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Effect of Wind-Measurement Height and Photovoltaic Area on the Least-Cost Hybrid Supply of a University Critical Bus in Kaduna, Nigeria: A Screening-Level Techno-Economic Assessment

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ABSTRACT
This screening-level assessment tests whether small wind belongs in a least-cost hybrid plant for a critical-facility bus at Kaduna State University (10.52° N, 7.44° E), and whether that answer depends on wind-measurement height and a limit on photovoltaic capacity. An open hourly load-following model used NASA POWER (2026) meteorology for 2022 and a synthesised critical load (peak 97.1 kW; 477 MWh yr−1). A generic turbine curve gave capacity factors of 4.8% at 10 m (mean 3.41 m s−1) and 19.2% at 50 m (mean 5.34 m s−1). Among 1,350 candidate grid combinations retained only if the loss-of-power-supply probability was at most 1%, the unconstrained cost minimum under the assumed prices was 320 kW of photovoltaics, 800 kWh of storage and 40 kW of diesel, with no wind: levelised cost 0.190 USD kWh−1, renewable fraction 91.4%, and diesel CO2 40 t yr−1, against 0.351 USD kWh−1 and 505 t yr−1 for diesel only. Capping photovoltaics at 200 kW brought 40 kW of wind into the optimum and raised the levelised cost to 0.215 USD kWh−1 within the explored design space. The wind-selection result is conditional on the synthetic load, screening costs and single-year resource series; a 10 m mean should not be used as hub-height input for this site.

Keywords: Hybrid Renewable System, Hub Height, Levelized Cost, Screening Assessment, University Campus, Nigeria

INTRODUCTION

University buildings in northern Nigeria face an unreliable grid and a rising diesel bill. Published sizing studies for campuses in Enugu, Kano, Maiduguri and Port Harcourt generally find that photovoltaics with storage and a diesel residual beat diesel-only supply on cost, and that wind is marginal unless the site is favourable (Diyoke et al., 2023; Kuhe et al., 2025). Comparable tropical and sub-Saharan hybrid analyses likewise show that storage, not small wind, often drives the step down in levelised cost once solar is present (Lambert et al., 2006). Those studies usually rely on a closed optimiser and often pass a 10 m wind speed to a turbine model written for hub height (Manwell et al., 2009).

Kaduna State University sits at 10.52° N, 7.44° E. Local planning figures quote a 10 m mean near 3.4 m s−1 and a daily irradiance near 5.5 kWh m−2. A critical bus of about 100 kW—laboratories, a clinic and selected teaching rooms—is the relevant first plant. Two questions decide its architecture. First, does the same wind series, read at 10 m and at 50 m, change the turbine capacity factor enough to alter a sizing decision? Second, if photovoltaic capacity is unconstrained, is wind in the least-cost mix under the assumed costs, and does wind enter if photovoltaic capacity is capped at 200 kW as a proxy for limited roof and car-park area?

The aim of this study is to answer both questions with a transparent hourly energy-balance model and an exhaustive search over a finite design grid, while separating satellite, synthesised and assumed inputs so that metered load and manufacturer data can replace the present screening assumptions without rewriting the method. The work is a screening-level techno-economic assessment, not a procurement-ready design.

MATERIALS AND METHODS

Study Boundary

The system is an off-grid critical bus. Grid purchase from Kaduna Electric is excluded. The simulation year is 2022. A plant is feasible only if the loss-of-power-supply probability (LPSP), defined as unmet energy divided by annual load, is at most 1%. The objective is minimum net present cost (NPC) among feasible plants under the assumed economic parameters.

Inputs

No on-site mast or interval meter was available. Table 1 separates satellite, synthesised and assumed inputs. The 10 m and 50 m NASA POWER wind products are height-specific reanalysis fields, not measured mast data (NASA POWER, 2026). The 200 kW photovoltaic cap is treated as a physical area restriction proxy (approximately 1,000–1,200 m2 of collector at typical packing densities), not an economic soft limit.

