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Research Article

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Posted Date: November 12th, 2026

DOI: https://doi.org/10.21203/rs.3.rs-11238794/v1

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Additional Declarations: No competing interests reported.

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Abstract

Comparing battery and green hydrogen storage requires a common energy boundary and consistent component-cost provenance, particularly when planning renewable-energy infrastructure. This study evaluates both pathways for a representative 24-h photovoltaic generation and demand profile in Nusantara Capital City, Indonesia. A year-specific representative-day dispatch model for 2024–2046 includes photovoltaic degradation, battery state of charge and replacement, electrolysis, hydrogen compression and storage, fuel-cell reconversion, and lifecycle costs. Delivered electricity, curtailment, and levelized cost of storage (LCOS) were assessed under mixed-vintage, monetary-normalised, and provenance-locked economic scenarios, followed by break-even analysis. In 2024, battery storage delivered 206.08 kWh/day, compared with 174.08 kWh/day from hydrogen, while curtailment was 437.82 and 151.45 kWh/day, respectively. Mixed-vintage LCOS favoured batteries (IDR 4,581.41/kWh versus IDR 8,105.05/kWh). Under provenance-locked assumptions, the ranking reversed (IDR 10,498.69/kWh for batteries versus IDR 8,947.97/kWh for hydrogen), with battery-capital-cost parity near USD 292.97/kWh at the baseline electrolyser CAPEX. The findings establish that technology rankings depend on storage service and documented economic inputs rather than being universal. These conditional thresholds provide decision evidence relevant to Sustainable Development Goal 7 on clean-energy

systems and Goal 9 on sustainable infrastructure, without measuring progress towards either goal or seasonal storage performance.

Keywords: battery energy storage; green hydrogen; levelized cost of storage; break-even analysis; techno-economic assessment; cost provenance

1 Introduction

Increasing penetration of variable renewable energy (VRE) creates a temporal mismatch between electricity generation and demand. Electricity storage can mitigate this mismatch by absorbing renewable surplus and returning energy when generation is insufficient, but the economic value of a storage technology depends on the service it provides, its conversion efficiency, storage duration, utilisation, lifetime, and replacement pattern. Consequently, comparisons based only on installed capital cost can be misleading. The levelized cost of storage (LCOS) is a lifecycle metric that relates discounted storage-pathway costs to useful electricity delivered and has been widely used to compare technologies with different cost and performance structures [1,2]. Related work on PV-storage economics has likewise shown that the cost of electricity delivered through storage should be distinguished from generation LCOE [3].

The comparison also has a sustainability-planning dimension. Sustainable Development Goal (SDG) 7 addresses renewable-energy deployment and clean-energy investment, while SDG 9 concerns resilient, resource-efficient infrastructure and the adoption of cleaner technologies [16,17]. For solar-dominant urban power systems, comparing how competing storage pathways absorb otherwise-curtailed electricity and return usable electricity can inform infrastructure appraisal relevant to these goals. However, storage LCOS alone does not measure household affordability, carbon emissions, or progress against SDG indicators.

Battery systems and hydrogen power-to-power systems represent fundamentally different storage pathways. Batteries typically provide high round-trip efficiency and are well suited to frequent intraday cycling, whereas a hydrogen pathway converts electricity to hydrogen through electrolysis, stores the

hydrogen, and reconverts it through a fuel cell. The additional conversion stages reduce electricity-return efficiency but allow energy and power capacities to be decoupled more readily, which can be advantageous at longer storage durations. Comparative optimisation studies therefore show no universal technology ordering. Crespi et al. found that battery storage remained competitive over a broad range of renewable self-generation levels, while hydrogen gained value as medium- and long-term shifting requirements increased [4]. Marocco et al. similarly showed that hydrogen can avoid costly oversizing in highly renewable systems where long-duration balancing is required [5]. System-level analyses of long-duration storage also demonstrate that energy-capacity cost and discharge efficiency are decisive performance parameters [6].

Although prior energy-system studies establish that storage duration and system configuration affect comparative economics [4–6], their conclusions cannot be transferred directly to a single representative-day application. For sustainability-oriented investment appraisal, economic comparisons also need to distinguish the monetary vintage and equipment scope of each cost input; otherwise, apparent progress towards lower-cost renewable integration may depend on inconsistent assumptions rather than demonstrated system performance.

These findings highlight a methodological problem in battery-hydrogen comparisons: the storage technologies must be evaluated under a common functional boundary. Different assumptions regarding the renewable surplus available for charging, charging-electricity cost, usable battery capacity, hydrogen compression, storage inventory, reconversion efficiency, and component replacement can change the LCOS denominator as well as the lifecycle cost numerator. LCOS is therefore application-specific rather than an intrinsic property of a technology [1,2].

A second comparability problem concerns the provenance of economic inputs. Published component costs may refer to different currencies, reference years, geographic markets, technology vintages, and equipment scopes. A battery value may represent a cell, pack, or installed system, whereas a hydrogen cost may or may not include compression, storage vessels, water treatment, balance-of-plant equipment, and component replacement. Directly combining such inputs can create an apparently precise cost

comparison that is not economically harmonised. This issue is particularly important when the two pathways have different numbers of capital components and replacement events.

The present study addresses these comparability issues using a case-study PV-load dataset for Nusantara Capital City, Indonesia. The dataset contains an hourly 24-h PV generation profile and an hourly electricity-demand profile. Rather than treating the hydrogen and battery configurations as separate calculations with different energy boundaries, this study reconstructs both pathways against the same hourly solar surplus and deficit. The technical reconstruction applies PV degradation before the load subtraction, explicitly models battery state of charge, hydrogen production and compression, cyclic tank inventory, fuel-cell reconversion, and component lifetime. The resulting storage service is then evaluated using incremental LCOS over a 23-year operating horizon.

