoreH2	Maritime Freight	<30% <50%	1 Mha	CCS
6	CCSNoLand	Maritime Freight	<10% <30%	0 Mha	CCS

3 Results

3.1 Excess renewable electricity development

The resulting renewable share in the power sector including storage limitations at the given conditions increases from 41% in 2020 (slightly higher than 2019 shares of VRE + hydro power at 37.2%,[77] mainly due to the lack of transmission grid limitations, somewhat lower VRE capacities and differing weather patterns) to 82% in 2050, whereas the renewable power production including ERE would cover 118% of the demand in 2050. The renewable share stabilises at around 80% after 2040, as the demand increases while the marginal benefit of additional renewable capacities decreases.

The resulting ERE increases with increasing VRE shares (Fig. 4), while also the peak (positive) residual load increases. At the progressive VRE capacity expansion scenarios assessed here, 231 TWh (832 PJ) of ERE is observed for 2050, or 33% of the assumed electricity demand. At the same time, a positive residual load of 94 TWh remains, which needs to be covered by other means.

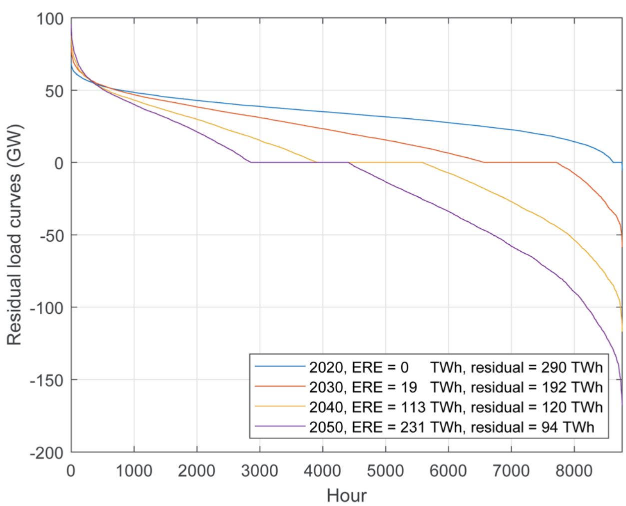

Fig. 4 Residual load duration curves for selected key years, with negative residual load = excess renewable electricity (ERE). The horizontal lines show the points where power storage balance the supply and demand, thereby reducing both positive and negative residual load.

3.2 Fuel deployment

The resulting ERE in 2050 can be used to produce 582 PJ (162 TWh) hydrogen, which can be further combined with CO_2 and processed to 530 PJ PtG-CH_4 or 402 PJ PtL. The total transport fuel demand in the scenarios assessed here amounts to 813–945 PJ in 2050. This span depends on the amount of hydrogen deployed, which has a superior fuel economy and thus half of the fuel is required for the same transport service compared to hydrocarbon fuels in ICEVs.

In this section, first the fuel developments are elaborated for each sector (see ESI for details†), followed briefly by a description of their differences across the assessed scenarios (Fig. 5).

Initially, the passenger land transport sector is the by far largest one in terms of fuel requirement. However, through the deployment of BEVs, the overall fuel demand decreases steadily towards zero in the mid-2040s, when the whole sector is assumed electrified. From 2030 onwards, all new vehicles are BEVs and thus no new ICEVs are deployed. Therefore, mainly the current diesel and Otto fuels are deployed, with only small shares of methane and hydrogen. Sugar beet based ethanol is the main biofuel in this sector.

In the freight land transport sector, a substantially larger share of hydrogen can in the medium term be reasonably expected compared to in other sectors, which is also fulfilled (a maximum of 83 or 139 PJ in one single year in the scenarios, depending on the maximum H_2 share allowed). Methane in liquefied form achieves large shares (max. 77 or 83 PJ), and some is supplied by PtL.

In maritime transport, rather large quantities of liquefied CH_4 are used (max. 124 PJ). Hydrogen is deployed up to the given hydrogen limit (max. 41 or 124 PJ), PtL is used with high variation, and several fuels achieve marginal shares (FAME, HVO, BtL).

In aviation, hydrogen is supplied up to the given limit (max. 40 PJ in 2050), and complemented by BtL and PtL as well as small shares of HVO and PBtL.

PtL, BtL, HVO and PBtL may be used in all sectors, with equal GHG abatement. Therefore the quantities of PtL used can equally effectively be used in any of these sectors, given a remaining demand. PtL is deployed at up to 242–392 PJ in scenarios 1–3, none in scenarios 4 and 5 and 161 PJ in scenario 6. PBtL is instead of PtL deployed in scenarios 4 and 5 (max. 287 PJ), and up to 59 PJ in scenario 6.

In scenario 1, aviation is only supplied partly with renewables towards 2050, whereas passenger land transport is completely renewable by 2038, freight land transport by 2045 and maritime transport by 2050.

If the hydrogen demand is increased (scenario 2, MoreH2), more hydrogen is deployed at the cost of PtL (S2 in Fig. 5). Thanks to the superior fuel economy of FCEV and thereby a reduced energy demand for the same transport service, almost the whole fuel demand can be covered renewably in this scenario.