Table 1: Classification of Model Inputs

Input	Class	Value used	Limitation
GHI, temperature, wind	Satellite	Hourly, 2022	Not a mast or TMY
Critical-bus load	Synthesised	Peak 97.1 kW; 477 MWh yr−1	Not metered
PV parameters	Assumed	$\gamma = -0.0038$ °C−1; NOCT = 45 °C	Generic module

Input	Class	Value used	Limitation
Turbine curve	Assumed	Cut-in 2.5, rated 11, cut-out 20 m s−1	Not a maker curve
Battery	Assumed	LiFePO4; SoC 20–95%; ηch = ηdis = 0.95	Screening
Component costs & fuel	Assumed	See Economics subsection	Not quotations
Discount rate; life	Assumed	10% real; 25 years	Policy choice

Resource and Load

NASA POWER supplied hourly global horizontal irradiance (GHI), 2 m temperature and wind at 10 m and 50 m for 2022, and a 2014–2023 monthly climatology for context (Figure 1; NASA POWER, 2026). The 2022 irradiance mean is 5.45 kWh m−2 day−1. The 10 m and 50 m wind means are 3.41 m s−1 and 5.34 m s−1. The load archetype combines a weekday teaching peak, an evening tail and a lower weekend shape (Figure 2). Annual energy is 476,945 kWh.

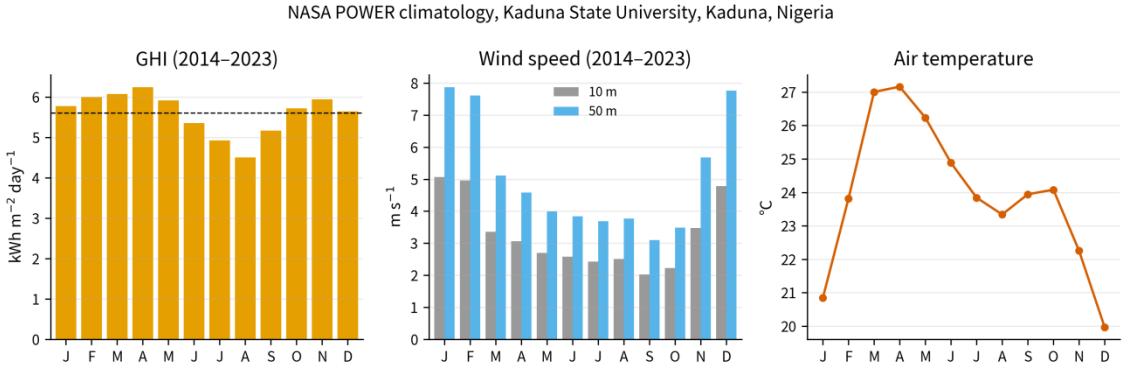


Figure 1: Monthly irradiance, wind at 10 m and 50 m, and air temperature at Kaduna (NASA POWER, 2014–2023)

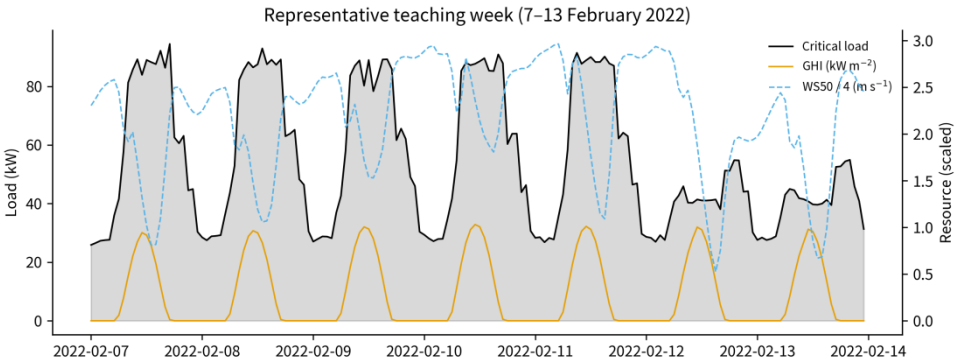


Figure 2: Synthesized critical load for 7–13 February 2022, with irradiance and scaled 50 m wind

Component Models and Dispatch

Photovoltaic AC output in hour t is obtained from a temperature-corrected DC estimate and a loss stack. Cell temperature and power are

$$Tcell,t = T2m,t + GHIt \times \frac{(NOCT - 20)}{800} \quad (1)$$

$$PPV,t = PSTC \times (GHIt / 1000) \times [1 + \gamma (Tcell,t - 25)] \times \eta loss \quad (2)$$

where PSTC is nameplate capacity (kW), γ = −0.0038 °C−1, NOCT = 45 °C, and ηloss = 0.98 × 0.98 × 0.99 × 0.98 × 0.96 accounts for soiling, mismatch, wiring, availability and inverter efficiency. Plane-of-array irradiance is approximated by GHI for a fixed tilt near latitude.

