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# Substituting Natural Gas with Hydrogen for Thermal Application in a Hard-to-Abate Industry: A Real Case Study

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**Abstract:** To pursue the total decarbonization goal set at 2050, the introduction of hydrogen to replace the usage of fossil fuel in hard-to-abate industrial sectors is crucial. Hydrogen will replace natural gas in hard-to-abate sectors where natural gas is required to make heat necessary for the industrial process. Naturally, all this is worthwhile if hydrogen is produced following a green pathway, meaning that it is connected with renewable sources. In this manuscript, a techno-economic analysis related to a real case scenario is carried out. The real system addressed involves continuous high-temperature industrial furnace operation with a seasonally variable but stable thermal energy demand, representing typical conditions of hard-to-abate industrial processes. Solar photovoltaic panels combined with batteries are used to generate and store electricity that in turn is used to generate green hydrogen. Different scenarios are considered, including mixed natural gas/hydrogen, the seasonal variability of industrial needs, and the variability of solar production. The economic aspects considered include the usage of anion exchange membrane water electrolyzers (AEMWEs) to produce green hydrogen, the improvement in efficiency during operations (operational costs, OPEX), and the decrease in the AEMWE cost (Capital expenditures, CAPEX) that occur over time. The study shows that the hydrogen production cost could decrease from 12.6 EUR kg$^{-1}$ in 2024 to 9.7 EUR kg$^{-1}$ in 2030, with further reduction to 8.7 EUR kg$^{-1}$ achievable through seasonal blending strategies. $CO_2$ emissions are significantly reduced through partial displacement of natural gas with green hydrogen, highlighting the environmental potential of the system.

**Keywords:** green hydrogen; water electrolyzers; AEM-WE; techno-economic analysis; $CO_2$ emissions

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Academic Editor: Andrea Rossin

Received: 29 March 2025
Revised: 19 May 2025
Accepted: 23 May 2025
Published: 1 June 2025

**Citation:** Mirshokraee, S.A.; Bedogni, S.; Bindi, M.; Santoro, C. Substituting Natural Gas with Hydrogen for Thermal Application in a Hard-to-Abate Industry: A Real Case Study. *Hydrogen* **2025**, *6*, 37. https://doi.org/10.3390/hydrogen6020037



## 1. Introduction

Global warming has been largely driven by rising $CO_2$ emissions from fossil fuel combustion and industrial activities, with a notable 2.1-gigaton increase observed in 2021 compared to 2020; this trend persists due to fossil fuels supplying around 80% of global energy and accounting for a significant share of transport and industrial emissions [1–5]. Consequently, the transition to renewable energy is increasingly seen as essential for decarbonization, a goal underscored by the COP 26 agreement, which reaffirmed the need for net-zero emissions by mid-century and for limiting global temperature rise to 1.5 °C [6]. Achieving this requires a 45% reduction in emissions within the decade, alongside broad deployment of renewable energy, coal-to-gas switching, and Carbon Capture and Storage (CCS) technologies, though CCS increases electricity costs due to high capital demands, especially in mid-merit plants [7–9]. Meanwhile, hydrogen is gaining prominence in clean energy strategies, with green hydrogen—produced via renewable-powered electrolysis—being advanced as a key long-term solution, supported by innovations in electrolysis and hydrogen storage systems [10–13].

While the decarbonization of the electrical industry is being enabled by solar and wind energy, advancements in storage technologies are required due to the intermittency inherent in these renewable sources, with lithium-ion batteries (LIBs) and hydrogen storage being evaluated as viable options, and the former being presently considered more cost-effective. Nonetheless, a longer operational life and greater resilience under demanding conditions have been attributed to hydrogen storage [14]. At present, as the majority of hydrogen is still produced from fossil fuels—resulting in substantial $CO_2$ emissions—it is classified by color codes based on environmental impact, with green hydrogen, generated via $CO_2$-free electrolysis powered by renewable energy, being increasingly promoted [15,16]. As a result of declining renewable energy costs and the applicability of hydrogen in a wide range of sectors, especially those difficult to decarbonize, a significant rise in the competitiveness of green hydrogen is expected within the next 5 to 15 years [17,18]. The possibility of storing green hydrogen and reconverting it to electricity using fuel cells—by which only water and heat are emitted—has been widely acknowledged [19,20]. In addition, hard-to-abate industries such as ammonia synthesis, cement manufacturing, and steel production are being considered for hydrogen integration, where its use as either a reagent or thermal energy source may allow the substitution of conventional fossil fuels or steam-reforming-based hydrogen that is typically linked with high greenhouse gas emissions [21–23].

In this context, green electricity-powered water electrolysis has been identified as an effective solution for addressing the emerging energy demands of industries and consumers, thereby positioning it as a central element of the Hydrogen Economy. Low-temperature water electrolyzers (WEs), including alkaline water electrolyzers (A-WEs) and proton exchange membrane water electrolyzers (PEM-WEs), are capable of supporting the variable input from renewable sources such as solar and wind energy [24–26]. A-WEs, which are cost-effective and free from platinum group metals (PGMs), are, however, limited in their application for large-scale uses due to safety concerns arising from the diaphragm's presence, lower efficiency, and an inability to supply pressurized hydrogen [27]. On the other hand, PEM-WEs are recognized for their higher efficiency, but their use is hindered by the high costs and limited availability of PGMs like iridium at the anode and platinum at the cathode [28,29]. Additionally, the environmental impacts of PEM-WEs are significant, particularly because of the fluorine-based polymers used in their membranes, which the European Commission plans to phase out by 2035 [30,31]. AEM-WEs, a relatively new family of low-temperature WEs, have been developed with the aim of combining the advantages of A-WEs and PEM-WEs. These include higher current efficiency, reduced reliance on critical materials, and improved safety, achieved through the use of a non-porous membrane that allows electrochemical pressurization, thereby preventing gas crossover and mixing [32]. Despite these advantages, AEM-WEs are still in the early stages of development, with a much lower technology readiness level (TRL) than the other electrolyzers. As a result, extensive research is required to enhance their performance and durability, particularly in the development of critical raw material (CRM)-free electrocatalysts and advanced polymeric materials that exclude fluorine [33–38].

Effective tools and methods should be utilized from an early stage of the technology development process to assess the techno-economic feasibility and probable future environmental performance of a proposed technology, as indicated by the information provided [39]. A step-by-step operation is followed in conducting techno-economic analysis (TEA), through which both the technical performance and economic viability of a process, product, or technology are evaluated [40]. Key factors such as capital expenditure (CAPEX), operational expenditure (OPEX), and production efficiency are considered in determining overall profitability. Through such analyses, an understanding of cost structures is enabled, while process design optimization and informed decisions on the viability and investability of technologies are facilitated [41]. The role of TEA in hydrogen production and utilization is crucial, as it assists decision-making in a sector characterized by rapid technological evolution and fluctuating market conditions. A significant barrier to the wide-scale adoption of conventional processes, such as water electrolysis, arises from the variability of capital and operational costs. By conducting TEA, stakeholders are enabled to identify cost drivers in basic hydrogen production pathways, and the economic impacts of integrating these technologies on a larger scale are analyzed. Strategic choices that balance technical and economic outcomes are realized by companies and researchers, thus improving the competitiveness of hydrogen as an energy carrier. This is considered essential for progressing toward cleaner energy systems and for guiding investments in green hydrogen infrastructure and production technologies.

