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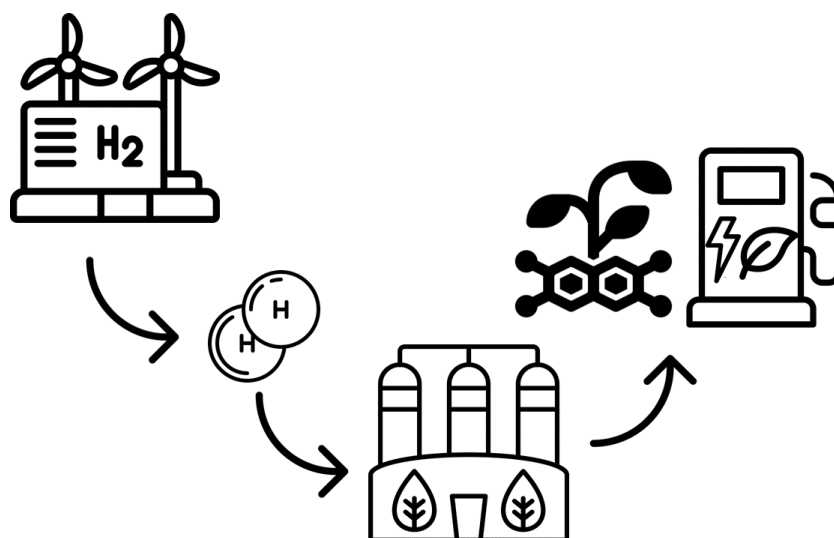
Technology Collaboration Programme

Integration of biorefineries and green hydrogen

Techno-economic feasibility and case studies

IEA Bioenergy Task 42 Biorefining in a circular economy

December 2024





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Techno-economic feasibility and case studies

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Abstract

To achieve sustainable development, the transition from a fossil-based economy to a circular economy is essential. The use of renewable energy sources to make the overall carbon footprint more favorable is an important prerequisite. In this context, valorizing all renewable resources through an optimized local integration is crucial. One opportunity arises through the synergy between the use of bioresources and green hydrogen. Through techno-economic assessments, this report analyses four local case studies that integrate bio-based processes with green hydrogen produced via electrolysis using renewable energy sources. An analysis of the use of web-GIS tools (i.e., Atlas of Biorefineries of IEA Bioenergy) to identify existing biorefineries that require hydrogen concerning territories with a potential availability of green hydrogen, has never been conducted before. This report evaluates the production costs of the target products as a function of the local green hydrogen supply costs. The results revealed that the relative impact of green hydrogen costs could vary widely, ranging from 1% to 95% of the total production costs, depending on the bio-based target product evaluated. Additionally, hydrogen demand in the target area could require an installed variable renewable energy capacity of 20 MW and 500 MW. On the whole, the local integration of biorefineries and green hydrogen could represent an optimal opportunity to make hydrogenated bio-based products 100% renewable.

1. Introduction

1.1 General and variable renewable energy sources as an opportunity for the biorefinery development

The future development of biorefineries could reveal many opportunities arising from the availability of green hydrogen (G-H₂). Many bio-based processes involve hydrogen as a reductive reactant, producing drop-in biofuels, biojet fuels, and biochemicals [1]. There are many technological routes to produce hydrogen, often represented by a different color. Green hydrogen (G-H₂) is typically achieved through water electrolysis by using renewable electricity (Figure 1). Another possibility to obtain renewable hydrogen is through the valorization of waste polymers [2], which can have significant economic prospects, alongside achieving net-zero CO₂ emissions [3]. A number of hydrogen valleys are emerging globally, producing G-H₂ from renewable energy sources (RESs) via electrolysis [4]. However, the main drawbacks of hydrogen, and in particular of green hydrogen, are its high cost and its current difficulty in long-term storage and transportation (by pipeline or trucks). One main characteristic of G-H₂ is its locally distributed production and availability, which is also a common feature of biomass availability [5]. Using G-H₂ in bio-based systems and biorefineries offers the advantage of local integration, avoiding costs and environmental impacts associated with long-distance transportation [6]. Variable renewable energy sources (VRESs) can generate more electricity than the grid can handle, leading to potential overloads or wasted energy if storage systems are not adequate. Instead of overloading the grid, this energy can be stored as chemical energy in the form of hydrogen. The transportation of renewable energy stored as hydrogen over long distances could be economically attractive in places where there is insufficient grid capacity or where grid extension is impractical or more expensive than hydrogen transport. Some examples include harnessing remote renewable energy from offshore wind using on-shore or big solar farms [7]. In recent years, several scientific studies have explored the possible integration between bio-based processes and hydrogen availability [8] [9]. Specifically, recent research has focused on the potential utilization of G-H₂ to convert bioresources, considering the variability in G-H₂ availability [10]. Additionally, hydrogen from water electrolysis and biomass gasification have been proposed as solutions to stabilize G-H₂ production, ensuring the continuous production of hydrogen [11]. The Power-to-X concept has also been applied to pyrolysis oil upgrading, producing marine fuels at a cost of approximately 120–170 EUR/ton (EUR/t) [12]. Coupling solar energy conversion with G-H₂ in the production of methyl succinic acid via the hydrogenation of itaconic acid directly in the electrolyzer represents a novel option to reduce the hydrogen cost to around 1.50 EUR/kg_{H₂} [13]. Papers in the literature typically assess separately the local potential of G-H₂ [14], [15] or the local bioenergy potential. Ikäheimo et al. studied several Biomass-to-Liquid (BtL) process pathways that were compared across nine European countries [16]. From that, the total optimal capacity of biomass-derived liquid fuel varied between 37 and 54 TWh/year (TWh/y) with costs in the range of 100-150 EUR/MWh. However, to the best of our knowledge, no previous studies so far explored the

potential local integration between RESs and biorefinery processes. One main issue in the integration between biorefineries and G-H₂ is the assessment of the biorefinery size, taking into account both G-H₂ and biomass availability.

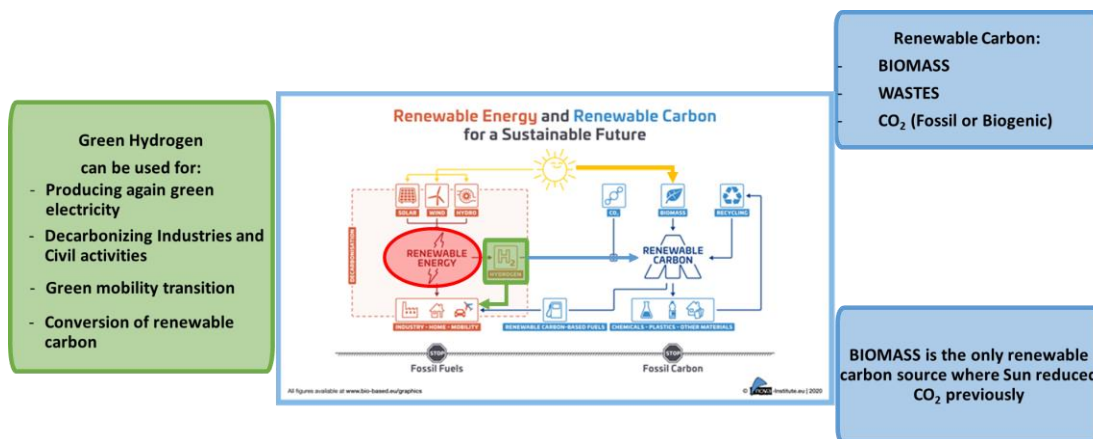


Figure 1. Renewable carbon sources and green hydrogen integration opportunity, adapted from [17]

1.2 Biomass availability and local green hydrogen

Biomass availability was recently surveyed in the JRC report "Biomass production, supply, use and flows in the European Union" [18], which includes domestic production and net imports, in the EU-27 in 2017 amounting to approximately 1 billion tons of dry matter (tdm). Of these availabilities, almost 70% of the biomass supply is from the agricultural sector, which includes food, residues collected, and grazed biomass, the 27% of remaining biomass sources are from forestry and less than 1% is from aquaculture. A recent study of the Imperial College[19] has provided an estimation of the sustainable biomass potential availability in the EU 27 + UK by 2030 and 2050. The sustainable biomass availability will be from 0.98 to 1.2 billion dry tons in 2030 and from 1 to 1.3 billion tons in 2050. However, to realize this potential, additional R&D would be required as well as the implementation of improved management strategies (e.g., the supply chain would need to be developed to mobilize all these resources, etc..). On the other hand, the specific local availability depends on a series of factors. This makes often major biomass availability dispersed in the rural lands, with a biomass density of about 50 – 60 t/km² per year [20].

As part of the Renewable Energy Directive (RED II), the European Commission set ambitious targets for 2030 and beyond in FIT for 55. Table 1 shows the forecasted penetration of Renewable Energy Sources (RES). The overall strategy implies a strong increase in the production of electricity from RES, mainly photovoltaic and wind until 1,102 GWe (46% wind and 54% photovoltaic) installed before 2030 [21]. On the whole, despite the benefit of RES like wind and photovoltaic in the pathway to decarbonization some limits to the implementation remain mainly lying to the integration of non-programmable RES into the power system and their non-constant productivity. As a result, in some hours, the produced electricity could be larger than the demand

thus causing a surplus of energy. When overgeneration occurs, electricity must be recovered in short-term or long-term storage, converted into different energy forms, or curtailed.

Table 1: Electricity production trajectories from RES in the coming years

	RED II	Fit for 55
Total RES share 2030	32%	42.5%
RES-Electricity share	59%	64-67%
RES Heating & Cooling share	33%	39-42%
RES-Transport share	14%	29%

As reported in many studies [22], hydrogen storage appears to be the most favorable technology because it offers a much larger potential for storing surplus renewable electricity, compared to other technologies such as compressed air storage, hydro pumps and batteries. This opens the opportunity to use hydrogen as an energy carrier. In the context of green hydrogen (G-H₂) production, the fluctuations of the capacity factor (namely the ratio of the actual electrical energy output over a daily and seasonal basis to the theoretical maximum electrical energy output over that period) can significantly impact the required scale and cost of the G-H₂. The need for low-cost electricity to produce G-H₂ through electrolysis could offer an option to use the surplus of renewable electricity at a local level. Identifying and locating these surpluses is important as it would allow to assess the most suitable position of hydrogen production plants to minimize:

- losses caused by the distance between RES plants and electrolyzers;
- the need to build new dedicated RES plants;
- and the non-profitable loss in the power network.

One of the main challenges in utilizing hydrogen as an energy carrier is current the technical limits of its storage and long-distance transportation, primarily due to its low boiling point (<-250 °C) and low density compared to other fuels. To address this, the concept of Power-to-X has emerged, which involves converting renewable hydrogen into various forms denoted as 'X.' This approach is increasingly favored by green hydrogen producers, as it provides a more viable solution for overcoming storage and transportation challenges [23]. On the other side, hydrogen can be a reactant in many processes for the production of fuels and chemicals. Table 2 shows the current G-H₂ production costs by matching the renewable energy source and the electrolyzer technology. The average current G-H₂ cost is in the range of 2-5 EUR/kg to which further storage and transportation costs must be added.

Table 2: Average G-H₂ production costs (EUR/kg_{H2}) [24]

	Solar	Onshore wind
Alkaline	1.7	2.8
PEM	3.2	4.8
SOEC	14.4	17.9

Selecting the best location to install electrolyzers for the production of G-H₂ through electricity surplus deriving from RES, is essential for the whole process to be as efficient as possible. Currently, the G-H₂ production cost through water electrolysis is the limit for its wide diffusion and utilization. Another possibility to supply G-H₂ is represented by Waste-to-H₂, where thermochemical routes can convert solid materials to syngas and then to pure green hydrogen by carbon capture. Against the advantage of enabling continuous G-H₂ production, the main disadvantages consist of higher CO₂ production as a by-product. Obviously, G-H₂ can in principle be used in the same sectors as other sources of hydrogen while ensuring a more positive carbon footprint. Using G-H₂ in bio-based systems and biorefineries would have the advantage to allow a local integration avoiding costs and environmental impacts due to storage for long times and transportation. In fact, a common characteristic of G-H₂ and biomass consists in the huge territorial dispersion (e.g. in the rural areas), leading to a potential opportunity for a green matching between them.

