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Techno-economic feasibility of green hydrogen as seasonal energy storage from surplus hydropower in Lao PDR

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Abstract
Lao PDR faces a structural energy security challenge from the seasonal nature of its hydropower-dominated generation fleet. During the wet season (May to October), the country exports surplus electricity at approximately \$0.05/kWh, yet imports approximately 1,765 GWh during the dry season at approximately \$0.11/kWh from Thailand. This paper assesses the techno-economic feasibility of a Power-to-Hydrogen-to-Power (P2H2P) system as a seasonal storage solution to displace this import deficit. A five-step calculation model was applied using a 2.0 GW surplus hydropower cap, a 4,320-hour wet season production window, a 55 kWh/kg electrolyser energy requirement, and a 50% fuel cell efficiency, requiring 105,910 tonnes of hydrogen annually from a 1.35 GW electrolyser. Two hydrogen production cost scenarios, drawn from the Lao PDR National Green Hydrogen and Ammonia Roadmap, were assessed: an optimistic scenario of \$1.24/kg at \$10/MWh electricity, and a conservative scenario of \$3.40/kg at \$60/MWh. On a variable cost basis, the optimistic scenario yields \$0.074/kWh, which is 33% below the \$0.11/kWh import benchmark, while the conservative scenario yields \$0.204/kWh, 85% above it. Once full system costs, including annualised fuel cell and seasonal hydrogen storage capital expenditure, are included, the Levelised Cost of Electricity rises to \$0.117/kWh (optimistic) and \$0.247/kWh (conservative), both above the import price. The findings show that while variable-cost hydrogen-stored electricity can be competitive with imports, the capital cost of seasonal storage infrastructure is the primary barrier to full system viability, identifying geological storage feasibility as the most urgent priority for future investigation.

Keywords: Green hydrogen; Power-to-Hydrogen-to-Power; Seasonal energy storage; Lao PDR; Techno-economic analysis.

1. Introduction
For several decades, the Lao People's Democratic Republic (Lao PDR) has pursued an ambitious national strategy centred on exploiting its vast water resources, with the aspiration to become the "Battery of Southeast Asia" (Phoumin and Phongsavath, 2024). This vision is underpinned by an immense theoretical hydropower potential, estimated to be between 24 and 26 gigawatts (GW), which has been established as the cornerstone of the nation's economic development (Asian Development Bank, 2019). By 2023, this development translated into an installed generation capacity of 11,652 MW with actual production of approximately 57,000 GWh, of which 83% (9,658 MW; 45,050 GWh) was derived from hydropower (Phongsavath, 2024). This expansion has yielded tangible benefits, including the achievement of near-universal domestic electricity access and the transformation of the power sector into a primary engine of economic growth, now accounting for over 20% of national export revenues (Asian Development Bank, 2019; UN ESCAP, 2022).

1.1. Rationale
Despite these achievements, Lao PDR faces a fundamental vulnerability that threatens its energy security and economic stability. The nation's power generation is inextricably linked to the seasonal rhythms of the Mekong River Basin, which creates distinct and opposing hydrological regimes.

The wet season, extending from May to October, contributes approximately 70% to 80% of the annual river discharge, facilitating high hydropower output that consistently exceeds domestic demand (Mekong River Commission, 2018). Conversely, the dry season, spanning November to April, experiences a substantial reduction in water inflow, forcing a commensurate decline in generation capacity (Asian Development Bank, 2019). This seasonality creates the "hydropower paradox," where the nation maintains status as a net electricity exporter during the wet season yet faces acute energy deficits during the dry season, necessitating imports to sustain grid stability (Phongsavath, 2024).

The financial inequity of this arrangement is well-documented: the wet-season export price to Thailand is substantially lower than the dry-season import price paid back to the same counterparty (Yong, 2023). This structural imbalance is both an energy security risk and a significant economic drain on the national utility. The study examines whether green hydrogen, produced via water electrolysis powered by surplus wet-season hydropower across a six-month production window, can serve as a practical domestic storage solution to close this seasonal gap and eliminate the costly import dependency.

1.2. Problem statement

The inherent consequence of this seasonal mismatch is a structural power trade deficit. To maintain grid stability during the driest months, the national utility, Électricité du Laos (EDL), is frequently compelled to purchase power from the very neighbouring countries to which it exports during the wet season (Asian Development Bank, 2019). In 2023, the country imported approximately 1,765 GWh during the dry season (Phoumin and Phongsavath, 2024), at a documented import price of approximately \$0.11/kWh from Thailand (Yong, 2023), which is more than double the price at which Laos sells its own generation. This dependency introduces considerable economic costs, exposes the national budget to volatile regional electricity prices, and fundamentally undermines the national goal of energy self-sufficiency, a vulnerability expected to intensify as climate change introduces greater unpredictability into Mekong Basin hydrology (Mekong River Commission, 2018). The techno-economic feasibility of a domestic Power-to-Hydrogen-to-Power (P2H2P) system for Lao PDR has not previously been quantified.

1.3. Research aim

The aim of this research is to conduct a quantitative techno-economic feasibility assessment of a green hydrogen energy storage system, powered exclusively by surplus domestic hydropower during the wet season, as a mechanism for Lao PDR to enhance energy security by fully displacing the dry-season electricity import deficit and determining whether domestically stored hydrogen can deliver electricity at a cost competitive with the current import price.

1.4. Research questions

- What is the required infrastructural scale of a P2H2P system designed to fully displace Lao PDR's 1,765 GWh dry-season import deficit? measured in terms of electrolyser capacity (GW), hydrogen storage volume (tonnes), and fuel cell reconversion capacity?
- What is the price per kWh of grid-ready electricity generated from the proposed hydrogen storage system under each cost scenario, calculated using the five-step techno-economic model?
- How does the domestically produced electricity price compare to the documented dry-season import price from Thailand, and what does this margin imply for policy?

- Which technological and economic variables, particularly fuel cell reconversion efficiency, hydrogen production cost, and full system capital costs, have the greatest impact on economic viability?

2. Literature review

This section explores the intersection of green hydrogen production and hydropower-dominant energy systems, focusing on the techno-economic feasibility of P2H2P configurations for long-duration seasonal energy storage. A systematic review following PRISMA guidelines was employed to synthesise the global evidence base and identify research gaps. The review directly informs the methodological approach and contextualises the results of this study.

2.1. Scope

This review synthesises evidence on the techno-economic feasibility of using hydropower to produce green hydrogen for seasonal energy balancing, examining the system configurations and technologies reported in the literature, the range of key techno-economic input parameters assumed, the spectrum of economic viability outcomes reported, and the variables most frequently identified as the dominant drivers of economic feasibility. These threads are drawn together in the concluding discussion in section 2.6.

2.2. Approach

2.2.1. Protocol

The PRISMA (Preferred Reporting Items for Systematic Reviews and Meta-Analyses) framework guided this review (Moher et al., 2009). A pre-defined protocol categorised the literature into two primary streams: (1) Primary Techno-Economic Analyses, which are studies conducting a complete, quantitative techno-economic assessment with specific data on system configurations, costs, efficiencies, and final economic metrics such as LCOH; and (2) Supporting Technical and Economic Studies, which provide essential context but not a full techno-economic model.

