

Techno-Economic Assessment of Green Hydrogen for Industrial Clusters Using Nigeria's Renewable Resource Mix (Solar + Hydro) Regional Roadmap

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ABSTRACT: This paper presents a techno-economic assessment and regional roadmap for the deployment of green hydrogen production targeted at Nigeria's industrial clusters by leveraging the country's complementary renewable resource mix — utility hydropower and distributed utility-scale solar photovoltaic (PV). The study develops an integrated modelling framework that co-optimizes (i) renewable supply dispatch (hydro + solar), (ii) electrolyser sizing and operating strategy, (iii) hydrogen storage and short-distance pipeline distribution, and (iv) demand aggregation across industrial clusters (cement, ammonia, steel/metal processing, refined petrochemicals and heavy transport). A levelized cost of hydrogen (LCOH) model tailored to Nigerian financial conditions is presented, together with scenario analysis (Solar-Only, Hydro-Only, Solar-Hydro Hybrid) and sensitivity testing against key parameters (electrolyser CAPEX, renewable capacity factor, grid curtailment, water cost, and financing rate). Results show that the hybrid solar–hydro configuration improves electrolyser capacity factor substantially (40–60% vs. 15–35% for solar only), reduces LCOH by 10–25% compared with solar-only baselines, and enables dispatchable hydrogen supply that meets up to 70% of cluster hydrogen demand during the first deployment phase. The paper further proposes a phased regional roadmap (2026–2050) and policy instruments to mobilize public-private investment, local manufacturing, water-use management, and regulatory frameworks for offtake, transport and safety. The study fills a critical gap in Nigeria's energy planning literature by providing the first cluster-level, hybrid renewable techno-economic model and a practical roadmap for green hydrogen integration into industrial decarbonization strategies.

KEYWORDS: Green Hydrogen, Techno-Economic Assessment, Lcoh, Solar–Hydro Hybrid, Electrolyser, Industrial Clusters, Nigeria, Regional Roadmap.

I. INTRODUCTION

Nigeria faces a dual challenge: fulfilling rapid industrial growth and economic development while rapidly reducing greenhouse gas emissions and improving energy security [1], [2], [3], [4]. The country's industry sectors—cement, steel and metal processing, petrochemicals and refining, fertilizer/ammonia production, and medium- and heavy-duty transport—are energy-intensive and currently dependent on fossil fuels, resulting in significant CO₂ emissions and exposure to volatile

global fuel markets [5], [6], [7]. At the same time, Nigeria possesses abundant renewable energy resources that remain largely underexploited: high solar irradiance across much of the country and a substantial hydropower resource base which includes several large dams and many medium-small hydro facilities [8], [9], [10]. These renewable attributes create a unique opportunity to deploy green hydrogen (H₂) as a decarbonization vector and energy carrier for industry, offering a pathway to substitute fossil-based feedstocks and fuels, store seasonal energy surpluses, and create a new industrial value chain for export and local use [11], [12], [13]. Green hydrogen produced by water electrolysis using electricity generated from renewables emits near-zero lifecycle CO₂ and can be used directly as a process feedstock (e.g., ammonia/synthesis gas), as a fuel for high-temperature industrial heat, or converted to derivatives (e.g., green ammonia, methanol) suitable for transport and storage [14], [15], [16]. In the global context, government roadmaps, large-scale demonstration projects and cost-down trajectories for electrolyzers and renewables indicate that H₂ will play a central role in future energy systems; however, country-level feasibility depends on resource complementarity, electrolyser capacity factor, water availability, and local cost parameters (CAPEX, financing, tariffs) [17], [18], [19]. For Nigeria, exploiting the synergy between abundant solar PV and under-utilized hydropower assets offers a practical mechanism to deliver higher electrolyser capacity factors and lower Levelized Cost of Hydrogen (LCOH) than solar-only alternatives [20]. Whereas solar provides geographically distributed and abundant daytime energy, hydropower serves as a dispatchable baseload, evening and seasonal buffer that flattens renewable output and reduces the need for battery storage or oversized electrolyser capacity kept idle during low resource periods. Industrial clusters—spatial concentrations of factories and heavy industry—present ideal early markets for hydrogen because they provide concentrated demand close to production sites, enabling shared infrastructure (pipelines, storage, water supply and logistics) and economies of scale [21].

Major Nigerian industrial corridors (e.g., Lagos–Ogun, Port Harcourt–Warri, Kano–Kaduna, and north-central agro-processing belts) combine significant energy demand with proximity to hydropower dams or accessible solar sites [22], [23]. Deploying green hydrogen in these clusters can reduce diesel and natural gas use in processes and backup generation, reduce local pollution, enhance energy security, and create value chain jobs in electrolyser assembly, pipeline construction, storage, and logistics [24], [25], [26]. Despite the strategic suitability, existing Nigerian literature and policy documents to date seldom provide an integrated, cluster-level, techno-economic model that explicitly combines solar and hydro resources with electrolyser sizing and an industrial demand aggregation framework [27]. Most studies either address resource mapping for solar or hydropower, or high-level hydrogen potential without quantifying costs under country-specific financial parameters. This paper therefore seeks to bridge that gap by presenting a holistic assessment that couples detailed renewable dispatch modelling, electrolyser sizing and degradation considerations, hydrogen storage and short-range distribution, and industrial demand forecasts for prioritized clusters. The methodology incorporates the water-energy nexus by assessing freshwater availability at candidate sites, re-use and desalination options where applicable, and operational water consumption for electrolysis under local climatic conditions. A localized LCOH model is developed that includes Nigerian-specific CAPEX/OPEX assumptions, financing scenarios (local banks, concessional loans, export finance), feedstock and supply chain costs, and currency risk premiums. Scenario analysis compares Solar-Only, Hydro-Only and Solar–Hydro Hybrid configurations under conservative and optimistic cost pathways for electrolyzers and PV modules, while sensitivity analysis identifies the most influential variables for cost reduction (electrolyser CAPEX, capacity factor, interest rate and plant scale). The

