Energy Policy 218 (2026) 115529

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Decarbonization potential and limits of e-fuel policies in the EU

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ARTICLE INFO

Keywords:
Hydrogen
Synthetic fuels
Carbon capture and utilization
Electrification
Energy System Model
Policy assessment
European Union

ABSTRACT

E-fuels (i.e., hydrogen synfuels derived from electrolysis and carbon capture) are increasingly viewed as strategic enablers to the European Union's (EU) energy transition, offering potential decarbonization pathways for hard-to-abate sectors. However, their representation in Integrated Assessment Models (IAMs) remain limited, and the implications of their deployment are insufficiently assessed. This study extends the energy module of the IAM WILIAM by incorporating e-fuels and associated carbon capture to evaluate their energy and environmental implications within the EU. We assess EU policy-aligned scenarios for large-scale e-fuel deployment using the WILIAM energy module. These scenarios are based on a Green Growth (GG) pathway close to 100% fossil-free electricity by 2050, with e-fuel variants reaching 5-15% of final energy demand. Results indicate that e-fuel deployment imposes significant additional electrification (+49% relative to GG without e-fuels), along with substantial infrastructure requirements (+0.7 TW of electricity generation capacity and 0.7 TW of electrolysis capacity). In the most ambitious scenarios, limited industrial CO_2 may necessitate alternative CO_2 sources such as direct air capture. Reductions in primary energy consumption and greenhouse gas (GHG) emissions are not meaningful relative to GG without e-fuels, owing to cumulative inefficiencies across the energy transformation chain as well as indirect effects such as increased electrification, depleted renewable potentials, and curtailment. Integrating fully-fledged GG across the full model would amplify these trends through higher electrification and constraints from land and materials modules. Hence, these results highlight the need for coordinated strategies (including sustainability criteria, system-level planning, and demand-management) to achieve real emission cuts.

1. Introduction

Hydrogen (H_2) is considered a key element of the energy transition since it offers a potential decarbonization solution for hard-to-abate industries and sectors (Davis et al., 2018; European Commission, 2020; Groppi et al., 2025; Ministerio para la Transición Ecológica y el Reto Demográfico, 2020). Particularly, H_2-based synthetic fuels,[1] (also known as H_2 synfuels), present a like-for-like alternative to replace their fossil-based counterparts (Johnson et al., 2025). These synfuels have the advantage of leveraging existing infrastructure for transport, storage, distribution, and usage of fossil gases and liquids, thereby facilitating fast and large-scale adoption (IEA, 2019). Furthermore, the adoption of H_2 synfuels as substitutes for fossil fuels could diversify energy sources, reducing dependence on conventional fuels and increasing energy security (Ruth and Stephanopoulos, 2023). Among the most prominent H_2 synfuels are synthetic methane (gaseous) and synthetic methanol

This article is part of a special issue entitled: Policies for Hydrogen published in Energy Policy.

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[1] Synthetic fuels are fuels produced via chemical reactions connecting reducing equivalents (such as hydrogen) with a carrier molecule such as CO_2 or nitrogen (Ruth and Stephanopoulos, 2023). When these synthetic fuels are derived from electrolytic hydrogen (i.e., hydrogen produced via electrolysis), they are commonly referred to as electro-fuels or e-fuels, with specific variants designated according to their composition: e-methane, e-methanol, etc. Note that the terms "synthetic fuels" or "e-fuels" do not, per se, imply a renewable origin. In regulatory contexts, renewable fuels of non-biological origin (RFNBOs), as defined in the Renewable Energy Directive (RED) III (European Parliament, 2023a), refer specifically to liquid and gaseous fuels whose energy content is derived from renewable sources other than biomass.

https://doi.org/10.1016/j.enpol.2026.115529
Received 15 September 2025; Received in revised form 25 July 2026; Accepted 26 July 2026
Available online 5 August 2026

(liquid). Synthetic methane, produced through the methanation of hydrogen and carbon dioxide (CO_2) (Safari and Dincer, 2018), can be injected into existing natural gas grids and used with current end-use technologies without requiring infrastructure modifications (Nemmour et al., 2023). Synthetic methanol, obtained via the synthesis of hydrogen and CO_2 (Bellotti et al., 2017), is also regarded as a synfuel with significant potential for transport (either as a blend, in its pure form, or by yielding suitable follow-up products) (Schorn et al., 2021), and represents a promising alternative fuel for ship engines (Rao et al., 2025). It can be utilized in transportation, industrial boilers, cooking, wastewater treatment, and as H_2 carrier for fuel cells (Nemmour et al., 2023).

At the European Union (EU) level, policy frameworks increasingly promote H_2 synfuels, especially those derived from electrolytic hydrogen (i.e., e-fuels) produced using low-carbon energy sources, to meet climate targets (see Table 1). Scenario-based studies, such as (Rodrigues et al., 2022), estimate up to 2.7 EJ of e-gas (i.e., gaseous e-fuel) and 2.5 EJ of e-liquids (i.e., liquid e-fuel) by 2050. Joint Research Centre (JRC) analyses, such as (Tsiropoulos et al., 2020), provide quantitative scenario comparisons, although e-fuel and hydrogen demands are not differentiated. (Tarvydas, 2022), also within the JRC analyses, reviews several scenario studies and identifies e-fuel demand levels of up to 2.2 EJ by 2050. Overall, current EU policy reflects a consistent view: a limited but strategic e-fuel role by 2030, moderate growth by 2040, and a pivotal role in achieving full decarbonization by 2050. By then, hydrogen use is expected to be largely driven by e-fuel production (European Commission, 2024a).

However, despite the growing interest on hydrogen and H_2 synfuels, their large-scale feasibility remains uncertain due to technological immaturity (e.g., electrolysis scale-up) (Hydrogen Technology World Expo, 2026; Muñoz et al., 2025) and the specific physical-chemical characteristics of hydrogen, which lead to low end-to-end efficiencies (Ahad et al., 2023; Davis et al., 2018; Johnson et al., 2025; Younas et al., 2022). High costs (mainly from electrolysis) (Johnson et al., 2025; IEA, 2023; Davis et al., 2018) further limit competitiveness relative to fossil fuels, even under policy instruments such as the Carbon Border Adjustment Mechanism (European Commission, 2021b). H_2 synfuels introduce additional challenges due to extra conversion steps and carbon sourcing from point sources or direct air capture (DAC) (De Kleijne et al., 2022), which increases energy requirements. These barriers underscore the complexity of scaling H_2 synfuels production and the need for comprehensive quantitative analysis in the broader energy transition. For this purpose, Integrated Assessment Models (IAMs) and Energy System Models (ESMs) are valuable tools. ESMs are particularly useful for guiding the design, planning, and application of future energy systems (Lund et al., 2017), while IAMs integrate a broad set of technological, economic, environmental, and social variables to support the search for solutions to the ongoing energy and environmental crises (De Blas et al., 2021; Intergovernmental Panel on Climate Change, 2023).

Table 1
Overview of EU policy frameworks and their objectives for H_2 synfuels.

Strategy/Policy framework	Objectives regarding H_2 synfuels
A Clean Planet for all (European Commission, 2018)	Projects around 3 EJ of e-fuel demand (produced with carbon-free electricity) by 2050, with 1.6 EJ corresponding to gaseous e-fuel, in 1.5°C-compatible scenarios.
EU hydrogen strategy (European Commission, 2020)	Reinforce hydrogen deployment (40 GW of electrolyzers and 10 million tons (Mt) of renewable hydrogen production by 2030) and highlights the role of synthetic low-carbon fuels in transport.
Fit for 55 (FF55) (European Commission, 2021a)	Anticipates 20 Mt of renewable hydrogen use by 2030, including 1.8 Mt for e-fuel production.
REPowerEU (European Commission, 2022a, 2022b)	Accelerates renewable hydrogen deployment to cut fossil fuel reliance, maintaining alignment with FF55 regarding e-fuels, with around 1.8 Mt hydrogen for their production in 2030.
ReFuelEU Aviation (European Parliament, 2023b)	Sets a minimum share of synthetic aviation fuels within the broader sustainable aviation fuel target, reaching 35% by 2050.
FuelEU Maritime (European Parliament, 2023c)	Promotes renewable and low-carbon fuels but does not set a specific quota for e-fuels, though their use is implied.
Climate target plan (CTP) 2040 (European Commission, 2024b)	Projects RFNBO consumption between 1.26 and 2.72 EJ by 2040, of which e-fuels account for around 0.63-1.55 EJ.

While current literature offers valuable insights into the EU's long-term decarbonization pathways, particularly for H_2-based fuels, it's however limited by key knowledge gaps. (Pickering et al., 2022) use a high-resolution optimization ESM to examine fully renewable scenarios and identify strategic regions for synthetic fuel production in the EU. However, their focus on DAC as the sole CO_2 source overlooks other carbon capture and utilization (CCU) options, such as industrial emissions. (Béres et al., 2024) soft-link the JRC-EU-TIMES (long-term) and PLEXOS (hourly) models to assess electrification needs, projecting a 2-3x increase in electricity demand by 2050. Yet, the lack of dynamic feedback between models may overlook important interactions, potentially causing them to misrepresent the viable energy system configurations. (Seck et al., 2022) integrate three complementary models (a detailed EU optimization model, an integrated model with endogenous technological learning, and a hydrogen import model) to evaluate the role of hydrogen and e-fuels in achieving EU climate goals. Their findings emphasize the need for coordinated development of hydrogen supply and demand, including CCU infrastructure. Nonetheless, their approach assumes exogenous energy demand and does not capture behavioral changes in the transport sector, which may influence the representation of demand-side policy assessments (Álvarez-Antelo et al., 2024). Bellocchi et al. (2023) focuses on the techno-economic optimization of green hydrogen pathways for the Italian energy system. The study provides valuable insights into interdependencies among key indicators (renewable energy sources capacity, system costs, primary energy mix) and annual CO_2 trends, but does not capture the dynamic transition to 2050, potentially missing non-linear effects and unforeseen system behaviors (cf. (Campos-Rodríguez et al., 2025)). On a broader modeling level, Liu et al. (2025) emphasize that H_2 synfuels are largely underrepresented in IAMs. While some regional models include H_2 synfuels, their scenario variation is limited, which may constrain their perceived role in decarbonization pathways. Recent reviews underscore additional gaps: Blanco et al. (2022) find that, within ESMs and IAMs, hydrogen is predominantly represented through electrolysis and mobility applications, with limited attention to alternative options such as hydrogen derivatives. In the specific context of e-fuels, only 17 of 500 studies reviewed by Galimova et al. (2022) include e-methanol, and over half exclude hydrocarbon-based e-fuels. According to the authors, few detailed global ESMs and IAMs represent e-fuels beyond hydrogen, indicating early-stage modeling capabilities; IAMs could benefit from methodological advances to better integrate e-fuels and e-chemicals into long-term scenarios (Galimova et al., 2022). Moreover, the overall CO_2 capture potential for synthetic fuel production across the entire energy system also remains unclear (Oshiro and Fujimori, 2022). Current CCU modeling for e-fuel production mainly focuses on DAC, often overlooking other relevant CO_2 sources like emissions from cement and pulp and paper industries. Only 1% of 550 studies reviewed by (Galimova et al., 2022) consider industrial CO_2 capture, despite these being hard-to-abate sectors, underscoring the need to include them in CCU assessments. Additionally, Ghaboulian Zare et al. (2025) highlight limited reproducibility due to insufficient transparency in model inputs and assumptions. Similarly, Quarton et al. (2020) call for global energy scenario studies to provide full disclosure of modeling methods and underlying data assumptions, while openly acknowledging model limitations.

This paper aims to fill the identified knowledge gaps through the following innovative contributions:

1) Integration of H_2 synfuels, both gaseous (e-methane) and liquids (e-methanol), into the System Dynamics (SD), multi-regional, and open source IAM WILIAM (Lifi et al., 2023; Samsó et al., 2023; Products derived from LOCOMOTION h2020, 2025). This integration, additionally, explicitly accounts for diverse CO_2 sources for synfuels production, such as DAC, industrial processes, coke, and refining, while evaluating the technical CO_2 capture potential from the latter three sources.
2) System-level assessment of the energy and environmental impacts associated with the adoption of H_2 synfuels, including fossil fuel dependence, primary energy (PE) consumption, electrification effects, infrastructure requirements (electrolyzers, electricity generation capacity by technology, etc.), greenhouse gas (GHG) emissions, availability of industrial CO_2 , and water requirements.
3) Exploration of multiple deployment scenarios, analysing three distinct levels of H_2 synfuel penetration characterized with varying speeds and target shares, grounded in a critical review of the existing policies and strategies related to H_2 synfuels.

Although the model is general and implemented for the nine global regions of the WILIAM energy module, in pursuit of actionable insights, the analysis presented in this paper focuses on current policies on H_2 synfuels in the EU. Hence a main objective of this research is to simulate the internal dynamics within the energy module driven by varying levels of EU policy-aligned H_2 synfuel deployment. The EU constitutes a particularly relevant case study for assessing the role of H_2 synfuels in the energy transition, given its ambitious decarbonization objectives and strategic interest in promoting a hydrogen economy (European Commission, 2019, 2020).

Next Section 2 outlines the methodology; the scenarios simulated are covered in Section 3; the results obtained are presented and discussed in Section 4; and Section 5 offers the conclusion.

2. Methodology

For this study, the multi-regional SD IAM WILIAM v1.4 (Lifi et al., 2023; Samsó et al., 2023; Products derived from LOCOMOTION h2020, 2025) was employed. In line with the scope of the research, the analysis focuses on the WILIAM's bottom-up energy module, which can be regarded as an ESM within a broader IAM framework. In this work, the module has been extended with new submodules on H_2 synfuels and CCU for H_2 synfuels (these extensions are integrated into the public release of WILIAM v1.4). The links with the rest of the IAM are beyond the scope of this work, although current and future capabilities of the model are covered in the discussion section.

