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THESIS NO.: M-190-MSESPM-2017-2026

End-Use Feasibility Assessment Of Green Hydrogen Production Using Surplus Hydropower In Nepal

by

Nabin Suwal

A THESIS

SUBMITTED TO DEPARTMENT OF MECHANICAL AND AEROSPACE ENGINEERING IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF

MASTER OF SCIENCE IN ENERGY SYSTEM PLANNING AND MANAGEMENT

DEPARTMENT OF MECHANICAL AND AEROSPACE ENGINEERING
LALITPUR, NEPAL

JUNE 2026

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Head
Department of Mechanical and Aerospace Engineering
Pulchowk Campus, Institute of Engineering
Lalitpur, Kathmandu
Nepal

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The undersigned certify that they have read, and recommended to the Institute of Engineering for acceptance, a report entitled "End-Use Feasibility Assessment Of Green Hydrogen Production Using Surplus Hydropower In Nepal" submitted by Nabin Suwal in partial fulfillment of the requirements for the degree of Master of Science in Energy System Planning and Management.

Supervisor
Dr. Nawraj Bhattarai
Department of Mechanical and Aerospace Engineering
Associate Professor
IOE, Pulchowk Campus

External Examiner
Assoc. Prof. Dr. Shailendra Kumar Jha
Kathmandu University, Dhulikhel, Nepal

Tribhuvan University
Institute of Engineering
Department of Mechanical and Aerospace Engineering
Pulchowk Campus

Committee Chairperson, Sudip Bhattrai, Ph.D.
Head of Department
Department of Mechanical and Aerospace Engineering
IOE, Pulchowk Campus

Date: June 12,2026

ACKNOWLEDGMENT

I am deeply grateful to my supervisor, Associate Professor Dr. Nawraj Bhattarai, for the guidance, patience, and careful attention brought to this work throughout its development. The feedback was substantive, the questions were consistently well directed, and the engagement with the technical and analytical dimensions of the research at every stage contributed materially to both its direction and its quality.

I am equally thankful to Dr. Sudip Bhattarai, Head of the Department of Mechanical and Aerospace Engineering, Pulchowk Campus, for sustaining an academic environment in which rigorous inquiry is genuinely supported. The institutional backing, departmental resources, and scholarly standards maintained within the department provided the conditions this work required to be carried out properly.

Finally, I acknowledge everyone who directly or indirectly contributed to the completion of this thesis. This work would not have been possible without their support.

Nabin Suwal
073/MSESPM/562

ABSTRACT

Nepal's hydropower system generates wet-season electricity surpluses while requiring dry-season imports. This thesis evaluates five utilization pathways for that surplus: direct domestic electrification, re-electrification via hydrogen fuel cells, hydrogen in heavy-duty transport, industrial fuel substitution, and green ammonia production for fertilizer import substitution.

The analysis covers 860 calendar days of cleaned energy data spanning 5 September 2022 to 11 January 2025, recording 4,765,656 MWh of export surplus and 3,873,716 MWh of import energy. Export energy is projected over a 20 year horizon using a hybrid seasonal SARIMA framework under three scenarios: conservative at 0%, moderate at 3%, and aggressive at 6% annual surplus growth. Under the moderate scenario, a 500 MW electrolyzer produces 37,974 tonnes of hydrogen per year at a 43.3% capacity factor and an LCOH of NPR 693/kg-H_2.

Direct electrification returns the strongest economic result, with an NPV of NPR 168.59 billion and a BCR of 1.82. Among hydrogen pathways, heavy duty transport leads with an NPV of NPR 44.55 billion and a BCR of 1.14. Green ammonia reaches 215,313 tonnes per year but requires an additional NPR 13.78/kg-NH_3 to achieve import substitution viability. Re electrification breaks even at NPR 55.15 per kWh against an avoided import value of NPR 12 per kWh, making it economically difficult to justify under present conditions.

Green hydrogen is not inherently superior to direct electricity use; its viability depends on the value of the end product. Direct electrification should be prioritised for surplus absorption, hydrogen transport suits high utilisation diesel displacing fleets, green ammonia warrants consideration as a longer term fertilizer security strategy, and re electrification remains a weak option unless the value of seasonal storage rises substantially.

Keywords: Green hydrogen; hydropower surplus; SARIMA; electrolyzer sizing; LCOH; green ammonia; direct electrification; MCDA

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LIST OF ABBREVIATIONS

BCR	Benefit-Cost Ratio
CAPEX	Capital Expenditure
CRF	Capital Recovery Factor
GHG	Greenhouse Gas
LCOA	Levelized Cost of Ammonia
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Hydrogen
LHV	Lower Heating Value
MAE	Mean Absolute Error
MCDA	Multi-Criteria Decision Analysis
NEA	Nepal Electricity Authority
NPV	Net Present Value
PEM	Proton Exchange Membrane
RMSE	Root Mean Square Error
SARIMA	Seasonal Autoregressive Integrated Moving Average
SEC	Specific Energy Consumption

1 INTRODUCTION

1.1 Background

1.1.1 Global Energy Transition

Global energy systems are undergoing structural transition due to climate-policy commitments, declining renewable-energy costs, and the need to decarbonize hard-to-electrify sectors. Fossil fuels still supply roughly 73% of global greenhouse gas emissions (Climate Watch, 2020), and the physical consequences of that dependence are rising temperatures, shifting precipitation patterns, more frequent extreme weather, which are no longer projections. They are recorded data. The Paris Agreement, adopted in 2015, formalized the international response by setting a target of limiting warming to well below 2°C above pre-industrial levels (United Nations Framework Convention on Climate Change, 2015), but translating that commitment into actual infrastructure change has proven far harder than drafting the agreement itself. Fig. 1-1 shows this increment in renewable energy useage.

What has changed the calculus more than any policy framework is cost. The price of solar photovoltaic electricity fell by over 85% between 2010 and 2020 (International Energy Agency, 2019). Wind power followed a similar trajectory. Suddenly, the argument that renewables were too expensive to displace fossil fuels became untenable in a growing number of markets. By 2020, the IEA reported that renewables accounted for nearly 29% of global electricity generation, with new capacity additions dominated by solar and wind (International Energy Agency, 2019). That share has continued to grow.

But electricity is only part of the problem. Decarbonizing power generation, while important, leaves untouched the sectors that are genuinely difficult to electrify: steel production, long-haul freight, shipping, aviation, and the high-temperature industrial processes that underpin modern manufacturing. These sectors collectively account for a substantial share of global emissions and have no straightforward pathway to direct electrification. This is where the energy transition gets complicated, and where hydrogen has entered the conversation as a potential solution rather than a peripheral curiosity (International Renewable Energy Agency, 2019).

1.1.2 Renewable Energy Integration Challenges

More renewables on the grid sounds straightforwardly good. In practice, it introduces a set of operational problems that conventional power systems were not built to handle. Solar and wind generation follow the sun and wind, not demand. When generation

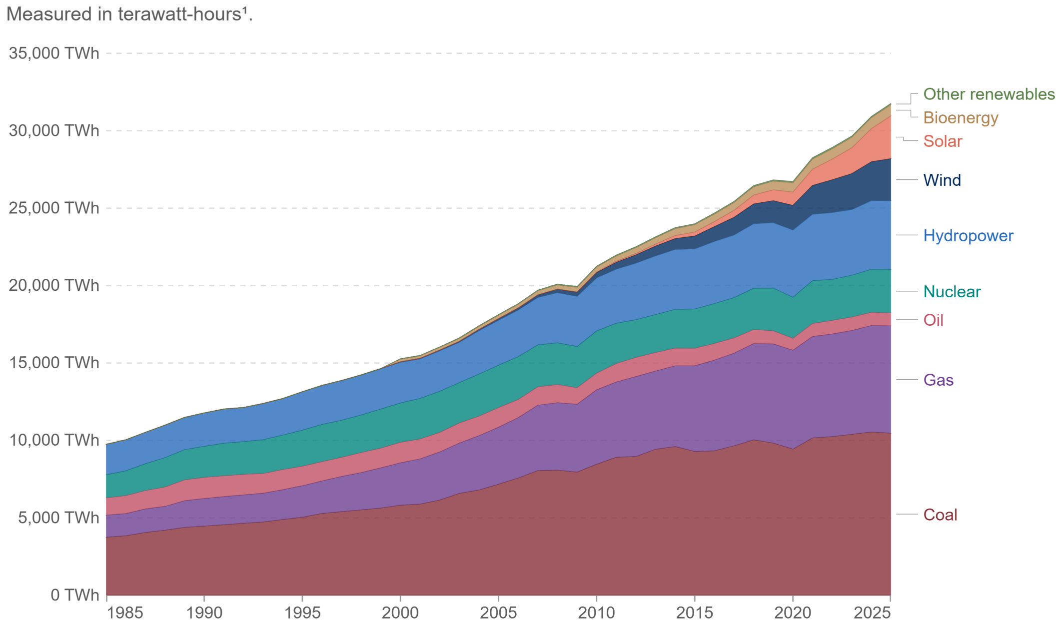

Figure 1-1 Electricity production by source. source: OurWorldinData.org/energy

exceeds load and there is nowhere to send the excess, grid operators have to curtail clean electricity. This is not a hypothetical future problem; it already happens at significant scale in systems like California, Germany, and parts of China (Kroposki et al., 2017).

Hydropower is more controllable than wind or solar, but it carries its own version of the variability problem. River discharge follows seasonal precipitation patterns, which means run-of-river hydropower plants generate far more in wet months than in dry ones. The generation profile is predictable, but the mismatch between peak generation and peak demand is real and recurring. In countries where hydropower provides the dominant share of electricity supply, that mismatch shapes the entire economics of the electricity system.

Storage is the obvious answer, and pumped hydro has historically been the dominant large-scale storage technology, accounting for over 90% of installed storage capacity globally (International Renewable Energy Agency, 2020). But pumped hydro requires specific geography, takes years to build, and is expensive to develop. Battery storage is scaling fast, but current economics make it unattractive for storage durations beyond a few hours. For multi-day or seasonal storage, where the energy volumes involved are orders of magnitude larger, neither batteries nor pumped hydro provide a satisfying answer at reasonable cost. That gap is a real constraint on how far variable renewable penetration can go without either wasting surplus generation or accepting reliability risks during deficit periods (Kroposki et al., 2017),(International Renewable Energy Agency, 2020).

1.1.3 Hydrogen as an Energy Vector

Hydrogen has the highest energy content per unit mass of any fuel that is approximately 120 MJ/kg on a lower heating value basis, roughly three times that of natural gas (Turner, 2004). It burns to produce water vapor. When produced from renewable electricity, its lifecycle greenhouse gas emissions are near zero. These characteristics make hydrogen relevant for applications requiring high specific energy or chemical feedstock substitution.

The complications are equally real. At atmospheric pressure and temperature, hydrogen is a gas with very low volumetric density. A kilogram of hydrogen occupies about 11 cubic meters at standard conditions. Storing and transporting it usefully requires either compression to several hundred bar, liquefaction to -253°C, or conversion to a hydrogen-bearing chemical compound. Each approach works, but each carries energy penalties and infrastructure costs that do not apply to natural gas or liquid fuels (Züttel, 2004).

Hydrogen is already produced and consumed globally at industrial scale roughly around 70 million tonnes per year, mostly for petroleum refining and ammonia synthesis (International Energy Agency, 2019). Almost all of it comes from natural gas reforming or coal gasification, processes that emit substantial CO2. This is what the energy industry calls grey hydrogen. When carbon capture is added to the same process, it becomes blue hydrogen, with debate ongoing about how effective the capture actually is when upstream methane leakage is counted. Green hydrogen, produced via electrolysis powered by renewable electricity, avoids direct CO2 emissions entirely and is the focus of the present study.

The costs of green hydrogen remain higher than grey hydrogen in most markets, but the gap is narrowing. Electrolyzer capital costs have fallen substantially over the past decade, and further reductions are expected as manufacturing scales up (Schmidt et al., 2017). In regions with very low-cost renewable electricity, green hydrogen is already approaching cost parity with grey hydrogen in some analyses, and projections from IRENA suggest that cost parity could be achievable across a broader range of geographies by 2030 (International Renewable Energy Agency, 2020).

1.1.4 Green Hydrogen and Hydropower

Among renewable electricity sources, hydropower occupies a particular position in the hydrogen production picture. It is dispatchable, highly reliable, and in many developing countries represents existing installed infrastructure that is already generating electricity, sometimes more than domestic demand can absorb. Where that surplus exists and where the counterfactual is curtailment or low-price export, the effective electricity cost for hydrogen production can be very low (Thapa et al., 2021).

The pairing of hydropower with electrolysis is not new. Large-scale hydroelectric-powered hydrogen facilities operated in Norway from the 1920s onward, and their operational history provides a real-world baseline for what this technology combination actually delivers in practice (Ulleberg et al., 2010). More recent analyses have examined surplus hydropower in regions including Brazil, sub-Saharan Africa, and South Asia, finding that seasonal surplus profiles in these systems can support substantial hydrogen production volumes. The seasonal concentration of surplus during wet months aligns reasonably well with the operating requirements of electrolyzers, provided the project economics are designed around seasonal rather than year-round operation (Thapa et al., 2021).

The efficiency chain from hydro generation to hydrogen end use involves several conversion steps. Commercial alkaline and PEM electrolyzers achieve system efficiencies in the range of 60–75% on a lower heating value basis (Schmidt et al., 2017). What happens after production depends on the end-use pathway: reconversion to electricity through a fuel cell adds another round of losses, while direct use as a transport fuel or chemical feedstock avoids that reconversion penalty. This efficiency arithmetic and its economic consequences for different end uses is a central theme of the present study.

1.2 Current Energy Scenario of Nepal

1.2.1 Electricity Generation Status

Nepal's electricity system is, in practical terms, a hydropower system. The country sits across some of the steepest river gradients in the world, fed by Himalayan snowmelt and the South Asian monsoon, and its theoretical hydropower potential is estimated at around 83,000 MW, of which approximately 42,000 MW is considered economically viable under current cost assumptions (Water and Energy Commission Secretariat, 2010). Installed capacity stood below 2,000 MW through the late 2010s, which means the country had developed perhaps 5% of what its rivers could theoretically support. That low utilization figure is not a reflection of poor resources. It reflects decades of political instability, difficult project development environments, financing constraints, and the challenges of building large civil works in remote mountain terrain. The pace of development has accelerated since the mid-2010s, driven by improved Independent Power Producer frameworks, increased private sector participation, and growing engagement from development finance institutions. Nepal Electricity Authority data shows a clear upward trajectory in installed capacity through the 2010s, with the wet-season surplus situation becoming more pronounced as each new project was added (Nepal Electricity Authority, 2020).

The broader energy picture is less clean. While electricity generation is almost entirely renewable, the overall national energy mix remains heavily weighted toward biomass for cooking and heating, and imported petroleum products for transport. The share of traditional biomass in total primary energy supply has historically been estimated above 70%, though this has declined as grid electricity access has improved (Water and Energy Commission Secretariat, 2010). This structural disconnect where a renewable electricity sector sitting alongside a fossil-fuel-dependent transport and cooking sector is not unique to Nepal, but it is particularly pronounced here and shapes the relevance of hydrogen as a potential bridge between the two.

1.2.2 Seasonal Surplus Energy Situation

Nepal's surplus electricity problem is structural, not incidental. Run-of-river plants, which dominate the installed base, produce power in proportion to river discharge. Roughly 70–80% of annual discharge in Nepal's river basins occurs during and immediately after the June-to-September monsoon, which means generation peaks sharply in wet months and falls well short of demand during the November-to-April dry season (Shrestha and Acharya, 2020). The system alternates between surplus and deficit in a predictable annual cycle, and that cycle has defined Nepal's energy planning challenge for as long as the sector has existed.

The current disposal mechanism for wet-season surplus is primarily export to India under bilateral power trade arrangements, supplemented by whatever domestic demand growth has occurred. That arrangement works up to a point, but it has real constraints: bilateral agreements cap the volume that can be traded, transmission interconnection capacity at border crossings is limited, and India's own wet-season generation tends to be elevated, meaning Nepal exports surplus electricity at times when it is worth least to the buyer (Shrestha and Acharya, 2020),(Acharya and Bhatt, 2020).

Thapa et al. quantified this surplus systematically for the first time in the published literature, modeling surplus volumes under several hydropower expansion scenarios and finding that even conservative projections support hydrogen production at meaningful scale (Thapa et al., 2021). Their analysis showed that the seasonal concentration of surplus in wet months could sustain electrolysis operations for a substantial portion of the year, producing hydrogen volumes with real implications for transport fuel and ammonia supply. That paper is one of the two primary published foundations for the present study.

1.2.3 Future Hydropower Expansion

The project pipeline beyond what was commissioned through 2020 is substantial. Upper Tamakoshi (456 MW), the largest domestically financed hydroelectric project in

Nepal's history, reached full commissioning in 2021 (Investment Board Nepal, 2018). Projects including Budhigandaki (1,200 MW), Upper Arun (900 MW), and Upper Karnali (900 MW) are in various stages of development, financing, and construction. The Government of Nepal has stated targets of 10,000 MW by 2030 and 15,000 MW by 2035, though actual commissioning has historically run behind declared schedules (Water and Energy Commission Secretariat, 2010).

When these projects come online, the surplus situation during wet months will worsen in the sense that more surplus will need to be absorbed or disposed of unless domestic demand grows fast enough to match, or regional power trade infrastructure expands significantly. Demand growth in Nepal is real and ongoing, driven by improved grid access, electric cooking adoption programs, and the early stages of electric vehicle uptake, but it starts from a low base and is unlikely to fully absorb the output of an expanded generation fleet on its own.

Cross-border electricity trade with India and Bangladesh offers one avenue for surplus absorption, but trade volumes depend on political negotiations, transmission infrastructure investment, and market pricing in importing countries all of which involve uncertainties that Nepal does not fully control (Acharya and Bhatt, 2020). Developing alternative uses for surplus electricity is therefore not just an academic exercise. It is a practical hedging strategy against the risk that export markets cannot absorb all of what Nepal's expanded generation fleet will produce.

1.2.4 Green Hydrogen Initiatives in Nepal

Nepal does not yet have a dedicated green hydrogen policy or any operational hydrogen production facility. The Alternative Energy Promotion Centre and the Nepal Electricity Authority have acknowledged hydrogen as a potential long-term application for surplus energy in planning documents, but formal program development has not followed (Nepal Electricity Authority, 2020). The engagement to date has been primarily at the research level.

Thapa et al. provided the first systematic quantification of green hydrogen production potential from Nepal's surplus hydropower, identifying transportation and electricity generation as the most viable near-term end-use options (Thapa et al., 2021). Gyanwali et al. followed with an integrated hydropower-hydrogen power system model showing that hydrogen integration can reduce curtailment and support grid decarbonization pathways (Gyanwali et al., 2022). These two papers constitute essentially the full published literature specifically addressing green hydrogen in Nepal, which is itself a measure of how early-stage the conversation is.

International development finance institutions including the Asian Development Bank have included Nepal in regional assessments of green hydrogen potential in South and Southeast Asia (Bajracharya et al., 2015), but these assessments are high-level. They establish that Nepal belongs on the map of potential hydrogen-producing countries, but they do not provide the country-specific technical and economic analysis that investment or policy decisions would require.

1.3 Significance of the study

Nepal is approaching a point in its hydropower development trajectory where the seasonal surplus problem will become harder to ignore. Each new project that comes online adds to wet-season generation that already exceeds domestic absorption capacity during peak months. The options on the table are curtailment, low-price export, pumped storage, demand side growth each have practical limits. Green hydrogen is not a silver bullet, but it deserves a rigorous comparative analysis alongside those alternatives rather than remaining a vague aspiration in planning documents.

The economic argument for this study is direct. Surplus electricity exported to India during wet months earns less per unit than the electricity Nepal imports from India during dry months (Shrestha and Acharya, 2020). If surplus electricity can be converted to hydrogen and used domestically at a value above that marginal export price, the net economic return from hydropower investment improves. Whether that conversion is economically viable, and which end-use pathway delivers the best return under Nepal's specific cost and market conditions, is precisely what has not been established.

From a research standpoint, Nepal is an interesting and underexamined case. Most green hydrogen techno-economic literature is anchored in OECD contexts, with cost assumptions and infrastructure conditions that do not transfer directly to a landlocked, developing-country, hydropower-dominated system. The specific combination of seasonal surplus profile, limited downstream industrial infrastructure, agricultural import dependence, and constrained regional trade options that characterizes Nepal has not been the subject of a structured multi-pathway end-use analysis.

