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Levelized Cost of Biohydrogen from Steam Reforming of Biomethane with Carbon Capture and Storage (Golden Hydrogen)—Application to Spain

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Abstract: The production of biohydrogen with negative CO_2 emissions through the steam methane reforming of biomethane, coupled with carbon capture and storage, represents a promising technology, particularly for industries that are difficult to electrify. In spite of the maturity of this technology, which is currently employed in the production of grey and blue hydrogen, a detailed cost model that considers the entire supply chain is lacking in the literature. This study addresses this gap by applying correlations derived from actual facilities producing grey and blue hydrogen to calculate the CAPEX, while exploring various feedstock combinations for biogas generation to assess the OPEX. The analysis also includes logistic aspects, such as decentralised biogas production and the transportation and storage of CO_2. The levelized cost of golden hydrogen is estimated to range from EUR 1.84 to 2.88/kg, compared to EUR 1.47/kg for grey hydrogen and EUR 1.93/kg for blue hydrogen, assuming a natural gas cost of EUR 25/MWh and excluding the CO_2 tax. This range increases to between 3.84 and 2.92, with a natural gas cost of EUR 40/MWh with the inclusion of the CO_2 tax. A comparison with conventional green hydrogen is performed, highlighting both prices and potential, thereby offering valuable information for decision-making.

Keywords: grey hydrogen; blue hydrogen; golden hydrogen; CCS; SMR; LCOH

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1. Introduction

The energy crisis that Europe is experiencing, as well as global warming, have highlighted the need to decarbonise the energy sector. Hydrogen is considered a key vector for achieving this goal. Several international production targets have been set, such as 20 Mt by 2030 in the European Union [1]. In the case of Spain, current production is about 600 kt [2]; whereas, the National Hydrogen Roadmap aims to install 4 GW of electrolysers (approximately 400 kt) by 2030 [3]. This target has been recently updated in the draft published in June 2023 of the National Integrated Energy and Climate Plan (NIECP) to 11 GW (1100 kt) by 2030 [4].

Currently, the majority of globally produced hydrogen comes from the process known as steam methane reforming (SMR) of natural gas. In 2021, 62% of the production was attributed to this method [5]. The SMR process yields a gas with a high concentration of hydrogen (round to 75%), along with additional amounts of methane (2–6%), carbon monoxide (7–10%) and carbon dioxide (6–14%) [6]. Furthermore, the water–gas shift reaction process transforms carbon monoxide into hydrogen and carbon dioxide. Equations (1) and (2) show the two reactions mentioned above.

$$CH_4 + H_2O \rightarrow CO + 3H_2 \quad (1)$$

$$CO + H_2O \rightarrow CO_2 + H_2 \quad (2)$$

Hydrogen produced by SMR is designated as grey hydrogen, emitting about 9 kg of CO_2 per kg of hydrogen produced. In order to decarbonise this production, it is possible to replace the natural gas with biomethane, producing the so-called biohydrogen [7]. Such biohydrogen is labelled as renewable [8], and might even generate negative emissions [7]. This is because the biomethane, derived from organic waste, contains carbon captured from the atmosphere by plants. These plants are eventually converted into organic waste, with plants and livestock serving as intermediate transformers. Thus, if the CO_2 captured in the SMR process is stored (CCS), it is definitely removed from the atmosphere, generating negative emissions. The authors have proposed the label "golden" for this biohydrogen with negative emissions based on SMR with CCS from biomethane [9], as the hydrogen might be considered as green, which would be transformed into yellow (golden) if we assimilate the CCS with the blue colour.

Spain has a high potential for the production of biogas from organic waste. Preliminary estimations identified a potential range from 44 TWh/year [10] to 60–90 TWh/year [11]. The most comprehensive and recent study by the Spanish gas association (SEDIGAS) [12] estimates a potential of 163 TWh/year. The production of biogas is carried out through the process known as anaerobic digestion, which is the first step to obtain biomethane. This widely known process has an efficiency in the range of 72–85% [13]. After obtaining biogas, it is necessary to convert it into biomethane. This conversion process is designated as upgrading, where impurities and CO_2 in the biogas are removed, obtaining nearly pure methane, indistinguishable from natural gas. Figure 1 summarises the procedure to produce golden hydrogen.

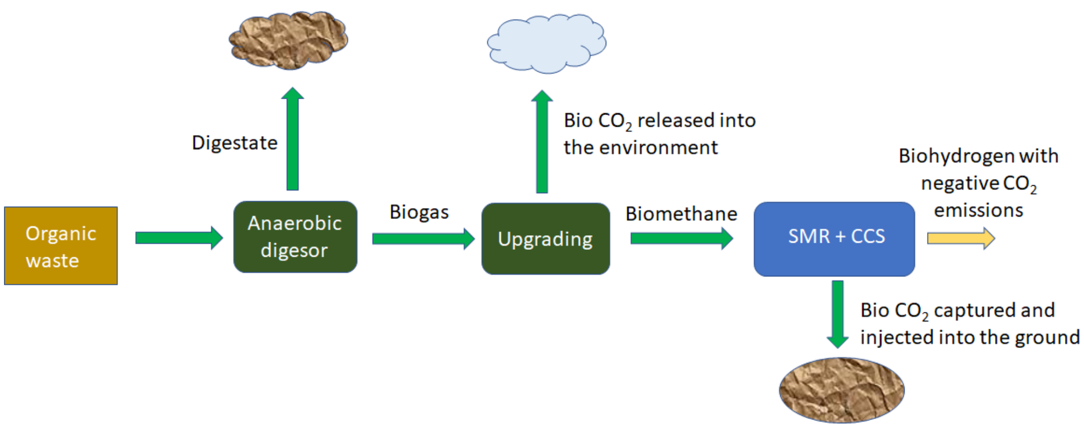

Figure 1. Stages for the production of golden hydrogen.

Regarding CO_2, there are two stages in which it is produced, as sketched in Figure 1: the first is during the upgrading of the biogas and the second is during the reforming of the biomethane. To obtain golden hydrogen, capturing the CO_2 from the SMR process is proposed, due to the complexity in managing the CO_2 released in the upgrading, given the numerous biogas facilities distributed throughout the country. Since it is a process with a high concentration of CO_2, the capture efficiency can reach a yield of 90% [5]. Between 2013 and 2020, three large facilities (capturing more than 0.8 Mt CO_2/year) in the world produced blue hydrogen: one in the US (2013) with a capture capacity of 1 Mt CO_2/year, and two in Canada with 1 Mt CO_2/year (2015) and 1.3 Mt CO_2/year (2020). In the same period, the total number of facilities incorporating large carbon capture units was 21, with an overall capture capacity of 39.4 Mt CO_2/year [14]. The starting of nine large facilities between 2026 and 2030 has been announced in the UK, with an initial overall foreseen capture of 14.5 Mt CO_2/year [15]. The Spanish Geological Survey has carried out a study identifying the preferred locations for storage in Spain [16], developing a map [17], where the total estimated capacity is higher than 11 Gt.

