

# Assessment of the Techno-Economic Viability to Produce Biohydrogen from Biowaste

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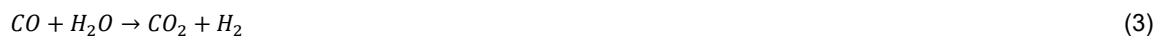
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The adoption of effective strategies to reduce the production costs of renewable H<sub>2</sub> and increase its competitive position compared to fossil-based H<sub>2</sub> in hard-to-abate sectors is a priority of the European Union. One of these strategies can be to diversify the use of renewable electricity by using other renewable resources such as biomass to produce biohydrogen. The aim of this paper was to assess the technical and economic performance of H<sub>2</sub> production by steam reforming (SR) of natural gas as well as three biohydrogen production systems using the levelized cost of H<sub>2</sub> (LCOH) as a methodology. Based on a 2,700 Kg H<sub>2</sub>/h facility, LCOH results showed that bio-oil reforming (€ 3.56/kg) is the least expensive way to produce biohydrogen compared to biomass gasification (€ 4.08/kg) and biogas reforming (€ 4.52/kg). Furthermore, the bio-oil reforming pathway provided an LCOH quite similar to the LCOH obtained by SR of natural gas (€ 3.52/kg), indicating that its use could be viable hard-to-abate sectors.

## 1. Introduction

In 2022, Italy produced around 0.60 Mt of H<sub>2</sub>, of which 98.65% was obtained from fossil fuels via conventional technologies such as steam methane reforming (SMR) and as by-product of ethylene and styrene production. Another minor amount (1.15%) was obtained as a by-product of chlorine and sodium chlorate production via electrolysis, while water electrolysis accounted for only 0.05% of total production (EHO, 2023). A major factor limiting the growth of renewable H<sub>2</sub> production is its high average levelized cost (LCOH), which depends on capital and operational expenditures (CAPEX and OPEX). The CAPEX represents the project's initial investment expenditures and mainly includes the costs of equipment, installation, engineering procurement and construction (EPC) and contingencies and owner costs (C&OC). While OPEX refers to the fixed (e.g. maintenance and insurance) and variable (e.g. raw material, electricity, fuel gas and water consumption) operation expenditures. In Italy in 2023, the H<sub>2</sub> production from unabated fossil-based sources offered a cheaper LCOH (€ 3.70/kg H<sub>2</sub>, excluding CAPEX because it is assumed that SMR plants are already operational) than both the use of fossil fuels with carbon capture utilization and storage (CCUS) (€ 4.40/Kg H<sub>2</sub>) and the use of electrolysis with a direct connection to a renewable energy source (€ 6.70/kg H<sub>2</sub>) (EHO, 2024). In line with the Hydrogen Strategy for a Climate-Neutral Europe, Italy intends to promote the production and use of renewable H<sub>2</sub> through mechanisms such as the National Hydrogen Strategy (NHS) and the National Recovery and Resilience Plan (NRRP). The preliminary NHS guidelines proposed a target of covering 2 % of final energy consumption with H<sub>2</sub> by 2030 (approximately 0.70 Mt H<sub>2</sub>/year), which would be partially met by the installation of 5 GW of electrolyzers (MISE, 2020). While the NRRP recognized the importance of developing projects to produce renewable H<sub>2</sub> in brownfield sites and hard-to-abate sectors (such as refining, steelmaking, chemical, transport, heating and cooling in buildings, electricity generation) as well as to improve its supply with the creation of H<sub>2</sub> valleys (H<sub>2</sub> supply chains) (Gandiglio and Marocco, 2024). In fact, building optimal H<sub>2</sub> supply chains across industrial zones is critical to minimize the overall cost of the energy systems (Fadhil et al., 2024). Despite the various mechanisms developed, increasing the economic competitiveness of renewable H<sub>2</sub> in key industrial sectors compared to fossil-based H<sub>2</sub> remains a priority of the European Union. On this basis, one strategy for reducing H<sub>2</sub> production costs can be to diversify the use of renewable electricity with the use of other renewable resources such as biowaste (e.g. biodegradable garden and park waste, food and kitchen waste

