# Design and Optimization of an Alkaline Electrolysis System for Small-Scale Hydropower Integration

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**Abstract:** Alkaline electrolysis systems are currently considered to be suitable for large-scale hydrogen production. Previous research has primarily focused on integrating renewable energy sources such as solar and wind into water electrolysis systems. However, intermittent issues stemming from the sporadic nature of renewable energy sources have led to the introduction of energy storage systems (ESSs) to address these intermittent challenges. Extensive research has been conducted on the efficiency and operational aspects of these systems. In contrast to other renewable energy sources, hydropower offers the advantages of stable output and high utilization, making it a promising solution for overcoming intermittent issues. In this study, we propose the design of an optimized alkaline electrolysis system tailored for small-scale hydropower generation. This approach allowed us to confirm the efficiency of a small-scale hydropower-based hydrogen production facility and the analysis of hydrogen production costs under diverse scenarios. Notably, the optimal selling price per kilogram of hydrogen was determined to be USD 15.6 when the operational time exceeded 20 h, albeit indicating a challenging market supply. Under the consideration of various scenarios and government subsidies, this study revealed that a USD 10/kgH$_2$ subsidy or 24 h of continuous operation achieved break-even points in the sixth and eighth years, respectively. Ultimately, the findings underscore the necessity for essential measures, including government backing and technological advancements in small-scale hydropower facilities, to enhance the economic viability of the green hydrogen market in South Korea.

**Keywords:** renewable energy; hydropower; electrolysis; hydrogen; energy economy

## 1. Introduction

As the global climate crisis escalates due to rising carbon emissions, numerous countries are actively endorsing carbon-neutral and net-zero policies. In technologically advanced nations, there is a growing quest for clean energy sources to replace fossil fuels. Among these, hydrogen has emerged as the most prominent global candidate for future clean energy, prompting substantial research in related technologies [1,2].

Hydrogen production can be broadly categorized into three main methods, with grey hydrogen being the most cost-effective, derived from natural gas reforming or coal gasification. Grey hydrogen production releases carbon, and when carbon capture and storage techniques are employed, it is termed blue hydrogen [3–5]. In contrast, green hydrogen is produced through electrolysis using electricity generated from renewable sources, gaining global attention as an environmentally friendly energy source. The key appeal lies in its complete absence of greenhouse gas emissions throughout the production process [6,7]. In the production process of green hydrogen, water is electrolyzed into oxygen and hydrogen using electricity generated from renewable sources. Ion exchange occurs across a liquid or solid membrane electrolyte. Membranes or diaphragms positioned

between the two electrodes separate the generated gases and prevent mixing to avoid accidents [8,9]. The core of the process for producing hydrogen from water lies in the electrolysis process, where ions are transferred through the membrane to generate hydrogen and oxygen. The two most widely used electrolysis technologies are alkaline electrolysis and polymer electrolyte membrane (PEM) electrolysis. Solid oxide electrolysis is used in specific scenarios but has limited adoption due to cost considerations [10–16].

Alkaline electrolysis devices are extensively utilized in commercial plants due to their cost efficiency and relatively extended lifespan. They are stable, do not require precious metal catalysts, and are relatively inexpensive for initial installations, making them suitable for large-scale facilities [17–20]. Nevertheless, challenges such as low hydrogen productivity, reduced durability, and difficulty in coping with power fluctuations persist [21]. On the contrary, polymer electrolyte membrane electrolysis systems use expensive materials, including precious metal catalysts, leading to higher costs. However, they offer higher operational current density compared to alkaline systems, enabling the production of high-purity hydrogen, and exhibit excellent adaptability to power fluctuations from renewable energy sources [22–25]. A more recent technology, solid oxide electrolysis (SOEC), operates in high-temperature environments (700–850 °C) and utilizes high-temperature steam electrolysis to produce hydrogen, offering the potential for higher system efficiency when integrated with nuclear energy and obtaining high-quality waste heat. While SOEC is currently under research at the kilowatt scale, overcoming challenges such as rapid performance degradation and short lifespan remains crucial [26].

Currently, research is underway globally to produce green hydrogen by integrating various renewable energy sources such as wind power, solar power, hybrid generation (wind + solar), hydropower, and geothermal power. Among these sources, solar and wind power are the most commonly commercialized, albeit with the need for additional energy storage systems (ESSs) due to power fluctuations and substantial initial investment costs [27–29]. To address the limitations in the pre-production phase of green hydrogen production, substantial research and development (R&D) efforts are being invested worldwide [30–32]. These studies explore diverse aspects of hydropower, considering economic factors, climate change impacts, and optimization methodologies. The first study based its components on actual costs from green hydrogen facilities constructed since 2022, emphasizing the need to promote small hydropower development for expanding renewable energy usage. This study simulated the potential of small hydropower plants [33]. The second study predicted hydropower generation under climate change, employing innovative algorithms and advocating for adaptive strategies and increased reliance on hydropower [34]. The third study assessed climate change impacts on run-of-river small hydropower, demonstrating a marginal decrease in generated energy [35]. The fourth study proposed a methodology for optimizing small run-of-river hydropower plants, suggesting the potential for user-friendly design tools [36]. Lastly, the fifth study focused on Greece's small hydropower potential, emphasizing capacity factors and flow duration curves for designing projects in intermittent-flow rivers [37]. Together, these studies offer comprehensive insights into the complexities and opportunities within the hydropower sector.

