

Technical Report Documentation Page

1. Report No.	2. Government Accession No.	3. Recipient's Catalog No.	
4. Title and Subtitle		5. Report Date	
		6. Performing Organization Code	
7. Author(s)		8. Performing Organization Report No.	
9. Performing Organization Name and Address		10. Work Unit No. (TRAIS)	
		11. Contract or Grant No.	
12. Sponsoring Agency Name and Address		13. Type of Report and Period Covered	
		14. Sponsoring Agency Code	
15. Supplementary Notes			
16. Abstract			
17. Key Words		18. Distribution Statement	
19. Security Classif. (of this report) Unclassified	20. Security Classif. (of this page) Unclassified	21. No. of Pages	22. Price



Economic and environmental evaluation of the role for waste CO₂ from ethanol fermentation to decarbonize transportation in the US

Niamh Keogh^{a,*}, James Abel^a, Christoph Falter^a, Gary Grimes^b, Florian Allroggen^a

^a *Laboratory for Aviation and the Environment, Department of Aeronautics and Astronautics, Massachusetts Institute of Technology, 77 Massachusetts Avenue, Cambridge, MA, USA*

^b *World Energy, 14700 Downey Ave, Paramount, CA, USA*

ARTICLE INFO

Keywords:

Biofuels
Electrofuels
Life-cycle assessment
Techno-economic analysis
Carbon abatement cost
Sustainable aviation fuels
Carbon capture and utilization
Carbon capture and storage

ABSTRACT

Transitioning to alternative energy carriers is one of the primary options for reducing greenhouse gas emissions attributable to transportation. In the US, ethanol from corn grain covers 10.5% of gasoline demand from road transport today. Its production could be scaled-up further to also make sustainable aviation fuel. Additionally, the biogenic CO₂ produced during fermentation could provide an option for carbon removal or for additional fuel production. In this study, we investigate the economic and environmental impacts of using the CO₂ from ethanol fermentation either through capturing and sequestering the CO₂ (CCS) or through the production of electrofuels (CCU), via fischer-tropsch and methanol-to-jet as conversion technologies. We find that CCS can increase the total offset CO₂ by 135% compared to ethanol-to-jet plants while increasing the minimum selling price (MSP) of the produced biofuel by 5-7%. Comparatively, there is significant variation in the results for CCU pathways, increasing the total offset CO₂ by 90 - 205%; however, the MSP of the electrofuels produced is 36 - 218% higher than the biofuels produced. This study highlights the trade-offs between fuel carbon intensity, costs, production volumes and output fuel mix for renewable fuel facilities, with the optimal configuration being dependent on the project's primary objectives.

1. Introduction

In 2022 the transportation sector used 117 EJ of energy, equivalent to 28% of global energy consumption [1]. Moreover, 23% of global greenhouse gas (GHG) emissions can be attributed to the transportation sector [2]. In order to address the GHG footprint of the transportation sector, a number of jurisdictions have implemented policies to encourage the transition to alternative energy carriers. Examples include (i) the Inflation Reduction Act (IRA) in the United States, which incentivizes the production of clean electricity, clean hydrogen, second-generation biofuels, and sustainable aviation fuels (SAF) [3], and (ii) the European Union's European Green Deal, which targets a 90% reduction in transport emissions by 2050 [4].

Liquid hydrocarbon fuels with lower GHG life-cycle emissions are particularly attractive for hard to abate transport modes that are reliant on high energy density fuels. For example, the aviation sector is reliant on jet fuel, which has an energy density of 12,000 Wh/kg, equivalent to 48 times the energy density of state-of-the-art Li-ion batteries [5]. Drop-in fuels can be used with existing fleet and infrastructure, thereby

enabling decarbonisation options in the short- and medium-term. To ensure safety and compatibility, such drop-in fuels must comply with the specifications in ASTM D1655 [6] (for fossil fuels) and ASTM D7566 [7] (for fuels containing synthesized hydrocarbons).

The potential resource availability [8–10], lifecycle environmental impact [11–14] and costs [15–20] of such fuels, including biofuels and electrofuels has been evaluated in the literature, finding that both biofuels and electrofuels are not without their own challenges. The production of biofuels is associated with water consumption which can be several orders of magnitude larger than for fossil fuels, and feedstock production which, under some circumstances, can cause significant GHG emissions from land use change [11,21]. Furthermore, the availability of suitable land and competition with other end use such as food, heat and electricity will likely restrict ability of biofuels for the transportation sector [8]. Second-generation biofuels produced from waste, residual, and lignocellulosic feedstocks may present a path to increased biofuel potential, but such feedstocks are often associated with high process complexity [22,23] and are subject to availability limits [21,24].

Scaling up electrofuels production will require capital investment on

* Corresponding author.

E-mail address: nkeogh@mit.edu (N. Keogh).

the order of 300 – 2100 USD/kW_{fuel} [25]. This is largely driven by the substantial electricity required for electrofuel production (2.3 – 2.8 MJ_{electricity}/MJ_{SAF}) including electricity required for electrolysis and process energy, the need for clean hydrogen production facilities and the availability of sustainable carbon sources [9,25]. These resources do not exist at sufficient scale today. More importantly, the availability of low-cost carbon sources may further restrict electrofuel production. Direct air capture technologies show promise as source of sustainable CO₂, however, the two technologies furthest along, liquid solvent and solid sorbent, are still in the early stages of commercial development. Both liquid solvent and solid sorbent processes are currently energy intensive (4.43 – 19.79 GJ/tCO₂) and expensive, with cost estimates of 168-600 \$/tCO₂ [26,27]. Other technologies such as direct ocean capture are in early assessment phases and will require significant development and scale up before they can be considered as a source of CO₂ for electrofuel production [28–30]. The use of CO₂ captured from industrial installations may be problematic in the long-term as reliance on such emissions may result in the undesired consequence of prolonging and possibly incentivization the continued use for fossil fuels in industries which could be decarbonized. CO₂ captured from industrial processes is a non-Carbon dioxide removal (CDR) technology. A non-CDR prevents the emission of additional CO₂ into the atmosphere, through storage or the utilization of CO₂ to produce a carbon-neutral fuel. In contrast, biomass-based electricity production, direct air capture and direct ocean capture can remove CO₂ from the atmosphere and when coupled with storage, these technologies can be net-negative. Such net negative CDR technologies can play an important role in achieving carbon targets as they can offset the need for in-sector emissions reduction in hard to abate sectors, while working toward carbon neutrality [31].

One exception to the waste gas challenge is the capture of biogenic waste gases such as the CO₂ produced during fermentation of corn grain to produce ethanol. The fermentation of corn grain produces approximately 3 kg of CO₂ per gallon of ethanol [32]. If captured this CO₂ can be permanently stored in a geological reservoir to further reduce the carbon intensity of the fuel produced or potentially be net negative if process emissions can be reduced. Alternatively, it can be utilized in the production of electrofuel to further offset fossil fuel usage in the transport sector. In the US, the corn grain ethanol industry has significant potential for biofuel production with fuel ethanol accounting for 10.5% of motor gasoline consumed in the US in 2022 [33]. Consumption of fuel ethanol in the US has increased from 1653 million gallon in 2000 to 14,023 million gallons in 2022 [33]. The initial driver to scale ethanol was to offset methyl tert-butyl ether (MTBE) as an octane enhancer and oxygenate for gasoline [34], with continued growth sustained due to supportive biofuels policies such as the Renewable Fuels Standard. The scale-up of fuel ethanol production has also correlated with a decrease in its carbon intensity, Lee et al. found that ethanol produced in 2019 had a carbon intensity of 45 gCO_{2e}/MJ (50% from agriculture activities, 45% from production processes, and 5% due to transport) reduced from 58 gCO_{2e}/MJ in 2005. This is due to increases in corn grain yield with constant fertilizer use, increases in the ethanol yield, and a reduction in the ethanol plant energy use [35]. In addition to the use of the waste CO₂ and an alternative to gasoline blending ethanol could be upgraded to produce distillate fuels, with the potential to offset emissions from other sectors such as aviation [18].

This study investigates the potential of ethanol plants in the US to reduce emissions from the transport sector, particularly focusing on aviation. Beyond the direct production of transportation fuels, we will assess how the CO₂ from corn fermentation is best used to support decarbonisation. Two options are considered: (1) Carbon capture and storage (CCS) case; and (2) Carbon capture and utilization (CCU) case, considering (a) fischer-tropsch (FT) and (b) methanol-to-jet (MTJ) as conversion technologies. We compare these pathways considering both costs and overall emissions reduction for the transport sector. This paper discusses how net negative CDR in ethanol production combined with increased jet fuel use combines with utilizing the carbon for net-zero fuel

production.

This study adds to the existing research in the field in a number of ways. Firstly, although previous studies have assessed the potentials cost and lifecycle emissions for waste CO₂, they have focused on either geological storage [36,37] or electrofuels production [10,38]. In this analysis we compare the costs and total emissions reductions associate with both pathways using a consistent modelling approach. Secondly, although in recent literature there has been a few studies that have assessed the technical feasibility of the MTJ conversion pathway [39,40], this is the first analysis to investigate the costs and lifecycle greenhouse gas (GHG) emissions associated with MTJ. Thirdly, utilization of carbon for electrofuels production provides the opportunity to use waste heat recovered from the exothermic FT process to reduce the energy requirements of the ethanol plant. We will assess the potential for waste heat integration in this analysis.

