Alliance for Climate Justice & Clean Energy

Comments on the Integrated System Plan (ISP) 2025-35

By: Alliance for Climate Justice and Clean Energy (ACJCE)

To: The Chairman

National Electric Power Regulatory Authority

NEPRA Tower, Ataturk Avenue (East)

G-5/1, Islamabad

Dated: September 27th, 2025

Subject: Comments on the ISP 2025-35 by the Alliance for Climate Justice and Clean Energy (ACJCE)

Dear Sir/Madam,

Attached herewith are comments from the ACJCE in response to the ISP 2025-35 prepared by ISMO for review and approval of NEPRA and shared by your office along with the NEPRA Public Hearing Notice, inviting comments in writing and participation from all stakeholders as published on your website.

ACJCE is a coalition of various civil society organizations comprising lawyers, journalists, academics, and policy professionals, specializing in environmental issues with a focus on the energy sector — particularly the transition away from fossil fuels and towards renewable sources. The undersigned organizations of the coalition are submitting these comments as concerned citizens and groups who are likely to be affected if the IGCEP and TSEP are approved in their current form by the authority: We offer these comments as groups committed to a just energy transition and as citizens who stand for a socially inclusive and green energy policy.

We hope that these comments and suggestions are taken up by NEPRA in the public hearing to be held on the matter and request to be allowed to present the same during the said hearing.

Best Regards,

Zain Moulvi

Member of ACJCE

Executive summary

A. There are Systemic Errors in the IGCEP's Demand Forecasting. We recommend that the IGCEP:

- Apply "realism tests" to GDP-driven demand forecasts by checking against past errors.
- Publish low-growth and sensitivity scenarios (±1–2% GDP) to reflect uncertainty.
- Integrate distributed solar, storage, and net metering as structural demand shifts, not marginal adjustments.
- Incorporate climate stress tests into demand projections, in line with the IMF's analytics National Adaptation Plan (2023).

B. The IGCEP's Treatment of Committed, Strategic, Hydropower, and Fossil Fuel Projects has not Followed Due Process and is Misaligned with Policies. We suggest that the ISP:

- Restore CCI oversight over project classifications.
- Uphold AREP 2019 and NEP mandates: exclude large hydro from "renewable" and model fossil fuel displacement.
- Apply the Least-Cost Violation (LCV) tool consistently, publishing results for all projects.
- Replace arbitrary "10% progress" rules with transparent, uniform standards that test the true least cost credentials and strategic costs and benefits of all projects in the committed pool.
- Conduct independent validation of all "strategic" designations.
- Require cost–benefit and trade-off analyses for partially built or risky projects.

C. The ISP is Excessively Hydroreliant and Rests on Inaccurate Hydrocosting Methodologies. We recommend that the Regulator:

- Commission independent, evidence based hydrological, seismic, and climate risk studies (not just WAPDA self-reports) and incorporate community based risk assessments under local knowledge systems
- Update feasibility studies to account for sedimentation, seismic hazards, and shorter dam lifespans.

- Disclose all hydro risk assessments and adopt transparent flood/earthquake methodologies.
- Explore risk-transfer mechanisms (e.g., insurance) for hydropower infrastructure.
- Incorporate ecological, displacement, and carbon cost accounting in tariff and planning assessments.
- Compare hydro with wind/solar, including carbon finance opportunities, to reveal true least-cost pathways.

D. The Formulation of TSEP is Sub-optimal. We Recommend that the ISP:

- Shift to **integrated co-optimization** of transmission and generation, not sequential planning.
- Standardize and reconcile line length and project cost reporting.
- Disaggregate grid station and line costs to establish true per-km benchmarks.
- Apply terrain-based costing methodologies for realistic projections.
- Provide financing details (debt–equity ratios, terms, FX assumptions) for all projects.
- Reconcile planned vs. actual expenditures to avoid cost rollovers.

E. The Cost of Hydro Evacuation Investments is Opaque and Sub-Optimal. We Suggest that the TSEP:

- Explicitly link hydro transmission costs to generation project economics.
- Disaggregate bundled PC-I allocations for accurate cost comparisons.
- Publicly disclose per-km costs and justify premiums for hydro corridors.
- Integrate transmission costs into LCOE and tariff assessments for hydro.
- Ensure equal scrutiny for hydro evacuation vs. renewable integration costs.

F. The ISP Ignores the Least Cost Potential of Distributed Solutions like Microgrids. The IGCEP and TSEP need to:

- Incorporate microgrids, mini-grids, and DERs into IGCEP least-cost modeling.
- Conduct geo-spatial trade-off analyses comparing centralized and distributed options.

- Set provincial-level deployment targets for DERs (aligned with AREP and NE-Plan).
- Prioritize microgrids for rural electrification, resilience, and equity.
- Ensure DISCOs implement GIS-based mapping of underserved zones for DER planning.

G. Balochistan's Renewable Energy Potential has been Ignored in the IGCEP and TSEP. We request that the ISP:

- Include Balochistan's wind/solar corridors in IGCEP/TSEP scenarios.
- Prioritize HVDC Chaghi–Muzaffargarh corridor to unlock 8 GW of wind–solar hybrid capacity.
- Treat Balochistan renewables as "strategic projects" to promote equity and national integration.
- Leverage hybridization efficiencies (wind + solar) to maximize utilization of new lines.
- Align investments with just transition principles to reduce inter-provincial disparities.

H. KAPCO's Extension Appears Unjustified on Environmental, Economic, and Regulatory Grounds. We ask that the ISP:

- Retire KAPCO at earliest opportunity—do not extend beyond original PPA expiry.
- Publish cost–benefit and reliability analyses before considering any extension.
- Replace ancillary service rationale with alternatives (storage, condensers, transmission upgrades).
- Ensure all extension/retirement decisions comply with NE-Plan evaluation procedures.

I. There are Missing Displacement Pathways in the ISP. The IGCEP should:

- Explicitly model renewable displacement of coal and gas plants.
- Quantify least-cost savings and system impacts of early retirements.
- Incorporate carbon-credit revenues/losses in displacement analyses.
- Align IGCEP/TSEP with AREP and NEP mandates for fossil substitution, not just capacity addition.

J. The Proposed Plan Risks Interprovincial Conflict and Inequity. We recommend that the ISP:

- Incorporate findings of the VRE Locational Study and Least-Cost Electrification Study on VRE potential in marginalized regions like Balochistan
- Develop province-specific renewable and distributed generation targets.
- Balance utility-scale projects with provincial microgrid and hybrid opportunities.
- Use CCI oversight to maintain constitutional consensus and avoid regional conflicts.

K. The ISP Suffers From Opaque Data and Missing Transparency. The Regulator should:

- Mandate independent validation of hydrological and cost data from WAPDA, PEDO, etc.
- Disaggregate project-level details (sites, technologies, costs, transmission).
- Publish methodologies for “strategic” designations and apply them consistently.
- Clarify status of overlapping solar projects (e.g., ACWA 1000/1800 MW vs. 2400 MW G2G).
- Model battery storage as a displacement tool for fossil fuels, not only as ancillary services.
- Ensure interprovincial impacts of planning are disclosed and debated.

Detailed Comments

A. Systemic Errors in Demand Forecasting

The demand forecasting methodology in the *Indicative Generation Capacity Expansion Plan (IGCEP) 2025* relies on econometric multiple regression models with category-wise demand equations for domestic, industrial, commercial, and agricultural consumers. Compared to earlier iterations, the new framework does represent technical progress. For example, disaggregated demand functions capture sectoral heterogeneity more effectively than a single aggregate model. The inclusion of multiple scenarios, particularly those incorporating demand-side management (DSM), enhances flexibility, while reliance on more than fifty years of data provides statistical robustness. Furthermore, the explicit recognition of conservation and net metering indicates greater awareness of demand-side drivers. The shift to hourly forecasting is especially useful for planning around intermittency, peak demand, and variable renewable energy (VRE) balancing.

Yet despite these improvements, fundamental weaknesses remain. IGCEP 2025 continues to rest on a top-down GDP-driven methodology that conflates government growth *targets* with independent forecasts, ignores the mounting role of climate change and external shocks, and assumes a proportional relationship between GDP and electricity demand. This assumption is increasingly out of step with a rapidly changing energy landscape shaped by distributed generation, energy efficiency, off-grid adoption, and shifting policy regimes. As a result, IGCEP's demand projections remain vulnerable to systemic overestimation and aspirational bias.

Distributed Solar and Storage: Structural Shifts in Demand

While the *Transmission System Expansion Plan (TSEP)* does acknowledge the decline in grid-connected consumption due to weak macroeconomic conditions and the rapid uptake of rooftop solar, it significantly underestimates the scale of off-grid and hybrid adoption. Between 2022 and 2025, Pakistan imported an estimated 38 to 45 GW of solar panels, with between 8 and 12 GW conservatively deployed in off-grid systems.[1] This growth has already reshaped demand. Grid sales fell by approximately 10 percent in 2023, followed by a further 2.8 percent reduction in 2024.[2]

The failure to model these shifts is compounded by the near absence of storage dynamics in demand forecasting. The Institute for Energy Economics and Financial Analysis (IEEFA) projects that battery imports could reach 8.75 GWh by 2030 under business-as-usual trends.[3] This will not only encourage further reductions in grid sales but will also transform the time-of-use patterns that underlie IGCEP's demand scenarios. Despite this, TSEP dismisses distributed solar and battery adoption as "short-term phenomena" with little relevance for long-term expansion planning. Such a position runs counter to international evidence: in markets ranging from Germany to South Australia, behind-the-meter PV and battery storage

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[1] Institute for Energy Economics and Financial Analysis (IEEFA). (2023). *Pakistan solar and battery market outlook*. Cleveland: IEEFA.
[2] Janjua, Z. Z. (2025, July 17). *Pakistan's quiet solar rush puts pressure on national grid*. *The Japan Times*. https://www.japantimes.co.jp/environment/2025/07/17/energy/pakistan-solar-national-grid/ japantimes.co.jp
[3] Institute for Energy Economics and Financial Analysis (IEEFA). (2023). *Pakistan solar and battery market outlook*. Cleveland: IEEFA.

have permanently altered utility demand, reducing grid dependence and shifting load profiles in ways that could not be dismissed as temporary.

The data on net metering further reinforces the point. By December 2024, Pakistan had over 156,000 net-metered connections with a combined installed capacity exceeding 4.1 GW.[4] Much of this capacity was deployed by households and commercial consumers, directly offsetting grid demand. Yet IGCEP continues to model net-metered PV as supply-side capacity rather than as a reduction in projected demand. The result is a set of demand forecasts that remain systematically overstated and misaligned with observable consumer behavior.

Optimism Bias in GDP-Driven Forecasting

A second structural weakness in IGCEP 2025 is its reliance on official GDP projections that have consistently proven over-optimistic. For instance, the Planning Commission's forecasts for the past three years have exceeded actual growth by an average of 34 to 40 percent. In fiscal year 2022–23, the government projected GDP growth of 5 percent, yet the economy contracted by 0.21 percent. In 2023–24, a target of 3.5 percent growth materialized as only 2.5 percent, while in 2024–25, the projection of 3.6 percent compared to a realized 2.7 percent growth rate. Such persistent optimism bias is not incidental but systemic, suggesting that official forecasts reflect aspirational goals rather than realistic economic trajectories.[5]

Because IGCEP's demand forecasts hinge almost entirely on these GDP trajectories, the errors are baked directly into energy planning. Under the Grid Code, IGCEP is required to conduct its own independent analysis of demand. At a minimum, this requires three adjustments: applying a "realism test" against historical bias, explicitly disclosing demand outcomes under alternative low-growth scenarios, and modeling sensitivity bands that capture the effect of ±1–2 percentage point deviations in GDP growth on electricity demand. Without such adjustments, demand forecasting risks becoming an exercise in extrapolating policy ambition rather than capturing probable outcomes.