from households, restaurants, caterers and retail premises, and wastes from food processing plants) and biomass residues (e.g. lignocellulosic materials generated by the agricultural, forest, and agro-industrial sectors). These materials can be used to produce biohydrogen via various primary biochemical (e.g. anaerobic digestion and fermentation) and thermochemical pathways (e.g. pyrolysis and gasification) (Yagüe et al., 2024). In anaerobic digestion microorganisms break down organic materials under oxygen-free conditions to produce biogas, which is mainly composed of CH<sub>4</sub> and CO<sub>2</sub>. While, pyrolysis is typically carried out at temperatures ranging from 300 °C to 500 °C in the absence of reagents such as O<sub>2</sub> (combustion) or H<sub>2</sub>O (hydrolysis) to convert biomass into a gaseous mixture of various condensable oxygenated compounds that, after cooling, form a liquid product known as bio-oil, a solid fraction known as biochar and small amounts of non-condensable gases (CO, CO<sub>2</sub>, CH<sub>4</sub>, and H<sub>2</sub>). Biomass pyrolysis can be categorized as slow or fast depending on the heating rate. While slow pyrolysis generates a high amount of biochar, fast pyrolysis produces much more bio-oil (around 60–70 % by mass) (Situmorang et al., 2020). Unlike pyrolysis, the biomass gasification occurs at temperatures ranging from 700 °C to 1200 °C in the presence of a gasifying agent such as air, O<sub>2</sub>, steam or their mixtures, resulting in the production of syngas which is mainly composed of CO and H<sub>2</sub> and minor amounts of CH<sub>4</sub>, CO<sub>2</sub> and N<sub>2</sub>, as well as tar and char. Based on the H<sub>2</sub> percentage in the gas (40 vol %) and reduced impurities, steam gasification appears to be most suitable for H<sub>2</sub> production than air gasification (Lepage et al., 2021). In a further step, intermediate products must be improved using processes such as steam reforming (SR) and water gas shift (WGS), followed by purifying processes such as pressure swing adsorption (PSA) to recover high-purity H<sub>2</sub>. Usually SR process occurs on light hydrocarbons in the presence of H<sub>2</sub>O to produce CO and H<sub>2</sub> as in the case of SMR described in Eq(1), but it can also occur on oxygenates, according to Eq(2). CO produced during SR can react with H<sub>2</sub>O in the WGS process, increasing the amount of H<sub>2</sub>, according to Eq(3). Recently, it was proposed to produce H<sub>2</sub> from biogas via reforming integrated with membrane-based CO<sub>2</sub> (Cormos et al., 2024). Also, it was proposed to transform condensable oxygen compounds (in gaseous state) obtained from fast pyrolysis of biomass into biohydrogen by a continuous SR process (Leijenhorst 2016), however in this paper we focused on the SR of bio-oil (Zhang et al., 2013).



Considering the above, this paper focused on assess the technical and economic performance of producing biohydrogen from biogas, bio-oil and syngas using the LCOH as a methodology and compare the outcomes with those of producing fossil-based H<sub>2</sub>. The LCOH shows the average cost of H<sub>2</sub> production per unit of H<sub>2</sub> and represent the minimum price at which H<sub>2</sub> must be sold to achieve a return of the investment of the project (break-even point) (Wolf et al., 2024). Additionally, given that some refineries in Italy have modified their production setups in the last decade to produce high-quality biofuels from biowaste instead of fossil fuels, but they still use fossil-based H<sub>2</sub> for refining, the biorefinery industry was considered as a model in which biohydrogen could be used if technological, economic, and environmental conditions allow it.

## 2. Biohydrogen production processes and demand of raw materials and energy

As showed in Figure 1 System 1 involved the H<sub>2</sub> production from natural gas via SR, while the systems for producing biohydrogen were defined as follows: biogas production from biowaste through anaerobic digestion (AD) (biochemical pathway) and its subsequent upgrading via SR, WGS and PSA (system 2); bio-oil production from biomass residues through fast pyrolysis (FP) and its subsequent upgrading via SR, WGS and PSA (system 3); syngas production from biomass residues through steam gasification (SG) and its subsequent upgrade via WGS and PSA (system 4). Considering the biorefinery industry as model, an H<sub>2</sub> productivity of 30,000 Nm<sup>3</sup>/h (2,700 Kg/h) was established for all systems which is the amount required by a biorefinery to process around 600,000 t/y of biowaste and produce 540,000 t/y of biofuels (Eni S.p.A., 2022). Furthermore, it was assumed that the systems operated for 8,760 h/y and have an operational lifespan of 20 years at a 7 % discount rate. The results concerning the demand for raw materials, energy and other inputs to produce 23,652 t H<sub>2</sub>/y (showed in Table 1) was determined after an extensive literature review and based on data from previously developed simulation models. In general, an H<sub>2</sub> recovery efficiency of the PSA unit of 85 % was assumed for all the systems, resulting in an H<sub>2</sub> demand of 1.18 kg prior to the PSA process (Yao et al., 2017).

