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From biofuels to e-fuels: an assessment of techno-economic and environmental performance

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The energy transition, alongside sufficiency measures, demands massive electrification supported by low-carbon electricity. However, carbon-based molecules will remain vital, especially in sectors like long-distance transport (aviation and shipping) and chemicals. Biogenic, atmospheric, or recycled carbon sources offer key alternatives to fossil fuels in the shift toward a circular carbon economy, aligning with sustainability goals like the Renewable Energy Directive (RED III). Based on 183 case studies, this work analyzes thermochemical conversion processes for fuel production, using lignocellulosic biomass, CO_2, and low-carbon hydrogen from electrolysis. Nine biofuel, e-fuel, and e-biofuel processes are evaluated, producing liquid hydrocarbons, synthetic natural gas, or methanol. Material and energy balances, determined using ProSimPlus®, compare carbon conversion and energy efficiency. Economic analysis estimates investment and production costs for industrial-scale units, while greenhouse gas (GHG) assessment considers different electricity mixes and biomass supply chains. The results show that substituting biomass with hydrogen improves carbon conversion: from 35–40% for biofuels to 65–70% for e-biofuels, and up to 80–85% for e-fuels with carbon capture. Hybrid energy sources boost energy efficiency for e-biofuels (61.3%) compared to biofuels (50.3%). However, using electricity (100 € per MWh) raises production costs, which are heavily dependent on electricity price assumptions. Aligning e-fuel and e-biofuel production with RED III requires a largely decarbonized electricity mix, while more comprehensive emission assessments are necessary for biofuels and e-biofuels, considering potential land-use impacts of massive biomass production.

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1 Introduction

Despite the ongoing energy transition, electrification alone cannot fully replace carbon-based molecules across all sectors. This is particularly true for long-distance air and maritime transport, which require high energy density carriers.[18] Carbon also plays a central role in organic chemistry, a sector in which the main challenge is "defossilization" rather than decarbonization. Thermochemical carbon conversion processes convert CO_2 or biomass into high-energy-density chemical compounds such as liquid hydrocarbons, synthetic natural gas, methanol, and dimethyl ether. Carbon dioxide transformation requires a significant external energy input, often provided by the hydrogen vector. The products of these processes are known as e-fuels, powerfuels, or renewable fuels of non-biological origin (RFNBO). Sustainable fuels can also be produced from biomass with or without external energy input. The carbon products resulting from these processes are respectively called biofuels and e-biofuels. In the context of energy transition with a growing share of non-dispatchable energy sources, these processes could be relevant as system flexibility solutions, by storing electrical energy in the form of easily storable molecules.

To be considered sustainable and help reach carbon neutrality, these fuels should produce significantly lower greenhouse gas emissions over their life cycle than conventional fossil fuels (−65% to −70% depending on the fuel).[12,13] This assumption can only be considered valid for advanced biofuels derived from lignocellulosic biomass. Compared to conventional first-generation biofuels,[29] the risk of significant indirect land-use change (ILUC) is reduced due to less competition with food and feed uses. However, the environmental benefits of fossil fuel substitution with biofuels are still highly debated. Indeed, it competes with material uses[5] and other mitigation strategies such as increasing natural carbon sinks.[10] The alternative carbon feedstock is CO_2 captured from concentrated industrial emissions or directly extracted from the atmosphere using direct air capture (DAC) systems. Although they offer significant potential, the abatement cost of CO_2 is higher for DAC technologies than post-combustion systems which are also more mature.[15] However, fossil CO_2 emissions from industrial sources will no longer be considered avoided for RFNBO production as of 2041 in the European Union.[9] The

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"defossilization" of carbonaceous molecule production also needs alternative energy sources. In addition to the chemical energy content of biomass, low-carbon electrolytic hydrogen has been identified as an essential alternative to fossil fuels for this transition.[23]

Since the early 2000s and the release of two seminal studies,[21,31] numerous studies have examined thermochemical processes for sustainable fuel production using lignocellulosic biomass, CO_2, and hydrogen as inputs. Simulations have explored a wide range of pathways for the production of useful carbonaceous molecules. The results of these studies show uneven technical performance, with a wide range of energy efficiencies (35 to 70%). The economic analysis of these processes also shows a wide range of production costs (from 50 € to 250 € MWh). Uncertainties in production costs and the lack of political incentives in the past decade did not allow for industrial deployment of second-generation biofuels. E-fuel production unit development is mainly dependent on the maturity level of industrial-scale electrolyzers.

The main aim of the paper is to compare representative biofuel, hybrid e-biofuel and e-fuel processes, to identify the main drivers of their techno-economic and environmental performance. In the first section, we compiled the most interesting processing routes for the production of high-energy-density carbonaceous molecules among a wide variety of processes from the literature. Then, we established the material and energy balances of the most interesting routes using process simulation. Finally, we carried out a techno-economic and environmental assessment to produce consolidated indicators including carbon conversion, energy efficiency, investment costs, net production costs, and life-cycle GHG emissions.

2 Methodology

2.1 Literature review

Among the different conversion pathways of non-fossil carbon into energy-dense molecules, we focused on the thermochemical conversion of lignocellulosic biomass and carbon dioxide, with the possibility of additional energy input. Products included liquid hydrocarbons, synthetic natural gas (SNG), methanol, and, to a lesser extent, dimethyl ether (DME). This preliminary step aimed to identify the most significant pathways among the wide variety of existing processes, thereby building a database of technical and economic performance. Numerous studies have compared technical and economic performance between a few specific processes. At the same time, several review articles provide methodological recommendations for assessing and discussing the performance of these processes. Zhang *et al.* (2020) evaluated the thermodynamic and economic performance of different biomass-to-fuel processes (SNG, methanol, DME, and jet fuel) with the integration of a solid-oxide electrolyzer.[35] Their results show that state-of-the-art BtX (Biomass-to-X) processes achieve similar efficiency (50%) regardless of the fuel produced. Enhanced steam electrolysis and, to a lesser extent, co-electrolysis cases achieve higher energy efficiencies but at higher levelized production costs. Anetjärvi *et al.* (2023) focused on methanol production, highlighting the benefits of two hybrid processes with different proportions of hydrogen compared to standalone e-methanol and bio-based methanol production.[4] Hybrid cases also achieved a lower levelized cost of production (LCOP) than e-methanol production and they reduce biogenic CO_2 emissions compared to biomass-based methanol production. Haarlemmer *et al.* (2012) aimed to clarify the main reasons for the large variation in production costs of second-generation biofuels in the previous literature.[20] They showed that biomass-to-liquids (BtL) fuels were likely to be produced in a 1.0–1.4 €/l range for a 400 MWth plant. Variability in production cost estimation is due to the unclear calculation of investment costs. They found significant differences in the ratio between gross equipment costs and the total depreciable capital cost, as well as in the choice of the economic lifetime of the plant. Haarlemmer *et al.* (2014) completed the analysis showing that the spread in the economic data sources explains much of the spread in the predictions.[19] They recommended not interpreting a single publication of data sources to draw strong conclusions. Unlike with gas and coal processes, predictions of the future costs of BtL plants are difficult because economies of scale will depend on the technology readiness level (TRL) and feedstock logistics. van den Oever *et al.* (2022) reviewed a panel of biomass-based Fischer–Tropsch plants and their energy conversion efficiency.[25] Among 6 identified energy conversion efficiency definitions, overall efficiency and biomass-to-fuel efficiency were the most common. Trying to identify the main variables affecting energy efficiency, they did not find any correlation between production costs and overall efficiency but a moderate correlation with biomass-to-fuel efficiency. Albrecht *et al.* (2017) proposed a standardized methodology to assess the techno-economic performance of alternative fuels.[2] They highlighted that the results of previous studies were difficult to compare due to significant differences in the applied methodology, level of detail, assumptions for economic factors, and market prices. Their methodology, adapted from the chemical industry, was organized as follows: literature survey, flowsheet simulation, and techno-economic assessment. Their results gave production costs ranging from 1.2 €/l to 2.8 €/l, with a high sensitivity of power-to-liquids (PtL) and power & biomass-to-liquids (PBtL) processes to electricity prices. Bernical *et al.* (2013) and Peduzzi *et al.* (2018) also conducted greenhouse gas emission assessments for comparison between biofuel and e-biofuel processes. Depending on the type of process and the electricity mix considered, they found emission values ranging from −29 kg $CO_{2,eq}$ per MWh to 213 kg $CO_{2,eq}$ per MWh,[6,26] with the co-production of green electricity explaining the negative values. Ali *et al.* (2024) conducted a more in-depth study of the environmental impact of carbon dioxide removal (CDR) and carbon capture and utilization (CCU) technologies, based on a life cycle analysis for different European locations.[3] In particular, they provided GHG emission estimates for the production of jet fuel, SNG, methanol, and DME from CO_2 captured *via* DAC and electrolytic hydrogen.