2. Methods

2.1. Case definitions

In order to assess the different storage or use cases for the waste CO₂ in ethanol facilities, we assess the scenarios shown in Fig. 1. In the baseline case ethanol is upgraded to distillate fuel and CO₂ is vented to the atmosphere; in Case 1 CO₂ is captured and stored in a geological reservoir; in Case 2a CO₂ is captured and converted to distillate fuel via FT; and in Case 2b CO₂ is captured and converted to fuel via the MTJ pathway. The technical set-up for each scenario is described in detail below.

2.1.1. Baseline case: Ethanol to jet upgrading only

The corn grain ethanol production process includes milling, liquefaction, saccharification, fermentation, and distillation. For this analysis, we assume a dry-mill process based on work by Kwiatkowski et al. [41], and GREET 2022 [42], as this technology is used by the majority of ethanol plants currently in operation in the US [43]. The ethanol-to-jet (ETJ) upgrading process outlined in Fig. 2, includes dehydration, oligomerization, hydrogenation and distillation. The ETJ model is adapted from Geleynse et al. [18], it assumes the facility is set up to maximize the production of jet range hydrocarbons, with a distillate output slate of 70% jet, 20% diesel, and 10% gasoline. It is assumed that wind electricity is used to meet the electricity demand as well as to produce green hydrogen required for ETJ upgrading (see section 2.2 for details), while natural gas is used to meet the heating requirements of the process. Details of mass and energy balances for both the ethanol production and ETJ upgrading process can be found in Table S1 in the supporting information (SI).

2.1.2. Case 1: Carbon capture and storage

The quantity of CO₂ (tCO₂) produced from corn grain fermentation is calculated from Hughes et al. as follows [32]:

Equation (1): Quantity of CO₂ from corn grain fermentation process.

$$CO_2 \text{ Fermentation} = \frac{EP \times EF \times CF_{EtOH}}{2024.62} \quad (1)$$

where EP is the production capacity of the ethanol facility in liters (L), EF is the emission factor for CO₂ (lb/L) and CF_{EtOH} is the capacity factor of the ethanol facility. EF was assumed at 1.67 lb CO₂/L based on the Illinois State Geological Survey [44], while the CF_{EtOH} was assumed to be 97% [10]. The assumed capacity factor of 97% for ethanol plants is in line with recent data from the U.S. Alternative fuels data center which demonstrates a 97% capacity factor for the years 2011 to 2019 [45]. The capacity of ethanol facilities in the US in 2021 ranged from 4 to 1420 ML, with an average capacity of 337 ML. It is assumed the fermentation process releases a 100% pure stream of CO₂, only cooling and compression are required before the CO₂ can be transported and injected

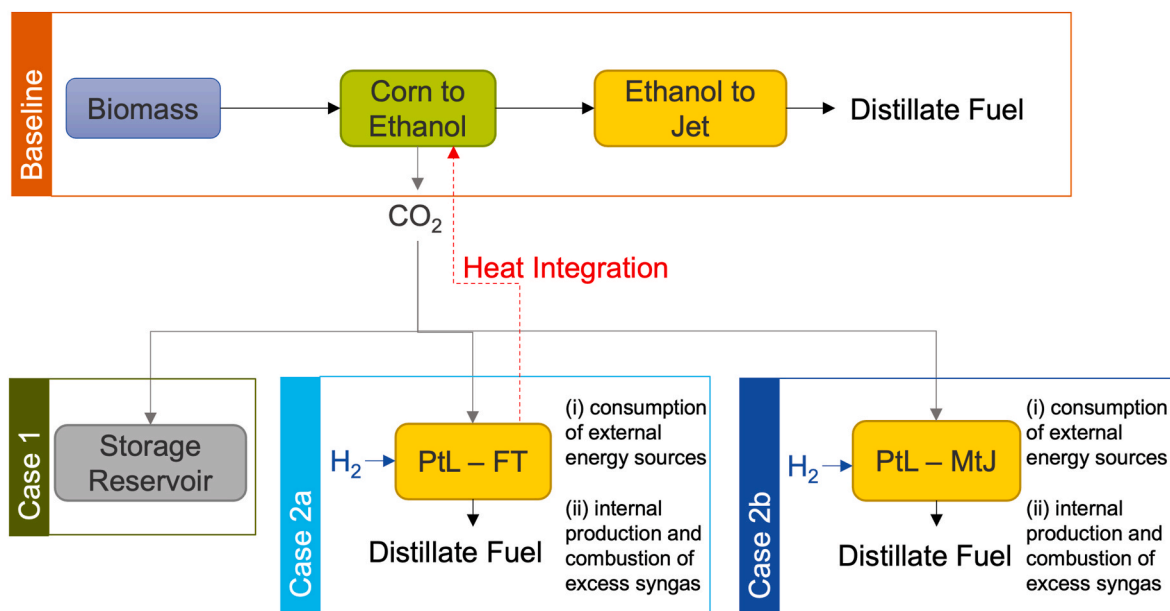


Fig. 1. Flow diagram of the cases analyzed, in all cases ethanol from corn grain fermentation is upgraded to distillate fuel. In the baseline case CO₂ is vented to the atmosphere, in Case 1 CO₂ is captured and stored in a geological reservoir. In Case 2a CO₂ is captured and covered to distillate fuel via the fischer tropesch process. In Case 2b CO₂ is captured and converted to distillate fuel via methanol-to-jet.

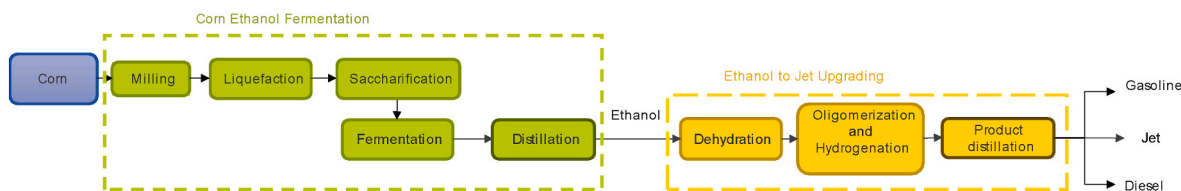


Fig. 2. Flow diagram outlining the corn grain ethanol fermentation process and ethanol to jet (ETJ) upgrading process.

into the geological storage reservoir. Given minimal processing is required for the CO₂ from fermentation, we assume that all CO₂ produced can be captured [10,32,46]. Other sources have referenced the presence of water in the fermentation CO₂ stream, we therefore assume water knockout drums present in the CO₂ compression train to render further processing unnecessary [32]. The CO₂ is assumed to be compressed to 15.3 MPa and cooled to 30 °C for it to be suitable for storage, total energy required for cooling and compression was taken to be 113.33 kWh/tCO₂ [32]. It is assumed that a pipeline will be built to

transport the CO₂, which is subsequently injected into a geological storage reservoir. The Illinois Basin is estimated to have a storage capacity of 12 – 172 billion tonnes of CO₂ [47]. We assume this to be the location for geological sequestration. We also assume that sequestration is permanent and there is no leakage from the storage reservoir.

2.1.3. Case 2a: Carbon capture and utilization - Fischer Tropsch pathway

The first technology considered for fuel conversion of the CO₂ is FT. In this pathway, CO₂ released from the fermentation process is cooled

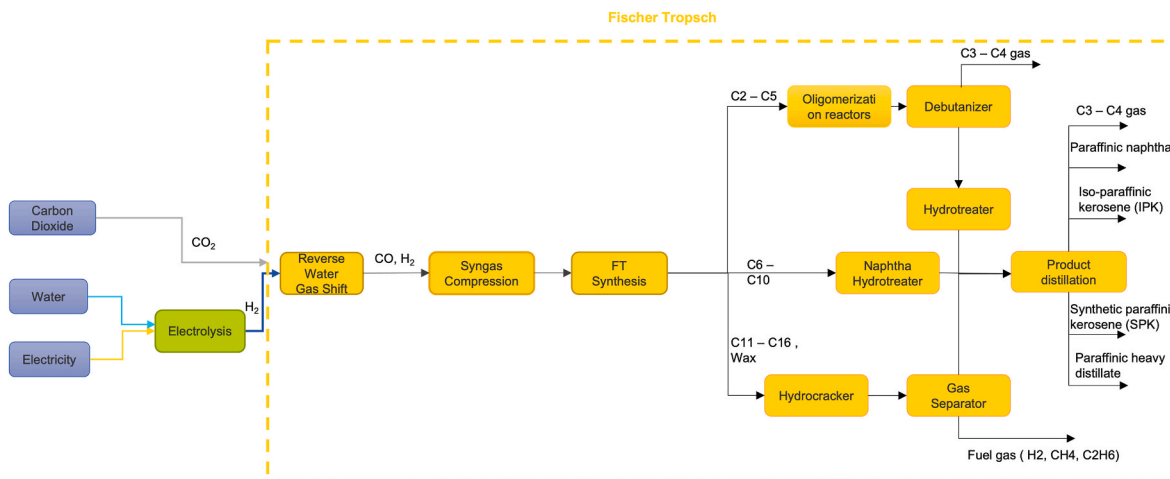


Fig. 3. Flow diagram outlining the Fischer Tropsch process.

and compressed before being converted to distillate fuel (see section 2.1.1). CO₂ and H₂ inputs are then used to produce carbon monoxide via the reverse water gas shift reaction (RWGS). The RWGS process requires significant energy input as the reaction takes place at a pressure of 2.45 MPa, a high temperature of 600 °C, and is endothermic [10,48]. Syngas (CO + H₂) is then fed into an FT synthesis unit at a CO:H₂ molar ratio of 1.8 [19], which is a thermocatalytic process that converts the syngas to liquid hydrocarbon fuels. FT synthesis produces a syncrude that must be hydrotreated to produce liquid hydrocarbon fuels. A low-temperature FT reactor with a cobalt catalyst operating at 220 °C is modeled. The process is outlined in Fig. 3. The output was based on the Anderson-Schulz-Flory theory using an alpha value of 0.9, resulting in a distillate output slate distribution of 46.5% jet, 27.8% diesel, and 25.7% naphtha [9,19].

