



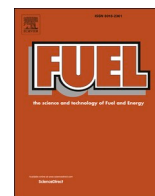
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Full Length Article

Locked in on RFNBOs – Will EU mandates for drop-in synthetic aviation fuels lead to decreased energy- and cost-efficiency?

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ABSTRACT

Decarbonization of the transportation sector implies that fossil fuels must be substituted with sustainable alternatives. Current EU policies incentivize large-scale deployment of synthetic aviation fuel production that can be classified as Renewable Fuel of Non-Biological Origin (RFNBO). Synthetic aviation fuel can be produced from methanol and this work presents a techno-economic assessment of three pathways (two combustion-based and one gasification-based) to produce synthetic methanol from biomass residues and renewable hydrogen. The results show that the gasification-based pathway can produce methanol at a lower cost (820 €/t methanol) and higher energy efficiency (46 %, for conversion of biomass, electricity and heat inputs to methanol) compared to combustion-based options (1,050–1,500 €/t methanol and ~37 % efficiency). The gasifier route requires less renewable hydrogen, resulting in a 30 % lower electricity demand. However, only 55 % of the gasification-based methanol is compliant with the RFNBO definition, since the regulation stipulates that biofuel cannot be counted towards the drop-in quotas. Furthermore, the findings indicate that RFNBO policies that favor production using CO₂ from combustion processes that supply energy to utility systems (e.g., district heating) risk leading to lock-in in inefficient systems, as electrification of heat supply could be a more efficient option. This work identifies such regulatory inconsistencies that increase risk related to investment decisions.

1. Introduction

In the 2020s, strategies to substitute the use of fossil fuels in the transportation sector have emerged in the European Union (EU). For aviation, drop-in quotas for sustainable aviation fuels (SAF) that increase over time constitute the main policy measure [41], and create strong incentives to scale up the production of SAF. It has been estimated that investments of around 175 billion \$/a are needed globally until 2050 to scale up the production of SAF by constructing 1,600–3,400 new production plants (the number could go as high as 8,000 [38], of which 300–400 should be operational by 2030 [30]).

Within the EU, SAF fuels are divided into three main categories: i) *advanced biofuels*, produced from biogenic feedstocks listed in RED III (Annex IX, Part A [42]); ii) *recycled carbon fuels*, produced from waste streams of non-renewable origin which are unsuitable for material recovery and/or produced as an unavoidable and unintentional consequence of industrial processes; and iii) *renewable fuels of non-biological origin* (RFNBO), meaning that synthetic fuel is produced from renewable hydrogen that is reacted with CO₂. EU rules dictate which feedstock can be used for each fuel category (discussed further in Section 2) and

provide specifications related to the production process. Thus, even though several technical pathways can be considered for synthetic fuel production (e.g., combustion or gasification-based pathways [53]), not all of them are necessarily compliant with RFNBO rules. For instance, biomass gasification to syngas with further processing to aviation fuel would be categorized as an advanced biofuel, while *residual* CO₂ from biomass gasification could be synthesized to RFNBO.

Although technically mature processes are available, the production of synthetic fuels is not without challenges. Sufficient volumes of non-fossil carbon feedstock and access to renewable electricity (or low-carbon hydrogen) are required to ensure low climate impacts. Becken et al. [6] estimated that in 2050, SAF could consume 9 % of global renewable electricity and 30 % of sustainable biomass supply, with significant energy losses. Drünert et al. [13] found that to substitute the German aviation fuel use (10.3 Mt/a in 2019) with e-fuels would require 440 TWh_{el}/a, while the current (year 2024) renewable electricity generation in Germany is 275 TWh/a [18]. Thus, the mere challenge of securing large volumes of energy and feedstock is an obstacle to industry growth [12] and can be a major source of reluctance to invest [37]. Attaining high energy and resource efficiency in SAF production can be a key for economic viability, as well as a means of keeping the demand for

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Nomenclature		P	Electricity [MW]
Nomenclature		Q	Heat [MW]
Nomenclature		x	Moles of compound [mol]
Nomenclature		<i>Greek</i>	
CAPEX	Capital expenditure	α	Power-to-heat ratio [$\text{MW}_{\text{el}}/\text{MW}_{\text{heat}}$]
CHP	Combined heat and power	β	Energy penalty [MJ/kgCO_2]
COP	Coefficient of performance	γ	CO_2 capture rate [%]
DAC	Direct air capture	η	Efficiency [–]
DH	District heating	λ	Excess air ratio [–]
ETS	Emissions trading system	<i>Subscripts and superscripts</i>	
FT	Fischer-Tropsch	B	Boiler
GHG	Greenhouse gas	bioMeOH	bio-methanol
OPEX	Operational expenditure	comp	Compression
PEM	Proton Exchange Membrane	CHP	Combined heat and power
RCF	Recycled carbon fuels	DH	District heating
RFNBO	Renewable fuels of non-biological origin	gen	Generation
rWGS	Reversed water gas shift	HP	Heat pump
SAF	Sustainable aviation fuel	i	Part of process route
SOEC	Solid-oxide electrolytic cell	inv	Investment
<i>Latin</i>		LHV	Lower heating value
C	Cost [€]	O&M	Operation and maintenance
E	Energy [MW]	tot	Total
FLH	Full load hours [h/a]		
m	Mass flow [kg/s]		

renewable electricity on a feasible level.

Furthermore, it is debatable whether the EU policy measures for SAF production are in alignment with other directives towards a reduced climate impact, such as the renewable energy directive [42], the waste hierarchy principle [40] and the energy efficiency directive [43]. Conflicting policy directives create uncertainty and increase investment risk for producers [12] that might delay deployment. If the regulatory landscape is not consistent, one or several policy measures might be expected to change at some point which could render an investment taken under previous conditions unprofitable. Thereby, assessing the policy measures in place is important to understand the investment conditions for sustainable technologies.

Against this background, the aim of this work is to analyze the current EU policy measures related to RFNBO production with respect to energy and cost efficiency, technology neutrality, and alignment with other directives aiming towards increased green energy supply within the EU. Particular attention is given to assessing how the aviation fuel regulations favor/disfavor principally different fuel production options. Here, we use methanol and methanol production options (via combustion and gasification of solid biomass residues) as an example of an intermediate energy carrier that can be further synthesized to aviation fuel. While previous studies have investigated the impact on RFNBO production cost of the EU aviation fuel policy regarding requirements on renewable electricity production and purchase conditions [28,34], we focus on the eligibility of feedstocks for RFNBO compliance and their use in synthetic fuel production processes. The main novelty and contribution of the work lies in providing a critical assessment of the investment conditions for RFNBO production, in terms of alignment with regulations, energy efficiency and cost. We also discuss potential system-level impacts of favoring different production pathways and evaluate whether such technology choices are motivated.

2. EU policy relating to synthetic aviation fuel production

Through the Green Deal, the EU aims to reach climate neutrality by 2050, with significant cuts in greenhouse gas (GHG) emissions. For the transportation sector, the EU has set a target that 29 % of energy supply should be renewable by 2030 [42], and drop-in biofuels and/or

synthetic fuels have been targeted as a defossilization strategy for aviation and maritime shipping. Fig. 1 illustrates the ramping up of blend-in quotas over time, starting at 2 % sustainable aviation fuels in 2025 and reaching 70 % by 2050, with 35 % being RFNBO [41]. A similar greenhouse gas intensity reduction scheme has been introduced for maritime transportation [44]. Fuel producers will be liable to a fine if they fail to deliver the required quotas and must compensate by supplying the missing volume in the next reporting period [41]. In addition, aviation is now included in the EU emissions trading system (ETS), and maritime transportation will be phased in by 2026, increasing the incentives to reduce fossil CO_2 emissions in these sectors. RFNBO fuels may be counted as twice their energy content (i.e., a multiplier of 2 is applied) towards reaching the transport sector energy targets. To facilitate the industrial transition to achieve these targets, the Clean Industrial Deal [39] aims to offer clear business incentives for industry to decarbonize within Europe.

According to the EU rules, RFNBOs must lead to GHG emissions reductions of at least 70 % when used, compared to fossil options [45]. Similarly, the renewable energy directive (RED III) states emission reduction demands of 65 % for liquid biofuel use, and 70–80 %, depending on the year of commissioning, for plants that use biomass to produce electricity, heat or cooling. RFNBOs are produced through carbon capture and utilization pathways, from CO_2 and hydrogen. The RFNBO energy content cannot originate from biogenic sources, implying that all hydrogen must be produced by renewable electricity, with requirements on additionality and temporal and geographical correlation [46]. There are also conditions on the origin of the carbon in RFNBOs, and how avoided emissions are calculated. CO_2 used in RFNBOs can be counted as avoided emissions if obtained from (i) fossil-fired power plants (until 2036, see Fig. 1) or industrial plants (until 2041) that are included in an emissions trading system, (ii) air, via direct air capture (DAC), (iii) biomass combustion, although the biogenic CO_2 cannot be intentionally generated for RFNBO production, (iv) geological sources, or (v) combustion of RFNBO or recycled carbon fuels (RCF). Biogenic CO_2 is projected to be the most long-term economically sustainable of these options, since fossil CO_2 is a short-term strategy given the deadline for counting as avoided emissions, and DAC is expensive and energy-intensive relative to other options.