The study also has relevance beyond Nepal's borders. Bhutan, Myanmar, the Democratic Republic of Congo, and several other countries share the combination of large hydropower resources, seasonal generation surplus, and limited domestic absorption capacity that makes Nepal's hydrogen question relevant at a regional or global level. A credible feasibility analysis for Nepal provides a methodological template and a set of benchmarks that those contexts can draw on.

1.4 Problem Statement

Nepal faces a structural energy problem that seasonal variation makes difficult to resolve. Wet months bring surplus hydropower that currently flows mostly into electricity exports, while dry seasons still require imports. Fossil fuels remain the default across transport and industry. The surplus generation that could serve longer-term purposes is largely treated as a short-term export commodity.

The existing literature leaves several questions unanswered. How surplus hydropower can be optimally directed toward hydrogen production has not been systematically examined. Whether hydrogen-based seasonal storage is technically feasible under Nepalese grid conditions has not been investigated in sufficient depth. A rigorous comparison of hydrogen end-use options specific to Nepal is absent. Whether hydrogen utilization pathways can compete economically with direct electricity export has also not been established with adequate analytical rigour.

A systematic feasibility assessment, grounded in Nepal's specific seasonal energy profile, is therefore needed to inform both further research and evidence-based policy decisions.

1.5 Objective

1.5.1 Major Objective

The main objective is to assess the technical and economic feasibility of green hydrogen production and its end use applications using surplus hydropower energy in Nepal.

1.5.2 Specific Objectives

The specific objectives are as follows:

- To analyze seasonal grid data to estimate surplus hydropower and its green hydrogen production potential.
- To assess the technical and economic feasibility of utilizing hydrogen for transport, industry, green ammonia, and re-electrification.
- To identify the most viable hydrogen pathway to guide Nepal's strategic energy planning.

1.6 Scope of the Work

This study draws on daily historical data covering electricity generation, export, import, and national demand. The scope is confined to green hydrogen production from surplus hydropower, with selected end-use pathways examined on a comparative basis. The techno-economic assessment is conducted using simplified but analytically meaningful indicators, comprising hydrogen production potential, electrolyzer utilization factor, levelized cost of hydrogen, import reduction potential, and revenue comparison across the evaluated pathways.

The study does not extend to detailed electrochemical modeling, dynamic grid stability simulation, detailed ammonia plant engineering design, or hydrogen transportation and distribution infrastructure planning. These dimensions fall outside the defined scope of this work and are identified as substantive areas warranting further dedicated investigation.

1.7 Limitation of Study

The analysis relies on published generation and demand data from the Nepal Electricity Authority and on techno-economic parameters drawn from international literature. While every effort has been made to select parameters appropriate to the Nepalese context, some cost figures — particularly for hydrogen infrastructure components such as refueling stations and ammonia synthesis plants — are sourced from global studies and may not fully reflect local procurement, construction, and financing costs in Nepal. These are identified explicitly in the methodology chapter, and sensitivity analyses are used to test the robustness of conclusions to cost uncertainty.

2 LITERATURE REVIEW

2.1 Nepal's Hydropower Development and Energy Transition

Nepal is one of the few countries in the world whose electricity system is almost entirely renewable, not because of recent policy ambition but because its rivers made hydropower the only practical large-scale generation option for most of the country's history. The theoretical hydropower potential has been estimated at around 83,000 MW, with roughly 42,000 MW considered economically viable (Water and Energy Commission Secretariat, 2010). Installed capacity reached approximately 2,000 MW by the early 2020s, meaning perhaps one-twentieth of what the rivers could support had actually been built.

That gap between potential and installed capacity reflects the difficulty of hydropower development in Nepal's context more than any lack of resource. Political instability through the 1990s and 2000s, complex land acquisition and resettlement issues, difficult high-altitude construction environments, and limited access to project finance collectively slowed the sector for decades (Shrestha and Acharya, 2020). The liberalization of the Independent Power Producer framework and improvements in grid transmission infrastructure in the 2010s changed that trajectory, and a growing number of projects moved from feasibility study to construction to commissioning. Nepal Electricity Authority data tracks the consequent rise in installed capacity through the decade and the shift from chronic load shedding to seasonal surplus (Nepal Electricity Authority, 2020).

The broader energy transition picture in Nepal is structurally uneven. The electricity sector is genuinely clean. The rest of the energy economy is not. Traditional biomass supplies a large share of cooking and heating energy, and imported petroleum products dominate transport. This combination means that Nepal's carbon footprint per unit of energy service in electricity is among the lowest in the region, while its per capita energy access and energy poverty metrics still reflect significant underdevelopment (Water and Energy Commission Secretariat, 2010),(Bajracharya et al., 2015). Connecting those two realities that are expanding clean electricity system and a fossil-fuel-dependent rest of the economy is the broader energy transition challenge that hydrogen could, in principle, help address.

Bajracharya et al. examined hybrid renewable system configurations for Nepal and identified the structural mismatch between seasonal hydropower surplus and non-electricity energy demand as a long-term planning challenge that conventional grid expansion does not resolve (Bajracharya et al., 2015). Their analysis is one of the few published studies that explicitly frames Nepal's energy problem in terms of sector coupling rather than simple electricity access, and it provides useful context for understanding why green hydrogen, which crosses the boundary between electricity and fuel, is a relevant technology to examine in this setting.

2.2 Surplus Energy Scenario in Nepal

The seasonal character of Nepal's electricity system is not a design flaw that better engineering could fix. It is a direct consequence of the country's hydrology. Most of Nepal's river discharge comes from the South Asian monsoon, which runs from June through September, plus some snowmelt contribution in spring. Run-of-river plants produce in proportion to that discharge, so generation is concentrated in a four-to-five month window that does not map neatly onto electricity demand, which is relatively stable year-round with modest seasonal variation (Shrestha and Acharya, 2020).

The result is a well-documented annual cycle: wet-season surplus that currently exceeds domestic absorption and must be exported or, in some cases, curtailed; dry-season deficit that requires imports from India and historically caused severe load shedding before the recent capacity additions reduced its severity. Shrestha and Acharya examined this pattern quantitatively using NEA operational data and found that the terms of trade embedded in it are unfavorable as Nepal sells surplus electricity at lower prices than it pays to import during deficit periods, generating a recurring economic cost that grows with each capacity addition that does not come with matching storage or new demand (Shrestha and Acharya, 2020).

Thapa et al. provided the most rigorous published treatment of the surplus-to-hydrogen conversion potential, estimating hydrogen production volumes under multiple hydropower expansion scenarios (Thapa et al., 2021). Their central finding was that wet-season surplus could support sustained electrolysis at scale sufficient to make hydrogen supply economically significant for either transport fuel substitution or grid re-electrification. Crucially, the surplus volumes they identified are not incidental, they are structural features of a run-of-river-dominated system that will persist and grow regardless of demand-side growth rates, at least over the medium term.

Gyanwali et al. approached the same surplus problem from a grid optimization angle, using a hydropower-hydrogen integrated power grid model to show that hydrogen production can reduce curtailment and improve system economics compared to a scenario where surplus is either wasted or exported at marginal prices (Gyanwali et al., 2022). Their model treated hydrogen as a seasonal storage mechanism within a broader grid balancing framework, which is a somewhat different framing from the end-use pathway comparison at the center of the present study, but the underlying surplus data and findings are consistent.

The price asymmetry in Nepal-India power trade deserves specific attention because it directly affects the economic case for domestic hydrogen production. Studies of bilateral power trade arrangements have noted that Nepal's negotiating position on surplus export prices is constrained by its dependence on the same trading relationship for dry-season imports (Shrestha and Acharya, 2020),(Acharya and Bhatt, 2020). This creates an economic logic for developing domestic alternatives to low-price export that is independent of any enthusiasm for hydrogen technology per se.

2.3 Hydrogen as an Energy Carrier

Hydrogen's basic physical and chemical properties are well established, and the literature on its role as an energy carrier is now very large. A few properties are worth anchoring clearly before the more applied discussions that follow. Hydrogen has a lower heating value of approximately 120 MJ/kg that is about three times that of natural gas on a mass basis and burns to produce water vapor with no direct CO2 emission (Turner, 2004). These properties make it, in principle, a clean, high-energy-density fuel. The complications arise when you need to actually store and move it.

At standard temperature and pressure, hydrogen is a gas with a volumetric energy density of around 0.01 MJ/L, compared to roughly 34 MJ/L for gasoline. That difference of three orders of magnitude is not a detail. It is the central physical challenge of the hydrogen economy (Züttel, 2004). Compression to 350 or 700 bar, liquefaction at cryogenic temperatures, or conversion to a hydrogen-carrying compound such as ammonia or methanol are the main approaches to dealing with this, each with its own energy penalty, infrastructure requirements, and cost profile.

What is different now is that renewable electricity costs have dropped enough to change the production cost equation, and that policy support has become serious enough in enough major economies to start building demand at scale (International Renewable Energy Agency, 2019),(International Energy Agency, 2019). Turner argued as early as 2004 that the long-term case for a hydrogen economy depends on renewable electricity becoming cheap enough to make electrolysis competitive with fossil-based production, and that this was a matter of when rather than whether (Turner, 2004). The trajectory of solar and wind costs since that paper was published has been broadly consistent with that prediction.

Staffell et al. reviewed the role of hydrogen and fuel cells across the full energy system, from stationary power to transport to industrial use, and found that no single application alone justifies the infrastructure investment required for a hydrogen economy and the economic case is strongest when multiple end-use sectors can share production and distribution infrastructure costs (Staffell et al., 2019). That finding is directly relevant for Nepal, where the scale of potential hydrogen production from surplus hydropower might exceed the near-term demand of any single sector, making a multi-pathway approach economically more robust than betting on one application.

2.4 Green Hydrogen Production Technologies

Water electrolysis, splitting H_2O into hydrogen and oxygen using electrical energy, has been practiced at industrial scale for over a century. The Birkeland-Eyde process for nitrogen fixation, early industrial hydrogen supply in Europe, and Norwegian hydroelectric-powered electrolysis facilities from the 1920s are all historical instances of large-scale electrolysis in operation (Ulleberg et al., 2010). What has changed is not the underlying chemistry but the cost and performance of the equipment, and the cost of the electricity driving it.

Three electrolysis technologies are relevant to a feasibility assessment for Nepal. Alkaline electrolysis is the oldest and most mature, using a potassium hydroxide solution as electrolyte and operating at relatively low pressure and temperature. It is the technology with the longest commercial track record, demonstrated operational lifetimes exceeding 20 years in some industrial installations, and currently lower capital costs per kilowatt than proton exchange membrane systems (Zeng and Zhang, 2010). Its limitations are slower dynamic response to power fluctuations and lower current density, which increases the physical footprint per unit of hydrogen output.

Proton exchange membrane electrolysis uses a solid polymer membrane as both electrolyte and separator and can respond to power input changes in seconds. It produces very high purity hydrogen directly, operates at higher current densities than alkaline systems, and is well suited to applications where input power varies (Grigoriev et al., 2020a). The trade-off is higher capital cost, driven by platinum group metal catalysts and the membrane itself, though costs have been coming down as manufacturing has scaled. For surplus hydropower applications, where input power is seasonal but relatively stable within the operating period, both alkaline and PEM are technically appropriate, and the economic comparison between them is sensitive to specific project parameters.

Solid oxide electrolysis operates at temperatures above 700°C, achieving higher thermodynamic efficiency than low-temperature processes by using waste heat to assist water splitting. It remains at a relatively early stage of commercial development, with durability under prolonged operation still an active area of research (Hauch et al., 2020). For a near-term project in Nepal, solid oxide electrolysis is not a realistic choice, but it is relevant to note as the direction in which electrolysis technology is developing.

Grigoriev et al. reviewed all three technologies in technical detail, covering operating principles, materials requirements, performance data, and development status (Grigoriev et al., 2020a). For alkaline and PEM systems, which are the commercially relevant options for Nepal, they reported system efficiencies in the range of 63-71% for alkaline and 56-68% for PEM on a lower heating value basis. The difference is modest and overlapping; cell-level and system-level choices matter more than the technology category in practice.

Schmidt et al. surveyed electrolyzer manufacturers, researchers, and system integrators to develop probabilistic cost projections through 2030 and 2050 (Schmidt et al., 2017). Their central estimates projected capital cost reductions of 50-70% from 2017 levels by 2030, driven by manufacturing scale-up and component learning rates. The projections have remained broadly consistent with actual cost trends observed since publication and provide the most widely cited basis for forward-looking techno-economic analysis of green hydrogen projects planned for commissioning in the current decade.

2.5 Hydrogen Storage and Transportation

Storage and transport are, in many ways, the harder half of the hydrogen problem. Producing green hydrogen is now technically and increasingly economically feasible. Getting it from the electrolyzer to where it is needed, in a useful form and at acceptable cost, remains the part of the supply chain with the most unresolved challenges.

Physical compression to high pressure is the most straightforward approach and is widely used for small to medium-scale applications. Compressing hydrogen from the electrolyzer outlet pressure (typically 1-30 bar for alkaline, 30-80 bar for PEM) to 350 or 700 bar for vehicular use consumes roughly 5-15% of the hydrogen's energy content (Züttel, 2004). That parasitic loss is manageable but not negligible, and it grows with each additional compression stage in the supply chain. Sdanghi et al. reviewed compression technologies and found that optimizing pressure levels across the production-to-use chain is important for minimizing delivered cost, particularly for distributed end uses like vehicle refueling where multiple compression steps may be involved (Sdanghi et al., 2019).

Cryogenic liquid storage achieves higher volumetric density than compressed gas, about 70 kg/m^3 compared to 40 kg/m^3 at 700 bar, but the liquefaction process itself consumes around 30% of the hydrogen's energy content, and maintaining cryogenic temperature during storage and transport requires additional infrastructure (Züttel, 2004). Liquefaction is economically justified for large-scale, long-distance transport applications where the density advantage outweighs the energy and capital costs, but for the scales and distances relevant to Nepal in the near term, compressed gas storage is the more practical option.

Underground geological storage, in salt caverns, depleted gas fields, or aquifers, can provide very large-scale, low-cost storage suitable for seasonal applications, and has been demonstrated in industrial hydrogen storage contexts in the United States and the United Kingdom (Tarkowski, 2019). Nepal's active tectonic setting and complex mountainous geology would require careful site-specific investigation before any underground storage option could be seriously considered, but the concept is relevant for longer-term planning as production volumes grow.

Chemical storage through conversion to hydrogen carriers, ammonia, methanol, or liquid organic hydrogen carriers, addresses the volumetric density problem by binding hydrogen into compounds that can be stored and transported using infrastructure much closer to what already exists for conventional liquid fuels. Ammonia stands out in this group because it has a well-established global production and distribution industry, contains 17.6% hydrogen by mass, and can be stored as a liquid at modest pressure (about 10 bar at room temperature) (Valera-Medina et al., 2018). The ammonia pathway is examined in detail in Section 2.6.4; the point here is that chemical conversion is a genuine and practical alternative to physical hydrogen storage for applications where the conversion energy cost is acceptable.

In Nepal's specific infrastructure context, there is no natural gas pipeline network, no existing compressed hydrogen distribution system, and limited industrial gas handling infrastructure outside the Kathmandu Valley. The practical storage and transport options for any near-term hydrogen project are therefore compressed gas in cylinders or tube trailers for distribution to proximate end uses, and ammonia synthesis for cases where the end use is agricultural or where longer-term export is considered. This infrastructure constraint is not a reason to dismiss hydrogen, but it is a real cost factor that must be counted honestly in any feasibility assessment.

2.6 Hydrogen Utilization Pathways

2.6.1 Re-electrification through Fuel Cells

Reconverting hydrogen to electricity through fuel cells closes the energy cycle from surplus wet-season generation to dry-season deficit supply, which is conceptually the most direct application of hydrogen storage in Nepal's context. Proton exchange membrane fuel cells are the leading technology for this application, operating at moderate temperature, starting quickly, and achieving electrical efficiencies of 45-60% at the cell stack level (Staffell et al., 2019). Combined heat and power configurations can recover waste heat to improve overall system efficiency, though the heat recovery benefit depends on having a suitable heat load nearby.

The problem with this pathway is round-trip efficiency. Taking surplus electricity through electrolysis, compressing and storing the hydrogen, and then running it through a fuel cell to generate electricity again, the overall round-trip efficiency at system level is typically 25-45% (Luo et al., 2015). Pumped hydro achieves 70-85%. That gap is large, and it matters economically because the value of electricity recovered is limited by what the power system would otherwise pay for that electricity during deficit periods. For re-electrification to make economic sense, either the electricity recovered needs to command a significant price premium, which is possible if it displaces expensive imported electricity during dry-season peaks, or the surplus electricity going in needs to be essentially free, meaning curtailed power that has no other value.

Ulleberg et al. documented the operational experience of the Utsira wind-hydrogen demonstration system in Norway, which ran a real island-scale integration of wind turbines, alkaline electrolysis, compressed hydrogen storage, and fuel cell power supply over multiple years (Ulleberg et al., 2010). The system worked as designed technically, but the analysis found that round-trip efficiency and capital cost made the hydrogen storage cycle considerably more expensive per kilowatt-hour delivered than battery storage for storage durations up to a few days. Hydrogen became more competitive as storage duration extended to weeks or months that is exactly the seasonal storage application relevant to Nepal's wet-to-dry-season transition.

Luo et al. examined energy storage technologies for large-scale renewable integration and placed hydrogen within a comparative framework against pumped hydro, compressed air, and batteries (Luo et al., 2015). Their analysis confirmed that hydrogen's relative advantage strengthens as storage duration and energy capacity requirements increase, supporting the view that seasonal storage in hydropower-dominated systems is among the more favorable niches for hydrogen energy storage technology. This is relevant but also sets expectations: re-electrification is unlikely to be the most economically attractive end use in a comparative analysis, and the present study will test that expectation against Nepal-specific data.

2.6.2 Transportation Applications

Hydrogen as a transport fuel has moved well past the demonstration stage in several major markets. Fuel cell electric vehicles using compressed hydrogen at 700 bar are commercially available from Toyota, Hyundai, and Honda, and hydrogen bus fleets are operating in Germany, the Netherlands, the United Kingdom, China, and South Korea, among others (International Energy Agency, 2019). The well-to-wheel efficiency of hydrogen fuel cell vehicles is estimated at 25-35%, lower than battery electric vehicles but better than conventional internal combustion on the same basis when hydrogen is produced from renewable electricity (Marcinkoski et al., 2015).

For Nepal, the transport sector's relevance to hydrogen is partly about energy economics and partly about import dependence. Nepal imports essentially all of its petroleum products, and the transport sector's fuel bill represents a significant and recurring foreign exchange cost. Converting even a portion of the urban transport fleet, buses, three-wheelers, trucks, to hydrogen fuel cell operation using domestically produced hydrogen would reduce that import expenditure and partially close the loop between the wet-season hydropower surplus and a real domestic demand (Bajracharya et al., 2015).

The practical challenge is infrastructure. Hydrogen refueling requires high-pressure dispensing equipment, safety systems, and a supply chain capable of delivering hydrogen from production point to station. Ogden's analysis of hydrogen infrastructure requirements for transportation identified the initial network build-out as the primary barrier as the chicken-and-egg problem where vehicles wait for stations and stations wait for vehicles (Ogden, 2004). Experience from South Korea and Germany, where coordinated government programs established anchor infrastructure networks ahead of large-scale vehicle deployment, suggests that this barrier can be overcome with deliberate policy support, but it does require upfront public investment in infrastructure that precedes commercial return.

Nepal's urban transport concentration in the Kathmandu Valley may actually simplify the infrastructure problem relative to more dispersed markets. A limited number of centrally located production and dispensing facilities could serve a significant fraction of the valley's fleet. This geographic argument has appeared in energy transition assessments for similar small, urbanization-concentrated developing countries, and it is worth examining quantitatively in the context of this study.

2.6.3 Industrial Applications

Hydrogen already serves as an industrial feedstock and reductant in several major industrial processes globally, and substituting grey hydrogen from fossil sources with green hydrogen is one of the most direct decarbonization interventions available to the industrial sector. Steel production via direct reduced iron uses hydrogen as a reductant in place of metallurgical coke; the chemical industry uses it for methanol synthesis and hydrocracking; refineries consume it for desulfurization and hydroprocessing (International Energy Agency, 2019).

