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PATHWAYS FOR PAKISTAN'S LOW-CARBON TRANSITION: POLICY, COSTS, AND HYDROGEN INTEGRATION

Gordhan Das Valasai[1], Muhammad Alam[2], Sajid Mahmood Lakhan[3], Atique u Rehman[4], Shahzad Ali[5], Sajjad Bhangwar[6]

[1 456]*Department of Mechanical Engineering, Quaid -e- Awam University of Engineering, Science and Technology, Nawabshah, Pakistan*

[2]*Renewable Energy and E-Mobility, Faculty of School of Electrical Engineering and Computer Science, Hochschule Stralsund, University of Applied Science Stralsund, Zur Schwedenschanze 15, 18435 Stralsund, Germany*

[3]*Senior Principal Consultant, Green Energy Associates, Karachi, Pakistan*

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Corresponding Author: * Gordhan Das Valasai

Abstract

Pakistan faces rising energy demand, increasing reliance on imported fuels, and growing climate vulnerability. Meeting its Nationally Determined Contribution (NDC) under the Paris Agreement requires a systemic shift toward low-carbon energy while ensuring affordability and energy security. This study employs a scenario-based optimization and dispatch model with hourly resolution (8,760 hours/year) to evaluate three decarbonization pathways, Business-as-Usual (BAU), NDC-aligned, and Accelerated Decarbonization, through 2050. The model minimizes total discounted system cost (TDSC) while enforcing energy balance, capacity evolution, emissions caps, and reliability constraints. It integrates power generation, hydrogen production via electrolysis, and transport demand. The NDC-aligned pathway reduces emissions by ~20% by 2030 and 45–50% by 2050 compared to BAU. The Accelerated pathway achieves 65–70% reductions by 2050 but increases average system costs by Rs 2–4/kWh. Hydrogen demand in transport reaches ~175,000 kg/year by 2050. Sensitivity analysis shows that a ±3–5 percentage point change in WACC alters hydrogen costs by up to 26%, while ±25% fuel price swings affect system affordability by 15–20%. Key levers include concessional finance, renewable tenders with storage, energy efficiency standards, and staged hydrogen deployment. A 2025–2050 roadmap prioritizes near-term investments in renewables and efficiency, followed by electrification and green hydrogen scale-up.

1. Introduction

Pakistan's energy system stands at a critical juncture, shaped by the confluence of rising demand, depleting domestic resources, fiscal constraints, and growing climate vulnerability. Over the past decade, annual electricity demand has grown at a rate of 5–7%, driven by population growth, urbanization, and expanding industrial activity [1], [2], [3]. Projections indicate that this upward trend will persist, with peak demand expected to more than double by 2050 under a business-as-usual trajectory. However, the country's ability to meet this demand sustainably is severely constrained by the decline of indigenous natural gas reserves, once a cornerstone of Pakistan's energy mix, which are projected to be insufficient to meet even half of domestic gas needs by 2030 [1]. This has led to an increasing reliance on imported fuels, particularly liquefied natural gas (LNG) and crude oil, which now constitute nearly 40% of the nation's primary energy supply. This dependence not only strains the national balance of payments but also exposes the economy to global price volatility, as evidenced during the 2022 energy crisis when surging LNG prices triggered widespread load-shedding and fiscal stress [1], [4], [5], [6].

In parallel, Pakistan faces mounting environmental and climatic challenges. As one of the most climate-vulnerable countries in the world, it has experienced increasingly severe impacts from extreme weather events, including devastating floods and prolonged heatwaves. These events have underscored the urgent need for climate resilience and mitigation action. In response, Pakistan submitted its updated Nationally Determined Contribution (NDC) under the Paris Agreement in 2021, committing to reduce greenhouse gas (GHG) emissions by 50% below the projected business-as-usual (BAU) level by 2030, conditional upon international financial and technological support. This ambitious target necessitates a fundamental transformation of the energy system, moving away from fossil fuel dependence toward a low-carbon, resilient, and domestically powered future [3], [7].

Despite growing recognition of the need for decarbonization, the policy landscape remains fragmented. Numerous energy system models have been developed to explore potential pathways for Pakistan's energy transition [8], [9]. However, many of these studies are limited in scope, focusing narrowly on technology-specific assessments, levelized cost comparisons, or isolated sectoral analyses. While such models provide valuable technical insights, they often lack integration with actionable policy instruments and fail to account for real-world implementation barriers such as financing constraints, institutional capacity, and grid integration challenges. Furthermore, few models incorporate high-resolution temporal dynamics or cross-sectoral linkages, such as between power, transport, and hydrogen, which are essential for evaluating system reliability and identifying optimal decarbonization levers [10], [11], [12], [13].

This study bridges these gaps by presenting a comprehensive, policy-oriented energy system model that evaluates Pakistan's low-carbon transition pathways through 2050. Unlike conventional studies, our approach integrates hourly dispatch modeling with long-term capacity expansion, enabling a realistic assessment of technical feasibility, system costs, and operational adequacy under varying scenarios. The framework explicitly incorporates policy-relevant variables such as the weighted average cost of capital (WACC), carbon pricing, renewable energy build-out rates, energy efficiency improvements, and hydrogen integration, allowing for direct translation of model outputs into actionable policy recommendations [14], [15], [16].

We address four key research questions to guide this analysis:

1. What levels of GHG emissions reductions can be achieved by 2030, 2040, and 2050 under current policies (BAU) compared to an NDC-aligned pathway and an accelerated decarbonization scenario [3]?
2. What are the system-wide cost impacts, both in terms of average electricity costs (Rs/kWh) and net present value (NPV) of investments, of pursuing the NDC-aligned versus accelerated decarbonization pathways [17], [18]?
3. Which policy interventions, renewable energy deployment, energy efficiency improvements, or

electrification of transport and industry, deliver the greatest marginal emissions abatement by 2030 and 2040, and at what cost [19], [20]?