The use of biohydrogen with negative emissions (HyBECCS) is garnering significant attention from the research community. Rosa et al. [18] assessed the potential in Europe of HyBECCS derived from biogas by SMR with CCS. They focus on this technology due to its maturity (technology readiness level of nine for SMR and from seven to eight for SMR with CCS). Proposed substrates included crop residues, urban organic waste and livestock manure, with the study examining the supply chain's integration of production and demand. Negative emissions emerged as a powerful tool for decarbonising hard-to-electrify sectors, and it was possible to integrate several energy carriers in a flexible way to achieve them.

In this sense, Moioli et al. [19] proposed the use of biomass to produce renewable gases through two methods: anaerobic digestion of organic waste to generate biogas and biomass gasification to produce syngas, which is subsequently converted to hydrogen. In both cases, biogenic CO_2 is produced, which can either be stored to achieve negative emissions or combined with hydrogen from electrolysis with renewable sources to produce biogenic synthetic methane. This approach envisages a complex system that transforms biomass, organic waste and surplus renewable electricity into biomethane, synthetic biogenic methane or other synthetic biofuels and negative CO_2 emissions.

Lefranc et al. [20] explored the application of golden hydrogen in fuelling a bus fleet in Madrid, demonstrating that negative emissions allowed for saving biomethane when golden hydrogen powers the buses equipped with fuel cells. Yagüe et al. [21] assessed its application in the tile sector, revealing substantial resource savings attributed to the negative emissions, which added an extra decarbonising capacity to golden hydrogen, in being more efficient in the use of the biomethane for the same level of decarbonising.

While the production of HyBECCS from biomethane via SMR offers notable benefits such as the use of existing infrastructure, technology maturity and stable feedstock prices, it is not the sole method for HyBECCS production. Full et al. [22] investigated dark photosynthesis with CCS as an alternative biohydrogen production with negative emissions production pathway. They report a levelized hydrogen cost ranging from EUR 4/kg without CO_2 revenue internalization to EUR 0.44/kg when accounting for it, based on a EUR 195/t CO_2 price for negative emissions.

The key to the negative emissions lies in the CO_2 supply chain management, as it was revealed in a recent communication from the European Commission to the Parliament [23]. In this document, an EU-wide industrial carbon management strategy was proposed that included the following: CO_2 capture for storage, from both fossil and biogenic sources, and direct atmospheric removal and utilization of captured CO_2, for example, for industrial uses such as synthetic fuels. Whilst initially both fossil and biogenic CO_2 might be used by industry, a shift towards biogenic CO_2 is foreseen for greater climate benefits. The Commission also envisages some challenges in managing this CO_2, particularly due to regulatory issues and the European Trade System's failure to recognise negative emissions. This lack of recognition complicates the assignment of a market price to the captured and stored biogenic CO_2, thereby not providing incentives for this process. The European Commission has also recently released a report [24] assessing the required transport network to manage the captured CO_2 between potential sources to users and storage. The authors estimate a need for a 19,000 km network from 2025 to 2050 with a required investment range of EUR 9.3 billion–EUR 23.1 billion; it is recommended that the development of storage capacities be located in southern and eastern Europe to reduce investment costs. The cross-border problems are also analysed, concluding that quality standards for transport and storage are essential.

As it is shown in the literature review, the analysis of biohydrogen with negative emissions is an emerging research area, encouraged by an increasing interest in carbon capture and storage technologies. Although the different processes involved are known, a detailed cost analysis encompassing the entire supply chain is missing.

In this paper, a detailed study of the different stages of golden hydrogen production and the costs associated with each of them has been conducted to assess economic viability, translated into the levelized cost of hydrogen (LCOH). The process encompasses the production of biogas, the subsequent upgrading, injection of biomethane into the natural gas grid, production of hydrogen in centralised hubs with CO_2 capture and finally, its transport and storage in geological sites. After a validation of the methodology with current costs of grey and blue hydrogen, the model is applied to four scenarios for golden hydrogen production, each involving different substrates and volumes of biomethane according to actual forecasts in Spain. This part of the supply chain has been revealed as a key issue, affecting not only the cost, but also the availability of golden hydrogen. Special attention was given to the locations of the production plant and the storage site, taking into account their impacts on the transport network for both hydrogen and CO_2. A sensitivity analysis was carried out to reveal the key aspects affecting the LCOH and a comparison with the current costs of grey, blue and green hydrogen was made. The results facilitate the identification of stages with a greater relative impact on the LCOH, providing insights for cost optimization.

2. Methodology

2.1. Golden Hydrogen Production and Supply Chain

The key to golden hydrogen lies in the use of a mature technology such as steam methane reforming, but replacing the usual feedstock, natural gas, with biomethane. The SMR process consists of two steps, summarised in Equations (1) and (2). The first step involves the reforming of methane with steam, producing CO and H_2. Since this reaction is endothermic and requires temperatures in the range of 700 °C–1100 °C [25], an additional quantity of methane is burned to achieve these conditions. The second step of the process aims to increase the hydrogen production, and involves the water gas shift reaction, shown in Equation (2). The burning of the additional quantity of methane leads to a reduction in hydrogen production, summarised in Equation (3), where *HMR* represents the hydrogen-to-methane ratio, η_{SMR} stands for the efficiency of the process and *LHV* represents the lower heating value of methane (9.952 kWh/Nm^3) and hydrogen (3 kWh/Nm^3).

$$HMR = \eta_{SMR} \cdot \left(\frac{LHV_{CH_4}}{LHV_{H_2}} \right) \tag{3}$$

The mass ratio of carbon dioxide to hydrogen (CHMR) is given by Equation (4), where M stands for the molar mass of CO_2 (44 kg/kmol) and H_2 (2 kg/kmol).

$$CHMR = \frac{M_{CO_2}}{HMR \cdot M_{H_2}} \tag{4}$$

Regarding the carbon dioxide capture potential, if the CO_2 capture system is placed on the flue gas using monoethanolamine, the most optimal capture rate can be obtained (90%) [26]. Employing typical efficiency values [26], Soler et al. [9] obtained the results listed in Table 1, where the mass of hydrogen obtained regarding methane consumption was assessed.

Table 1. Conversion ratios for SMR with or without CO_2 capture. Adapted from Soler et al. [9].