A concise overview of the WILIAM model, with a particular focus on the energy module, is presented in S1 of the Supplementary material. For a comprehensive description, please refer to the project deliverables (Lifi et al., 2023; Samsó et al., 2023) and the model's wiki (Products derived from LOCOMOTION h2020, 2025). Additionally, a concise validation assessment of the energy module is provided in S2 of the Supplementary material. For full details on the validation of the energy module cf. (De Blas et al., 2026, In Preparation).

2.1. H_2 synfuels submodule

To model H_2 synfuels within the WILIAM model, a dedicated submodule has been developed and integrated into the energy module. Fig. 1 illustrates the interaction between components related to hydrogen and H_2 synfuels, as well as their interconnections with final energy (FE), PE, electricity generation, and CCU.

The general operation of this submodule begins with the estimation of the demand for H_2 synfuels, both gaseous (e-methane) and liquids (e-methanol).[2] This demand is derived from substitution policies applied at the level of FE demand in end-uses. Specifically, these policies specify the share of total gaseous and liquid fuel demand that is to be replaced by H_2 synfuels (see Equation (1)). Since H_2 synfuels are functionally equivalent to their fossil counterparts and can be used within existing infrastructure with minimal modification, demand-side substitution components do not require explicit modeling.

$$E_{i,t}^{syn} = s_{i,t} \cdot FE_{i,t}^{total} \tag{1}$$

Where: t denotes the time over the simulation period (2015-2050); i refers to the type of H_2 synfuel (gas for e-methane, liquid for e-methanol); $E_{i,t}^{syn}$ represents the annual demand for H_2 synfuel i (EJ/year); $s_{i,t}$ is the policy-determined substitution share for fuel type i (dimensionless (dmnl)); and $FE_{i,t}^{total}$ is the total FE demand for fuel type i (EJ/year) (corresponding to the total FE demand for gaseous and liquid fuels in the economy). Note: $s_{i,t}$ is an exogenous policy parameter, while $FE_{i,t}^{total}$ is endogenously determined by the end-use submodule, making $E_{i,t}^{syn}$ a function of both policy-driven and endogenous variables.

Meeting H_2 synfuels demand requires corresponding production technologies, which include both synfuel production technologies ($H_2 \rightarrow$ H_2-liquid synfuel and $H_2 \rightarrow$ H_2-gas synfuel) and hydrogen production technologies (specifically electrolysis).

Based on the estimated annual demand for H_2 synfuel, $E_{i,t}^{syn}$, the submodule calculates the required amount of pure hydrogen, $E_t^{H_2}$ (EJ/year), considering the conversion efficiencies of methanation (Sabatier reaction) and methanol synthesis (low-pressure process), denoted by η_i^{syn} (dmnl, lower heating value (LHV) basis) (see Equation (2)). This hydrogen requirement, in turn, determines the electricity demand for electrolysis, E_t^{elec} (EJ/year), considering the efficiency of electrolyzers, η_t^{elz} (dmnl, LHV basis) (see Equation (3)). In addition, water requirements for electrolysis, $V_t^{H_2O\ elz}$ (Mm^3/year), are estimated using a water intensity factor, $H_2O\ elz\ Int$ (m^3/ton H_2) (see Equation (4), with LHV_{H_2} equal to 119.9 MJ/kg). The model also computes the CO_2 requirements for synfuels, $CO_2{}_t^{req\ syn}$ (Mt CO_2/year), based on the amount of CO_2 needed per MJ of synfuel produced, $CO_2\ Int_{i,t}^{req\ syn}$ (kg CO_2/kg synfuel) (see Equation (5), with LHV_{gas} and LHV_{liquid} equal to 50 and 18.1 MJ/kg, respectively); CO_2 sourcing, along with associated energy and environmental implications, is analysed in Section 2.2. All efficiencies and intensities are fixed model parameters, except for the efficiency of electrolyzers, whose future value can be set exogenously as part of scenario assumptions to reflect technological developments. The complete parametrization of the aforementioned parameters, together with their corresponding units and data sources, is provided in Table 2.

$$E_t^{H_2} = E_{gas,t}^{syn} \Big/ \eta_{gas}^{syn} + E_{liquid,t}^{syn} \Big/ \eta_{liquid}^{syn} \tag{2}$$

$$E_t^{elec} = E_t^{H_2} / \eta_t^{elz} \tag{3}$$

$$V_t^{H_2O} = H_2O\ elz\ Int \cdot E_t^{H_2} / LHV_{H_2} \tag{4}$$

$$CO_2{}_t^{req\ syn} = CO_2\ Int_{gas}^{req\ syn} \cdot E_{gas,t}^{syn} \Big/ LHV_{gas} + CO_2\ Int_{liquid}^{req\ syn} \cdot E_{liquid,t}^{syn} \Big/ LHV_{liquid} \tag{5}$$

[2] E-methanol is used in this study as a representative liquid H_2 synfuel pathway, as it captures the common upstream power-to-liquid chain shared by liquid H_2 synfuel pathways (i.e., electrolysis and CCU) (Dieterich et al., 2020), and can serve as an intermediate for hydrocarbon target products or be used either as a blend or in its pure form (Schmidt et al., 2018; Schorn et al., 2021). This proxy-based representation enables the model to assess the key system-level implications of liquid H_2 synfuel deployment.

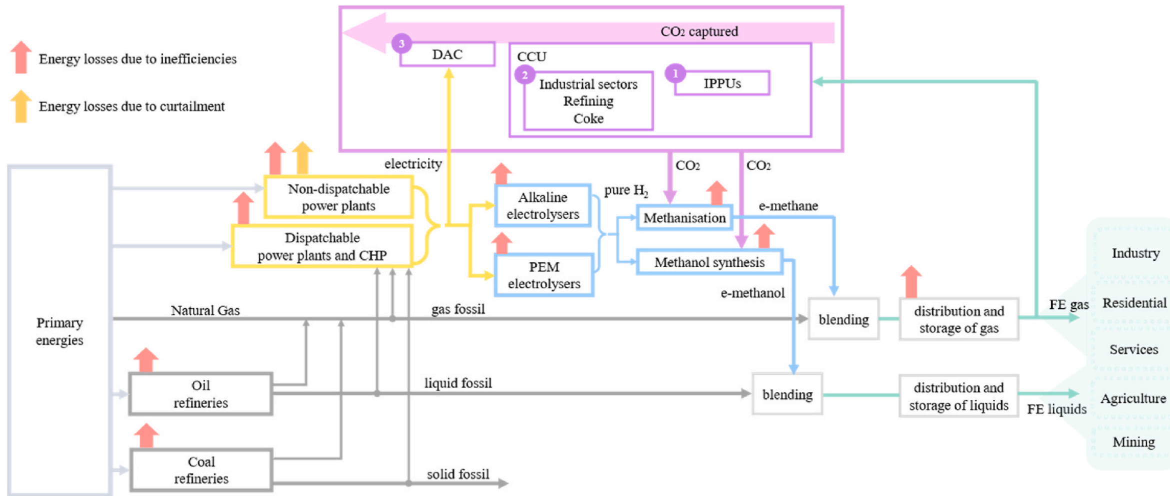

Fig. 1. Schematic representation of hydrogen and H_2 synfuel production interactions with other components of the WILIAM model (components not directly affected by H_2 synfuels are omitted). Note: the arrows in the figure represent the physical flow of energy. Regarding the flow of information in the model, this would be the other way round (from FE demand to PE supply). FE and PE definitions used in WILIAM are provided in S1 of the Supplementary material.

Table 2
Main parameters used in the H_2 synfuels submodule, including symbols, units, values, and sources. For parameters with multiple sources, the adopted value was determined by calculating the mean of the values reported across these sources. Note: H_2 gas (liquid) fuel refers specifically to e-methane (e-methanol) in this study. [a] Refers to stationary electrolyzers, which operate at this value in the model; reduced endogenously only when existing capacity would otherwise overproduce hydrogen under declining demand conditions.

Parameter	Unit	Value	Sources
Efficiency $H_2 \rightarrow H_2$ gas fuel (η_{gas}^{syn})	% LHV	78.8	(Hoppe et al., 2018; Mehrjerdi, 2019; Meylan et al., 2016; Safari and Dincer, 2018)
Efficiency $H_2 \rightarrow H_2$ liquid fuel (η_{liquid}^{syn})	% LHV	85	(Battaglia et al., 2021; Bellotti et al., 2017; Herdem et al., 2020; Kiss et al., 2016; Rihko-Struckmann et al., 2010)
Efficiency of electrolyzers (η_t^{elz}) (at initial time t_0)	% LHV	Alkaline: 58 PEM: 57	Campos-Rodríguez et al. (2025)
Water req. for electrolysis ($H_2O\ elz\ Int$)	m^3/ton H_2	9	Campos-Rodríguez et al. (2025)
CO_2 req. for gaseous synfuels ($CO_2\ Int_{gas}^{req\ syn}$)	kg CO_2/kg synfuel	2.75	Mehrjerdi (2019)
CO_2 req. for liquid synfuels ($CO_2\ Int_{liquid}^{req\ syn}$)	kg CO_2/kg synfuel	1.42	Bellotti et al. (2017)
Capacity factor of electrolyzers (CF^{elz})	dmnl	0.68[a]	Hydrogen Europe (2023)
Lifetime of electrolyzers (L_t^{elz}) (at initial time t_0)	years	Alkaline: 9.4 PEM: 7.8	(Buttler and Spliethoff, 2018; David et al., 2019; FCH JU, 2014; IEA [International Energy Agency], 2019; Schmidt et al., 2017)

Regarding the modeling of infrastructure, the submodule endogenously tracks the evolution of installed capacity for hydrogen production technologies over time. For electrolyzers,[3] the required installed capacity, P_t^{elz} (TW), is linked to the required amount of pure hydrogen through the capacity factor, CF^{elz} (dmnl; fixed model parameter; see Table 2 for parametrization), as detailed in Equation (6). The model accounts for both capacity expansion, $\dot{P}_{exp\ t}^{elz}$ (TW/year), and decommissioning flows, $\dot{P}_{decom\ t}^{elz}$ (TW/year), as expressed in Equation (7). Capacity decommissioning follows the approach described in Equation (8): a progressive decommissioning proportional to the inverse of the lifetime, L_t^{elz} (years; see Table 2), which can also be set exogenously to reflect technological developments. Capacity expansion is calculated using one of two approaches: (i) exogenous (supply-driven), where policy targets specify how much capacity to install each year, and (ii) endogenous (demand-driven), where sufficient capacity is installed each year to meet pure hydrogen demand. This study adopts the endogenous, demand-driven approach, with capacity expansion determined according to Equation (9). Note that Equations (6)–(9) represent a feedback loop, whose numerical resolution can be carried out through appropriate simulation software (in this case, the Vensim DSS software). Finally, the submodule computes total electrolyzer capacity investment costs (M\$/year) over time based on unitary capacity investment costs (M\$/MW) for these technologies (cf. S3 of the Supplementary material for details).

$$E_t^{H_2} = P_t^{elz} \cdot CF^{elz} \cdot 8760\ h/year \cdot \eta_t^{elz} \tag{6}$$

$$P_t^{elz} = \int_{t_0}^{t} \left(\dot{P}_{exp\ t}^{elz} - \dot{P}_{decom\ t}^{elz} \right) dt \tag{7}$$

$$\dot{P}_{decom\ t}^{elz} = P_t^{elz} / L_t^{elz} \tag{8}$$

$$\dot{P}_{exp\ t}^{elz} = \begin{cases} 0, \ if\ E_t^{H_2} \leq E_{t-dt}^{H_2} \\ \dfrac{dE_t^{H_2}}{dt} \cdot \dfrac{1}{\eta_t^{elz} \cdot CF^{elz} \cdot 8760\ h/year}, \ if\ E_t^{H_2} > E_{t-dt}^{H_2} \end{cases} \tag{9}$$

Following the previous calculations, the submodule is integrated into the WILIAM energy module. The electricity demand for electrolysis is placed in the energy transformation chain at the level of transformation output (TO) (in terms of the accounting framework of the WILIAM energy module), with a positive sign to increase the necessary quantity of electricity to be generated in each of the nine regions. Conversely, H_2 synfuels (gaseous and liquid) are also placed at the level of TO, but with a negative sign, to subtract the necessary quantity of gases and liquids to be produced (in each of the nine regions). It is important to note that the total FE demand for gaseous and liquids fuels is not directly affected by

[3] Electrolyzers are categorized into stationary units, which are used to satisfy FE demand, and flexible units, which are used for flexibility purposes (cf. (Parrado-Hernando et al., 2024)).

the H_2 synfuels submodule; what varies is the production pathway of these carriers, which can be either conventional (e.g., oil refining) or electrolysis-based (i.e., indirect electrification).

Beyond the direct accounting adjustments introduced by the H_2 synfuels submodule within the WILIAM energy module, its integration also triggers a set of indirect systemic effects driven by the internal dynamics of the model. These include changes in infrastructure requirements (e.g., electricity generation capacities), PE consumption, GHG emissions, etc. Such effects might be constrained by structural limits embedded in the model, such as renewable energy source (RES) potentials, variable RES (VRES) curtailment, etc. Moreover, these interactions are shaped by the cross-cutting assumptions underpinning scenario design within the energy module (e.g., electrification of FE, prioritization of a fossil-free electricity system, etc.). The same reasoning applies to the CCU for H_2 synfuels submodule (cf. Section 2.2), whose integration into the WILIAM model likewise induces both direct accounting effects and indirect systemic responses.

2.2. CCU for H_2 synfuels submodule

A dedicated submodule has been developed and incorporated to the WILIAM energy module to represent CCU processes for H_2 synfuels production. Based on the estimated CO_2 demand, the submodule allocates sources across industrial processes and product uses (IPPUs) (i.e., non-energy uses in non-energy sectors), industrial energy use, energy sector own consumption (coke and refining), and DAC. Emission reductions and energy penalties enable an impact assessment of the CCU-related implications of H_2 synfuel production and are accounted for within both the energy module and the GHG emissions submodule.