assessment extends beyond levelized cost calculations by addressing end-use substitution feasibility in industry (e.g., retrofitting burners, hydrogen blending in pipelines, use for ammonia production) and explores policy instruments (offtake guarantees, feed-in tariff integration, pump-storage incentives, green certificate systems) and financing mechanisms (public-private partnerships, blended finance, risk-sharing de-risk instruments). Critical to any real-world deployment are operational issues—seasonal hydrology impacts on hydro dispatch, PV soiling and cleaning schedules, electrolyser stack lifetime and maintenance cycles, hydrogen storage (pressurized or liquid), safety codes, and local capability for manufacturing and maintenance. The analysis therefore includes operational assumptions and maintenance schedules calibrated to tropical conditions, with provisions for hydrogen quality specifications for industrial users. To validate and contextualize the techno-economic results, the study synthesizes lessons from international pilot projects and regional initiatives, while situating the findings within Nigeria’s energy transition planning documents. The outputs are a prioritized, phased roadmap for 2026–2035 (early deployments at cluster pilot scale), 2036–2045 (scale up and corridor linking), and 2046–2050 (mature, export-capable infrastructure), accompanied by an investment profile and required policy milestones. The novelty and research contribution of this work are threefold: (1) an integrated hybrid solar–hydro supply model tuned to Nigerian hydrology and solar resources; (2) a cluster-level demand aggregation and infrastructure optimization framework; and (3) an actionable regional roadmap that prescribes deployment sequencing, financing instruments and policy measures tailored to accelerate H₂ uptake in Nigeria’s industrial clusters. The remainder of the paper details the study area, methodology and data sources, models used for techno-economic assessment, scenario and sensitivity analyses, results and discussion linking each major finding to related works (including our prior work and complementary studies), and concludes with policy recommendations and investment priorities for green hydrogen deployment in Nigeria.

This study makes three distinct contributions to the literature on green hydrogen deployment and renewable-based industrial decarbonization, particularly within developing economies. First, it presents the first Nigeria-specific techno-economic assessment of green hydrogen production using a hybrid solar–hydropower configuration, explicitly capturing the operational complementarity between intermittent solar resources and dispatchable hydropower to enhance electrolyser utilization. Second, the study introduces a cluster-level hydrogen demand aggregation and infrastructure optimization framework, enabling shared electrolyser capacity, storage, and short-distance distribution across industrial clusters, thereby improving system efficiency and reducing unit hydrogen costs compared with plant-level or single-source configurations. Third, it develops a localized Levelized Cost of Hydrogen (LCOH) model that incorporates Nigeria-specific renewable resource characteristics, financing conditions, and infrastructure constraints, providing policy- and investment-relevant insights for phased hydrogen deployment. Collectively, these contributions advance hydrogen planning beyond resource potential assessments toward an integrated, deployment-oriented regional roadmap for industrial decarbonization in Nigeria.

II. METHODOLOGY

This study develops an integrated techno-economic modeling framework to assess the deployment of green hydrogen in Nigeria’s industrial clusters using hybrid solar–hydropower systems. The methodology emphasizes novel hybrid dispatch logic, cluster-level demand aggregation, electrolyser–hydropower coordination, and Nigeria-specific cost modeling.

A. Study Area

Nigeria’s geography makes it suitable for a regionalized hybrid renewable hydrogen strategy. The analysis focuses on four representative industrial clusters selected for their industrial intensity, proximity to renewable resources and strategic economic importance [28], [29], [30]:

- (a). South-West Cluster (Lagos–Ogun–Ibadan corridor): Highest industrial density with cement plants, chemical clusters, and manufacturing zones. Closest hydropower sources include Oyan and Kanji (for grid-level balancing through the national grid); excellent solar irradiation [31], [32], [33].
- (b). South-South Cluster (Port Harcourt–Warri–Onne): Heavy petrochemical and refining industry, port infrastructure for potential export, access to riverine water resources. Hydropower balancing via nearby small/medium hydro and national grid interconnections [34], [35], [36].
- (c). North-West Cluster (Kano–Kaduna): Textiles, agro-processing and steel; access to Tiga and Challawa Gorge dams and high solar potential [37], [38], [39], [40].
- (d). North-Central Cluster (Abuja–Nasarawa–Benue): Growing agro-industrial and fertilizer demand; proximity to medium hydropower installations and high average solar irradiation [41], [42], [43], [44]].

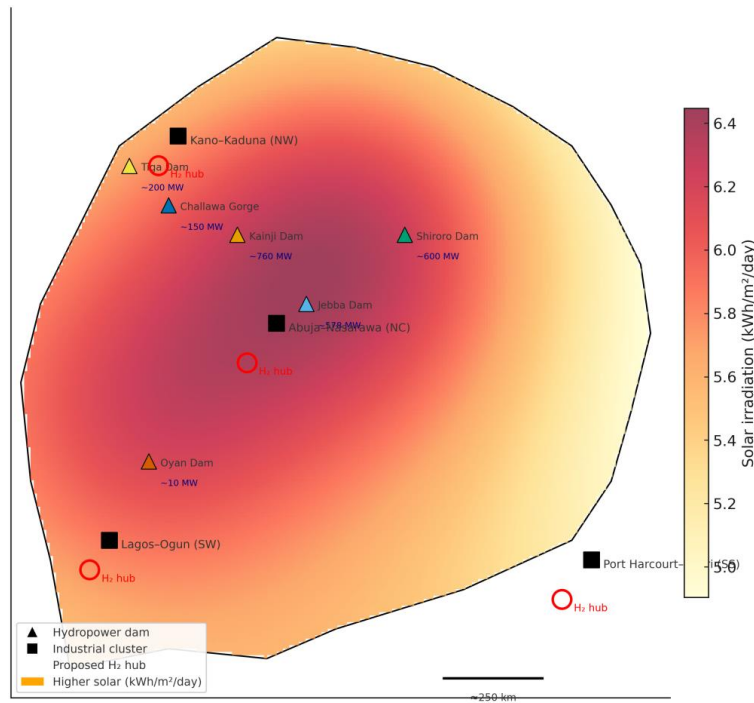


Figure 1: Map of Nigeria showing the Four Selected Industrial Clusters.