These efforts primarily focused on the development of new materials for electrolysis stacks and strategies to enhance efficiency, thereby reducing the production cost of hydrogen [38–40]. Governments are also investing in the establishment of hydrogen trade networks to alleviate supply–demand disparities. They are formulating national strategies and regional plans to bolster the foundation for green hydrogen initiatives [41,42]. Consequently, it is anticipated that as electrolysis technology advances, leading to increased electrolysis capacity and a larger green hydrogen market, the production cost of green hydrogen will decrease, aided by the utilization of carbon pricing mechanisms [43–45].

However, it is essential to recognize that these efforts may take time to have an immediate impact on reducing the current production cost of green hydrogen [46,47]. Many research outcomes from pilot projects and R&D initiatives remain undisclosed. Therefore, what is needed at present is the exploration of multiple scenarios for green hydrogen

production systems, ranging from small- to large-scale, by harnessing various renewable energy sources [48–51]. Importantly, there is a shortage of research on green hydrogen pilot facilities directly integrated with small-scale hydropower generation without the need for energy storage. To address this gap, this study constructed a green hydrogen production facility directly linked to 700 kW small-scale hydropower generation. The research utilized actual data from the Seongnam pilot facility and small-scale hydropower, including generation capacity and equipment costs. The evaluation encompassed efficiency, energy utilization, and economic feasibility. The objective of this study was to provide blueprints and reference materials for scenarios and support projects for hydropower-integrated hydrogen production facilities for researchers, industry partners, and government officials considering similar facilities in countries with power markets similar to South Korea. Additionally, in a situation where only a few companies dominate the electrolysis market, this study aimed to reveal the impact of electrolysis equipment prices on hydrogen selling prices through an economic analysis of the green hydrogen production facility.

## 2. Materials and Methods

The small-scale hydropower plant in Seongnam (Water Purification Plant) utilizes the residual headwater of the inflowing water from the Paldang Water Intake to the Seongnam Water Purification Plant. It is equipped with two Francis-type turbine generators (with capacities of 340 and 360 kW) and operates for over 350 days annually, making it suitable for the installation of a hydrogen production facility. The small-scale hydropower-based green hydrogen production research facility was constructed to explore the technical feasibility of a small-scale hydropower-integrated green hydrogen production system. The maximum output of the small-scale hydropower plant is 700 kWh, and the capacity of the alkaline electrolysis applied here is 600 kWh, producing 10.9 kgH$_2$/h. This pilot facility is located at the Korea Water Resources Corporation's Seongnam Water Purification Plant, and its goal includes producing and supplying hydrogen using small-scale hydropower. The calculation of the operational efficiency of this small-scale hydropower is as follows:

$$\text{Operational Efficiency}(\%) = \frac{\text{Annual power generation (kWh)}}{\text{Facility Capacity (kWh)} \times 24\text{h} \times 365 \text{ days}} \times 100 \quad (1)$$

while the theoretical voltage for electrolysis is 1.23 V, it involves an endothermic reaction. This change in enthalpy, known as the higher heating value (HHV), and the power consumption are 1.48 V and 39.4 kWh/kgH$_2$, respectively [52]. Through this, the efficiency of the electrolysis system can be determined as follows:

$$\text{Efficiency of electolysis}(\%) = \frac{39.4 \text{ kWh } \times \text{Hydrogen production}(\text{kg/h})}{\text{Capacity of Electrolysis}} \times 100 \quad (2)$$

The economic viability of hydrogen production can be analyzed from various perspectives. For instance, the levelized cost of hydrogen (LCOH) can be assessed from the cost standpoint of hydrogen production. Additionally, the economic feasibility can be analyzed based on the net present value (NPV), which considers the cumulative revenue expected from green hydrogen sales during a specific project period, along with investment and operating costs for business model evaluation and selection. This study analyzed the economic viability of hydrogen production in this system based on LCOH. The cost of a hydrogen production system in a water-electrolysis-based green hydrogen production system can be broadly categorized into operational expenditure (OPEX) and capital expenditure (CAPEX). OPEX includes utility costs, which encompass electricity and water consumed by the electrolysis system, periodic stack replacement costs, and labor costs. CAPEX includes the purchase and installation costs of the electrolysis system and hydrogen storage tanks, as well as site construction expenses. The specific formulas for calculating CAPEX and OPEX are as follows:

$$\text{CAPEX} = \text{CE (Electrolysis purchasing cost)} + \text{CI (Installation cost)} + \text{CC (Construction cost)} \quad (3)$$

$$\text{OPEX} = \text{Labor cost} + \text{Stack replacement cost} + \text{Electricity cost} + \text{Water cost} \quad (4)$$