The analysis excludes BECCU (bioenergy with CCU) because of its techno-economic constraints (e.g., relatively high cost when compared to fossil fuels) (Emenike et al., 2020), and it is further excluded from the industrial sector since bioenergy use is currently limited and its deployment could exacerbate pressures on land use, biomass availability, biodiversity, and other non-energy factors that fall outside this energy-focused study's scope (Jones and Albanito, 2020). Likewise, power plants as CO_2 sources for CCU are not considered due to the high share of fossil-free electricity envisaged by 2050 under EU climate neutrality objectives (almost 100%), within which H_2 synfuel deployment is anticipated. Moreover, the CO_2 uses considered in this work are restricted to the CO_2 demand for H_2 synfuels production, with other potential uses (e.g., CO_2 storage) left out of the scope of this paper.

2.2.1. Industrial CO_2 potential for CCU

CO_2 capture potential for each sector s, $Potential_{CC_{s,t}}$ (Mt CO_2/year), is endogenously estimated within the submodule from the annual emissions of each sector, $CO_{2s,t}$ (Mt CO_2/year), combined with the sector-specific capture viability factor, p_{CC_s} (dmnl), representing the relative carbon capture potential, and the capture effectiveness, η_{CC_s} (dmnl), as expressed in Equation (10).

$$Potential_{CC_{s,t}} = p_{CC_s} \cdot \eta_{CC_s} \cdot CO_{2s,t} \tag{10}$$

The WILIAM model provides detailed sectoral coverage (including energy, industry, agriculture, services, and mining; cf. Section 5.3 of the economy module from (Products derived from LOCOMOTION h2020, 2025)) with emissions ($CO_{2s,t}$) calculated endogenously by the GHG emissions submodule, enabling the implementation of the aforementioned approach. The methodology used to quantify sectoral capture viability factors p_{CC_s} and capture effectiveness η_{CC_s} (fixed model parameters) is detailed in Appendix B.

2.2.2. Allocation of CO_2 demand between carbon capture technologies

After determining CO_2 demand (cf. Equation (5) in Section 2.1) and sectoral capture potential (cf. Section 2.2.1), a rule-based hierarchical scheme endogenously allocates the CO_2 demand for synfuels. CO_2 demand is first met using the CO_2 capture potential from IPPUs, distributed proportionally by sector's capture potential. Once the CO_2 capture potential from IPPUs is exhausted, CO_2 is allocated proportionally (weighted by each sector's capture potential) from eligible industrial energy uses and from energy sector own consumption. Remaining demand is filled by DAC if all previous CO_2 capture potentials are exhausted.[4] This prioritization represents a structural modeling assumption adopted for this study, motivated by the high concentration and process-inherent nature of IPPUs emissions (difficult to abate through electrification or fuel substitution), which make them comparatively attractive near-term CO_2 sources for utilization. In this sense, IPPUs streams are assumed to constitute primary sources of CO_2 for synfuels production before alternative routes (e.g., DAC) become dominant (European Commission, 2024a; Galimova et al., 2022). Furthermore, the rationale for this allocation is based on the relative technological maturity of the corresponding carbon capture technologies: post-combustion CCU (within IPPUs, industrial energy uses, and energy sector own consumption) is commercially available at scale, whereas DAC remains under development, faces technical uncertainties, presents significant resource demands and environmental trade-offs, and exhibits uncertain long-term development prospects (Eke et al., 2025; Motlaghzadeh et al., 2023; Ozkan et al., 2022; Trompoukis et al., 2025).

All captured CO_2 is recorded in the WILIAM GHG emissions submodule. To avoid double counting (since H_2 synfuel combustion is modeled using the emission factors of their fossil counterparts), sectoral CO_2 emissions are reduced by the captured amount, and energy-related CO_2 emissions are further reduced to include DAC contributions.

2.2.3. Energy penalty of CCU

Each CO_2 capture process incurs an energy penalty reflecting the energy requirements of CCU. Amine-based CO_2 capture is energy-intensive, requiring 2.5-3.5 GJ/t CO_2 reflecting the thermal energy needed for solvent regeneration (Rezaei et al., 2023), reducible by 0.5 GJ/t CO_2 via heat recovery. For modeling purposes, a fixed energy penalty of 3 GJ gas/t CO_2 (equivalent to 0.003 EJ gas/Mt CO_2) is assumed for CCU systems within IPPUs, industrial energy uses, and energy sector own consumption. For DAC, a low-temperature amine-based solid sorbent technology which regenerates at ~100°C, typical of large-scale DAC applications (Hou et al., 2025) is considered. It consumes 200-300 kWh_{el}/t CO_2 (electricity for blowers/compressors) and 1500-2000 kWh_{th}/t CO_2 (thermal energy for regeneration). As in the GCAM model, thermal energy is electrified via heat pumps (Morrow et al., 2023; Motlaghzadeh et al., 2023). Using Carnot efficiency (22°C cold reservoir, 100°C regeneration) to convert thermal energy into electricity, total electricity use is ~3 GJ/t CO_2 (0.003 EJ/Mt CO_2), which is the fixed model parameter assumed in the model. For comparison, GCAM assumes 2.5 GJ/t CO_2 (Motlaghzadeh et al., 2023).

CCU energy requirements, whether from industrial sources, coke, refining or DAC, are reflected in the energy transformation chain. For CCU within IPPUs and industrial energy uses, these requirements increase sectoral FE intensities, whereas for CCU within coke, refining or DAC, they increase sector energy own consumption on top of the values estimated by the transformation submodule (since energy own consumption is estimated through calibrated empirical parameters that reflect existing activities but do not capture additional CCU energy requirements, as CCU has not yet been deployed at scale).

In addition to the above, two indicators related to carbon capture technologies can be derived. The first is the gross CO_2 capture intensity by technology, defined as the amount of CO_2 captured per unit of energy consumed (i.e., the inverse of the energy penalty). This value equals

[4] As a structural model constraint, the model does not allow industry to increase fossil fuel use to obtain additional CO_2, as doing so would render H_2 synfuels unnecessary.

333 Mt CO_2/EJ (gas) for CCU systems within IPPUs, industrial energy uses and energy sector own consumption, and 333 Mt CO_2/EJ (electricity) for DAC. The second indicator is the net CO_2 capture intensity by technology, which is calculated by subtracting the CO_2 emission intensity (Mt CO_2/EJ) associated with the energy used to operate the process from the gross CO_2 capture intensity by technology. This includes direct emissions from gas combustion in CCU systems (within IPPUs, industrial energy uses, and energy sector own consumption) and indirect emissions from electricity consumption in DAC; these intensities are accounted for in the GHG emissions submodule in terms of CO_2 intensity emissions by type of FE (in this case, gas and electricity).

2.2.4. Water consumption and waste products of CCU

Water requirements for CCU are estimated using a water intensity factor. A value of 1.7 m^3/t CO_2 captured (fixed model parameter) is assumed for CCU systems within IPPUs, industrial energy uses, and energy sector own consumption, based on (Young et al., 2019). No water requirements are considered for low-temperature DAC (Fasihi et al., 2019). The model also computes the amount of waste products originated from amine-based CO_2 capture processes, considering a waste quantity generation of 3.2 kg/t CO_2 captured (IEAGHG, 2012) for CCU systems within IPPUs, industrial energy uses, and energy sector own consumption, and an average sorbent loss of 7 kg/t CO_2 captured for DAC (Madhu et al., 2021).

3. Scenarios

This study's results are based on WILIAM model simulations, including a Reference scenario (REF), a Green Growth scenario (GG), and three GG variants with different levels of synfuel deployment, all within EU: GG-H_2syn-5%, GG-H_2syn-5%-fast, and GG-H_2syn-15%. These intend to reflect plausible expansion pathways aligned with current EU policy frameworks, cf. strategies mentioned in Table 1 ,[5] and aim to assess their energy and environmental impacts within the energy transition context.

To ensure transparency and traceability, the Supplementary material includes the configuration scenario parameter files needed to replicate these simulations with WILIAM v1.4, as well as guidance on their use.

3.1. Common hypotheses

All scenarios share the following assumptions:

- The simulation period extends until 2050.[6] Policy implementation begins in 2025 and is applied exclusively to the EU region, while the rest of the regions follow a business-as-usual narrative across all scenarios (i.e., evolving in line with current production and consumption trends).
- The WILIAM energy module (on which this energy-focused study is centred and from which the results presented in Section 4 are derived) is run largely without feedbacks from the rest of the WILIAM model, in line with the main objective of this paper (simulate the internal dynamics within the energy module driven by varying levels of EU policy-aligned H_2 synfuel deployment). In particular, land use (i.e., endogenous bioenergy potentials) and material feedbacks (e.g., uranium availability) have been deactivated. However, some links are kept active such as the one with the economy module to project future FE demand for non-energy sectors through FE intensities. In addition, FE demand of households is estimated using a mixed approach: top-down estimation for buildings (derived from the economy module) and a bottom-up approach for passenger transport (Álvarez-Antelo et al., 2024). Population is calculated exogenously within the demography module, based on historical data of fertility rate and life expectancy at birth. Gross domestic product (GDP) per capita is determined endogenously within the economy module and is parametrized to follow growth trajectories at rates like those of the past, assuming a continuation of present trends (and without feedbacks from eventual biophysical constraints).
- Solar photovoltaic (PV) (open space) potential is determined endogenously through interactions with the land module, cf. (Ferreras-Alonso et al., 2024; Products derived from LOCOMOTION h2020, 2025), and constrained by a certain level of minimum Energy Return on Investment (EROI) of the installations, cf. the method of (Dupont et al., 2020). In this study, a minimum EROI of 5:1 is selected. For hydropower, the potential is set at 1.8 EJ/year, including both dammed and run-of-river installations (value taken from the MEDEAS model (Capellán-Pérez et al., 2017), and regionally distributed based on (Papagianni et al., 2020)). The potential of wind power plants (onshore and offshore) is estimated based on the minimum EROI of the installations, cf. the method of (Dupont et al., 2020). In this study, a minimum EROI of 5:1 is selected, resulting in potentials of 4.0 EJ/year for wind onshore and 3.0 EJ/year for wind offshore (fixed) (Dupont et al., 2018; Papagianni et al., 2020; Products derived from LOCOMOTION h2020, 2025). It is important to note that these values may be lower than standard technical wind potentials, as the method incorporates a top-down limitation on the kinetic energy available in the atmospheric boundary layer, as well as net energy and sustainability-related constraints.
- This work follows the methodology of (Parrado-Hernando et al., 2024) to consider the additional system burden from a high share of VRES, including potential flexibility options to mitigate it, but modeling hydropower dammed as dispatchable (from the perspective of electricity system operation), given the limitations of this approach in adequately capturing hydropower interactions.

3.2. Scenario definition & parametrization

Reference scenario (REF). The REF scenario serves as a baseline for evaluating the impact of the policy measures introduced in the other scenarios. It evolves in line with current production and consumption trends, with no measures to promote FE substitution. Consequently, FE demand follows current trends, and the FE mix changes are negligible, remaining at approximately 20% electricity, 19% gas, and 49% liquid fuels. Capacity expansion and utilization priorities reflect prevailing trends, remaining a 61% fossil-free electricity generation system by 2050. FE demand for gaseous and liquid fuels continues to be largely supplied by fossil fuels, with no adoption of H_2 synfuels. A concise rationale for the baseline scenario trends is provided in S2 of the Supplementary material.

Green Growth scenario (GG). In this study, a Green Growth (GG) scenario is parametrized as a framework to introduce H_2 synfuel policies and assess their impact on low-carbon transition pathways (cf. GG-H_2syn-5%, GG-H_2syn-5%-fast, GG-H_2syn-15%). Based on the dominant institutional transition narrative (Kallis et al., 2025; Wiedmann et al., 2020), the GG scenario typically focuses on supply-side strategies, including large-scale end-use electrification and high RES integration. It reflects policy orientations aligned with the European Green Deal 2050 targets (European Commission, 2019, 2024a, 2024b, 2024c).

The parametrization of the GG scenario involves the implementation of measures across the following areas:

[5] The EU policy frameworks summarized in Table 1 cannot be translated one-to-one into model inputs. Rather, they provide the policy context from which exogenous H_2 synfuel deployment pathways are defined. Quantitative information from these frameworks is extracted, harmonized, and curated to derive the share of total gaseous and liquid fuel demand that is to be replaced by H_2 synfuels, as detailed for each specific case in the parametrization of the GG-H_2syn-5%, GG-H_2syn-5%-fast, and GG-H_2syn-15% scenarios (cf. Section 3.2).

[6] The time step used for all simulations is 0.25 year, and the integration method is Euler's.

- FE electrification: The scenario promotes a shift from fossil fuels to electricity across productive end-use sectors. Additionally, for passenger transport, two measures are implemented: (1) a behavioral shift reducing private car use by ∼20%, with the reduced demand reallocated to buses (60%) and trains (40%); and (2) a technological shift replacing 90% of diesel/gasoline cars with electric vehicles (EVs) by 2050. As a result, the FE mix shifts from 20% electricity, 19% gas, and 49% liquid fuels to 45% electricity, 12% gas, and 32% liquids by 2050, with the remainder from solid fossil fuels, biomass, and heat. A concise rationale for the GG scenario trends is provided in S4 of the Supplementary material.
- Capacity expansion priorities: Highest expansion priority is given to wind power plants (onshore and offshore) and solar PV (urban and open space), in line with the provisions from (European Commission, 2024c), followed by hydropower dammed, power plants operated by solid biomass, and then nuclear. Capacities operated by gas, liquid, and solid fuels are deprioritized. Combined heat and power (CHP) plants are included, especially those operated by solid biomass.[7]
- Capacity utilization priorities: RES capacities receive top dispatch priority, except power plants operated by solid biomass (lower due to environmental concerns). Nuclear has moderate priority, while capacities operated by gas, liquid, and solid fuels are deprioritized. CHP plants operated by solid biomass and waste are given higher dispatch priority than the former. These capacity utilization and expansion priorities promote a transition toward a nearly 100% fossil-free electricity generation system by 2050 when assessed solely in terms of capacity substitution. However, the actual fossil-free share is determined endogenously and may be lower due to operational constraints (e.g., VRES curtailment) and biophysical limits (e.g., RES potentials).
- As in the REF scenario, FE demand for gaseous and liquid fuels continues to be largely supplied by fossil fuels, with no adoption of H_2 synfuels.

