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Electrification-enabled production of Fischer-Tropsch liquids – A process and economic perspective

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HIGHLIGHTS

• Balancing carbon efficiency and price uncertainties with electrified BtL pathways.

• Efuels require low-carbon electricity to meet strict sustainability mandates.

· Stable biomass and electricity markets, key for long-term investment in biofuels.

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ABSTRACT

Transitioning to biofuels is crucial for reducing greenhouse gas (GHG) emissions in transportation, but limited biomass availability requires maximizing carbon efficiency. This study evaluates Fischer-Tropsch liquid (FTL) production from biomass, focusing on the impact of partial electrification and carbon capture and storage (CCS) on efficiency and flexibility. Five configurations-ranging from a biomass-intensive base case to a fully electrified process-are simulated and assessed through techno-economic and GHG evaluations under fluctuating energy prices. Full electrification achieves the highest carbon efficiency, increasing carbon-to-liquid fuel conversion from 37 % to 91 %, but faces challenges due to high electricity demand (up to 2.5 MWh per MWh of fuel) and reliance on low-carbon grids. Partial electrification offers a cost-effective alternative, reducing production costs by up to 40 % compared to fully electrified cases, while maintaining a carbon efficiency of around 60 %. CCS enables net-negative emissions, though its viability hinges on sufficiently strong carbon pricing incentives. Compliance with sustainability mandates, such as Renewable Fuels of Non-Biological Origin (RFNBO) requirements, depends on access to decarbonized electricity. Overall, partially electrified BtL pathways enhance carbon utilization, reduce emissions, and offer resilience to market fluctuations. These pathways provide a promising balance of environmental and economic performance, outperforming both traditional BtL under high biomass prices and fully electrified e-fuels in terms of cost. Their advantages make them attractive from both investment and policy perspectives-especially in markets supported by stable electricity prices, carbon incentives, and sustainability-driven regulation.

1. Introduction

Addressing the climate crisis due to fossil fuel-related CO_2 emissions requires a comprehensive diversification of energy sources in all sectors [1]. In the transportation sector, the European Union (EU) has targeted the deployment of electric vehicles, advanced biofuels, and other low-carbon fuels [2]. The revised Renewable Energy Directive mandates

that EU countries achieve at least 29 % renewable energy use in transport by 2030, including a minimum of 5.5 % advanced biofuels, of which at least 1 percentage point must come from Renewable Fuels of Non-Biological Origin (RFNBOs) [3].

Drop-in fuels are a viable solution for reducing fossil dependence and greenhouse gas (GHG) emissions, as they can be used directly in existing fuel systems without major infrastructure changes [4,5]. These fuels must originate from renewable sources to ensure lower carbon

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Nomenclature		SMR	Steam methane reformer
		SOEC	Solid oxide electrolyzer
Abbreviat	tions		
AGR	Acid gas removal	Variables	
ASU	Air separation unit	A ₀	Base capacity
BtL	Biomass-to-liquid	A	Employed capacity
BtX	Biomass-to-X	C ₀	Base cost of equipment
CC	Combustion chamber	CRF	Capital recovery factor
CCS	Carbon capture and storage	$\mathbf{E}_{el,in,x}$	Electricity introduced to the process
Comp	Compressor	$\mathbf{E}_{\mathbf{FTL},\mathbf{x}}$	Energy content in FTL for configuration x
eSMR	Electrified steam methane reformer	E _{GHG}	Process GHG emissions
FBG	Fluidized bed gasifier	El _{demand}	Specific electricity demand
FT	Fischer-Tropsch	ER	Electrification ratio
FTL	Fischer-Tropsch Liquid	EY	Energy yield
GHG	Greenhouse gas	ex	GHG emissions related to X
IGCC	Integrated grand composite curve	FCI	Fixed capital investment
KPI	Key performance indicator	IC	Indirect costs
LHV	Lower heating value	$\dot{m}_{C,x}$	Carbon mass flow rate of stream x
Μ	Mixer	$\eta_{\rm C}$	Carbon efficiency
O&M	Operation and maintenance	$\eta_{el,margina}$	Marginal electricity efficiency
PBtL	Power-and-biomass-to-liquid	Px	Electricity generated/used in equipment x
PEM	Proton exchange membrane electrolyzer	PC	Production cost
PtL	Power-to-liquid	R _f	Carbon recovery factor
RENBO	Renewable fuels of non-biological origin	TCI	Total capital investment
(R)WGS	(Reversed) water gas shift	TDIC	Total direct and indirect cost
S	Splitter	TIC	Total installed cost
-	-F		

footprints compared to conventional hydrocarbons. Among the most promising routes for producing renewable drop-in fuel is the highly feedstock flexible thermochemical Biomass-to-X (BtX) pathway [6]. BtX is an umbrella term encompassing various conversion routes that transform biomass into synthetic energy carriers, often involving gasification followed by chemical synthesis [7]. In this study, BtX specifically refers to gasification-based pathways, which include pretreatment, gasification, syngas conditioning, and catalytic synthesis. These routes can be used to produce a variety of fuels and chemicals, such as Fischer-Tropsch liquids (FTL), methanol, ethanol, and dimethyl ether. Fischer-Tropsch (FT) synthesis is well established at the process level, though primarily from fossil sources, and is widely implemented at industrial scale, with some plants producing up to 8 million tons per year [8]. In addition to its commercial maturity, several studies have highlighted its economic potential compared to alternatives, such as gasification followed by methanol-to-gasoline, largely due to its simpler synthesis pathway [9]. Coupling biomass gasification with FT synthesis offers particularly promising "drop-in-ability", as the generated syngas can be converted into synthetic fuels with the ability to directly replace fossil fuels-such as diesel, kerosene, or gasoline-depending on design parameters, market demands and regulatory requirements [10]. Biomass-gasification-based FTL production is in this paper denoted as BtL (biomass-to-liquids).

Despite the advantages regarding both feedstock and product flexibility, BtL still suffers from relatively low carbon utilization as a considerable amount of biomass carbon is lost in carbon dioxide (CO₂) [11]. Enhancing carbon efficiency is vital, given the limited availability of biomass and its competing uses across different sectors [12,13]. Such limitations raise concerns regarding the future alignment of BtL pathways with evolving biomass regulations and sustainability targets. A promising strategy to improve carbon efficiency is the integration of electrification, identified by the IPCC (Intergovernmental Panel on Climate Change) as essential for meeting global climate targets [14]. In fact, integrating water electrolysis to supply hydrogen (H₂) reduces the need to oxidize carbon within the syngas to meet stoichiometric requirements for fuel synthesis. Power-to-X (PtX) technologies, including power-to-liquid (PtL) or e-fuel production, shift the reliance from biomass to renewable electricity. However, producing large volumes of e-fuels requires significant H₂ and CO₂ inputs, posing logistic and technical challenges in regions where renewable CO₂ availability or reliable low-carbon electricity may be limited [15,16].

In parallel to electrification, scientific literature reports notable progress in biomass-derived FT synthesis, with, e.g., Ail et al. [10] showing that BtL fuels can be economically viable for fossil-neutral fuels, particularly in countries with abundant biomass resources. Detsois et al. [17] have created relevant business scenarios and conducted sensitivity analyses on various operational aspects of BtL production. Kumar et al. [18] conducted a technoeconomic analysis of an innovative chemical gasification system for the FTL process, focusing on two distinct gas cleaning configurations. Extensive work has also explored electrification options to increase carbon efficiency. For example, Mesfun et al. [19] examined biorefinery concepts that couple biomass gasification with different electrification options, including electrified steam reformers, vapor recompression heat pumps, and electrolysis. They demonstrated significant potential of electricity-enhanced lignocellulosic-based biorefinery concepts as pathways for alternative transportation fuels, as the concepts exhibited improved resource and carbon efficiency, substantial GHG reductions, increased production capacity and strong economic viability, especially in scenarios with high fuel demand. Dossow et al. [20] similarly explored how direct and indirect electrification can address the inherent limitations in BtX processes, and in particular highlighted the role of electrolysis in improving energy yields, with co-electrolysis of CO2 and H2O enabling improved efficiency and carbon utilization. Zang et al. [21] assessed well-to-wheel GHG emissions of e-fuel production via FT synthesis for various H₂ production methods and CO₂ sources in standalone and integrated systems. Other studies investigating this so-called Power-and-Biomass-to-Liquid (PBtL) concept include Nielsen et al. [22], which focused on optimizing the performance of fuel-assisted solid oxide electrolysis within an FT process. Dietrich et al. [23] compared BtL, PtL and PBtL routes to produce synthetic paraffinic kerosene via FT synthesis, highlighting their specific advantages under varying economic and regional conditions. They found better performance in fuel yield for PBtL, with biomass-based product yields increasing up to threefold compared to BtL processes due to the integration of renewable H₂. Habermeyer et al. [24] further explored a flexible combined heat, power and fuel production concept that accounts for the seasonal mismatch between solar energy supply and heat and power demand and demonstrated that PBtL can outperform BtL economically beneficial than BtL in scenarios with affordable electricity. Although previous studies have identified trade-offs, such as between power demand and capital costs, they typically focus on isolated process improvements or narrowly defined configurations, making it difficult to conduct holistic evaluations of technical performance, costs, and environmental benefits under fluctuating market conditions.