2.2.2. Information sources and search strategy

A structured search was conducted across three major academic databases: Google Scholar, Scopus, and Dimensions.ai, limited to articles published from 2010 to 2025. The search string combined terms covering: ("green hydrogen" OR electrolysis OR "hydrogen storage" OR "power-to-hydrogen") AND (hydropower OR hydroelectric) AND ("techno-economic" OR "LCOE" OR "feasibility" OR "LCOH") AND ("seasonal storage" OR "long-duration storage" OR "energy balancing" OR "grid stability" OR "energy security").

2.2.3. Eligibility and selection

Inclusion criteria required peer-reviewed journal articles or full-text conference papers in English, published 2010–2025, containing a quantitative techno-economic analysis of a system generating hydrogen primarily from hydropower. Exclusion criteria removed purely qualitative studies, non-green hydrogen studies, grey literature, and studies where hydropower was only a minor component. An initial search yielded 21,757 records. After removing 11,602 duplicates and screening 10,155 unique records by title and abstract, 126 articles were reviewed in full. Following detailed assessment, 107 were excluded, resulting in a final selection of 19 studies for synthesis.

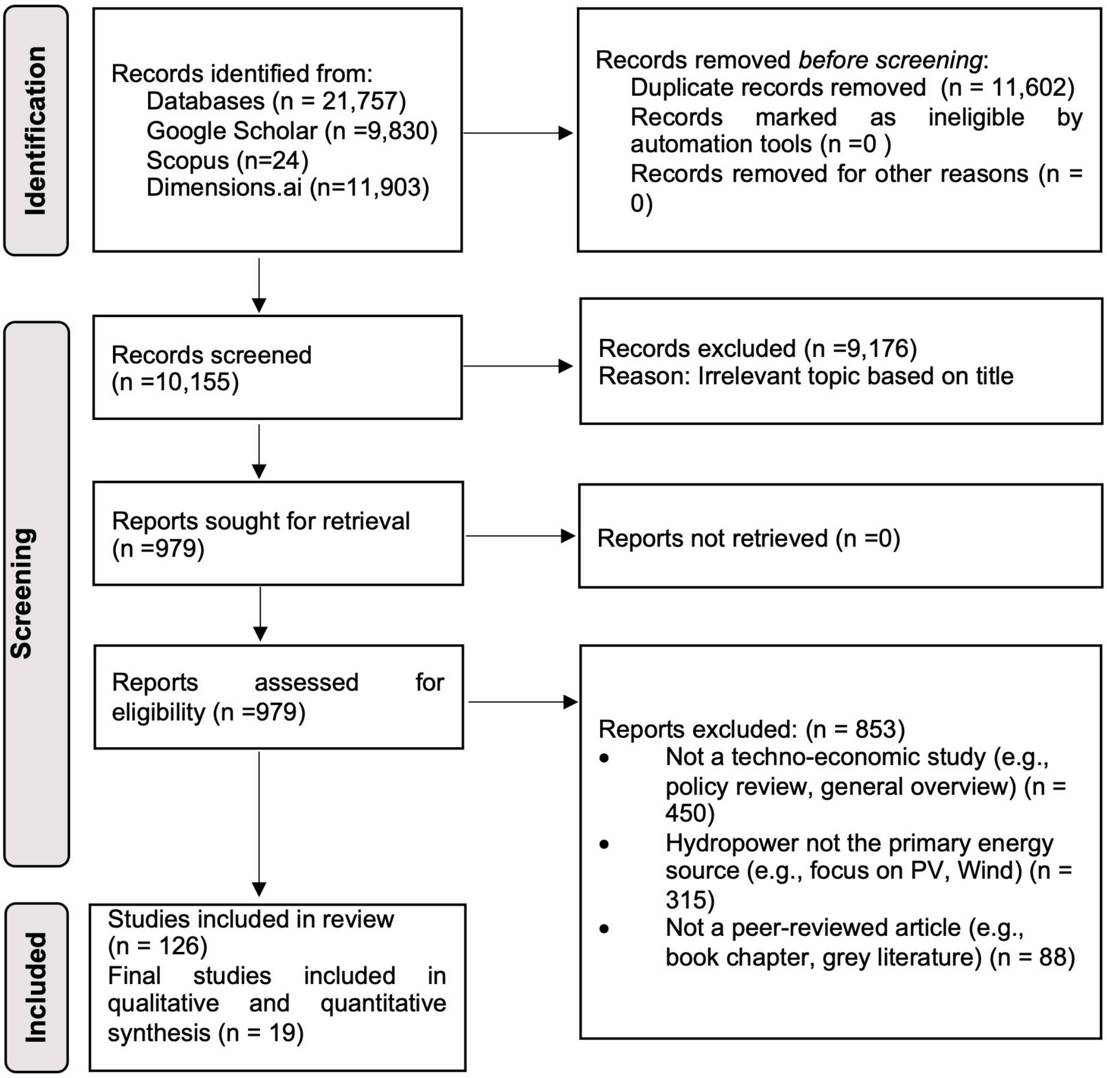

Figure 1. PRISMA flow diagram of the literature search and selection process

2.3. Findings and discussion

2.3.1. Corpus overview

The final corpus consists of 19 peer-reviewed studies, over 90% of which were published since 2020. The geographical focus reveals specific clusters: Asia (7 studies, notably Nepal and Indonesia), South America (5 studies: Brazil, Ecuador, Honduras, Uruguay), and Europe (4 studies: Norway, Slovenia, Switzerland). The remaining studies cover Nigeria, the USA, and one general modelling study. Despite this breadth, a significant geographical gap remains: no study addresses the hydropower-exporting nations of the Mekong region.

2.3.2. System configurations, technologies, and sourcing

The dominant electricity sourcing strategy across the reviewed literature is the utilisation of surplus, curtailed, or spilled hydropower, framing the electricity input as having a near-zero or very low opportunity cost(Nadaleti et al., 2020). Technological choices are split between PEM electrolysers, preferred for fluctuating run-of-river sources due to rapid response times (Hagen, 2024; Sangolt et al., 2025), and Alkaline water electrolysis (AWE), favoured for larger, more stable systems due to lower capital cost and technological maturity (Aremu et al., 2025; Jovan and Dolanc, 2020). For large-scale seasonal storage, geological formations like salt caverns are consistently identified as the most viable option due to low cost per unit of energy stored, although feasibility is highly location-dependent (Gabrielli et al., 2024; María Villarreal Vives et al., 2023). Where geology is unsuitable, engineered above-ground storage in high-pressure tanks is modelled, but its high capital cost is noted as a significant barrier (Paneru et al., 2024; Sangolt et al., 2025).

2.3.3. Range of techno-economic input parameters

Financial and technical assumptions varied significantly. Electrolyser CAPEX ranged from a low of $474/kW for AWE technology (Aremu et al., 2025; Thapa et al., 2021) to a high of $1,800/kW for PEM(Siburian et al., 2024). System efficiencies also varied: electrolyser efficiency was typically assumed between 55% and 75%. For full P2H2P systems, overall Round-Trip Efficiencies (RTE) were reported generally between 28% and 42% (Kafle et al., 2024). Financial parameters were similarly heterogeneous, with discount rates ranging from 4% to 10% (most commonly 7–8%) and project lifetimes typically between 20 and 30 years.