A techno-economic analysis (TEA) was carried out in this study, focusing on the use of anion exchange membrane water electrolyzers (AEM-WEs) for green hydrogen production, which was applied to thermal processes within a representative case of a hard-to-abate industry—whose identity, due to confidentiality agreements with the industrial partner, was not disclosed. While various sectors such as cement, glass, ceramics, iron and steel, and chemicals were considered as potential beneficiaries of this approach, the replacement of natural gas with hydrogen gas—whether partially or entirely in a blended mode—was evaluated with the objective of reducing final $CO_2$ emissions. The technology of AEM-WEs was selected for detailed investigation because of its distinctive characteristics, including the lack of critical raw material (CRM) usage, the presence of a solid polymeric membrane enabling hydrogen pressurization, and the absence of fluorinated compounds within the membrane. Furthermore, the feasibility of producing the required green electricity directly from photovoltaic (PV) solar cells was assessed as part of the integrated system. Following this assessment, methods aimed at enhancing the overall efficiency of the process were proposed, while a sensitivity analysis was also performed to examine the influence of cost variation over time on system performance.

## 2. Methods

In this work, the complete or partial replacement of natural gas with hydrogen used for thermal application in a hard-to-abate industrial process is investigated. Due to confidentiality reasons, the hard-to-abate industry and its operations cannot be disclosed.

The energy required to heat the furnace operating in an industrial process within the hard-to-abate sector was fulfilled through the annual usage of natural gas, whose consumption profile was derived from monthly measured values, as presented in Figure 1. In this context, the substitution or partial replacement of natural gas with hydrogen was considered, as hydrogen can also be utilized to provide the necessary thermal energy. Accordingly, the equivalent amount of hydrogen required to generate the same energy output was calculated, with the mass of hydrogen (in kilograms) corresponding to the energy provided by natural gas (in standard cubic meters, smc) being determined through (Equation (1)):

$$m_{H_2} = \frac{E_{NG} \times V_{NG}}{LHV_{H_2}} \tag{1}$$

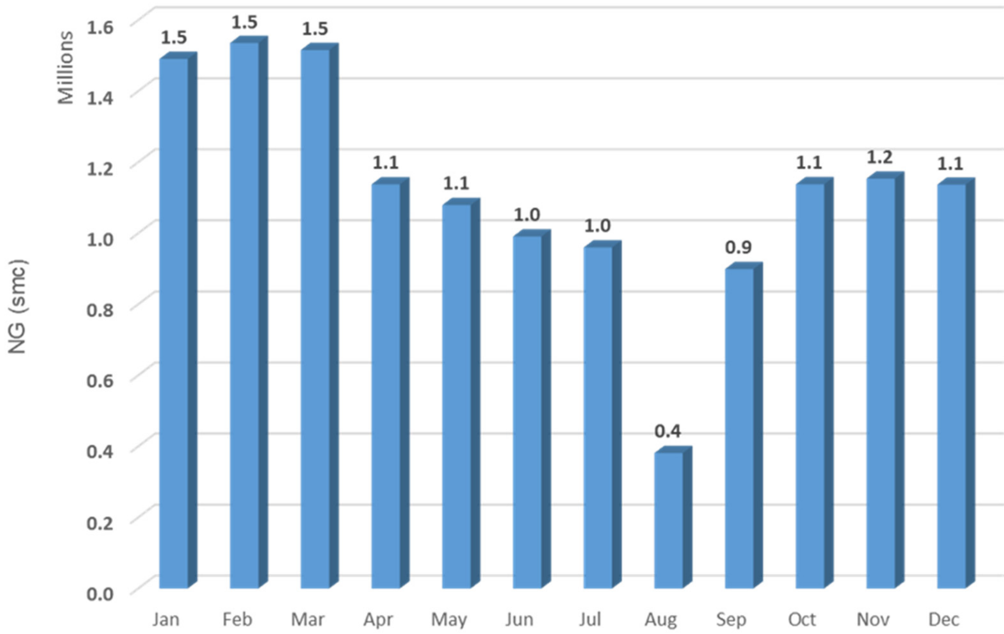


**Figure 1.** Annual required natural gas (NG) in the process of heating a furnace in the hard-to-abate industry considered in this study.

In the equation, $E_{NG}$ is the energy content per smc of the natural gas, usually $E_{NG} \approx 38$ MJ smc$^{-1}$ for its composition and $LHV_{H_2}$ is the lower heating value of hydrogen, approximately 120 MJ kg$^{-1}$ [42,43]. A 100% combustion efficiency for both fuels is assumed, and secondary energy losses are neglected, with this simplification being stated explicitly as a modeling assumption. In (Equation (1)), a direct comparison of the energy equivalence between hydrogen and natural gas is enabled, and this calculation is regarded as a critical step in the evaluation of the feasibility of natural gas replacement by hydrogen in a range of industrial energy applications. Using the known energy content of natural gas and the selected volume, the required mass of hydrogen to achieve an equivalent energy output is calculated through (Equation (1)).

The required amount of hydrogen was calculated so that a green production method capable of meeting industrial energy needs could be designed, with a simplified schematic of the process being shown in Figure 2. For this analysis, simplified hypotheses were adopted, in which (i) only AEM-WE was considered for hydrogen production, and (ii) hydrogen was assumed to be produced on-site, thereby eliminating the necessity for transportation. Moreover, all associated costs were calculated without inclusion of the combustion section, as the focus was placed solely on the costs of natural gas and hydrogen gas. These costs were subsequently compared over different time periods in order to evaluate temporal variations.

In this techno-economic study, two main scenarios were considered. In the first scenario, the objective was to assess whether the proposed approach for producing green hydrogen and utilizing a natural gas/hydrogen mixture for industrial thermal energy production is feasible. For this evaluation, both the actual costs and the predicted costs were considered. Importantly, the state of the art and prediction of the costs (capital and operational) related to hydrogen production using AEM-WE were taken from the technology key performance indicators (KPIs) of the Clean Hydrogen Partnership (former FCHJU) with particular reference to the Strategic Research and Innovation Agenda 2021–2027 [44].