If arable land for crops for biofuel production decreases to zero in 2050 (scenario 3, NoLand), the hydrogen demand from ERE is first fulfilled and then PtCH_4 is produced and used

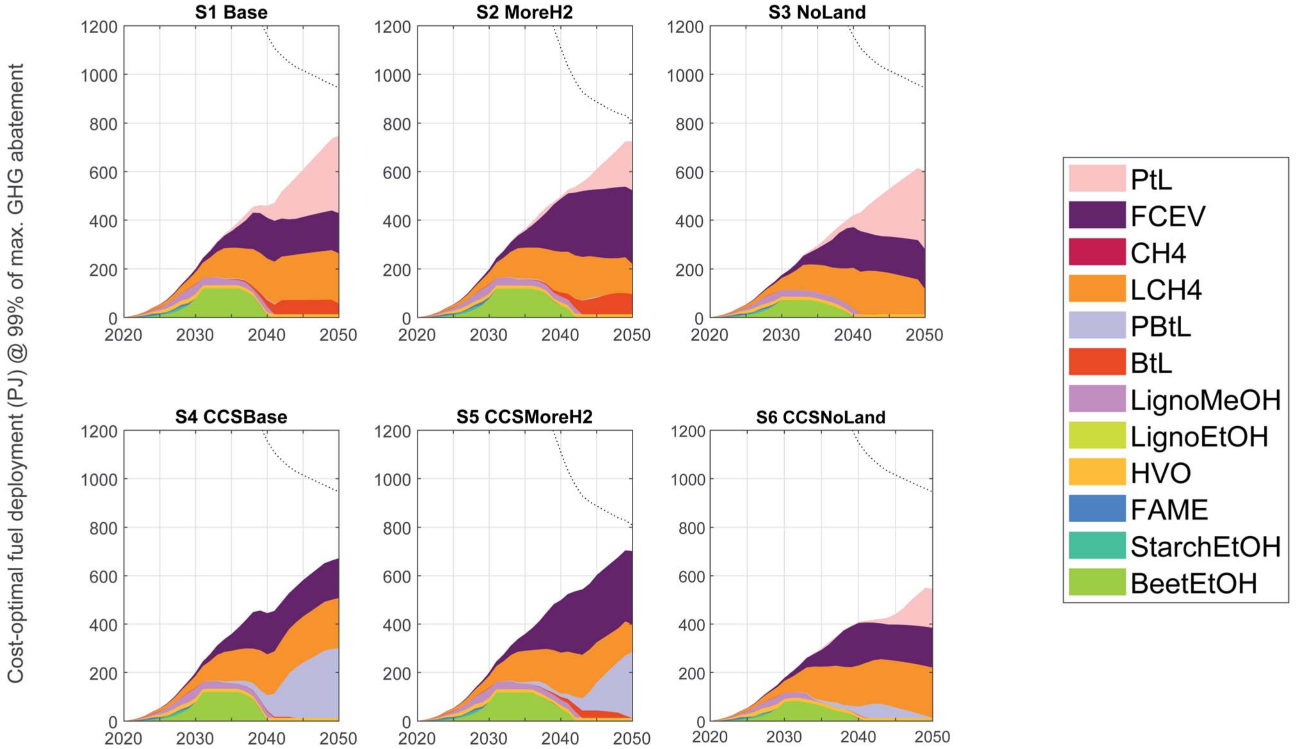

Fig. 5 Cost-optimal fuel deployment at 99% of the maximal GHG abatement in the scenarios. Abbreviations: PtL = power-to-liquid, FCEV = fuel-cell electric vehicle (with hydrogen as fuel), CH_4 = methane, LCH_4 = liquefied methane (both stemming from any of the methane producing options), PBtL = power-to-biomass-to-liquid, BtL = biomass-to-liquid, LignoMeOH = lignocellulose-based methanol, LignoEtOH = lignocellulose-based ethanol, HVO = hydrotreated vegetable oil, FAME = fatty-acid methyl ester, StarchEtOH = starch-based ethanol, BeetEtOH = sugar beet based ethanol. The areas show the deployment in petajoule (PJ) of the different options over time, and the dotted line shows the total fuel demand (which is outside of the graph until *ca.* 2040.) The demands differ between scenarios due to differing fuel economies of the deployed fuels, while keeping the transport service constant across scenarios.

directly as a gaseous fuel until the demand is saturated. Then, CH_4 is supplied in liquefied form (LCH_4) until that demand is saturated. As a last option, PtL is produced. This is determined by the GHG abatement cost and also reflects the order of conversion efficiencies (see Table 3 in the ESI†), which has a double effect on both the fuel GHG emissions as well as on the fuel costs.

If carbon capture and storage (CCS) is assumed to be a large scale option and in an LCA serves as a reference case for the CO_2 used in PtL and $PtCH_4$ processes (scenario 4, CCSBase), the option of adding hydrogen to the FT-process emerges as a lower-cost option than PtL. Thereby, the carbon contained in the feedstock supplied to the FT-process is better utilised.

If on top of this, the hydrogen upper demand is increased (scenario 5, CCSMoreH2), hydrogen is deployed at the cost of PBtL.