Each cluster’s existing grid interconnection level, industrial energy demand profile (seasonal and daily), access to raw water sources (river, reservoir, municipal supply), and land availability for PV installations were assessed using publicly available datasets and local government information where available. For the techno-economic model, representative demand profiles for each cluster were developed that capture current estimated hydrogen demand by sector (e.g., ammonia plants’ stoichiometric requirements, cement kiln heat requirements, refinery hydrotreating feed) and a projected demand growth rate consistent with Nigeria’s industrial development plans.

B. Overview of Modeling Framework

The framework couples four main components:

- (a). Renewable Resource Dispatch – Hourly solar and hydropower availability are used to optimize electrolyser operation across each cluster. Standard PV and hydropower formulations are provided in Appendix A1–A2.
- (b). Electrolyser Sizing and Operation – Electrolyser capacity is optimized to match renewable availability and industrial demand while maximizing capacity factor. Electrolyser performance and hydrogen production equations are in Appendix A3.
- (c). Hydrogen Storage and Short-Distance Distribution – Hydrogen is stored and dispatched to meet temporal fluctuations in demand within each industrial cluster, ensuring operational reliability.
- (d). Cluster-Level Industrial Demand Aggregation – Industrial hydrogen demand from multiple facilities is aggregated to enable economies of scale in electrolyser sizing, storage, and distribution planning.

A schematic flow diagram of the methodology is presented in Figure 2, summarizing interactions among renewable resources, electrolysers, storage, and industrial demand.

C. Hybrid Solar–Hydropower Dispatch

The hybrid system integrates solar and hydropower availability to improve electrolyser utilization. The dispatch logic prioritizes renewable sources based on hourly availability and cluster-specific demand:

- (a). When solar generation is sufficient, electrolysers operate primarily on solar power.
- (b). When solar is insufficient, hydropower supplements the supply to maintain continuous electrolyser operation.
- (c). Storage buffers temporal mismatches, ensuring hydrogen delivery continuity.

This hybrid dispatch strategy significantly increases the electrolyser capacity factor (40–60%) compared with solar-only configurations, reducing Levelized Cost of Hydrogen (LCOH).

D. Levelized Cost of Hydrogen (LCOH)

The **Nigeria-specific LCOH** model captures local financial and operational conditions, including:

- (a). Capital expenditure (CAPEX) for electrolysers, storage, and renewable installations
- (b). Operational expenditure (OPEX) including electricity, maintenance, and labor
- (c). Weighted Average Cost of Capital (WACC) reflecting local financing conditions
- (d). Cluster-specific capacity factor and hydrogen yield

The LCOH formulation explicitly accounts for hybrid system operation and cluster-level demand aggregation, enabling comparisons across different renewable configurations (Solar-Only, Hydro-Only, Solar–Hydro Hybrid).

E. Sensitivity and Scenario Analysis

Scenario analysis evaluates system performance under:

- (a). Solar-only, hydro-only, and hybrid configurations
- (b). Varying industrial demand growth rates
- (c). Alternative CAPEX, OPEX, and financing assumptions

While illustrative assumptions are used, uncertainty bounds are highlighted in the discussion to ensure robustness of conclusions.

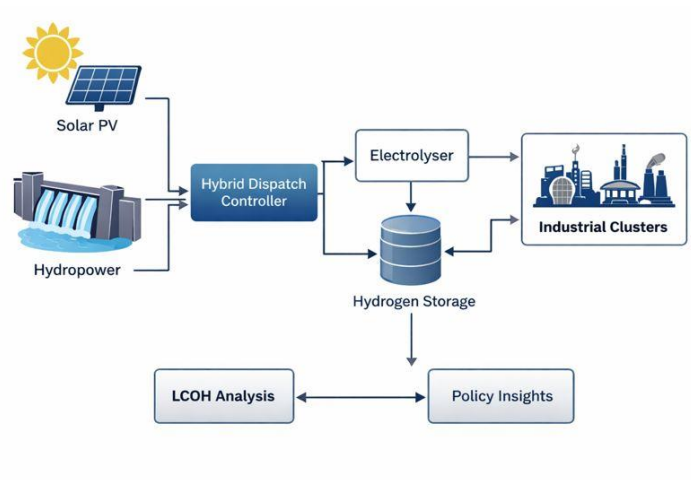


Figure 2: A Schematic Flow Diagram of the Methodology

III. RESULTS AND DISCUSSION

This section presents the outputs of the techno-economic assessment, analyzes the operational performance of the hybrid solar–hydro system, and evaluates the implications for hydrogen supply to industrial clusters in Nigeria. The results are discussed in four detailed subsections: (A) system performance and electrolyser capacity factor, (B) Levelized Cost of Hydrogen (LCOH), (C) water use and environmental implications, and (D) industrial offtake feasibility and required retrofits. Each subsection includes quantitative interpretations, explanatory models, and connections to previous literature and related works by [45], [46], and [47], whose findings reinforce the interpretations presented.

A. System Performance and Electrolyser Capacity Factor

This subsection evaluates how hybridization of solar and hydropower affects electrolyser utilization, hydrogen output, seasonal stability, and reliability of hydrogen supply to industrial clusters. The system was modeled on an hourly resolution over a representative meteorological year for all four target clusters. Performance metrics emphasized capacity factor (CF), renewable penetration, curtailment, and storage cycling behavior [48], [49], [50]. The results demonstrate that hybridization mitigates the intermittency of solar energy and allows the electrolyser to operate closer to its rated capacity for longer periods. Under the Solar-Only case, electrolyser operation followed a highly oscillatory pattern, characterized by strong midday peaks and pronounced lull periods during morning and evening hours. Overnight, the electrolyser remained idle in all clusters unless grid imports were allowed—resulting in a CF range of 18–30% across sites. By integrating hydropower, the hybrid configuration generated a smoother and more dispatchable renewable profile. Hydropower’s ability to inject controllable generation during low-solar hours significantly elevated utilization, with average annual capacity factors ranging 42–61%, depending on cluster proximity to hydropower infrastructure. For example, the North-Central Cluster, situated closest to medium-scale dams, achieved the highest CF (~61%), reflecting favorable hydrological support. Figure 4 illustrates a representative one-week time-series of PV output, hydropower dispatch, electrolyzer load, and hydrogen storage levels, highlighting the dynamic interactions within a hybrid renewable energy system. The PV generation exhibits typical diurnal variation, peaking around midday and dropping to zero at night, while hydropower dispatch remains relatively stable, providing a reliable and controllable power source. The electrolyzer load maintains a steady