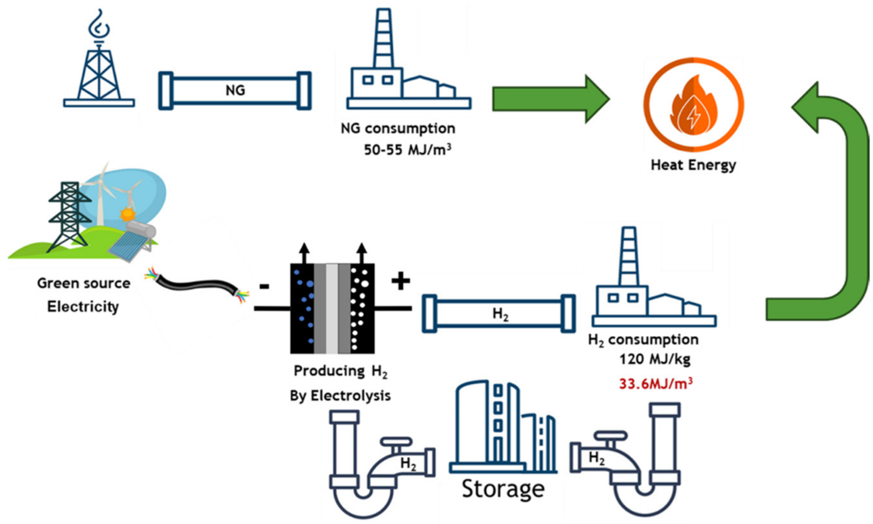


**Figure 2.** Schematic of the hydrogen production system capable of replacing NG.

One of the most important considerations was the use of a green energy source to generate the electricity required for green hydrogen production. In this specific case, only a single renewable energy source was used and, specifically, solar energy via photovoltaic (PV) solar cells. PV solar energy was selected due to its high availability at the industrial site and to simplify the system design for clearer techno-economic analysis. Using only PV as an energy source minimizes infrastructure complexity and supports scalable, practical solutions for industrial decarbonization.

After confirming the feasibility of the proposed method in the first scenario, the second scenario was introduced with the goal of improving the overall performance. In this second scenario, adjustments to hydrogen production were explored, which consequently affected the natural gas/hydrogen ratio across different months of the year to maximize the benefits of coupling the process with solar energy. Various ratios (e.g., 50%, 18%) were considered for different periods, such as assigning a specific natural gas/hydrogen ratio to each month or each season.

However, a major challenge in this approach was identified. Industrial facilities are typically designed to operate with a fixed fuel ratio, and modifying this ratio requires both time and significant costs. Therefore, any proposed changes must yield substantial benefits to justify the adjustment. As a result, it was determined that altering the natural gas/hydrogen ratio more than twice per year would not be practical.

Thus, in this study, a comparison was made between two systems: one with a fixed ratio throughout the entire year and another with two different ratios for different seasons. In the single-ratio system, 18% of the total energy consumption was supplied by hydrogen. In contrast, in the two-ratio system, hydrogen contributed 10% of the total energy during low-sunshine seasons and 25% during high-sunshine seasons. In both cases, the total hydrogen production over one year was approximately 1 million kg, which was one of the key reasons for selecting 18% as the hydrogen contribution in the single-ratio system.

HOMER Pro software was chosen for this study because it is a widely used and validated tool for optimizing hybrid renewable energy systems [45]. It allowed for modeling the interaction between renewable energy production, electrolyzer operation, hydrogen storage, and grid interactions, while minimizing the levelized cost of hydrogen production. Its simulation and optimization capabilities made it possible to evaluate different system configurations quickly and identify the most cost-effective and operationally feasible solutions for the industrial case considered. In the HOMER model setup, several key assumptions were made to simulate the system performance and costs. The energy consumption profile was based on the monthly natural gas usage of a furnace operating in a hard-to-abate industrial sector, assuming hydrogen could replace or blend with natural gas without significant modifications. The electricity supply was considered to come exclusively from photovoltaic (PV) solar panels, based on the solar irradiance profile typical for the installation region. The system components modeled included PV panels, AEM-WEs for hydrogen production, hydrogen storage tanks, a small battery to balance daytime energy generation, and a DC-AC converter when needed. Costs, efficiency, and lifetime values for each component were derived from either Clean Hydrogen Partnership targets or supplier quotations. Unfortunately, the supplier quotation could not be disclosed or displayed. Excess electricity generated was assumed to be sold to the grid at one-third of the grid purchase price (0.05 EUR $kWh^{-1}$). No dynamic financial modeling (e.g., inflation or interest rates) was included. Additionally, a seasonal hydrogen blending strategy was applied in the second scenario, adjusting the hydrogen/natural gas ratio between 10% and 25% depending on the solar energy availability. Lifetime assumptions for the PV system (20 years), AEM-WEs (5–7 years), and hydrogen tanks (20 years) were incorporated into the optimization.

The role of clean hydrogen in reducing industrial $CO_2$ emissions has been increasingly supported by recent studies. For example, large-scale hydrogen deployment in hard-to-abate sectors could lead to substantial emission reductions, as highlighted in both global techno-economic assessments and sector-specific case studies [46,47].

In this study, $CO_2$ emissions were calculated based on the replacement of natural gas combustion, using an emission factor of 2.15 kg $CO_2$ per normal cubic meter ($Nm^3$) of natural gas. Since hydrogen production is powered entirely by photovoltaic (PV) electricity, the system was considered near-zero-emission. Emissions from the balance of plant—including water purification, compression, and storage— were not calculated separately, as their energy demand is minimal and assumed to be covered by the same renewable source.

## 3. Results

### 3.1. First Scenario—Using PV as an Electricity Resource

A system was developed, as presented in Figure 3, based on the previously stated considerations, with the objective of producing the amount of hydrogen gas required to supply 50% of the furnace's daily energy demand, in which hydrogen and natural gas are utilized as fuels for heat generation. The electricity needed for hydrogen production was assumed to be provided directly by photovoltaic (PV) solar panels installed on-site, where hydrogen generation was also carried out. The system was configured so that hydrogen could be produced during daylight hours using solar energy, and any excess hydrogen generated during this period was intended to be stored for later use when solar irradiation is unavailable. To facilitate this, a hydrogen storage tank was integrated into the system for the eventual accumulation of surplus hydrogen. Additionally, a battery was incorporated into the design, intended exclusively for storing enough electrical energy to satisfy the system's primary power load. This arrangement was defined as the first scenario examined in this study.

Cost data and key performance indicators (KPIs) were collected from quotations received from different suppliers or found in the literature and reported in Tables 1–3 below [44].

