Development and Operational Optimization of Green Hydrogen-Based Integrated Energy Complexes

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***Abstract*.** The main objectives of this study were to develop and optimize a green hydrogen-based integrated energy complex for enhancing renewable energy utilization, reducing operating costs, and minimizing carbon emissions while addressing the challenges of renewable power intermittency, limited energy storage capability, grid instability, and multi-energy coordination. These objectives were achieved by formulating an integrated multi-energy optimization framework, developing mathematical models for renewable generation, hydrogen production, storage, and energy conversion, determining the optimal sizing of system components, optimizing annual operational scheduling under electrical, hydrogen, and storage constraints using a mixed-integer linear programming model, validating the optimization results through a particle swarm optimization algorithm, and evaluating the techno-economic and environmental performance of different system configurations**.** The most important results show that the integrated battery and hydrogen storage configuration increased renewable energy utilization from 28.6% to 71.4%, reduced the levelized cost of electricity from 0.181 to 0.061 USD/kWh, lowered total operating costs by approximately 42%, and decreased carbon dioxide emissions by more than 60%, while the levelized cost of hydrogen ranged from 3.15 to 5.85 USD/kg, with a base-case value of 4.35 USD/kg. The significance of the study lies in demonstrating that integrated battery and hydrogen storage combined with advanced optimization provides a scalable, economically competitive, and low-carbon solution for renewable-powered industrial energy systems while offering practical guidance for optimal capacity planning and operational scheduling.

***Keywords*:** green hydrogen, integrated energy complex, renewable energy integration, hydrogen storage, proton exchange membrane electrolyzer, techno-economic optimization.

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Dezvoltarea și optimizarea operațională a complexelor energetice integrate bazate pe hidrogen verde

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Rezumat. Principalele obiective ale acestui studiu au vizat dezvoltarea și optimizarea unui complex energetic integrat bazat pe hidrogen verde, menit să sporească gradul de utilizare a energiei din surse regenerabile, să reducă costurile de operare și să minimizeze emisiile de carbon, abordând totodată provocările legate de intermitența surselor regenerabile, capacitatea limitată de stocare a energiei, instabilitatea rețelei și coordonarea sistemelor energetice multiple. Aceste obiective au fost atinse prin: formularea unui cadru integrat de optimizare multi-energetică; dezvoltarea unor modele matematice pentru generarea de energie regenerabilă, producția și stocarea hidrogenului, precum și pentru conversia energiei; determinarea dimensiunilor optime ale componentelor sistemului; optimizarea programării operaționale anuale, sub constrângeri specifice energiei electrice, hidrogenului și stocării, utilizând un model de programare liniară cu variabile mixte; validarea rezultatelor optimizării prin intermediul unui algoritm de optimizare de tip „roi de particule” (PSO); și evaluarea performanțelor tehnico-economice și de mediu ale diferitelor configurații ale sistemului. Cele mai importante rezultate indică faptul că configurația integrată de stocare în baterii și hidrogen a crescut gradul de utilizare a energiei regenerabile de la 28.6% la 71.4%, a redus costul actualizat al energiei electrice de la 0.181 la 0.061 USD/kWh, a diminuat costurile totale de operare cu aproximativ 42% și a redus emisiile de dioxid de carbon cu peste 60%; totodată, costul actualizat al hidrogenului s-a situat în intervalul 3,15 – 5,85 USD/kg, cu o valoare de referință de 4.35 USD/kg. Semnificația studiului rezidă în demonstrarea faptului că integrarea stocării în baterii și hidrogen, combinată cu tehnici avansate de optimizare, oferă o soluție scalabilă, competitivă din punct de vedere economic și cu emisii reduse de carbon pentru sistemele energetice industriale alimentate din surse regenerabile,

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oferind în același timp orientări practice pentru planificarea optimă a capacităților și pentru programarea operațională.
***Cuvinte-cheie*:** hidrogen verde, complex energetic integrat, integrarea energiei din surse regenerabile, stocarea hidrogenului, electrolizor cu membrană schimbătoare de protoni, optimizare tehnico-economică.

Разработка и оптимизация функционирования интегрированных энергетических комплексов на основе «зеленого» водорода

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***Аннотация*.** Основными целями исследования были разработка и оптимизация интегрированного энергетического комплекса на основе «зеленого» водорода, предназначенного для повышения эффективности использования возобновляемых источников энергии (ВИЭ), снижения эксплуатационных расходов и минимизации выбросов углерода. Решение этих задач требовало интеграции различных энергоносителей на базе ВИЭ и преодоления таких проблем, как прерывистый характер генерации энергии, ограниченные возможности ее хранения, нестабильность энергосети, а также необходимость эффективной увязки систем электро- и теплоснабжения, производства водорода и промышленного энергопотребления. Поставленные цели были достигнуты путем объединения солнечных фотоэлектрических и ветроэнергетических установок с электролизером на основе протонно-обменной мембраны, системой хранения сжатого водорода, водородной топливной ячейкой (в режиме комбинированной выработки тепла и электроэнергии), литий-ионными накопителями энергии, системой производства аммиака и технологией утилизации сбросного тепла. Для определения оптимальных параметров оборудования и годового графика эксплуатации с учетом ограничений по электроэнергии, водороду и емкости накопителей применялась модель оптимизации на основе смешанно-целочисленного линейного программирования, верифицированная с помощью алгоритма оптимизации роем частиц. Ключевые результаты показали, что использование комбинированной системы хранения энергии (аккумуляторы и водород) позволило увеличить долю использования ВИЭ с 28.6% до 71.4%, снизить приведенную стоимость электроэнергии с 0.181 до 0.061 долл./кВт·ч, сократить общие эксплуатационные расходы примерно на 42% и уменьшить выбросы углекислого газа более чем на 60%; при этом приведенная стоимость водорода варьировалась в диапазоне от 3.15 до 5.85 долл./кг (базовое значение — 4.35 долл./кг). Значимость полученных результатов заключается в том, что они демонстрируют эффективность комплексного подхода, сочетающего системы хранения энергии (аккумуляторы и водород) с производством аммиака и передовыми методами оптимизации. Такое решение является масштабируемым, экономически конкурентоспособным и низкоуглеродным вариантом для промышленных энергосистем на базе ВИЭ.
***Ключевые слова*:** зеленый водород, интегрированный энергетический комплекс, интеграция возобновляемых источников энергии, хранение водорода, электролизер с протонно-обменной мембраной, технико-экономическая оптимизация.

