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Do RFNBO regulations promote exergetic efficiency in sustainable aviation fuel production? A comparative exergoeconomic analysis

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ABSTRACT

Decarbonizing the aviation sector will require deployment of sustainable aviation fuels (SAF) compatible with existing infrastructure. To accelerate this transition, the EU's Renewable Energy Directive (RED III) has established increasing SAF drop-in quotas covering aviation biofuels and Renewable Fuels of Non-Biological Origin (RFNBO), with a specific drop-in quota for RFNBO. Although these policies aim to support emission reduction in the sector, they risk incentivizing energy-intensive production pathways at the expense of other pathways with comparable emission reduction. This raises the question of whether current regulatory definitions promote pathways aligned with the Energy Efficiency Directive (EED).

To address this, the study evaluates three SAF production pathways in terms of exergetic efficiency and production costs. Exergoeconomic analysis is combined with a regulatory assessment to compare SAF production pathways under RED III using carbon sourced from combustion (RFNBO-compliant), reforming or gasification processes (aviation biofuel-compliant) to produce methanol as an intermediate for SAF production, for both stand-alone and refinery-integrated configurations.

The results show that the RFNBO-compliant pathway exhibits lower exergetic efficiency (58%) compared to reforming (68%) and gasification (86%), while leading to higher production costs. Reforming and gasification pathways reduce the levelized fuel production cost by 45% and 59%, respectively. Refinery integration reduces the efficiency penalty by 18% and production costs by 30–50% while providing flexibility to meet RFNBO requirements.

This study highlights a misalignment between EU policies (RED III and the EED), as RFNBO aviation fuel compliance requirements are not technology-neutral, favoring pathways with lower exergetic efficiency and higher levelized production costs.

1. Introduction

Decarbonizing the aviation sector remains a challenging aspect of the energy transition due to the limited availability of short-term sustainable alternatives to liquid fuels. Recent frameworks have been developed in the European Union (EU) including the Renewable Energy Directive (RED III) and ReFuelEU Aviation, establishing blend-in quotas for sustainable aviation fuel (SAF) deployment and greenhouse gas (GHG) emission reduction [1,2]. In parallel, the EU Energy Efficiency Directive (EED) emphasizes improvements in energy performance across sectors, including transportation fuel production [3]. These policies aim to accelerate aviation decarbonization in the EU while promoting resource efficiency, energy efficiency and technological innovation. However, by defining compliance primarily based on feedstock origin and energy source, they risk incentivizing energy intensive pathways that rely on limited resources.

Within the EU regulatory framework, obligations are expressed as minimum drop-in quotas for SAF on intra-EU flights [1]. Chemically synthesized fuels can be produced from carbon dioxide and hydrogen or from syngas, a mixture of carbon monoxide and hydrogen, using available technologies, e.g., gasification or reforming [4]. The ReFuelEU Aviation directive defines SAF as fuel which falls into the category of synthetic aviation fuels, aviation biofuels, as well as recycled carbon aviation fuels. To be classified as SAF, they must lead to at least 70% GHG emission savings compared to their fossil equivalent. ReFuelEU

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Nomenclature

ASU	Air Separation Unit
ATR	Autothermal Reformer
BECCS	Bioenergy with Carbon Capture and Storage
CBAM	Carbon Border Adjustment Mechanism
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDR	Carbon Dioxide Removal
DACCS	Direct Air Carbon Capture and Storage
EED	Energy Efficiency Directive
EU	European Union
EU-ETS	EU Emission Trading System
GHG	Greenhouse Gas
LCH	Low Carbon Hydrogen
MeOH	Methanol
PSA	Pressure Swing Absorption
RED	Renewable Energy Directive
RFNBO	Renewable Fuel of Non-Biological Origin
SAF	Sustainable Aviation Fuel
SMR	Steam Methane Reformer
SOEC	Solid Oxide Electrolyzer Cell
UCO	Used Cooking Oil

Exergy

T_{ref}	Reference temperature (K)
T	Temperature (K)
P_{el}	Electrical power (MW)
η	Efficiency (−)
$\dot{Q}$	Heat flow (MW)
$\dot{Ex}$	Exergy flow (MW)
x_k	Number of moles of species *k* (mol)
$\dot{m}$	Mass flow (kg/s)
$ex_{k,ch}{}^0$	Standard chemical exergy of species *k* (kJ/mol)
η_{ex}	Exergy efficiency (−)
ε_{loss}	Exergy loss (−)

Emissions

E	Total CO_2 emissions (g CO_2/MJ_{fuel})
E_F	CO_2 emissions from fossil fuel equivalent (g CO_{2eq}/MJ_{fuel})
e_i	CO_2 emissions from the supply of inputs (g CO_2/MJ_{fuel})
e_p	Production CO_2 emissions (g CO_2/MJ_{fuel})
e_{td}	Transport and distribution CO_2 emissions (g CO_2/MJ_{fuel})
e_u	End-use CO_2 emissions (g CO_2/MJ_{fuel})
e_{ccs}	CO_2 emission savings from carbon capture and geological storage (g CO_2/MJ_{fuel})

Cost

LCOMeOH	Levelized Cost of Methanol (€/ton MeOH)

Aviation mandates that, starting from 2025, at least 2% of the fuel supplied at EU airports must be SAF, increasing to 70% by 2050. Additionally, within this target, a drop-in quota of 1.2% must come from synthetic aviation fuels, defined as Renewable Fuels of Non-Biological Origin (RFNBO), by 2030, rising to 35% by 2050 [2].

The main difference among the above-mentioned fuel categories lies in the origin of carbon atoms and the energy source. *RFNBOs* are produced using renewable electricity to power electrolyzers and captured CO_2, i.e., all energy content of the produced fuel must come from renewable and non-bioenergy sources [5,6]. Carbon dioxide captured from fossil sources can be used to produce RFNBOs until 2036 for power plants and until 2041 for industrial processes, otherwise, biogenic carbon dioxide is required [5]. *Aviation biofuels* are the umbrella category that includes any liquid or gaseous fuel produced from carbon and hydrogen originating from specific sustainable biogenic feedstock. Aviation biofuels can be produced through hydrogenation of vegetable oil and animal fats, or from biogenic waste and residues listed in Annex IX Part A of RED II, to be classified as SAF and thereby contribute to the minimum drop-in quotas. In this work, chemically synthesized fuels and hydrogen that achieve substantial GHG emission reduction but do not comply with the aforementioned criteria are referred to as *low-emission aviation fuels* and *low-emissions hydrogen* [7]. Low production emission fuels do not count for the drop-in quotas but contribute to GHG emission reduction in the plant. Hydrogen produced using electrolyzer powered by renewable electricity is categorized as *low carbon hydrogen* in alignment with the Hydrogen and Gas Market directive [8]. EU directives implicitly include a combination of electricity, steam and chemical-based pathways thus, an exergy-based assessment is necessary to ensure a thermodynamically consistent evaluation of their relative performance.

As EU fuel-related policies push for increased production and use of renewable fuels, it is essential to understand how existing refinery infrastructure can be adapted for their production. Refineries are key players in the transition to SAF due to the diversity of processes they manage, including gas separation, catalytic upgrading and the large volumes they handle, making them well positioned to adapt to SAF production. Integration of SAF production into existing refineries can enable efficient use of by-products, such as heat, oxygen, off-gases, or CO_2, and co-production of fuel-range products that can be used to decarbonize other transportation sectors, such as maritime. Despite these potential advantages, only a limited number of studies have investigated the implications of stand-alone compared to refinery-integrated production [9–12], identifying benefits such as improved resource utilization and reduced costs. There is therefore a lack of knowledge regarding the advantages with respect to exergetic efficiency, cost, and regulatory compliance of refinery-integrated production for generic refineries, without assuming a specific plant layout or operating conditions.

Key aspects remain unaddressed, such as the allocation of hydrogen across competing refinery streams and the integration of RFNBO production within the existing refinery. In this context, several studies have evaluated RFNBO production pathways, typically presenting conceptual process designs of standalone production plants [13,14]. In practice, most announced RFNBO projects are also based on stand-alone production plants, typically located at the CO_2 source [15], especially using biogenic point sources, targeting the production of intermediates such as methanol or direct production of SAF [16,17].

A few studies have included exergoeconomic analysis of stand-alone SAF production in combination with emission accounting [12,18], but these are often limited in scope, focusing on specific technologies or sites and rarely addressing regulatory implications. Other studies have focused on the socio-technical impact of policy frameworks, such as RED III and ReFuelEU Aviation, for fuel producers [4,19–21]. However, limited attention was paid to process design, thermodynamic constraints, and refinery integration options. In contrast, SAF studies often focus on stand-alone production plants, evaluating specific technologies isolated from a broader industrial context, for example, to produce methanol [13,22] or methanol-to-jet fuel [23,24]. Therefore, there is a lack of comprehensive analysis linking thermodynamic performance with regulatory and economic considerations. The aforementioned studies vary in scope and focus, but they all clearly identify the availability of renewable electricity as a key bottleneck for SAF production

[25,26]. Therefore, evaluating processes based on energy and exergy performance is crucial to ensure the efficient use of resources, such as renewable electricity, and to ensure the viability and scalability of SAF production pathways.

To enable a consistent comparison across pathways, a simplified yet thermodynamically consistent framework is adopted. Given the heterogeneous nature of biogenic feedstocks, a homogeneous proxy is chosen, methane, to represent their conversion behavior, enabling a consistent comparison of different production pathways. Similarly, aviation fuel is represented by its intermediate methanol, which can be upgraded to jet fuel through the methanol-to-jet (MtJ) process [27]. This abstraction allows the thermodynamic and economic performance of alternative pathways to be evaluated on a common basis. A limitation of conventional energy metrics is that they do not distinguish between energy quality and irreversibility, which limits their ability to capture fundamental efficiency differences across conversion pathways. Exergy provides a thermodynamically consistent measure that accounts for both energy quality and process irreversibility, enabling a more rigorous assessment of pathway performance [28,29]. Therefore, this perspective becomes more relevant and suitable for analyzing processes with electrical inputs and chemical reactions.

This study addresses the following questions:

- How do SAF production pathways compliant with EU aviation fuel regulations compare in terms of exergetic efficiency and economic performance?
- How does integrating SAF production into a refinery compare to stand-alone production in terms of exergy efficiency and levelized production costs?