According to these KPIs, the system with the minimum cost was identified using HOMER software [45]. A sensitivity analysis was carried out during the optimization phase on the cost of AEM-WEs at two distinct time points—namely, the current year (2024) and a future projection (2030)—with the parameters corresponding to the optimized system in both cases being presented in Table 4. It is demonstrated through the results that a higher efficiency is anticipated for the future configuration, through which a notable cost reduction is also expected to be achieved. The cost of producing 1 kg of hydrogen is thus projected to decline from EUR 12.6 to EUR 9.7, primarily due to improvements in the performance and longevity of AEM-WEs. This projected cost decrease—from EUR 12.6 kg$^{-1}$ in 2024 to EUR 9.7 kg$^{-1}$ in 2030—is attributed to two principal contributing factors. First, an increase in AEM-WE efficiency from 60% to 66.5% is expected, by which the electricity consumption per kilogram of hydrogen produced would be reduced. Second, a substantial reduction in the CAPEX of AEM-WEs is anticipated, from EUR 550 kW$^{-1}$ to EUR 300 kW$^{-1}$, as a result of expected improvements in manufacturing processes, material cost reductions, and the realization of economies of scale. Through the interaction of these advancements, a significant overall reduction in hydrogen production cost over time is projected.

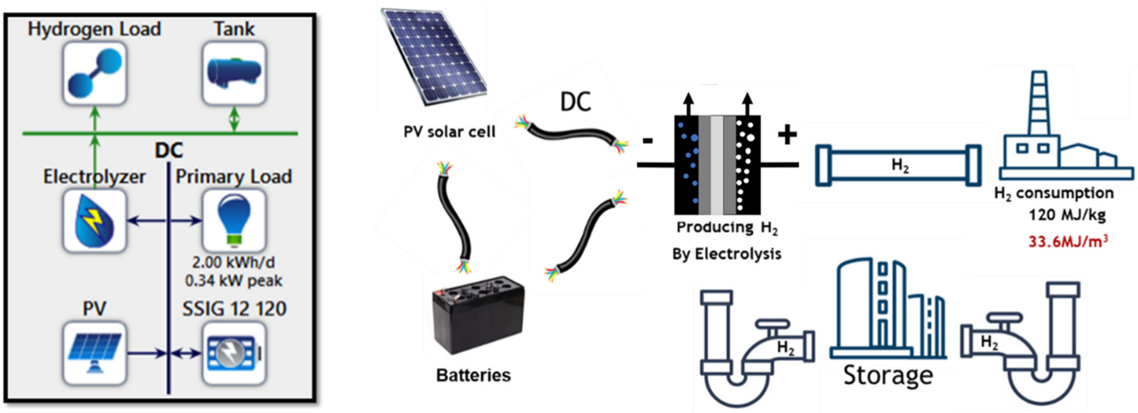


**Figure 3.** Using PV solar cells as the only source of electricity for hydrogen production stacks (first scenario).

**Table 1.** KPIs for PV solar cells.

| PV Solar Cells | Present (2024) | |
|---|---|---|
| Capex | 850 | (€ kW$^{-1}$) |
| O&M | 11.9 | (€ kW$^{-1}$ y$^{-1}$) |
| Lifetime | 20 | (y) |
| Capacity | 1 | (kW) |
| Derating Factor | 80 | (%) |

**Table 2.** KPIs for hydrogen tank.

| Hydrogen Tank | Present (2024) | |
|---|---|---|
| Capex | 1200 | (€ kg$^{-1}$) |
| O&M | 10 | (€ y$^{-1}$ kg$^{-1}$) |
| Lifetime | 20 | (year) |

Additionally, it was shown in this scenario that the efficiency of using only PV solar cells to provide electricity is higher, particularly when compared to a scenario where grid electricity is the sole energy source. When grid electricity, priced at EUR 0.15 kWh$^{-1}$, is utilized, the cost per kg of hydrogen is determined to be EUR 10.7 in 2024 and is projected to decrease to EUR 9.7 in 2030. This indicates that, with future KPIs, the costs of both scenarios are expected to converge. The cost breakdown by component for the first scenario at both time points is displayed in Figure 4, where the costs of each component are calculated, annualized, and presented in a bar chart, with each bar segmented to show the costs related to CAPEX, operational and maintenance (O&M) costs, and replacement expenses. In addition, pie charts are provided, which illustrate the percentage of the total cost attributed to each specific component.

**Table 3.** KPIs for AEM-WEs (defined by European Commission) [44].

| AEM-WE | Now (2024) | | Future (2030) | |
|---|---|---|---|---|
| Capex | 550 | (EUR $kW^{-1}$) | 300 | (EUR $kW^{-1}$) |
| O&M | 12.22 | (EUR $kW^{-1}$ $y^{-1}$) | 10.38 | (EUR $kW^{-1}$ $y^{-1}$) |
| Replacement | 300 | (EUR $kW^{-1}$) | 300 | (EUR $kW^{-1}$) |
| Efficiency | 60 | (%) | 66.5 | (%) |
| Lifetime | 5 | (y) | 5 | (y) |

**Table 4.** The volume of each component for the first scenario.

| Compound | Now (2024) | | Future (2030) | |
|---|---|---|---|---|
| AEM-WE | 170,000 | (kW) | 165,000 | (kW) |
| Generic flat plate PV | 330,000 | (kW) | 284,000 | (kW) |
| Hydrogen Tank | 80,500 | (kg) | 80,000 | (kg) |