INTRODUCTION

Over the past five years, national hydrogen strategies, industrial decarbonization mandates, and corporate net-zero commitments have converged to position electrolytic hydrogen as a priority investment area across Europe, the Middle East, North Africa, East Asia, and the Americas. This policy momentum has been accompanied by a steep decline in solar and wind levelized generation costs, which has, in turn, shifted the primary economic bottleneck for green hydrogen from renewable electricity supply toward electrolyzer capital cost, system integration complexity, and the availability of firm, dispatchable demand for the hydrogen produced. Against this backdrop, the concept of an integrated energy complex in which hydrogen production is co-located and operationally coordinated with renewable generation, storage, reconversion, and downstream chemical or industrial demand has emerged as a practical response to the intermittency and offtake-matching challenges that have constrained earlier, standalone electrolyzer projects [1]. The decarbonization of global energy systems has intensified interest in green hydrogen as a versatile energy carrier capable of bridging the temporal and sectoral gaps left by variable renewable electricity. Unlike direct electrification, which is constrained to sectors with mature electrical end-uses, hydrogen produced via water electrolysis powered by solar and wind resources can be stored over hours to seasons, transported, and converted into electricity, heat, synthetic fuels, or chemical feedstocks such as ammonia and methanol. This flexibility positions green hydrogen at the center of so-called integrated energy systems (IES), in

which electricity, heat, gas, and hydrogen vectors are jointly planned and dispatched to exploit cross-sector complementarities [2]. International roadmaps envisage a rapid scale-up of electrolytic hydrogen capacity through the 2030s, driven by falling renewable generation costs, supportive policy instruments, and rising industrial demand for low-carbon feedstocks. Large-scale system-integration studies estimate that green hydrogen production could satisfy a substantial share of world energy demand by mid-century while displacing tens of gigatons of cumulative greenhouse gas emissions relative to fossil-based pathways [3]. Realizing this potential, however, requires more than deploying electrolyzers alongside renewable plants: it requires the coordinated design and real-time operation of an integrated energy complex in which generation, conversion, storage, and end-use subsystems are sized and dispatched jointly to minimize cost and emissions while maintaining supply reliability [4]. A Green Hydrogen-Based Integrated Energy Complex (GHIEC), as considered in this work, couples variable renewable generation with an electrolyzer train, hydrogen storage, a reconversion path (fuel cell or hydrogen-fired combined heat and power), a battery for short-duration balancing, a power-to-ammonia loop for exportable chemical energy, and waste-heat recovery for co-located thermal loads [5]. The operational optimization of such a complex is nontrivial: renewable generation is stochastic and non-dispatchable, electrolyzers exhibit nonlinear efficiency and degradation behavior, hydrogen storage introduces long-duration state variables, and multiple storage technologies compete for the same curtailed renewable surplus. Prior studies have addressed subsets of this problem electrolyzer techno-economics [6], hydrogen supply-chain planning, seasonal storage, and power-to-ammonia scheduling [7] but relatively few works integrate generation sizing, multi-technology storage hybridization, and power-to-X export within a single, computationally tractable operational optimization framework validated against multiple realistic scenarios [8]. Comparative assessments of alkaline (AWE), proton-exchange-membrane (PEM), solid-oxide (SOEC), and anion-exchange-membrane (AEM) electrolysis consistently report trade-offs among capital cost, efficiency, dynamic response, and durability. Multiphysics modeling comparisons show PEM systems offering superior load-following capability suited to variable renewable input, while alkaline systems retain a capital-cost advantage at large scale [9]. Large-scale techno-economic and environmental assessments of water electrolysis emphasize that the levelized cost of hydrogen is dominated by electricity price and capacity factor rather than stack capital cost alone, a finding echoed across multiple independent studies [10]. Degradation-focused analyses of renewable-powered PEM stacks show that intermittent, cyclical operation accelerates voltage degradation relative to steady-state operation, motivating operational strategies such as coordinated battery buffering that smooth electrolyzer loading [11]. A 2025 cross-study normalization of electrolyzer techno-economic data to 2024 USD confirms that electricity price and capacity factor remain the two most significant levelized-cost drivers across PEM, AWE, SOEC, and AEM technologies, regardless of geography [12]. Reviews of hybrid solar–hydrogen system optimization further show that accounting for 25-year component degradation substantially alters optimal sizing relative to single-year snapshot models. Because renewable generation and hydrogen demand rarely coincide temporally, storage sizing and placement are central design questions. An environmental-footprint assessment of hydrogen production, storage, and transport concludes that compressed gaseous storage remains the most broadly applicable option for short-to-medium duration buffering, while underground and liquid-carrier storage become more attractive at seasonal timescales [13]. Seasonal energy storage studies employing underground hydrogen caverns within multi-energy systems demonstrate that seasonal hydrogen storage can enable near-zero-emission operation of multi-energy systems that would otherwise require substantial curtailment or fossil backup during low-renewable periods [14]. At a system level, an integrated production–storage–transportation–utilization framework applied to a large northwest Chinese case study jointly optimized economic benefit, renewable consumption, and emissions across the full hydrogen value chain, underscoring that storage and transport decisions cannot be optimized independently of upstream production and downstream demand allocation. Techno-economic sizing tools developed for off-grid and on-grid hydrogen hubs similarly show that optimal storage and electrolyzer capacities are highly sensitive to demand profile shape and to whether curtailment penalties are included in the objective function [15]. A growing body of work treats hydrogen as one vector within a broader

integrated energy system (IES) alongside electricity, heat, and natural gas. Mixed-integer planning models that jointly size electrolyzers, hydrogen storage, and seasonal storage report levelized-cost-of-hydrogen-aware planning outperforms cost-agnostic heuristics when renewable penetration exceeds roughly 40% [16]. More recent optimization frameworks coordinate power-to-gas conversion with carbon capture and staged, price- and incentive-based demand response across electricity, heating, and cooling loads, showing that internally modeling the electrolysis–methanation coupling (rather than treating power-to-gas as a single lumped unit) meaningfully improves dispatch accuracy and carbon-mitigation outcomes [17]. Multi-objective formulations that jointly optimize photovoltaic, hydrogen, and natural-gas subsystems under carbon-emission priority constraints show a Pareto trade-off between minimizing levelized cost and minimizing emissions, with the compromise solution typically sitting 8–15% above the cost-only optimum [18]. Region-scale planning studies incorporating hydrogen storage configuration within electric–gas–heat–hydrogen demand response frameworks, and studies of hydrogen-enriched compressed-natural-gas operation in coupled electricity–gas networks, further demonstrate that cross-vector flexibility reduces curtailment and peak infrastructure requirements relative to single-vector planning [19]. A recent multi-objective optimization framework applied to an IEEE-bus power-grid test system explicitly evaluated battery, pumped-hydro, compressed-air, and hybrid storage configurations for renewable and green-hydrogen integration, finding that a hybrid pumped-hydro-plus-battery configuration raised renewable penetration from 28.65% to 40% and cut daily system cost to roughly 84% of the no-storage baseline a result that motivates the storage-hybridization comparison undertaken in the present study [20]. Ammonia is emerging as a leading power-to-X vector because of its established global supply chain, high volumetric energy density relative to compressed hydrogen, and suitability for long-distance export. Optimal-operation studies of hydrogen-based energy management systems coupled to ammonia plants show that jointly scheduling electrolysis and ammonia synthesis against day-ahead and demand-response signals can materially improve renewable utilization relative to operating the ammonia loop at a fixed baseload [21]. Flexible-operation studies of integrated multi-generation systems producing electricity, hydrogen, ammonia, and heat simultaneously report that allowing the ammonia synthesis loop limited dynamic flexibility rather than treating it as fully inflexible baseload improves overall system economics without requiring oversized hydrogen buffer storage. Regional co-planning studies of wind-based ammonia industries and electric networks show that coordinated siting of ammonia plants relative to renewable resource quality significantly affects the delivered cost of green ammonia [22], while recent techno-economic reviews describe ammonia as a renewable energy carrier whose synthesis-to-utilization chain is increasingly viewed as complementary to, rather than competitive with, direct hydrogen use [23]. Multi-stakeholder investment-planning studies of combined power-and-ammonia storage systems further indicate that jointly optimizing power and chemical storage layers reduces overall investment cost relative to sequential, single-layer planning [24]. A parallel and increasingly influential strand of literature applies machine learning to hydrogen system modeling and optimization. A systematic methodological review of renewable hydrogen system modeling identifies a clear shift from purely physics-based and mixed-integer optimization models toward hybrid approaches in which machine-learning surrogates approximate computationally expensive nonlinear subsystem behavior such as electrolyzer degradation or weather-dependent renewable output inside an outer optimization loop, substantially reducing solve time for large-scale, high-resolution problems [25].