4. How sensitive are the outcomes to key uncertainties, particularly fluctuations in financing costs (WACC ±3–5 percentage points) and imported fuel prices (±25%) [4], [21]?

By answering these questions within a transparent, scenario-driven framework, this study aims to provide decision-makers with a clear, evidence-based roadmap for achieving Pakistan's climate commitments without compromising energy security or economic affordability. Special emphasis is placed on the role of green hydrogen, particularly in hard-to-abate sectors like heavy transport and industry, as a strategic vector for deep decarbonization. The integration of hydrogen production via electrolysis, coupled with hourly modeling of renewable availability and demand patterns, allows us to assess its technical viability, cost trajectory, and policy requirements [22], [23], [24].

Ultimately, this paper contributes to the growing body of literature on energy transitions in developing economies by offering a holistic, integrated assessment tailored to Pakistan's unique socio-economic and geopolitical context. The findings are designed to support the development of a balanced, equitable, and climate-compatible energy strategy, one that reduces import dependence, enhances energy access, creates green jobs, and positions Pakistan as a leader in the regional clean energy transition [4], [14].

2. Methodology

This study uses a capacity-investment and hourly-dispatch model to assess Pakistan's decarbonization pathways. The model minimizes total discounted system cost (TDSC) over the planning horizon while enforcing physical and policy constraints. TDSC aggregates capital expenditure, fixed and variable O&M, fuel, and carbon costs, net of salvage, discounted to the base year. The framework resolves annual investment decisions and verifies 8,760-hour operational feasibility using synchronized profiles for solar, wind, temperature, electricity demand, and hydrogen demand. Outputs include emissions, system cost (NPV), LCOE, LCOH, and reliability [25], [26].

The mathematical program is structured around a small set of constraint families that mirror the energy system's physics and policy rules. Energy balance holds for every energy carrier (electricity, hydrogen) and time slice: total outputs minus inputs and conversion losses equal exogenous demand. Capacity evolution links yearly stocks to last year's capacity, minus retirements, plus new builds, ensuring realistic build-out dynamics. Resource and availability limits cap hourly generation by installed capacity and availability factors that capture intermittency, derating, and maintenance. A firm capacity and reserve margin constraint requires dispatchable capacity to meet peak load with a stated margin to maintain reliability. Emissions accounting sums fuel use times emission factors: a scenario-dependent emissions cap can bind annual totals. The hydrogen subsystem tracks hourly tank inventory as Electrolyser output (at an efficiency rate) minus end-use demand and storage losses. A generic storage state-of-charge equation governs both electricity and hydrogen storage, with separate charge/discharge efficiencies and exogenous losses [27], [28], [29].

Cost and performance metrics are defined consistently with planning practice. The capital recovery factor (CRF) converts one-time investments to equivalent annualized costs; LCOE and LCOH divide annualized investment plus O&M and fuel by annual delivered electricity or hydrogen, respectively. These metrics allow cross-scenario cost comparisons and facilitate policy interpretation (e.g., tariff impacts, fuel-switch economics).

Sets and indices follow standard notation: $\mathcal{Y}$ for years; $\mathcal{T}$ for technologies (e.g., gas turbine, PV, wind, battery, electrolyser, storage); $\mathcal{C}$ for carriers (electricity, hydrogen); $\mathcal{S}$ for time slices/hours; and $\mathcal{F}$ for fuels. Parameters include the discount rate r, reserve margin RMRM, emission factors EF_f, availability factors $AF_{t,s}$, and technology lifetimes. Decision variables cover new capacity additions, dispatch by technology and hour, storage charge/discharge flows and state-of-charge, Electrolyser input power, and hydrogen inventory [30], [31].

The formulation is scenario-driven. "BAU," "NDC-aligned," and "Accelerated" pathways differ only in exogenous levers: renewable capacity trajectories, electrification rates, efficiency gains, carbon price, and cost of capital (WACC). All other model structures remain unchanged. Sensitivity tests vary WACC, imported fuel prices, and demand to examine robustness. This design keeps causal attribution clear (policy levers → system response) while maintaining transparency and reproducibility. The equations listed below present the objective and each constraint in compact form, followed by the cost and levelization metrics used throughout the results and policy discussion.

The total discounted system cost (TDSC) sums up all costs (investment, O&M, fuel, carbon, minus salvage) over the years, discounted to present value. The optimization minimizes this sum.

$$minTDSC = \Sigma_{(y \in \mathcal{Y})} \left[1/(1+r)^{(y-y0)} * \Sigma_{(t \in \mathcal{T})} \left(C_{(t,y)}^{(inv)} + C_{(t,y)}^{(fix)} + C_{(t,y)}^{(var)} \right) \right]$$

$$TDSC_{min} = \sum_{y \in \mathcal{Y}} \frac{\left(I_y + FOM_y + VOM_y + FUEL_y + CarbonCost_y - Salvage_y \right)}{(1+r)^{y-y_0}}$$

For each energy carrier and time slice, the total energy output minus input (conversions/losses) equals the demand. This enforces system balance.

$$\sum_t Out_{t,c,s} - \sum_t In_{t,c,s} = Demand_{c,s}$$

Tracks the installed capacity for each technology t each year: capacity rolls forward from last year minus retirements plus any new builds.

$$Cap_{t,y} = Cap_{t,y-1}(1 - retire_t) + NewCap_{t,y}$$

Generation from each technology is limited by its available capacity and the resource's availability (e.g., derating for weather/intermittency).

$$Gen_{t,s} \leq Cap_{t,y} \cdot AF_{t,s}$$

The sum of dispatchable ("firm") capacities must be enough to cover the peak system load plus a reserve margin for reliability.