In essence, the expected revenue from hydrogen sales is the primary source of income that can be anticipated from a water-electrolysis-based green hydrogen production system. The key economic analysis metric, the LCOH, can be calculated as follows [53]:

$$\text{LCOH} = \frac{\text{CR} + \text{OPEX}}{\text{Revenue from hydrogen sales}} \quad (5)$$

$$\text{CR} = \text{CAPEX} * \text{Capital recovery factor} + \text{Discount rate} * \text{Salvage value} \quad (6)$$

The CR (capital recovery) cost encompasses the depreciation costs associated with the operation of the electrolysis facility and includes CAPEX based on the CRF (capital recovery factor). The equation for CR is as follows:

$$\text{Capital Recovery Factor} = \frac{r(1+r)^N}{(1+r)^N - 1} \quad (7)$$

($r$: Discount rate; $N$: project period (year))

All components applied in this study were based on the actual costs incurred in the construction of the green hydrogen demonstration facility conducted since 2022. Among the analytical components applied in this study, the most significant weight from a pricing perspective was the stack of alkaline electrolysis. It was benchmarked at an average price of USD 3477/kW, obtained from a domestic electrolysis company of the actual Seongnam demonstration facility. This provided amount includes the costs of system equipment, such as electrolysis stacks and balance of plant (BOP), as well as miscellaneous procurement costs like piping and safety equipment (the exchange rate: 1330 KRW/USD). The cost of electricity was calculated using the electricity rates in South Korea in 2022. Hydrogen prices were determined based on the average market prices at hydrogen refueling stations. The cost of stack replacement was computed using the maintenance cost data provided by the electrolysis company. Labor costs were allocated on an hourly basis. For 4-h shifts, the labor costs encompassed the wages of one skilled technician. In the case of shifts lasting up to 8 h, the labor cost accounted for two technicians. When shifts were extended to 16 and 24 h, the labor costs included the wages of three and four technicians, respectively. It was assumed that the expected lifespan of the alkaline electrolysis stack is 10 years [54], with an annual inflation rate of 4.7%, while the stack replacement cost was set at 4% of the cost of building the electrolysis system. Other expenses necessary for operating the demonstration facility, such as management fees and insurance premiums, were estimated at 10% of OPEX and included in the investment cost of the Seongnam Demonstration Facility. These calculation factors were employed to derive the LCOH, and the LCOH represents the hydrogen production cost, including the factors indicated in Table 1. It does not encompass the costs associated with hydrogen transportation and storage.

**Table 1.** The economic analysis factors for electrolysis system.

| Parameter | Value | Unit |
|---|---|---|
| Stack price | 3477 | USD per kWh |
| Stack capacity | 600 | kWh |
| Installation cost | 353,233 | USD |
| Building construction | 730,827 | USD |

**Table 1.** *Cont.*

| Parameter | Value | Unit |
|---|---|---|
| | 42,890 (Operating Time: 4 h/day) | USD per year |
| | 85,780 (Operating Time: 5–8 h/day) | USD per year |
| Labor cost | 128,670 (Operating Time: 9–16 h/day) | USD per year |
| | 171,560 (Operating Time: 17–24 h/day) | USD per year |
| Stack replacement | 45,951 | USD per year |
| Electricity cost | 0.15 | USD per kWh |
| Hydrogen price | 7.33 | USD per kilogram of hydrogen |
| Basis year | 2022 | Year |
| Inflation rate | 4.7 | % |
| Depreciation period | 10 | Year |
| Exchange rate | 1330 | KRW per USD |

## 3. Results and Discussion

### 3.1. Small-Scale Hydropower Analysis

The small-scale hydropower generation consistently supplied an annual average of 3691 MWh (from 2018 to 2022) of electricity, exhibiting an efficiency rate of 60.2% compared to the total generation capacity (6132 MWh). The small-scale hydropower exhibited varying levels of generation depending on the season, with the summer (from June to August) showing the lowest generation at 279 MWh and the spring (from March to May) at 327 MWh, which was the highest. The efficiencies for summer and spring were 54.6% and 64.0%, respectively. Since the low generation of small-scale hydropower is related to the difficulty of operating the electrolysis system, we examined the hourly generation data in July during the low-generation summer period. The variation in generation between the highest and lowest generation levels was 19% based on the total generation capacity. This indicates that the small-scale hydropower maintained a relatively stable utilization rate, making it a reliable source of green hydrogen production [55–57]. This trend is shown in Figure 1. With an average power load fluctuation rate of less than 20% per day, it is anticipated that stable system operation could be achieved without power storage devices (ESSs). As a result, this demonstration was designed without ESSs.