Fiscal Year	Govt Target/Predicted Growth (%)GDP	Actual Growth (%) GDP	Difference (pp)	Percentage eror (%)	Direction
2022-23	5.00%	-0.21%	5.21%	N/A	Overestimation
2023-24	3.50%	2.51%	0.99	40%	Overestimation
2024-25*	3.60%	2.68%	0.92	34%	Overestimation

Table 1: Over-optimistic GDP Forecasts: Systemic Errors

Climate Shocks and the Absence of Stress Testing

Perhaps the most glaring omission in IGCEP 2025 is the absence of climate stress testing. The plan is being advanced in the midst of nationwide floods, yet the demand forecasts implicitly assume the absence of such events. This assumption is untenable given Pakistan's

[4] National Electric Power Regulatory Authority (NEPRA). (2024). *Net metering statistics*. Islamabad: NEPRA.
[5] Government of Pakistan, Planning Commission. (2023–2025). *Annual GDP forecasts*. Islamabad.

well-documented exposure to hydrological disasters. The country has experienced at least seven major climate-related shocks in the past two decades, with frequency doubling compared to earlier decades.[6]

Historical data underscores the stakes. In 2010, flood damages equivalent to nearly six percent of GDP cut projected growth from 4.5 percent to 2.4 percent. In 2022, losses of $30 billion—about 4.8 percent of GDP—turned a 5 percent growth projection into outright contraction, with GDP falling between –0.3 and –0.4 percent. Even in 2025, where floods are smaller in scale (0.3 percent of GDP), growth is projected to fall by up to one percentage point below target.[7] These shocks do not merely depress growth but also reduce electricity demand. A one-percentage-point drop in GDP growth in 2025–26, from 3.7 percent to 2.7 percent, would reduce demand projections by at least 1,100 GWh. While modest in the short term, such deviations compound over time, amplifying errors in long-term planning.

Sectoral vulnerabilities heighten these risks. Hydropower assets are increasingly exposed to glacial melt, sudden lake outbursts, and shifting water availability (Yao et al., 2022; Hugonnet et al., 2021).[8] Agriculture, the sector most dependent on water flows, sustained $5.6 billion in losses during the 2022 floods alone, with over 1.1 million hectares of cropland inundated in Sindh (Asian Development Bank, 2012).[9] Industrial hubs in Sindh also suffered contraction, contributing to a 0.7 percent fall in industrial GDP, while household demand was suppressed by widespread displacement. Taken together, these dynamics demonstrate that demand for electricity in Pakistan is not a smooth function of GDP growth but a volatile outcome shaped by recurrent shocks.

International best practice requires that such risks be explicitly modeled. Pakistan's *National Adaptation Plan* (2023) mandates climate stress testing in economic and infrastructure planning. The World Bank's *Country Climate and Development Report* for Pakistan (2022) and the IMF's staff reports both rely on climate-adjusted models to ensure that macroeconomic projections reflect quantifiable impacts of disasters.[10]By neglecting these requirements, IGCEP undermines its credibility and risks anchoring energy planning in assumptions that are neither evidence-based nor aligned with the country's own adaptation strategies.

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[6] Emergency Events Database (EM-DAT). (2023). *Pakistan disaster data 1970–2023*. Brussels: CRED.
[7] World Bank. (2022). *Pakistan Country Climate and Development Report*. Washington, DC: World Bank.
[8] Hugonnet, R., et al. (2021). Accelerated global glacier mass loss in the early twenty-first century. *Nature*, 592, 726–731. https://doi.org/10.1038/s41586-021-03436-z; Yao, T., et al. (2022). Asian glacier retreat and implications for hydropower. *Nature Reviews Earth & Environment*, 3, 257–271. https://doi.org/10.1038/s43017-022-00286-5
[9] Asian Development Bank (ADB). (2012). *Addressing climate change in Pakistan*. Manila: ADB
[10] World Bank (2022)

Year	Estimated Damages & Losses	Share of GDP	Projected GDP Growth	Actual/Updated GDP Growth	Growth Impact
2010	≈ US$ 9.7 billion (≈ PKR 855 billion)	~5.8%	4.50%	2.40%	–2.1 pp
2022	≈ US$ 30 billion (≈ PKR 6.5 trillion)	~4.8%	5%	–0.3% to –0.4%	–5.3 pp
2025*	≈ US$ 1.4 billion (≈ PKR 409 billion)	~0.33%	3.0–3.5%	2.0–2.5%	up to ~ 1.0 pp

Table 2:Flooding and GDP Forecasts: Why Accounting for Natural Disasters Is Critical [11]

Sectoral Shifts and Demand Elasticities

The assumption of proportional growth between GDP and electricity demand also overlooks significant sectoral shifts. In agriculture, for example, solarization of tubewells has already reduced demand in several DISCOs. The Punjab government's "CM Solarization Program" aims to transition tube wells in the 10–20 kW range to solar, and distribution companies such as FESCO and MEPCO have reported reductions of 45–50 percent in tubewell demand during FY2025.[12] Yet IGCEP's agricultural demand forecasts remain tethered to GDP growth and crop output, failing to account for fuel substitution or demand collapse during climate shocks such as floods and droughts.

Industrial demand displays similar volatility. Empirical studies have found significant price elasticity of demand, with subsectors such as textiles exhibiting elasticities of –0.81 and electronics of –0.31 (Chaudhry, 2015).[13] When tariffs rise, industries substitute away from grid electricity, either by shifting to captive generation or installing embedded solar. Recent evidence shows that by March 2025, large exporting firms had installed an additional 142 MW of captive solar capacity.[14] Conversely, IMF-mandated subsidy reforms temporarily

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[11] National Disaster Management Authority (NDMA). *Pakistan Floods 2010 – Damage & Losses Report* (2024). Retrieved from https://www.ndma.gov.pk/storage/publications/July2024/kCLYJkRG6P6eJjnNoauC.pdf ; World Bank. *Pakistan Floods 2010: Damage and Needs Assessment* (2011). Retrieved from https://documents1.worldbank.org/curated/en/655781468058769881/pdf/846060WP0P09910Box0382140B00PUBLIC0.pdf ; World Bank. *Pakistan Floods 2022: Post-Disaster Needs Assessment (PDNA)* (2022). Retrieved from https://thedocs.worldbank.org/en/doc/4a0114eb7d1cecbbbf2f65c5ce0789db-0310012022/original/Pakistan-Floods-2022-PDNA-Main-Report.pdf ; Profit by Pakistan Today. "Pakistan's 2025 floods inflict $1.4 billion damage, agriculture sector hardest hit" (Arif Habib Research) (2025, September 8). Retrieved from https://profit.pakistantoday.com.pk/2025/09/08/pakistans-2025-floods-inflict-1-4-billion-damage-agriculture-sector-hardest-hit/ ; Arab News Pakistan. "Pakistan Floods Preliminary Estimates" (2025). Retrieved fromhttps://www.arabnews.pk/node/2614895/business-economy .

[12] Chaudhry, T. (2015). Price elasticities of industrial electricity demand in Pakistan. *Energy Policy*, 86, 173–181. https://doi.org/10.1016/j.enpol.2015.06.033.

[13] International Growth Centre (IGC). (2021). *Temperature and electricity demand in Pakistan*. London: IGC

[14] Unpublished research by Climate Action and Energy Access (CAEA)

pushed some industries back to the grid, with 280 captive power users reconnecting in 2025 and contributing approximately 700–750 MW of load. Such oscillations cannot be adequately captured by models that assume linear growth.

The domestic and commercial sectors reveal similar omissions. Household demand is highly sensitive to appliance adoption, energy efficiency, and substitution toward rooftop solar. By the end of 2024, net-metered rooftop solar exceeded 4.1 GW, much of it installed in homes and commercial complexes. Climate variability further complicates the picture: empirical evidence suggests that a one-degree Celsius rise in temperature increases electricity demand by 8.5 percent (International Growth Centre, 2021).[15] At the same time, disasters such as the 2022 floods suppressed demand in submerged areas while increasing demand in resettlement centers. These shifts are ignored in IGCEP's baseline models, which treat demand as a smooth extension of GDP and population growth.

Recommendation:

Although IGCEP 2025 demonstrates some methodological improvements compared to earlier iterations, its demand forecasts remain compromised by outdated assumptions. By treating electricity demand as a fixed function of GDP and population growth, the plan fails to integrate the structural transformations already reshaping Pakistan's energy landscape. Distributed generation, rooftop solar, battery storage, subsidy reforms, and recurrent climate shocks are not marginal phenomena but central drivers of demand trajectories.

A credible demand forecasting framework must therefore evolve in three directions. *First*, it must adjust for historical optimism bias in GDP projections by incorporating realism tests and sensitivity bands. *Second*, it must explicitly integrate distributed solar and storage as structural breaks rather than incremental adjustments. *Third*, it must apply climate stress tests to reflect Pakistan's recurrent exposure to floods and other disasters. Without these changes, IGCEP's forecasts risk being aspirational rather than credible, reinforcing supply-side overbuild and undermining the country's transition to a resilient, least-cost energy future.

B. IGCEP's Treatment of Committed, Strategic, Hydropower, and Fossil Fuel Projects Violates the Legal and Regulatory Framework and is Inconsistent with Key Policy Principles

Electricity in Pakistan is not merely a sectoral concern but a constitutional subject, listed under Entry 34 of the Federal Legislative List Part II. This places it within the shared domain of the federation and provinces, where the principle of cooperative federalism must guide energy governance, balancing national priorities with provincial needs and interests. Articles 153 and 154 of the Constitution of Pakistan establish the Council of Common Interests (CCI) as the relevant forum for policymaking, coordination, and regulation in relation to electricity. Article 154(1) explicitly provides that "the Council shall formulate and regulate policies in relation to… the matter in entry 34 (electricity) and shall exercise supervision and control over related institutions"[16] In practice, this constitutional role of the CCI makes it the supreme decision-making body for energy governance, with federal and provincial consensus as the legal and political foundation of electricity planning.

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[15] International Growth Centre (IGC). (2021). *Temperature and electricity demand in Pakistan*. London: IGC
[16] Constitution of the Islamic Republic of Pakistan, 1973 (as amended). Arts. 153–154.

It was precisely in this constitutional framework that, in August 2020, the CCI adopted the Alternative and Renewable Energy Policy 2019 (AREP), thereby giving it binding force across all subsequent planning instruments, including the IGCEP[17]. The AREP is not an isolated policy document but part of a larger portfolio of policies that together comprise the National Electricity Plan (NEP), which under Section 14A of the NEPRA Act is binding on the power regulator and its planning instruments as well as licensees conducting planning activities such as ISMO and NGC.[18] Crucially, both the NEP and the AREP mandate that all generation capacity additions be made on the basis of least-cost principles. In addition, the AREP provides specific guidance on renewable energy, defining it to include solar, wind, hydrogen, biomass, and biogas—but notably, explicitly excluding large hydropower given its environmentally and socially destructive history in Pakistan. The Policy clarifies that only a "separate policy is under consideration for small hydro," rejecting attempts by the then federal power ministry to dilute AREP targets by folding hydro into the renewable category[19]. This exclusion reflects the policy's recognition that large hydro, far from being a clean energy source, has historically caused ecological degradation, displacement, and cost overruns[20].

Most importantly, the AREP requires not only that at least 30 percent of on-grid generation capacity must come from renewables by 2030, but also that renewables must be actively solicited for the displacement of fossil fuel plants where this results in lower system costs [21]. This is a binding constitutional and policy directive: the AREP envisions renewable deployment as both a capacity expansion tool and a displacement mechanism to phase out expensive, polluting coal and gas generation. The IGCEP, as a technical planning document, is legally subordinate to this framework. Any failure to incorporate displacement modeling of fossil fuels or any attempt to reclassify large hydro as renewable therefore represents not merely a planning weakness but a violation of the constitutional order of energy governance established by the CCI.