The economic analysis is intentionally performed in three stages. First, a mixed-vintage reconstructed scenario preserves the baseline component-cost compilation while correcting the technical and lifecycle accounting. Second, historical source costs are rebased to a common 2024 monetary basis. Third, a provenance-locked scenario corrects the documented source and currency conventions for key hydrogen components while retaining the same technical dispatch. This separation distinguishes technical-model effects from monetary harmonisation and source-provenance effects.

The study addresses three research questions. RQ1 asks how battery and green hydrogen storage pathways compare in hourly energy utilisation, delivered electricity, curtailment, and lifecycle storage cost under a common solar-surplus boundary. RQ2 asks which technical and economic parameters determine break-even conditions between the two storage pathways. RQ3 asks to what extent harmonising component-cost provenance, currency, and monetary reference year affects the relative economic ranking. Collectively, these questions aim to provide transparent, bounded evidence for renewable-storage investment decisions relevant to SDG 7 and sustainable-infrastructure appraisal under SDG 9 [16,17].

The contribution is therefore not a claim that either technology is intrinsically superior. Instead, the study provides a common-boundary hourly reconstruction, lifecycle LCOS with explicit replacement logic, a cost-provenance audit, and break-even boundaries that identify when the economic ordering

changes. This framing is intended to support transparent storage planning under uncertain technology costs and limited temporal data. This planning relevance is assessed through energy utilisation and lifecycle cost rather than through direct estimation of SDG attainment.

2 Methods

2.1 Research design and analytical framework

The study uses a comparative techno-economic modelling design. Battery storage and green hydrogen storage are simulated as independent alternatives supplied by the same PV-load profile; the two pathways are not operated simultaneously in a hybrid system. Both pathways receive the same hourly upstream solar surplus and are evaluated against the same hourly deficit. The technical outputs are then annualised using a representative-day approach for each operating year from 2024 to 2046. Figure 1 summarises the case-study inputs, technical assumptions, lifecycle parameters, and variables examined in sensitivity and break-even analysis.

(a) Case-study inputs

PV generation profile	**24 h**
Electricity-demand profile	**24 h**
Gross PV-load surplus	**721.98 kWh/day**
Battery technical capacity	**576 kWh**
Electrolyser rated power	**80 kW**
Fuel-cell rated power	**11 kW**

(b) Technical assumptions

PV degradation	**1%/year**
Battery degradation	**3.5%/year**
Battery round-trip efficiency	**80%**
Electrolyser SEC	**55 kWh/kg-H_2**
Compressor electricity	**2.23 kWh/kg-H_2**
Fuel-cell efficiency	**55% LHV**
H_2 storage duration	**1 day**

(c) Economic and lifetime inputs

Analysis period	**2024-2046**
Project life	**23 years**
WACC	**9.7%**
O&M escalation	**4%/year**
Battery replacement interval	**5 years**
Battery replacement cost	**60% initial CAPEX**
EL / FC lifetime	**60,000 / 40,000 FLH**

(d) Sensitivity and break-even variables

Battery CAPEX	**varied**
Electrolyser CAPEX	**varied**
Electrolyser SEC	**varied**
Fuel-cell efficiency	**varied**
Hydrogen tank cost	**varied**
Storage duration	**varied**
WACC	**varied**

Fig. 1 Model inputs, technical assumptions, economic parameters, and sensitivity variables.

Note: Case-study inputs use a 24-h PV and load profile supplied for the Nusantara Capital City case. The economic scenarios differ in cost treatment; the technical dispatch equations are otherwise unchanged.

2.2 Case-study data and temporal representation

The source dataset comprises one 24-h PV generation profile and one 24-h electricity-demand profile. The undegraded profile produces a gross positive PV-load surplus of 721.98 kWh/day. The analytical horizon begins in 2024 and covers 23 operating years through 2046. PV degradation is applied to the PV output before subtracting load, rather than to an already calculated surplus. With a 2022 source-profile base year and 1% annual PV degradation, the reconstructed positive surplus in 2024 is 695.41 kWh/day.

For each calendar year, the degraded 24-h PV profile is paired with the fixed 24-h demand profile and dispatched hourly. Daily technical results are multiplied by 365 to construct annual energy quantities. The model is therefore a year-specific representative-day hourly model, not an 8,760-h chronological annual simulation. Recent site-specific hydrogen studies have likewise used 24-h dynamic assessment to resolve intraday interactions [14], but such a temporal representation should not be interpreted as seasonal validation. It captures intraday power limits, state transitions, and conversion losses but cannot represent seasonal renewable variability, prolonged multi-day deficits, or inter-day storage carry-over beyond the imposed cyclic condition.

2.3 Common solar-surplus boundary

For hour h in operating year t, the same upstream surplus and deficit are supplied to both storage alternatives:

$$P_{sur,t,h} = \max(P_{PV,t,h} - P_{load,t,h}, 0)$$

$$P_{def,t,h} = \max(P_{load,t,h} - P_{PV,t,h}, 0)$$

This common boundary is essential because a storage comparison is biased if one technology is allowed to charge from a different quantity of renewable surplus than the other. The zero-opportunity-cost baseline assumes that positive PV surplus would otherwise be curtailed. The implication of this assumption is examined in the limitations.

2.4 Battery-storage model

The battery alternative uses a 576-kWh technical capacity with an operating state-of-charge (SOC) window from 50% to 90%, giving 230.4 kWh of usable internal energy when new. The battery power limit is represented using a C-rate of 0.36 h^-1. Round-trip efficiency is 80%; for hourly accounting, charge and discharge efficiencies are split symmetrically as the square root of round-trip efficiency, giving approximately 89.44% for each direction. The incremental storage state is initialised at the lower SOC bound.