Substrate	η_{SMR} [p.u.]	HMR $\left[\frac{kmolH_2}{kmolCH_4}\right]$	CHMR $\left[\frac{kgCO_2}{kgH_2}\right]$	H_2 Production $\left[\frac{tH_2}{GWh-HHVCH_4}\right]$	CO_2 Captured $\left[\frac{kgCO_2}{kgH_2}\right]$
Without CCS	0.759	2.52	8.74	20.36	0
With CCS	0.691	2.29	0.96	18.54	8.64

As the key difference between golden hydrogen and blue hydrogen lies in the replacement of natural gas with biomethane, it is necessary to include its management in the supply chain, as outlined in Figure 2. Regarding the biomethane, it is obtained in a distributed way from different substrates. In 2023, there were 12 plants operating in Spain, with an overall production of 522 GWh/year and other 19 plants in construction with a total anticipated production of 1197 GWh/year [9]. Each plant injects its production into the natural gas (NG) grid, commercializing it through guaranties of origin (GO) certificates, approved in Spain in 2023 [27]. A guarantee of origin certificate is an electronic certificate for 1 MWh of renewable gas, including its tracking. Once the biomethane is available in the grid, the centralized SMR + CCS plant redeems the required GOs and produces hydrogen and biogenic CO_2. As mentioned earlier, 90% of the CO_2 released by the SMR plant is captured, while the remaining 10% is released into the atmosphere. The costs and issues of transporting CO_2 are lower than in the case of hydrogen, so the SMR + CCS plant is preferably located close to the demand, and the captured CO_2 is injected into the CO_2 grid, and transported in supercritical state to the geological storage sites [28]. In Spain, the most available sites for storage are deep saline aquifers, with existing experimental works in Hontomín (Burgos) [29].

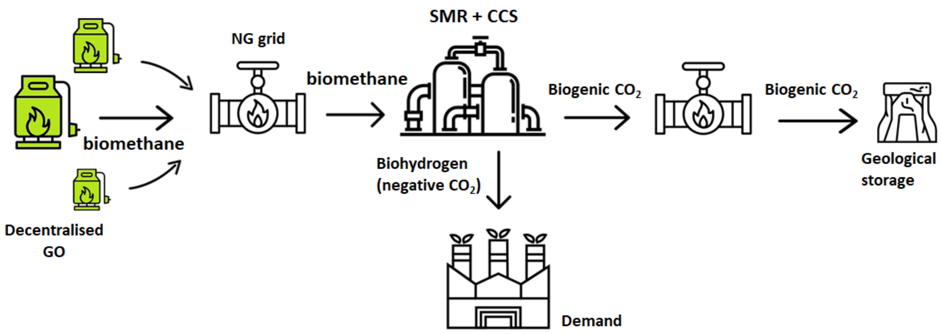

Figure 2. Supply chain of golden hydrogen.

2.2. Levelized Cost of Hydrogen

To determine the cost of hydrogen production, the levelized cost of hydrogen was employed, using the formulation of Bejan [30]. The LCOH consists of two components: capital expenditure (CAPEX) and operational expenditure (OPEX), as outlined in Equation (5).

$$LCOH = CAPEX + OPEX \tag{5}$$

The CAPEX is determined by Equation (6), where *INV* represents the investment, *HP* is the annual hydrogen production and *CRF* is the capital recovery factor.

$$CAPEX = \frac{INV \cdot CRF}{HP} \tag{6}$$

The capital recovery factor is given by Equation (7), where *wacc* is the weighted average capital cost, and *N* is the lifespan of the project.

$$CRF = \frac{wacc \cdot (1 + wacc)^N}{(1 + wacc)^N - 1} \tag{7}$$

Regarding the OPEX (Equation (8)), it includes the cost of biomethane (*bm*), operation and maintenance (*om*) and the cost of CO_2 management (CO_2).

$$OPEX = OPEX_{bm} + C_{om} \cdot CELF_{om} + OPEX_{CO2} \tag{8}$$

The cost of biomethane (Equation (9)) includes the cost of biogas (*bg*), upgrading (*ug*) and injection into the natural gas grid (*inj*).

$$OPEX_{bm} = C_{bg} \cdot CELF_{bg} + C_{ug} \cdot CELF_{ug} + C_{inj} \cdot CELF_{inj} \tag{9}$$

The cost of CO_2 management (Equation (10)) includes the cost of transportation from the SMR plant to the geological storage site (*tpt*), injection and storage in the geological site (*stg*) and the CO_2 tax (*tax*).

$$OPEX_{CO2} = C_{tpt} \cdot CELF_{tpt} + C_{stg} \cdot CELF_{stg} - C_{tax} \cdot CELF_{tax} \tag{10}$$

The cost of any x-th item (C_x) is given at year zero in a mass basis (EUR/kg H_2), and all of them are accumulated and annualized using the constant escalation levelization factor (*CELF*), given in Equation (11). For Equations (11) and (12), *r* is the nominal escalation rate (equal to zero for all items except for the carbon tax).

$$CELF_x = \left[\frac{k_x \cdot \left(1 - k_x^N\right)}{1 - k_x} \right] \cdot CRF \tag{11}$$

$$k_x = \frac{1 + r_x}{1 + wacc_x} \tag{12}$$

Considering *r* equal is to zero leads to the factor in brackets in Equation (11) being equal to the inverse of the capital recovery factor *CRF* and thus the constant levelization factor $CELF_X$ becomes one. The weighted average capital cost used is 8%, according to the International Energy Agency (IEA) [14].

2.3. Considerations on CO_2

In this work, CO_2 was only captured in the SMR plant, not in the upgrading process. This is seen as a preliminary step in deploying this technology, facilitating the transportation of CO_2 to its geological storage site from concentrated generation points. Therefore, the CO_2 removed in the upgrading process was released into the atmosphere for simplicity, although it might be commercialised as biogenic CO_2 for e-fuels production. In order to assign an economic value to the captured CO_2, two possibilities were considered. On one hand, negative emissions might be commercialised in a future trade system (currently not allowed). On the other hand, the CO_2 might be used to produce e-fuels or green chemicals. In the latter case, no negative emissions would be accounted for (except if the CO_2 remains in the chemical product) but the economic value assigned can be taken as the one in the trade system, as biogenic CO_2 is replacing fossil one. Such cost would be accounted for as negative, as it would be considered an income. In any case, EUR 80/t CO_2 was taken as the cost for the CO_2 removed [31]. This value was updated with a nominal rate of 8%, according to the IEA, which considers a CO_2 tax in 2019 of EUR 15/t CO_2 and of EUR 180/t CO_2 in 2050 [14], thus resulting in 8.3%.

2.4. Cost of Biomethane

The costs associated with biomethane include three main components: production of biogas, upgrading to biomethane and grid injection. The biogas cost depends on the substrate used in its production. Table 2 summarises the main substrates available in Spain [10]. It is evident that the collection process significantly influences the cost, with substrates linked to urban waste having lower costs. Using the hydrogen production ratio given in Table 1 (18.54 t H_2/GWh-HHV CH_4) and the lower and higher heating value of methane (9.952 kWh/Nm^3 and 11.04 kWh/Nm^3, respectively), the cost of biogas can be obtained per unit of mass of hydrogen produced, as summarised in Equation (13), where C_{bge} stands for the cost of biogas per unit of energy (EUR/MWh-LHV).

$$C_{bg} = 0.04862 \cdot C_{bge} \tag{13}$$

Table 2. Costs of biogas based on substrates [10].