If arable land for crops for biofuel production decreases to zero in 2050 (scenario 6, CCSnoLand), some shares of both PtL and PBtL are deployed.

The dominating crops grown for biofuel production are sugar beet for the medium term until ethanol is no longer demanded in the passenger road sector, followed by poplar mainly for BtL and PBtL production and some maize silage for BME production.

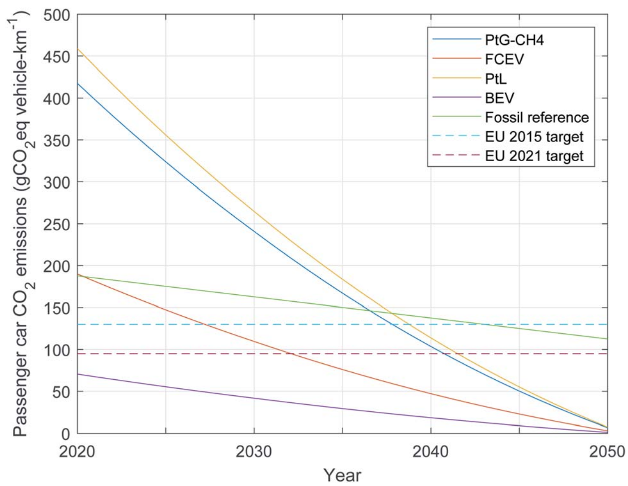

Fig. 6 Well-to-wheel CO_2 emissions of different electrofuels if produced from the German electricity mix, assuming developments according to targets set for 2030 and a nearly GHG emission free mix by 2050. Abbreviations: PtG-CH_4 = power-to-gas-CH_4, FCEV = fuel-cell electric vehicle (with hydrogen as fuel), PtL = power-to-liquid, BEV = battery-electric vehicle. The fossil reference is assuming that the fuel economy of internal combustion engine vehicles improves by 40% by 2050 compared to 2020 and is fuelled by fossil fuels with an emission factor of 94.1 kg CO_2eq per GJ_{fuel},[56] with European Union (EU) targets for 2015 and 2021 shown.[78]

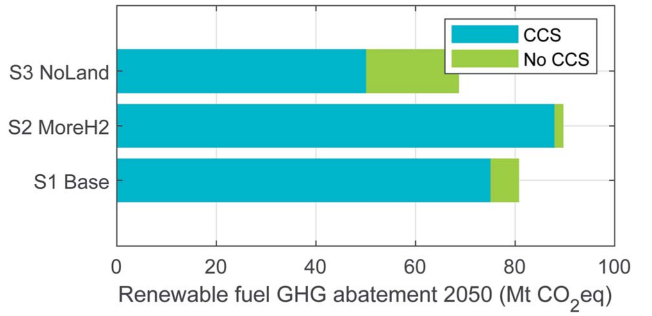

Fig. 7 Total greenhouse gas abatement of deployed renewable fuels in the scenarios in 2050, with and without carbon capture and storage (CCS).

3.3 GHG abatement potential and cost of electrofuels

The GHG emissions of electrofuels based on the electricity mix break even with fossil fuels at below 200 g CO_2 per kWh, which is set to be reached by 2038 with the given emission reduction targets (Fig. 6). Prior to 2038, hydrocarbon electrofuels based on the electricity mix lead to more GHG emissions than fossil fuels, based on the electricity emissions alone. In contrast, hydrogen from the electricity mix does provide a slight climate benefit even in the short term.

The GHG emissions of ERE are negligible, why this source is superior to the electricity mix for electrolysis until the mix is fully renewable.

In 2050, a peak of 136 GW of ERE would be theoretically available (Fig. 4). In the assessed scenarios, at most 88 GW electrolyser capacity is used for hydrogen production, and thus the highest peaks (7% of the total electric energy) are left untapped.

Under the ERE curve a decreasing capacity factor can be observed at increased capacities (Fig. 8a). The marginal benefit of adding additional electrolyzer capacities decreases, especially around 80 GW and upwards, where additional capacities increase the ERE capture only slightly (Fig. 8b). This is also reflected in a strongly increasing marginal CAPEX cost of hydrogen, starting at 5 € per GJ and reaching up to 16 € per GJ at full usage of the ERE, at a CAPEX of 800 € kW_{cap} in 2050, with most of the increase above 200 TWh (Fig. 8c).

Fuelling station infrastructure contributes to 6.4–12.1 € per GJ, whereas hydrogen was assumed to be produced on-site, and thus transport costs were omitted.

At a price of 50 € per tCO_2, the CO_2 input for hydrocarbon electrofuels results in an additional cost of around 3 € per GJ. Furthermore, ERE was assumed to carry no costs. If an ERE price of 40 € per MWh (4 ct kWh^{-1}, at the lower range of current levelized cost of electricity (LCOE) from wind and solar PV power in Germany[79]) were assumed, the price of hydrogen would increase by 18 € per GJ.