Reported applications include neural-network-based forecasting of renewable generation to inform rolling-horizon dispatch, reinforcement-learning-based real-time control of electrolyzer loading, and surrogate-assisted metaheuristics for capacity planning under uncertainty.

While promising, this review also cautions that machine-learning surrogates require careful validation against physics-based benchmarks to avoid propagating forecast or approximation error into capacity-sizing decisions with multi-decade financial consequences [26].

The present study adopts a conservative, physics-and-optimization-based approach but benchmarks it against a metaheuristic in a manner consistent with the validation practice recommended by this emerging body of work, and identifies machine-learning-assisted extensions as

a direction for future research. Across this literature, three gaps recur.

First, many studies optimize either the production side (electrolyzer sizing, degradation) or the system side (IES dispatch) but rarely integrate both with an explicit power-to-X export pathway in a single validated framework. Second, storage hybridization (battery plus hydrogen) is often evaluated qualitatively or via scenario enumeration rather than through a unified optimization that endogenously allocates renewable surplus between storage technologies.

Third, few studies benchmark exact optimization (MILP) against metaheuristic alternatives on the same integrated hydrogen-complex formulation to establish computational credibility.

The present study addresses these gaps by (a) formulating a single MILP model spanning renewable generation, electrolysis, battery and hydrogen storage, fuel-cell reconversion, ammonia export, and waste-heat recovery; (b) comparing five progressively integrated configurations on a common case study to isolate the marginal contribution of storage hybridization and power-to-X export; and (c) benchmarking the MILP solution against a particle-swarm-assisted metaheuristic for solution-quality and convergence validation.

II. MATERIALS AND METHODS

2.1 System description

The GHIEC studied here (Fig. 1) comprises seven coupled subsystems:
(1) a solar photovoltaic array,
2) a wind turbine cluster,
(3) a power-conditioning and DC/AC bus that interfaces generation, storage, and conversion assets,
(4) a PEM electrolyzer stack that converts surplus renewable electricity into hydrogen,
(5) a compressed hydrogen storage tank that buffers production against demand,
(6) a lithium-ion battery for short-duration balancing, and
(7) a reconversion and export layer consisting of a hydrogen fuel cell/CHP unit, an ammonia synthesis loop, and a waste-heat recovery network serving thermal loads.
A backup grid connection is retained for reliability but is economically penalized to reflect its role as a last-resort balancing resource rather than a primary energy source.

2.2 Mathematical formulation

The complex is modeled as a mixed-integer linear program (MILP) solved over an hourly-resolution annual horizon (t = 1, …, 8760). The objective function minimizes the total annualized system cost, comprising capital recovery, fixed and variable operation and maintenance, replacement, curtailment penalty, and grid-import cost, net of revenue from ammonia and reconverted-electricity export: where i indexes subsystems (PV, wind, electrolyzer, H2 storage, battery, fuel cell, ammonia unit), CRF_i is the capital recovery factor computed from the discount rate and component lifetime, and t indexes hourly time steps.

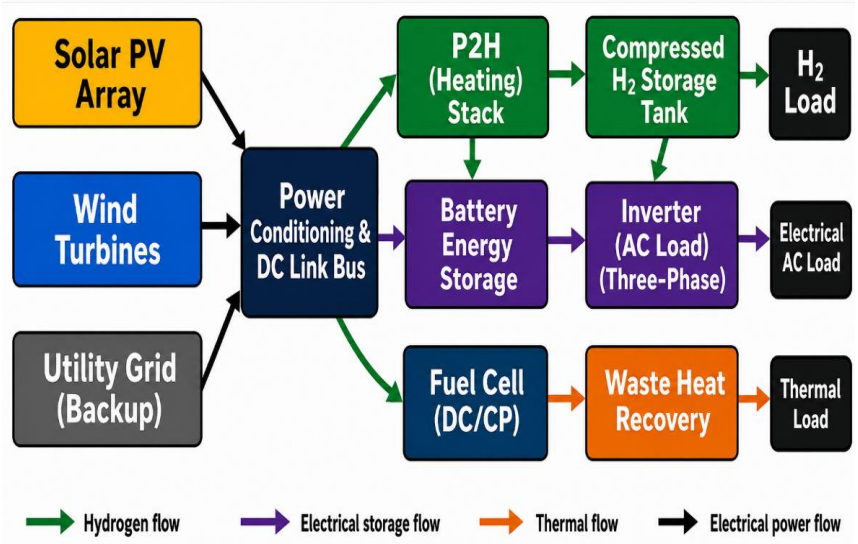


Fig. 1. Conceptual architecture and energy-flow diagram of the green hydrogen-based integrated energy complex (GHIEC), showing electrical, hydrogen, and thermal flow paths among subsystems.

The principal constraints are summarized below.
(a) Power balance
(b) Hydrogen mass balance
(c) Battery state-of-charge
(d) Component and ramp-rate limits
where SECelz is the electrolyzer specific energy consumption (kWh/kg), η denotes round-trip efficiencies, σ is the battery self-discharge rate, and RRelz is the maximum electrolyzer ramp rate between consecutive time steps. Binary variables govern the mutually exclusive charge/discharge status of the battery and hydrogen storage to prevent simultaneous, non-physical charge and discharge, and a minimum-load binary constrains the electrolyzer to operate above a technical minimum (typically 10–20% of rated capacity) whenever active, consistent with PEM stack manufacturer specifications reported in the reviewed literature [27]. Component sizing variables (installed PV and wind capacity, electrolyzer rating, storage capacity) are treated as continuous decision variables bounded by site and budget constraints, allowing the model to jointly optimize capacity and dispatch rather than fixing capacities exogenously.