Wind AC output uses a generic Class-III cubic power curve evaluated on the 50 m series (hub height taken as 50 m; rated capacity is the decision variable in the search). Fractional power is

$$f(v) = 0 \quad if\ v < vin\ or\ v \geq vout \quad (3)$$

$$f(v) = (v^3 - vin^3)/(vr^3 - vin^3) \quad if\ vin \leq v < vr \quad (4)$$

$$f(v) = 1 \quad if\ vr \leq v < vout \quad (5)$$

with vin = 2.5 m s−1, vr = 11 m s−1, vout = 20 m s−1. Then Pwind,t = Prated × f(v50,t) × 0.94. The 10 m series is used only for the capacity-factor comparison, not for sizing.

Battery energy Et is bounded by state-of-charge limits SOCmin = 0.20 and SOCmax = 0.95 of usable capacity Ebat. Maximum charge and discharge power is 0.5 Ebat. Charge and discharge efficiencies are each 0.95. Dispatch is load-following in order: (i) serve load from concurrent PV and wind; (ii) charge the battery with surplus up to power and energy limits; (iii) discharge the battery to cover residual load; (iv) start diesel for any remaining deficit, subject to rated capacity and a 30% minimum-load floor when running; (v) record unmet energy if diesel cannot cover the residual. Diesel fuel use (L h−1) follows a linear curve

$$F = F0\,Prated + F1\,Pgen, \quad F0 = 0.080\,L\,kWh - 1, F1 = 0.246\,L\,kWh - 1 \quad (6)$$

when the set is running and zero otherwise. Diesel CO2 is 2.68 kg L−1. LPSP, renewable fraction (RF) and annual diesel energy follow from the hourly totals:

$$LPSP = Eunmet / Eload \quad (7)$$
$$RF = 1 - Ediesel / Eload_served \quad (8)$$

Economics and Search

Installed capital costs used in the search are 720 USD kW−1 for photovoltaics, 2,100 USD kW−1 for wind, 240 USD kWh−1 for LiFePO4 storage, 380 USD kW−1 for diesel and 210 USD kW−1 for conversion, plus a 12% balance-of-system adder. Annual fixed O&M is 1.5%, 3.0%, 1.0%, 4.0% and 1.0% of the respective capital items. Fuel is 0.85 USD L−1. Battery replacement is charged at year 10 (85% of capital), converter replacement at year 15 (70%), and diesel overhaul every 8 years (25% of diesel capital). NPC and LCOE over N = 25 years at real discount rate r = 0.10 are

$$NPC = C0 + \Sigma y = 1..N\,(OMy + Fuely + Replacementsy) / (1+r)y \quad (9)$$
$$LCOE = NPC / \Sigma y = 1..N\,Eservedy / (1+r)y \quad (10)$$

The search grid is the Cartesian product of PV ∈ {0, 40, …, 320} kW, wind ∈ {0, 10, 20, 40, 60} kW, battery ∈ {0, 100, 200, 400, 600, 800} kWh and diesel ∈ {0, 40, 60, 80, 100} kW (1,350 combinations). Plants with LPSP> 1% are discarded. A second search repeats the rule with PV capped at 200 kW. One-at-a-time sensitivity multiplies selected parameters by 0.8 and 1.2 with the unconstrained optimum sizes held fixed. Monte Carlo (n = 400, seed 42) draws independent factors on capital costs (±15–25%), fuel price (0.75–1.40), discount rate, GHI (±6%) and 50 m wind (±10%); each draw re-scores the fixed unconstrained architecture (sizes are not re-optimised).