This scenario is not intended to mirror a likely or realistic future. Moreover, a fully-fledged GG scenario would require including more policies and hypotheses across the full model, which is beyond the scope of the current work. Rather, the GG scenario used here provides an energy transition context against which the implications of H_2 synfuel deployment can be assessed in the subsequent scenarios. Therefore, the policy implications of this article refer to the role of H_2 synfuels within this context, rather than to the GG pathway itself.

Green Growth with gradual H_2 synfuel deployment (GG-H_2syn-5%). This scenario reflects a policy rationale aligned with current EU policy targets for H_2 synfuels within a GG narrative, where direct FE electrification and the deployment of a fossil-free electricity generation system remain the dominant decarbonization strategies. The policy targets for H_2 synfuels are informed by FF55 for 2030 and by the long-term trajectories reported in the CTP.

Building on the GG scenario, the scenario assesses H_2 synfuel deployment aligned with the FF55 targets through 2030 and extends the FF55 trends to 2050, in accordance with the objectives outlined in the CTP (European Commission, 2024a, 2024b). The parametrization of the scenario entails assigning values to the share of total gaseous and liquid fuel demand to be replaced by H_2 synfuels (variable $s_{i,t}$, cf. Section 2.1 from the Methodology). To this end, the absolute quantities of e-methane and e-methanol demand reported in the CTP impact assessment report (European Commission, 2024a) for 2030, 2040, and 2050 were extracted and curated,[8] and then, these values were divided by the total FE demand for gaseous and liquid fuels from the GG scenario. Values for intermediate years were obtained through linear interpolation, with H_2 synfuel demand assumed to be zero in 2025. Below is an explanation of how the absolute quantities of e-methane and e-methanol were obtained, including the assumptions for data curation, and the resulting shares ($s_{i,t}$):

- The CTP impact assessment report provides aggregated projections for e-gas demand, which in this study is assumed to consist entirely of e-methane. Under this assumption, e-methane demand amounts to 0.2 EJ/year in 2030 and 2040, increasing to 1.7 EJ/year by 2050.[9] These values correspond to shares ($s_{gas,t}$) of 2%, 3%, and 30% of total gaseous FE demand in the GG scenario, respectively.
- The CTP impact assessment report provides aggregated projections for e-liquids, requiring further assumptions for disaggregation by liquid fuel type. According to the report, e-liquids are consumed primarily in the transport sector. In this study, road transport, navigation, and aviation are considered for e-methanol[10]. Under these assumptions, e-methanol demand amounts to 0.6 EJ/year in 2040, increasing to 1.4 EJ/year in 2050.[11] These values correspond to shares ($s_{liquid,t}$) of 3% and 9% of total liquid FE demand in the GG scenario, respectively.

Combined, e-methane and e-methanol demand reach 3.1 EJ/year in 2050, or around 5% of total FE demand in the GG scenario.

Finally, electrolyzers are assumed to maintain a static 50/50 market share between alkaline and PEM subtechnologies, with efficiency (η_t^{elz}) improving linearly to 68% and lifetime (L_t^{elz}) increasing to 14.6 years for both subtechnologies by 2050 (IEA [International Energy Agency], 2019). In addition, unitary capacity investment costs for electrolyzers are assumed to follow a medium improvement trajectory over time (cf. the medium improvement values in Table S1 of the Supplementary material).

Green Growth with accelerated H_2 synfuel deployment (GG-H_2syn-5%-fast). This scenario reflects a strategy of accelerated fossil fuel substitution aimed at strengthening EU geopolitical energy, resulting in a higher near-term demand for H_2 synfuels, while remaining consistent

[7] Solid biomass-based capacities are included in the scenarios since they are already deployed technologies within the existing EU electricity generation system (accounting for around 6% of current renewable generation). Nevertheless, their treatment as renewable electricity and heat generation options represents an optimistic approach in this study, since their associated land use impacts are not explicitly assessed (cf. Section 4.4). Moreover, additional carbon capture technologies are not considered, which can be justified by the additional techno-economic constraints (e.g., increased levelized cost of electricity) (Emenike et al., 2020).

[8] The impact assessment report for the climate target plan presents four scenarios through 2050 (S1, S2, S3, and LIFE) (European Commission, 2024d). For the sake of simplicity, in this work, scenario S1 is considered as reference, as it represents "linear" trajectories between 2030 and 2050.

[9] Across the sectors defined in the CTP impact assessment report, e-methane demand in 2050 in the GG-H_2syn-5% scenario is associated with industry (∼0.7 EJ/year; ∼10% of total sectoral energy consumption), the residential sector (∼0.6 EJ/year; ∼10% of total sectoral energy consumption), and the services sector (∼0.4 EJ/year; ∼10% of total sectoral energy consumption), with negligible use in the transport sector.

[10] This study does not explicitly assess sectoral-level interactions among alternative transport decarbonization pathways, such as direct electrification and modal shift versus e-fuels. Such an assessment would require a dedicated sectoral analysis based on specific transport scenarios, which is outside the scope of this system-level study.

[11] Across the sectors defined in the CTP impact assessment report, e-methanol demand in 2050 in the GG-H_2syn-5% scenario is associated with heavy goods vehicles (∼0.2 EJ/year; ∼16% of total energy consumption for heavy goods vehicles), navigation (∼0.6 EJ/year; ∼29% of total energy consumption for navigation), and aviation (∼0.6 EJ/year; ∼32% of total energy consumption for aviation), with negligible use in industry and the residential and services sectors. Note that e-methanol is excluded from passenger cars, with the CTP report favoring fuel cell vehicles (not included in this work) and, above all, electric vehicles due to their zero pollutant emissions.

with the long-term targets defined in the GG-H_2syn-5% scenario. The policy targets for H_2 synfuels are informed by REPowerEU for e-methane and by FF55 for e-methanol in 2030, and by the long-term trajectories reported in the CTP.

The scenario assumes the EU meets the REPowerEU goal of "phasing out Russian fossil fuel imports by 2030" (European Commission, 2022a), replacing Russian natural gas with domestically produced e-methane. Therefore, e-methane demand in 2030 is estimated based on 2024 EU natural gas imports (5.62 EJ/year) (Eurostat, 2025), of which 19% (~1 EJ/year) originated from Russia (European Commission, 2022a). From 2030 to 2050, e-methane demand follows a linear trajectory to reach the target of the CTP impact assessment report (European Commission, 2024a), as in the GG-H_2syn-5% scenario. Projected e-methane demand is 1 EJ/year in 2030, increasing to 1.4 EJ/year in 2040 and 1.7 EJ/year by 2050, corresponding to shares ($s_{gas,t}$) of 11%, 19%, and 30% of total gaseous FE demand in the GG scenario, respectively. E-methanol demand and the corresponding shares ($s_{liquid,t}$) remain the same as those in GG-H_2syn-5%.

Electrolyzer market shares, technical parameters (η_t^{elz}; L_t^{elz}), and unitary capacity investment costs match those in GG-H_2syn-5%.

Green Growth with intensive H_2 synfuel deployment (GG-H_2syn-15%). In this scenario H_2 synfuels play a prominent role in the EU energy transition. It is the most ambitious demand pathway, with H_2 synfuels covering around 15% of total FE demand by 2050. The e-methane policy targets are informed by REPowerEU for 2030 and by the long-term trajectories reported in the CTP, while incorporating additional demand assumptions for the residential sector. The e-methanol policy targets are informed by EU-aligned complementary literature.

In this scenario, e-methane demand follows the GG-H_2syn-5%-fast trajectory, while adding a substantially higher level of demand in the residential sector than considered in the CTP impact assessment report. According to (Fuel Cells and Hydrogen 2 Joint Undertaking, 2016), up to 44% of natural-gas-sourced building heat could potentially be replaced by pure hydrogen. In this study, under a more infrastructure-compatible pathway assumption, this potential demand is assumed to be met by e-methane instead. Based on current residential heating demand from IEA Energy Balances (IEA, 2026) and adjusting to avoid double counting with the CTP impact assessment report values, projected e-methane demand amounts to 1 EJ/year in 2030, 2.1 EJ/year in 2040, and 3.1 EJ/year in 2050, corresponding to shares ($s_{gas,t}$) of 11%, 29%, and 55% of total gaseous FE demand in the GG scenario, respectively. E-methanol demand is derived from (Galimova et al., 2022) (LUT model), aligned with Paris Agreement goals, and provides higher values than those in previous scenarios, corresponding to a faster and broader deployment of e-methanol. Demand amounts to 1 EJ/year in 2030, 3.2 EJ/year in 2040, and 3.7 EJ/year in 2050, corresponding to shares ($s_{liquid,t}$) of 4%, 17%, and 23% of total liquid FE demand in the GG scenario. Combined, e-methane and e-methanol demand reach 6.8 EJ/year in 2050, or around 15% of total FE demand in the GG scenario.

Electrolyzer market shares, technical parameters (η_t^{elz}; L_t^{elz}), and unitary capacity investment costs follow previous scenario assumptions.

3.3. Summary of the scenarios

A summary of the five scenarios assessed with the model is provided in Table 3. Moreover, Fig. 2 provides quantified projections of H_2 synfuel demand (e-methane and e-methanol) between 2025 and 2050 across the three H_2 synfuel penetration scenarios.

4. Results and discussion

This section shows the results obtained with the WILIAM model applying the scenarios for EU until 2050 described in the previous section.

4.1. Electricity generation system

Fig. 3 (left) shows EU electricity generation by source and the share of fossil-free generation under the REF, GG, GG-H_2syn-5%-fast, and GG-H_2syn-15% scenarios (GG-H_2syn-5% is omitted due to its similarity with GG-H_2syn-5%-fast). To simplify the figure, technologies from the capacity submodule are grouped as follows: Coal & Oil, Gas, Nuclear, Hydro (dammed and run-of-river), RoRES (solid biomass, waste, geothermal, and oceanic), Solar (open space, concentration solar power, and urban), and Wind (onshore, offshore).

In the REF scenario, electricity generation ranges 10-12 EJ/year, with fossil-based accounting for 39% of generation, and RES 43% by 2050. By contrast, the GG scenario reaches 27 EJ/year, almost tripling current levels through FE electrification policies across end-use sectors and passenger transport. Here, Solar, Wind, and RoRES expand substantially, while Nuclear and Hydro rises moderately, and fossil-based generation declines to 2% by 2050. Over the same period, RES increase to 83% of generation. Curtailment reaches 5.6% from 2040 onward. In the GG-H_2syn-5%-fast case, indirect electrification through e-methane and e-methanol, whose deployment levels rely on exogenous substitution shares (30% of total gaseous FE demand and 9% of total liquid FE demand, respectively), increases electricity generation required by 5.6 EJ/year[12] (+21%) relative to GG in 2050; the production of these H_2 synfuels requires 18% of total electricity generation in 2050 to be allocated to electrolysis. Fossil-based electricity generation reaches 3% and RES 77% (slightly below GG), largely through higher Nuclear and RoRES (notably solid biomass) rather than additional Solar, Wind, or Hydro. Two factors explain this: limited RES potentials restricting Wind and Hydro expansion, and VRES curtailment (partially mitigated but not eliminated by flexibility technologies), which reaches 6% from 2038 onward. The GG-H_2syn-5% variant produces comparable outcomes, though medium-term electrification is lower (+0.4 EJ in 2030 vs. +2.0 EJ in the fast variant). In the GG-H_2syn-15% scenario, H_2 synfuels cover ~15% of total FE demand in 2050 (based on the exogenous substitution shares defined for the scenario), increasing electricity generation required by 13 EJ/year above GG (+49%) in 2050. Wind and Hydro potentials shift generation further toward Nuclear and RoRES. Curtailment increases significantly (reaching 6.8% from 2036), as higher electricity demand to produce H_2 synfuels exceeds the system's VRES flexibility, exacerbating inflexibility-related losses. These findings align with (Béres et al., 2024), who report increased curtailment with higher hydrogen integration. As a result, RES provide 70% of electricity generation (lower than in other GG scenarios), while fossil-based generation rises to 4%. Furthermore, electrolyzers alone consume 12.9 EJ/year of electricity, nearly equivalent to the combined Wind and Solar generation (12.6 EJ/year), which operate close to their variability management limits, while Wind in particular approaches its resource potential.

Fig. 3 (right) presents the EU electricity generation capacity by source under the REF, GG, GG-H_2syn-5%-fast, and GG-H_2syn-15% scenarios, including the electrolyzer capacity requirements. These results closely align with those in Fig. 3 (left), reflecting the direct link between installed capacity and generation. Solar and Wind exhibit higher generation capacity shares due to their lower capacity factors. Compared to the GG scenario, the inclusion of H_2 synfuels leads to a substantial increase in total capacity requirements: +0.3 TW (+7%) in GG-H_2syn-5%-fast and +0.7 TW (+14%) in GG-H_2syn-15%. In parallel, electrolyzer capacity requirements reach 0.3 TW in GG-H_2syn-5%-fast and 0.7 TW in

[12] The absolute increase in electricity generation required is driven partially by exogenous e-methane and e-methanol assumptions, while the resulting generation mix is endogenously determined by the model under operational and biophysical constraints.

Table 3
Summary of the scenarios assessed with the model. Targets applied to the EU region, the rest of the regions follow a REF path.