Previous review studies have either attempted to make comparisons between different sectors, to evaluate production costs for a sector based on statistical data, or to propose techno-economic and environmental assessment methodologies. However, we did not find any comprehensive study that includes technical, economic, and environmental assessment of process performance for a large spectrum of resources, products, and pathways, based on literature data and simulation.

Our assessment of technical and economic performance is based on an initial synthesis of existing works, both in-house and from the literature. Each case study is characterized and classified to build an exhaustive tree structure of the existing panel. These made it possible to limit the scope of the study to the most interesting conversion processes according to literature data. We made a first distinction between biofuels (BtX) processes, e-fuels (PtX) processes, and e-biofuels (PBtX) processes. The second distinction was established depending on the type of fuel produced. The number of case studies listed for each of the 12 value chains is shown on the right-hand side of Fig. 1.

Most of the 183 case studies from 33 sources are based on process simulations rather than experimental data. The SI details the sources' chronological breakdown (see the section "Database of the 183 case studies"). Among them, Peduzzi *et al.* (2018) compared the performance of different BtL and PBtL processes, with torrefaction or grinding only, entrained flow or fluidized bed gasifiers, with or without a high-temperature stage, using a multi-criteria optimization model.[27] Seiler *et al.* (2010) followed a similar approach, focusing on the differences between fast pyrolysis and torrefaction, or between electrolysis and steam methane reforming (SMR) for additional hydrogen production.[30] Bernical *et al.* (2013) made a performance comparison between a BtL process using torrefaction and an entrained flow gasifier and two corresponding PBtL processes, using alkaline electrolysis *versus* high-temperature electrolysis for hydrogen production.[6] Hillestad *et al.* (2018) followed the same purpose, using a solid-oxide electrolysis cell (SOEC) technology for electrolysis.[22] Dossow *et al.* (2021) explored one step further by assessing the evolution of the technical performance of PBtL processes.[11] To do so, they gradually increased the hydrogen supply until reaching maximum carbon conversion. To a lesser extent, the literature provides some case studies of the thermochemical production of fuels other than liquid hydrocarbons. Tock *et al.* (2010) provided a comprehensive analysis of BtL, PBtL, BtMeOH (biomass-to-methanol), PBtMeOH (power & biomass-to-methanol), and PBtDME (power & biomass-to-dimethyl ether) cases, taking into account energetic, economic, and environmental considerations.[32] The same considerations were assessed by de Fournas & Wei (2022) with two methanol production processes, BtMeOH and PBtMeOH, using a proton exchange membrane (PEM) electrolysis to produce hydrogen.[16] We also find the same methodology for synthetic natural gas production in ref. 17 through a techno-economic assessment of several cases of BtSNG (biomass-to-synthetic natural gas) and PBtSNG (power & biomass-to-synthetic natural gas) processes. Based on the literature review, we identified 35 conversion processes, characterized by different carbon and energy feedstocks, desired products, or technological choices.

2.2 Process simulation

2.2.1 Pathways selection. Based on a review of over 180 case studies, we identified a representative panel of nine conversion pathways for simulation, covering biofuel (BtX), e-biofuel (PBtX), and e-fuel (PtX) routes. Selection was guided by literature relevance, data availability, and consistency with previous modelling efforts.

The three target fuel types are liquid hydrocarbons, synthetic natural gas (SNG), and methanol. For each, we retained one representative BtX, PBtX, and PtX pathway (Fig. 2), leading to a total of nine configurations. Dimethyl ether (DME) was excluded due to limited data coverage.

The complete list of 35 pathways initially considered, as well as detailed selection criteria and technology mapping, is provided in the SI.

2.2.2 Modelling assumptions. Each process simulation follows harmonized assumptions to ensure comparability across the nine selected pathways. Lignocellulosic biomass is

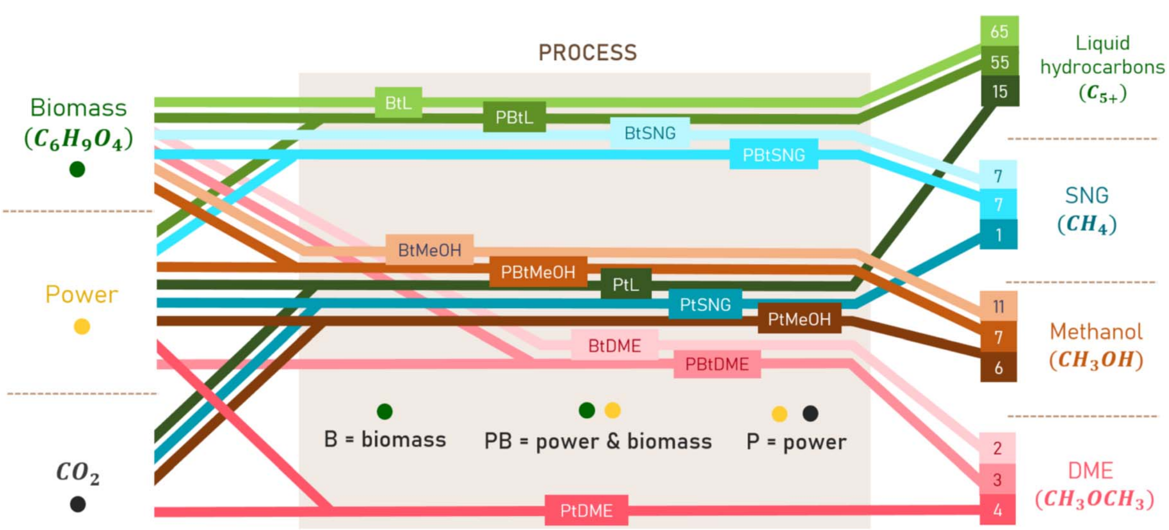

Fig. 1 Scope of the 12 selected biofuel, e-biofuel, and e-fuel thermochemical pathways.

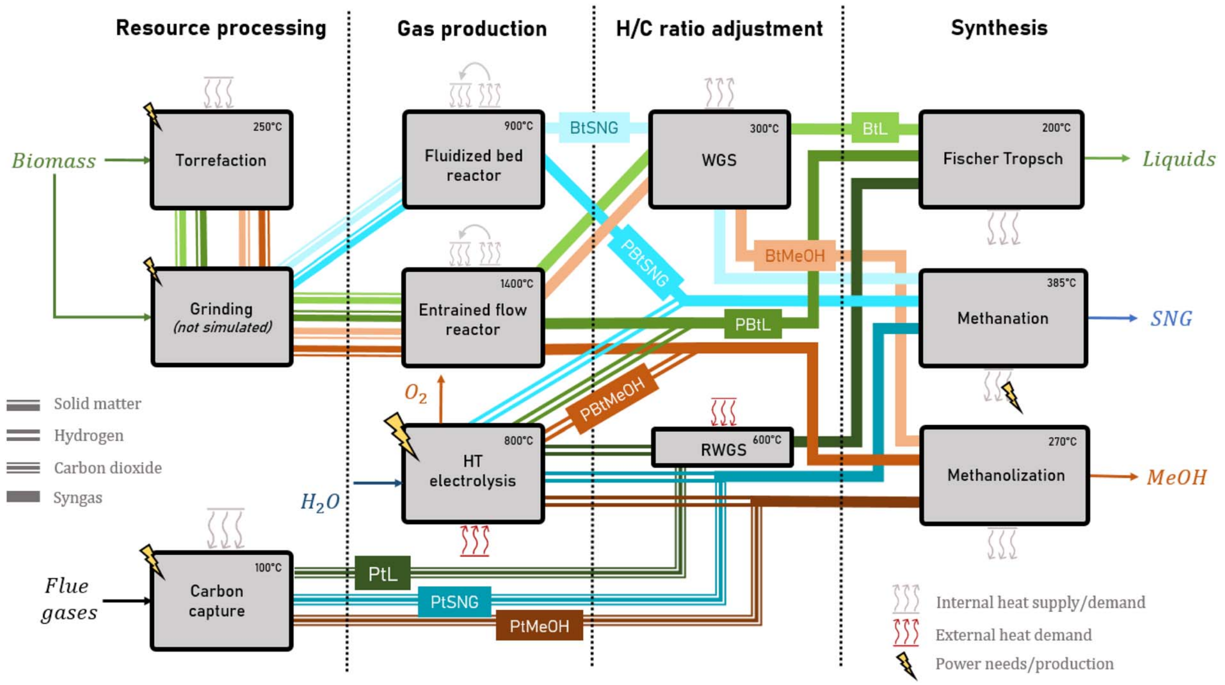

Fig. 2 Description of the 9 selected pathways, with the simulated transformation blocks.

modelled using pseudo-components with calibrated heating values reflecting average elemental composition ($C_6H_9O_4$). Biomass is pretreated through torrefaction to improve energy density and grindability.