Energy Planning Principles and Policy Mandates

Pakistan's energy planning framework is anchored in principles of affordability, universal access, equity, inter-provincial harmony, and transparent competition. These values are not abstract but codified in law and policy. The Regulation of Generation, Transmission and Distribution of Electric Power Act (as amended in 2018) emphasizes eliminating energy poverty, fostering transparent and competitive markets, and aligning sectoral development with climate commitments. Similarly, the National Electricity Policy (NEP) and National Electricity Plan (NE-Plan) require that all new capacity additions be pursued on a competitive, least-cost basis, with only narrowly defined exceptions for strategic projects. Strategic status is limited to projects serving one of four public-interest functions: (i) security of energy supply; (ii) water–energy–food nexus; (iii) regional integration; or (iv) municipal

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[17] Government of Pakistan. (2019). *Alternative and Renewable Energy Policy 2019.* Ministry of Energy (Power Division). Retrieved from https://www.nepra.org.pk/Policies

[18] National Electric Power Regulatory Authority (NEPRA). (1997). *Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997 (NEPRA Act, as amended 2018).* Government of Pakistan.

[19] Government of Pakistan. (2019). *Alternative and Renewable Energy Policy 2019.* Ministry of Energy (Power Division). Retrieved from https://www.nepra.org.pk/Policies

[20] Deemer, B. R., Harrison, J. A., Li, S., Beaulieu, J. J., Delsontro, T., Barros, N., Bezerra-Neto, J. F., Powers, S. M., dos Santos, M. A., & Vonk, J. A. (2016). Greenhouse gas emissions from reservoir water surfaces: A new global synthesis. *BioScience, 66*(11), 949–964. https://doi.org/10.1093/biosci/biw117

[21] Government of Pakistan. (2019). *Alternative and Renewable Energy Policy 2019.* Ministry of Energy (Power Division). Retrieved from https://www.nepra.org.pk/Policies

waste management. These checks exist to balance federal-provincial consensus (through the Council of Common Interests, CCI) with fiscal prudence and sustainability.

IGCEP 2025's Arbitrary Redefinition of "Committed"

Despite this framework, the IGCEP 2025 redefines "committed projects" to include only those with PC-I/LOS approval, financial close, and at least 10% disbursement and construction progress. On its face, this is a tightening compared to IGCEP 2024, and it does help exclude costly, ecologically unsustainable projects such as Madyan, Gabral Kalam, and Gwadar. Yet the new criterion is arbitrary and top-down, imposed by the Power Division without the constitutionally mandated oversight of the CCI. This is a potential violation of the legal process since the list of committed projects under the NEPRA determined IGCEP 2021 had received sanctity of approval by the CCI which was also confirmed by the NE plan.[22] While we welcome the reopening and trimming of this disastrous category that promotes uncompetitive and ecologically dangerous projects, we also note that the correct procedure and due process has not been followed. As a result, not all projects within the re-configured pool have been rationalised for their inclusion or exclusion, nor have have they been treated transparently or equally and another uneven playing field has been introduced. By shifting the goalposts without due process, the IGCEP undermines both policy coherence and inter-provincial trust.

Moreover, this reclassification fails to trigger the required test of least-cost validation or strategic qualification for projects that remain in the committed pool. The NE-Plan makes clear that re-opening the "committed" category should subject every project to either competitive least-cost modeling as candidates or a formal case-by-case strategic justification. IGCEP 2025 does neither.

Weaknesses in Transparency and Methodology

While the Least Cost Violation (LCV) mechanism is a welcome innovation—quantifying the fiscal penalty of including non-optimal projects, such as Diamer Bhasha Dam (USD 3 billion increment) and ACWA solar (USD 0.28–0.48 billion)—its application is inconsistent. In some scenarios, committed project costs are embedded in present value totals rather than disclosed separately, effectively masking the fiscal burden. Equally problematic, assumptions that the government will absorb LCV costs are fiscally unrealistic given Pakistan's debt crisis.

Other weaknesses include:

- Arbitrary thresholds such as the 10% progress benchmark, which treats site preparation as equivalent to substantive construction. For instance, Tarbela 5th Extension, with less than 5% actual progress at the time the draft IGCEP was formulated despite seven years of delays, is still classified as committed.

- Vague standards for "under construction" projects, which can encompass projects with minimal mobilization, blurring sunk costs with reversible commitments.

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[22] The NE-Plan notes: "all generation projects, which have been declared committed in approved IGCEP 2021, pursuant to the CCI decision No. 2(8)/2021-CCI(48) dated September 13, 2021, shall be included as committed projects"

- Absence of trade-off analysis between abandoning risky projects versus completing them, despite the NE-Plan's requirement to assess least-cost outcomes on a case-by-case basis.

International best practice limits the committed category to projects where significant private investments and contractual obligations already exist—to avoid harming third-party developers. In Pakistan's case, most committed projects are public sector undertakings (hydro, nuclear, imported coal), where such contractual reliances do not apply or apply only in very limited degrees. In these circumstances, transparent cost–benefit analysis is essential, not automatic grandfathering of pet projects.

Strategic Projects: Undefined and Unaccountable

The treatment of "strategic projects" is equally opaque. While the NE-Plan defines clear criteria, IGCEP 2025 includes projects like Diamer Bhasha Dam and ACWA solar without a transparent demonstration of their compliance. The LCV tool is used for these two but ignored for the rest of the portfolio including C5. Worse, in some unconstrained scenarios, Diamer Bhasha is wrongly modeled as "optimized", obscuring its true opportunity cost.

The result is that strategic designation risks becoming a political label rather than a technical classification. Without independent validation, strategic projects serve as loopholes through which expensive, non-optimal capacity additions bypass least-cost principles. The

Scale of the Problem: Committed Projects as the Norm

The consequences of these definitional flaws are profound. By 2035 a large number of committed or "strategic" projects are hydropower and nuclear – The plan adds nearly 10 GW of hydropower capacity additions by 2035. These sources do not align with clean energy targets, nor have their economic and environmental costs been transparently modeled.

This inversion—treating committed projects as the norm rather than the exception—directly contradicts NEP's directive that capacity additions be competitive and least-cost by default, with only narrowly justified deviations.

Toward a Credible Framework

If IGCEP is to fulfill its statutory purpose as Pakistan's Integrated System Plan (ISP), the treatment of committed and strategic projects must be radically overhauled. At minimum, this requires:

- Formal CCI oversight of all committed and strategic classifications.
- Transparent publication of LCV calculations for every project, not just selective ones.
- Rigorous trade-off analysis between completing, delaying, or abandoning partially built projects.
- Clear, uniform standards for what qualifies as "under construction."

- Independent and transparent validation of strategic projects against NE-Plan criteria.

Without these reforms, IGCEP risks becoming less an instrument of least-cost planning than a vehicle for politically driven project selection, undermining affordability, equity, and inter-provincial harmony

C. The ISP Needs to Rethink Hydrocosting and Hydroreliance:

The IGCEP's expansion plan places disproportionate emphasis on large hydropower projects, positioning them as a cornerstone of Pakistan's future energy mix. While hydropower has long been promoted as a source of clean and cheap energy, the evidence from Pakistan and globally points in the opposite direction. Large dams and mega-hydropower projects carry high ecological, social, financial, transmission, and climate risks. They have historically suffered from delays, cost overruns, displacement, and ecological degradation—and these risks are amplified in the current era of climate volatility. Despite these realities, IGCEP forecasts lock in heavy hydropower reliance without transparent analysis of the fragilities inherent in this pathway.[23]

Economic and Construction Risks of Mega-Hydro

Large hydropower projects in Pakistan have repeatedly failed to meet budget and time expectations. The World Commission on Dams (2000) found that major hydropower projects worldwide experience average cost overruns of 56%, while an Oxford University study places this figure even higher at 96%[24]. Pakistan's own experience reinforces these findings:

- Neelum–Jhelum ballooned from a projected cost of USD 1 billion to over USD 5 billion, and since commissioning in 2018 has faced structural failures, tunnel collapses, and repeated shutdowns[25]. Eventually it had to be abandoned

- Diamer–Bhasha, now scheduled for commissioning in 2030, has already been delayed for decades due to land acquisition and financing issues, with cost escalations exceeding PKR 100 billion [26].

- Dasu, funded in part by the World Bank, was classified as a Category A project, indicating "significant adverse environmental impacts that are sensitive, diverse, or unprecedented". Even so, the project has already experienced delays, security challenges, and displacement of over 7,000 people, with costs approaching USD 8 billion.[27]

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[23] Ansar, Atif and Flyvbjerg, Bent and Budzier, Alexander and Lunn, Daniel, Should We Build More Large Dams? The Actual Costs of Hydropower Megaproject Development (March 10, 2014). Energy Policy, March 2014, pp.1-14., Available at SSRN: https://ssrn.com/abstract=2406852; World Commission on Dams, 2000

[24] Ibid.

[25] NEPRA. (2023). State of Industry Report 2023. Islamabad: National Electric Power Regulatory Authority.

[26] Abbas, H. (2024, January 22). Cost of Hydropower from Tarbela and Neelum-Jhelum Hydropower (Unpublished report)

[27] World Bank. (2014). *Dasu Hydropower Stage I Project: Environmental and Social Impact Assessment*. Washington, DC: World Bank

Rehabilitation costs for existing dams also continue to spiral. Between 2015 and 2023, rehabilitation for Mangla surged from Rs. 1 billion to Rs. 21 billion, while Warsak's revised PC-I rose from Rs. 22 billion to Rs. 61 billion—a 177% increase despite only 14% completion.[28] These trends reveal systemic weaknesses in financial planning and oversight, pushing costs onto consumers through tariff hikes.[29]

Social and Ecological Fragilities

Hydropower's impacts are not confined to balance sheets. They reshape entire ecosystems and uproot communities:

- Displacement: Tarbela's original construction displaced 96,000 people (Scudder, 2005), and newer projects such as Diamer–Bhasha continue to impose resettlement pressures without adequate compensation[30].

- Downstream ecological collapse: Diversion of Indus flows has shrunk the Indus Delta, leading to mangrove loss, saline intrusion, and devastation of fisheries—losses valued at nearly USD 50 billion[31].
- These are not incalculable "externalities". They are quantifiable costs that can and should be integrated into the IGCEP's costing methods. For instance, independent studies show that when factoring sedimentation and seismic risks, generation costs are PKR 53.6/kWh at Tarbela – much higher than presumed in IGCEP 2025-35[32]

- Riverine impacts: Projects such as Ghazi Barotha have left 54 km of the Indus River largely dry during low-flow seasons[33].

- Community conflict: Water diversions have triggered interprovincial disputes, most notably between Sindh and Punjab over Indus flows[34].

Such legacies demonstrate that hydropower projects are not "green" or "clean." They carry enduring social scars and amplify interprovincial tensions.