The heat and electricity requirements of the FT process can be met in two ways:

- (i) The first is through consumption of external energy sources. We consider the electricity demand to be supplied by wind electricity as a significant quantity is already being procured for on-site hydrogen production. The heat requirement is assumed to be met by the combustion of fossil natural gas. (Case 2a (i)).
- (ii) The second option is to produce excess syngas in the RWGS step, which can be combusted in a combined heat and power (CHP) unit to provide the required heat and electricity (Case 2a (ii)). We note that electricity required for hydrogen production would still be provided through electricity procured from wind generation.

While using syngas generated internally to meet the energy requirement can lower the CI of the fuel produced by displacing fossil natural gas use, it comes with the trade-off of requiring a larger initial input of CO₂ and H₂. Both options are considered in this analysis, for the case of energy being supplied by external sources the FT model is adapted from Issacs et al. [9] and Albrecht et al. [48] requiring 4.1 kg CO₂/kg distillate fuel, and 0.6 kg H₂/kg distillate fuel. In the case of producing syngas internally to meet the energy requirements the FT model is based on Zang et al. [19] with input requirements of 6.8 kg CO₂/kg distillate fuel, and 0.64 kg H₂/kg distillate fuel. See Table S2 and S3in SI for further details.

FT synthesis is an exothermic process, releasing 13.81 MJ/kg distillate fuel. As we assume the FT plant and the ethanol plant are co-located this presents an opportunity for the excess heat released during the FT synthesis to offset a portion of the low-temperature heat demand for the corn grain ethanol fermentation process. The potential for heat exchange is estimated by assuming a two-stage shell-and-tube heat exchanger, which are one of the most common heat exchanger types used in industrial applications, cater to a broad temperature range (−200 °C, to 600+ °C), and are available in a variety of sizes (3 to 1000 m²) [49]. The heat exchanger size was approximated using the method proposed by Peters et al., as shown in equation (2):

Equation (2): Area required for shell and tube heat exchanger.

$$A = \frac{\dot{q}}{F \times U \times \Delta T_{o,m}} \quad (2)$$

where A is the area required for the shell and tube heat exchanger, \dot{q} is the heat transfer rate, F is the correction factor for multipass shell and tube heat exchanger determined to be 0.87, U is the overall heat transfer co-efficient equal to 425 W/m² K and $\Delta T_{o,m}$ is the mean overall mean temperature difference between the two streams. $\Delta T_{o,m}$ can be calculated as follows:

Equation (3): Mean overall temperature difference between the two different streams in a heat exchanger.

$$\Delta T_{o,m} = \frac{(T_{h,in} - T_{c,out}) - (T_{h,out} - T_{c,in})}{\ln \left[\frac{(T_{h,in} - T_{c,out})}{(T_{h,out} - T_{c,in})} \right]} \quad (3)$$

where T_{h,in} is the inlet temperature of the hot stream, T_{h,out} is the outlet temperature of the hot stream, T_{c,in} is the inlet temperature of the cold stream, and T_{c,out} is the outlet temperature of the cold stream.

2.1.4. Case 2b: Carbon capture and utilization - Methanol to jet pathway

The second pathway considered for fuel conversion is MTJ (Fig. 4). Similar to Case 2a the first processing step for the CO₂ is RWGS to produce syngas. The syngas is converted to methanol via methanol synthesis, at a CO:H₂ molar ratio of 0.6 and a temperature of 300 °C and a pressure of 5.1 MPa [50]. The methanol can be upgraded to distillate fuels in a two-stage process.

The first step is the methanol-to-olefins reaction (MTO), which converts methanol to light olefins (predominantly ethene and propene). Since it was first proposed by Mobil Corporation in 1977, there has been research on the reaction principle, use of different catalysts and process development to commercialization [51–53]. Here we use mass and energy balances based on work by Tian et al. [52], considering a DMTO-II process. Details are provided in the SI.

The second stage of MTJ upgrading is the olefins to jet process. Tabak et al. [54] investigated the Mobil olefins to gasoline/diesel (MOGD) process, a catalytic reaction designed to produce gasoline or diesel from light olefins. Given that the hydrocarbon range for jet A falls between gasoline and diesel, it is reasonable to assume that the MOGD process could also be used to produce jet A. Based on Tabak et al. [54], we use first principles to estimate the mass and energy balance of the MOGD process assuming that it has been adapted to maximize jet A output. Similar to Case 2a, the heat and electricity required for the MTJ pathway are assumed to be provided either by

- (i) The consumption of external energy sources
- (ii) The internal production and combustion of excess syngas

We consider both options in this analysis. The process input requirements were determined to be 3.67 kg CO₂/kg distillate fuel, and 0.51 kg H₂/kg distillate fuel for the scenario with external heat and electricity use, and 5.18 kg CO₂/kg distillate fuel, and 0.58 kg H₂/kg distillate fuel for the scenario with excess syngas production to meet energy requirements. The requirements to internally to meet the energy requirements the MTJ process is adapted from models by Zang et al. [19]. See Tables S4 and S5 in SI for further details.

2.2. Feedstock and input availability

Data from the US Energy Information Administration (EIA) showed that there were 197 ethanol facilities in the US in 2021, producing 66,411 million liters of ethanol [55]. Assuming an average capacity factor of 97% for ethanol plants the potential for waste biogenic CO₂ from these ethanol production plants is estimated to be 50 million tonnes [10,32]. The locations and capacities of US ethanol plants are shown Fig. 5.

Hydrogen is the other primary input required for the production of synthetic fuels from waste CO₂ (Case 2a and Case 2b). To maximize the lifecycle GHG emissions benefit and minimize logistics costs for H₂ transportation we assume hydrogen is produced locally at the ethanol plant using wind or solar electricity. To calculate the levelized cost of hydrogen we adapt the model created by Abel et al. [56], assuming PEM electrolysis. The model calculates the levelized cost of electricity (LCOE) from wind and solar across the US at a resolution of 1 km * 1 km, removing areas unsuitable for locating large-scale wind or solar farms such as urban settlements, water bodies, snow and ice, forests, areas where the slope of the terrain exceeds 20% for wind or 3% for solar. Additionally, agricultural land is excluded for solar electricity

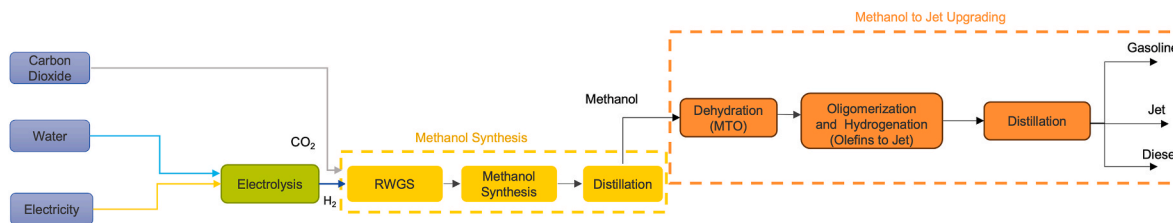


Fig. 4. Flow diagram outlining the methanol synthesis process and the methanol to jet upgrading process.