Table 1 provides a structured comparison of recent related works, outlining key configurations, electrification levels, CCS integration, modeling approaches, and scopes of analysis. While previous studies have focused on either BtL, PBtL, or syngas-level electrification, few have systematically compared multiple pathways under harmonized assumptions. Moreover, CCS is often excluded, and sensitivity to electricity market dynamics and regional GHG intensity is rarely addressed. This study aims to address these gaps.

Building on previous findings, this study provides a detailed assessment of how different degrees of electrification in FTL production can enhance process performance and economic resilience in fluctuating energy markets. By systematically evaluating different degrees of electrification alongside carbon capture and storage (CCS), the study quantifies key techno-economic and environmental trade-offs that influence the feasibility of FTL production. First, partial electrification is examined to assess how it can enhance flexibility in response to varying energy markets. Second, the GHG emissions of each configuration are quantified, providing critical insights into their ability to meet stringent climate targets. By integrating both current and projected biomass and electricity market conditions, this study aims to clarify the role of electrification and CCS in shaping the long-term competitiveness of BtL pathways.

The paper begins with a description of the configurations studied, providing an overview of each configuration and the key process units, and highlighting their differences (Section 2). Next, the methodology used to simulate and analyze these configurations is presented, along-side the performance indicators applied to assess technical, economic, and environmental performance (Section 3). The results are presented and discussed in Section 4, focusing on the role of electrification in shaping performance outcomes. The paper concludes with Section 5, which summarizes the key findings and broader implications.

2. Design of process configurations

The study design for investigating various process configurations is based on the biomass gasification-based BtL process outlined by Mesfun et al. [19]. Two principal variations are introduced to enhance the process flexibility and improve emissions performance, thus illustrating a range of gasification and CO2 management options: (1) integration of H₂ produced via PEM (proton exchange membrane electrolyzer) to enable higher hydrogen-to-carbon monoxide (H2/CO) ratio in the syngas, and (2) CO2 management through CCS to achieve potential negative emissions. For each configuration, two heat integration strategies are also evaluated to examine the impact of excess heat utilization on system efficiency and emissions. To maintain consistency across gasificationbased configurations, we set a baseline biomass input of 100 MW. This scale reflects a technically realistic and industrially relevant size for thermochemical biomass conversion, consistent with prior technoeconomic studies and aligned with planned large-scale Swedish initiatives [30]. For comparability, the PtL case uses a carbon input equivalent to the total carbon in the 100 MW biomass feed. Table 2 outlines the core technology blocks included in each of the five evaluated configurations: the Base Case, BtL with carbon capture and storage (BtL-CCS), partially electrified PBtL-CCS, the highly electrified PBtLmax, and the fully electrified PtL configuration.

Section 2.1 describes the studied configurations, while Section 2.1.1 provides further specifics on each process section, including syngas conditioning, heat recovery, and carbon management.

2.1. Outline of explored configurations

2.1.1. Base case

The Base Case process comprises direct oxygen- and steam-blown fluidized bed gasification, steam methane reforming (SMR), water gas shift (WGS), acid gas removal (AGR), and FT synthesis as the primary process steps. The wet biomass is dried on a conveyor belt before being fed into the gasifier. The raw gas is then cooled and cleaned of tar and other contaminants.

2.1.2. BtL-CCS

This configuration captures the effect of using CCS on the carbon recovery by capturing the CO_2 separated in the AGR, for subsequent permanent storage, which enables negative emissions. The only modification to the BTL configuration is the addition of monoethanolamine-based CO_2 capture for permanent storage.

2.1.3. PBtL-CCS

As the first step of electrification, a PEM unit generates H₂, which is

Table 1

Comparison of key literature on Fischer–Tropsch-based fuel production, illustrating differences in process configurations, electrification levels, CCS inclusion, and modeling scope. The gaps identified form the basis for this study's contribution.

Ref	Configurations	Electrification	CCS	GHG, TEA	Identified gaps addressed in this study
Habermeyer et al. (2021) [24]	BtL, PBtL, Hybrid (switching between modes)	Partial + Conditional	No	TEA	No CCS; No GHG assessments; Missing higher levels of electrification.
Dossow et al. (2021) [25]	BtL, PBtL, PBtL _{max}	None → Maximum partial	No	GHG (electricity only)	No CCS; Comparison limited to BtL vs PBtL; No fully electrified case.
Habermeyer et al. (2024) [26]	BtL, PBtL	None + Partial	No	TEA & GHG	Missing higher levels of electrification.
Kreutz et al. (2020) [27]	BtL	None	Yes	TEA, GHG price estimations.	No electrification; No feedstock market sensitivity analysis.
Kourou et al. (2024) [28]	ATR, Electrolysis, <i>E</i> - rWGS, CSDRM	Partial → Full	No	TEA	Focus on syngas generation; no biomass gasification or PBtL integration; not a full BtL chain.
Hillestad et al. (2018) [29]	BtL, PBtL	None \rightarrow Partial	No	TEA	No full electrified case; sensitivity to market changes or GHG impact by region.
This study	BtL, BtL-CCS, PBtL, ePBtL, PtL	None \rightarrow Full	Yes (conditional)	TEA & GHG	Compares five BtL-to-PtL configurations under consistent assumptions; includes cost and emissions sensitivity to electricity mix and market prices

Table 2

nembrane electrolyzer, AGK – actu gas removal, FT – Fischer-Tropsch, GCS – Carbon Capture and storage.										
	Pretreatment and gasification	ASU	Gas cleaning	SMR	(R)WGS	PEM	AGR	FT	CCS	Condensing turbine steam cycle
Base Case	×	×	×	×	х	-	×	×	-	×
BtL-CCS	×	×	×	×	×	-	×	×	×	×
PBtL-CCS	×	×	×	×	×	×	×	×	×	×
PBtLmax	×	-	×	×	×	×	×	×	-	×
PtL	_	-	-	\times^1	-	×	-	×	-	-

Technology blocks included in each evaluated process configuration. The table indicates the presence (\times) or absence (-) of specific unit operations across the studied configurations. ASU = air separation unit, SMR = steam methane reforming, WGS = water gas shift, RWGS = reversed water gas shift, PEM = proton exchange membrane electrolyzer, AGR = acid gas removal, FT = Fischer-Tropsch, CCS = carbon capture and storage.

¹ Electrified SMR.

2.1.4. PBtLmax

CO₂ are converted to CO and water.

fed into the FT reactor. The size of this unit is carefully selected to ensure that the H_2 /CO ratio of the syngas meets the FT synthesis requirements without the need for water gas shift (WGS). Additionally, this configuration incorporates CCS to further enhance its carbon recovery factor.

The $PBtL_{max}$ configuration represents the next level of electrification

as it is designed to maximize the effective utilization of the biomass

carbon. To this end, the capacity of the PEM unit is increased and

combined with an RWGS (reversed water gas shift) unit, in which H₂ and

2.1.5. PtL In this

In this configuration, the first section of the BtL (biomass pretreatment and gasification island) is substituted with $bio-CO_2$ from an external source. The PtL configuration converts electricity and CO_2 into synthetic liquid fuels. The syngas for the FT synthesis is produced from H₂ produced via PEM and $bio-CO_2$ in an RWGS process. The two major steps of tar reforming and AGR are eliminated in this configuration as there is no tar production or sulfur in the original feedstock, and the CO_2 content of the product is negligible.

2.2. Overview of production sections

In essence, the different process configurations can be divided into



Fig. 1. Simplified block diagram for the studied process configurations. Red colored boxes, connectors and text indicate differences from the Base Case, while colored enveloping boxes are used to distinguish different main process sections.

five main sections, some of which apply only to specific configurations: 1) syngas production, 2) syngas conditioning, 3) CCS, 4) FT synthesis and syncrude refining, and 5) purge gas handling and heat integration, as outlined below and in Fig. 1.

2.2.1. Syngas production

This process relies on lignocellulosic biomass as feedstock. A mixture of birch and pine is selected as feedstock, with properties as shown in Table 3. Hot air at 100 °C is used to dry biomass with an initial moisture content of 55 % in the conveyor dryer. This process yields a stream of dried biomass with a moisture content of 9 % and a moist air stream at 80 °C. The dried biomass is converted to raw syngas through gasification, which deconstructs the feedstock primarily into CO and H₂.

A pressurized (10 bar) bubbling fluidized bed is selected for this study, using steam and oxygen (O_2) as gasification media. CO_2 is used as the carrier for the biomass feed. Fluidized bed gasification was selected due to its proven suitability for medium-scale biomass gasification and its balance between technical performance and feedstock flexibility. Alternative technologies such as fixed bed gasifiers are typically limited to small-scale applications, with throughput constrained by reactor design and particle size limitations [31]. On the other hand, entrained flow gasifiers, while common in coal-based applications, are less suitable for woody biomass without extensive and energy-intensive pretreatment [31].

