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Modelling and Cost Assessment of Hydrogen Production with Hybrid Energy Sources

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Abstract

Green hydrogen production holds significant potential for supporting Indonesia's clean energy transition towards Net Zero Emissions (NZE) by 2060. However, its current Levelized Cost of Hydrogen (LCOH) of USD 4.3 to USD 8.3 per kilogram makes it less cost-effective than fossil fuel-derived hydrogen. This study aims to analyze the economics of a Hydrogen Plant (H2P) utilizing hybrid energy sources in Gresik. The methodology integrates advanced modeling techniques, including the Levelized Cost of Hydrogen (LCOH) and Net Present Value (NPV) analysis, to quantify production costs and assess long-term profitability. Data for this study was meticulously collected from a Hydrogen Plant in Gresik through historical operational records, technical specifications, projected energy demand, and meteorological data. By systematically comparing five alternative configurations: Grid+Solar PV (50.6 kWp), Grid+Solar PV (100 kWp), Grid+Solar PV (200 kWp), Grid+Solar PV (400 kWp), and Grid+Microhydro (76 kW). Configuration 5 was found to be the most economical under current assumptions, achieving the lowest LCOH of IDR 100,023/kg (USD 6.23/kg) and the highest NPV (IDR 22,935,241,285). This result is align with global decarbonization goals which are projected to be economically competitive at USD 2/kg by 2050.

Keywords: *NZE, Hydrogen, Energy Transition, LCOH, NPV*

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INTRODUCTION

The escalating impacts of climate change present a critical global challenge, necessitating urgent efforts to reduce greenhouse gas emissions and transition toward sustainable energy systems [1]. Indonesia, as the 2022 G20 Presidency, has assumed a pivotal role in this global endeavor by committing to achieve net zero emissions (NZE) by mid-century. This commitment is formalized in Presidential Regulation No. 22/2017, which outlines a comprehensive roadmap for renewable energy development through 2050. Based on the International Energy Agency (IEA) reports in "An Energy Sector Roadmap to Net Zero Emissions in Indonesia". Hydrogen produced from fossil fuels in Indonesia is projected to still have the lowest price compared to other resources. Low-carbon hydrogen is projected to be economically competitive around 2050 at 2 USD/kg H2. Green hydrogen, produced from renewable energy sources such as solar, wind, and hydropower, is globally recognized as a key element in the clean energy transition [2]. Unlike conventional hydrogen produced from fossil fuels, green hydrogen offers a carbon-neutral alternative capable of significantly reducing emissions across various industrial sectors [3]. Moreover, it serves as a flexible energy carrier, enabling the storage and transport of renewable energy, thereby facilitating decarbonization in sectors that are otherwise difficult to electrify [4]. Despite its potential, current hydrogen production remains dominated by fossil fuel-based grey and brown hydrogen, underscoring the critical need for a transition toward green hydrogen to achieve a sustainable energy future.

Hydrogen production faces several challenges that hinder its widespread adoption. Common obstacles affecting all hydrogen types include limited infrastructure for transport and storage [5]. Specific to green hydrogen, production via water electrolysis encounters issues such as energy losses during the process, sustainability concerns, and high production costs [6]. The main factors affecting the cost of producing green hydrogen are the capital investment in the electrolyzer, its capacity factor which reflects actual utilization relative to the cost of electricity coming from renewable sources [7][8]. In 2020, the investment cost for alkaline electrolyzers ranged between USD 750 and 800 per kilowatt (kW). When capacity factors are low, for example below 10% (less than 876 full-load hours annually), the capital cost is distributed over fewer units of hydrogen produced, resulting in production costs of USD 5 to 6 per kilogram or higher. In contrast, grey hydrogen production costs range from USD 1 to 2 per kilogram, depending on natural gas prices, which typically vary between USD 1.9 and 5.5 per gigajoule (GJ). As capacity factors increase, the capital cost contribution to the overall hydrogen cost decreases, making electricity costs the dominant factor in production economics [9].

Gresik's Hydrogen Plant serves as a critical case study for this research, representing a practical application of green hydrogen within existing energy infrastructure. The hydrogen produced onsite is primarily used as a cooling medium for the generator units at the Gresik Combined Cycle Power Plant (PLTGU). However, the plant's current hydrogen production costs are elevated due to reliance on grid electricity, which is largely fossil-fuel based, and limited renewable energy capacity. Addressing these challenges through optimized hybrid energy configurations is essential to improve economic feasibility and support Indonesia's broader clean energy transition objectives.