1.3 Content of the report

This report presents a techno-economic evaluation of four real case studies to determine the alignment between existing biorefineries and the potential availability of green hydrogen. In particular, process design and mathematical models were employed to estimate the production costs of four bio-based target products: biomethane derived from the CO₂ of biogas, green diesel obtained through triglyceride hydrogenation, aromatics from lignin-rich streams of lignocellulosic biorefineries, and aviation fuels produced via bioethanol conversion. Each study was localized by referencing an existing biorefinery listed in the IEA Bioenergy Global Atlas of Biorefineries and analyzing the availability of green hydrogen in the corresponding region. The most promising biorefinery conversion processes and biogenic CO₂ conversion processes using hydrogen as a reactant were identified to outline potential case studies. The first step involved selecting the bio-based process of interest, subsequently, a biorefinery was identified using the IEA Bioenergy Biorefinery Atlas [25]. Based on the hypothesis that variable renewable energy (VRE) farms could cause issues related to electricity dispatching on the grid due to overloading, two preliminary steps concerning green hydrogen (G-H₂) were undertaken. The first step involved verifying the availability of variable renewable energy sources (VRES) within 10, 50, and 100 km of the identified biorefinery. The second step focused on quantifying the potential availability of G-H₂. From a technical point of view, hydrogen demand depends on several factors, including the size of the biorefinery and the hydrogen requirements of the technology or process relative to the production capacity (e.g., kg_{H₂} per kg of feedstock or product). The description of the bio-based processes was studied, and mass and energy balances were carried out to perform a techno-economic analysis, including the sizing of the biorefinery sections. After determining the G-H₂ demand from the biorefinery assessment, a comparison was made between the potential G-H₂ availability and its demand. If the potential G-H₂ supply exceeded the demand, the integration was deemed feasible and considered an opportunity. However, if the G-H₂ demand was too high to be met by local VRESs, a different biorefinery from the Biorefinery Atlas was identified. Finally, four final case studies were analyzed in detail. The production cost of the hydrogenated target product was calculated, excluding the cost of hydrogen supply. By summarizing the production cost and hydrogen supply cost, the final production cost of the target product was calculated and compared to its market value.

2. Bio-based processes using Hydrogen

Many bio-based processes for biofuels and/or chemicals precursors include hydro-treating steps and hydrogen use as a chemical reactant. One expression often used in the bio-based economy is “high-added value compounds”. This sentence refers to a precise technical definition, namely the difference between the final product market price multiplied by the process yields and the Raw Material (RM) supply cost as displayed below:

$$\text{Added value} = \text{Product market price} * \text{process yield} - \text{RM market price} \quad (1)$$

The added value quantifies how much economic value is added to the initial raw material through the specific conversion process. In the case of hydro-treatment, low added values can be convenient when the hydrogenation process serves to produce large volumes. When the added value is high, lower volumes can be economically convenient. This latter case coincides with the typical characteristic of biomass, especially biomass residues, and G-H₂ through the overproduction of renewable electricity. Figure 2 provides a draft classification of the hydrogen using processes in terms of hydrogen volumes needed and the added value of the final products. The technologies were mapped based on preliminary assessment using scientific references and review papers. The box dimension is proportional to the data variability ranges. Overlaying this distribution with a TRLs classification a preliminary feasibility of the technologies integration can be achieved. High-added value products typically have low TRLs, while technologies with higher TRLs typically produce products with lower added values. Obviously, the current cost of G-H₂ makes its use economically sustainable for processes in which the added value is high even if it currently coincides with low TRL technologies, still far from the market implementation. In particular, bio-based plants requiring hydrogen amounts lower than 1,000-2,000 t_{G-H₂}/y (about 30 – 40 MW of RES installed) can be feasible in terms of local G-H₂ through the overproduction of renewable electricity. Plant sizes higher are possible only through dedicated installed facilities for the production of renewable electricity. When the added value is in the range of 100 – 200 EUR/t_{RM}, the cost of supplying green hydrogen cannot exceed 1-2 EUR per kg, namely about one-third or half the current cost (i.e. grey hydrogen) [26]. When the added value is higher than 300 EUR/t_{RM} and the quantity of hydrogen per unit of raw material is low (i.e. lower than 100 kg_{H₂}/t_{RM}), the cost of supplying G-H₂ can even reach 3 EUR per kg. Plants/technologies requiring more than 2-3,000 t/y of G-H₂ imply an installed overall photovoltaic energy of 150-200 MW capacity (roughly 2-300 ha of soil consumption) or wind more than 100 MW capacity (roughly 10-20 ha of soil consumption) and this could be feasible only through dedicated facilities.

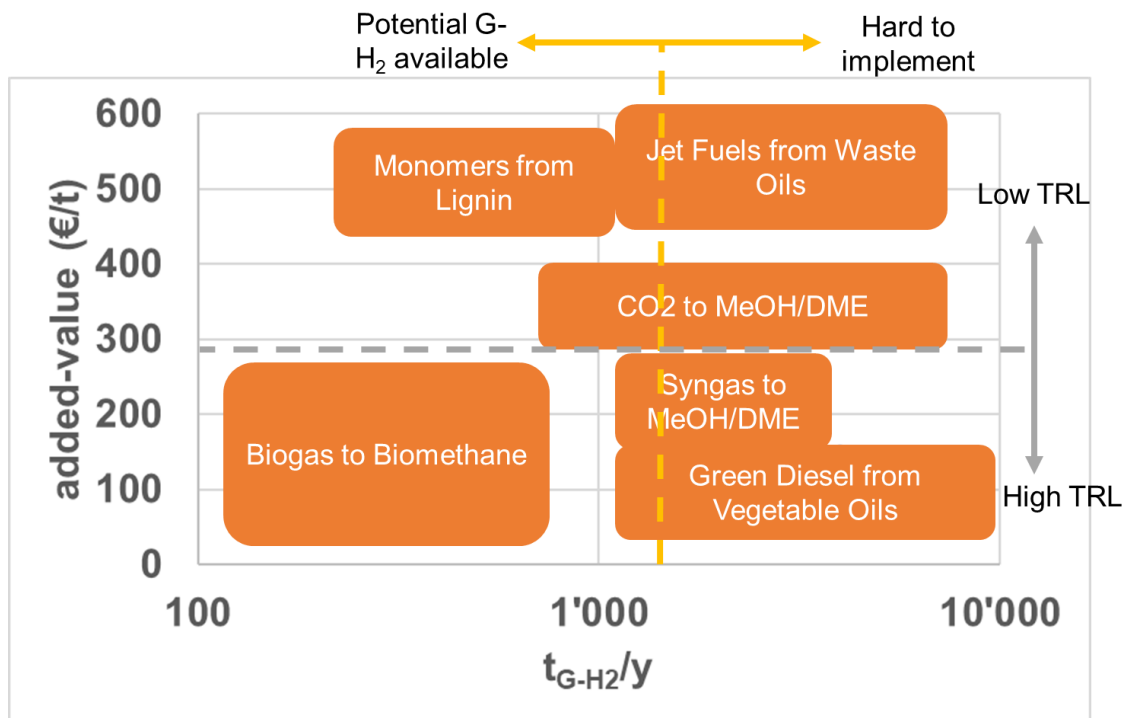


Figure 2: biobased processes using green hydrogen through the overproduction of renewable electricity

2.1 Converting biomass/intermediates and/or biogenic CO₂

A detailed analysis of the biorefineries was essential to define the scope of the work. Biorefinery conversion processes using hydrogen as a reactant were identified. The commercial-scale processes for converting biomass can be summarized as producing green diesel (GD), Sustainable Aviation Fuels (SAF), and aromatics. Table 3 contains each main process converting biogenic carbon and hydrogen to bioproducts adding value to the carbon atoms of biomass. Drop-in diesel can be derived by hydrogenation reactions of triglycerides as vegetable oils, microbial oils, used oils, and lipids. Advanced biofuels from waste and residues from oils and fats can be called SAFs when they can be used as drop-in fuels in the aviation sector [27]. SAFs can be derived from second-generation bioethanol through three primary steps: alcohol dehydration, oligomerization, and hydrogenation, followed by filtration to yield naphtha, SAF, and green diesel [28]. The lignin-derived aromatics compounds (i.e., benzene, toluene, xylene (BTX), and alkyl phenols, cresols,...) can be produced through hydrodeoxygenation (HDO) processes[29]. Further, the most promising biogenic CO₂ conversion processes using hydrogen can produce biomethane [14], methanol, dimethyl ether, and FT-diesel synthesis [15].

All the bio-based resources containing carbon listed in Table 3 can be used as feedstock for various conversion processes, including thermochemical (e.g., gasification, pyrolysis), biochemical (e.g., syngas fermentation, microbial depolymerization of lignin), or catalyzed (e.g., transesterification of lipids, acid-catalyzed hydrolysis of sugars) technological strategies. The latter type of process is the most commonly used to convert bioresources, intermediates, biogenic

CO₂, and hydrogen into both fuels and chemicals. Medium or high pressures characterize the hydrogenation processes.[30]. Heat integration is often favorable due to the exothermic nature of the reactions involved, with temperatures ranging between 300 and 400 °C [31]. In most of these processes, the use of excess hydrogen requires recycling.

Table 3. Hydrogen utilization in biorefineries.

	Process Pathways	Final products
Energy and Fuels	CO ₂ (biogas, fermentation gas, exhaust gases) + H ₂ → Biomethane	Grid injection, biofuel
	CO ₂ (biogas, fermentation gas, exhaust gases) + H ₂ → C ₂ /C _n bioproducts, Methanol, DiMethyl Ether	Maritime fuels, bio-LNG
	Biomass Gasification → syngas (H ₂ /CO adjustment) → C ₂ /C _n bioproducts, Methanol, DiMethyl Ether, parafines	Maritime fuels, aviation fuels
	Lipid sources (used oils, vegetable oils, microbial oils, algae) + H ₂ → parafines/isoparafines	Diesel, aviation fuels, biolubricants
	BioAlcohols + H ₂ → parafines/isoparafines	Diesel, aviation fuels
	Biomass/Lignin Hydrothermal liquefaction/pyrolysis → biocrude + H ₂ → aromatics/parafines/isoparafines	Bioaromatics, aviation fuels
Chemicals	Lignin + H ₂ → aromatics	Bioaromatics
	Biosuccinic acid + H ₂ → BDO	Building blocks for polymers
	Sugars + H ₂ → polyalcohols	Sugar alcohols

2.2 Green hydrogen production, storage, transportation

The potential availability of G-H₂ was calculated by multiplying the installed capacity of VRE by the specific local capacity factor associated with the type of renewable energy source (solar or wind). The G-H₂ supply chain analysis was performed using simplified models from the literature to estimate the contributions to the final hydrogen cost [32]. In particular, VRE coupled with electrolyzers was considered the process pathway for producing G-H₂ [33]. Figure 3 illustrates the two possible storage options for hydrogen: compressed and stored in a cavern, or liquefied and stored in tanks. G-H₂ production also depends on its phase due to the different energy requirements for compressing or liquefying the hydrogen [32]. G-H₂ can be transported by pipeline if it is in a gaseous state, or by trucks if it is either gaseous or liquid. Using the local VRE potential overproduction and the distance between the renewable energy source farms and the biorefinery as input data, the maximum hydrogen flow rate and G-H₂ supply costs were calculated, taking into account each possible storage and transportation method: gas pipeline, gas truck, or liquid truck.

Following the energy train of Figure 3, a different energy capacity is necessary to produce gaseous or liquefied G-H₂:

$$E_{RES,p} = F_{H_2,demand} LHV_{H_2} (1 + Losses_{STOR,p}) \frac{(E_{STOR,p} + LHV_{H_2})}{LHV_{H_2}} \frac{E_{ELEC}}{LHV_{H_2}} \quad (2)$$

where $E_{RES,p}$ is the electricity demand (MJ/hour, MJ/h) to produce a continuous mass flowrate of hydrogen $F_{H_2,demand}$ (kg/h) with the phase p (gas or liquid), $Losses_{STOR,p}$ is a percentage of hydrogen lost with the phase p during the storage time with the hypothesis of storage for 60 days, $E_{STOR,p}$ is the energy consumption for the compression or the cooling/liquefaction of 1 kg of hydrogen (MJ/kg) to obtain the phase p , LHV_{H_2} is the Lower Heating Value of hydrogen (120 MJ/kg), and E_{ELEC} is the electricity to be fed to the electrolyzer to produce 1 kg of hydrogen (MJ/kg); data, parameters, and more details are from Reuß et al. (2017) [32].

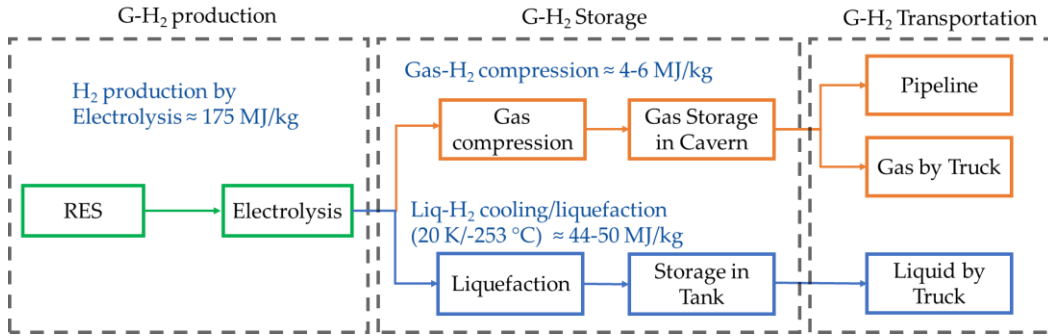


Figure 3. Green hydrogen supply scheme for the calculation of the green hydrogen potential production (adapted from [32]).