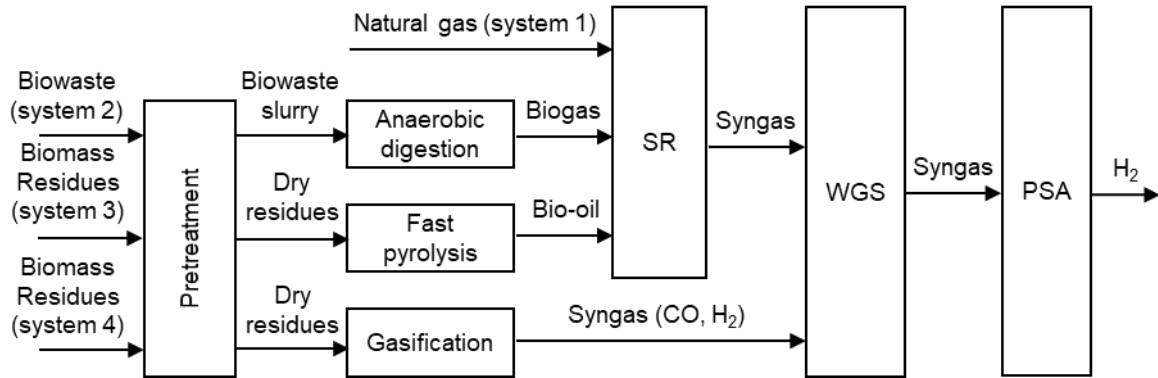


Figure 1: Schematic representation of the biohydrogen production systems under analysis

Table 1: Raw material and energy demand to produce 23,652 t H<sub>2</sub>/y via system 1 (Eni S.p.A., 2022), system 2 (Ardolino et al., 2018), system 3 (Zhang et al., 2013) and system 4 (Yao et al., 2017)

Description	System 1	System 2	System 3	System 4
Intermediates demand (t/y)				
H <sub>2</sub> yield in reforming and WGS (% by mass)	41	41	14	
CH <sub>4</sub>	67,212	67,212		
Biogas (28.46 % by mass of CH <sub>4</sub> )		236,204		
Bio-oil			193,059	
Syngas (2.60 % by mass of H <sub>2</sub> )				1,070,844
Raw materials demand (t/y)				
NG (95.64 % by mass of CH <sub>4</sub> )	70,276			
Biowaste (biogas yield of 17.90 % by mass)		1,319,579		
Dry biomass (7.00 % moisture) (bio-oil yield of 60.82% by mass)			317,427	
Wet biomass (25.00 wt% moisture) (bio-oil yield of 48.97% by mass)			394,240	
Dry biomass (16.00 % moisture) (dry biomass rate of 0.45 Kg/kg syngas)				481,986
Wet biomass (32.00 % moisture) (wet biomass rate of 0.56 Kg/kg syngas)				595,496
Energy and other materials consumption				
Fuel gas (t/y)	8,754	8,754	0	0
Electricity (MWh/y)	10,884	144,157	47,994	96,971
Water (t/y)	225,4999	238,599	185,224	118,258

### 3. Economic assessment

The LCOH is calculated from the point at which the present value of all income received from H<sub>2</sub> sales balances a single present value of overall cost (CAPEX and OPEX), as showed in Eq(4). When H<sub>2</sub> price, H<sub>2</sub> productivity and OPEX remained constant during the plant lifespan, the LCOH can be determined by Eq(5) (IEAGHG, 2013).

$$\sum_n \frac{(\text{Hydrogen production})_n * (\text{Hydrogen price})_n}{(1+r)^n} = \sum_n \left[ \frac{(\text{CAPEX})_n}{(1+r)^n} + \frac{(\text{OPEX})_n}{(1+r)^n} \right] \quad (4)$$

$$\text{LCOH} = \frac{(\text{CAPEX} \times \text{CCF}) + \text{OPEX}}{\text{Plant Productivity}} \quad (5)$$