Battery usable capacity declines by 3.5% per operating year. A replacement is scheduled every five operating years, at which point technical age is reset. The replacement cost is 60% of initial battery CAPEX. During each hour, charge input is limited by available surplus, charging power, and remaining usable SOC. Discharge is limited by hourly deficit, discharging power, and stored internal energy. Any remaining positive surplus is classified as curtailed energy, while any remaining deficit is classified as unmet deficit. The battery assumptions are consistent with the case configuration and the 80% VRLA reference round-trip efficiency reported by IRENA [7].

2.5 Green hydrogen storage model

The hydrogen pathway consists of an 80-kW electrolyser, compressor, compressed-hydrogen tank, and 11-kW fuel cell. The electrolyser specific electricity consumption (SEC) is 55 kWh/kg-H2. Hourly hydrogen production is therefore the electrolyser electricity input divided by SEC. The source configuration also reports a daily electrolyser energy requirement of 564.44 kWh/day; in the reconstructed dispatch, actual hourly electrolyser use is constrained by the common PV surplus and the 80-kW power limit.

Compression electricity is represented using 2.23 kWh/kg-H2, adopted from the U.S. Department of Energy H2A/HDSAM estimate as a conservative high-pressure compression proxy [8]. The cited DOE value is associated with compression for a 440-bar fill from a 20-bar source condition; it is used here as an electricity proxy for the high-pressure storage pathway rather than as an exact 20-to-350-bar

thermodynamic calculation. At the nominal electrolyser mass flow of 1.4545 kg-H2/h, this corresponds to approximately 3.244 kW of compressor power.

The baseline storage duration is one representative day. Tank capacity is expressed in kg-H2 rather than electrical kWh and is sized at approximately 9.976 kg-H2. The tank-cost proxy is based on NREL's Type-1 compressed-hydrogen storage estimate for the 200-350 bar range [9]. The proxy represents uninstalled vessel cost and therefore does not independently capture site-specific installation, permitting, or additional balance-of-plant costs.

2.6 Cyclic hydrogen inventory and fuel-cell reconversion

Because the temporal model repeats one representative day, the hydrogen inventory is constrained to a cyclic daily condition. The opening inventory is solved such that end-of-day hydrogen mass equals the opening mass for each year:

$$M_{H2,end,t} = M_{H2,start,t}$$

This condition prevents the representative day from creating or destroying hydrogen inventory when annualised. Fuel-cell electricity yield is calculated on a lower-heating-value basis using 33.3 kWh/kg-H2 and 55% electrical efficiency, giving 18.315 kWh/kg-H2. Hourly fuel-cell electricity is limited by the 11-kW rated power, hourly electrical deficit, and available tank inventory.

2.7 Component lifetime, degradation, and replacement

The lifecycle model distinguishes calendar degradation from utilisation-based component life. The electrolyser stack lifetime is 60,000 full-load hours (FLH), the fuel-cell system lifetime is 40,000 FLH, and compressor lifetime is 25 years. Cumulative operating hours are tracked from hourly dispatch. A replacement event is triggered when cumulative FLH crosses the applicable lifetime threshold. The compressor requires no replacement within the 23-year horizon. Battery degradation age is reset after each scheduled battery replacement.

2.8 Lifecycle economic analysis

Economic comparison uses incremental LCOS rather than retail tariff or total-system PV levelized cost of electricity. PV generation is treated as an upstream existing resource, so PV plant CAPEX and O&M are outside the storage-pathway boundary. The LCOS for storage pathway s is:

$$LCOS_s = [C0,s + \text{sum_t}((C_O\&M,s,t + C_rep,s,t + C_charge,s,t)/(1+r)^t)] \,/\, [\text{sum_t}(E_del,s,t/(1+r)^t)]$$

where C0 is initial storage-pathway CAPEX, C_O&M is annual operation and maintenance cost, C_rep is replacement expenditure, C_charge is charging-electricity opportunity cost, E_del is electricity delivered from storage, r is WACC, and t is the operating year. Initial CAPEX is incurred at t = 0. The baseline WACC is 9.7%, annual O&M escalation is 4%, and charging opportunity cost is zero because the PV input is treated as otherwise-curtailed surplus. The LCOS formulation follows the application-specific lifecycle logic emphasised in the LCOS literature [1,2].

2.9 Economic input scenarios and cost-provenance treatment

Three economic scenarios are reported. The mixed-vintage reconstructed scenario preserves the baseline case-study component costs while applying the corrected technical dispatch and lifecycle logic. It therefore serves as a reconstruction benchmark rather than a harmonised market-cost estimate.

The monetary-normalised scenario rebases historical literature values to a common 2024-U.S.-dollar basis using U.S. Consumer Price Index ratios. For example, the IRENA central 2016 VRLA value of USD 263/kWh is rebased to approximately USD 343.74/kWh in 2024 dollars [7,10]. Monetary rebasing is strictly an inflation adjustment; it is not a forecast of market price or technology learning.

The provenance-locked scenario retains the same technical dispatch and monetary-normalisation framework but makes the currency and source basis of key hydrogen-component proxies explicit. For the fuel cell, EUR 3,000/kW is treated as a 2021 literature-vintage stationary fuel-cell CAPEX proxy, corresponding to the upper end of the large-scale stationary range reported by Yue et al. [15]. Because the modelled unit is 11 kW, this value is used as a transferable literature proxy rather than a size-specific vendor quotation. The compressor proxy of EUR 1,600/kW is traceable to Crespi et al. through the OECD

methodology, which also specifies 1% annual O&M and a 25-year lifetime [4,11]. Both euro-denominated proxies are converted using an average 2021 exchange rate of approximately USD 1.183/EUR [13] and rebased to 2024 dollars. This yields 2024-dollar proxies of approximately USD 4,108.48/kW for the fuel cell and USD 2,191.19/kW for the compressor. The original equipment quotation year behind the transferred literature values is not independently documented; publication year is therefore used transparently as the monetary-vintage proxy.