$$\sum_{t \in firm} Cap_{t,y} \geq (1 + RM) \cdot PeakLoad_y$$

Calculates total annual emissions: fuel consumed by each technology, weighted by its emission factor.

$$Emis_y = \sum_{t,f} FuelUse_{t,f,y} \cdot EF_f$$

System-wide emissions in year y must not exceed the allowed emissions cap.

$$Emis_y \leq Cap_y$$

Tracks the hydrogen tank/storage balance hour by hour takes last hour's inventory, adds produced H_2, subtracts demand and storage losses.

$$H_t = H_{t-1} + \eta_{elec} \cdot P_t^{elec} - D_t^{H2} - Loss_t$$

Hourly storage state of charge: updated by charging (with efficiency), discharging (with losses), and any self-discharge or losses. Works for both electric and H_2 storage.

$$SOC_t = SOC_{t-1} + \eta_{ch} P_t^{ch} - \frac{P_t^{dis}}{\eta_{dis}} - Loss_t$$

Capital Recovery Factor: Converts a lump-sum investment into equivalent annual payments, based on discount rate and asset life.

$$CRF = \frac{r(1+r)^n}{(1+r)^n - 1}$$

Levelized Cost of Electricity: average total cost per unit of output, considering investment, O&M, fuel, over the asset's life.

$$LCOE = \frac{I \cdot CRF + FOM + VOM + FUEL}{E_{ann}}$$

Levelized Cost of Hydrogen: same as above, but for hydrogen; calculates cost per unit produced.

$$LCOH = \frac{I_{H2} \cdot CRF + OPEX_{H2}}{H2_{ann}}$$

Emission Intensity: CO_2 emissions per unit of final energy delivered, measures system's carbon profile.

$$EI = \frac{Emis_y}{E_{final,y}}$$

Table 1 provides a comprehensive notation and parameter definition framework for the optimization and dispatch model used in Pakistan's energy system analysis.

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Table 1: Notation and parameter definitions used in the optimization and dispatch framework

I_y	Investment expenditure in year y	USD
FOM_y	Fixed operation and maintenance cost in year y	USD
VOM_y	Variable operation and maintenance cost in year y	USD
$FUEL_y$	Fuel cost in year y	USD
$CarbonCost_y$	Carbon/CO_2 cost in year y	USD
$Salvage_y$	Salvage value (undepreciated asset) in year y	USD
r	Discount rate (annual effective, fraction, e.g., 0.08)	(fraction, e.g., 0.08)
y	Year (variable index)	,
y_0	Base year	,
$\mathcal{Y}$	Set of planning years	,
t	Technology index (e.g., gas turbine, PV)	,
c	Energy carrier index (e.g., electricity, hydrogen)	,
s	Time slice index (e.g., season, hour)	,
$Out_{t,c,s}$	Output of technology t for carrier c in slice s	MWh, kg
$In_{t,c,s}$	Input to technology t of carrier c in slice s	MWh, kg
$Demand_{c,s}$	Demand for carrier c in slice s	MWh, kg
$Cap_{t,y}$	Installed capacity of technology t in year y	MW, kg/h
$Cap_{t,y-1}$	Capacity of technology t, previous year	MW, kg/h
$retire_t$	Retirement fraction for technology t	(fraction, e.g., 0.03)
$NewCap_{t,y}$	New capacity addition of technology t in year y	MW, kg/h
$Gen_{t,s}$	Generation from technology t in slice s	MWh, kg
$AF_{t,s}$	Availability factor for t, slice s	(fraction, 0-1)
$firm$	Set of firm (dispatchable) technologies	,
RM	Required reserve margin	(fraction, e.g., 0.15)
$PeakLoad_y$	System peak load in year y	MW
$FuelUse_{t,f,y}$	Fuel consumption by technology t of fuel f in year y	TJ, GJ, MMBtu
EF_f	Emission factor for fuel f	tCO_2/TJ or $kgCO_2$/GJ
f	Fuel type index (e.g., natural gas, diesel)	,
Cap_y	Emissions cap in year y	tCO_2
$Emis_y$	Total system emissions in year y	tCO_2

H_t	Hydrogen inventory at hour t	kg
η_{elec}	Electrolyser efficiency (hydrogen per input electricity)	kg/kWh
P_t^{elec}	Electricity supplied to Electrolyser at hour t	kW
D_t^{H2}	Hydrogen demand at hour t	kg
$Loss_t$	Losses (boil-off, parasitics, storage) at hour t	kg (or MWh for storage)
SOC_t	State of charge at hour t	MWh, kg
η_{ch}	Charging efficiency	(fraction, 0-1)
P_t^{ch}	Charging power at hour t	kW
P_t^{dis}	Discharging power at hour t	kW
η_{dis}	Discharging efficiency	(fraction, 0-1)
n	Asset lifetime	years
CRF	Capital recovery factor	(dimensionless)
I	Investment cost	USD
FOM	Fixed operation and maintenance cost (annual)	USD/yr
VOM	Variable operation and maintenance cost (annual)	USD/yr
$FUEL$	Fuel cost (annual)	USD/yr
E_{ann}	Annual electricity produced	MWh
I_{H2}	Hydrogen system investment cost (CAPEX)	USD
$OPEX_{H2}$	Hydrogen system operating cost (annual)	USD/yr
$H2_{ann}$	Annual hydrogen production	kg
$E_{final,y}$	Final energy delivered in year y	MWh, kg

Analytical Framework

The study applies an optimization and dispatch framework with hourly balancing capability. The framework minimizes total system cost while enforcing constraints on demand satisfaction, generation capacity, and emissions. This dual structure allows assessment of long-term investment pathways alongside short-term operational adequacy.