The assessment of proposed hydrofleet requires updated hydro-geological and water flow forecasts and studies modeling climate related infrastructural risks

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[28] WAPDA. (2023). *Annual report 2023*. Lahore: Water and Power Development Authority.
[29] NEPRA. (2023). State of Industry Report 2023. Islamabad: National Electric Power Regulatory Authority.
[30] International Rivers. (2020). *The Bhasha Dam: A case study in displacement and resistance*. Berkeley, CA: International Rivers.
[31] LUMS. (2022). *Hydropower fragility and climate change risks in Pakistan*. Lahore: Energy Institute at LUMS.
[32] Pakistan Renewable Energy Initiative for Development (PRIED) & ZiZAK. (2024, September 24). *Study reveals hidden costs of hydropower*. *The News International*. https://www.thenews.com.pk/print/1219607-study-reveals-hidden-costs-of-hydropower
[33] World Commission on Dams. (2000). *Dams and development: A new framework for decision-making*. London: Earthscan
[34] Mustafa, D. (2010). Hydropolitics in Pakistan: Peril and promise. United States Institute of Peace

Currently, the only hydrological studies relied on by the IGCEP are self reported by WAPDA and unvalidated by ISMO or the regulator. These are reportedly based on a historical record of the previous five years flow data.[35] However, these are wholly insufficient for predicting hydrological trends over the 10 year planning horizon of the IGCEP. As noted in multiple country climate risk profiles and climate change models, Pakistan's weather and hydrological patterns are exhibiting a break from the past and becoming "even more volatile and extreme."[36]

A credible assessment of hydropower as a least-cost and system-reliable option requires grounding in comprehensive hydrological, seismic, and climate forecasting studies rather than self-reported data. This begins with vulnerability assessments that evaluate how extreme weather events, shifting precipitation patterns, glacier melt, droughts, and seismic hazards may alter river flows, reservoir stability, and overall generation potential. Such studies must combine General Circulation Models (GCMs), Global Hydrological Models (GHMs), and Representative Concentration Pathways (RCPs) with localized flow studies, seismic hazard mapping, and community knowledge of local risks. Equally critical is a transparent and standardized methodology for flood- and earthquake-risk assessment, ensuring that dams and ancillary infrastructure are designed to withstand both the "new climate normal" and tectonic shocks. This will necessitate much higher costs demonstrating the true cost of hydro reliant systems if one undertakes responsible planning.

Updated feasibility studies are also essential, accounting not only for climate impacts but also for declining dam lifespans due to siltation, sediment loads, and the structural vulnerabilities exposed by seismic activity. In parallel, basin-wide modeling should capture interannual variability, legacy environmental impacts, and seismic fault-line sensitivities in adjacent areas to prevent underestimation of long-term risks. To guarantee integrity, all hydrological, seismic, and climate studies must be disclosed publicly, moving beyond the current reliance on opaque self-reporting by WAPDA. Finally, risk-transfer mechanisms such as insurance for hydro-infrastructure must be explored, so that both climate- and earthquake-induced uncertainties do not become systemic risks to Pakistan's power system. Only through such comprehensive, transparent, and science-based analysis can hydropower's role in the generation mix be evaluated against least-cost and strategic criteria.

Climate Vulnerabilities

Hydropower projects are highly vulnerable to climate stressors, yet IGCEP's hydrological risk modeling is weak and opaque. The plan claims to account for seasonality but relies solely on feasibility studies prepared by executing agencies, with little disclosure of methodology. Independent analyses paint a far more troubling picture:

- Water stress due to glacier melt, erratic precipitation, and drought is expected to reduce hydropower efficiency drastically over the next decade[37]
- These risks also pose severe dangers to hydropower systems with rapid melt and sudden lake outbursts from its 7,200 glaciers, threatening both the civil works, hydraulic infrastructure, and the associated transmission systems (Yao et al. 2022;

[35] Reported by WAPDA during its tariff petition hearing held on 11th September 2025 by NEPRA

[36] International Monetary Fund. (2023). *Pakistan: Request for a stand-by arrangement; staff report, staff statement, and statement by the Executive Director for Pakistan (Country Report No. 2023/260)*. Annex I: Pakistan's climate disasters—looking back and ahead in times of accelerating climate change. IMF.

[37] LUMS. (2022). *Hydropower fragility and climate change risks in Pakistan*. Lahore: Energy Institute at LUMS

Hugonnet 2021). The IMF (2023) and World Bank (2022) both classify Pakistan's hydropower fleet as "highly vulnerable" to climate-induced flooding, glacial lake outburst floods, and sedimentation[38].

- LUMS (2022) found that seasonal variability in hydropower output could force Pakistan to rely more heavily on gas and local coal, raising emissions and system costs by over PKR 70 billion in FY2024 alone.[39]
- Globally impact of current warming trends shows significant impacts on hydropower's efficiency with as high as projected 17% reduced capacity by 2050 keeping in view potential escalations in emissions trends[40]
- Rehabilitation cost escalations have been as high as 177% in recent years in some projects.[41] This is likely from flooding, siltation, and other impacts. Studies and protective measures are needed

Far from offering long-term stability, hydro-dependence entrenches fragility, requiring expensive fossil backup and locking in higher system costs.

Rehabilitation, Redesign, and Rising Tariffs

The need for repeated rehabilitation underscores hydro's structural weaknesses. Sedimentation has reduced Tarbela's storage by over 30%[42], while floods in Khyber Pakhtunkhwa have damaged multiple small hydel projects, requiring billions in repair costs[43]. Failures at Sukkur Barrage and flood damage to Daral Khwar and Ranolia reveal the vulnerability of both large and small hydro to climate extremes[44].

These rehabilitation costs are routinely passed on to consumers. In 2023, Mangla's return on investment allowance alone reached Rs. 637 million, more than triple its 2020 level[45]. Without independent technical audits, consumers bear escalating costs with little accountability.

Hydro as a Misaligned "Clean Energy" Strategy

Hydropower is often counted as renewable, but its true climate footprint is substantial. Dasu alone is expected to emit 4,500 tonnes of CO_2 and 38 tonnes of methane annually, while dam construction itself involves massive embodied carbon in cement and steel[46]. Coupled with

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[38] International Monetary Fund (IMF). (2023). *Pakistan: Climate macroeconomic assessment program*. Washington, DC: IMF. ; World Bank. (2022). *Pakistan Country Climate and Development Report*. Washington, DC: World Bank

[39] LUMS (2022)

[40] International Energy Agency (IEA). (2022). *Climate impacts on Latin American hydropower*. Paris: IEA. Retrieved from https://www.iea.org/reports/climate-impacts-on-latin-american-hydropower/climate-impacts-on-latin-american-hydropower

[41] Water and Power Development Authority (WAPDA). (2025). *Petition for determination of revenue requirements for FY 2025–26*. Islamabad: National Electric Power Regulatory Authority (NEPRA). Retrieved from https://www.nepra.org.pk/Admission%20Notices/2025/09%20Sep/WAPDA%20petition%202025-26%20for%20upload.pdf

[42] WAPDA (2023)

[43] NEPRA (2023)

[44] Government of Pakistan. (2022). *Pakistan Energy Yearbook 2022*. Islamabad: Ministry of Energy

[45] NEPRA (2023)

[46] World Bank (2014)

ecological destruction and displacement, hydro does not meet the standards of sustainability or climate alignment.

At the same time, IGCEP plans to add over 10 GW of new hydropower, ignoring interprovincial water conflicts, deltaic collapse, and the rising costs of rehabilitation. This trajectory defies both the least-cost principle and Pakistan's commitments under renewable energy policies.

Hydropower and the Carbon Credit Blind Spot

With carbon markets becoming increasingly relevant to global energy finance, it is no longer sufficient to evaluate hydropower solely on the basis of generation cost. The financial implications of greenhouse gas (GHG) emissions—and the opportunity costs of foregone carbon credits—must also be considered. Tarbela Dam illustrates this clearly. With an installed capacity of 4,888 MW, its theoretical generation over 49 years (1976–2024) amounts to more than 2 billion MWh. Applying a conservative emission factor of 265.68 kg/MWh, Tarbela is estimated to have released approximately 556 million tonnes of CO_2 since commissioning[47]. Because one carbon credit equals one tonne of CO_2, this translates into 556 million credits. At a modest voluntary market rate of USD 12.90 per credit, Pakistan has effectively foregone a potential opportunity worth USD 7.18 billion (≈ Rs. 2 trillion at Rs. 280/USD)[48]. Spread across Tarbela's actual annual generation of 17,935 GWh in FY 2023–24, this missed climate finance represents an opportunity cost of nearly Rs. 156/kWh—exposing how hydropower, far from being "cost-free," has deprived Pakistan of critical climate-linked revenues.

This raises an obvious counterfactual: what if Pakistan had instead prioritized renewable energy sources that qualify for carbon finance? WAPDA's recent tariff petition would allow bulk hydropower tariffs to rise as high as Rs. 11.56/kWh – a near 90% increase – even as the levelized cost of new wind and solar continues to decline globally[49]. Unlike hydropower, wind and solar projects can generate verified carbon credits, thereby lowering their effective cost once climate finance is factored in. Proper accounting would thus reveal that renewables are not only environmentally superior but could have been financially cheaper for Pakistan, reducing consumer burdens rather than increasing them.

Scientific evidence further undermines the claim that hydropower is "clean." Reservoirs emit substantial volumes of methane and carbon dioxide, sometimes in quantities comparable to fossil-fuel plants (Deemer et al., 2016).[50] Because of these emissions, large dams are largely excluded from international carbon markets, leaving countries like Pakistan to absorb both the ecological degradation and the opportunity cost of lost climate finance. These costs are rarely acknowledged in tariff petitions, but they must be considered in any fair assessment of

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[47] Abbas, H. (2024, January 22). Cost of Hydropower from Tarbela and Neelum-Jhelum Hydropower (Unpublished report)

[48] Rauf, M. F. A. (2024). Unlocking climate finance: Potential carbon credits from renewable energy. Pakistan Institute of Development Economics (PIDE). https://pide.org.pk/research/unlocking-climate-finance-potential-carbon-credits-from-renewable-energy/

[49] International Renewable Energy Agency (IRENA). (2024). *Renewable power generation costs in 2023*. Abu Dhabi: IRENA.

[50] Deemer, B. R., Harrison, J. A., Li, S., Beaulieu, J. J., DelSontro, T., Barros, N., Bezerra-Neto, J. F., Powers, S. M., dos Santos, M. A., & Vonk, J. A. (2016). Greenhouse Gas Emissions from Reservoir Water Surfaces: A New Global Synthesis. BioScience, 66(11), 949-964. https://doi.org/10.1093/biosci/biw117

hydropower's role in the national energy mix. In any case, they must certainly constitute a key factor for assessment in the IGCEP – both from a least cost and strategic perspective.

When these opportunity costs are properly internalized, the financial "shortfalls" presented in hydropower tariff petitions are not a matter of genuine sustainability but of misallocation of resources toward projects that are environmentally regressive and economically shortsighted. Consumers are being asked to pay more, not because Pakistan's power system is inherently unsustainable, but because its accounting framework ignores the true costs and benefits of different energy choices.

Therefore, NEPRA must, as part of its regulatory responsibility, require WAPDA to transparently account for these trade-offs in its tariff framework. Only when the full financial, ecological, and opportunity costs of hydropower are recognized can tariffs be set fairly and independently and trade offs on true long term costs for IGCEP be assessed accurately. A genuine least-cost comparison—including solar and wind, which qualify for climate finance, generate zero emissions, and continue to decline in cost—would demonstrate that the proposed hydropower expansion is neither the cheapest nor the cleanest path forward. By approving the IGCEP in its current form, Pakistan risks locking itself into an energy trajectory that is financially punitive, environmentally damaging, and globally misaligned.

D. Flawed Formulation of TSEP: Failure of Integrated Systems Planning

The Transmission System Expansion Plan (TSEP)[51] exhibits a number of structural weaknesses that reduce its value as a rigorous planning document and undermine its coherence with other sectoral frameworks.

Disconnected planning processes: TSEP vs. IGCEP

Perhaps the most fundamental critique is the lack of integration between TSEP and IGCEP. At present, TSEP functions largely as a derivative of IGCEP, mapping transmission needs after generation expansion has already been projected. This sequencing prevents a genuinely integrated least-cost planning framework. Transmission and generation are treated in silos, when in fact grid expansion constraints should shape the feasibility, siting, and timing of new generation. A truly integrated model would co-optimise generation and transmission investments, rather than having TSEP lag behind IGCEP. Without such integration, there is a risk that the transmission system will either overbuild redundancies or fail to keep pace with the generation expansion plan, leading to stranded capacity or system bottlenecks.