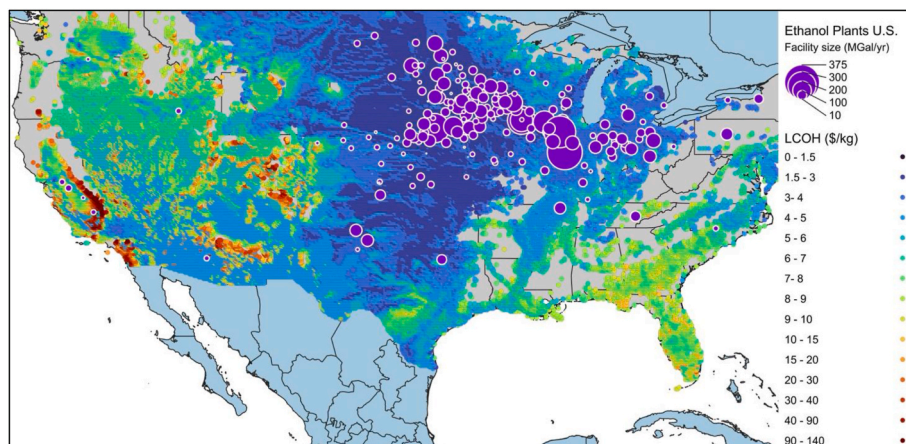


Fig. 5. Ethanol plant locations, weighted by size, vs the predicted levelized cost of hydrogen across the US in 2050.

generation. In the case of wind electricity we assume that farmers are willing to allow the siting of wind turbines on agricultural land, as wind turbines typically have minimal impact on surrounding agriculture activities [57]. Electricity production from wind and solar is modeled using data from Global Wind Atlas [58] and Global Solar Atlas [59]. These datasets provide details on the radiation data, wind speed data

2.3. Techno-economic assessment

The minimum selling price (MSP) of the distillate fuel produced is calculated using a simplified approach as shown in equation (4):

Equation (4): Minimum Selling Price.

$$MSP = \frac{\left(\frac{CAPEX}{\left(\frac{1 - (1 + WACC)^{LT}}{WACC} \right)} \right) + FS_{cost} + OM_{cost} + Elec_{cost} + H_2_{cost} + NG_{cost} + Chem_{cost} + CS\&T_{cost} - Rev_{co-product}}{VF_{out}} \quad (4)$$

and capacity factors for PV modules and wind turbines. We combine this data with technical and financial data from the literature on wind turbines and PV modules to determine the LCOE (see SI for further details). We find that it is more cost-effective to transport renewable electricity to produce hydrogen on-site, thereby assuming that it is possible to get permitting and build the required transmission lines. A cost minimization optimization problem is solved for each ethanol plant location by calculating the cost of hydrogen produced on-site at the ethanol plant with the electrolyzer sized to meet the requirements of the co-located PtL plant and electricity delivered to the plant through a dedicated connection. The key parameters for calculating the hydrogen cost are detailed in the SI They are set at aggressive levels of development (see SI for discussion and sensitivity analysis). A map of the local LCOH is included in Fig. 5. Ethanol facilities are evaluated on a basis of largest to smallest, so resources used by larger facilities become unavailable to smaller facilities. The LCOH at ethanol plants under 2050 assumption ranged from 2.18 \$/kg to 2.58 \$/kg, this is consistent with findings from Lane et al. [60] and Vijayakumar et al. [61].

where, CAPEX is the total capital costs, FS_{cost} is the feedstock cost, OM_{cost} is the operating and maintenance costs, $Elec_{cost}$ is the electricity cost, H_2_{cost} is the hydrogen cost, NG_{cost} is the natural gas costs, $Chem_{cost}$ is the cost of chemicals (including catalysts, enzymes and yeast), VF_{out} is the volume of fuel output, $CS\&T_{cost}$ is the storage and transportation cost of captured carbon, $Rev_{co-product}$ is the revenue from co-products produces (e.g. dried distillers grain and corn oil), LT is the lifetime of the plant and $WACC$ is the weighted average cost of capital, calculated from equation (5):

Equation (5): Weighted average cost of capital.

$$WACC = CD \times DR \times (1 - TR) + CE \times (1 - DR) \quad (5)$$

where, CD is the cost of debt assessed at 7.5% [62], DR is the debt ratio assessed at 60% [63], TR is the tax rate set to 24% [63], and CE is the cost of equity assessed at 9% [64].

The capital costs for each pathway were determined by multiplying the required equipment cost by direct and indirect cost factors per the method by Peters et al. [49]. All pathways are evaluated under the assumption that they have reached high technological maturity and are

widely available at commercial scale. For ethanol production, equipment costs are taken from Kwiatkowski et al. [41], with the additional ETJ upgrading capital costs based on Geleynse et al. [18]. The FT capital costs are based on Albrecht et al. [48]. In the MTJ pathway the RWGS costs are taken from Albrecht et al. [48], and the methanol synthesis equipment costs are estimated based on Tan et al. [65]. In the MTJ upgrading process, the methanol to olefins process is modeled using on Onel et al. [66], while the equipment required for the oligomerization, hydrogenation and distillation steps are assumed to be similar to the ETJ upgrading process. The MSP is evaluated for every ethanol facility in the US in 2022, with the equipment costs calculated relative to the size required based on ethanol production capacity for ethanol and ETJ equipment and CO₂ produced for FT and MTJ equipment. Economies of scale are considered by using equipment-specific scale factors. All equipment costs are adjusted to 2022 dollars using the Chemical Engineering Plant Cost Index. Details of the values used for each pathway are included in the SI.

Results from the mass and energy balances for each pathway inform the input of operational expenditure. Electricity costs and hydrogen costs are calculated as shown in Section 2.2. The natural gas cost is based on the average natural gas price from 2000 to 2022 in the state the ethanol plant is located [67]. Costs for the transportation and geological storage of captured carbon in the CCS scenario is based on Smith et al. [68], assuming pipeline transportation of 100 miles.

2.4. Lifecycle assessment

The LCA is conducted using the outputs from the mass and energy balance models. The system boundary is considered to include biomass feedstock cultivation and collection, transportation, electricity generation, feedstock-to-fuel conversion, and fuel combustion. The functional unit for the LCA is the fuel's lower heating value (LHV) in megajoules (MJ), with results expressed in gCO_{2e}/MJ. Emissions values for materials and energy inputs are sourced from GREET 2022 [42]. For electricity generation the emissions associated with electricity generation infrastructure is included. CO_{2e} is calculated for non-CO₂ emissions species on the basis of 100 year global warming potential from the IPCC's Sixth Assessment Report (AR6) [24]. The energy allocation method is used to allocate the total plant life cycle emissions among each useful product. In the ethanol production facility emissions are allocated between the ethanol, dried distillers gain and corn oil. In the ETJ, FT, and MTJ process emissions are allocated among the middle distillate fuel output products, including diesel, jet, gasoline and naphtha range fuels.

The total offset CO₂ is calculated following equation (6):

Equation (6): Total offset CO_{2e}

$$TOC = \sum E_{DF} \times (CI_{FDF} - CI_{RDF}) \tag{6}$$

where E_{DF} is the energy output of the fraction of the middle distillate fuel being considered, CI_{FDF} is the carbon intensity of the fossil equivalent of the middle distillate fuel being considered and CI_{RDF} is the carbon intensity of the output the middle distillate fuel being considered. In the case of ethanol production, we assume that the ethanol will be used to offset fossil gasoline through blending. The total offset CO₂ is calculated by summing the CO₂ offset for each middle distillate fuel output from the process for all ethanol plant in the US.

The carbon abatement cost (CAC) highlights the pathways that are most effective at reducing emissions at the lowest cost. The CAC is calculated from equation (7):

Equation (7): Carbon abatement cost

$$CAC = \frac{\sum_F (VF_{F,Ren} \times MSP_{F,Ren}) - \sum_F (VF_{F,fossil} \times MSP_{F,fossil})}{TOC_F} \tag{7}$$

where VF is the volume of fuel, MSP is the minimum selling price, F is the set of fuels produced and replaced, Ren specifies the renewable fuels produced, and fossil specifies the fossil fuels replaced.

3. Results

3.1. Minimum selling price

Fig. 6 shows the MSP of biofuel produced in the baseline case ETJ facility ranges between 1.00 and 1.26 \$/L dependent on plant size. An increase to 1.06 – 1.33 \$/L is observed in Case 1 when the ETJ plant is integrated with CCS, due to the additional cost associated with capture and storage of CO₂. We find a minor decrease 0.97 – 1.22 \$/L for Case 2a when heat integration between the FT and ethanol plants is included. In comparison, Tao et al. found a corn grain ETJ fuel cost of 1.11 \$/L [69], and Staples et al. found a corn grain ETJ fuel cost range of to 0.84 – 3.65 \$/L [70], showing that our results are within the range of estimates in recent literature. It is also evident that the plant capacity has a minimal influence on the MSP of ethanol produced, due to capital costs being relatively low in comparison to the feedstock costs.

In Case 2a, and 2b the MSP is 36% – 219% higher for electrofuels produced via the FT and MTJ pathways than the MSP of biofuels produced in the corn grain ETJ pathway. Additionally, the plant capacity has a significant impact on the MSP of electrofuels, with a range of 1.59 –



Fig. 6. Minimum selling price for distillate fuel produced for the scenarios investigated in the baseline case, Case 1, Case 2a and Case 2b.

2.40\$/L for in Case 2a (FT pathway), 1.39 – 4 \$/L in Case 2b (MTJ pathway). This can be attributed to the sensitivity to capital costs of nascent electrofuel technologies. Other researchers have found cost ranges for electrofuels from the FT process to be 1.42 – 4 \$/L [9,19], indicating general agreement with the results found in this study. We note that the MSP of fuel produced in both Case 2a(ii) and 2b(ii), when excess syngas is produced and combusted to meet energy requirements, is 9.3-18.6% higher than the scenario where external sources are used to meet the energy requirements (Case 2a(i) and 2b(i)). This is due to fact that the CO₂ and H₂ resources are partially used to offset natural gas and electricity, thus reducing the volume of distillate fuel produced from the process. Additionally, as the cost of natural gas and electricity are low relative to SAF, the use of CO₂ and H₂ to offset a lower value product contribute to increasing the MSP of the fuel produced.

The average price in the U.S. in 2021 was 0.58 \$/L for gasoline, 0.51 \$/L for jet, and 0.56 \$/L for diesel [71], highlighting the significant premium for SAF and renewable diesel particularly in Cases 2a and 2b, the electrofuel pathways.