The study aims to assess alternative production pathways by evaluating their exergetic performance, cost-effectiveness, and compliance with EU directives, thereby integrating thermodynamic, economic, and policy perspectives. GHG emissions are evaluated to confirm whether the pathways meet the 70% reduction required by regulations. The studied pathways provide a generalized framework to evaluate diverse feedstocks and decarbonization strategies based on combustion, reforming and gasification. The combustion pathway is representative of any combined heat and power plant that provides steam and electricity, such as refineries or district heating plants retrofitted with carbon capture and an electrolyzer connected to renewable electricity to produce fuels. The gasification pathway represents industries that convert complex or waste-derived feedstocks into syngas. Finally, the reforming pathway is targeted at refineries since it utilizes existing hydrogen production units retrofitted with carbon capture to produce liquid fuels.

The novelty of the work lies in adopting a comprehensive exergetic analysis, economic evaluation and regulatory assessment of SAF production pathways. While exergoeconomic analysis is commonly used to compare different conversion pathways in literature, it is rarely applied together with consideration of explicit policy constraints. In this work, regulatory frameworks criteria are directly incorporated into the evaluation, enabling a systematic analysis of trade-offs between efficiency, cost and regulatory compliance. This approach allows for identifying inconsistencies between policy objectives and system-level performance. The methodology used is relevant, applicable and transferable to other studies, however the policy implications are specific to contexts where fuel targets similar to RFNBO are in place, in this case, the RED III regulatory framework in the EU.

The main contributions of this work are to (i) select simplified representative SAF production pathways that capture a broad span of processes for SAF production while avoiding excessive process-specific detail, enabling consistent comparison under technical and regulatory conditions, (ii) quantify the trade-offs between exergetic efficiency and production costs across stand-alone and refinery-integrated configurations, and (iii) identify potential misalignments between policy frameworks, specifically RED III and EED, highlighting how RFNBO compliance criteria may favor less efficient and more costly pathways.

2. Sustainable aviation fuel production pathways

Fig. 1 shows the production pathways for SAF. The technologies considered are further explained in Section 3.1. Rather than providing a comprehensive review of all SAF routes reported in the literature, this section defines the SAF production pathways used in the analysis. The pathways are presented at an aggregated level and therefore do not distinguish between specific feedstock types. The production pathways are divided between stand-alone and integrated into a refinery pathways. Three stand-alone production pathways based on combustion, reforming, and gasification technologies. Additionally, an integrated case is studied by integrating the reforming pathway into a refinery that requires significant volumes of hydrogen, e.g., for the hydrogenation of lipid-based feedstocks.

Stand-alone pathways

Combustion pathway (CCGT-SOEC): The combustion pathway includes any combined heat and power (CHP) plant that provides steam and electricity to a given system, e.g., boilers at refineries or for district heating production. A gas turbine combined cycle (CCGT) can be assumed when using gas feedstock assuming that the plant would invest in a post combustion carbon capture (CCS) technology to capture its carbon dioxide from the flue gas. A solid-oxide electrolyzer cell (SOEC) uses renewable electricity to produce hydrogen. Methanol, i.e., the intermediate fuel, is produced using a direct synthesis process from CO_2 and H_2. This pathway is selected as the reference pathway throughout the work as it enables the production of RFNBO methanol in accordance with current EU directives.

Reforming pathway (SMR): The reforming pathway is targeted at refineries that currently rely on SMR for hydrogen production and want to produce SAF. This pathway assumes a steam methane reformer (SMR) followed by a water gas shift reactor (WGS). Hydrogen is separated from the produced gas using a pressure swing absorption (PSA) unit, and CO_2 is captured from the flue gas using post combustion CCS. The captured CO_2 and produced H_2 react to methanol using a direct synthesis process to produce the intermediate fuel.

Gasification pathway (ATR): The gasification pathway includes industries that convert complex or waste-derived feedstocks into syngas for the production of carbon building blocks. In this work, syngas generation is represented by an autothermal reformer (ATR), which is suitable for gaseous feedstocks. The process assumes to use an ATR reactor to partially oxidize the feedstock to produce syngas ($CO + H_2$) using pure oxygen from an air separation unit (ASU). The syngas is sent to a benchmark methanol synthesis process to produce the intermediate fuel.

Integrated into a refinery pathway

The integrated pathway (SMR-SOEC) targets refineries that typically rely on SMR for hydrogen production and expect to maintain their hydrogen demand for processes such as hydrocracking or hydrogenation of lipid-based feedstock. Therefore, the SMR continues to operate with a post-combustion CCS unit to produce separate CO_2 and H_2 streams. Additionally, an SOEC, powered by renewable electricity, is operated in parallel to produce renewable hydrogen. Methanol, i.e., the intermediate fuel, is synthesized directly from CO_2 and one of the two H_2 streams, while the other H_2 stream is used internally at the refinery. Two configurations are possible (i) *linear*, where hydrogen and carbon come from the same source, whereas (ii) *hydrogen reallocation*, where hydrogen is decoupled from the carbon feedstock. The additional hydrogen produced and used at the refinery is hereinafter referred to as *co-produced hydrogen*. The configuration enables the allocation of the co-produced hydrogen, providing the plant with flexibility in fuel definition and

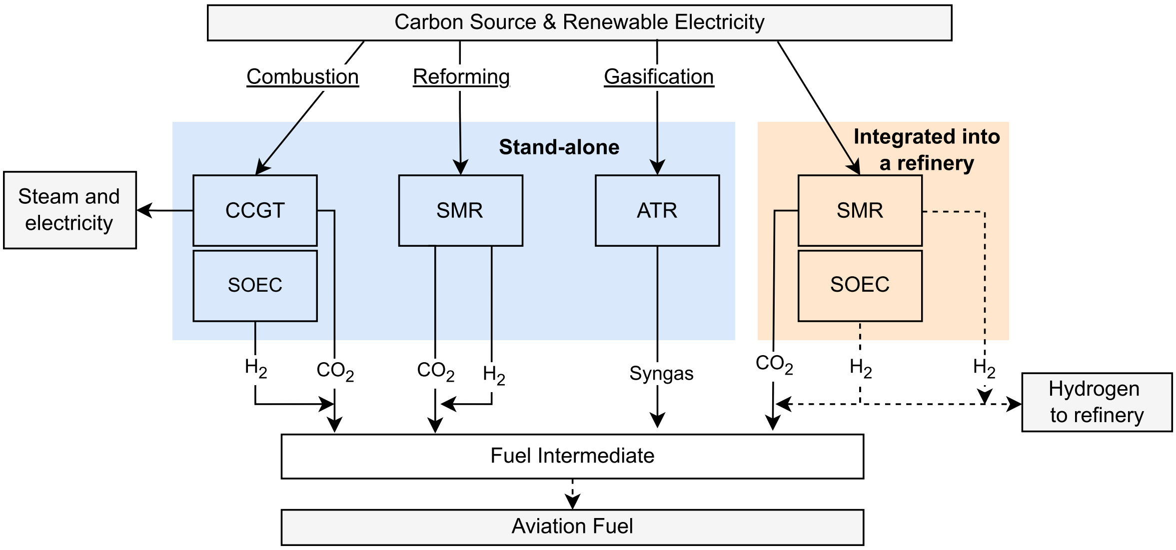

Fig. 1. Overview of pathways using a carbon source and renewable electricity to produce methanol as an intermediate for aviation fuel. The pathways are presented at an aggregated level and therefore do not distinguish between specific feedstock types. Pathways are separated between stand-alone and integrated into a refinery. Abbreviations: CCGT, combined cycle gas turbine; SOEC, solid oxide electrolyzer cell; SMR, steam methane reforming; ATR, autothermal reforming.

allocation under the RED III directive. Thus, depending on whether SOEC hydrogen is supplied to methanol synthesis or refinery operations, the resulting products may qualify differently as RFNBO fuels.

3. Methodology

Fig. 1 illustrates four technological pathways for producing a given quantity of synthetic methanol, as an intermediate for SAF, from carbon source and renewable electricity. A key challenge in the assessment of biofuel processes lies in representing the complex composition of typical biogenic feedstocks. To address this, methane is thus used as a proxy for any biogenic feedstock listed in the RED III directive, such as feedstock derived from forest residues or municipal biogenic waste [1]. This simplification enables consistent carbon and hydrogen balance while avoiding uncertainties related to variable biomass composition and moisture content. Despite the simplification, the approach allows for a robust comparison of different production pathways. A change of feedstock from methane to a more complex biomass structure would translate to an increase in exergy demand and equipment costs, but these effects are expected to impact all production pathways in a similar manner. Likewise, modeling jet fuel production introduces additional complexity, given the specific properties, such as composition and density, required to meet aviation fuel standards. Therefore, this work focuses on methanol production as an intermediate product for SAF, which can be upgraded via the methanol-to-jet (MtJ) process.

Section 3.1 describes the technologies and assumptions made to analyze the described pathways. Additional information on each technology is shown in Supplementary Material S.1. Lastly, Section 3.2 describes the key performance indicators analyzed in this work, including exergetic analysis, GHG emission savings calculations, and economic analysis.

3.1. *Technology descriptions and assumptions*

The methodology is based on simplified thermodynamic calculations that capture the fundamental characteristics and constraints of methanol production. Efficiencies of key unit operations were assumed to be at the upper end of reported ranges to illustrate the maximum potential performance of each pathway, where applicable. Table 1 shows a list of the key performance parameters for the process technologies used in this work, together with the corresponding data sources. These parameters are used as inputs to the thermodynamic and exergy assessment of each pathway, including the refinery-integrated configuration.

3.1.1. *Combined cycle gas turbine plant with CO_2 capture (CCGT)*

A combined cycle gas turbine plant is chosen to represent methane combustion, producing CO_2, heat and electricity. CO_2 is captured from the flue gas using an amine post-combustion absorption unit, with a capture rate of 90% [30]. The CCGT plant includes a HRSG and steam turbine which co-generates heat and electricity that can be used to satisfy the demands of the downstream carbon capture, SOEC electrolyzer and methanol synthesis process. Any surplus of heat is sold to a district heating network. The CCGT plant is sized to produce the stoichiometric CO_2 required for methanol synthesis through reaction (R1). Consequently, the cogenerated heat and power do not match the plant's demand. The plant generates a surplus of electricity, which cannot be used in the process, since the electrolyzer must operate using renewable electricity from non-biological sources. Hence, it is assumed that electricity is sold to the grid, and heat is sold to a district heating network. The parameters used to characterize the CCGT's conversion rate, heat and electrical efficiency are summarized in Table 1. Eqs. (1) and (2) are used to calculate the electricity and heat after the steam turbine (4 barg), produced by the plant.

$$P_{el} = \dot{Q}_{fuel} \bullet \eta_{el} \tag{1}$$

$$\dot{Q}_{steam\ 2barg} = \dot{Q}_{fuel} \bullet \eta_{heat} \tag{2}$$

3.1.2. *Autothermal reformer (ATR)*

Autothermal methane reformer technology is chosen to represent syngas production from methane. ATR combines catalytic reforming with direct reforming, using oxygen, steam, and catalyst section [31]. A reactor consisting of a burner and a fixed catalyst bed is used, as shown in Supplementary Material S.1. It is assumed that oxygen for the reactor is produced in a cryogenic air separation unit (ASU). The syngas ratio required for methanol production is approximately 2.1, calculated according to Eq. (3) via a combination of reactions R1,R2, and R3. The parameters used for conversion rates and electricity demand are summarized in Table 1.

$$CH_4 + 2\,O_2 \rightarrow 2\,H_2O + CO_2 \quad \Delta H = -800.77\,kJ/mol\,C \tag{R1}$$

Table 1
List of the key performance parameters of process technologies within the described SAF production pathways. The reaction numbers correspond to those defined in Section 2. Complete combustion is assumed for all technologies.