The main features are:

- Scenario design: Three contrasting pathways are evaluated, business-as-usual (BAU), NDC-aligned, and accelerated decarbonization.
- Temporal resolution: Annual investment and cost results are combined with 8,760 hourly profiles for solar PV, wind, temperature, and hydrogen demand, enabling realistic resource adequacy checks.
- Sectoral scope: The model integrates power generation, hydrogen production via electrolysis, and transport demand to capture cross-sector interactions.
- Key outputs: Results include emissions trajectories ($MtCO_2e$), system costs and levelized metrics (Rs/kWh for electricity, Rs/kg H_2 for hydrogen), net present value (NPV) of system expenditures, and reliability and affordability indicators relevant for policy evaluation.

This integrated framework provides the consistency needed for both policy-neutral scenario comparison and transparent reporting of trade-offs between cost, emissions, and reliability.

3. **Scenarios**

Three scenarios are developed to explore hydrogen integration: Business-as-Usual (BAU), NDC-aligned, and Accelerated Decarbonization (AD). BAU assumes continuation of current policies and investment trends, with average renewable build-out of 1-2 GW per year, consistent with Pakistan's historic EPC pace (NEPRA, 2022; AEDB, 2021). NDC-aligned reflects Pakistan's 2021 NDC target of 50% GHG reduction by 2030, conditional on international support (MoCC, 2021). Accelerated Decarbonization assumes 3-4 GW per year renewable additions, matching the tender pipeline and announced projects (AEDB, 2022; NTDC, 2022). Transport electrification shares (10-40%) follow the National Electric Vehicle Policy (MoE, 2020). Efficiency levels of 5%, 10%, and 15% by 2050 are assumed in BAU, NDC-aligned, and Accelerated scenarios, respectively. Table 1 summarizes the design of the three scenarios. Each scenario alters one or more levers (renewable capacity build-out, electrification rate, efficiency, and carbon pricing).

Table 2: Summary of Key Policy Levers Shaping Decarbonization Scenarios in Pakistan

Scenario	BAU	NDC-aligned	Accelerated
Build-out (GW/y)	1-2	2-3	3-4
Rationale	Matches historic EPC + grid pace	Meets 2030-2040 tender pipeline	Programmatic tenders + grid upgrade
Electrification (2050)	~10%	~25%	~40%
Rationale	Linear, stock turnover only	Piecewise linear with modest acceleration	Logistic S-curve; infra-constrained
Efficiency (2050) (%)	5	10	15
Carbon price (Rs/tCO_2)	0	1,500	2,500
Rationale	No explicit pricing	Near MAC at NDC cap	Near MAC at deep cap
WACC (%)	10	8	6
Rationale	Commercial risk	Partial de-risking	Blended/concessional

Solar and wind profiles shape the system's behavior through the year. Solar output shows a clear bimodality (Figure 1a): many hours near zero at night and a consistent daytime mode. The annual series (Figure 2a) displays the expected diurnal cycle; summer production dips because higher cell temperatures reduce efficiency, with 5-10% losses in hot weeks (Figure 4). Wind contributes more evenly. Its distribution clusters around 0.3-0.5 p.u. and 0.7-0.9 p.u. (Figure 1b), indicating dual seasonal peaks that complement solar, especially during evenings and shoulder months (Figure 2b). Ambient temperature ranges from 15-42 °C (Figure 1c), which explains the PV derating but does not overturn the basic complementarity. Hydrogen demand averages 20-25 kg h^{-1} with stable daily patterns (Figure 2d); cumulative demand exceeds 175,000 kg by 2050 (Figure 3), showing that small hourly flows aggregate into a meaningful annual quantity.

Emissions trajectories diverge sharply by scenario. Under BAU, energy-related CO_2 rises from about 220 $MtCO_2e$ in 2020 to ~340 $MtCO_2e$ in 2050, reflecting continued reliance on imported oil and LNG and only modest efficiency gains. The NDC-aligned pathway peaks near 250 $MtCO_2e$ around 2030 and declines to ~190 $MtCO_2e$ by 2050, 45-50% lower than BAU in the terminal year and consistent with a conditional pledge. The accelerated pathway reaches ~110 $MtCO_2e$ by 2050, 65-70% below BAU, which is only feasible when faster renewable build-out, higher electrification, and stronger efficiency progress act together. The pattern implies that moderate reform bends the curve this decade, while alignment with a 1.5 °C-consistent range demands the full accelerated bundle.

System costs shift from fuel-dominated to asset-dominated spending as decarbonization deepens. BAU averages ~Rs 16 kWh^{-1}, driven by fuel imports. NDC-aligned costs rise to ~Rs 18 kWh^{-1} because of capital-intensive renewable additions and grid integration but import exposure falls. Accelerated action lifts early costs to ~Rs 19-20 kWh^{-1} and then stabilizes around 2040 as renewable LCOE declines, and the fuel bill shrinks. Despite higher upfront capital, the system-wide NPV is only 8-10% above BAU; reduced imports and lower emissions provide macroeconomic gains not fully visible in the average kWh metric. Financing conditions are pivotal here: lower WACC compresses this gap and improves affordability.

Policy levers show distinct effects and costs. Sustaining an extra 1 GW y^{-1} of renewables through 2040 delivers roughly 8-10 $MtCO_2e$ of additional annual abatement and is generally the least-cost option (< Rs 1,500 tCO_2^{-1}). 5% cumulative efficiency gain cuts emissions by about 5-6 $MtCO_2e$ and reduces system cost by ~2% by lowering service energy requirements; many measures approach the low-cost range once transaction frictions are managed. Transport electrification reduces liquid fuel imports by ~12% by 2040 under moderate uptake, with accelerated adoption roughly doubling that effect; its early-year marginal abatement cost sits higher (> Rs 2,500 tCO_2^{-1}) due to vehicle and infrastructure capital but declines as costs and WACC fall. Taken together, the least-regret near-term package is renewables plus efficiency, with electrification scaling as finance de-risks capital and networks are ready. Figures 1-4 and Table 1 provide the supporting distributions, time profiles, and scenario levers used to produce these outcomes.