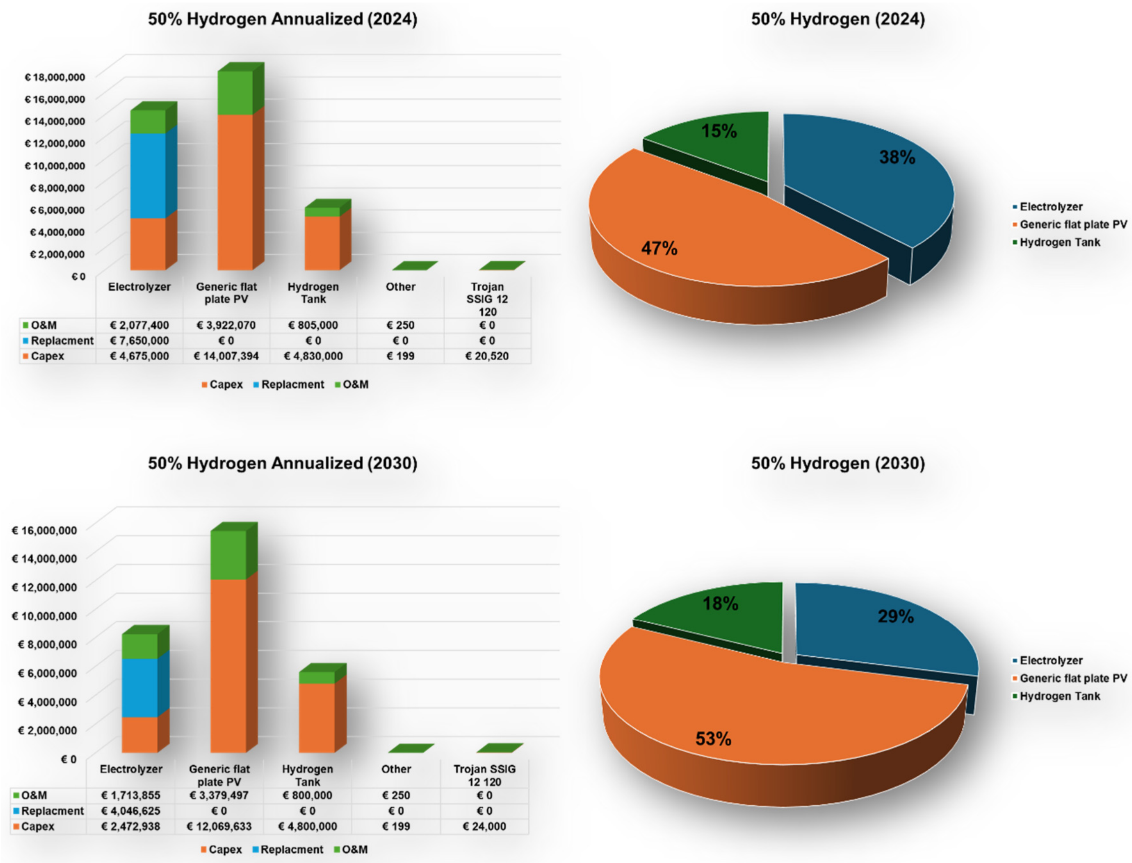


**Figure 4.** Bar and pie charts related to the first scenario cost for two different times [Now (2024) and Future (2030)].

While the possibility of relying solely on PV solar cells as the electricity source was examined through the design of the first scenario, technical feasibility was confirmed, although economic viability was not ensured. As the analysis progressed, it was concluded that without the implementation of cost-reduction measures and enhancements to system efficiency, the proposed approach would remain limited. Consequently, in the subsequent phase, modifications were introduced to the system, by which a reduction in total cost was intended. During this redesign, the KPIs originally based on European Commission estimates were substituted with actual performance metrics, which had been obtained from quotations provided by multiple suppliers, thereby increasing the market relevance of the analysis.

### 3.2. Reducing the Costs (Second Scenario)

Although 18% of the daily energy demand was supplied by hydrogen gas in the second scenario, no impact on the final cost per kilogram of hydrogen was observed as a result of this production shift. Following this, the KPIs for the AEM-WE cost were updated, with actual supplier data being used, as presented in Table 5. Furthermore, a modification was implemented whereby the excess electricity produced daily by the PV system was sold to the grid at a rate set to one-third of the purchase price from the grid, amounting to EUR 0.05. Based on these modifications, an updated system configuration was determined and optimized to achieve both cost minimization and a reduction in surplus electricity generation. As part of this configuration, the inclusion of a converter was necessitated, by which the DC electricity generated by the PV panels was converted into AC (Figure 5).

**Table 5.** KPIs for AEM-WEs (real cost).

| Electrolyzer | Present (2024) | | Future (2030) | |
|---|---|---|---|---|
| Capex | 2000 | (EUR kW$^{-1}$) | 1000 | (EUR kW$^{-1}$) |
| O&M | 12.22 | (EUR kW$^{-1}$ y$^{-1}$) | 12.22 | (EUR kW$^{-1}$ y$^{-1}$) |
| Replacement | 1000 | (EUR kW$^{-1}$) | 1000 | (EUR kW$^{-1}$) |
| Efficiency | 63.5 | (%) | 66.5 | (%) |
| Lifetime | 7 | (y) | 7 | (y) |

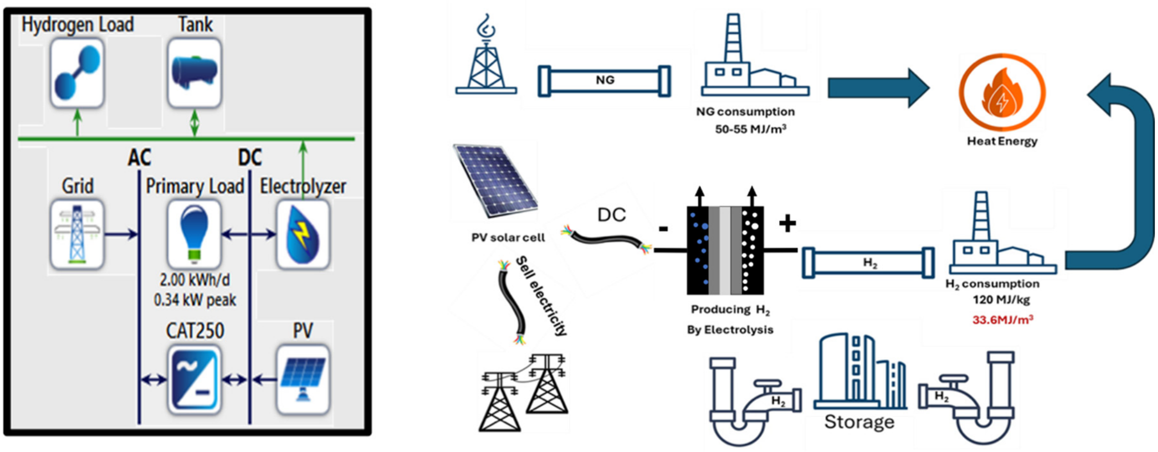


**Figure 5.** Selling excess electricity to the grid (second scenario).

Once the optimal systems corresponding to both the 2024 timeline and the anticipated conditions of 2030 had been computed, a system configuration characterized by the specifications listed in Table 6 was identified. The hydrogen production cost per Kg was subsequently derived through the division of the total annualized system cost by the total yearly hydrogen output. Under these calculations, hydrogen was priced at 17.1 EUR kg$^{-1}$ for the year 2024, with a projected reduction to 13.3 EUR kg$^{-1}$ by 2030. In Figure 6, a breakdown of the annualized cost per system component is depicted, from which the economic infeasibility of the current system becomes apparent. Accordingly, it is recognized that substantial cost-reduction strategies must be implemented, alongside a reduction in excess electricity generation, in order to enhance both the economic and operational performance of the system.