In the pursuit of advancing green hydrogen production and optimizing its economic feasibility, numerous studies have been conducted to explore various energy configurations and technologies to make hydrogen cost decreases. Research by Minutillo et al. [10] focuses on the infrastructure of hydrogen refueling stations (HRS) that utilize renewable energy sources to produce green hydrogen without CO_2 emissions. LCOH was assessed for various configurations of electricity supply management and plant capacities. By analyzing the annual electricity distribution supplied by the grid and solar power plants, the optimal configuration was achieved when the annual electricity supply from the grid was equal to 50%. Borges et al. [11] investigated the effect of production scale on hydrogen production costs using electrolyzer systems integrated with renewable energy sources. Their findings indicate that increasing electrolyzer capacity from 1 MW to 10 MW can reduce LCOH from $5.50/kg to $3.80/kg, representing a 30.9% cost saving. Khan et al. [8] analyzed scale effects in hydrogen production via water electrolysis and their impact on LCOH. Results showed that increasing system capacity from 5 MW to 20 MW reduces LCOH from $4.00/kg to $2.50/kg, a 37.5% cost saving. This research highlights that larger electrolyzer capacities significantly decrease capital costs per unit, a key factor in lowering LCOH.

Most previous studies remain theoretical or rely on data from contexts outside Indonesia, making them less relevant for local operational conditions and policy frameworks. There is also a lack of research examining the implementation and performance of green hydrogen production at operational Hydrogen Plants, which limits the generalizability of findings to real-world applications. This study employs a multi-criteria approach that integrates economic indicators Net Present Value (NPV), Internal Rate of Return (IRR) and Levelized Cost of Hydrogen (LCOH) with environmental metrics (CO_2 emissions), providing valuable insights for the development of transition energy systems and enriching both the literature and practical knowledge in green hydrogen production. The research makes a significant contribution to advancing scientific understanding and practical applications in the field, while also accelerating the adoption of green hydrogen technology in emerging markets, supporting sustainable development, and strengthening energy security.

METHODS AND ANALYSIS

This study employs a detailed techno-economic modelling approach to evaluate hydrogen production using hybrid energy sources at the Hydrogen Plant in Gresik. The methodology is structured into flow chart shown in Figure 2, adapted from a hydrogen plant evaluation framework, to ensure a thorough and practical assessment aligned with real operational conditions. This research employs a system identification approach to analyze the hydrogen production process at the Gresik facility. The object of this study is the hydrogen plant, which utilizes an Alkaline Water Electrolyzer (AWE) to produce hydrogen from water. The hydrogen plant's power supply is derived from a combination of the Electrical grid and solar photovoltaic (PV) system as shown in Figure 1. Current configuration consist of Grid + Solar PV 50.6 kWp that uses approximately 91% PLN Grid and 9% Solar PV as energy sources for the alkaline-type electrolyzer.