Technology	Parameters	Value	Units	Comment/Reference
Combined cycle gas turbine (CCGT)	Total exergy efficiency	0.88	$MW/MW_{fuel,LHV}$	Assuming steam production at 300 °C and 60 barg, expanded with a steam turbine to 4 barg [47]
	Energy efficiency steam production	0.43	$MW_{steam}/MW_{fuel,LHV}$	
Autothermal reformer (ATR)	Conversion rate (R1/R2/R3)	90	%	From 50 to 100% [48]
	Reaction split (R1:R2:R3)	10:45:45	R1:R2:R3% of CH_4 reacting	Thermodynamic balance to reach autothermal
	Pressure in the reactor (R1/R2/R3)	28	bar	[48]
Steam methane reformer (SMR)	Conversion rate for reaction R4	80	%	From 40 to 100% [49]
	Pressure in the reactor R4	28	bar	[49]
Carbon capture	CO_2 capture efficiency	90	%	[50]
	Reboiler duty	3,600	kJ/kg of CO_2	
	Steam pressure provided to the reboiler	2	barg	
Pressure swing absorption (PSA)	Electricity demand	5	kWh/kg H_2	[51]
Solid oxide electrolyzer cell (SOEC)	Efficiency electrolyzer (Electricity to hydrogen)	75	% (LHV basis)	[39]
	Steam demand for SOEC	5.21	kWh/kg H_2	Stoichiometric value (9 ton low pressure steam/ton H_2) at 2 barg [52].
Cryogenic Air Separation Unit (Cryogenic ASU)	Electricity for Cryogenic ASU unit	0.2	$kWh_{el}/kg\ O_2$	[53]
Methanol synthesis (MeOH synthesis)	Conversion rate (R8 and R9)	99	%	[32]
	Temperature in the reactor (R8 and R9)	250	°C	
	Pressure in the reactor (R8)	50	bar	
	Pressure in the reactor (R9)	100	bar	

$$CH_4 + \frac{1}{2}O_2 \rightarrow 2\,H_2 + CO \quad \Delta H = -36.12\,kJ/mol\,C \tag{R2}$$

$$CH_4 + H_2O \rightarrow 3\,H_2 + CO \quad \Delta H = 205.71\,kJ/mol\,C \tag{R3}$$

$$syngas\ ratio = \frac{H_2 - CO_2}{CO + CO_2} \approx 2.1 \tag{3}$$

3.1.3. Steam methane reformer (SMR) with CO_2 capture

Steam methane reformer (SMR) with CO_2 capture is used to represent the reforming of methane. The process flow diagram of the steam methane reforming process, including a carbon capture unit, is shown in Supplementary Material S.1. The reactor is designed using tubes and a combustion chamber. Reaction R3 and R4 occur in the tubes while in the combustion chamber reaction R1, R6 and R7 provide heat. When the main product is methanol, the residual hydrogen is combusted internally with methane and CO_2 (R7). After the SMR, a water gas shift reactor is used to convert most of the unconverted CO to CO_2 using R5. Hydrogen is separated from the resulting gas by a pressure swing adsorption (PSA) unit. The SMR configuration considered is not optimized for high energy efficient methanol production, but rather for maximizing hydrogen output, reflecting typical refinery designs. The parameters used for conversion rates and electricity demand are summarized in Table 1.

$$CH_4 + 2\,H_2O \rightarrow 4\,H_2 + CO_2 \quad \Delta H = 164\,kJ/mol\,C \tag{R4}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \quad \Delta H = -41\,kJ/mol\,C \tag{R5}$$

$$CO + \frac{1}{2}O_2 \rightarrow CO_2 \quad \Delta H = -283\,kJ/mol\,C \tag{R6}$$

$$H_2 + \frac{1}{2}O_2 \rightarrow H_2O \quad \Delta H = -241\,kJ/mol\,C \tag{R7}$$

3.1.4. Methanol synthesis

Methanol synthesis is used to produce the intermediate fuel, methanol, for further production of SAF. Methanol is synthesized through direct synthesis (H_2 and CO_2) or conventional synthesis (syngas), depending on the selected production pathway. The process flow diagram is shown in Supplementary Material S.1. Depending on the feedstock used for methanol synthesis (CO_2 or CO), reaction R8 or R9 occurs, assuming high recycling ratio a 99% feedstock conversion is possible [32]. For this reason, the recycle stream is assumed to require compression work comparable to that of the fresh feed [33]. The exothermic direct synthesis reaction (R8) is assumed to generate enough heat to separate the methanol from the water formed in a distillation column [22,33,34]. Table 1 summarizes the reactor conversion rate, operating temperature and pressure parameters.

$$CO_2 + 3\,H_2 \rightarrow CH_3OH + H_2O \quad \Delta H = -50\,kJ/mol\,C \tag{R8}$$

$$CO + 2\,H_2 \rightarrow CH_3OH \quad \Delta H = -91\,kJ/mol\,C \tag{R9}$$

3.1.5. Solid oxide electrolyzer cell (SOEC)

Solid oxide electrolyzer (SOEC) is used to produce hydrogen using renewable electricity. In electrolysis, hydrogen is produced by water splitting. SOEC is selected over proton exchange membrane (PEM) or alkaline electrolysis due to its higher electricity to hydrogen efficiency, 75% (LHV basis) [35]. Electricity and steam requirements are summarized in Table 1.

3.2. Key performance indicators

3.2.1. Exergy analysis

Mass and energy balances are performed for each production pathway according to Eq. (4). Basic thermodynamic equations are used to determine the energy content of the reactants and products, the net reaction heat, and the compression work, thereby completing the energy balance. The energy flows are transformed to exergy terms according to Eqs. (5) and (6). The reference state considered for all the streams and for the standard chemical exergy ($e_{i,ch}^{0}$) is standard conditions (T_{ref} = 298 K and P_{ref} = 1.01 bar). Work is regarded as pure exergy, while for heat streams, exergy ($\dot{Ex}_q$) is calculated using Eq. (5). The material streams entering and leaving the system are considered to be at standard conditions, and their chemical exergy is computed according to Eq. (6). Additionally, exergy efficiency and exergy losses of each production pathway are calculated according to Eqs.(7) and (8). Finally, Eq. (9) shows how the exergy flow is lost throughout the process, assuming that all the required exergy to drive processes is added at the initial starting point (input) to produce the same final product (methanol). The equation describes the exergy flow in each step of the pathway y, for each production pathway i, normalized by the reference pathway (CCGT-SOEC).

$$\dot{Ex}_{CH_4} + \dot{Ex}_{El} + \dot{Ex}_{steam\ demand} = \dot{Ex}_{CH_3OH} + \dot{Ex}_{El\ produced} + \dot{Ex}_{steam\ produced} + \dot{Ex}_{loss} \tag{4}$$

$$\dot{Ex}_q = \left(1 - \frac{T_{ref}}{T}\right)\dot{Q} \tag{5}$$

$$\dot{Ex}_{ch} = \dot{m}\sum_i x_i\, \mathrm{ex}_{i,\,ch}{}^0 \tag{6}$$

$$\eta_{ex} = \frac{\dot{Ex}_{products}}{\dot{Ex}_{input}} = \frac{\dot{Ex}_{CH_3OH} + \dot{Ex}_{Heat_{CHP}} + \dot{Ex}_{El_{CHP}}}{\dot{Ex}_{CH_4} + \dot{Ex}_{El_{SOEC}} + \dot{Ex}_{El_W}} \tag{7}$$

$$\varepsilon_{loss} = \frac{\dot{Ex}_{input} - \dot{Ex}_{products}}{\dot{Ex}_{products}} = \frac{\dot{Ex}_{loss}}{\dot{Ex}_{products}} \tag{8}$$

$$\dot{Ex}^*_{i,y} = \frac{\dot{Ex}_{input\,i} - \dot{Ex}_{loss\,i,y}}{Ex_{input\,CCGT-SOEC}} \tag{9}$$

3.2.2. Greenhouse gas emission savings

The absolute direct emissions and emissions reduction potential of each production pathway are calculated and compared using the methodology described in RED III [6]. Thus, all pathways are evaluated against the 70% GHG emission savings threshold required to qualify as SAF. Methanol is an intermediate in jet fuel production. Consequently, this analysis does not account for emissions associated with the downstream upgrading process, as the incremental emissions and corresponding savings are comparable for all production pathways when assuming a single end product.

The emissions savings are calculated using Eq. (10), where the term E_F refers to the fossil fuel reference with an emissions intensity of 94 g CO_{2eq}/MJ of fuel [6]. In this work, the absolute emissions and emissions savings are determined exclusively based on CO_2 emissions. The total emissions (E), calculated according to Eq. (11), are expressed as g CO_2/MJ of fuel produced (LHV basis) [1,6]. Total emissions (E) are defined as emissions from the supply of inputs (e_i), production emissions (e_p), transport and distribution emissions (e_{td}), end-of-use emissions (e_u), and emissions savings through CCS (e_{ccs}). Table 2 shows a summary of the assumptions considered to calculate the total emissions (E).

Table 2

Assumptions considered for each term of Eq. (11) to calculate total emissions (E) of a fuel production pathway to comply with the RFNBO definition.