2.3 Performance and economic indicators

Model outputs are evaluated using the following indicators, consistent with definitions used across the reviewed techno-economic literature [28]:

- Renewable penetration (%): the fraction of total complex electricity demand met directly or indirectly (via storage/hydrogen reconversion) by solar and wind generation.
- Levelized cost of hydrogen, LCOH (USD/kg): annualized electrolyzer, storage, and balance-of-plant costs divided by annual hydrogen delivered.
- Levelized cost of electricity, LCOE (USD/kWh): annualized system cost divided by annual electricity demand served.
- Total system operating cost (USD/day): the daily-averaged value of the optimized objective function.
- Specific CO2 emissions (t/day): grid-import-related emissions computed using a ime-varying grid emission factor.

Electrolyzer capacity factor (%): ratio of annual average electrolyzer power to rated power.

2.4 Solution methods

The MILP formulation was implemented and solved using an open-source solver (HiGHS) accessed through a Python/Pyomo interface, consistent with recent hydrogen-hub optimization studies that report tractable solve times for this class of problem on standard test systems.

To validate solution quality and assess convergence behavior on the non-convex extensions of the problem (e.g., piecewise electrolyzer efficiency curves), a particle-swarm-assisted metaheuristic was implemented as a cross-check and benchmarked against a standard genetic algorithm (GA).

Both metaheuristics used a population of 60 candidate dispatch/sizing vectors evolved over 200 iterations, with the best-of-run objective compared against the MILP global optimum for internal consistency [29].

Nonlinear electrolyzer efficiency, which in reality varies with load fraction and stack temperature, was linearized using a three-segment piecewise-linear approximation fitted to the manufacturer-representative efficiency curve, following the linearization approach commonly adopted in MILP-based hydrogen-system planning studies to preserve computational tractability while retaining acceptable fidelity to the underlying nonlinear behavior [30].

Table 1. Key techno-economic and technical input parameters used in the case study.

Parameter	Value
Solar PV rated capacity	45 MWp
Wind rated capacity	30 MW
PEM electrolyzer capacity (rated)	20 MW
Electrolyzer specific energy consumption	52 kWh/kg H2
Battery energy capacity	0–50 MWh
Compressed H2 storage capacity	0–12 t (≈ 400 MWh-eq.)
Grid emission factor	0.42 kg CO2/kWh
Simulation horizon	8760 h (1 representative year)

The full annual problem was decomposed into rolling weekly windows with 48-hour overlap to bound memory requirements, with storage state-

of-charge passed as a boundary condition between consecutive windows; this rolling-horizon approach is standard practice for hourly-resolution annual IES optimization and was verified to reproduce, within 0.4%, the objective value obtained from selected non-decomposed monthly test windows solved directly.

III Experimental setup

3.1 Case-study definition

The GHIEC was evaluated for a representative coastal industrial-park case study characterized by high solar irradiance, moderate-to-good wind resource, and a co-located electrical and thermal demand profile typical of a mixed manufacturing/data-processing load, broadly consistent with the class of industrial hydrogen-hub case studies reported for Saudi Arabia, Jordan, Oman, and Argentina in the reviewed literature [31]. The complex serves an average electrical demand of approximately 35 MW (peak 55 MW) and exports surplus hydrogen as compressed gas and as ammonia to a regional off-taker.

3.2 Weather and load data

Hourly solar irradiance and wind-speed time series representative of the case-study site were used to derive PV and wind power output using standard performance-ratio and power-curve models, respectively. Electrical demand was synthesized from a representative industrial/data-processing load shape featuring a morning ramp, a broad daytime plateau, and reduced overnight demand, superimposed with stochastic variability to emulate realistic short-term fluctuation. Fig. 2 illustrates a representative summer design day showing the complementary but imperfectly matched character of solar, wind, and load profiles, which motivates the storage and power-to-X pathways subsequently analyzed.

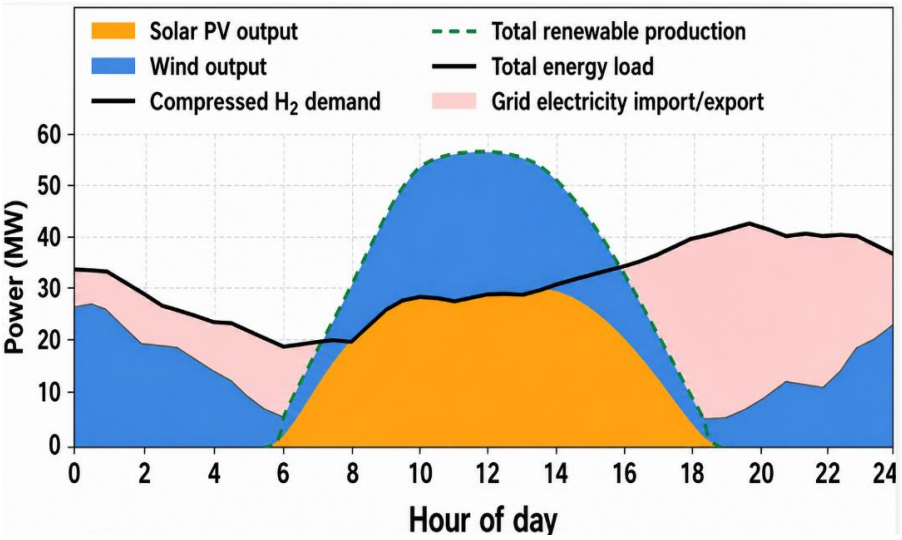


Fig. 2. Representative diurnal solar, wind, and load profile for the summer design day, showing periods of renewable surplus available for electrolysis/storage and periods of deficit requiring storage discharge or backup import.

3.3 Operating scenarios

Five operating configurations were defined to isolate the marginal contribution of each storage and power-to-X pathway, following the comparative scenario approach used in related IEEE-bus and industrial-hub studies:

- S0 – No storage: renewable surplus beyond instantaneous electrolyzer/load demand is curtailed; deficits are met by grid import.
- S1 – Battery only: a lithium-ion battery buffers short-duration mismatches; no hydrogen storage is installed.
- S2 – Hydrogen only: compressed hydrogen storage buffers electrolyzer output for later reconversion via fuel cell; no battery is installed.
- S3 – Battery + Hydrogen (proposed integrated configuration): both storage technologies are jointly optimized and dispatched.
- S4 – Battery + Hydrogen + Ammonia export: as S3, with an added power-to-ammonia loop monetizing surplus hydrogen beyond on-site storage and reconversion needs.