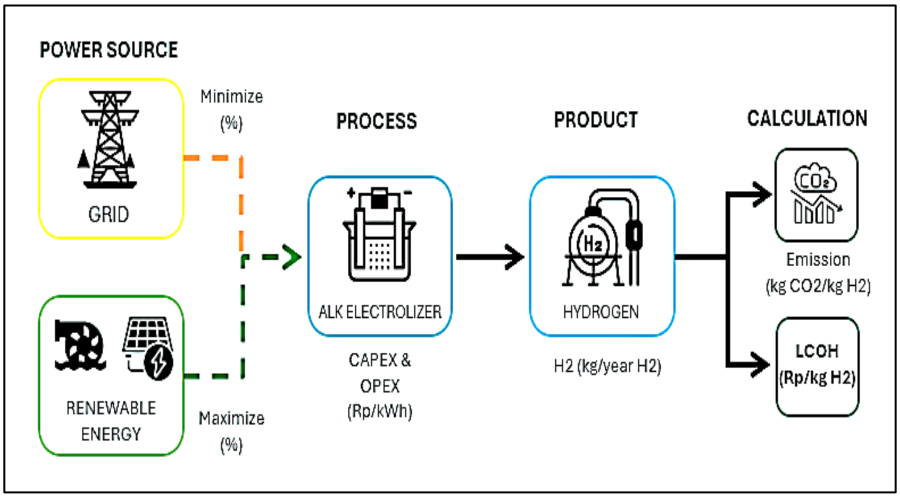

Figure 1. Schematic of Hybrid Hydrogen Plant

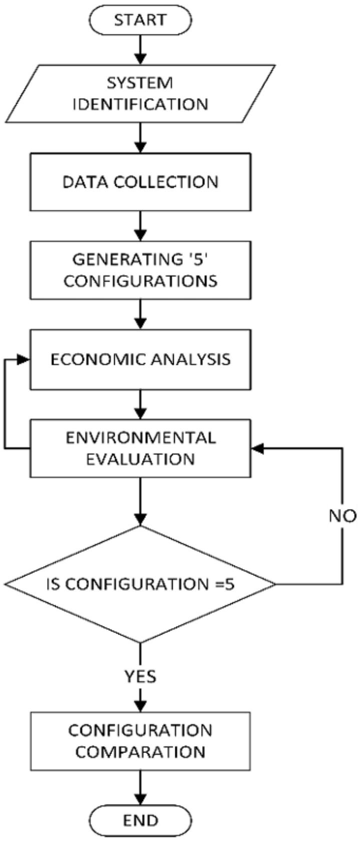

Figure 2. Cost Assessment Flowchart

Table 1. Cost Structure of Hydrogen Plant

No	Component	CAPEX (Rp/kWp)	OPEX (IDR/year)	Replacement Cost (IDR)	Lifetime
Existing Configuration					
1	**Solar PV**	**4,222,222***	**142,222.22**	**10,621,739.13**	12 Years
	Modul PV	4,772,727			
	Inverter	2,170,566			
	Proteksi, Cabling, aksesoris	5,491,518			
	Commisioning & Testing	1,787,411			
2	**H_2 Plant**	**355,431,383****	**2,013,104,356**		30 Years
	H2 Plant / electrolizer	353,754,941			
	Hydrogen Generating Building	1,676,443			
Configuration System					
3	**Microhydro** [12]	**45,642,857**	**912,857.14**		30 Years
	Perlton Turbine	12,000,000			
	Generator + Control Panel	10,000,000			
	Penstock	9,571,429			
	Powerhouse, intake, tailrace	9,571,429			
	Commisioning & Testing	4,500,000			

*) Cost refers to the year installed (2023)
**) Cost refers to the year installed (2013)

The data collection involves gathering detailed cost structure from the Gresik facility over a three-month period. Table 1 displays the general hydrogen production cost structure which includes two main components, namely Capital Costs (CAPEX), Operating Costs (OPEX) and Replacement Cost. Table 2 displays the cost elements that make up OPEX in H_2 Plant. Accurate site-specific data form the foundation for reliable analysis and modelling.

The lifetime of each component in this case solar PV and electrolizer is determined based on the procurement contract in the Unit. While the micro-hydro system lifetime is assumed for 30 years. The maintenance cost of the electrolizer in H_2P uses maintenance history data for the last 2 years, while in the solar PV and micro hydro system the maintenance cost assumes 1% and 2% of the initial investment cost, respectively.

Table 3 displays the configuration of a hybrid system consisting of grid electricity, solar PV, and micro-hydro. This model provides a comprehensive framework for identifying cost-effective and sustainable pathways for hydrogen production. Furthermore, the analysis includes a comparison of production patterns using either a single hydrogen plant unit as "Operation Pattern 1" and two units operating in parallel as "Operation Pattern 2", to determine how plant configuration and production scale affect economic performance and the levelized cost of hydrogen.

Economic analysis evaluates the financial viability of each configuration using key indicators such as Net Present Value (NPV), Internal Rate of Return (IRR), Payback Period, and Levelized Cost of Hydrogen (LCOH).

Table 2. OPEX Cost Structure of Hydrogen Plant

Parameter	Value	Description
Electrical Capacity of each H_2 plant (kW)	86	Total Plant : 2 Units
Nominal Hydrogen Flow (Nm3/jam)	15	
Daily Production Load (kg/day)	32,328	Operating time: 24 hour
Electric Demand (kWh/kg H_2)	63.8	
Daily Electric Demand (kWh/day)	2062.52	Avg value from hystorical data (2024)
Water Demand (liter/day)	323.28	
Price of Demineralized water (IDR/m^3)	225	
Water Consumption Cost (IDR/day)	72,738	
KOH Demand (kg/hari)	138.55	Elektrolit (H20 + 30% wt. KO
KOH Consumption Cost (Rp/hari)	2,216,800.00	IDR 16,000/Kg
Operator Cost (IDR/year)	180,000,000	3 shift/day @1 person
Maintenance Cost (IDR/year)	184,744,859	Actual data (2024)