The G-H₂ supply cost calculation could be summarized by following set of equations:

$$H_{2,cost,p,t} = \frac{C_{TOT,p,t}}{F_{H_2,demand} h_{yearly}} \quad (3)$$

$$C_{TOT,p,t} = C_{CAPEX,p,t} + C_{fixOPEX,p,t} + C_{varOPEX,p,t} \quad (4)$$

$$C_{CAPEX,p,t} = C_{investment,p,t} AF \quad (5)$$

$$C_{investment,p,t} = C_{investment,RES} + C_{investment,ELEC} + C_{investment,STOR,p} + C_{investment,TRANS,p,t} \quad (6)$$

$$AF = \frac{(1 + WACC)^n WACC}{(1 + WACC)^n - 1} \quad (7)$$

$$C_{fixOPEX,p,t} = C_{investment,RES} OM_{RES} + C_{investment,ELEC} OM_{ELEC} + C_{investment,STOR,p} OM_{STOR} + C_{investment,TRANS,p,t} OM_{TRANS} \quad (8)$$

$$H_{2,cost,p,t} = \frac{C_{TOT,p,t}}{F_{H2,demand} h_{yearly}} \quad (9)$$

where $H_{2,COST,p,t}$ (EUR/kg) is the final G-H₂ supply cost supposing the phase p and transportation scenario t (pipeline or by truck); h_{yearly} (h/y) is the working hours per year of the biorefinery; $C_{TOT,p,t}$ (EUR/y) is the total cost to implement the G-H₂ production, storage, and transportation; C_{CAPEX} , $C_{fixOPEX}$, and $C_{varOPEX}$ are the investment costs, fixed operating costs, and variable operating costs, respectively; AF is the annuality factor (%); $WACC$ is the Weighted Average Cost of Capital; $C_{investment}$ is the investment cost to install the VRES capacity, electrolyzers, storage systems, and the transportation infrastructures; OM are the operating and maintenance costs; and $C_{TRUCK,p}$ are the variable costs for the truck transportation scenario for the fuel supply.

3. Case studies identification

Table 4 shows the case studies analyzed through georeferenced data of the biorefineries and the local G-H₂ potential availability. In particular, four territorial studies were conducted, changing the main bio-based process from Table 3, using the Atlas of Biorefineries portal [25].

Table 4. Case study overview – input data.

Tag in Figure 17	Main bio-based process	Plant size	Localization	Local VRE individuated
a	Biogas upgrading to biomethane by methanation	3 MWth	Basilicata (Italy)	Wind farms for 219 MW–10 km
b	Hydroprocessed Esters and Fatty Acids (HEFAs) from oils and lipids	700,000 t/y of oil as feedstock	North Dakota (USA)	Wind farms for 300 MW (40 km) or 615 MW (100 km)
c	Lignin hydrotreatment	70,000 t/y of lignin from a lignocellulosic biorefinery	Alagoas (Brazil)	Wind farms for 220 MW–300 km
d	Sustainable Aviation Fuels from bioethanol	180,000 t/y of 2nd gen. ethanol to be converted	North Queensland (Australia)	Solar farm for 110 MW–30 km

3.1 Case studies localization

As part of the activities of IEA Task 42, the "Global Biorefineries Atlas" portal was developed and made public during the 2019-2021 period [34]. This WebGIS portal on global biorefineries was developed using open-source tools and it allows to visualize, query, and download the collected data. All data reported on the portal stem from a process of collection, analysis, and harmonization of various databases that track the development of the bioeconomy in general (e.g., JRC, IEA Bioenergy, BBI, DOE, European and National Projects, etc.), with a focus on the development of biorefineries, whether energy-driven or product-driven.

During the 2022-2024 period, the portal has been continuously updated, verifying and updating the plants already cataloged, adding new plants, and implementing new functionalities. through the use of the information reported on the developed portal and the bibliographic analysis of

technical documents prepared by other public bodies, the sites where the case studies were developed were identified.

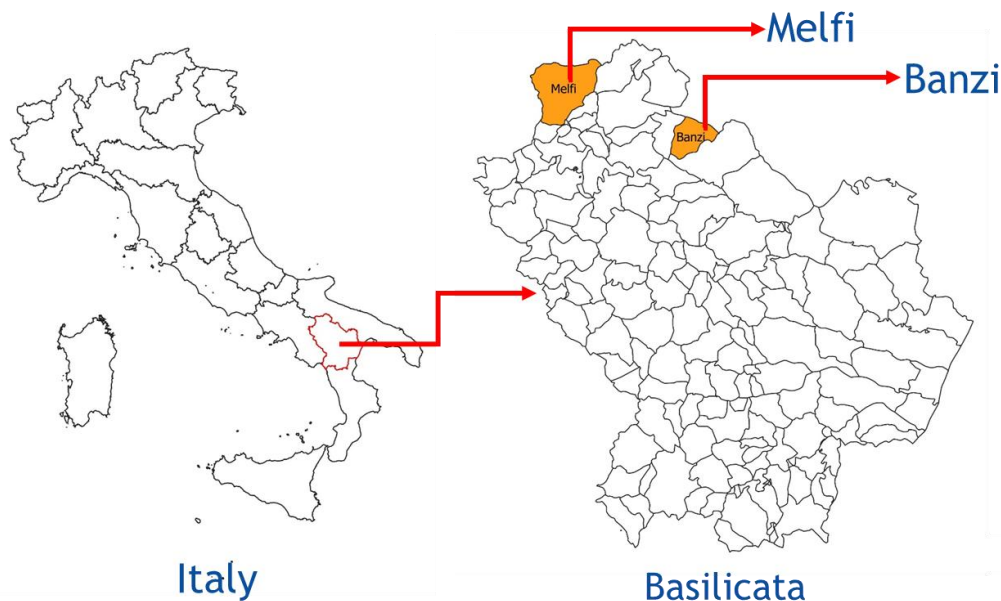


Figure 4. Localization of the first case study “Biogas upgrading to biomethane by methanation” in Basilicata region - Italy.

The localization of 1st case study was in Basilicata Region, South Italy. The Basilicata is a small Region, with a population of about 572 thousand people and a surface of about 10,000 km². From an energetic point of view, as reported by statistics elaborated every year by TERNA, which is the Italian company that manages the Italian electricity network, Basilicata Region produces, from 2017 to today, more electricity than it consumes [35]. The renewable source produces more than 91% of electricity and wind is the main source. Each inhabitant consumes about 5,101 kWh per year. The power surplus in 2021 was 768.4 GWh, which is ceded to other regions [35]. The distribution of RES plants by the municipality was acquired from the AtIaimpianti portal managed by GSE [36]. To calculate the production of electricity by RES plants, equivalent hours were calculated, i.e. the number of hours per year during which a plant, hypothetically, generates electricity at nominal power and are equal to the ratio between the gross production generated in a year and the nominal power. In this way, the production of RES by the municipality was calculated and knowing the consumption per municipality, equal to the number of inhabitants times the annual consumption per inhabitant provided by TERNA, the possible electrical surpluses by the municipality were estimated. From the analysis, it was clear that the municipalities of Melfi and Banzi (Figure 4) are those with the largest electrical surplus and furthermore in these municipalities, there are a biogas plant with nominal power of 1MW.

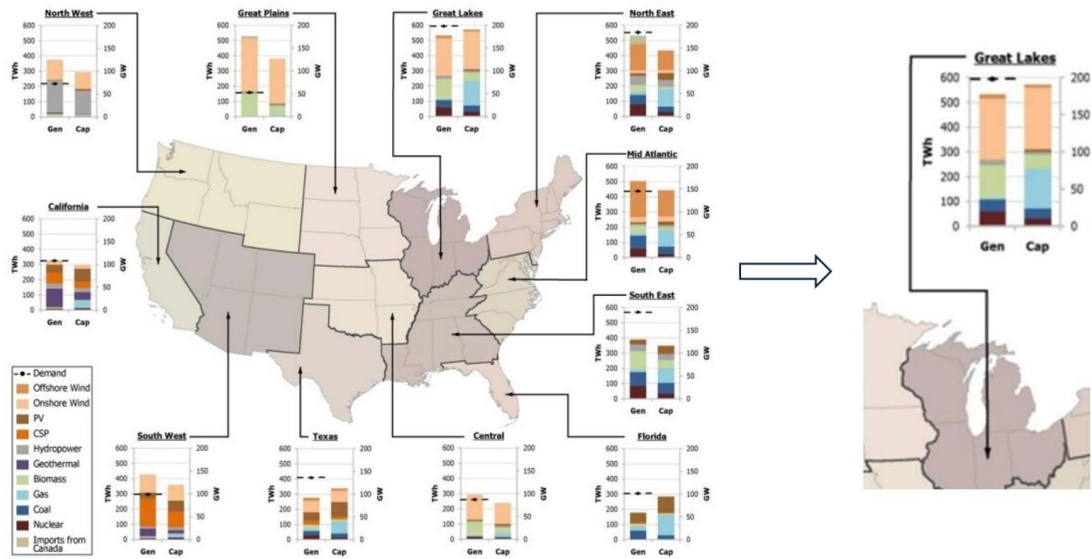


Figure 5. Localization of the second case study “Hydroprocessed Esters and Fatty Acids (HEFA) from oils and lipids” in North Dakota – USA, adapted from [37].

The 2nd case study was implemented in North Dakota in USA. It is a landlocked U.S. state in the Upper Midwest. It is part of the Great Plains region, characterized by broad prairies, steppe, temperate savanna, Badlands, and farmland. From energetic point of view, as reported by report “Renewable Electricity Futures Study - Exploration of High-Penetration Renewable Electricity Futures” [37] elaborated by National Renewable Energy Laboratory (NREL) providing an analysis of the implications and challenges of renewable electricity generation levels—from 30% up to 90%, with a focus on 80%, of all U.S. electricity generation from renewable technologies—in 2050. It’s possible to observe that Great Plains is forecast to be net exporter of electricity by 2050, with a total electricity exceeding regional electricity demand (Figure 5).

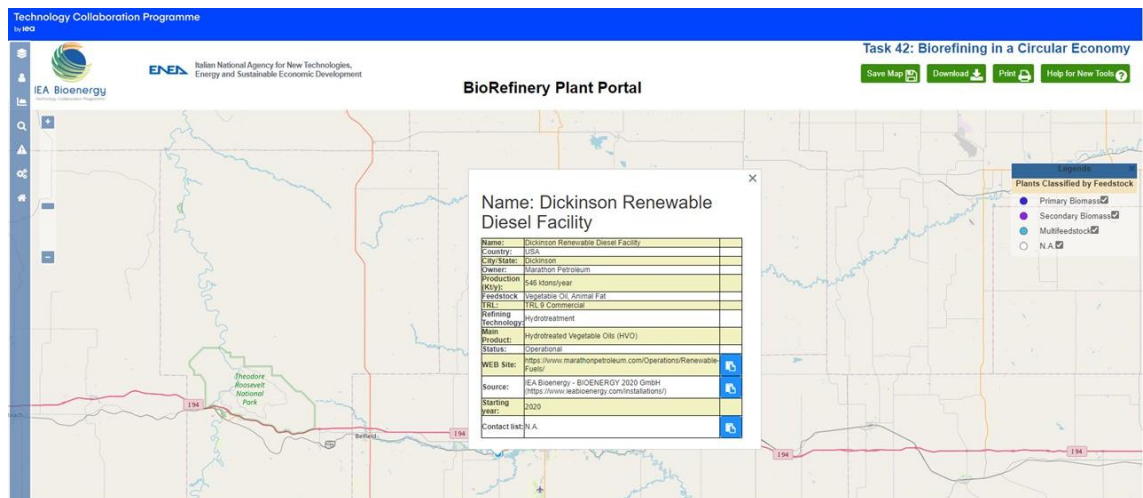


Figure 6. Details of the Dickinson Biorefinery in North Dakota – USA, from the Biorefinery Atlas [34].

In particular wind energy supply and biomass supply were most significant in this region. Moreover, in this region, in particular in Dickinson North Dakota, the petroleum company Marathon, converted the petroleum refinery into a renewable diesel facility, which became fully operational in 2021 as the second largest facility of its kind in the United States. The information associated with this plant can be found in the IEA Task 42 Global Biorefinery Atlas (Figure 6).

