RSC Sustainability

PAPER

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Cite this: *RSC Sustainability*, 2025, **3**, 3144

Meeting U.S. light-duty vehicle fleet climate targets with battery electric vehicles and electrofuels†

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Mitigating greenhouse gas (GHG) emissions from light-duty vehicle (LDV) fleets cannot solely rely on battery electric vehicles (BEVs). This study focuses on a potential complementary solution: electrofuels (e-fuels, produced with electrolytic hydrogen and carbon dioxide) and specifically e-gasoline deployment in the U.S. as a drop-in fuel compatible with existing vehicles and fueling infrastructure. This study uses (1) fuel- and vehicle-level analyses to determine the energy and feedstock inputs that would enable e-gasoline to have lower GHG emissions than conventional gasoline or vehicle electrification and (2) fleet-level analysis to understand whether deploying e-gasoline in the U.S. LDV fleet can help reach 2015–2050 cumulative emission budgets under exogenous BEV deployment scenarios. For each scenario, we analyzed required e-gasoline production volumes and associated demands for feedstock, renewable electricity, and critical materials for water electrolyzers and electricity generation. The results show that e-gasoline GHG intensity is most sensitive to the GHG intensity of the electricity used for electrolysis. Deploying e-gasoline produced from fully renewable energy has the potential to assist the fleet in meeting climate targets. In the absence of other measures, slower deployment of BEVs or insufficient low-GHG intensity electricity for BEV charging increases the need for e-gasoline and an aggressive production ramp-up. When e-gasoline is produced through optimistic pathways (*e.g.*, fuel-level GHG intensity as low as 7 g CO_2-eq per MJ), meeting a 2 °C climate target would require a peak production of 17–400 billion L per year by ~2040 depending on the BEV deployment scenario (requiring an estimated 2–45 times the 2023 U.S. carbon capture capacity, 60–1400 times the 2020 U.S. electrolytic hydrogen production, and 0.4–9 times the 2022 U.S. renewable electricity production). Without significant recycling of electrolyzer inputs, cumulative material demand could exceed global reserves of iridium, and place pressure on yttrium, nickel, and platinum reserves depending on the assumed electrolyzer technology. Mitigating GHG emissions from land passenger mobility cannot solely rely on BEVs and e-fuels; other complementary strategies based on vehicle efficiency, other low carbon fuels, trip avoidance, and modal shift must be considered.

Received 18th October 2024
Accepted 23rd May 2025

DOI: 10.1039/d4su00654b

rsc.li/rscsus

Sustainability spotlight

Electrofuels, especially drop-in ones (*e.g.*, e-gasoline), may complement battery electric vehicles (BEVs) to help light-duty vehicle fleets meet climate targets. E-gasoline can have low greenhouse gas (GHG) emissions and is compatible with existing vehicles and fueling infrastructure. However, scale-up challenges make its mitigation potential unclear. This work evaluates whether e-gasoline can help the U.S. light-duty vehicle fleet meet 1.5 and 2 °C climate targets. We find that e-gasoline can assist in meeting climate targets, but associated resource use and the required deployment speed may create challenges, especially under a slow deployment of BEVs or an insufficient supply of low-GHG electricity for BEV charging. Our work aligns with the UN Sustainable Development Goals of climate action (SDG13) and affordable and clean energy (SDG7).

1. Introduction

1.1 Background and motivation

Climate change is an existential threat to human societies and ecosystems[1] and global leaders have agreed to limit the increase in average global temperature to 2 °C, and ideally 1.5 °C, above pre-industrial levels.[2] In 2021, the U.S. transportation sector emitted 1.8 Gt carbon dioxide equivalent (CO_2-eq), accounting for 28.5% of total U.S. greenhouse gas (GHG) emissions, of which

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† Electronic supplementary information (ESI) available. See DOI: https://doi.org/10.1039/d4su00654b

58% resulted from light-duty vehicles (LDVs).[3] Meeting climate targets requires substantial mitigation of GHG emissions from the LDV fleet. Many mitigation efforts focus on replacing conventional internal combustion engine vehicles (ICEVs) fueled with gasoline or diesel with battery electric vehicles (BEVs).[4] But even with relatively optimistic BEV deployment, our prior work[5] projected a considerable GHG mitigation gap to 2050 for the LDV fleet to meet a sectoral carbon budget. Complementary solutions to BEVs are required, including those focused on ICEVs. Despite growing ambitions for BEVs, the Annual Energy Outlook (AEO) 2023 reference case projects that over 70% of the vehicle stock in 2050 will be ICEVs under current policies.[6] Due to the timing of fleet turnover, even if new policies increase BEV sales, it would still take years or decades to materially change the vehicle stock, meaning solutions that reduce the GHG emission contributions from ICEVs will be critical.[5]

Complementary solutions for ICEVs include improving fuel consumption, reducing vehicle weight, and switching to alternative lower GHG intensity fuels, such as lower GHG intensity biofuels or electrofuels (e-fuels).[5] Electrofuels are hydrocarbon fuels derived from combining electrolytic hydrogen and captured CO_2 through chemical synthesis.[7] To produce low-GHG intensity e-fuels, low-GHG intensity feedstocks and energy sources are required.[8,9] There are a number of feedstock and conversion pathways that are capable of producing a range of liquid and gaseous e-fuels, including methanol, methane, dimethyl ether, ammonia, gasoline, and diesel.[8] With respect to the LDV fleet, drop-in e-fuels, *i.e.*, those that have similar properties to gasoline (e-gasoline) or diesel (e-diesel), are potentially attractive for use in ICEVs, plug-in hybrid electric vehicles (PHEVs) and hybrid electric vehicles (HEVs), especially due to their compatibility with existing vehicles as well as distribution and refueling infrastructure.[7,8,10,11]

Despite the conceptual simplicity of using electricity to turn CO_2 into hydrocarbons, e-fuels remain an emerging technology with unclear potential compared to other more mature alternative fuel options. Biofuels, for example, currently dominate the market for renewable liquid fuels[12] and remain an important option for decarbonizing the transportation sector. While drop-in biofuels such as renewable gasoline and renewable diesel derived from biomass exist, the most common biofuels (*e.g.*, bioethanol and biodiesel) are compatible only as low-level blends;[13,14] biofuels also raise concerns about land use change[15] and feedstock availability,[16] thereby limiting their overall sustainable supply.[17,18] In contrast, e-fuels require only a relatively generic set of globally available production inputs (primarily electricity and CO_2), making them attractive to investigate as a potentially scalable alternative drop-in fuel for decarbonizing the LDV fleet.

Challenges of e-fuels include their currently limited production, projected high costs in the near term, uncertainty about the feasibility of their large-scale deployment, and potential competition from other sectors (*e.g.*, aviation and heavy-duty vehicles), as well as requirements for these fuels to be produced with low environmental impacts including low GHG intensity. The first operating pilot facility to integrate all processes to produce e-gasoline began operation in Chile at the end of 2022[19] and the first commercial-scale facility in the U.S. is expected to begin operation in 2027.[20]

To provide insights into the GHG mitigation potential of e-fuels and their potential roles in helping LDV fleets meet climate targets, life cycle assessments (LCAs) are needed at the fuel, vehicle, and fleet levels along with an assessment of the feasibility of large-scale deployment (industry scale-up, timing, costs, *etc.*).

At the fuel level, LCAs of e-fuels have reported a wide range of GHG emission intensities (1.3–441 g CO_2-eq per MJ for e-gasoline, e-diesel, or undifferentiated fuel mixtures),[7,9,10,21–27] largely due to variations in the GHG intensities of the feedstock (CO_2 sources) and energy sources (*e.g.*, used in water electrolysis for hydrogen production and carbon capture). Studies have found that the most important parameter determining e-fuel GHG intensity is the GHG intensity of electricity, especially electricity used in water electrolysis.[22,24] For example, Liu *et al.*[24] estimated that an electricity emission factor of less than 139–144 g CO_2-eq per kWh (well below that of even the most efficient unabated fossil fuel power plants[27]) would be needed for e-diesel using CO_2 from direct air capture (DAC) to achieve a lower GHG intensity than conventional diesel.

Vehicle-level assessments are required to compare fuels or energy carriers used in distinct vehicles, *e.g.*, e-gasoline in an ICEV or electricity in a BEV. GHG emissions per vehicle kilometer traveled (vkt) from using e-gasoline in an ICEV were reported to be higher than those from a BEV under low-carbon grids, if e-gasoline production and BEV charging rely on the same grid mix.[7,28] A major contributor to this result is the much higher efficiency of the BEV compared to the ICEV.[29] While the vehicle-level results suggest some challenges for e-fuels, their production facilities can be more easily located near low-GHG electricity generation (*i.e.*, off-grid renewables) compared to charging all BEVs in the U.S. with low-GHG electricity, which would require the entire grid to be low-GHG.

Analyzing the GHG mitigation potential of large-scale deployment of fuel/vehicle options over time requires a dynamic fleet-level LCA, which considers fleet turnover and market shares of technologies. Some high-level system modeling studies have included e-fuels when simulating cost-minimal fuel/vehicle deployment in the U.S. and EU fleets to meet climate targets.[30,31] These studies focused only on scenarios with high BEV and renewable electricity penetration levels and did not include life cycle emissions related to renewable electricity generation, vehicle manufacturing, and e-fuel production.[30,31] Few LDV fleet-level LCAs have estimated the mitigation potential of the large-scale deployment of e-fuels.[32–35] However, existing studies consider deploying BEVs and e-fuels as competing strategies instead of complementary strategies, and thus overlook potential interactions between BEV and e-fuel deployment (see a review of fleet-level studies in the ESI, Section 1.1†). To meet climate targets, the required contribution from e-fuels will be different depending on the mitigation gaps (*i.e.*, the remaining emissions that must be mitigated to meet climate targets) under different BEV deployment scenarios and electricity sources used for charging BEVs and PHEVs. Given the uncertainty in projected BEV deployment, neglecting interactions between BEV and e-fuel deployment may lead to an incomplete evaluation of the mitigation potential of the large-scale deployment of e-fuels in the fleet.

Whether e-fuels could or should serve as a complementary strategy to BEVs to bridge the GHG mitigation gap depends not just on their fuel-, vehicle-, and fleet-level GHG intensities but also on the feasibility of their large-scale deployment (*e.g.*, required industry growth rate, feedstock, energy, critical material requirements, and associated costs).

The required e-fuel industry growth rate could be high due to its early stage of development. The large-scale deployment of low-GHG e-fuels requires captured CO_2, electrolytic hydrogen, and low-GHG electricity. Given that supply capacities of energy and feedstock are currently low[36–38] and demands from other sectors are projected to be high,[30] whether there will be sufficient energy and feedstock to produce e-fuels to bridge mitigation gaps is uncertain. Critical materials, such as platinum-group metals and rare-earth elements, are essential components in specific water electrolysis and renewable electricity technologies, both pivotal in the transition to clean energy and currently rely on supply chains with considerable geographical concentration.[39] Due to the lack of fleet-level LCAs assessing the use of e-fuels in the LDV fleet and the associated feasibility, it remains unclear whether deploying e-fuels can bridge mitigation gaps in the fleet. As the U.S. LDV fleet is projected to be dominated by ICEVs until 2050 under current regulations,[6] the demand for low-GHG drop-in e-fuels could be extensive if they are relied upon for meeting climate targets. We use the U.S. as a case study to explore the potential role of drop-in e-fuels (specifically e-gasoline) and associated scale-up challenges in mitigating LDV fleet GHG emissions.

1.2 Objectives

This study aims to (1) determine energy and feedstock input combinations that enable e-gasoline to achieve lower GHG intensity than conventional gasoline and vehicle electrification through fuel- and vehicle-level LCAs; and (2) evaluate whether deploying e-gasoline has the potential to bridge the mitigation gaps (cumulative GHG emissions from 2015–2050) under different exogenous BEV deployment scenarios through fleet-level LCAs. The latter objective is fulfilled by (i) determining the required deployment of e-gasoline in the U.S. LDV fleet to maintain fleet-level GHG emissions within sectoral carbon emission budgets consistent with 1.5 and 2 °C climate targets under various BEV deployment scenarios; and (ii) understanding whether using e-gasoline to bridge mitigation gaps is likely to be feasible considering the required industry growth rate and demands for feedstock, low-GHG electricity generation, and critical materials. The starting year 2015 is used for consistency with our past work,[5] however, we adjust for the portion of the carbon budget already used from 2015–2020 and so most results are presented for the period 2020–2050.

2. Methods

This study includes fuel-, vehicle-, and fleet-level LCAs as well as assessments of the feasibility of the large-scale deployment of e-gasoline (Fig. 1).

The fuel-level LCAs estimate the GHG emissions from producing and combusting e-gasoline and compare them with conventional gasoline. E-gasoline production is then incorporated into the FLAME (Fleet Life Cycle Assessment and Material-Flow Estimation) model.[5,40] The vehicle, automotive material flow, and LCA modules of FLAME are used to conduct vehicle-level LCAs which include embodied vehicle emissions. The vehicle-level GHG emissions from using e-gasoline in ICEVs-G, PHEVs, and HEVs are compared with those from using conventional gasoline in these vehicles and as well with BEVs. Both fuel- and vehicle-level LCAs include scenarios involving variations in e-gasoline production pathways and energy sources to explore the conditions required for an ICEV using e-gasoline to have lower GHG emissions than an ICEV using conventional gasoline or a BEV.