Table 3. Hybrid System Configuration

No.	Configuration	Solar PV Capacity (kWp)	Water Turbine Capacity (kWp)
1	Grid + Baseline	50.6	-
2	Grid + Moderate PV Expansion	100	-
3	Grid + Significant PV Expansion	200	-
4	Grid + Large-scale PV Expansion	400	-
5	Grid + Baseline PV + Micro-hydro	50.6	76

a. Net Present Value (NPV)

Net Present Value (NPV) is utilized to measure the difference between the present value of cash inflows and outflows over the project's lifespan as shown in Equation (1). The data required for NPV calculation include CAPEX, OPEX, and net benefit, derived from gross benefit that has been discounted by the prevailing interest rate [13].

$$NPV = \sum_{t=0}^{T} \frac{Net\ Benefit}{(1+r)^t} - Initial\ Investment \quad (1)$$

Where r is interest rate, T is project life, and t is year of cash flow.

b. *Internal Rate of Return* (IRR)

Internal Rate of Return (IRR) is calculated by identifying the discount rate that yields a positive Net Present Value (NPV), compared to a discount rate that yields a negative NPV as shown in Equation (2). The IRR value is then compared with the prevailing investment's required rate of return [14].

$$IRR = i_1 + \left(\frac{NPV_1}{NPV_1 - NPV_2} \times (i_2 - i_1)\right) \quad (2)$$

Where i_1 is interest rate (%), i_1 is interest rates that could result in a positive Net Present Value (NPV) (%), i_2 is interest rates that could result in a negative Net Present Value (NPV) (%), NPV_1 is NPV positive, and NPV_2 is NPV negative.

c. *Pay Back Period* (PBP)

Payback Period (PBP) is the time required to recover the costs of a project investment. The value of the Payback Period is obtained by dividing the total investment cost by the income earned in one year as shown in Equation (3).

$$PBP\ (t) = \frac{CAPEX}{Annual\ Income} \quad (3)$$

d. The Levelized Cost of Hydrogen (LCOH)

Levelized Cost of Hydrogen (LCOH) is used to evaluate the total economic cost of hydrogen production over the project's lifespan in a consistent and standardized manner. LCOH can be calculated as Equation (4). Total Life Cycle Cost is the total cumulative cost incurred throughout the entire life cycle of a hydrogen production project, from the initial investment to the end of its operating life.

$$LCOH = \frac{Total\ Life\ Cycle\ Cost}{Total\ Production\ (kg)}$$

$$= \frac{\Sigma\ Discounted\ Annual\ Cost_t}{Total\ Production\ (kg)} \quad (4)$$

Σ Discounted Annual $Cost_t$ shows that the total life cycle cost is calculated by summing up all the discounted annual costs (present value) over the life of the project. Discounted annual costs calculated by multiplied Total annual cost in Equation (6) to Discount factor 5%. Where N is the plant life time and r is interest rate.

$$Annual\ capital\ cost = investment \cdot \frac{r(1+r)^N}{(1+r)^N - 1} \quad (5)$$

$$Total\ Annual\ Cost = Annual\ capital\ cost + annual\ O\&M \quad (6)$$

Environmental evaluation, assesses CO_2 emissions per kilogram of hydrogen produced and evaluates potential eligibility for carbon tax credits based on emission thresholds. This step highlights trade-offs between renewable energy integration and emission reductions, providing critical sustainability insights. In each configuration there is a difference in the percentage of the use of electrical energy sources from the grid and RES (renewable energy sources) as shown in Equation (7) and (8). Each configuration shows a downward trend in grid energy usage to optimize RES usage.

$$E\%_{RES}\,(\%) = \frac{Total\ Energy\ from\ RES}{Total\ Energy\ used} \quad (7)$$

$$E\%_{grid}\,(\%) = \frac{Total\ Energy\ from\ grid}{Total\ Energy\ used} \quad (8)$$

The percentage obtained will determine the calculation of the amount of emissions expressed in kg CO_2 in every kg of Hydrogen produced as shown in Equation (9).