The Transmission System Expansion Plan (TSEP) is intended to serve as a complementary instrument to the Indicative Generation Capacity Expansion Plan (IGCEP), together forming the backbone of Pakistan's Integrated System Planning (ISP) framework. The objective of this integration is to ensure a least-cost pathway for meeting national demand, balancing both generation and transmission expansion in a manner consistent with overarching policy mandates. As articulated in the Grid Code (PC-4), *"the IGCEP shall identify any new capacity requirements by type, capacity, location and year-by-year projects development sequence along with their commissioning dates by taking into account the capacity retirements, annual outage periods, and Transmission System aspects"* (National Transmission & Despatch Company [NTDC], 2020, p. xx).[52] Conversely, the TSEP requires

[51] NTDC. (2023). *Transmission System Expansion Plan (TSEP)*. Lahore: NTDC.
[52] Ibid

each Transmission Network Operator (TNO) to propose expansion strategies not only for accommodating IGCEP's generation additions but also for fulfilling its broader licensing obligations, including congestion reduction, loss minimization, and compliance with system reliability standards (NEPRA, 2017).[53]

The mutual relationship between these two planning documents is critical. As Section 14A of the NEPRA Act requires, all sectoral planning must align with the National Electricity Policy and the National Electricity Plan (Government of Pakistan, 2018). This means that the IGCEP is legally obligated to propose a least-cost generation pathway consistent with the Alternative and Renewable Energy Policy (AREP 2019), which mandates a minimum of 30 percent variable renewable energy (VRE) by 2030 (Government of Pakistan, 2019). Correspondingly, the TSEP must lay out a transmission strategy that enables this transition in a technically sound and cost-efficient manner. Thus, neither plan should assume the other *a priori*; instead, both must iteratively inform one another to ensure that policy targets are met.

Yet, in practice, the TSEP 2023–34 explicitly concedes that it has been developed *"based on the Indicative Generation Capacity Expansion Plan 2025–35 (IGCEP 2025)."* By subordinating transmission expansion entirely to the IGCEP's projections, the TSEP abandons its role as an independent planning instrument. The problem is compounded by the IGCEP's admission of an incomplete and in places absent allocation of transmission costs in the candidate projects[54] – a plain violation of the NE-plan.[55] This approach prevents consideration of alternative scenarios where transmission investment might facilitate greater VRE integration, earlier fossil fuel displacement, or more equitable interprovincial access. Instead of testing whether the IGCEP's assumptions represent the least-cost option, the TSEP uncritically reproduces them.

TSEP's current structure also undermines its analytical credibility. Internal inconsistencies in line lengths, aggregated costs that blur distinctions between substations and lines, and an absence of terrain- or financing-specific methodologies weaken the ability of stakeholders to scrutinize efficiency. The most critical weakness is the siloed approach whereby TSEP merely follows IGCEP, rather than being integrated with it into a co-optimised national least-cost planning exercise. Unless these gaps are addressed, TSEP risks remaining a wish-list of projects rather than a coherent, transparent roadmap for transmission system development.

Inconsistent reporting of line lengths

The TSEP does not report disaggregated costs by projects so the NTDC revised investment

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[53] Ibid

[54] The IGCEP opens with a disclaimer that "The IGCEP is inclusive of tentative costs pertaining to power system evacuation and transmission system expansion for optimized generation projects. Whereas, the exact transmission system expansion and associated costs shall be allocated to the optimized generation project (s) following a detailed study of transmission system expansion cost allocation. In this regard, concept paper for transmission line expansion cost allocation has already been developed and submitted to MoE (PD), for subsequent approval by CCI. This may impact the selection / optimization or ranking of the optimized generation project for which ISMO shall in no circumstances be held liable or accountable."

[55] Strategic Directive 5(d) of the national electricity plan requires that "specific component of the transmission cost for each associated generation project shall be incorporated in pursuance to the criteria to be approved by the CCI"

plan was consulted.[56] However, line lengths for some projects are inconsistent which proves to be a hurdle when determining the actual costs per kilometer . For example, for the transmission lines out of lahore north and islamabad west, the length cited in TSEP either differs from the investment plan's figure or is not mentioned appropriately enough to distinguish the costs (see Table 3). Such discrepancies make it impossible to establish reliable unit costs and cast doubt on whether project scopes are being accurately reconciled across NTDC's planning layers.

projects	voltage	length as per TSEP	length as per investment plan
Lahore North → Lahore South	500	105	not mentioned
Lahore North → Nokhar	500	45	includes the entire length (and costs) of Balloki-Lahore North-Nokhar, but only lahore north-nokhar mentioned in TSEP
Maira S/S – Suki Kinari	500	156	not mentioned
Islamabad West in/out (Ghazi Brotha–Rewat)	500	5.9	300km

Table 3

Aggregated costing that obscures line economics

Project costs are often reported in aggregated packages that combine grid station, transformer, and multiple transmission line expenditures. For many of the 220/132 kv transmission lines mentioned in the TSEP do not have , the same PC-I allocation is used to represent the full grid station plus several associated double-circuit lines. Without disaggregation, the real per-km cost of the line infrastructure cannot be calculated, which blocks meaningful analysis of cost efficiency and terrain-related differentials. In addition, the many very short spur or in/out projects (2–15 km) where the bulk of the cost lies in the associated grid station and transformers. Bundling these together yields inflated per-km costs that appear disproportionately high compared to long-haul corridors. Without cost separation, these distortions undermine benchmarking exercises.

Absence of terrain-based costing methodology

Although mountainous alignments are known to cost more than twice as much per km as plains, TSEP collapses all costs into uniform averages at the voltage level. No

[56] National Transmission and Despatch Company (NTDC). (2023). *NTDC transmission investment plan (revised): FY 2023–FY 2025*. Lahore: NTDC

methodological notes are provided to show how tower design, foundations, or access costs are factored into the estimates. This leads to deceptively smooth projections that understate risk of overruns.

Lack of financing transparency

Unlike the Revised Investment Plan, which identifies sources of funding (World Bank, ADB, GoP, commercial loans) and provides local/foreign breakdowns, TSEP provides only aggregate USD estimates. There is no disclosure of debt–equity ratios, repayment terms, interest rate assumptions, or sensitivity to exchange-rate fluctuations. This is a serious omission given Pakistan's repeated foreign exchange pressures.

Rolling forward estimates without reconciliation

In many cases, TSEP appears to simply roll forward earlier "planned" costs into spot-year aggregates without reconciling them with revised PC-Is or actual expenditures. This practice ignores historical experience with cost overruns in Pakistan's transmission rehabilitation and expansion programs, reducing the plan's credibility as a financial roadmap.

E. Non-Transparency and High Comparative Costs in Hydro Evacuation Investments

Scale of Hydro-Related Transmission Investment

Hydropower projects account for some of the largest single transmission investments in NTDC's pipeline. From the Revised Investment Plan alone, over PKR 260–270 billion (~USD 0.95 billion) is allocated to major hydro evacuations such as Dasu, Suki Kinari/Kohala/Mahal, Tarbela 5th Extension, and Mohmand. If long-term projects such as Diamer-Bhasha, Dasu Stage II, Kohala, and Azad Pattan are included, the figure rises substantially higher, potentially making hydro-related dispersal the dominant category of new transmission expenditure.

Project	PKR billion	USD million (≈278.7 PKR/USD)	Status	Notes
Dasu HPP Stage I – Evacuation	132.25	~474.6	Ongoing/Committed	WB-financed, 500/765 kV corridor
Suki Kinari / Kohala / Mahal – Evacuation (bundled)	79.93	~286.9	Ongoing/Committed	Bundled under one PC-I, multiple HPPs

Mohmand HPP – Evacuation (2 lines)	11.35	~40.7	Ongoing/Committed	220 kV Mohmand–Jamrud & Mohmand–Nowshera
Tarbela 5th Ext. – Evacuation	4.14	~14.8	Ongoing/Committed	500 kV Tarbela–Islamabad West + interconnector
Neelum–Jhelum / Karot / Azad Pattan – Dispersal scheme	~21.7	~77.9	Completed (2018–22)	Multi-phase dispersal scheme

Table 4

Lack of Transparency in Costing

Despite the sheer magnitude of investment, transmission costs for hydro evacuations are rarely accounted for in generation-side economics. PC-I allocations often bundle grid stations, transformers, and multiple line segments, leaving no clarity on the cost of line construction alone. For many projects, the same allocation covers both a new 500 kV grid station and several associated lines. This makes it impossible to calculate the true per-km cost of hydro corridors and masks whether project-level overruns are being absorbed in "aggregate" budgets.

Hydro Lines Are Systematically More Expensive and are still privileged

Evidence from comparing per-km costs shows that hydro evacuation lines are significantly more expensive than other categories of projects:

- Dasu evacuation: ~USD 3.0m/km (157 km, mountainous terrain).
- Suki Kinari evacuation: ~USD 3.8m/km (75 km, mountainous).
- By contrast, plains-based 500 kV lines like Lahore North–South or Sialkot–Lahore cost only ~USD 0.35–0.6m/km.
- Even Gwadar–Pak-Iran Border (220 kV, 75 km in plains) shows ~USD 0.15m/km, an order of magnitude lower than hydro corridors.

Project	Type	Voltage / Config	Length (km)	PC-I Cost (PKR m)	pkr costs per km	Cost per km (USD m/km)	Notes

Dasu HPP evacuation	Hydro	765 kV D/C	157	132,250	842.3566879	3.008416742	Mountainous corridor; WB-financed
Suki Kinari evacuation	Hydro	500 kV D/C	75	79,930	1065.733333	3.806190476	Bundled with Kohala/Mahal
Tarbela 5th Ext. evacuation	Hydro	500 kV D/C + S/C	57	4,140	72.63157895	0.2593984962	Smaller cost package; includes GS works
Lahore North – Lahore South	Other (urban ring)	500 kV D/C	105	20,732	197.447619	0.705170068	Plains corridor
Lahore North – Nokhar	Other	500 kV D/C	45	20,732	460.7111111	1.645396825	Same PC-I as GS + lines, inflates cost
Sialkot New – Lahore North	Other	500 kV D/C	55	10,770	195.8181818	0.6993506494	Plains corridor
Vehari upgradation (Multan–Sahiwal–Vehari)	Other	500 kV D/C	35	11,300	322.8571429	1.153061224	Plains corridor
Gwadar – Pak-Iran Border	Other (cross-border)	220 kV D/C	75	10,664	142.1866667	0.5078095238	Flat terrain

Table 5: estimated costs pr/km

This shows a **3x–10x** cost premium for hydro evacuations compared to thermal, solar, or cross-border projects. Much of this is due to terrain (mountains, river crossings, access roads), but TSEP does not systematically present this differentiation in transmission factors or assess its impact for least cost pathways. .

Hidden Burden on the Power System

Because TSEP aggregates costs and does not explicitly link them to individual generation projects, the true cost of bringing hydro to the grid is invisible in LCOE or tariff debates.

Hydropower is often promoted as "cheap" or "least cost," but in reality, when high-cost transmission evacuations are added, the delivered cost rises significantly. The absence of this accounting gives a misleading picture of hydro's competitiveness relative to alternatives like solar or wind, whose transmission lines are shorter, cheaper, and built in plains terrain.

Implications for Planning

- TSEP's lack of transparency prevents regulators, financiers, and the public from seeing the full system cost of hydropower expansion.
- Because hydro is politically favored, its higher transmission cost burden is effectively hidden in ISMO's aggregated envelopes, while renewables face more scrutiny on integration costs.
- This uneven treatment risks biasing IGCEP/TSEP outcomes, overstating the "least-cost" status of hydropower while underplaying cheaper alternatives.