Syngas is produced *via* gasification, using either entrained-flow reactors for liquids and methanol or fluidized-bed reactors for SNG. Carbon capture is modelled using a post-combustion amine-based system. Electrolytic hydrogen is supplied *via* solid oxide electrolysis cells (SOECs), selected for their favorable integration potential.

Fuel synthesis steps include Fischer–Tropsch synthesis (for hydrocarbons), methanation (for SNG), and methanol synthesis, with standard separation and recycling loops. The H/C ratio of syngas is adjusted depending on the synthesis route, either *via* the water-gas shift (WGS) reaction with steam (biofuels), reverse-WGS (e-fuels), or by tuning hydrogen input (e-biofuels), to meet optimal synthesis requirements.

All simulations are carried out using ProSimPlus®, with consistent thermodynamic models and reaction conditions. Full modelling details, operating parameters, and chemical reactions are provided in the SI.

2.2.3 Performance criteria. Two key performance indicators were used to assess and compare the simulated pathways. The carbon conversion efficiency quantifies how effectively the carbon from biomass or CO_2 feedstock is transferred into the final fuel products. The overall energy efficiency evaluates the proportion of input energy (from biomass and/or electricity) retained in the chemical energy of the fuel.

Several definitions of energy efficiency exist in the literature. In this study, we adopted the overall energy efficiency (η_{ov}), which accounts for electricity and heat integration across the full process chain and is the most widely used metric in comparative assessments.

Full equations, input/output assumptions, and alternative indicators (*e.g.*, internal yield or primary energy efficiency) are detailed in the SI.

2.3 Economic analysis

The economic analysis aims to evaluate the investment and production costs associated with each simulated pathway at the industrial scale. We decided to use two main indicators:

- Capital intensity (€ per kW output), defined as the total depreciable capital cost per unit of fuel output;
- Net production cost (NPC) (€ per MWh), calculated from fixed and variable annualized costs.

Equipment costs are estimated from literature-based reference values, scaled to the appropriate unit sizes using standard cost-scaling laws and updated using the Chemical Engineering Plant Cost Index (CEPCI). An installation factor is applied to capture indirect costs such as utilities, piping, and infrastructure.

Operating costs include biomass and electricity inputs, maintenance, labor, and financial charges. Capital is assumed to be fully debt-financed at a 7% interest rate over a 20 year lifetime period. The electricity and biomass prices reflect average French market values in 2023.

A summary of key economic assumptions is provided in Table 1. Detailed cost equations, equipment reference data, and calculation methodology are available in the SI.

2.4 Environmental analysis: life cycle greenhouse gas emissions

As substitutes for fossil fuels, biofuel, e-biofuel, and e-fuel production require other primary resources. Both biomass

Table 1 Economic analysis parameters

Parameter	Value
Loan interest rate	7%
Lifetime	20 years
Availability	0,9
Electricity price	100,7 €/MWh
Biomass price	21,6 €/MWh
Natural gas price	44,4 €/MWh
Paraffin wax price	1,54 €/kg
Exchange rate $/€	0,93

and electricity supply have non-zero climate impacts. We assessed greenhouse gas (GHG) emissions using a cradle-to-gate life cycle approach, in line with the methodology defined in the Renewable Energy Directive III (RED III).[12] The analysis includes emissions from the extraction, transformation, and transport of input resources (biomass, electricity, and CO_2), while excluding infrastructure and land-use change impacts (LUC/ILUC), as permitted under RED III.

Biogenic CO_2 was considered climate-neutral. The analysis focuses on key contributors: upstream emissions from electricity and biomass supply, as well as minor fossil-based auxiliaries (*e.g.* natural gas and waxes).

Several emission scenarios were defined to reflect varying input assumptions.[7] For biomass, we considered both the RED III default value (26.4 $kgCO_{2,eq}$ per MWh) and a lower estimate based on an alternative recent French study from ADEME (16.1 $kgCO_{2,eq}$ per MWh),[1] with one key variable being the assumed transport distance of the feedstock (<500 km for the RED III scenario or = 35 km for the ADEME scenario). For electricity, we used 2022 French grid data (54.4 $kgCO_{2,eq}$ per MWh) and a projected 2050 low-carbon mix (13 $kgCO_{2,eq}$ per MWh, based on the "N1 scenario of RTE).[28] These scenarios allow us to assess the sensitivity of each pathway's climate impact to upstream emissions.

A summary of the emission factors used in each scenario is provided in a tabular form in the SI. Emissions were further assessed under different electricity supply configurations (EU mix, nuclear, renewable mix, and CHP), with detailed results also provided in the SI.

3 Results

3.1 Carbon conversion and energy efficiency

3.1.1 Simulation results. Fig. 3(a) shows the carbon conversion rates of the 9 simulated processes. Carbon conversion increases from 35–39% for biofuels (BtX), to 65–71% for e-biofuels (PBtX), and up to 77–85% for e-fuels (PtX).

The overall energy efficiencies calculated from the energy and material balances of the 9 simulations are illustrated in Fig. 3(b). Energy efficiencies follow a slightly different pattern: 48–55% for BtX, 56–64% for PBtX, and 55–61% for PtX. Among the three process families, PBtX configurations systematically show the highest energy yields across all three fuel types. Liquid hydrocarbon production performs slightly worse than methanol or SNG, with differences ranging from −3 to −8% in carbon conversion and −1 to −8% in energy efficiency.

These trends are further discussed in the key findings section (Section 5.1).

3.1.2 Comparison with the literature. To confirm the general trends observed in our simulations, we compared our results with over 180 case studies from the literature. We defined the power penetration rate τ_{power} as follows:

$$\tau_{power} = \frac{P_{elec}}{P_{elec} + P_{biomass}} \tag{1}$$

P_{elec} is the electric input power of the electrolyzer and $P_{biomass}$ is the biomass input power.

Each process was positioned on a continuum from BtX ($\tau_{power} = 0$) to PtX ($\tau_{power} = 1$), with hybrid PBtX processes occupying intermediate positions based on the share of electricity in the total primary energy input.

Fig. 4(a) shows that carbon conversion generally increases with τ_{power}: it ranges from 30–40% for BtX, 60–90% for PBtX around $\tau_{power} \approx 0.5$, and up to 75–100% for PtX. These trends align well with the simulation results. The absence of case studies between $\tau_{power} = 0.6$ and 1 reflects the practical limitation of biogenic carbon supply in hybrid processes without CO_2 capture.

Fig. 4(b) shows that energy efficiency in the literature varies widely—from less than 20% to more than 80%, regardless of the fuel type—mainly due to divergent definitions of efficiency and uneven coverage of heat recovery.[2,33] Nevertheless, a general pattern emerges: energy yield tends to increase from BtX to PBtX and then declines for PtX, consistent with our simulations.

These comparisons and their implications are discussed in Section 5.1.

3.2 Investments and production costs

3.2.1 Results of the study. Fig. 5(a) presents the breakdown of investment costs by process block. Across all pathways, total capital costs range from 3000 to 5500 € per kW output, corresponding to approximately 1 billion euros for a 400 MW input industrial-scale plant. The syngas production step—*via* gasification and/or electrolysis—is the main cost driver, representing 50–68% of total investments for e-biofuel and e-fuel processes.

Biomass pretreatment (drying, grinding, and torrefaction) is also significant: it accounts for 35% of capital costs for BtX, 24% for PBtX, and 14% for PtX, which also includes CO_2 capture unit costs. E-biofuel processes tend to have lower capital intensity (2993–3501 € per kW) than biofuels (2914–4876 € per kW) and notably lower than e-fuels (4146–5455 € per kW).

Fig. 5(b) shows net production costs, which range from 118 to 271 € per MWh depending on the product and pathway. On average, biofuels (BtX) cost 118–146 € per MWh, while e-biofuels (PBtX) cost 140–163 € per MWh. E-fuels (PtX) are the most expensive, at 212–271 € per MWh.