4. Results and Discussion

Solar and wind shape the system's behavior through the year. Solar output is bimodal (Figure 1a): many night hours near zero and a daytime mode that tracks clear-sky conditions. The annual series (Figure 2a) shows a stable diurnal cycle; hot weeks reduce output by about 5-10% because of temperature derating (Figure 4). Wind contributes more evenly. Its distribution clusters around 0.3-0.5 p.u. and 0.7-0.9 p.u. (Figure 1b), giving dual seasonal peaks that complement solar in evenings and shoulder months (Figure 2b). Ambient temperature ranges from 15-42 °C (Figure 1c), which explains PV derating but does not change the basic complementarity. Hydrogen demand averages 20-25 kg h^{-1} with regular daily patterns (Figure 2d); cumulative demand exceeds 175,000 kg by year-end (Figure 3), showing that small hourly flows add up to a material annual volume.

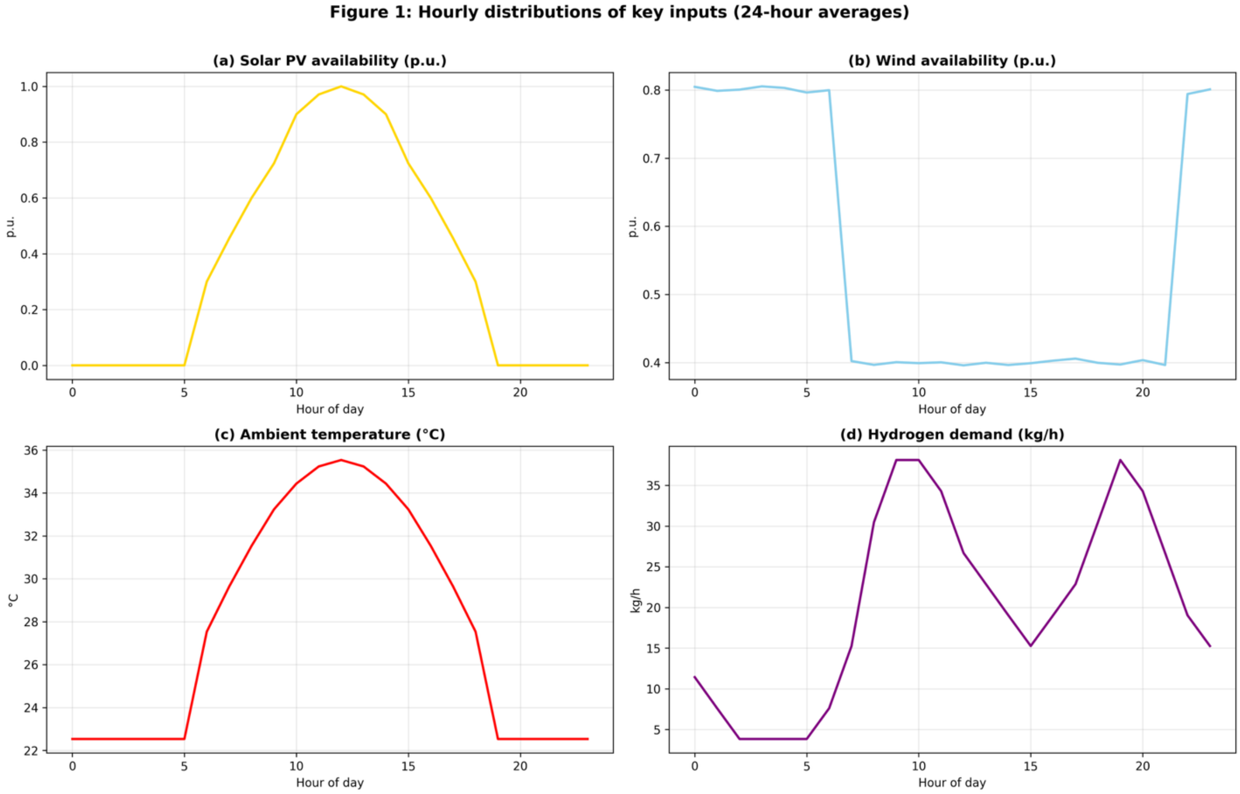

Figure 1: Hourly distributions of key model inputs: (a) solar PV availability (p.u.), (b) wind availability (p.u.), (c) ambient temperature (°C), and (d) hydrogen demand (kg/h).