At the fleet level, the fleet module of FLAME is combined with the above modules to estimate the GHG emissions from the U.S. LDV fleet from 2015–2050 (although we focus on 2020–2050 for projected rather than historical results). We examine different mitigation scenarios based on assumptions about BEV deployment levels and the electricity sources used to charge BEVs and PHEVs (see "Section 2.3.3 BEV deployment scenarios" for more information). Overall, we aim to explore the potential of drop-in e-fuels (specifically e-gasoline) as a complementary mitigation solution. We estimate CO_2 emission budgets for the U.S. LDV fleet to meet 1.5 and 2 °C climate targets to determine the mitigation gaps under various BEV deployment scenarios. The backcasting module in FLAME is used to estimate the required annual volumes of e-gasoline to bridge the mitigation gaps. The associated required industry growth rates and demands for feedstock, energy, and critical materials are then estimated to examine the feasibility of deploying the required volumes of e-gasoline. The following sections provide details on methods, data sources, and assumptions used in the LCAs.

2.1 Fuel-level LCA

2.1.1 Functional unit and system boundary. The functional unit of the fuel-level LCAs is one MJ of fuel produced and combusted during vehicle use. The system boundary includes electricity generation, heat generation, carbon capture and compression, hydrogen production, syngas production (reverse water gas shift reaction or co-electrolysis), and chemical synthesis (Fischer–Tropsch synthesis or methanol synthesis with the methanol-to-gasoline process), hydro-processing (hydrocracking or hydrotreatment), product separation & upgrading, and e-gasoline transportation & distribution. GHG emissions from fuel combustion are taken into account. As the carbon emitted from e-gasoline combustion is captured from either industrial flue gas or the atmosphere, no GHG emissions are assumed to result from e-gasoline combustion (see "Section 2.1.2.2 CO_2 sources" for more information). Emissions from constructing and decommissioning equipment and infrastructure related to fuel production (*e.g.*, electrolyzers and carbon capture facilities) are excluded to maintain consistency with the system boundaries used for the conventional gasoline pathway in FLAME; embodied emissions from the construction of

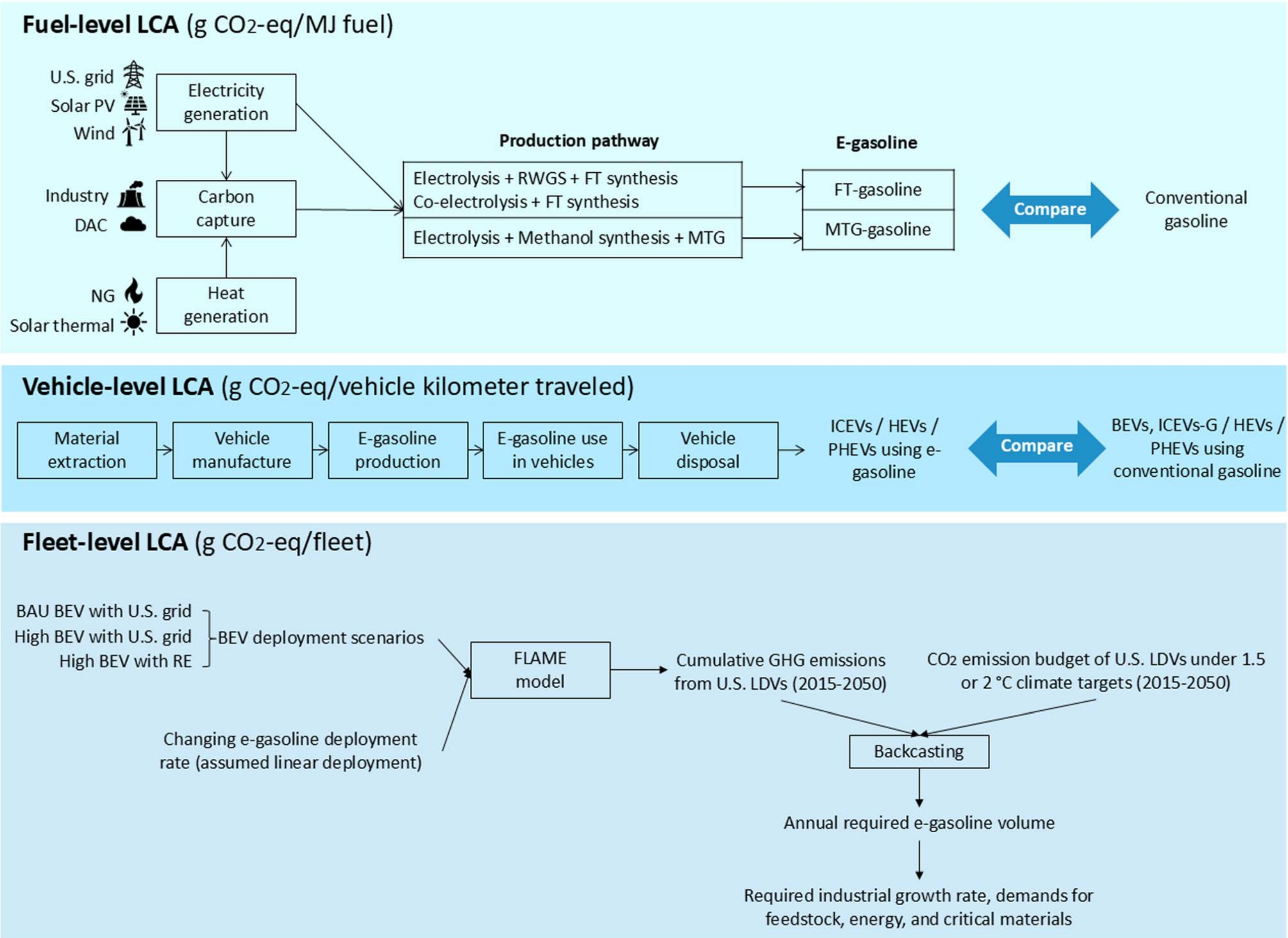

Fig. 1 Overview of method frameworks of the fuel-, vehicle-, and fleet-level life cycle assessments. Notes: the FT process yields a mixture of products, and thus energy allocation is applied to obtain results for FT-gasoline. FLAME: Fleet Life Cycle Assessment and Material-Flow Estimation model; Solar PV: Solar Photovoltaic; NG: Natural Gas; DAC: Direct Air Capture; RWGS: Reverse Water Gas Shift reaction; FT synthesis: Fischer–Tropsch synthesis; MTG: Methanol-To-Gasoline; ICEVs-G: Internal Combustion Engine Vehicles using Gasoline; HEVs: Hybrid Electric Vehicles; PHEVs: Plug-in Hybrid Electric Vehicles; BEVs: Battery Electric Vehicles; LDV: Light-Duty Vehicle; RE electricity: Renewable Electricity (solar PV and onshore wind specifically for this project); fleet-level LCA scenarios: BAU BEV with U.S. grid: business-as-usual deployment level of BEVs and BEVs charged with U.S. grid electricity; high BEVs with U.S. grid: 100% new BEV sales by 2035 and BEVs charged with U.S. grid electricity; high BEVs with RE: 100% new BEV sales by 2035 and BEVs charged with renewable electricity.

electricity generators are, however, included in electricity GHG intensity. Emissions from hydrogen transportation and storage, and CO_2 transportation and storage are not included as the study assumes e-gasoline production plants are located close to water electrolyzers and CO_2 sources (*i.e.*, low transport requirements) and the feedstock supply is steady or continuous (*i.e.*, low storage needs).

2.1.2 E-gasoline production characteristics

2.1.2.1 E-gasoline production pathways. We examine two types of e-gasoline: FT-gasoline produced through the Fischer–Tropsch (FT) route and MTG-gasoline produced through the methanol-to-gasoline (MTG) route. These e-gasoline variants and production routes are selected as, at the time of writing, they are the most widely studied routes for synthetic gasoline production.[41,42]

For FT-gasoline, we modeled two production pathways: electrolysis-based and co-electrolysis-based production pathways (Fig. 2A and B). Both combine CO_2 with H_2 or water to produce syngas (a mixture of H_2 and CO), and then pass syngas to FT synthesis to produce FT wax, which is hydrocracked into liquids and further refined and upgraded into FT-gasoline.[9,22] The two pathways differ in the way they produce syngas. The electrolysis-based pathway includes electrolysis combined with a reverse water gas shift (RWGS) reaction.[8,25] It first electrolyzes water through alkaline electrolysis (AEL) or proton exchange membrane (PEM) electrolysis to generate H_2.[8,43–45] Then the RWGS reaction combines H_2 and CO_2 to produce carbon monoxide (CO), which is blended with additional H_2 to form syngas with an H_2/CO molar ratio of 2 : 1.[21] We select AEL as the default water electrolysis technology for the electrolysis-based production pathway as it is the most mature technology.[9,43,44] We also provide information on PEM electrolysis for the fuel-level result comparison with previous studies (in ESI Section 3.1†) and critical material analysis. The co-electrolysis-based pathway is represented by the solid oxide electrolyzer cell (SOEC) technology, a future production pathway that is

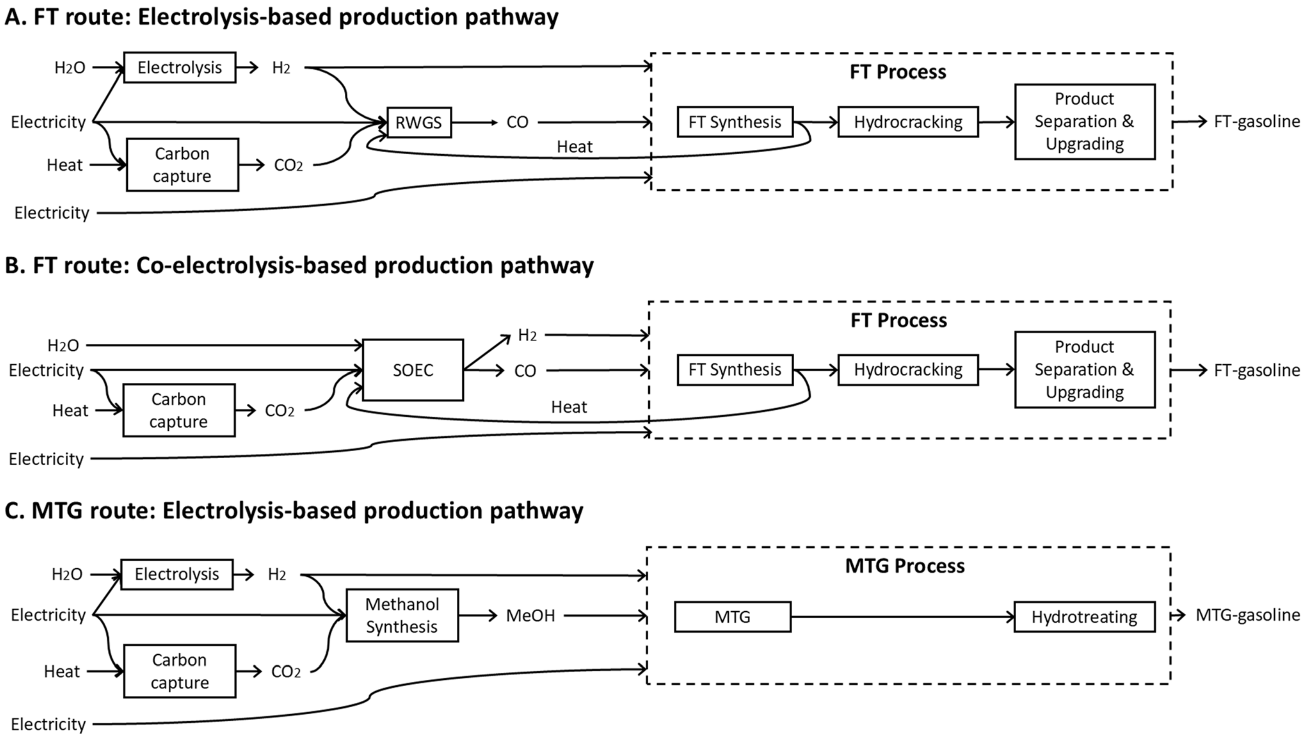

Fig. 2 Production pathways for e-gasoline produced from carbon dioxide modeled in the study: (A) Fischer–Tropsch (FT) gasoline produced from the electrolysis-based pathway; (B) FT-gasoline produced from the co-electrolysis-based pathway; (C) Methanol-to-gasoline (MTG) gasoline produced from the electrolysis-based pathway. The dashed boxes represent all processes included in the FT or MTG process. SOEC: Solid Oxide Electrolyzer Cell; RWGS: Reverse Water Gas Shift reaction; MeOH: Methanol. Whether external heat is needed for carbon capture depends on the concentration of CO_2 sources.[27]

expected to be more efficient and less GHG-intensive than the electrolysis-based pathway.[9,22] It uses an SOEC to simultaneously electrolyze water and CO_2 to generate syngas directly at typical operating temperatures of around 800–1000 °C.[9,22,46] The syngas is further converted to FT-gasoline through the FT process, involving FT synthesis, hydrocracking, and product separation and upgrading. FT synthesis is a commercially mature stepwise polymerization reaction that was originally designed for converting fossil-based syngas into liquid fuels.[21,47] For e-gasoline production, FT synthesis converts syngas produced from electrolytic H_2 and captured CO_2 into FT wax.[9,21] The process is exothermic, and the released heat can meet the heat demand for both the RWGS reaction and SOEC;[21,23] any surplus heat is treated as waste heat (*i.e.*, no emission credits). The FT wax is hydrocracked with additional hydrogen input to yield a mixture of FT-fuels, a product slate of FT-gasoline, FT-diesel, and FT-kerosene.[21] FT-gasoline needs to be further separated from the mixture and upgraded to improve the cold flow properties.[21] FT-gasoline is mainly composed of paraffins and olefins.[21,48] Estimates of the relative yield of e-gasoline vary across studies and across assumed process conditions (with example ranges from 26–37%[21,27,46]), requiring markets for the other products; from an LCA standpoint, using energy allocation, the exact mixture is moot as all products are assumed to have the same emissions intensity per MJ.