### 3.2. Experimental Facility Configuration and Evaluation

First, the electrolysis system was configured to convert the alternating current (AC) power from a 0.7 MW small-scale hydropower generation facility, integrated into the power grid, into direct current (DC) power for supply to the electrolysis device, as depicted in the diagram. According to the data obtained from operations at the actual pilot facility, the efficiency of the AC to DC conversion ranged from 89.3% to 92.5%, with an average conversion rate of 90.9%. The hydrogen produced by the electrolysis device is initially stored in a low-pressure buffer tank. The stored low-pressure hydrogen is then compressed to high pressure (250 bar) using a compressor and supplied to a tube trailer. This entire process is controlled and operated by an integrated control system. The integrated control system must continuously monitor the operation status of renewable energy and the electrolysis system in real-time and notify users immediately in the case of equipment abnormalities. This configuration can be seen in Figure 2. Technical analysis indicated that the consumption power of hydrogen production can be expressed as production efficiency. The design of stack efficiency and the system efficiency (stack with BOP) were 55 and 63 kWh/kg, respectively. With the designed efficiency of this electrolysis system, it could produce 10.9 kg/h of hydrogen, and the actual amount of produced hydrogen was 10.7 kg/h. A hydrogen production rate of 98.1% was achieved at the rated power input.

The hydrogen production exhibited a standard deviation of 0.2, confirming stable operation without significant efficiency variations.
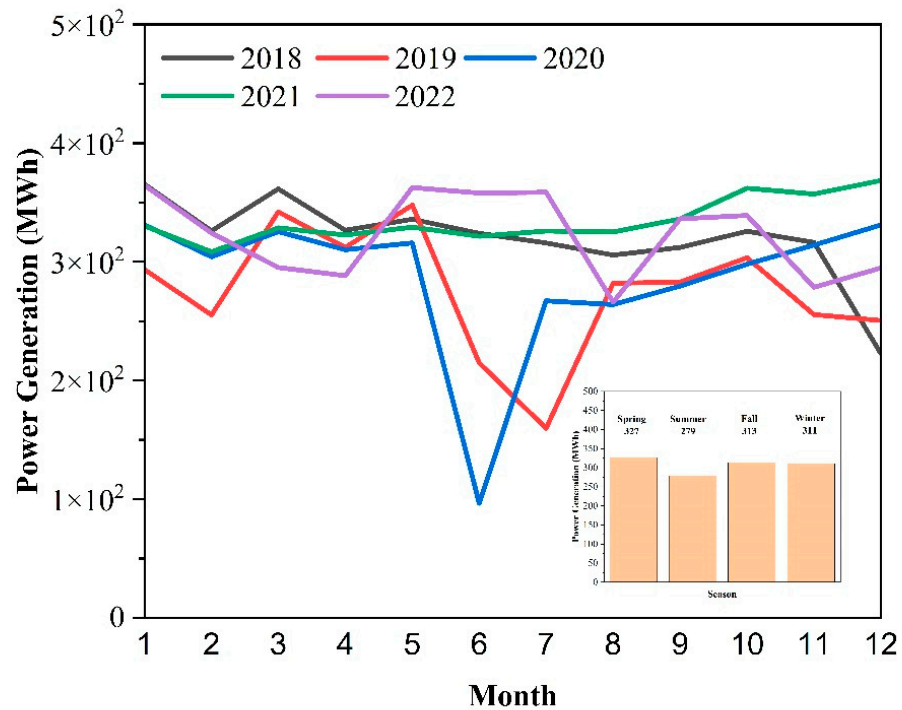