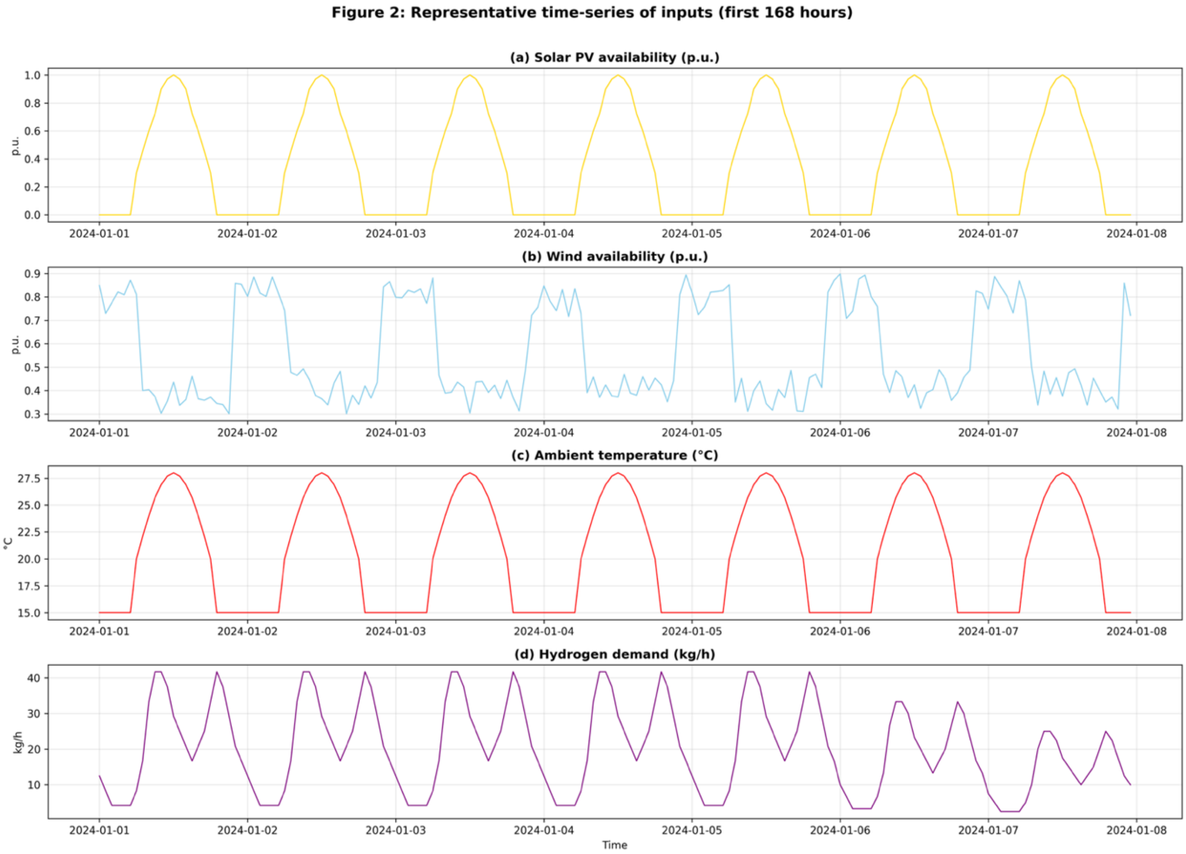

Figure 2: Time-series profiles of key model drivers for one year: (a) hourly solar PV availability (p.u.), (b) hourly wind availability (p.u.), (c) ambient temperature (°C), and (d) hydrogen demand (kg/h).

Emissions diverge by pathway. Under BAU, energy-related CO_2 rises from about 220 $MtCO_2e$ in 2020 to ~340 $MtCO_2e$ in 2050, driven by oil and LNG use and modest efficiency gains. The NDC-aligned pathway peaks near 250 $MtCO_2e$ around 2030 and declines to ~190 $MtCO_2e$ by 2050, about 45% below BAU in the terminal year. The accelerated pathway reaches ~110 $MtCO_2e$ by 2050, around 65-70% below BAU. These results suggest moderate reform can bend the curve this decade, while alignment with a 1.5 °C-consistent range requires the full accelerated bundle, faster renewable build-out, stronger efficiency, and staged electrification. Import share is defined as the ratio of imported fuels in total primary energy supply (TPES). Table 3 reports 2030/2040/2050 triplets for each scenario for easy comparison.

Table 3: Scenario outcomes for BAU, NDC-aligned, and Accelerated Decarbonization pathways (2030, 2040, 2050).

Scenario	Year	Emissions ($MtCO_2e$)	Avg. System Cost (Rs/kWh)	Renewable Share (%)	Import Share (% of TPES)
BAU	2030	260	16.2	38	44
	2040	300	16.3	40	46
	2050	340	16.5	42	48
NDC-aligned	2030	250	17.5	45	40
	2040	210	18.0	55	34
	2050	190	18.0	60	30
Accelerated	2030	230	19.5	50	36
	2040	160	18.8	65	28
	2050	110	18.5	75	22

Costs shift from fuels to capital as decarbonization deepens. BAU averages 16 Rs/kWh and remains exposed to import volatility. NDC-aligned costs rise to ~Rs 18 kWh^{-1} as capital-intensive renewables and grid integration enter but import exposure falls. The accelerated path lifts early costs to 19-20 Rs/kWh and then decreases by ~2040 as renewable LCOE declines, and the fuel bill shrinks. Despite higher upfront capital, system-wide NPV is only ~8-10% above BAU; avoided imports and lower emissions deliver macro benefits not visible in the average-kWh metric. Financing conditions are pivotal: lower WACC compresses the cost gap and improves affordability (see Sensitivity Analysis).

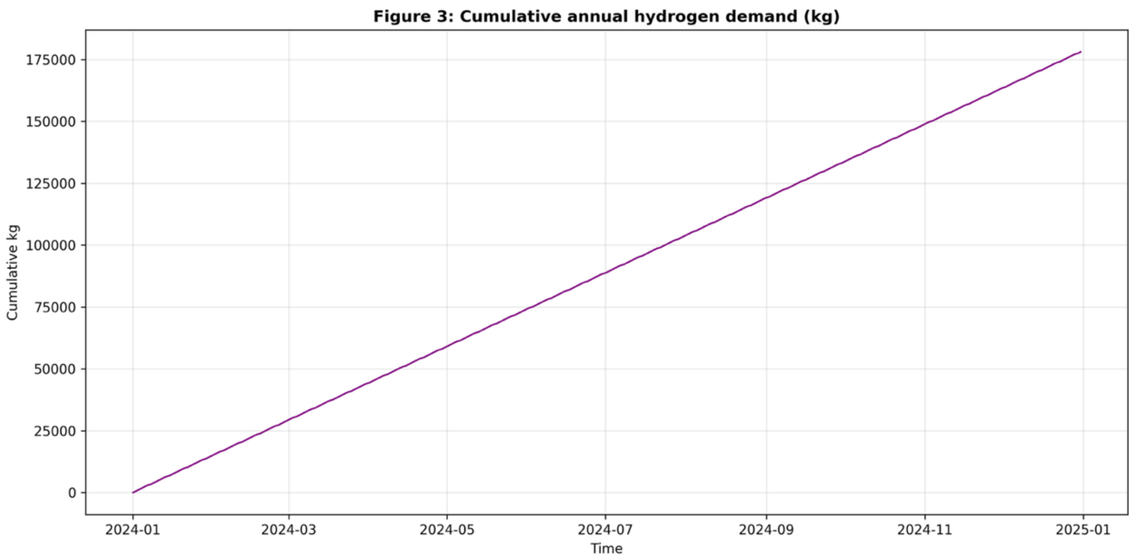

Figure 3: Annual hydrogen demand for transport sector by 2050.