The process temperature is finely tuned by regulating the O_2 flow, directly influencing the extent of oxidation [33].

2.2.2. Conditioning

The conditioning section ensures that the syngas meets all necessary prerequisites before it is introduced into the FT synthesis reactor. The primary requirements for the FT reactor, as well as the techniques employed to meet the requirements, are outlined in Table 4. Gas cleaning, SMR, (R)WGS, and AGR are the four major process steps to prepare the syngas for the FT synthesis. (See Table 5.)

After the initial gas cleaning, steam tar reforming is applied to efficiently convert tar into valuable gases such as H_2 , methane (CH₄), and CO [34]. The high H_2 /CO ratio achieved makes the syngas well-suited for downstream Fischer–Tropsch synthesis. Additionally, due to limited single-pass efficiency and the production of undesired light hydrocarbons in the FT synthesis, it is necessary to recirculate the tail gas back to the SMR, where light hydrocarbons are heated and transformed catalytically with steam into CO and H_2 . This process is operated at high temperatures, sustained by burning a portion of the purge gas to heat the process indirectly.

Next, the syngas will go through the (R)WGS reaction (Eq. 1), where the H_2 /CO ratio is adjusted.

$$CO + H_2O \leftrightarrows CO_2 + H_2; \Delta H = -41 \text{ kJ/mol}$$
(1)

The direction of this reaction is decided based on the molar content of each inflow component and is controlled by temperature, with higher temperature favoring the endothermic reverse reaction (RWGS). In BtL

Table 3 Properties of the raw biomass feedstock (mixture of birch and pine) [32].

Parameter Value	
LHV (MJ/kg _{daf}) ^a 20.7	
Proximate analysis (%mass, DS ^b)	
C 50.9	
Н 6.2	
N 0.2	
0 41.8	
S 0.02	
Cl <0.01	

^a daf = dry ash free.

^b DS = dry solids.

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Table 4

FT requirements and selected conditioning techniques.

Requirements	Limitations	Employed technique
Tars	Concentration below dew point (to avoid condensation on surfaces) [35]	Tar reforming
CH ₄	<2 % (inert) [36]	SMR
H ₂ /CO ratio	Slightly >2 [36]	Water gas shift
CO ₂	<5 % [36]	Amine scrubber AGR
Sulfur (COS, H ₂ S,	<60 ppb (most important poison)	Removed through
CS ₂)	[35]	amine scrubber AGR
H ₂ O	Low [36]	Water knock-out
		before FT
Hydrocarbons	-	Recycle to improve
		efficiency
C_2H_2	Low (inert) [36]	Controlled in the
		recirculation
N ₂	Low (inert) [36]	Controlled in the
		recirculation
HCN	<10 ppb (poison) [36]	Controlled in the
		recirculation
NH ₃	<10 ppb (poison) [36]	Controlled in the
		recirculation

Гable	5

Capital cost reference data.

Process section	Scaling parameter	Scaling exponent	Base size	Base cost (M€)	Base year	Ref
Belt dryer	production,	0.65	100	7	2014	[49]
Gasification feeding system	production, MW _{th}	0.60	20	6	2014	[49]
ASU	oxygen, ton/day	0.65	442	27	2017	[19]
FB gasifier	biomass feed, MW _{th}	0.60	170	70	2020	[19]
Compressor	feed, kmol/	0.70	285	4	2014	[49]
SMR/rWGS	feed, kmol/	0.60	31,733	74	2014	[49]
eSMR	feed, kmol/	0.60	31,733	37	2014	[19]
WGS	feed, kmol/ h	0.65	59,000	6	2009	[19]
AGR	shifted syngas, Nm ³ /h	0.65	15,695	2.5	2018	[19]
PEM	electricity input, MW	1	1	0.8	2016	[50]
CCS	gas flow, Nm ³ /s	0.70	3.90	5.19	2010	[51]
FT reactor ¹	syngas feed, Nm ³ /h	0.75	70,630	56	2007	[52]
FT upgrading	FT crude, ton/day	0.65	6	15	2007	[53]
Steam turbine	MW _e , production	0.70	10.3	10	2002	[54,55]
Steam turbine +	MW _e , production	0.70	12.3	3.8	1999	[56]

¹ FT synthesis cost was adapted from [54] to match this study's configuration by deducting the estimated costs of the reformer and recycle compressor from the original aggregated cost.

and BtL-CCS configurations, WGS is used to increase the H_2 content of the gas; thus, the forward reaction occurs. Conversely, in PBtL_{max} and PtL configurations, the surplus H_2 content drives the reaction in reverse, thus converting the excess H_2 to CO and H_2O , while reducing CO₂.

Since CO_2 is unnecessary for the FT synthesis, it must be eliminated to reduce the reactor size and, consequently, the overall costs. In addition, harmful gases like hydrogen sulfide (H₂S) and ammonia,

detrimental to FT catalysts, may be present in the syngas. In the AGR step, the majority of the H_2S and a portion of the CO_2 are removed through amine scrubbing, followed by a final polishing step using guard beds. This results in a sulfur-free gas suitable for the synthesis process. The AGR unit is positioned downstream of the WGS reactors as sulfur compounds are necessary to maintain the activity of the cobalt-based catalyst through sulfation [25].

In electricity-assisted configurations (PBtL-CCS, PBtL_{max}, and PtL), H_2 produced through water electrolysis in a PEM is introduced into the process. These configurations vary in terms of 1) where the H_2 is added, 2) the design capacity of the PEM and the resulting H_2 production rate, and 3) the handling or utilization of the co-produced O_2 .

2.2.3. CCS

An amine technology with 85 % efficiency is selected to capture CO₂. Captured CO₂ is transported via truck and ship to long-term storage sites. Carbon is captured at 60 °C and compressed to 50 bar for storage. Monoethanolamine-based CO₂ capture has a relatively high CO₂ loading capacity and a high absorption rate. The technique involves chemically absorbing CO₂ at low temperatures in the absorber and then regenerating the CO₂ at high temperatures in the stripper.

2.2.4. FT and syncrude refinery

FT synthesis is the central conversion step to obtain a hydrocarbon product mixture. Low-temperature FT technologies operating between 170 and 270 °C are generally beneficial in producing transportation fuel [37]. If the H₂/CO ratio is already adjusted to meet the FT requirement, Co-based catalysts are often preferred for low-temperature FT due to their very low WGS activity, as opposed to Fe-based catalysts [38]. The recommended H₂/CO feed ratios range between 2.0 and 2.3 in this case [37]. Further upgrading can be considered state of the art and might target hydrocarbon fractions ranging from FT diesel or jet fuel to waxes [39].

After the FT reactor, the product stream is separated into a gaseous phase, a liquid organic product, and a liquid watery phase. A portion of the product gas is recirculated back into the process after passing through the SMR, enabling carbon recirculation. The remaining gas stream is purged from the process to limit the recirculation of inerts to the FT reactor to both meet the process requirements (Table 3) and avoid unnecessary increments in reactor size [40]. The purge gas is directed to the purge handling section (see below).

The liquid hydrocarbon chains of FT products can be predicted according to the Anderson-Schulz-Flory distribution, which describes chain growth according to the number of carbon atoms in the reaction medium. This is governed by a polymerization chain model, as shown in Eq. 2 [41].

$$\log(W_n/n) = n\log\alpha + \log\left((1-\alpha)^2/\alpha\right)$$
⁽²⁾

where α is the growth probability factor and W_n is the mass fraction (wt %) of a product which consists of *n* carbon atoms produced via the reaction shown in Eq. 3 [10]:

$$n \text{ CO} + 2 n \text{ H}_2 \rightarrow (-\text{ CH}_2 -)_n + n \text{H}_2 \text{O}$$
 3

2.2.5. Purge gas combustion and heat integration

Steam is a key inflow required for all gasification-based configurations in various operation units (i.e., SMR and WGS). Two heat sources for steam generation are thus considered: (1) process stream cooling, and (2) combustion of purge gas.

As for process heat integration, two distinct options are proposed based on the assumed geographical location of the plant, according to which low-temperature heat can be recovered or not. The first option (a) involves the implementation of a backpressure Rankine steam cycle, which allows for the simultaneous production of process steam, electricity, and heat for district heating (DH). It thus enables the exploitation of the synergies between power production and local heating demands, but requires a suitable heat sink nearby. This option is termed "*CHP mode*" (combined heat and power).

The second option (b) also involves a Rankine cycle, but with a condensing steam turbine producing only electricity in addition to the process steam. Such configuration is ideal for situations in which electricity generation is the primary focus, and excess heat is dissipated through cooling at lower temperatures. This option is termed "condensing mode". The PtL configuration primarily relies on direct electrification rather than steam-driven reactions, thus, does not justify any heat integration. Some key considerations in both integration options are taken into account for this process, such as:

- Radiative heat from the 1000 °C boiler.
- Constant temperate heat from the FT reactor.
- Process steam inlet stream, supplied to the gasifier, gas cleaning, SMR, and WGS units, with operating conditions of approximately 350 °C and 20 bar.
- Steam generated during FT reactor cooling.