For MTG-gasoline, we consider an electrolysis-based pathway (Fig. 2C). It combines electrolytic H_2 and captured CO_2 to produce methanol through methanol synthesis,[11,21] a mature technology used commercially.[49,50] Methanol is then passed to the MTG process to produce raw gasoline, which needs to be upgraded through hydrotreating to useable road fuel.[11,21] The typical composition of MTG-gasoline is 50% paraffins, 20% olefins, and 30% aromatics.[21] The MTG process is a technology that is specific for gasoline production and was developed by Exxon Mobil in the 1970s.[41,51,52] The MTG technology has been applied at the HIF Haru Oni Demonstration Plant in Chile to produce 130 000 L of e-gasoline per year[19] and is expected to be applied in the HIF Matagorda eFuels Facility in the U.S. to produce 750 million L of e-gasoline per year by 2027.[20]

2.1.2.2 CO_2 sources. CO_2 can be sourced from flue gas or the atmosphere through DAC.[8,25,53–55] We consider CO_2 from both post-combustion industrial flue gas and DAC as they are more widely studied than other sources (*e.g.*, capturing pre-combustion and oxy-combustion flue gas). We include capturing industrial flue gas as e-fuel production can utilize carbon captured from industrial sources.[53] DAC is a less mature carbon capture technology, capturing less than 0.01% of total CO_2 captured in the U.S. in 2023.[37] Compared to capturing the post-combustion industrial flue gas, DAC uses more energy due to the more dilute concentration of CO_2 in the ambient atmosphere.[56] Nevertheless, DAC has some advantages. The location of the capture system is flexible and there is no need to transport CO_2.[56–58] DAC is also not limited by the amount of CO_2

emitted from industrial sources,[54] which may further decline in availability as industries decarbonize. DAC powered by renewable energy can avoid emissions from combustion of fossil fuels while capturing CO_2 from industrial flue gas cannot prevent but only delay emissions until the combustion of synthetic fuels.[57]

As using industrial CO_2 to produce e-fuels eventually results in CO_2 emissions during fuel combustion, it leads to the issue of how to allocate CO_2 emissions between the industrial process and fuel combustion during vehicle use. Studies have attributed none, partial, or all CO_2 emissions to e-fuel production.[7,24] As we consider e-gasoline as carbon-neutral in terms of combustion, all CO_2 emissions are allocated to the industrial process. The credit for the captured CO_2 is allocated entirely to the purchaser of CO_2, with no implicit emission benefit granted to the capture site.

Energy use for CO_2 capture and compression depends on the CO_2 source and the concentration. For industrial sources, high-concentration CO_2 sources (*e.g.*, natural gas processing) require less electricity than low-concentration CO_2 sources (*e.g.*, natural gas combined cycle power plants) (∼100 *versus* ∼330 kWh per t CO_2).[27] These numbers are indicative, but the exact values vary depending on the flue gas stream and the capture technology. DAC requires not only electricity (150–720 kWh per t CO_2) but also heat (3.4–15 GJ per t CO_2) to release concentrated CO_2.[27,56,57,59] The wide range of values derives from the various approaches (liquid solvent approach or solid sorbent approach) and the extent of heat integration.[27,56,57,59] We utilize energy consumption data for capturing industrial flue gas and DAC from the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model 2022.[27] For industrial sources, we adopt data based on the use of the methyl diethanolamine (MDEA) CO_2 removal process to capture flue gas from natural gas combined cycle power plants,[60] which have been reported to have high carbon capture potential[53] and projected to remain a major non-renewable electricity source in the U.S.[6] For DAC, we adopt data on low-temperature adsorption-based DAC (solid sorbent approach) under current status as future technological improvements are uncertain and its temperature requirement (<100 °C)[61] can be addressed by most renewable heat technologies, including solar thermal energy.[62] The electricity demand for CO_2 compression is calculated using the thermodynamic compression formula in ref. 60 and the outlet pressure is set to the default value of 2219 psia in GREET 2022.[27] The choice of energy sources, especially the heat sources used in carbon capture, impacts the GHG emissions of e-fuels.[22] Natural gas is a common heat source for DAC, while low-GHG electricity, industrial waste heat, solar thermal energy, and nuclear power are potentially less GHG-intensive sources.[22,24] We consider three electricity sources (2022 U.S. grid electricity, solar PV, and wind power) and two heat sources

Table 1 E-gasoline production scenarios modeled in fuel-level LCA

#	Scenario[a]	Production pathway	CO_2 source[b]	Electricity source[c]	Heat source[d]
1	FT-ELE-DAC + GRID + NG	FT + electrolysis	DAC	U.S. grid	Natural gas
2	FT-ELE-DAC + PV + NG	FT + electrolysis	DAC	Solar PV	Natural gas
3	FT-ELE-DAC + WIND + NG	FT + electrolysis	DAC	Wind	Natural gas
4	FT-ELE-DAC + PV + ST	FT + electrolysis	DAC	Solar PV	Solar thermal energy
5	FT-ELE-DAC + WIND + ST	FT + electrolysis	DAC	Wind	Solar thermal energy
6	FT-ELE-IND + GRID + NA	FT + electrolysis	IND	U.S. grid	NA
7	FT-ELE-IND + PV + NA	FT + electrolysis	IND	Solar PV	NA
8	FT-ELE-IND + WIND + NA	FT + electrolysis	IND	Wind	NA
9	FT-COE-DAC + GRID + NG	FT + co-electrolysis	DAC	U.S. grid	Natural gas
10	FT-COE-DAC + PV + NG	FT + co-electrolysis	DAC	Solar PV	Natural gas
11	FT-COE-DAC + WIND + NG	FT + co-electrolysis	DAC	Wind	Natural gas
12	FT-COE-DAC + PV + ST	FT + co-electrolysis	DAC	Solar PV	Solar thermal energy
13	FT-COE-DAC + WIND + ST	FT + co-electrolysis	DAC	Wind	Solar thermal energy
14	FT-COE-IND + GRID + NA	FT + co-electrolysis	IND	U.S. grid	NA
15	FT-COE-IND + PV + NA	FT + co-electrolysis	IND	Solar PV	NA
16	FT-COE-IND + WIND + NA	FT + co-electrolysis	IND	Wind	NA
17	MTG-ELE-DAC + GRID + NG	MTG + electrolysis	DAC	U.S. grid	Natural gas
18	MTG-ELE-DAC + PV + NG	MTG + electrolysis	DAC	Solar PV	Natural gas
19	MTG-ELE-DAC + WIND + NG	MTG + electrolysis	DAC	Wind	Natural gas
20	MTG-ELE-DAC + PV + ST	MTG + electrolysis	DAC	Solar PV	Solar thermal energy
21	MTG-ELE-DAC + WIND + ST	MTG + electrolysis	DAC	Wind	Solar thermal energy
22	MTG-ELE-IND + GRID + NA	MTG + electrolysis	IND	U.S. grid	NA
23	MTG-ELE-IND + PV + NA	MTG + electrolysis	IND	Solar PV	NA
24	MTG-ELE-IND + WIND + NA	MTG + electrolysis	IND	Wind	NA

[a] Scenarios are named according to the following rule: "production pathway" – "CO_2 source" + "electricity source" + "heat source". FT = Fischer–Tropsch; MTG = methanol-to-gasoline; ELE = electrolysis-based production pathway; COE = co-electrolysis-based production pathway; DAC = direct air capture; IND = post-combustion industrial flue gas; GRID = 2022 U.S. grid electricity; PV = solar PV; WIND = onshore wind power; NG = natural gas; ST = solar thermal energy; NA = not applicable. [b] For CO_2 sources, DAC CO_2 is CO_2 captured from the atmosphere by the low-temperature adsorption-based approach, while IND CO_2 is CO_2 captured from the post-combustion flue gas from natural gas combined cycle power plants through the methyl diethanolamine (MDEA) approach. [c] For each scenario, the electricity source is assumed to be the same for all production steps (*i.e.*, electrolysis/co-electrolysis, carbon capture & compression, syngas production, Fischer–Tropsch and methanol-to-gasoline processes). [d] External heat is only consumed for DAC but not for capturing industrial flue gas. NA = not applicable.

(natural gas and solar thermal energy) for carbon capture (both industrial flue gas and DAC) to explore their impacts on the GHG intensity of e-gasoline.

2.1.3 E-gasoline production scenarios in fuel-level LCAs. Fuel-level LCAs are conducted under 24 scenarios generated by combining variations in the production pathway, electricity source, and heat source, as described in the preceding sections (Table 1). We use several example energy sources as representatives of low- and high-GHG electricity and heat sources and do not intend to represent specific scenarios (see Table 2 Note c). We adopt three combinations of electricity and heat sources: (1) high-GHG electricity (2022 U.S. grid electricity) with high-GHG heat (natural gas); (2) low-GHG electricity (solar PV or wind) with high-GHG heat (natural gas); and (3) low-GHG electricity (solar PV or wind) with low-GHG heat (solar thermal energy). These combinations allow us to explore the impact on GHG emissions at each life cycle stage of switching from high- to low-GHG energy sources.

2.1.4 Data sources. Parameters, values, and sources for the fuel-level LCAs are shown in Table 2. Most of the default mass and energy balance parameters related to direct e-gasoline production (*i.e.*, electrolysis, syngas production, methanol synthesis, FT process, and MTG process) are obtained from Soler *et al.*[21] to ensure pressure and molar ratios of the inputs and outputs match across reaction steps. Alternate data sources for mass and energy balances[21–23,27] are analyzed as part of a sensitivity analysis (see methods in ESI Section 2.1† with results shown as error bars and discussed further in "Section 3.4 Sensitivity analysis" and ESI Section 3.3†). With the recognition of co-products from FT and MTG processes, we apply energy allocation to obtain values for e-gasoline. We assume the embodied emissions of onshore wind electricity and solar PV electricity across all technologies are constant from 2020 to 2050 due to the lack of projections. Although we acknowledge variations in the reported embodied emissions across technologies,[63–65] these variations are relatively small when

Table 2 Default fuel-level LCA parameters modeled in the study[a]

Parameter		Unit	Value	References
Lower heating value of e-gasoline		MJ/kg	43.1	21
Lower heating value of e-gasoline		MJ/L	30.9	27
GHG emission intensity of conventional gasoline		g CO_2-eq/MJ LHV	91	27
Emission factor of 2022 U.S. grid electricity[b]		g CO_2-eq/kWh	438	27,66
Emission factor of electricity from solar PV[c]		g CO_2-eq/kWh	39.2	27
Emission factor of electricity from wind power[c]		g CO_2-eq/kWh	10.4	27
Emission factor of heat supply from natural gas		g CO_2-eq/MJ heat	75.4	22
Emission factor of heat supply from solar thermal energy		g CO_2-eq/MJ heat	0.251	22
CO_2 capture & compression	Industrial flue gas capture: electricity consumption	kWh/kg CO_2	0.34	27
	Industrial flue gas capture: external heat consumption	MJ/kg CO_2	0	27
	DAC: electricity consumption	kWh/kg CO_2	0.72	27
	DAC: external heat consumption	MJ/kg CO_2	14.88	27
H_2 production	AEL: electricity consumption	kWh/kg H_2	50	21
	PEM: electricity consumption	kWh/kg H_2	48	42
Syngas production	RWGS: electricity consumption	kWh/kg CO	0.14	21
	RWGS: H_2 consumption	kg/kg CO	0.07	21
	RWGS: CO_2 consumption	kg/kg CO	1.57	21
	SOEC: electricity consumption	kWh/kg syngas ($CO : H_2 = 7.3$ by mass)	7.91	21
	SOEC: CO_2 consumption	kg/kg syngas ($CO : H_2 = 7.3$ by mass)	1.38	21
Methanol synthesis	Electricity consumption	kWh/kg MeOH	0.276	21
	H_2 consumption	kg/kg MeOH	0.192	21
	CO_2 consumption	kg/kg MeOH	1.4	21
FT process	CO consumption	kg/kg e-gasoline	2.41	21
	H_2 consumption	kg/kg e-gasoline	0.33	21
	Electricity consumption	kWh/kg e-gasoline	0.193	21
MTG process	Electricity consumption	kWh/kg e-gasoline	0.196	21
	MeOH consumption	kg/kg e-gasoline	2.28	21
	H_2 consumption	kg/kg e-gasoline	0.001	21
E-gasoline transportation & distribution	GHG emissions	kg CO_2-eq/kg e-gasoline	0.01	27

[a] LHV: lower heating value; PV: photovoltaic; DAC: direct air capture; AEL: alkaline electrolysis; PEM: proton exchange membrane; RWGS: reverse water gas shift; SOEC: solid oxide electrolyzer cell; FT: Fischer–Tropsch; MTG: methanol-to-gasoline; MeOH: methanol. [b] U.S. electricity grid emissions factors estimated by using the emission factors of electricity from different sources in GREET 2022 and annual projected grid mix through 2050 in the Annual Energy Outlook (AEO) 2022.[27,66] [c] We did not distinguish emission factors across sub-technologies of solar PV and wind power as the variations are relatively small when compared to emissions from U.S. grid electricity. We also note that there is substantial variability in the estimated intensity of low GHG sources; thus, although we draw emission factors from GREET 2022 based on solar PV and wind, these should be treated primarily as generic representations of low and ultra-low GHG power sources.

compared to emissions from U.S. grid electricity, resulting in minor impacts.