3.2. Fuel volumes, carbon intensity and total carbon reduction

Fig. 7 (a) shows the carbon intensity of the distillate fuel produced for the scenarios investigated, while Fig. 7(b) shows the corresponding fuel output for each case. It is evident that a substantial quantity of biofuel can be produced in the baseline ETJ case, with the potential to offset 32% of 2022 US jet fuel consumption, 4% of 2022 US diesel consumption and 1% of 2022 US gasoline consumption [72]. The biofuel produced would lower the carbon intensity of the fuel by 15.8% (~14.1 gCO_{2e}/MJ) relative to fossil fuel equivalents. The main contributors to the high carbon intensity of corn grain ETJ fuels are natural gas required for process heat (28.1 gCO_{2e}/MJ), followed by the associated induced

land use change (ILUC) emissions (25.3 gCO_{2e}/MJ) and emissions related to corn farming (19.8 gCO_{2e}/MJ). Integration of the ETJ pathway with CCS in Case 1 can significantly reduce in carbon intensity of the corn grain ETJ fuel by 19.7 gCO_{2e}/MJ, whereas heat integration between FT and ETJ in Case 2a results in a minor reduction (5.3 gCO_{2e}/MJ) of the carbon intensity of the biofuel produced via ETJ.

If the CO₂ is utilized for electrofuel production rather than sequestered in geological storage, an additional 38% of distillate fuels can be produced via FT in Case 2a(i) or 44% via MTJ in Case 2b(i). The GHG emissions for electrofuels produced result in a 77.6% reduction compared to fossil jet fuel in Case 2a(i); with a carbon intensity of 19.95 gCO_{2e}/MJ, and a GHG emission reduction 75.7% relative to fossil jet fuel in Case 2b(i); with a carbon intensity of 21.62 gCO_{2e}/MJ. The primary contributors to emissions in these pathways are the embodied emissions from wind energy and emissions from natural gas associated with energy required for fuel conversion.

Alternatively, the energy required for fuel conversion can be met by the internal production and combustion of additional syngas, (Cases 2a(ii) and 2b(ii)). Such a practice would reduce the carbon intensity of the electrofuels produced via FT to 11.97 gCO_{2e}/MJ in Case 2a(ii) (40% reduction compared to Case 2a(i)), or 12.09 gCO_{2e}/MJ via MTJ (44% reduction compared to Case 2b(i)). However, such internal syngas use comes at the cost of reducing the fuel output of the plant. For Case 2a (FT) fuel output is reduced by 3.78 billion liters (40% as compared to Case 2a(i)) across all plants or for Case 2b (MTJ), by 3.58 billion liters (33% as compared to Case b(i)). This trade-off is highlighted in Fig. 7(c) which shows that the total offset CO₂ is lower for Case 2a(ii) and 2b(ii) than for Case 2a(i) and 2b(i) respectively despite Case 2a(ii) and 2b(ii) having a lower carbon intensity. This highlights the importance of considering carbon conversion efficiency along with LCA reduction when considering the most effective options for decarbonisation.

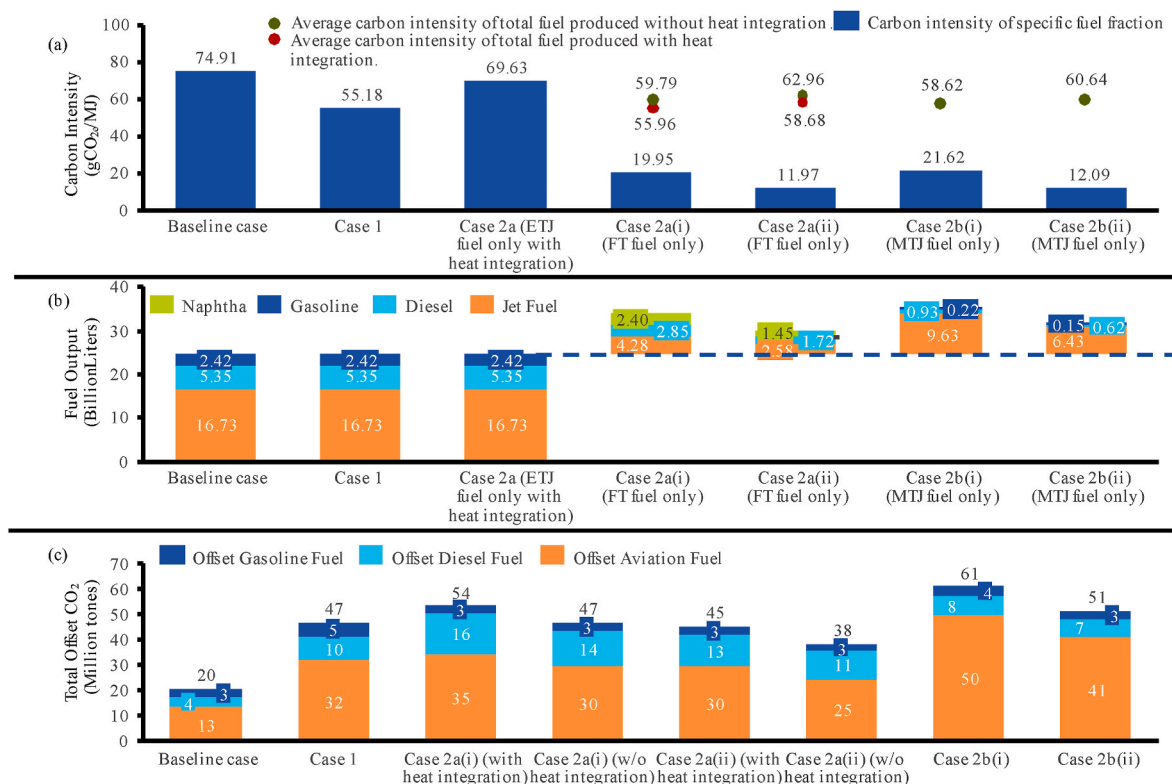


Fig. 7. The carbon intensity of distillate fuel produced (graph (a)), quantity of distillate fuel produced (graph (b)), and combined total offset CO_{2e} for co-located plants (graph (c)) for the scenarios investigated in the baseline case, Case 1, Case 2a and Case 2b. In graph (a) the carbon intensity of specific fuel fraction refers to the carbon intensity of the fuel produced from a single process (i.e. ethanol-to-jet, fischer tropesch, or methanol-to-jet); the average carbon intensity of total fuel produced refers to the weighted average carbon intensity of the total fuel produced from all processes at co-located plants (e.g., the weighted average of the SAF produced from ETJ and MTJ in Case 2b).

It is also evident from Fig. 7 (c) that utilization of CO₂ for electrofuel production (Case 2), can result in higher (0.32% - 30.12%) total offset CO₂ than sequestration of the CO₂ (Case 1). This is due to the choice of conducting an attributional LCA, using energy allocation, which is consistent with regulatory schemes for renewable fuels including the European Union Renewable Energy Directive [73], the Carbon Offsetting and Reduction Scheme for International Aviation [74], and the California Low Carbon Fuels Standard [75]. Under this method electrofuels produced from the CO₂ (Case 2) are considered within a separate system boundary to the biofuel produced via ETJ. Thus 100% of the CO₂ captured is allocated to electrofuel production to reduce transport emissions. However, in Case 1 the capture and sequestration of the CO₂ is counted within the ethanol production step meaning 63.2% of the associated emissions reduction are allocated to the ethanol produced which is subsequently upgraded, while the remaining 36.8% emissions reduction is allocated to the co-produced dried distillers' grain and corn oil. We note that the choice of energy allocation to all products of the ethanol production process reduces the benefit to the ethanol CI by 13.04 gCO_{2e}/MJ. This loss in benefits resulting from consistent application of energy allocation can be a challenge to the ethanol producer if there are no cost premiums for decarbonized co-products. Such an outcome could be driven by specific market or policy contexts. To maintain a fair allocation of emission burden and benefits, this analysis maintains the energy allocation methods, acknowledging that other methods (including full allocation to the main product) are plausible.

3.3. Carbon Abatement Cost (CAC)

Fig. 8 depicts the distribution of CAC for ETJ facilities in the U.S. under the various scenarios considered. In the baseline case, we find a median CAC of 1085 \$/tCO_{2e}. This CAC value is driven by the fact that the biofuels produced are approximately twice the price of their fossil fuel equivalents while providing minimal (~16%) reductions in carbon intensity relative to fossil fuels. Integration with CCS, as described in Case 1 results in a decrease in the CAC. In fact, Case 1 shows the largest decrease in CAC to a median of 527 \$/tCO_{2e} as capture and storage is relatively inexpensive, increasing cost by ~11.7%, while reducing the carbon intensity of the biofuel by 26%. The CAC of the CCU pathways range from 717 \$/tCO_{2e} (Case 2b(i) median value) to 971 \$/tCO_{2e} (Case 2a(ii) median value). The reason behind the high CAC for the CCU pathways is that electrofuels cost approximately 2.5 - 7 times their fossil fuel equivalents, while offering a carbon intensity of 12.0 - 21.6 gCO_{2e}/MJ.

CAC is an important metric for policymakers and industry stakeholders as it gives an indication of the economic efficiency of different emissions mitigation options. It also highlights the significant investments required for the scale up of biofuels and electrofuels to reduce transport sector emissions. The CAC range found in this study indicates at the challenge biofuels and electrofuels face in being cost competitive strategies for emissions mitigation, given the record high of the European Union's Emissions Trading Scheme is 107.25 \$/tCO₂ [76].