**Figure 1.** Trends in small-scale hydropower generation from 2018 to 2022.
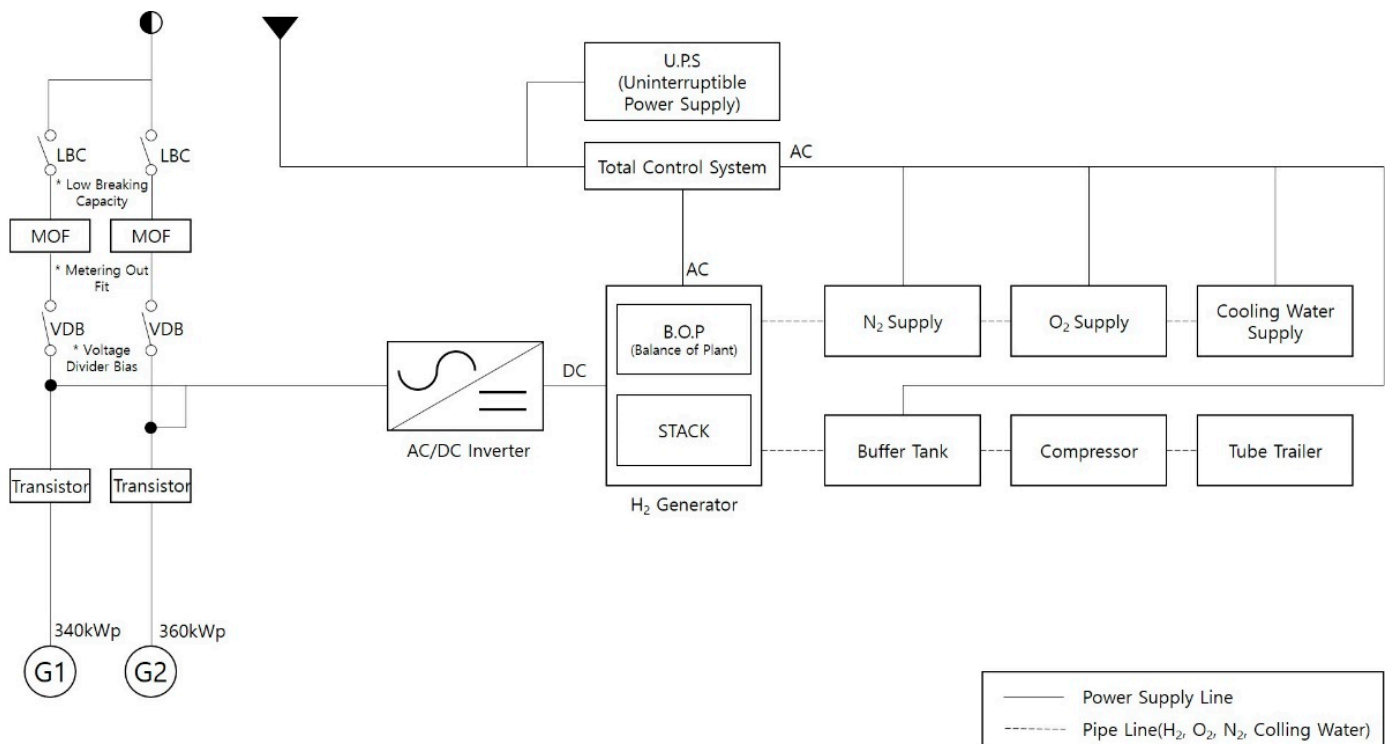


**Figure 2.** Configuration of the experimental facility.

However, the theoretical power consumption of hydrogen production was 39.4 kWh/kg, and the conversion factor of the stack in this electrolysis system was 70%. According to the data presented in Table 2, the actual input power of the balance of plant (BOP) was 12 kWh, which did not include other systems, such as the compressor. Usually, the power

consumption of the compressor system is 15% of the total system, in which case the conversion factor of this electrolysis system would be 60%.

**Table 2.** Calculation of the energy utilization factor.

| Electricity (Stack) | Electricity (BOP) | Hydrogen (kg/h) | H$_2$ (HHV) | Conversion Factor |
|---|---|---|---|---|
| 600 | 12 | 10.7 | 56 kWh/kg | 70.3% |