The minimal hydrogen cost would end up at 12 € per GJ (43 € per MWh), or 0.7 ct per vehicle-km, whereas the high hydrogen cost would be 46 € per GJ (166 € per MWh), or 4.6 ct per vehicle-km. For PtG-CH_4, the corresponding high and low values end up at 14–48 € per GJ (50–173 € per MWh), or 1.7–9.5 ct per vehicle-km and for PtL 15–60 € per GJ (54–216 € per MWh), or 1.5–10 ct per vehicle-km. The cost of different parameters on the overall costs per vehicle-km and per GJ are shown in Fig. 9.

The emerging large cost spans are due to high uncertainties regarding future costs, and *e.g.* a higher electricity price and hydrogen transport costs would widen the span further. For comparison, at the time of writing fuelling station prices excluding taxes were at 67 € per GJ for H_2 (9.5 € per kg, minus 19% VAT[80]), 15 € per GJ for natural gas (1.1 € per kg, minus 0.19 € per kg energy tax and 19% VAT[81,82]) and 13 € per GJ for diesel (1.1 € per L minus 0.47 € per L^{-1} energy tax and 19% VAT[82,83]).

In comparison, the average price of all passenger cars sold in Germany in 2018 was 33.5 t€,[67] which with a discount rate of 5%, a life time of 14 years and 14 tkm driven yearly results in 24 ct per vehicle-km. Thus, the vehicle price has a larger effect than the fuel costs given here (excluding taxes), which amounts to 0.7–10 ct per vehicle-km for the given options.

The GHG abatement of the ERE-based hydrocarbon electrofuels results in around 90 kg CO_2eq per GJ_{fuel} (with the reference of 94.1 kg CO_2eq per GJ_{fuel} (ref. 56)). With the CO_2 inputs stated in Table 1, this results in 1.3 and 1.7 kg CO_2eq per kg $CO_{2,in}$ for PtL and PtG-CH_4, respectively, which is superior to the CCS reference case of 1 kg CO_2eq per kg $CO_{2,in}$.

The resulting GHG abatement costs are at around 250 € per $MtCO_2$eq for hydrogen, higher than for BME at 200 € per

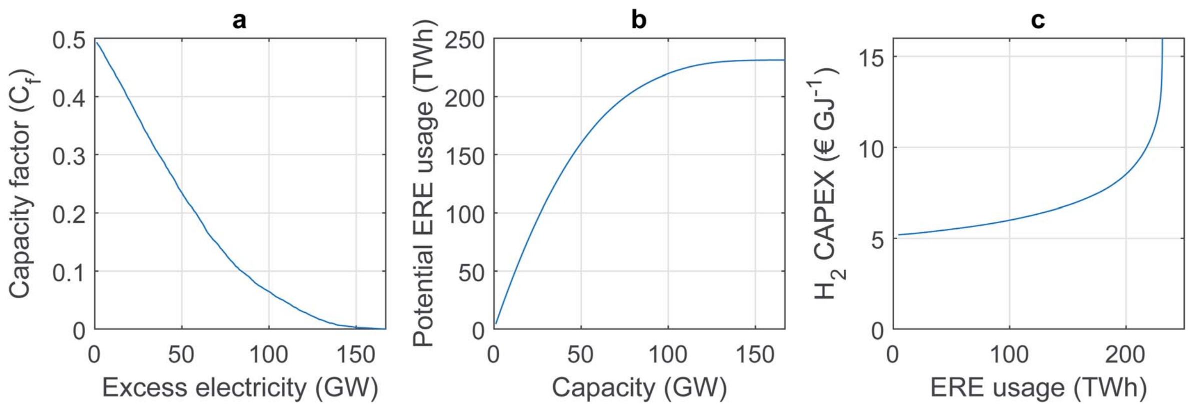

Fig. 8 Capacity factor and capital expenditure (CAPEX) at different production levels for the given excess renewable electricity (ERE) in 2050.

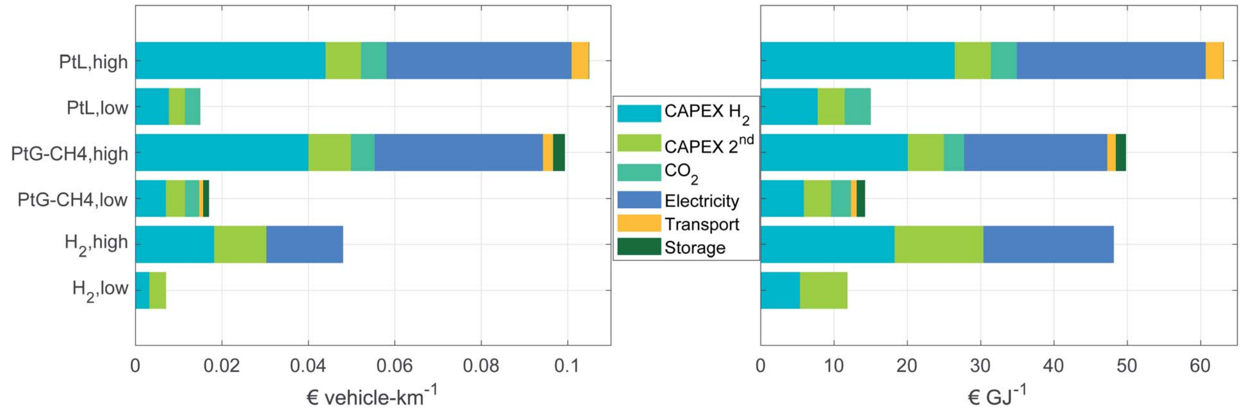

Fig. 9 Electrofuel cost breakdown to key parameters. The storage and fuelling of hydrogen is represented by CAPEX 2nd, whereas for the other options they go under storage. Hydrogen was assumed to be produced on-site, and thus transport costs are omitted. In the low case, the minimum value of the overall parameter combinations is used, and in the high case the maximum value is used, with the addition of an ERE cost of 40 € per MWh.