Electrolyser sensitivity bounds are interpreted against IRENA's reported cost ranges, including approximately USD 650-1,000/kW around 2020 and substantially lower long-term values under large-scale deployment [12]. The baseline SEC of 55 kWh/kg-H2 is retained from the case configuration, with sensitivity informed by IRENA efficiency benchmarks [12].

2.10 Sensitivity and break-even analysis

One-way sensitivity analysis varies battery CAPEX, electrolyser CAPEX, electrolyser SEC, fuel-cell efficiency, hydrogen-vessel cost, storage duration, and WACC. In addition, a two-dimensional break-even surface is calculated for battery CAPEX and electrolyser CAPEX. The break-even condition is defined by equality of pathway LCOS. Positive values of H2 LCOS minus battery LCOS indicate lower battery LCOS; negative values indicate lower hydrogen LCOS. The final two-dimensional map is calculated under the provenance-locked economic scenario so that the switching boundary is consistent with the paper's final cost-provenance treatment.

2.11 Model verification and scope of inference

The reconstruction was verified using internal mass- and energy-balance checks, end-of-day SOC and hydrogen-inventory residuals, annual aggregation checks, and independent recalculation of headline LCOS values from discounted lifecycle cost and discounted delivered electricity. The model reproduces the source gross daily surplus of 721.98 kWh/day before degradation and yields a 2024 degraded surplus of 695.41 kWh/day after applying degradation to PV output.

The model is intended to evaluate intraday solar-surplus storage and economic switching conditions. Because it lacks a measured 8,760-h chronology, no conclusion is drawn about seasonal adequacy or the general superiority of long-duration hydrogen storage. Studies using multi-year or interconnected representative-period methods show that hydrogen can become increasingly valuable when seasonal balancing and renewable oversizing are represented explicitly [5,6].

3 Results

3.1 Hourly solar-surplus reconstruction and storage dispatch

After applying two years of 1% annual PV degradation from the 2022 source profile, the 2024 representative day contains 695.41 kWh of positive PV-load surplus. The same surplus is supplied independently to the battery and hydrogen pathways. Figure 2(a) shows the degraded PV generation and load profile, while Fig. 2(b) shows electricity returned by each storage pathway. The battery and fuel-cell traces therefore represent alternative simulations rather than simultaneous operation.

The battery delivered 206.08 kWh/day to the load in 2024. The hydrogen pathway delivered 174.08 kWh/day, so the battery returned approximately 18.4% more electricity. Conversely, the hydrogen pathway absorbed substantially more of the available solar surplus. Battery curtailment was 437.82 kWh/day, whereas hydrogen curtailment was 151.45 kWh/day. The hydrogen pathway used 522.77 kWh/day in the electrolyser, produced 9.505 kg-H2/day, consumed 21.20 kWh/day for compression, and drew 543.96 kWh/day across the electrolyser-compressor train.

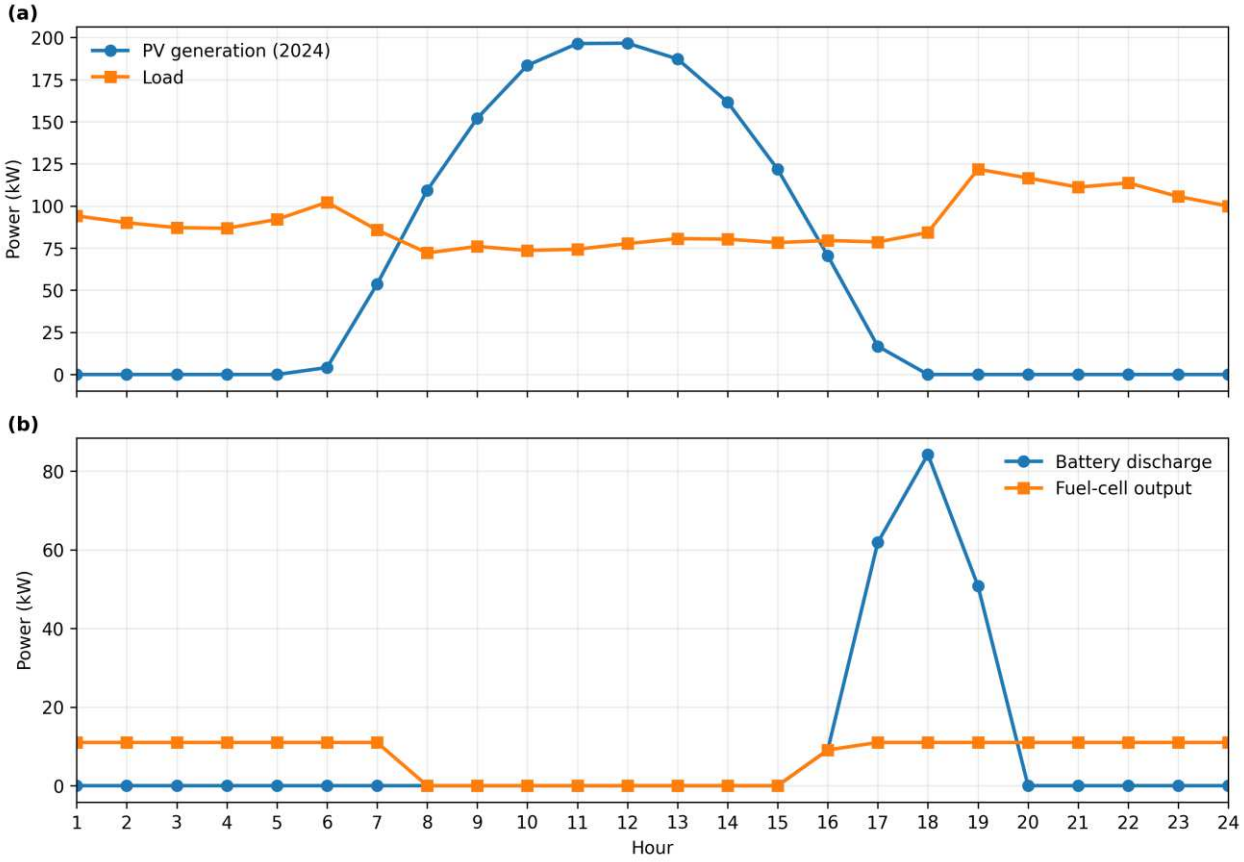


Fig. 2 Representative-day PV, load, battery discharge, and fuel-cell output in 2024.