These values are typically 2 to 5 times higher than 2023 fossil fuel market prices. Sensitivity analysis and discussion on cost

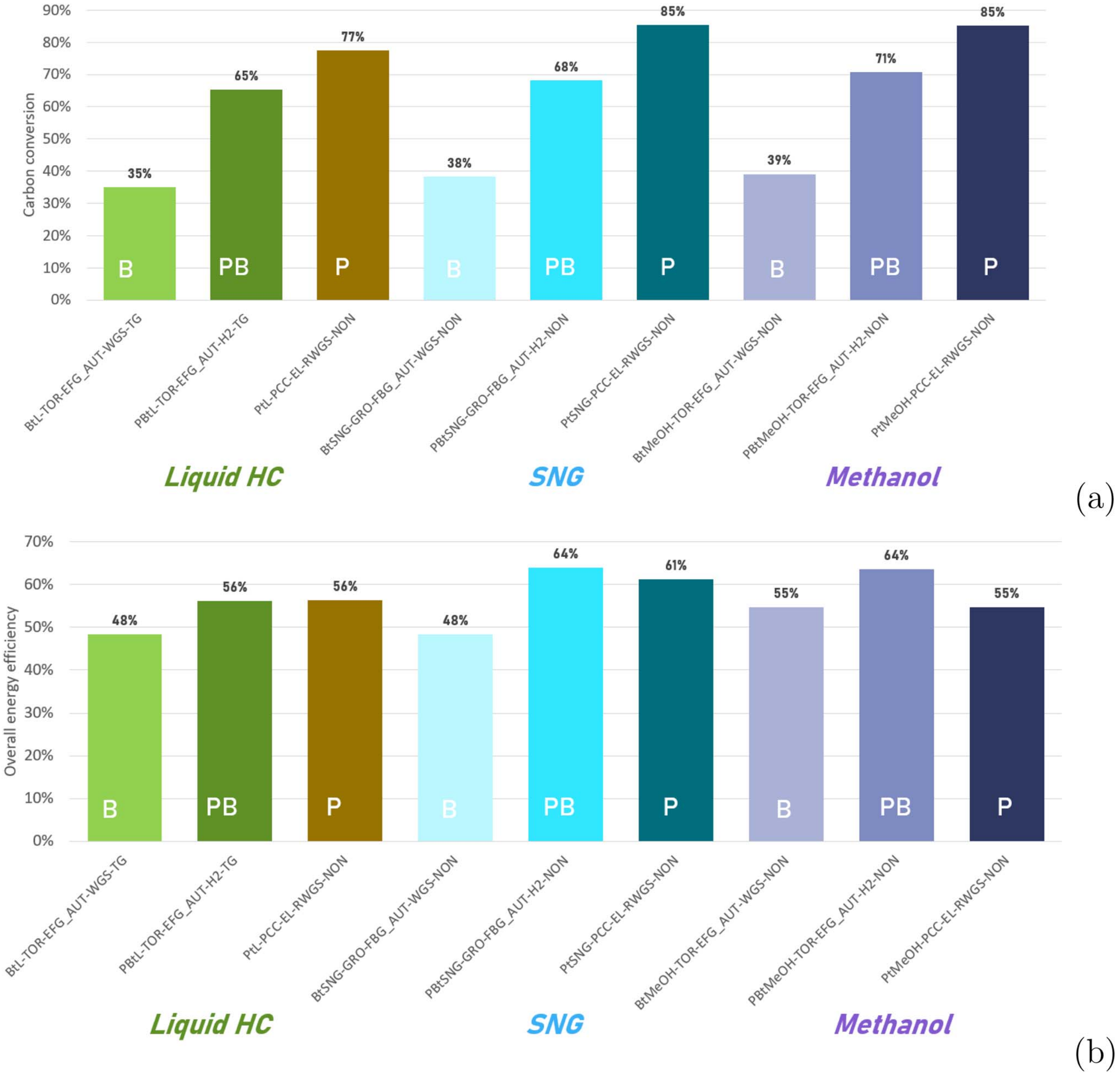

Fig. 3 Carbon conversion η_C (a) and overall energy efficiency $\eta_{ov.}$ (b) for the nine simulated biofuel, e-biofuel and e-fuel production pathways. The corresponding process configurations are detailed below each bar and in the SI.

drivers are detailed in Sections 4.2.2 and 5.1. Detailed component-level costs are available in the SI (see the section "Reference costs and dimensions of equipment").

3.2.2 **Sensitivity.** In Fig. 6, we conducted a sensitivity analysis on production costs by varying key economic assumptions of the economic model (Table 1) for three representative cases (BtL, PBtL, and PtL). A −30% to +30% variation range is applied to each parameter, except for the availability of the installation, which cannot exceed 100%. For the BtX cases, variations of the installation factor and biomass price have the most significant impact, resulting in a +/−10% production cost variation. For PBtX and PtX processes, electricity price variations significantly impact production costs (+/−14% for PBtL and +/−20% for PtL).

3.2.3 **Comparison with the literature.** Fig. 7 compares our simulated net production costs with literature case studies. A wide dispersion is observed among published values, ranging from 50 € per MWh in the most optimistic scenarios to over 200–250 € per MWh in the most conservative ones.

Despite this variability, literature data confirm the strong influence of electricity price on the cost of e-fuels and e-biofuels. This is consistent with our own sensitivity analysis (dotted lines), which aligns well with the distribution of literature cases for PBtX and PtX processes.

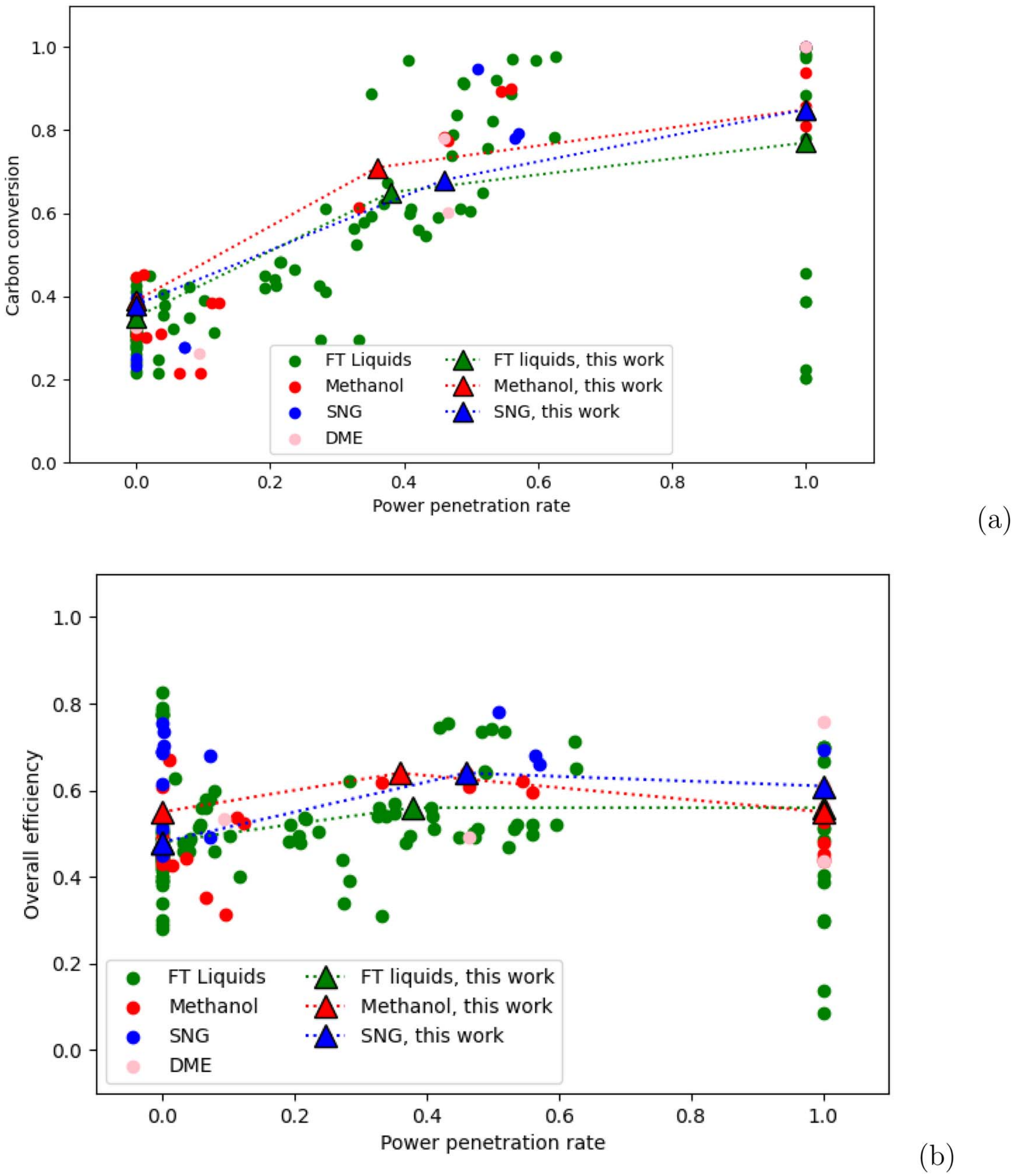

Fig. 4 Carbon conversion and energy efficiency from biofuels (left) to e-fuels (right). Simulation points (triangles) and literature cases (circles).