$MtCO_2eq$ (Fig. 10). PtL costs about 320 € per $MtCO_2eq$, whereas PtG-CH_4 is not deployed as the CH_4 demand is supplied by biofuels in the main scenario. Liquid fuels are generally the most expensive ones, and would thus be dropped first at more modest GHG targets. As can be seen in Fig. 10, the fuel mix changes substantially over time. In 2030, HVO is the least-cost fuel, whereas in 2050 it is one of the most expensive, which is due to increased feedstock prices and a small share of the built production capacity being used (such overcapacity effects diminish if the GHG target is relaxed). Biofuels contribute to somewhat more GHG abatement in 2050 than they do in 2030, but FCEV and PtL go from having a minor role to being the dominating options. Also, a shift from mainly liquid fuels to gaseous fuels dominating can be observed. Ethanol vanishes due to the option being assumed only for passenger cars, which are fully electrified by the end.

Combining biofuels and electrofuels based on ERE, the total renewable fuels share across the transport sectors reaches 67–92%, while the total GHG abatement of renewable fuel deployment increases from 3 $MtCO_2eq^{-1}$ in 2020 to between 50-89 $MtCO_2eq$ in 2050 (Fig. 7), of which biofuels contribute 10–22 $MtCO_2eq$ and electrofuels up to 74 $MtCO_2eq$. In the CCS scenarios, combined electrobiofuels contribute between 20–46 $MtCO_2eq$. The maximum GHG abatement is achieved when arable land is used and hydrogen usage is high; if there were no limits for hydrogen usage, over 100 $MtCO_2eq$ could be abated, when converting all ERE to hydrogen and replacing ICEVs run on fossil fuels. FCEVs run on renewable hydrogen are more

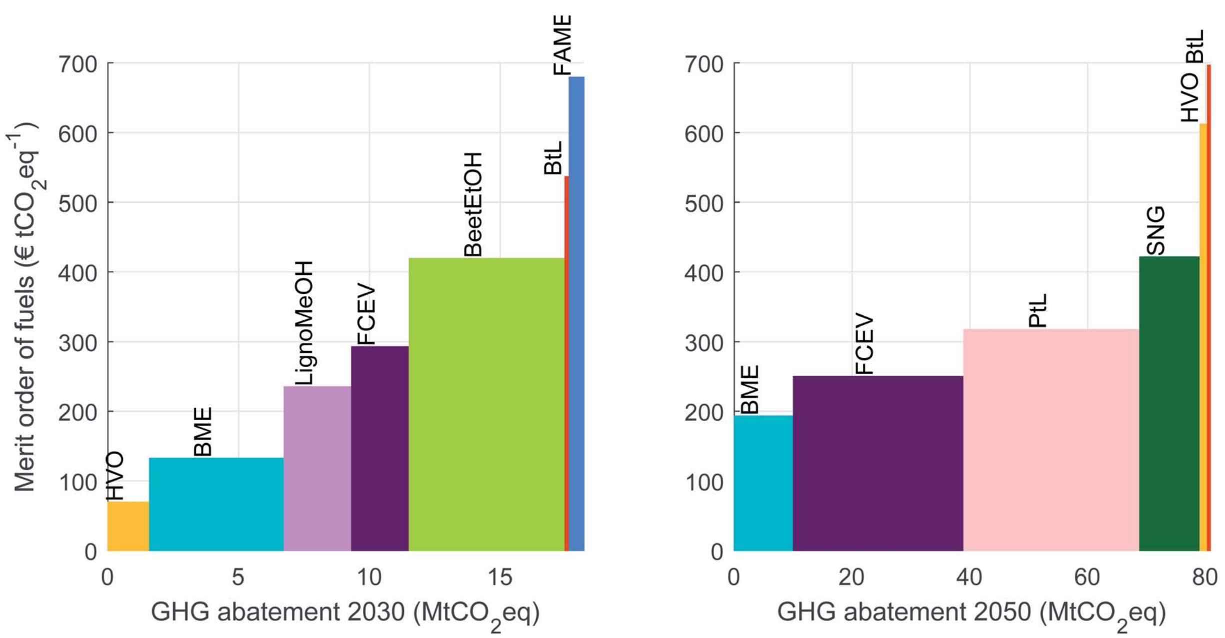

Fig. 10 Merit order of fuel options in 2030 and 2050 in the 99% of maximal GHG abatement cost optimal baseline case in scenario 1, with a weighted average across feedstock inputs. The CH_4-options are supplied in liquefied form to the end user.

resource-efficient than ICEVs run on PtG/PtL, both in terms of fuel production efficiency as well as in the vehicle, resulting in a lower energy demand for the same transport service. The availability of CCS especially affects the scenarios with lower hydrogen demand, by reducing the GHG abatement achieved through fuels.