*3.3. Economic Evaluation and Analysis*

The economic evaluation of the green hydrogen production system revealed several critical insights. The CAPEX includes the costs associated with the electrolysis equipment, construction expenses, and installation costs, with the majority of this budget allocated to the electrolysis equipment being 65.8%. On the contrary, the OPEX encompasses labor costs, component replacement expenses, electricity costs, and maintenance costs [58–62]. Among the factors included in the OPEX, labor costs depend on the number of permanent employees according to the operating hours of the hydrogen production facility, ranging from a minimum of USD 42,890 to a maximum of USD 171,560. Labor costs account for approximately 15.5–17.7% of the OPEX. Figure 3 represents each factor in the CAPEX and OPEX. The most significant factor within the OPEX is the cost of electricity [63]. In this study, we took into consideration the electricity expenses associated with the electrolysis system, excluding the costs related to selling renewable energy. While small-scale hydropower generation is considered relatively cost-effective compared to other forms of renewable energy, it is apparent that the electricity cost, ranging from 54.2% to 71.2%, presents the most prominent challenge in achieving cost-effective green hydrogen production [64–66]. This underscores the critical importance of securing a reliable and cost-efficient source of electricity for green hydrogen production.
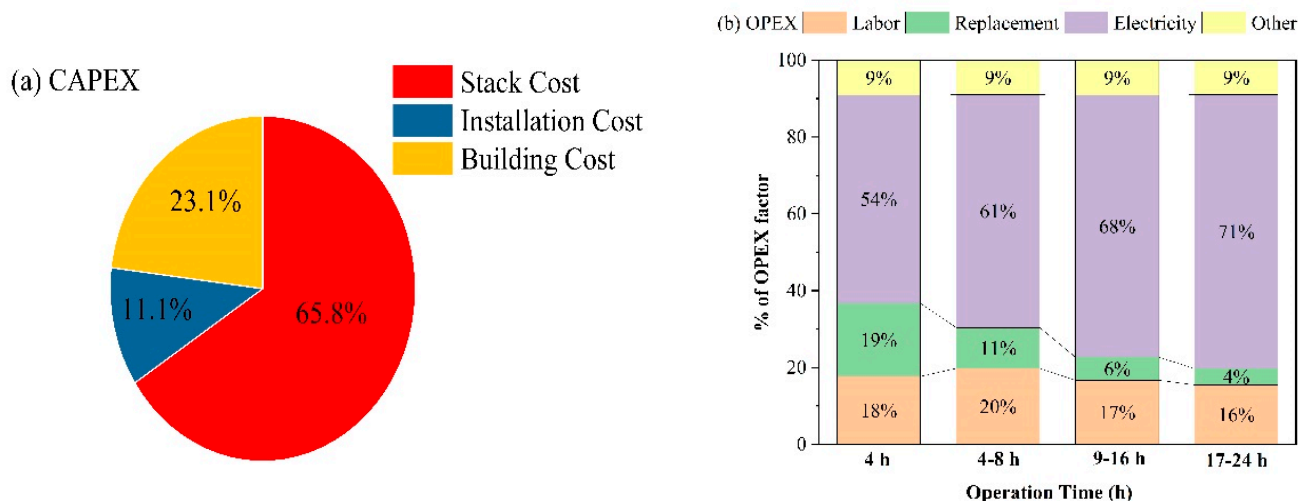


**Figure 3.** The ratios of each factor in (**a**) the capital expenditure (CAPEX) and (**b**) the operational expenditures (OPEX) for the Seongnam Green Hydrogen Demonstration Facility.

A comprehensive analysis of the calculated annual hydrogen production quantities in response to variations in small-scale hydropower output was conducted (Figure 4). Notably, there was an increase in hydrogen production during the years 2018 and 2022, coinciding with higher levels of electricity generation. Figure 4 also shows an analysis of the LCOH based on the CAPEX and OPEX depending on operating hours for the Seongnam Green Hydrogen Demonstration Facility. This analysis provided a significant difference when applying the actual CAPEX and OPEX of the green hydrogen production facility in Seongnam, South Korea. In recent times, various policies have been proposed, aiming to set the target cost of hydrogen below USD 1/kgH$_2$. However, when actual values are