Nepal's current industrial base does not include large-scale steel production or heavy chemical manufacturing, which limits the direct applicability of the globally dominant hydrogen industrial markets to the Nepalese context. What Nepal does have is a manufacturing sector that currently relies on diesel generators and grid electricity with reliability problems, a cement and brick industry that uses heavy fuel oil and coal for process heat, and a food processing sector with combined heat and power needs. For these applications, hydrogen-based fuel or hydrogen-fueled combined heat and power systems represent technically feasible substitution options, even if the market size is modest compared to global industrial hydrogen consumers.

Staffell et al. identified stationary combined heat and power as one of the near-term commercial anchors for fuel cell technology in industrial and commercial settings, noting that the economics improve substantially when both heat and electricity outputs are valued against realistic alternative supply costs (Staffell et al., 2019). In Nepal, where industrial energy costs are elevated by fuel import costs and grid unreliability, the avoided cost of diesel or grid supply could make hydrogen CHP competitive at relatively small scales. This is speculative at present, and the present study will assess it more rigorously, but the literature basis for treating it as a serious option is sound.

2.6.4 Green Ammonia Production

Green ammonia has attracted more attention in the hydrogen literature over the past five years than any other end-use pathway, and for reasons that go beyond fertilizer supply. Ammonia contains 17.6% hydrogen by mass, is liquid at modest pressure (approximately 10 bar at room temperature), and has a mature global production and distribution industry that has operated safely at scale for decades (Valera-Medina et al., 2018). This combination makes it simultaneously the most practical form of large-scale hydrogen storage and transport, a commodity with established global markets and pricing, and the primary feedstock for nitrogen fertilizers that feed much of the world's agricultural output.

Nepal is a net fertilizer importer. Urea, which is synthesized from ammonia, is the dominant nitrogen fertilizer used in Nepali agriculture, and its import cost is a recurring burden on the agricultural economy. Domestic green ammonia production from surplus hydropower hydrogen would substitute for those imports while also creating a productive domestic use for wet-season electricity that currently exports at low prices (Kroposki et al., 2017). Whether that substitution is economically viable at realistic production scales depends on the competitiveness of domestic production costs relative to import parity prices which is a calculation this study will make explicitly.

Smith et al. reviewed the current and future role of ammonia synthesis in a carbon-free energy landscape, covering both the established Haber-Bosch process and emerging electrochemical ammonia synthesis routes that could in principle bypass hydrogen production entirely (Smith et al., 2020). Their analysis concluded that Haber-Bosch-based green ammonia production, using green hydrogen as feedstock, is the only near-term commercially viable route, and that the economics depend heavily on the cost of electricity for electrolysis and the capital cost of the synthesis plant. The Haber-Bosch process requires temperatures of 400-500°C and pressures of 150-300 bar, consuming roughly 8-10 GJ of energy per tonne of ammonia excluding the hydrogen production step (Smith et al., 2020).

Valera-Medina et al. reviewed ammonia as an energy carrier across its full lifecycle as production, storage, transport, and utilization in combustion and fuel cell systems (Valera-Medina et al., 2018). Their review is the most comprehensive published treatment of the ammonia energy vector concept and confirms that ammonia's logistical advantages over pure hydrogen are substantial. For a landlocked country like Nepal, where export of gaseous or liquid hydrogen would require entirely new infrastructure, ammonia export through existing chemical handling channels could be a more realistic longer-term pathway. In the nearer term, domestic fertilizer substitution is the more tractable and immediate market.

Morgan et al. examined the technical and economic feasibility of small-to-medium scale green ammonia production for agricultural applications using renewable electricity, finding that plants in the range of a few hundred tonnes per day can achieve reasonable economics if electricity costs are low and plant capacity factors are maintained above approximately 70% (Morgan et al., 2017). The scale requirement is relevant for Nepal: the surplus hydropower volumes identified by Thapa et al. (Thapa et al., 2021) need to be checked against the minimum economic scale for an ammonia plant, a comparison the present study addresses.

2.7 Multi-Criteria Decision Analysis Methods for Energy Pathway Selection

Energy pathway selection depends on multiple indicators simultaneously. A least-cost option may perform poorly on energy security; a technically attractive pathway may be economically weak; a high-emission-reduction option may be difficult to scale. Multi-Criteria Decision Analysis (MCDA) is therefore widely used in energy planning because it allows alternatives to be compared across several criteria in a transparent and structured way (Mardani et al., 2015). In this study, MCDA is used as a synthesis layer after the technical, economic, environmental, and energy-security indicators have been calculated, not as a substitute for the underlying analysis.

Several MCDA methods exist. The Analytic Hierarchy Process (AHP) derives weights from pairwise comparisons and is appropriate when expert judgement is the primary source of preference information (Saaty, 1980). TOPSIS ranks alternatives by their distance from an ideal and anti-ideal solution, though it is sensitive to the choice of normalisation method and distance metric (Hwang and Yoon, 1981). ELECTRE and PROMETHEE are outranking methods that compare alternatives pairwise and can accommodate preference thresholds, but they require indifference and veto threshold parameters that cannot be readily justified in a screening-level assessment. VIKOR identifies compromise solutions by balancing group utility against individual regret, but introduces an additional compromise parameter that requires explicit policy assumptions (Opricovic and Tzeng, 2004).

The Weighted Average Method (WAM), also referred to as the weighted-sum or simple additive weighting approach, was selected for this study (Triantaphyllou, 2000). The decision problem is a pathway-screening exercise with a fixed set of alternatives and a small number of criteria; the objective is to examine how rankings shift under alternative national priorities. WAM normalises each criterion score, multiplies it by an explicitly stated weight, and sums the products into a total score, making the method straightforward to audit, reproduce in Python, and interpret for policy and engineering readers.

Table 2-1 Comparison of selected MCDA methods and rationale for using WAM

Method	**Main principle**	**Strength**	**Reason not selected as main method**
Weighted Average Method (WAM)	Normalised criterion scores are multiplied by weights and summed	Transparent, simple, reproducible, suitable for screening and sensitivity analysis	Selected because it matches the thesis objective and available data
AHP	Weights are obtained through pairwise comparison	Strong when expert judgement is central	Requires expert comparison matrix and consistency testing beyond the current scope
TOPSIS	Alternatives are ranked by closeness to the ideal solution and distance from the anti-ideal solution	Useful for ideal-solution ranking	Sensitive to normalisation and distance-metric choices
ELECTRE/ PROMETHEE	Outranking based on pairwise dominance and decision thresholds	Useful for non-compensatory decision-making	Requires preference, indifference, and veto thresholds that are not available for this study
VIKOR	Identifies a compromise solution between group utility and regret	Useful when compromise ranking is needed	Requires additional compromise parameters and policy-preference assumptions

The principal limitation of WAM is compensability: weak performance on one criterion can be offset by strong performance on another. This is acceptable here because WAM is applied only after the physical feasibility and break-even economics of each pathway have been verified separately. Policy-weight sensitivity cases are also included to test whether rankings change when energy security or fertiliser security receives greater importance.

The WAM score for each pathway is given by:

$$S_i = \sum_{j=1}^{n} w_j x_{ij}, \qquad \sum_{j=1}^{n} w_j = 1 \tag{2.1}$$

where S_i is the weighted score of pathway i, w_j is the weight assigned to criterion j, and x_{ij} is the normalised performance of pathway i under criterion j.

2.8 Techno-Economic Assessment of Green Hydrogen

The levelized cost of hydrogen is the standard metric for comparing production systems across different technologies, scales, and electricity sources. It is defined as the total lifetime cost of production, capital expenditure, operating expenditure, financing costs, and replacement, divided by the total hydrogen output over the project life (James et al., 2016). The measure is straightforward in concept but sensitive to assumptions in practice. Electricity cost, electrolyzer capital cost, capacity factor, and discount rate are the four parameters to which LCOH is most responsive, and they interact: a low electricity cost matters more when the capacity factor is high enough to spread capital cost over sufficient output (Schmidt et al., 2017).

Current LCOH estimates for green hydrogen from renewable sources range from around USD 2-5/kg in regions with very low-cost renewable electricity to USD 6-12/kg or more in higher-cost settings (International Renewable Energy Agency, 2019). For surplus hydropower specifically, where the effective electricity cost may be the marginal export price of curtailed power rather than a market electricity price, the LCOH calculation takes a different form. The opportunity cost framing, what does the surplus electricity earn if not directed to electrolysis?, can substantially reduce the apparent production cost compared to analyses that use market electricity prices. Gyanwali et al. applied this framing explicitly in their Nepal grid model and found that the economics of hydrogen production from curtailed surplus are considerably more attractive than from grid electricity purchased at average tariff (Gyanwali et al., 2022).

Delivered hydrogen cost to end users is consistently higher than production cost once compression, storage, and distribution are included. The Hydrogen Council's scaling analysis found that infrastructure costs in the supply chain from production to end use can double or triple the production cost depending on end-use application, distribution distance, and whether the infrastructure must be purpose-built or can share costs with existing systems (Hydrogen Council, 2017). This means that LCOH at the electrolyzer gate substantially understates the cost that end users actually face, and any comparison of pathways needs to account for downstream costs specific to each application.

Jovan and Dolanc reviewed techno-economic analyses of green hydrogen production systems using multiple renewable sources and found that hydropower-based systems, where studied, tend to achieve lower LCOH than wind or solar-based systems at comparable scale, largely because the higher and more predictable capacity factor of hydropower improves capital utilization (Jovan and Dolanc, 2020). The same principle applies to surplus hydropower with the caveat that surplus is seasonal, so the effective annual operating hours for the electrolyzer depend on the duration of the surplus period rather than the capacity factor of the hydro plant overall.

Sensitivity analysis is treated as standard practice in hydrogen techno-economic assessments, and the published literature consistently identifies the same parameters as dominant: electricity cost and electrolyzer capital cost together typically account for 60-80% of LCOH variation across scenarios (Schmidt et al., 2017), (James et al., 2016). For Nepal-specific analysis, the discount rate deserves particular attention. Infrastructure project financing costs in developing-country contexts are typically higher than the 5-8% discount rates used in most OECD-based analyses, and applying a more realistic 10-12% rate for Nepal can add meaningfully to LCOH and shift the relative economics of capital-intensive versus operating-cost-intensive pathways.

2.9 Green Hydrogen Studies in Nepal

Hydrogen has drawn growing global attention as a clean energy carrier suited to renewable energy integration, long-duration storage, and decarbonization of sectors that are difficult to electrify directly. Research on water electrolysis technologies indicates that falling electrolyser costs and efficiency improvements are steadily strengthening the case for green hydrogen (Schmidt et al., 2017; Grigoriev et al., 2020a).

The International Energy Agency(IEA) has identified hydrogen as a central component of future low-carbon energy systems, with particular relevance to transportation, industry, seasonal storage, and ammonia production (International Energy Agency, 2019). The International Renewable Energy Agency(IRENA) has similarly reported that large-scale deployment of renewable powered electrolysis can bring down production costs substantially and support global decarbonization targets (International Renewable Energy Agency, 2019).

In Nepal, growing hydropower output and seasonal electricity surpluses have motivated dedicated research on green hydrogen. Thapa et al. found that excess hydroelectricity could be used productively for hydrogen generation rather than being curtailed or exported at low value, and highlighted transport and power generation as potential applications (Thapa et al., 2021).Gyanwali et al. analysed hydrogen integration within Nepal's future energy system using a hydropower-hydrogen integrated grid model and found that such systems could reduce renewable curtailment and support cleaner transport and energy sector outcomes (Gyanwali et al., 2022).

2.10 Research Gap

These contributions are valuable, but Nepal-focused research to date has concentrated mainly on hydrogen production potential, renewable energy integration, and general techno-economic feasibility. Comparative evaluation of specific end-use pathways under Nepalese conditions remains sparse. The question of which utilisation route best suits Nepal's seasonal hydropower characteristics, dry-season deficits, industrial fuel demand, and ammonia production potential has not been systematically examined. A comparative feasibility assessment across end-use applications, covering re-electrification, transport and industrial fuel substitution, and green ammonia production, is therefore needed to identify the most appropriate utilisation pathway for Nepal.

3 METHODOLOGY

3.1 System flow diagram

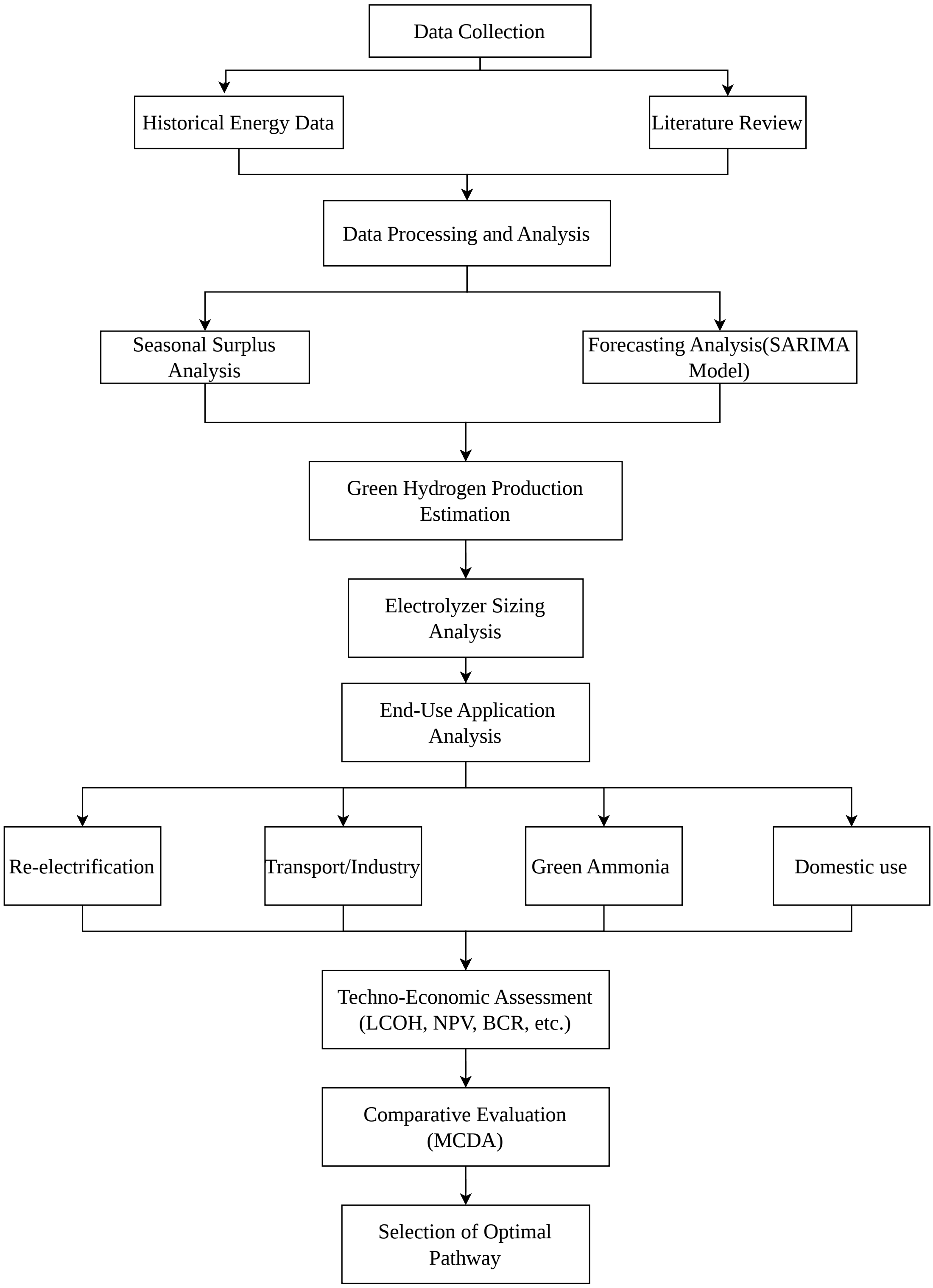

Figure 3-1 Overall Methodology of the study

This study adopts a techno-economic, environmental and decision support framework to assess whether Nepal's seasonal hydropower surplus can be economically converted into green hydrogen and its derivative products. Rather than treating feasibility as a binary question, the analysis is structured around a more policy-relevant enquiry: Under what technical, economic, and policy conditions can green hydrogen provide greater strategic value than direct electricity export of Nepal's seasonal hydropower surplus? This framing produces actionable thresholds rather than merely confirming that costs currently exceed revenues.

The methodology proceeds through six sequential stages. Historical energy data from the Nepal Electricity Authority (NEA) feeds a seasonal surplus characterisation module, from which electrolyzer sizing scenarios are derived. Each sizing scenario is evaluated across four hydrogen end-use pathways that are re-electrification through fuel cells, transport and industrial fuel substitution, and green ammonia production — alongside a direct domestic electrification benchmark. All calculations are denominated in Nepalese Rupees (NPR).The overall computational framework is implemented in Python.

3.2 Data Collection and Analysis

The empirical foundation is a daily energy balance dataset from NEA records, with required fields: daily export energy ($energy_{export}$, MWh), daily import energy (import, MWh), and date.

3.2.1 Duplicate Date Treatment

Duplicate records may occur when multiple entries are available for the same calendar date. Since the unit of analysis in this study is daily energy, duplicate records are aggregated by date. For each duplicate date, numerical energy variables are summed:

$$E_{d,j}^{\text{clean}} = \sum_{r=1}^{n_d} E_{r,j} \tag{3.1}$$

where $E_{d,j}^{\text{clean}}$ is the cleaned value of variable j on date d, $E_{r,j}$ is the value of the r^{th} record for that date, and n_d is the number of duplicate records on date d.

3.2.2 Missing Date and Missing Value Treatment

After duplicate aggregation, the date index is expanded to a continuous daily calendar. Missing dates are identified by comparing the observed date series with the complete calendar series:

$$N_{\text{missing dates}} = N_{\text{calendar days}} - N_{\text{observed days}} \tag{3.2}$$

The missing-date percentage is calculated as:

$$P_{\text{missing}} = \frac{N_{\text{missing dates}}}{N_{\text{calendar days}}} \times 100 \tag{3.3}$$

For energy variables, missing values are treated using interpolation where short gaps occur. If a missing period is long or physically inconsistent, the value is filled using monthly median values to preserve seasonal characteristics:

$$E_d^{\text{filled}} = \text{Median}(E_m) \tag{3.4}$$

where E_m represents all valid observations in the same calendar month as date d.

3.2.3 Outlier Detection

Outliers are detected using both the interquartile range method and the Z-score method. The IQR method identifies outliers as values outside the following bounds:

$$E < Q_1 - 1.5 \times IQR \tag{3.5}$$

$$E > Q_3 + 1.5 \times IQR \tag{3.6}$$

where Q_1 and Q_3 are the first and third quartiles, respectively, and:

$$IQR = Q_3 - Q_1 \tag{3.7}$$

The Z-score method is also applied:

$$Z_d = \frac{E_d - \mu_E}{\sigma_E} \tag{3.8}$$

where E_d is the daily value, μ_E is the mean, and σ_E is the standard deviation. Values with $|Z_d| > 3$ are flagged as possible outliers. Outliers are not automatically removed because high export or import values may represent real seasonal operating conditions rather than data errors.

3.3 Analysis of Seasonal Energy Patterns

The cleaned dataset is analysed to identify Nepal's seasonal surplus and deficit patterns. Since Nepal's electricity generation is strongly influenced by hydrological seasonality, monthly and seasonal aggregation is essential.

Daily export energy is interpreted as the amount of electricity actually exported and therefore as the main electricity stream that could alternatively be diverted to hydrogen production. Monthly export energy is calculated as:

$$E_m^{\text{export}} = \sum_{d \in m} E_d^{\text{export}} \tag{3.9}$$

Similarly, monthly import energy is calculated as:

$$E_m^{\text{import}} = \sum_{d \in m} E_d^{\text{import}} \tag{3.10}$$

The net monthly energy balance is estimated as:

$$E_m^{\text{net}} = E_m^{\text{export}} - E_m^{\text{import}} \tag{3.11}$$

where positive values indicate net export or surplus conditions, and negative values indicate net import or deficit conditions.

The annual export energy is calculated as:

$$E_y^{\text{export}} = \sum_{d \in y} E_d^{\text{export}} \tag{3.12}$$

The analysis produces daily export curves, monthly export and import profiles, seasonal boxplots, export duration curves, import duration curves, monthly demand trends, and a correlation matrix among major power-system variables.