Note: Battery discharge and fuel-cell output are independently simulated alternatives supplied by the same PV-load profile; they are not simultaneous outputs from one hybrid system.

3.2 Lifecycle operation and component replacement

Across the 23 operating years, electrolyser utilisation accumulates to approximately 51,180 FLH, below the assumed 60,000-FLH stack lifetime; no electrolyser replacement is therefore triggered. Fuel-cell utilisation reaches approximately 123,948 FLH, exceeding the 40,000-FLH lifetime three times and triggering three replacement events. The 25-year compressor lifetime exceeds the project horizon, so no compressor replacement occurs. Battery replacement follows the fixed five-year schedule, with technical degradation age reset after each replacement.

3.3 Lifecycle LCOS across economic scenarios

Under the mixed-vintage reconstructed scenario, discounted lifecycle cost is IDR 2.942 billion for the battery pathway and IDR 4.525 billion for the hydrogen pathway. Discounted delivered electricity is 642,091 kWh for the battery and 558,264 kWh for hydrogen. The resulting LCOS values are IDR 4,581.41/kWh and IDR 8,105.05/kWh, respectively.

Monetary normalisation changes the relative ordering. With historical source costs rebased to a common 2024-dollar basis, battery LCOS rises to IDR 10,498.69/kWh and hydrogen LCOS is IDR 8,545.21/kWh. After the fuel-cell and compressor cost provenance and currency conventions are corrected, the provenance-locked hydrogen LCOS becomes IDR 8,947.97/kWh, while the battery remains IDR 10,498.69/kWh. Under this final scenario, the hydrogen LCOS is IDR 1,550.72/kWh lower than the battery LCOS. Figure 3 shows the three scenario pairs. The ranking change reflects economic-input treatment; the technical dispatch itself is unchanged between the normalised and provenance-locked scenarios.

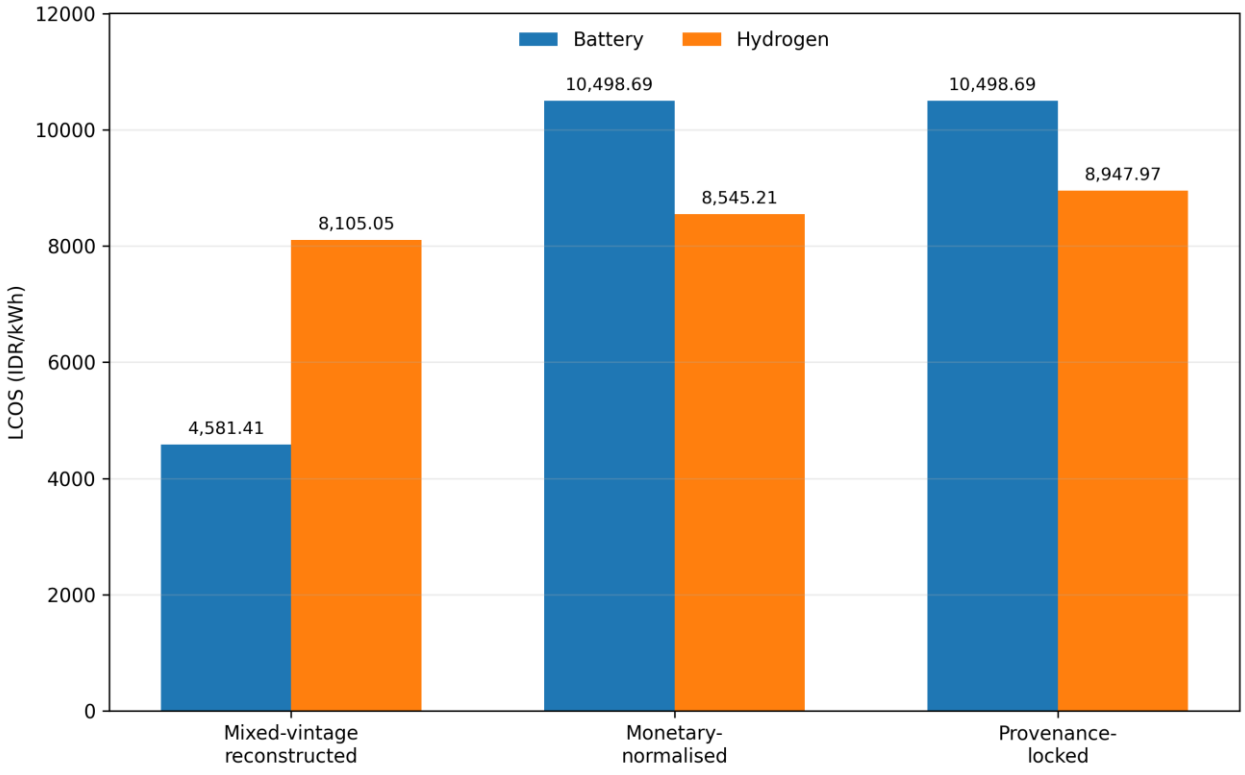


Fig. 3 Battery and hydrogen LCOS under three economic input treatments.