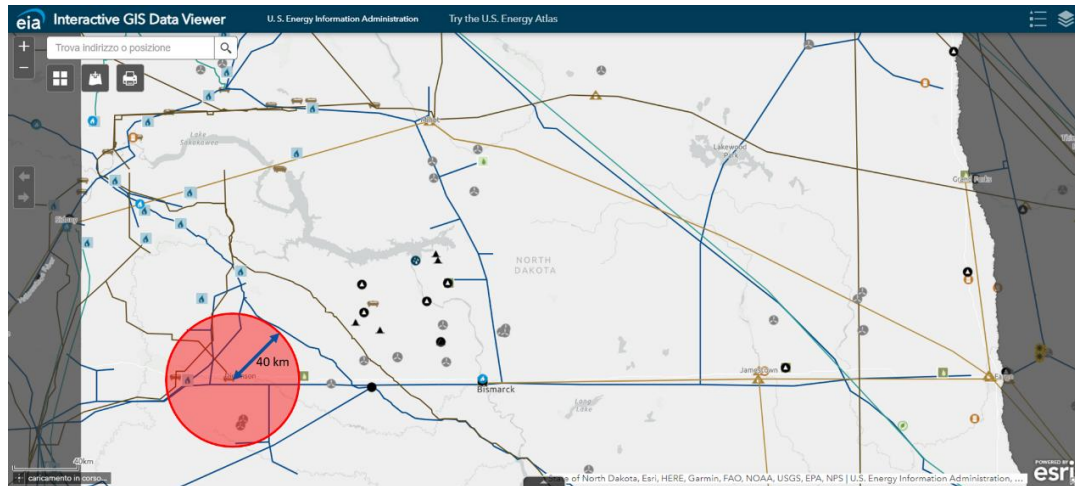


Figure 7. Localization of the second case study “Hydroprocessed Esters and Fatty Acids (HEFA) from oils and lipids” and VRE farms individuated near the Dickinson Biorefinery in North Dakota – USA considering a radius of 40 km [38].

From data acquired from U.S. Energy Information Administration (EIA) and in particular the U.S. Energy Atlas [38] is possible to see that within a radius of 40km (Figure 7) and 100km (Figure 8) there are wind farms from Dickinson for a total of 300 and 615 MW installed, respectively.

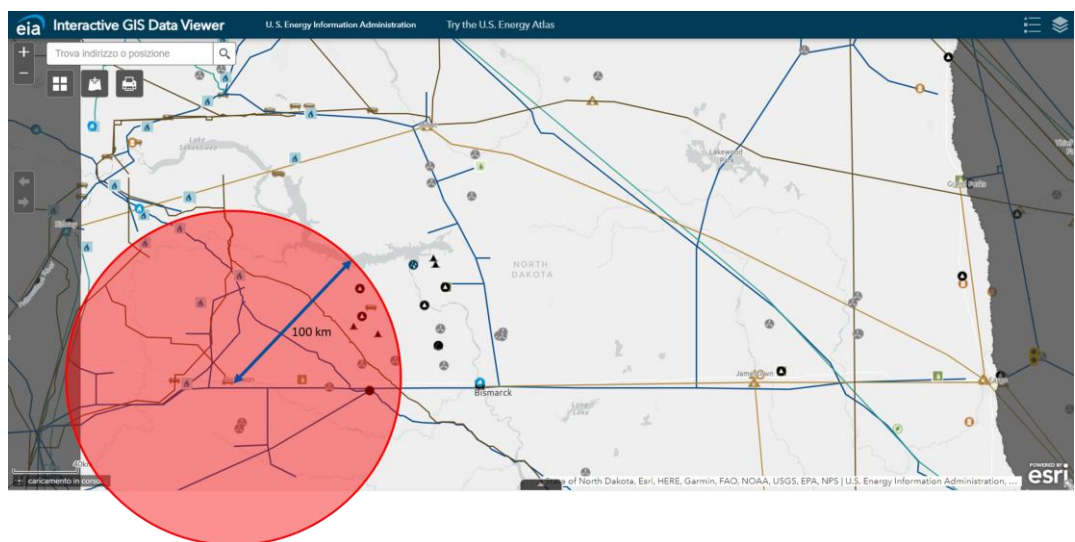


Figure 8. Localization of the second case study “Hydroprocessed Esters and Fatty Acids (HEFA) from oils and lipids” and VRE farms individuated near the Dickinson Biorefinery in North Dakota – USA considering a radius of 100 km [38].

The 3rd case study was located in Brazil. It is the world's second-largest ethanol producer and third-largest biodiesel producer [39]. In September 2016, at the twenty-first session of the Conference of the Parties (COP21), Brazil officially joined the Paris Agreement. Following a reduction in the Intended Nationally Determined Contribution (NDC) submitted in 2022, which was criticized by civil society and climate experts, the Brazilian government announced in November 2023 a new target to reduce greenhouse gas (GHG) emissions by 48.4 percent by 2025 and 53.1 percent by 2030 compared to 2005 emissions.

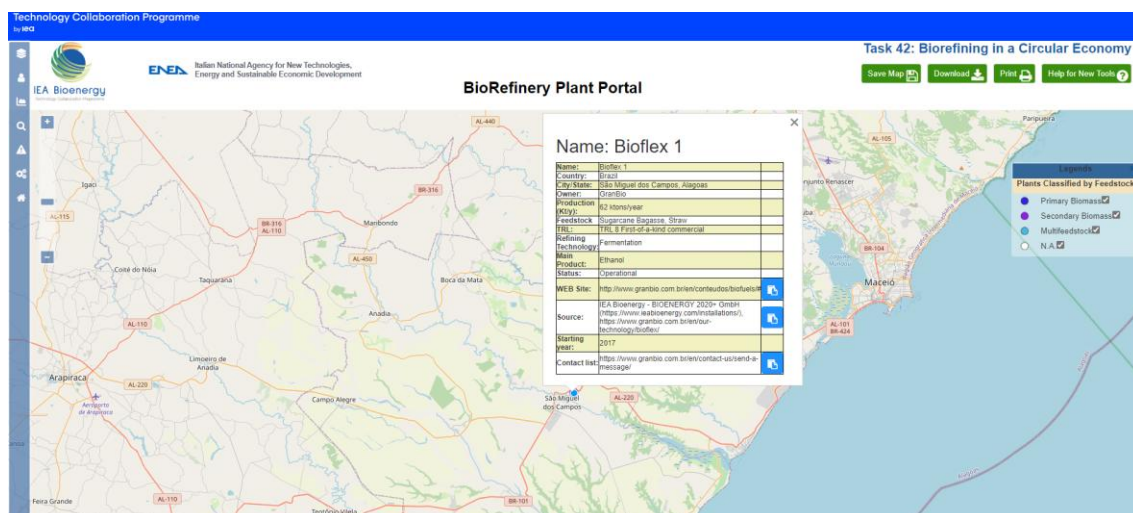


Figure 9. Details of the Bioflex 1 Biorefinery in Alagoas – Brazil, from the Biorefinery Atlas [34].

To ensure compliance with the targets and reduce GHG emissions in the transportation sector, the Brazilian government launched the National Biofuels Program, called *RenovaBio*, in December 2016, which modified the policy and regulatory framework for the use of biofuels in the country. *RenovaBio*'s goals are in line with the country's commitments under the Paris Agreement and other international environmental commitments. Considering these new goals and policy implemented, this country was selected as case study. The plant selected as a reference was the Bioflex 1 plant (Figure 9). This plant started in 2014 and produces cellulosic ethanol, from sugarcane bagasse and straw with a capacity production of ethanol of 65 kt/year. According to GlobalData.com [40], company who tracks and profiles over 170,000 power plants worldwide, Brazilian wind developer *Casa dos Ventos Energias Renovaveis* has planned to invest at least BRL 700 million (more or less 135.7MEUR) in a 220-MW wind project in the state of Alagoas, northeastern Brazil, the same state of Bioflex 1. The Figure 10 shows some information about this project extracted by GlobalData.com. According to GlobalData.com [40], company who tracks and profiles over 170,000 power plants worldwide, Brazilian wind developer *Casa dos Ventos Energias Renovaveis* has planned to invest at least BRL 700 million (more or less 135.7MEUR) in a 220-MW wind project in the state of Alagoas, northeastern Brazil, the same state of Bioflex 1. The Figure 10 shows some information about this project extracted by GlobalData.com.

The development of this wind farm will ensure that a renewable electricity source will be available in the vicinity of the plant, the surplus of which could be used for the production of green hydrogen to be integrated with the product of the biorefinery under consideration, aimed at the possible production of aromatics from lignin derived from the production of 2nd generation ethanol.

Project Type	Onshore
Total Capacity (MW)	220
Active Capacity (MW)	-
Pipeline Capacity (MW)	220
Project Status	Permitting
Project Location	Alagoas, Brazil
Project Developer	Casa dos Ventos Energias Renovaveis

Source: GlobalData Power Intelligence Center

Description

The project is being developed and currently owned by Casa dos Ventos Energias Renovaveis. The company has a stake of 100%.

The wind power project consists of 50 turbines.

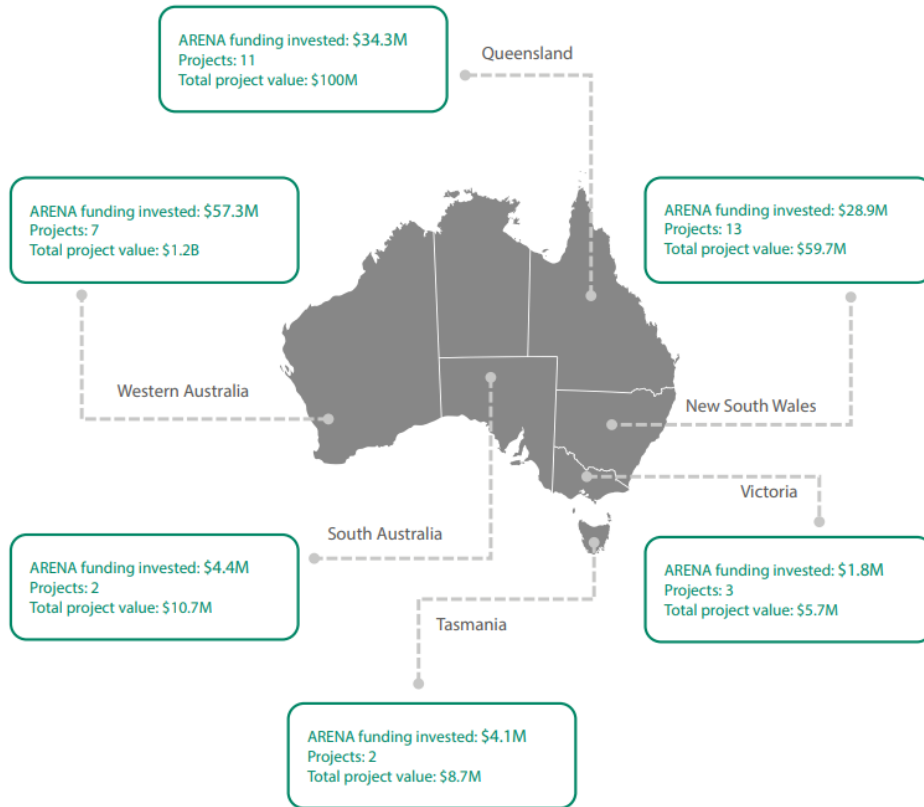
Development status

Post completion of the construction, the project is expected to get commissioned in 2024.

Figure 10. Details of the Wind farm selected for the third case study “Lignin hydrotreatment” in Alagoas – Brazil, adapted from [40].

The fourth case study focuses on Australia. According to the Australian Renewable Energy Agency [41], the country aims to expand bioenergy as a key energy source. Currently, bioenergy represents 5% of Australia's renewable energy generation, compared to 7% in other OECD countries. To achieve this goal, the Australian Government has developed a roadmap to define the role of the bioenergy sector in the nation's energy transition. Released in 2021, the Bioenergy Roadmap (<https://arena.gov.au/knowledge-bank/australias-bioenergy-roadmap-report/>) seeks to guide future investments and policy decisions within the bioenergy sector. Australia's bioenergy sector has the potential to contribute approximately \$10 billion to the country's GDP annually, create 26,200 new jobs, reduce emissions by about 9%, divert an additional 6% of waste from landfill, and enhance fuel security. Figure 11 illustrates ARENA's funding for bioenergy-related projects in Australia.

**TOTAL ARENA FUNDING FOR BIOENERGY RELATED PROJECTS BY STATE AND TERRITORY
(AS AT 30 SEPTEMBER 2021)**



Source: ARENA

Figure 11. Total ARENA funding for Bioenergy related projects by state and territory for the localization of the fourth case study “Sustainable Aviation Fuels from bioethanol” in North Queensland - Australia, adapted from [41].

The first theme addressed in the *Bioenergy Roadmap* focuses on “Enabling market opportunities in hard-to-abate sectors,” identifying three priority market opportunities, including aviation. Progress in the aviation sector by the 2030s is expected to include the early deployment of pre-commercial sustainable aviation fuel (SAF) production plants, paving the way for a viable Australian-based industry. This could result in up to 1,908 ML per annum of SAF production, representing approximately 18% of the aviation fuel market [41]. Additionally, according to ARENA, the use of renewable hydrogen in Australia could significantly reduce emissions in high-temperature industries. To support this, the Australian Government has developed a *National Hydrogen Strategy*, which is set to be updated in 2023.