Term	Abbreviation	Assumption
Supply of rigid inputs	$e_{i\ rigid}$	Carbon feedstock and steam supply are treated as rigid inputs, substituting their energy value for an alternative source (electricity).
Supply of elastic inputs	$e_{i\ elastic}$	Electricity supply is treated as elastic, accounting for its upstream emissions.
Production emissions	e_p	Based on each technology, depending on carbon capture rates (see Section 3.1).
Emissions from existing use	$e_{ex\text{-}use}$	The ex-use and end-of-use emissions cancel each other (until 2041, or 2036 for CHP plants).
End-of-use emissions	e_u	
Transport and distribution emissions	e_{td}	Highly dependent on the plant location and feedstock sourcing thus, not considered. For this reason, the reported total emissions should be interpreted as lower-bound estimates.
Emissions savings through CCS	e_{ccs}	No carbon is stored in the studied pathways.

$$Savings = \frac{E_F - E}{E_F} \tag{10}$$

$$E = e_i + e_p + e_{td} + e_u - e_{ccs} = \left(e_{i_{elastic}} + e_{i_{rigid}} - e_{ex-use}\right) + e_p + e_{td} + e_u - e_{ccs} \tag{11}$$

To calculate the emissions from the supply of inputs (e_i), the feedstock needs to be defined as elastic, rigid and ex-use (Eq. (11)). Following RED III [6], rigid inputs are those whose supply cannot be expanded to meet extra demand, such as industrial waste and by-product streams and incorporated processes that represent less than 10% of the economic value of the output. Elastic inputs represent 10% or more of the economic value, or the supply of those inputs can be increased to meet extra demand. Electricity and steam are considered as elastic inputs when bought from the grid and as rigid inputs when produced within the plant boundaries. Regardless of its origin, it is regarded as a rigid input if it accounts for more than 50% of the total energy required for fuel production. In this work, carbon feedstock and steam supply are treated as rigid inputs, as carbon feedstock accounts for more than 50% of the total energy required for fuel production and steam is provided by a nearby plant. The emissions associated with these rigid inputs are accounted for using a substitution approach, whereby their energetic use within the plant is assumed to displace an equivalent amount of electricity-based energy that would otherwise be required at the refinery, in line with RED III accounting principles. In contrast, electricity supply is treated as an elastic input, and its emissions explicitly include upstream electricity generation. Under the RED III methodology, if the electricity is sourced entirely from renewable generation, the associated carbon emissions are set to zero [6]. In the sensitivity analysis, both the electricity and steam emission factors are varied, including scenarios with renewable electricity.

The term *ex-use* in Eq. (11) is defined as the emissions from existing use, corresponding to the carbon incorporated into the fuel's chemical composition that would otherwise have been released to the atmosphere as CO_2. Ex-use applies when using biogenic carbon as input. However, industrial fossil carbon can also be accounted for until 2041, or 2036 if the CO_2 originates from the combustion of fuels for electricity generation. When emissions of the ex-use can be accounted for, the use emissions (e_u) term and ex-use emissions ($e_{ex\text{-}use}$) are equal, therefore canceling the terms in Eq. (11). In this work, the ex-use term applies and cancels out with the end-of-use emissions term (see Table 2). Additionally, transport and distribution (e_{td}) emissions are not considered in the calculations because they depend heavily on the source of imported feedstock and plant location. Therefore, the reported values should be interpreted as a lower-bound estimate (see Table 2). These emissions affect all pathways similarly; thus, the comparative assessment remains valid. To achieve 70% emission savings for RFNBO, the total emissions must be below 28 g CO_{2eq}/MJ of fuel. Finally, to evaluate if the pathway qualifies as RFNBO, Eqs. (10) and (11) can be rewritten as Eq. (12).

$$E_{RFNBO} = \left(e_{i_{elastic}} + e_{i_{rigid}}\right) + e_p \ll 28\ \mathrm{gCO_2eq/MJ} \tag{12}$$

3.2.3. Economic analysis

The capital and operational costs are calculated to compare the cost structure of the process pathways. The default economic parameters required for CAPEX calculation are shown in Supplementary Material S.2. The investment costs are annualized based on an interest rate of 7.5% and a 20 year lifetime. Additionally, operational expenditure (OPEX) calculations are shown in Table 3. Given their distinct economic and regulatory characteristics, the analysis includes both fossil-derived and bio-based methane. For simplification, representative market prices for natural gas and biomethane are used. Electricity price was assumed to represent a conservative for future scenario in Sweden considering that a future system needs to cover the long-term marginal costs of new electricity production.

Table 3
Assumptions for variable operational costs (OPEX).

OPEX	Value	Units	Comments/References
Maintenance and insurance costs	5	% of fixed capital	Estimated using factorial methods [54]. Including taxes, plant overhead, labor/supervision costs, lab costs, rate on capital and insurance.
Full load hours	8,000	hours/year	Assumption.
Heat price	55	€/MWh	Derived marginal steam production cost assuming natural-gas boiler efficiency of 90% and fossil natural gas price of 50 €/MWh [55].
Electricity price	50	€/MWh	Low-end electricity price (50–70 €/MWh) for future scenarios in Sweden (2050) where electricity prices need to be high enough to cover the long-term marginal cost of new electricity production [56].
Fossil-based natural gas price	50	€/MWh	Base-case commodity natural gas price assumption representative of 2023 conditions [55].
Bio-based methane price	100	€/MWh	Assumed biomethane price to reflect the high-end of biomethane prices, set as twice the fossil natural gas base case [55].
Hydrogen selling price	3–5	€/kgH$_2$	Predicted hydrogen cost from SMR with carbon capture in Europe (Sweden at the higher end) [57].
	6–8	€/kgH$_2$	Predicted hydrogen cost with grid-connected electricity (Sweden at the lower end) [57].

The total costs for fuel production (M€/year) and the specific costs, i.e, the levelized cost of methanol (LCOMeOH, €/ton methanol), for each fuel production technology are calculated according to Eqs. (13) and (14), respectively. The capital and operating costs considered are interdependent, meaning that relative proportions are more relevant than absolute values. Therefore, the levelized cost of methanol is expressed as a ratio (LCOMeOH*) of each pathway's LCOMeOH to that of the reference pathway (CCGT-SOEC) (Eq. (15), see Section 2).$LCOMeOH_i^* < 1$ indicates that the pathway i is cheaper than the reference pathway, whereas$LCOMeOH_i^* > 1$ indicates that it is more expensive.

The sensitivity analysis varied the CAPEX by ± 50%, and the variable OPEX by ± 25%. Operational costs were adjusted to reflect correlated price dynamics across energy carriers by applying the same proportional change to heat, electricity and hydrocarbon prices for each scenario. The OPEX variables are varied simultaneously, rather than one-at-a-time.

$$C_{fuel\ production} = C_{Fixed\ capital} + C_{Fixed\ OPEX} + C_{Feedstock} + C_{el_{comp}} + C_{el_{SOEC}} + C_{heat} \tag{13}$$

$$LCOMeOH_i = \frac{C_{fuel\ production_i}}{\dot{m}_{methanol\ produced_i}} \tag{14}$$

$$LCOMeOH_i^* = \frac{LCOMeOH_i}{LCOMeOH_{CCGT-SOEC}} \tag{15}$$

4. Results and Discussion

The results are presented and discussed in the following four sections. Section 4.1 provides an overview of the policy implications for each fuel production pathway studied, including its main performance indicators: exergy efficiency, emissions, and costs. Section 4.2 focuses on the impact of exergy destruction throughout the production process. Section 4.3 presents the implications for GHG emission savings to achieve the threshold defined by RED III. Finally, Section 4.4 shows the costs expressed as the ratio of each production pathway's LCOMeOH to the reference pathway (CCGT-SOEC).

4.1. Implications of the RED III directive

Table 4 provides an overview of the performance of stand-alone and integrated methanol synthesis based on methane and renewable electricity conversion, and its connection with the fuel definition according to EU directives. Fuel categories used in the following analysis are defined in the Introduction, see Supplementary Material S.3 for details. Furthermore, Fig. 2 presents visually the exergy flows for the defined pathways, where all values are normalized to a production rate of 1 exergy unit of methanol.

The results shown in Table 4 indicate that, for the stand-alone pathways, the reforming and gasification pathways are competitive with the combustion pathway for most indicators. Nevertheless, under the EU RED III directive, only the combustion pathway is compliant with

Table 4
Energy and exergy efficiency, CO$_2$ emissions, and relative levelized costs of methanol for each stand-alone process pathway studied. The levelized costs of methanol are normalized to the reference pathway (RFNBO methanol production via CCGT-SOEC using biogenic feedstock). Abbreviations: CCGT, combined cycle gas turbine; SOEC, solid oxide electrolyzer cell; SMR, steam methane reforming; ATR, autothermal reforming; RFNBO, renewable fuel of non-biological origin; LCOMeOH, levelized cost of methanol.

	Combustion	Reforming	Gasification	Integrated into a refinery (linear)	Integrated into a refinery (hydrogen reallocation)
Production pathways	**CCGT-SOEC**	**SMR**	**ATR**	**SMR-SOEC**	
Energy efficiency (%)	51	57	84	67	
Exergy efficiency (%)	58	68	86	68	
Production emissions (e_p) (kg CO$_2$/ton MeOH)	152	152	≃0	152	
Relative levelized cost of methanol (LCOMeOH*)with fossil-based feedstock (−)	0.82	0.40	0.29	0.76	
Relative levelized cost of methanol (LCOMeOH*) with bio-based feedstock (−)	1.00	0.59	0.45	0.95	
Fuel definitions according to the directives					
Fossil feedstock (MeOH)	RFNBO[a]	Fossil (low-emissions)	Fossil (low-emissions)	Fossil (low-emissions)	RFNBO[b]
Fossil feedstock (H$_2$)	–	–	–	RFNBO	Fossil (low-emissions)
Biogenic feedstock (MeOH)	RFNBO	Biofuel	Biofuel	Biofuel	RFNBO[b]
Biogenic feedstock (H$_2$)	–	–	–	Low carbon hydrogen	Biogenic (low-emissions)

[a] Classified as RNFBO until 2036, thereafter classified as fossil.
[b] Classified as RNFBO until 2041, thereafter classified as fossil.