F. Microgrids and Least-Cost Planning: A Missed Opportunity in IGCEP 2025

The National Electricity Policy (NEP 2021) is explicit about the role of microgrids and distributed energy resources (DERs) in Pakistan's energy transition. It states:

> *"In order to promote electricity access to areas where grid expansion is financially unviable, off-grid and micro-grid solutions will be explored. Integrated planning shall provide for rural electrification and provision of electricity to unserved areas of the country."* (Government of Pakistan, 2021, p. xx).[57]

This mandate establishes that microgrids are not marginal supplements to centralized generation but a core component of least-cost electrification in areas where conventional grid extension is neither economically viable nor technically reliable. Microgrids are modular, community-scale systems designed to serve localized demand clusters. Their distributed structure not only lowers costs of access in remote or peri-urban regions but also enables faster recovery after system disruptions compared to centralized grids, which may take days or weeks to restore.

The global evidence supporting microgrids is instructive. For instance, in Puerto Rico, recurrent hurricanes and systemic failures of the centralized grid have demonstrated the fragility of traditional electricity systems. In response, microgrids have proliferated as tools of resilience and transition. A particularly notable case is Adjuntas, where community organizations and local businesses collaborated to build a solar-plus-storage microgrid. This system enables essential services—such as pharmacies and grocery stores—to operate autonomously for up to ten days during outages, ensuring continuity of economic and social life even in the absence of the central grid[58] (Marqusee & Samaras, 2019). Far from being backup measures, these microgrids now form the backbone of Puerto Rico's clean energy resilience strategy.

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[57] Government of Pakistan. (2024). *National Electricity Plan 2024–27*. Ministry of Energy.
[58] Marqusee, J., & Samaras, C. (2019). *Resilience in Puerto Rico: Microgrids and Distributed Energy After Hurricane Maria*. Energy Policy, 128, 41–50.

For Pakistan, the analogy is direct. Floods, heatwaves, and frequent grid instability create conditions where microgrids could play an equally vital role in ensuring reliable supply. Yet, despite explicit policy recognition, IGCEP 2025 fails to incorporate microgrid and distributed solutions into its least-cost planning framework. Instead, the plan privileges three large-scale, utility-connected solar projects, evaluated primarily on their integration into the transmission system. No comparative modeling is undertaken to assess whether distributed solar micro- or mini-grids, sited near demand centers, could deliver cheaper and faster results.

There is no meaningful analysis in IGCEP 2025 of the demand-side impacts, transmission implications, or least-cost benefits of developing micro- and mini-grids, or of community-based off-grid projects, either as alternatives to centralized mega-projects or as solutions for electrifying underserved areas. What is missing is a bottom-up, geo-spatial assessment that compares large-scale generation and transmission investments against localized, distributed solutions. Such trade-off analysis is central to identifying least-cost pathways, particularly in rural and peri-urban contexts where centralized grid expansion is expensive and unreliable.

The World Bank's Least-Cost Electrification Study (2020)[59] underscores this gap. Using a GIS-based platform, the study mapped non-electrified populations and systematically compared grid extension with mini- and off-grid solutions. The results were striking: in Khyber Pakhtunkhwa (KP), 60 percent of unserved populations could be electrified more cheaply through mini- or off-grid systems, while in Balochistan, the share was 32 percent. The findings were equally compelling in Punjab's agrarian districts—Vehari, Sahiwal, Pakpattan, Muzaffargarh, Multan, Bahawalnagar, and Bahawalpur—where over half of the unserved population could be connected at lower cost through distributed renewable solutions rather than through centralized grid extension. Despite this robust, location-specific evidence, IGCEP 2025 does not incorporate such geo-spatial trade-off assessments into its modeling framework. By overlooking these findings, the plan not only undercuts its claim to follow a least-cost pathway but also risks locking Pakistan into higher-cost, transmission-heavy infrastructure while leaving large segments of the population underserved.

This kind of comparable least costs assessment and associated trade-off analysis on multiple pathways should have served as an analytical foundation for Pakistan's integrated planning. Their omission from IGCEP 2025 is therefore not simply a gap but a missed opportunity to substantiate the plan's least-cost claims with robust, location-specific data. The failure to test centralized generation against distributed alternatives undermines the credibility of IGCEP's modeling and risks entrenching a transmission-heavy, fossil-dominated system that is costlier, less inclusive, and less resilient than available alternatives.

Pakistan's own policies reinforce this critique. The ARE Policy (2019)[60] explicitly includes mini- and micro-grids within renewable capacity targets of 20 percent by 2025 and 30 percent by 2030. Similarly, the National Electricity Plan (2024–27) envisions at least 20 MW of DERs to be deployed at the DISCO level, while NEPRA's regulations authorize cooperatives, community enterprises, and welfare organizations to operate microgrids of up to 5 MW in unserved areas. Moreover, the NE Plan obliges DISCOs to maintain updated GIS-based mapping of consumers and non-electrified zones to inform DER pathways. None of these policy commitments are reflected in IGCEP 2025.

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[59] World Bank. (2020). *Least-cost electrification plan for Pakistan: GIS-based decision support tool* (Vol. 2). Washington, DC: World Bank

[60] Government of Pakistan. (2019). *Alternative and Renewable Energy Policy 2019*. Ministry of Energy.

By ignoring distributed generation evidence and sidelining microgrids, IGCEP 2025 effectively narrows Pakistan's energy transition options. Instead of leveraging least-cost community-driven solutions, it doubles down on centralized generation and long-haul transmission. This approach risks stranded assets, higher system costs, and lost opportunities for inclusive electrification—outcomes that are inconsistent with both global best practice and Pakistan's own declared policies.

G. Absent Transmission Scenarios: The Neglect of Balochistan's Renewable Energy Potential

The omission of Balochistan from the transmission planning scenarios in IGCEP 2025 and TSEP represents a profound missed opportunity. According to the World Bank's Variable Renewable Energy (VRE) Locational Study (2021), Balochistan possesses the single largest concentration of high-quality wind resources in Pakistan, with more than 8 GW of evacuable potential by 2030, most notably in the western region around Chaghi.[61] This scale of potential is not peripheral but transformative: it could make Balochistan a cornerstone of Pakistan's clean energy transition. The only significant barrier is not resource availability but the absence of adequate transmission infrastructure to bring this electricity to national load centers.

The Bank's modeling explicitly highlighted that investment in transmission to unlock these resources would be economically rational and competitive. It concluded that "the resulting per-unit cost for wind power from western Balochistan, including the evacuation infrastructure, will be competitive," demonstrating that grid connectivity is not a sunk cost but an enabler of least-cost generation.[62] The proposed scenario was ambitious but realistic: an initial 6 GW hybrid project (wind plus solar) in western Balochistan, supported by a high-voltage direct current (HVDC) transmission line linking Chaghi to Muzaffargarh in Punjab. This 1,000 km line would open approximately 8 GW of transmission capacity, transforming Balochistan into a net energy exporter to the rest of the country. By balancing provincial resource endowments with national demand centers, this strategy would strengthen system resilience, lower generation costs, and reduce reliance on imported fossil fuels.

Beyond system economics, the developmental rationale for prioritizing Balochistan's renewable resources is equally compelling. The province remains one of the most economically marginalized in Pakistan, with limited industrial activity, weak infrastructure, and low electrification rates. Large-scale renewable investments, coupled with transmission connectivity, would not only diversify the national energy mix but also generate employment, local business opportunities, and infrastructure development in an underserved region. Such investments align with the principles of a just transition, ensuring that the benefits of the energy transition are distributed equitably across provinces rather than concentrated in existing industrial hubs. This underscores how priority investments in Balochistan could support "regional integration" countering the inter-provincial disparities thereby serving precisely the strategic goals envisioned by the NE-plan. They ought to have qualified more readily as "strategic projects" compared to the hydropower investments preferred by the IGCEP, *even if they proved more expensive*. Yet they have been overlooked without any rationale despite credible grounds for their inclusion or at least strong gourds for conducting a scenario analysis on their integration.

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[61] World Bank (2021)
[62] Ibid.

The study also emphasized that wind and solar complementarities in the Chaghi region make hybridization especially efficient. Strong wind conditions coincide with solar availability, which allows for continuous utilization of the interconnection line. As more generation is added, the per-unit cost of transmitting power declines, with the Bank describing the resulting cost curve as "very reasonable. This suggests that the project would achieve not only technical and economic viability but also scale economies that improve over time—precisely the kind of structural transformation needed in Pakistan's power system.

Yet, despite these clear findings, neither IGCEP nor TSEP incorporates such transmission scenarios. Their modeling continues to prioritize generation corridors in Sindh and Punjab, neglecting the possibility of leveraging Balochistan's high-quality renewable resources. This omission is more than a technical oversight—it risks locking Pakistan into a spatially imbalanced energy transition where the country's most resource-rich province remains excluded from national planning. By failing to model and integrate Balochistan's RE potential, IGCEP and TSEP undermine their own credibility as forward-looking, least-cost planning documents.

H. KAPCO's Extension in IGCEP 2025–35: A Departure from Least-Cost and Policy Commitments

The treatment of Kot Addu Power Company Limited (KAPCO) in IGCEP 2025–35 highlights structural weaknesses in Pakistan's generation planning. Despite the expiry of its Power Purchase Agreement (PPA), the plan extends KAPCO's operation until 2029—eight years beyond its original contractual life—without transparent justification. This raises concerns about adherence to least-cost principles, consistency with national policies, and the credibility of the IGCEP's optimization process.

The Alternative and Renewable Energy Policy (AREP) 2019 explicitly requires early displacement of expensive thermal plants in favor of renewables, except where constrained by binding contracts (Government of Pakistan, 2019). KAPCO does not fall under this exception. Its electricity is among the most costly on the grid at Rs. 42.51/kWh, excluding capacity payments of another Rs. 14 billion annually (NEPRA, 2022). It also carries a troubled record: over 400 days lost to force majeure outages and payment irregularities amounting to Rs. 151 billion, as reported by the Central Power Purchasing Agency (CPPA-G, 2022). Yet, despite these facts, KAPCO secured extensions in previous IGCEPs on the promise that grounds would be disclosed in the Transmission System Expansion Plan (TSEP)—a promise still unfulfilled. IGCEP 2025 now continues this departure from both the AREP 2019 and the National Electricity Policy (NEP) 2021, which mandates progressive reliance on renewable and indigenous resources.

The rationale advanced for KAPCO's continuation—support for grid stability and ancillary services—remains unsubstantiated. IGCEP 2025 itself records declining system-wide load factors, evidence of chronic overcapacity (NTDC, 2024). Retaining an aging RLNG plant in an oversupplied system does little to enhance reliability. Instead, it diverts resources from proven alternatives such as synchronous condensers, energy storage, and transmission upgrades, all of which could strengthen grid stability without the costs and emissions tied to fossil fuels. Moreover, the underutilization of renewables is routinely excused on reliability grounds, despite research showing that variability studies and grid-flexibility investments can integrate wind and solar far more effectively than prolonging inefficient thermal plants (IEA, 2023).

KAPCO's inclusion also disregards the procedural safeguards mandated by the National Electricity Plan (NE-Plan) 2024–37. Annexure 2 of the NE-Plan requires that any retirement or extension proposal undergo technical, legal, economic, social, and ecological evaluation, with attention to consumer impacts and transparency (Government of Pakistan, 2024). No such analysis has been disclosed for KAPCO. The absence of this process raises fundamental questions: Has any least-cost analysis been conducted? If so, to what extent and with what degree of public participation? Without disclosure, the process fails the test of accountability.

Although KAPCO's dispatch has been minimal in recent years, its continued presence ensures capacity payments without utilization—an inefficiency directly contrary to the IGCEP's least-cost mandate (NEPRA, 2022). Each year of extension locks scarce financial resources into an obsolete, emissions-intensive asset rather than reallocating them to renewable integration and grid modernization. This inconsistency undermines investor confidence, sending a signal that least-cost optimization can be overridden to accommodate legacy fossil plants.