2.2 Vehicle-level LCA

2.2.1 Functional unit and system boundary. The functional unit of the vehicle-level LCAs is one vkt. The system boundary includes e-gasoline production modeled in the fuel-level LCAs and vehicle-related life stages (material extraction, vehicle manufacture, vehicle use, and vehicle disposal). The emissions associated with constructing and decommissioning necessary infrastructure (*e.g.*, roads, highways, transmission lines, and refineries) are excluded – except for embodied emissions from electricity generating facilities, as infrastructure represents a larger share of emissions in renewable energy production.

2.2.2 Approach and data sources. Vehicle-level LCAs are conducted using the vehicle, automotive material flow, and LCA modules in the FLAME model. FLAME is a fleet-based life cycle model that simulates vehicle fleet turnover as a function of time and the associated life cycle GHG emissions.[40] The model and data sources are described in ref. 40 and 5. The vehicle-level LCAs consider two vehicle size categories (car and light truck), four technology categories (ICEV-G, BEV, PHEV, and HEV), and three fuel types (conventional gasoline, electricity, and e-gasoline). The vehicle-level LCAs in this paper use vehicles of model year 2022 with a 15-year lifetime.[5] The lifetime distance traveled is assumed to be 278 660 km for a car and 295 094 km for a light truck.[5] E-gasoline production is added to FLAME in this study and the parameters and assumptions are drawn from the fuel-level LCAs described in "Section 2.1 Fuel-level LCA". We assume that 1 L of e-gasoline replaces 1 L of conventional gasoline, and thus the fuel economy for ICEVs, PHEVs, and HEVs using both these fuels is the same. This assumption is reasonable because the lower heating values (LHV) of the fuels are similar (conventional gasoline: 31.3 MJ per L;[27] e-gasoline 29.2–30.9 MJ per L (ref. 9 and 27)) and overall there is real-world variation in the LHV of both fuels.

2.3 Fleet-level LCA

2.3.1 Functional unit and system boundary. The functional unit of the fleet-level LCAs is the transport services provided by the U.S. LDV fleet. The system boundary includes fuel and vehicle-related life cycle stages of all LDVs in the U.S. from 2020 to 2050. The emissions associated with constructing and decommissioning necessary infrastructure (*e.g.*, roads, highways, transmission lines, e-fuel production facilities, and refineries) are excluded from the analysis.

2.3.2 E-gasoline production scenarios in fleet-level LCAs. Fleet-level LCAs are conducted under four scenarios generated by combining variations in the e-gasoline production pathways and energy sources (Table 3). The fleet-level analysis selects FT-gasoline as the e-gasoline because the fuel-level LCAs show that the GHG intensities of MTG-gasoline are close to those of FT-gasoline produced *via* co-electrolysis-based production pathways (see "Section 3.1.1 Fuel-level GHG emissions"). The scenarios are based on using DAC for capturing CO_2 as e-gasoline produced from DAC-based CO_2 is less controversial for assuming carbon-neutral combustion and is more consistent with meeting future climate targets.[54] We select scenarios using both the mature production pathway (FT + electrolysis) and the more advanced prospective pathway (FT + co-electrolysis). For each case, we use wind power and solar thermal heat and solar PV power and solar thermal heat as the representatives of best- and mid-case inputs, respectively. These scenarios are optimistic (low-GHG energy sources) as e-gasoline is generally not viable as a mitigation option under higher emitting cases (*e.g.*, those using natural gas for heat or the U.S. grid for electricity). The results and discussion focus on the mature production pathway (FT + electrolysis) with the best-case energy input (wind power and solar thermal heat), and results for the remaining scenarios are shown in the ESI.† The fleet-level analysis from 2020–2050 employs the same set of parameters for e-gasoline production as the fuel-level analysis for the same timeframe. These parameters are set based on studies that represent the near-term state of the technology. A static representation, although a limitation, is adopted due to the lack of data needed for more precise projections.

2.3.3 BEV deployment scenarios. The number of ICEVs, PHEVs, and HEVs (*i.e.*, vehicles that can use e-gasoline) in the LDV fleet through 2050, their fuel consumption and vkt determine the required volume of e-gasoline. A major factor related to the number of these vehicles is the deployment level of BEVs

Table 3 E-gasoline production scenarios modeled in the fleet-level LCAs in the FLAME model[a]

No	Fleet-level scenario[b]	E-gasoline production scenario[c,d]
1	Mature production pathway best-case	FT-ELE-DAC + WIND + ST
2	Mature production pathway mid-case	FT-ELE-DAC + PV + ST
3	Advanced production pathway best-case	FT-COE-DAC + WIND + ST
4	Advanced production pathway mid-case	FT-COE-DAC + PV + ST

[a] FLAME model: fleet life cycle assessment and material-flow estimation model. [b] Scenarios named "Mature production pathway" are represented by the electrolysis-based production pathway (Fischer–Tropsch + electrolysis), while scenarios named "Advanced production pathway" are represented by the co-electrolysis-based production pathway (Fischer–Tropsch + co-electrolysis). The "best-case" and "mid-case" are the scenarios with the lowest and median GHG intensities, respectively, under each combination of e-gasoline type, production pathway, and CO_2 sources. [c] E-gasoline production scenarios are named using the following rule: "production pathway" – "CO_2 source" + "electricity source" + "heat source". FT = Fischer–Tropsch; ELE = electrolysis-based production pathway; COE = co-electrolysis-based production pathway; DAC = direct air capture; PV = solar PV; WIND = onshore wind power; ST = solar thermal energy. [d] For each scenario, the electricity source is the same for all production steps (*i.e.*, electrolysis/co-electrolysis, carbon capture, syngas production, and Fischer–Tropsch process).

in the fleet. This study constructs three BEV deployment scenarios: (1) business-as-usual deployment of BEVs and charging BEVs and PHEVs with U.S. grid electricity (BAU BEV with U.S. grid). This is represented by the AEO 2022 reference case, where the share of BEVs in LDV sales is projected to increase from 1% in 2022 to 10% in 2050[66] and the grid follows AEO 2022 reference case projections; (2) 100% new BEV sales by 2035 and charging with U.S. grid electricity (high BEV with U.S. grid); and (3) 100% new BEV sales by 2035 and charging with renewable electricity (high BEV with RE). The high deployment level of BEVs is adapted from California's 100% new zero-emission vehicle sales by 2035 strategy.[67] Renewable electricity is assumed to come from onshore wind electricity or solar PV electricity. For the high BEV with RE scenario, the same renewable electricity source is assumed for producing e-gasoline and charging BEVs and PHEVs. As we focus on the interactions between BEVs and e-fuels, PHEV deployment is assumed to be the same (less than 2% of vehicle sales) across scenarios. The vehicle sales and stock by technology from 2020 to 2050 are shown in ESI Section 3.6.†

2.3.4 Approach and data sources. The fleet-level GHG emissions are estimated using FLAME's fleet module combined with its vehicle, automotive material flow, and LCA modules. The version of FLAME used in this study focuses on the U.S. LDV fleet from 2015 to 2050. It simulates fleet size and composition, projected changes in the electric grid, improvements in vehicle fuel efficiency, material flow, and availability of secondary materials, along with other fleet characteristics and dynamics as outlined in ref. 5. The fleet-level LCAs consider two vehicle categories (car and light truck) and 10 technology categories (*e.g.*, ICEV-G, ICEV-D, BEV, or PHEV – each with multiple electric drive ranges). The model considers the six original fuel types (gasoline modeled as E10, diesel, E85, compressed natural gas & liquefied petroleum gas, hydrogen, and electricity) in FLAME and is updated in this study to include e-gasoline. The characteristics of the 2021 model-year vehicles from ref. 68 are also updated in FLAME and the model is updated with AEO 2022 (ref. 66) data including total LDV stock, total new LDV sales, LDV technology market shares in new sales, and national electricity mixes between 2021 and 2050.

2.4 CO_2 emission budgets to meet climate change targets

We adopt cumulative CO_2 emission budgets of 26 Gt and 33 Gt CO_2 for the U.S. LDV fleet from 2015 to 2050 (Fig. 3), which are consistent with climate targets of 1.5 and 2 °C above pre-industrial levels, respectively. These budgets are quantified using methods developed in our prior work,[69] which are based on global carbon emission pathways developed using Integrated Assessment Models (IAMs).[70] This study pairs CO_2 emission budgets from IAMs with GHG emissions (consolidated as CO_2-eq using 100-year global warming potentials, GWPs) from the LDV fleet for the LDV sectoral targets and backcasting analysis. As previously explained, most of our results are presented from 2020–2050, but are based on the full budget from 2015–2050, subtracting historical emissions from 2015–2020. Further details on the calculation methods and comparison with budgets in our prior work[5] are provided in ESI Section 2.3.†

2.5 Backcasting to estimate required volumes of e-gasoline to bridge mitigation gaps

To estimate the required volumes of e-gasoline to bridge the mitigation gaps, we use the backcasting module in FLAME.[5]

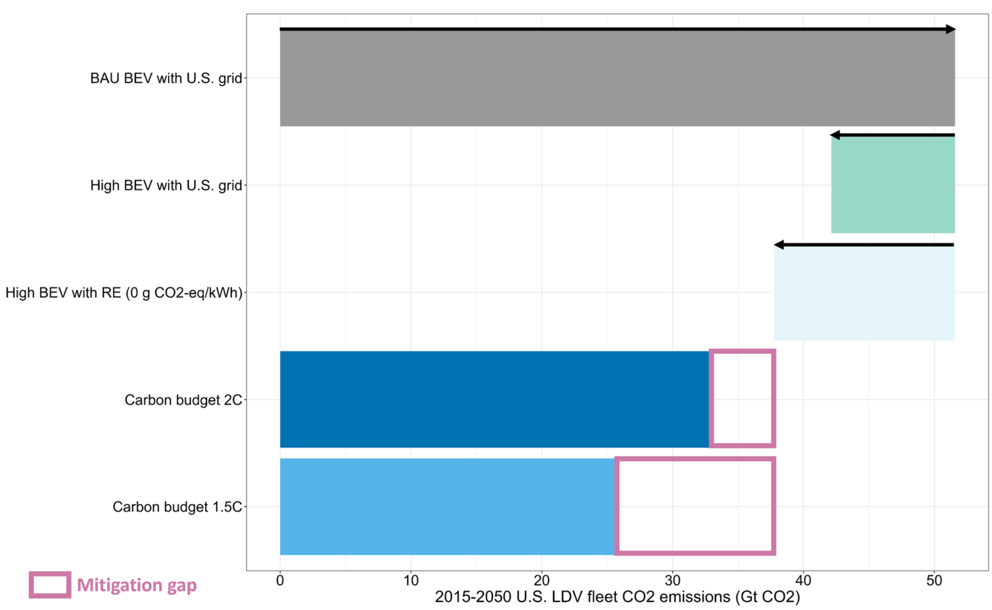

Fig. 3 2015–2050 U.S. light-duty vehicle (LDV) fleet cumulative greenhouse gas emissions *versus* CO_2 emission budget under prospective future development. The renewable electricity in this figure is assumed to have zero embodied GHG emissions. The top three bars are reported as CO_2-eq as they result from FLAME, which reports CO_2 and non-CO_2 GHGs, while the carbon budgets (bottom two bars) are reported as CO_2 as they result from emission budgets of integrated assessment models that are reported as CO_2 (see ESI Section 2.3† for details).

This study assumes that the percentage of e-gasoline in the conventional gasoline pool increases from 0% to 100% with a linear annual growth rate starting in 2022. The maximum percentage of 100% e-gasoline in the pool allows us to explore the maximum mitigation potential of e-gasoline in the fleet and the complete phase-out of fossil fuels. The starting year of 2022 is selected as the first e-gasoline pilot project began production in 2022.[19] The fleet-level cumulative GHG emissions from the U.S. LDV fleet can be expressed as a function of the annual e-gasoline growth rate. By applying a search-and-try process constrained by the U.S. LDV emission budgets, we obtain the minimum annual e-gasoline growth rate, which is then transformed into the annual required volume of e-gasoline. The volume is then used to estimate the required industry growth rate and demands for feedstock, energy, and critical materials as described in 2.6.

To better understand these growth rates, we compare them with historical growth rates of the oil refining, biodiesel, and ethanol industries in the U.S. as well as with unconventional (very high) growth rates (*e.g.*, World War II U.S. liberty ship deployment) in terms of emergence growth rates. The emergence growth rate is the maximum annual growth rate after the formative phase of the industry, which reflects the steepness of the logistic growth curve.[71] It has been used as a unitless metric to measure how technology diffuses from the formative phase to the saturation phase.[71] Although the demand for e-gasoline resulting from our model may not follow a logistic growth curve, the use of the emergence growth rate concept provides a basis for comparison against historical case studies (more in ESI Section 2.4†).