4 Discussion

4.1 Usage of carbon for electrofuel *vs.* CCS

In this paper, the results indicate that using CO_2 for producing electrofuels is beneficial compared to CCS from a GHG abatement perspective given three conditions, namely (1) if the options of using hydrogen directly or in combination with biofuel processes are saturated, (2) as long as there is still a demand for hydrocarbon fuels for which otherwise fossil fuels would be used, and (3) there is unused ERE, *i.e.* VRE is curtailed. The renewable electricity-based hydrocarbon electrofuels replacing fossil fuels abate up to 70% more GHG than if the carbon would instead be stored (CCS).

The RED II fossil fuel reference emission factor of 94.1 kg CO_2eq per GJ_{fuel} used here is higher than average combustion-related emission factor values used for German national reporting for gasoline (73.1), diesel (74.0) and natural gas (55.9),[84] as the national reporting allocates the substantial upstream, refinery and distribution emissions[85,86] to other sectors. When replacing fossil fuels it is reasonable to assume that the whole production chain is replaced, and thus the here used emission factor is valid. Compared to current practise, it can be argued that the renewable fuels compete with liquid fossil fuels on the margin, and thus the same fossil reference applies for gaseous fuels. Using shale oil or gas[87] as a reference on the margin would increase the emission factor of the fossil reference,[88,89] and thus also the benefit compared to CCS. However, an almost GHG emission-free electricity source is required in order for it to be beneficial to use carbon for electrofuels instead of carbon storage, and fossil fuel upstream emission reductions (UER) would decrease the benefit compared to CCS.

As a comparison to this study, Sternberg and Bardow[90] performed a present-day assessment of electrofuels, comparing CO_2-utilization for electrofuels with the reference cases with and without carbon storage, as in this study. Their results suggest that CO_2 utilization for electrofuels would abate less emissions than CCS. Similarly, Lehtveer *et al.*[40] assess the long-term role of electrofuels in road and ocean transportation, concluding that at a limited carbon budget, it is more economical to store carbon than to use it for electrofuels. In both cases, these differences appear to come down to differing system boundaries.

Sternberg and Bardow[90] compares different usages of ERE, including heat storage and heat pumps, dispatchable power, BEVs and chemicals. A direct comparison of using ERE for these options results in the prioritisation of heat pumps, BEV as well as power storage and feed-in.

In this paper, power storage and feed-in was assumed as a priority, before allowing ERE for other usages (Fig. 4). Heat pumps perform a climate benefit already with the German power mix,[91,92] thanks to a high conversion efficiency from power-to-heat (coefficient of performance, COP[93]). However, there are also other options for heat provision, such as solar and geothermal,[91] which have a larger exergetic efficiency[94] and do not rely on high exergy sources such as electricity.[95] Such alternative options do not exist for fuel production. Seasonal variations reduce the benefit of using ERE for heat pumps in the summer, while in the winter it may be a necessity. Thus, the relative benefits of different ERE usage options need to be analysed as part of a system.

Likewise, BEV are superior to the fossil reference already with the present power mix,[92] which is not the case for hydrocarbon electrofuels (Fig. 6). Therefore, these options are not necessarily direct competitors of surplus power for achieving ambitious GHG targets, as long as hydrocarbon fuels are demanded. Chemicals and industrial hydrogen usage on the other hand are strong competitors due to the lack of renewable alternatives and the current practise of producing hydrogen from natural gas. Classical life-cycle assessments of singular pathways cannot capture these aforementioned issues, and a systems perspective is necessary.

Lehtveer *et al.*[40] analyse global transitions with details on all energy sectors, at given global carbon budgets. Most scenarios assume CCS and nuclear power. This keeps the VRE share relatively low, as fossil sources combined with CCS can be used to meet the targets. In scenarios without CCS, larger shares of VRE are required to meet targets, which also allows for more ERE and thus more electrofuels. In scenarios without nuclear and large-scale CCS, VRE is the most important option for achieving the GHG targets, whereby ERE may increase substantially.

It would be sensible to allow for the maximal use of this resource base, and minimize curtailment. Unless hydrogen and BEV fully displace the demand for hydrocarbon fuels, this also means that carbon is better used for this purpose, instead of being stored. Instead, fossil fuels can stay stored in the ground, which by definition are proven as a long-term storage, and issues of *e.g.* acceptance of carbon storage[40] are avoided.