RESULTS AND DISCUSSION

Measurement Height

The generic curve returns a capacity factor of 4.8% on the 10 m series and 19.2% on the 50 m series. The two series are the same NASA POWER product and the same year; the difference is height. A sizing that inserts 3.41 m s−1 into a hub-height curve understates the wind resource by about a factor of four in energy terms under this turbine model (Manwell et al., 2009). All plants below use the 50 m series. The capacity factors are descriptive of the assumed curve, not verified field performance.

Unconstrained Least-Cost Plant

Under the assumed costs and the 1% LPSP limit, the feasible cost minimum contains no wind: 320 kW of photovoltaics, 800 kWh of storage and 40 kW of diesel (Table 2). Levelised cost is 0.190 USD kWh−1. The renewable fraction is 91.4%. LPSP is 0.56%. Annual diesel energy is about 41 MWh, fuel use about 15,080 L, and diesel CO2 40.4 t yr−1. The diesel-only reference (100 kW) costs 0.351 USD kWh−1 and emits 505 t CO2 yr−1 on about 188,500 L yr−1. Figure 3 places the minimum on the cost–renewable-fraction plane. Figure 4 shows monthly generation: photovoltaic energy dominates every month, with a wet-season diesel residual in July–September; wind is absent. Figure 5 shows evening diesel blocks and daily battery cycling in a wet-season week.

Table 2: Feasible Cost Minima under the 1% Loss-of-Power-Supply Limit (Screening Costs)

Quantity	Unconstrained	PV capped at 200 kW
Photovoltaics	320 kW	200 kW
Wind	0 kW	40 kW
Battery	800 kWh	400 kWh
Diesel	40 kW	60 kW
LPSP	0.56%	0.50%
Renewable fraction	91.4%	73.9%
Diesel CO2	40.4 t yr−1	132 t yr−1
Capital cost	565,376 USD	438,278 USD
Net present cost	819,325 USD	924,399 USD
Levelised cost	0.190 USD kWh−1	0.215 USD kWh−1

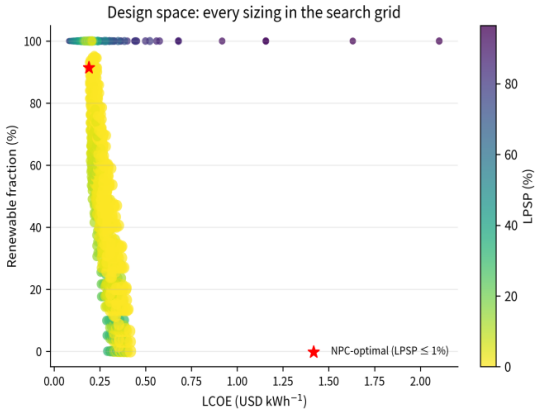


Figure 3: Design space. The star is the feasible net-present-cost minimum

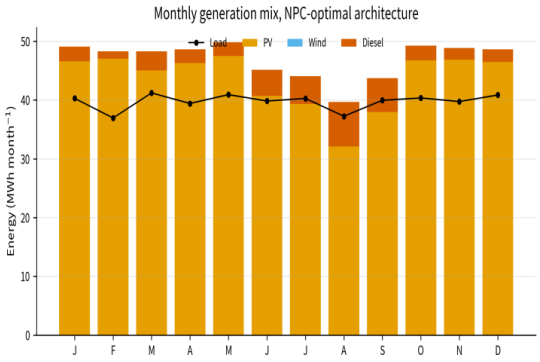


Figure 4: Monthly generation mix of the unconstrained minimum. Wind contribution is zero; diesel is the wet-season residual