	REF	GG	GG-H_2syn-5%	GG-H_2syn-5%-fast	GG-H_2syn-15%
FE gas substitution by e-methane ($s_{gas,t}$)	0%	0%	Slow growth until 2040 followed by high penetration reaching 30% by 2050	Fast uptake from 2030, reaching 30% in 2050	Fastest and higher uptake reaching 55% by 2050
FE liquid substitution by e-methanol ($s_{liquid,t}$)	0%	0%	Gradual deployment reaching 9% by 2050		Fast deployment starting in 2030, achieving 23% by 2050
FE electrification	Continuation of current trends (~20% of total FE)	Extensive electrification of productive end-use sectors, combined with ~20% reduction in private car use reallocated to buses and trains, and a 90% replacement of conventional vehicles with EVs by 2050, increases electricity's share of FE demand to 45%.			
Capacity expansion of power plants	Continuation of current trends	Strong deployment of RES, with highest priority given to wind power plants and solar PV. Hydropower dammed is preferred over power plants operated by solid biomass, and then nuclear, which in turn is favored over capacities fueled by gas, liquid, and solid. CHP plants are included, especially those operated by solid biomass.			
Capacity utilization of power plants	Continuation of current trends (61% fossil-free sources by 2050)	A fossil-free mix (nearly 100% fossil-free sources by 2050, limited by operational and biophysical constraints) is promoted in which demand is first met by wind power plants, solar PV, and hydropower, followed by power plants operated by solid biomass, and then nuclear. Remaining shortfalls are covered by capacities fueled by gas, liquid, and solid.			

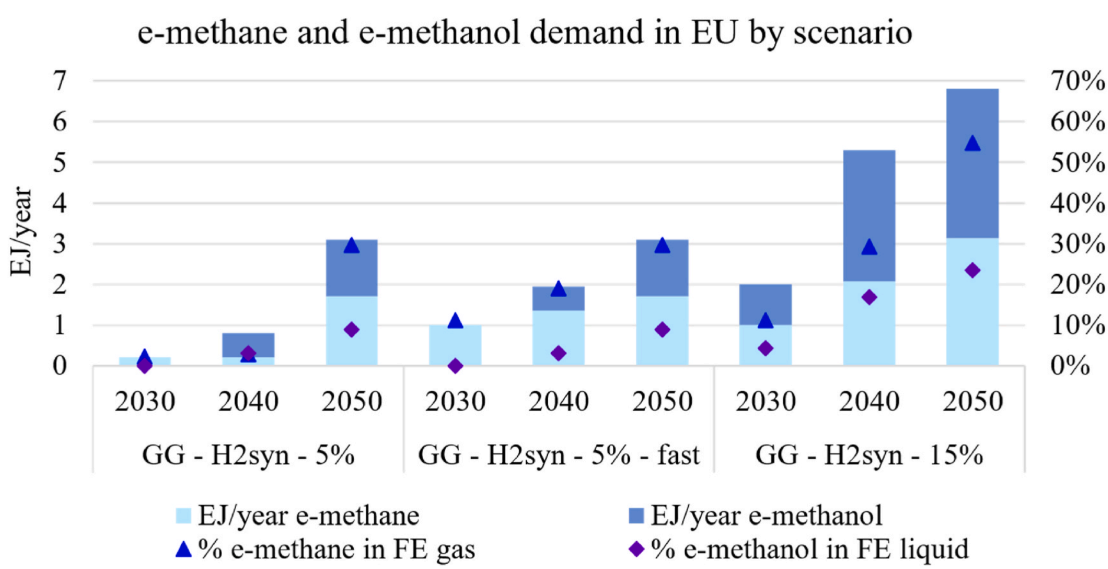

Fig. 2. Projected demand of e-methane and e-methanol between 2025 and 2050 across the three H_2 synfuel penetration scenarios (GG-H_2syn-5%, GG-H_2syn-5%-fast, and GG-H_2syn-15%). Stacked bars show annual demand (EJ/year, primary axis) for e-methane (light blue) and e-methanol (dark blue). Blue triangles and purple diamonds indicate, on the secondary axis, the shares of e-methane in total FE gas demand ($s_{gas,t}$) and e-methanol in total FE liquid demand ($s_{liquid,t}$), respectively. By 2050, combined e-methane and e-methanol demand reaches ~5% of total FE demand in GG-H_2syn-5% and GG-H_2syn-5%-fast, and ~15% in GG-H_2syn-15%. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article).

GG-H_2syn-15%.[13] The additional generation capacity mainly comes from non-VRES technologies (mainly Nuclear, RoRES and Hydro), as VRES are limited by resource potential and curtailment, as previously discussed. It is important to highlight that, while electrolyzers have not yet been deployed at scale, the projected installed electrolyzer capacity in 2050 (dedicated solely to H_2 synfuel production) could correspond to 24-54% of the EU's 2025 total electricity generation capacity. Additionally, the annual electrolyzer capacity expansion entails substantial investment costs, reaching around 45000 M$\$_{2015}$/year or 0.25% of the EU's GDP[14] in GG-H_2syn-15% (cf. Fig. S5 and Fig. S6 of the Supplementary material, respectively), thereby highlighting the macroeconomic scale of the required deployment, in addition to the technical challenges associated with large-scale implementation.

4.2. CCU for H_2 synfuels

Fig. 4 shows CO_2 captured for H_2 synfuel production in EU by source, alongside the remaining capture potential, categorized by H_2 synfuel scenario. Under the GG scenario, total CO_2 capture potential from IPPUs and from industrial energy uses and energy sector own consumption is approximately 400 Mt CO_2/year in 2025, declining progressively to 324 Mt CO_2/year by 2050 due to FE electrification policies that reduce direct CO_2 emissions in industrial energy uses. In both GG-H_2syn-5% and GG-H_2syn-5%-fast, IPPUs' potential alone fully covers CO_2 demand. However, in the GG-H_2syn-15% scenario, with higher H_2 synfuel demand, IPPUs' potential (~249 Mt CO_2/year in 2050) is exhausted, requiring additional capture from industrial and energy sectors, which are also depleted by 2039, necessitating DAC.

All scenarios incur an energy penalty linked to H_2 synfuel production, either via electricity for DAC or gas for CCU within IPPUs, industrial energy uses and energy sector own consumption. In the worst case (GG-H_2syn-15%), by 2050 this penalty could reach 1.0 EJ/year of gas and 0.4 EJ/year of electricity, representing 15% of total FE gas demand

[13] In these scenarios, stationary electrolyzers dominate total electrolyzer capacity, accounting for around 85% or more of installed capacity.

[14] To provide an order of magnitude, private investment in climate change mitigation in the EU reached 0.8% of EU's GDP in 2023 (Eurostat, 2024), while the European Commission estimates that additional green investment needs to reach the 2030 target amount to 3.2% of EU's GDP per year (Andersson et al., 2025).

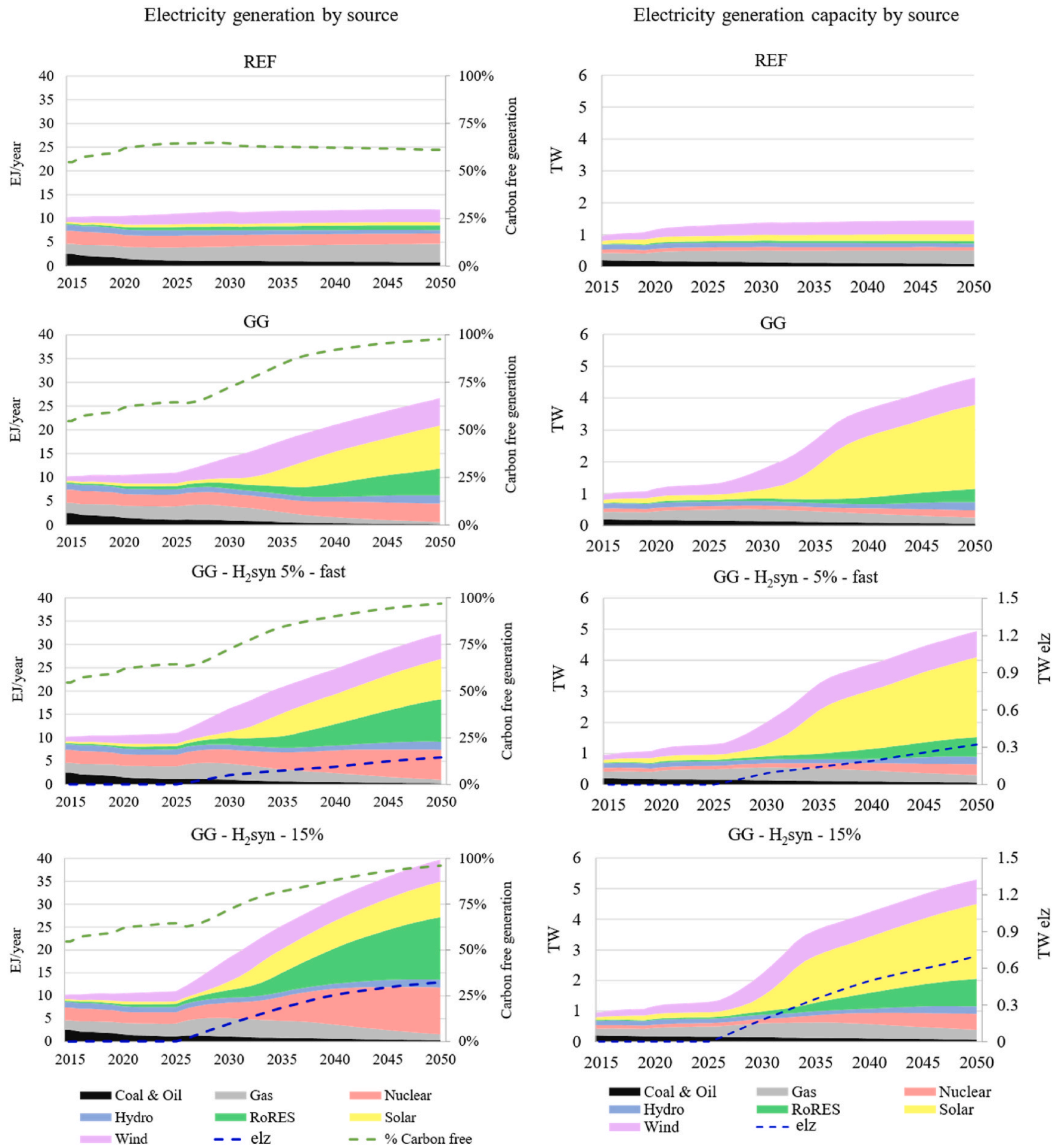

Fig. 3. EU electricity generation (left) and installed capacity (right) by source and scenario (2015-2050). Stacked areas show generation (EJ/year) and capacity (TW) by source. The dashed green line (left panels) indicates the carbon-free share of total electricity generation (equivalent to fossil-free since capacities with added carbon capture are not considered; secondary axis). The dashed blue lines represent the electricity consumption for electrolyzers (EJ/year, left panel) and the electrolyzer capacity requirements (TW, right panel; secondary axis). elz: electrolyzers. Grouping of technologies: Coal & Oil, Gas, Nuclear, Hydro (dammed and run-of-river), RoRES (solid biomass, waste, geothermal, and oceanic), Solar (open space, concentration solar power, and urban), and Wind (onshore, offshore). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article).

and 2% of FE electricity demand.

Fig. 5 illustrates the gross and net CO_2 capture per unit of energy consumed by technology in EU.[15] Initially, DAC captures less net CO_2 per unit of energy due to its reliance on electricity in a partially decarbonized electricity generation system. By 2050, it nearly reaches its technical maximum of 333 Mt CO_2/EJ in scenarios GG-H_2syn-5% and GG-H_2syn-5%-fast, whereas the GG-H_2syn-15% scenario shows lower net CO_2 capture because of a smaller fossil-free share of electricity generation (driven by the higher penetration of H_2 synfuels, as explained in Section 4.1). In contrast, CCU within IPPUs, industry, and energy remains constant at 277 Mt CO_2/EJ, as it depends on gas with a fixed CO_2 intensity emission factor. Consequently, the latter captures less net CO_2 than DAC from the early stages of the simulation period (from 2027 to 2030 onward, depending on the scenario). Over time, as the EU electricity generation system becomes increasingly decarbonized, DAC emerges as the more effective option in terms of net CO_2 capture per unit of energy consumed. Nevertheless, DAC is subject to significant uncertainty regarding both technical performance and large-scale adoption. Hence, near-term CCU deployment within IPPUs, industry, and energy should be considered as a viable solution given its reliance on commercially available at scale technology.

[15] Although DAC is only deployed in the GG-H_2syn-15% scenario, Fig. 5 also presents associated emissions (in relative terms, Mt CO_2/EJ) for the other scenarios, representing the potential emissions that would occur if DAC were implemented under the respective scenario assumptions.

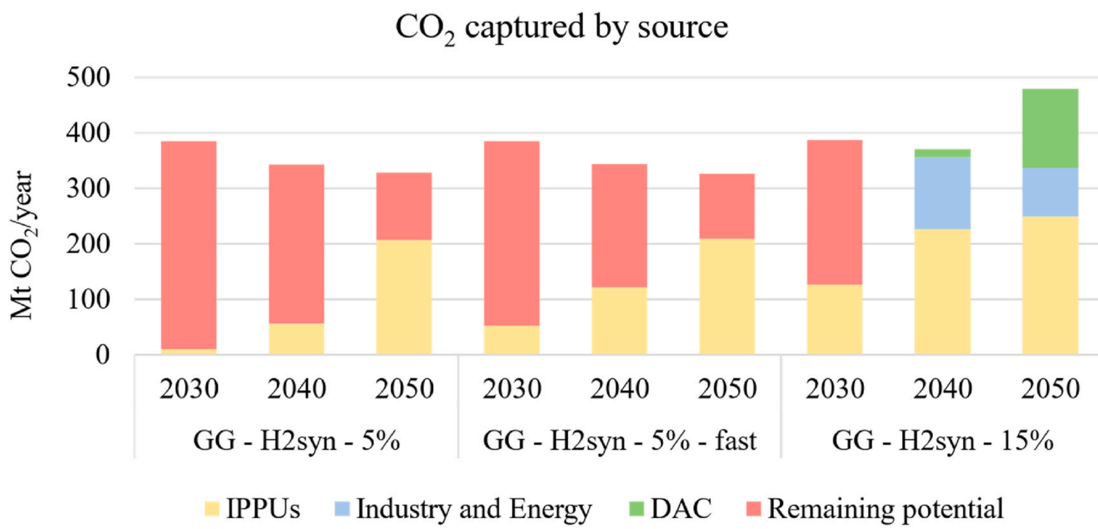

Fig. 4. CO_2 captured for H_2 synfuel production in EU by source (IPPUs, Industry and Energy, and DAC) and remaining capture potential (2030-2050) across the three H_2 synfuel scenarios (GG-H_2syn-5%, GG-H_2syn-5%-fast, and GG-H_2syn-15%).