Table 4. Cost comparison by renewable source system type

Study	System Type	LCOH Range (USD/kg H2)	Key Cost Drivers
Astriani et al., 2024 [15]	PV, Wind, Hybrid	4.26 - 14.378	Electrolyzer cost, electricity tariff
Borges et al., 2024 [11]	PV, Wind, Hybrid	3.13 - 3.48 EUR/kg	Capital expenditures, maintenance, variable costs
Colella, 2018 [16]	Grid, Renewable	2 - 3	Capital costs, electricity costs
Di Micco et al., 2022 [17]	PV	10.71 EUR/kg	Capital
Dokhani et al., 2023 [18]	Grid, PV, Wind	3.51 - 7.7	Electricity costs
Fabianek & Madlener, 2024 [19]	PV, Wind, Hybrid	4.5 - 5.3	Location dependent factors
Gül & Akyüz, 2023 [6]	PV	1.53 - 6.8	CAPEX, OPEX,
Ibáñez-Rioja et al., 2023 [20]	PV, Wind, Hybrid	2 EUR/kg (by 2030)	CAPEX, OPEX, learning curves
Li et al., 2023 [21]	PV, Wind, Hybrid	13.1665 CNY/kg	No mention found
Munther et al., 2024 [22]	PV	2.75 - 2.94	Investment costs, operational costs, electricity costs
Nasser & Hassan, 2023 [23]	PV, Wind, Waste heat, Grid	1.19 - 12.16	Interest rate, inflation rate, degradation rate
Ram et al., 2024 [24]	PV, Wind, Hybrid, Grid	8.73 - 13.00	Investment costs, operational costs, electricity costs
Shaner et al., 2016 [25]	PV, Grid	5.5 - 12.1	Capital expenses, operational costs, electricity costs
Touili et al., 2020 [26]	PV	5.57 - 6.51	No mention found
Xi et al., 2023 [27]	PV, Grid, Hybrid	2.13 - 3.93	Investment costs, operational costs, electricity costs

$$Emisi(\frac{kg\ CO2}{kg\ H2}) = E\%_{grid}\,(\%) \cdot Em_{grid}\left(\frac{kg\ CO2}{kWh}\right) \cdot EC\left(\frac{kg\ CO2}{kWh}\right) \quad (9)$$

Where $E\%_{grid}$ is percentage of energy used from the grid, $E\%_{RES}$ is percentage of energy used from renewable energy, Em_{grid} is emission factor from grid, and EC is electricity Consumption per kilogram of Hydrogen (kWh/kg H_2).

Carbon tax is a policy mechanism that considers the total cost of hydrogen production and encourages the adoption of more sustainable production methods, can be presented as the following equation (10):

$$Carbon\ Tax\ Credit\ (Rp) = Emission\ (ton\ CO2) \times Carbon\ tax\ rate \quad (10)$$

The legal basis for the carbon tax has been established and its derivative regulations are being drafted by the Ministry of Finance of the Republic of Indonesia. Based on Law No. 7/2021 on Harmonization of Tax Regulations Article 13: “The carbon tax rate is set higher or equal to the carbon price in the carbon market with a minimum rate of IDR 30,000 per kilogram of carbon dioxide equivalent (CO_2e)”.

To analyze the economics of various energy mix scenarios in hydrogen production, this study refers to a comparative review of previous studies estimating the Levelized Cost of Hydrogen (LCOH). This comparison is important to understand the range of costs that have been reported in various renewable energy system configurations and the key cost drivers. Table 4 presents a summary of recent comparative studies on the cost of hydrogen production (LCOH) from different types of renewable energy source systems. The table specifically displays the LCOH ranges in USD/kg H_2 or EUR/kg H_2, along with the key cost drivers identified by each study. This data includes Photovoltaic (PV), Wind and Hybrid based system configurations that integrate multiple renewable sources or are grid connected.

RESULTS AND DISCUSSIONS

Economic and Environmental Analysis of Hydrogen Production with Current Model Configuration (Grid + Solar PV 50.6 kWp)

Before conducting a comparative study of hybrid energy source configurations, we will first assess the economics of hydrogen production with current configuration (Grid + Solar PV 50.6 kWp) that uses average 91% PLN Grid and 9% Solar PV as energy sources for the alkaline-type electrolyzer. As illustrated in Table 5, the economic analysis of hydrogen production incorporates a range of parameters, along with the operational and technical data from the Gresik facility in 2024. “Operation pattern 2” is related to two units operating in parallel.

The result of the economic calculation of the current model configuration : Grid + Solar PV (50.6 kWp), ilustrated in Table 6. Total Lifecycle Cost is obtained from the Discounted Annual Cost over a life time of 30 years. Total production is also calculated for the 30-year period.