3. Methodology and input data

A detailed process flow chart is created for each technology configuration to establish mass and energy balances, which form the basis for the subsequent performance evaluation. Several key performance indicators (KPIs) are calculated to assess energy and carbon efficiency, economic viability, and GHG footprint across configurations.

Process stream data, including mass flow, temperature, and energy content, are collected from the process simulation of each configuration. Pinch analysis is employed to develop the integrated grand composite curve (IGCC) for each configuration, enabling quantification of electricity production as a by-product of meeting the steam demand of the main process. Energy and carbon flows are tracked throughout the process chain, and the degree of electrification in each configuration is quantified. A marginal electricity efficiency metric is introduced to evaluate by how much an additional electricity input enhances the process.

Next, each configuration's investment and production costs are calculated to provide a comprehensive economic assessment. Investment costs cover capital expenditure for equipment, installation, and infrastructure, while production costs include operating expenses such as feedstock, utilities, and maintenance. To illustrate the impact of market dynamics, production costs are evaluated under varying prices for biomass, electricity, and avoided emissions. Finally, net GHG emissions (in CO_2 equivalents) are reported per net amount of produced FTL, offering a clear measure of environmental performance.

3.1. Simulation of considered configurations

3.1.1. Process simulation

Simulations are carried out using Aspen HYSYS V14® and Aspen Plus V14®, focusing on identifying energy and carbon losses and evaluating the impact of electrification on process performance. Each configuration is simulated for a Base Case plant capacity of 100 MW_{daf} (dry, ash-free) biomass input.

A key component of the process simulation is the gasification model, which is developed using a ODimensional steady-state reactor implemented at a high level to define the input and output streams. This semiempirical model was implemented in Aspen Plus® with feeding biomass set as non-conventional components, with the biomass and char proximate and elemental analysis specified in PROXANAL and ULTANAL models. The attributes of NC components in Aspen Plus are estimated using the HCOALGEN model for enthalpy and specific heat derivation and the DCOALIGT property model for density calculations. The dried biomass is first decomposed into its atomic constituents using a calculator block and a yield reactor that takes ultimate and proximate analysis of the feedstock as input. The evolution of volatiles, tar, and char is controlled by polynomial functions of gasification temperature fitted with empirical data [42,43]. The functions are implemented using a calculator block in Aspen Plus to derive the yields of permanent gas, tar and char. For simplicity, tar is represented by naphthalene, and all nitrogen and sulfur present in biomass are assumed to remain in char during devolatilization. To accurately model the high-temperature gasification process, the Peng-Robinson equation of state, modified with the Boston-Mathias alpha function, is applied and used to describe the thermodynamic properties of the selected species CO, H₂, CO₂, CH₄, H2O, O2, C2H4, N2, NH3, C6H6, C6H6O, and C10H8. During pyrolysis stage of this process, which is modeled as a yield reactor, permanent gas (CO, H₂, CO2, CH4), tar (represented by C6H6, C6H6O, C10H8) and char (C×HnOy) are formed. In the model, char is decomposed in a yield reactor and mixed with volatile gases and tar before being passed through an oxidation zone, along with oxygen and steam. The oxidation zone is modeled as a plug flow reactor where oxidation reactions occur. The resulting products then enter the reduction zone, which is also modeled as a plug flow reactor. Departing from the detailed modeling and validation of biomass fluidized bed gasification, which is extensively covered in the literature (e.g., [42-47]), this research emphasizes systems-level design of biorefinery concepts, complemented by a highlevel representation of the major conversion steps.

Additional simulation and operational specifications of major process units are outlined in the supplementary material.

3.1.2. Heat integration

The heat integration optimizations are carried out using a singleobjective evolutionary algorithm that incorporates the Genetic Diversity Evaluation Method and the sequential least squares quadratic programming algorithm script, available in the Python library [48]. First, hot streams and total steam requirements for each configuration are identified based on simulation results. These thermal streams are then subjected to Pinch Analysis techniques. An advanced Pinch Analysis method, the IGCC, extends the traditional grand composite curve by including additional thermal streams, including those from systems supplying external utilities to the process. In all configurations, steam generation thermal streams are introduced at 20 bar and 350 °C. Finally, all streams are integrated using Pinch Analysis, applying a minimum temperature difference ($\Delta T_{min}/2$) of 10 °C to ensure feasible heat exchanger areas for effective stream matching.

3.2. Performance assessment

3.2.1. Energy and carbon performance

To assess the efficiency of each configuration in converting input energy into the desired fuel product, we first define the liquid fuel efficiency (η_{FTL}) as the ratio of the chemical energy content of the FTL product (\dot{E}_{FTL}) to the total energy input to the system (\dot{E}_{feed}), based on lower heating values (LHV). This metric isolates the performance of the core fuel synthesis chain and allows for direct comparison of how effectively each configuration converts available energy into liquid hydrocarbons, independent of any co-product generation, and is calculated on a general form as:

$$\eta_{FTL} = \frac{E_{FTL}}{\dot{E}_{feed}} \tag{4}$$

where the FTL product to energy input ratio depends on the pathway, according to Eqs. 5–9:

Base Case
$$\frac{\dot{E}_{FTL}}{\dot{E}_{feed}} = \frac{\dot{m}_{product} \bullet LHV_{product}}{\dot{m}_{biomass} \bullet LHV_{biomass} + P_{Aux}}$$
 (5)

$$BtL - CCS \frac{\dot{E}_{FTL}}{\dot{E}_{feed}} = \frac{\dot{m}_{product} \bullet LHV_{product}}{\dot{m}_{biomass} \bullet LHV_{biomass} + P_{Aux} + P_{CCS}}$$
(6)

$$PBtL - CCS \ \frac{\dot{E}_{FTL}}{\dot{E}_{feed}} = \frac{\dot{m}_{product} \bullet LHV_{product}}{\dot{m}_{biomass} \bullet LHV_{biomass} + P_{Aux} + P_{CCS} + P_{PEMEL}}$$
(7)

$$PBtL_{max} \ \frac{\dot{E}_{FTL}}{\dot{E}_{feed}} = \frac{\dot{m}_{product} \bullet LHV_{product}}{\dot{m}_{biomass} \bullet LHV_{biomass} + P_{Aux} + P_{PEMEL}}$$
(8)

$$\mathsf{PtL} \ \frac{\dot{E}_{FTL}}{\dot{E}_{feed}} = \frac{\dot{m}_{product} \bullet LHV_{product}}{\dot{m}_{Bio-CO2} \bullet LHV_{Bio-CO2} + P_{Aux} + P_{PEMEL}}$$
(9)

where \dot{m}_x and LHV_x denote the mass flow rate and LHV of stream x, respectively, and P_x denotes the electricity demand for different process steps (auxiliaries, CCS, and electrolysis), depending on configuration.

To provide an overall insight into each configuration's performance, we also calculate the energy yield, *EY*, by considering both the energy of the FTL product, and any potential exports of electricity and/or heat to district heating. However, *EY* depends on the chosen system boundaries for each configuration. The general form of *EY* (adapted from [20]) is defined as:

$$EY = \frac{\dot{E}_{prod}}{\dot{E}_{feed}} \tag{10}$$

where, similarly as to above, the product to energy input ratio depends on the pathway, according to Eqs. 11–15:

Base Case
$$\frac{\dot{E}_{prod}}{\dot{E}_{feed}} = \frac{\dot{m}_{product} \bullet LHV_{product} + P_{sc} + Q_{DH}}{\dot{m}_{biomass} \bullet LHV_{biomass} + P_{Aux}}$$
 (11)

$$BtL - CCS \ \frac{\dot{E}_{prod}}{\dot{E}_{feed}} = \frac{\dot{m}_{product} \bullet LHV_{product} + P_{sc} + Q_{DH}}{\dot{m}_{biomass} \bullet LHV_{biomass} + P_{Aux} + P_{CCS}}$$
(12)

$$PBtL - CCS \ \frac{\dot{E}_{prod}}{\dot{E}_{feed}} = \frac{\dot{m}_{product} \bullet LHV_{product} + P_{sc} + Q_{DH}}{\dot{m}_{biomass} \bullet LHV_{biomass} + P_{Aux} + P_{CCS} + P_{PEMEL}}$$
(13)

$$PBtL_{max} \frac{\dot{E}_{prod}}{\dot{E}_{feed}} = \frac{\dot{m}_{product} \bullet LHV_{product} + P_{sc} + Q_{DH}}{\dot{m}_{biomass} \bullet LHV_{biomass} + P_{Aux} + P_{PEMEL}}$$
(14)

$$\mathsf{PtL} \; \frac{\dot{E}_{prod}}{\dot{E}_{feed}} = \frac{\dot{m}_{product} \bullet LHV_{product}}{\dot{m}_{Bio-CO2} \bullet LHV_{Bio-CO2} + P_{Aux} + P_{PEMEL}} \tag{15}$$

The power output (P_{sc}) and district heating (Q_{DH}) generated in the steam cycle can vary based on whether a back-pressure or condensing turbine is used. Consequently, identical process equipment may employ different steam utilization strategies, resulting in variations in overall system performance.