In contrast, no clear correlation emerges between biomass price and the net production cost of BtX pathways in the literature, suggesting less influence of this input parameter or greater heterogeneity in process assumptions.

3.3 GHG emissions

3.3.1 Results of the study. Fig. 8 presents the life-cycle GHG emissions of the 9 processes under different scenarios. Using 2022 values for the French electricity mix (54.4 $kgCO_{2,eq}$ per MWh) and RED III biomass factors ($kgCO_{2,eq}$ per MWh) (see Section 3.4), emissions range:

• For liquid hydrocarbons: 57 to 96 $kgCO_{2,eq}$ per MWh (BtL to PtL),

• For SNG: 87 to 112 $kgCO_{2,eq}$ per MWh (PtSNG to BtSNG),

• For methanol: 51 to 101 $kgCO_{2,eq}$ per MWh (BtMeOH to PtMeOH).

Assuming the 2050 French electricity mix (13 $kgCO_{2,eq}$ per MWh) (see Section 3.4), emissions drop to 21–24 $kgCO_{2,eq}$ per MWh for e-fuels and 34–66 $kgCO_{2,eq}$ per MWh for e-biofuels. Using the alternative ADEME biomass emission factor (16.1 $kgCO_{2,eq}$ per MWh) reduces emissions across BtX and PBtX pathways, between 33 and 95 $kgCO_{2,eq}$ per MWh for biofuels and between 49 and 87 for e-biofuels.

Under conservative assumptions, only 4 out of 9 processes meet the RED III threshold for sustainable fuels. With 2050 electricity and ADEME biomass factors, all but BtSNG comply.

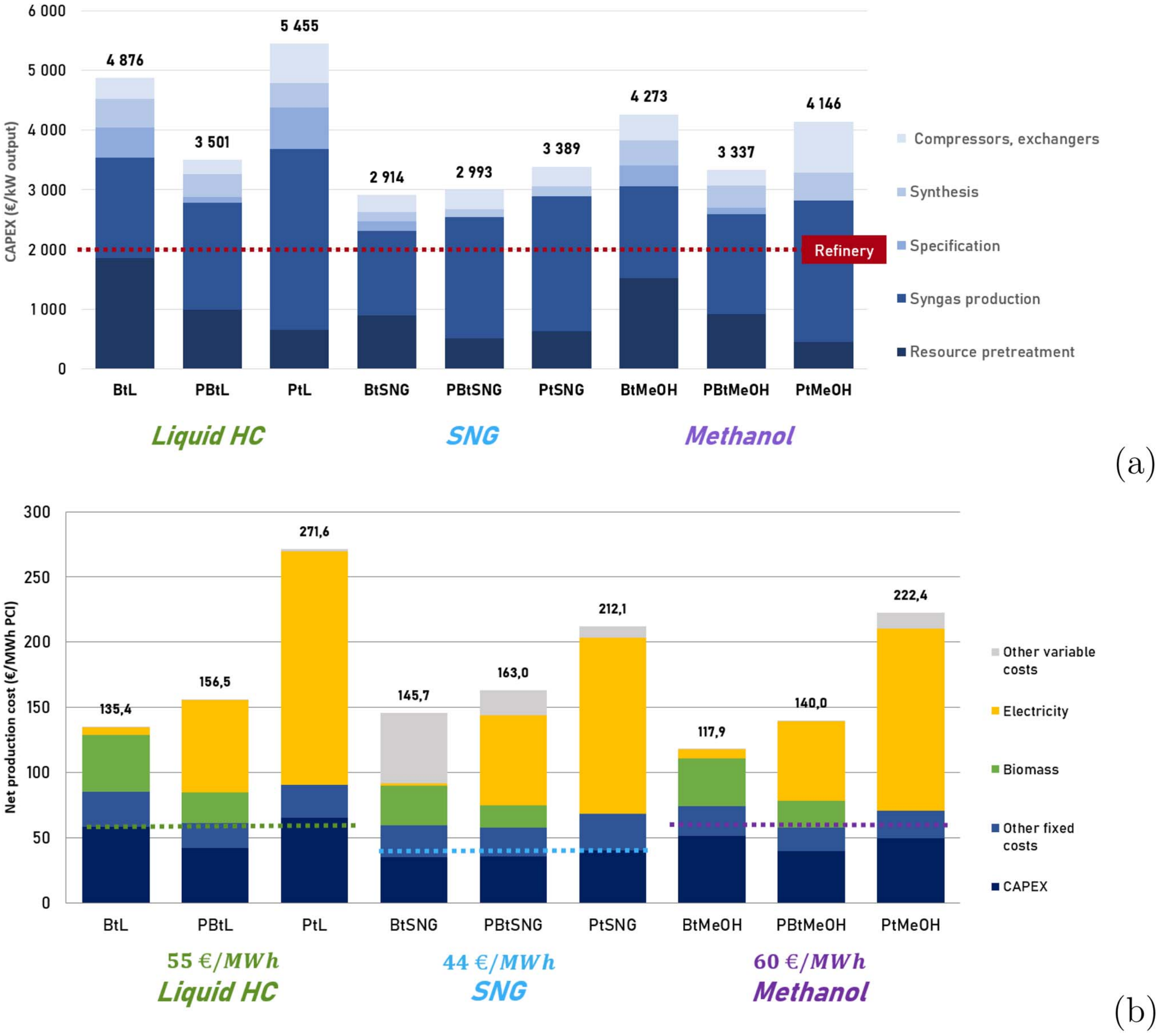

Fig. 5 Capital costs (a) and net production costs (b) of the 9 simulated processes. Green, blue, and purple dotted lines represent the average market prices of the corresponding products in 2023 (Sources: US Energy Information Administration, EEX, Trading Economics).

The latter exceeds the threshold due to the use of fossil paraffin wax in the gasification step.

3.3.2 Sensitivity. Fig. 9 shows the sensitivity of GHG emissions from liquid hydrocarbon production to the carbon intensity of the electricity mix. Similar trends are observed for methanol and SNG (see the SI section "Production costs sensitivity").

In the BtL pathway, emissions vary little with electricity assumptions due to the dominant role of biomass. In contrast, emissions from PBtL and PtL are highly sensitive. PtL emissions fall below PBtL when electricity carbon intensity drops below 35 kg $CO_{2,eq}$ per MWh. To comply with RED III, PtL and PBtL require electricity below 70 and 120 kg $CO_{2,eq}$ per MWh, respectively.

Under current French electricity conditions (54.4 kg $CO_{2,eq}$ per MWh), both processes meet the RED III criteria. This is not the case for the current European mix or in most projections for 2030, especially for PtL, whose footprint today may exceed that of fossil kerosene.

These findings underscore the dependence of synthetic fuel sustainability on the decarbonization of the power sector.

Taking as reference values the emission factor for the European electricity mix in 2030 (114 kg $CO_{2,eq}$ per MWh) and the emission factor for biomass supply from RED III (26.2 kg $CO_{2,eq}$ per MWh), the emissions from the PBtL process reached 109 kg $CO_{2,eq}$ per MWh, matching the emission cap set by RED III, which is around 110 kg $CO_{2,eq}$ per MWh. A cross-sensitivity analysis combining electricity and biomass factors is provided in the SI (see the section "GHG sensitivity analysis").