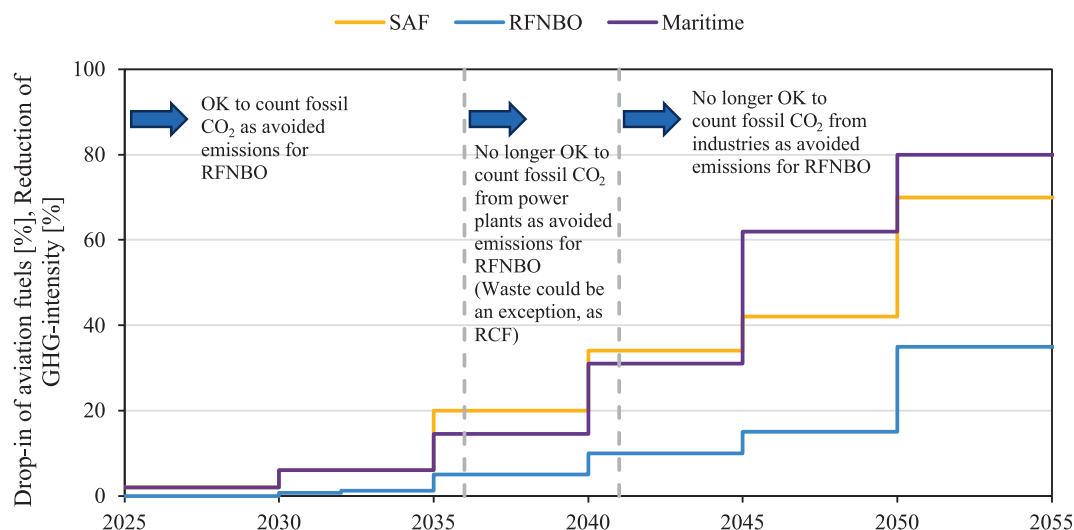


Fig. 1. The ramping up over time of drop-in sustainable aviation fuels, RFNBO for aviation, and demands on GHG-intensity reduction in maritime transport in the EU. SAF, sustainable aviation fuels; RFNBO, renewable fuels of non-biological origin; RCF, recycled carbon fuels.

The requirement on non-intentional CO₂ generation implies that bio-carbon resources must be used as fuel for other energy purposes first, before use as aviation fuel. Examples include combustion in combined heat and power plants, or as a substitute for fossil fuels in industrial processes. The EU renewable energy directive (RED III [42]) states that forestry biomass should be used according to a *cascade principle*, meaning that biomass should be used according to its highest economic and environmental value, prioritizing material production, reuse and recycling over energy use. Thus, biomass residues from harvesting and forest industry material production, such as branches, tops, and bark, could be used for energy purposes. In general, waste should be handled according to the waste hierarchy [40], prioritizing material re-use and recycling before energy recovery. Lastly, another relevant directive is the energy efficiency directive [43], stating that “energy efficiency first” should be an important principle when planning for new large-scale energy consuming investments.

3. Methanol production routes

Three principally different routes for production of synthetic methanol from biomass feedstock are considered in this work, based on combustion and gasification technology, as described in Section 3.1. All routes use solid biomass as raw material (e.g., forest industry residues such as bark, branches and tops in the form of wood chips) to produce methanol. Practical considerations and characteristics of the routes are discussed in Section 3.2 and summarized in Table 1.

Methanol is used as an example of an (intermediate) liquid fuel that can serve as an energy carrier for use as maritime fuel or as a feedstock that can be upgraded to SAF [20]. Other fuels could also be considered for aviation, such as Fischer-Tropsch (FT) liquids [11] or hydrogen [22]. The main difference between methanol and FT-liquids lies in the synthesis and distillation processes, both fuels can be synthesized from biomass residues or CO/CO₂. However, the focus of this work is not to compare liquid fuels, but to provide a transparent assessment of technological pathways to produce them. For the interested reader, techno-economic comparisons of various jet fuel production processes have been presented in previous studies, for example [8,36].

3.1. Description of production routes

Fig. 2 illustrates the three production routes considered. The first route (i) is based on combustion of biomass in a combined heat and power (CHP) plant boiler, followed by absorption-based post-

combustion capture of CO₂ from the generated flue gases. The captured CO₂ is subsequently transported to a methanol synthesis plant where hydrogen for the synthesis is produced by an electrolyzer.

The second route (ii) is also based on combustion, but in an oxygen-fired boiler to enable separation of CO₂ from the flue gas by condensation of water vapor. Since air is not used as a combustion medium, energy-intensive separation of CO₂ and nitrogen can be avoided. The CO₂ is thereafter processed to methanol in a co-located synthesis plant. Hydrogen for the synthesis, and oxygen for the oxy-combustion, are produced by an on-site electrolyzer.

Route three (iii) uses a gasifier to convert the solid biomass to syngas (CO and H₂) that is used to synthesize methanol. CO₂ is also generated in the gasification process and can either be captured and stored to achieve negative emissions (BECCS) [16,25], or be synthesized to methanol along with the syngas. In this work, the CO₂ is assumed to be converted to methanol to maximize the fuel yield. It is important to note that in the gasifier route, the hydrogen used to convert all CO/CO₂ to methanol comes from two sources: the biomass conversion in a steam environment, and electrolysis of water as in the other routes. Thus, not all of the produced methanol would be classified as RFNBO according to current EU rules. The methanol derived from gasifier syngas will be referred to hereafter as bio-methanol.

These three routes reflect a broad range of scenarios that could motivate different technology selections. The CHP route represents a current technical system where both heat and electricity production from solid fuels are considered valuable, that was incentivized as a means of increasing the share of bio-based electricity (e.g. the implementation of green electricity certificates in Sweden [27]). In this paper we assess whether the CHP system is a suitable alternative also in the future, or if there are other technical systems that perform better and motivate a change of system. In a future where renewable electricity is abundant, electricity production from thermal power plants (such as the CHP plant) would be costly and redundant, making the oxy-fuel heat-only boiler competitive to generate CO₂ for synthesis at a low capture cost. In the opposite scenario where renewable electricity is scarce, a gasifier-based route would be motivated as it consumes less electricity for hydrogen production than combustion-based options and preserves the energy in the biomass feedstock as far as possible.

3.2. Spatial assumptions and practical implications

Fig. 3 illustrates the spatial aspects of how the routes are assumed to be implemented. The CHP plant is assumed to be located in an urban

Table 1

Overview of advantages (+) and drawbacks (–) related to practical implementation of the production routes studied.

	CHP plant	Oxy-fuel plant	Gasifier plant
Cost	+ Possibility of retrofitting existing CHP plants. – Costly CO ₂ separation, especially if retrofit.	+ Low-cost heat-only boiler and carbon capture process. + Co-production of H ₂ and O ₂ in electrolyser.	– Large scale required for economic feasibility and cost-competitiveness.
Location	– Limited to urban areas or industrial sites with a heat demand. – Spatial constraints in cities, potential lack of space to build plants. + Synthesis can be placed at other locations but requires CO ₂ transportation infrastructure.	+ Location flexible, can be placed close to source of biomass residues and/or renewable electricity, where there is a demand for industrial heat.	+ Location flexible, can be placed close to source of biomass residues and/or renewable electricity.
Infrastructure, Energy system	+ Co-produces electricity and district heating for local energy systems. – City power grids are often constrained, challenging to get green electricity for on-site H ₂ production in the near-term.	+ Avoids CO ₂ transport, since co-located with synthesis plant. + Can supply utility heat if relevant heat sinks are available nearby. – Needs large-scale access to electricity supply for hydrogen production.	+ Relatively lower hydrogen demand and electricity consumption compared to oxy-fuel/CHP plant configuration.
Operation	– Seasonally varying heat demand and CHP plant operation, implies varying CO ₂ feedstock supply.	+ Year-round operation as an industrial facility. + Possibility to buy biomass at a lower price than CHP plants, thanks to year-round operation.	+ Year-round operation as an industrial facility. + Possibility to buy biomass at a lower price than CHP plants, thanks to year-round operation.

area with a demand for district heating. Surplus electricity and grid connection capacity is often limited in urban areas, implying a poor location for large-scale deployment of electrolysis, so the CO₂ captured from the CHP plant is instead transported to a non-urban area with better access to renewable electricity generation and grid connection for hydrogen supply.