Note: Technical dispatch and discounted delivered electricity are unchanged between the monetary-normalised and provenance-locked scenarios; only economic input treatment differs.

3.4 Sensitivity and break-even conditions

The sensitivity analysis shows that battery CAPEX is a major switching parameter. In the mixed-vintage reconstructed scenario, an electrolyser CAPEX of approximately USD 402.8/kW is required for hydrogen to reach parity when battery CAPEX is held at USD 150/kWh. Conversely, with electrolyser CAPEX fixed at USD 1,512/kW, the mixed-vintage battery-capital-cost break-even is approximately USD 265.37/kWh. At USD 263/kWh, the two pathways are already close to parity, with battery LCOS of approximately IDR 8,032.74/kWh and hydrogen LCOS of IDR 8,105.05/kWh.

The provenance-locked break-even map in Fig. 4 shifts this boundary because the cost basis is harmonised and the hydrogen component provenance is corrected. At the baseline electrolyser CAPEX of USD 1,512/kW, battery-hydrogen parity occurs at a battery CAPEX of approximately USD 292.97/kWh. If electrolyser CAPEX falls to USD 1,000/kW, the corresponding battery parity value falls to approximately USD 239.71/kWh; at USD 650/kW electrolyser CAPEX, battery parity falls to approximately USD 203.31/kWh. These values define combinations of capital costs rather than a single technology ranking.

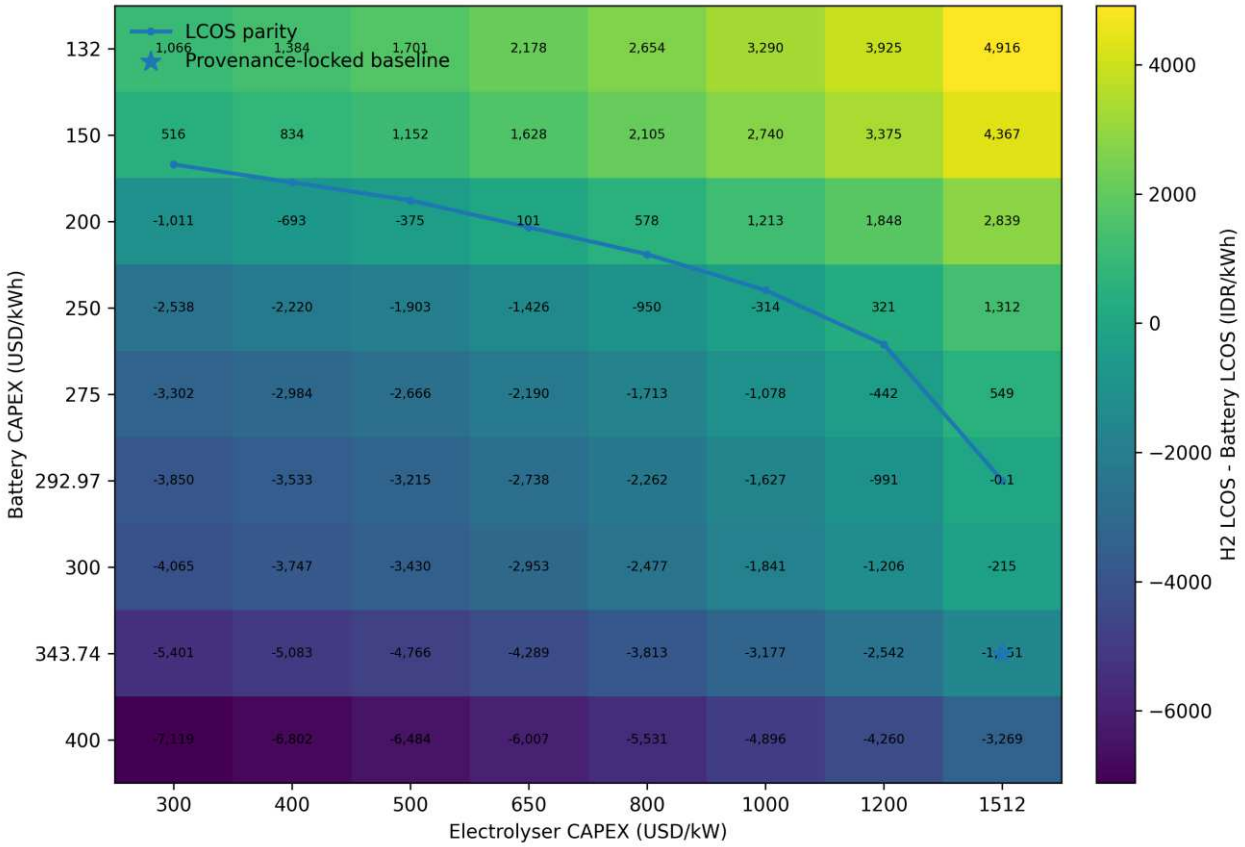


Fig. 4 Battery-electrolyser CAPEX break-even map under provenance-locked economics.

Note: Cell values are H2 LCOS minus battery LCOS in IDR/kWh. Negative values indicate lower hydrogen LCOS and positive values indicate lower battery LCOS. The line is the LCOS parity boundary, and the star marks the provenance-locked baseline.

3.5 Other sensitivity dimensions

Fuel-cell efficiency, WACC, hydrogen-vessel cost, electrolyser SEC, and storage duration influence the LCOS gap but do not independently eliminate it across all baseline assumptions. Under the mixed-vintage low-battery-cost case, varying fuel-cell efficiency, WACC, or tank cost alone does not achieve parity. When battery CAPEX is raised to the IRENA central 2016 VRLA reference of USD 263/kWh, however, the system is close enough to parity that comparatively small changes can switch the ranking; examples include an electrolyser CAPEX near USD 1,489/kW, tank cost near USD 1,567/kg-H2, WACC near 8.97%, or fuel-cell efficiency near 56.4% under the corresponding sensitivity calculation.