**Table 6.** The volume of each component for the second scenario.

| Component | Now (2024) | | Future (2030) | |
|---|---|---|---|---|
| Electrolyzer | 60,000 | (kW) | 55,000 | (kW) |
| Generic flat plate PV | 85,000 | (kW) | 85,000 | (kW) |
| Hydrogen Tank | 60,000 | (kg) | 55,000 | (kg) |
| CAT | 52,000 | (kW) | 52,000 | (kW) |

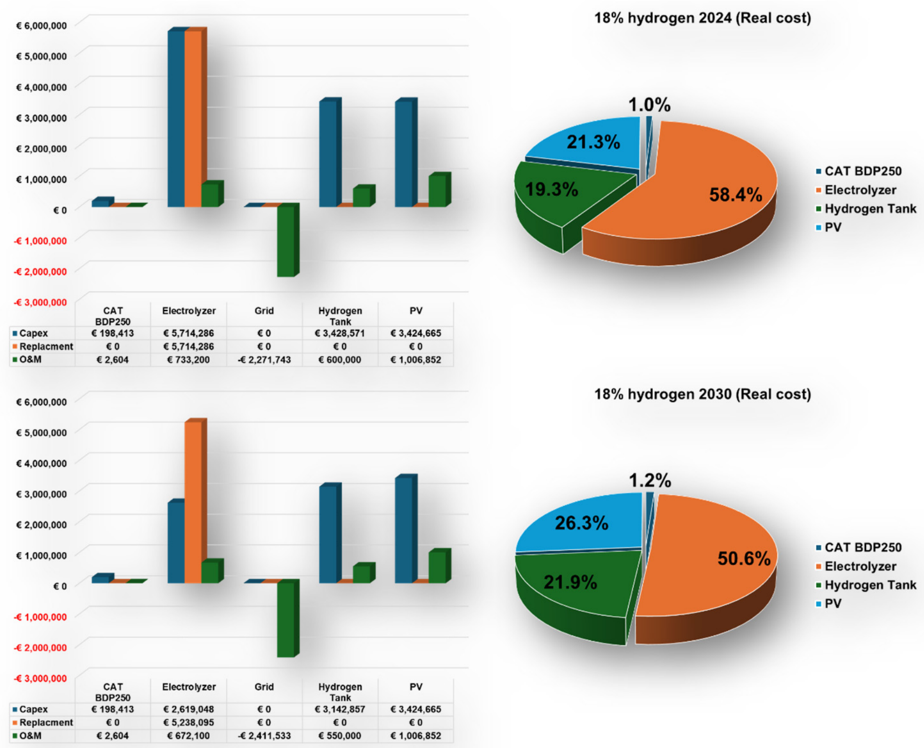


**Figure 6.** Bar and pie charts related to the second scenario cost for two different times [Now (2024) and Future (2030)].

Emphasis has been placed on the daily energy demand profile as a critical aspect in evaluating the application of solar energy within this research. Over a one-year period, the monthly energy production from PV solar cells—depicted in Figure 7—was observed to follow a parabolic trajectory, with its maximum output occurring mid-year, specifically in August. This production pattern, typically associated with Southern Europe (notably Italy), is expected to differ across various European regions and to be inverted in countries located in the Southern Hemisphere. Conversely, a contrasting trend has been identified in the energy demand profile, in which reduced consumption during the summer and heightened demand during winter have been recorded. Due to this seasonal divergence, the need for potential mitigation strategies has been underscored, highlighting the importance of aligning energy generation with consumption patterns.

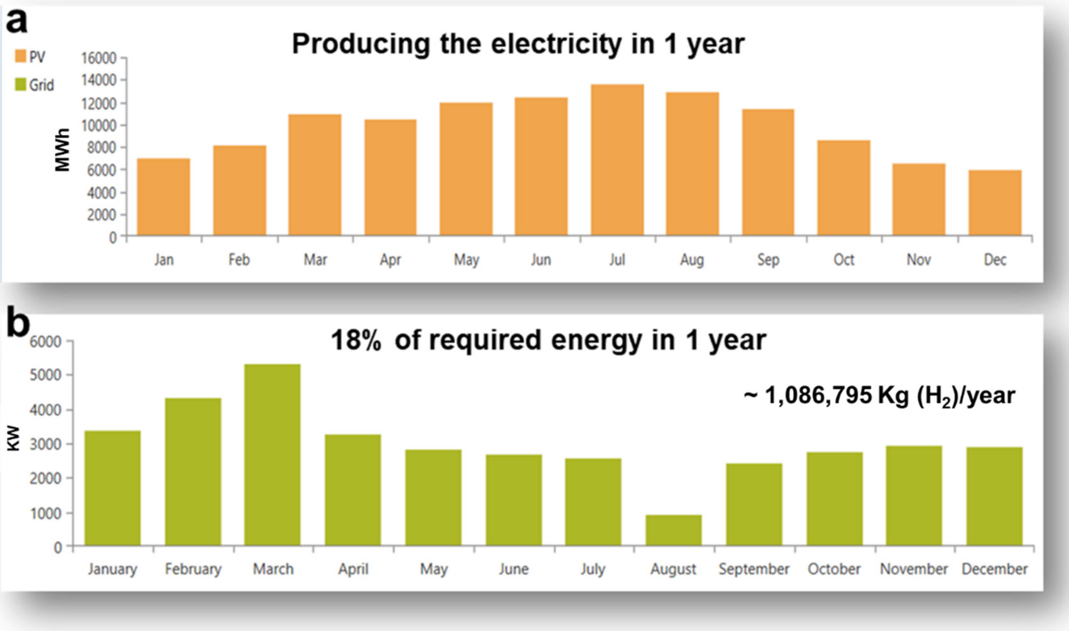


**Figure 7.** (**a**) Monthly production of PV solar cells in one year and (**b**) monthly profile of 18% of required energy for one year.

An adjustment of the industrial work schedule to more closely match the solar energy production profile—by increasing operational activity during periods of high solar irradiance in summer and reducing it during winter, when daylight availability is limited—has been proposed as a potential solution. Nevertheless, the practicality of such an adjustment is diminished, as scheduling decisions are frequently constrained by external socio-economic conditions; for instance, in Italy, the peak of summer, particularly the month of August, is traditionally designated as a widespread vacation period. Consequently, the implementation of such scheduling changes would be associated with significant logistical and financial burdens and is therefore not considered a viable strategy.

An adjustment of the hydrogen production profile throughout the year has been proposed as a second suggestion, by which the total daily energy demand would be preserved while allowing the NG/hydrogen ratio used in the furnace to be seasonally modified. Although such a strategy could enhance compatibility with solar energy availability, daily or monthly variations in this ratio are constrained, since the equipment employed by the industry is typically configured to operate under specific NG/hydrogen settings, which are not intended to be altered frequently without incurring substantial costs and requiring significant adaptation time. Consequently, the adoption of a seasonal hydrogen usage strategy, characterized by two fixed ratios—one designated for periods of high solar irradiance and another for low-sunlight seasons—has been identified as a more viable and less disruptive solution.