Based on "Operation Pattern 1," the existing condition of H_2P, the "Grid + Solar PV (50.6 kWp)" configuration the levelized cost of hydrogen (LCOH) is IDR 138,212/kg or USD 8.61/kg. For the configuration in “Operating Pattern 2” produces a total of 23,599 kg of hydrogen per year, the Levelized Cost of Hydrogen (LCOH) is IDR 104,897/kg or USD 6.54/kg. This result is aligns with the economies of scale principle, which states that the per-unit cost of production tends to decrease as output volume grows. Previous research also highlights that larger electrolyzer capacities significantly decrease capital costs per

Table 5. Economic Analysis Parameters

Parameter	Operation Pattern 1	Operation Pattern 2
Investment (IDR)	18,704,472,444	18,704,472,444
Annual O&M cost (IDR):		
Operator cost	180,000,000	180,000,000
Water cost	26,549	53,099
Electricity cost	784,848,277	1,624,049,224
Maintenance cost	191,941,303	191,941,303
Discounted rate (%)	5	5
Life time (year)	30	30
H_2 Production (kg/year)	11,800	23,599
Average electricity demand (kWh/year)	752,822	1,505,644

Table 6. LCOH of current model configuration: Grid + Solar PV (50,6 kWp)

Operation Pattern	Total Lifecycle Cost (IDR)	Total Production (kg)	LCOH (IDR/kg)	LCOH (USD/kg)*
1	48,925,913,785	353,992	138,212	8.61
2	74,265,239,432	707,983	104,897	6.54

*) 1 USD = IDR 16.045

Table 7. Relation of Energy Supply Proportion to Emission and Carbon Tax Credit

No	Configura-tion	Operation Pattern	Energi Proportion			Total Emission	Carbon
			Grid	PV	Microhidro	($TonCO_2$/year)	Tax Credit
1	Grid + PV (50.6 kWp)	1	0.94	0.06	-	574.84	17,245,258
		2	0.97	0.03		1,186.89	35,606,590
2	Grid + PV (100 kWp)	1	0.87	0.13	-	538.52	16,155,651
		2	0.94	0.06		1,150.57	34,516,983
3	Grid + PV (200 kWp)	1	0.74	0.26	-	463.19	13,949,971
		2	0.87	0.13		1,075.24	32,311,303
4	Grid + PV (400 kWp)	1	0.49	0.51	-	317.95	9,538,610
		2	0.74	0.26		930.00	27,899,942
5	Grid + PV (50.6 kWp)	1	0.32	0.06	0.62	205.28	6,158,356
		2	0.66	0.03	0.31	817.32	24,519,688

unit which is a key factor in lowering LCOH.

Based on "Operation Pattern 2" (with higher hydrogen production reaches 23,599.44 kg/year), the "Existing Grid + PV (50.6 kWp)" configuration has an energy supply proportion of 0,97 from the grid and 0,03 from solar PV (Table 7). The high LCOH value (IDR 129,328/kg or USD 8.06/kg) indicates that the dominant reliance on electricity from PLN Grid, which may have higher emission and cost components, contributes to the less competitive hydrogen price. Although there is a contribution of PV, the small percentage (about 3%) is not significant in lowering the cost. The total emissions generated in this configuration are also relatively high, at 1,186.89 $TonCO_2$/year. The emissions generated have consequences for the amount of carbon tax credit that must be paid. Based on Law No. 7/2021 of Ministry of Finance of the Republic of Indonesia on Harmonization of Tax Regulations Article 13, the amount to be paid is IDR 35,606,590.

A comparison of the economic price of hydrogen with various configurations of hybrid energy source configuration

The second problem focuses on comparing the economics of hydrogen from different hybrid energy source configurations as shown in Table 8. This study presents five different hybrid configurations and two types of operation pattern. The total investment of both operating patterns shows the same value because H_2P in Gresik consists of two units of plant.

The data consistently indicates that increasing the total production volume significantly reduces the Levelized Cost of Hydrogen (LCOH) across all configurations, highlighting the economic benefits of economies of scale. Figure 3 ilustrated Operation Pattern 1, Configuration 5 (Grid + PV (50.6 kWp) + Microhidro) demonstrates the lowest LCOH at USD 8.01/kg. When transitioning to Operation Pattern 2 the LCOH for all configurations decreases substantially, with Configuration 5 maintaining its lead as the most economical at USD 6.23/kg, while configurations 1 through 4 all converge to an LCOH of USD 6.54/kg. This suggests that while increased production volume generally improves cost effectiveness. Configuration 5 provides a distinct economic advantage at both lower and higher production scales.