3.4 Forecasting of Future Export Energy

A major limitation of using only historical data is that the available dataset covers only a short period, whereas hydrogen infrastructure is assessed over a 20-year project life. Therefore, future daily export energy is forecast before calculating hydrogen production. Hydrogen is not forecast directly. Instead, the daily electricity export series is forecast first, and hydrogen production is then calculated from forecasted electricity availability.

The forecast period starts immediately after the final observed historical date and continues for the full 20-year project horizon. The general forecasting relationship is:

$$\hat{E}_d^{\text{export}} = f(E_{d-1}^{\text{export}}, E_{d-2}^{\text{export}}, ..., S_d, \epsilon_d) \tag{3.13}$$

where $\hat{E}_d^{\text{export}}$ is the forecasted export energy on day d, S_d represents seasonal components, and ϵ_d represents the residual error term.

3.4.1 Stationarity Testing

Before applying time-series forecasting, stationarity is examined using the Augmented Dickey-Fuller test. The null hypothesis of the ADF test is that the time series contains a unit root and is non-stationary. The test regression can be represented as:

$$\Delta E_t = \alpha + \beta t + \gamma E_{t-1} + \sum_{i=1}^{p} \phi_i \Delta E_{t-i} + \epsilon_t \tag{3.14}$$

where E_t is export energy at time t, ΔE_t is the first difference, p is the lag order, and ϵ_t is the error term. If the ADF test fails to reject the null hypothesis, differencing is applied.

3.4.2 SARIMA-assisted Forecasting Framework

Because the export-energy series is daily and seasonally influenced, a seasonal autoregressive integrated moving average model is used as the main classical forecasting framework. A SARIMA model is denoted as:

$$SARIMA(p, d, q)(P, D, Q)_s \tag{3.15}$$

where p, d, and q are the non-seasonal autoregressive order, differencing order, and moving-average order, while P, D, and Q represent the corresponding seasonal components. The parameter s represents the seasonal period.

The SARIMA model can be written generally as:

$$\Phi_P(B^s)\phi_p(B)(1 - B)^d(1 - B^s)^D E_t = \Theta_Q(B^s)\theta_q(B)\epsilon_t \tag{3.16}$$

where B is the backshift operator, $\phi_p(B)$ and $\theta_q(B)$ are non-seasonal autoregressive and moving-average polynomials, and $\Phi_P(B^s)$ and $\Theta_Q(B^s)$ are seasonal autoregressive and moving-average polynomials.

Due to the limited historical record, the study uses a hybrid SARIMA-assisted approach. The observed seasonal export pattern is first extracted from the cleaned historical data, and SARIMA is used to model the residual and trend behaviour. This reduces the risk of overfitting while preserving Nepal's monsoon-driven export seasonality.

3.4.3 Walk-forward Forecast Validation

Forecasting performance is evaluated using walk-forward validation. In this approach, the model is trained on an initial portion of the time series and tested on the next unseen period. The training window is then expanded, and the process is repeated. Forecast accuracy is measured using mean absolute error, root mean square error, and mean absolute percentage error:

$$MAE = \frac{1}{n}\sum_{i=1}^{n}|E_i - \hat{E}_i| \tag{3.17}$$

$$RMSE = \sqrt{\frac{1}{n}\sum_{i=1}^{n}(E_i - \hat{E}_i)^2} \tag{3.18}$$

where E_i is the observed value and $\hat{E}_i$ is the forecasted value.

3.4.4 Long-term Scenario Development

Because Nepal's hydropower generation and export capacity may expand over the project period, three long-term scenarios are developed. These scenarios do not represent exact predictions; rather, they represent plausible planning pathways.

Table 3-1 Forecast scenarios used in the study

Scenario	Annual Growth Rate	Interpretation
Scenario A	0%	Conservative continuation of observed seasonal export profile
Scenario B	3%	Moderate hydropower and export growth pathway
Scenario C	6%	Aggressive hydropower expansion and surplus growth pathway

For each scenario, the forecasted export energy is scaled as:

$$E_{d,y}^{\text{scenario}} = \hat{E}_d^{\text{base}}(1+g)^{y-y_0} \tag{3.19}$$

where $E_{d,y}^{\text{scenario}}$ is forecasted export energy on day d in year y, $\hat{E}_d^{\text{base}}$ is the base seasonal forecast, g is the scenario growth rate, and y_0 is the first forecast year.

3.4.5 Technical justification of surplus-growth scenarios

The three long-term exportable-surplus scenarios used in this thesis are planning scenarios rather than deterministic forecasts. Their purpose is to bracket the range of surplus electricity that could realistically become available for hydrogen production, given the uncertainty in how quickly new hydropower output will be absorbed by domestic demand and cross-border export. The growth model is:

$$E^{(s)}_{\text{surplus},y} = E_{\text{surplus},1}(1 + g_s)^{y-1} \tag{3.20}$$

where $E_{\text{surplus},1}$ is the first-year surplus baseline from historical seasonal data and $g_s \in \{0\%, 3\%, 6\%\}$.

Cross-check with NEA data. NEA projects total electricity demand to reach 20,585 GWh by FY 2025/26 and 56,008 GWh by FY 2035/36 (Nepal Electricity Authority, 2020), while the 16th Periodic Plan targets 11.76 GW of installed capacity (Water and Energy Commission Secretariat, 2010). Thapa et al. project wet-season surplus of at least 11 TWh in 2025, rising to 25 TWh by 2028 (Thapa et al., 2021), and Gyanwali et al. estimate that 40% of total wet-season energy will be surplus by 2030 (Gyanwali et al., 2022). Taken together, these figures confirm that surplus exists and will grow, but that a meaningful share will be absorbed by electrification programs and cross-border trade (Acharya and Bhatt, 2020), which is precisely why a range of scenarios is needed rather than a single number.

Conservative case ($g_s = 0\%$). This case assumes that any new hydropower generation is fully offset by domestic load growth (electric cooking, mobility, industrial use) and export absorption, leaving the hydrogen-available surplus roughly constant over the 20-year horizon. It does not claim that capacity stops growing; it represents the worst case for hydrogen and serves as the lower-bound test of pathway viability.

Moderate case ($g_s = 3\%$). This is the central case, used for electrolyzer selection and all primary pathway comparisons. A 3% annual growth in hydrogen-available surplus is consistent with a situation where hydropower capacity expands steadily but only a portion of new output converts into usable surplus after demand and export absorption. The rate aligns with the slow-to-medium surplus trajectories in comparable Nepal studies (Thapa et al., 2021; Gyanwali et al., 2022).

Aggressive case (g_s = 6%). This upper-bound case reflects rapid surplus growth, consistent with the 16th Plan capacity pipeline (Water and Energy Commission Secretariat, 2010) coming online faster than demand and export infrastructure can absorb. Literature projections of 10,000 MW surplus by 2030 and 39,000 MW by 2040 under optimistic conditions (Gyanwali et al., 2022) support this as a plausible upper bound, even if not a guaranteed outcome. It is included as a sensitivity test, not a forecast.

Table 3-2 Technical interpretation of surplus-growth scenarios

Scenario	g_s	Physical interpretation	Relation to Nepal planning data	Role
Conservative	0% /yr	New generation absorbed by demand and export; hydrogen-available surplus stays flat	Consistent with full demand absorption per NEA forecasts (Nepal Electricity Authority, 2020)	Lower bound
Moderate	3% /yr	Gradual surplus growth after partial domestic and export absorption	Aligned with Nepal hydrogen literature (Thapa et al., 2021; Gyanwali et al., 2022)	Central case
Aggressive	6% /yr	Rapid surplus growth if commissioning outpaces absorption	Consistent with 16th Plan pipeline and optimistic surplus projections (Water and Energy Commission Secretariat, 2010; Gyanwali et al., 2022)	Upper-bound sensitivity

3.5 Hydrogen Production Estimation

Hydrogen production is calculated from forecasted daily export energy. The study assumes that surplus hydropower is converted to hydrogen using water electrolysis. The conversion pathway is:

$$\text{Surplus Electricity} \rightarrow \text{Electrolyzer} \rightarrow \text{Green Hydrogen} \tag{3.21}$$

The specific energy consumption of the electrolyzer is assumed to be:

$$SEC = 50 \text{ kWh/kg-H}_2 \tag{3.22}$$

This is equivalent to:

$$1 \text{ MWh} = \frac{1000}{50} = 20 \text{ kg-H}_2 \tag{3.23}$$

Daily hydrogen production is therefore estimated as:

$$m_{H_2,d} = \frac{E_d^{\text{used}} \times 1000}{SEC} \tag{3.24}$$

where $m_{H_2,d}$ is daily hydrogen production in kg/day, E_d^{used} is the daily electricity supplied to the electrolyzer in MWh/day, and SEC is the electrolyzer specific energy consumption in kWh/kg-H_2.

Monthly and annual hydrogen production are calculated as:

$$m_{H_2,m} = \sum_{d \in m} m_{H_2,d} \tag{3.25}$$

$$m_{H_2,y} = \sum_{d \in y} m_{H_2,d} \tag{3.26}$$

The water requirement for electrolysis is estimated using the stoichiometric water requirement for hydrogen production. The minimum theoretical water requirement is approximately 9 kg of water per kg of hydrogen. A practical water factor is applied to include purification and auxiliary losses:

$$W_d = m_{H_2,d} \times w_f \tag{3.27}$$

where W_d is water requirement and w_f is the practical water requirement factor in kg-water/kg-H_2.

3.6 Electrolyzer Sizing and Operational Analysis

Electrolyzer sizing is performed to identify the capacity that best matches Nepal's seasonal surplus profile. The electrolyzer is modelled as an alkaline water electrolyzer (AWE). AWE is chosen over PEM electrolysis because it is commercially mature, does not require noble-metal catalysts, and carries a lower capital cost of approximately $800–1,000/kW at large scale (Schmidt et al., 2017), which is important in a screening-level study where economics drive pathway ranking. PEM electrolysis offers better dynamic load-following but its higher CAPEX weakens the economic case; it is retained as a sensitivity alternative. Because Nepal's surplus hydropower follows a predictable seasonal pattern rather than the fast variability of wind or solar, AWE's slower ramp rate is not a practical limitation here.

The specific electricity consumption assumed is SEC = 50 kWh/kg-H_2, consistent with near-term AWE performance targets (Schmidt et al., 2017; International Energy Agency, 2019). The model operates at system level; stack voltage, current density, and degradation are outside its scope.

The following electrolyzer capacities are evaluated:

$$P_{\mathrm{elz}} = \{100, 250, 500, 750, 1000, 1500\} \text{ MW} \tag{3.28}$$

For each electrolyzer size, the maximum daily electricity consumption is:

$$E_d^{\mathrm{cap}} = P_{\mathrm{elz}} \times 24 \tag{3.29}$$

where E_d^{cap} is the daily electrolyzer capacity in MWh/day.

The actual daily electricity used by the electrolyzer is limited by both available export energy and electrolyzer capacity:

$$E_d^{\mathrm{used}} = \min\left(E_d^{\mathrm{export}}, E_d^{\mathrm{cap}}\right) \tag{3.30}$$

Unused surplus energy is calculated as:

$$E_d^{\mathrm{unused}} = E_d^{\mathrm{export}} - E_d^{\mathrm{used}} \tag{3.31}$$

The annual electrolyzer capacity factor is calculated as:

$$CF_{\mathrm{elz}} = \frac{\sum_{d=1}^{365} E_d^{\mathrm{used}}}{P_{\mathrm{elz}} \times 8760} \tag{3.32}$$

The surplus capture ratio is calculated as:

$$SCR = \frac{\sum_{d=1}^{365} E_d^{\mathrm{used}}}{\sum_{d=1}^{365} E_d^{\mathrm{export}}} \tag{3.33}$$

The balanced electrolyzer size is selected by considering LCOH, capacity factor, surplus capture, and pathway performance. The study does not select the largest electrolyzer automatically because larger electrolyzers may capture more surplus but operate at lower capacity factor and higher hydrogen cost.

3.7 Levelized Cost of Hydrogen

The levelized cost of hydrogen is calculated for each electrolyzer size over the project life. The LCOH is defined as the discounted lifetime cost divided by discounted lifetime hydrogen production:

$$LCOH = \frac{\sum_{t=1}^{N} \frac{C_{\text{capex},t} + C_{\text{opex},t} + C_{\text{stack},t} + C_{\text{elec},t}}{(1+r)^t}}{\sum_{t=1}^{N} \frac{m_{H_2,t}}{(1+r)^t}} \tag{3.34}$$

where N is the project life, r is the discount rate, $C_{\text{capex},t}$ is annualised capital cost, $C_{\text{opex},t}$ is operating and maintenance cost, $C_{\text{stack},t}$ is stack replacement cost, $C_{\text{elec},t}$ is electricity opportunity cost, and $m_{H_2,t}$ is annual hydrogen production.

The capital recovery factor is calculated as:

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1} \tag{3.35}$$

Annualised capital cost is calculated as:

$$C_{\text{capex,annual}} = CAPEX \times CRF \tag{3.36}$$

Because this study treats export electricity as the alternative use of surplus hydropower, the electricity input cost is represented as an opportunity cost based on the export electricity value:

$$C_{\text{elec},t} = E_t^{\text{used}} \times P_{\text{export}} \tag{3.37}$$

where P_{export} is the export electricity value in NPR/kWh.

3.8 End-Use Pathway Assessment

Five alternative end-use pathways are evaluated. Each pathway is assessed using technical output, energy displacement, emission reduction, economic value, and strategic relevance to Nepal.

3.8.1 Pathway 1: Direct Domestic Electrification

The first pathway assumes that surplus electricity is used directly in Nepal instead of being converted into hydrogen. This pathway is included because direct electrification avoids hydrogen conversion losses and therefore represents a strong benchmark.

$$\text{The pathway is: Surplus Electricity} \rightarrow \text{Domestic End-use} \tag{3.38}$$

The domestic end-use bundle includes EV charging, electric cooking, heat pumps, and irrigation pumping. For simplicity, the study evaluates these applications as a combined direct-electrification pathway.

The useful delivered electricity is:

$$E^{\text{direct}}_{\text{useful},d} = E^{\text{export}}_{d} \times \eta_{\text{direct}} \tag{3.39}$$

where η_{direct} represents the delivery efficiency of direct electricity use.

The economic value of domestic electrification is calculated as:

$$V_{\text{direct},t} = E^{\text{direct}}_{\text{useful},t} \times P_{\text{domestic}} \tag{3.40}$$

where P_{domestic} is the estimated value of domestic electricity use in NPR/kWh.

The export benchmark value is:

$$V_{\text{export},t} = E^{\text{export}}_{t} \times P_{\text{export}} \tag{3.41}$$

Direct domestic electrification is considered economically stronger than export when:

$$V_{\text{direct},t} > V_{\text{export},t} \tag{3.42}$$

The break-even domestic electricity value is therefore:

$$P_{\text{domestic,BE}} = P_{\text{export}} \tag{3.43}$$

This means direct domestic use becomes preferable to export if the useful domestic value of electricity exceeds the export value.

The direct electrification pathway targets Nepal's structurally recurring wet-season surplus, which arises from a fundamental mismatch between peak run-of-river generation during June–September and relatively low domestic consumption in the same period (Shrestha and Acharya, 2020). IPPAN has reported that curtailed electricity worth USD 192.47 million is anticipated in FY 2024/25 during the wet season alone, and this figure is projected to grow in subsequent years (Paudel et al., 2024). A recent study estimates Nepal will have approximately 3.8 TWh of surplus electricity during the wet season of 2028, with installed capacity exceeding peak load by approximately 3,500 MW by the same year (Paudel et al., 2024).

The wet-season electrical load addressed by this pathway spans flexible and deferrable end-uses that can operate seasonally without firm year-round supply commitments. National-level estimates indicate that electric cooking, replacing half of LPG consumption, could absorb up to 4,000 MW of additional demand, lift irrigation up to 1,450 MW, and cold storage up to 400 MW (Shrestha, 2022). Electrification of Nepal's agriculture sector alone could increase annual electricity demand by 2,800 GWh, equivalent to 32% of total national demand in FY 2021–22, a scale sufficient to absorb the entire near-term wet-season surplus (Thapa, 2022). Since these loads operate only during the approximately four-month surplus window, the effective annual utilisation factor is approximately 33%; this does not affect the energy value calculation since $E_{\text{export},d}$ in equation (3.37) is already defined on a wet-season basis.

The energy served, $E_{\text{direct useful},d}$, is the quantum of wet-season surplus electricity delivered to domestic end-uses net of distribution losses, with no intermediate conversion step. This is the critical thermodynamic advantage of direct electrification: the hydrogen-to-power conversion chain loses 60–70% of the original energy input (Gupta, 2026), whereas direct electrification delivers surplus to useful service in a single step, making it the natural upper-bound benchmark against which the hydrogen pathways evaluated in this study are compared.

Table 3-3 Direct Electrification Pathway

Parameter	Value / Description	Ref
Surplus pool (2028 projection)	~3.8 TWh wet season	(Paudel et al., 2024)
Excess installed capacity (2028)	~3,500 MW above peak load	(Paudel et al., 2024)
Electric cooking potential	Up to 4,000 MW	(Shrestha, 2022)
Lift irrigation potential	Up to 1,450 MW	(Shrestha, 2022)
Cold storage potential	Up to 400 MW	(Shrestha, 2022)
Agricultural sector demand increase	~2,800 GWh/yr (~32% of FY 2021–22 demand)	(Thapa, 2022)
Wet-season utilisation factor	~33% (4 months out of 12)	—
Energy served	Surplus GWh delivered to domestic end-use, net of distribution losses, no conversion	—
Thermodynamic advantage over hydrogen	Direct use avoids 60–70% round-trip energy loss of hydrogen pathway	(Gupta, 2026)]

3.8.2 Pathway 2: Re-electrification Using Hydrogen and Fuel Cells

The second pathway evaluates hydrogen as a seasonal energy storage medium. In this pathway, wet-season surplus electricity is converted into hydrogen, stored, and later converted back into electricity during dry-season deficit periods.

The conversion chain is:

$$\text{Electricity} \rightarrow \text{H}_2 \rightarrow \text{Storage} \rightarrow \text{Fuel Cell} \rightarrow \text{Electricity} \tag{3.44}$$

Daily hydrogen production is calculated using the electrolyzer model described earlier:

$$m_{H_2,d}^{\text{prod}} = \frac{E_d^{\text{used}} \times 1000}{SEC} \tag{3.45}$$

The hydrogen storage balance is:

$$S_d = S_{d-1} + m_{H_2,d}^{\text{prod}} - m_{H_2,d}^{\text{used}} \tag{3.46}$$

where S_d is the hydrogen stored at the end of day d.

The electrical energy obtainable from stored hydrogen through a fuel cell is:

$$E_d^{\text{FC,potential}} = m_{H_2,d}^{\text{available}} \times LHV_{H_2} \times \eta_{\text{FC}} \tag{3.47}$$

where LHV_{H_2} is the lower heating value of hydrogen in kWh/kg and η_{FC} is fuel-cell efficiency.

Actual re-electrified energy is limited by available hydrogen, fuel-cell power capacity, and dry-season import demand:

$$E_d^{\text{re-elec}} = \min\left(E_d^{\text{import}}, P_{\text{FC}} \times 24, E_d^{\text{FC,potential}}\right) \tag{3.48}$$

Hydrogen consumed by the fuel cell is:

$$m_{H_2,d}^{\text{used}} = \frac{E_d^{\text{re-elec}}}{LHV_{H_2}\eta_{\text{FC}}} \tag{3.49}$$

The round-trip efficiency is:

$$\eta_{\text{RTE}} = \eta_{\text{elz}} \times \eta_{\text{storage}} \times \eta_{\text{FC}} \tag{3.50}$$

The dry-season import offset is calculated as:

$$I_{\text{offset}} = \frac{\sum E_d^{\text{re-elec}}}{\sum E_d^{\text{import}}} \times 100 \tag{3.51}$$

The levelized cost of re-electrified electricity is:

$$LCOE_{\text{re-elec}} = \frac{\sum_{t=1}^{N} \frac{C_{H_2,t} + C_{\text{storage},t} + C_{\text{FC},t} + C_{\text{O\&M},t}}{(1+r)^t}}{\sum_{t=1}^{N} \frac{E_{\text{re-elec},t}}{(1+r)^t}} \tag{3.52}$$

This pathway is economically competitive when:

$$LCOE_{\text{re-elec}} \leq P_{\text{import avoided}} \tag{3.53}$$

where $P_{\text{import avoided}}$ is the avoided dry-season electricity import value.