2.3.4. Economic viability outcomes

The LCOH was the most common metric used to evaluate economic viability and spanned a wide range. At the lower end, Aremu et al. (2025) calculated $1.17/kg for Nigeria's Jebba station, while Thapa et al. (2021) estimated $1.34–$2.45/kg in Nepal. Mid-range values ($2.00–$4.50/kg) were common, including the USA ($2.00–$3.50/kg, Andrus, 2025), Ecuador ($2.34–$4.01/kg, Pinchao et al., 2024), and Honduras ($2.89/kg, Zúniga-Paguada and Reyes-Duke, 2025). At the higher end, Siburian et al. (2024) found $5.15/kg in Indonesia, while Sangolt et al. (2025) calculated €4.19–€6.21/kg for an off-grid plant in Norway. Table 1 provides a representative summary.

Table 1. Techno-economic and LCOH outcomes from the reviewed literature

Study Focus	LCOH/LCOE Value	Electrolyser CAPEX	Key Assumption
Ecuador (Surplus Hydro)	$2.34 - $4.01 / kg	$700/kW (PEM)	Utilizes otherwise wasted energy.
Uruguay (Surplus Hydro)	$2.10 - $2.80 / kg	$800/kW (Alkaline)	Includes other renewables.
Slovenia (Run-of-River)	€4.16 / kg	€600/kW (Alkaline)	Models a specific plant's operation.
Nigeria (Jebba Station)	$1.17 / kg	$474/kW (Alkaline)	Assumes very low electricity cost.
Indonesia (Excess Power)	$2.58 / kg	$1,250/kW (PEM)	Models a financial case for a utility.
Nepal (Surplus Hydro)	$1.34 - $2.45 / kg	$474/kW (Alkaline)	High surplus energy availability.
Brazil (Spilled Energy)	$0.303 / kWh	Not specified	National-level potential analysis.
USA (Columbia River)	$2.00 - $3.50 / kg	$840/kW (Alkaline)	Large-scale system modeling.
Honduras (Hydro Potential)	$2.89 / kg	$1,250/kW (PEM)	National-level potential analysis.
Indonesia (Excess Power)	$5.15 / kg	$1,800/kW (PEM)	Models a specific plant with higher costs.

2.3.5. Key sensitivities and economic drivers

Sensitivity analyses across the literature are consistent in identifying the most influential variables:

- Electrolyser capital cost: Over 90% of the studies identified high electrolyser CAPEX as the critical variable with a disproportionate effect on LCOH. Sangolt et al. (2025) and Paneru et al. (2024) demonstrate that even minor changes in electrolyser CAPEX significantly alter the LCOH, confirming it as the primary economic barrier.
- Electricity input cost: Jovan and Dolanc (2020) showed that the economic case is often entirely dependent on securing electricity substantially below standard market rates.
- Capacity factor: The number of annual operating hours of the electrolyser was a critical driver. Andrus (2025) and Hagen (2024) explicitly conclude that maximising operating hours is fundamental to lowering per-unit hydrogen cost.

2.4. Transferability

The following lessons from the reviewed literature are directly transferable to the Lao PDR context and inform the design approach adopted in this study:

- Sizing and phasing: Initial projects are most feasible at modest scales (e.g., 5–10% reservoir coverage). Expansion should be phased and guided by empirical data on grid constraints and local conditions.
- Coordination: Coordinated operation of hydropower and hydrogen production is crucial for maximising efficiency and minimising costs.
- Techno-economics: Transparent and standardised reporting of all economic assumptions (CAPEX, OPEX, discount rate) is essential for comparing projects and attracting investment.
- Data and benchmarking: Open-access benchmark datasets, including hourly generation, inflows, and costs, would accelerate learning, validate models, and build investor confidence.

2.5. Current gaps in the literature

The literature shows that hydropower-to-hydrogen integration has progressed rapidly, but several critical gaps remain. Firstly, while the complementarity between hydropower and hydrogen production is well established at a seasonal scale, this seasonal complementarity does not guarantee energy security at a diurnal level. As highlighted by Gabrielli et al. (2024), hydrogen storage is operated through both long-term seasonal cycles and shorter-term cycles, and the low round-trip efficiency of the P2H2P cycle means hydropower must still respond dynamically to hourly demand fluctuations.

Secondly, there is no consensus on the optimal scale of hydrogen production relative to the host hydropower plant. Many studies impose conservative assumptions limiting electrolyser capacity to a fraction of hydropower output, which may underutilise the full potential of available surplus energy.

Thirdly, techno-economic reporting remains inconsistent, creating a significant barrier to comparing findings across studies and building investor confidence. While studies in Nigeria (Aremu et al., 2025) and Nepal (Thapa et al., 2021) report very low LCOH values below $2.50/kg, studies in Norway (Sangolt et al., 2025) and Indonesia (Siburian et al., 2024) report values exceeding $5.00/kg due to higher CAPEX and less favourable conditions. Critically, no study addresses the hydropower-exporting nations of the Mekong region, a gap that the current research directly addresses.

Taken together, this review confirms that the dominant system configurations in the literature rely on surplus or spilled hydropower with PEM or Alkaline electrolysers; that key techno-economic input parameters, particularly electrolyser CAPEX, system efficiencies, and discount rates, vary widely across studies; that reported LCOH outcomes range from $1.17/kg to $6.64/kg depending on these assumptions; and that electrolyser capital cost and electricity input cost are consistently identified as the dominant drivers of economic feasibility. Hydropower-to-hydrogen integration demonstrates strong potential as a strategic solution for seasonal energy storage and decarbonisation, and several transferable lessons are evident: prioritising surplus electricity to ensure low input costs, matching electrolyser technology to the specific hydropower source, and focusing project design on the three critical economic drivers identified above. Critical gaps remain regarding geological storage feasibility, integration into national energy models, and the water-energy nexus. The most significant geographical gap, namely the absence of research on Mekong region hydropower-exporting nations, is directly addressed by the present study.

3. Research methods

3.1. Research design

The study employs a quantitative, simulation-based research design. A simulation model allows for rigorous and reproducible evaluation of technical feasibility and economic viability prior to any capital commitment, based on established engineering parameters and official national data. The research follows a linear, deductive logic: starting from a defined policy target (full displacement of the 1,765 GWh dry-season import deficit at $0.11/kWh), the model works backwards through the energy conversion chain to determine the physical scale of infrastructure required and the resulting cost of output electricity.

This study adopts a quantitative, simulation-based research strategy structured as a sequential five-step calculation chain: (1) total energy required in hydrogen form at the assumed fuel cell efficiency; (2) total hydrogen mass using the LHV constant; (3) required electrolyser capacity within the six-month wet season production window; (4) electricity output per kg of stored hydrogen; and (5) the output electricity price compared against the dry-season import price benchmark. A sensitivity analysis tests how the result changes under different input assumptions.

3.2. Assumptions and boundary conditions

The following core assumptions bound the scope and interpretation of this research:

- Surplus hydropower cap: Capped at 2.0 GW, consistent with estimated available surplus above domestic demand and export obligations (Phongsavath, 2024).
- Wet season production window: 6 months × 30 days × 24 hours = 4,320 hours (May–October).
- Electrolyser energy requirement: 55 kWh/kg H_2 (Hubert et al., 2024), representing the system-level energy consumption of a PEM electrolyser at beginning-of-life, comprising 51 kWh/kg stack and 4.2 kWh/kg balance-of-plant energy.
- Fuel cell reconversion efficiency: 50% electrical efficiency for stationary PEMFC systems, following Staffell et al. (2019).
- Hydrogen production cost: Two scenarios drawn from the Lao PDR Hydrogen and Ammonia Production Roadmap (Ministry of Energy and Mines et al., 2024): an optimistic $1.24/kg at $10/MWh surplus electricity, and a conservative $3.40/kg

at $60/MWh, both at a 60–70% capacity factor for Lao PDR seasonal hydropower surpluses.