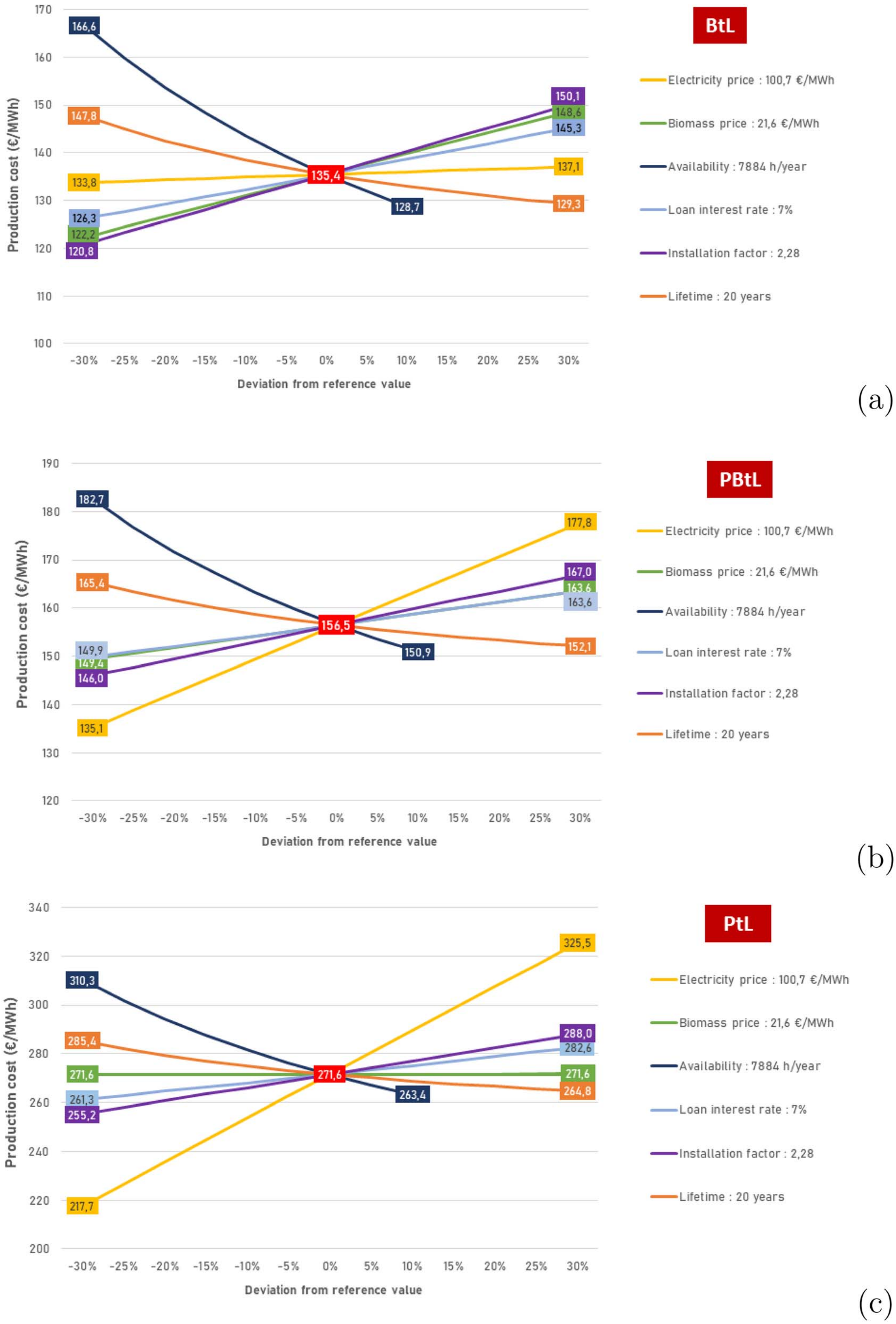

Fig. 6 Sensitivity analysis on net production costs for BtL (a), PBtL (b), and PtL (c) processes.

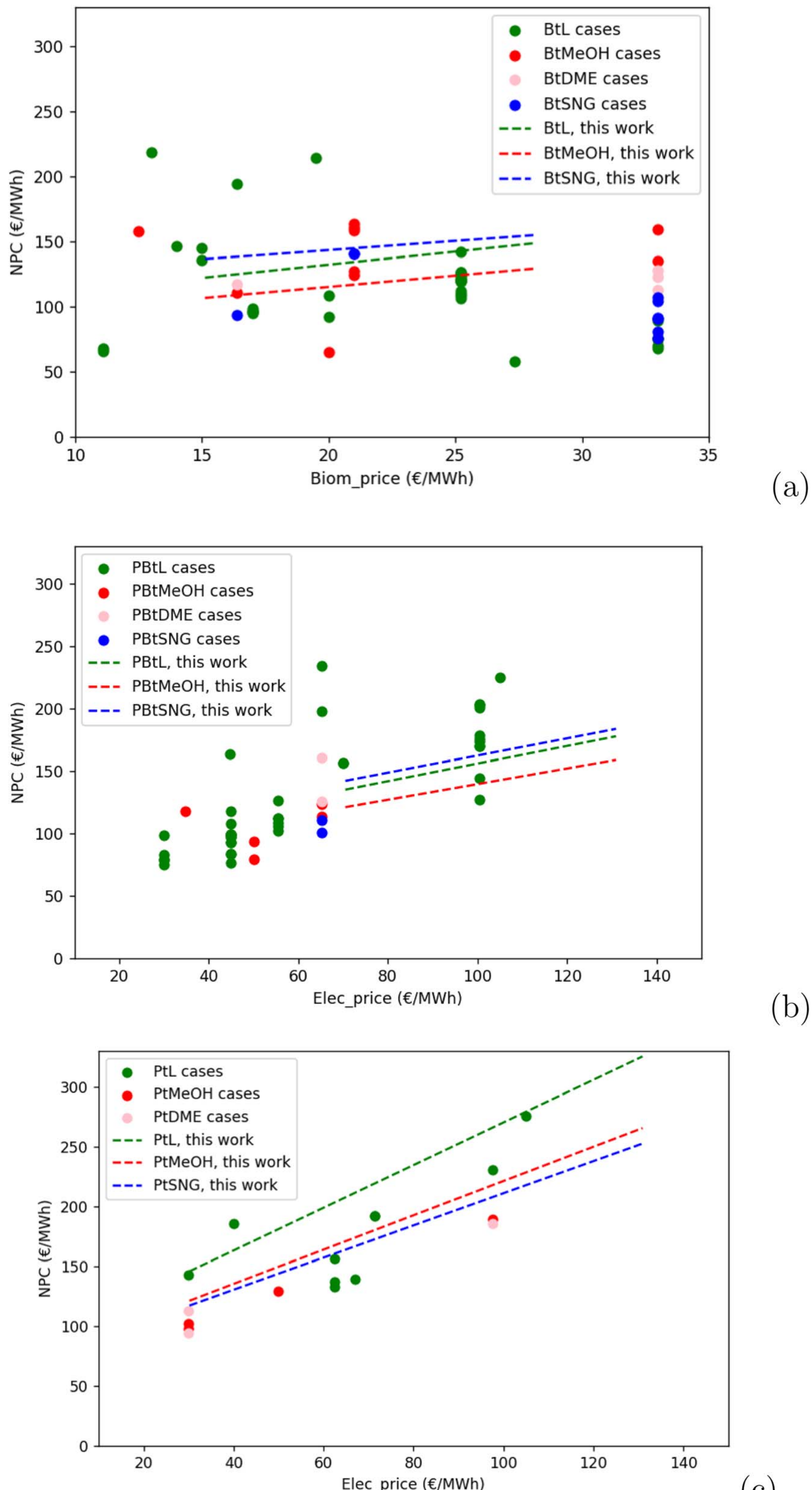

Fig. 7 Net production costs of BtL cases regarding biomass input price assumption (a), PBtL cases regarding electricity input price assumption (b), and PtL cases regarding electricity input price assumption (c).

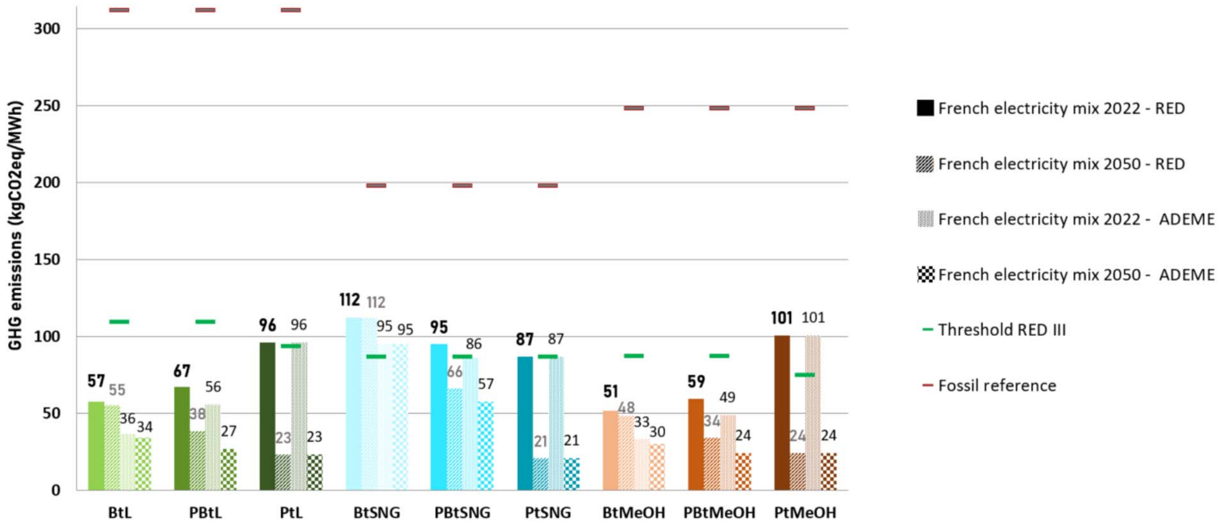

Fig. 8 GHG emissions of the 9 BtX, PBtX, and PtX processes over their life cycle under the four different scenarios.