The re-electrification pathway is motivated by Nepal's structural seasonal energy imbalance rather than an absolute deficit. In FY 2023/24, Nepal exported 1,946 million units during the monsoon season but imported 1,895 million units in the dry season, yielding a net export of barely 51 million units that confirms that the surplus is purely seasonal rather than absolute (Mallik, 2025). Dry-season river discharge falls to just 16% of the annual total against 84% during the wet season. This causes drastic fluctuation in run-of-river generation output (Kafle et al., 2025). In FY 2022/23, Nepal imported 1,854.53 GWh of electricity from India at a peak of 665 MW to cover this deficit (Paudel et al., 2024). Hydrogen-based seasonal storage directly bridges this structural gap by charging during June–September surplus and discharging during November–April deficit — a storage duration that batteries cannot serve economically (Fokkema et al., 2022).

The three-stage conversion chain in equation (3.43) relies on the component assumptions summarised in Table 3-4.

AWE is preferred over PEM electrolysis for this pathway given its lower capital cost and suitability for continuous surplus absorption, accepting the trade-off of slower dynamic response (Grigoriev et al., 2020b). Compressed storage at 200 bar is assumed as self-discharge losses over multi-month durations are negligible, unlike battery storage which is unsuitable for seasonal timescales (Fokkema et al., 2022).

What Re-electrification Supports and Energy Served?

The re-electrified output $E_{\text{re-elec},d}$ from equation (3.47) targets partial offset of dry-season electricity imports, which reached 1,854.53 GWh at a peak of 665 MW in FY 2022/23 (Paudel et al., 2024), alongside a reduction in dependence on cross-border transmission capacity. At the assumed round-trip efficiency of approximately 31%, where $\eta_{\text{elz}} \approx 0.67$, $\eta_{\text{storage}} \approx 0.99$, and $\eta_{\text{FC}} \approx 0.47$, approximately 1.18 TWh of dry-season electricity is recoverable from the projected 3.8 TWh wet-season surplus

Table 3-4 Re-electrification Pathway

Component	Technology	Efficiency	Remark
Electrolyser	Alkaline (AWE)	63–71%	Cost-effective for baseload wet-season surplus (Grigoriev et al., 2020b)
Storage	Compressed H_2 at ~200 bar	~99%	Negligible self-discharge over seasonal durations (Fokkema et al., 2022)
Fuel cell	PEM	47–50%	Grid-quality electricity re-conversion (Barnhart and Benson, 2015)
Round-trip η_{RTE}	AWE × Storage × PEM FC	30–35%	Consistent with equation (3.49) (Barnhart and Benson, 2015)
Storage duration	Seasonal	4–8 months	Covers November–April dry-season deficit (Mallik, 2025)

by 2028 (Paudel et al., 2024). The round-trip efficiency of hydrogen energy storage systems typically ranges from 30 to 50%, a notable disadvantage relative to batteries; however, hydrogen's distinctive value lies in its capacity to store energy across months rather than hours (Sustainability Directory, 2025), which is precisely the timescale of Nepal's seasonal imbalance. This characteristic justifies benchmarking $\text{LCOE}_{\text{re-elec}}$ in equation (3.51) against the avoided import price $P_{\text{import avoided}}$ rather than the standard domestic tariff.

3.8.3 Pathway 3: Hydrogen Transport Application

The third pathway evaluates hydrogen use in heavy-duty transport, such as intercity buses and freight trucks. Light-duty vehicles are not treated as the primary hydrogen market because battery-electric vehicles are generally more efficient for passenger transport.

The pathway is:

$$\text{Electricity} \rightarrow \text{H}_2 \rightarrow \text{Compression and Delivery} \rightarrow \text{Fuel-cell Heavy Transport} \tag{3.54}$$

The delivered hydrogen cost is calculated as:

$$C_{H_2,\text{delivered}} = LCOH + C_{\text{compression}} + C_{\text{storage}} + C_{\text{distribution}} \tag{3.55}$$

Hydrogen demand for a heavy-duty vehicle fleet is estimated as:

$$m_{H_2}^{\text{transport}} = N_v \times D_v \times h_v \tag{3.56}$$

where N_v is the number of vehicles, D_v is annual distance travelled per vehicle, and h_v is hydrogen consumption in kg/km.

Diesel displacement is estimated using equivalent useful energy:

$$V_{\text{diesel displaced}} = \frac{m_{H_2}^{\text{transport}} \times LHV_{H_2} \times \eta_{\text{FCV}}}{LHV_{\text{diesel}} \times \eta_{\text{diesel}}} \tag{3.57}$$

where $V_{\text{diesel displaced}}$ is diesel displaced, LHV_{diesel} is the lower heating value of diesel, η_{FCV} is fuel-cell vehicle efficiency, and η_{diesel} is diesel vehicle efficiency.

The transport break-even hydrogen price is:

$$P_{H_2,\text{BE}}^{\text{transport}} = \frac{V_{\text{diesel displaced}} \times P_{\text{diesel}} + V_{\text{carbon}}}{m_{H_2}^{\text{transport}}} \tag{3.58}$$

where P_{diesel} is diesel price and V_{carbon} is any monetised carbon benefit. Hydrogen transport is economically feasible when:

$$C_{H_2,\text{delivered}} \leq P_{H_2,\text{BE}}^{\text{transport}} \tag{3.59}$$

Vehicle Categories, Fleet Numbers and Energy Requirement

The pathway targets vehicle categories where battery-electric solutions face practical limits of range, payload, or refuelling time. In 2017/18, Nepal's diesel vehicle fleet, comprising buses, minibuses, trucks, tippers, and pickups, stood at 270,723, having grown 16.4 times since 1989/90 (Das et al., 2021), with annual transport diesel consumption reaching approximately 892,770 kilolitres (Phys.org, 2022). Full replacement of the heavy-duty diesel fleet would require approximately 76 million kg of hydrogen for intercity buses, 27 million kg for minibuses and mini-trucks, and 119.6 million kg for trucks, cranes, and dozers, totalling approximately 222.6 million kg per year (N Shakya and Thapa, 2022).

Fuel Replacement Benefit

Fuel cells are approximately 20% more efficient than internal combustion engines, such that 1 kg of hydrogen displaces approximately 4.8 litres of diesel in useful energy terms (Clean Air Task Force, 2025). At Nepal's annual transport diesel consumption of

Table 3-5 Heavy-Duty Transport Pathway: Fleet and Energy Parameters

Vehicle Category	**Fleet Size**	**H_2 Consumption**	**Annual Distance**	**H_2 Required (Total Fleet)**
Intercity / Heavy Buses	~25,000	~4.4 kg/100 km (The Annapurna Express, 2025)	~60,000 km/yr	~76 million kg (N Shakya and Thapa, 2022)
Trucks / Tippers / Cranes	~100,000	~9 kg/100 km (International Council on Clean Transportation, 2022)	~40,000 km/yr	~119.6 million kg (N Shakya and Thapa, 2022)
Minibuses / Mini-trucks	~50,000	~5 kg/100 km	~30,000 km/yr	~27 million kg (N Shakya and Thapa, 2022)
Total (Full Replacement)	**~175,000**	—	—	**~222.6 million kg/yr**

approximately 893 million litres, full fleet conversion would theoretically eliminate the entire transport diesel import bill. The near-term realistic scope targets approximately 50,000 high-utilisation captive fleet vehicles, displacing an estimated 200 to 250 million litres of diesel annually. A pilot hydrogen bus on the Kathmandu–Dhulikhel route confirmed operational viability, recording a fuel economy of 15.8 km/kg and a full-tank range of 700 km (The Annapurna Express, 2025), supporting the feasibility of hydrogen deployment across Nepal's intercity corridors.

Total Energy Served

Using the lower heating value of hydrogen at 33.3 kWh/kg, full fleet replacement of approximately 175,000 vehicles yields a total energy served of approximately 7,413 GWh per year. For the near-term target of 50,000 high-utilisation vehicles, the energy served is approximately 2,100 GWh per year, representing a significant share of Nepal's projected 3.8 TWh wet-season surplus available for hydrogen production (Paudel et al., 2024).

3.8.4 Pathway 4: Industrial Fuel Substitution

The fourth pathway evaluates hydrogen as a substitute for fossil fuels in selected industrial applications. The sectors considered include cement, brick kilns, industrial boilers, and steel processing. These sectors are selected because they require thermal energy and may be difficult to fully electrify in all cases.

The pathway is:

$$\text{Electricity} \rightarrow \text{H}_2 \rightarrow \text{Industrial Burner or Process Heat} \rightarrow \text{Fossil Fuel Displacement} \tag{3.60}$$

For each sector s, useful thermal energy supplied by hydrogen is:

$$Q_{s,H_2} = m_{H_2,s} \times LHV_{H_2} \times \eta_{s,H_2} \tag{3.61}$$

The equivalent fossil fuel displaced is:

$$F_{s,\text{displaced}} = \frac{Q_{s,H_2}}{LHV_{s,\text{fuel}} \times \eta_{s,\text{fuel}}} \tag{3.62}$$

The avoided fuel cost is:

$$V_{s,\text{fuel avoided}} = F_{s,\text{displaced}} \times P_{s,\text{fuel}} \tag{3.63}$$

The sectoral emission reduction is:

$$CO_{2,s}^{\text{avoided}} = F_{s,\text{displaced}} \times EF_{s,\text{fuel}} \tag{3.64}$$

where $EF_{s,\text{fuel}}$ is the emission factor of the replaced fossil fuel.

The industrial hydrogen break-even price is:

$$P_{H_2,\text{BE}}^{\text{industry}} = \frac{\sum_s \left(V_{s,\text{fuel avoided}} + V_{s,\text{carbon}}\right)}{\sum_s m_{H_2,s}} \tag{3.65}$$

The industrial substitution pathway is feasible when the delivered hydrogen cost is lower than or equal to the break-even hydrogen value:

$$C_{H_2,\text{delivered}} \leq P_{H_2,\text{BE}}^{\text{industry}} \tag{3.66}$$

Fuels to be Replaced and Purpose

Coal meets over half of Nepal's industrial energy demand, with the remainder supplied by fuelwood, diesel, and electricity, with diesel serving primarily as backup captive generation fuel (Climate Analytics, 2023). Hydrogen substitution in this pathway therefore targets coal and diesel as the primary fuels displaced across the four sectors identified in equation (3.59). The sectors considered are cement and clinker kilns, brick kilns, steel rolling mills, and industrial boilers serving food, dairy, and tea processing.

These are selected on the basis that they require high-temperature thermal energy and present limited scope for direct electrification in the near term.

Table 3-6 Industrial Fuel Substitution Opportunities for Hydrogen

Sector	Fuel Replaced	Purpose	Thermal Energy Intensity	Ref.
Cement Clinker Kilns	Coal	Calcination and kiln firing at 1400 °C to 1450 °C.	5.411 $GJ\,t^{-1}$ cement; thermal energy contributes approximately 91 % of total energy demand.	(Energy Efficiency Centre, FNCCI, 2015; Karki and Dahal, 2020)
Brick Kilns	Coal, fuelwood	Brick firing in fixed-chimney and bull-trench kilns.	4124.56 MJ per 1000 bricks.	(KC et al., 2025)
Steel Rolling Mills	Coal, furnace oil, diesel	Billet reheating furnaces and captive backup power generation.	Approximately 26 033 $MJ\,t^{-1}$ of steel produced.	(KC et al., 2025; Energypedia contributors, 2015)
Industrial Boilers	Diesel, coal, rice husk	Steam generation for pasteurization, heating, and process heat applications in food, dairy, and tea industries.	Sector-dependent; diesel-fired backup systems remain common.	(Energypedia contributors, 2015)

Scale of Fuel Demand

Nepal's total industrial energy consumption stands at approximately 114.5 PJ, with coal accounting for 48% of this total (Thapa et al., 2024). In the cement sector specifically, thermal energy accounts for 91% of total energy consumption, with an average specific thermal consumption of 5.411 GJ per tonne of cement, considerably above regional benchmarks, indicating substantial substitution potential (Energy Efficiency Centre, FNCCI, 2015). The energy served by this pathway is the useful thermal energy Q_{s,H_2} delivered by hydrogen to industrial processes across sectors, net of burner efficiency η_{s,H_2}, as captured in equation (3.60). A full hydrogen substitution scenario for Nepal's cement industry alone would require approximately 2,002 MW of continuous power for hydrogen production (Khanal, 2025), far exceeding the available wet-season surplus. The pathway is therefore evaluated as partial substitution targeting the highest coal-intensity applications, where the break-even hydrogen price from equation (3.64) is compared against delivered coal and diesel prices. Nepal's NDC targets adoption of low-emission technologies in brick and cement industries to replace coal by 2030 (Climate Analytics, 2023), providing the policy basis within which this pathway's economic feasibility is assessed.

3.8.5 Pathway 5: Green Ammonia Production

The fifth pathway evaluates hydrogen conversion into green ammonia for fertilizer import substitution. This pathway is particularly relevant to Nepal because ammonia can be used as a precursor for nitrogen fertilizer.

The pathway is:

$$\begin{tikzcd}
\text{Electricity} \arrow[r] & \mathrm{H_2} \arrow[r] & \mathrm{N_2}\text{ sep.} \arrow[d] \\
\text{Fertilizer sub.} & \mathrm{NH_3} \arrow[l] & \text{Haber-Bosch} \arrow[l]
\end{tikzcd}$$

The stoichiometric relationship for ammonia production is:

$$N_2 + 3H_2 \rightarrow 2NH_3 \tag{3.67}$$

Based on molecular masses:

$$6\ \text{kg-H}_2 \rightarrow 34\ \text{kg-NH}_3 \tag{3.68}$$

Therefore:

$$1\ \text{kg-H}_2 \rightarrow 5.67\ \text{kg-NH}_3 \tag{3.69}$$

Annual ammonia production is:

$$m_{NH_3,t} = m_{H_2,t} \times 5.67 \times \eta_{NH_3} \tag{3.70}$$

where η_{NH_3} is the ammonia synthesis efficiency or availability factor.

The levelized cost of ammonia is calculated as:

$$LCOA = \frac{\sum_{t=1}^{N} \frac{C_{H_2,t}+C_{\text{ASU},t}+C_{\text{HB},t}+C_{\text{NH}_3,\text{storage},t}+C_{\text{O\&M},t}}{(1+r)^t}}{\sum_{t=1}^{N} \frac{m_{NH_3,t}}{(1+r)^t}} \tag{3.71}$$

where $C_{\text{ASU},t}$ is the cost of nitrogen separation, $C_{\text{HB},t}$ is Haber-Bosch synthesis cost, and $C_{\text{NH}_3,\text{storage},t}$ is ammonia storage cost.

The fertilizer import-substitution value is:

$$V_{\text{fertilizer},t} = m_{NH_3,t} \times P_{NH_3,\text{import parity}} \tag{3.72}$$

The ammonia pathway is economically competitive when:

$$LCOA \leq P_{NH_3,\text{import parity}} \tag{3.73}$$

The break-even ammonia price is:

$$P_{NH_3,\text{BE}} = LCOA \tag{3.74}$$

In this study, green ammonia is not assessed only as a commodity product. It is also assessed as a strategic fertilizer-security pathway because it may reduce Nepal's dependence on imported nitrogen fertilizer.

Fertilizer Context in Nepal

Nepal produces no chemical fertilizers domestically and relies entirely on imports, predominantly from or through India (Wikipedia contributors, 2025). Of total fertilizer consumed nationally, approximately 65% is urea, 30% DAP, and 5% potash, against an annual requirement of roughly 550,000 metric tonnes, of which only about 125,000 metric tonnes is supplied in a timely manner (myRepublica, 2025). Despite an annual urea demand of approximately 700,000 metric tonnes, only 426,000 metric tonnes was imported in FY 2022/23, meeting just 53% of total demand (Pokharel, 2024). Ammonia is the direct chemical precursor to urea via the Haber–Bosch reaction, and also feeds DAP and ammonium sulphate production chains, making it the most strategically important feedstock for any domestic fertilizer manufacturing programme.

Table 3-7 Estimated Ammonia Requirement for Fertilizer Production

Fertilizer Type	Share of Use	Annual Demand (MT)	Role of NH_3	NH_3 Required (approx.)
Urea $CO(NH_2)_2$	65%	~357,500	Direct precursor; 0.567 kg NH_3/kg urea	~202,700 MT
DAP $(NH_4)_2HPO_4$	30%	~165,000	Partial nitrogen from NH_3	~40,000 MT
Ammonium sulphate	~5%	~27,500	Direct NH_3 derivative	~10,000 MT
Total	**100%**	**~550,000**	—	**~252,700 MT NH_3/yr**

Sources: (Wikipedia contributors, 2025; myRepublica, 2025)

Energy Served

To meet Nepal's annual urea demand, approximately 397,100 metric tonnes of ammonia is required, with hydrogen production alone necessitating a stable electricity supply of around 350 MW per year (Pokharel, 2024). This level of power supply is well within Nepal's projected wet-season surplus, confirming technical feasibility at the national scale (Thapa et al., 2021). The energy served by this pathway is delivered as chemical energy embodied in ammonia and its derivative fertilizers, quantified through equation (3.68) as nitrogen fixed per unit of hydrogen consumed. The economic value of this energy service is the fertilizer import-substitution value $V_{\text{fertilizer},t}$ from equation (3.71), benchmarked against import parity pricing. Nepal's annual fertilizer subsidy bill has reached NPR 38.5 billion, with urea imported at up to USD 1,022 per tonne at peak global prices (The Kathmandu Post, 2023), illustrating the scale of import expenditure that domestic green ammonia production could displace. The pathway is accordingly treated as a strategic food-security and foreign-exchange option, evaluated alongside the energy-value comparisons in equations (3.71) to (3.73).

3.9 Techno-economic Analysis

The economic performance of each pathway is evaluated using net present value, internal rate of return, discounted payback period, benefit-cost ratio, and break-even price.

3.9.1 Net Present Value

Net present value is calculated as:

$$NPV = \sum_{t=0}^{N} \frac{B_t - C_t}{(1 + r)^t} \tag{3.75}$$

where B_t is the benefit in year t, C_t is the cost in year t, r is the discount rate, and N is the project life.

A pathway is economically viable if:

$$NPV > 0 \tag{3.76}$$

3.9.2 Internal Rate of Return

The internal rate of return is the discount rate that makes the NPV equal to zero:

$$0 = \sum_{t=0}^{N} \frac{B_t - C_t}{(1 + IRR)^t} \tag{3.77}$$

A pathway is financially attractive if its IRR exceeds the required discount rate.

3.9.3 Benefit-Cost Ratio

The benefit-cost ratio is calculated as:

$$BCR = \frac{\sum_{t=1}^{N} \frac{B_t}{(1+r)^t}}{\sum_{t=1}^{N} \frac{C_t}{(1+r)^t}} \tag{3.78}$$

A value greater than one indicates that discounted benefits exceed discounted costs.

3.9.4 Discounted Payback Period

The discounted payback period is the first year in which cumulative discounted cash flow becomes positive:

$$\sum_{t=0}^{T} \frac{B_t - C_t}{(1 + r)^t} \geq 0 \tag{3.79}$$

where T is the payback year.

3.9.5 Break-even Price Analysis

Since hydrogen pathways may not be profitable under present market prices, break-even price analysis is included. This method identifies the minimum selling price or strategic value required for each pathway to equal or exceed the value of direct electricity export.

For hydrogen sale:

$$P_{H_2,\mathrm{BE}} = \frac{C_{\mathrm{annual,total}}}{m_{H_2,\mathrm{annual}}} \tag{3.80}$$

For ammonia sale:

$$P_{NH_3,\mathrm{BE}} = \frac{C_{\mathrm{annual,NH_3}}}{m_{NH_3,\mathrm{annual}}} \tag{3.81}$$

For re-electrified electricity:

$$P_{\mathrm{elec,BE}} = \frac{C_{\mathrm{annual,re\text{-}elec}}}{E_{\mathrm{re\text{-}elec,annual}}} \tag{3.82}$$

A pathway becomes more attractive than export when:

$$P_{\text{market or strategic value}} \geq P_{\text{break-even}} \tag{3.83}$$

This approach allows the study to identify not only whether a pathway is feasible today, but also under what price, subsidy, carbon value, or strategic premium it could become feasible.