considered, it becomes apparent that there are many challenges to overcome in order to achieve this goal [67]. The resulting LCOH values were relatively high in the Seongnam case, which can be attributed to several factors. These factors include the limited number of green hydrogen demonstration projects in South Korea and disparities between theoretical values in reports and real-world operational data. The growth of the electrolysis market is experiencing a rapid expansion, leading to a decrease in the stack of electrolysis costs. Comparing the LCOH based on the stack of electrolysis costs (USD 250/kW) reported by the IRENA report [68], the results indicate an LCOH of around USD 12.8/kgH$_2$ for 20 h of operation (Figure 4). This amount is lower than the calculated production cost of USD 15.6/kg of hydrogen from the actual data, but it does not show a significant difference. This confirms that cost reduction is essential not only in stack prices but also in other aspects, such as construction costs.
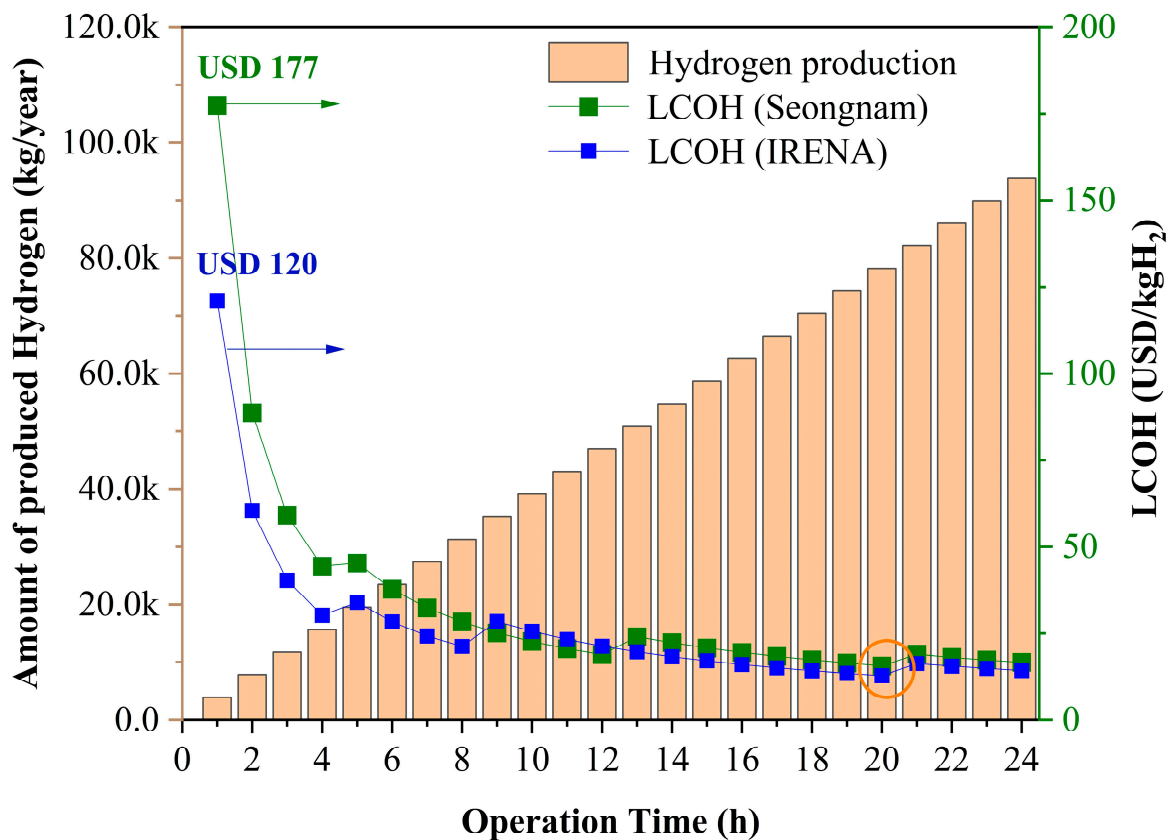


**Figure 4.** Amount of hydrogen production and LCOH based on the operating hours for Seongnam vs. IRENA report [68].

The optimized hydrogen production and constructed scenarios were determined for future outlooks in alignment with the subsidy support framework currently being implemented by the government, as depicted in Figure 5. Utilizing the actual values and considering the reference hydrogen cost of USD 15.6/kg of hydrogen and an operation time of 20 h, it becomes evident that a minimum subsidy of USD 10/kg of hydrogen is required. While reaching a break-even point in the sixth year is feasible, obtaining this amount of subsidy in the present circumstances is a considerable challenge.
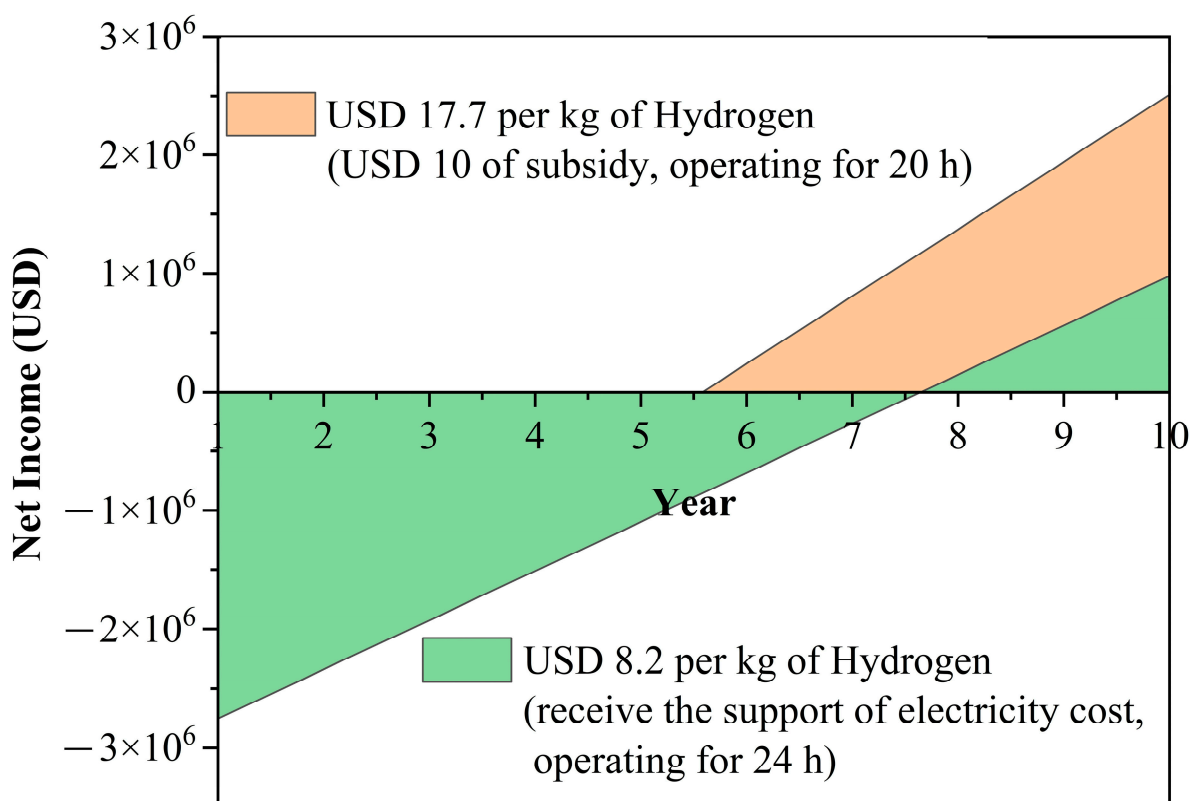
**Figure 5.** The break-even point for hydrogen prices according to the scenarios.