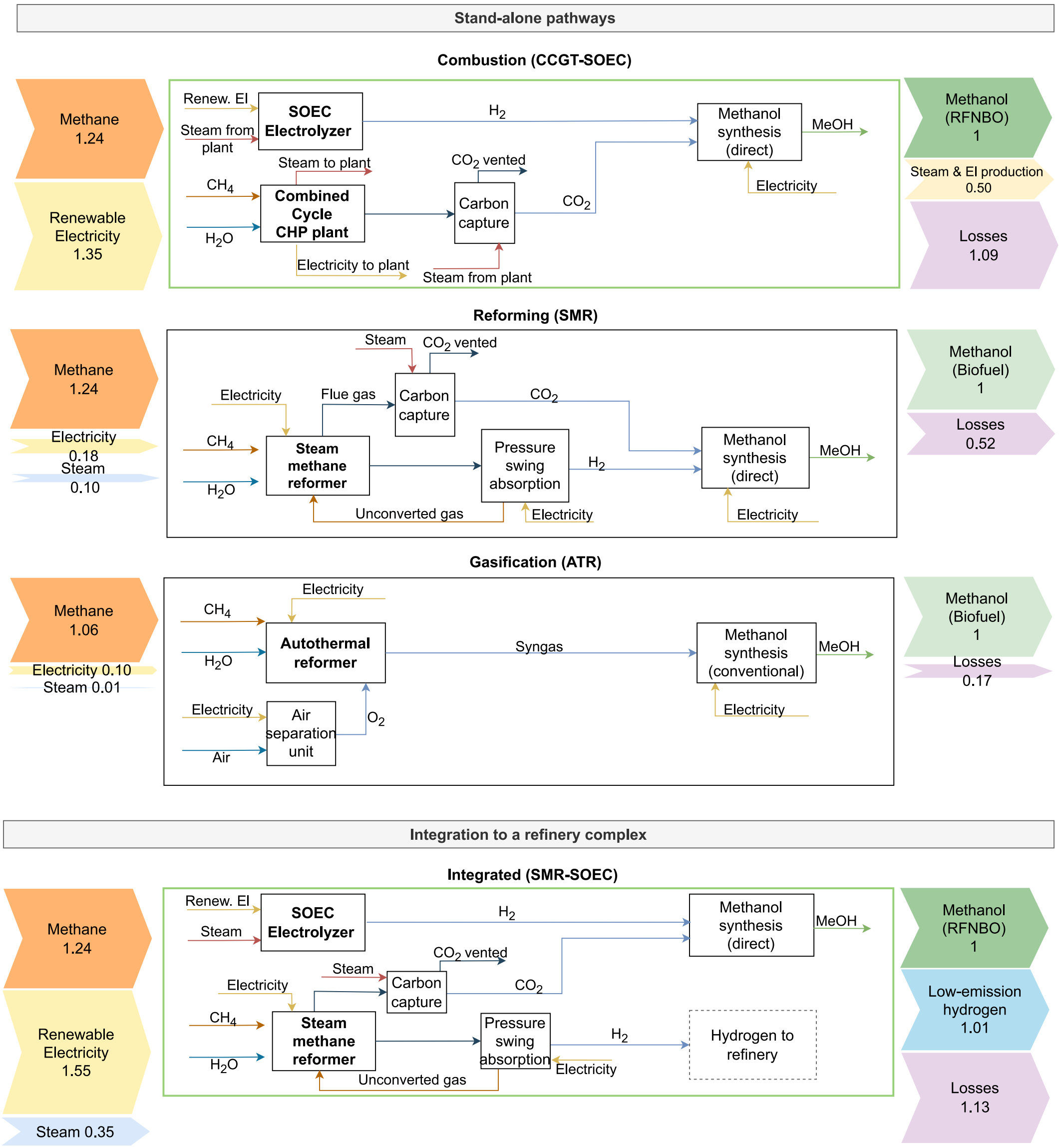

Fig. 2. Exergy-based process flow diagram of the analyzed pathways. Overall flows are normalized to 1 GWh/year of methanol production. Abbreviations: CCGT, combined cycle gas turbine; SOEC, solid oxide electrolyzer cell; CHP, combined heat and power; SMR, steam methane reforming; ATR, autothermal reforming; RFNBO, renewable fuel of non-biological origin.

the requirements for classification as an RFNBO fuel. Methanol produced through the reforming and gasification pathway can be classified as aviation biofuels when biogenic feedstock is used, allowing the fuel produced to count towards the minimum SAF drop-in quota mandates, but not towards RFNBO production [2]. The gasification pathway has the highest exergy and energy efficiencies, as well as the lowest emissions and costs.

There are substantial differences between the exergetic efficiency of the combustion (58%) and reforming (68%) pathways, whereas the energy efficiency varies much less (51 and 57%, respectively). Most EU regulations, including RED III and EED, refer to energy content as the main metric for compliance, which does not fully capture these thermodynamic losses. Pathways with similar energy efficiency can differ significantly with respect to exergetic efficiency, which highlights the value of exergy-based metrics.

In the integrated pathway, the flexibility to perform hydrogen reallocation allows the production of RFNBO-compliant methanol. In contrast, when no hydrogen reallocation is performed (linear), aviation biofuel methanol is produced. The integrated pathway consumes the same amount of hydrocarbons as the combustion and reforming pathway and has 11% more electricity demand than the combustion pathway, with the benefit of co-producing hydrogen (Fig. 2). The resulting cost competitiveness depends on the assumed hydrogen price (see Section 3.4). Thus, SMR provides high flexibility for the production system, allowing the separation of the produced CO_2 and H_2 gases to meet regulatory requirements. On the contrary, using the analyzed SMR configuration, ATR would make the system less flexible but also less complex.

4.2. Exergy losses

The exergy losses for the stand-alone pathways are illustrated in Fig. 3. The exergy flows for each step, calculated following Eq. (9), are normalized with respect to the initial exergy input for the reference pathway (CCGT-SOEC). The CCGT-SOEC case has two outputs: fuel (methanol) and energy (heat and power from the CCGT). To ensure a visual comparison of the main product (methanol) across pathways, heat and power produced within system boundaries are excluded from the

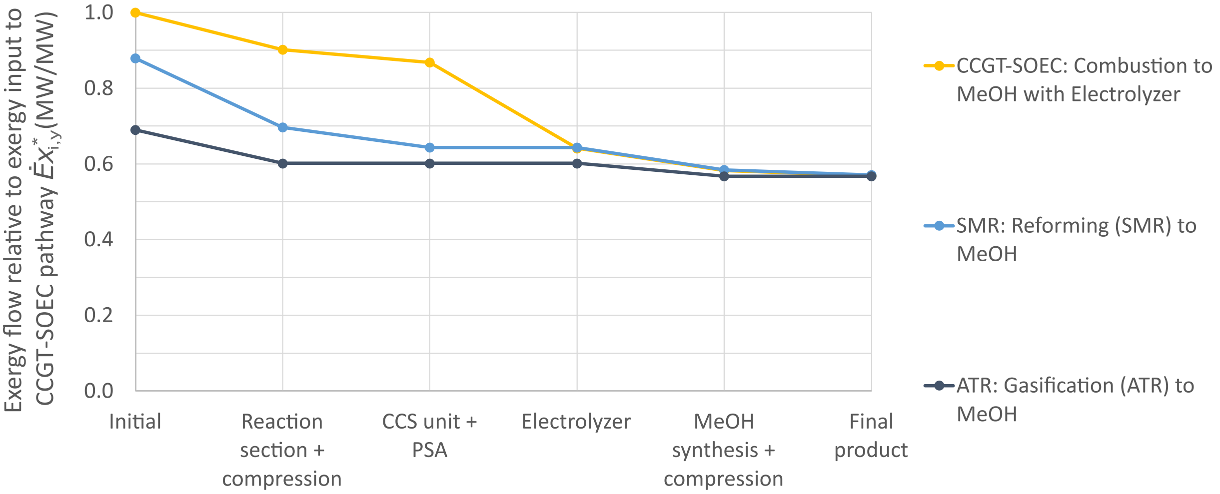

Fig. 3. Exergy losses for the stand-alone pathways from methane to methanol (MeOH), relative to the combustion-based pathway (CCGT-SOEC). The x-axis shows the successive process steps from the initial conversion reaction to the final methanol product, expressed as $\dot{E}x^*_{i,y}$. The y-axis shows how the exergy flow is lost throughout the process, normalized to the combustion-based pathway, illustrating the exergy added and retained through each step x and, consequently, the exergy losses along the pathway. For the CCGT-SOEC pathway, heat and power produced within the system boundaries are excluded to enable a visual comparison of the main product (methanol) across pathways. Abbreviations: CCGT, combined cycle gas turbine; SOEC, solid oxide electrolyzer cell; SMR, steam methane reforming; ATR, autothermal reforming; CCS unit, carbon capture unit; PSA, pressure swing absorption.

figure.

Fig. 3 is in line with Table 4 and Fig. 2, showing that the reference pathway, entailing combustion of methane to produce CO_2 and producing hydrogen through electrolyzers, leads to the highest exergy losses. Even under the assumptions of high-efficiency conversion technologies, the largest exergy demand arises from the conversion losses in