3.4. Comparison to current use of ethanol offsetting gasoline

Today ethanol produced in the U.S is primarily blended with gasoline to reduce emissions from light duty vehicles. If we consider offsetting gasoline for road vehicles as the end use for the ethanol rather than upgrading via ETJ to produce distillate fuels to offset jet fuel and diesel, the results change substantially. As shown in Fig. 8, the CAC for ethanol is 78% lower than when the ethanol is upgraded to SAF via the ETJ process (baseline case,). It is 64% lower in Case 1, 54% - 64% lower in Case 2a, and 53% - 59% lower in Case 2(b). This can be attributed to the fact that without the additional equipment and energy required to upgrade ethanol to distillate fuel, the ethanol can be produced at an MSP of 0.53 - 0.57 \$/L in the baseline case, 0.57 - 0.61 \$/L in Case 1, and 0.52 - 0.55 \$/L in Case 2(with heat integration). The carbon intensity of the corn ethanol is also lower than ETJ at 48.05 gCO_{2e}/MJ in the baseline case, 25.69 gCO_{2e}/MJ in Case 1, 43.02 gCO_{2e}/MJ in Case 2a with heat integration. These findings indicate that ethanol use in gasoline blending is a more effective option for decarbonizing emissions from the transport sector than upgrading the ethanol to distillate fuels via ETJ, at least as long as there is an end use for the ethanol. This finding highlights the trade-off between reducing overall emissions and targeting the emissions reduction a specific industry (e.g. aviation).

4. Final remarks

Biofuels and electrofuels offer pathways to reduce emission in hard-to-abate sectors such as aviation and heavy-goods vehicles. In this study we investigate the environmental and economic impacts of producing distillate fuel via ETJ from ethanol facilities in the US. We also consider capture of the waste CO₂ from ethanol fermentation and storing it in a geological reservoir (Case 1) or utilizing the CO₂ to produce electrofuel via FT (Case 2a) or via MTJ (Case 2b). Additionally, for both FT and MTJ we compare the option to use either (i) external energy sources (i.e. natural gas and wind electricity), with the use of (ii) internal production

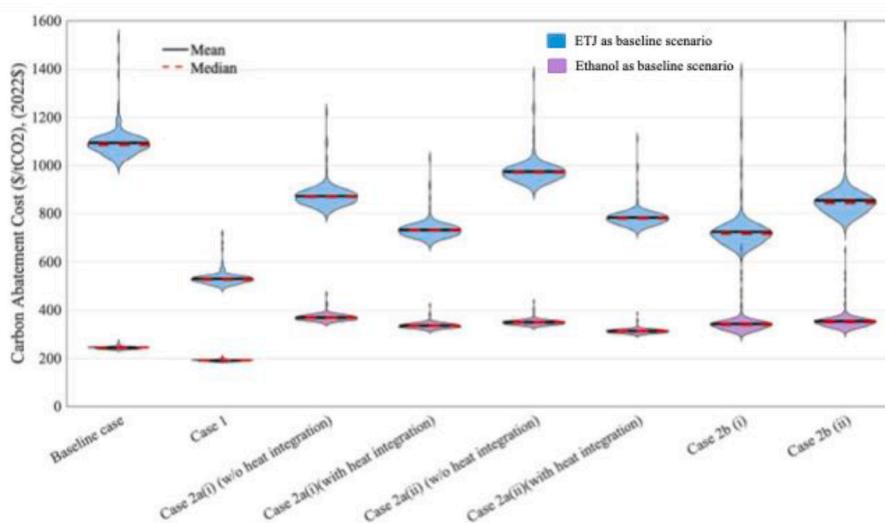


Fig. 8. Distribution of carbon abatement cost (CAC) for co-located plants for the scenarios investigated in the baseline case, Case 1, Case 2a and Case 2b, for both Ethanol-to-Jet (ETJ) as the baseline case and ethanol as the baseline case.

and combustion of syngas. In the case of FT, we also investigate the potential for heat integration between the FT plant and the ethanol plant.

The results show that the addition of CCS to ethanol production or the utilization of CO₂ produced from corn grain fermentation can increase the decarbonisation potential of an ETJ plant, increasing the total offset CO₂ by 135% in for the CCS case and 90 – 205% for the CCU case compared to the baseline scenario of ETJ only. Similarly, both cases improve the economic efficiency of emissions reduction with the CAC decreasing by an average of 52% in the CCS case and by 11 – 33% in CCU cases, relative to the baseline. This highlights that the net negative CDR in ethanol production plants can offset more CO₂ overall if utilized to produce fuels, however CCS is a more economically efficient pathway for carbon abatement.

In considering the CCS case versus the CCU case it is evident that the CCS case results in large carbon savings (19.73 gCO_{2e}/MJ) at the lowest cost due to the fact that geological sequestration requires minimal equipment in comparison to a fuel conversion plant. However, the CCU case results in increasing the overall distillate fuel output by 5.75 – 10.78 billion liters (23% - 44%). Similarly, within the CCU case, both FT and MTJ conversion technology for the electrofuel production the internal production and combustion of syngas to meet energy requirements reduced the carbon intensity of the fuel by 7.98 gCO_{2e}/MJ for FT and 9.53 gCO_{2e}/MJ for MTJ. However, this comes at the trade-off of reducing the electrofuel production by 3.55 and 3.58 billion liters respectively (33% - 40%). Future work should consider alternative technologies for heating such as hydrogen combustion or resistive heating that would reduce the carbon intensity of the process without reducing electrofuel production.

If ethanol is used for gasoline blending rather than ETJ upgrading, a larger total CO₂ reduction and lower CAC across all cases is found. However, the offset fuel mix differs significantly, with ethanol primarily reducing emissions from gasoline, while ETJ upgrading primarily reduces emissions from jet and diesel. This output slate may be of key importance in future defossilizing economies if the trends in electric vehicle adoption for light duty transport continue to increase [77], as this will lead to a reduction in the demand and price of gasoline. This in turn may result in an increase in the CAC of ethanol, as it becomes relatively more expensive than gasoline.

The trade-offs between fuel carbon intensity, costs, fuel production quantities and offset fuel mix found between the different cases in this study highlights that choosing the optimal pathway is dependent on the main objectives of the project. For instance, if emissions reduction at the lowest cost from the transport sector is the main goal ethanol for gasoline blending with CCS is the most effective option, comparatively if maximizing SAF production is the main goal then Case 2b(i) for the ETJ plant is the most effective option. Consideration of these trade-offs and their potential implications is also of key importance in designing policy for renewable fuels to ensure it is effective in achieving its intended goals.

CRedit authorship contribution statement

Niamh Keogh: Writing – original draft, Visualization, Methodology, Formal analysis, Data curation, Conceptualization. **James Abel:** Methodology, Data curation. **Christoph Falter:** Methodology, Data curation. **Gary Grimes:** Methodology, Data curation. **Florian Allroggen:** Writing – review & editing, Supervision, Methodology, Funding acquisition, Conceptualization.

Acknowledgements

This research was partially funded by World Energy. This research was also partially funded by the US Federal Aviation Administration Office of Environment and Energy through ASCENT, the FAA Center of Excellence for Alternative Jet Fuels and the Environment, project 001 through FAA Award Number 13-C-AJFE-MIT under the supervision of Prem Lobo. Any opinions, findings, conclusions, or recommendations expressed in this material are those of the authors and do not necessarily reflect the views of the FAA.

Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.biombioe.2026.109096>.

Data availability

Data will be made available on request.