The term “levelized” refers to the fact that the single present value of overall cost can be transformed into a series of uniform (level) annuities (although the periods can be other than years) using so-called levelization factors. The levelization factor used in Eq(5) to convert CAPEX into annual values was the Capital Charge Factor (CCF), which can be calculated using the Eq (6). The resource cited here provides additional information about the application of economic factors (Blank and Tarquin, 2012).

$$CCF = \frac{r \times (1+r)^n}{(1+r)^n - 1} \quad (6)$$

The factor  $(1+r)^n$  showed in Eq(4) and Eq(6) is known as the compound amount factor, where  $r$  is an interest rate (7 %) and  $n$  the plant lifespan (20 years) (Richard et al. 2024). On the other hand, to estimate the CAPEX, the total direct plant costs (TDPC) for each of the installations that are part of the biohydrogen production systems were first calculated using the cost-to-capacity method according to the Eq(7) (Yao et al., 2017). In Eq(7), the terms “reference capacity” and “reference capital” refer to the process capacity and investment capital of a known plant (data obtained from previous studies). While the terms “scaling capacity” and “scaled capital” refer to the process capacity and investment capital of the plant that will be implemented. Because the calculations in Eq(7) concern a whole plant, a scale factor of 0.80 was used (Arfan, et al., 2023). Prior to applying the cost-to-capacity method, the known plant costs that have a specified reference year were adjusted for inflation using the chemical engineering plant cost index according to the Eq(8).

$$Scaled\ Capital = Reference\ Capital * \left( \frac{Scaling\ Capacity}{Reference\ Capacity} \right)^{Scale\ Factor} \quad (7)$$

$$Reference\ Capital = Original\ Cost * \frac{Present\ Cost\ Index}{Original\ Cost\ Index} \quad (8)$$

The resulting scaled capitals showed in Table 2 highlight that the steam gasification plant (€ 235 M) has the highest capital compared to the other plants. However, this capital is lower when compared to each of the overall biohydrogen production systems, given that system 2 consists of the integration of the biogas production plant and the SMR plant (total of € 206 M), and system 3 consists of the integration of the bio-oil production plant and the bio-oil reforming plant (total of € 287 M).

Table 2: Investment estimate for each of the plants that integrate the systems under analysis

Description	Reference capacity (kg/h)	Reference capital (€ M)	Scaling capacity (kg/h)	Scaled capital (€ M)	Source
System 1					
SR plant (based on CH <sub>4</sub> processed)	198	6	7,673	118	(Yao et al., 2017)
System 2					
AD plant (based on CH <sub>4</sub> produced)	287	6	7,673	88	(Yao et al., 2017)
SR plant (based on CH <sub>4</sub> processed)	198	6	7,673	118	(Yao et al., 2017)
System 3					
FP plant (based on bio-oil produced)	3,600	40	22,039	170	(Arfan et al., 2023)
Bio-oil SR plant (based on bio-oil processed)	50,000	225	22,039	117	(Sarkar and Kumar, 2010)
System 4					
SG plant (based on syngas produced)	4,080	15	122,242	235	(Yao et al., 2017)

The engineering procurement and construction costs (EPC) and the contingencies and owner's costs (C&OC) were then added to the TDPC, using the percentages proposed in the literature (Spallina et al., 2016). The final estimated CAPEX for each of the systems under evaluation are shown in Table 3. These amounts were then converted into annuities using the CCF, as described above. On the other hand, OPEX was estimated considering the annual expenses of raw materials (€ 0.02/MJ NG, € 25/t biowaste, € 60/t wet biomass residues), fuel gas (€ 0.02/MJ NG), electricity (€ 198/MWh), water (€ 2.82/t), maintenance (2% of CAPEX), insurance and taxes (2% of CAPEX). While the plant productivity was calculated as the product of production capacity and the plant's equivalent working hours (8760 h/y). Figure 2 highlights CAPEX and OPEX per year, while final LCOH results were summarized in Table 4. CAPEX and raw material costs are the most important factors influencing LCOH in all the systems analyzed, for example, in system 1 the cost of NG accounted for 67% of the total annual costs. Consequently, the LCOH of system 1 is equal to the LCOH of system 3 only when CAPEX was not considered. On the other hand, energy consumption (electricity and fuel gas) has a significant impact on the LCOH of system 2, but it is reduced in system 3 and system 4 since secondary products such as char are used to cover part of the energy requirement.