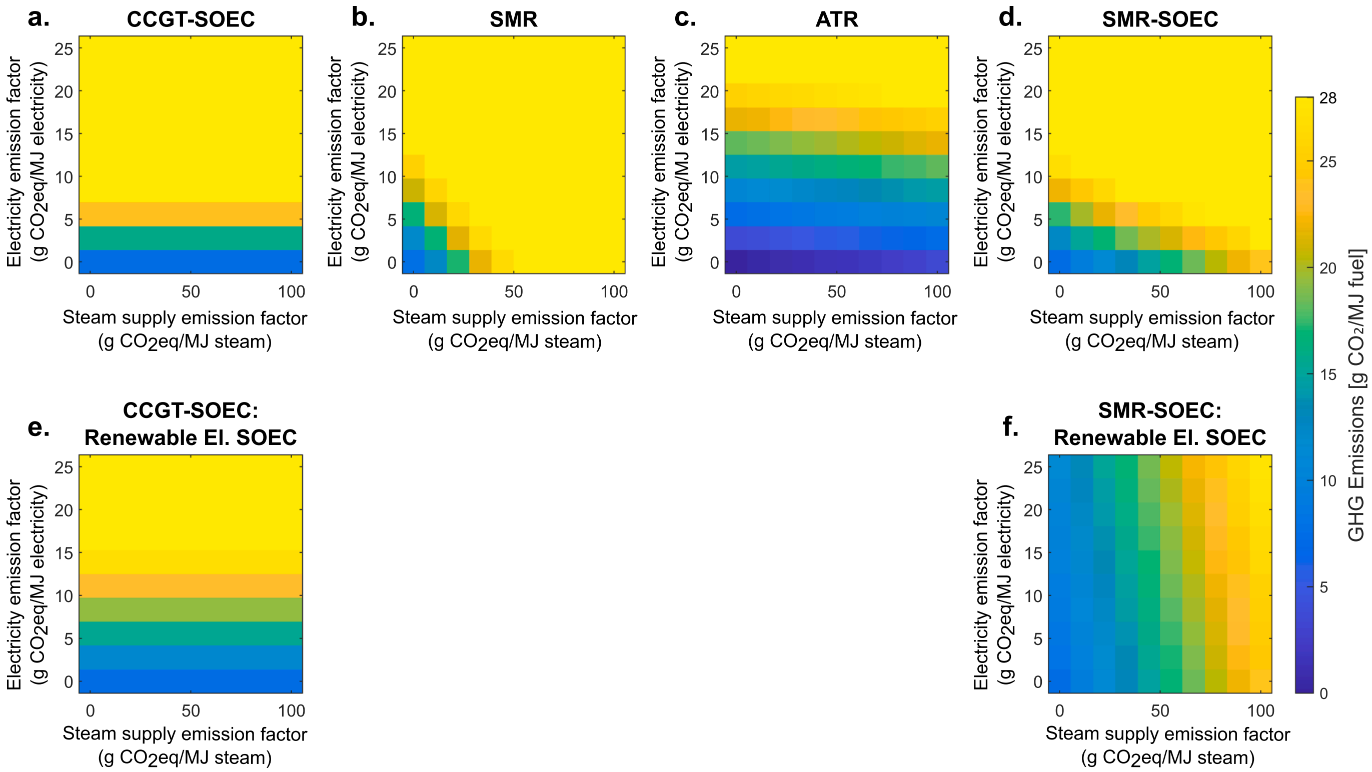

Fig. 4. GHG emission impacts as a function of electricity and steam supply emission intensity factor. Carbon feedstock (methane) is considered a rigid input and assumed to be substituted by electricity. For the integrated pathway (4d and 4e), emissions from the carbon feedstock are excluded because they are allocated to the hydrogen produced. Fig. 4e and 4f assume that the electricity for the electrolyzer comes from a fully renewable source (0 g CO_{2eq}/MJ fuel) while the rest of the processes use electricity from the grid. Emissions exceeding 28 gCO_2/MJ fuel are shown in yellow for visualization, regardless of their exact value. Areas below 28 g CO_2/MJ (all areas except yellow) indicate that 70% GHG emission savings can be achieved. Transport and distribution (e_{td}) emissions are excluded because they are heavily dependent on plant location and source of imported feedstock. Thus, under a conservative approach, pathways should remain below 20 g CO_2/MJ fuel (green area). Abbreviations: CCGT, combined cycle gas turbine; SOEC, solid oxide electrolyzer cell; SMR, steam methane reforming; ATR, autothermal reforming; GHG, greenhouse gas; El, electricity. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

the electrolyzer, placing the starting point of the combustion pathway above the other fuel production pathways. Additionally, most of the exergy destruction in the combustion pathway occurs during the combustion reaction process itself. Furthermore, the reforming pathway exhibits a substantial exergy loss during the reaction due to its endothermic nature and the steam required for the process. The largest exergy loss for the gasification pathway occurs in the reaction section, due to the oxygen requirement for the reaction. The losses thereafter are minimal. Note that methanol synthesis results in larger losses when using the direct synthesis process considered in the combustion and reforming pathways ($CO_2 + H_2$), compared to the conventional method shown in the gasification pathway ($CO + H_2$), since it requires more compression and is less exothermic.

4.3. Greenhouse gas emission savings

Fig. 4 shows the impact of the emissions intensity of electricity and heat on the total GHG emissions of the fuel produced by the considered production pathways.

Based on the methodology described in Section 2.3, a 70% emission savings can be achieved when total emissions remain significantly below 28 g CO_{2eq}/MJ of fuel (corresponding to all colored zones other than those represented in yellow in Fig. 4). Because downstream processing and transport and distribution emissions would raise total emissions similarly across all pathways, this represents a lower bound estimate. To ensure compliance under more conservative assumptions, total emissions should ideally remain below 20 g CO_{2eq}/MJ of fuel (green areas in Fig. 4).

The electricity emission intensity has the highest impact on the cases with SOEC (Fig. 4a and d), indicating that the fuel produced can only achieve the 70% emission savings threshold if the electricity emission intensity is $<$ 10 g CO_{2eq}/MJ of electricity. For context, Sweden has an electricity emission factor of 4.1 g CO_{2eq}/MJ of electricity ($\sim$15 g CO_{2eq}/kWh), but other European countries, such as Spain or Germany, exceed 50 g CO_{2eq}/MJ of electricity ($\sim$180 g CO_{2eq}/kWh). The emissions intensity of steam supplied has a high impact on the cases running with SMR, due to the large heat consumption for the reaction and the reboiler duty of the carbon capture unit. In the case of a stand-alone SMR (Fig. 4b), one would need to supply low-carbon steam ($<$40 g CO_{2eq}/MJ of steam) in order to achieve 70% emission savings. For example, methane combustion leads to a steam supply emission intensity of $\sim$ 55 g CO_{2eq}/MJ of steam. In contrast, for the integrated pathway SMR-SOEC (Fig. 4f), if low-carbon electricity can be sourced ($<$10 g CO_2/MJ of electricity), 70% emissions savings can still be realized using heat from higher emissions sources. The ATR system has low consumption of both electricity and heat, which makes it suitable for countries where the electricity and steam supply emission intensity is below 20 g CO_{2eq}/MJ (Fig. 4c).

When the SOEC is run with 100% renewable electricity (0 g CO_{2eq}/MJ fuel), the GHG emissions are impacted. For the CCGT-SOEC (Fig. 4e), since enough heat and electricity are produced in the CCGT for compressors, electrolyzer heat, and carbon capture, the emission impact is dependent on the carbon source (bio-based methane). In this case, the methane feedstock corresponds to approximately 45% of the total exergy input, meaning that, following the methodology, it should be considered as elastic input if it is imported.

When bio-based methane is regarded as elastic input, even if all the electricity is 100% renewable (0 g CO_{2eq}/MJ fuel), a maximum of 71% GHG emission savings can be achieved for CCGT-SOEC pathway. Therefore, when adding transport and distribution emissions (e_{td}), total emissions will be above the 70% GHG emission savings threshold. Thus, treating bio-based methane as an elastic input, accounting for its upstream emissions, would not meet the requirements for RFNBO classification. In contrast, for the integrated pathway (SMR-SOEC), since the carbon feedstock emissions can be allocated to the hydrogen produced, 70% emission savings can be achieved with an electricity emissions factor up to 50 g CO_{2eq}/MJ of electricity.

Production emissions (e_p) can be reduced for all the pathways studied by achieving higher conversion and/or capture rates, increasing the total emission savings. Assuming 100% capture rate in the carbon capture unit would lower the total emissions of the respective pathways (Fig. 4a, b, d, and e) by 7.65 g CO_2/MJ fuel, compared to the values in

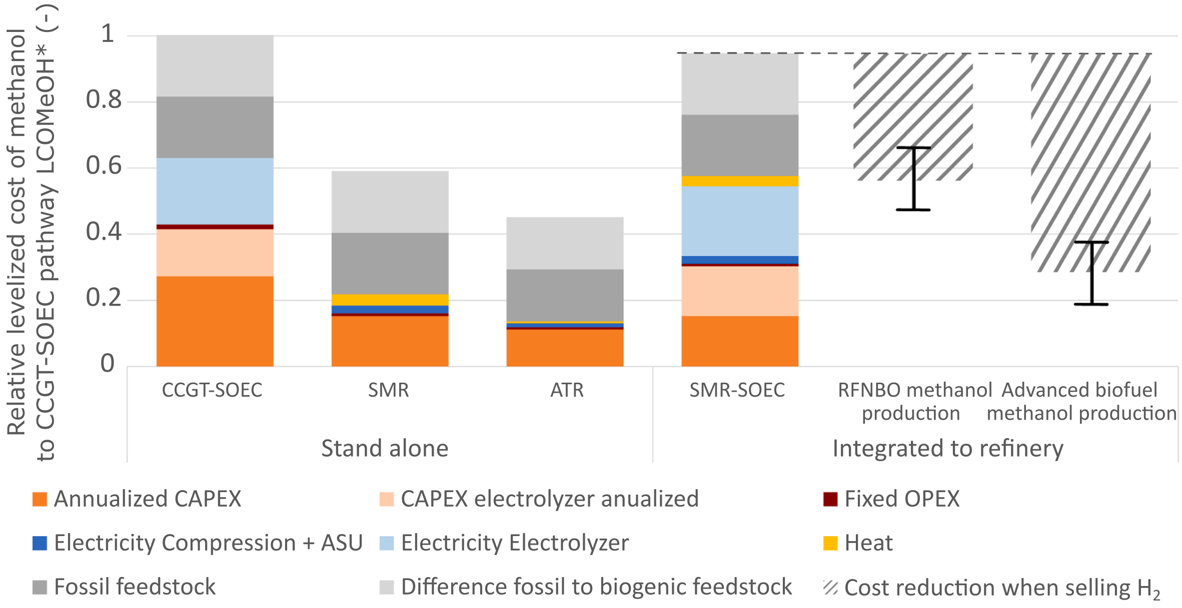

Fig. 5. Relative levelized cost of methanol (LCOMeOH*), for each pathway normalized for the reference case (CCGT-SOEC using biogenic feedstock). Light gray indicates the cost increase if bio-based methane is used instead of fossil methane. For the integrated SMR-SOEC pathway, the potential LCOMeOH* reduction when valuing co-produced hydrogen is shown (H_2 cost of 3–5 €/kg H_2 assumed for SMR with carbon capture, 6–8 €/kg H_2 for electricity-based production, see Table 3). Abbreviations: CCGT, combined cycle gas turbine; SOEC, solid oxide electrolyzer cell; SMR, steam methane reforming; ATR, autothermal reforming; RFNBO, renewable fuel of non-biological origin; CAPEX, capital expenditure; OPEX, operational expenditure; ASU, air separation unit.

Fig. 4. Nevertheless, independent of the assumptions, achieving 70% emission savings would not be possible when using fossil carbon feedstock after 2041, as the $e_{ex\text{-}use}$ term cannot be accounted for. Since $e_{ex\text{-}use}$ is around 68 g CO_{2eq}/MJ of fuel, the savings can only be achieved if the total emissions are below 28 g CO_2/MJ of fuel.

4.4. Economic analysis

Fig. 5 shows the relative levelized costs of methanol (LCOMeOH*) for each pathway studied, expressed relative to the reference pathway (CCGT-SOEC).

The studied production pathways leading to RFNBO methanol (CCGT-SOEC and SMR-SOEC) show similar LCOMeOH*. In contrast, the pathways leading to aviation biofuel (ATR and SMR) can reduce the LCOMeOH* by 45% and 59%, respectively, compared to the reference case. The costs obtained are in the range of 1,700–2,000 €/ton MeOH and 600–1,200 €/ton MeOH for aviation biofuels, which are consistent with literature values [21,36–38].

The most significant costs are associated with operational expenses (OPEX) linked to purchasing the carbon feedstock (methane) and electricity to run the electrolyzer, which aligns with exergy destruction results (Fig. 3). For the CCGT-SOEC pathway, the CCGT investment has a strong influence on the total costs, corresponding to 27% of the CAPEX. However, the additional electricity and heat generated by the CCGT do not bring sufficient economic benefits to significantly reduce the specific costs, resulting in only a 12% cost reduction.

Moreover, the choice of carbon source has a substantial impact on the overall costs of all pathways studied, particularly in the pathways without electrolyzer, where biogenic carbon feedstock accounts for 60%–70% of the total costs (see Fig. 5). Thus, reliance on biogenic carbon feedstock increases production costs.