In contrast, the oxy-fuel plant is assumed to be located in a non-urban area with access to renewable electricity. We assume that the oxygen-fired boiler is of heat-only type with production of low-pressure steam, which enables a simpler construction than the CHP plant which also includes a steam cycle and turbine. Part of the steam produced is supplied to the SOEC electrolyzer, and the remaining steam is assumed to be supplied to a nearby industrial process with a heat demand. However, we assign no economic value to the steam supplied to the industrial user. In other words, the oxy-fuel boiler is not economically motivated by the industrial steam demand, but rather as a low-cost CO₂ source.

In this regard, the oxy-fuel route might be seen as an unconventional case, but it is not unreasonable to extrapolate that the current EU rules

for RFNBO might favor systems where biomass is more valuable as a source of CO₂ than as a source of energy or raw material. For instance, under the assumption that biomass has a lower heating value of 18.6 MJ/kg_{dry} (5.16 MWh/ton_{dry}) and a 50 wt-% carbon content, 1 ton of dry biomass contains 0.5 ton of carbon and generates 1.83 ton of CO₂ if completely combusted. According to Eq. (1), this implies that 2.8 MWh of dry biomass generates 1 ton of CO₂. Thus, for a CO₂ price of 100 €/t, the energy content in dry biomass would be less valuable than CO₂ at an energy price below 36 €/MWh (Eq. (2)). Currently, moist biomass residues used for combustion in Sweden are priced at around 25–55 €/MWh [47]. If the CO₂ market price increases, e.g. because of increasing RFNBO drop-in quotas that make CO₂ a scarce commodity, incentives might be created to incinerate biomass only for the purpose of CO₂ generation, thereby wasting the biomass energy content and molecular structure.

The minimum fine that aviation fuel producers are liable to pay for not meeting drop-in quotas corresponds to two times the price difference between conventional aviation fuel and synthetic aviation fuel. Assuming that conventional aviation fuel is priced around 1,000 €/t and that sustainable aviation biofuels are available at market prices around 2,500 €/t [14], the minimum fee should be at least 3,000 €/t SAF, or 250 €/MWh SAF. This is equivalent to around 1,000 €/tCO₂, assuming an emission factor of 70 gCO₂/MJ aviation fuel [45]. Such a high CO₂ price corresponds to a biomass price of 360 €/MWh (Eq. (2)), which is around 10 times higher than current price levels. Thus, biomass would be more valuable as CO₂ (with zero energy content) that can be sold to synthetic fuel producers, than as fuel energy, and motivates our above assumptions regarding the oxy-fuel boiler energy supply.

$$5.16 \frac{\text{MWh}_{\text{dry}}}{\text{ton}_{\text{dry}}} \cdot \frac{1 \text{ ton}_{\text{dry}}}{0.5 \text{ tonC}} \cdot \frac{12 \text{ tonC}}{44 \text{ tonCO}_2} = 2.8 \frac{\text{MWh}_{\text{dry}}}{\text{tonCO}_2} \quad (1)$$

$$2.8 \frac{\text{MWh}_{\text{dry}}}{\text{tonCO}_2} \cdot \frac{\text{€}}{\text{MWh}_{\text{dry}}} = \frac{\text{€}}{\text{tCO}_2} \quad (2)$$

The gasifier is also assumed to be located in a non-urban area, if possible close to sources of biomass residues. Feedstock availability in large quantities is important for the economic viability of the gasifier, as the extensive gas cleaning technology requires large scale for cost-effective implementation [2]. The gasifier is assumed to be designed for maximum syngas yield, at the expense of no supply of utility energy (given the assumption of no economic value for industrial heat supply). However, this can be adapted on a case-to-case basis. The residual heat that leaves the gasifier process is, e.g., in the form of low temperature condensate from biomass drying, and flue gases.

Note that heat supply to urban areas is included as a system service in all routes, to ensure a fair comparison. As stated previously, the CHP plant delivers district heating since it is located in an urban area. The oxy-fuel and gasifier plants located in non-urban areas cannot supply urban district heating. This can be compensated by implementation of power-to-heat (PtH) through heat pumps in the urban area. The heat pump needs to be supplied with low-grade heat that could be obtained from locally available sources, such as industrial excess heat, wastewater, seawater, ambient air, or the ground. Power-to-heat implies an increased electricity consumption of the corresponding routes, which is further discussed in the results section.

Table 1 summarizes practical considerations for the implementation of the three routes, with respect to cost, location, energy infrastructure, and operational characteristics. For instance, the CO₂ supply from CHP plants can vary seasonally depending on operating patterns and heat demand variations, which might put demands on flexibility in the downstream synthesis process. In contrast, the oxy-fuel and gasification routes are assumed to operate year-round at full load, which might be beneficial in terms of securing feedstock contracts to a lower cost than a consumer with seasonal operation. All the routes are based on technology with a high level of maturity and that has been demonstrated. In

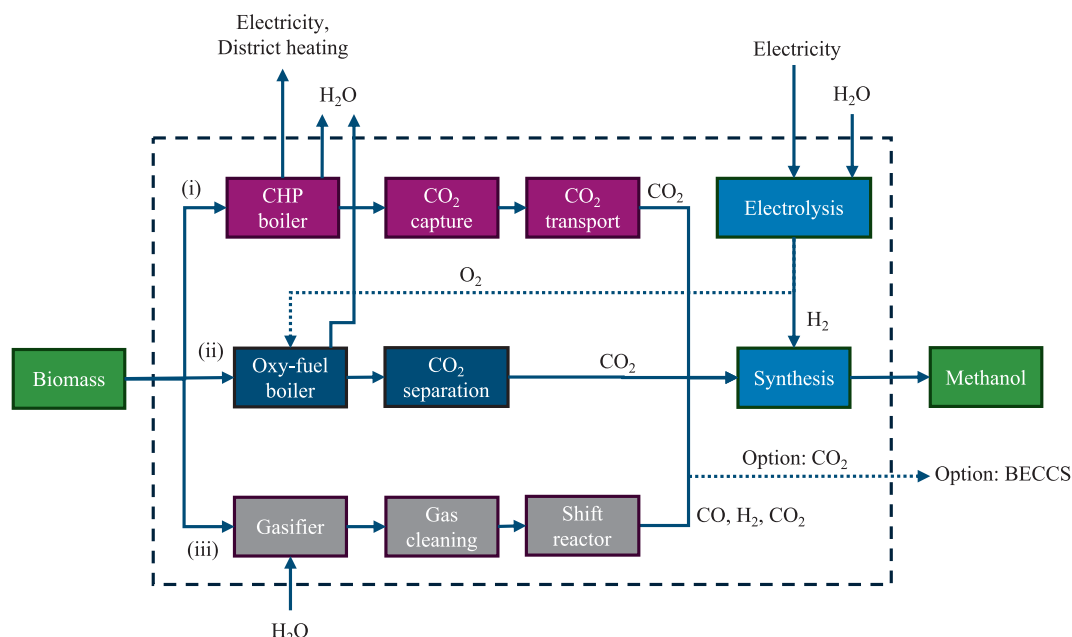


Fig. 2. Overview of process routes to convert solid biomass residues to synthetic methanol. The dashed line indicates the system boundary applied in this work.