- Import price benchmark: The documented dry-season import price of $0.11/kWh from Thailand, used as the primary competitiveness benchmark throughout this study (Yong, 2023).
- Secondary data reliance: The model relies exclusively on secondary data sources.

3.3. Case study: The Lao PDR national energy system

The case study focuses on the national energy system of Lao PDR, selected because it represents the most pronounced example of the hydropower paradox in the Mekong region. The Energy Security White Paper defines the wet season as “typically May through October” and confirms an estimated surplus of approximately 2.0–2.5 GW available from the domestic generation fleet above domestic demand and export obligations (Phongsavath, 2024), directly corroborating the wet season window and surplus cap adopted as model inputs in section 3.2.

3.4. Modelling approach and system process-flow

The analysis was conducted using a sequential five-step techno-economic calculation model developed in Microsoft Excel. The modelled P2H2P value chain follows this sequential flow:

- Input: Surplus wet-season hydropower (GWh), capped at 2.0 GW over a 4,320-hour production window (May–October, 6 months), is directed to the electrolyser plant rather than being spilled.
- Conversion: Electricity is fed into the electrolyser at 55 kWh per kg of hydrogen produced (Hubert et al., 2024).
- Storage: Produced H_2 is stored in underground geological storage for the duration of the wet season until it is needed during the dry season. Above-ground compressed gas storage is shown to be physically impractical at the required scale in section 4.5. The required storage volume is derived in step 2 of the calculation framework (see section 3.6).
- Reconversion: Stored H_2 is withdrawn during the dry season and fed into a fuel cell reconversion unit operating at 50% electrical efficiency.
- Output: Grid-ready electricity is supplied to the national grid during the dry season, displacing the need to import power from Thailand. The target output volume and its cost relative to the import price are determined in steps 4 and 5 of the calculation framework (see section 3.6).

3.5. Input parameters and assumptions

The model is defined by eight core input parameters presented in Table 2. The wet season production window is defined as 4,320 hours, covering the full surplus availability period from May to October. The 50% fuel cell reconversion efficiency follows Staffell et al. (2019), who apply 50% as the electrical efficiency for stationary hydrogen-to-power conversion. The electrolyser energy consumption of 55 kWh/kg is sourced from Hubert et al. (2024), which reports a beginning-of-life PEM system consumption of 55.2 kWh/kg. The H_2 LHV of 33.33 kWh/kg is the standard international value confirmed by the Energy Transitions Commission (2023),citing IEA definitions. The sensitivity analysis in section 4 examines the impact of improving fuel cell efficiency to 60% using Solid Oxide Fuel Cell (SOFC) technology. The $0.11/kWh import benchmark is sourced from Yong (2023), which cites EDL pricing data confirming that Lao PDR imports power from Thailand at approximately $0.11/kWh during the dry season.

Table 2. Core input parameters for the P2H2P techno-economic simulation

Parameter	Value	Unit	Description
A. Energy demand inputs			
Dry season electricity deficit	1,765	GWh/year	Target to be fully displaced by P2H2P system
Wet season surplus hydropower cap	2.0	GW	Safety cap above domestic demand and export obligations
Wet season production window	4,320	Hours	6 months (May–Oct) × 30 days × 24 h
B. Electrolysis and storage parameters			
Electrolyser energy requirement	55	kWh/kg H_2	PEM system value at beginning of life
H_2 lower heating value (LHV)	33.33	kWh/kg	Standard international physics constant
H_2 production cost — Scenario 1 (optimistic)	1.24	USD/kg	At $10/MWh surplus electricity; 60–70% capacity factor
H_2 production cost — Scenario 2 (conservative)	3.40	USD/kg	At $60/MWh electricity input
C. Reconversion and economic benchmark			
Fuel cell reconversion efficiency	50	%	Stationary PEMFC baseline; 60% examined in sensitivity analysis
Dry-season import price (Thailand)	0.11	USD/kWh	Primary competitiveness benchmark for this study

3.6. The five-step calculation framework

The techno-economic model is structured as a sequential five-step calculation chain, summarised in Table 3.

Table 3. Summary of the five-step P2H2P techno-economic calculation framework

Step	What is calculated	Result
1	Total H_2 energy to store (1,765 GWh ÷ 50% fuel cell efficiency)	3,530 GWh
2	Total H_2 mass to produce (3,530,000,000 kWh ÷ 33.33 kWh/kg LHV)	105,910 tonnes
3	Required electrolyser capacity (105,910,000 kg ÷ 4,320 hrs × 55 kWh/kg)	1.35 GW
4	Electricity output per kg H_2 stored (33.33 kWh/kg × 50%)	16.665 kWh/kg
5a	Output price — Scenario 1, optimistic ($1.24/kg ÷ 16.665 kWh/kg)	$0.074/kWh
5b	Output price — Scenario 2, conservative ($3.40/kg ÷ 16.665 kWh/kg)	$0.204/kWh
—	Dry-season import benchmark (Thailand)	$0.11/kWh

3.7. Two-scenario hydrogen cost framework and full system costing

The Lao PDR Hydrogen and Ammonia Production Roadmap (Ministry of Energy and Mines et al., 2024) presents a range of potential hydrogen production costs depending on electricity input price: an optimistic estimate of $1.24/kg at $10/MWh surplus electricity, and a conservative estimate of $3.40/kg at $60/MWh. Both figures assume a capacity factor of 60–70% for Lao PDR seasonal hydropower surpluses. This study models both scenarios in parallel throughout sections 3 and 4, rather than relying on the optimistic figure alone, to provide a more complete picture of the range of plausible outcomes.

Both the variable-cost output price and the full LCOE are reported throughout this study, rather than the full LCOE alone, for two reasons. First, the variable cost inputs ($1.24/kg and $3.40/kg) are drawn directly from a Lao PDR-specific government planning document, whereas the fuel cell and storage capital cost inputs are drawn from general international literature not yet validated for the Lao PDR context; collapsing both into a single full LCOE figure would obscure this difference in evidentiary reliability. Second, reporting both layers allows the source of any cost gap with the import price to be attributed specifically to either the variable production cost or the capital cost of infrastructure, which is necessary to identify where policy intervention would be most effective. In addition to the variable hydrogen production cost, the full system cost of the P2H2P pathway includes two further capital-intensive components not captured in the per-kilogram hydrogen cost: the fuel cell reconversion plant and the seasonal hydrogen storage facility. To address this directly, the model is extended beyond the variable-cost-only output price (step 5) to calculate a full Levelised Cost of Electricity (LCOE) that annualises these capital costs and expresses them on a $/kWh basis, consistent with the output electricity delivered. The fuel cell plant is sized to the average dry-season reconversion power requirement of approximately 409 MW, at an assumed capital cost of $1,352/kW for stationary PEM fuel cell systems, based on the current (2025) mid-case total overnight cost reported by Reznicek et al. (2026). This capital cost is annualised using a capital recovery factor of 0.0944, calculated at a 7% discount rate over a 20-year project lifetime, consistent with the discount rate and lifetime assumptions used across the comparable studies reviewed in section 2. Hydrogen storage is costed using the levelised cost of underground salt cavern storage of approximately $2.3/kg H_2 (Chen et al., 2022), since above-ground compressed gas storage at the scale of 105,910 tonnes is shown in section 4.5 to be physically impractical.