4.2 The benefit of BEV and FCEV

Using hydrogen directly in transport would decrease the need for carbon while also achieving higher conversion efficiencies across all steps in the WTW pathway compared to hydrocarbon electrofuels. However, issues of presently low hydrogen demand, costly infrastructure and vehicles as well as safety concerns regarding hydrogen transport and storage are challenges which inhibit a large-scale deployment to date. BEVs are an even more efficient transportation option which likewise do not require CO_2, and without which a renewable transport transition will be very challenging. A focus on hydrogen and BEVs reduces the demand for hydrocarbon fuels and thus enables the use of the scarce CO_2 for other sectors or for carbon storage, and reduces CO_2 emissions. Other fuels which do not contain carbon, such as ammonia,[96,97] should also be considered.

4.3 Carbon sources and constraints

Renewable carbon can be derived through bioenergy with carbon capture (BECC) or direct air carbon capture (DACC) powered by renewable energy, with the former being limited by

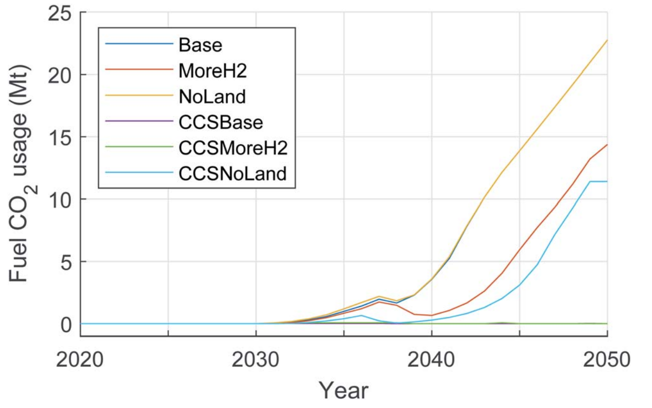

Fig. 11 Resulting total input CO_2 usage for hydrocarbon electrofuels.

the same concerns as for biofuels, whereas the latter is still a technology in its infancy and likewise would depend on the limited ERE availability (and thus possibly low capacity factors).

In this paper, up to 22 $MtCO_2$ would be required by 2050 as carbon source for electrofuel production in Germany (Fig. 11). A long-term recovery potential of between 5 (UBA[98]) and 8–11 (Billig *et al.*[99]) $MtCO_2$ has been estimated from future scenarios of biogas production. This could cover up to half of the long-term CO_2 demand in the cases that have been assessed here. Therefore, CO_2 capture at industrial point sources is likely to be needed as an alternative renewable carbon source, for which estimates for 2050 range from 14 to 73 $MtCO_2$.[98,100] However, depending on future decarbonization pathways for the industry sector, their potential CO_2 supply might diminish over time. Thus, DACC may be required in order to cover the CO_2 demand given in this paper.

In the scenarios, there is a residual load gap of 94 TWh (337 PJ) in 2050 which is not fulfilled by VRE (Fig. 4). If this gap would be fully fulfilled by methane combustion, with a conversion efficiency $\eta_{el} = 60\%$ and CO_2 emissions according to Table 1, 31 $MtCO_2$ would be available for capture. This would serve as an upper limit for the CO_2 source from electricity generation. However, many other options for decreasing the residual load gap are available, as discussed below.

Due to national land scarcity, nature conservation and acceptance constraints for VRE capacity expansion, electrofuel imports will likely be needed to achieve high renewable targets in mobility. Strategies for electrofuel production in areas of ample surplus renewable electricity or specially dedicated renewable parks with little land use trade-offs have been suggested,[101] but are also complicated by geo-political challenges.[102] For ease of transportation, carbon may be needed to bind the hydrogen,[103] and thus the renewable fuel parks would need to be coupled with a carbon source such as through DACC or BECC.[104,105]

4.4 Uncertainties and limitations

Several uncertain factors apart from the ones explicitly addressed affect the developments assessed here, which need to be highlighted.

In this study, competing usages of ERE have been omitted, such as seasonal and daily variations of heat generation and storage (Power-to-Heat, PtH) as well as hydrogen production for the chemical sector (power-to-chemicals). Some electricity storage was included, which was converted back and fed into the grid in times of low renewable production. PtH is an important future option for decarbonising heat provision. However, as pointed out above, heat pumps achieve emission reductions compared to fossil-fuelled alternatives already with the present electricity mix[92] and thus may not necessarily compete for ERE. PtH[106] competes with ligno-cellulosic biomass as the main renewable options for industrial applications.[91,107] In this study, forest residues were excluded for fuel production; future studies should determine optimal usages of biomass, carbon and electrification across sectors.

As a 100% renewable share in the power supply was not achieved under the given settings, despite high available electricity storage capacities, some ERE may be needed for power-to-power (*i.e.* hydrogen/PtX used for electricity generation) instead of being used as transport fuels. Although the electricity load was scaled to take a higher demand through sector coupling into account, a more holistic analysis of this needs to be performed in future work. A market for ERE-usage will likely result in above zero ERE prices, which requires further research.

In addition, the charging pattern of EVs (a charging pattern was omitted in this study), other demand adaptations and the expansion of system-friendly wind and solar power[23,46,108,109] or a transmission grid expansion would decrease the available ERE.