Policy-relevant drivers are clear. Sustaining an extra 1 GW y^{-1} of renewables through 2040 yields about 8-10 $MtCO_2e$ of additional annual abatement and sits in the low marginal-cost range (< Rs 1,500 tCO_2^{-1}). A 5% cumulative efficiency gain removes ~5-6 $MtCO_2e$ and trims system cost by ~2% by cutting service energy needs. Moderate transport electrification reduces liquid fuel imports by ~12% by 2040; accelerated uptake roughly doubles that effect. Early-year marginal abatement costs are lowest for renewables, moderate for efficiency, and higher for electrification (> Rs 2,500 tCO_2^{-1}) until vehicles, networks, and financing mature. Figures 1-4 provides the distributions, time profiles, and scenario levers that generate these outcomes; sensitivity ranges referenced in Sensitivity Analysis do not change the ranking of levers. As shown in Figure 4, PV output decreases during hot weeks due to higher ambient temperatures (Figure 1c), leading to ~5–10% derating.

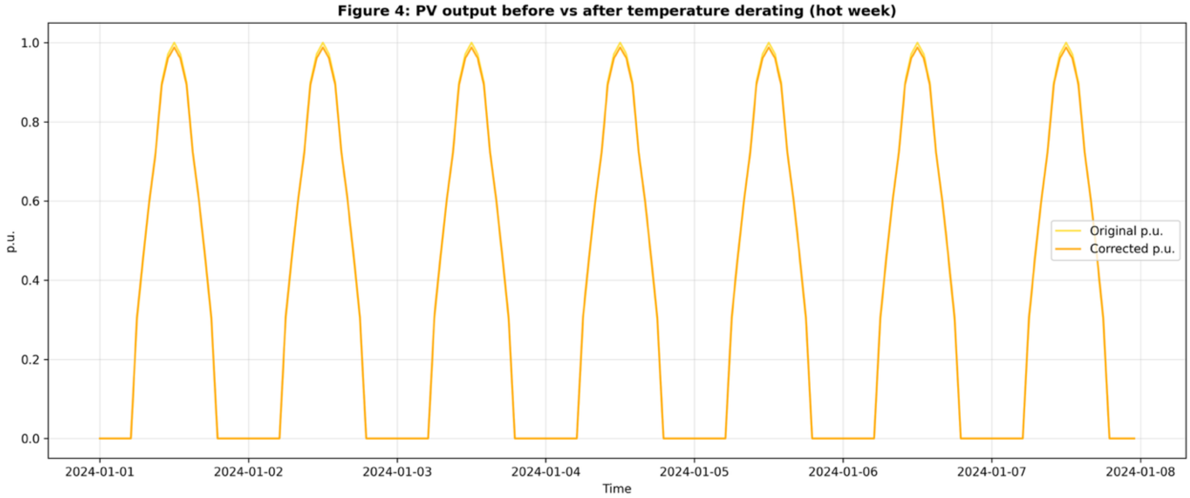

Figure 4: PV output before and after applying temperature derating

5. Sensitivity Analysis

We test the robustness of results to three policy-salient uncertainties that materially affect costs and trajectories: (i) the weighted average cost of capital (WACC), (ii) imported fuel prices, and (iii) demand levels. All constraints (energy balance, capacity evolution, adequacy, emissions caps, storage) remain binding in every run; feasibility is not relaxed.

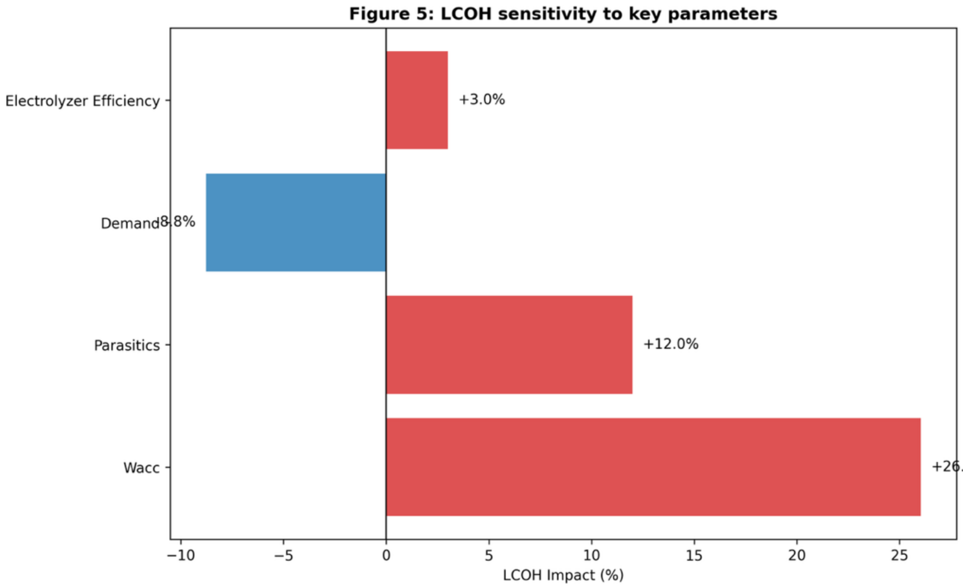

Figure 5: Sensitivity of the levelized cost of hydrogen (LCOH) to key parameters

As shown in Figure 5, WACC has the strongest impact on LCOH (+26%), followed by parasitic losses (+12%), while electrolyser efficiency and demand shocks exert smaller effects." Ensure the caption reads: "Figure 5. Sensitivity of the levelized cost of hydrogen (LCOH) to key parameters (WACC, parasitic, electrolyser efficiency, demand shocks).