Within the repeated-day model, approximately one day of hydrogen storage gives the lowest cost among the tested durations. Extending nominal storage duration adds vessel CAPEX without creating seasonal shifting value because every modelled day has the same profile and the hydrogen inventory is cyclic. This result therefore applies only to the representative-day service and is not evidence against long-duration or seasonal hydrogen storage.

4 Discussion

4.1 Technical trade-offs and storage-service characteristics

The common-boundary reconstruction reveals a clear technical trade-off. Battery storage returns more electricity to the load because its conversion chain is shorter and its round-trip efficiency is substantially higher. The hydrogen pathway, however, can absorb a larger share of the available PV surplus before the conversion-power and storage constraints are reached. As a result, lower curtailment does not necessarily imply more electricity returned to the load. For an electricity-storage comparison, the relevant service denominator is delivered electricity rather than renewable electricity absorbed.

This pattern is consistent with comparative storage literature. Crespi et al. found that batteries can remain economically attractive across high levels of renewable self-generation, while hydrogen becomes more competitive when medium- and long-term shifting gains importance [4]. Marocco et al. demonstrated a stronger role for hydrogen in a 100% renewable system where long-term storage avoided costly oversizing of renewable generation and batteries [5]. The present case is different: it is dominated by repeated daily solar-surplus shifting and therefore does not reproduce the system conditions that create seasonal value for hydrogen.

4.2 Break-even conditions and cost-provenance sensitivity

The main economic finding is that the storage ranking is conditional. A deterministic mixed-vintage calculation favours the battery, but the result changes once historically sourced costs are placed on a common monetary basis. The change is driven particularly by the battery CAPEX assumption. IRENA reports a central 2016 VRLA installation-cost value of USD 263/kWh, whereas the mixed-vintage

baseline uses USD 150/kWh [7]. The latter therefore represents a substantially lower-cost battery assumption than the central historical reference. The fact that the mixed-vintage battery break-even is approximately USD 265/kWh shows why the selected cost vintage is capable of changing the sign of the comparison.

Electrolyser CAPEX has a similar but asymmetric effect. At USD 150/kWh battery CAPEX, the mixed-vintage hydrogen pathway requires electrolyser CAPEX of roughly USD 403/kW to reach parity. This is below the approximate USD 650-1,000/kW range reported by IRENA around 2020, although it lies above some long-term cost projections under large-scale deployment [12]. Thus, the low battery-cost case creates a stringent cost target for hydrogen, whereas a higher and source-consistent battery cost moves the system much closer to parity.

The provenance-locked scenario strengthens the methodological conclusion. The source audit found that key fuel-cell and compressor values in the case input set were not consistently documented in currency and source scope. The fuel-cell proxy is therefore anchored to an explicit 2021 stationary-system cost benchmark [15], while the compressor proxy is traced through Crespi et al. and the OECD methodology [4,11]. Converting these euro-denominated proxies consistently and rebasing them to 2024 dollars raises hydrogen LCOS relative to the purely monetary-normalised scenario but does not restore the mixed-vintage ranking. Because the fuel-cell benchmark is transferred from a different equipment scale, this scenario should be interpreted as a provenance-constrained comparison rather than a project-specific market quotation. Cost provenance is therefore not a cosmetic reporting issue; it is a structural model input capable of influencing the technology ordering.

4.3 Implications for storage planning

For the evaluated Nusantara daily solar-surplus service, the battery pathway offers the higher electricity-return efficiency, while hydrogen offers stronger surplus absorption. These attributes correspond to different planning objectives. If the primary requirement is frequent intraday shifting with high electricity-return efficiency, battery storage has a technical advantage. If the system objective

362 increasingly values low-curtailment operation, separable energy and power capacities, multi-day
363 resilience, or sector coupling, hydrogen may provide additional value that is not represented fully by the
364 present electricity-only representative-day model.

365 The results therefore support a threshold-based planning approach. Instead of asking which
366 technology is universally cheaper, planners can identify the battery and electrolyser cost combinations,
367 financing conditions, efficiency assumptions, and service durations under which the LCOS ordering
368 changes. This is particularly useful for fast-moving technology markets because break-even boundaries
369 can be updated without reinterpreting a single fixed scenario as a permanent technology preference.

370 A hybrid battery-hydrogen architecture may also be relevant in future work, with batteries serving
371 high-frequency daily cycling and hydrogen serving longer-duration or cross-sector functions. Such
372 complementarity has been observed in system-optimisation studies [4,5], but demonstrating it for
373 Nusantara would require a chronological multi-day or annual dataset and is outside the boundary of the
374 present analysis.

375 ### 4.4 Alignment with Sustainable Development Goals

376 The findings are relevant to SDG 7 through the planning of storage technologies that enable greater
377 use of solar electricity, particularly the infrastructure and technology considerations associated with
378 renewable-energy deployment [16]. The hydrogen pathway absorbed more of the available 2024 solar
379 surplus, but returned less electricity to the load than the battery pathway. This trade-off matters when
380 evaluating resource utilisation: a lower curtailment figure should not be interpreted as evidence of lower
381 delivered-electricity cost or higher power-system reliability. The break-even thresholds offer a transparent
382 way to assess conditional economic feasibility; they do not show that the case study increases the
383 renewable share, provides universal access, or lowers end-user tariffs.