A German copper plate approach has been used, without power transmission restrictions. In order to capture real curtailment situations, transmission limitations would need to be highlighted. This is – ceteris paribus – likely to result in a higher potential for ERE, depending on future transmission grid capacity assumptions.[42] However, at low transmission capacities, higher VRE capacities would be required to achieve renewable targets in the power sector and the positive residual load would increase. In order to use ERE for hydrogen production, more infrastructure (electrolysers, hydrogen grids, storage) would be needed, which would achieve lower capacity factors and thus increase costs substantially.

Therefore, investments in transmission capacities are to a large extent a necessary and more cost-effective measure to match demand and supply,[110,111] and thus a copper plate focus without grid constraints as used in this study should not be too far off real optimal developments if considering Germany only. The marginal benefit of additional wind and solar power at high VRE shares such as in this study decreases sharply,[24] unless spatial and temporal arbitrage options such as continental transmission grids and H_2 storage are available.[112–114] Thus, a system where high amounts of ERE are achieved would be rather costly compared to a spatio-temporal smoothing of VRE generation. Even at the extreme ERE developments considered in this study, the amounts are not sufficient to supply even just the transport sector with renewable fuels, and imports or carbon storage compensation schemes would thus be necessary to achieve net-zero emissions in transport.

The achievable GHG abatement of different carbon usage pathways depends on conversion efficiencies and losses. Here, the processes were assumed to be without carbon losses for both hydrocarbon electrofuels and for carbon storage, whereas in both cases imperfect processes and losses are likely. The exact impact of such losses and possible countermeasures such as recycling of process surplus carbon needs to be further highlighted. Similarly, the relative benefits of conversion pathways leading to the same end product, such as BtL, PBtL and PtL, are linked to uncertainties regarding *e.g.* conversion efficiencies and require a stronger research focus.

As discussed above, vehicle costs may have some impact on costs, although resource scarcity would likely lead to efficient pathways (BEV and FCEV despite higher vehicle costs than for ICEVs) being prioritised for achieving high renewable targets. Future studies should include vehicle cost estimates for all transport sectors in order to analyse this effect more holistically.

Ammonia (NH_3) has been highlighted as a promising fuel[96,97] which avoids the use and emissions of carbon, and should be included in future studies.

All of these factors combined with sensitivity analyses should be covered in future research.

5 Conclusions

In high VRE capacity scenarios, large quantities of ERE for hydrogen production may become available. In this study, 231 TWh ERE could be observed for 2050, equivalent to 33% of the assumed electricity demand. This energy could run electrolysers for producing 582 PJ (162 TWh) hydrogen, which could be further combined with CO_2 and processed to 530 PJ PtG-CH_4 or 402 PJ PtL.

CO_2 usage for producing hydrocarbon electrofuels is limited by decreasing anthropogenic CO_2 emissions. Bioenergy with carbon capture as well as captured emissions from industry may cover a substantial demand, but direct air capture may become an important additional source of carbon.

A first priority for renewable transport is the deployment of BEVs, and as a second priority FCEVs, which are both substantially more efficient than producing hydrocarbon electrofuels for combustion in ICEVs. However, given (1) an unsaturated demand for renewable hydrocarbon fuels, (2) a saturated renewable hydrogen demand and (3) unused ERE capacities which would otherwise be curtailed, carbon is better used for fuel production than being stored. Carbon used for producing hydrocarbon electrofuels which replace fossil fuels achieve an up to 70% higher GHG abatement than if it were used for storage. Instead, fossil fuels can stay in the ground and issues such as acceptance of carbon storage are avoided.

Producing hydrogen from ERE alone results in low capacity factors of the electrolysers. An increasing ERE utilization results in a decreasing capacity factor, leading to a strongly decreasing marginal benefit of increased electrolyser capacities. When using large shares of ERE for hydrogen production, GHG abatement costs of 250–320 € per tCO_2eq for hydrogen and PtL respectively are achieved, which is competitive with biofuels when assuming high biomass price increases. An above zero price of ERE would increase the cost, while the price of input CO_2 may increase due to scarcity. Furthermore, costly transport infrastructure is necessary in cases when on-site electrolysis is not viable.

Nevertheless, electrofuels are a necessary resource for achieving high renewable targets, even when assuming a high share of BEVs and substantial amounts of biofuels. Due to various limitations of the different renewable transport pathways, a variety of renewable options are necessary for achieving high renewable shares in transport. A key issue is to what extent they can be produced sustainably.

Electrofuels based on ERE under the VRE expansion scenarios were found to be able to mitigate up to 74 $MtCO_2eq$ in 2050, or only about 46% of current German transport emissions, despite very high ERE developments which would be suppressed by continental transmission grids. Future industrial usage of hydrogen and PtH would decrease the potential available for transport. Biofuels added a GHG abatement of up to 22 $MtCO_2eq$, despite assuming only a small share of the biomass residue potential available for transport. The achieved renewable share in transport was 67–92%, depending on the level of hydrogen usage in FCEV, arable land available for biofuel production and whether the carbon can be stored instead of used for fuel production. Considering also heat and industrial demand, a substantial gap of renewable hydrogen and electrofuels would need to be supplied by imports for achieving 100% renewable shares, unless the transport fuel demand is substantially further reduced.

Conflicts of interest

There are no conflicts to declare.

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