4 Discussion

4.1 Technical performance: carbon and energy efficiency

The gradual addition of electrolytic hydrogen to biomass enables a higher carbon conversion rate compared to the BtX case, with a +30% increase in carbon conversion for PBtX processes and a +45% increase for PtX processes. In biofuel processes, CO_2 carbon losses occur in the gasification and water-gas shift units. In e-biofuel processes, they are less significant because the ideal H/C ratio is achieved through the external supply of hydrogen, avoiding the need for the water-gas shift reaction. In e-fuel processes, CO_2 losses are explained by the 0.9 carbon capture recovery rate. Fischer–Tropsch liquid processes exhibit slightly lower carbon conversion performance (about −5% compared to SNG or methanol production). This can be attributed to the additional loops for tail-gas recycling and heavy-oil hydrocracking, which tend to increase carbon losses. The large variability of carbon conversion values reported in the literature for Fischer–Tropsch liquids (Fig. 4(a)) can be explained primarily by whether or not a tail-gas recycling

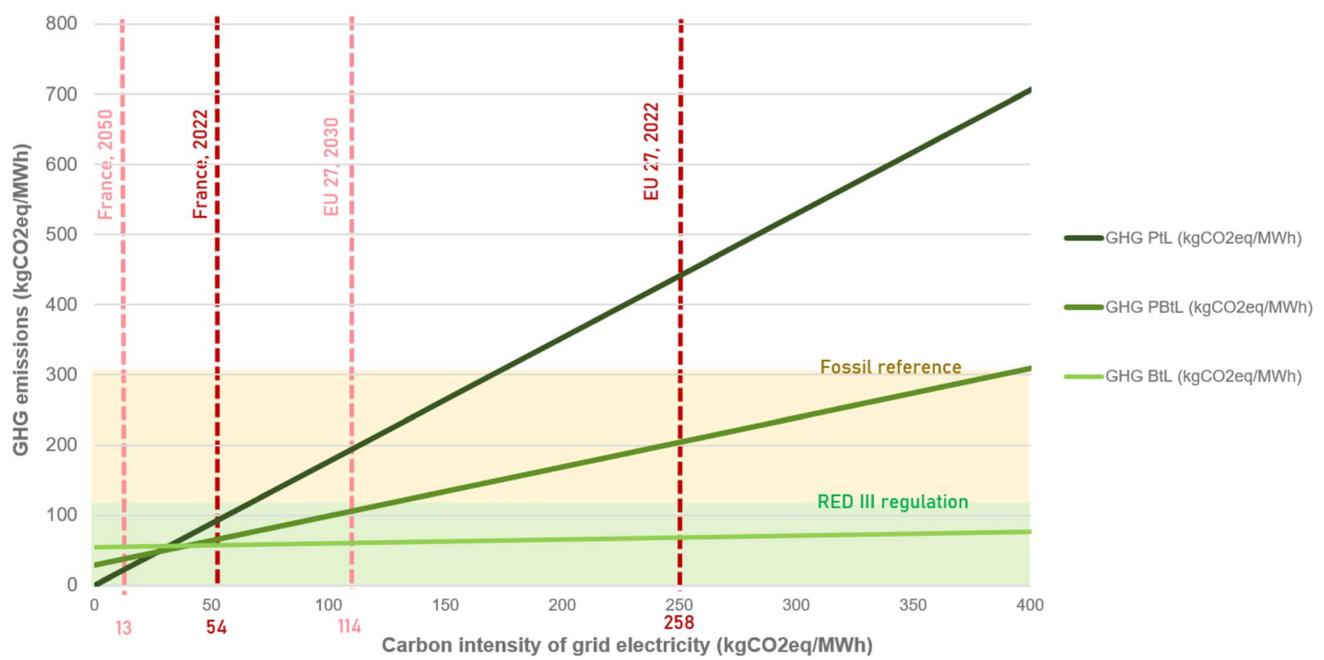

Fig. 9 Sensitivity analysis of GHG emissions of liquid hydrocarbon production for the carbon intensity of electricity. The reference values for the French and European electricity mixes in 2022 are shown in red, while the projections for the French mix in 2050 and the European mix in 2030 are shown in pink. Yellow indicates the emission level of fossil kerosene, and green is the threshold set by the RED III regulation on sustainable fuels.

loop is included. In cases without recycling, the share of hydrocarbons in the valuable C_5–C_{20} fraction is significantly lower, which results in reduced overall carbon utilization. By contrast, when tail gases are reformed and recycled, the effective conversion efficiency increases markedly. Other factors, such as the type of gasifier, the H/C adjustment strategy, and the inclusion of heavy oil upgrading in system boundaries, also contribute to the dispersion. Nevertheless, the presence or absence of tail-gas recycling provides the first-order explanation for the wide spread in literature values.

As observed in several previous studies,[6,11,22,35] the addition of electrolytic hydrogen to biomass significantly improves overall energy efficiencies of liquid hydrocarbons, SNG, and methanol production. The production of hydrogen by SOEC electrolysis technology reaches higher conversion rates than PEM or alkaline electrolysis,[6,11] which explains the improvement in the energy balance of biofuel processes. Moreover, PBtX cases achieve higher energy yields than the corresponding PtX case on average, by avoiding carbon capture energetic costs and reducing the need for hydrogen production. The interpretation of efficiency results strongly depends on the chosen system boundaries and on how the efficiency indicator itself is defined. Using a primary-energy-based efficiency, which converts electricity through a "primary energy factor", tends to penalize processes with high electricity demand. For instance, the primary energy efficiency of the PtL process decreases from 48% when using a renewable mix electricity source (PEF = 1) to 18% when powered by nuclear electricity (PEF = 3). Similarly, the PBtL process sees its primary energy efficiency fall from 57% to 33% under the same change in the electricity source. The complete sensitivity analysis of energy efficiency to different electricity supply assumptions is provided in the SI.

4.2 Economic performance: cost drivers

The synthetic gas production step (which includes gasification and electrolysis units) represents the highest proportion of the total investment cost, regardless of the process. This share is even predominant in e-biofuel and e-fuel processes. This indicates that the electrolyzer's cost strongly influences these integrated systems' capital cost.

Preprocessing steps also incur significant costs, especially in biofuel and e-biofuel processes involving drying, grinding, and torrefaction units. In the case of deploying a second-generation biofuel industry, biomass preprocessing steps might be decentralized to be located closer to the raw resource extraction sites. This organization would help reduce biomass supply costs by limiting the transport of water in biomass.[34]

For these case studies, investment costs of the biofuel process are higher than those of the e-biofuel process and lower than those of the e-fuel process for the three products. This can be explained by the high cost of electrolyzers, which benefit from virtually no economies of scale (scale factor close to 1). E-biofuel processes do not require a WGS reactor and an Air Separation Unit (ASU), which offsets the additional cost of the electrolyzer. Since oxygen is a byproduct of water electrolysis, the supply of oxygen for gasification is ensured by the electrolysis.

Biofuels display lower production costs ([117.9–145.7] € per MWh) than e-biofuel processes ([140.0–163.0] € per MWh), which in turn have much lower production costs than e-fuel processes ([212.1–271.6] € per MWh). The progressive substitution of the input feedstock (biomass for 21.6 € per MWh by electricity at 100.7 € per MWh) plays a key role in net production cost increases. As electricity prices play a key role in the production cost of e-biofuel and e-fuel processes, these costs are highly dependent on electricity price variation. Because of energy losses in the process, thermochemical conversion tends to amplify the impact of electricity prices on final production costs. For example, a variation in electricity prices of ± 1 € per MWh impacts the production cost of PtL by ± 1.8 € per MWh. Under cheaper electricity prices of around 70 € per MWh, the production costs of e-biofuel processes fall to the same level as those of biofuel processes. E-fuels have to be produced with very low-cost electricity (30 to 50 € per MWh) to be competitive with biofuel production costs.