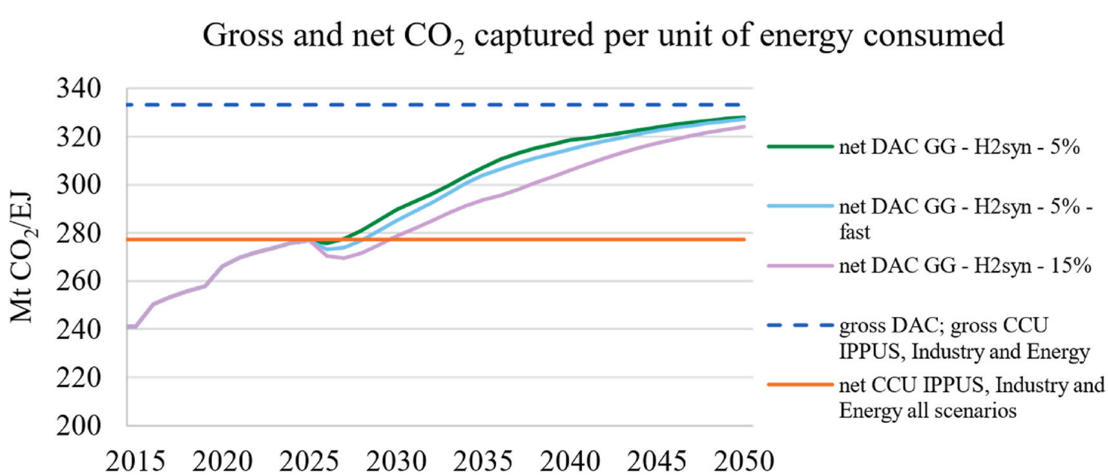

Fig. 5. Gross and net CO_2 captured per unit of energy consumed in EU (2015-2050): gross excludes operational emissions, while net subtracts direct and indirect emissions from energy use during capture (cf. Section 2.2.3 for details). Gross CO_2 capture for DAC and CCU IPPUs, Industry and Energy (dashed blue) coincidentally align and remain constant across scenarios due to fixed energy penalties. Net CO_2 capture for CCU IPPUs, Industry, and Energy (solid orange) is also constant, as both the energy penalty and CO_2 intensity emission for FE gas are fixed. Net CO_2 capture for DAC varies across scenarios, due to its dependence on the CO_2 intensity emission of the electricity mix. Note: in these indicators, "energy" refers to secondary energy. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article).

4.3. PE consumption and environmental impacts

Fig. 6 illustrates PE consumption of coal, natural gas, and oil in EU for each scenario. Compared to the REF scenario, the GG scenario shows a significant reduction in these energy sources, with PE coal, natural gas, and oil decreasing by 58%, 60%, and 37%, respectively. However, introducing H_2 synfuel policies temporarily increase PE consumption of coal and natural gas during the transition period. Relative to the GG scenario, PE coal rises by up to +21% in 2040 before converging back to GG levels by 2050, while PE natural gas increases by up to +23% in 2038 and similarly returns to GG levels by mid-century. In contrast, PE oil declines progressively as H_2 synfuel penetration expands, reaching reductions of up to 22% by 2050 compared to GG.

The temporary rise in coal and natural gas reflects systemic effects associated with the transition from a fossil fuel-based supply of FE fuels to an electricity-based supply for H_2 synfuels. This shift occurs within an electricity generation system that, although progressively decarbonized (from 65% fossil-free generation in 2025 to 96-98% by 2050), still relies partly on fossil sources during the transition, including solid fossil and gas fuels. Moreover, this effect is amplified by electrolysis and synfuel conversion inefficiencies, and the energy penalties associated with CO_2 capture processes. Together, these factors partially offset (and in some cases temporarily reverse) reductions in coal and natural gas consumption. This rebound effect is more pronounced under more stringent H_2 synfuel deployment targets (such as GG-H_2syn-15%) than in less ambitious pathways. Finally, although the electricity generation system reaches a high degree of decarbonization by 2050 (96-98%), this remains insufficient to significantly lower coal and natural gas amid the extensive electrification envisioned. It is important to note that these increases are partially driven by exogenous e-methane and e-methanol assumptions, but they are also shaped by the endogenous allocation of the electricity mix by the model under operational and biophysical constraints, preventing the system from reaching a fully fossil-free mix during the transition. Despite these dynamics, oil consumption decreases due to the substitution of FE liquids with e-methanol, while the limited role of liquid fuels in the electricity generation system mitigates

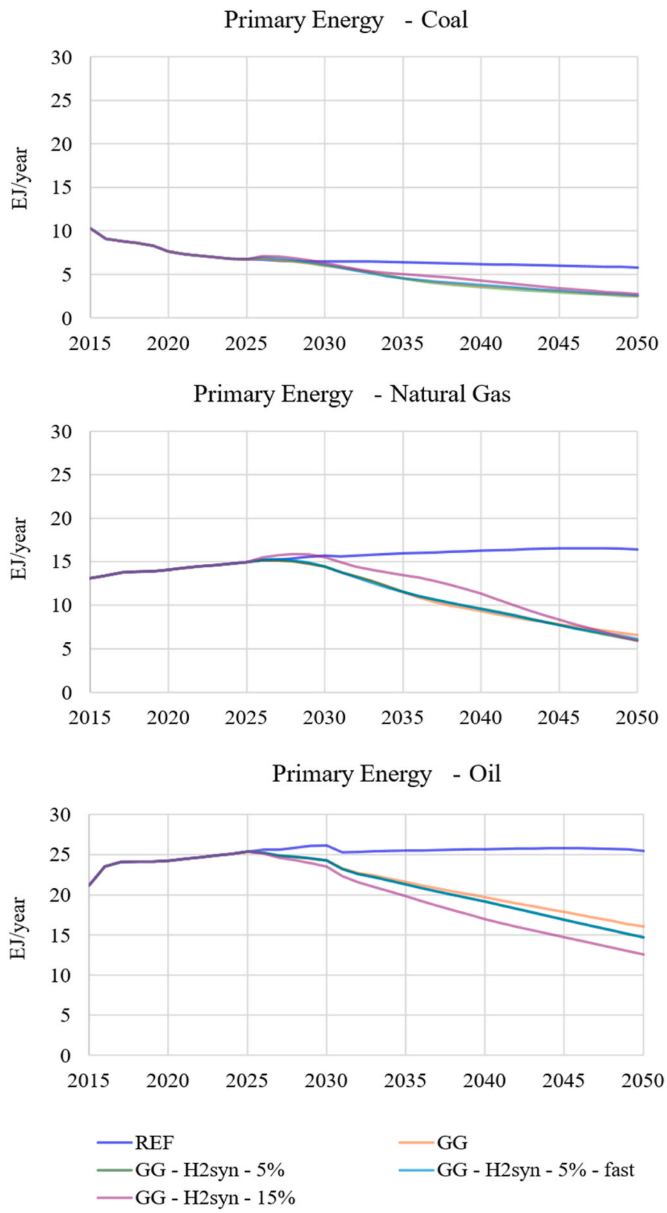

Fig. 6. PE consumption of coal, oil, and natural gas in EU for each scenario (2015-2050).

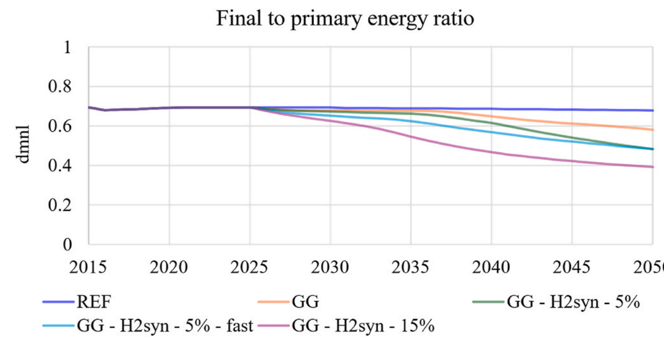

Fig. 7. Ratio of total FE to PE across the EU energy system in each scenario (2015-2050).

the indirect rebound effects observed for coal and natural gas.

Fig. 7 presents the ratio of total FE consumption to PE consumption across the EU energy system, further illustrating the inefficiencies in the energy supply chain mentioned above (fuel-based electricity generation, electrolysis and synfuel conversion, CO_2 capture processes, etc.). The GG-H_2syn-15% scenario is the least efficient (with a 19% absolute efficiency drop by 2050 relative to GG), followed by GG-H_2syn-5% and GG-H_2syn-5%-fast (both with smaller efficiency declines).

The model also estimates water requirements for electrolysis and CCU, projecting a total consumption of 652 Mm^3/year for the GG-H_2syn-5% and GG-H_2syn-5%-fast scenarios by 2050 (with a faster uptake in the latter), and 1231 Mm^3/year for GG-H_2syn-15%.[16] For reference, these values correspond to up to 6 times the water required for hydrogen non-energy uses in the EU (Campos-Rodríguez et al., 2025), or roughly 0.7% of current annual industrial freshwater withdrawals of the EU.[17] Although such aggregate values suggest a limited impact at the EU level, localized pressures may arise in regions with constrained water availability (Tonelli et al., 2023).

Additionally, the model estimates the amount of waste products originated from amine-based CO_2 capture processes, reaching up to 2.1 Mt/year. These streams primarily consist of degraded solvents, reclaiming residues, and contaminated wastewater. Their management requires attention due to the potential human toxicity and eco-toxicity associated with amines, nitrosamines, and related degradation products. In current industrial practice, such wastes are typically handled as hazardous materials and treated through specialized wastewater treatment (e.g. UV photolysis, UV plus ozone, activated carbon adsorption, catalytic reduction, and electrochemical reduction) prior to discharge (Abad et al., 2025). Although established management routes exist, the scale-up of capture systems may amplify associated environmental burdens, underscoring the importance of incorporating solvent degradation and waste treatment impacts into system-level sustainability assessments.

Finally, Fig. 8 presents CO_2, methane (CH_4) and nitrous oxide (N_2O) emissions, expressed in CO_2eq, across the energy system and IPPUs in EU for each scenario. In the GG scenario, relative to current levels, mid-century reductions reach 45% for CO_2, 34% for CH_4, while N_2O emissions remains nearly constant. By contrast, relative to the GG scenario, large-scale deployment of H_2 synfuels in the GG-H_2syn-15% scenario achieves only a ~7% cut in CO_2, negligible change in N_2O, and a +28% increase in CH_4 (the latter due to e-methane continues relying on existing gas transmission infrastructure, maintaining associated fugitive emissions). As a result, overall CO_2eq reduction is therefore limited to ~7% relative to GG. This limited reduction stems from the indirect electrification driven by H_2 synfuels which, combined with electrolysis and synfuel conversion inefficiencies, imposes substantial pressure on the electricity generation system that, as explained in Section 4.1, reduces the share of fossil-free electricity generation. Consequently, the CO_2eq intensity of electricity doubles compared to the GG scenario (see Fig. 9A), increasing emissions associated with electrolysis (the most emission-intensive stage of H_2 synfuel production, cf. Fig. 9D and E), and placing additional burden on the overall electricity generation system, thereby raising total CO_2eq emissions and offsetting the direct savings from substituting FE fuels with H_2 synfuels.

Although in our simulations H_2 synfuels may eventually reach an emission intensity level broadly consistent with the Renewable Energy Directive (RED) III requirement for renewable fuels of non-biological

[16] These estimations account solely for water requirements for hydrogen and H_2 synfuel production, including CO_2 capture processes. Potential water returns within hydrological basins (e.g., from synfuel combustion) are not considered and lie beyond the scope of this study.

[17] Current industrial freshwater withdrawals of the EU amounts to 185000 Mm^3/year. Data obtained from FAO AQUASTAT (Food and Agriculture Organization of the United Nations (FAO), n.d.), accessed via the World Bank Group (World Bank Group, n.d).