Substrate	Cost (EUR/MWh-LHV)
Biodegradable waste in a sanitary landfill	6–10
Organic fraction of municipal solid waste	30–40
Wastewater treatment plant (WWTP) sludge	30–40
Cereal stubble	45–55
Corn (whole plant)	65–75
Pig manure	65–75

The second step in producing biomethane involves the upgrading of the biogas, which includes a cleaning process to remove impurities (such as H_2S and others), obtaining a mixture of CO_2 and CH_4, followed by a second operation to remove the CO_2. A scaling behaviour is observed in these costs, with Table 3 providing representative values based on the volume flow rate of the treated biogas [10]. Taking into account the heating values of CH_4 and the hydrogen production ratio when CCS is applied (18.54 t H_2/GWh HHV CH_4), it is possible to obtain the curve fit given in Equation (14), where Q_{bg} stands for the volume flow rate of biogas (Nm^3/h).

$$C_{ug} = 3.84 \cdot Q_{bg}^{-0.265} \tag{14}$$

Table 3. Costs of upgrading as a function of the volume flow rate of treated biogas [10].

Volume flow rate of biogas (Nm^3/h)	200	500	1000	2000
Cost of upgrading (EUR/MWh-LHV)	18–20	14–18	11–14	9–12

The average production of biomethane plants in Spain in 2023 was 545 Nm^3/h [32]. Assuming a concentration of 65% of methane in biogas [10], the average biogas flow rate was 838 Nm^3/h. Thus, the upgrading cost can be assessed for this average flow rate, resulting in EUR 0.645/kg H_2.

The last cost associated with biomethane is the injection cost for different flow rates, as given in Table 4 [10]. Applying the same conversion as in the upgrading process, Equation (15) is derived.

$$C_{inj} = 50.35 \cdot Q_{bg}^{-0.758} \tag{15}$$

Table 4. Costs of biomethane injection based on the volume flow rate of treated biogas [10].

Volume flow rate of biogas (Nm^3/h)	200	500	1000	2000
Cost of injection (EUR/MWh-LHV)	15–20	8–12	5–7	2–4

Using the average production of biomethane plants in Spain, the injection cost results in EUR 0.306/kg H_2.

2.5. Investment of SMR Plant

Lipman [6] provided the levelized cost of hydrogen obtained from natural gas using SMR with and without CCS, along with information on efficiency, natural gas cost and plant size. Table 5 displays the values obtained without CCS, and Table 6 includes the values with CCS. The costs are given in USD 2003, which were converted into EUR 2020 subsequently. In both tables, the last column (cNG_cH2, share of the natural gas cost in the LCOH) was calculated in the current study, assuming that the LCOH depends only on investment and natural gas costs, that is, neglecting the operation and maintenance costs. In this sense, the investment cost obtained includes a conservative margin. The cNG_cH2 value was derived from Equation (16), where C_{NG} stands for the cost of natural gas (USD/GJ) and C_{H2} represents the levelized cost of hydrogen (USD/GJ).

$$cNG\_cH2 = \frac{C_{NG}}{C_{H2} \cdot \eta_{SMR}} \quad (16)$$

Table 5. Economic data for SMR plants without CCS [6].

Hydrogen Production (kg/day)	LCOH (USD/GJ)	Natural Gas Cost (USD/GJ)	η_{SMR}(%)	cNG_cH2 (%)
480	24.75	6.16	60	41.48
24,000	9.73	4.27	72	60.95
609,000	5.5	3.0	81	67.34
609,000	6.6	3.9	81	72.95
609,000	6.85	4.1	81	73.89

Table 6. Economic data for SMR plants with CCS [6].

Hydrogen Production (kg/day)	LCOH (USD/GJ)	Natural Gas Cost (USD/GJ)	η_{SMR}(%)	cNG_cH2 (%)
24,000	12.41	4.27	72	47.79
609,000	7.20	3.0	81	51.44

In Tables 5 and 6, it is observed that *cNG_cH2* increases with the production (size) of the plant. In other words, the relative investment cost decreases as the size of the plant increases.

Utilizing Equation (16) and neglecting the operation and maintenance costs, as mentioned earlier, the investment of the plant could be expressed by Equation (17). In this equation, the higher heating value of hydrogen (39.38 kWh/kg) was used; *INV* stands for the investment (USD2003) and *P* represents the hydrogen production (kg/day). Table 7 provides the resulting investment.

$$INV = \frac{C_{H2} \cdot \left(\frac{39.38 \cdot 3600}{10^6}\right) \cdot (1 - \mathrm{cNG\_cH2}) \cdot P \cdot 365}{CRF} \quad (17)$$

Table 7. Investment of SMR without CCS plants derived from the data in Table 5.

Hydrogen Production (P) (kg/day)	$\mathbf{INV_{noCCS}}$ $\mathbf{(USD_{2003})}$
480	3,846,130
24,000	50,448,185
609,000	605,214,704
609,000	601,471,108
609,000	602,510,996

Applying Equation (17), the scaling law given in Equation (18) was obtained, with the currency (dollars) referred to year 2003.

$$INV_{noCCS\_2003} = 44,068 \cdot P^{0.713} \quad (18)$$

The investment for the plant with CCS was obtained as a summation of Equation (18) plus another scaling law that measures the difference between both plants. By applying Equations (16) and (17) to Table 6, the investment of SMR with CCS was obtained (third column in Table 8). Subtracting from it the investment corresponding to the second and third rows in Table 7 (no CCS plant investment for the same hydrogen production), the fourth column in Table 8 was achieved, representing the incremental cost of the CCS plant compared to no CCS. The scaling law for this difference is given in Equation (19), and thus the investment in SMR plants with CCS is expressed by Equation (20), with the currency (dollars) referred to 2003.

$$INV_{CCS\_2003} - INV_{noCCS\_2003} = 6132 \cdot P^{0.8592} \quad (19)$$

$$INV_{CCS\_2003} = 44,068 \cdot P^{0.713} + 6132 \cdot P^{0.8592} \quad (20)$$

Table 8. Investment of SMR with CCS plants derived from data in Table 6 and incremental investment of CCS plants compared to no CCS plants.

Hydrogen Production (kg/day)	cNG_cH2 (%)	INV_{CCS_2003} (USD)	$INV_{CCS\_2003} - INV_{noCCS\_2003}$ (USD)
24,000	47.79	86,032,633	35,584,449.54
609,000	51.44	1,177,984,909.19	572,770,204.78

The scaling laws obtained in Equations (18) and (20) should be updated to the current time. Instead of applying a time scaling factor, such as CEPCI (chemical engineering plant cost index) or a similar metric, data from the IEA Greenhouse Gas R&D Programme (IEAGHG) [33] were used. In this report, the cost for a SMR plant producing 100,000 Nm^3/h (214,286 kg/day) of hydrogen with and without CCS is provided, referred to 2020. The investment without CCS was EUR 175.35 million, whereas with CCS, it reached EUR 308.96 million. By maintaining the scale factor and updating the constants in Equations (18) and (20), Equations (21) and (22) were derived, with the currency (euros) referred to 2020.

$$INV_{noCCS} = 27,727 \cdot P^{0.713} \quad (21)$$

$$INV_{CCS} = 27,727 \cdot P^{0.713} + 3511 \cdot P^{0.8592} \quad (22)$$

2.6. Cost of Operation and Maintenance of SMR Plant

The report of the IEAGHG [33] also provides details on the cost of operation and maintenance for the plant with a capacity of 100,000 Nm^3/h, summarised in Table 9. This table includes only fixed costs. Regarding variable costs (methane, makeup water, chemicals and catalysts), the cost of methane accounts for 99.4%, so only this cost has been considered for simplicity's sake. The steam required for the process is usually produced by a cogeneration plant, which also exports electricity to the grid, whose revenue has not been considered. Thus, converting the costs given in Table 9 into relative costs results in EUR 0.096/kg H_2 in plants without CCS and EUR 0.148/kg H_2 in plants with CCS.