2.6 Demand for critical materials to produce e-gasoline for the U.S. LDV fleet

We consider critical material use in three water electrolysis technologies, six wind power technologies, and four solar PV technologies for producing e-gasoline under various scenarios. Critical material use for other stages is excluded due to the lack of data and lower supply chain concerns (*e.g.*, carbon capture[72]). There are 13 critical materials for water electrolyzers (aluminum, cobalt, gadolinium, iridium, lanthanum, manganese, nickel, platinum, samarium, strontium, titanium, yttrium, and zirconium), eight critical materials for wind electricity generation (aluminum, dysprosium, manganese, molybdenum, neodymium, nickel, praseodymium, and terbium), and nine critical materials for solar PV electricity generation (aluminum, cadmium, gallium, germanium, indium, selenium, silicon, silver, and tellurium) included in the study. The selection of materials is based on the literature on critical materials for each technology[39,73–79] and the critical material list published by the United States Geological Survey (USGS) in 2021.[80] We do not include critical materials used in vehicle components but compare the material demand from e-gasoline production with that of battery manufacturing under high BEV deployment scenarios using results from Tarabay *et al.*[81] We apply dynamic material flow analysis (MFA) to estimate the annual and cumulative demand for critical materials. We generate multiple scenarios based on market shares of technologies and assumptions regarding material recovery. Further details on the MFA are provided in ESI Section 2.5–2.7.†

3. Results & discussion

3.1 Key parameters that make e-gasoline competitive for GHG mitigation

3.1.1 Fuel-level GHG emissions. The fuel-level GHG emissions intensities range from 6–385 g CO_2-eq per MJ for FT-gasoline and 6–338 g CO_2-eq per MJ for MTG-gasoline, depending on the energy source and production pathway (Fig. 4). The higher ends of the ranges for FT- and MTG-gasoline are associated with the electrolysis-based production pathways using CO_2 from DAC and powered by 2022 U.S. grid electricity and natural gas heat. The lower ends of the FT- and MTG-gasoline ranges are associated with using CO_2 captured from industrial flue gas and powered by wind electricity under the co-electrolysis-based and electrolysis-based production pathway, respectively. These wide ranges can primarily be attributed to variations in energy sources, particularly electricity sources. All FT-gasoline and MTG-gasoline pathways that use 2022 U.S. grid electricity (438 g CO_2-eq per kWh) have much higher emissions than petroleum-derived gasoline (91 g CO_2-eq per MJ). All DAC pathways that use natural gas as the heat source have emissions similar to or higher than those of petroleum-derived gasoline. Higher GHG emissions in the electrolysis-based pathway are due to the lower efficiency of AEL compared to the SOEC technology; likewise, DAC pathways demonstrate higher GHG emissions compared to industrial CO_2 capture, due to higher heat and electricity consumption. MTG–gasoline results are similar to co-electrolysis-based FT-gasoline pathways due to similar reaction efficiencies.

As detailed in ESI Section 3.1,† our results generally fall within the ranges reported in the literature, with most variations due to differences in the assumed electricity mix and associated emissions; some key sources (*e.g.*, GREET 2022[27]) show higher emissions owing to higher H_2 and CO_2 input assumptions for the RWGS reaction. Such differences are explored in "Section 3.4 Sensitivity analysis".

When U.S. grid electricity powers e-gasoline production, over 60% of fuel-level GHG emissions of e-gasoline are associated with electricity generation for electrolysis (or co-electrolysis), due to the high electricity demand from these processes. The remaining GHG emissions result mainly from carbon capture, especially emissions from heat generation from natural gas to power DAC in those pathways that include DAC. Employing low-GHG electricity for the electrolysis (or co-electrolysis) stage and a low-GHG heat source for DAC are generally necessary and sufficient conditions for e-gasoline to have lower GHG emission intensity than conventional gasoline. To be competitive with conventional gasoline, the electricity GHG intensity for electrolysis (or co-electrolysis) must be lower than 100–121 g CO_2-eq per kWh (ESI Section 3.2†) when 2022 U.S. grid electricity is used for all other processes and DAC is heated with solar thermal energy. These break-even electricity GHG intensities increase to 139–159 g CO_2-eq per kWh when we account for

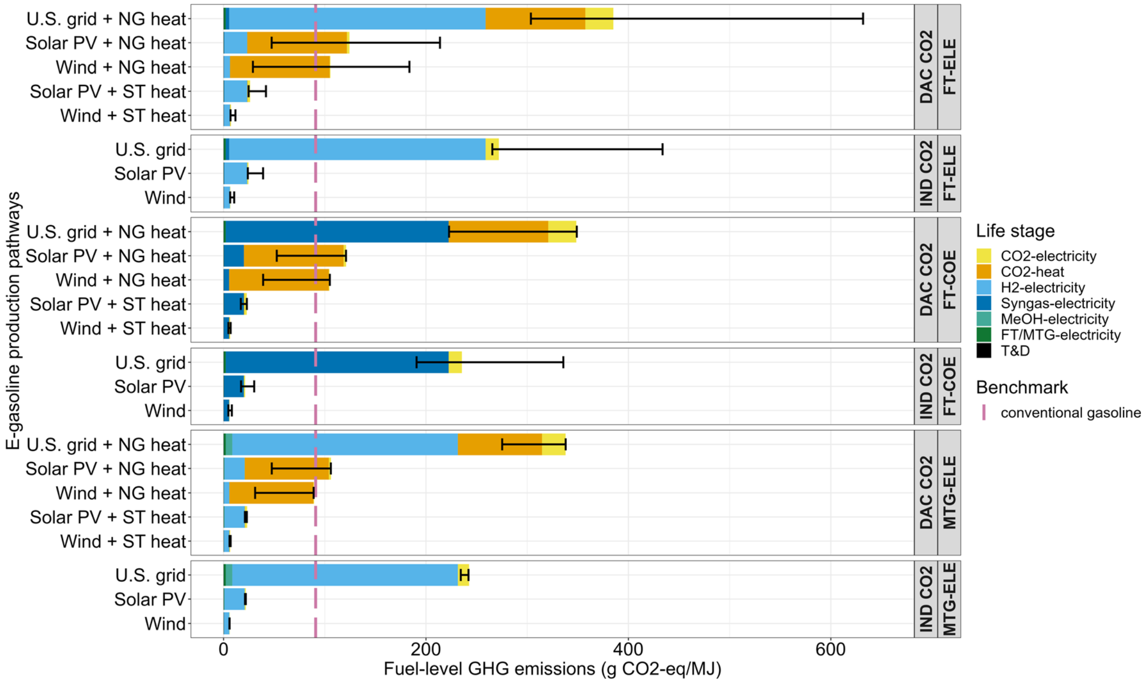

Fig. 4 Fuel-level (well-to-wheel) GHG emission intensity of e-gasoline produced from various production pathways and conventional petroleum-derived gasoline. For energy sources on the *y*-axis, the first is the electricity source for all stages of e-gasoline production, while the second is the heat source for direct air capture (DAC) as industrial carbon capture does not require external heat. Emissions for e-gasoline include emissions from carbon capture, water electrolysis or co-electrolysis, syngas production, methanol synthesis, Fischer–Tropsch (FT) process, and methanol-to-gasoline (MTG) process. No direct emissions are assumed from the combustion of e-gasoline. Life cycle GHG emission intensity from conventional gasoline is 91 g CO_2-eq per MJ,[27] which includes emissions from fuel production and fuel combustion during vehicle use. The emission factor of U.S. grid electricity is 438 g CO_2-eq per kWh for 2022. Error bars represent results using mass and energy balance from other data sources (details in ESI Sections 2.1 and 3.3†). ELE: electrolysis; COE: co-electrolysis; NG: natural gas; ST: Solar thermal; DAC: Direct Air Capture CO_2; IND: Industrial flue gas CO_2; T&D: Transportation & Distribution.

emissions from electricity used across the entire e-gasoline production chain (Fig. 5). The lower and upper ends of the range are associated with electrolysis- and co-electrolysis-based production pathways for FT-gasoline, respectively. They are close to previously reported break-even values of 144 g CO_2-eq per kWh (ref. 24) or 116 g CO_2-eq per kWh (ref. 10) (electrolysis + DAC with no heat input) and 143 g CO_2-eq per kWh (ref. 10) (co-electrolysis + DAC with no heat input) between FT-fuels and conventional diesel. These break-even electricity GHG intensities are lower than U.S. grid electricity emission intensity in 2022 (438 g CO_2-eq per kWh) and the projection by AEO 2022 for 2050 (316 g CO_2-eq per kWh),[27,66] indicating that e-gasoline produced using the projected U.S. grid would not mitigate GHG emissions compared to petroleum-derived gasoline.

3.1.2 Vehicle-level GHG emissions. Vehicle-level GHG emissions from using e-gasoline in ICEVs, PHEVs, and HEVs are dominated by emissions related to e-gasoline production (no emissions are assumed from e-gasoline combustion); embodied emissions from vehicle manufacturing and disposal are minor contributors when e-gasoline is produced from high GHG energy sources (ESI Section 3.4†). Whether vehicle-level GHG emissions from using e-gasoline in ICEVs, PHEVs, and HEVs can compete with those of BEVs depends on the well-to-wheel efficiency and the GHG intensity of the electricity used for charging and/or for producing fuels.

Well-to-wheel efficiency estimates energy losses during fuel production, fuel transportation & distribution, vehicle fueling, and fuel combustion during vehicle use.[82] The higher well-to-wheel efficiency of BEVs (estimated as 64%) compared to those of HEVs or ICEVs-G using e-gasoline based on the various production processes (6–11% and 5–10%, respectively) (methods in ESI Section 2.2† and results in ESI Section 3.5†) indicates that e-gasoline is not an efficient way to 'electrify' LDVs. The low efficiencies of the e-gasoline vehicles result from the energy-intensive fuel production processes and the low vehicle efficiencies. The results presented in this section and shown in Fig. 5 are for cars, but results follow similar trends for light trucks. During fuel production and vehicle use phases, an ICEV-G using e-gasoline uses 1.3–1.6 kWh of electricity per vkt, while a BEV300 uses 0.21 kWh of electricity per vkt. If electricity from the same source is used for charging BEVs and producing e-gasoline, a BEV300 would have lower life cycle GHG emissions than an e-gasoline ICEV-G unless the electricity emission factor (for both BEV charging and e-fuel production) falls below 13–18 g CO_2-eq per kWh. This occurs when the higher embodied emissions from manufacturing and disposing of BEVs compared to ICEVs-G (38 g CO_2-eq per vkt *vs.* 19 g CO_2-eq per vkt (ref. 5)) become a more significant relative contributor to total emissions when very low GHG electricity is used for fuel production. This scenario, however, is not realistic as it is

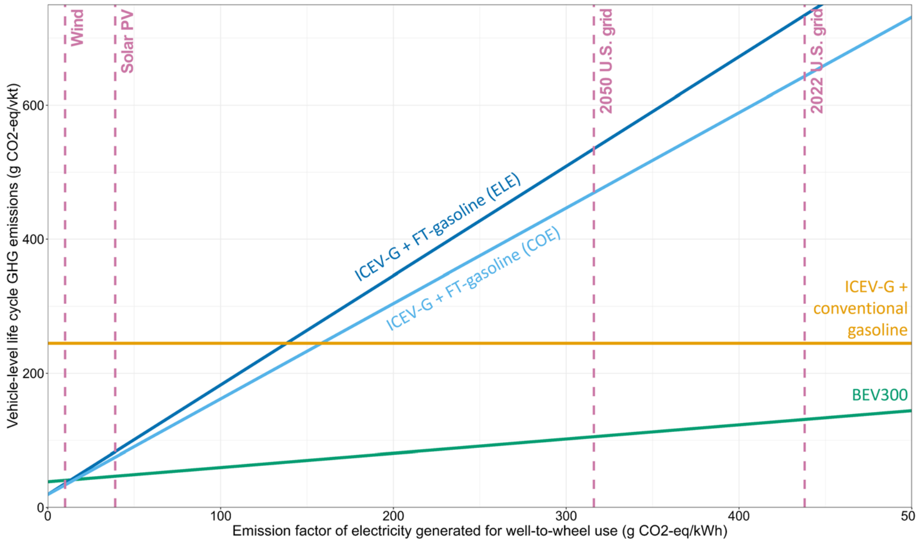

Fig. 5 Vehicle-level GHG emissions for different vehicle technologies (cars) and fuels produced from various production pathways, shown as a function of the emission factor of electricity. The results are for cars only (no light trucks). The figure includes Fischer–Tropsch (FT) gasoline produced from two production pathways (ELE: Electrolysis and COE: Co-electrolysis) and direct air capture (DAC) CO_2 heated by solar thermal energy. FT-gasoline produced using industrial CO_2 is removed from the figure as it is very close to the production pathway of using DAC CO_2 heated by solar thermal energy. Vehicle-level GHG emissions include emissions from vehicle production, electricity generation, fuel production, vehicle use, and vehicle disposal. Contributions from each life stage are shown in ESI Section 3.4.† The emission factors of U.S. grid electricity are 438 g CO_2-eq per kWh for the year 2022 and are projected to be 316 g CO_2-eq per kWh by 2050.[27,66]

unlikely that fuel cycle GHG emissions would reach such low levels without an associated decrease in vehicle cycle emissions. More plausible, however, is a scenario in which BEVs are charged with the 2022 U.S. grid average, while e-gasoline is produced with off-grid renewables; in this case, the breakeven grid intensity for e-gasoline (FT-gasoline produced from CO_2 captured by DAC with solar thermal heat) is 68–78 g CO_2-eq per kWh.