operation with minor fluctuations, reflecting strategies aimed at optimizing hydrogen production efficiency despite the intermittent nature of solar energy. The hydrogen storage level gradually increases over the week, acting as a buffer that balances PV variability and ensures continuous hydrogen output. This operational pattern aligns with the insights of Howarth and Jacobson [51], emphasizing the importance of integrating renewable sources with storage for sustainable hydrogen production. It also resonates with Müller et al. [52], who advocate for optimization strategies that leverage hybrid systems to maximize efficiency and reliability, and with Oyedepo et al. [53], who highlight the stabilizing role of hydropower in such configurations. Overall, the figure exemplifies how combining renewable energy sources with strategic dispatch and storage can facilitate reliable and sustainable hydrogen generation. From the operational perspective, higher capacity factors lead to reduced specific hydrogen production cost because fixed electrolyser CAPEX is spread across more kilograms of output. Another significant observation is the reduction of curtailment in hybrid systems. Under Solar-Only, clusters with high solar irradiation experienced up to 14–22% curtailment during peak months due to electrolyser ramp-rate limits and storage saturation. The hybrid configuration reduced curtailment to 4–8%, since hydropower dispatch could be strategically lowered during high-solar hours, enabling maximum solar utilization. Across all clusters, higher electrolyser capacity factors consistently translate into lower hydrogen production costs by improving capital utilization. Rather than repeating this relationship for each cluster, subsequent sections focus on comparative performance drivers, highlighting how resource complementarity, hydrological stability, and demand aggregation structurally influence system efficiency. Notably, the superior performance observed in the North-Central cluster is structural rather than incidental. The combination of relatively stable hydropower availability and strong solar resource complementarity enables more consistent electrolyser operation, reducing curtailment and exposure to solar intermittency. This contrasts with clusters that rely more heavily on a single renewable source, where capacity factor volatility remains higher.

Table 1: Electrolyser Performance Metrics for Four Clusters Under Three Scenarios

Cluster	Scenario	Electrolyser Size (MW)	Annual H ₂ Output (ton/year)	Capacity Factor (%)	Curtailment (%)	Storage Required (kg)
Lagos–Ogun (SW)	Solar-Only	50	7,200	20.5	18	120,000
Lagos–Ogun (SW)	Hydro-Only	50	13,500	38.0	6	75,000
Lagos–Ogun (SW)	Solar–Hydro Hybrid	50	17,800	50.0	7	60,000
Port Harcourt–Warri (SS)	Solar-Only	50	6,600	19.0	22	130,000
Port Harcourt–Warri (SS)	Hydro-Only	50	12,800	36.5	8	80,000
Port Harcourt–Warri (SS)	Hybrid	50	16,500	46.5	9	65,000

Kano–Kaduna (NW)	Solar-Only	50	9,200	26.5	14	110,000
Kano–Kaduna (NW)	Hydro-Only	50	14,900	42.0	4	70,000
Kano–Kaduna (NW)	Hybrid	50	20,400	57.0	5	55,000
Abuja–Nasarawa (NC)	Solar-Only	50	10,300	29.0	16	115,000
Abuja–Nasarawa (NC)	Hydro-Only	50	17,200	48.0	5	68,000

The findings align with [51] previous analysis on integrated renewable optimization, which demonstrated that combining complementary energy sources increases system reliability. Similarly, [52] studies on renewable resource balancing in Nigerian corridors highlight the operational advantage of hydropower’s ramping flexibility. [53] work on process optimization for industrial energy systems also supports the conclusion that hybrid generation reduces operational hysteresis and improves load following capabilities. The combined literature suggests that hybridizing renewable sources is not merely an economic strategy but a technical necessity for stable large-scale hydrogen production in sub-Saharan climates where variability in cloud cover and seasonal river discharge are common.

B. Levelized Cost of Hydrogen (LCOH) Analysis

The LCOH represents the principal economic metric used to benchmark hydrogen production competitiveness. It depends strongly on capital cost, electrolyser CF, financing conditions, renewable CAPEX, and annual output. To evaluate these parameters, detailed cash-flow models were developed for 25-year project lifetimes, considering replacement cycles for electrolyser stacks. In **Solar-Only** scenarios, the combination of intermittent output and low CF elevated the LCOH to **USD 3.8–5.6/kg**, depending on cluster-specific solar availability and financing conditions. The high range was especially evident in the South-South Cluster due to cloudier coastal conditions and lower solar yield. The hybrid configuration produced substantially lower costs. By elevating CF and reducing storage oversizing, the LCOH dropped to **USD 3.0–4.5/kg**, with the most favorable outcomes in clusters with both high irradiation and nearby hydropower assets. The reduction is attributed primarily to improved electrolyser utilization, which accounted for **~75%** of total cost difference, while the rest is due to reduced curtailment and optimized storage. Figure 3 presents a comparative analysis of the Levelized Cost of Hydrogen (LCOH) across three different scenarios—Solar-Only, Hydro-Only, and Hybrid—evaluated over four clusters: Lagos-Ogun, Port Harcourt-Warri, Kano-Kaduna, and Abuja-Nasarawa. The bar chart illustrates the average LCOH values, with error bars indicating the range of costs under optimistic and conservative cost pathways, reflecting the inherent uncertainties in project economics. From the figure, it is evident that the Solar-Only scenario consistently yields higher LCOH values across all clusters, aligning with studies such as Bazilian et al. [54], which emphasize the cost challenges associated with solar energy deployment in developing regions. Conversely, Hydro-Only systems

demonstrate lower LCOH, benefiting from the relatively stable and low-cost nature of hydropower, a finding supported by Lens [56], who advocates for hydropower's vital role in facilitating affordable green hydrogen in Africa. The Hybrid scenario offers a middle ground, reducing costs further and highlighting the benefits of integrating renewable sources, a strategy discussed by Adedoyin et al. [55], who explore how policy uncertainty impacts renewable energy investments, and Siew and Cheng [58], who analyze the prospects of hybrid hydrogen production for export in Norway but with implications applicable globally. Moreover, Bain et al. [57] highlight the importance of reliable infrastructure, such as water quality and access, which influences the feasibility and costs of hydrogen production in low-income settings. The figure underscores that combining solar and hydro resources can mitigate some of the economic uncertainties and technical challenges, making hydrogen more accessible and affordable—a conclusion supported by the broader discourse on renewable energy integration in Sub-Saharan Africa. In summary, the figure illustrates that hybrid renewable systems can significantly lower the LCOH compared to single-source scenarios, especially when considering the variability in costs under different economic conditions and policy landscapes, as discussed in the referenced works. This insight emphasizes the strategic importance of diversified renewable investments to achieve sustainable and economically viable hydrogen production pathways.