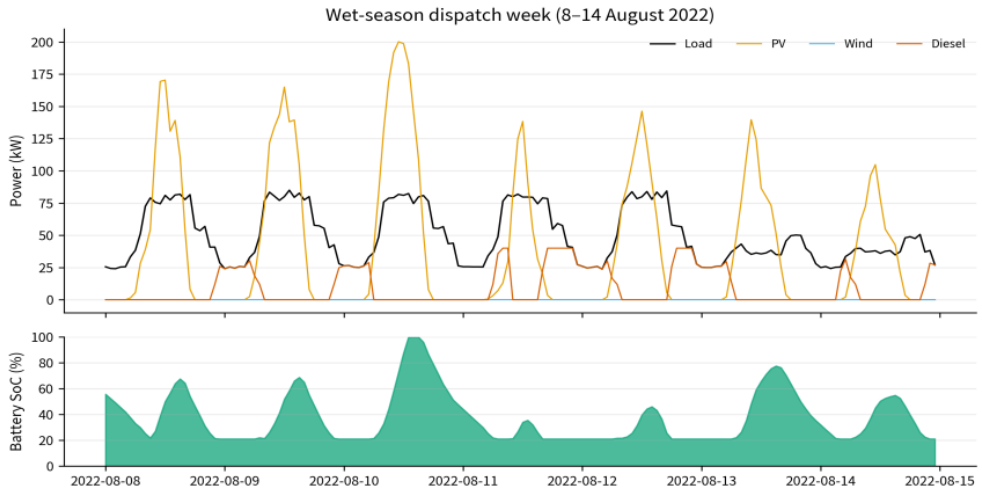


Figure 5: Dispatch and battery state of charge, 8–14 August 2022

Photovoltaic Area Cap and Architecture Comparison

With photovoltaics limited to 200 kW, the feasible minimum is 200 kW of photovoltaics, 40 kW of wind, 400 kWh of storage and 60 kW of diesel (Table 2). Levelised cost rises to 0.215 USD kWh−1 and the renewable fraction falls to 73.9%. Within the explored grid and cost set, wind therefore appears as a substitute for photovoltaic area rather than as a free complement. Removing diesel entirely, even at 320 kW of photovoltaics, 60 kW of wind and 800 kWh of storage, leaves LPSP = 5.06% and is rejected.

Table 3 and Figure 6 compare the best feasible member of each family. Storage, not wind, produces the step from a photovoltaic–diesel plant (0.252 USD kWh−1; renewable fraction 46.5%; about 103,100 L yr−1) to the unconstrained minimum. The no-diesel row is infeasible and is reported only for contrast; its 0.209 USD kWh−1 LCOE is not a valid optimum under the 1% LPSP rule.

Table 3: Best Plant in each Family under the Search Grid. LCOE in USD kWh−1; CO2 in t yr−1

Family	PV	Wind	Batt.	DG	LCOE	RF %	CO2 t	Status
Diesel only	0	0	0	100	0.351	0	505	Feasible
PV–diesel	200	0	0	80	0.252	46.5	276	Feasible
PV–battery–diesel	320	0	800	40	0.190	91.4	40	Feasible
PV–wind–battery–diesel	280	10	600	40	0.193	84.0	75	Feasible
No diesel	320	60	800	0	0.209	100	0	Infeasible (LPSP 5.06%)

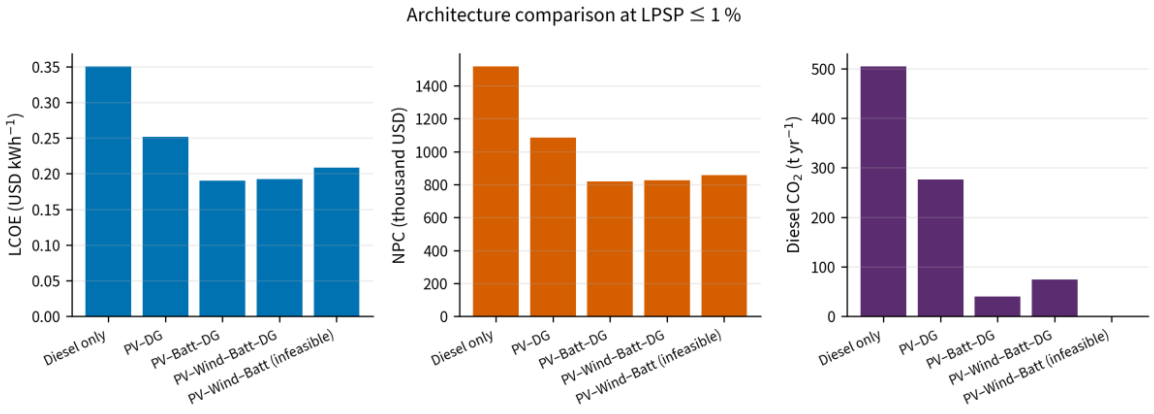


Figure 6: Cost and diesel carbon dioxide by architecture. The no-diesel case fails the reliability limit