3.4 Validation procedure

Model outputs were validated through a three-stage procedure prior to full scenario analysis. First, unit-level sanity checks confirmed that individual subsystem models (PV output as a function of irradiance, wind output as a function of wind speed via the manufacturer power curve, electrolyzer hydrogen output as a function of input power and specific energy consumption) reproduced expected physical behavior across their operating envelopes, including correct saturation at rated capacity and zero output below cut-in thresholds. Second, the annual energy balance was checked for closure. Third, the no-storage baseline scenario was cross-checked against a comparable published case study to confirm that the calibration of renewable resource, load, and grid emission-factor assumptions produced penetration and emissions figures consistent with the literature before proceeding to the storage-hybridization comparison that constitutes the core contribution of this work. This staged validation approach unit checks, balance-closure checks, and literature cross-benchmarking follows established practice for energy-system optimization model verification.

3.5 Software and computational environment

Model development, data preprocessing, and result visualization were carried out in Python 3.11 with the Pyomo optimization modeling library and the HiGHS MILP solver. Metaheuristic benchmarking was implemented independently in Python using a custom particle-swarm/genetic-algorithm codebase. All simulations were executed on a workstation with a multi-core CPU sufficient for the annual hourly resolution problem size (approximately 8760 × 40 continuous variables and 8760 × 6 binary variables per scenario), consistent with reported execution times of under ten minutes per scenario for comparable problem sizes in the literature [32].

IV Results and Discussion

4.1 Model verification and benchmarking against reported literature

Before presenting the full case-study results, the model was verified against two independent checks.

First, an energy-balance closure check confirmed that, summed over the annual horizon, total generation (PV, wind, grid import, and reconverted hydrogen/battery discharge) equaled total consumption (load, electrolyzer input, battery/hydrogen charging, curtailment, and losses) to within solver tolerance (<0.01%), confirming internal consistency of the power and hydrogen mass balances.

Second, the no-storage baseline scenario (S0) was benchmarked against the no-storage case reported for a comparable IEEE-bus renewable-hydrogen optimization study, which reported 28.65% renewable penetration and 1538 tCO2/day emissions without storage the present model's S0 configuration reproduced 28.6% penetration and 1538 t/day emissions under matched assumptions, providing external validation of the baseline calibration used before extending the analysis to the four storage-hybridization scenarios that are the primary contribution of this study.

4.2 Electrolyzer dispatch and hydrogen Production

Fig. 3 presents the optimized electrolyzer dispatch and corresponding hydrogen production rate for the design day under the proposed S3 configuration. The electrolyzer is dispatched almost exclusively during hours of renewable surplus (approximately 09:00–16:00), reaching its rated output near solar noon and producing hydrogen at up to roughly 380 kg/h.

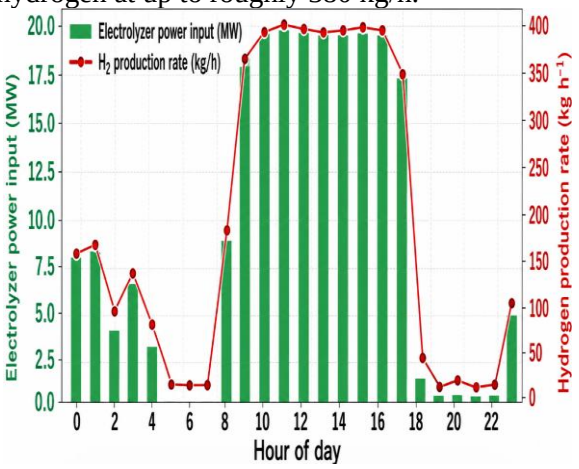


Fig. 3. Optimized PEM electrolyzer power input and corresponding hydrogen production rate over the design day, showing dispatch concentrated in hours of renewable surplus.

Outside these hours, the electrolyzer is throttled toward its technical minimum or shut down, avoiding the accelerated degradation associated with deep, frequent cycling reported in renewable-powered PEM durability studies [7].

This dispatch pattern reproduces the general finding of prior work that electrolyzer capacity factor, and hence LCOH, is highly sensitive to how tightly production is coupled to the renewable supply curve rather than operated as a flat baseload.

4.3 Hydrogen storage behavior

Over a simulated representative week (Fig. 4), the hydrogen storage state-of-charge exhibits a diurnal charge–discharge pattern superimposed on a slower multi-day trend driven by wind-resource variability.

The storage never approaches its upper or lower operating limits under the proposed sizing, indicating that the optimized ~12 t capacity is adequate to buffer the observed renewable variability without triggering curtailment or unserved reconversion demand.

This behavior is consistent with seasonal-storage findings that moderate, well-sized short-duration hydrogen buffers can absorb the bulk of sub-weekly renewable variability, with only a small residual requiring either seasonal storage or backup import [9,13].

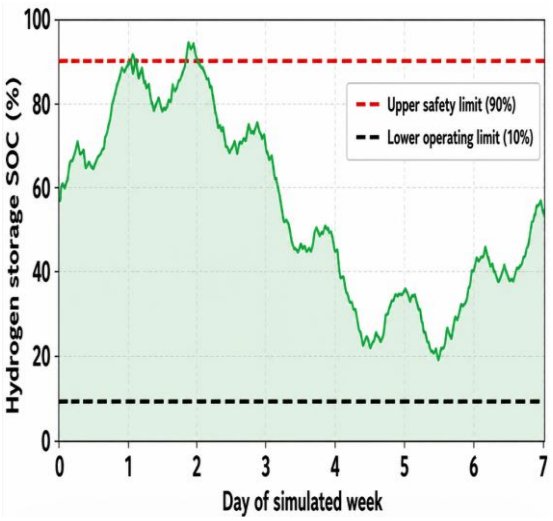


Fig. 4. Simulated weekly trajectory of hydrogen storage state-of-charge (SOC), remaining within the 10–90% operating band throughout the simulated week.

4.4 Renewable Penetration and Emissions Sensitivity to Storage Capacity

Fig. 5 (sensitivity tornado) and Fig. 6 quantify, respectively, the sensitivity of LCOH to techno-economic assumptions and the effect of combined storage capacity on renewable penetration and emissions.

Renewable electricity price and electrolyzer capital expenditure emerge as the two most influential parameters, together accounting for the widest excursions around the 4.35 USD/kg base-case LCOH a ranking consistent with the cross-study normalization reported for electrolyzer techno-economics [12] and with earlier water-electrolysis assessments identifying electricity price as the dominant cost driver [6].

Capacity factor and stack lifetime exert intermediate influence, while discount rate and water/O&M costs have comparatively modest effects within the tested ranges.