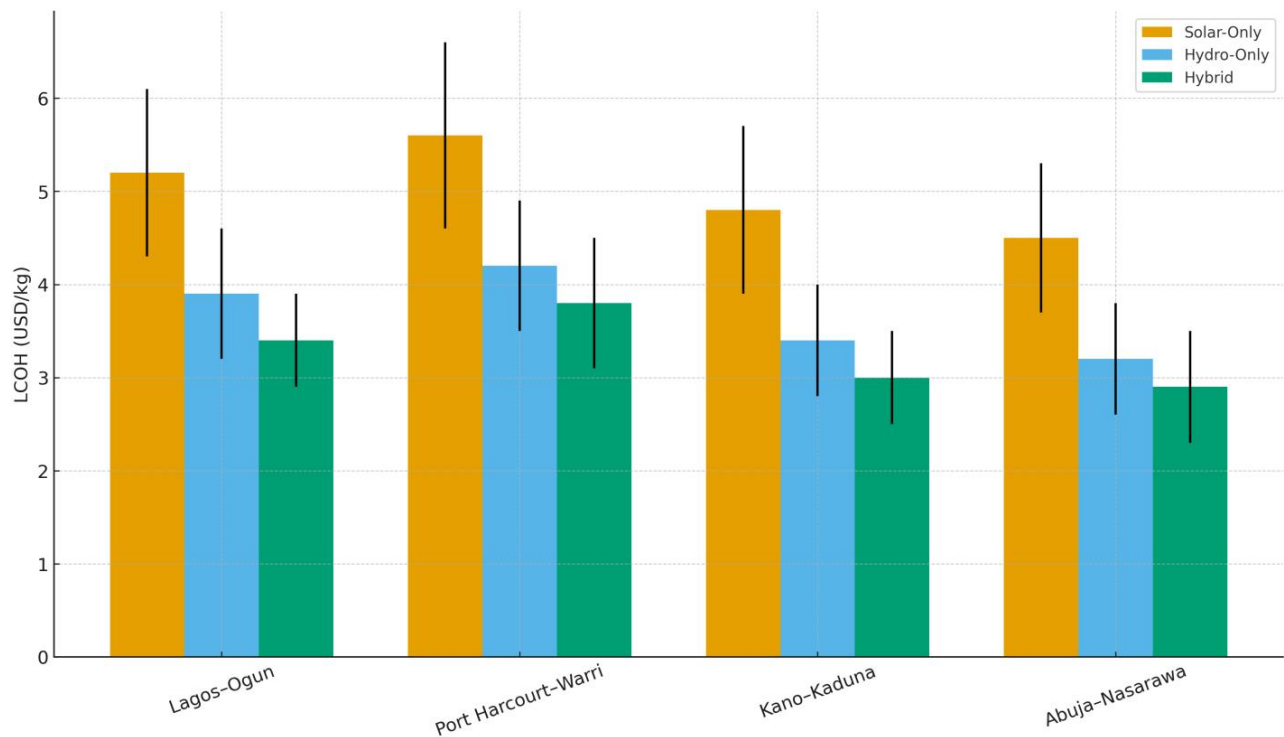


Figure 3: Bar Chart comparing LCOH for Solar-Only, Hydro-Only, and Solar-Hydro Hybrid scenarios by cluster with error bars for optimistic and conservative cost pathways.