References

- [1] International Energy Authority, "World energy balances." doi: <https://doi.org/10.1787/enestats-data-en>.
- [2] Greenhouse Gas Emissions from Energy - Data Product, IEA, 2024. Accessed: Nov. 12 [Online]. Available, <https://www.iea.org/data-and-statistics/data-product/gr-eehouse-gas-emissions-from-energy>.
- [3] Credits and Deductions Under the Inflation Reduction Act of 2022, Internal Revenue Service, 2024. Accessed: Mar. 13, . [Online]. Available: <https://www.irs.gov/credits-and-deductions-under-the-inflation-reduction-act-of-2022>.
- [4] The European green deal - European Commission, Accessed: Mar. 13, 2024. [Online]. Available: https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/european-green-deal_en.
- [5] A.H. Epstein, S.M. O'Flarity, Considerations for reducing aviation's CO₂ with aircraft electric propulsion, *J. Propul. Power* 35 (3) (May 2019) 572–582, <https://doi.org/10.2514/1.B37015>.
- [6] ASTM International, *Standard Specification for Aviation Turbine Fuels*, 2016. West Conshohocken, PA.
- [7] Standard specification for aviation turbine fuel containing synthesized hydrocarbons, Accessed: Jul. 07, . [Online]. Available, <https://store.astm.org/d7566-24d.html>, 2025.
- [8] M.D. Staples, R. Malina, S.R.H. Barrett, The limits of bioenergy for mitigating global life-cycle greenhouse gas emissions from fossil fuels, *Nat. Energy* 2 (2) (Feb. 2017) 16202, <https://doi.org/10.1038/nenergy.2016.202>.
- [9] S.A. Isaacs, M.D. Staples, F. Allroggen, D.S. Mallapragada, C.P. Falter, S.R. H. Barrett, Environmental and economic performance of hybrid power-to-liquid and biomass-to-liquid fuel production in the United States, *Environ. Sci. Technol.* 55 (12) (2021) 8247–8257, <https://doi.org/10.1021/acs.est.0c07674>.
- [10] G. Zang, et al., Synthetic methanol/fischer–trropsch fuel production capacity, cost, and carbon intensity utilizing CO₂ from industrial and power plants in the United States, *Environ. Sci. Technol.* 55 (11) (Jun. 2021) 7595–7604, <https://doi.org/10.1021/acs.est.0c08674>.
- [11] X. Zhao, F. Taheripour, R. Malina, M.D. Staples, W.E. Tyner, Estimating induced land use change emissions for sustainable aviation biofuel pathways, *Sci. Total Environ.* 779 (2021), <https://doi.org/10.1016/J.SCITOTENV.2021.146238>, 146238–146238.
- [12] M. Prussi, et al., CORSIA: the first internationally adopted approach to calculate life-cycle GHG emissions for aviation fuels, *Renew. Sustain. Energy Rev.* 150 (2021), <https://doi.org/10.1016/J.RSER.2021.111398>, 111398–111398.
- [13] M.D. Staples, R. Malina, P. Suresh, J.I. Hileman, S.R.H. Barrett, Aviation CO₂ emissions reductions from the use of alternative jet fuels, *Energy Policy* 114 (2018) 342–354, <https://doi.org/10.1016/J.ENPOL.2017.12.007>.
- [14] R. Sacchi, et al., How to make climate-neutral aviation fly, *Nat. Commun.* 14 (1) (Jul. 2023) 3989, <https://doi.org/10.1038/s41467-023-39749-y>.
- [15] Q. Smejkal, U. Rodemerck, E. Wagner, M. Baerns, Economic assessment of the hydrogenation of CO₂ to liquid fuels and petrochemical feedstock, *Chem. Ing. Tech.* 86 (5) (2014) 679–686, <https://doi.org/10.1002/cite.201300180>.
- [16] G. Seber, R. Malina, M.N. Pearlson, H. Olcay, J.I. Hileman, S.R.H. Barrett, Environmental and economic assessment of producing hydroprocessed jet and diesel fuel from waste oils and tallow, *Biomass Bioenergy* 67 (Aug. 2014) 108–118, <https://doi.org/10.1016/j.biombioe.2014.04.024>.
- [17] R.-U. Dietrich, et al., Cost calculations for three different approaches of biofuel production using biomass, electricity and CO₂, *Biomass Bioenergy* 111 (Apr. 2018) 165–173, <https://doi.org/10.1016/j.biombioe.2017.07.006>.