By adopting this approach, in which a daily energy profile was established using 10% hydrogen during the colder season and 25% during the warmer season, greater alignment between annual energy demand and PV solar cell production was achieved, as depicted in Figure 8—thereby enhancing system efficiency and significantly lowering both operational costs and surplus electricity generation. The economic impact of this seasonal adjustment is conveyed in Figure 9, where it is indicated that hydrogen production costs are expected to reach EUR 11.4 kg$^{-1}$ at present (2024) and decline to EUR 8.7 kg$^{-1}$ under future (2030) assumptions. When evaluated against the preceding scenario, these figures confirm that a seasonal hydrogen blending strategy represents an effective method for reducing total system costs and energy use; however, further refined analyses must be conducted to identify the most economically viable hydrogen proportions for use across differing seasonal conditions.

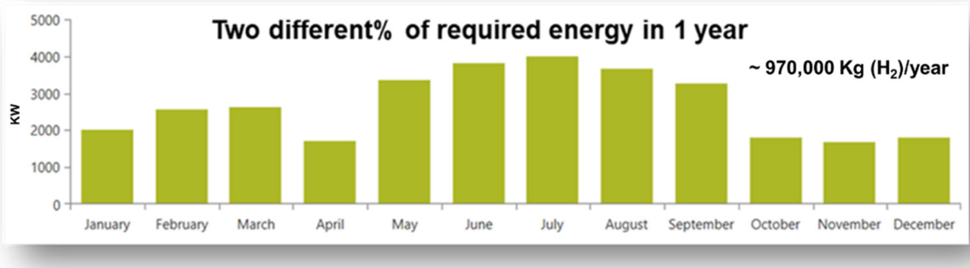


**Figure 8.** Monthly profile of required energy for two different ratio scenarios.

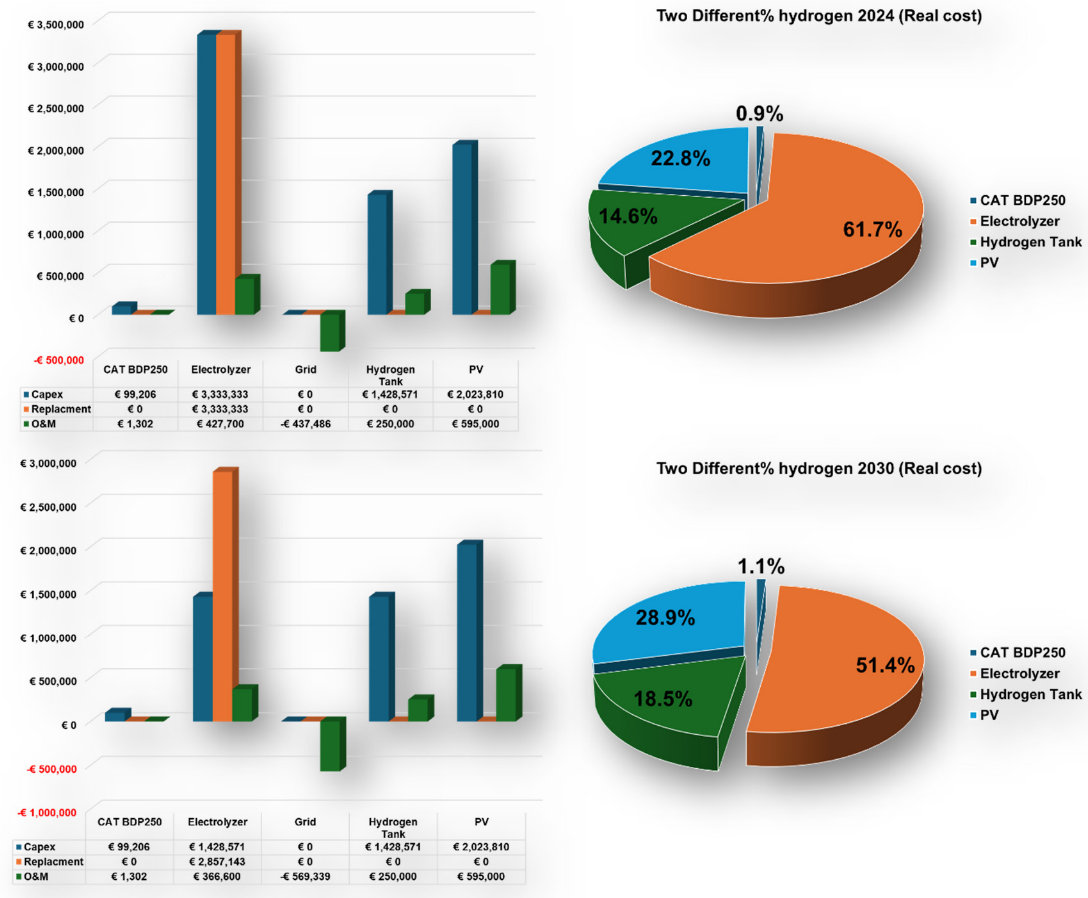


**Figure 9.** Bar and pie charts related to two different fuel ratio scenario costs for two different times [Now (2024) and Future (2030)].

## 4. Outlook

The key outcomes of this techno-economic analysis highlight the feasibility of integrating green hydrogen into industrial thermal applications using PV energy. The study demonstrated that PV-only electricity can supply the required energy for hydrogen production, with hydrogen production costs projected to decrease significantly from 12.6 EUR $kg^{-1}$ in 2024 to 9.7 EUR $kg^{-1}$ in 2030. The adoption of a seasonal hydrogen blending strategy was also shown to optimize system efficiency and reduce overall costs. In addition, increased hydrogen use led to substantial reductions in $CO_2$ emissions, reinforcing the environmental benefits of the proposed approach. Detailed simulations, system sizing, and sensitivity analyses were conducted to support these findings, while the focus remains on the major results relevant for practical industrial adoption.

A deeper analysis revealed that the largest portion of the total system cost is associated with capital investment, with AEM-WE costs being the primary contributor. Sensitivity studies showed that reductions in AEM-WE CAPEX would have the most significant impact on improving project economics. Therefore, achieving cost reductions through technological advancements and scaling up production is crucial to enhancing the competitiveness of green hydrogen in industrial sectors. These findings emphasize that continued innovation and cost optimization are essential for enabling widespread industrial decarbonization using renewable hydrogen solutions.

Additionally, a comparison was made between the projected electrolyzer costs for AEM-WEs, as stated by European Commission targets and the actual costs estimated by manufacturers. This comparison, shown in Figure 10, reveals that the expected costs are still far from the current real costs. The system with European KPIs was recalculated for an 18% ratio and used for this comparison. Bridging this gap is crucial to creating a greener future and reaching the goal of the European Green Deal.