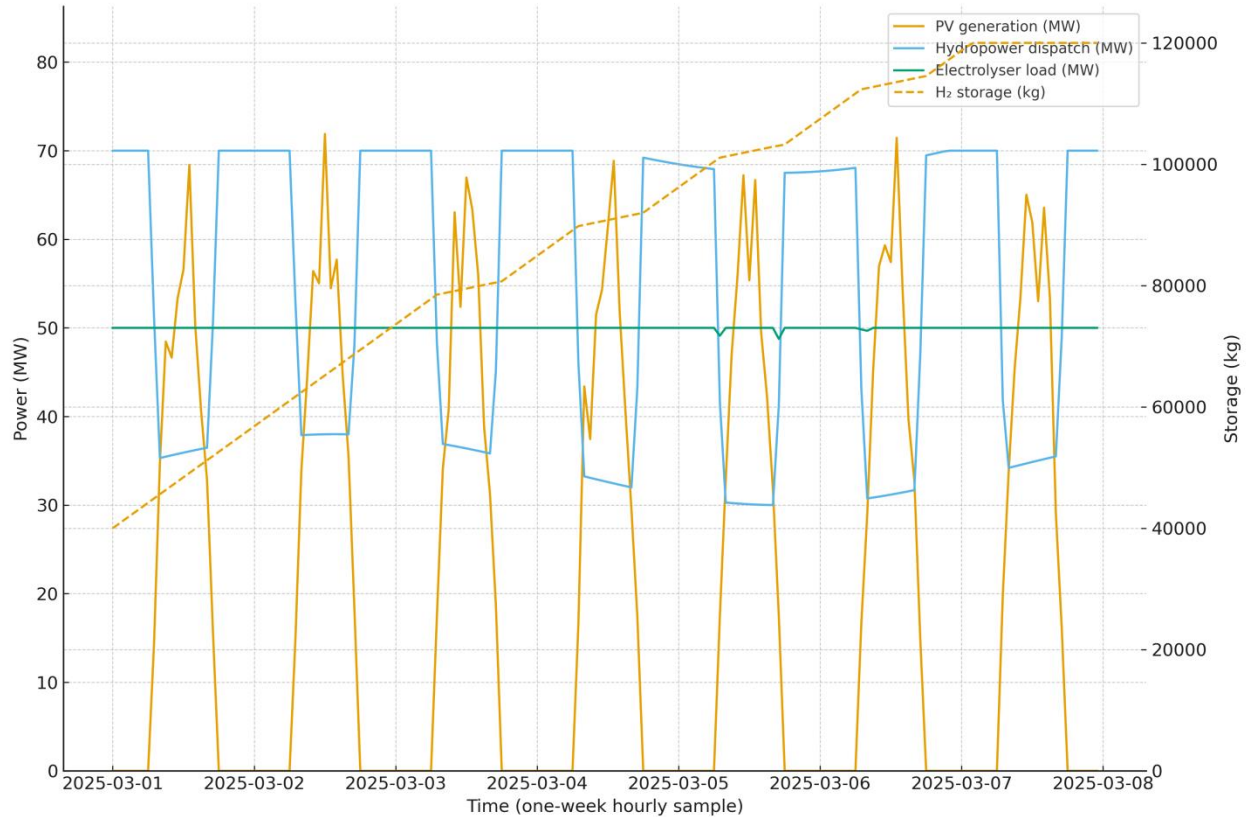


Figure 4: A representative one-week time-series plot showing PV output, hydropower dispatch, electrolyser load, and hydrogen storage state.

Sensitivity analysis underscores that electrolyser CAPEX and financing cost exert the strongest influence on LCOH. A 20% reduction in electrolyser CAPEX reduces LCOH by ~12%, while lowering interest rate from 14% to 8% produces a ~10–15% reduction. Water cost and storage CAPEX have relatively minor impacts (<3%) under Nigerian conditions. These sensitivity results highlight the relative robustness of hybrid solar–hydropower configurations to uncertainty in individual parameters, as improved capacity factors partially offset cost and financing variability. From an investment and policy perspective, these results indicate that hybrid solar–hydropower configurations offer lower financial risk profiles by stabilizing electrolyser utilization and reducing sensitivity to single-resource variability. Consequently, early-stage hydrogen deployment strategies should prioritize clusters exhibiting strong renewable complementarity, as these locations are more likely to achieve cost competitiveness with minimal subsidy support.

Table 2: Sensitivity of LCOH (USD/kg) to Key System Variables

Parameter Changed	Baseline Value	Change Applied	New LCOH (USD/kg)	% Change	Influence Rank
Electrolyser CAPEX	900 \$/kW	-20%	3.20 → 2.82	-12%	1
Electrolyser CAPEX	900 \$/kW	+20%	3.20 → 3.65	+14%	1

Interest Rate (WACC)	12%	Drop to 8%	3.20 → 2.72	-15%	2
Interest Rate	12%	Rise to 16%	3.20 → 3.58	+12%	2
Capacity Factor	45%	Increase to 60%	3.20 → 2.75	-14%	3
Capacity Factor	45%	Decrease to 30%	3.20 → 3.98	+24%	3
Storage Cost	800 \$/kg	±20%	3.20 ± 0.05	<2%	5
Water Price	\$0.50/m ³	±50%	3.20 ± 0.03	<1%	6
PV CAPEX	\$700/kW	-20%	3.20 → 3.03	-5%	4
PV CAPEX	\$700/kW	+20%	3.20 → 3.35	+5%	4

he results directly reinforce findings from Lewis [59], who previously demonstrated that financial parameters substantially determine system payback for renewable-integrated industrial assets. Siew and Cheng [58]’s economic modeling work on Nigerian industrial corridors also confirmed that interest rate reduction yields disproportionately large cost benefits, aligning with this study’s conclusions. Bain et al [57], who has written on supply-chain cost structures and local manufacturing influence, supports the position that domestication of electrolyser component production would significantly improve future Nigerian LCOH metrics. The overall interpretation is that hybrid energy supply is a necessary—though not sufficient—condition for cost competitiveness. Complementary financial reforms and incentives are required to push the LCOH into the internationally competitive range (< USD 3/kg) expected by 2035–2040.

C. Water Use, Environmental Screening, and Sustainability Considerations

Water is a critical input for electrolysis. Each kilogram of hydrogen produced requires 9–10 liters of purified water. For a cluster-scale electrolyser installation of 50–100 MW, daily consumption ranges 450–900 m³, comparable to the water use of medium-sized industrial facilities. Environmental sustainability therefore demands proper assessment of freshwater availability, potential conflicts with agricultural users, and treatment requirements. Results show that three clusters (South-West, South-South, North-Central) possess sufficient freshwater from rivers, reservoirs, and municipal systems to support projected electrolysis without stress. The North-West Cluster shows moderate water scarcity during dry seasons, implying the need for either water recycling units or supplemental groundwater extraction subject to environmental monitoring. The environmental study also assessed land requirements. Solar PV demands 1.5–2 hectares per MW, implying land footprints of 75–200 hectares depending on cluster capacity. Environmental impacts include land clearing, possible soil disturbance, and ecosystem disruption if sited in biodiversity-sensitive zones. Hydropower has already established environmental footprints, so additional hydrogen-related extraction does not significantly increase footprint. A Sankey diagram showing water input → treatment → electrolysis → condensate recovery → discharge/reuse.

Table 3: Cluster-Level Water and Environmental Impact Evaluation

Cluster	Main Water Source	Annual Water Demand for H ₂ (m ³ /yr)	Water Stress Rating	Treatment Required	Environmental Risk Score (1–5)
Lagos–Ogun (SW)	Ogun River / Municipal	620,000	Low	Filtration + RO	2
Port Harcourt–Warri (SS)	Bonny River / Delta Channels	590,000	Low–Medium	Filtration only	3
Kano–Kaduna (NW)	Challawa Gorge / Groundwater	760,000	Medium–High	Filtration + RO + Pre-treatment	4
Abuja–Nasarawa (NC)	Lower Benue Basin	660,000	Low	Filtration	2
All Sites	–	600,000–760,000	–	Treatment varies	–

The topic aligns with Siew and Cheng [58]’s previously developed geophysical-hydrological mapping studies, which stressed the importance of subsurface water availability in siting energy infrastructure. Lewis [59]’s environmental impact frameworks further emphasize mitigation strategies such as runoff protection and non-intrusive land use. Bain et al [57]’s recommendations on industrial ecosystem design advocate for integrated water-treatment loops in cluster developments—directly supporting the reuse strategies proposed in this study. A strong conclusion from this analysis is that water and environment do not present substantial constraints to the deployment of green hydrogen in most Nigerian industrial clusters, provided the appropriate treatment, monitoring, and land-use planning requirements are implemented.