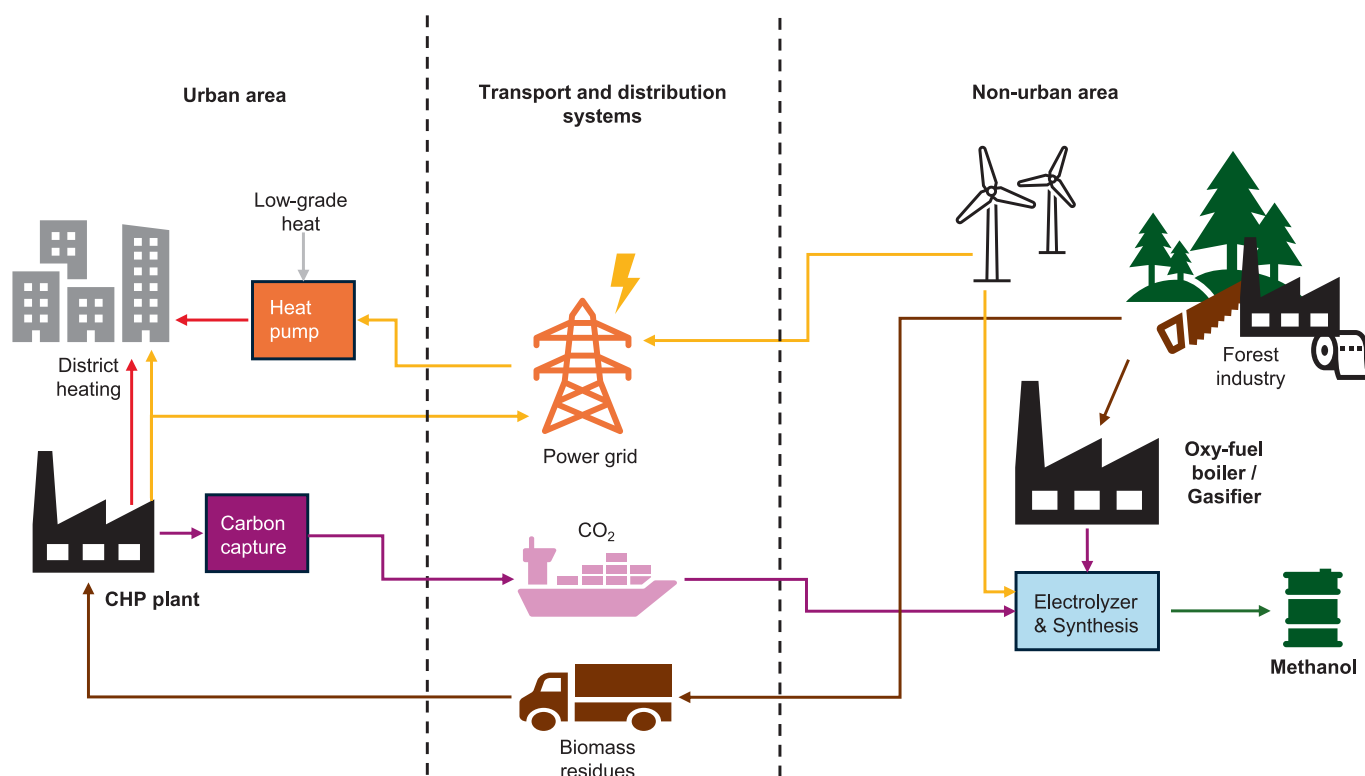


Fig. 3. Overview of the assumed placement of processes in urban/non-urban areas, and transport and distribution systems to connect them.

the case of gasification, economic viability has not yet been reached for the applications considered here, i.e., a gasifier that produces nitrogen-free syngas from biomass at a quality that is sufficient for liquid fuel synthesis. However, gasifiers are commercially available for other industrial applications, and we consider it a proven technology.

4. Techno-economic assessment

The following sections provide technical details about the three

routes studied. For each route, the cost and energy efficiency are estimated. Detailed calculations with mass and energy balances can be found in the [Supplementary Materials](#). We opt for a simple analysis of the techno-economic performance of each route, since our aim is to compare systems that are, in themselves, significantly different and representative of extreme cases, making route-specific details of minor importance for the analysis. Studies that apply detailed process simulation to estimate techno-economic performance parameters have been presented elsewhere (e.g., [3,7,15]).

All processing routes are dimensioned for a methanol production rate of 100 MW (LHV basis). The moist biomass feedstock (50 wt-% moisture content) is assumed to have an approximate dry ash-free molar composition ratio of C:H:O = 1:1.44:0.66, and the lower heating value of dry biomass is set to 18.6 MJ/kg, with a 50 wt-% carbon content in the dry fuel. For each route, the energy requirements and methanol production rate are calculated.

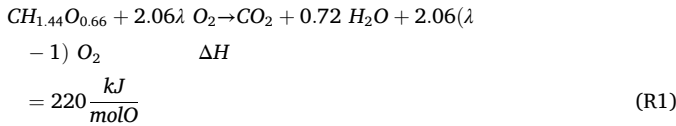
4.1. CHP plant with CO₂ capture

The CHP plant is assumed to have the techno-economic properties presented in Table 2. Solid biomass fuel is combusted in a boiler with the purpose of generating steam for electricity and district heating generation, Eqs. (3)–(5). The moist biomass is combusted with an excess air ratio (λ) of 1.2, Reaction (R1). The CHP plant is assumed to have a seasonal operating profile due to heat demand variations, with 5,000 full load hours per year.

$$Q_{\text{fuel}} \cdot \eta_B = P_{\text{el}} + Q_{\text{DH}} \quad (3)$$

$$P_{\text{el}} = Q_{\text{fuel}} \cdot \eta_{\text{el}} \quad (4)$$

$$Q_{\text{DH}} = \frac{P_{\text{el}}}{\alpha} = Q_{\text{fuel}} \cdot \eta_{\text{heat}} \quad (5)$$



After flue gas cleaning processes, the flue gases generated by combustion contain mainly nitrogen (N₂), water vapor (H₂O) and carbon dioxide (CO₂). A flue gas condenser is used to condense the vapor and contributes to additional district heating generation. Thereafter, the CO₂ ($\dot{m}_{\text{CO}_2}$) and N₂ are separated in an amine scrubber (post-combustion CO₂ capture) by absorption of CO₂ in a monoethanolamine (MEA) solution, often used for benchmarking of CO₂ capture processes. The CO₂ capture process requires steam as a heat source for regenerating the solvent, i.e., to release the absorbed CO₂ from the liquid solution. The steam is extracted from the CHP steam cycle, which reduces the electricity and

Table 2

Techno-economic assumptions for combustion plants, electrolyzer and synthesis plant. Based on [10,21]. The techno-economic assumptions for the oxy-fuel boiler are assumed to be the same as those of an air-fired hot-water boiler. The gasifier plant is assumed to have the same cost assumptions as the biomass-fired CHP plant (see Section 4.6). All investment costs are annualized with a lifetime of 25 years and an interest rate of 7.5 %.

Biomass conversion plants	Biomass-fired heat-only boiler	Biomass-fired CHP plant
Capacity [MW _{fuel,LHV}]	100	100
Lifetime [years]	25	25
Investment cost [M€/MW _{fuel,LHV}]	0.48	1
Fixed OPEX [k€/MW _{fuel,LHV}]	38.2	42
Variable OPEX (excl. fuel) [€/MW _{fuel,LHV}]	3.9	1.4
Net electrical efficiency (η_{el}) [MW _{el} /MW _{fuel,LHV}]	0	0.283
Heat efficiency (η_{heat}) [MW _{fuel,LHV} /MW _{fuel,LHV}]	1.15	0.826
Boiler efficiency (η_B) [MW _{steam} /MW _{fuel,LHV}]	0.9	0.9
Power-to-heat ratio (α)	0	0.37
Electrolysis and synthesis	Solid-oxide electrolyzer	Methanol synthesis plant
Investment cost (CAPEX)	1.1 M€/MW _{el+steam}	1.4 M€/MW _{methanol}
Fixed OPEX [k€/a]	12 % of CAPEX	5 % of CAPEX
Steam demand, SOEC [MW _{steam} /MW _{el}]	0.24	–

heat generation [Eqs. (6)–(8)]. The energy requirements for a 90 % capture rate (γ) and conditioning (compression and liquefaction) are in total 4.09 MJ/kgCO₂ (β_{tot}), of which 0.41 MJ/kgCO₂ is electricity (β_{el}) [33].

$$Q_{\text{CCS}} = \beta_{\text{tot}} \dot{m}_{\text{CO}_2} \gamma \quad (6)$$

$$P_{\text{el,CCS}} = P_{\text{el}} - \beta_{\text{el}} \dot{m}_{\text{CO}_2} \gamma \quad (7)$$

$$Q_{\text{DH,CCS}} = Q_{\text{DH}} - \beta_{\text{tot}} \dot{m}_{\text{CO}_2} \gamma + (P_{\text{el}} - P_{\text{el,CCS}}) \quad (8)$$

4.2. Oxy-fuel combustion plant

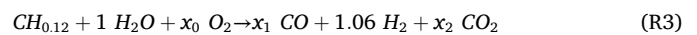
The oxy-fuel combustion plant is assumed to be a heat-only boiler that combusts moist biomass to generate steam. With the oxygen-firing system, the excess air ratio (λ) is reduced compared to the air-fired boiler, to 1.05. Since no nitrogen enters the boiler, the resulting combustion flue gases consist of mostly CO₂ and H₂O. The water is separated from the CO₂ by condensation of the water vapor, which results in a CO₂ capture rate of 97.5 % [17]. Thus, for this process design, no steam is needed to drive the CO₂ separation. Instead, the energy penalty lies in oxygen production, which in this route comes from the co-located electrolyzer that is dimensioned to supply hydrogen to the synthesis reaction. Energy and mass balances (Supplementary Materials) confirm that enough oxygen is generated by electrolysis to supply the oxy-fuel boiler. The cost of the oxy-fuel boiler is assumed to be similar to an air-fired hot-water boiler, see Table 2.

4.3. Gasifier plant

The gasifier plant consists of several sections: first, the moist biomass feedstock is dried with steam (R2); second, the dry biomass is converted to raw gas in a steam gasifier. The raw gas is composed of a mix of CO, CO₂, H₂, CH₄ and tars. A gas cleaning process removes impurities and tar components, and the composition of the raw gas is adjusted in a reversed water gas shift (rWGS) reactor to reach a H₂:CO ratio of 2:1. The cleaned and shifted gas (containing CO, H₂ and CO₂) is sent to the methanol synthesis process. The gasifier is assumed to have a similar cost structure as the CHP plant since similar equipment units are used in both plant types [50,51], see Table 2.