The IGCEP's decision to carry KAPCO until 2029 is therefore indefensible. It violates AREP 2019, NEP 2021, and NE-Plan 2024–37, all of which require transparent, least-cost, and renewable-centered planning. Unless NTDC can publish a credible cost–benefit and reliability analysis justifying KAPCO's role beyond 2025, its retirement should be accelerated to the earliest possible date. Anything less represents not only a misallocation of resources but also a breach of policy commitments, undermining the energy transition and consumer affordability.

I. Missing Displacement Pathways in IGCEP and TSEP

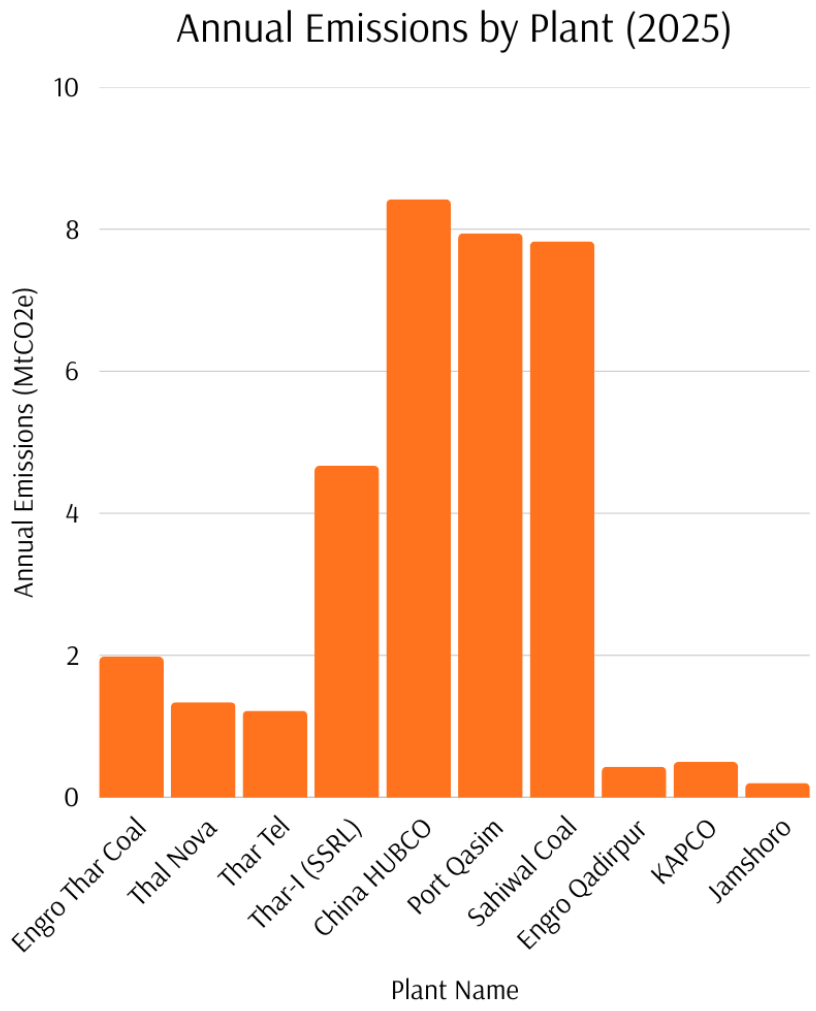
One of the most significant omissions in both the Integrated Generation Capacity Expansion Plan (IGCEP) and the Transmission System Expansion Plan (TSEP) is the failure to model scenarios that explicitly consider the displacement of existing coal and gas-fired power plants. This omission is striking because national energy policy itself makes such displacement a central planning principle. The Alternative and Renewable Energy Policy[63] explicitly states that the induction of new renewable capacity will not only be driven by the need to expand generation but also by the objective of displacing more expensive electricity from thermal plants wherever such displacement results in lowering the average system generation cost, as determined by IGCEP outputs. Further, AREP requires that each annual iteration of the IGCEP should include a section on displacement options to be fed into the annual auctions for capacity additions, ensuring that fossil-heavy portfolios are continually stress-tested against cheaper and cleaner renewable alternatives.

The National Electricity Plan (NEP 2023)[64] reinforces this policy direction by mandating that the TSEP serve as the analytical basis for system security and network reliability, including options for early retirement of existing fossil plants. In other words, system planning is not meant to be confined to incremental capacity addition; it must also model substitution scenarios where renewable energy plants progressively replace coal and gas generation, reflecting least-cost and climate-aligned pathways. By neglecting this requirement, both

[63] Government of Pakistan. (2019). *Alternative and Renewable Energy Policy 2019*. Ministry of Energy (Power Division)
[64] National Electricity Policy [NEP]. (2023). *National Electricity Plan 2023*. Ministry of Energy (Power Division)

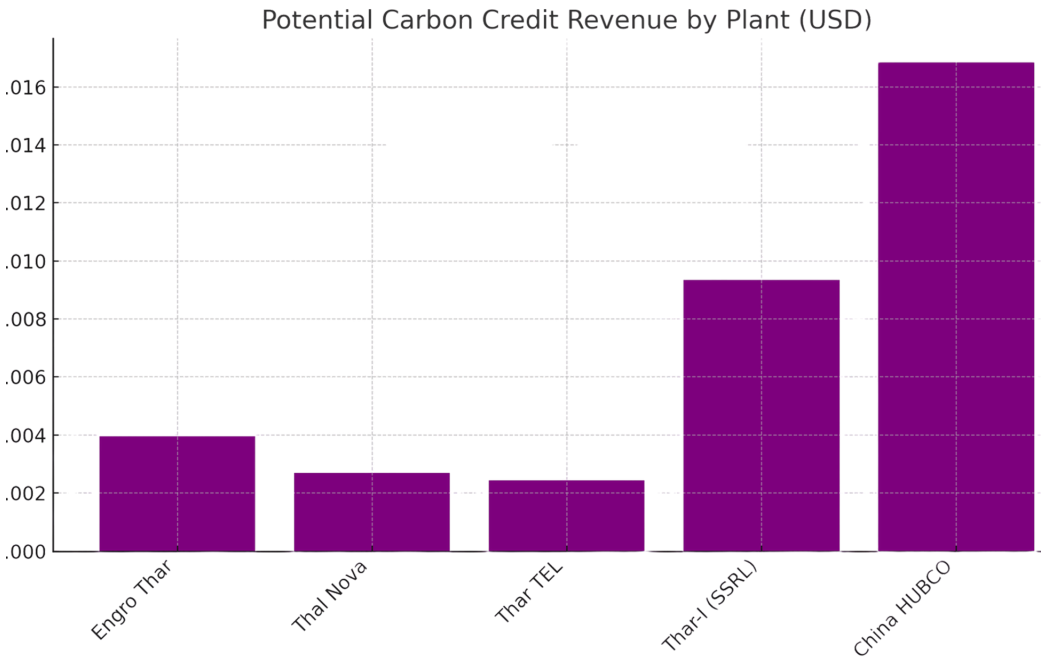
IGCEP and TSEP remain structurally incomplete: they evaluate what to add, but not what to phase out.

The economic consequences of this blind spot are far from abstract. Analysis suggests that Pakistan is foregoing approximately USD 0.7 billion in potential carbon-credit revenue per decade from just five existing coal plants[65]. This foregone finance represents not only a missed opportunity for reducing fiscal stress in the power sector but also a significant deviation from the country's stated policy goal of accessing international climate finance flows. If carbon pricing is factored into system costs, displacement of coal becomes not only an environmental imperative but also a financial necessity. Graph 2 shows potential carbon credit revenue lost by 5 major coal plants amongst pakistan's energy mix.



Graph 1: annual emissions by plant (ACJCE calculations)

[65] Rauf, M. F. A. (2024). *Unlocking climate finance: Potential carbon credits from renewable energy*. Pakistan Institute of Development Economics (PIDE). https://pide.org.pk/research/unlocking-climate-finance-potential-carbon-credits-from-renewable-energy



Graph 2: potential carbon credit revenue per plant

Therefore, the IGCEP should explicitly model a displacement pathway that incorporates:

1. The system-wide least-cost gains from replacing coal and gas with renewables.
2. The total economic impact of foregone carbon credits if fossil plants are retained.
3. The network and security implications of early retirements, including TSEP-linked reinforcements.

Absent such analysis, the IGCEP and TSEP effectively default to a static fossil-heavy portfolio, which is inconsistent with both AREP and NEP policy mandates. More critically, this failure deprives decision-makers of the analytical tools required to weigh the real trade-offs between fossil lock-in and renewable transition. In doing so, Pakistan risks committing to an electricity system that is costlier, dirtier, and financially shortsighted, undermining its own least-cost planning principles.

J. The Proposed ISP Risks Increasing Interprovincial Inequity, Conflict, and Regional Disparities

The neglect of the VRE Locational Study and the Least-Cost Electrification Study in IGCEP 2025 highlights how Pakistan's centralised planning mechanisms themselves reproduce patterns of inter-provincial inequity. By relying on uniform, top-down assumptions, the plan overlooks the fact that renewable and distributed solutions are inherently geographically differentiated and must be tailored to provincial contexts. Sindh and Balochistan possess some of the country's most abundant solar and wind corridors, while Punjab and Khyber Pakhtunkhwa face distinct challenges of rural electrification where mini- and micro-grids would often represent the least-cost pathway. Yet IGCEP's modelling treats the system as homogenous, flattening these differences and thereby privileging centralised projects in

already dominant regions over solutions that could deliver more equitable provincial outcomes.

By prioritizing three large utility-scale solar projects in Punjab without testing them against distributed alternatives in other provinces, IGCEP 2025 risks channeling investment disproportionately toward one region, while provinces with equal or greater renewable potential are sidelined. This not only distorts the least-cost frontier but also deepens the perception of unequal treatment among provinces—a longstanding issue in Pakistan's federal energy politics.

The VRE Locational Study identified corridors in southern Sindh and western Balochistan where hybrid solar–wind parks could unlock up to 8 GW of capacity with relatively low transmission requirements. These findings, if reflected in IGCEP, would have pointed to an inter-provincial rebalancing of investment and the creation of new economic opportunities in historically underserved provinces. Their omission in IGCEP 2025, however, perpetuates the familiar cycle where transmission bottlenecks and central planning biases steer new projects toward Punjab, consolidating its position as the anchor of the grid while marginalizing peripheral regions.

Similarly, the Least-Cost Electrification Study emphasized that rural electrification strategies must be tailored to provincial geographies. In Balochistan's scattered settlements, microgrids and off-grid solar were often shown to be more viable than extending the central grid. In Sindh's flood-prone areas, hybrid systems offered resilience benefits that centralized planning could not. In Khyber Pakhtunkhwa's mountainous terrain, mini-hydro and microgrids emerged as least-cost solutions. By excluding such insights, IGCEP and TSEP 2025 effectively masks the provincial diversity of energy needs, treating Pakistan as a homogeneous system where one set of centralized solutions applies equally everywhere.

This approach produces two forms of inequity:

1. Investment inequity, where provinces with the most renewable potential or distributed demand needs are systematically under-prioritized.

2. Access inequity, where underserved populations in remote provinces are left out of the least-cost framework and continue to experience energy poverty despite abundant local resources.

The broader outcome is a planning framework that reinforces center–periphery divides in Pakistan's federal energy system. By privileging Punjab-centric, utility-scale solar projects while overlooking distributed and locational opportunities in Sindh, Balochistan, and Khyber Pakhtunkhwa, IGCEP 2025 risks exacerbating political and economic tensions around resource allocation, undermining national cohesion in the energy transition.