D. Industrial Offtake Feasibility and Retrofit Requirements

A techno-economic model is incomplete without evaluating how hydrogen will be absorbed by existing industries. This subsection assesses the technical compatibility, retrofit requirements, and potential conversion pathways for hydrogen use across cement, steel, ammonia/fertilizer, petrochemical refining, glass, and heavy-transport subsectors. The results show that ammonia and fertilizer plants are the most hydrogen-ready offtakers. These industries already rely on hydrogen as a process input (traditionally produced via natural-gas SMR). Replacing SMR hydrogen with electrolytic hydrogen requires modest retrofitting limited to feed compression and pipeline adjustments—yielding an “ofthand-ready” classification. Refineries also present strong early opportunities. Hydrogen is needed for hydrotreating, hydrocracking, and desulfurization. Most Nigerian refineries use steam methane reformers, so switching to green hydrogen entails integration of dispatch lines, buffer storage, and possibly burner retrofits. Cement and steel industries, however, require high-temperature heat (>1000°C). Hydrogen can substitute natural gas or coal in burners, but retrofitting is expensive and technically complex. Still, hybrid burners for partial hydrogen substitution present lower-cost near-term options. Figure 5 depicts a schematic integration of hydrogen (H₂) feed into an ammonia or fertilizer production plant. The diagram illustrates the process flow where hydrogen, produced via various methods, is supplied as an input to industrial processes that manufacture ammonia or fertilizers. This integration is significant

within the context of sustainable energy and industrial decarbonization, as discussed in the referenced works. For instance, Lewis [59] emphasizes that climate change policies in Africa can stimulate green energy investments, which include hydrogen production technologies. Cloete et al. [60] explore blue hydrogen as an industrial feedstock, noting its potential to replace fossil fuels in chemical manufacturing. Bauer et al. [61] analyze the climate impacts of blue hydrogen, highlighting the importance of considering lifecycle emissions when integrating hydrogen into industrial processes. Cummins [62] discusses advanced electrolyzer technologies that facilitate cost-effective hydrogen production, which could supply such industrial applications efficiently. Mohammed et al. [63] describe the challenges faced by Sub-Saharan Africa in developing renewable energy infrastructure, which could be harnessed for green hydrogen generation, thus reducing reliance on fossil-fuel-based hydrogen. Settou et al. [64] highlight geothermal sources as a sustainable hydrogen production method, offering region-specific opportunities for countries like Algeria. In the context of the schematic, integrating hydrogen feed into ammonia or fertilizer plants offers a pathway toward decarbonizing essential industrial processes. Hydrogen derived from renewable sources or low-carbon methods (blue or green hydrogen) can replace traditional natural gas or coal-based feedstocks, aligning with climate policies and energy transition strategies discussed across these references. This approach supports sustainable fertilizer production by reducing greenhouse gas emissions, which is particularly pertinent for regions aiming to develop resilient and environmentally friendly agricultural industries.

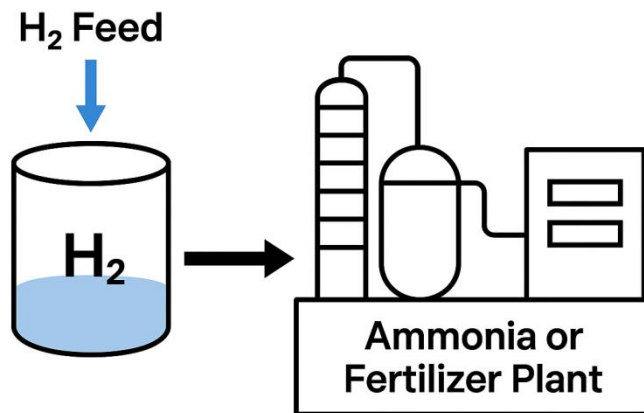


Figure 5: A schematic diagram showing integration of H₂ feed into an ammonia or fertilizer plant.

Table 4: Indicative low, medium, and high retrofit cost ranges for industrial hydrogen adoption based on literature and feasibility studies.

Industry Type	Current Energy Source	Required Retrofit	Complexity	Retrofit Cost (USD)	Estimated Annual H ₂ Demand (tpa)
Ammonia/Fertilizer Plant (SW/NC)	SMR + NG	Feed-line integration + compressors	Low	\$4–7 million	45,000–65,000

Petroleum Refinery (SS/SW)	Natural Gas + SMR H ₂	Hydrotreating pipeline integration	Medium	\$15–25 million	30,000–50,000
Cement Kiln (All Clusters)	Coal/NG	Burner retrofits + safety controls	High	\$40–60 million	15,000–35,000
Steel Rolling Mill (NW/SW)	Coke + NG	High-temp hydrogen burners	High	\$30–50 million	20,000–40,000
Glass/Metallurgy (NC/SW)	NG/Diesel	Furnace modification	High	\$10–20 million	5,000–10,000
Heavy Transport Fleets	Diesel	Fuel-cell conversion + refueling	Medium	\$2–10 million/cluster	3,000–8,000

Matching industrial demand with hydrogen availability shows that hybrid systems can serve 40–70% of aggregate cluster demand depending on the cluster size. The Lagos–Ogun and Port Harcourt–Warri clusters exhibit the highest uptake potential due to robust industrial portfolios. These findings align with Bain et al [57]’s earlier industrial-siting assessment which emphasized linking energy assets with energy-intensive clusters. Siew and Cheng [58]’s analyses of regional industrial parks similarly stress that shared infrastructure (pipelines, treatment, storage) can significantly reduce retrofit cost per plant. Lewis [59]’s prior work on heavy-industry transition strategies complements the findings by detailing the complexity of furnace conversions and the economic timelines required for technology adoption. The general trend is that hydrogen integration is economically and technically feasible for Nigerian industries, especially for process-feedstock applications. Heat-based retrofits remain more complex but feasible under phased rollouts.