Two break-even production costs are calculated as key policy metrics. The variable-cost break-even is the hydrogen cost at which the P2H2P output price equals the $0.11/kWh import price on a variable-cost-only basis. The full LCOE break-even is the hydrogen cost at which the full system cost (including annualised fuel cell and storage capital expenditure) equals the $0.11/kWh import price; this is derived by subtracting the annualised capital cost components ($0.030/kWh fuel cell and $0.013/kWh storage) from the import price and multiplying by the step 4 conversion factor of 16.665 kWh/kg.

3.8. Data collection and limitations

All input parameters are drawn from secondary sources across three levels of authority: official national government documents (Ministry of Energy and Mines et al., 2024; Phoumin and Phongsavath, 2024), peer-reviewed academic and technical literature (Energy Transitions Commission, 2023; Staffell et al., 2019), and verified industry reporting (Yong, 2023). The most policy-critical parameter, the $1.24/kg hydrogen production cost, is sourced directly from a national government planning document, ensuring internal consistency between the model assumptions and the Lao PDR policy context within which the results are interpreted. The five-step model is straightforward to follow and verify: step 1 uses only the fuel cell efficiency, step 2 uses only the hydrogen LHV, step 3 uses only the production window and electrolyser energy requirement, step 4 combines the LHV and fuel cell efficiency, and step 5 divides the hydrogen production cost by the step 4 result. Because each step depends on a small number of clearly defined inputs, it is easy to see exactly how a change in any one parameter, such as a higher hydrogen cost or a lower fuel cell efficiency, flows through to the final output price. This traceability is what makes the two-scenario comparison introduced in section 3.7, and the sensitivity analysis presented in section 4.4, meaningful: the effect of any single parameter on the final output price can be isolated and attributed directly, rather than obscured within a more complex model.

The principal limitations of this study are as follows. First, while this study extends beyond the variable hydrogen production cost to incorporate the annualised capital cost of the fuel cell reconversion plant and seasonal hydrogen storage, the electrolyser capital cost itself is not separately disaggregated, as it is embedded within the $1.24/kg and $3.40/kg hydrogen production costs at the assumed capacity factors (Ministry of Energy and Mines et al., 2024) (Ministry of Energy and Mines et al., 2024). A fully disaggregated capital cost model remains a priority for future investment-grade analysis.

Second, the model assumes uniform electrolyser operation across all 4,320 wet season hours, whereas in practice the hydropower surplus will be unevenly distributed across hours and months.

Third, the storage cost calculation relies on published levelised costs for underground geological storage rather than a site-specific feasibility assessment, as the geological storage potential of Lao PDR has not yet been characterised; this remains the most significant outstanding uncertainty in the full system cost estimate. These limitations do not invalidate the central finding but define the boundaries within which the results should be interpreted.

4. Results and discussion

4.1. System sizing results

The five-step model yields a consistent and internally coherent set of results. A P2H2P system designed for full import displacement requires: a 1.35 GW electrolyser plant operating across 4,320 production hours; seasonal hydrogen storage for 105,910 tonnes; and a fuel cell reconversion plant sufficient to discharge 1,765 GWh during the dry season. The electrolyser capacity of 1.35 GW represents approximately 67.5% of the available 2.0 GW surplus input, confirming that the electricity resource is not the binding constraint on system feasibility. The 55 kWh/kg energy requirement is sourced from Hubert et al. (2024), which confirms a beginning-of-life PEM system consumption of 55.2 kWh/kg, consistent with the 55–75% system efficiency range reported in the reviewed literature (Kafle et al., 2021). These scale estimates are broadly consistent with large-scale hydropower-to-hydrogen systems modelled in Brazil (Nadaleti et al., 2020) and the United States (Andrus, 2025).

4.2. Calculation results

4.2.1. Hydrogen energy and mass

To recover 1,765 GWh of electricity at 50% fuel cell efficiency, 3,530 GWh of hydrogen energy must be stored. Converting this using the LHV constant yields a total hydrogen production requirement of 105,910 tonnes. For every unit of electricity ultimately delivered during the dry season, two units of hydrogen energy must be produced and stored during the wet season. The 50% reconversion efficiency follows Staffell et al. (2019), who apply this value for stationary hydrogen-to-power conversion in their global energy system analysis.

4.2.2. Electrolyser capacity and output yield

Producing 105,910 tonnes within the 4,320-hour wet season window requires a production rate of 24,516.44 kg/hour, translating to a required electrolyser capacity of 1.35 GW. Every kilogram of stored hydrogen, when passed through a fuel cell at 50% efficiency, yields 16.665 kWh of grid-ready electricity. This conversion ratio directly determines the output electricity price in step 5.

4.2.3. Output electricity price

On a variable production cost basis, the output electricity price under scenario 1 (optimistic) is $0.074/kWh, and under scenario 2 (conservative) is $0.204/kWh. Both figures are sourced directly from the Lao PDR Hydrogen and Ammonia Production Roadmap (Ministry of Energy and Mines et al., 2024), corresponding to surplus electricity input costs of $10/MWh and $60/MWh respectively, at a capacity factor of 60–70% for Lao PDR seasonal hydropower surpluses. Scenario 1 is consistent with the lower end of the LCOH range from comparable international literature (Aremu et al., 2025; Thapa et al., 2021), while scenario 2 sits within the mid-to-upper range observed across the broader literature reviewed in section 2. Neither output price is affected by the wet season window length, as both are driven solely by the hydrogen production cost and the fuel cell conversion yield per kilogram.

4.2.4. Comparative economic analysis

The central economic finding is presented in Table 4. On a variable production cost basis, domestically produced hydrogen-stored electricity costs $0.074/kWh under the optimistic scenario (33% below the $0.11/kWh import benchmark), but $0.204/kWh under the conservative scenario, 85% above the benchmark. When the annualised capital costs of the fuel cell reconversion plant and seasonal hydrogen storage are added to produce a full Levelised Cost of Electricity (LCOE), both scenarios rise above the import price; substantially so for scenario 2, and marginally for scenario 1.

Table 4. P2H2P output vs. Thailand dry-season import price, variable cost and LCOE

Metric	Scenario 1 (Optimistic)	Scenario 2 (Conservative)	Unit
Reference prices			
Wet-season export price to Thailand	$0.05	$0.05	USD/kWh
Dry-season import price from Thailand	$0.11	$0.11	USD/kWh
Variable production cost only (Step 5)			
H_2 production cost	$1.24/kg	$3.40/kg	USD/kg
Output electricity price	$0.074	$0.204	USD/kWh
vs. import price ($0.11/kWh)	−33% (less expensive)	+85% (more expensive)	%
Full system cost — capital costs included (full LCOE)			
+ Fuel cell plant CAPEX (annualised)	$0.030	$0.030	USD/kWh
+ Hydrogen storage CAPEX (annualised)	$0.013	$0.013	USD/kWh
= Full LCOE	$0.117	$0.247	USD/kWh
vs. import price ($0.11/kWh)	+6.4% (more expensive)	+124.2% (more expensive)	%

On a variable production cost basis only, the optimistic scenario represents a potential annual saving of approximately $62.8 million USD relative to continued imports, equivalent to approximately $1.57 billion USD over a 25-year project lifetime acurrent prices. However, once the full system is costed to include capital expenditure for the fuel cell reconversion plant and seasonal hydrogen storage, neither scenario remains cost-competitive with the $0.11/kWh import price: the full LCOE rises to $0.117/kWh under the optimistic scenario and $0.247/kWh under the conservative scenario, representing cost increases of 6.4% and 124.2% respectively above the import benchmark.