4.3 GHG performance: RED III compliance

The analysis of emissions from these 9 processes over their life cycle shows that the production of e-fuels is more efficient than biofuel production only if the electricity mix is low-carbon, <35 kg $CO_{2,eq}$ per MWh for Fischer–Tropsch liquids. Compliance with the emission threshold set by RED III is achievable for the most decarbonized electricity mixes, such as in France (54 kg $CO_{2,eq}$ per MWh) or Sweden. However, it will not be achievable for e-fuels in the short term considering the average European electricity mix. This analysis underlines the ambitious nature of the RED objectives for current electricity mixes in Europe. An analysis of process-related GHG emissions under different electricity supply assumptions (EU mix, nuclear, renewable mix, and CHP) is also provided in the SI. It shows that most of the processes studied comply with the RED III sustainability requirements when low-carbon electricity sources are considered (renewable mix and nuclear). In contrast, e-fuel and e-biofuel processes exceed the permitted emission threshold when higher-carbon electricity sources are used, such as combined heat and power generation or the current European electricity mix.

4.4 Efficiency metrics in multi-criteria frameworks

The definition of overall efficiency adopted in this study, which compares electricity and chemical fuels on a common basis, ensures comparability across the vast majority of techno-economic assessments of BtL and PBtL pathways. Among the 184 case studies reviewed, 174 apply a similar definition, confirming that this convention provides a representative benchmark. Yet, electricity and fuels do not deliver the same type of service. Electricity can be converted into useful work with high efficiency, but storage and grid integration remain costly and technically challenging. Liquid fuels, on the other hand, even if converted with a lower efficiency, are easier to store and transport, and benefit from mature infrastructures. They are also essential in hard-to-electrify sectors such as aviation. In this perspective, PBtL or PtL pathways can be understood not only as

Table 2 Aggregated simulation results for the main key performance indicators under reference assumptions

	BtX	PBtX	PtX
Carbon conversion	35–40%	65–70%	80–85%
Energy efficiency	50–55%	55–65%	55–60%
Capital costs	3000–5000 € per kW	3000–3500 € per kW	3500–5500 € per kW
Net production costs	120–150 € per MWh	140–160 € per MWh	220–270 € per MWh
GHG emissions[a]	50–110 kg $CO_{2,eq}$ per MWh	60–95 kg $CO_{2,eq}$ per MWh	90–100 kg $CO_{2,eq}$ per MWh

[a] Values calculated based on the French electricity mix in 2022 and the RED III biomass emission factor.

conversion processes, but also as flexibility options that transform intermittent electricity into storable energy carriers. This difference echoes the conceptual distinction between flow-based and stock-based energy resources.

Alternative indicators have been proposed to capture these qualitative differences. In process-level studies, "primary energy efficiency" metrics apply correction factors to electricity (typically 2.6–3), reflecting conventions that trace it back to thermal power generation. While efficiency inherently depends on the definition of system boundaries, we nonetheless performed a comparative assessment on a primary-energy basis, assuming different electricity supply mixes characterized by distinct primary energy factors (PEFs). This approach allows evaluating the sensitivity of conversion efficiencies to the underlying electricity source. Fasahati and Maravelias (2018) make a related point by extending the boundary downstream, comparing electricity-to-motion and fuel-to-motion efficiencies.[14] Both perspectives reinforce that efficiency is not an intrinsic property but a contextual one, shaped by the boundaries and assumptions chosen.

As biomass- and power-based conversion processes jointly mobilize energy and carbon, their assessment cannot rely on a single performance indicator. Overall efficiency should be interpreted alongside carbon conversion, production costs, capital investments, and environmental impacts (GHG balance, LCA). Multi-objective optimization studies underline that trade-offs are inherent,[26] and complementary system-level indicators such as the Energy Return On Investment (EROI) provide valuable integrative perspectives.[8]

The results should therefore be seen as providing consistent and harmonized performance indicators at the process scale, which can be mobilized as inputs to broader energy system analyses. In energy optimization models such as EnergyScope, these indicators contribute to the evaluation of systemic trade-offs, including electricity generation mixes, storage options, and infrastructure constraints.[24]

5 Conclusions

This article provides an analysis of 4 techno-economic performance indicators and 1 environmental indicator: carbon conversion, energy efficiency, investment costs, production costs, and GHG emissions. Based on a significant database and simulations of nine relevant biofuel, e-fuel, and e-biofuel processes, the synthesis of the results identified several key trends (see Table 2). The comparison of simulation results with numerous case studies from the open and internal literature enabled consolidated estimates of the technical and economic performance of these main biofuel, e-fuel, and e-biofuel pathways and revealed the interesting trade-offs offered by PBtX hybrid chains. First, replacing the hydrogen from biomass resources with electrolytic hydrogen improves carbon conversion by a factor of up to 2. More importantly, complementing biomass and electricity through e-biofuel processes allows reaching an optimal H/C ratio, increasing the energy efficiency by around 10%. Global investment costs for biofuel, e-biofuel, or e-fuel greenfield plants are between 3000 and 5500 € per kW output. Those numbers are 1.5 to 2.5 times higher than investments in traditional refineries of the same scale. Considering a 100 € per MWh electricity market price and internalizing the abatement cost of CO_2, production costs are 2 times (biofuels and e-biofuels) to 5 times (e-fuels) higher than average market values for liquid hydrocarbons, SNG or methanol. Lifecycle GHG emissions are weakly dependent on the electricity mix for biofuels, moderately for e-biofuels, and strongly for e-fuels. Under RED III assumptions for biomass production, without considering land-use effects, second-generation biofuels meet the sustainability criteria. E-fuels (respectively e-biofuels) would need a carbon intensity below 70 kg $CO_{2,eq}$ per MWh (respectively 120 kg $CO_{2,eq}$ per MWh) for electricity production to be considered sustainable fuels under European regulations. The emission caps set by RED III can already be reached with the French electricity mix but not the European one. This work provides harmonized performance indicators at the process scale, which constitute a building block for broader energy system analyses. In this perspective, the distinction between electricity and fuel energy services and the need for multi-criteria evaluation highlight promising directions for future system-level research. Further research on biomass supply conditions should provide a more systemic understanding of LUC impacts on the environmental balance of these sustainable fuels. Additionally, the authors advocate for integrating hybrid e-biofuels into European regulatory frameworks, given their promising technical, economic, and environmental trade-offs.

Author contributions

EC: conceptualization, methodology, software, investigation, formal analysis, visualization, and writing – original draft. LM: methodology, validation, formal analysis, investigation, visualization, and writing – review & editing. GB: conceptualization, methodology, validation, formal analysis, writing – review & editing, supervision, and funding acquisition.

Conflicts of interest

There are no conflicts to declare.

Abbreviation

ADEME	Agence De l'environnement et de la maîtrise de l'energie - French agency for ecological transition
AGR	Acid gas removal
BtDME	Biomass-to-dimethyl ether
BtL	Biomass-to-liquids
BtMeOH	Biomass-to-methanol
BtSNG	Biomass-to-synthetic natural gas
BtX	Biomass-to-X (molecule)
CAPEX	Capital expenditure
CEPCI	Chemical engineering plant cost index
DME	Dimethyl ether
DAC	Direct air capture
EPEX	European energy exchange
EF	Entrained-flow
FICB	Fast internally circulating fluidized bed
FT	Fischer–Tropsch
GHG	Greenhouse gas
ILUC	Indirect land-use change
ISBL	Inside battery limit
Liquid HC	Liquid hydrocarbons
LHV	Lower heating value
MeOH	Methanol
NPC	Net production cost
PEG	Point d'echange gaz (gas point exchange)
PEM	Proton exchange membrane
PBtDME	Power-&-biomass-to-dimethyl ether
PBtL	Power-&-biomass-to-liquids
PBtMeOH	Power-&-biomass-to-methanol
PBtSNG	Power-&-biomass-to-synthetic natural gas
PBtX	Power-&-biomass-to-X (molecule)
PtDME	Power-to-dimethyl ether
PtL	Power-to-liquids
PtMeOH	Power-to-methanol
PtSNG	Power-to-synthetic natural gas
PtX	Power-to-X (molecule)
RED III	Renewable energy directive (second revision)
RFNBO	Renewable fuel of non-biological origin
RTE	Réseau transport d'electricité, the French transmission system operator
SMR	Steam methane reforming
SNG	Synthetic natural gas
SOEC	Solid oxide electrolysis cell
TRL	Technology readiness level
TSO	Transmission system operator
WGS	Water-gas shift

Data availability

The data supporting this article, including performance data for biofuel, e-biofuel, or e-fuel processes, are available at https://doi.org/10.5281/zenodo.15040781. They do not include results from previous in-house studies. The simulation files generated using ProsimPlus® are not publicly available due to confidentiality constraints but can be provided upon request by contacting the corresponding author. The equipment cost data, sourced from the literature, are available in the SI (see the section "Reference costs and dimensions of equipment").

Supplementary information (SI) is available. See DOI: https://doi.org/10.1039/d5se00786k.

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