Table 9. Operation and maintenance costs of SMR plants of 100,000 Nm^3/h of hydrogen production capacity (currency, euros, referred to 2020) [33].

Concept	SMR without CCS (EUR/year)	SMR with CCS (EUR/year)
Direct labour	2,280,000	2,580,000
Administrative	991,714	1,323,590
Insurance	1,709,520	3,053,280
Maintenance	2,564,280	4,579,920
Total	7,545,514	11,536,790

2.7. CO_2 Costs

The costs associated with CO_2 included biogenic CO_2 removed from the SMR flue gases, transportation of CO_2 to its geological storage site, injection in this site and the CO_2 tax. With the assumed nominal rate (8%) for the CO_2 tax (EUR 80/t CO_2), its CELF resulted in 2.342. Considering 8.64 t CO_2 captured for each ton of hydrogen produced, the levelized cost of CO_2 captured was EUR −1.619/kg H_2.

The second cost linked to CO_2 is the transportation to the geological storage site. Itul et al. [34] estimated costs between EUR 1.8 and 12/t CO_2 in the US, depending on distance and volume. In the case of the EU, a typical cost of EUR 5/t CO_2 was considered for short onshore pipelines (180 km) and small volumes (2.5 Mt/year). As an indication, in the case of a large plant (609,000 kg/day), the CO_2 captured reaches 1.92 Mt CO_2/year. To be conservative, an average value of EUR 6.90/t CO_2 was considered, which was converted into EUR 0.06/kg H_2.

The last cost related to CO_2 is storage, also provided in [34]. In the case of deep saline aquifers, the estimated range was EUR 2–12/t CO_2. Higher costs (EUR 2–20/t CO_2) would be expected for off-shore depleted oil and gas reservoirs. An average value of EUR 11/t CO_2 was considered in this work, converted into EUR 0.1/kg H_2.

2.8. Assumptions for Validation

In order to validate the model, grey and blue hydrogen LCOH were used for comparison. Three representative natural gas costs were selected: EUR 25, 40 and 60/MWh-HHV. The lowest price corresponded to costs prior to the Ukrainian war, the intermediate cost was similar to the current cost, and the highest cost reflected an intermediate value between the high peaks during the first two years of the mentioned war.

Regarding the size of the plant, three cases were considered: 200 t H_2/year, 9000 t H_2/year and 300,000 t H_2/year, representing small, medium and large units, respectively, according to [6].

2.9. Scenarios Considered

In the case of the biohydrogen, the LCOH is heavily dependent on the biomethane cost, which, in turn, is greatly influenced by the substrate used to obtain biogas. Additionally, biomethane production is limited, so it is necessary to perform an assessment of the potential production of a region or country. This section considers a recent study developed by SEDIGAS [12] regarding the potential of biomethane in Spain. Four scenarios have been considered. Scenario 1 assumes that the substrate is only the organic fraction of municipal solid waste (MSW), with the SMR plant located close to the waste treatment plant, allowing the injection cost of biomethane to be neglected. The annual hydrogen production is set to 2700 tons, based on a treatment plant for 1,000,000 inhabitants [18]. In scenario 2, the mix of substrates and biomethane potential (11.04 TWh) has been taken from [10], which aligns well with the Biogas Roadmap [35] and the NIECP [4] of Spain. Scenarios 3 and 4 consider the analysis carried out by SEDIGAS [12], but with two approximations. This is managed in this way because the most important substrate foreseen by SEDIGAS to produce biomethane is constituted by intermediate crops (58.8 TWh), but it is not clear that such potential can be deployed, at least in the near term. For this reason, scenario 3 considers only 20% of the potential of intermediate crops, whereas scenario 4 includes the total potential foreseen by SEDIGAS. Table 10 summarises the potential of each scenario along with the assumed biogas cost. Weighting each cost with the potential of biomethane, the assessed average biogas cost was EUR 35/MWh for scenario 1, EUR 48.27/MWh for scenario 2, EUR 56.60/MWh for scenario 3 and EUR 60.47/MWh for scenario 4, all on an LHV basis.

Table 10. Potential of biomethane in the scenarios considered based on different substrate availability. The last column represents the assumed biogas cost, obtained from Table 2.

Substrate	Potential (TWh) Scenario 1	Potential (TWh) Scenario 2	Potential (TWh) Scenario 3	Potential (TWh) Scenario 4	Biogas Cost Assumed (EUR/MWh-LHV)
Agricultural waste		4.5	24.8	24.8	50–60 *
Manure		0.9	25.5	25.5	70
Intermediate crops		0.0	11.8	58.8	70
Forest waste		0.0	27.7	27.7	70
Industry waste		2.2	6.4	6.4	50

Table 10. *Cont.*

Substrate	Potential (TWh) Scenario 1	Potential (TWh) Scenario 2	Potential (TWh) Scenario 3	Potential (TWh) Scenario 4	Biogas Cost Assumed (EUR/MWh-LHV)
Organic fraction MSW	7.92	1.8	7.9	7.9	35
WWTP sludge		0.6	3.0	3.0	35
Landfill gas		1.1	8.8	8.8	8
Total	7.92	11	116	163	

(*) A cost of 50 EUR/MWh-LHV is assumed for scenarios 3 and 4. In scenario 2, a cost of EUR 60/MWh-LHV is assumed due to a blend of manure and lignocellulosic matter [10].

3. Results

3.1. Validation of the Model

Before obtaining the cost of golden hydrogen, the cost model was validated determining the costs of grey and blue hydrogen and comparing them with current references. The influence of scale and gas prices was also assessed. Figure 3 shows the LCOH obtained for grey hydrogen, and Figure 4 for blue hydrogen. The CO_2 costs were reduced to EUR 0.34/kg H_2 in the blue hydrogen. In both cases (grey and blue hydrogen), the share of the investment was low, except for the small unit at any natural gas price.