Effect of Increasing PV Capacity (Configurations 1-4)

Table 8 shows that increasing PV capacity from 50,6 kWp to 400 kWp (Scenario 1-

Table 8. Cost comparation of five configurations

Conf.	Operation Pattern 1 (Total Production 353,991.6 kg/life cycle)			Operation Pattern 2 (Total Production 707,983.2 kg/life cycle)		
	Investment (IDR)	O&M Cost (IDR)	LCOH (USD/kg)	Investment (IDR)	O&M Cost (IDR)	LCOH (USD/kg)
1	18,704,472,444	1,965,948,129	8.61	18,704,472,444	3,614,307,627	6.54
2	19,424,116,888	1,920,080,899	8.62	37,408,944,888	3,568,440,396	6.54
3	20,863,405,776	1,827,057,441	8.62	74,817,889,776	3,475,416,938	6.54
4	23,695,050,219	1,640,541,193	8.61	140,468,370,133	3,288,900,690	6.54
5	22,173,329,587	1,515,820,761	8.01	22,173,329,587	3,164,180,258	6.23

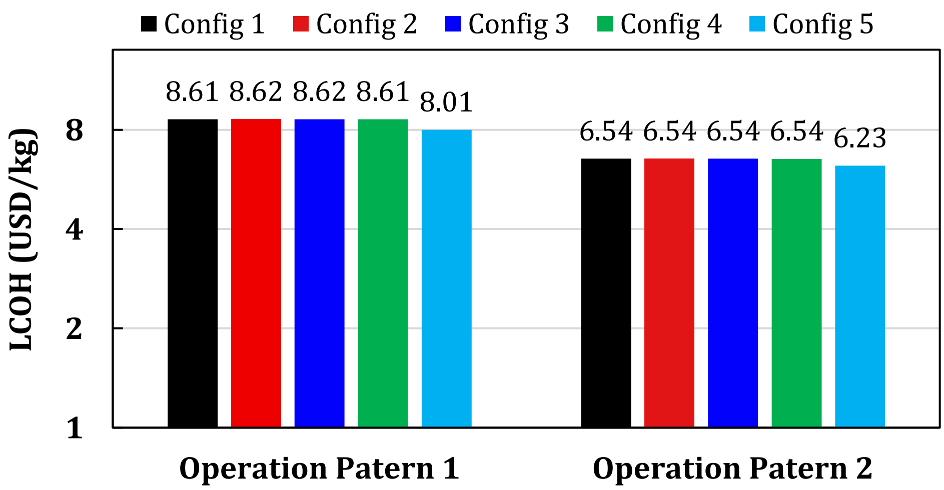

Figure 3. LCOH of Various System Configurations under Operational Patterns 1 and 2

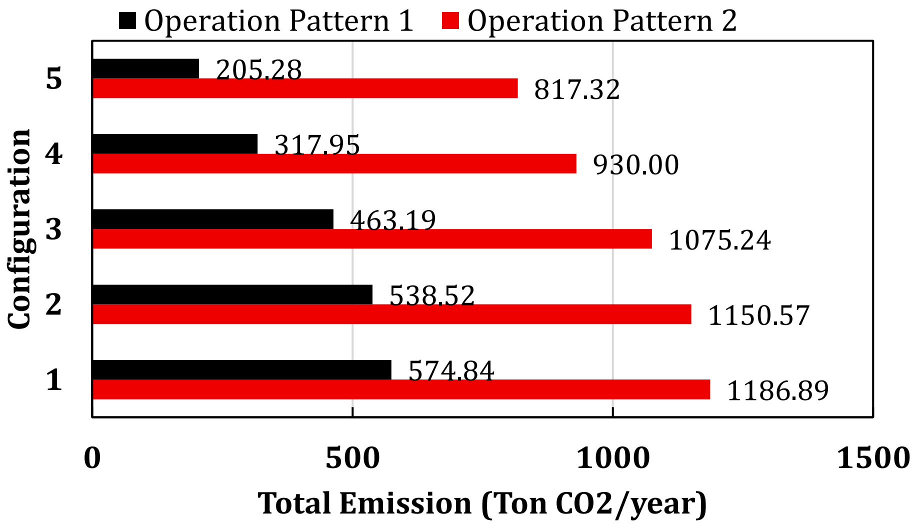

Figure 4. Total Emission of Various System Configurations under Operational Patterns 1 and 2

4), OPEX gradually decreases, reaching Rp 1,640,541,193 in Scenario 4 (Grid + PV 400 kWp). This decrease in OPEX, indicates that a greater contribution of energy from the internal PV system reduces dependence on grid electricity, which may have higher tariffs. The most significant decrease in OPEX occurred in Scenario 5 (Grid + PV 50.6 kWp + Microhydro 76 kW) with an OPEX of Rp 1,515,820,761. This highlights the effectiveness of diversifying renewable energy sources (particularly the addition of micro-hydro with a high capacity factor) in reducing operational costs.