The fuel cell plant CAPEX of $0.030/kWh is derived from a plant sized to the average dry-season reconversion power requirement (approximately 409 MW) at an assumed capital cost of $1,352/kW for stationary PEM fuel cell systems, based on the current (2025) mid-case total overnight cost reported by Reznicek et al. (2026), annualised using a capital recovery factor of 0.0944 (7% discount rate, 20-year project lifetime). The hydrogen storage CAPEX of $0.013/kWh is derived from the levelised cost of underground salt cavern storage at approximately $2.3/kg H_2 (Chen et al., 2022), annualised using a capital recovery factor of 0.0944 (7% discount rate, 20-year project lifetime) over the total storage volume of 105,910 tonnes, and expressed on a per-kWh output basis by dividing by the annual energy output of 1,765 GWh. Both figures assume underground geological storage, since the alternative of above-ground compressed gas storage at the scale of 105,910 tonnes is shown in section 4.5 to require approximately 7,000 large pressure vessels and is not considered a practically feasible option at this scale.

Lao PDR currently sells power to Thailand at $0.05/kWh and buys it back at $0.11/kWh, an arrangement described as a “dire disconnect” reflecting the structural inequity of existing power purchase agreements in the Mekong region (Yong, 2023). On a variable cost basis, the P2H2P system narrows or reverses this inequity depending on the hydrogen production cost scenario. However, once full system costs are included, the P2H2P pathway does not yet offer a lower-cost alternative to continued imports under either scenario modelled in this study.

4.3. Sensitivity analysis results

The sensitivity analysis results are presented in Table 5. On a variable-cost-only basis, the $0.074/kWh result is robust across a wide range of scenarios. Even under the pessimistic assumption of 40% fuel cell efficiency, the variable-cost output price of $0.093/kWh remains 15% below the $0.11/kWh import benchmark, and the variable cost advantage is eliminated only if hydrogen production cost rises above approximately $1.83/kg, which is a 48% increase above the optimistic baseline. This break-even sits between the two scenarios drawn from the roadmap: it is above scenario 1 ($1.24/kg) but below scenario 2 ($3.40/kg), confirming that the conservative scenario alone is sufficient to erase the variable-cost advantage, consistent with the $0.204/kWh result reported in section 4.3. This variable-cost break-even should not, however, be read as a measure of overall system competitiveness. A more policy-relevant threshold is the full LCOE break-even, defined as the hydrogen production cost at which the full system (including annualised capital costs) equals the $0.11/kWh import price. This threshold is approximately $1.12/kg, which is below even the optimistic scenario 1 figure of $1.24/kg. This means that at the current fuel cell and storage capital cost assumptions, and at baseline 50% PEMFC efficiency, hydrogen would need to be produced below $1.12/kg for the full system to break even with imports on a levelised cost basis. Once the annualised capital expenditure of the fuel cell reconversion plant ($0.030/kWh) and hydrogen storage ($0.013/kWh) is added, the full LCOE for the optimistic scenario rises to $0.117/kWh, just

6.4% above the \$0.11/kWh import price before any sensitivity is applied and the conservative scenario rises further to \$0.247/kWh, 124.2% above the import price.

Table 5. Variable-cost output electricity price under alternative assumptions

Variable	Baseline value	Baseline price	Optimistic case	Pessimistic case	Relationship
H_2 production cost	\$1.24/kg	\$0.074/kWh	\$1.00/kg → \$0.060/kWh	\$3.40/kg → \$0.204/kWh (scenario 2)	Direct
Fuel cell efficiency	50%	\$0.074/kWh	60% → \$0.062/kWh	40% → \$0.093/kWh	Inverse
Electrolyser energy requirement	55 kWh/kg	\$0.074/kWh	47 kWh/kg (lower H_2 cost)	65 kWh/kg (higher H_2 cost)	Indirect
Wet season window	4,320 hrs	\$0.074/kWh	Higher surplus available	5-month window	Scale only
Variable-cost break-even threshold — variable cost advantage is lost if H_2 production cost rises above approximately \$1.83/kg (+48% above baseline)					

Under the optimistic fuel cell efficiency scenario of 60%, achievable with Solid Oxide Fuel Cell (SOFC) technology, the output price falls to approximately \$0.062/kWh, widening the cost advantage over the \$0.11/kWh import price to 44%. Under the pessimistic scenario of 40% fuel cell efficiency, the output price rises to \$0.093/kWh but still remains 15% below the import benchmark. Across all fuel cell efficiency scenarios tested at scenario 1 H_2 cost (\$1.24/kg), the variable-cost advantage over continued imports is maintained. When full system capital costs are included, the picture varies by efficiency level: adding the fuel cell plant (\$0.030/kWh) and hydrogen storage (\$0.011/kWh, recalculated for the reduced H_2 volume of 88,259 tonnes at 60% efficiency) CAPEX to the most favourable 60% SOFC case yields a full LCOE of approximately \$0.102/kWh, marginally below the \$0.11/kWh import price, making the 60% SOFC scenario the only combination tested that achieves full-system cost-competitiveness with imports. Under the baseline 50% PEMFC efficiency, the full LCOE of \$0.117/kWh remains marginally above the import price; full-system cost-competitiveness is therefore achievable under SOFC technology but not under the baseline PEMFC assumption. Closing this gap depends primarily on reducing the capital cost of seasonal hydrogen storage, since underground geological storage can reduce storage CAPEX by an order of magnitude relative to the above-ground compressed gas storage assumed in this study (María Villarreal Vives et al., 2023). These findings are fully consistent with the global literature, which universally identifies electrolyser CAPEX and electricity input cost as the primary economic drivers of hydrogen production viability (Paneru et al., 2024; Sangolt et al., 2025).

4.4. Synthesis and implications

The results show a mixed techno-economic picture for the P2H2P system in Lao PDR. The physical and technical case is sound: the country's surplus hydropower resource is more than sufficient to power a 1.35 GW electrolyser over the full six-month wet season, and the engineering of the value chain is well-characterised in the global literature reviewed in section 2. On a variable production cost basis, the economic case is positive under the optimistic scenario (\$0.074/kWh, 33% cheaper than imports) but negative under the conservative scenario (\$0.204/kWh, 85% more expensive than imports). Once full system costs are included, however, neither scenario is cost-competitive with continued imports: the full LCOE of \$0.117/kWh (optimistic) and \$0.247/kWh (conservative) both exceed the \$0.11/kWh import benchmark, by 6.4% and 124.2% respectively.