384 For SDG 9, especially the emphasis on resource-efficient and sustainable infrastructure under target
385 9.4, consistent investment assumptions are important to technology appraisal [17]. In this case, changing
386 the source year, currency convention, and equipment-cost provenance changed the apparent LCOS

ranking without changing technical dispatch. This demonstrates why credible comparisons for sustainable infrastructure should report both functional service and lifecycle cost provenance. However, this study does not calculate lifecycle greenhouse-gas emissions, embodied materials, or observed SDG indicators, and its repeated-day profile cannot validate resilience during prolonged renewable shortfalls. The SDG contribution is therefore limited to decision-support evidence for storage planning rather than a quantified sustainability outcome.

4.5 Limitations and methodological implications

Four limitations define the scope of inference. First, the model annualises one 24-h PV-load profile and therefore does not capture seasonal renewable variation, changing demand patterns, prolonged low-generation periods, or chronological inter-day carry-over. The storage-duration sensitivity should consequently be interpreted as a daily-service result. Second, the study reports incremental storage-pathway LCOS. PV plant CAPEX and O&M are excluded from both alternatives, and the values should not be interpreted as total-system LCOE or retail electricity tariffs.

Third, the baseline assumes zero opportunity cost for surplus PV electricity because it is treated as otherwise curtailed. Export value or alternative uses of surplus electricity would change the economics of both pathways and should be included where such markets exist. Fourth, several equipment costs are literature proxies rather than project-specific vendor quotations. CPI rebasing improves monetary comparability but does not represent technology learning, regional procurement conditions, installation mark-ups, or future market prices. In particular, the fuel-cell CAPEX is transferred from a broader stationary-system benchmark [15], while the hydrogen-vessel value is an uninstalled storage proxy [9]; neither should be interpreted as a project-specific installed quotation for the 11-kW case configuration.

These limitations also provide methodological guidance. Comparative storage studies should use a common upstream energy boundary, report electricity delivered from storage as the LCOS service denominator, include parasitic loads such as hydrogen compression, model component replacement consistently, and document currency, cost year, and equipment scope for each major CAPEX input.

Where seasonal storage is a research question, interconnected representative periods or full chronological modelling are preferable to a repeated single-day profile [5,6].

5 Conclusions

This study demonstrates that the relative economic performance of battery and green hydrogen storage is conditional on the storage service, technical system boundary, and provenance of techno-economic inputs. Under a common hourly solar-surplus boundary, the battery pathway delivered more electricity back to the load, whereas the hydrogen pathway absorbed a larger share of available solar surplus and reduced curtailment more strongly. Under the reconstructed mixed-vintage economic scenario, the battery LCOS was lower than the hydrogen LCOS. Sensitivity and break-even analysis, however, showed that this ranking is not stable across defensible economic assumptions. Battery CAPEX emerged as a critical switching parameter, with a provenance-locked parity value of approximately USD 292.97/kWh at the baseline electrolyser CAPEX of USD 1,512/kW. Monetary harmonisation and correction of component-cost provenance were sufficient to reverse the relative ordering, demonstrating that cost source, currency, reference year, and equipment scope can materially determine comparative conclusions. For the evaluated daily solar-surplus service, battery storage provides the higher electricity-return efficiency, whereas hydrogen absorbs a larger share of available solar surplus. Potential advantages of hydrogen at longer storage durations cannot be established from the present representative-day dataset. The principal contribution is therefore the identification of boundary conditions under which the preferred storage pathway changes. For Nusantara and similar renewable-energy applications, storage alternatives should be compared using consistent system boundaries, lifecycle definitions, cost provenance, and break-even conditions rather than a single deterministic LCOS ranking. These results provide bounded decision-support evidence relevant to SDG 7 and SDG 9 by strengthening the transparency of renewable-storage and sustainable-infrastructure appraisals, but they do not quantify environmental impacts or SDG indicator progress.

List of abbreviations

- CAPEX - capital expenditure
- EL - electrolyser
- FC - fuel cell
- FLH - full-load hours
- H2 - hydrogen
- LCOS - levelized cost of storage
- LHV - lower heating value
- O&M - operation and maintenance
- PV - photovoltaic
- RTE - round-trip efficiency
- SEC - specific electricity consumption
- SOC - state of charge
- VRE - variable renewable energy
- WACC - weighted average cost of capital

Declarations

Availability of data and materials

The 24-hour photovoltaic-generation and electricity-demand profiles used in this study were obtained from PT PLN (Persero) with permission for research purposes. The processed data, model inputs and calculation workbook, annual lifecycle summaries, sensitivity outputs, and break-even calculations supporting the findings are available from the corresponding author upon reasonable request. Access to the underlying data remains subject to the terms of permission granted by PT PLN (Persero).

Competing interests

The authors declare that they have no competing interests.

Funding

This research received no specific grant from any funding agency in the public, commercial, or not-for-profit sectors.

Authors' contributions

G: conceptualization, methodology, formal analysis, validation, visualization, writing - original draft, writing - review and editing, supervision, project administration, and correspondence. RH: investigation, data curation, case-study formulation, visualization, and writing - review and editing. MAB: conceptualization, supervision, validation, and writing - review and editing. M: methodological review, validation, and writing - review and editing. All authors read and approved the final manuscript.

Acknowledgements

The authors acknowledge PT PLN (Persero) for providing the case-study electricity-load and photovoltaic-generation data used in the underlying analysis.

Declaration of generative AI and AI-assisted technologies in manuscript preparation

During the preparation of this manuscript, the authors used ChatGPT (OpenAI) to assist with manuscript organization, English-language revision, formula and computational consistency checks, literature-source verification, and preparation of data-derived visualisations. All AI-assisted outputs were independently reviewed and verified against the source data, calculation workbook, and cited literature. The authors take full responsibility for the accuracy, integrity, interpretation, and final content of the manuscript.

Ethics approval and consent to participate

Not applicable.

Consent for publication

Not applicable.

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