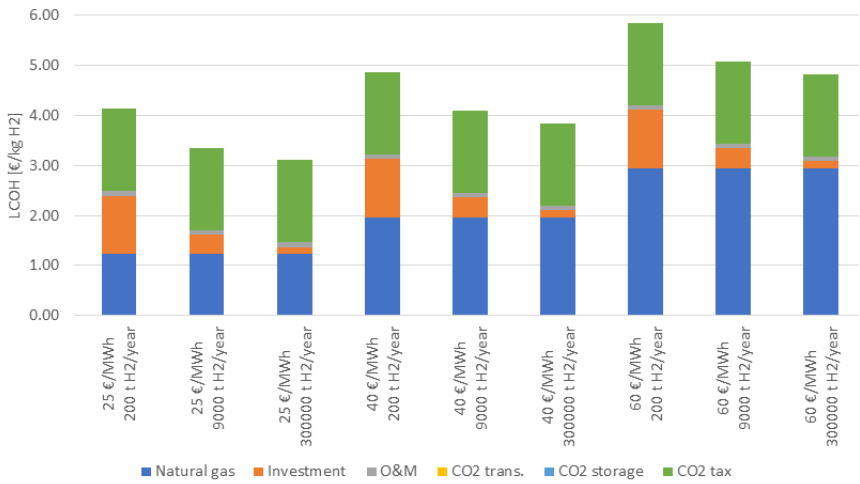

Figure 3. Levelized cost of grey hydrogen obtained with the proposed model.

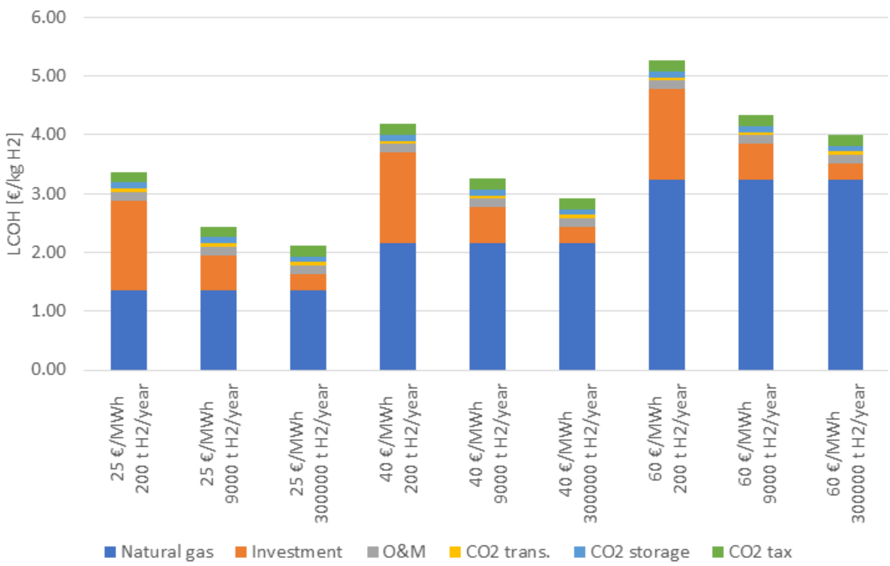

Figure 4. Levelized cost of blue hydrogen obtained with the proposed model.

According to data from the IEA [14], the maximum LCOH for grey hydrogen from natural gas with SMR is EUR 1.49/kg H_2 (EUR 22/MWh-HHV for natural gas cost, investment corresponding to a plant of 9000 t H_2/year, carbon tax of EUR 15/t CO_2 with a nominal rate of 0, and the rest of assumptions similar to those considered in the proposed model). Introducing these assumptions into the model, the cost for a medium size plant with the lowest natural gas cost resulted in EUR 1.7/kg H_2, indicating good agreement with the IEA data. Using data from the EU [2], the average LCOH in EU members in 2022 was EUR 5.7/kg H_2, corresponding to an average natural gas price of EUR 76.32/MWh [36]. Scaling the last column in Figure 3 from EUR 60/MWh to EUR 76.32/MWh, an LCOH of EUR 5.62/kg H_2 was obtained, demonstrating good agreement as well. In the case of blue hydrogen, IEA considers USD 2.1/kg H_2, whereas the model with the same assumptions produced EUR 2.11/kg H_2, achieving good agreement too.

Finally, the cost of CO_2 capture can be determined by excluding the CO_2 tax, transportation and storage and considering the CO_2 capture ratio (8.64 kg CO_2/kg H_2). In this case, in the scenarios with a natural gas cost of EUR 25/MWh, the obtained cost ranged from EUR 62.92/t CO_2 (small size) to EUR 35.33/t CO_2 (large size), in accordance with the IEA [37].

3.2. Scenarios Analysis

Table 11 displays the number of SMR plants required to harness the total potential of each scenario. In scenario 1, the unitary production was set to 2700 t H_2/year, whereas in the rest, a large plant (609,000 kg H_2/day) was used as the baseline. The hydrogen potential in scenarios 1 and 2 was 147 kt/year and 205 kt/year, respectively (between 25% and 34% of current demand). The hydrogen potential in scenarios 3 and 4 was 2151 kt and 3022 kt, respectively (3.6 and 5 times the current demand).

Table 11. Number of SMR plants required to harness the potential of each scenario and unitary hydrogen production.

Substrate	Potential (TWh)	Total Hydrogen Production (t/day)	Number of SMR Plants	Unitary Hydrogen Production (kg/day)
Scenario 1	7.92	402.3	55	7397
Scenario 2	11	558.7	1	558,740
Scenario 3	116	5892	10	589,216
Scenario 4	163	8280	14	591,393

Figure 5 illustrates the levelized cost of golden hydrogen in the considered scenarios. As expected, the cost of the feedstock (biomethane) was higher than the cost of natural gas in fossil hydrogen. For biohydrogen, the biomethane cost (including biogas, upgrading and injection) ranged from EUR 2.35/kg H_2 in scenario 1 to EUR 3.89/kg H_2 in scenario 4. In comparison, in fossil hydrogen the natural gas cost varied from EUR 1.23/kg H_2 (assuming a natural gas cost of EUR 25/MWh-HHV) to EUR 2.95/kg H_2 (for a natural gas cost of EUR 60/MWh-HHV). Despite the fluctuation in biogas cost across the scenarios, the LCOH of golden hydrogen exhibited a minimal variation, ranging from EUR 1.84/kg H_2 to EUR 2.88/kg. On the other hand, with similar natural gas costs (EUR 40/MWh-LHV to EUR 60/MWh-LHV) the LCOH of blue hydrogen in large SMR units spanned from EUR 2.92/t H_2 to EUR 4/t H_2. The income from CO_2 taxes enabled achieving a comparable cost between golden and blue hydrogen when the latter was based on natural gas costs between EUR 25/MWh-HHV and EUR 40/MWh-HHV, with golden hydrogen even attaining lower costs than blue hydrogen for higher natural gas costs.