For pathways that include an electrolyzer, its CAPEX and electricity consumption represent approximately 38% of total costs when biogenic carbon feedstock is used. Although solid-oxide electrolyzers (SOECs) offer higher efficiency, they are not yet established in the market. The commercially available alternatives, such as proton-exchange-membrane (PEM) or alkaline electrolyzers, have slightly lower efficiency but are less capital intensive. If, in the future, renewable electricity is cheap and abundant, the cost advantage of SOEC's higher efficiency may decrease, making less efficient technologies more economically favorable.

For the integrated pathway (SMR-SOEC), two sources of hydrogen are produced, one for fuel production and one for the refinery, e.g., for hydrogenation of lipid-based feedstock (see description in Section 2). Fig. 5 shows the effect of crediting the co-produced hydrogen in the integrated pathway using hatched bar graphs. The LCOMeOH depends on the regulatory fuel definition of methanol and the hydrogen under RED III. When hydrogen is reallocated between the two technologies, the co-produced hydrogen originates from an SMR with carbon capture, while the methanol qualifies as RFNBO. Independent of the feedstock origin, the range of LCOMeOH for the integrated into a refinery pathway is cost-competitive with stand-alone pathways. Thus, when considering the effect of crediting the co-produced hydrogen, the costs drop by 30–50% when producing RFNBO methanol and by 60–80% when producing aviation biofuel methanol, from the integrated pathway without crediting the hydrogen as an offset. Additionally, the costs from aviation biofuel can decrease by 13–30% when compared with the ATR pathway.

A sensitivity analysis of the LCOMeOH was performed, based on the conditions mentioned in Section 3.2.3, and can be found in Supplementary Material S.4. The sensitivity analysis indicates that the operational costs have the highest effect on the production pathway's cost-effectiveness. CAPEX has the highest impact in the scenario CCGT-SOEC (∼ ±14%), while in SMR and SMR-SOEC, the CAPEX impact is (∼ ±7%). For the pathways with SOEC, its CAPEX has an impact of ∼ ±7% on the total costs. The operational costs were varied simultaneously (±25%) and proved to have the highest impact, especially for the pathways containing an SOEC, showing a change of ∼ ±15%. This highlights that reducing operational expenditures, especially for SOEC-based pathways, is critical for improving the economic viability of RFNBO production.

5. Broader impacts of the EU RED III Directive

5.1. Feedstock usage

5.1.1. Fossil vs biogenic carbon

The continued use of fossil-derived CO_2 as an input for RFNBOs is subject to regulatory limitations. RED III and ReFuelEU Aviation directives state that CO_2 from a fossil source can be used until 2036, which can be extended until 2041 for CO_2 captured from emissions sources other than those resulting from fuel combustion for electricity generation, such as CCGT [6]. As stated in the RED III Directive, the previously mentioned years are subject to revision depending on progress in EU Emission Trading System (EU-ETS) sectors towards the EU-wide 2040 climate target [6]. For industrial actors aiming at entering the SAF market, fossil-sourced carbon feedstock can be a short-sighted investment if the possibility of switching to bio-based feedstock is not incorporated from the initial design phase. Without such flexibility, the project's operational timeline may exceed the economic lifetime of the plant, locking the technology into a system that cannot comply with the regulatory requirements and leaving it constrained by limited feedstock options.

To ensure RFNBO-compliant SAF production over the entire project lifetime, industries should consider flexible technologies (e.g., CCGT, SMR, and ATR) that can perform the transition to bio-based feedstock without requiring significant process modifications. The cost of the carbon feedstock has a lower impact on the production cost of RFNBO methanol compared to the cost of producing aviation biofuel methanol, as RFNBO production requires large amounts of electricity. Nevertheless, a change of feedstock should be considered during the feasibility study, because the bio-based feedstocks can substantially increase the cost.

5.1.2. Implications of using methane as a proxy feedstock for fuel production

Refineries produce fuels for a variety of transportation sectors: aviation, maritime, and road transportation. In this study, methane is used as a homogeneous proxy to represent biogenic feedstock, enabling consistent evaluation and comparison of different conversion pathways. While alternative carbon sources may affect absolute values, similar relative trends between pathways are expected. While methane could be used as a transport fuel directly e.g., in heavy-duty trucks or in maritime transportation [11], conversion to methanol provides a versatile liquid intermediate suitable for further upgrading into fuels for sectors such as aviation. Converting methane into methanol incurs an exergy loss of around 60%,[1] and requires additional exergy input for its reforming (Section 3.2). Furthermore, combustion of methanol produces 20% more emissions than combustion of methane per MWh of fuel,[2] due to the lower heating value of methanol. The Directives encourage upgrading fuels with a higher share of renewable energy, even though the conversion process emits CO_2.

Adapting the production pathways to process a wider range of biomass feedstocks, e.g., solid biomass (woodchips) or bio-oil (pyrolysis oil of sawdust), would lead to higher feedstock availability but more energy demand, because of lower LHV values and increased contaminant content. In comparison to bio-based methane, there is a 34% decrease in energy content when using pyrolysis oil and a 62% decrease when using solid biomass, such as woodchips. Using more complex

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[1] Per mass, from 50 MJ/kg of methane to 20 MJ/kg of methanol.

[2] Meaning 247.97 vs 197.43 g CO_2/kWh of fuel.

biomass would require equipment changes for combustion, pyrolysis, or gasification of solids and liquids, as well as higher exergy requirements for separation and purification. Therefore, a change of feedstock from bio-based methane will translate to an increase in exergy demand and equipment costs, similarly in all production pathways.

5.2. Unintended consequences of the RED III Directive

The pathways studied may raise concerns from a regulatory and sustainability perspective. Advanced biofuel, biofuel, and RFNBO are counted towards the minimum blend-in quota requirements for drop-in SAF. Additionally, there is a separate quota that needs to be fulfilled with RFNBO. Following the RED III supply targets, RFNBO fuels will be in high demand in the future. Despite all production pathways studied yielding the same intermediate product (methanol), the classification as an RFNBO is not distributed equally. Under the current EU directive, only the combustion-based pathway (CCGT-SOEC) and the integrated pathway (SMR-SOEC) produce MeOH that is RFNBO compliant, and that can be counted towards the renewable fuel blend-in quota. In contrast, alternative pathways (SMR and ATR), despite requiring only about half the exergy input (see Section 4.2), do not meet the same eligibility criteria for classification under the current EU framework. This leads to an overall increase in energy consumption for the production of an equivalent fuel output.

5.2.1. Can hydrogen cover the RFNBO shortfall?

According to the cost results (see Section 4.4), the stand-alone RFNBO production pathway offers low profitability for refineries. Nevertheless, the costs are lowered with the integrated pathway when the co-produced hydrogen is credited. This hydrogen could either be sold to offset costs or diverted to the refinery's own lipid hydrogenation process. Although the RED III regulation states that sending RFNBO hydrogen for hydrogenation of biofuels would not contribute to RFNBO production, the option is discussed in this paragraph. In lipid hydrogenation, hydrogen is added to remove oxygen and to saturate double bonds. Considering vegetable oil (triolein) as the lipid-based feedstock, the hydrogen that removes oxygen (66.6 mol%) is purged away as water, while the rest of the added H_2 (33.3 mol%) remains in the fuel molecules,[3] leading to 2.19% of RFNBO energy content in the product obtained. From all the hydrogen required for hydrogenation, 33.3 mol% of it would need to be produced using renewable electricity to claim an RFNBO fraction. Producing all the hydrogen required using an SOEC would convert a large hydrogen fraction (66.6 mol%) back into water, resulting in inefficient use of renewable electricity. ReFuel Aviation requirements state that 1.2% of RFNBO is required on average by 2030 [2]. Although this first target could be technically achieved by allocating renewable hydrogen to the production of hydrogenated vegetable oil, it would not incentivize industries to increase the volume of SAF production, slowing the decarbonization of aviation fuel.

5.3. Outlook for sustainable aviation fuels

Fig. 6 compares the distribution of input energy (MJ input per MJ of refinery aviation products) of fossil, RFNBO, and SAF aviation fuel production pathways, showing how the fuel fractions are distributed in the refinery product: refinery gases, naphtha, jet fuel, diesel, and wax. The three selected pathways are (1) starting from crude oil in a conventional mineral refinery, (2) production of RFNBO methanol (CCGT-SOEC) followed by the methanol-to-jet (MTJ) process [24], and (3) using lipid-based feedstock to convert to SAF, maximizing jet fuel production [39].

UCO and crude oil have similar exergy efficiency for conversion to refinery products. Production of 1 MJ of refinery products requires 1.03 MJ of crude oil or 1.22 MJ of UCO. To produce refined RFNBO fuel from the CCGT-SOEC pathway studied, 2.77 MJ are needed (see Fig. 6), i.e., 206% more exergy. Converting methanol to fuel is relatively energy efficient thus, a stand-alone ATR enables methanol production at 1.33 $MJ_{in}/MJ_{refined}$ (in exergy terms, see Section 4.2), with 83% of the input from methane and the remainder from electricity and heat.

5.3.1. Role of refinery by-products for multi-sector decarbonization

Historically, refineries have aimed to maximize production of gasoline and diesel fractions while minimizing the production of refinery gases, such as methane, ethane, and propane (see Fossil fuel in Fig. 6). Short-chain hydrocarbons have had a low value, making it unprofitable to condition them for distribution. Therefore, they have been seen as a source of hydrogen (through SMR) or fuel (heat production). In the context of future SAF-oriented refineries, however, these streams may represent a valuable co-product rather than a loss. For future refineries, the production of short-chain hydrocarbons can be seen as an opportunity for the production of marine fuel, promoting the decarbonization of multiple transportation sectors (Section 3.5.1) [11,19].

5.3.2. SAF market perspectives

Although the EU is actively promoting SAF production, airlines also have the option to purchase carbon credits to offset their GHG emissions. Nevertheless, it does not exempt them from complying with the minimum-share requirements for drop-in of SAF and RFNBO. Fig. 7 uses the calculated costs for RFNBO and aviation biofuel methanol (Fig. 5) to compare them with the cost of producing jet fuel from crude oil, compensating for its emissions with carbon credits. For comparison and simplification, in Fig. 7, all fuel categories, i.e., refinery gas, naphtha, diesel, and wax, are assumed to be valued equally to jet fuel.