The gasifier is modelled in a simplified manner by Reactions (R3)–(R4), assuming a total energy efficiency of 70 % [1]. That is, 70 % of the energy in the biomass feedstock ends up in the produced syngas (CO + H₂), and the remaining 30 % is supplied to the endothermic gasification reaction from combustion of feedstock, generating CO₂. Efficiency measures could be implemented to reach higher gasification energy efficiencies, but 70 % efficiency was demonstrated in the GoBiGas plant [1] and represents a feasible value.

Assuming that combustion of biomass releases 220 kJ/mol O consumed (R1), and that 2.06 mol O are stoichiometrically needed to combust 1 mol of CH_{0.12}, the theoretical energy content of biomass is 453.2 kJ/mol. A first guess on the raw gas composition (x_1 , x_2 in R3) is made based on enthalpy data and Reaction (R3). An iterative procedure is then followed to find the adjusted raw gas composition after the rWGS reactor, so that the targeted 70 % energy efficiency and H₂:CO ratio are achieved. The procedure is illustrated in the Supplementary Materials.



Steam is needed for biomass drying (R2), the gasification reaction (R3) and the rWGS reaction (R4). It is assumed that process energy integration enables sufficient steam production from the 30 % of the biomass energy content that does not end up in the syngas products. Energy

balances confirm that this could be feasible, as < 10 MW steam is stoichiometrically needed per 100 MW biomass gasified, see the [Supplementary Materials](#).

4.4. Methanol synthesis

In the methanol synthesis process, CO₂ or CO is reacted with hydrogen according to Reactions (R5) and/or (R6). The reactions take place at temperatures of around 200–300 °C and 50–100 bar using Cu/Zn/Al₂O₃ catalysts. The reactions are highly exothermic, and the reactor needs to be cooled. With a high recycling ratio in the synthesis process, CO₂-to-methanol conversion rates approach 100 % [29], which is assumed in this work with an approximate recycling ratio of 3.¹ The assumed plant cost is given in [Table 2](#).

The gaseous reactants (CO₂, H₂ and/or syngas) are compressed before the methanol synthesis. In this work, the gases are compressed to a reaction pressure of 50 bar with an assumed compressor isentropic efficiency of 75 %. Multi-stage compression (2–3 stages) is applied with intercooling between the stages to maintain the compressor exit temperature at around 200–250 °C. The methanol produced via (R5) contains water and needs to be distilled to acceptable purity levels. It has been estimated that a large share of the heat needed for distillation can be recovered from the heat generated in the synthesis plant [5]. Excess heat would also be available from processes to upgrade methanol to jet fuel.



4.5. Electrolyzer

In this work, hydrogen at atmospheric pressure is assumed to be produced by a solid-oxide electrolyzer cell (SOEC), which uses renewable electricity and steam (6 bar). The use of steam enables a higher electricity-to-hydrogen efficiency (85 % [52], corresponding to 39.2 kWh_{el}/kgH₂) compared to other options (alkaline, PEM). The electrolyzer cost and steam demand are given in [Table 2](#). The SOEC is chosen as it represents the best-case scenario in terms of minimized electricity consumption; the low-temperature electrolyzer options would have a lower performance in terms of energy use.

Note that the electrolyzer cost is intentionally set to an optimistic level that favors e-methanol production as far as possible. This implies that if CO₂-based fuels are not cost-competitive with favorable, best-case scenario assumptions, they are unlikely to be cost-competitive in practice, with current technology and cost levels. Recent reports on electrolyzer costs indicate significantly higher investment cost levels than assumed here (compare 1.1 M€/MW input energy as assumed in [Table 2](#), and 1.8–2.2 M€/MW_{el} as reported by IEA for alkaline and PEM electrolysis [24]. The cost of BASF's PEM electrolyzer in Ludwigshafen was reported to cost 2.8 M€/MW_{el} [4]. However, cost reductions might be possible once electrolyzer manufacturing and installation have reached full maturity. The electrolyzer is dimensioned to follow the operation of the boiler/gasifier, not accounting for volatility in renewable electricity supply.

In the oxy-fuel route, the co-generated oxygen is used in the oxygen-fired combustion reaction. Oxygen could potentially also be used in the gasifier to simplify CO₂ separation processes [32]. In the CHP route, the oxygen is not consumed and could be sold as a byproduct [5]. However,

revenue from selling oxygen is not included in this work.

4.6. Economic assumptions and key performance indicators

The cost of producing methanol from biomass via each production route is calculated, considering the cost components specified in Eq. (9). Index *i* denotes parts of the process routes. [Table 3](#) presents economic assumptions regarding electricity and biomass prices, revenue from district heating supply, and transport of CO₂ from the CHP plant to a methanol synthesis plant. The capital cost of amine-absorption CO₂ capture is based on a previous publication [19]. The operational cost of CO₂ capture is calculated based on loss of revenue due to decreased electricity and heat production. All options are evaluated for a plant scale of 100 MW methanol output and all investment costs are annualized with a lifetime of 25 years and an interest rate of 7.5 %. The cost calculations are available in the [Supplementary Materials](#).

$$C_{\text{tot}} = \sum_{i \in I} (C_i^{\text{inv}} + C_i^{\text{O\&M}} + C_i^{\text{el}}) + C^{\text{biomass}} - C^{\text{revenue}} \quad (9)$$

The specific methanol production cost (€/MWh_{methanol}) is calculated with Eq. (10), based on the total cost (*C*_{tot}), methanol production rate (*m*_{methanol}) and the full load operating hours of the respective process route. In addition to cost performance, the routes are compared based on energy efficiency of methanol production (*η*_{methanol}), as calculated by Eq. (11), using the estimated energy inputs and methanol production for each route. The notations used are visualized in [Fig. 4](#). Eq. (12) calculates the total efficiency (*η*_{tot}) of each route, considering all useful outputs (methanol, steam, district heating, electricity). The ratio (*ε*) of electricity consumption for methanol production (*P*_{used}) to bioenergy utilization (in the form of electricity generation (*P*_{gen}), district heating and industrial steam supply (*Q*_{useful}), and bio-methanol (*E*_{bioMeOH})) is calculated by Eq. (13). Steam used for carbon capture and electrolysis is not included in bioenergy utilization.

$$C_{\text{methanol}} = \frac{C_{\text{tot}}}{\dot{m}_{\text{methanol}} \cdot \text{FLH}} \quad (10)$$

$$\eta_{\text{methanol}} = \frac{E_{\text{methanol}}}{P_{\text{used}} + Q_{\text{lowgrade-heat}} + E_{\text{biomass,LHV}}} \quad (11)$$

$$\eta_{\text{tot}} = 1 - \frac{Q_{\text{loss}}}{P_{\text{used}} + Q_{\text{lowgrade-heat}} + E_{\text{biomass,LHV}}} \quad (12)$$

$$\varepsilon = \frac{P_{\text{used}}}{P_{\text{gen}} + Q_{\text{useful}} + E_{\text{bioMeOH}}} \quad (13)$$

The net power consumption of each route is also calculated, with Eq. (14), which includes electrolysis, compression work, and electricity generated by the CHP steam turbine. Since the CHP plant also supplies district heating as an energy system service, we add the electricity needed to compensate for lack of heat supply from the oxy-fuel and gasifier routes (see [Section 3.2](#)). We assume that a heat pump with an average annual COP (coefficient of performance) of 2.5 is used, to supply the same amount of district heating as in the CHP route and for SOEC

Table 3
Economic assumptions for energy prices and CO₂ transportation costs.

Parameter	Unit	Base case	Sensitivity analysis range
Biomass price ^a	€/MWh	30	30–200
Electricity price	€/MWh	50	0–200
District heating revenue	€/MWh	25	–
CO ₂ transportation cost ^b	€/tCO ₂	25	–

^a30 €/MWh biomass corresponds to 155 €/t dry biomass, assuming a lower heating value of 18.6 MJ/kg dry biomass and an ash content significantly below 1 %.

^bBased on [26].

¹ Note that the electricity consumption related to methanol synthesis (reactant and recycle compression) depends on the reaction pressure and the recycling ratio, and might increase/decrease if other conditions than assumed in this work are applied. However, such a change impacts all routes in the same way and will not affect their relative competitiveness.