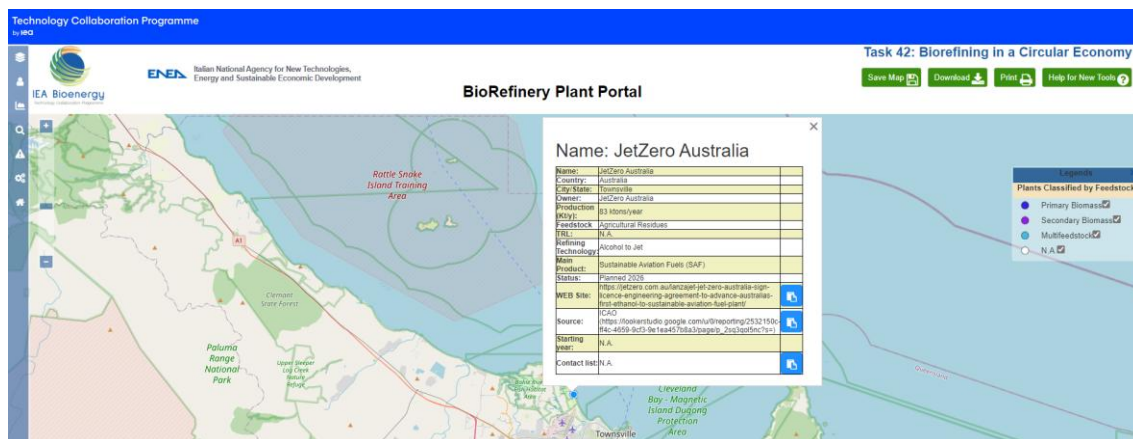


Figure 12. Details of the JetZero Biorefinery in North Queensland - Australia, from the Biorefinery Atlas [34].

Furthermore, the government has launched the \$2 billion *Hydrogen Headstart* initiative [42], aimed at scaling up large green hydrogen projects across the country. These factors collectively make Australia an ideal choice for this case study. The biorefinery selected as a reference is the planned JetZero Australia plant, to be located in Townsville, Queensland. All relevant information about this plant is available in the IEA Task 42 *Global Biorefinery Atlas*. Figure 12 displays the information related to JetZero as reported in the Atlas.

3.2 Case studies description and assessment

The Technical assessment of the identified biorefinery was carried out using common modeling and simulation methodologies. Specifically, process simulations of the biorefinery processes were conducted to obtain mass and energy balances, employing rigorous thermodynamic and reaction kinetics approaches for the reaction and purification sections. Preliminary designs were utilized for reactor sizing, always considering reaction kinetics data from the literature. For the final techno-economic assessment by calculation of the production costs, a cash flow analysis of the case studies was conducted. Cash flows are defined as the net movement of money into or out of a company resulting from investments, while depreciation refers to the reduction in the value of an asset over time. Depreciation is calculated using a linear model and is treated as a production cost, even though it does not represent an actual cash flow for the company:

$$CF_i = (Pp_p - C_{OperatingBio}) \cdot (1 - tax) + Dep \cdot tax - C_{InvestmentBio} \quad (10)$$

where CF_i is the Cash Flow for the year i , P is the mass annual flowrate of the target product obtainable from the biorefinery, p_p is the product production cost to be calculated, $C_{OperatingBio}$ is the operating cost of the biorefinery, Dep is the depreciation, and $C_{InvestmentBio}$ is the investment cost for the biorefinery. Capital costs were estimated using shortcut methods, recognizing that the investment costs of chemical plants often scale with increasing throughput, while the specific

investment costs decrease. Scaling functions were applied to estimate the resulting investment costs:

$$C_{Biorefinery} = C_{base} \left(\frac{ProcessCapacity}{BaseloadCapacity} \right)^m \quad (11)$$

where C_{base} consists of the investment costs for the biorefinery equipment related to the reference process capacity (*BaseloadCapacity*); *ProcessCapacity* is the flowrate, characteristic length/size, and heat/power requirement of the equipment; and m is the exponential factor for the equipment type [43]. The Net Present Value (*NPV*) method represents the comparison of the present worth of all cash inflows to the present worth of all cash outflows associated with the investment project. The formula for *NPV* used in this study is the following:

$$NPV = \sum_{i=0}^{t_{ls}} \frac{CF_i}{(1+r)^i} \quad (12)$$

when

$$NPV = 0 \rightarrow p_p = ProductionCost \quad (13)$$

where t_{ls} (y) is the lifespan of the biorefinery and r is the interest rate. This methodology provided the production cost of the target product using Equation 4, excluding the G-H₂ supply cost. The G-H₂ supply cost must be added afterward, based on the specific territorial case study scenario and its corresponding assessment.

3.2.1. Biogas upgrading to biomethane by methanation

The first one was the biogas upgrading process converting CO₂ to CH₄ by methanation using hydrogen. The methanation technology was assessed in terms of techno-economic analysis by sizing the reactor and biomethane purification based on a typical biogas plant size (about 3 MWt) [44] with a biogas composition of 50/50 (CH₄/CO₂) [45]. The plant is made up of biogas production, water electrolysis and upgrade section which is constituted by “Mixing and Preparation”, “Reaction” and “Separation” subsections, as shown in Figure 13. The inlet volumetric flow rate of biogas is equal to 590 SCM/h while the molar flow of hydrogen from the electrolyzer makes sure that at the reactor inlet the molar ratio between hydrogen and carbon dioxide is equal to 4.

The upgrade section to design and optimize could improve the yield of the biogas plants. With methanation, carbon dioxide overall conversion can reach a value of around 100%. In addition to this, the heat realised in the reactor and oxygen from water electrolysis are valuable co-products that can be utilized in the biogas production section.

This work was performed with these hypotheses and considerations done a priori:

- The biogas conditions are set to atmospheric pressure and at 40°C. This value of temperature is common in biogas plants which operate with thermophilic or mesophilic bacteria [46].

- According to the report of Bertuccioli et al. [47], pressure and temperature at the electrolyzers outlet are equal to 14-30 bar and 30-80°C. Electrolyzers able to work at higher pressure are analysed in the literature. In the work of Saebea et al. [48], it is shown that is not favourable to reach pressure higher than 20 bar due to the crossover flux of hydrogen from cathode to anode that reduces the electrolyzer performance and efficiency. Thus, hydrogen is assumed to be available at 35°C and in the range of 6-20 bar of pressure.

- The separation of unconverted hydrogen to observe the constraint in terms of the composition of final biomethane will be achieved using a membrane separator. Membrane separator is chosen because, in contrast to adsorption and absorption, it can operate continuously, consumes less energy, and solvents are not necessary [49].

The target purity of the biomethane was determined by the Italian laws for introducing biomethane into the national natural gas distribution network (volumetric hydrogen content < 2% and methane > 97%, [50]).

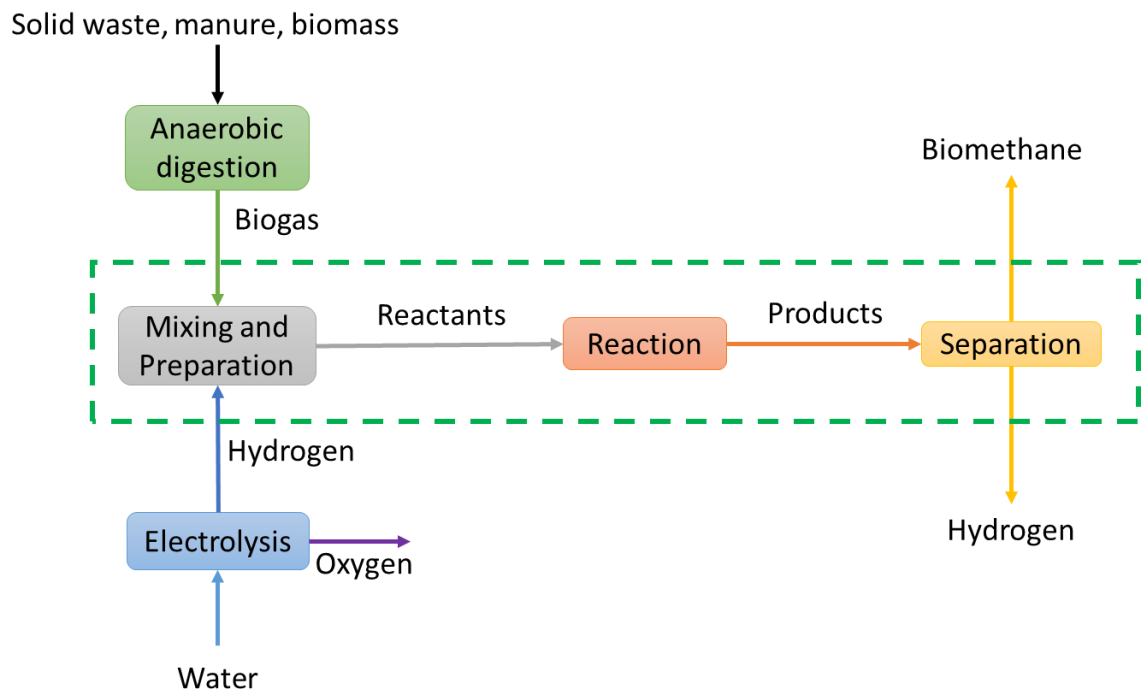


Figure 13. Block diagram of the methanation plant

A geo-localized analysis of two biogas plants in the Basilicata region (Italy) was performed in order to integrate these plants with the potential G-H₂ production using only RES overproduction [51] in the same municipalities where biogas plants exist.

3.2.2. Hydroprocessed Esters and Fatty Acids from oils and lipids

The second integrated process considered was the triglycerides hydrogenation producing GD (a drop-in fuel) [52]. A plant size of about 700 kt of oil (replacing five different oil sources: palm, sunflower, soybean, microbial, and cardoon [53], [54], [55]) was studied by design of the hydrogenation reactor and diesel purification train. Finally, an evaluation of the hydrogen request was performed for each different oil source. The design sequence of the process integer is

presented in Figure 14, where the design will begin with the reactor, then with the partial condenser, PSA unit and finally with the distillation column. First, a co-current multi-bed adiabatic reactor is fed with a mixture of hydrogen and vegetable oil.

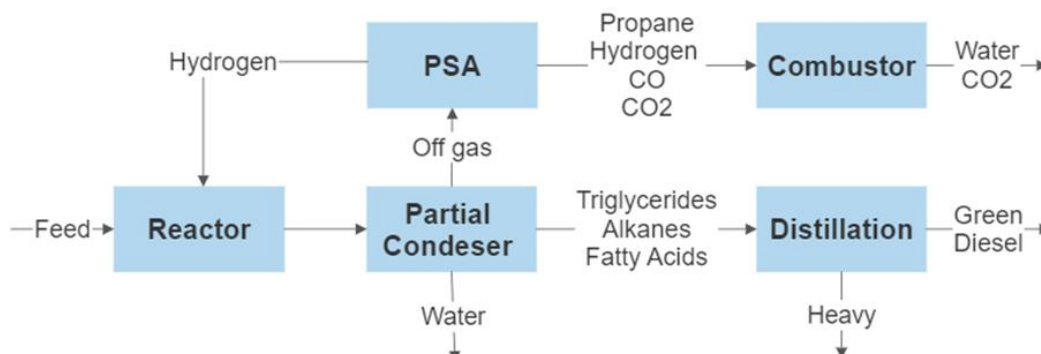


Figure 1: Design sequence of the green diesel production process

The products from the hydrotreatment reactor undergo a partial condenser separator where the pressure is reduced to a gaseous phase, composed principally of hydrogen, propane, carbon monoxide and dioxide, and two liquid phases, water and an organic phase composed of hydrocarbons, triglycerides, and fatty acids. In a manner to recover hydrogen, which is the main component in the gaseous phase, a PSA (Pressure Swing Adsorption) unit is used. Hydrogen is separated, compressed and reuse in the system. The tail gas from the PSA unit and off gas from the distillation column, undergoes a combustor for energy recovery. Finally, the organic liquid phase is treated in the distillation tower where heavy components like triglycerides and fatty acids are obtained in the bottom and diesel fraction is obtained in the distillate. An existing biorefinery was individuated by Biorefinery Atlas in North Dakota – Dickinson.

3.2.3. Lignin hydrotreatment

The third case study was on the direct lignin hydrogenation to produce alkyl phenols and BTX [56]. The lignin-rich stream can be derived from a second-generation ethanol biorefinery. Lignin valorization represents an alternative to its combustion [57]. Using literature data and simulation tools, the direct hydrogenation process was assessed to evaluate both capital and operating costs, target product yields, and the pure hydrogen requirement. A plant size of about 10 t/h of lignin from a lignocellulosic biorefinery in Brazil – Alagoas (from Biorefinery Atlas) was considered.