A central technical constraint underlying the full LCOE result is the physical scale of seasonal hydrogen storage. At 105,910 tonnes, above-ground compressed gas storage is not a practically feasible option: at a typical storage density of approximately 15 kg/m^3 for compressed gas vessels at 150 bar, the required storage volume exceeds 7 million m^3, equivalent to approximately 7,000 large pressure vessels. This finding directly supports the case for investigating underground geological storage, such as salt caverns or saline aquifers, where levelised storage costs are an order of magnitude lower than above-ground alternatives (María Villarreal Vives et al., 2023). The storage cost component used in this study's full LCOE calculation already assumes underground geological storage; the absence of site-specific geological characterisation data for Lao PDR is therefore the most critical remaining evidence gap, as the feasibility and actual cost of such storage in the Lao PDR context has not been established.

What distinguishes the Lao PDR context from comparable studies in the literature is the combination of an exceptionally low input electricity cost (\$10/MWh surplus hydropower in the optimistic scenario), a high and well-documented import price benchmark (\$0.11/kWh), and an asymmetric export-import price arrangement that makes continued import dependency costly. Both hydrogen production cost scenarios are grounded directly in the Lao PDR Hydrogen and Ammonia Production Roadmap (Ministry of Energy and Mines et al., 2024) at capacity factors of 60–70% for Lao PDR seasonal hydropower surpluses, cross-validated against the Energy Security White Paper (Phongsavath, 2024) and consistent with comparable international studies (Aremu et al., 2025; Thapa et al., 2021). This cross-source consistency provides confidence in the reliability of the variable cost input parameters; confidence in the full LCOE result is correspondingly lower, given that the fuel cell and storage capital cost figures are drawn from general international sources rather than Lao PDR-specific data.

The cost comparison presented in sections 4.3 and 4.4 treats imported and domestically produced electricity as economically equivalent, evaluated solely on a \$/kWh basis. This understates the case for the P2H2P pathway to the extent that energy security carries value beyond unit cost. The motivation for this study, set out in section 1.2, is precisely that import dependency exposes Lao PDR to risks the \$0.11/kWh benchmark does not price: supply disruption from regional grid constraints or counterparty decisions, exposure to volatile international energy markets, foreign currency outflow, and the prospect that climate-driven hydrological variability (Mekong River Commission, 2018) could simultaneously reduce Thailand's own exportable surplus during Lao PDR's dry season. A domestically controlled storage system would substantially reduce these risks regardless of its cost relative to imports. Quantifying this security value (for example, as an avoided-disruption cost or a diversification premium) is beyond the scope of the techno-economic model presented here, which is consistent with international practice in treating energy security as a qualitative or separately costed consideration rather than folding it into LCOE. However, the magnitude of the full LCOE premium identified in this study (6.4% under scenario 1, 124.2% under scenario 2) varies significantly by scenario: under scenario 1, the gap is narrow enough that energy security considerations could plausibly tip the overall assessment toward investment, whereas under scenario 2 the gap remains too large for security value alone to bridge; it should therefore be read as a relevant but partial consideration, not a basis for overturning the central cost finding.

Future research applying an explicit energy security valuation framework to the P2H2P option is identified as a priority in section 5.6.2.

Overall, the findings indicate that the variable cost of hydrogen production from surplus hydropower can be competitive with electricity imports under favourable conditions, but the capital cost of seasonal-scale storage infrastructure is the decisive barrier to full system viability, consistent with the universal finding across the literature reviewed in section 2 that storage and electrolyser capital costs are the dominant economic drivers of P2H2P feasibility (Paneru et al., 2024; Sangolt et al., 2025).

5. Conclusions

This research makes a direct and quantified contribution to the policy debate on energy security in Lao PDR. By comparing the cost of domestically produced hydrogen-stored electricity against the documented dry-season import price under two scenarios and on both a variable-cost and full-system basis, the study provides a costed and reproducible framework for evaluating the P2H2P option against continued import dependency. The findings offer evidence-based guidance for policymakers at the Ministry of Energy and Mines and executives at EDL, and establish a methodological template for evaluating P2H2P systems in other hydro-dominant developing economies in the Mekong region that face structurally similar seasonal energy challenges. The principal numerical results are summarised in Table 6.

Table 6. Summary of principal quantitative results

Item	Value	Unit
System inputs		
Dry season electricity import deficit	1,765	GWh/year
Available wet season surplus cap	2.0	GW
Wet season production window	4,320	Hours (May–October)
System sizing results		
H_2 energy to produce and store	3,530	GWh
H_2 mass to produce	105,910	Tonnes
Required electrolyser capacity	1.35	GW
Economic results		
Electricity output per kg H_2	16.665	kWh/kg
Output electricity price — Scenario 1 (optimistic, variable cost)	$0.074	USD/kWh
Output electricity price — Scenario 2 (conservative, variable cost)	$0.204	USD/kWh
Full LCOE (included fuel cell + storage CAPEX) — Scenario 1	$0.117	USD/kWh
Full LCOE (included fuel cell + storage CAPEX) — Scenario 2	$0.247	USD/kWh
Dry-season import price (benchmark)	$0.11	USD/kWh
Cost saving vs. import — Scenario 1, variable cost only (annual at 1,765 GWh)	$0.03559/kWh (33%)	approximately $62.8M/year

5.1. Addressing the research questions

RQ1 - Required system scale: A 1.35 GW electrolyser plant producing 105,910 tonnes of hydrogen over the 4,320-hour wet season window (May–October), together with a seasonal hydrogen storage facility and a fuel cell reconversion plant sufficient to discharge 1,765 GWh over the dry season.

RQ2 - On a variable production cost basis, $0.074/kWh under scenario 1 (optimistic) and $0.204/kWh under scenario 2 (conservative). When the annualised capital costs of the fuel cell reconversion plant and seasonal hydrogen storage are added to produce a full Levelised Cost of Electricity, the price rises to $0.117/kWh (scenario 1) and $0.247/kWh (scenario 2).

RQ3 - Comparison with import price: On a variable production cost basis, the domestic P2H2P cost is 33% cheaper than the $0.11/kWh dry-season import price (Yong, 2023) under scenario 1, representing a potential annual saving of approximately $62.8 million USD and a 25-year cumulative saving of approximately $1.57 billion USD, but 85% more expensive under scenario 2. Once full system capital costs are included, however, neither scenario remains cost-competitive with imports: the full LCOE exceeds the $0.11/kWh benchmark by 6.4% under scenario 1 and 124.2% under scenario 2. This implies that domestic hydrogen storage is not currently a lower-cost alternative to imports once capital expenditure is accounted for, and that closing the gap depends primarily on reducing the capital cost of seasonal hydrogen storage infrastructure.

RQ4 - Critical variables: Fuel cell reconversion efficiency and hydrogen production cost are the two most influential variables. Even under pessimistic assumptions (40% fuel cell efficiency), the variable-cost output price of $0.093/kWh remains 15% below the import benchmark, and the variable-cost advantage is eliminated only if hydrogen production cost rises above approximately $1.83/kg, which is a 48% increase above the optimistic baseline. However, once full system capital costs are included, cost-competitiveness with imports is only achieved under the most favourable combination tested: the 60% SOFC efficiency case yields a full LCOE of approximately $0.102/kWh, marginally below the $0.11/kWh import price. Under the baseline 50% PEMFC efficiency, the full LCOE of $0.117/kWh exceeds the import price. Closing this remaining gap under the baseline assumption depends primarily on reducing the capital cost of seasonal hydrogen storage. The full LCOE break-even hydrogen cost, defined as the production cost at which the full system equals the $0.11/kWh import price at baseline efficiency, which is approximately $1.12/kg, below the Roadmap's optimistic scenario 1 estimate of $1.24/kg, providing a precise and quantified policy target for cost reduction efforts.