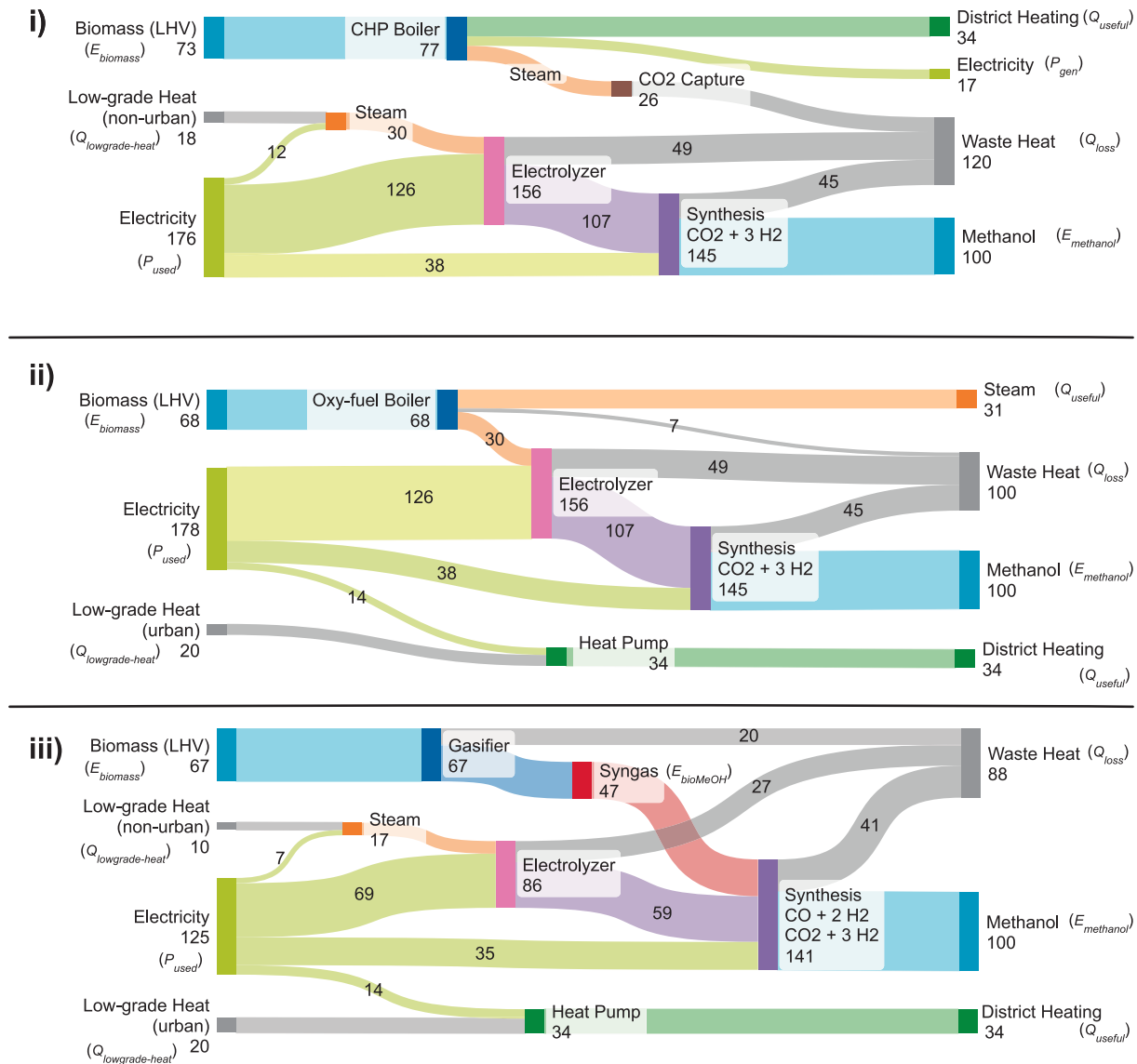


Fig. 4. Energy balances for the three methanol production routes. Unit: MW. i) CHP plant, ii) oxy-fuel boiler, iii) gasifier. Note that both electricity, heat and chemical energy are represented in the diagrams, but not carbon flows, since CO₂ has zero energy content. The values are normalized to 100 MW methanol production. Notations refer to Eqs. (11)–(13).

steam supply.

$$P_{net} = P_{electrolyzer} + P_{comp} + P_{HP,DH} + P_{HP,SOEC} - P_{gen,CHP} \quad (14)$$

5. Results

The results are presented in two parts. Section 5.1. illustrates the energy balances for the three conversion routes. Section 5.2 presents findings for cost and energy efficiency.

5.1. Energy balances

Fig. 4 presents energy balance diagrams for the three conversion routes. Performance indicators for each route are summarized in Table 4. The gasifier route has the lowest electricity use, with an electricity-to-bioenergy utilization ratio (ϵ) of approximately 2.4. The oxy-fuel combustion route and the CHP-based route consume more electricity due to a larger demand for externally supplied hydrogen. For the CHP route, the electrolyzer and synthesis compressors consume electricity corresponding to more than three times the useful energy

from biomass combustion ($\epsilon = 3.5$). Only approx. 10 % of the total electricity consumed by the CHP route can be covered by self-generated electricity, and the CHP route is thereby a net-consumer of electricity, rather than a producer. If low-temperature electrolysis is applied instead (67 % efficiency), the share of self-supplied electricity is even smaller (7.5 %). The oxy-fuel route consumes the same amount of electricity as the CHP route, but has a higher ϵ of 5.3 due to the use of biomass combustion energy as SOEC steam, which is not included in the definition of bioenergy utilization in Eq. (13). Thus, the gasification-based route ranks better in terms of energy efficiency (Table 4). Similar conclusions have been drawn based on exergy analysis [31] and support these findings.

While the CHP route supplies district heating, it also generates the most low-temperature waste heat of the three options (Fig. 4). If applying heat pumps to upgrade this waste heat to useful temperature levels (e.g. for district heating), significantly more heat could be supplied from the electrolyzer waste heat than is supplied by the biomass combustion. While challenges related to placement of electrolysis plants in urban areas with grid congestion might limit the implementation of this strategy, the electricity consumed by heat pumps to upgrade low-

Table 4

Performance indicators for the routes. Steam used for carbon capture and electrolysis is not included in bioenergy utilization (ϵ , Eq. (13)). The percentages reported under “EU classification of methanol output” are further elaborated in Section 5.2.1.

Performance indicator	Unit	CHP	Oxy-fuel	Gasifier
Methanol production energy efficiency, η_{methanol} , Eq. (11)	$\text{MW}_{\text{methanol}}/\text{MW}_{\text{input}}$	0.37	0.37	0.45
Total energy efficiency, η_{tot} , Eq. (12)	$\text{MW}_{\text{output}}/\text{MW}_{\text{input}}$	0.55	0.57	0.60
Electricity use per biomass energy utilization, ϵ , Eq. (13)	$\text{MW}_{\text{el}}/\text{MW}_{\text{bio-utalized}}$	3.5	5.3	2.4
Net electricity use per methanol produced, P_{net} , Eq. (14)	$\text{MW}_{\text{el}}/\text{MW}_{\text{methanol}}$	1.6	1.8	1.2
Total waste heat generated per methanol produced	$\text{MW}_{\text{loss}}/\text{MW}_{\text{methanol}}$	1.2	1.0	0.9
EU classification of methanol output	—	RFNBO	RFNBO	RFNBO (55 %), Advanced biofuel (45 %)

temperature heat is relatively small. It would take 7 and 10 % of the total oxy-fuel and gasifier route power consumption, respectively, to compensate for the lack of district heating delivered by these routes. Even when the gasifier route supplies the same amount of district heating (through heat pumps) as the CHP plant, it still consumes less electricity than the CHP route per MW of methanol produced (Fig. 4).

Thus, traditional energy system designs based on solid fuel combustion can lead to high electricity consumption (ϵ) when integrated with new energy demands (production of synthetic fuels). It is not rational to use a CHP plant to produce a small amount of electricity, if electricity is already available from external sources in the quantities needed for electrolysis and synthesis. Electrification of district heating can be a more energy efficient system design compared to the lock-in effects created by the RFNBO related rules, which supports the continued combustion of biomass to supply energy system services that could be met with a lower total energy use with other technical system designs. From an energy system perspective, it might therefore be beneficial to include bio-methanol (as is partially produced by the gasifier route) in the RFNBO scope, or to qualify bio-methanol for the synthetic aviation fuel quotas (Fig. 1), rather than limiting the definition to carbon feedstocks having to be a byproduct of other, inefficient, energy supply and not allowing the use of bioenergy in RFNBOs.

5.2. Cost and efficiency of biomass-to-methanol routes

5.2.1. Total annual cost and production of methanol

Fig. 5 presents the total annual cost of biomass-to-methanol production via the routes considered in the work, and the annual production of methanol. Clearly, the largest cost components are related to hydrogen supply; namely, the SOEC capital cost and the electricity consumed to run it, which together comprise around 55–60 % of the total annual cost for the combustion-based routes, and 44 % for the gasifier route where part of the hydrogen is obtained from the biomass feedstock and steam fed to the gasifier. The amount of methanol produced annually mainly depends on the full-load operating hours of the plants, and to a lesser degree on carbon capture rates. A CHP plant with 5,000 full load hours obviously produces less methanol than the other routes. Still, the annual CHP-route cost is in the same range as the other routes, due to large capital expenditure. Operating the CHP plant with 8,000 full-load hours would yield a cost performance comparable to the oxy-fuel option.