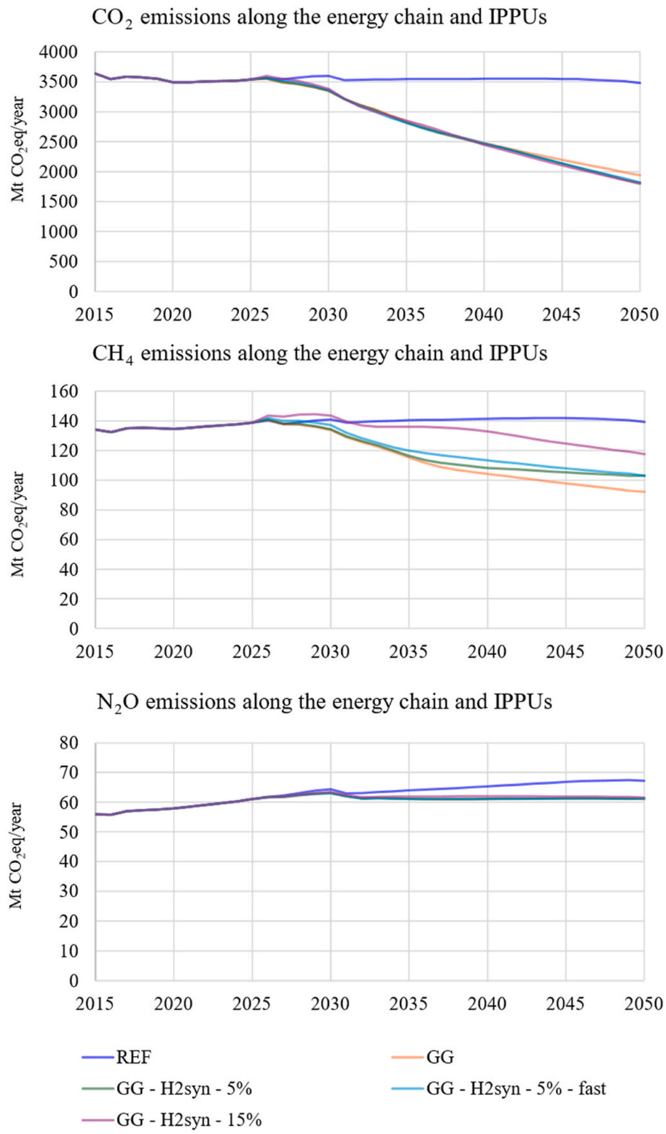

Fig. 8. CO_2, CH_4, and N_2O emissions, expressed in CO_2eq, across the energy system (i.e., the energy transformation chain) and IPPUs (i.e., non-energy uses in non-energy sectors) for each scenario (2015-2050).

origin (RFNBOs) (i.e., achieving a minimum of 70% emissions savings relative to the fossil fuel comparator of 94 Mt CO_2eq/EJ (European Parliament, 2023a; European Commission, 2023)), this occurs only around 2045-2050 and does not result in substantial system-wide CO_2eq reductions (cf. Fig. 9B and C). Overall, the compounded penalties and inefficiencies mentioned above prevent an additional reduction of up to 198 Mt CO_2eq/year by 2050, which would be equivalent to an additional reduction in overall CO_2eq emissions of ~10%, relative to the GG scenario. Such a reduction would primarily require the electricity generation system to be 100% fossil-free while producing the same amount of H_2 synfuels. In our simulations, however, the electricity system does not reach full decarbonization, thereby preventing these additional CO_2eq reductions. It should be noted, however, that the CO_2eq intensities of e-methane and e-methanol reported in this study are not intended to reproduce the generator-level GHG accounting methodology established in (European Commission, 2023) (although both calculations are conceptually aligned), but rather constitute system-level indicators derived from the WILIAM model. Nevertheless, the practical implementation of the EU emission savings criteria related to the renewable origin of the electricity used for RFNBO production remains a relevant source of uncertainty and may require an additional system-level perspective. Current EU legislation seeks to ensure that electricity demand for RFNBO production is fully renewable by introducing provisions such as additionality and tight temporal correlation between RES electricity generation and electrolyzer operation (European Commission, 2023; European Parliament, 2018). However, tight temporal correlation may reduce electrolyzer utilization rates unless accompanied by substantial overcapacity in RES generation and storage, thereby increasing total investment costs and potentially affecting the feasibility of large-scale renewable hydrogen implementation (EWI, 2025; Tovar et al., 2025). For example, Parkes (2025) reports that several industry stakeholders have advocated moving toward monthly correlation, which could increase the relevance of system-level interactions beyond strict generator-level matching and further reinforce the system-level assessment considered in this work. Accordingly, this system-level perspective remains relevant and complementary to current legislation, because generator-level compliance may not capture the indirect and systemic effects of allocating significant amounts of electricity and CO_2 to H_2 synfuel production. These effects include, for example, VRES curtailment, exhaustion of RES potentials, or the reduced availability of low-carbon electricity for other end-uses not related to H_2 synfuels. Therefore, the results suggest that current EU sustainability criteria for RFNBOs could be complemented by systemic implications to avoid net increases of CO_2eq emissions. Finally, it is important to acknowledge that (European Commission, 2023) constrains the inclusion of fossil-origin CO_2 as avoided emissions after 2041. In our simulations, these fossil-origin CO_2 sources (i.e., those from IPPUs and Industry and Energy) persist and should not be credited as avoided emissions under the post-2041 RFNBO emissions-accounting constraint. To reflect this, Fig. 9F and G report additional RFNBO-compliant CO_2eq intensities for e-methane and e-methanol, in which CO_2 captured from IPPUs and Industry and Energy is no longer counted as a negative-emission component from 2041 onward. Under this stricter accounting approach, the CO_2eq intensities of e-methane and e-methanol increase and no longer comply with the 70% emissions savings threshold. In other words, the compliance observed in the original system-level indicators shown in Fig. 9B and C depends on crediting fossil-origin CO_2 as avoided emissions after 2041, which is not allowed under (European Commission, 2023).

4.4. *Limitations and further work*

The simulated scenario results depend on several uncertain assumptions. This includes the performance of immature technologies modeled, which are not yet deployed commercially at scale and exhibit technical challenges. For instance, the efficiency and lifetime of electrolyzers are uncertain, directly affecting electricity generation required and installed capacity. Similarly, for DAC, the electricity-based energy penalty is uncertain and influences system requirements in a comparable way. Even mature technologies, such as post-combustion CCU, are subject to uncertainties, particularly regarding the industrial CO_2 potential for CCU; estimating this potential is highly uncertain due to limited data for calibrating sector-specific capture viability factors, which in turn directly affects the timing of deploying alternative CO_2 capture technologies, such as DAC, to satisfy CO_2 demand for H_2 synfuels.

Additional uncertainties and limitations of the study arise from specific submodules of the WILIAM energy module, with the most significant being the RES potentials and the variability management submodules. For RES potentials, uncertainties are particularly pronounced when dependent on the minimum EROI (for solar PV and wind power plants), given the difficulty to select a robust threshold to sustain complex societies. Few estimates exist in the literature pointing to a 5-15:1 threshold (cf. e.g., (Brandt, 2017; De Castro and Capellán-Pérez, 2020; Hall et al., 2009)). The value adopted in this study (5:1) corresponds to higher solar and wind potentials but is associated with a significant level

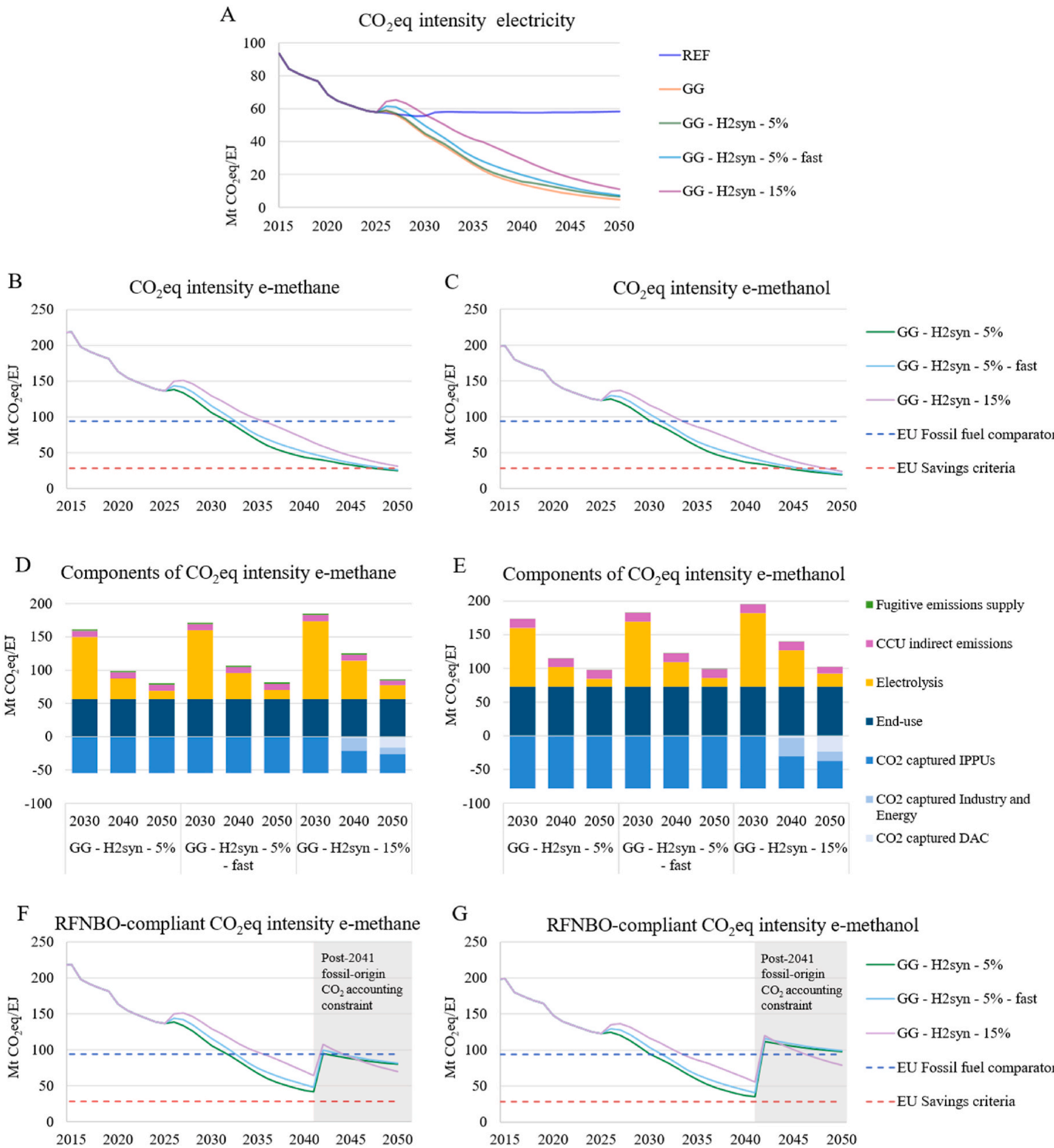

Fig. 9. CO_2eq intensity of electricity (A), e-methane (B), and e-methanol (C) in EU (2015-2050). CO_2eq intensities of e-methane and e-methanol account for CO_2eq from the following sources (D, E): synfuel end-use, fugitive emissions during synfuel transmission, indirect emissions from electricity consumed in electrolysis, indirect emissions from energy penalties in CCU processes, and (negative) emissions from CO_2 captured by source (IPPUs, Industry and Energy, and DAC). The end-use component corresponds to the CO_2eq intensity emission of the fuel, while the CO_2 captured component (IPPUs + Industry and Energy + DAC) reflects the CO_2 requirement for synfuel. These values are very similar because the CO_2 captured to produce the fuel is subsequently released during end-use. Both parameters are assumed to be constant throughout the model simulation. The CO_2 captured component is conceptually related to the "emissions from inputs' existing use or fate" term in the GHG accounting methodology established in (European Commission, 2023), which refers to the emissions that are avoided and incorporated into the chemical composition of the fuel that would otherwise have been emitted as CO_2 to the atmosphere. Since fossil-origin CO_2 sources (i.e., those from IPPUs and Industry and Energy) should not be credited as avoided emissions after 2041 (under the stricter RFNBO emissions-accounting constraint, cf. (European Commission, 2023)), the figure also reports additional RFNBO-compliant CO_2eq intensities for e-methane (F) and e-methanol (G) in which these sources are no longer counted as negative-emission components from 2041 onward. For reference, the figure shows the fossil fuel comparator and the EU savings criteria relative to fossil fuels (−70%), based on (European Parliament, 2023a; European Commission, 2023).

of risk. Assuming higher thresholds would reduce this risk but would also reduce solar and wind potentials, thereby lowering the share of fossil-free electricity generation and diminishing the performance of H_2 synfuels in terms of PE consumption and GHG emissions reduction. Regarding VRES variability, curtailment reduces capacity expansion and utilization of VRES technologies (solar and wind) and influences the performance of H_2 synfuels in a similar manner to RES potential constraints. However, the variability management submodule entails inherent uncertainties, such as the maximum system-level share of electricity curtailment, as well as structural limitations. These include the absence of certain demand-side management options such as individual boilers and heat pumps, the lack of statistical significance in the method for stationary storage, or the assumption that capacity factors of technologies other than solar and wind remain unaffected. Further details are provided in (Parrado-Hernando et al., 2024).

Another factor influencing the analysis concerns the hypotheses underlying net energy analysis (NEA) for H_2 synfuels, which was not explicitly addressed in this work. Nevertheless, from the perspective of NEA and its integration within the WILIAM framework, literature review shows that most of the energy requirements of H_2 synfuels and CCU correspond to process energy (i.e., energy consumed in the processes), whereas the energy embodied in the manufacturing of the facilities can be negligible in a first approximation (Ali et al., 2024; Capellán-Pérez et al., 2017; Simon, 2023; Terlouw et al., 2021).