3.2 Fleet-level analysis: bridging the mitigation gaps with e-gasoline

3.2.1 Demand for e-gasoline. Deploying low GHG intensity e-gasoline in the U.S. LDV fleet could contribute to bridging the mitigation gaps remaining after BEV deployment and facilitate meeting the 1.5 or 2 °C climate targets. We illustrate the potential of e-gasoline by presenting results for the case of FT-gasoline produced from the electrolysis-based production pathway using DAC CO_2 and powered by wind electricity and solar thermal heat (7 g CO_2-eq per MJ). This optimistic pathway combines the most mature e-fuel production pathway (electrolysis) with the most promising large-scale future supply of non-fossil CO_2 (DAC), and utilizes the lowest GHG energy supply (wind electricity and solar thermal heat) among the pathways we studied. We select the e-gasoline production scenario with the lowest GHG energy supply to demonstrate the maximum mitigation potential that e-gasoline can achieve. If it is found to be challenging or infeasible to bridge the mitigation gaps under these conditions, then the other higher GHG intensity options would not be viable. The results for the other e-gasoline production scenarios are discussed in "Section 3.4 Sensitivity analysis". Fig. 6 shows the annual end-use demand for different fuels and energy carriers in the U.S. LDV fleet required to meet 1.5 or 2 °C climate targets under the BEV deployment scenarios. Under all scenarios, demand for liquid fuel is projected to persist until 2050 due to the time required for fleet turnover. With the assumed linear growth rate, most scenarios require that e-gasoline eventually reaches a 100% share of the liquid fuel demand; thus, scenarios are more often differentiated by the year at which the 100% share is reached. Equivalent cumulative emissions can be reached through faster growth rates and lower ultimate shares, but this would (a) require faster industry growth and (b) would likely be incompatible with emission targets beyond 2050. For the low BEV deployment scenario (BAU BEV with U.S. grid), ICEVs-G would continue to represent over 79% of the U.S. LDVs stock during every year of the simulation from 2020–2050. To meet 1.5 and 2 °C climate targets, 100% of conventional gasoline needs to be replaced with e-gasoline by 2033 and 2047, respectively. In both cases, this results in a peak annual demand of 12.4 EJ (400 billion L) for e-gasoline in those respective years, close to 75% of 2022 motor gasoline consumption by the U.S. transportation sector.[83] In the high BEV deployment scenarios, the dominant vehicle technology would shift from ICEVs-G to BEVs during 2020–2050 and over 90% of the LDV fleet would be BEVs by 2050. In 2050, 0.84 EJ (27 billion L) of e-gasoline would be needed to bridge the mitigation gaps under the high BEV deployment scenarios, with the exception of the 2 °C high BEV with RE scenario, where the mitigation gap is small and most ICEVs-G could still use conventional gasoline. When BEV deployment is high but all BEVs and PHEVs are charged with U.S. grid electricity (high BEV with U.S. grid), the peak annual demands of 12 EJ in 2025 (390 billion L) and 4.6 EJ (150 billion

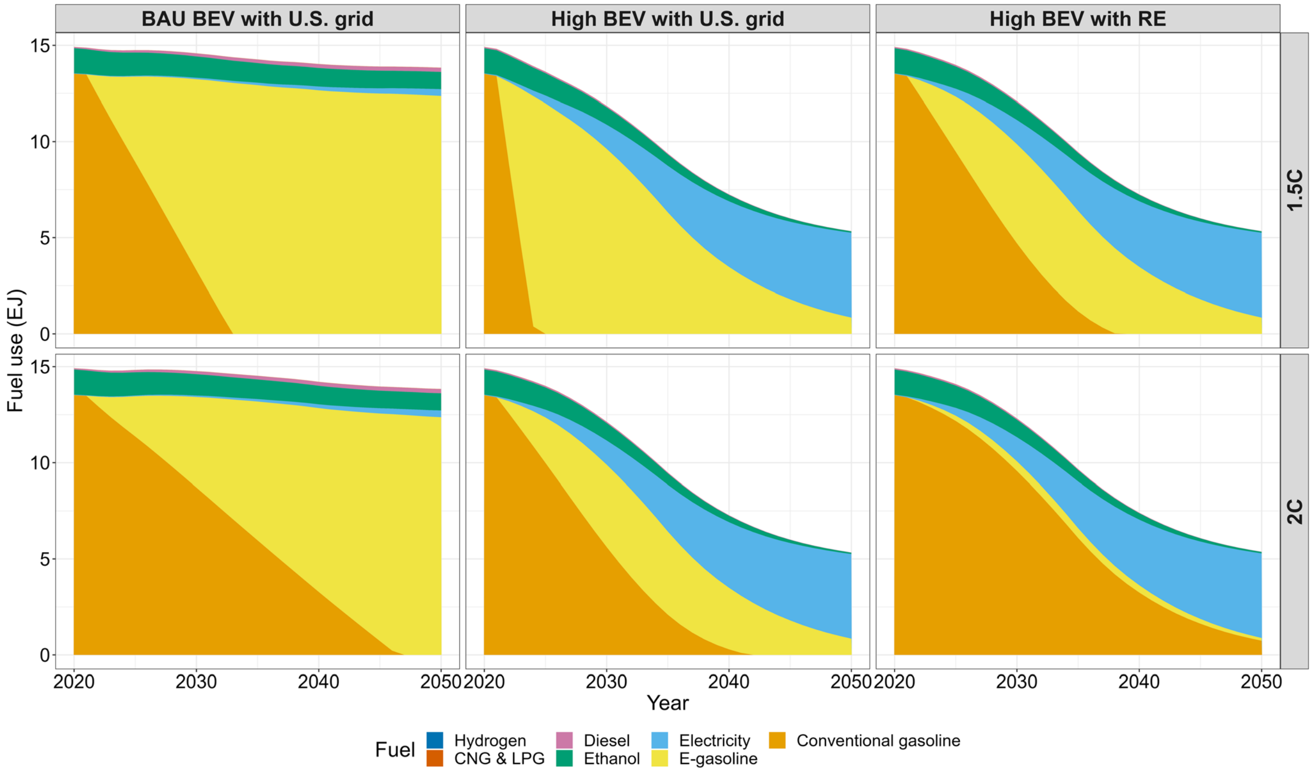

Fig. 6 2020–2050 annual end-use demand for fuels from the U.S. light-duty vehicle fleet under various scenarios to meet 1.5 or 2 °C climate targets. The values in the figure are for fuel and energy carriers used during the vehicle operation stage only. Energy used for fuel production is not included. These fleet-level results correspond to Fischer–Tropsch gasoline produced from the electrolysis-based production pathway using direct air capture CO_2 and powered by wind electricity and solar thermal heat. For other scenarios see ESI Section 3.7.†

L) in 2033 for e-gasoline are needed to meet 1.5 and 2 °C climate targets, respectively. Hence, bridging mitigation gaps with e-gasoline would require substantial production, especially when vehicles using conventional fuels dominate the fleet.

3.2.2 Required growth rate of e-gasoline to bridge the mitigation gaps. To supply sufficient e-gasoline to bridge the mitigation gaps, the e-gasoline industry would need to grow from essentially no production before 2022 to peak annual production with annual average growth rates of 0.48 EJ per year (16 billion L per year), 0.40 EJ per year (12 billion L per year), and 0.04 EJ per year (1.4 billion L per year) under the 2 °C scenarios of BAU BEV with U.S. grid, high BEVs with U.S. grid, and high BEVs with RE, respectively. As a reminder, these assume an optimistic e-gasoline emission profile; even faster growth would be required with higher GHG emission intensities.

These absolute growth rates are converted to percentage emergence growth rates (see Section 2.5 and ESI Section 2.4†) and compared with other historical industries in Fig. 7. To meet climate targets, the lower BEV deployment scenarios require emergence growth rates lower than 50% per year, which are comparable to those of U.S. biodiesel and ethanol production (but ethanol and biodiesel growth slowed before reaching the large volumes required in most of our e-fuel scenarios). The high BEV deployment scenarios require emergence growth rates higher than 77% per year, close to the rate of U.S. nuclear weapon deployment. Meeting the 1.5 °C climate target under the high BEV with U.S. grid scenario would require the highest emergence growth rate (480% per year), substantially higher than that of World War II U.S. liberty ship deployment. These results are due to the lower long-term mitigation potential of e-gasoline under high electrification because of the smaller number of remaining vehicles that can use e-gasoline. As BEVs powered by U.S. grid electricity have higher emissions than vehicles powered by e-gasoline produced from renewable energy, it would be more difficult for the fleet to reduce emissions in the long run under the high BEV with U.S. grid scenario. Therefore, emissions would need to be reduced more quickly in the short run, requiring the highest deployment rate of e-gasoline. Such rapid growth of the e-gasoline industry required to meet climate targets is likely unrealistic. The extreme growth rates required in some scenarios are particularly noteworthy considering the narrow focus of this analysis (*i.e.*, only U.S. LDVs); incorporating potential demand from other sectors (*e.g.*, aviation, marine shipping, and heavy-duty vehicles) could pose further challenges for both the speed of scale-up required and the associated resource use discussed in Section 3.2.3.

3.2.3 Demand for feedstock and renewable electricity for e-gasoline production. Demand for e-gasoline results in demand for feedstock (captured CO_2 and hydrogen) and renewable electricity, which may limit the feasibility of its large-scale deployment to bridge the mitigation gaps (Fig. 8). The

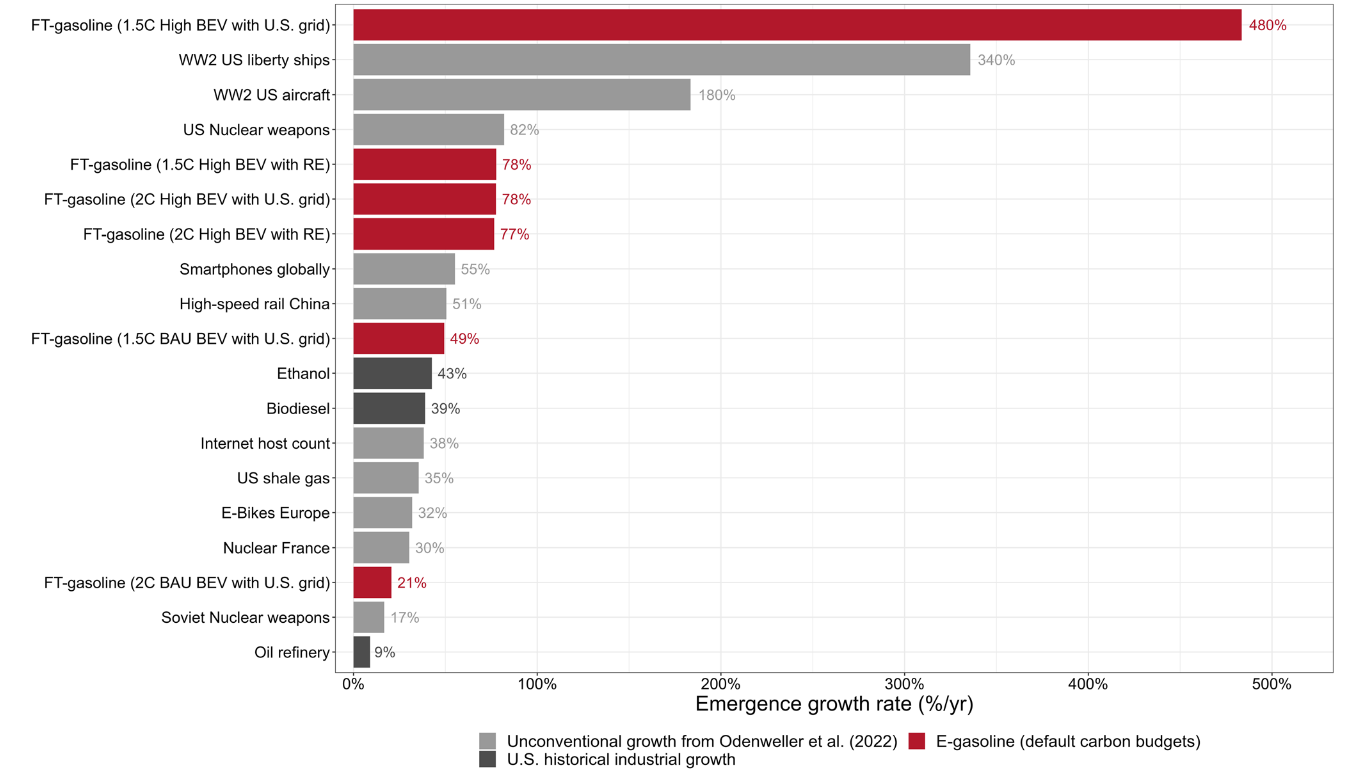

Fig. 7 Emergence growth rates of e-gasoline to meet 1.5 and 2 °C climate targets under various scenarios compared with historical industrial growth in the U.S. and examples of unconventional growth from the literature. These fleet-level results represent Fischer–Tropsch (FT) gasoline produced from the electrolysis-based production pathway using direct air capture CO_2 powered by wind electricity and solar thermal heat. Carbon budgets consistent with 1.5 and 2 °C climate targets are included. Data on U.S. historical industrial growth (oil refinery, biodiesel, and ethanol) are obtained from ref. 84 and 85. Data on unconventional growth is obtained from ref. 71. Methods for calculating emergence growth rates are provided in ESI Section 2.4.†

following discussion focuses on FT-gasoline produced *via* the electrolysis-based production pathway using DAC CO_2 and powered by wind electricity and solar thermal heat (results for other scenarios are provided in ESI Section 3.8†). Under the 2 °C BAU BEV with U.S. grid, high BEV with U.S. grid, and high BEV with RE scenarios, 1, 0.4, and 0.05 Gt per year of captured CO_2 would be required, respectively, in the peak production years (2047, 2033, and 2033). These peak demands could theoretically be met by the 1.6 Gt of CO_2 estimated to be available from all major U.S. sources in 2018.[53] However, the operational capture capacity in the U.S. in 2023 was only 0.022 Gt per year with only 2 kt from DAC.[37] The global capture capacity projected by the International Energy Agency (IEA) to be operating by 2030 is 0.44 Gt,[37] only sufficient to meet the 2 °C target under the most aggressive BEV deployment scenario (high BEV with RE). The global number is provided for context only, as large-scale imports of CO_2 are unlikely.