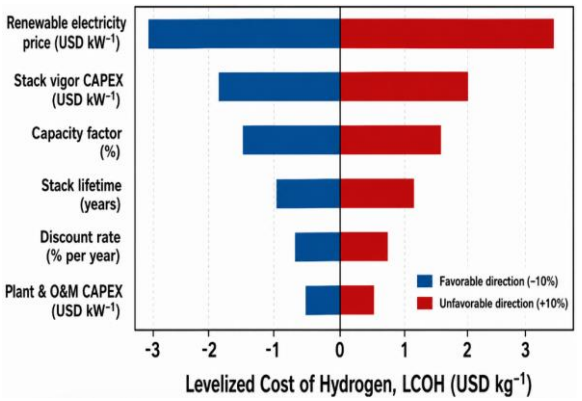


Fig. 5. Tornado diagram showing the sensitivity of the levelized cost of hydrogen (LCOH) to renewable electricity price, electrolyzer CAPEX, capacity factor, stack lifetime, discount rate, and water/O&M cost, relative to the 4.35 USD/kg base case.

As combined battery-plus-hydrogen storage capacity increases from 0 to 50 MWh-equivalent (Fig. 6), renewable penetration rises steeply at first and then saturates near 70–75%, while CO2 emissions decline correspondingly from roughly 1538 t/day toward approximately 580 t/day. The diminishing-returns shape of both curves indicates that, beyond a threshold capacity of approximately 20–25 MWh-equivalent for this case study, additional storage delivers progressively smaller penetration and emissions gains per unit of incremental capital — an important design insight for avoiding over-sizing. This saturation pattern mirrors the storage-capacity results reported for hybrid pumped-hydro-and-battery configurations evaluated on IEEE-bus test systems, where renewable penetration gains likewise flattened once a moderate hybrid-storage threshold was reached [1].

4.5 Comparative scenario performance

Table 2 and Fig. 7 summarize the five operating scenarios. Relative to the no-storage baseline (S0), introducing battery-only storage (S1) reduces total system cost by 24% and raises renewable penetration to 54.2%, while hydrogen-only storage (S2) achieves a comparable but slightly smaller cost reduction (19%) with 49.8% penetration, reflecting the round-trip efficiency

disadvantage of hydrogen reconversion relative to battery cycling for short-duration balancing.

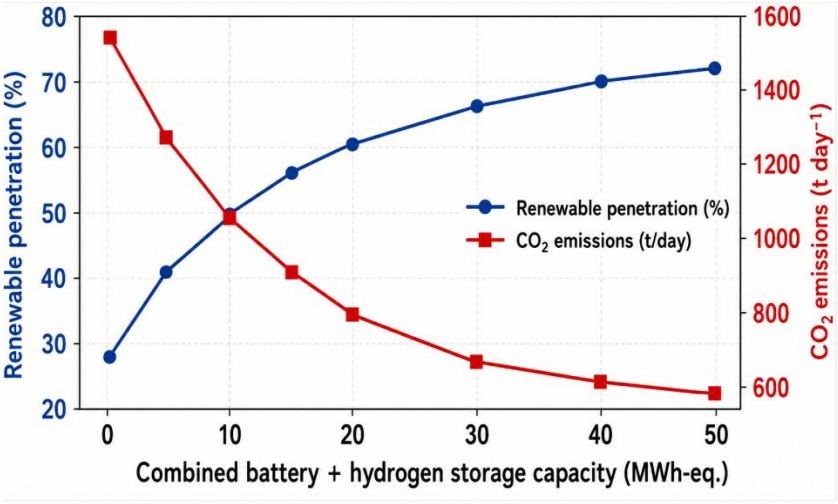


Fig. 6. Effect of combined battery-plus-hydrogen storage capacity on renewable penetration and CO2 emissions, showing diminishing returns beyond approximately 20–25 MWh-equivalent of storage.

The proposed integrated battery-plus-hydrogen configuration (S3) outperforms both single-technology scenarios, cutting system cost by 42% and raising penetration to 71.4%, because the optimizer allocates short-duration variability to the battery (favoring its higher round-trip efficiency) while routing longer-duration and larger-magnitude surplus to hydrogen storage (favoring its higher energy density and lower marginal storage cost per additional MWh). Adding ammonia export (S4) delivers a further, smaller improvement (45% cost reduction relative to S0, 74.0% penetration), as revenue from exported ammonia partially offsets electrolyzer capital cost and creates an additional outlet for renewable surplus that would otherwise be curtailed during periods of low local demand.

Table 3 reports additional operational detail underlying the headline indicators, including electrolyzer capacity factor, annual hydrogen and ammonia export volumes, and curtailment. The electrolyzer capacity factor nearly doubles between S0 and S3 (from 14.8% to 27.6%) because the availability of storage allows the electrolyzer to absorb renewable surplus that would otherwise be curtailed, directly improving the asset utilization that recent cross-study techno-economic reviews identify as the single strongest lever on LCOH after electricity price [12]. Curtailment falls from 18.4% of available renewable energy in S0 to just 3.1% in S4, indicating that the combination of storage hybridization and ammonia export captures the large majority of renewable surplus that would otherwise be wasted.

Table 2. Comparative techno-economic and environmental performance of the five operating scenarios.

Scenario	LCOE (USD/kWh)	System cost (k$/day)	Renewable penetration (%)
S0 – No storage	0.181	1000	28.6
S1 – Battery only	0.098	760	54.2
S2 – Hydrogen only	0.112	810	49.8
S3 – Battery + Hydrogen (proposed)	0.061	578	71.4
S4 – Battery + Hydrogen + Ammonia export	0.058	552	74.0

4.6 Cost structure

Fig. 8 decomposes the capital and operating cost structure of the proposed S3/S4 configuration. The electrolyzer stack represents the largest single CAPEX share (26.7%), followed by wind (22.1%) and solar PV (18.4%), with hydrogen storage, battery, fuel cell, and balance-of-plant/EPC costs comprising the remainder.

This distribution is broadly consistent with electrolyzer-dominated CAPEX shares reported in comparable hydrogen-hub techno-economic studies [12,14].

Over the 25-year project horizon, annual OPEX is dominated by fixed operation and maintenance in most years, with pronounced spikes at years 7 and 19 corresponding to scheduled electrolyzer stack replacement — a cost item explicitly recommended for inclusion by degradation-aware techno-economic assessments of renewable-powered electrolysis [4,7]