In addition to the limitations discussed above, it is important to acknowledge that the present analysis does not constitute a full systemic study; rather, it focuses exclusively on the supply side, and examines which energy system could sustain the expansion of H_2 synfuels based on current EU policy frameworks, in order to assess the incremental benefits of their use compared to a GG scenario without these synfuels. Given that the tested policies do not deliver commensurate benefits relative to the scale of the undergoing transformation of the energy system, this raises questions about the effectiveness of measures that focus solely on the supply side. Indeed, the projected 2050 energy system becomes distorted in both magnitude and composition (exhibiting greater dependence on nuclear and solid biomass for electricity generation) due to the need to meet very high demand under existing constraints. Given these circumstances, it is necessary to go beyond technological issues and investigate systemic studies that consider both reductions in production and consumption (Pichler et al., 2025) or consider what level of social welfare is achieved with the resources consumed (O'Neill et al., 2018). Hence, the scenarios designed in this work shouldn't be interpreted as a recommendation from the authors. The design of a fully sustainable energy system scenario would require the integration of many aspects that fall beyond the scope of the current research and therefore merit thorough examination for further work. That exercise is a very ambitious, currently ongoing work requiring the joint contribution of WILIAM developers. Among the key missing elements are:

- Modeling of a full hydrogen economy. Expanding hydrogen deployment to additional hard-to-abate sectors, such as non-energy uses, freight transport, high-temperature industry, and other H_2 synfuels (IEA [International Energy Agency], 2019), would substantially increase demand. Therefore, under these conditions, the feasibility of producing hydrogen primarily from domestic solar and wind (European Commission, 2020) appears even more unfeasible, reinforcing the potential role of hydrogen imports in EU (Tatarenko et al., 2023). However, this pathway raises concerns about perpetuating energy dependence within the EU, which is at odds with the REPowerEU strategy (European Commission, 2022a). In this regard, incorporating FE trade (another missing element) and defining global scenarios in future work would allow the model to better capture these aspects (e.g., the goal of phasing out Russian fossil fuel imports), as well as the implications of H_2 synfuel deployment for other global regions.
- Comprehensive assessment of CO_2 supply and demand. Ongoing work could incorporate additional CO_2 sources, such as BECCU or power plants with added carbon capture, as well as endogenous cost-based allocation of CO_2 demand across sources. It could also broaden the scope of CO_2 demand beyond its use in H_2 synfuels, for example by considering current CO_2 demand for food and beverages (although this remains relatively small compared with large-scale H_2 synfuel deployment (BIP Europe, 2024)). Expanding the range of CO_2 demands may lead to an earlier depletion of industrial CO_2 potential than projected in this study (cf. (Galimova et al., 2022)), thereby requiring additional sources. Moreover, the implementation of decarbonization measures in IPPUs, coke, and refining (e.g., hydrogen-based processes (Campos-Rodríguez et al., 2025)), or the substitution of industrial energy uses with pure hydrogen could exacerbate this situation by further reducing these potentials.
- Definition of global scenarios. In this study, only policies in the EU were applied, while other regions followed a reference scenario. This simplification has certain implications. First, given that fossil fuel availability and prices in the WILIAM model are determined globally, the sensitivity of these dynamics to EU-level demand is low. Implementing a global GG scenario would likely significantly alter fossil fuel demand and, consequently, their availability and prices, triggering indirect effects (such as rebound effects) that would influence the economy module, impact GDP, and ultimately feedback into regional FE demand. Second, if uranium availability constraints were considered, global uranium use for electricity generation could limit EU uranium supply and nuclear-based electricity, potentially reducing the share of fossil-free electricity generation.
- Analysis of other systemic effects, including land use impacts, mineral availability, and energy system investment requirements (i.e., NEA). Increased reliance on solid biomass for electricity generation may raise land use, land use change, and forestry (LULUCF) related emissions (Mediavilla et al., 2025) with the risk of further reducing the already limited GHG emission reductions achieved in the energy transformation chain and IPPUs (despite the optimistic approach adopted for solid biomass-based capacities in our simulations) (Creutzig et al., 2015). Simultaneously, mineral shortages, such as uranium, could limit nuclear-based electricity generation (Capellán-Pérez et al., 2014), while material requirements linked to the changing energy mix could exacerbate risk availability for some minerals (Capellán-Pérez et al., 2019; IEA, 2025). Additionally, considering the higher up-front energy investment requirements for RES infrastructure compared to conventional energy systems could further increase FE demand during the transition. This, in turn, could lead to higher PE consumption, additional infrastructure, and increased GHG emissions, potentially slowing the transition to RES (Delannoy et al., 2024; Capellán-Pérez et al., 2019; De Castro and Capellán-Pérez, 2020). Hence, these effects, would likely exacerbate the limited benefits associated with deploying H_2 synfuels.
- Consistent economy-energy links. The consistent development of an IAM implies that the introduction of a new feature in one module must also ensure consistency across all other modules. This is achieved mainly in two ways. First, through indirect effects captured by the model, such as those describe above for land use impacts or mineral availability (all of which the model is designed to capture). Second, in some cases, the modeling needs to be further extended to achieve consistency. In the case of H_2 synfuels, the most notable extension within an IAM such as WILIAM (which is both process-based and features a highly detailed economy module) concerns the consistent representation of economy-energy links. Indeed, this remains a weakness in the state of the art of IAMs and lies at the knowledge frontier (Arias et al., 2026; Pauliuk et al., 2017). The integration of H_2 and H_2-based fuel supply represents an even more nascent area, given that these are emerging technologies (e.g., (Caiafa et al., 2025; Rinaldi et al., 2024). Future work is planned to integrate the hydrogen-related investments and associated flows of energy computed in the energy module to the gross fixed capital formation (GFCF) function (through investment matrix) and input-output technical coefficients in the economy module (Campos-Rodríguez et al., 2024). The energy module already produces the inter-module variables required by the input-output economic modeling framework to link both modules, i.e., the energy flows and investments (cf. results on total electrolyzer capacity investment costs in Section 4). Finally, future work could incorporate economic indicators, such as the levelized cost of hydrogen (LCOH), to guide the expansion of H_2 synfuels according to their competitiveness relative to fossil-based counterparts, rather than relying solely on exogenous deployment pathways.

5. Conclusion and policy implications

This paper presents a system-level assessment of the energy and environmental implications of H_2 synfuels, including their dependence on fossil fuels, PE consumption, electrification, infrastructure requirements, GHG emissions, availability of industrial CO_2, and water requirements. The analysis is conducted within the IAM WILIAM, with a focus on its bottom-up energy module, and addresses key gaps in the current literature: the limited representation of H_2 synfuels in ESMs, the limited explicit modeling of diverse CO_2 sources for CCU, and the insufficient exploration of alternative H_2 synfuel deployment scenarios. Although the model is general and applicable to any region, it was employed to assess various EU policy-aligned scenarios, including a GG pathway and variants thereof with different levels of H_2 synfuel penetration. Simulation results indicate that the deployment of H_2 synfuels would have profound implications across multiple dimensions. These include extensive electrification (up to +49% relative to GG), substantial capacity requirements for both electricity generation (+0.7 TW) and electrolysis (0.7 TW), and a shortage of industrial CO_2 for CCU (in extreme scenarios). However, the analysis also reveals persistent challenges in reducing PE consumption and GHG emissions. These are largely attributable to two factors: compounded inefficiencies in key processes (electrolysis, synfuel conversion, and CO_2 capture processes) and indirect effects of H_2 synfuel deployment, including increased electrification, depleted RES potentials, and VRES curtailment.

The European Parliament specifies in RED III (European Parliament, 2023a) that it is still in the process of evaluating the impacts of renewable fuels of non-biological origin (RFNBOs) deployment: "*By 1 July 2028, the Commission should assess the impact of the methodology defining when electricity used for producing renewable fuels of non-biological origin can be considered fully renewable, including the impact of additionality and temporal and geographical correlation on production costs, GHG emissions savings, and the energy system, and should submit a report to the European Parliament and the Council*". To support this purpose, the main policy-relevant takeaways of this study are:

- H_2 synfuel deployment should be delayed until the electricity generation system is sufficiently clean to meet EU sustainability standards, to avoid undermining decarbonization in other sectors. Moreover, the sustainability criteria should be more restrictive to ensure meaningful GHG emission reductions, in proportion to the energy system transformations implemented.
- The EU should complement generator-level sustainability criteria for RFNBOs with the assessment of the systemic capacity of the energy system to meet emission targets. Focusing solely on individual generators may unintentionally increase net GHG emissions, as constraints in scaling up fossil-free electricity generation can trigger indirect system-wide effects.
- Compliance with the sustainability criteria for RFNBOs may depend on crediting fossil-origin CO_2 as an eligible source for RFNBO production after 2041, which current legislation does not allow. Therefore, the development and large-scale deployment of alternative CO_2 sourcing pathways, such as DAC, should be accelerated to move beyond reliance on industrial processes, coke, and refining. This would also help prevent potential CO_2 availability constraints and ensure the long-term scalability of H_2 synfuels.
- Producing all EU H_2 synfuel demand with domestic RES is challenging, creating strong supply-side pressure. Consequently, supply-side measures alone may be ineffective, necessitating their integration with demand-side strategies and systemic transformative change.

Glossary

BECCU	Bioenergy with carbon capture and utilization
CCU	Carbon capture and utilization
CHP	Combined heat and power
CO_2	Carbon dioxide
CH_4	Methane
CTP	Climate target plan
DAC	Direct air capture
EROI	Energy Return on Investment
ESM	Energy System Model
EU	European Union
FE	Final energy
FF55	Fit for 55
NEA	Net energy analysis
GDP	Gross domestic product
GFCF	Gross fixed capital formation
GG	Green Growth
GHG	Greenhouse gas
H_2	Hydrogen
IAM	Integrated Assessment Model
IPPUs	Industrial processes and product uses
JRC	Joint Research Centre
LCOH	Levelized cost of hydrogen
LHV	Lower heating value
LULUCF	Land use, land use change, and forestry
Mt	Million tons
N_2O	Nitrous oxide
PE	Primary energy
PV	Photovoltaic
RED	Renewable Energy Directive
RES	Renewable energy source
RFNBO	Renewable fuel of non-biological origin
SD	System dynamics
TO	Transformation output
VRES	Variable renewable energy sources

Data availability

Data will be made available on request. The WILIAM v1.4 model is available via GitHub at https://github.com/LOCOMOTION-h2020/WILIAM_model_VENSIM/releases/tag/WILIAM_v1.4.

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

During the preparation of this work the authors used DeepL Translate and ChatGPT to assist in synthesizing content and refining English language expression for academic purposes. After using this tool/service, the authors reviewed and edited the content as needed and take full responsibility for the content of the published article.

CRediT authorship contribution statement

Juan Manuel Campos-Rodríguez: Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Software, Validation, Visualization, Writing – original draft, Writing – review & editing. **Laura Bartolomé-Quevedo:** Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Visualization, Writing – original draft, Writing – review & editing. **David Vega-Maza:** Conceptualization, Methodology, Supervision, Writing – review & editing. **David Álvarez-Antelo:** Investigation, Software, Validation. **Fernando Antonio Frechoso-Escudero:** Methodology, Supervision, Writing – review & editing. **Íñigo Capellán-Pérez:** Methodology, Project administration, Supervision, Writing – review & editing.

Funding

Juan Manuel Campos-Rodríguez acknowledges financial support from an FPU (Formación de Profesorado Universitario) Grant of the

Ministry of Science, Innovation and Universities (no. FPU23/03998). Laura Bartolomé-Quevedo acknowledges financial support from the UVa 2024 pre-doctoral grant programme, co-funded by Banco Santander. Íñigo Capellán-Pérez acknowledges financial support from a Juan de la Cierva-Incorporación Research Fellowship of the Ministry of Economy and Competitiveness of Spain (no. IJC2020–046215-I). This work has been partially developed under the LOCOMOTION project (funded by the European Union's Horizon 2020 research and innovation programme under grant agreement no. 821105) and the HYDRA project (funded by the European Union's Horizon Europe research and innovation programme under grant agreement no. 101137758).

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.

Appendix A. CCU potential parametrization

The methodology for quantifying the sector-specific capture viability factor, p_{CC_s}, uses a selective, all-or-nothing approach. Only industrial sectors meeting defined technical and economic criteria are considered viable CO_2 sources. These criteria reflect the main factors that condition the feasibility of carbon capture across industrial processes. First, the complexity and degree of integration of emission sources directly affect technical viability. Combustion-based plants, such as coal- or gas-fired power stations, typically emit from a centralized boiler, producing a flue gas suitable for CO_2 separation. In contrast, facilities such as refineries comprise multiple, highly integrated units (including crackers, furnaces, and reactors) making capture implementation significantly more complex. Second, the volume of emissions is a key economic factor. The capital and operational expenditures associated with capture technologies are typically justified only for large point sources or clusters of emitters with similar processes. A widely accepted threshold to define large emitters is 0.1 Mt CO_2eq/year (Intergovernmental Panel on Climate Change, 2005). Third, the partial pressure of CO_2 in the gas stream, and therefore its concentration, strongly influences capture efficiency and cost. Processes with high CO_2 content, such as ammonia production (~100%), offer more favourable conditions than dilute sources, such as natural gas power plants (7-10%) or cement kilns (~10%) (Ghiat and Al-Ansari, 2021). Other relevant considerations include the cost and technological readiness level of the available capture technologies, the possibility of retrofitting or redesigning existing facilities, and the availability of reliable data. In practice, this methodology classifies industrial processes as either fully eligible or ineligible for capture. For the sake of simplicity, viable sectors receive 100% potential ($p_{CC_s} = 1$), non-viable sectors 0% ($p_{CC_s} = 0$). For the sectors identified as suitable for CCU, a capture efficiency, η_{CC_s}, is assumed based on post-combustion capture using amine-based solvents (absorption), a well-established technology in which CO_2 is chemically absorbed from flue gases and subsequently released during solvent regeneration for reuse (Tan et al., 2025), and currently the most widely applied at industrial scale (Rezaei et al., 2023). Sector-specific efficiencies, are taken from (Cachola et al., 2023).

The sectors included in this assessment, along with their parametrization for p_{CC_s} and η_{CC_s}, are summarized in Table B.1.

Table B.1
Sectoral parametrization of CCU across IPPUs, industrial energy uses, and sector own consumption. Values of p_{CC_s} are derived from the authors' own assessment, whereas η_{CC_s} is sourced from (Cachola et al., 2023).

Category	Sector	Capture viability factor p_{CC_s} (dmnl)	Capture effectiveness η_{CC_s} (%)
IPPUs	Cement production	1	0.90
	Lime production	1	0.90
	Chemical industry	1	0.85
	Non-energy products from fuels and solvent use	0	N/A
	Other process uses of carbonates	1	0.85
	Metal industry	1	0.85
	Glass production	0	N/A
Industrial energy use	Mining and manufacturing iron	1	0.85
	Mining and manufacturing copper	1	0.85
	Mining and manufacturing nickel	1	0.85
	Mining and manufacturing aluminium	1	0.85
	Mining and manufacturing precious metals	0	N/A
	Mining and manufacturing lead zinc tin	0	N/A
	Mining and manufacturing other metals	0	N/A
	Manufacture food	0	N/A
	Manufacture wood	1	0.62
	Manufacture chemical	1	0.85
	Manufacture plastic	1	0.85
	Manufacture other non-metal	0	N/A
	Manufacture metal products	0	N/A
	Manufacture electronics	0	N/A
	Manufacture electrical equipment	0	N/A
	Manufacture machinery	0	N/A
	Manufacture vehicles	0	N/A
	Manufacture other	0	N/A
	Construction	0	N/A
Energy sector own consumption	Coke	1	0.85
	Refining	1	0.65

Appendix B. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enpol.2026.115529.

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