Under the 2 °C BAU BEV with U.S. grid, high BEV with U.S. grid, and high BEV with RE scenarios, the peak annual demand for electrolytic hydrogen to produce e-gasoline is 140, 53, and 6 Mt, respectively. These peak demands are 60–1400 times the 2020 U.S. electrolytic hydrogen production (0.1 Mt),[86] and two of three are higher than the 9 Mt per year from announced (as of 2023) U.S. low carbon H_2 projects (green and blue hydrogen) by 2030.[87] Assuming a focus on electrolytic hydrogen, the above demands would require newly installed capacities of 40, 36, and 4 GW per year on average before 2030 or cumulative newly installed capacities of 2000, 630, and 77 GW during 2022–2050, if AEL were the exclusive technology. Given that the 2030 planned global manufacturing capacity of water electrolyzers (based on existing announcements) is just over 130 GW per year,[88] 28–31% of this capacity would be required to produce hydrogen only for the U.S. LDV fleet when BEVs were charged with U.S. grid electricity. Considering the competitive demand for hydrogen in other sectors under net-zero strategies (*e.g.*, 34–66 Mt in 2050 according to ref. 30), securing hydrogen supply for e-gasoline production could be challenging.

To produce the required volumes of e-gasoline under the 2 °C BAU BEV with U.S. grid, high BEV with U.S. grid, and high BEV with RE scenarios, 8200, 3000, and 350 TWh of low-GHG electricity, respectively, would be needed in the peak years. In the case of wind, this would require the newly installed generating capacities of 99, 28, and 3.5 GW per year or the cumulative newly installed capacities of 2900, 800, and 100 GW during 2022–2050, assuming that the capacity factor increases from 0.44 in 2022 to 0.48 in 2050.[89] Under the less aggressive BEV deployment scenarios (BAU BEV with U.S. grid and high BEV with U.S. grid), these demands are 3 and 9 times the 2022 U.S.

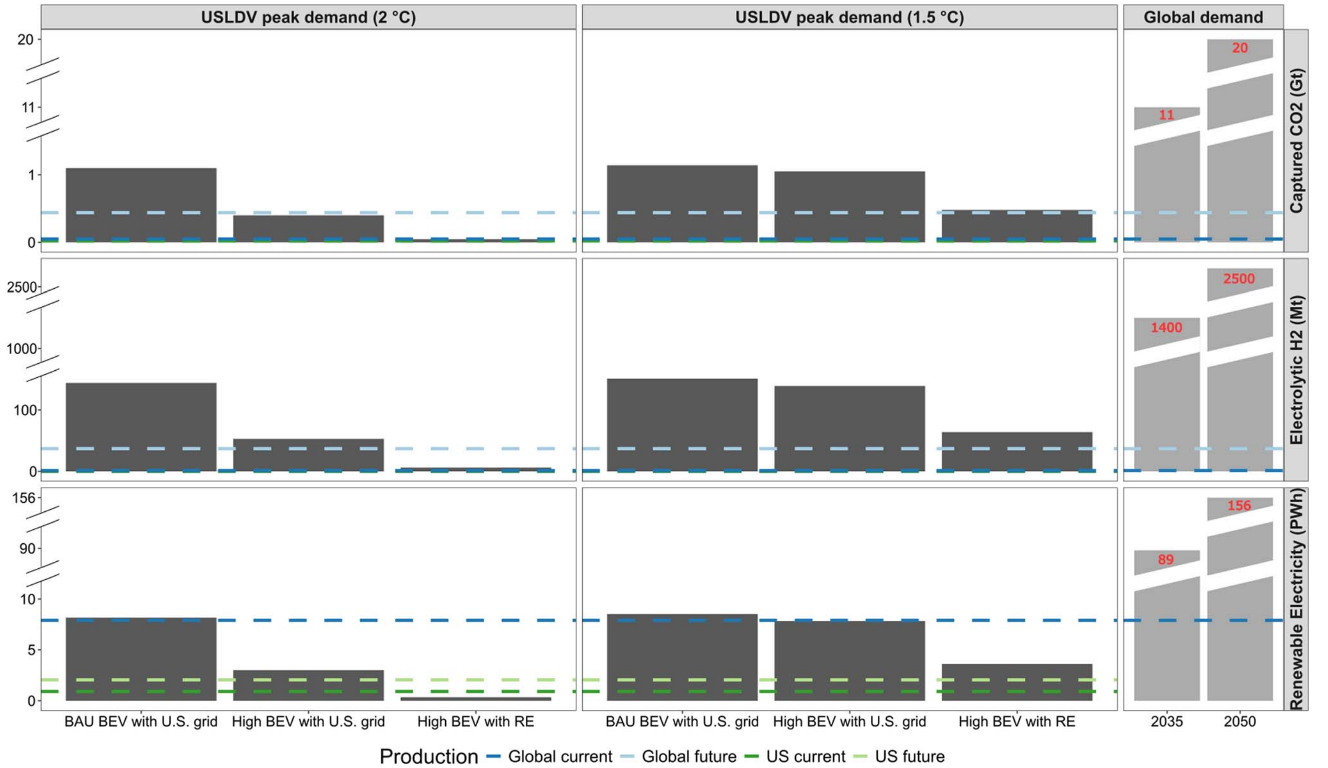

Fig. 8 Peak annual demand for e-gasoline feedstock and energy carriers for the U.S. LDV fleet to meet climate targets. These fleet-level results correspond to Fischer–Tropsch gasoline produced from the electrolysis-based pathway using direct air capture CO_2 and powered by wind electricity and solar thermal heat. The figure includes our model results for the U.S. LDV fleet (peak demand years range from 2033 to 2047) as well as high-level scoping estimates of feedstock and energy carrier demand to satisfy global e-fuel demand in 2035 (55% e-fuel share) and 2050 (100% e-fuel share). These demand estimates are compared with current (source data within the range from 2020–2023) and future U.S. and global production levels (2030 global data for CO_2 and H_2 and 2050 U.S. data for renewable electricity); data is from ref. 37, 38, 66, 86, 92 and 93. Detailed numeric results and results for alternative e-gasoline production pathways are shown in ESI Section 3.8.1.†

renewable electricity generation (913 TW h), respectively.[38] These demands are of the same order of magnitude as those projected in the Princeton Net-Zero America E+ RE+ scenario, which assumed nearly 100% replacement of diesel, gasoline, jet fuel, and LPG with synthetic liquid fuels produced from hydrogen and CO_2 by 2050 (ESI Section 3.8.2†).[30] To further examine the renewable electricity demand for e-gasoline, the demands are compared to the AEO 2022 reference case, which is the projection of electricity supply under existing laws and policies.[90] With the exception of the 2 °C high BEV with RE scenario, the peak renewable electricity demands in all our scenarios are higher than the projected renewable electricity supply in the AEO 2022 reference case, indicating that more aggressive expansion of renewable electricity generation would be needed to make e-gasoline a feasible solution under our scenarios.

As e-fuels are also attractive for other sectors (*e.g.*, aviation and heavy-duty vehicles) and regions, competing demands would further increase the burden on supply growth in e-fuels and the required feedstock and energy carriers. We perform a high-level scoping estimate of global e-fuel demand by scaling our U.S. scenarios. Specifically, we benchmark against the 2 °C and BAU BEV with U.S. grid scenario, which results in approximately 55% of U.S. gasoline being replaced with e-fuel in 2035. This is similar to the projected e-fuel share (58%) in the peak year (2033) for the 2 °C and high BEV with U.S. grid scenario. Applying a similar 55% replacement rate for all global petroleum products (with e-gasoline) and natural gas (with e-methane) under the IEA World Energy Outlook 2024 Stated Policies scenario[91] would require 3.2 trillion L of e-gasoline and 0.9 Gt of e-methane in 2035. This corresponds to a global e-gasoline & e-methane demand of 141 EJ, which would require 11 Gt of captured CO_2, 1400 Mt of electrolytic H_2, and 89 PWh of renewable electricity (e-methane production data from ref. 21). This would respectively require 228 times the current (2023) global amounts of captured CO_2, 1010 times the current (2020) global electrolytic H_2 production capacity, and 11 times the current (2021) global renewable electricity supply, as outlined in Fig. 8. These requirements are more aggressive than those estimated for U.S. LDVs by 2035 under the 2 °C and BAU BEV with U.S. grid scenario: 30, 722, and 5 times the current U.S. production of captured CO_2, electrolytic H_2, and renewable electricity, respectively. If we further extend the analysis to 2050 with a 100% e-fuel share, the global demand for feedstock and energy carriers in 2050 would be 1.7 times the 2035 levels. These numbers further illustrate the immense resource requirements and scale-up challenges that could be associated with an e-fuel focused decarbonization scenario.

3.2.4 Demand for critical materials from water electrolyzers, renewable electricity generation, and battery manufacturing. The following discussion focuses on critical material demand from water electrolyzers, renewable electricity generation, and battery manufacturing to meet the 2 °C climate target with FT-gasoline (produced from wind electricity and DAC CO_2 heated by solar thermal energy) under the high BEV with U.S. grid scenario (results for other scenarios are provided in ESI Section 3.9†).

Critical materials in water electrolyzers estimated to be in high demand from e-gasoline production are primarily determined by the assumed electrolyzer technology market share. To meet the 2 °C climate target, cumulative demands from 2020–2050 for most materials are estimated to be less than 10% of the 2021 global reserves despite material recovery assumptions, with the exception of iridium (Fig. 9). Iridium is a critical catalyst material for PEM electrolyzers and its current U.S. supply is dominated by imports.[73] Under the high BEV with U.S. grid scenario, our results show that 140% and 290% of the 2021 global reserves of iridium would be needed if PEM electrolyzers were to have 50% and 100% of the market share, respectively, without material recovery. If 100% material recovery is assumed, the numbers would decrease to 11% and 22%. Under the 1.5 °C climate target, there are other materials whose cumulative demands may exceed 10% of global reserves without material recovery, including yttrium, nickel, and platinum, underscoring the importance of recycling and recovery to reduce supply chain risks. Further concerns arise from whether supply growth can keep pace with demand growth, especially given the long mine lead time, around 16 years from discovery to production.[94] For example, to meet the 2 °C climate target under the high BEV with U.S. grid scenario, the annual average iridium demand by 2030 would need to be 7 times the 2021 U.S. consumption, assuming FT-gasoline production *via* PEM electrolysis. The fast growth rate could lead to a mismatch in timing between when critical materials are needed and when they could become available. Such challenges could potentially be mitigated, but only with sufficient advanced planning and lead time.

A sufficient supply of critical materials for associated renewable electricity generation is estimated to be less challenging. Even without material recovery, the cumulative demands for critical materials from wind turbines and solar panels from 2020 to 2050 are estimated to be similar to or less than 10% of the 2021 global reserves (ESI Section 3.9.2†).