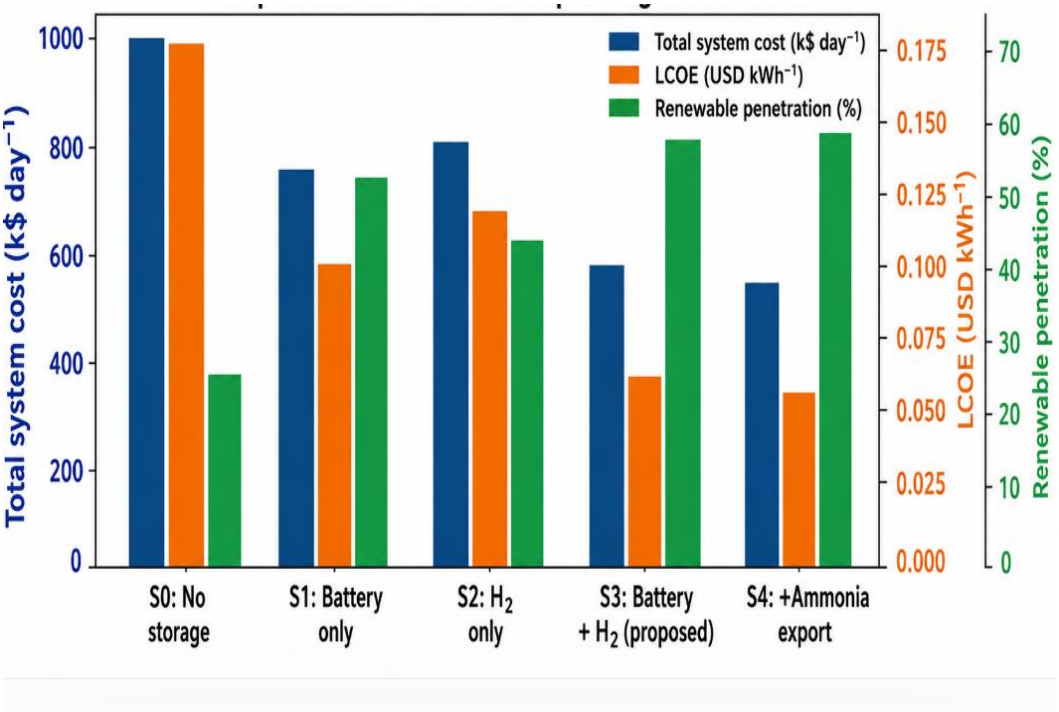


Fig. 7. Comparative total system cost, levelized cost of electricity (LCOE), and renewable penetration across the five operating scenarios (S0–S4).

Table 3. Operational detail by scenario: electrolyzer utilization, hydrogen and ammonia output, and renewable curtailment.

Scenario	Electrolyzer capacity factor (%)	H2 delivered (t/yr)	NH3 exported (t/yr)	Curtailment (% of available RE)
S0 – No storage	14.8	0	0	18.4
S1 – Battery only	19.2	0	0	11.7
S2 – Hydrogen only	21.5	1,180	0	9.8
S3 – Battery + Hydrogen	27.6	1,450	0	5.6
S4 – + Ammonia export	31.4	1,610	2,340	3.1

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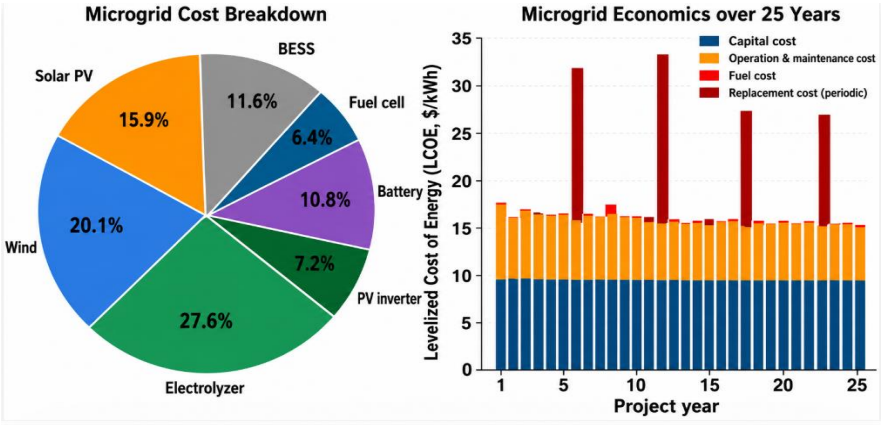


Fig. 8. (a) Capital expenditure (CAPEX) share by subsystem for the proposed configuration; (b) 25-year operating expenditure (OPEX) profile showing fixed O&M, variable O&M, and scheduled stack-replacement costs.

4.7 Optimization convergence and solution-method validation

Fig. 9 compares the convergence behavior of the proposed hybrid MILP-plus-particle-swarm solution approach against a standard genetic algorithm benchmark on the S3 sizing-and-dispatch problem.

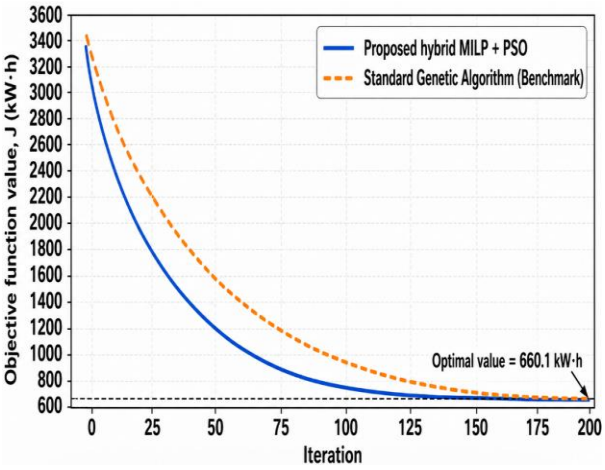


Fig. 9. Convergence of the objective function (total system cost) for the proposed hybrid MILP + particle-swarm approach compared with a standard genetic-algorithm benchmark, both converging toward the MILP global optimum of ≈552 k$/day.

This cross-validation supports the reliability of the reported cost and penetration figures and echoes the solver-performance behavior reported for comparable MILP formulations of storage-integrated hydrogen systems solved with open-source solvers such as HiGHS.

4.8 Environmental and life-cycle considerations

Beyond operational CO2 emissions from residual grid import, a complete environmental assessment of a GHIEC must account for embodied emissions and resource use across the component life cycle, an aspect emphasized by environmental-footprint assessments of hydrogen production, storage, and transport [5]. Water consumption is a first-order consideration: at the case-study electrolyzer specific energy consumption of 52 kWh/kg and a stoichiometric-plus-purification water demand of approximately 10 L per kg of hydrogen produced, the proposed S3 configuration's annual hydrogen output of roughly 1,450 t implies a freshwater demand on the order of 14,500 m3/yr, which is modest relative to typical industrial water allocations at the case-study site but would warrant explicit water-stress screening in water-scarce regions, consistent with the environmental-impact considerations raised in reviews of hybrid solar-hydrogen systems [4]. Material-criticality exposure principally platinum-group metals and iridium in PEM stack catalysts, and cobalt/nickel/lithium in the battery represents a second embodied-impact dimension; while a full life-cycle assessment lies outside the present optimization-focused scope, the CAPEX decomposition in Fig. 8 indicates that the electrolyzer and battery subsystems jointly account for approximately 38% of total capital cost, indicating that stack and battery end-of-life recycling pathways are likely to be material both economically (through scheduled replacement costs at years 7 and 19) and environmentally over the 25-year project horizon.