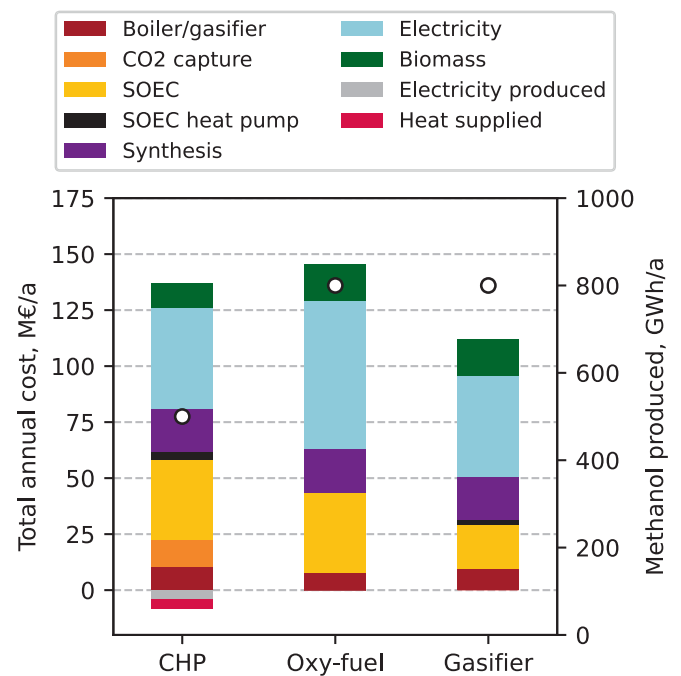


Fig. 5. Breakdown of total annual cost of methanol production routes, with respect to process steps, for 100 MW of methanol output. Electricity and biomass prices are set at 50 and 30 €/MWh, respectively. Markers indicate the annual production of methanol for each route, based on the assumed full-load operating hours. Note that the cost of producing district heating through heat pumps in the oxy-fuel and gasifier routes (see Fig. 3) is not included in the figure (comparable to the cost of SOEC heat pumps for steam supply).

If the CO_2 generated by the gasifier route is permanently stored instead of converted to methanol, the need for SOEC capacity and electricity to run it would decrease considerably or not be needed at all, leading to a significantly (around 45 %) reduced total annual cost. However, storing the CO_2 reduces the annual methanol production by 55 %. That is, in this example, 55 % of the gasified biomass carbon ends up as CO_2 and can be synthesized to RFNBO, whereas 45 % becomes bio-methanol (via $\text{CO} + \text{bio-H}_2$) and is classified as an advanced biofuel according to current EU definitions. In contrast, in the combustion-based routes (CHP, oxy-fuel), 100 % of the produced methanol can be classified as RFNBO, provided that the other requirements not related to the origin of carbon and hydrogen are also fulfilled.

Two additional remarks can be made related to CO_2 handling in the routes. First, the cost of transporting CO_2 from the combustion site to a synthesis plant located elsewhere is low relative to the large cost of producing hydrogen from electricity (~3 % of total costs assuming a CO_2 transportation cost of 25 €/t CO_2). Thus, it is not a necessity for cost-effectiveness to co-locate the source of carbon and the source of hydrogen/synthesis plant. Second, it is uncertain whether the CO_2 generated in the gasifier route must be separated from the syngas to be processed separately for it to be accepted as RFNBO fuel according to the EU rules. Such a requirement implies that additional CO_2 separation equipment must be installed, which can increase the capital expenditure and operating costs (energy demand) for the gasifier route. The more cost-effective option would be to keep the CO_2 mixed with the syngas and simply mix in the extra hydrogen required to synthesize the CO_2 to methanol, i.e., without extra separation steps.

5.2.2. Energy efficiency and methanol production cost

Fig. 6 shows the energy efficiency (Eq. (11)) and specific methanol production cost (€/MWh) for the routes considered. The gasifier achieves the lowest production cost (~140 €/MWh methanol, or 820 €/t methanol) and highest efficiency (45 %), while the oxy-fuel production

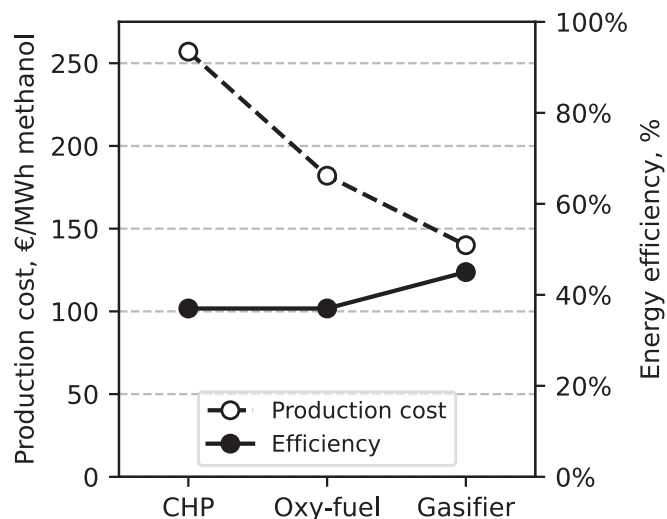


Fig. 6. Specific methanol production cost of routes and methanol production energy efficiency (Eq. (11)). Electricity and biomass prices are set at 50 and 30 €/MWh, respectively.

cost is around 180 €/MWh (1,055 €/t) with an efficiency of 37 %. The CHP route energy efficiency is similar, at 37 %, but due to the lower utilization (5,000 full load hours), the production cost increases to 255 €/MWh (1,495 €/t). Increasing the CHP full load hours to 8,000 per year results in a similar production cost as the oxy-fuel route. All routes have a higher energy efficiency than an electricity-intensive DAC-based option, estimated to 32–34 % [35].

According to EU rules for how feedstock for RFNBOs can be obtained, CO or CO₂ cannot be generated solely for the purpose of synthesis, it must be a by-product and the combustion energy must be put to use. However, the benefit of producing heat and power from biomass combustion is small, both from a cost and system-level energy efficiency perspective. As shown in Fig. 5, the CHP plant obtains revenue from selling the generated electricity to the grid, but this revenue is small (around 10 %) compared to the cost of electricity required for methanol synthesis. Similarly, the revenue from supplying district heating (assuming a revenue of 25 €/MWh) is small compared to the cost of methanol production (>200 €/MWh methanol for the CHP plant, Fig. 6). Given the low economic benefit of supplying heat and electricity, it can be discussed whether the EU requirement on feedstock being a by-product is economically justified.

5.2.3. Sensitivity to electricity and biomass price

Fig. 7 shows the impact of electricity price and biomass feedstock price on the methanol specific production cost for the three routes, assuming that all routes operate with 8,000 full load hours (note the difference from the base case in which the CHP plant operates for 5,000 h/year). Given the slope of the lines, the gasifier route is the lowest-cost option independent of electricity and biomass prices, although the difference between the production costs for the different routes is comparatively small for electricity prices close to 0 €/MWh (that is, in a scenario where renewable electricity is in excess). The oxy-fuel plant consistently has a lower production cost than the CHP plant route. However, the difference between the CHP and oxy-fuel production costs is small, and the oxy-fuel plant could also be designed for electricity generation, so this analysis alone is not sufficient to conclude that one combustion-based option outperforms the other. Clearly, the electricity price has a stronger impact on the methanol production cost than the biomass price.

6. Discussion

6.1. Regulatory inconsistencies and system-level impacts

Considering that the planned EU drop-in quotas for RFNBOs in aviation fuels are as high as 35 % in 2050, a large-scale expansion of RFNBO production can be expected, which will have substantial consequences on a wider system level in terms of energy and material use.

6.1.1. Using residues and by-product CO₂ as feedstock for synthetic fuels

Carbon-based feedstocks are obviously required to produce carbon-based fuels. Requiring that the carbon feedstock comes from waste, residues or by-products from an industrial process, implies that the demand, and thereby the value, for such waste and residues will increase, especially since jet fuel producers are liable to a high fine if they fail to acquire enough resources to supply their SAF quotas. In extreme cases, the waste material and residue by-products used for RFNBO might become more valuable than the traditional main outputs from industrial processes. Thereby, the EU RFNBO rules risk creating incentives to increase the generation of waste and CO₂ to be able to produce more aviation fuels. For example, sawmills might use thicker saw blades that increase the amount of sawdust and residues generated, at the expense of reduced sawn wood output for material production. This strongly contradicts the principles stated by the waste hierarchy and the biomass cascade principle [40,42], whereby waste generation should be minimized. Furthermore, it is debatable whether such streams should be called “waste” at all, given that there are technological solutions available, such as the ones studied in this work, to fully convert waste into