Based on Figure 4 the increased proportion of renewable energy (PV and Microhydro) directly correlates with a reduction in total carbon emissions. In Operation Pattern 1, Configuration 1 (Grid + PV 50.6 kWp) resulted in the highest emissions, reaching 574.84 TonCO_2. As PV capacity increased, emissions decreased to 317,95 TonCO_2 in Configuration 4 (Grid + PV 400 kWp). The most significant reduction was observed in Configuration 5 (Grid + PV 50.6 kWp + Microhydro 76 kW), which yielded 205.28 TonCO_2 emissions, indicating that diversifying energy sources by incorporating microhydro significantly reduces the carbon footprint. In Operation Pattern 2, despite a significant increase in total hydrogen production, the downward trend in emissions with an increasing proportion of renewable energy remained consistent. The higher production volume (due to the operation of two electrolyzers) resulted in substantially higher total emissions for each configuration in Operation Pattern 2.

The Most Economical Hybrid Energy Source Configuration for Hydrogen Plant in Gresik

In addition, the most economical hybrid energy source configuration for the Hydrogen Plant in Gresik will be identified. Furthermore, the most appropriate recommendations will be provided to support the national renewable energy mix target. As illustrated in Table 9, Configuration 5 (Grid + Solar PV 50.6 kWp + Microhydro 76 kW) in Operation Pattern 2 is optimal solution for hydrogen production. This configuration effectively balances economic feasibility and environmental sustainability.

From an economic perspective, this configuration shows the lowest Levelized Cost of Hydrogen (LCOH), which is Rp 100,023/kg or equivalent to USD 6.23/kg. This cost advantage is supported by the principle of economies of scale achieved through the doubling of hydrogen production. Configuration 5 recorded the highest overall Net pre-

Table 9. Result of configuration 5 : Grid+ Solar PV (50.6 kWp) and Microhydro (76 kW)

Parameter	Operating Pattern 1	Operating Pattern 2
Investment (IDR)	22,173,329,587	22,173,329,587
Annual O&M cost (IDR)	1,515,820,761	3,164,180,258
Hidrogen Production (kg/year)	11,800	23,599
Lifetime (year)	30	30
LCOH (IDR/kg)	128,464	100,023
LCOH (USD/kg)	8.01	6.23
NPV	14,655,813,194	22,935,241,285
IRR	4.33%	22.09%
PBP	22	20
Total Emission (TonCO_2)	205.28	817.32
Carbon Tax Credit (IDR)	6,158,356	24,519,688

sent Value (NPV) of Rp 22.935.241.285 and an Internal Rate of Return (IRR) of 22.09%. These figures significantly exceed the established discount rate of 5%, indicating a very strong financial feasibility of the project. Although in this study the LCOH range is still relatively high compared to other countries (table 4) it is possible to decrease according to the 2023 National Hydrogen Strategy projection to around 2 USD/kg H_2 by 2050. Configuration 5 also provides the most environmentally friendly option, although total carbon emissions increase in Operation Pattern 2 due to higher production volume. This configuration maintains the lowest emissions (817.32 TonCO_2) compared to other scenarios under the same operating pattern.

CONCLUSIONS

Based on the comprehensive modelling and analysis results, several key conclusions can be drawn:

1. Hydrogen production with the current model configuration (Grid + PV 50,6 kWp) which is highly dependent on the PLN grid (94% grid and 6% Solar PV in Operating Pattern 1) shows a relatively high Levelized Cost of Hydrogen (LCOH) of IDR138,212/kg (USD 8.61/kg). The dominant reliance on grid electricity is a major factor in the high cost of hydrogen production, as well as generating significant levels of CO_2 emissions (574.84 TonCO_2/year). This indicates that the existing configuration is not economically or sustainably optimal for achieving competitive green hydrogen targets.
2. Comparison of various hybrid energy source configurations reveals important findings. Increasing the capacity of Solar PV individually in Grid + PV combinations (Configurations 1 to 4) actually leads to emissions decreased to 317.95 TonCO_2 (Operation Pattern 1) and 930 TonCO_2 (Operation Pattern 2).
3. Configuration 5 (Grid + PV 50.6 kWp + Microhydro 76 kW) was found to be the most economical under current assumptions. This configuration produces the lowest LCOH, IDR100,023/kg (USD 6.23/kg), recorded the highest overall Net Present Value (NPV) of Rp 22,935,241,285 and an Internal Rate of Return (IRR) of 22.09%. These advantages are driven by the contribution of a stable baseload energy source from Microhydro, which reduces dependency on the grid and complements the intermittent nature of Solar PV.

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