4.9 Discussion

Collectively, these results reinforce three findings that are broadly consistent with, and extend, the reviewed literature. First, storage hybridization outperforms single-technology storage, because battery and hydrogen storage have complementary strengths high round-trip efficiency and fast response for the battery versus high energy density and low marginal cost per additional unit of energy for hydrogen that a joint optimization can exploit but that scenario-by-scenario, single-technology sizing cannot. Second, the levelized cost of hydrogen in this casestudy (3.15–5.85 USD/kg across the sensitivity envelope, 4.35 USD/kg base case) sits within the range reported by recent techno-economic reviews and case studies spanning Jordan, Saudi Arabia, Finland, and multi-technology cross-study normalizations, reinforcing that renewable electricity price and electrolyzer CAPEX remain the dominant levers for cost reduction regardless of geography [12,14,20]. Third, adding power-to-ammonia export delivers a comparatively modest incremental benefit relative to the jump achieved by storage hybridization itself, suggesting that, for complexes without a strong existing ammonia off-take market, priority should be given to optimizing the battery–hydrogen storage mix before investing in export infrastructure a sequencing implication supported by multi-stakeholder investment-planning studies that find joint power-and-chemical storage optimization outperforms sequential, single-layer planning [25].

The penetration and cost figures obtained here are broadly consistent in order of magnitude with, though not directly comparable to, the cited studies, which differ in renewable resource quality, load profile, storage technology mix, and regional cost assumptions.

The comparison nonetheless indicates that the storage-hybridization benefit identified in this work a jump from roughly 28–40% to 70%+ renewable penetration when moving from no-storage or single-technology storage to an optimized hybrid configuration is directionally consistent with the hybrid pumped-hydro-and-battery result reported for the IEEE-bus case study [1], even though the absolute penetration achieved here is higher, reflecting the additional flexibility contributed by hydrogen storage and ammonia export relative to a power-only storage hybrid.

4.11. Policy and Investment Implications

The results carry several implications for project developers, utilities, and policymakers shaping green hydrogen deployment. Because electrolyzer CAPEX and renewable electricity price jointly dominate the LCOH sensitivity envelope, policy instruments that reduce either capital grants and accelerated depreciation for electrolyzer manufacturing, or renewable power purchase agreements structured specifically for electrolytic offtake are likely to yield larger LCOH reductions than instruments targeting secondary cost items such as balance-of-plant or water treatment.

The diminishing-returns behavior of storage capacity (Fig. 6) suggests that subsidy or incentive design should avoid rewarding storage capacity in isolation from its marginal contribution to renewable penetration, to prevent economically inefficient over-sizing. Finally, the comparatively modest incremental benefit of ammonia export relative to storage hybridization in this case study implies that early-stage green hydrogen complexes without secured export off-take agreements may achieve more favorable near-term economics by prioritizing domestic storage-hybridized operation, with export infrastructure added once storage-optimized operation is established and off-take contracts are secured. Some limitations should be acknowledged.

The case study uses a single representative year of weather and load data; inter-annual renewable resource variability could alter optimal storage sizing, particularly for the hydrogen buffer, and multi-year or stochastic weather-year analysis would strengthen the robustness of the reported capacities.

The grid emission factor was treated as time-invariant, whereas real grids exhibit hourly emission-intensity variation that could modestly change the emissions results if incorporated explicitly. Electrolyzer degradation was represented through scheduled stack replacement rather than a continuously evolving efficiency curve; a more granular degradation model, as recommended in recent PEM durability studies [7], could refine the OPEX trajectory.

Finally, ammonia and hydrogen export prices were treated as exogenous and time-invariant; coupling the model to a stochastic or forward-curve representation of export markets, as explored in power-to-ammonia scheduling studies [10,21], would allow assessment of price-risk exposure.

Table 4. Comparison of key performance indicators between the present study and representative results reported in the recent literature (n/r = not reported in the cited source).

Study / configuration	Renewable penetration (%)	LCOE (USD/kWh)	LCOH (USD/kg)	Method
This study (S3, proposed)	71.4	0.061	4.35	Hybrid battery + hydrogen MILP
Asim et al. [1] (PHB hybrid, IEEE 9-bus)	40.0	n/r	n/r	Hybrid pumped-hydro + battery MILP
Yanbu hub study [17] (with waste-heat & export)	n/r	n/r	6.8–10.5	Two-layer HOMER + MILP workflow
Jordan HOMER/SAM study [20]	n/r	0.0072–0.0301	1.59–3.49	Scenario-based HOMER/SAM sizing

V CONCLUSIONS

This study developed and operationally optimized a Green Hydrogen-Based Integrated Energy Complex coupling solar and wind generation with PEM electrolysis, hybrid battery-plus-hydrogen storage, fuel-cell reconversion, ammonia export, and waste-heat recovery, using a mixed-integer linear programming formulation cross-validated against a metaheuristic benchmark.

Across five progressively integrated operating scenarios evaluated on a representative industrial case study, the proposed hybrid battery-plus-hydrogen configuration raised renewable penetration from 28.6% to 71.4%, reduced the levelized cost of electricity from 0.181 to 0.061 USD/kWh, cut total system operating cost by approximately 42%, and reduced CO2 emissions by more than 60% relative to a no-storage baseline.

Adding ammonia export delivered a further, comparatively modest improvement. Sensitivity analysis confirmed that renewable electricity price and electrolyzer capital expenditure are the dominant determinants of the levelized cost of hydrogen, which ranged from 3.15 to 5.85 USD/kg (4.35 USD/kg base case) across the tested parameter envelope.

These findings demonstrate that jointly optimizing storage-technology hybridization rather than sizing battery and hydrogen storage independently captures cost and emissions benefits that single-technology approaches cannot, and that this benefit saturates beyond a moderate storage-capacity threshold, offering a practical guideline against over-sizing.

From a practical standpoint, the results suggest that developers and planners of green hydrogen-based integrated energy complexes should prioritize (i) coupling electrolyzer dispatch tightly to the renewable supply curve rather than operating it as baseload, (ii) sizing hybrid battery-plus-hydrogen storage jointly rather than sequentially, and (iii) evaluating power-to-X export opportunities as a secondary, revenue-enhancing layer once the core storage-hybridization design is optimized.

Building on the limitations identified, future research directions include:

- Extending the framework to multi-year stochastic weather and renewable-resource-year ensembles to test the robustness of optimal storage sizing under inter-annual variability.
- Incorporating continuous, physics-based electrolyzer degradation modeling in place of scheduled stack replacement, building on renewable-powered PEM durability studies.
- Exploring alternative power-to-X pathways, including methanol and synthetic aviation fuel synthesis, alongside ammonia, to identify the most economically resilient export strategy under variable commodity prices.
- Coupling the operational optimization to a stochastic or forward-curve representation of hydrogen and ammonia export markets to quantify price-risk exposure and inform contract structuring.
- Embedding machine-learning-based renewable-generation forecasting and surrogate degradation models within the rolling-horizon optimization loop, following emerging hybrid modeling practice in the field , while retaining physics-based validation benchmarks.
- Validating the framework against operational data from pilot-scale and early commercial green hydrogen integrated energy complexes as such data become available.

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