Due to the structural complexity of biomass-derived lignin, the first issue to solve in a simulative approach is represented by its modeling: the most common method is to use model compounds, such as vanillin, eugenol, guaiacol and others[58]. This approximation can lead to substantial differences between the simulation and the real process. Lignin is modeled as a mix of different oligomers, each of them composed of a combination of the most common lignin structural units. By dosing the ratios between the different functional groups, chemical bonds and the different monomers of these oligomers, a chemical structure as similar as possible to the one presented

by Kumar et al.[59] was simulated. Oligomers' properties were estimated by using existing databases and correlations[60]. This method allows a representation of conventional lignin with a limited error margin in the estimation of its properties, such as the bond amount and the monolignol composition.

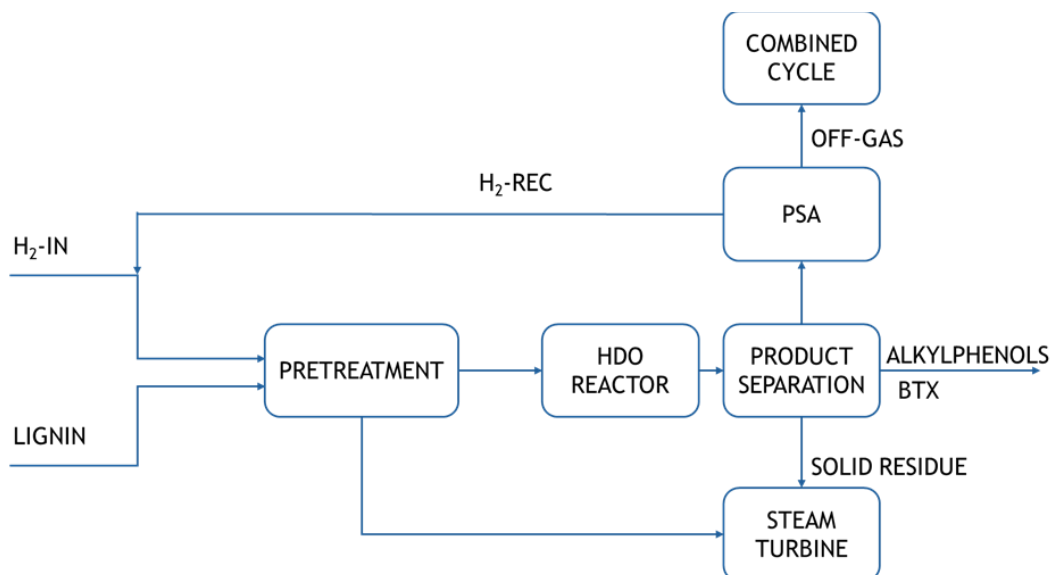


Figure 25. Block flow diagram for the lignin HDO process.

For the lignin hydrodeoxygenation step, whose corresponding complete (Figure 15), several reaction models have been proposed by various authors. However, they are either based on model compounds [61], so they have not been considered suitable for simulation purposes. To model the HDO reaction, a thermodynamic-based method was used a set of reactions starting from pure lignin, was identified and the reactor yield was obtained following a temperature approach procedure.

3.2.4. Sustainable Aviation Fuels from bioethanol

Further, a 4th case study was performed considering the production of SAF by Alcohol-to-Jet (AtJ) process [62], supposing an SAF production of 90,000 t/y. This process involves the conversion of ethanol through three main processes in series: dehydration, oligomerization, and hydrogenation (Figure 16). A mixture of alkanes can be obtained with very low hydrogen consumption.

One advantage of the dehydration, oligomerization, and hydrotreating process steps is that they have been demonstrated on a commercially relevant scale with a consequent low risk of scale-up. In particular, research on ethanol dehydration catalysis started with alumina and transition metal oxides and moved to silicoaluminophosphates (SAPOs), H-ZSM-5 zeolite catalysts, and heteropolyacid catalysts [63]. Up to 100% ethanol was dehydrated to ethylene with a 99.9% selectivity at 250 °C and a 2 h⁻¹ weight hourly space velocity using a 0.5% La-2%PH-ZSM-5 catalyst [64]. The resulting ethylene can then undergo a catalytic oligomerization process

to linear α -olefins [65]. An under-construction biorefinery was identified in North Queensland, Australia.

Ethanol from 2nd gen. sugars

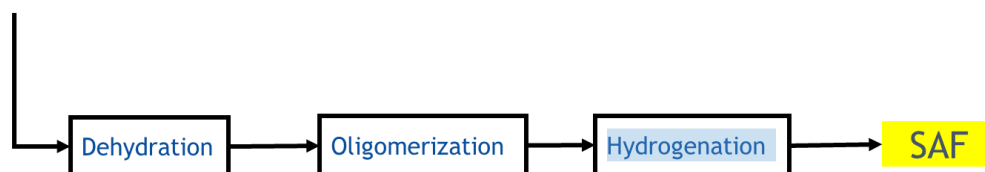


Figure 36. Block flow diagram for the bioethanol conversion to SAF.

4. Results of the assessments

After completing the process assessment through the individual techno-economic analysis, the optimal localization of the plants was finally assessed. Table 4 provides a summary of the case study inputs, including biorefinery size, location, and potential variable renewable energy (VRE) farms situated around the biorefineries. The biorefinery size is the most important parameter affecting the G-H₂ requirements and the capital costs (economies of scale). Typically, anaerobic digestion plants are much smaller than lignocellulosic biorefineries and vegetable oil biorefineries [25]. Table 5 shows the main sizes of the biorefineries considered in the case studies, along with their G-H₂ requirements. The lowest G-H₂ requirement is for the first case study (580 t/y), which is compatible with the potential VRE production within a 10 km radius of the biogas plants (wind farms with a capacity of 219 MW, corresponding to about 6000 t/y of G-H₂, assuming a 20% capacity factor). The data indicated that this process implies a high ratio between the hydrogen required and the product so that only small-scale applications could be suitable (Figure 19). Similar conclusions were reported by other authors. Witte et al. [66] selected a small-size biogas plant (3 MWth) and estimated a low G-H₂, resulting in a modest biomethane production (around 153 kg/h). According to Peters et al. [67], the optimized routes in the CO₂ to biomethane pathway can produce around 30–40 kg of biomethane for MWhe, which is used to produce G-H₂.

The highest hydrogen demand was found in case study 2 due to the large biorefinery size (700,000 t/y of feedstock), requiring between 27,000 and 30,000 t/y of hydrogen. This range depends on the five different oil sources analyzed. To supply such a large quantity of G-H₂, a vast amount of installed VRE power would be needed in a region with a significant RES surplus. North Dakota has the capacity to generate more than 350,000 GWhe/y from RESs [37], while the state consumes less than 160,000 GWhe/y. Therefore, the 1700 GWhe required for water electrolysis could be produced from renewable sources. The Dickinson Biorefinery, which produces GD via vegetable oil hydrogenation, was selected through the Biorefinery Atlas, and several wind farms are installed around it. Considering a capacity factor of 40% for wind energy in North Dakota, two nearby wind farms (150 MW installed) within a 40 km radius would be insufficient to meet the total G-H₂ demand (about 21,000 t/y). Therefore, three additional wind farms (104 + 106 + 105 = 315

MW installed) were considered, extending the distance between the G-H₂ production sites and the biorefinery to up to 100 km. From these five wind farms, a potential G-H₂ production of 40,000 t/y could be achieved. However, increasing the transport distance for hydrogen is expected to increase the G-H₂ supply costs.

For the third case study, the hydrotreatment of lignin was considered, assuming a pure lignin stream derived from a lignocellulosic biorefinery. By processing approximately 350,000 t/y of lignocellulosic biomass, about 70,000 t/y of lignin could be available for valorization. Although many lignin-derived products are still characterized by low TRL values, some estimates are nevertheless possible.

Table 5. Case study overview – main results.

Tag in Figure 17	Main bio-based process	Plant size	G-H ₂ needs (t/y)	Potential Green hydrogen availability (t/y)
a	Biogas upgrading to biomethane by methanation	1200 t/y of biomethane from CO ₂ of biogas	750	6,000
b	Hydroprocessed Esters and Fatty Acids (HEFA) from oils and lipids	550,000 t/y of renewable diesel	27,000 – 30,000	21,000 (40 km); 40,000 (100 km)
c	Lignin hydrotreatment	9000 t/y of Alkyl Phenols	2500	12,000
d	Sustainable Aviation Fuels from bioethanol	90,000 t/y of SAF	900	3000

4.1 Bio-based compounds production costs

Using process simulation tools and thermodynamic models [56], the production cost of lignin-based alkyl phenols was estimated. The hydrogen demand for this hydrogenation process was calculated to be 2500 t/y, lower than the potential 12,000 t_{H₂}/y (with a capacity factor of 0.20) obtainable from wind farm closest to the selected biorefinery in Alagoas, Brazil, which has an installed capacity of 220 MW and is located 300 km from the biorefinery.

The final case study involves the production of SAFs from second-generation bioethanol. A biorefinery that was under construction [68] was considered, which will process 180,000 t/y bioethanol, converting it to alkanes via a typical three-step process including alcohol dehydration, oligomerization, and hydrogenation [62]. This project is set to launch in North Queensland, Australia. Despite the large size of the biorefinery, the amount of G-H₂ required for this process is very low (900 t/y), comparable to the biomethane production case study (750 t/y). A notable aspect concerns the sizes of the biorefineries. In the first case study (methanation process), the biorefinery size was 1200 t/y of methane, while in the last case study, it was 90,000 t/y of SAFs. These values correspond to approximately 60,000 GJ/y and 3,600,000 GJ/y, respectively, in terms of energy content. Thus, the last one is 60 times bigger (on an energy-based scale), but with a hydrogen consumption that is only 20% higher. A nearby solar farm, 30 km away, could cover this hydrogen requirement, potentially producing about 3000 t_{H₂}/y (assuming a capacity factor of \approx 0.15).

The production cost of the target products was calculated through a process assessment (mass and energy balances), process design of the main equipment (e.g., reactors, distillation columns, etc.), and economic analysis based on cash flows. An interest rate of 5% was assumed, and the costs were calculated in euros per year. The product selling price was adjusted to find the value that made the Net Present Value (NPV) equal to zero. The production cost was first estimated excluding the G-H₂ supply costs. Then, the specific G-H₂ supply cost for each case was assessed and added to the bio-based product cost to determine the impact of G-H₂ costs on total production costs for the different cases.

For the first case study, a techno-economic analysis was performed by sizing a methanation reactor and biomethane purification system based on the typical size of a biogas plant (about 3 MWt, CH₄/CO₂ ≈ 50/50). The analysis focused on equipment for biogas upgrading (biogas/hydrogen mixing and mixture preparation via heating, methanation reactor, purification membranes, and vacuum pump). The kinetic parameters [69] for methanation reactor sizing and permeance parameters [70] for biomethane purification membranes were sourced from the literature. The key economic factor affecting the CO₂-based biomethane production cost was the final yield of biomethane (about 92% mol). The compression system to reach the optimal methanation pressure of 8 bar was the most expensive element, costing 9.5 cEUR/kg_{CH₄}. Starting from 495 kg/h of CO₂, 153 kg/h of CO₂-derived biomethane can be produced, achieving a final biomethane stream of 333 kg/h with 95% purity and a Higher Heating Value (HHV) of 34.5 (MJ/normal cubic meter, MJ/Nm³). The CO₂-based biomethane production cost was approximately 0.16 EUR/kg, excluding the hydrogen cost, which represents the most important cost.

The production cost of GD derived from vegetable oils (VOs), microbial oils (MOs), or used cooking oils (UCOs) was first estimated without considering the G-H₂ supply cost. The hydrogenation of oils (triglycerides) produces alkanes (C₁₃–C₁₇ range), shorter chains (naphtha), isomers, CO, CO₂, and propane. Purge gases and waste streams were assumed to be burned to generate heat (for heat integration) and green electricity. Overall, an average GD yield in mass of 80% (diesel on renewable oil as feedstock) was identified as optimal through the simulation carried out in this study. Due to the high economies of scale (CAPEX of around 400 MEUR), OPEX dominated (260 MEUR/y, excluding the cost of oil supply). The main cost item was the feedstock supply, ranging from 350 MEUR to 1.4 BEUR per year. A wide production cost range (0.75–2.70 EUR/kg) was attributed to uncertainty in the supply oil cost, which varied from 500 EUR/t (e.g., UCO) to 2000 EUR/t (e.g., MO).

The third case, focusing on lignin conversion, involved a more complex economic analysis due to the limited availability of process data for a rigorous assessment. Using a thermodynamics-based procedure [56], the production of Alkyl Phenols (APs), along with BTX and power as by-products, was evaluated. Specifically, a lignin-based alkyl phenol yield of 12–15% was assumed. The by-products (BTX) with yields of 7–8% were estimated to be sold at 0.50 EUR/kg. Based on these process results, the primary cost item was the lignin supply cost. If lignin is considered a

waste from the lignocellulosic biorefinery (cost equal to zero), the AP production cost was about 1.40 EUR/kg. If the lignin cost increased to 400 EUR/t_{dry}, the final AP cost rose to 3.80 EUR/kg.