Because carbon efficiency has both environmental and economic implications, we evaluate the fraction of carbon in the feedstock that ends up in the final liquid product. The carbon efficiency, η_C , is calculated as:

$$\eta_C = \frac{m_{C,prod}}{\dot{m}_{C,feed}} \tag{16}$$

where $\dot{m}_{C,prod}$ is the carbon content in the final liquid product, and $\dot{m}_{C,feed}$ is the carbon content introduced into the process. To illustrate the effect of CCS, we also define a carbon recovery factor, R_f , as

$$R_f = \frac{\dot{m}_{C,prod} + \dot{m}_{C,CCS}}{\dot{m}_{C,feed}} \tag{17}$$

where $\dot{m}_{C.CCS}$ represents the carbon captured and stored.

3.2.2. Electrification analysis

To capture the impact of electrification, we calculate the specific electricity demand (amount of electricity required per unit of produced FTL) as:

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$$El_{demand} = \frac{P_{ASU} + P_{Aux} + P_{PEMEL} + P_{CCS} - P_{SC}}{\dot{m}_{product} \bullet LHV_{product}}$$
(18)

The terms in the numerator account for the electricity requirements of the air separation unit (P_{ASU}) , the auxiliaries (P_{Aux}) , the PEM electrolyzer (P_{PEMEL}) , and the CCS (P_{CCS}) , respectively, minus any power generated by the steam cycle (P_{SC}) .

To emphasize the share of electric energy input, we introduce the electrification ratio, *ER*, calculated as:

$$ER = \frac{P_{ASU} + P_{Aux} + P_{PEMEL}}{\text{total energy input}}$$
(19)

Finally, we define the marginal electricity efficiency, $\eta_{el,marginal}$, to measure how effectively each additional unit of electricity (beyond what is used in the Base Case) is converted into extra FTL product:

$$\eta_{el,marginal} = \frac{E_{FTL,x} - E_{FTL,Base}}{E_{el,in,x} - E_{el,in,Base}}$$
(20)

where $E_{FTL,x}$ and $E_{FTL,Base}$ denote the final liquid fuel energy outputs of configuration x and the Base case, respectively. Similarly, $E_{el,in,x}$ and $E_{el,in,Base}$ denote the electricity supplied to the process in configuration x and the Base case. This metric helps quantify the benefit of electrification in terms of increased fuel production.

3.2.3. Economic performance

The mass and energy balance results form the foundation for cost estimation. To determine capital costs, critical equipment within the battery limits is identified, and major equipment costs (e.g., reactors), are derived from relevant technical reports. Table 5presents the scaling factors used to calculate total capital investment, alongside the parameters necessary for scaling each unit. The input data for scaling the equipment is available in the supplementary document.

Equipment costs are scaled using:

$$C = C_0 \left(\frac{A}{A_0}\right)^f \tag{21}$$

where C_0 is the base cost of the unit, A_0 and A are the base and actual capacities, respectively, and f is the scaling exponent. Prices are standardized to 2023, using the Chemical Engineering Plant Cost Index (CEPCI):

$$C_{2023} = C_{base \ year} \frac{CEPCI_{2023}}{CEPCI_{base \ year}} \tag{22}$$

The resulting bare erected costs include the purchased equipment cost, which is multiplied by a factor of 2.9 [58]—assuming carbon steel construction for all units—to account for erection, piping, instrumentation, and site preparation. This yields the estimated total installed cost (*TIC*). Indirect costs (*IC*), encompassing engineering, contractor fees, legal expenses, and more, are set at 60 % of TIC. Additionally, a contingency allowance of 10 % is added to the sum of TIC and IC, called the total direct and indirect costs (*TDIC*), to give the fixed capital investment (*FCI*). As noted in [57,58], a working capital estimate between 5 and 15 % of FCI is generally accepted for preliminary designs. In this study, a mid-range value of 10 % was selected to reflect a conservative yet balanced assumption that avoids overestimating capital requirements, particularly given the early-stage nature of the analysis. Finally, the sum of FCI and WC yields the total capital investment (*TCI*), as shown in Table 6.

The total production cost (*PC*, in \notin /MWh), accounts for annual capital repayment and operating and maintenance (*O*&*M*) costs:

$$PC = \frac{CRF \bullet TCI + O\&M_{fixed} - O\&M_{variable} - Revenue}{FTL_{annual}}$$
(23)

where FTL_{annual} is the annual production of FTL (MWh), O&M_{fixed} and

Table 6

Calculation of total capital investment (adapted from [18,57]). TIC = total installed cost.

Component	Calculation method
Indirect capital costs (IC)	60 % of TIC
Total direct and indirect costs (TDIC)	TIC + IC
Contingency	10 % of TDIC
Fixed capital investment (FCI)	TDIC + Contingency
Working capital (WC)	10 % of FCI
Total Capital Investment (TCI)	FCI + WC

 $O\&M_{variable}$ the fixed and variable O&M costs, respectively, and *Revenue* the revenue for by-product sales (e.g., electricity, heat, oxygen, CO₂ capture credits). The capital recovery factor (*CRF*) amortizes TCI over the plant's life at a fixed interest rate and is calculated as:

$$CRF = \frac{(1+i)^n \bullet i}{(1+i)^n - 1}$$
(24)

where *i* is the interest rate and *n* the economic lifetime of the plant. We set a 20-year operational lifespan, with 90 % annual uptime (7884 h) and an interest rate of 8 % [20]. $O\&M_{fixed}$ is set as 3 % of *TCI* [59], accounting for the expenses for operating supplies, planned and unplanned maintenance and repairs, spare parts, and payroll. $O\&M_{variable}$ differs by configuration and includes all feedstock costs (biomass, electricity, and bio-CO₂). Variable annual costs are determined based on the energy and mass balances and market and literature values for utilities and consumables. *Revenue* covers income from sold electricity and/or district heating, oxygen, as well as CO₂ capture credits.

Table 7 lists the 2023 market prices of energy carriers and other cost parameters.

Given the many potential uncertainties that affect production costs—such as capital expenses, O&M rates, and feedstock logistics—this study focuses its sensitivity analysis on biomass and electricity prices to reflect the most influential energy market dynamics. The production costs are thus analyzed under varying electricity and biomass prices to gauge their sensitivity to key market fluctuations and to estimate a range of production costs. The analysis also identifies crossover points at which one configuration becomes more profitable than another, offering valuable insights into the competitiveness of each technology configuration under changing market conditions. This approach is essential for understanding how different market scenarios—such as changes in energy prices, biomass availability, or emission pricing—affect the economic viability of each configuration. We consider both current and

Table 7

Market prices of energy carriers and variable O&M cost components for the year 2023.

Parameter	Value	Unit	Comment	Ref
Biomass price (forest residue)	21	€/MWh	Swedish energy market for forest residues	[60]
Electricity prices (buy)	40	€/MWh	Average Nordic electricity purchase price	[61]
Electricity prices (sell)	29	€/MWh	Average Nordic electricity selling price	[61]
O ₂	60	€/ton	Literature-based estimate	[20]
Bio-CO ₂	23	€/ton	General value IEA value for bio- based CO_2 feedstock	[<mark>62</mark>]
CO ₂ revenue	84	€/ton	EU ETS reported price	[63]
CO ₂ transport and storage	15	€/ton	IPCC-based cost (transport + storage)	[64]
District heating	30	ϵ /MWh _{th}	Average Swedish price back- calculated from consumers' prices, excluding taxes and distribution	[65]

optimistic future avoided-emissions prices, emphasizing the need for production systems that can adapt to uncertain and evolving market scenarios. By clarifying the relative robustness and profitability of different configurations, the analysis guides decision-making regarding operational strategies and long-term investments.

3.2.4. Greenhouse gas emission performance

The study targets fossil neutrality by ensuring all configurations avoid using fossil-based energy sources or utilities. However, while biobased carbon emissions are exempt from taxation, the biomass supply chain and electricity production still contribute to overall emissions, underscoring the importance of managing these sources to maintain environmental sustainability.

The GHG footprints are estimated using a simplified approach based on the RED method for emission allocation. Table 8 lists the GHG emission factors applied in this study. The process-related GHG emission (E_{GHG}) are then calculated according to Eq. 25:

$$E_{GHG} = e_{bio} + e_{el} + e_C - e_{CCS} \tag{25}$$

where e_{bio} covers emissions from the procurement of biomass feedstocks, e_{el} corresponds to the emissions from the local electricity mix, e_C accounts for CO₂ transportation, and e_{CCS} represents the avoided emissions through CCS. All configurations are compared against a fossil fuel reference to gauge their net GHG impact.