3.10 Environmental and Energy Security Assessment

The environmental assessment quantifies fossil fuel displacement and associated carbon dioxide emission reductions for each pathway.

For fossil fuel displacement, avoided emissions are calculated as:

$$CO_2^{\text{avoided}} = F_{\text{displaced}} \times EF_{\text{fuel}} \tag{3.84}$$

where $F_{\text{displaced}}$ is the amount of fossil fuel displaced and EF_{fuel} is the emission factor.

For electricity import reduction through re-electrification:

$$CO_2^{\text{avoided,import}} = E_{\text{re-elec}} \times EF_{\text{grid import}} \tag{3.85}$$

For direct electrification:

$$CO_2^{\text{avoided,direct}} = E_{\text{direct}} \times EF_{\text{replaced fuel}} \tag{3.86}$$

Energy security is assessed using three indicators: import reduction, seasonal storage contribution, and domestic value creation. The import reduction ratio is calculated as:

$$IR = \frac{\text{Avoided imported energy or fuel}}{\text{Baseline imported energy or fuel}} \times 100 \tag{3.87}$$

3.11 Sensitivity and Uncertainty Analysis

Because hydrogen economics are sensitive to uncertain assumptions, deterministic sensitivity analysis and Monte Carlo uncertainty analysis are performed.

3.11.1 Deterministic Sensitivity Analysis

The following parameters are varied:

- electricity export price,
- electrolyzer CAPEX,
- electrolyzer specific energy consumption,
- discount rate,
- hydrogen delivery cost,
- ammonia import-parity price,
- fossil fuel price.

For each parameter x, low and high cases are evaluated:

$$x_{\text{low}} = x_{\text{base}}(1 - \delta) \tag{3.88}$$

$$x_{\text{high}} = x_{\text{base}}(1 + \delta) \tag{3.89}$$

The effect on LCOH, LCOA, NPV, and pathway ranking is recorded. Results are presented using tornado plots to identify the most influential parameters.

3.11.2 Monte Carlo Uncertainty Analysis

Monte Carlo simulation is used to evaluate the combined uncertainty of multiple variables. Instead of using a single deterministic value, uncertain parameters are represented by probability distributions.

For example:

$$CAPEX_{\text{elz}} \sim Triangular(C_{\text{min}}, C_{\text{mode}}, C_{\text{max}}) \tag{3.90}$$

$$SEC \sim Triangular(SEC_{\text{min}}, SEC_{\text{mode}}, SEC_{\text{max}}) \tag{3.91}$$

$$P_{\text{export}} \sim Triangular(P_{\text{min}}, P_{\text{mode}}, P_{\text{max}}) \tag{3.92}$$

For each Monte Carlo iteration k, pathway costs and benefits are recalculated:

$$LCOH^{(k)} = f(CAPEX^{(k)}, SEC^{(k)}, P_{\text{export}}^{(k)}, r^{(k)}) \tag{3.93}$$

The probability of feasibility is estimated as:

$$P_{\text{feasible}} = \frac{N(LCOH^{(k)} \leq P^{(k)}_{H_2,\text{market}})}{N_{\text{MC}}} \tag{3.94}$$

where N_{MC} is the total number of Monte Carlo simulations.

For ammonia:

$$P_{\text{feasible,NH}_3} = \frac{N(LCOA^{(k)} \leq P^{(k)}_{NH_3,\text{import parity}})}{N_{\text{MC}}} \tag{3.95}$$

This analysis provides a probabilistic view of feasibility instead of relying only on one base-case estimate.

3.12 Multi-Criteria Decision Analysis

Because the best hydrogen pathway for Nepal may not be determined by cost alone, a multi-criteria decision analysis is applied. Five pathways are ranked:

1. Direct domestic electrification,
2. Re-electrification,
3. Hydrogen transport,
4. Industrial fuel substitution,
5. Green ammonia production.

Four criteria are used: economic viability, technical feasibility, energy security, and environmental benefit.

Table 3-8 Base MCDA criteria and weights

Criterion	Weight
Economic viability	35%
Technical feasibility	25%
Energy security	20%
Environmental benefit	20%

The weighted MCDA score for pathway i is calculated as:

$$S_i = \sum_{j=1}^{n} w_j x_{ij} \tag{3.96}$$

where S_i is the total score of pathway i, w_j is the weight of criterion j, and x_{ij} is the normalised score of pathway i under criterion j.

For benefit-type indicators, normalisation is performed as:

$$x_{ij} = \frac{X_{ij} - X_j^{\min}}{X_j^{\max} - X_j^{\min}} \tag{3.97}$$

For cost-type indicators, normalisation is performed as:

$$x_{ij} = \frac{X_j^{\max} - X_{ij}}{X_j^{\max} - X_j^{\min}} \tag{3.98}$$

The pathway with the highest MCDA score is identified as the most suitable pathway under the base weighting structure.

3.12.1 MCDA Sensitivity Cases

Two additional MCDA weighting cases are included to test whether pathway rankings change under different national priorities.

Table 3-9 MCDA sensitivity weighting cases

Case	Economic	Technical	Energy Security	Environmental
Base case	35%	25%	20%	20%
Energy-security priority	25%	20%	35%	20%
Fertilizer-security priority	25%	20%	30%	25%

This sensitivity analysis is included because Nepal's most suitable hydrogen pathway may depend on whether policy priority is least-cost energy use, dry-season security, fossil-fuel import reduction, or fertilizer import substitution.

3.13 Selection of the Most Suitable Pathway

The final pathway recommendation is not based on a single indicator. Instead, each pathway is evaluated using five decision layers:

1. technical feasibility,
2. economic feasibility,
3. break-even price realism,
4. environmental benefit,
5. MCDA ranking.

The final decision rule is:

$$\text{Best Pathway} = \arg\max_{i} \left(S_i\right) \tag{3.99}$$

subject to the condition that the pathway must also have a physically meaningful end-use market in Nepal.

Therefore, a pathway with high theoretical hydrogen consumption but weak Nepal-specific demand is not automatically selected. This is particularly important for transport hydrogen, where light-duty mobility may be better served by direct electrification, while hydrogen may only be relevant for selected heavy-duty applications.

4 RESULT AND OBSERVATIONS

4.1 Data Cleaning and Historical Energy Pattern

The uploaded dataset contained 851 raw records. After duplicate aggregation and daily calendar cleaning, the analysis produced 860 calendar days from 2022-09-05 to 2025-01-11. The cleaned period contains 4,765,656 MWh of export/surplus energy and 3,873,716 MWh of import energy. Table 4-1 summarizes the data audit.

Table 4-1 Data cleaning audit for the uploaded dataset.

Indicator	Value
Raw records	851
Cleaned calendar days	860
Cleaned period	2022-09-05 to 2025-01-11
Duplicate-date rows	20
Missing calendar days	29
Missing calendar days (%)	3.37
Total export/surplus (MWh)	4,765,656
Total import (MWh)	3,873,716

The historical profiles show clear seasonality. Export is concentrated in the wetter hydropower period, while import is more visible during lower-generation periods. This seasonal structure is the physical basis for the hydrogen assessment. If surplus were flat throughout the year, electrolyzer utilization would be easier. Instead, the observed seasonal concentration creates a trade-off between high surplus capture and low electrolyzer capacity factor.

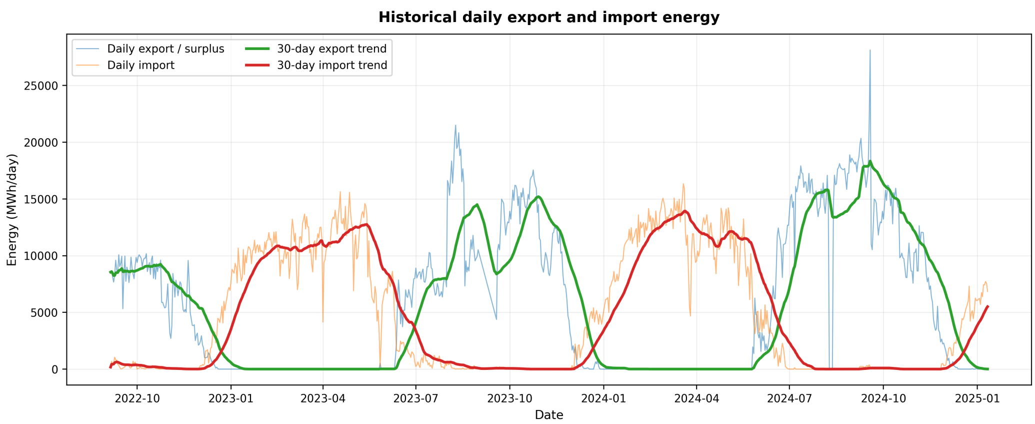

Figure 4-1 Historical daily electricity export and import after data cleaning.

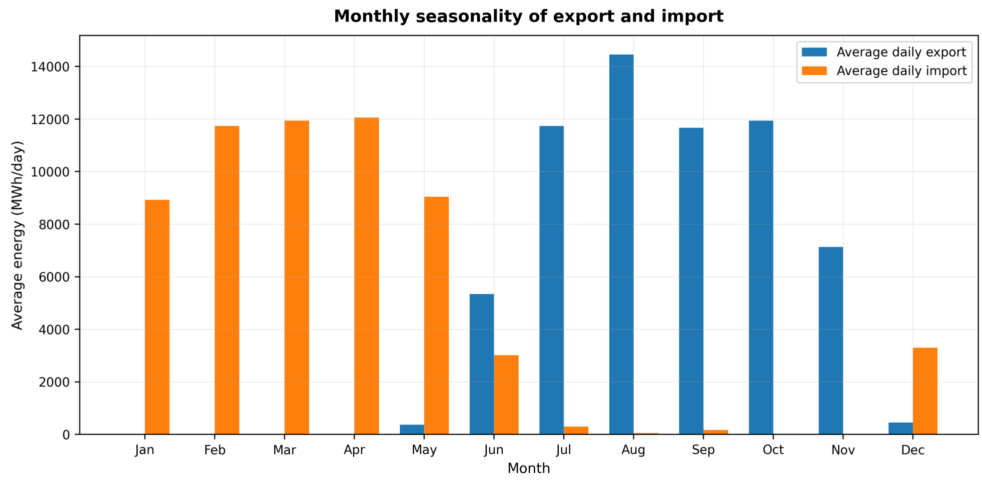

Figure 4-2 Monthly export and import climatology showing seasonal surplus and deficit behaviour.

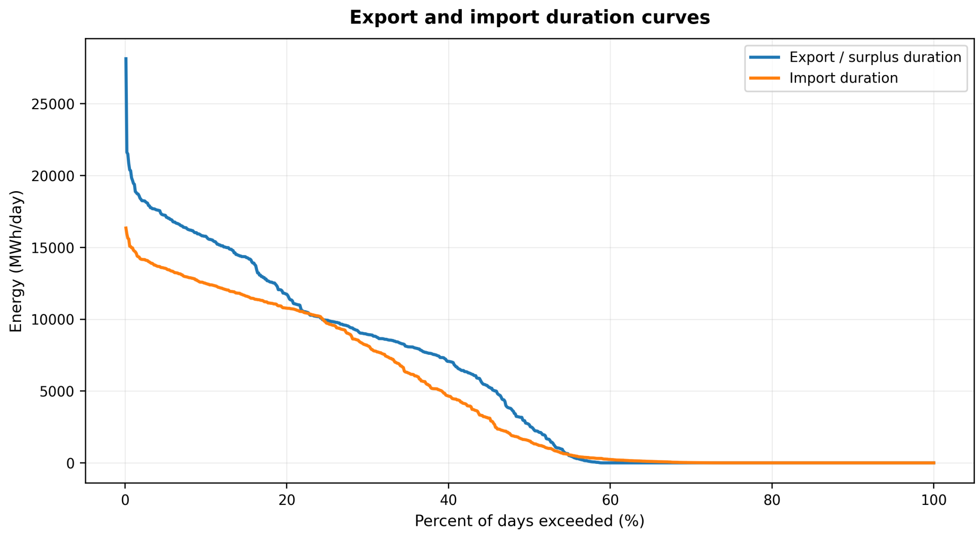

Figure 4-3 Export and import duration curves. The export duration curve is used to interpret electrolyzer size and surplus capture

4.2 Forecasting Results

The historical data were used to construct a seasonal export profile and then extend future exportable electricity over the project horizon. Three forecast scenarios were considered: conservative 0%, moderate 3%, and aggressive 6% annual growth. The moderate scenario is used as the central case because it represents a plausible long-term increase in exportable surplus without assuming an extremely rapid expansion.

The export forecast validation used 172 days. The export forecast produced an MAE of 4,109.6 MWh/day and RMSE of 5,085.6 MWh/day. The import forecast produced MAE of 224.0 MWh/day and RMSE of 397.5 MWh/day. MAPE was not used as the main indicator because export and import series include many near-zero days, which make percentage errors unstable.

Table 4-2 Forecast validation summary.

Target	Validation days	MAE (MWh/day)	RMSE (MWh/day)
Export energy	172	4,109.6	5,085.6
Import energy	172	224.0	397.5

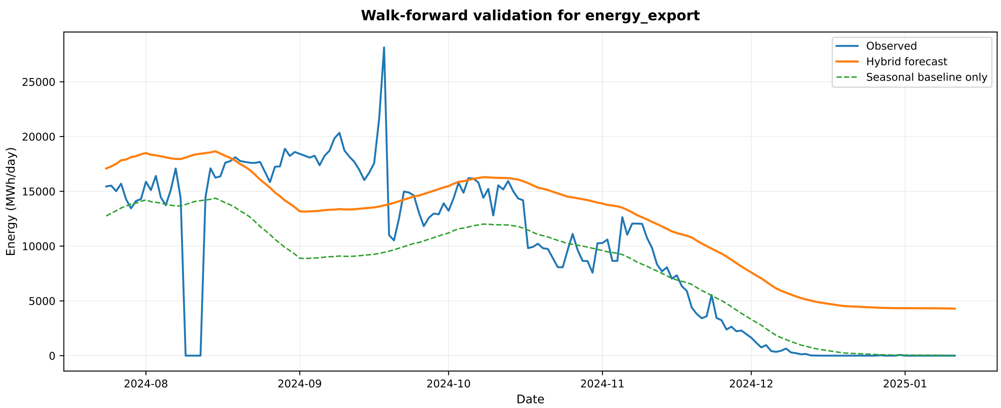

Figure 4-4 Export-energy validation using the hybrid seasonal SARIMA-assisted forecasting approach.

The 20-year forecast covers 2025-01-12 to 2045-01-11. The conservative scenario produces 38.23 TWh of exportable surplus, the moderate scenario produces 51.36 TWh, and the aggressive scenario produces 70.31 TWh. These values show that the long-term hydrogen opportunity increases substantially under higher surplus-growth assumptions.

Table 4-3 Twenty-year export and import forecast by scenario.

Scenario	Total export (TWh)	Avg. export (TWh/yr)	Year 1 export (TWh)	Year 20 export (TWh)	Total import (TWh)
Conservative 0%	38.23	1.91	1.91	1.91	
Moderate 3%	51.36	2.57	1.91	3.35	36.66
Aggressive 6%	70.31	3.52	1.91	5.78	

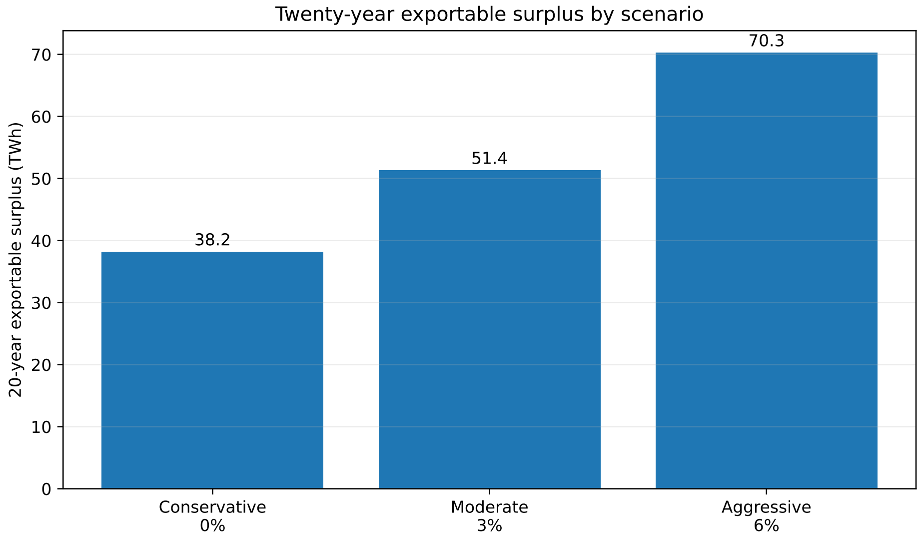

Figure 4-5 Total forecast exportable surplus under conservative, moderate, and aggressive scenarios.

4.3 Electrolyzer Sizing Results

Electrolyzer sizing results for the moderate scenario are shown in Table 4-4. The 100 MW and 250 MW systems have lower LCOH and higher capacity factors, but they capture only a limited share of surplus. Larger systems capture more surplus but suffer lower capacity factors and higher LCOH. The 500 MW electrolyzer provides the most balanced result: approximately 37,974 tonnes-H_2/year, 43.35% capacity factor, 77.63% surplus capture, and NPR 693/kg-H_2 LCOH.

Table 4-4 Electrolyzer sizing results under the moderate 3% scenario.

Electrolyzer (MW)	Annual H2 (t/yr)	Capacity factor (%)	Surplus capture (%)	Unused export (GWh/yr)	LCOH (NPR/kg)
100	9,173.9	52.362	18.755	1,987.1	646.769
250	21,198.1	48.397	43.336	1,385.9	664.354
500	37,974.0	43.349	77.632	547.081	693.001
750	47,143.2	35.878	96.376	88.624	758.191
1,000.0	48,904.5	27.914	99.977	0.558	855.432
1,500.0	48,915.7	18.613	100	0	1,063.1

The result shows why the largest electrolyzer is not automatically optimal. A 1500 MW system captures almost all surplus, but it operates at only 18.61% capacity factor and has an LCOH above NPR 1,063/kg-H_2. The 750 MW case captures 96.38% of surplus, but its LCOH is higher than the 500 MW case. Therefore, 500 MW is selected as the base design, while 750 MW can be considered a high-surplus-capture sensitivity case.

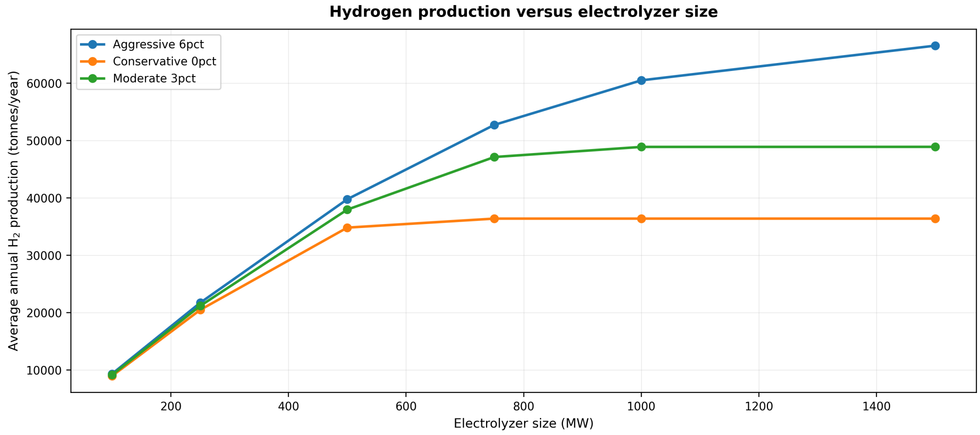

Figure 4-6 Hydrogen production increases with electrolyzer size, but the incremental gain reduces as surplus becomes fully captured.