The final case study, involving SAF production via bioethanol upgrading, was assessed using data from the Ulysses project under construction in Australia and data from the literature on the three bio-based processes involved: dehydration, oligomerization, and hydrogenation [62]. This process generates significant waste during the first reaction, with about 40% of the mass lost as water. Assuming high efficiency in the subsequent processes, up to 50%wt of alkanes/isoalkanes in the C10–C14 range (SAF) can be produced. Ethanol-based diesel can also be produced, accounting for 5%wt. As with the previous cases, the raw material costs are the largest variable, leading to a wide production cost range: between 1.73 and 3.00 EUR/kg.

4.2 Green hydrogen supply cost impact

In order to estimate the final production cost of the selected bio-based products, the specific G-H₂ cost was calculated considering the following factors:

- The hypothesis of overproduction of VRE (energy source cost = 0) or not;
- Different renewable energy demands for various hydrogen storage and transportation phases (more energy is required for liquid hydrogen);
- Economies of scale for the storage and transportation infrastructures according to REU et al. [32].

Based on these factors, the supply cost of the G-H₂ for each case study was calculated. A breakdown of these costs is shown in Figure 17. The main effect on the G-H₂ cost is essentially due to economies of scale. In general, when the storage and transportation system needs to handle very high flow rates, the optimal transportation phase is gas, and pipeline transport is more sustainable. Low hydrogen flow rates are associated with very high storage costs for gas due to a very low scaling factor (0.28) in the cavern. This results in costs of 3.16 and 2.95 EUR/kg_{H₂} for Biomethane—Italy and SAF—Australia, respectively. The electrolyzer costs depend on the capacity factor of the selected VRES. The higher the annual operating time of the electrolyzer, the lower the specific cost to produce 1 kg of hydrogen. Therefore, comparing similar G-H₂ requirements—750 and 900 t_{H₂}/y for Italy and Australia, respectively—the G-H₂ cost related to the electrolyzers is lower for the latter (2.16 versus 3.10 EUR/kg_{H₂}, both liquid hydrogen). When distances are long but the hydrogen flow rates are medium, as in the case study in Brazil, transportation costs have a high impact. On the other hand, the GD—USA case study revealed results for a specific and peculiar case, with an enormous G-H₂ demand (up to 30 kt_{H₂}/y), a high transportation distance (up to 100 km), and a very efficient VRES (estimated in North Dakota at about 40% capacity factor). Combining these features, the G-H₂ supply cost for the production of GD in the Dickinson Biorefinery of North Dakota is particularly low, between 1.89 and 4.24 EUR/kg_{H₂}. The very low transportation costs are related to hydrogen in the liquid phase for low hydrogen demand (0.07 EUR/kg_{H₂} for Biomethane—Italy and 0.08 EUR/kg_{H₂} for SAF—Australia).

For each case studied, the minimum supply costs are approximately in the range of 2.00 to 3.50 EUR/kg_{H2}, while the maximum costs are more variable, from about 4.00 to 9.00 EUR/kg_{H2}.

4.3 Overall production costs

The overall product cost includes the production cost without the G-H₂ supply cost and the hydrogen costs are calculated by the specific hydrogen requirement multiplied by the G-H₂ supply from Figure 19. Figure 18 illustrates these costs by explicitly showing the contributions from G-H₂ and the process itself.

In the first case study on biogas upgrading via methanation, a cost range between 2.37 and 5.62 EUR/kg of methane was identified. The contribution of the main CO₂ conversion and purification process was found to be negligible. In fact, due to the zero cost of the feedstock (biogas), the simplicity of the methanation reaction (which is not equilibrium-limited and exothermic at temperatures below 370 °C [71]), and the final purity of the biomethane (97% methane and up to 2% hydrogen by volume), one kilogram of CO₂-derived methane can cost less than 20 cEUR/kg (approximately 14.40 EUR each thermal megawatt-hour (EUR/MWht)), significantly below the market price of methane [72].

On the other hand, biomethane produced from biogas-derived CO₂ has the highest cost impact from G-H₂. Up to 97% of the total biomethane cost is related to the G-H₂ supply due to the high specific demand for G-H₂. As methanation requires 0.5 kg of H₂ to produce methane, the baseline cost of CO₂-derived biomethane is essentially half the cost of one kilogram of hydrogen. As a result, with hydrogen (including fossil-based) priced above 2 EUR/kg, the minimum production cost of synthetic methane is 1 EUR/kg (approximately 72 EUR/MWht). For this first case study, the technical feasibility is confirmed in terms of potential G-H₂ availability and process efficiency. On the whole, the economic feasibility could be improved by further analysis, particularly to reduce the G-H₂ supply cost to within the range of 0.50–1.00 EUR/kg.

An opposite situation can be observed in the second case study on the hydrogenation of vegetable, used, or microbial oils. The impact of G-H₂ costs is in the range of 7–11%, mainly due to the high cost of the feedstock. A minimum production cost of 0.84 EUR/kg (i.e., 2.07 EUR/GJ) can be associated with an oil cost of 500 EUR/t (e.g., palm oil, etc.) and a G-H₂ cost of 1.89 EUR/kg_{H2}. This value is comparable to the market price of diesel. The maximum production cost calculated in this study is 2.90 EUR/kg, considering an oil supply cost of 2000 EUR/t (e.g., algae lipids, microbial oils, etc.), with a G-H₂ cost impact of 7%. The hydrogen cost could increase significantly without compromising the economic feasibility of this bio-based process, thanks to the low hydrogen demand of about 4–5% (an average value across various oil sources), as shown in Figure 19.

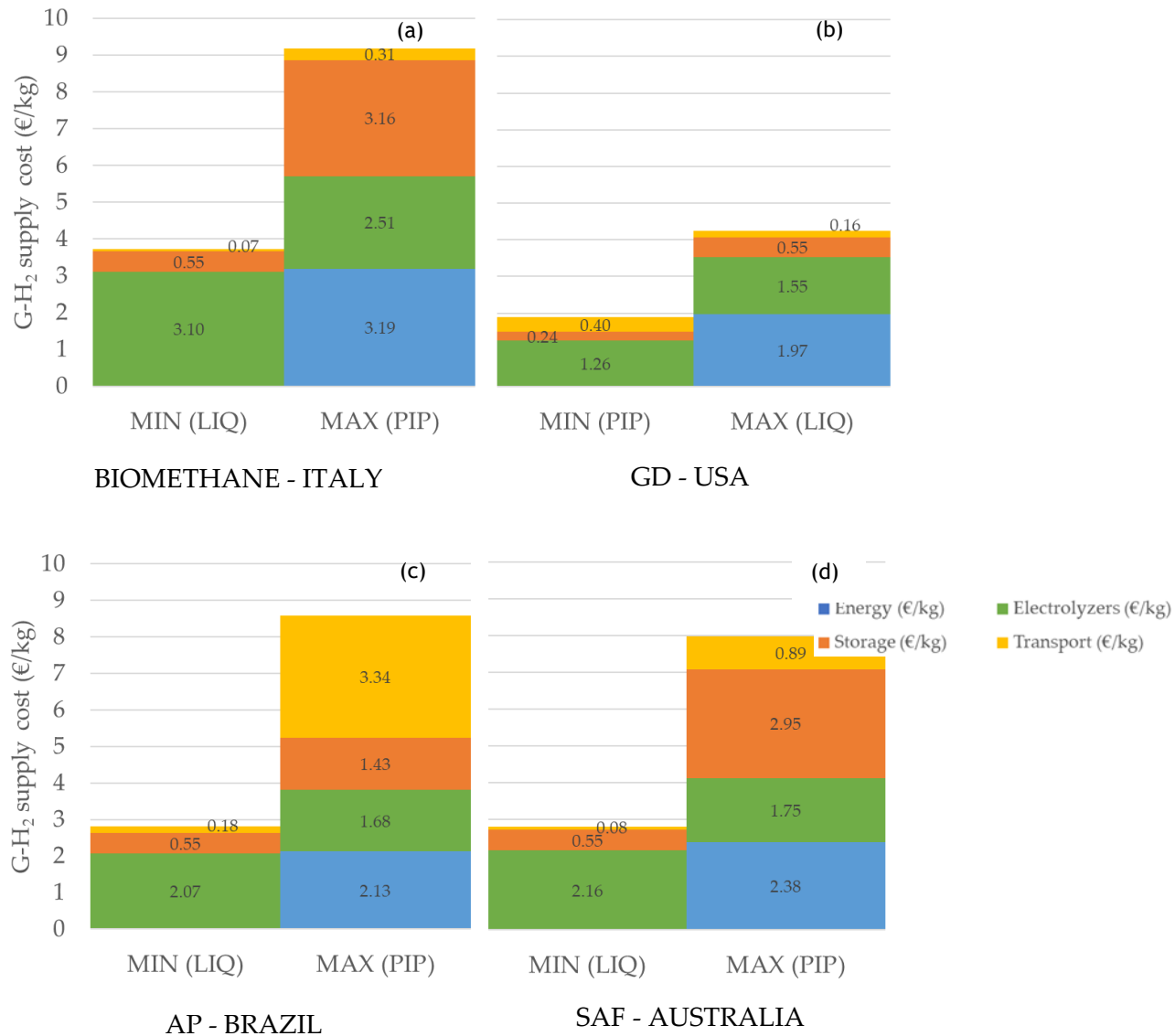


Figure 17. Green hydrogen supply cost breakdown for each territorial case study: (a) biogas upgrading to bio-methane by methanation localized in Italy; (b) Hydroprocessed Esters and Fatty Acids from oils and lipids localized in USA; (c) lignin hydrotreatment localized in Brazil; (d) Sustainable Aviation Fuels from bioethanol localized in Australia.

The third case study on direct lignin hydrogenation is considered the most uncertain due to both the difficulty of assessing the technical process and the high G-H₂ demand for each kilogram of alkyl phenol produced, which is around 27% (Figure 19). Moreover, a large range in G-H₂ supply costs was calculated (with a difference of about 5.8 EUR/kg_{H₂} between the lowest and highest values). Consequently, production costs of up to 6.15 EUR/kg_{AP} were identified, compared to a minimum production cost of 2.17 EUR/kg, depending on lignin supply costs ranging from 0 (assuming waste lignin) to 400 EUR/t. The AP selling price can be considered to fall within a similar range of 2.5–3.1 EUR/kg [73]. The techno-economic feasibility of this case is promising, but it requires further studies and insights due to the limited availability of data and models.

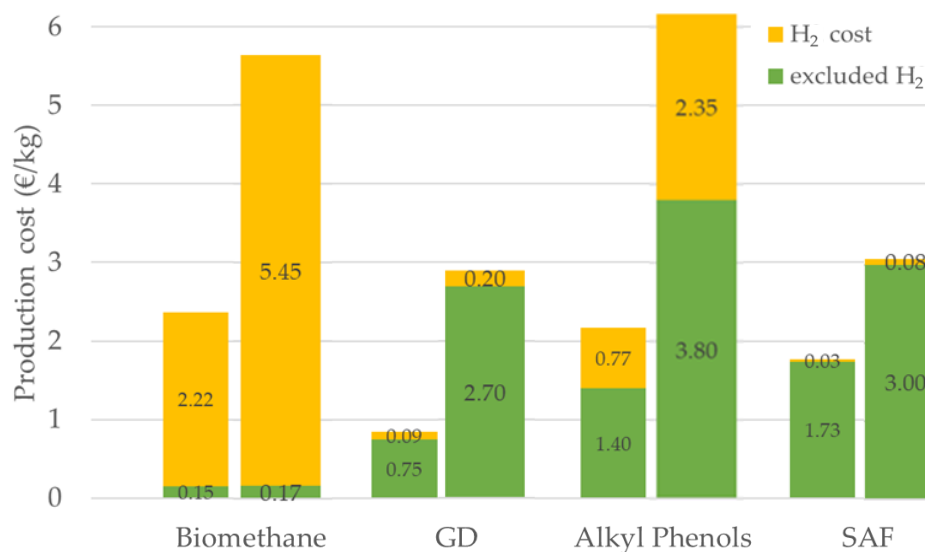


Figure 18. Bio-based compounds production cost excluding the green hydrogen supply cost (green bar) and including the green hydrogen supply cost (yellow bar), considering the minimum process production cost (on the left) or the maximum one (on the right).

Finally, the last case study on the production of aviation fuels from second-generation ethanol also requires further investigation, especially regarding the cost of feedstock supply. This case presents the lowest specific G-H₂ demand (about 1%), and its impact on production costs is negligible (1.5–2.5%). However, the SAF production costs could be too high (in the range of 1.76–3.08 EUR/kg), considering an SAF yield of about 50% (kg of SAF per kg of bioethanol) and a co-production of GD at 5% by weight. This cost range aligns with the market price of SAFs [74]. Due to the low hydrogen demand and the efficiency of the conversion process, this case study can be considered economically and technically feasible.