To examine how different grid emission intensities impact the GHG footprint of each configuration, we perform a comparative analysis using country-specific data as a form of sensitivity analysis. Germany and France are selected as case studies due to their contrasting electricity grid emission factors and biomass resource availability. Germany represents a relatively higher-emission grid, while France is a low-emission grid. For each configuration, the GHG emissions are calculated based on the electricity demand and the respective country's 2023 emission factor. This approach highlights how national grid differences can affect the overall environmental performance of electrified renewable fuel pathways.

4. Results and discussion

This section presents the results of this study using a structured approach to provide critical insights into the interplay between technical efficiency, economic viability, and environmental performance, thus offering a holistic view on each configuration's overall feasibility.

First, an analysis of the energy balances and the corresponding KPIs is presented. These findings clarify each configuration's energy utilization and efficiency. Furthermore, the carbon flow is examined alongside relevant KPIs, offering insights into the carbon pathways and retention within the process.

Next, the focus shifts to electrification, examining the electrification ratio and marginal electrification efficiency. These metrics reveal how additional electrical input affect both process performance and energy

Table 8

GHG emission factors.

Sector	value	Unit	Reference
Average Nordic electricity mix	25.11	gCO _{2,eq} /MJ	[66]
Average European electricity mix	58.33	gCO _{2,eq} /MJ	[67]
German electricity mix	120	gCO _{2,eq} /MJ	[67]
French electricity mix	14.72	gCO _{2,eq} /MJ	[67]
Swedish electricity mix	6.39	gCO _{2,eq} /MJ	[67]
Biomass harvest and transportation	2.20	$gCO_{2,eq}/MJ_{LHV}$	[68]
District heating ^a	202	gCO _{2,eq} /MJ	[69]
CO ₂ transport ^b	0.10	$gCO_{2,eq}/ton - km$	[70]
Diesel	95.0	$g \ CO_{2,eq}/MJ$	[3]

^a Swedish average emission factor for 2022.

^b Assumes an average distance of 200 km by truck and 1200 km by ship.

integration.

After the technical performance comparison, the analysis shifts to the economic assessment, where we evaluate and compare investment and production costs for each configuration. We also investigate how market fluctuations impact the economic resilience of the examined configurations.

Finally, the environmental implications are assessed through a comparative analysis of GHG emissions.

4.1. Energy and carbon performance

The heat integration between the process configurations and the steam power cycle (Condensing mode) is illustrated by the IGCCs in Fig. 2. In these curves, blue lines represent the steam streams within the steam cycle, while red lines denote other thermal streams, including steam generation for the FTL production process. The proposed steam cycle fulfills each configuration's steam requirements, with steam exiting the turbine at 350 °C and 20 bar while simultaneously generating electricity. The remaining steam continues to expand within the turbine, passing through subsequent stages of the cycle.

In Fig. 2, the flat segments at 1000 °C and 250 °C in the red curve reflect radiation heat contributions from the combustion chamber and the gasifier, respectively. Each configuration is self-sufficient in steam, eliminating any need for external steam sources. Net power generation for condensing mode equals approximately 11 MW, 12 MW, 12 MW, and 17 MW for the Base Case, BtL-CCS, PBtL-CCS, and PBtL_{max} configurations, respectively. The corresponding values for CHP mode are 8.2 MW, 9.3 MW, 10 MW and 10 MW, with the DH delivery amounting to 3.0 MW, 2.9 MW, 7.8 MW and 16 MW, respectively. However, since there is no steam demand in the PtL configuration, heat integration is not justified, as the process primarily relies on direct electrification rather than steam-driven reactions.

The abscissas of the blue curves appear smaller because the steam required by the processes is incorporated into the red curves. The corresponding plots for the configurations in CHP mode are presented in the supplementary material.

The results presented in Fig. 3 show the distinct performance of each configuration across the energy and carbon KPIs (liquid fuel efficiency (η_{FTL}), energy yield (*EY*), carbon efficiency (η_C), and carbon recovery factor (R_f)) and their variations between CHP and Condensing modes. In addition, the full balances are presented in the form of Sankey diagrams for all configurations in the supplementary material.

The energy efficiency of liquid hydrocarbon production (η_{FTL}) is identical between CHP mode and condensing mode for each configuration. The PBtL_{max} configuration achieves the highest η_{FTL} , reflecting efficient use of both biomass and externally supplied H₂. Conversely, the fully electrified PtL configuration shows a notable decrease in η_{FTL} due to its high electricity demand and the absence of biomass-derived energy, highlighting a key trade-off between full electrification and overall energy efficiency. In contrast, BtL-CCS exhibits the lowest η_{FTL} values, as the energy required for CO₂ capture and compression adds to the system demand without increasing the final energy content of the FTL product.

A similar trend is observed for the overall energy yield (EY), which, however, exhibits a difference between CHP and condensing mode. The EY takes into account all energy outputs, which rewards the CHP setup across all configurations. The simultaneous generation of electricity and heat in CHP mode enhances energy recovery and contributes to higher EY values. Partial electrification further improves EY by increasing the total fuel output per unit of input energy.

Both carbon efficiency (η_C) and carbon recovery factor (R_f) remain consistent across CHP and condensing modes for all configurations. These metrics are determined by process design and carbon utilization strategies, which are unaffected by the choice of energy integration mode. Configurations with CCS, such as BtL-CCS and PBtL-CCS, exhibit significantly higher R_f due to the effective capture and storage of



Fig. 2. Integrated Grand Composite Curves (IGCCs) for a) Base Case, b) BtL-CSS, c) PBtL-CCS and d) PBtL_{max} integrated with condensing steam turbine (condensing mode).



Fig. 3. Liquid Fuel Efficiency (η_{FTL}), Energy yield (*EY*), carbon efficiency (η_c), and carbon recovery factor ($_{Rf}$) for each configuration under CHP and condensing modes.

carbon, with recovery exceeding 90 % in both CHP and condensing modes. This reflects the near-complete carbon utilization in the FTL product or via storage through CCS. By contrast, non-CCS configurations (Base Case and PBtL_{max}) show lower recovery rates, as some carbon is lost as emissions. The addition of electrolysis increases the FTL product's carbon content, thus increasing the η_C , as more carbon is preserved for conversion rather than lost as CO₂. The carbon recovery rate for the highly electrified PBtL_{max} thus reaches 78 % without CCS, compared to 94 % for PBtL-CCS. This relatively modest difference reflects that design choices in PBtL_{max}—such as increased H₂ input and reduced reliance on

the WGS reaction—already contribute significantly to CO_2 mitigation, thereby reducing the added benefit of CCS in this case. By contrast, the fully electrified PtL configuration achieves both a η_C and an R_f of 91 %, reflecting efficient utilization of the incoming carbon stream. Despite the lack of biomass integration, the PtL process effectively uses carbon inputs to produce FTL products with minimal losses, offering a robust pathway for sustainable fuel production.

These findings highlight the trade-offs between electrification, CCS, and energy integration strategies. While CHP improves energy yield, the choice of CCS and the level of electrification strongly influence carbon efficiency and recovery, with configurations like BtL-CCS and PtL achieving high carbon utilization rates through optimized process designs. The energy yield trends align well with results reported by Dossow et al. [20], which range between 40 and 45 % for electrification ratio values between 0 and 1, for the PBtX-PEMEL-FT-LT case. The incorporation of CHP further enhances the EY, highlighting its role in improving overall system efficiency. Carbon efficiency values also follow trends reported by Dossow et al. [20], increasing from approximately 30 % to 90 % across the same ER range for the PEMEL-FT case. Notably, CCS enables less-electrified configurations to achieve carbon efficiencies comparable to those with higher ER.

4.2. Electrification analysis

Fig. 4 shows the specific electricity demand for each configuration. In the Base Case, the condensing turbine-based steam cycle supplies enough power for the ASU and AGR units, even allowing surplus electricity export (approximately 0.4 MWh_{el}/l_{FTL}). As a result, there is



Fig. 4. Comparison of product-specific electricity demand for each configuration under CHP and condensing modes. EL-x denotes the electricity generated by the steam cycle, where x indicates the CHP or condensing integration steam cycle.

minimal reliance on external power. However, once H_2 is introduced, electricity consumption increases sharply, primarily due to the high energy requirements of the PEM electrolyzer. In both PBtL-CCS and PBtL_{max}, the demand for electricity exceeds the steam cycle's generation capacity, thereby necessitating a reliance on external electricity sources. While these configurations achieve enhanced carbon retention, they become less energy-independent: this trade-off could raise operating costs and increase vulnerability to energy supply disruptions. By contrast, the fully electrified PtL configuration requires approximately 20 MWh_{el}/l_{FTL}, entirely supplied by the grid. It shifts away from biomass entirely, maximizing carbon retention and virtually eliminating process emissions. However, it underscores the tension between carbon efficiency and energy self-sufficiency.

Fig. 5 shows the electrification ratio (*ER*) and marginal electrification efficiency ($\eta_{el.marginal}$). In the Base Case, the ER is only 9 % (minimal reliance on electricity) with a marginal electrification efficiency of 0 % (reference configuration). By introducing a PEM electrolyzer in PBtL-CCS, the ER increases to 35 % and the $\eta_{el.marginal}$ reaches around 60 %, mirroring the previously discussed increase in carbon recovery factor when introducing H₂.