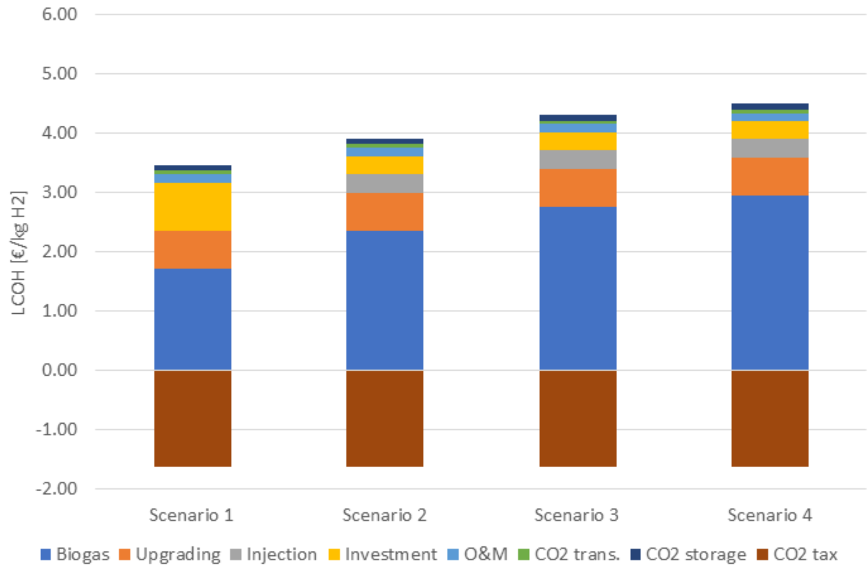

Figure 5. Levelized cost of golden hydrogen obtained with the proposed model.

4. Discussion

An interesting revelation from the analysis was the impact of carbon tax on the competitiveness of different hydrogen production methods. Figures 3 and 4 show how the inclusion of carbon tax incentivised the use of blue hydrogen, where capture of CO_2 cost was competitive compared with cases with low CO_2 concentrations (steel, cement, power generation and direct air capture) [37]. This low cost also appeared in large units of golden hydrogen production (scenario 3), where EUR 50.8/t CO_2 was obtained. This economic advantage positions it as a compelling technique for atmospheric CO_2 removal. In comparison, direct air capture costs ranged from EUR 125/t CO_2 to EUR 279/t CO_2, reinforcing the economic viability of golden hydrogen in the decarbonization landscape [37].

The key to the golden hydrogen's competitiveness lies in the negative cost associated with the carbon tax. Initially positioned at EUR -1.62/kg H_2 due to the 8% nominal escalation rate, this substantial value is justified by the IEA predictions. If we consider the carbon tax cost with a CELF equal to one, akin to the other components of the OPEX, the negative cost reduces to EUR -0.69/kg H_2. This adjustment still guarantees the competitiveness of golden hydrogen, highlighting its potential role as a key player in the collective effort towards sustainable and economically viable decarbonization.

Alongside generating revenue, negative emissions play a key role in decarbonisation, especially in hard-to-electrify industries. In this sense, blue hydrogen is associated with emissions of 0.96 kg CO_2/kg H_2, whereas green hydrogen produced through renewable electrolysis results in zero emissions. Golden hydrogen, on the other hand, achieves negative emissions, amounting to -8.64 kg CO_2/kg H_2 [9], and can reach up to -11.6 kg CO_2/kg H_2 when CO_2 from the biogas upgrading process is captured and stored [18]. These negative emissions produce a bonus in the decarbonisation, allowing the supplementation of golden hydrogen with fossil natural gas without losing decarbonisation potential. To illustrate this, Figure 6, taken from Soler et al. [9], shows that a blend of 72% of golden hydrogen with 28% of fossil methane produces zero CO_2 emissions. However, 100% of green hydrogen (renewable electrolysis) should be employed for the same goal.

The current demand of hydrogen in Spain is 600,000 t/year, mainly used in chemical industries and refineries [3]. The proposed NIECP [4] foresees a demand of approximately 1.1 Mt for green hydrogen from renewable electrolysis (11 GW electrolysers) by 2030. With the current production of biomethane in Spain, the production of golden hydrogen would hardly reach 200 kt. However, if the potential estimated by SEDIGAS [12] (scenario 4) were fully dedicated to produce golden hydrogen, it could surpass 3 Mt. Considering a more realistic potential (scenario 3), production could exceed 2 Mt. Thus, to achieve the NIECP

2030 production target with golden hydrogen would require only 52% of the biomethane potential under realistic assumptions (scenario3) or 37% with the full deployment of intermediate crops (scenario 4). In the former case, the LCOH is EUR 2.69/kg H_2 and in the latter it is EUR 2.88/kg H_2, both significantly lower compared to the current LCOH for green hydrogen with renewable electrolysis, ranging from EUR 4/kg to EUR 4.5/kg for electrolyser investment between USD 1000/kW to USD 650/kW and an electricity cost of EUR 65/MWh. To achieve costs similar to those of golden hydrogen, the electricity costs should be around EUR 20/MWh for the same investment cost [38].

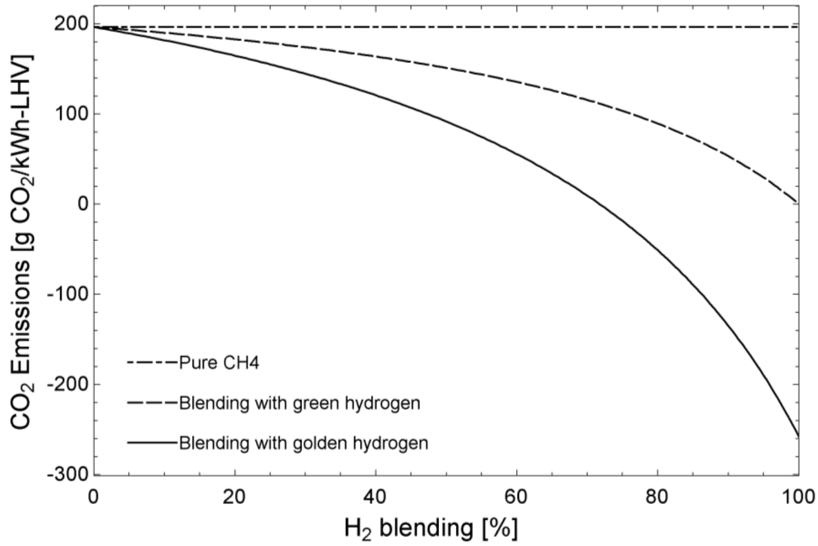

Figure 6. Decarbonisation potential of blends of H_2 (green or golden) with pure methane.

A key factor to use golden hydrogen is the availability of storage sites. As previously mentioned, the estimated storage capacity in Spain [17] is 11 Gt of CO_2. If all the realistic biomethane potential (scenario 3) were converted into golden hydrogen, the annual CO_2 captured would amount to 18.6 Mt, indicating a reserve capacity of 592 years.