Policy levers separate clearly. Each sustained +1 GW y^{-1} of renewables yields ~8-10 $MtCO_2e$ additional annual abatement by 2040 and sits in the low marginal-cost range (< Rs 1,500 tCO_2^{-1}). A 5% efficiency gain removes ~5-6 $MtCO_2e$ and trims system cost by ~2%. Electrification is slower at first, higher early marginal cost (> Rs 2,500 tCO_2^{-1}) due to vehicles and networks, but becomes essential for deep cuts and green-hydrogen scale-up. Sensitivities confirm the transition is finance-constrained: WACC at 10-12% versus 4-6% in OECD markets explains higher LCOE/LCOH; lowering WACC by 2-4 pp compresses the NDC-Accelerated cost gap more than any single technology tweak. Fuel-price shocks (±25%) reinforce the value of domestic renewables; demand shocks (±10%) do not change lever ranking. The near-term least-regret set is renewables + concessional finance + efficiency, with electrification ramping as grids and capital costs allow.

6. Conclusion

Pakistan's transition potential is high but gated by finance and delivery, not by resource limits. Under an NDC-aligned pathway, emissions can fall about 20% by 2030 and ~45-50% by 2050; an accelerated package delivers ~65-70% cuts by 2050. Costs shift from fuels to capital: average system costs rise by ~Rs 2-4 kWh^{-1} versus BAU, yet the lifetime premium is modest (~8-10% NPV) and buys lower import exposure and price volatility. Hourly feasibility holds with PV-wind complementarity and manageable PV derating in hot months. Sensitivities confirm financing conditions dominate outcomes: a ±5 pp change in WACC moves hydrogen costs by about ±26%, while ±25% fuel-price shocks shift affordability by ~15-20%. Overall, the results show the NDC is achievable with consistent policy, but meeting a 1.5 °C-aligned range requires faster renewable build-out, firm efficiency gains, and staged electrification supported by cheaper capital.

7. Recommendations

Prioritize measures that unlock capital and de-risk delivery: lower WACC toward 6-7% using concessional finance, green bonds, and MDB-backed guarantees, and deploy sovereign "green-tagged" instruments to crowd in private investment. Run larger, faster renewable auctions with hybrid PV+wind+storage lots, align grid codes and tariffs for flexibility, and cap curtailment through clear interconnection timelines. Launch hydrogen and transport pilots in Karachi, Lahore, and freight corridors to anchor early demand; test industrial blending where process heat allows, while mapping future export links with GCC/South Asia. Tighten efficiency through appliance and industrial standards, target parasitic loads, and pair with demand-side management to smooth peaks. Specify high-temperature-rated PV and heat-resilient designs in procurement to protect yields. Sequence policy as least-regret first (renewables + finance + efficiency), then scale electrification and hydrogen as networks and financing mature.

8. Policy Roadmap

Pakistan's transition should be sequenced to match delivery capacity and financing depth while preserving affordability. 2025-2030 focuses on unlocking capital and near-term abatement: expand renewable tenders with explicit hybrid PV-wind-storage lots; lower WACC via concessional/blended finance and sovereign green instruments; enforce efficiency/standards to curb parasitic; and launch hydrogen and e-mobility pilots on priority corridors. 2030-2040 scales electrification and flexibility: accelerate sectoral electrification (transport / industry), deepen storage and demand response, retrofit industry, and codify blending rules and guaranteed offtake for early H_2 use. 2040-2050 moves to system-wide decarbonization: large-scale green hydrogen (industry and heavy transport), deeper industrial fuel-switch, and regional export integration with GCC/South Asia, under a stable finance architecture that keeps WACC in the 6-7% range and caps curtailment through firm grid codes and interconnection timelines. Table 4 summarizes the roadmap for 2025–2050.

Table 4: Policy Roadmap: Findings, Actions, Lead Agencies, and Timeline

Finding	Policy Action	Lead Agency	Supporting Agencies	Timeline
Slow renewable build-out	Accelerate solar/wind auctions; streamline licensing	AEDB (Alternative Energy Development Board)	NEPRA, NTDC, PPIB	Short-term (2025–2030)
Limited grid flexibility	Invest in transmission upgrades and smart grid systems	NTDC	MoE, DISCOs	Medium-term (2030–2040)
High fossil fuel import dependency	Introduce carbon price and fuel import caps	MoF, MoCC	NEPRA, OGRA	Medium-term (2030–2040)
Lack of hydrogen standards	Develop national H_2 standards and safety codes	PSQCA	NEECA, MoCC	Short-term (2025–2030)
Weak financing environment	Provide green bonds, concessional loans for RE and H_2	SBP, MoF	SECP, MoE	Short-term (2025–2030)
Low EV/H_2 adoption	Incentivize EV/H_2 fleets (buses, taxis); provide refuelling infra	MoT	MoE, Provincial Govts.	Medium-term (2030–2040)
Inefficient energy demand	Enforce building codes, appliance standards	NEECA	Provincial Energy Depts., MoCC	Short-term (2025–2030)
Insufficient research & skills	Establish H_2 research centres and training programs	HEC, MoE	Universities, Industry	Long-term (2040–2050)
Weak institutional coordination	Create inter-ministerial Energy Transition Council	MoE (Chair)	MoF, MoCC, NEPRA, AEDB	Short-term (2025–2030)

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