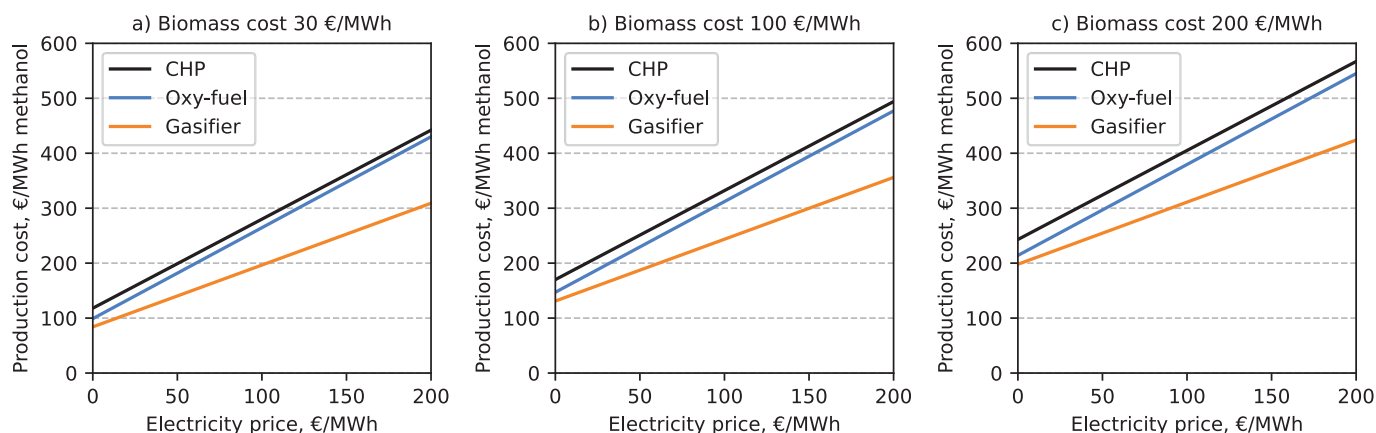


Fig. 7. Sensitivity of specific methanol production cost to electricity price and biomass price, assuming 8,000 full load hours of operation for all routes. Note that the cost of producing district heating through heat pumps in the oxy-fuel and gasifier routes (see Fig. 3) is not included in the figure, since it does not directly contribute to the methanol production.

high-quality material products [49].

As described in Section 3.2, the EU RFNBO rules might also lead to systems where biomass is more valuable as CO₂ (with zero energy content) that can be sold to synthetic fuel producers, than as fuel energy. If EU rules justify spending substantial amounts of money to acquire biogenic carbon for aviation fuels, the bioenergy market will be significantly distorted. Additionally, this implies a risk of strengthening lock-in effects in inefficient combustion-based energy systems that use limited resources in sub-optimal ways, solely to comply with policies.

6.1.2. Technology neutrality and demand for renewable electricity

As shown in the results, synthetic fuel production requires substantial amounts of hydrogen if CO₂ is used as a feedstock. The EU's requirements on RFNBOs to be based on non-biological energy sources pushes strongly for increased use of renewable electricity to produce hydrogen, and narrows the selection of eligible production technologies, even though the same product can be produced through other processing routes with lower energy requirements (e.g., gasification). Thus, the rules are not technology neutral – some technologies are clearly favored over others – as has also been observed in previous works [9,48]. Additionally, the EU rules for RFNBOs are in conflict with the EU energy efficiency directive, stating that “efficiency first” should be an important guiding principle when making decisions about new technology investments. In this sense, the aviation fuel regulations can be interpreted as disfavoring long-term sustainable options with high energy efficiency, in this case the gasifier route that preserves energy in the biomass, in favor of solutions that meet short-term targets.

Requiring that hydrogen for RFNBO is produced from renewable electricity puts significant pressure on expanding wind and/or solar power capacity and grid connection capacity that are urgently needed to decarbonize industrial processes through electrification. Grid capacity is already a limiting factor in many parts of the world [23] and public acceptance of wind power can make it challenging to scale up renewable electricity generation at the rate required to enable RFNBO production quotas to be met. On top of electricity consumption for hydrogen production, CO₂ capture applied to flue gas sources is also energy demanding and costly. Forcing RFNBO to be produced from captured CO₂ thus leads to further increases in energy consumption for combustion-based routes, compared to the gasifier that can avoid such separation processes. In summary, technological systems that strive towards high energy efficiency and efficient use of limited resources should be favored, which is not the case in the current EU RFNBO rules.

6.2. Investment conditions for sustainable aviation fuel production

To enable the deployment of sustainable aviation fuel production, the relevant actors must perceive the investment conditions as sufficiently favorable for an investment to be economically viable. This implies risk minimization, as large, long-term, investments are at stake. However, with current EU regulations being in conflict with each other (Section 6.1), the investment risk is likely to be perceived as high. Furthermore, if the regulations do not align towards a common target, at least one of them will eventually need to be changed to address the inconsistency. Investors who have placed their bets on a regulation that changes over time, are therefore at the risk of their project losing competitiveness in favor of other solutions. Thus, there is a risk that the economic lifetime of an investment could be drastically shortened by a sudden change in regulations, reducing the long-term viability of the investment and making it challenging to recover sunk costs.

Applied to the RFNBO case, a concrete example would be the requirement to supply hydrogen from renewable electricity (hydrogen supply from biomass is by definition not allowed and will cause the produced fuel to be classified as advanced biofuel), which implies that carbon feedstock must be in the form of CO₂. Second, the double-counting of RFNBOs towards energy use targets in the transportation sector (Article 27 in RED III) incentivizes production of fuels with low

energy efficiency, rather than alternative fuels that might have equivalent carbon footprint but lower cost and/or higher energy efficiency. These two conditions greatly favor combustion-based production routes, but only as long as they are upheld, since the gasifier option performs better in terms of cost and efficiency.

7. Conclusion and policy implications

The present work provides a techno-economic assessment of methanol synthesis routes and highlights potential system-level impacts of technology selection under the EU regulatory conditions for sustainable transportation fuels, focusing on renewable fuels of non-biological origin (RFNBO). The current EU RFNBO classification rules steer fuel producers towards combustion-based production systems with low energy and cost efficiency (estimated at ~37 % and 180–255 €/MWh methanol (1,055–1,500 €/t methanol), respectively). With a gasification-based scheme, the same output (although partly classified as advanced biofuel according to EU) can be obtained with higher energy efficiency (46 %) and to a lower cost (140 €/MWh or 820 €/t). The regulatory aspects that favor inefficient combustion-based options are: (i) hydrogen must originate from renewable electricity, (ii) the carbon feedstock (e.g. CO₂) cannot be generated intentionally for synthesis purposes, implying that some other utility service must be provided by the production plant. In contrast, the findings show that utility heat can be produced via heat pumps at a lower energy penalty than the difference in electricity consumption between combustion and gasification-based routes (supplying vs not supplying utility heat). If a CHP plant is retrofitted to co-produce synthetic fuel, its electricity and/or heat output will be severely reduced, and the plant will become a net consumer of power instead of a producer.

RFNBO carbon feedstock should by definition be in the form of residues or waste without other economic uses. However, since the monetary value of RFNBO is likely to be high (minimum fee of not supplying estimated at > 250 €/MWh SAF) compared to the price of utilities (e.g., electricity or district heating in the range 10–100 €/MWh), industrial systems might be incentivized to generate more residues (and CO₂) to produce RFNBO, with lowered resource efficiency as a result. Requiring that hydrogen for RFNBO is based on renewable electricity also puts significant additional pressure on the expanding electricity system. The gasification-based production route, in which part of the hydrogen is obtained from steam gasification of biomass, can produce methanol with a 30 % lower electricity consumption than a combustion-based route. Thus, the current EU RFNBO classification rules might lead to lock-in in inefficient and sub-optimal energy systems based on combustion, when other processes (e.g., gasification and electrification of heat demands) would be a more efficient option with respect to both cost and energy efficiency.

Based on these results, the main conclusion from this work is that the EU policy on drop-in requirements for RFNBOs is in conflict with other EU directives, such as the energy efficiency directive, the waste hierarchy and the biomass cascade principle. While all studied production routes for synthetic methanol production use the same carbon feedstock and produce the same product, they are not considered equal by the EU classification rules for sustainable aviation fuels. Thus, the regulations do not achieve technology neutrality. The internal conflicts between regulations lead to uncertainty and risk related to investment decisions. Changes to one or several regulations might be expected for policy alignment, which can put investments already taken at the risk of losing competitiveness. Under the current conditions, our assessment is that it is difficult to estimate long-term consequences of investments in large-scale production of synthetic transportation fuels. That is, the investment conditions are uncertain and might thereby slow down the deployment of sustainable energy systems. A review of the policy landscape surrounding SAF might be undertaken to align regulations, enhance long-term stability, and avoid inefficient use of energy and limited resources.

CRediT authorship contribution statement

Johanna Beiron: Writing – original draft, Methodology, Conceptualization. **Simon Harvey:** Writing – review & editing, Project administration, Funding acquisition. **Henrik Thunman:** Writing – review & editing, Methodology, Funding acquisition, Conceptualization.

Declaration of competing interest

The authors 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.fuel.2025.137181>.

Data availability

The data that has been used is available in the [Supplementary materials](#).

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