Electrification intensifies further in PBtL_{max}, where the ER reaches 69 % with the $\eta_{el.marginal}$ dipping slightly to 55 %, implying a diminishing return on additional electrification. In the PtL configuration, the $\eta_{el.marginal}$ is 0 %, because the shift to electrification is complete rather than incremental.

Unlike energy yield, electrification metrics are unaffected by the heat integration mode for all configurations, as the heat integration mode simply determines the desired energy form from the same amount of steam—either a combination of heat and electricity, or electricity alone.

Overall, the progression from biomass-centric to electrified systems



Fig. 5. Electrification ratio (*ER*) and marginal electrification efficiency (η_{el} , marginal) for each configuration under CHP and condensing modes.

reveals the critical balance between internal electricity generation, external grid dependency, and carbon efficiency. This spectrum from partial to full electrification highlights how each pathway's carbon efficiency gains must be weighed against its growing reliance on external power. In highly electrified pathways, strategic integration of renewable electricity sources thus emerges as a key factor for ensuring economic and environmental viability.

Although direct introduction of H_2 into the process significantly improves the carbon recovery factor, thereby enhancing overall carbon efficiency, it also heightens reliance on external energy sources. On the other hand, the availability of sustainable biomass is likely to face increasing constraints due to rising demand from sectors such as food, feed, chemicals, and energy. In the context of a fossil-free circular economy, prioritization of biomass use becomes critical, particularly as land availability may also decline due to environmental protections and increased needs for carbon storage in living biomass [71]. These pressures underscore the importance of maximizing carbon utilization in biomass-to-fuel processes. Configurations that achieve high carbon efficiency—either through electrification or carbon capture—can significantly improve the viability of biofuel production within future biomass constraints [72].

4.3. Economic performance

Fig. 6 illustrates the specific capital investment per energy unit of FTL for each configuration, showing the distribution of costs across key process components. Conditioning, which includes intermediate steps like (R)WGS, AGR, and (e)SMR, plays an important role in meeting the requirements of the FT reactor. The FT reactor accounts for a large share of overall costs, increasing by approximately 20 % in the PtL configuration due to its larger capacity (1.2 times that of the Base Case). Collectively, FT synthesis and upgrading represent around half of the total costs, with upgrading contributing a notable fraction.

In the Base Case and BtL-CCS, costs are dominated by biomassrelated components such as the gasifier and feedstock handling. BtL-CCS incurs slightly higher conditioning costs due to CCS integration. By introducing moderate electrification with a relatively small PEM electrolyzer and an eliminated WGS reactor, PBtL-CCS lowers both conditioning and CCS costs, reducing total capital investment compared to BtL-CCS. PBtL_{max} achieves the lowest investment costs by further reducing reliance on biomass infrastructure, including the gasifier and ASU, while increasing the PEM size to optimize the mix of biomass and electricity inputs. By contrast, the fully electrified PtL has the highest investment due to its larger PEM unit and expanded FT reactor capacity. CHP mode incurs requires additional infrastructure, resulting in modestly higher capital costs.

The process cost breakdowns for PBtL and BtL configurations show overall agreement with literature, though deviations appear in the PEM and FT reactor categories. For instance, in our PBtL configuration, the PEM unit accounts for ~34-35 % of total costs, compared to over 53 % in the study by Habermeyer et al. [27]. This difference likely stems from the use of PEM electrolysis in our model versus alkaline electrolysis in the study, with variations in system integration and supporting infrastructure. PEM systems integrate key utilities like power conversion and cooling more tightly, concentrating related costs within the PEM block. The FT reactor also represents a larger cost share in our analysis, due to more detailed modeling of product upgrading, internal heat exchange, and tail gas handling. These differences reflect varying assumptions and allocation methods across subsystems. While total process costs remain comparable, the observed shifts in sub-process contributions underscore the importance of clearly defined system boundaries and cost allocation strategies in techno-economic assessments.

Overall, these results demonstrate a clear trade-off between capital intensity, biomass dependence, and electrification.

Fig. 7 shows the total production cost for the configurations, ranging from 130 to 190 ϵ /MWh_{FTL}. While differences in sub-process cost shares



Fig. 6. Specific investment costs (M€/MW_{FTL}) for each configuration under CHP and condensing modes, broken down by major cost components: PEM, FB gasifier, feedstock handling, FT reactor, ASU, conditioning, CHP, and Condensing steam cycle.



Fig. 7. Total production costs (€/MWh_{FTL}) for each configuration under CHP and condensing modes, broken down by cost components: CAPEX, O&M, biomass, electricity, oxygen, bio-CO₂, CO₂ revenue, and district heating (DH). Red diamonds represent net production costs.

are expected due to variations in modeling detail and technology choices, the alignment in total production cost is more critical for assessing economic feasibility. In this regard, our results remain consistent with reported values, reinforcing the overall validity of the analysis. The values for the Base Case configurations align with the similar process reported by [20,28].

In the Base Case, biomass costs dominate, contributing approximately 39 €/MWh_{FTL} to overall costs. In contrast, configurations like PBtL_{max} mitigate electricity costs (approximately 30 €/MWh_{FTL} in condensing mode) through reduced biomass handling and CCS infrastructure, thereby lowering total production costs. While larger PEM units can benefit from economies of scale in practice, a scaling factor of 1.0 was applied in this study as a conservative assumption. This approach avoids introducing non-linear cost effects and focuses on isolating the influence of capacity size. At the same time, PtL's substantial reliance on grid electricity introduces additional complexity to its economic and environmental performance. This configuration needs a stable and substantial power supply, along with higher-capacity electrical infrastructure and stringent operational protocols, to manage price volatility and ensure reliable operation. While stable electricity supply is assumed in this study, real-world scenarios may involve grid stability challenges, increased maintenance demands for high-capacity PEM units, and risks of downtime during price surges.

maintain a more balanced energy input mix, offering resilience to market fluctuations. These findings emphasize that the interplay between biomass and electricity costs governs the economic viability of FTL production.

Overall, PtL maximizes carbon efficiency but faces higher production costs and operational demands. $PBtL_{max}$, striking a balance between biomass and electricity, emerges as a more cost-effective and adaptable option, particularly in markets characterized by fluctuating energy prices. To further assess the impact of PEM and CCS costs on the total production cost, a sensitivity analysis is provided in the Supplementary Material.

Fig. 8 evaluates the production cost sensitivities to varying biomass and electricity prices for the five process configurations. Two CO₂ revenue scenarios are considered: current CO₂ at 67 ϵ /ton (top) and high at 150 ϵ /ton (bottom). In the figure, darker colors indicate higher costs. The Base Case exhibits sharp cost increases with rising biomass prices (due to its heavy reliance on biomass) and sees negligible influence from electricity prices (due to minimal electrification). Increasing CO₂ revenue does not affect its costs since the Base Case lacks CCS.

By contrast, BtL-CCS benefits markedly from higher CO_2 revenue, offsetting increased biomass expenses. PBtL-CCS exhibits a more balanced sensitivity to both biomass and electricity prices, thanks to moderate electrification, and also benefits from increased CO_2 revenue. This makes PBtL-CCS more economically viable than biomass-dominant

In comparison, PBtL-CCS and PBtLmax rely on smaller PEM units and



Fig. 8. Biomass vs. electricity market price effects for each configuration for different CO₂ revenues, under the condensing mode.

configurations in volatile biomass markets. $PBtL_{max}$, which leans more on electricity with reduced reliance on biomass, displays stronger sensitivity to electricity prices. Finally, PtL is fully electrified and thus unaffected by biomass price shifts, but highly sensitive to electricity price levels.

While the CHP strategy marginally lowers net production costs (via district heating revenue), its overall impact on relative cost differences

among the configurations is limited. The analysis for the CHP mode process is reported in the supplementary material.

These results complement those from the sensitivity analysis provided by Dietrich et al. [24], which highlighted the PBtL configuration's dependence on electricity prices and their uncertain trajectory, but without comparing this reliance to other configurations or evaluating how carbon pricing could enhance PBtL's competitiveness. By contrast,



Fig. 9. Net GHG emissions (kg CO2,eq/ MJ_{FTL}) for each configuration under CHP and condensing modes, broken down by emissions sources: heat, CCS, CO₂ transport, electricity, and biomass harvest and transport. Red diamonds represent net emissions, and horizontal lines show the diesel reference (dashed black), 65 % reduction (requirement for renewable fuels of biological origin, dashed red), and 70 % reduction (requirement for RFNBOs, solid blue).

the present findings show that when integrating CCS, PBtL has the potential to outperform fully biomass-dependent configurations, offering a more flexible solution under dynamic market conditions.

4.4. Greenhouse gas emission performance

Fig. 9 compares the GHG emissions of each configuration against a fossil fuel reference (diesel), demonstrating significant emission reductions across most pathways. In contrast, the PEM-assisted configurations without CCS ($PBtL_{max}$, PtL) show higher emissions, primarily driven by their reliance on electricity, which emerges as the largest GHG source across all pathways. By comparison, the steam cycle integration has a minimal effect on overall emissions, given the relatively low internal electricity production and modest heat replacement gains.