Table 3: CAPEX estimation for the implementation of the systems under analysis (€ M).

Equipment	System 1	System 2	System 3	System 4
Total direct plant cost (TDPC)	118	206	287	235
Indirect Cost (IC) (14 % of TDPC)	17	29	40	33
Engineering procurement and construction (EPC) (TDPC + IC)	135	235	327	268
Total contingencies and owner's costs (C&OC) (15 % of EPC)	20	35	49	40
CAPEX (EPC + C&OC)	155	270	376	308

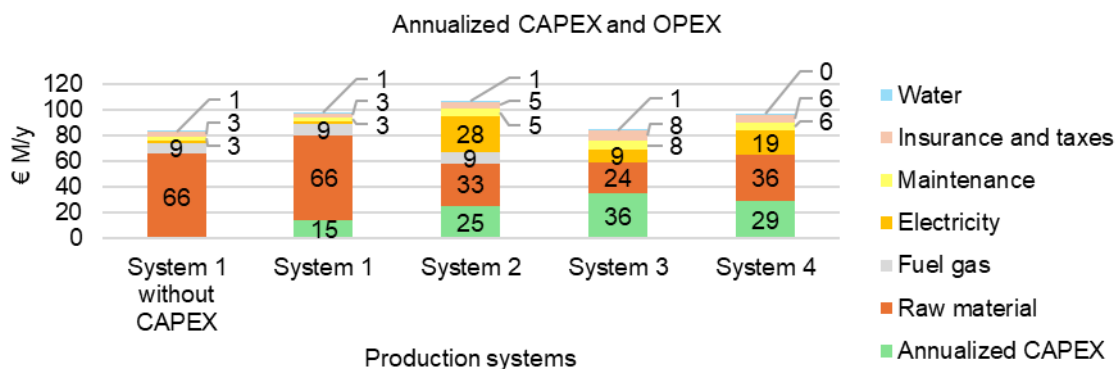


Figure 2: Estimate of the annualized CAPEX and OPEX of the systems under analysis

Table 4: LCOH results obtained for the systems under analysis.

Description	System 1 (without CAPEX)	System 1	System 2	System 3	System 4
LCOH (€/Kg)	3.52	4.14	4.52	3.56	4.08

#### 4. Conclusions

In this paper the technical and economic performance of three biohydrogen production systems were analysed and the results were compared to typical H<sub>2</sub> production from NG reforming. Based on a 2,700 Kg H<sub>2</sub>/h facility, preliminary LCOH results showed that bio-oil reforming (€ 3.56/kg) is the least expensive way to produce biohydrogen when compared to biomass gasification (€ 4.08/kg) and biogas reforming (€ 4.52/kg). In fact, the LCOH of the bio-oil reforming pathway was quite similar to the LCOH of the natural gas SR pathway when CAPEX was not considered (€ 3.52/kg) and even lower than the LCOH of fossil-based H<sub>2</sub> production with CCUS (€ 4.40/Kg H<sub>2</sub>, as reported in the introduction). This result indicates that the H<sub>2</sub> production from bio-oil reforming could be economically competitive and viable in hard-to-abate sectors. On the other hand, although biohydrogen production from biogas reforming appears to be less-cost effective mainly due it requires a large amount of raw material as well as energy (electricity), its economic performance, as well as that of the other biohydrogen production systems can improve if the raw material is available at no economic cost. Additionally, from an environmental perspective combining biohydrogen production with CCUS could be an option to develop negative emission systems. Although the preliminary LCOH analysis can still be improved by considering additional costs (e.g. catalysts, operation labor, waste disposal and environmental impact costs), the results showed that biohydrogen production can be competitive compared to H<sub>2</sub> production from NG. In fact, a future study could include in addition to financial costs also environmental impact costs, considering as suggested by the ISO standard ISO15686-5 (life-cycle cost) the economic loss of well-being (e.g., human health and biodiversity) due pollutant emissions of each system as well as the mitigation cost of any necessary intervention. Overall, the results are positive to encourage the reduction of fossil-based H<sub>2</sub> consumption in hard-to-abate sectors, improving waste and residual biomass management, and promoting a net zero greenhouse gas emissions economy in Italy and Europe.

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