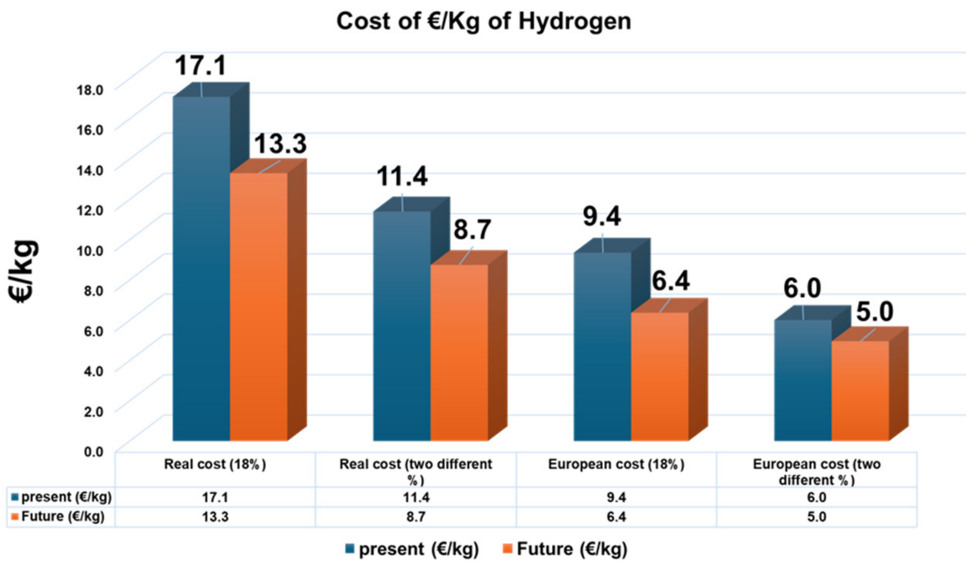


Figure 10. The comparison between different scenarios.

While the proposed system shows strong potential, practical limitations remain. Technical challenges include solar intermittency and hydrogen supply continuity. High upfront costs may hinder adoption in smaller industries. Regulatory uncertainties around hydrogen blending and safety, as well as environmental concerns like land use and water availability, must also be considered for large-scale implementation.

In future, research should focus not only on reducing the cost of AEM-WEs but also on advancing the underlying technologies. Key technical routes include the development of critical raw material-free (CRM-free) electrocatalysts, the improvement of membrane durability and conductivity, and the design of more efficient stack architectures. Additionally, large-scale production methods are essential to achieve significant cost reductions through economies of scale. Interdisciplinary collaboration among material scientists, chemical engineers, and system integration experts will be crucial to accelerate the technological maturity and industrial deployment of AEM-WE systems [26].

Figure 11 displays $CO_2$ emissions for various NG/hydrogen ratios. A simple observation highlights the substantial reduction in $CO_2$ emissions with higher hydrogen usage, reinforcing the importance of adopting this approach consistently.

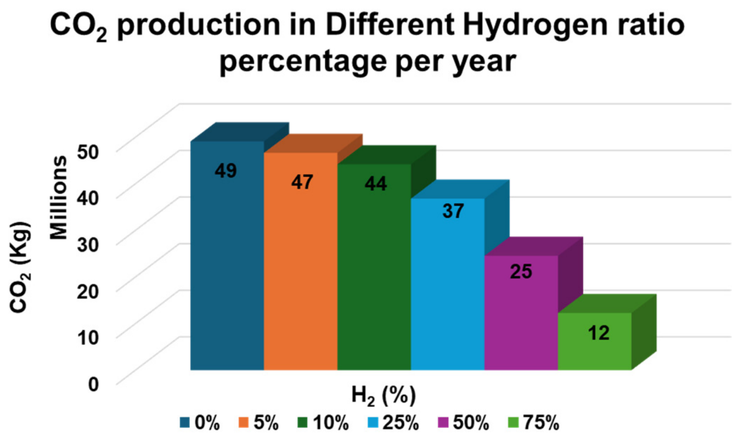


**Figure 11.** The amount of $CO_2$ production in different NG/hydrogen ratios.

## 5. Conclusions

In conclusion, this study demonstrates the technical feasibility and environmental benefit of integrating green hydrogen into hard-to-abate industrial thermal processes using solar PV-powered AEM-WEs. Across two modeled scenarios, the system showed promising results in terms of $CO_2$ emission reductions and projected cost improvements. The first scenario, based on EU target KPIs, projected a hydrogen cost reduction from 12.6 EUR $kg^{-1}$ in 2024 to 9.7 EUR $kg^{-1}$ in 2030. The second scenario, which applied real supplier data and introduced a seasonal hydrogen blending strategy (10% in winter and 25% in summer), further reduced the projected cost to 8.7 EUR $kg^{-1}$ by 2030. This seasonal blending approach also improved the match between solar energy availability and hydrogen demand, minimizing excess electricity generation and improving system efficiency. Sensitivity analyses confirmed that capital expenditures, especially for AEM-WEs, remain the primary cost drivers. Therefore, future cost reductions and efficiency improvements in AEM technology will be critical for economic viability. These findings support the broader adoption of green hydrogen as a decarbonization solution for industrial sectors, especially when coupled with strategic system design and flexible operating models.

**Author Contributions:** Conceptualization, S.A.M., S.B., M.B. and C.S.; methodology, S.A.M.; software, S.A.M.; validation, S.A.M. and M.B.; formal analysis, S.A.M.; investigation, S.A.M. and M.B.; data curation, S.A.M.; writing—original draft preparation, S.A.M., S.B., M.B. and C.S.; writing—review and editing, S.A.M., S.B., M.B. and C.S.; supervision, S.B., M.B. and C.S.; project administration, M.B. and C.S.; funding acquisition, C.S. All authors have read and agreed to the published version of the manuscript.

**Funding:** C.S acknowledges the National Recovery and Resilience Plan (PNRR), Mission 2 "Green Revolution and Ecological Transition", Component 2 "Renewable Energy, Hydrogen, Network and Sustainable Mobility", Investment 3.5 "Hydrogen Research and Development", European Union—Next Generation EU—Ministry of Ecological Transition, 2025–2026; project AMBITION "Development and Testing of a Scalable Anionic Membrane Electrolyzer Using Platinum-Free, Non-Critical, and Non-Toxic Materials for the Production of Clean and Green Hydrogen". PON Research and Innovation 2014–2020 "Education and research for recovery—REACT-EU" program is greatly acknowledged.

**Data Availability Statement:** Data that are not under any confidentiality agreement will be shared upon request to the corresponding author.

**Acknowledgments:** This work was rearranged from Chapter 7 of the doctoral thesis "Assessment of anion exchange membrane electrolyzers and fuel cells for green hydrogen production and conversion: from materials to device" of Seyed Arian Mirshokraee. This work did not go through any peer review process before being considered in this journal. S.A.M. acknowledges a Ph.D. scholarship on Green Issues from action IV.5 of the PON Research and Innovation 2014–2020 "Education and research for recovery—REACT- EU" program.

**Conflicts of Interest:** Authors Stefano Bedogni and Massimiliano Bindi was employed by the company Edison S.p.A. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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