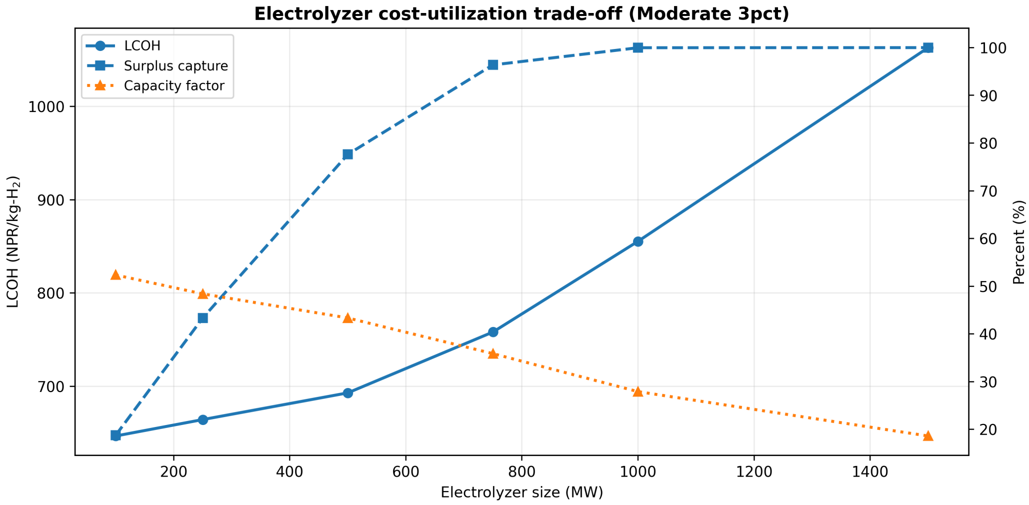

Figure 4-7 Trade-off between LCOH and surplus capture for different electrolyzer sizes.

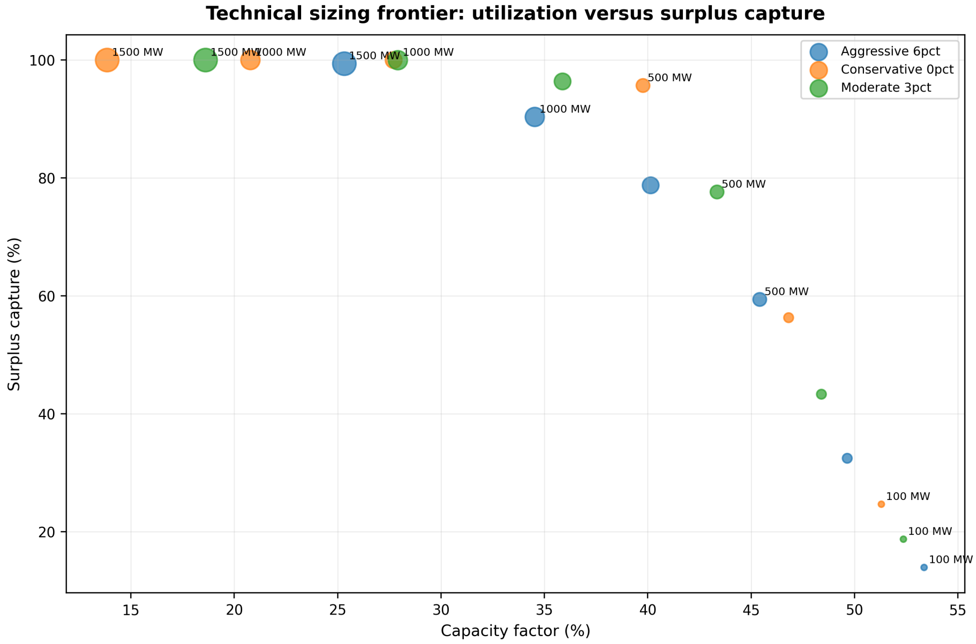

Figure 4-8 Utilization-capture frontier. The selected 500 MW case balances surplus capture and operational utilization.

4.4 Green Ammonia Results

Green ammonia and delivered hydrogen require separate interpretation. Green ammonia is compared with fertilizer import-substitution value, while delivered hydrogen is compared with diesel-equivalent and industrial reference values.

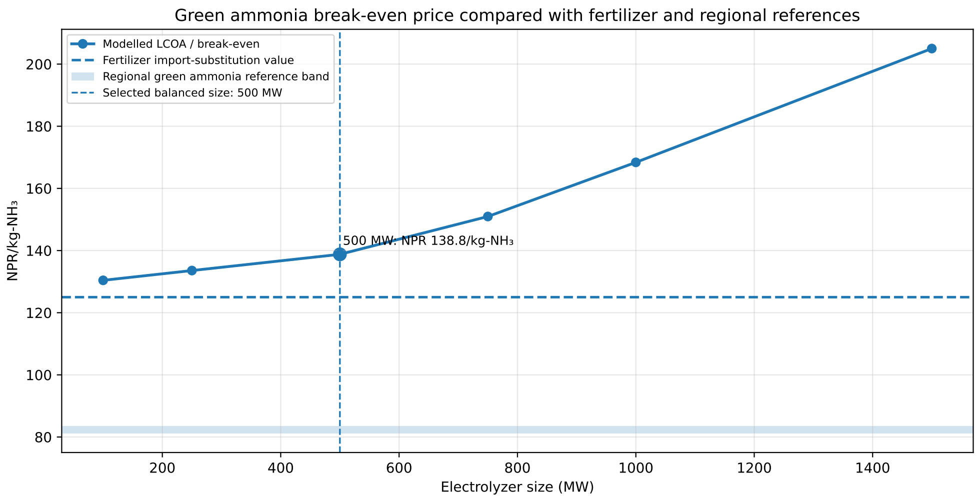

Figure 4-9 Green ammonia break-even price compared with fertilizer and regional reference values. The 500 MW case remains above the fertilizer substitution value.

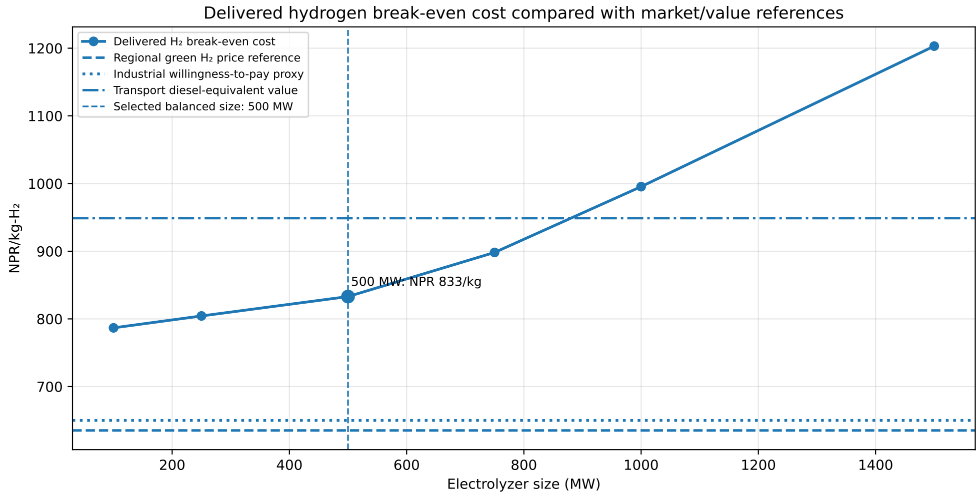

Figure 4-10 Delivered hydrogen break-even cost compared with hydrogen and fuel-substitution reference values.

4.5 Transport and Industrial Substitution Results

Hydrogen transport is economically attractive in the model only because the assumed diesel-equivalent value is high relative to delivered hydrogen cost. This result should be interpreted carefully. It does not imply that all transport should use hydrogen. Battery-electric vehicles are likely more efficient for light-duty use, while hydrogen may be relevant for long-distance buses, freight corridors, or captive fleets where centralized refueling is practical. Industrial fuel substitution has lower economic performance because the assumed industrial willingness-to-pay is below the delivered hydrogen cost.

4.6 Re-electrification Analysis

Hydrogen Storage and Re-electrification Performance

The re-electrification pathway stores surplus wet-season hydrogen as compressed gaseous hydrogen (CGH_2) at 350 bar in steel pressure vessels, the most commercially established configuration for large-scale hydrogen buffering (International Energy Agency, 2019). The analysis does not design individual vessels, compressors, or site layouts; storage is represented at system level by the mass of hydrogen carried across the monsoon-to-dry-season transition.

Seasonal storage balance

The daily hydrogen inventory evolves according to:

$$S_d = S_{d-1} + \dot{m}_{H_2,\text{prod},d} - \dot{m}_{H_2,\text{used},d}, \qquad S_{\max} = \max_d (S_d) \tag{4.1}$$

For the 500 MW central case under the moderate 3% growth scenario, the model yields a peak seasonal inventory of $S_{\max} \approx 36{,}640$ t-H_2, corresponding to a stored chemical energy of:

$$E_{\text{stored}} = S_{\max} \times LHV_{H_2} = 36{,}640 \times 10^3 \times 33.3 \approx 1{,}220 \text{ GWh} \tag{4.2}$$

This is a large seasonal buffer, which is expected: hydrogen is being used here as a long-duration storage medium spanning the entire monsoon-to-dry-season cycle, a role that batteries cannot serve economically at this scale (International Renewable Energy Agency, 2020).

Storage cost

CGH_2 storage at 350 bar carries a capital cost of approximately \$650–1,200/kg-H_2 capacity, with annual operating costs of \$6–12/kg-H_2 and efficiency losses of 5–10% (Züttel, 2004). At the scale of $S_{\max} = 36{,}640$ t-H_2, storage CAPEX is the dominant cost component of this pathway and the principal reason it produces a higher LCOE than the direct-use alternatives. Underground salt-cavern storage would reduce long-run costs but is not geologically available in Nepal (Züttel, 2004).

Fuel cell assumptions and electricity served

Discharge is modelled through a proton exchange membrane fuel cell (PEMFC), selected for its commercial maturity in modular stationary applications, sub-minute start-up capability, and ability to follow variable dry-season load profiles more flexibly than high-temperature alternatives such as SOFCs (Staffell et al., 2019). Stack voltage, degradation, and heat recovery are outside the scope of this study.

The potential electricity output on day d is:

$$E_{\text{FC,potential},d} = \dot{m}_{H_2,\text{avail},d} \times LHV_{H_2} \times \eta_{\text{FC}} \tag{4.3}$$

Actual electricity served is the minimum of potential output, rated fuel-cell capacity, and dry-season import demand:

$$E_{\text{re-elec},d} = \min\big(E_{\text{import},d},\ P_{\text{FC}} \times 24,\ E_{\text{FC,potential},d}\big) \tag{4.4}$$

where $LHV_{H_2} = 33.3$ kWh/kg and $\eta_{\text{FC}} = 50$–60%, consistent with system-level PEM stationary performance (Staffell et al., 2019). The full-chain round-trip efficiency (electrolysis → storage → fuel cell) is approximately 30–35% (Staffell et al., 2019).

Under the 500 MW central case, the model yields approximately 638,406 MWh/yr of re-electrified electricity delivered during dry-season deficit periods. This figure is jointly constrained by the hydrogen inventory available for discharge and the dry-season import demand; it is not a simple function of storage volume alone.

Economic assessment

The value of re-electrified electricity is benchmarked against the avoided dry-season import price of NPR 12/kWh, since the pathway displaces electricity Nepal would otherwise purchase from the grid rather than serving a premium retail market. The feasibility condition is:

$$\mathrm{LCOE}_{\text{re-elec}} \leq P_{\text{import,avoided}} \tag{4.5}$$

The model yields a break-even LCOE of approximately NPR 55.15/kWh against an avoided import value of NPR 12/kWh. The pathway is technically viable, it can physically deliver dry-season electricity, but is not economically competitive under current price assumptions. The gap is driven primarily by the high storage CAPEX and the low round-trip efficiency. It is retained in the multi-criteria decision analysis (MCDA) on the basis of its strategic value as a seasonal energy security option, despite a negative NPV at current electricity prices.

Table 4-5 Hydrogen storage and re-electrification results for the 500 MW central case

Parameter	**Value**	**Basis**
Storage technology	CGH_2, 350 bar steel tanks	Commercially established (International Energy Agency, 2019)
Peak inventory S_{max}	≈36,640 t-H_2	Seasonal balance model output
Stored chemical energy	≈1,220 GWh (LHV)	$S_{max} \times 33.3$ kWh/kg
Storage CAPEX	\$650–1,200/kg-H_2	(Züttel, 2004)
Storage OPEX	\$6–12/kg-H_2/yr	(Züttel, 2004)
Efficiency loss (storage)	5–10%	(Züttel, 2004)
Fuel cell type	PEM (PEMFC)	Modularity, fast response (Staffell et al., 2019)
Electrical efficiency η_{FC}	50–60%	System-level PEM stationary range (Staffell et al., 2019)
Round-trip efficiency	≈30–35%	(Staffell et al., 2019)
Electricity served	≈638,406 MWh/yr	Model output
Electricity reference value	NPR 12/kWh	Avoided dry-season import price
Break-even LCOE	≈NPR 55.15/kWh	Model output
Economic status	Not profitable at current import price	Break-even cost ≫ avoided import price
Strategic value	Seasonal electricity security	Retained in MCDA on non-economic criteria

4.7 Environmental Results

Environmental results are reported in $ktCO_2$/year. Under the moderate 500 MW case, direct domestic electrification avoids 1,598 $ktCO_2$/year, hydrogen transport avoids 623 $ktCO_2$/year, green ammonia avoids 345 $ktCO_2$/year, industrial fuel substitution avoids 121 $ktCO_2$/year, and re-electrification avoids 31.9 $ktCO_2$/year.

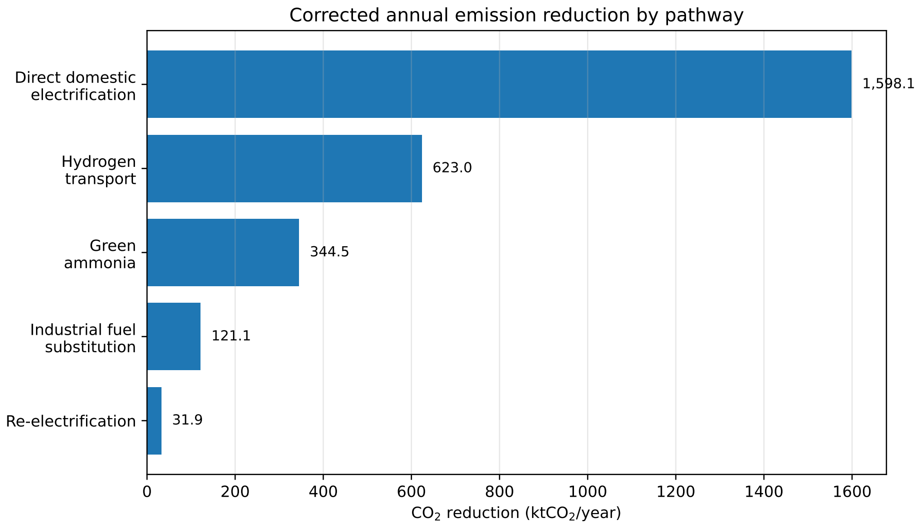

Figure 4-11 Corrected annual emission reduction by pathway. Direct domestic electrification has the highest emission benefit because it avoids hydrogen conversion losses.

4.8 Pathway Economic Results

The central pathway comparison uses a common 500 MW hydrogen plant. This avoids mixing pathway economics with different electrolyzer sizes. The MCDA section separately reports best-configuration results.

Table 4-6 Moderate scenario pathway results using the common 500 MW hydrogen plant.

Pathway	Output	NPV (NPR bn)	BCR	BE	Ref.	Margin	CO_2 (kt/yr)
Direct domestic electrification	2,445,783 MWh/yr	168.59	1.82	8.80	16.00	7.20	1,598.1
Hydrogen transport	37,974 t-H_2/yr	44.55	1.14	833.00	948.88	115.88	623.0
Green ammonia	215,313 t-NH_3/yr	-30.04	0.90	138.78	125.00	-13.78	344.5
Industrial fuel substitution	13,291 t-H_2/yr	-24.62	0.78	833.00	650.00	-183.00	121.1
Re-electrification	638,406 MWh/yr	-278.89	0.22	55.15	12.00	-43.15	31.9

Direct domestic electrification is the strongest overall pathway. The positive margin is NPR 7.2/kWh, calculated from the domestic-use value of NPR 16/kWh and export opportunity value of NPR 8.8/kWh. This leads to NPV of NPR 168.59 billion and BCR of 1.82.

Hydrogen transport is the strongest hydrogen pathway under base economics. The delivered hydrogen cost is NPR 833/kg-H_2, while the diesel-equivalent reference is NPR 948.88/kg-H_2. The positive margin is NPR 115.88/kg-H_2, producing NPV of NPR 44.55 billion and BCR of 1.14. This result applies to heavy-duty or captive diesel-displacing fleets, not general passenger vehicles.

Green ammonia is close to its fertilizer substitution value but not yet profitable in the common 500 MW case. It produces 215,313 t-NH_3/year, but its break-even cost is NPR 138.78/kg-NH_3 against a reference value of NPR 125/kg-NH_3. The shortfall is NPR 13.78/kg-NH_3.

Re-electrification is weakest. It delivers 638,406 MWh/year but costs NPR 55.15/kWh against an avoided import value of NPR 12/kWh. It also requires approximately 36,640 tonnes of seasonal hydrogen storage. These numbers explain the negative NPV of NPR -278.89 billion and BCR of 0.22.

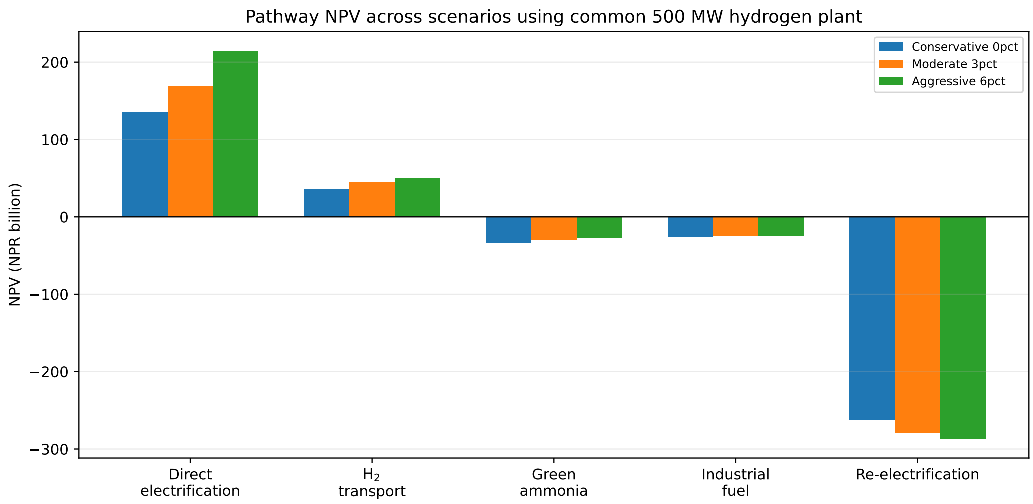

Figure 4-12 Pathway NPV across conservative, moderate, and aggressive scenarios using the common 500 MW hydrogen plant.

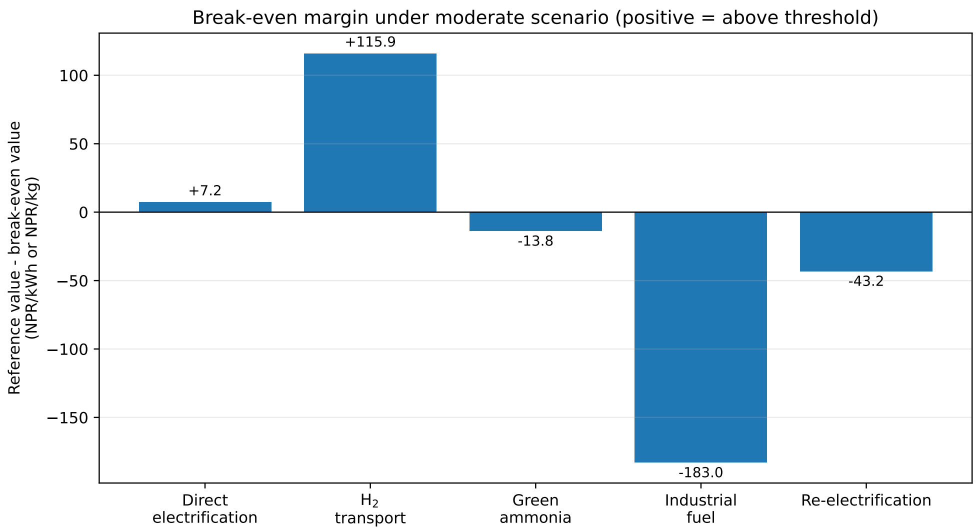

Figure 4-13 Break-even margin under the moderate scenario. Positive values mean the reference value is above the break-even value.