When measured against the fossil reference, all bio-based pathways (Base Case, BtL-CCS, PBtL-CCS, PBtL_{max}) meet the 65 % GHG reduction threshold set by the Renewable Energy Directive [3] for fuels of biological origin. The emissions reported for the Base Case and PBtLmax align with the values reported for BtL and PBtL in [27], meeting the 65 % reduction target. However, the fully electrified PtL configuration clearly falls short of the 70 % reduction requirement set for RFNBOs, even when considering Nordic emission factors, which are comparatively low due to the relatively high penetration of renewable energy sources. Notably, satisfying the formal RFNBO criteria involves more than just surpassing the 70 % GHG reduction threshold. Under the revised RED and its delegated acts [3], producers must also ensure that the electricity used for H₂ generation is demonstrably renewable. This can mean either direct coupling to a newly built renewable installation (e.g., a dedicated wind or solar farm) that adds fresh renewable capacity to the system, or meeting stringent additionality and temporal correlation rules via power purchase agreements. In practice, if the regional grid mix is not already dominated (>90 %) by renewables, producers must show that their electricity consumption coincides with newly contracted renewable generation, to ensure additionality rather than relying on existing renewable production.

Failure to meet these criteria generally means that the H_2 , and thus the resulting fuel, will not qualify as RFNBO. Given that RFNBO subquotas apply in multiple sectors (e.g., aviation and shipping), noncompliance can severely limit market uptake and financing opportunities.

As illustrated in Fig. 10, which explores country- or region-specific electricity mixes, highly electrified pathways depend heavily on a low-carbon power supply to achieve significant net emission reductions. Even in higher-emission contexts, such as Germany or the average EU mix, where emissions are roughly double those of the Nordic average, the Base Case and CCS-integrated configurations still easily surpass the 65 % reduction target. By contrast, PBtL_{max} and especially PtL fail to meet the targets. Indeed, PtL can approach or even exceed the fossil reference at the highest-emitting considered grids (Germany and EU average).

In practical terms, the results indicate that a high share of biomass relative to electricity input, or integrating CCS, leads to consistently low emissions irrespective of grid emission intensity, thus offering a degree of robustness. Conversely, fully electrified configurations (PtL) must either be located in (or be directly connected to) regions offering nearzero-emission electricity, or secure compliant power purchase agreements, to fulfill legislative standards for RFNBOs. Failing to secure such low-carbon electricity would disqualify a PBtL fuel from counting toward renewable or low-carbon fuel mandates, undermining its economic and policy rationale. While this study's analysis focuses primarily on overall GHG impacts, real-world deployment will depend on whether producers can fulfill the RFNBO requirements, reflecting the growing importance of matching electricity supply and demand, demonstrating additionality, and maintaining strong policy incentives.

4.5. Study limitations

This study relies on steady-state Aspen HYSYS simulations, with some units—such as gasification, gas cleaning, and reforming—modeled using equilibrium or stoichiometric assumptions. The modeling of the FT synthesis is included but remains generalized from literature. These choices reflect the early-stage nature of the assessment.

All cost estimates presented in this study are subject to notable uncertainty, particularly at a conceptual design level. As highlighted by, e. g., Towler and Sinnott [58], scaling-based capital estimates can carry margins of error of ± 30 % or more, reflecting uncertainties in both



Fig. 10. Comparison of net GHG emissions for each pathway across different country- or region-specific electricity grids (2023 averages for the mentioned countries. Horizontal lines represent the diesel reference (dashed black), 65 % reduction (requirement for renewable fuels of biological origin, dashed red), and 70 % reduction (requirement for RFNBOs, solid blue), respectively.

equipment pricing and site-specific factors. In addition, some equipment costs—such as for the FT reactor—are based on older, yet commonly used, sources due to limited availability of updated vendor data. While still widely referenced in early-stage TEAs, the age of these data introduces further uncertainty. Similarly, the typical assumption that fixed O&M costs amount to about 3 % of total installed costs can vary significantly between first-of-a-kind (FOAK) plants and more mature nth-of-a-kind (NOAK) ones. This variability arises from, e.g., differences in operational experience, maintenance intervals, and technology learning curves. Although our sensitivity analysis addresses electricity and biomass price variations, it does not explicitly cover uncertainties in O&M expenses or capital costs. Future studies might incorporate stochastic or probabilistic methods to capture these and other uncertainties more comprehensively.

5. Conclusions

This study examined how varying degrees of electrification and carbon capture and storage (CCS) integration affect the technoeconomic and environmental performance of Fischer-Tropsch liquid (FTL) production from biomass. Comparing configurations ranging from low electrification (Base Case, BtL-CCS) to partial (PBtL-CCS, PBtL_{max}) and full electrification (PtL) highlights the trade-offs and opportunities in achieving high carbon and energy efficiency while balancing capital investment, operating costs, and greenhouse gas (GHG) emissions under evolving market and policy conditions. Key findings include:

- Partial vs. full electrification: Partially electrified configurations (PBtL-CCS, PBtL_{max}) strike a beneficial compromise between carbon efficiency and economic feasibility. By leveraging both biomass and electricity, they reduce vulnerability to market fluctuations for either energy source, making them more resilient in volatile energy markets. Fully electrified configurations (PtL) offer maximum carbon efficiency, but depend heavily on low-cost low-carbon electricity and large PEM electrolyzers, making them economically vulnerable to electricity price volatility and high capital expenditure.
- **Biomass-dependency**: Configurations with high biomass usage (Base Case, BtL-CCS) remain cost-competitive when biomass prices are low, but with sharply declining economic performance if biomass prices rise. Their economic viability thus depends on stable and affordable feedstock supply.
- Role of CCS: CCS-enabled configurations (BtL-CCS, PBtL-CCS) achieve negative GHG emissions, emphasizing the potential of coupling biomass with CO₂ capture to deliver negative emissions. Adoption of CCS, however, requires a supportive carbon pricing framework that rewards negative emissions and offsets the added costs of CCS.
- Impact of electricity-related GHG emissions: Electricity emerges as the dominant source of GHGs in highly electrified configurations, underscoring the importance of a low-carbon or renewable electricity grid. Regions with high-share renewable grids maximize the emission reduction benefits of electrification, whereas grids with higher carbon intensities may prevent these pathways from meeting strict sustainability mandates, such as the Renewable Fuels of Non-Biological Origin (RFNBO) requirements within the EU.
- Adaptability and cost trade-offs: Partial electrification can enhance operational flexibility and reduce sensitivity to market volatility by leveraging biomass when electricity prices are high and electricity when biomass prices rise. Conversely, fully electrified PtL eliminates dependence on biomass supply chains but requires access to stable, large-scale renewable electricity infrastructure. District heating can offer an additional revenue stream but typically exerts a modest influence on overall profitability.
- Policy and market stability: Supportive carbon pricing, incentivizing renewable power, and stable biomass and electricity markets are critical for reducing uncertainties and encouraging long-term investment in these advanced biofuel production technologies.

Similarly, CCS adoption depends on sufficient carbon revenues to offset extra capital and operational expenditures.

Industrial stakeholders should focus on partially electrified configurations like PBtL-CCS and PBtL_{max}, as they can capitalize on the flexibility of those pathways when electricity or biomass prices fluctuate. Although fully electrified PtL may be an attractive long-term option given its high carbon efficiency and biomass independence, its economic viability relies on abundant, low-cost renewable electricity. In regions with predominantly non-renewable electricity grids, integrating CCS becomes essential to achieve substantial GHG reductions, but is contingent on favorable carbon pricing.

Future research should explore the performance of these configurations under uncertain market conditions, by adopting stochastic or probabilistic methods to capture the variability and interdependence of key factors, such as electricity and biomass prices, carbon credits, and policy shifts. Such analysis would provide valuable insights into the resilience of each configuration under real-world variability, guiding strategic decisions accounting for both economic feasibility and sustainable technology development. These directions aim to refine the role of advanced biofuel technologies in decarbonizing the energy sector and achieving long-term sustainability goals.

CRediT authorship contribution statement

Mahsa Mehrara: Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. Sennai Mesfun: Validation, Supervision, Software, Methodology. Johan Ahlström: Data curation, Conceptualization. Andrea Toffolo: Writing – review & editing, Supervision, Methodology, Formal analysis. Elisabeth Wetterlund: Writing – review & editing, Supervision, Resources, Funding acquisition.

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

During the preparation of this manuscript, the authors utilized the tool ChatGPT-40 to receive suggestions aimed at improving the readability and language of parts of the text. After using the tool, the authors thoroughly reviewed and edited the content as necessary and take full responsibility for the final content of the article.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Mahsa Mehrara reports financial support was provided by Swedish Energy Agency. Mahsa Mehrara reports financial support was provided by Bio4Energy. 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.apenergy.2025.126083.

Data availability

Data will be made available on request.

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