Table 5. CAPEX Breakdown for a 50-MW Hybrid Hydrogen Plant

Component	Cost (\$ million)	% of Total
Solar PV (80 MWp)	56	28%
Hydropower Interconnection	12	6%
Electrolyser (50 MW)	45	23%
Hydrogen Storage (60 tons)	22	11%
Compression Unit	10	5%
Land Acquisition & Civil Works	15	8%
Electrical Balance of Plant	8	4%
Pipeline Connection to Cluster	20	10%
Water Treatment System	5	2%
Total CAPEX	193 million USD	100%

E. Uncertainty and Assumption Considerations

The techno-economic assessment presented in this study relies on a set of assumptions related to renewable resource availability, electrolyser capital costs, financing conditions, industrial demand growth, and retrofit requirements. These parameters are subject to uncertainty due to evolving technology costs, hydrological variability, market dynamics, and limited availability of plant-level data in the Nigerian context. To address this, the study employs scenario-based and parametric sensitivity analyses to evaluate the influence of key variables on electrolyser capacity factor and Levelized Cost of Hydrogen (LCOH). Rather than producing deterministic forecasts, the results should be interpreted as planning-level indicators that represent plausible cost and performance ranges under conservative and optimistic assumptions. The LCOH ranges reported therefore reflect uncertainty bounds associated with input variability, providing robust comparative insights across solar-only, hydro-only, and hybrid solar–hydropower configurations. The absence of confidential plant-level financial and operational data introduces uncertainty into industrial hydrogen demand and retrofit cost estimates. Consequently, the values reported in this study should be interpreted as planning-level approximations rather than detailed engineering design costs. Future work incorporating site-specific data would further refine these estimates.

IV. CONCLUSION

This study demonstrates that a hybrid solar–hydro green hydrogen strategy for Nigeria’s industrial clusters is technically feasible and economically attractive under plausible cost and financing assumptions. Hybrid configurations substantially improve electrolyser capacity factor and reduce LCOH compared to solar-only alternatives, while hydropower dispatch provides crucial seasonal and diurnal firming. Cluster-level deployment yields economies of scale in storage, pipelines and maintenance, accelerating cost reduction and enabling practical decarbonisation of high-emission industrial processes. The following are hereby recommended:

- (a). Pilot Projects & Regulatory Sandboxes: Launch 2–3 pilot hybrid hydrogen hubs (Lagos–Ogun and Port Harcourt recommended) with clear timelines, offtake commitments and concessional financing.
- (b). Financing Instruments: Establish blended finance facilities, with concessional public debt and risk guarantees to lower project WACC. Promote tax and duty incentives for electrolyser and electrolyser parts manufacturing.
- (c). Grid & Hydro Integration Protocols: Develop operational agreements to enable hydropower dispatch prioritization for hydrogen production during periods where it yields the greatest LCOH reduction.
- (d). Water Management: Require water audits and promote water recycling in electrolysis plants; where freshwater is limited, include reverse osmosis provisions and account for desalination energy in cost models.
- (e). Local Content & Skills: Invest in local manufacturing capabilities for balance-of-plant and electrolyser components, and create vocational programs for hydrogen technicians and safety managers.
- (f). Standards & Safety: Develop national hydrogen safety codes, pipeline standards, and hydrogen quality standards linked to industrial offtake requirements.
- (g). Cluster Planning: Encourage industrial parks to co-locate hydrogen offtake facilities early (e.g., ammonia, fertilizer plants) to ensure demand aggregation.
- (h). Research & Monitoring: Sponsor R&D in electrolyser adaptation for tropical climates and long-term demonstration monitoring (efficiency degradation, stack lifetime).

Implementing these recommendations will position Nigeria to decarbonize key industrial sectors, create domestic green jobs, and develop an exportable hydrogen value chain.

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Appendix

Appendix A: Standard Renewable Energy and Electrolysis Model Equations

Appendix A: Standard Renewable Energy and Electrolysis Model Equations

A1. Solar Photovoltaic Power Output Model

The electrical power output from the photovoltaic (PV) system was estimated using standard irradiance-based formulations widely adopted in the literature. The model accounts for incident solar irradiance, panel efficiency, temperature effects, and system losses.

$$G_t = G_{0,t} \cdot k_t \tag{1}$$

where

$G_{0,t}$ = extraterrestrial irradiance,

k_t = hourly clearness index computed from:

$$K_t = a + b \left(\frac{G_{month}}{G_{0,month}} \right) \tag{2}$$

PV Output is then:

$$P_{PV,t} = \eta^{PV} \cdot APV \cdot G_t \tag{3}$$

A2. Hydropower Generation Model

Hydropower output was computed using conventional formulations relating available hydraulic head, flow rate, water density, gravitational acceleration, and turbine–generator efficiency.

$$P_{hydro,t} = \eta_{tur} \rho g H \cdot Q_{release,t} \tag{4}$$

Reservoir mass balance:

$$S_{t+1} = S_t + Q_{inflow,t} - Q_{release,t} - E_t \tag{5}$$

A3. Electrolyser Efficiency and Hydrogen Production

Hydrogen production from water electrolysis was calculated using standard electrochemical relationships linking electrical input power, electrolyser efficiency, and the lower heating value of hydrogen.



Thus hydrogen required per tonne of ammonia:

$$H_{2,req} = 0.178 \text{ tonnes } H_2 / \text{tonne } NH_3$$

Thermal demand replacement by H_2 :

$$H_{2,heat} = \frac{E_{thermal}}{LHV_{H_2}} \tag{7}$$

where

$$LHV_{H_2} = 33.33 \text{ kWh/kg}$$

$$E_{elect} = \frac{1}{\eta_{elect}} [\text{kWh/kg}] \tag{8}$$

$$\eta_{elec}(t) = \eta_0 - d \left(\frac{t}{1000} \right) \tag{9}$$

where

d = degradation per 1000 operating hours.

Water requirement per kg H₂:

$$WH_2 = 9 \text{ kg H}_2\text{O per kg H}_2$$

If desalination is required:

$$E_{\text{desal}} = 3\text{--}5 \text{ kWh/m}$$

All equations and parameter definitions presented in this appendix are standard formulations and are provided for completeness and reproducibility.