4.9 Pathway Comparison Across Scenarios

Across all three scenarios, direct domestic electrification remains the strongest overall pathway. Its NPV increases from NPR 135.12 billion in the conservative case to NPR 214.64 billion in the aggressive case. Hydrogen transport remains positive in all three scenarios. Green ammonia remains negative, but its margin improves as surplus increases. Re-electrification remains strongly negative in all scenarios.

Table 4-7 Pathway comparison across conservative, moderate, and aggressive scenarios using the common 500 MW hydrogen plant.

Scenario	Pathway	NPV (NPR bn)	BCR	BE	Ref.	Margin
Cons. (0%)	Direct domestic electrification	135.12	1.82	8.80	16.00	7.20
	Hydrogen transport	35.22	1.12	850.82	948.88	98.06
	Green ammonia	-33.86	0.88	141.63	125.00	-16.63
	Industrial fuel substitution	-25.24	0.76	850.82	650.00	-200.82
	Re-electrification	-262.04	0.22	55.40	12.00	-43.40
Mod. (3%)	Direct domestic electrification	168.59	1.82	8.80	16.00	7.20
	Hydrogen transport	44.55	1.14	833.00	948.88	115.88
	Green ammonia	-30.04	0.90	138.78	125.00	-13.78
	Industrial fuel substitution	-24.62	0.78	833.00	650.00	-183.00
	Re-electrification	-278.89	0.22	55.15	12.00	-43.15
Aggr. (6%)	Direct domestic electrification	214.64	1.82	8.80	16.00	7.20
	Hydrogen transport	50.12	1.15	823.44	948.88	125.44
	Green ammonia	-27.71	0.91	137.23	125.00	-12.23
	Industrial fuel substitution	-24.25	0.79	823.44	650.00	-173.44
	Re-electrification	-286.59	0.22	54.67	12.00	-42.67

4.10 MCDA Results

MCDA was used only as a decision-support layer after the numerical pathway results were calculated. The economic values used for interpretation are already shown in Tables 4-6 and 4-7. To avoid mixing different result bases, the MCDA table below reports ranking and weighted scores only. NPV, BCR, break-even value, and margin should be read from the pathway economics tables.

Table 4-8 Base-weight MCDA ranking across the three scenarios.

Scenario	Rank 1	Score	Rank 2	Score
Conservative 0%	Direct domestic electrification	1.000	Hydrogen transport	0.422
Moderate 3%	Direct domestic electrification	1.000	Hydrogen transport	0.374
Aggressive 6%	Direct domestic electrification	1.000	Hydrogen transport	0.316

Table 4-9 Remaining base-weight MCDA ranking across the three scenarios.

Scenario	Rank 3	Score	Rank 4	Score	Rank 5	Score
Conservative 0%	Green ammonia	0.332	Industrial fuel substitution	0.135	Re-electrification	0.005
Moderate 3%	Green ammonia	0.315	Industrial fuel substitution	0.121	Re-electrification	0.004
Aggressive 6%	Green ammonia	0.298	Industrial fuel substitution	0.107	Re-electrification	0.003

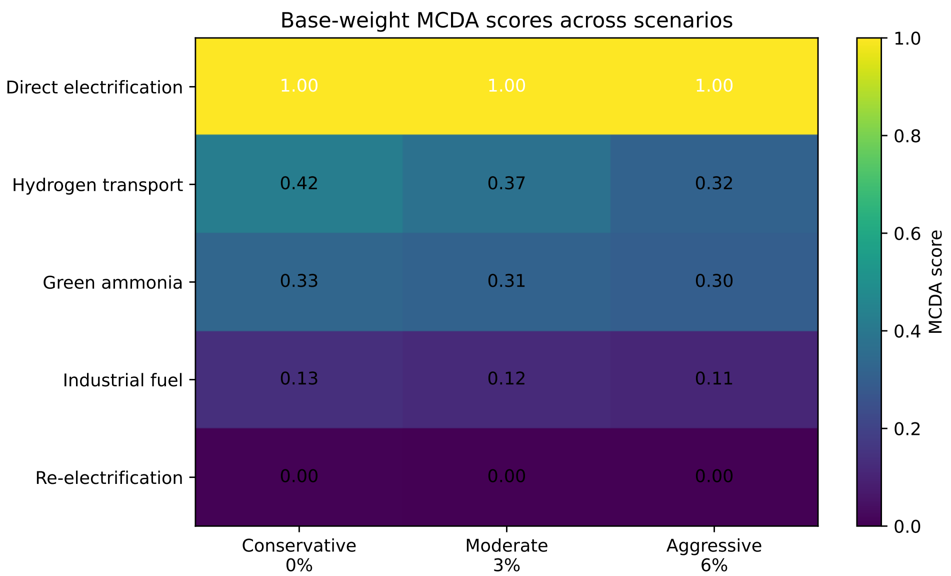

Figure 4-14 Base-weight MCDA scores across the three scenarios. Direct domestic electrification remains rank 1 in all scenarios.

The MCDA result is consistent with the economic tables. Direct domestic electrification remains rank 1 in all scenarios because it has the highest NPV, highest BCR, highest corrected emission reduction, and no conversion loss. Hydrogen transport remains the best base-economic hydrogen pathway because it is the only hydrogen pathway with positive NPV in the common

500 MW case. Green ammonia ranks below hydrogen transport in the base-weight case because it has negative NPV, but it becomes more important under fertilizer-security weighting.

Table 4-10 Moderate-scenario MCDA policy sensitivity. Scores change when policy weights change, but pathway NPV and BCR remain those reported in Table 4-6.

MCDA case	Rank	Pathway	Score
Base weights	1	Direct domestic electrification	1.000
Base weights	2	Hydrogen transport	0.374
Base weights	3	Green ammonia	0.315
Base weights	4	Industrial fuel substitution	0.121
Base weights	5	Re-electrification	0.004
Energy-security priority	1	Direct domestic electrification	1.000
Energy-security priority	2	Green ammonia	0.408
Energy-security priority	3	Hydrogen transport	0.385
Energy-security priority	4	Industrial fuel substitution	0.090
Energy-security priority	5	Re-electrification	0.003
Fertilizer-security priority	1	Direct domestic electrification	1.000
Fertilizer-security priority	2	Green ammonia	0.448
Fertilizer-security priority	3	Hydrogen transport	0.388
Fertilizer-security priority	4	Industrial fuel substitution	0.089
Fertilizer-security priority	5	Re-electrification	0.003

The policy-sensitivity table should be read carefully. Changing MCDA weights changes the pathway score and ranking, but it does not change NPV or BCR. Under energy-security and fertilizer-security priorities, green ammonia rises above hydrogen transport because ammonia is assigned higher strategic value for fertilizer import substitution. This does not make ammonia financially profitable; the economic gap remains the NPR 13.78/kg-NH_3 shortfall reported in Table 4-6.

4.11 Sensitivity and Uncertainty Results

The deterministic sensitivity analysis shows that LCOH is most sensitive to export electricity price. A 30% increase in export electricity price raises LCOH by NPR 132/kg-H_2, while a 30% decrease reduces it by NPR 132/kg-H_2. Discount rate, electrolyzer CAPEX, and SEC are the next most important variables.

Table 4-11 Sensitivity of LCOH for the selected 500 MW electrolyzer.

Parameter change	New LCOH ($NPR/kg\text{-}H_2$)	Change ($NPR/kg\text{-}H_2$)
Export electricity price -30%	561.0	-132.0
Discount rate -25%	615.0	-78.0
Electrolyzer CAPEX -30%	617.1	-75.9
SEC improvement -10%	623.7	-69.3
SEC degradation +10%	762.3	69.3
Electrolyzer CAPEX +30%	768.9	75.9
Discount rate +25%	771.0	78.0
Export electricity price +30%	825.0	132.0

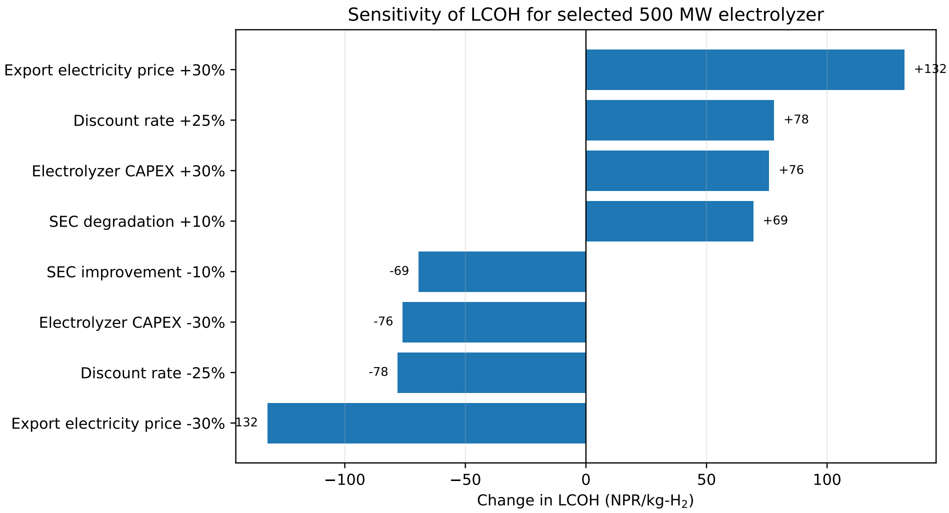

Figure 4-15 Sensitivity of LCOH for the selected 500 MW electrolyzer.

Monte Carlo analysis gives a median LCOH of NPR 696.4/kg-H_2 with a 5–95% range of NPR 556.5–877.7/kg-H_2. The median delivered hydrogen cost is NPR 838.6/kg-H_2, and the median green ammonia break-even price is NPR 173.7/kg-NH_3. This confirms that the hydrogen result is uncertainty-sensitive, while green ammonia generally remains above the fertilizer reference value.

Table 4-12 Monte Carlo uncertainty range for selected indicators.

Indicator	5%	Median	95%
LCOH (NPR/kg-H_2)	556.5	696.4	877.7
Delivered H_2 cost (NPR/kg-H_2)	686.2	838.6	1,032.5
Green ammonia break-even (NPR/kg-NH_3)	144.8	173.7	208.4

5 DISCUSSION

Green hydrogen is technically feasible for Nepal, but surplus hydropower is not automatically best directed toward it. The most efficient non-export pathway is direct domestic electrification, since it avoids the conversion losses that come with producing, storing, distributing, and reconverting hydrogen. EV charging, electric cooking, heat pumps, and irrigation pumping all use electricity more efficiently than any hydrogen pathway. Hydrogen makes economic sense only where direct electrification cannot easily do the job: fertilizer production, heavy-duty transport, selected industrial heat, and long-duration strategic storage. Surplus electricity alone is not sufficient justification for hydrogen deployment; the end-use value must exceed production, storage, delivery, and opportunity costs.

Under the moderate scenario, direct domestic electrification draws on the average forecast surplus of 2.45 TWh/year, valuing useful domestic electricity at NPR 16/kWh against an export opportunity value of NPR 8.8/kWh. The resulting margin of NPR 7.2/kWh yields an NPV of NPR 168.59 billion and a BCR of 1.82. This does not imply that all surplus can automatically be absorbed domestically; rather, it shows that where Nepal can cultivate flexible domestic demand at close to NPR 16/kWh, direct electrification outperforms hydrogen conversion of the same electricity.

Among electrolyzer configurations, the 500 MW plant offers the most defensible central case. The 250 MW option carries a lower LCOH but captures only 43.3% of available surplus. The 750 MW option captures 96.4% but at a lower capacity factor and higher LCOH. At 500 MW, the plant captures 77.6% of surplus, produces 37,974 t-H2/year, and maintains a 43.3% capacity factor.

Hydrogen transport yields a positive result because the delivered cost falls below the diesel-equivalent reference value. In the moderate 500 MW case, delivered hydrogen costs NPR 833/kg-H2 against a diesel-equivalent reference of NPR 948.88/kg-H2, a margin of NPR 115.88/kg-H2. This supports targeted pilots in high-utilization heavy-duty transport, though the finding should not be extended to passenger vehicles, where direct electrification retains the efficiency advantage.

Green ammonia is not the strongest pathway on base economics, but it is the most Nepal-specific in strategic terms. The 500 MW case produces 215,313 t-NH3/year, a quantity relevant at fertilizer-supply scale. The break-even cost, however, is NPR 138.78/kg-NH3 against a fertilizer import-substitution reference of NPR 125/kg-NH3, leaving a negative margin of NPR 13.78/kg-NH3. Viability therefore depends on additional value through a fertilizer-security premium, policy support, carbon pricing, or cost reduction.

Re-electrification produces the weakest result of the pathways examined. Converting electricity to hydrogen and back to electricity incurs large round-trip losses and requires approximately 36,640 tonnes of seasonal hydrogen storage. In the moderate case the pathway delivers 638,406 MWh/year at a cost of NPR 55.15/kWh, well above the avoided import value of NPR 12/kWh.

Re-electrification is therefore not recommended as a priority pathway.

The results are internally consistent, but their realism is conditional on reference values. Direct electrification depends on whether flexible domestic demand can absorb surplus at NPR 16/kWh. Hydrogen transport depends on whether high-utilization, diesel-displacing fleets exist at sufficient scale. Green ammonia depends on fertilizer import-substitution value and policy conditions. Re-electrification would require a substantially higher dry-season reliability premium than the assumed import value. These results are accordingly best understood as techno-economic screening estimates rather than investment-grade financial projections.

6 CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusion

The final model confirms that Nepal's surplus hydropower can support meaningful green hydrogen production, but hydrogen is not automatically the best use of surplus electricity. Under the moderate 3% scenario, the selected 500 MW electrolyzer produces 37,974 t-H_2/year, captures 77.6% of forecast surplus, and gives an LCOH of NPR 693/kg-H_2.

Direct domestic electrification is the strongest overall pathway, with NPV of NPR 168.59 billion, BCR of 1.82, and emission reduction of 1,598 ktCO_2/year. Hydrogen transport is the strongest hydrogen-based pathway under base economics, with NPV of NPR 44.55 billion and BCR of 1.14. Green ammonia is strategically important for fertilizer import substitution but requires an extra NPR 13.78/kg-NH_3 of value or equivalent cost reduction in the central case. Industrial fuel substitution is below its reference value, and re-electrification is the weakest pathway because its break-even cost of NPR 55.15/kWh is far above the avoided import value of NPR 12/kWh.

6.2 Recommendations

1. Prioritize direct domestic electrification for immediate surplus absorption through EV charging, electric cooking, irrigation, flexible industrial loads, and demand creation near hydropower corridors.
2. Use 500 MW as the central electrolyzer planning case for further analysis. It is the best balance between utilization, surplus capture, and hydrogen output under the moderate scenario.
3. Develop targeted hydrogen transport pilots for high-utilization heavy-duty or captive diesel-displacing fleets.
4. Continue green ammonia analysis as a fertilizer-security pathway, but do not claim it is base-case profitable unless the fertilizer-security value, subsidy, or cost reduction is explicitly included.
5. Do not prioritize large-scale re-electrification under current assumptions. It should remain a strategic reserve option unless storage value or avoided dry-season import price increases substantially.
6. Improve future work using hourly dispatch data, actual export contract prices, site-specific electrolyzer siting, detailed transmission constraints, and sector-specific demand surveys.

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A ADDITIONAL INFORMATION

A.1 Key Assumptions

Table A-1 Selected assumptions used in the model.

Parameter	Value	Unit	Justification note
project_life_years	20	years	thesis project horizon; common lifetime used for electrolyzer project screening.
discount_rate	0.08	fraction	base discount rate; sensitivity should test 6-12%.
export_price_npr_per_kwh	8.8	NPR/kWh	Base opportunity cost of using exported electricity for H2;
avoided_import_price_npr_per_kwh	12	NPR/kWh	Avoided dry-season import or high-value electricity assumption; Used as base case assumption and tested through sensitivity analysis.
domestic_electrification_value_npr_per_kwh	16	NPR/kWh	Weighted value of combined direct domestic electrification: EV charging, cooking, heat pumps and irrigation.
sec_kwh_per_kg_h2	50	kWh/kg-H2	Base electrolyzer specific energy consumption; equivalent to 20 kg-H2/MWh.
electrolyzer_capex_usd_per_kw	1,000.0	USD/kW	installed electrolyzer CAPEX assumption; sensitivity tests lower/higher values.
fuel_cell_efficiency	0.52	fraction	Fuel-cell electrical efficiency assumption for re-electrification.
diesel_price_npr_per_litre	155	NPR/L	Base case diesel price assumption for substitution economics.
fertilizer_import_value_npr_per_kg_nh3	125	NPR/kg-NH3 equivalent	Fertilizer import-substitution value proxy selected as primary ammonia comparator.
mcda_economic_weight	0.35	fraction	base weight for economic viability.
mcda_technical_weight	0.25	fraction	base weight for technical feasibility.
mcda_security_weight	0.2	fraction	base weight for energy/fertilizer security.
mcda_environment_weight	0.2	fraction	base weight for environmental benefit.

A.2 Outlier Diagnostics

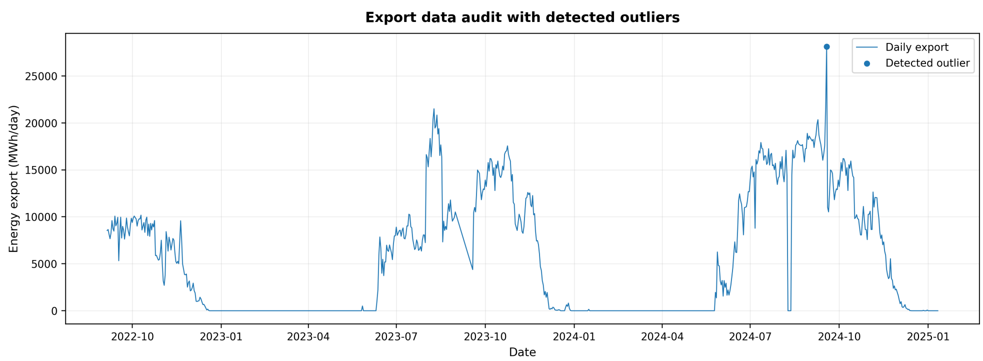

Figure A-1 Outlier diagnostic for daily export energy.

A.3 Data Used

Table A-2 Energy Data Used in this study

Date	NEA	NEA Subs.	IPP	Import	Total Avail.	Export	Demand	Interruption	Deficit	Requirement	Net India Exch.
9/5/2022	10574	12864	19561	173	43172	8547	34625	10	0	34635	0
9/6/2022	10325	12791	19119	688	42923.519	8646	34278	200	0	34478	0
9/7/2022	11012	12479	18917	418	42826	8117	34709	480	0	35189	0
9/8/2022	10881	12729	18668	496	42774	7668	35106	0	0	35106	0
9/9/2022	9302	12732	18891	1047	41972	8285	33687	0	0	33687	0
9/10/2022	8996	12557	19032	817	41403	9598	31805	8	0	31813	0
9/11/2022	10073	12887	19842	788	43589	8736	34853	0	0	34853	0
9/12/2022	10341	12889	19251	421	42902	8477	34425	0	0	34425	0
9/13/2022	9851	12748	19441	342	42382	10075	32308	15	0	32323	0
9/14/2022	10007	12688	19236	152	42083	9037	33046	0	0	33046	0
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮
1/2/2025	7268	5494	16257	6159	35178	0	35178	1000	0	36178	6159
1/3/2025	7603	5384	16317	6242	35546	0	35546	1750	0	37296	6242
1/4/2025	6930	5388	16119	5699	34136	0	34136	1700	0	35836	5699
1/5/2025	7598	5448	15979	6739	35764	0	35764	1200	0	36964	6739
1/6/2025	7095	5157	15849	6389	34490	0	34490	1000	0	35490	6389
1/7/2025	7376	5296	15231	7438	35340	0	35340	1550	0	36890	7438
1/8/2025	7160	5204	15439	7421	35225	0	35225	1950	0	37175	7421
1/9/2025	7580	5176	15658	7723	36137	0	36137	1800	0	37937	7723
1/10/2025	7192	5101	15642	7554	35489	0	35489	2100	0	37589	7554
1/11/2025	6251	5017	15623	6845	33735	0	33735	1700	0	35435	6845

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