5. Discussion

The present work provides a detailed analysis of the opportunities arising from the territorial integration of bio-based processes (more generally, biorefineries) and G-H₂ by using a novel web GIS approach. Based on the four case studies developed, more general insights can be derived, particularly regarding the differences in the specific G-H₂ demand for producing e-fuels (e.g., e-methane) versus bio-e-fuels (e.g., GD). From a thermal perspective, hydrocarbon synthesis processes that convert (biogenic) CO₂ and H₂ are generally self-sufficient, as the reactions involved are mostly exothermic. This means that the production of e-fuels primarily requires electrical energy for hydrogen production.

In particular, for methane synthesis, the hydrogen-to-carbon (H/C) ratio is equal to 4, and as the carbon chain length increases, it approaches 3. The stoichiometric coefficients can vary depending on the nature of the fuel, whether it consists of linear or isomerized alkanes. Methane has the highest stoichiometric hydrogen requirement per kilogram of fuel, equal to 0.5; however,

considering the efficiency of the methanation process and the purification step, this increases to 59% (Figure 19). The main economic finding underscores that the critical cost factor is G-H₂. If its cost exceeds 1–2 EUR/kg, biogas methanation may not be economically viable.

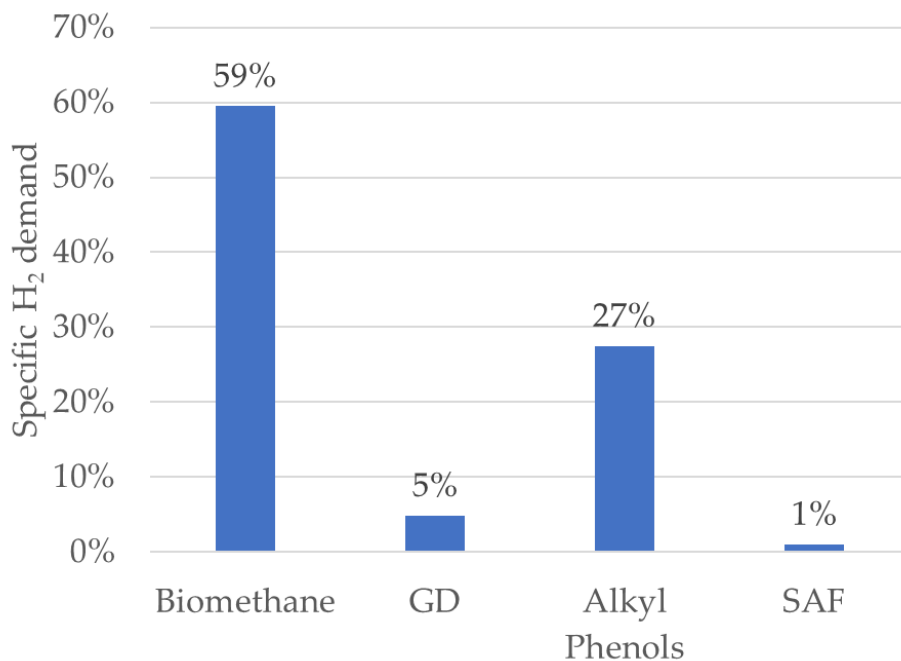


Figure 19. Specific demand (%wt) relative to the amount of target product produced.

A similar analysis can be performed for the production of hydrogenated biofuels, where the synthesis can start from different types of renewable carbon sources: lipids (triglycerides) and/or fatty acids, and ethanol. The most common and currently industrialized process in several countries is the hydrogenation of triglycerides and fatty acids, producing HEFAs or HVOs (Hydrotreated Vegetable Oils). The hydrogen demand for this process is approximately 5%, minimizing its impact on the overall cost, as described in the previous section.

The third category of bio-based intermediates for alternative fuel synthesis is ethanol, which can be converted into aviation fuels through dehydration, oligomerization, and hydrogenation steps. In this case, the stoichiometric reaction is balanced by the addition of only one hydrogen molecule for each ethanol molecule converted into alkanes. This makes the process particularly attractive for producing hydrocarbons from biomass sources without needing large amounts of hydrogen and/or CO₂ capture/storage (as required for FT-diesel, methanol, or dimethyl ether). On the other hand, biorefineries often operate at large scales, which could lead to a G-H₂ demand that is too high for local production. Additionally, energy-driven bioproducts typically have low added value. Based on the results presented in the previous sections and through generalizations, an approximate summary graph was produced. By multiplying the specific G-H₂ demand (e.g., Figure 19) with the biorefinery size (biorefinery productivity), the total G-H₂ demand can be estimated.

Each bio-based process is associated with a different main bioproduct, each having a distinct selling price. Further, Figure 20 shows that processes with lower market prices must be linked to a lower G-H₂ demand to ensure techno-economic feasibility. When hydrogen requirements are very high, higher final market prices are necessary. For instance, the production of chemicals, such as aromatics, which require G-H₂ in the range of 1–10 kt/y (equivalent to 30–200 MW of installed VRE), appears to be an optimal choice for integrating bio-based and hydrogen sources on a local scale. Conversely, small-scale processes associated with medium G-H₂ demand, such as e-methane production from biogenic CO₂, have limited added value. Significant challenges arise when producing GD using only locally sourced G-H₂ due to the high hydrogen demand.

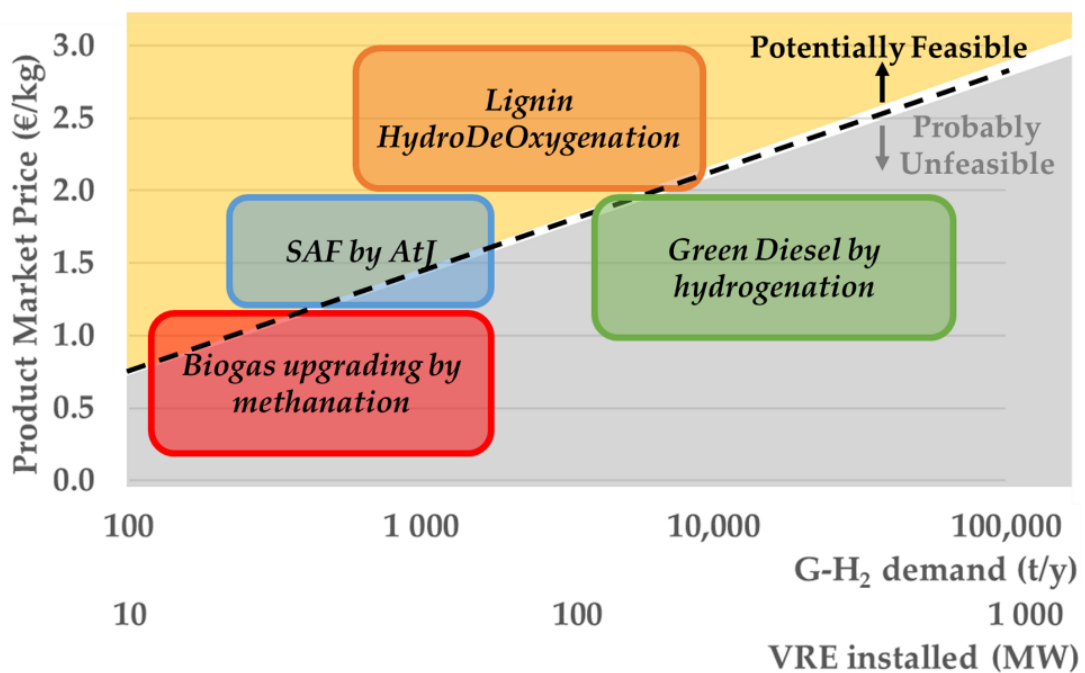


Figure 20. Bio-based processes and green hydrogen integration overview in terms of hydrogen requirements and techno-economic feasibility (log-scale).

In the case study discussed in the previous sections, the matching was considered feasible by extending the radius for obtaining G-H₂ to up to 100 km in North Dakota, where high-performance wind energy is available with a capacity factor of about 40%. However, relocating a biorefinery that converts lipids to GD to another region, especially for large plants (producing more than 300–500 kt of diesel), might render the local production of G-H₂ for several tens of thousands of tons infeasible. The possibility of establishing large-scale biomass sinks or G-H₂ production sites is limited to a few territories worldwide.

Table 6 provides a summary of bio-based processes related to the VRE required to produce the necessary G-H₂, the productivity of the biorefinery, and the market price of the target products. The case studies presented in this work align with one or more parameters identified as essential for making the integration between G-H₂ and bio-based processes feasible. In particular, following the guidelines in Figure 20, the availability of VRES farms within 100 km can be achieved

relatively easily. Lipids and alcohols may require a lower demand for hydrogen compared to CO₂ or molecules with low hydrogen content, such as lignin (see Figure 19). On the other hand, biogas methanation and lignin hydrotreatment require a relatively small biorefinery size, in the range of 1,000 – 10,000 t/y. Consequently, all four processes of this work can be considered as potentially feasible. The parameter related to the product market price is more difficult to match; energy-driven products (i.e., biofuels) tend to have a very low market price, whereas chemicals (e.g., phenols and aromatics from lignin) can command very high prices, making the integration with high G-H₂ demand more feasible.

In general, for the production of biochemicals (e.g., aromatics, BDO from succinic acid, polyalcohols from sugars), the matching process might be simpler due to the higher added value and smaller biorefinery sizes. For biofuels, the volumes are typically much larger, making it more difficult to achieve a local integration of biorefineries and G-H₂ production. Future research should focus on the unique characteristics of G-H₂: its locally distributed production and availability—a feature it shares with biomass. On the other side, the main challenge will be to combine bioresource availability with G-H₂ on a regional scale, while identifying the optimal biorefinery size to match the production capacity of both raw materials.

Table 6. Summary table presenting all possible parameters for evaluating the opportunities arising from the integration of local green hydrogen and biorefineries.

Evaluation Parameter	Range of feasibility	Process assessed as possible in this study
Variable renewable energy sources installed within approximately 100 km of the biorefinery	10 – 100 MW	(a) Biogas methanation; (b) Hydroprocessed Esters and Fatty Acids from lipids; (c) Lignin hydrotreatment; (d) Bioethanol to Sustainable Aviation Fuels
Specific green hydrogen demand (kg _{H2} /kgPRODUCT)	< 10%wt	(b) Hydroprocessed Esters and Fatty Acids from lipids; (d) Bioethanol to Sustainable Aviation Fuels
Biorefinery size (productivity)	< 50,000 t/y	(a) Biogas methanation; (c) Lignin hydrotreatment
Target product market price	≥ 2 EUR/kg	(c) Lignin hydrotreatment

Frequently, biomass collection is a critical factor in determining the size of biorefineries due to the limited availability of local raw materials. Often, biomass needs to be imported, which can negate the environmental benefits because of the emissions generated from transporting the material. Renewable energy sources can present similar challenges, as both wind and photovoltaic systems require land and soils. Future developments in this work could also assess the availability of bioresources within a defined distance.

6. Conclusions

The use of green hydrogen in biorefineries offers the advantage of enabling local integration while minimizing costs and environmental impacts associated with long-term storage and

transportation. Both green hydrogen and biomass are widely dispersed across rural areas, creating opportunities for synergistic integration. However, hydrogen's main drawback is its high cost and the challenges associated with long-term storage and transport via pipeline or truck. In this study, we analyzed and modeled green hydrogen availability across four case studies, utilizing literature data and modeling to assess supply costs based on hydrogen requirements and distances between variable renewable energy farms and biorefineries. The impact of green hydrogen supply costs on the economic viability of biorefineries can vary significantly from one bio-based process or bio-product to another due to the wide range of specific hydrogen demands. Depending on the end product, hydrogen supply costs significantly affect the final production costs, ranging from approximately 92–95% for biomethane, 7–10% for green diesel, 28–35% for alkyl phenols derived from lignin, and 1.5–1.9% for Sustainable Aviation Fuel from ethanol. Overall, the territorial case studies identified feasible matches between existing biorefineries and green hydrogen sourced from variable renewable energy overproduction. From a supply chain perspective, the cost of green hydrogen could potentially be maintained below 6–8 EUR/kg. Analyzing these evaluations, the conversion of renewable carbon (i.e., biogenic CO₂) could, in some cases, lead to economically unsustainable production costs due to the current high impact of hydrogen supply costs on the overall cost. The biomethane from the biogas case study required more than 0.5 kg of hydrogen per kg of methane produced. Consequently, the cost of 3–4 EUR/kg_{BioCH₄} is related to the green hydrogen supply, whereas the biomethane market value can reach at most 0.40–0.60 EUR/kg. Conversely, the valorization of bioethanol through Alcohol-to-Jet processes presented a very low demand for hydrogen, leading to the conclusion that green hydrogen does not significantly impact the production costs of Sustainable Aviation Fuel. The local integration of biorefineries and green hydrogen represents a promising pathway for producing 100% renewable bio-based products, especially when biorefinery capacities are below 50,000 tons per year, specific hydrogen demand is under 10% (H₂/product), installed variable renewable energy power ranges from 10 to 100 MW, and bioproduct market prices exceed 2 EUR/kg.

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