In response to this challenge, we investigated a scenario where the most significant segment of operational expenses, the electricity costs, receives support. Within this scenario, the hydrogen price was USD 8.2 for 24 h of continuous operation, representing only a marginal 6% deviation from the actual hydrogen price at refueling stations. Importantly, this scenario allowed us to surpass the break-even point by the eighth year. Hence, it is our contention that, at this juncture, securing electricity subsidies for the hydrogen economy stands as the most promising solution to drive the advancement of green hydrogen initiatives in South Korea.

## 4. Conclusions

In conclusion, this study made a significant contribution by establishing a green hydrogen production facility directly integrated with small-scale hydropower generation. The evaluation conducted here covered efficiency, energy utilization, and economic feasibility, offering a blueprint for similar facilities in regions with power markets akin to South Korea's.

The Seongnam Green Hydrogen Production Facility faces a formidable challenge despite sustaining an operational rate exceeding 60%. This challenge arises primarily from the recent upsurge in energy costs. Even with a meticulous optimization of operational hours to a span of 20 h, the LCOH remained fixed at approximately USD 15.6/kgH$_2$.

The integration of small-scale hydropower-connected green hydrogen pilot facilities holds substantial potential in advancing green hydrogen initiatives. This pricing scenario places constraints on the facility's competitiveness within the dynamic hydrogen energy market. It is worth noting that South Korea's electrolysis facilities have yet to establish official performance and safety credentials for extended operations beyond the one-year mark. Consequently, the Seongnam facility, in synergy with its small-scale hydropower counterpart, envisions securing a robust foothold in continuous operational technology through prolonged experimental research. This indicates future possibilities for development.

In terms of the specific numerical scenarios for green hydrogen pricing:

Scenario 1: Based on the optimized hydrogen production cost, the minimum subsidy required was USD 10/kgH$_2$. In this scenario, the break-even point was reached in the sixth year.

Scenario 2: In the scenario where electricity costs receive support, the hydrogen selling price for 24 h of continuous operation was USD 8.2/kgH$_2$. In this case, the break-even point was achieved by the eighth year.

These break-even points indicate the number of years it would take for the hydrogen production facility to recover its costs and start generating positive returns under each scenario. This highlights the financial challenges and considerations associated with green hydrogen production in the given context. However, it is important to note that South Korea's electrolysis facilities have not yet established official performance and safety credentials for extended operations beyond one year; therefore, the Seongnam facility is conducting experimental research to secure a strong position in continuous operational technology. Additionally, for the economic production and sale of green hydrogen in the current situation of electrolysis and green hydrogen markets in South Korea, the following strategies are necessary based on the analyses conducted in this paper: (1) reducing output limitations through ensuring the stability of the domestic power grid; (2) increasing the efficiency of small-scale hydropower generation and electrolysis systems through technological development; (3) alleviating technological monopolies among small businesses through government support for technology transfer to private companies involved in electrolysis system manufacturing; (4) reviewing the appropriate capacities of electrolysis systems considering actual renewable energy generation; and (5) establishing carbon emission rights and support systems for renewable energy-integrated green hydrogen production facilities.

In order to implement a strategy toward a carbon-neutral society, the demand and supply goals for green hydrogen in Korea are expected to grow steadily. Based on the research conducted in this paper, it will be possible to consider strategies not only for small-scale but also for large-scale green hydrogen production facilities to ensure their economic viability.

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