5.2. Contributions of the research

This research makes three original contributions. First, it provides the first published, quantitative techno-economic calculation of a P2H2P seasonal energy storage system specific to Lao PDR, directly addressing the geographical gap in the global literature identified in section 2. Second, the transparent five-step calculation framework, extended to a two-scenario, two-layer (variable cost and full LCOE) costing structure, is fully reproducible and can be adapted for comparable hydro-dominant developing economies. Third, the research establishes with quantified precision that while green hydrogen storage can be cheaper than imports on a variable production cost basis, it is not yet cost-competitive once the capital expenditure of fuel cell reconversion and seasonal storage is included, reframing the policy conversation from a general question of feasibility to the specific, quantified barrier of storage capital cost, and the conditions (principally geological storage feasibility) under which that barrier could be overcome.

5.3. Limitations of the study

- Electrolyser CAPEX not independently disaggregated: The \$0.074/kWh and \$0.204/kWh variable-cost output prices, and the \$0.117/kWh and \$0.247/kWh full LCOE figures, rely on the assumption that the roadmap's \$1.24/kg and \$3.40/kg hydrogen production costs are themselves capital-cost-inclusive levelised figures; this assumption could not be independently verified against the roadmap's underlying methodology, as electrolyser CAPEX is not separately disaggregated in the published source.
- Secondary data: All parameters are drawn from secondary sources; accuracy depends on their reliability.
- Storage cost not site-verified: The underground salt cavern storage CAPEX of \$2.3/kg H_2 is drawn from a US Intermountain-West case study (Chen et al., 2022) rather than Lao PDR-specific geological data; the geological storage potential of Lao PDR has not yet been characterised, and this remains the most significant outstanding uncertainty in the full LCOE estimate.
- Uniform production assumption: The model assumes uniform electrolyser operation across 4,320 hours; actual surplus is unevenly distributed and subject to inter-annual variability.
- Fuel cell CAPEX from a single source: The \$1,352/kW fuel cell capital cost is drawn from a single US-based stationary PEM fuel cell cost report (Reznicek et al., 2026) and has not been cross-validated against other sources or against Southeast Asian cost and supply chain contexts.
- Energy security value not quantified: The cost comparisons in this study treat imported and domestically stored electricity as equivalent, valued only on a \$/kWh basis. The energy security benefits motivating this research (section 1.2), reduced exposure to supply disruption, price volatility, and climate-driven hydrological risk shared with the import counterparty, are discussed qualitatively in section 4.5 but are not assigned a monetary value, which would require a dedicated energy security valuation framework beyond this study's scope.

5.4. Recommendations

5.4.1. For policymakers

- Commission a full investment-grade LCOE model: This study establishes that domestic hydrogen storage is cost-competitive with imports on a variable production cost basis, but not yet on a full system cost basis, primarily due to the capital cost of seasonal hydrogen storage. The most urgent next step is therefore a fully disaggregated, investment-grade techno-economic model for Lao PDR specifically, one that separates out electrolyser CAPEX from the Roadmap's per-kg figures and replaces the literature-sourced fuel cell and storage CAPEX assumptions used in this study with site- and country-specific data, to confirm whether the full LCOE gap identified here can be closed.
- Commission a national geological storage survey: Underground geological storage can reduce storage costs by an order of magnitude versus above-ground compressed gas. A survey of the Vientiane Basin and central Lao formations should be commissioned immediately.

- Initiate a pilot-scale P2H2P project: Commission a pre-feasibility study for a 20–50 MW pilot at a reservoir with documented spill volumes to generate real operational data and attract multilateral climate finance.
- Pursue concessional climate finance: The project's alignment with energy security and regional decarbonisation provides a compelling basis for financing from the ADB Clean Energy Fund, the Green Climate Fund, and ASEAN climate facilities.
- Renegotiate the EDL–EGAT import arrangement: The documented asymmetry between the $0.05/kWh export price and $0.11/kWh import price (Yong, 2023) should be addressed through renegotiation of the power sharing agreement in parallel with P2H2P development.

5.4.2. For future research

- Disaggregate electrolyser capital cost: This study's fuel cell and storage capital costs are now incorporated into a full LCOE; the genuine remaining gap is a separately disaggregated electrolyser CAPEX, and replacement of the literature-sourced fuel cell and storage cost assumptions with site- and country-specific Lao PDR data, to produce a fully investment-grade model.
- Develop an hourly-resolution dispatch model: Advance beyond the annual energy balance model to an hourly simulation capturing the precise timing and variability of surplus generation across the wet season.
- Assess regional hydrogen export potential: Model the economic case for scaling the system to produce hydrogen or ammonia for export to Thailand, Vietnam, and China.
- Conduct an environmental life-cycle assessment: Quantify the net GHG emissions profile of the system to validate its green credentials and assess eligibility for carbon credit frameworks.
- Evaluate hybrid storage configurations: Evaluate hybrid architectures combining compressed gas for short-duration balancing with ammonia synthesis for long-duration seasonal storage.
- Develop an energy security valuation framework: Quantify the value of reduced import dependency, for example, as an avoided-disruption cost or diversification premium, to determine whether energy security benefits, alongside cost, justify P2H2P investment even where the full LCOE exceeds the import price.

5.5. Conclusion

Lao PDR's hydropower paradox is not a resource problem but a temporal one. The country possesses an abundant clean energy surplus for six months of the year (May–October) and a well-documented, financially costly import dependency for the other six. The current arrangement of selling electricity to Thailand at $0.05/kWh and buying it back at $0.11/kWh is both economically irrational and strategically unnecessary given the available technology (Yong, 2023).

This research provides a layered, two-scenario, two-layer answer to the question of P2H2P feasibility for Lao PDR. On a variable production cost basis, a system powered by 2.0 GW of surplus wet-season hydropower can produce and store 105,910 tonnes of hydrogen over the six-month wet season (4,320 hours) and reconvert it to 1,765 GWh of grid-ready electricity at $0.074/kWh under the optimistic Roadmap scenario ($10/MWh electricity), 33% below the current $0.11/kWh import price, but at $0.204/kWh under the conservative roadmap scenario ($60/MWh electricity), 85% above the import price. When the full system is costed to include the capital expenditure of the fuel cell reconversion plant and seasonal hydrogen storage, the full Levelised Cost of Electricity rises to \$0.117/kWh and \$0.247/kWh respectively, above the import price under both scenarios. The required electrolyser capacity of 1.35 GW is technically well-characterised in the global literature reviewed in section 2, and the cost trajectory for electrolyser technology is firmly downward; however, the capital cost of seasonal-scale hydrogen storage is identified as the decisive barrier to full system viability.

The immediate priorities are clear: a fully disaggregated, investment-grade capital cost model; a geological storage feasibility survey for Lao PDR specifically, given the central role storage cost plays in the full LCOE result; and a pilot-scale project to generate the operational and cost data needed to refine these estimates and engage multilateral climate finance. These steps will determine whether Lao PDR can transform the 'Battery of Southeast Asia' ambition from a seasonal aspiration into a year-round reality, on its own terms, at its own prices, and without the costly dependency on its neighbours that currently defines its dry season.

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