As BEVs require critical materials for battery manufacturing, we adopt cumulative demands for aluminum, cobalt, lithium, manganese, and nickel under 0% and 90% material recovery for high BEV deployment scenarios from Tarabay *et al.*,[81] which assumed 100% BEV sales by 2035 consistent with our study. For

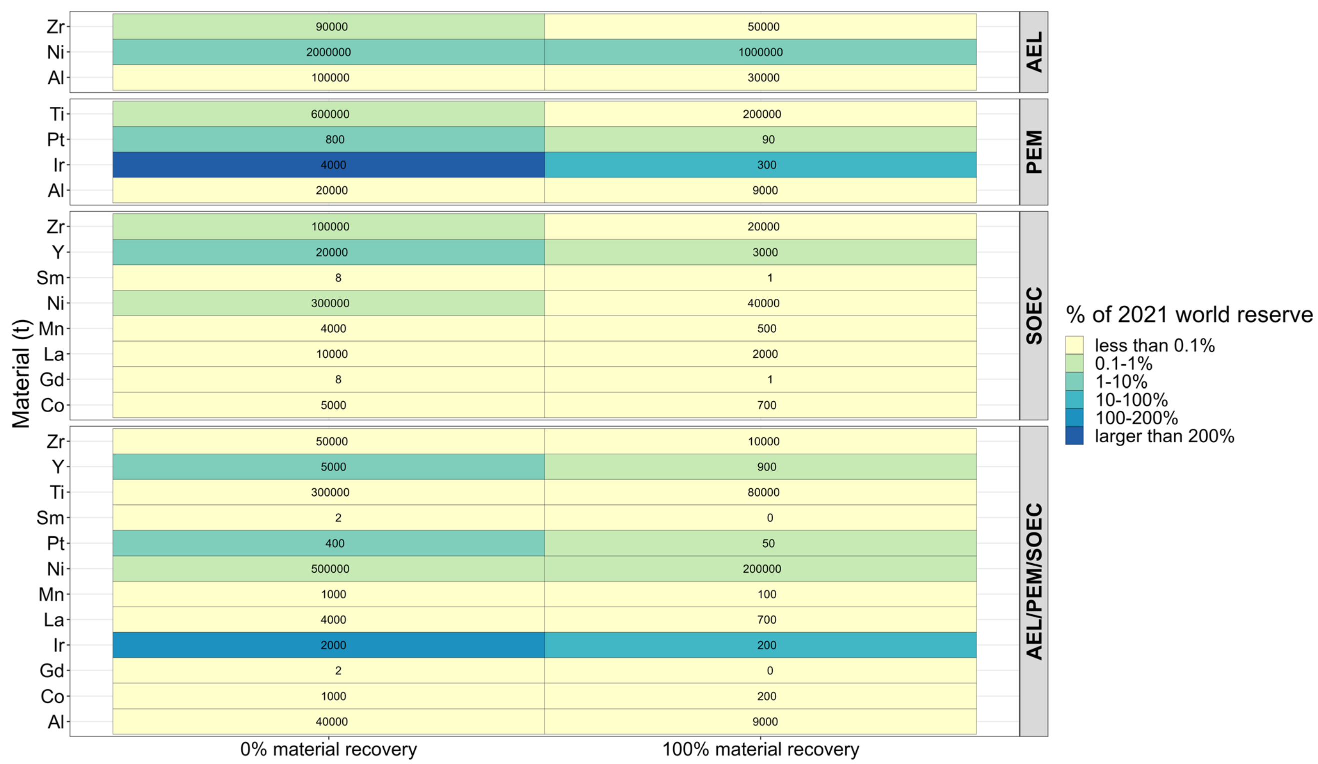

Fig. 9 Cumulative demand from 2020 to 2050 for critical materials from water electrolyzers with 0% and 100% material recovery under the high BEV with U.S. grid scenario to meet the 2 °C climate target. These fleet-level results correspond to Fischer–Tropsch gasoline produced from wind electricity and CO_2 captured by direct air capture heated by solar thermal energy. The top three panels represent scenarios with 100% of a certain electrolyzer technology, and the last panel represents a scenario with a 20% share of alkaline electrolyzer (AEL), 50% of proton exchange membrane (PEM), and 30% of solid oxide electrolyzer cells (SOECs). We include material use for water electrolyzers only for e-gasoline production but not for hydrogen production for fuel cell vehicles. Al: aluminum; Co: cobalt; Gd: gadolinium; Ir: iridium; La: lanthanum; Mn: manganese; Ni: nickel; Pt: platinum; Sm: Samarium; Ti: titanium; Y: yttrium; Zr: zirconium. Other scenarios are presented in ESI Section 3.9.1.†

consistency with our previous work,[5] GHG emission estimates assume the use of 100% lithium manganese oxide (LMO) cathodes, which introduces a minor inconsistency with the updated battery technology market shares that we use for calculating critical minerals: 71% nickel manganese cobalt oxide cathode (NMC 622), 25% lithium nickel cobalt aluminum oxide cathode (NCA), and 4% lithium iron phosphate cathode (LFP) from ref. 81. The use of LMO slightly underestimates the burdens of electric vehicle production. The resulting inconsistencies in the fleet-level GHG emissions and demand for e-gasoline to bridge mitigation gaps are expected to be minor given the relatively low contribution of battery production when BEVs are charged with U.S. grid electricity. Therefore, our emphasis is on the estimates to provide insight into the critical material demand arising from manufacturing the following products, *i.e.*, electrolyzers, wind turbines and solar panels, and batteries. Under the high BEV with U.S. grid scenario, results show that the demands for cobalt, nickel, lithium, and iridium would exceed 10% of the 2021 global reserves to meet the 2 °C climate target even with 90–100% material recovery (Table S30†). Cobalt is the material of the highest concern, reported to use over 60% of the 2021 global reserves due to the high assumed market share of batteries containing cobalt. Cobalt, lithium, and nickel are predominantly associated with battery manufacturing, while iridium is exclusively linked to electrolyzer manufacturing (Fig. S16†).

The estimates of feedstock, energy requirements, and critical materials are based on near-term technologies, which may result in overestimates if future technological advancements occur. Additionally, there are uncertainties associated with variations in technology parameters reported in the literature (*e.g.*, electrolyzer efficiency). Nevertheless, the results provide insights into the challenges associated with large-scale deployment of e-gasoline.

3.3 Other factors that impact the mitigation potential of e-gasoline

Factors beyond those included in our study that are expected to impact the mitigation potential of e-gasoline include its production cost, the motivation of the industry to rapidly increase production, and non-climate environmental and health risks, such as from the upstream fuel production and the direct tailpipe emissions that result from continued use of combustion engine vehicles. We discuss these factors based on insights from the literature.

High e-fuel production costs for both FT-fuels and MTG-gasoline are likely to cause economic barriers for its large-scale deployment with reported production costs ranging from \$0.72 to \$8.3 per L (\$0.02–0.27 per MJ)[9,21,22,42,95,96] (methods in ESI Section 2.8† and results in ESI Section 3.10†), substantially higher than the average 2018–2022 production cost of conventional gasoline (\$0.57 per L or \$0.018 per MJ)[97] (all values in 2022 USD). The wide range of production costs arises from variations in economic and production scenario assumptions. Economically, the production cost is mainly driven by the assumed prices of electricity and CO_2. The lowest cost of \$0.72 per L (\$0.02 per MJ) is based on an electricity price of \$0.05 per kWh and a CO_2 price of \$82 per t CO_2,[7] while the highest cost of \$8.3 per L (\$0.27 per MJ) assumes prices of \$0.08 per kWh and \$1600 per t CO_2, respectively.[42] For production scenarios, lower costs are associated with co-electrolysis due to higher production efficiency[22,42] and with the utilization of industrial flue gas due to lower energy consumption.[7,9,22,42,96]

These variations lead to a range of carbon abatement costs (from \$31 per t CO_2 (ref. 7) to \$11 000 per t CO_2 (ref. 22)). As the emitted GHGs from e-fuel production are dominated by CO_2,[27] we compare these abatement costs with the social cost of carbon to evaluate the social benefits of deploying e-fuels. For FT-fuels and MTG-gasoline whose carbon abatement costs are close to or lower than the 2020–2050 social cost of carbon (\$140–540 per t CO_2),[98] they were reported to be produced using electricity with an emission factor of around 16–26 g CO_2-eq per kWh and at a price below \$0.08 per kWh.[7] This suggests that it would be cost-beneficial to replace conventional gasoline with e-gasoline only when low-GHG and inexpensive electricity is used in its production. E-fuels should therefore be considered as a potential decarbonization strategy when drop-in fuels are required, but more cost-effective mitigation solutions such as biofuels,[26] and demand-side reduction strategies[99] are also worth considering as priority actions.

Although the possibility of low abatement costs offers incentives to replace conventional gasoline with e-gasoline, whether the industry would be motivated to scale up e-gasoline production is uncertain. In the 2 °C high BEV with U.S. grid scenario, the demand for e-gasoline is estimated to quickly grow by 0.4 EJ per year (12 billion L per year) before 2033 and then drop by 0.2 EJ per year (7 billion L per year) after 2033 on average. This is likely not reasonable and would be challenging for investors unless export markets could be developed, and/or production systems were flexible to produce products that would remain in high demand in the future, such as those possibly for other sectors (*e.g.*, aviation) where electrification will be difficult.

Apart from climate impacts, e-fuel production and combustion are linked to other environmental and health risks, such as water depletion and air pollution. E-fuel production has been reported to involve high water consumption due to water losses in electricity generation and water electrolysis.[27,33] Combusting e-gasoline in ICEVs-G results in tailpipe emissions of air pollutants, which are anticipated to be at similar levels to those from conventional gasoline; however there have been limited studies on this topic[48,100] (ESI Section 3.11†). Tailpipe emissions of vehicles using e-gasoline are not expected to yield major air quality co-benefits when compared to measures such as direct electrification and travel demand reduction. Air pollutant emissions and other non-climate impacts should be further investigated in future work.

3.4 Sensitivity analysis

To evaluate the impact of our mass and energy balance source data for our default scenarios for the e-gasoline pathways, we conducted a sensitivity analysis on fuel-level GHG emissions using multiple data sources[9,21–23,27] (see ESI Sections 2.1 and 3.3† and the error bars in Fig. 4). The results based on carbon capture and other process data from GREET 2022[27] tend to skew higher compared to other sources, while comparisons with Soler *et al.*[21] for additional process data show more variability. Heat requirements for DAC are particularly variable across sources, which impacts conclusions regarding whether a low-carbon heat source for DAC is a necessary condition for e-gasoline to be less GHG-intensive than conventional gasoline. Otherwise, despite some variability, the qualitative results presented in Section 3.1.1 Fuel-level GHG emissions remain consistent across data sources.

Returning to our default scenarios, we further investigate the annual and peak volumes of e-gasoline required for both electrolysis and co-electrolysis-based pathways, using either wind electricity (10 g CO_2-eq per kWh) or solar electricity with slightly higher embodied emissions (39 g CO_2-eq per kWh). The results are presented in ESI Section 3.7† and show minimal differences between the electrolysis and co-electrolysis-based pathways. In contrast, assuming higher life cycle emissions from renewable energy results in substantially higher required volumes of e-gasoline (Fig. 6) in peak years (up to 120% higher), depending on the underlying BEV deployment scenario and carbon budget. Bridging mitigation gaps with higher GHG intensity e-gasoline would be more challenging due to the higher required volumes.

3.5 Study limitations

An important model limitation is the static representation of e-gasoline production technologies, including the production process performance and material intensities. The study adopts parameters (which are already highly uncertain) based on the near-term state of technologies due to the absence of data on future performance, potentially leading to overestimations with future technological advancements. The use of e-gasoline also raises important questions regarding carbon accounting and how/if credits for captured CO_2 should be allocated between the capture site and the resulting fuel product; any credits retained by the capture facility could dramatically reduce the implied GHG benefit of fuels. Despite these limitations, the findings highlight challenges expected with the large-scale deployment of e-gasoline. Additionally, the significant and rapid industry scale-up requirements along with non-climate environmental impacts (*e.g.*, air pollution) could pose challenges to large-scale deployment. These factors should be addressed in future research.

4. Conclusions

This study analyzes the mitigation potential of e-gasoline in the U.S. LDV fleet at the fuel, vehicle, and fleet levels. Low-GHG energy sources are required for e-gasoline to be less GHG-intensive than conventional gasoline and vehicle electrification. At the fleet level, we estimate the required volumes of e-gasoline in the U.S. LDV fleet to meet 1.5 or 2 °C climate targets under different exogenous BEV deployment scenarios. We show that e-gasoline produced from fully renewable energy has the potential to assist the fleet in meeting climate targets, but would require very aggressive production ramp up – even before considering potential e-fuel use in other sectors. In the absence of other measures, slower deployment of BEVs or insufficient low-GHG intensity electricity for BEV charging further increases the need for e-gasoline and aggressive production ramp-up. Producing the required volume of e-gasoline is expected to be challenging due to the early stage of the industry and the considerable demands for feedstock, low-GHG electricity, and critical materials. Other factors such as high production costs and tailpipe emissions of air pollutants are beyond the scope of this study but may further limit opportunities for e-gasoline. Mitigating GHG emissions from land passenger mobility cannot solely rely on BEVs and e-fuels, other complementary technologies (*e.g.*, vehicle downsizing and efficiency improvements, biofuels or other low carbon fuels) and strategies based on avoidance and modal shift (*e.g.*, reducing travel demand and improving public transit) should also be considered.

Data availability

The data supporting this article have been included as part of the ESI.†

Author contributions

Dijuan Liang: conceptualization, methodology, software, formal analysis, writing – original Draft, visualization. Alexandre Milovanoff: conceptualization, methodology, software. Hyung Chul Kim: conceptualization, writing – reviewing and editing. Robert De Kleine: conceptualization, writing – reviewing and editing. James E. Anderson: conceptualization, writing – reviewing and editing. I. Daniel Posen: conceptualization, methodology, writing – reviewing and editing, supervision. Heather L. MacLean: conceptualization, methodology, writing – reviewing and editing, supervision, funding acquisition.

Conflicts of interest

The authors declare the following financial interests/personal relationships which may be considered potential competing interests: authors Hyung Chul Kim, Robert De Kleine and James E. Anderson are employed by Ford Motor Company. The research was also funded in part by Ford Motor Company. The authors retained scientific independence in pursuing this work and no editorial control was exercised by the sponsor.

Acknowledgements

This work was supported by a gift from the Ford Motor Company University Research Project (URP) Grant and a University of Toronto James Armstrong Civil Engineering Graduate Scholarship (D. Liang). This research was undertaken, in part, thanks to funding from the Canada Research Chairs Program (CRC-2020-00082 held by IDP and CRC-2020-00131 held by HLM). The authors would like to thank Nadine

Alzaghrini and Wei Shen for their helpful comments; any errors or views expressed in the article should be attributed to the authors alone.

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