- [18] S. Geleynse, K. Brandt, M. Garcia-Perez, M. Wolcott, X. Zhang, The alcohol-to-jet conversion pathway for Drop-In biofuels: techno-economic evaluation, *ChemSusChem* 11 (21) (2018) 3728–3741, <https://doi.org/10.1002/cssc.201801690>.
- [19] G. Zang, P. Sun, A.A. Elgowainy, A. Bafana, M. Wang, Performance and cost analysis of liquid fuel production from H2 and CO2 based on the Fischer-Tropsch process, *J. CO2 Util.* 46 (Apr. 2021) 101459, <https://doi.org/10.1016/j.jcou.2021.101459>.
- [20] S. Lagouvardou, B. Lagemann, H.N. Psarافتis, E. Lindstad, S.O. Erikstad, Marginal abatement cost of alternative marine fuels and the role of market-based measures, *Nat. Energy* 8 (11) (Nov. 2023) 1209–1220, <https://doi.org/10.1038/s41560-023-01334-4>.
- [21] M.D. Staples, et al., Water consumption footprint and land requirements of large-scale alternative diesel and jet fuel production, *Environ. Sci. Technol.* 47 (21) (Nov. 2013) 12557–12565, <https://doi.org/10.1021/es4030782>.
- [22] P. Cavelius, S. Engelhart-Straub, N. Mehlmer, J. Lercher, D. Awad, T. Brück, The potential of biofuels from first to fourth generation, *PLoS Biol.* 21 (3) (Mar. 2023) e3002063, <https://doi.org/10.1371/journal.pbio.3002063>.
- [23] Y. Liu, et al., Biofuels for a sustainable future, *Cell* 184 (6) (Mar. 2021) 1636–1647, <https://doi.org/10.1016/j.cell.2021.01.052>.
- [24] Sixth assessment report — IPCC." Accessed: Jul. 16, 2024. [Online]. Available: <https://www.ipcc.ch/assessment-report/ar6/>.
- [25] S. Brynolf, M. Taljegard, M. Grahn, J. Hansson, Electrofuels for the transport sector: a review of production costs, *Renew. Sustain. Energy Rev.* 81 (Jan. 2018) 1887–1905, <https://doi.org/10.1016/j.rser.2017.05.288>.
- [26] N. McQueen, K.V. Gomes, C. McCormick, K. Blumanthal, M. Pisciotta, J. Wilcox, A review of direct air capture (DAC): scaling up commercial technologies and innovating for the future, *Prog. Energy* 3 (3) (Jul. 2021), <https://doi.org/10.1088/2516-1083/abf1ce>, 032001–032001.
- [27] R. Hanna, A. Abdulla, Y. Xu, D.G. Victor, Emergency deployment of direct air capture as a response to the climate crisis, *Nat. Commun.* 12 (1) (Jan. 2021) 368, <https://doi.org/10.1038/s41467-020-20437-0>.
- [28] S. Kim, M.P. Nitzsche, S.B. Rufer, J.R. Lake, K.K. Varanasi, T.A. Hatton, Asymmetric chloride-mediated electrochemical process for CO2 removal from oceanwater, *Energy Environ. Sci.* 16 (5) (May 2023) 2030–2044, <https://doi.org/10.1039/D2EE03804H>.
- [29] I.A. Digdaya, et al., A direct coupled electrochemical system for capture and conversion of CO2 from oceanwater, *Nat. Commun.* 11 (1) (Sep. 2020) 4412, <https://doi.org/10.1038/s41467-020-18232-y>.
- [30] M.D. Eisman, K. Parajuly, A. Tuganov, C. Eldershaw, N. Chang, K.A. Littau, CO2 extraction from seawater using bipolar membrane electrodialysis, *Energy Environ. Sci.* 5 (6) (May 2012) 7346–7352, <https://doi.org/10.1039/C2EE03393C>.
- [31] J. Strefler, N. Bauer, F. Humpenöder, D. Klein, A. Popp, E. Krieger, Carbon dioxide removal technologies are not born equal, *Environ. Res. Lett.* 16 (7) (Jul. 2021) 074021, <https://doi.org/10.1088/1748-9326/ac0a11>.
- [32] S. Hughes, A. Zoelle, Cost of capturing CO2 from industrial sources, *Natl. Energy Technol. Laboratory* (Jul. 2022) [Online]. Available: https://www.netl.doe.gov/projects/files/CostofCapturingCO2fromIndustrialSources_071522.pdf.
- [33] Ethanol explained - supply of ethanol - U.S. Energy Information Administration (EIA)." Accessed: Nov. 26, 2024. [Online]. Available: <https://www.eia.gov/energyexplained/biofuels/ethanol-supply.php>.
- [34] C. Johnson, K. Moriarty, T. Alleman, D. Santini, History of Ethanol Fuel Adoption in the United States: Policy, Economics, and Logistics, Nov. 2021, <https://doi.org/10.2172/1832224>. NREL/TP-5400-76260, 1832224, MainId:6072.
- [35] U. Lee, H. Kwon, M. Wu, M. Wang, Retrospective analysis of the U.S. corn ethanol industry for 2005–2019: implications for greenhouse gas emission reductions, *Biofuel Bioprod. Biorefining* 15 (5) (2021) 1318–1331, <https://doi.org/10.1002/bbb.2225>.
- [36] S. Paltsev, J. Morris, H. Khesghi, H. Herzog, Hard-to-Abate sectors: the role of industrial carbon capture and storage (CCS) in emission mitigation, *Appl. Energy* 300 (Oct. 2021) 117322, <https://doi.org/10.1016/j.apenergy.2021.117322>.
- [37] P. Bains, P. Psarras, J. Wilcox, CO2 capture from the industry sector, *Prog. Energy Combust. Sci.* 63 (Nov. 2017) 146–172, <https://doi.org/10.1016/j.pecs.2017.07.001>.
- [38] I. Dimitriou, P. García-Gutiérrez, R.H. Elder, R.M. Cuéllar-Franca, A. Azapagic, R. W.K. Allen, Carbon dioxide utilisation for production of transport fuels: process and economic analysis, *Energy Environ. Sci.* 8 (6) (2015) 1775–1789, <https://doi.org/10.1039/C4EE04117H>.
- [39] S. Bube, N. Bullerdiék, S. Voß, M. Kaltschmitt, Kerosene production from power-based syngas – a technical comparison of the Fischer-Tropsch and methanol pathway, *Fuel* 366 (Jun. 2024) 131269, <https://doi.org/10.1016/j.fuel.2024.131269>.
- [40] K. Atsonios, J. Li, V.J. Inglezakis, Process analysis and comparative assessment of advanced thermochemical pathways for e-kerosene production, *Energy* 278 (Sep. 2023) 127868, <https://doi.org/10.1016/j.energy.2023.127868>.
- [41] J.R. Kwiatkowski, A.J. McAloon, F. Taylor, D.B. Johnston, Modeling the process and costs of fuel ethanol production by the corn dry-grind process, *Ind. Crops Prod.* 23 (3) (May 2006) 288–296, <https://doi.org/10.1016/j.indcrop.2005.08.004>.
- [42] M. Wang, et al., "Greenhouse gases, regulated emissions, and energy use in technologies model, Excel) (2022), <https://doi.org/10.11578/GREET-Excel-2022/dc.20220908.1>. Oct. 10, 2022.
- [43] US Department of Energy, "Alternative fuels data center: ethanol production." Accessed: May 24, 2024. [Online]. Available: <https://afdc.energy.gov/fuels/ethanol-production>.
- [44] Y. Lu, D. Garner, C. Korose, S. Chen, M. Rostam-Abadi, *Inventory of Industrial Stationary CO2 Emissions in the Illinois Basin*, Illinois State Geological Survey, Champaign, 2007.
- [45] Alternative fuels data center: maps and data - U.S. ethanol plants, capacity, and production." Accessed: Feb. 05, 2026. [Online]. Available: <https://afdc.energy.gov/data/10342>.
- [46] A. Laude, O. Ricci, G. Bureau, J. Royer-Adnot, A. Fabbri, CO2 capture and storage from a bioethanol plant: carbon and energy footprint and economic assessment, *Int. J. Greenh. Gas Control* 5 (5) (Sep. 2011) 1220–1231, <https://doi.org/10.1016/j.jggc.2011.06.004>.
- [47] Carbon management – prairie research institute." Accessed: Jan. 08, 2025. [Online]. Available: <https://prairie.illinois.edu/research/carbon-management/>.
- [48] F.G. Albrecht, D.H. König, N. Baucks, R.-U. Dietrich, A standardized methodology for the techno-economic evaluation of alternative fuels – a case study, *Fuel* 194 (Apr. 2017) 511–526, <https://doi.org/10.1016/j.fuel.2016.12.003>.
- [49] Max S. Peters, K.D. Timmerhaus, R.E. West, *Plant Design and Economics for Chemical Engineering*, 5th Edition, McGraw-Hill Higher Education, 2003.
- [50] G. Zang, P. Sun, A. Elgowainy, M. Wang, Technoeconomic and life cycle analysis of synthetic methanol production from hydrogen and industrial byproduct CO2, *Environ. Sci. Technol.* 55 (8) (Apr. 2021) 5248–5257, <https://doi.org/10.1021/acs.est.0c08237>.
- [51] F.J. Keil, Methanol-to-hydrocarbons: process technology, *Microporous Mesoporous Mater.* 29 (1) (Jun. 1999) 49–66, [https://doi.org/10.1016/S1387-1811\(98\)00320-5](https://doi.org/10.1016/S1387-1811(98)00320-5).
- [52] P. Tian, Y. Wei, M. Ye, Z. Liu, Methanol to Olefins (MTO): from fundamentals to commercialization, *ACS Catal.* 5 (3) (Mar. 2015) 1922–1938, <https://doi.org/10.1021/acscatal.5b00007>.
- [53] M.R. Gogate, Methanol-to-olefins process technology: current status and future prospects, *Petrol. Sci. Technol.* 37 (5) (Mar. 2019) 559–565, <https://doi.org/10.1080/10916466.2018.1555589>.
- [54] S.A. Tabak, S. Yurchak, Conversion of methanol over ZSM-5 to fuels and chemicals, *Catal. Today* 6 (3) (Jan. 1990) 307–327, [https://doi.org/10.1016/0920-5861\(90\)85007-B](https://doi.org/10.1016/0920-5861(90)85007-B).
- [55] US Energy Information Administration, U.S. fuel ethanol plant production capacity [Online]. Available, <https://www.eia.gov/petroleum/ethanolcapacity/>.
- [56] J.M. Abel, Comparative Assessment of the Societal Cost of PtL and LH2 as Aviation Fuels, Massachusetts Institute of Technology, Thesis, 2023 [Online]. Available: <https://dspace.mit.edu/handle/1721.1/150287>. (Accessed 28 September 2023).
- [57] K. Maguire, S. Tanner, J.B. Winikoff, R. Williams, Utility-Scale Solar and Wind Development in Rural Areas: Land Cover Change (2009–20), ERR-330, U.S. Department of Agriculture, Economic Research Service, 2024, <https://doi.org/10.32747/2024.8374829.ers>. Accessed: Jun. 16, 2025. [Online]. Available: <https://www.ers.usda.gov/publications/pub/?id=10248>.
- [58] Global wind atlas." Accessed: Aug. 20, 2025. [Online]. Available: <https://globalwindaatlas.info>.
- [59] Global solar atlas." Accessed: Aug. 20, 2025. [Online]. Available: <https://globalsolaratlas.info/map>.
- [60] B. Lane, J. Reed, B. Shaffer, S. Samuelsen, Forecasting renewable hydrogen production technology shares under cost uncertainty, *Int. J. Hydrogen Energy* 46 (54) (Aug. 2021) 27293–27306, <https://doi.org/10.1016/j.ijhydene.2021.06.012>.
- [61] V. Vijayakumar, A. Jenn, L. Fulton, Low carbon scenario analysis of a hydrogen-based energy transition for On-Road transportation in California, *Energies* 14 (21) (Jan. 2021) 7163, <https://doi.org/10.3390/en14217163>.
- [62] Massachusetts Institute of Technology Energy Initiative, The Future of Solar Energy, Massachusetts Institute of Technology Energy Initiative, 2015. Accessed: Sep. 18, 2023. [Online]. Available, <https://energy.mit.edu/wp-content/uploads/2015/05/MITEI-The-Future-of-Solar-Energy.pdf>.
- [63] U.S. Energy Information Administration, *Electricity Market Module of the National Energy Modeling System: Model Documentation 2022*, 2022.
- [64] Finance for climate action: scaling up investment for climate and development," Grantham Research Institute on Climate Change and the Environment. Accessed: Oct. 12, 2023. [Online]. Available: <https://www.lse.ac.uk/granthaminstitute/publication/finance-for-climate-action-scaling-up-investment-for-climate-and-development/>.
- [65] E.C.D. Tan, et al., "Process design and economics for the conversion of lignocellulosic biomass to hydrocarbons via indirect liquefaction. Thermochemical Research Pathway to High-Octane Gasoline Blendstock Through Methanol/Dimethyl Ether Intermediates, NREL/TP-5100-62402, 1215006, Mar. 2015, <https://doi.org/10.2172/1215006>.
- [66] O. Onel, A.M. Niziolek, C.A. Floudas, Optimal production of light olefins from natural gas via the methanol intermediate, *Ind. Eng. Chem. Res.* 55 (11) (Mar. 2016) 3043–3063, <https://doi.org/10.1021/acs.iecr.5b04571>.
- [67] Natural gas industrial price, Accessed: Jul. 15, 2024. [Online]. Available, https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPGO_PIN_DMcf_a.htm.
- [68] E. Smith, J. Morris, H. Khesghi, G. Teletzke, H. Herzog, S. Paltsev, The cost of CO2 transport and storage in global integrated assessment modeling, *Int. J. Greenh. Gas Control* 109 (Jul. 2021) 103367, <https://doi.org/10.1016/j.jggc.2021.103367>.
- [69] Z. Huang, G. Grim, J. Schaidle, L. Tao, Using waste CO2 to increase ethanol production from corn ethanol biorefineries: techno-economic analysis, *Appl. Energy* 280 (2020) 115964.
- [70] M.D. Staples, et al., Lifecycle greenhouse gas footprint and minimum selling price of renewable diesel and jet fuel from fermentation and advanced fermentation production technologies, *Energy Environ. Sci.* 7 (5) (Apr. 2014) 1545–1554, <https://doi.org/10.1039/C3EE43655A>.
- [71] U.S. total refiner petroleum product prices." Accessed: Sep. 20, 2024. [Online]. Available: https://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_a.htm.

- [72] U.S. Energy Information Administration - EIA - Independent statistics and analysis." Accessed: Sep. 19, 2024. [Online]. Available: <https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T03.07C#/?f=A&start=1949&end=2023&charted=10-15>.
- [73] Directive (EU), 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast) (text with EEA relevance.), 328 Accessed: Dec. 24, 2024. [Online]. Available: <http://data.europa.eu/eli/dir/2018/2001/oj/eng>, 2018.
- [74] ICAO, "ICAO document-CORSIA Methodology for Calculating Actual Life Cycle Emissions Values."
- [75] R. Chen, "CA-GREET3.0 Lookup Table Pathways Technical Support Documentation".
- [76] European Electricity Prices and Costs," Ember. Accessed: Sep. 19, 2024. [Online]. Available: <https://ember-climate.org/data/data-tools/european-electricity-prices-and-costs/>.
- [77] U.S. Share of Electric and Hybrid Vehicle Sales Increased in the Second Quarter of 2024 - U.S. Energy Information Administration (EIA)." Accessed: Oct. 11, 2024. [Online]. Available: <https://www.eia.gov/todayinenergy/detail.php?id=62924>.