Fig. 7 contextualizes the impact of carbon price for fossil-based jet fuel, showing that it is significant but insufficient to make aviation biofuels or RFNBO-compliant SAF competitive until the emission price is ~ 400 €/ton CO_2, which is similar to the voluntary market price for bioenergy with carbon capture and storage (BECCS-CDR) credits. RFNBO jet fuel currently costs about 3.5–4 €/L, depending on the electricity price, which is roughly eight times the price of fossil jet fuel (~0.5 €/L). Under RED III, this cost gap is addressed through a minimum blend-in quota, which creates a guaranteed demand for RFNBO-SAF and effectively reduces exposure to direct price competition with fossil jet fuel. Consequently, its deployment relies strongly on policy instruments, and cost-competitiveness is unlikely to be achieved if the policy is not in place. In the absence of mandatory blending requirements, carbon pricing would represent an alternative mechanism to improve the competitiveness of RFNBO-SAF relative to fossil jet fuel. Only at CO_2 emission prices exceeding approximately 1,000 €/ton CO_2 (above direct air capture (DACCS-CDR) voluntary market price), RFNBO-SAF would become more cost-effective than offsetting the fossil jet fuel emissions (see Fig. 7). With current CO_2 prices around 100–200 €/ton CO_2 (2025) [40], paying the emission price remains the lower-cost compliance option.

For fossil-based jet fuel, when the carbon price exceeds approximately 200 €/ton CO_2 (Fig. 7), the carbon emissions become the major cost driver, rather than the underlying fuel product cost. Under such conditions, importing low-carbon fuels produced outside the EU may become economically favorable, as these imports are currently not subject to the Carbon Border Adjustment Mechanism (CBAM) [41]. As a result, the current EU regulatory framework may unintentionally favor import of externally produced fuels over more energy-efficient domestic pathways, highlighting an inconsistency between exergy efficiency, GHG regulation and economic resilience.

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[3] 9 mol of H_2 are required to saturate each mole of triolein ($C_{57}H_{104}O_6$) and remove all the oxygen (3 mol for olefinic saturation and 6 mol for oxygen removal). From each mole of triolein, 3 mol of n-paraffins and 1 mol of propane are obtained.

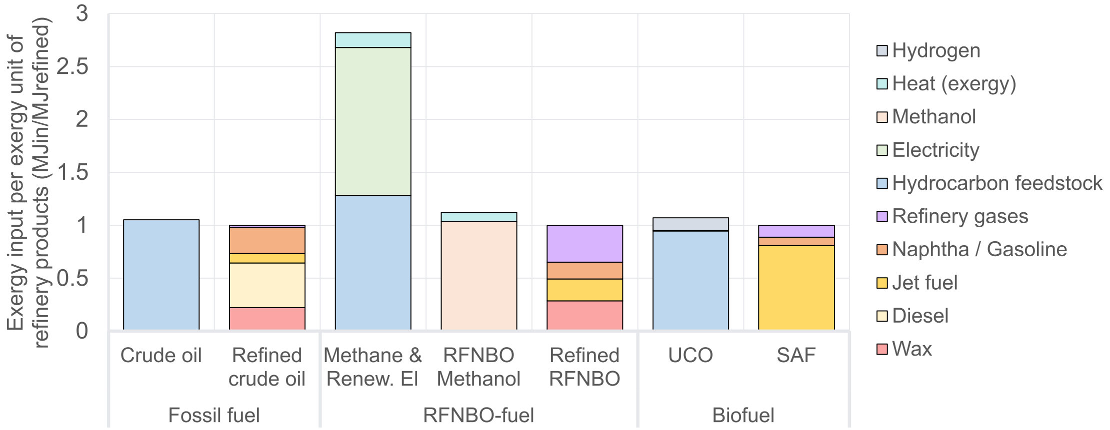

Fig. 6. Exergy input per refinery product (distribution of different fuels, including gasoline and jet fuel). The analysis is done for a European oil refinery using crude oil [42], a future refinery producing RFNBO (CCGT-SOEC pathway studied) [24], and for a used cooking oil (UCO) refinery, maximizing the yield of SAF (based on [39]). Abbreviations: RFNBO, renewable fuel of non-biological origin; UCO, used cooking oil; SAF, sustainable aviation fuel; Renew. El, renewable electricity.

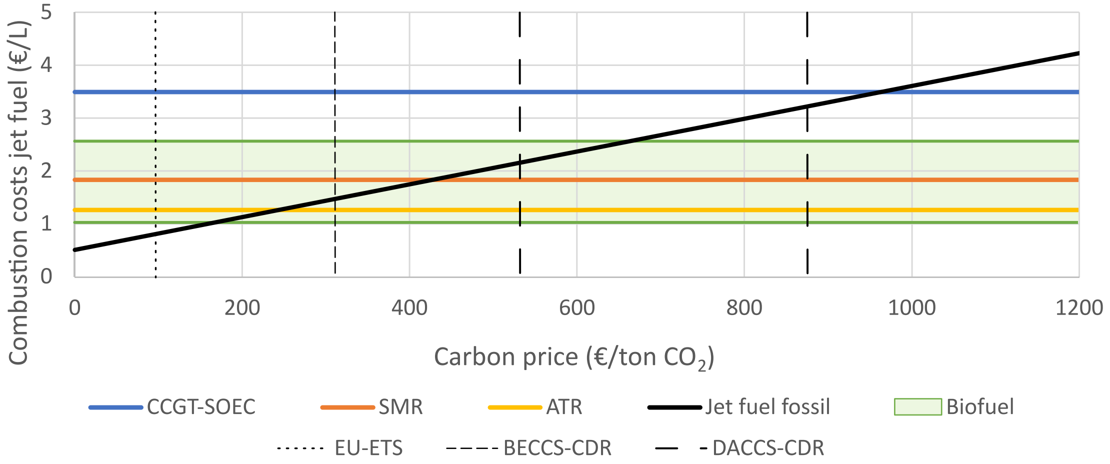

Fig. 7. Combustion costs (€/L jet fuel) for different fuel production pathways (CCGT–SOEC, SMR, and ATR), compared with fossil and biogenic jet fuel. Costs include methanol-to-jet fuel conversion, assuming an exergy efficiency of 88% and a mass yield of 34% [24], using bio-based methane and electricity as inputs. Biogenic SAF prices are assumed to be 2–5 times higher than fossil jet fuel [43], with literature ranges for animal fats and rapeseed oil pathways indicated [39,43,44]. Carbon prices reflect EU-ETS levels and voluntary market prices for BECCS and DACCS [45,46]. Abbreviations: CCGT, combined cycle gas turbine; SOEC, solid oxide electrolyzer cell; SMR, steam methane reforming; ATR, autothermal reforming; EU-ETS, European union emissions trading system; BECCS, bioenergy with carbon capture and storage; DACCS, direct air carbon capture and storage; CDR, carbon dioxide removal.

6. Conclusions

This study evaluated sustainable aviation fuel (SAF) production pathways using exergoeconomic methodology to assess their ability to comply with the EU Renewable Energy Directive III (RED III). Three stand-alone production pathways were studied based on combustion, reforming, and gasification of the feedstock. By adopting a simplified thermodynamic representation of biogenic feedstocks, this study pinpoints fundamental pathway differences and enables a consistent comparison of their exergetic and economic performance. The simplification clarifies the structural differences between conversion pathways without including complex feedstock compositions. Additionally, a refinery-integrated pathway was investigated, enabling the co-production of hydrogen and aviation fuel using two alternative hydrogen production technologies. The allocation of hydrogen between refinery and aviation fuel production enables flexibility of aviation fuels production tailored to different regulatory targets.

The results demonstrate a fundamental inconsistency between RFNBO compliance and exergetic efficiency. Existing policies prioritize carbon origin over exergetic performance which favors electricity-intensive pathways, potentially delaying cost-effective decarbonization. Meeting EU regulatory requirements for RFNBO fuel decreases the exergetic efficiency by 33% compared to gasification-based production, which preserves a larger fraction of the exergy content of the feedstock. Discrepancies between energy and exergy efficiencies indicate that focusing only on energy efficiency may favor less efficient processes. However, the gasification-based fuel is not RFNBO-compliant under RED III. Under representative cost conditions, the reforming and gasification pathways leading to aviation biofuel can reduce the levelized production cost of the fuel by 45% and 59%, respectively, relative to the stand-alone combustion pathway producing RFNBO. All pathways can potentially meet the 70% GHG emissions savings requirement for aviation fuels. However, this is dependent on the level of decarbonization of the electricity grid, process emissions and transport and distribution emissions. Thus, compared to RFNBO-compliant production under RED III requirements, reforming and gasification pathways achieve higher exergetic efficiency and lower levelized production cost.

In addition, the study shows that integration into a refinery offers allocation flexibility to meet regulatory targets while achieving higher exergy efficiency (18% increase) and lower production cost (30–50%

reduction when valorizing hydrogen) than stand-alone RFNBO pathways, without compromising refinery hydrogen production. Thus, if the regulations remain unchanged, the combined production of low-emissions hydrogen and RFNBO fuel would be the preferred case for RFNBO-compliant pathway. While the methodological approach and the results are transferable, the policy implications are case-specific to contexts where fuel targets similar to RFNBO are in place, such as in the European Union.

The results of this study indicate that the binding targets for RFNBO production set out in the RED III directive favor technological pathways with low exergy efficiencies, that are not in line with aims and targets set under the Energy Efficiency Directive (EED). Hence, complying with RFNBO definition incentivizes SAF production from energy-depleted sources, requiring fuel producers to adopt specific configurations even when they are not the most exergy- or cost-efficient. As a result, investment decisions become highly dependent on the stability of the regulatory framework.

CRediT authorship contribution statement

Judit Fortet Casabella: Writing – original draft, Visualization, Validation, Software, Methodology, Data curation, Conceptualization. **Johanna Beiron:** Writing – review & editing, Visualization, Validation, Supervision, Software, Methodology, Conceptualization. **Tharun Roshan Kumar:** Writing – review & editing, Visualization, Validation, Methodology. **Moa Sundén:** Writing – review & editing, Supervision, Methodology, Conceptualization. **Simon Harvey:** Writing – review & editing, Project administration, Funding acquisition. **Henrik Thunman:** Writing – review & editing, Supervision, Methodology, Funding acquisition, Conceptualization.

Declaration of Generative AI and AI-assisted technologies in the writing process

During the preparation of this paper, the authors used *ChatGPT* in order to improve the language and readability. After using this tool/service, the authors reviewed and edited the content as needed, and they take full responsibility for the content of the publication.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Henrik Thunman reports financial support was provided by Swedish Energy Agency. Henrik Thunman reports financial support was provided by VAROPreem. Henrik Thunman reports financial support was provided by Borealis AG. Moa Sunden reports a relationship with VAROPreem that includes: employment. The perspectives/interpretations/conclusions expressed by the co-authors in this scientific article are the personal view of Moa Sundén and do not necessarily represent the opinions or positions of the affiliated institution, VAROPreem. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ecmx.2026.101948.

Data availability

Data will be made available on request.

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