A key factor in the development of golden hydrogen is the scalability and maturity of the SMR with CCS process. This technology has seen significant improvements since 2003, when Lipman [6] gathered various data used in this work to assess the investment costs for such plants. In his report, Lipman details two facilities: a smaller scale plant (24,000 kg H_2/day) and a larger one (609.000 kg H_2/day). From 2013 to 2020, the IEA [14] reported three plants producing blue hydrogen, with capacities ranging from 317,098 kg/day to 412,227 kg/day. Rosa et al. [18] assigned a technology readiness level of 9 to SMR technology and between 7 and 8 to SMR with CCS. This high maturity is reflected in the investment costs: the IEAGHG [33] estimated the investment for a plant of 214.286 kg H_2/day of capacity at EUR 308.96 million in 2020. Comparatively, a similar facility in 2003, using direct correlations derived from Lipman [6] (Equation (20)), would have required an investment of EUR 512.03 million. Using the CEPCI index [39] for 2003 (402) and for 2020 (596.2), the investment estimated from Lipman's data scales to EUR 759.4 million, approximately 2.46 times the current estimate provided by IEAGHG. This cost reduction can be attributed to the learning process experienced over nearly 20 years.

The breakdown presented in Figure 5 shows that the cost of biomethane is the most important component of the LCOH of golden hydrogen, followed by revenue derived from the CO_2 tax. For plants of small capacity, as depicted in scenario 1, the investment cost also plays a crucial role. While the cost of biomethane is expected to remain stable, it may still exhibit some uncertainty, as it relies on long-term purchase agreements and the biomethane market is just beginning to develop. On the other hand, although the CO_2 tax is expected to be high in the long term, its current value is subject to volatility. These three variables have been selected for a sensitivity analysis of the golden hydrogen's LCOH, as shown in Figure 7. Except for the scenarios with significant nominal escalation rates of the CO_2 tax, the LCOH remains parallel to the horizontal axis, indicating low sensitivity to CO_2 tax variations. Specifically, an increase in the CO_2 tax rate results in a lower LCOH for a given biogas cost. Conversely, a decrease in the CO_2 tax rate, even to negative values, leads to an increase in the LCOH for a given biogas cost, albeit with a limit. Moreover, the LCOH is strongly dependent on the biogas cost, as anticipated from Figure 5. The additional cost of LCOH for low production levels (low investment cost) necessitates a lower biogas cost to maintain the same LCOH as with higher production levels.

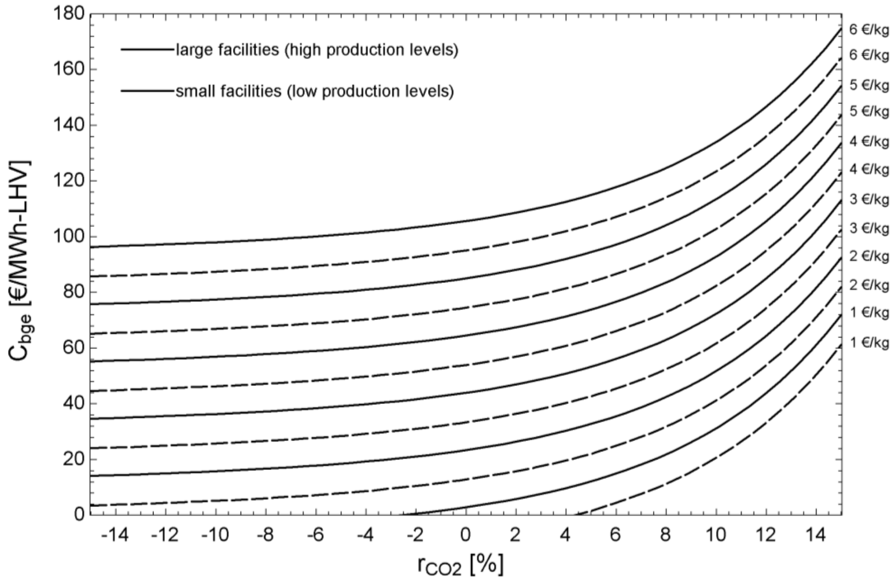

Figure 7. Sensitivity analysis of levelized cost of golden hydrogen.

5. Conclusions

As the global community intensifies its efforts towards decarbonization, the imperative to explore diverse and innovative pathways becomes increasingly evident. The quest for sustainable energy solutions requires a multi-technological approach. In this context, the proposed model to assess the LCOH of golden hydrogen emerges as a noteworthy contribution, aligning with the broader goal of reducing carbon emissions across various sectors.

Validated against the LCOH benchmarks of grey and blue hydrogen, the model not only demonstrates robustness but also highlights the potential of golden hydrogen as a competitive and environmentally responsible alternative. In contrast to blue hydrogen, golden hydrogen exhibits lower costs, with dependence of the feedstock cost compensated by the revenues from negative emissions. Moreover, the higher stability in the costs of biogas is a positive point for golden hydrogen.

Additionally, the production of golden hydrogen leverages the maturity of SMR technology, being necessary to deploy the CCS in both capture and storage aspects. Considering the pivotal role of CCS in achieving net-zero emissions [14,28], an anticipated surge in CCS adoption underscores the strategic positioning of golden hydrogen in the evolving energy landscape.

The analysis conducted on the production and costs of golden hydrogen has its Achilles' heel in the management of captured CO_2. Whereas the capture and storage exhibit high technology readiness levels, the infrastructure required for transporting CO_2 from the SMR facility to geological storage sites is still under development. However, the European Commission is encouraging its expansion in the coming years. This network development should be complemented by the inclusion of negative emissions in the European Trade System, in order to generate revenue for golden hydrogen production. In this sense, the volatility of the CO_2 tax presents another barrier to the promotion of this energy carrier, especially in the short term.

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Abbreviations

List of Acronyms

Acronym	**Meaning**
HyBECCS	Biohidrogen with carbon capture and storage
CAPEX	Capital expenditures
CEPCI	(chemical engineering plant cost index)
CCS	Carbon capture and storage
EU	European Union
GO	Guaranty of origin
HHV	Higher heating value
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas R&D Programme
LCOH	Levelized cost of hydrogen
LHV	Lower heating value
MSW	Municipal solid waste
NG	Natural gas
NIECP	National Integrated Energy and Climate Plan
OPEX	Operation expenditures
SEDIGAS	Spanish Gas Association
SMR	Steam methane reforming
WWTP	Waste water treatment plant

List of Symbols

Symbol	**Meaning**	**Units**
CELF	Constant escalation levelization factor	-
CHMR	Mass ratio of carbon dioxide to hydrogen	-
C	Cost	EUR/kg H_2
cNG_cH2	Ratio of cost of natural gas to hydrogen	-
CRF	Capital recovery factor	$year^{-1}$
η	Efficiency	-
HHV	Higher heating value	kWh/Nm^3
HMR	Hydrogen-to-methane ratio	-
HP	Hydrogen annual production	kg/year
INV	Investment	EUR or USD
k	Ratio of increase in nominal escalation rate and wacc	-
LHV	Lower heating value	kWh/Nm^3
M	Molar mass	kg/kmol
N	Number of years	year
Q	Volume flow rate Nm^3/h	Nm^3/h
r	Nominal escalation rate	-
wacc	Weighted average capital cost	-
P	Daily hydrogen production	kg/day

List of Subscripts

Subscript	**Meaning**
bg	biogas
bge	biogas per unit of energy
bm	biomethane
inj	injection
om	operation and maintenance
stg	storage
tax	taxes
tpt	transport
ug	upgrading
x	x-th component of cost

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