To address this inequity, IGCEP should explicitly incorporate the provincial dimensions of least-cost planning, building on the World Bank's VRE and LCE studies. Provincial-level mapping of renewables, distributed generation, and electrification needs must be embedded in the modeling framework, with clear targets for each province. This would not only strengthen least-cost planning but also ensure a fairer distribution of investment, access, and benefits across Pakistan's federating units.

In addition, the ISP's hydro dominance and the irregular and top down decision making process creates dangerous grounds for stoking inter-provincial conflicts. As earlier noted, the treatment of committed and strategic projects in the IGCEP, bypasses the CCI which is the appropriate constitutional forum for this decision making. It also violates inter-provincial consensus on the definition of RE enshrined in the ARE policy. There is already a history of conflict around these practices from the previous IGCEP as can be seen in the following excerpt taken from a letter by the Government of Sindh to the regulator in 2021 at the occasion of the IGCEP 2021.

CHIEF SECRETARY
GOVERNMENT OF SINDH

No. PS/CS/83 /2021
Karachi, 17th September, 2021

Subject: Dissenting Note on Indicative Generation Capacity Expansion Plan ("IGCEP")

Dear Sir,

Assalam Alaikum,

The Council of Common Interests ("CCI") is a Constitutional forum created under Article 153 of the Constitution. It is noteworthy to mention here that Pakistan being a Federation with strong Federating units, the Constitution makers in their infinite wisdom had bifurcated the legislative lists so as to ensure that the Federal Government does not unilaterally decide on matters which also affect the Federating units. It was in this context, Article 154 (1) was introduced in the Constitution, which reads as under:

> "The Council shall formulate and regulate policies in relation to matters in Part II of the Federal Legislative List and shall exercise supervision and control over related institutions."

2. It was in light of this, that the issue of IGCEP was brought before the CCI, because any decision on the said matter would have a direct impact on the Federating Units as well as its populace. It was the wisdom of the Constitution makers that such issues should be properly deliberated amongst the Federation and Federating Units and no decision should be made without due regard of the contentions raised by a Federating unit. It is therefore shocking to note that the minutes of 48th meeting of CCI issued on 13.09.2021 and received in the Chief Minister Sindh's office on 15.09.2021 erroneously mention that the decision to approve the controversial IGCEP was made unanimously. It is even more shocking to read the phrase "unanimously" because throughout the meeting, the Chief Minister Sindh as well as the Energy Minister, Government of Sindh had categorically objected to the way and manner in which IGCEP was being proposed and how it would have the affect of ignoring the cheaper electricity options of renewable energy such as wind and solar. Though our contentions have been recorded in the minutes, infact our opposition is mentioned unequivocably in Para 25 of the minutes, it is rather odd to read that the decision has been made unanimously, which is hard to fathom.

4. It is further imperative to state that when the Chief Minister Sind had raised the issue that ARE Policy 2019 is being amended through IGCE 2021 whereby Hydel is being made part of RE whereas it was not pa of RE in ARE Policy, 2019. The Minister for Power stated that the claim wa not based on facts (Para 15). However, the decision in Para 31 (b) states tha Hydel projects shall be included in the definition of RE and RE Policy shall b suitably amended. This in itself is sufficient to establish that the members the CCI were briefed and assured on something totally different to what ha been decided.

The exclusion of PEDO projects, while justified on ecological and least cost grounds, may also inflame legal disputes as the decision indicates an uneven and unequal approach between federal and provincial projects with the former favored over the latter.

J. KE's 640 MW Renewable Portfolio: Why It Should Be Excluded from the IGCEP

Although the IGCEP has modeled KE's 640 MW RE portfolio into a separate scenario there are still weaknesses in the modeling. The treatment is neither transparent nor compliant with the policy requirements of least-cost planning and stakeholder accountability. Across the documents, KE's renewable capacity appears in three overlapping categories: (i) 620 MW of "committed" renewables in RCA sensitivity scenarios, (ii) a hard-wired block of 640 MW (420 MW solar and 220 MW hybrid solar–wind) scheduled before 2027, and (iii) ~400 MW of wind post-2030 if deemed least-cost. Yet,

rather than being attributed to specific projects, this capacity is presented as a lump sum, with no traceable link to KE's Power Acquisition Programme or project-level detail [66].

This lack of disaggregation has serious implications. Without site-specific data, stakeholders cannot assess the necessity, costs, or impacts of each project, nor can they evaluate whether such projects meet the least-cost standard that underpins the IGCEP framework. In particular, a discussion of the particulars of the Sindh Solar Energy Project (SSEP)—a World Bank–funded, 350 MW programme involving 120 MW at Deh Halkani and 150 MW at Deh Metha Ghar—appears nowhere in IGCEP tables, despite being a central part of KE's acquisition strategy[67]. Likewise, specific mention of KE's 150 MW of solar in Balochistan (50 MW Winder, 100 MW Bela) and its publicly announced 220 MW hybrid solar–wind project at Dhabeji are absent[68]. This absence not only undermines transparency but also prevents proper scrutiny of their costs, transmission requirements, and social implications.

Even more troubling is the lack of least-cost assessment. The IGCEP tables do not map associated transmission investments, despite the fact that SSEP's PC-1 explicitly identifies "substation upgrades and transmission lines" as integral components (Government of Sindh, 2019). According to World Bank and IFC Environmental, Health, and Safety (EHS) standards, such facilities qualify as "associated facilities" that must undergo environmental and social risk assessment[69]. Neither KE nor the IGCEP process has disclosed the required Environmental and Social Management Plan (ESMP), nor have they provided any detailed cost allocations. The absence of these disclosures suggests that KE's renewables portfolio, as presented, is ineligible for treatment as "committed capacity" under both national planning and international financing standards.

The risk profile is not only fiscal but also social. The expansion of renewable generation entails land use, displacement risks, and community-level impacts that should be integrated into least-cost modeling. The World Bank's 2024 Least-Cost Electrification Study stressed that renewable projects must be assessed on a full social-cost basis, including avoided health damages and climate benefits[70]. Yet KE's projects are being advanced without such an integrated framework, undermining both credibility and compliance.

For these reasons, NEPRA should require that KE's 640 MW renewable block should not be allowed into the committed portfolio in IGCEP until:

1. All projects are disaggregated by site and technology,

2. Full least-cost assessments (including transmission and tariff impacts) are publicly disclosed, and

3. ESMPs and related risk studies are published in accordance with World Bank funding requirements.

Absent these steps, any inclusion of KE's renewables as "committed" capacity undermines

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[66] K-Electric. (2023). *Power Acquisition Programme 2023–2030.* Karachi: K-Electric

[67] World Bank. (2019). *Sindh Solar Energy Project (P159712): Project Appraisal Document.* Washington, DC: World Bank.

[68] K- Electric (2023)

[69] International Finance Corporation (IFC). (2012). *Performance Standards on Environmental and Social Sustainability.* Washington, DC: World Bank Group

[70] World Bank. (2024). *Pakistan Least-Cost Electrification Study.* Washington, DC: World Bank.

transparency, contravenes least-cost principles, and exposes both consumers and communities to hidden financial and social costs. The authority is requested not to allow it into the pool of committed, strategic, or artificially optimized projects.

K. Opaque Data, Biased Methodologies, and Missing Transparency in IGCEP and TSEP

A central weakness of both the Integrated Generation Capacity Expansion Plan (IGCEP) and the Transmission System Expansion Plan (TSEP) lies in their pervasive lack of transparency, incomplete analytics, and reliance on data sources that are vulnerable to conflict of interest. Rather than functioning as independent and verifiable least-cost planning exercises, both plans depend heavily on inputs from executing agencies such as WAPDA and PEDO for hydrological risk assessments and seasonal variability projections of the hydro fleet. These assessments are neither independently validated by the regulator nor vetted by the system operator (ISMO). Given that these agencies have a direct stake in the approval of hydropower projects, the absence of an external validation framework leaves the analysis open to bias, selective reporting, and over-optimistic assumptions.

Equally problematic is the failure to properly account for the transmission system costs associated with generation additions. The National Electricity Plan (NE-Plan) explicitly requires that all generation candidates be evaluated with their full transmission implications, yet the TSEP fails to allocate or disaggregate transmission expansion costs by generation source. Instead, costs are presented in aggregate form, leaving policymakers and the public unable to assess which generation sources impose the heaviest transmission burden. Without this clarity, the claim that IGCEP 2025 represents a least-cost pathway is fundamentally unsubstantiated.

The opacity extends to project-level details as well. In the case of K-Electric's 620 MW renewable portfolio, the IGCEP lumps these projects together under a generic "committed" block without disaggregating sites, technologies, land arrangements, or transmission needs. Even projects tied to the Sindh Solar Energy Program (SSEP) and KE's own Power Acquisition Program, such as the 220 MW hybrid Dhabeji project, are not explicitly named. Similarly, the ACWA Power projects—1000 MW and 1800 MW respectively—are presented as strategic commitments without disclosure of their siting, contractual structure, or rationale for selection. The absence of this information renders independent assessment impossible, insulating these projects from scrutiny and undermining the credibility of the planning process.

Moreover, the criteria for classifying projects as "strategic" remain hidden from public view. Neither IGCEP nor TSEP discloses the analytical basis or trade-offs considered in granting strategic status, despite the fact that such designations carry massive financial and ecological implications. By treating strategic selection as an opaque administrative decision rather than a transparent, criteria-based exercise, the plans effectively shield politically favored projects from least-cost testing and regulatory oversight.

The opacity also manifests in several specific omissions. The interprovincial impacts of generation and transmission choices—long recognized as critical for cooperative federalism—are not assessed, leaving provincial goals, regulatory capacities, and planning frameworks unsynchronized. In the case of KAPCO, no explanation is provided for its extension, despite the previous IGCEP assigning this responsibility explicitly to the TSEP. Likewise, battery energy storage systems (BESS) are relegated to a narrow role in ancillary services, with no modeling of their potential to displace fossil fuel projects by shifting renewable generation across time. This omission ignores one of the most

transformative tools available for achieving least-cost decarbonization.

There is confusion about the relationship between ACWA 1000 / ACWA 1800 and the 2400 MW of large Solar committed in last years draft IGCEP

There is also ambiguity around the 2400 MW of large solar that was committed in the previous IGCEP (ostensibly as G2G projects) but has not been explicitly included in this iteration. Since the IGCEP fails to clarify the disaggregated composition of ACWA 1000MW and ACWA 1800MW but the TSEP retains mention of investments at Haveli Bahadur Shah, Muzaffargarh, and Jhang which were the the proposed locations of three projects under the 2400 MW of previously committed solar capacity, it is unclear whether the ACWA projects are the same as these earlier committed solar projects.

S/N	Site Location	Capacity (MW)	Connection Scheme	Expected Commissioning
1	Near HBS (will be included in Peak July 2028 base case)	1200	In/out S/C of 500 kV Muzafargarh - HBS OHL at the site	2027-28
2	Near Muzafargarh	600	In/out S/C of 220 kV Multan - KAPCO OHL at the site	2026-27
3	Near Jhang	600	In/out S/C of 220 kV Jhang to TT Singh OHL at the site	2026-27

Taken together, these flaws highlight a structural bias in IGCEP and TSEP toward unviable utility scale solar, hydropower, and large-scale, politically favored projects, while neglecting independent validation, cost transparency, and credible least-cost analysis. Without correcting these deficiencies—through disaggregated data disclosure, independent validation of hydrological and cost assumptions, and clear methodologies for strategic project selection—the credibility of Pakistan's energy planning framework will remain compromised.

The following organizations of ACJCE endorse these comments:

S #	Organization Names	Logos
1	Alternative Law Collectives	

2	The Knowledge Forum	
3	Policy Research Institute for Equitable Development (PRIED)	
4	Alternate Development Services	
5	Climate Action Center	
6	Indus Consortium	

7	Lok Sujag	
8	Climate Action Energy Access	