Uncertainty

On the unconstrained plant with sizes held fixed, levelised cost moves with the discount rate, irradiance and battery and photovoltaic capital cost, and is insensitive to wind capital cost (Figure 7). Across 400 Monte Carlo draws the 5th, 50th and 95th percentiles of levelised cost are 0.157, 0.197 and 0.239 USD kWh−1; the mean renewable fraction is 91.2% (Figure 8). These intervals describe cost uncertainty for the selected architecture, not a re-optimised architecture choice under each draw. They are conditional on the synthesised load and the screening prices. They do not reverse the height comparison, which uses one data product at two heights.

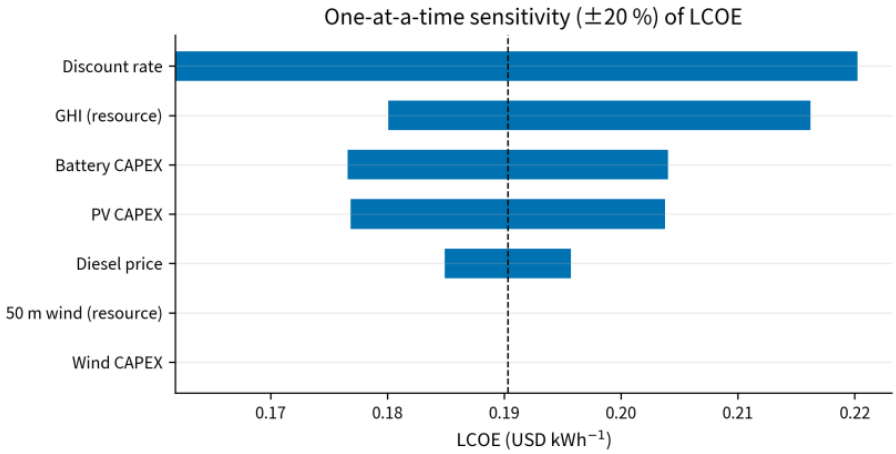


Figure 7: One-at-a-time ±20% sensitivity of levelised cost for the unconstrained plant

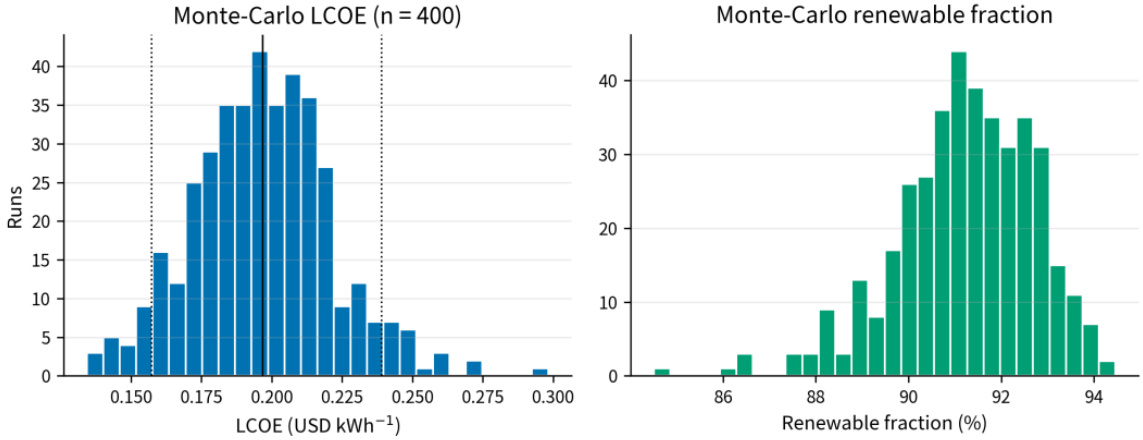


Figure 8: Monte Carlo levelised cost and renewable fraction (n = 400; sizes fixed)

The numerical pattern agrees with other northern Nigerian campus studies that find a photovoltaic–battery–diesel plant cheaper than diesel alone under comparable assumptions (Diyoke et al., 2023; Kuhe et al., 2025). It disagrees with any study that treats a 10 m mean near 3.4 m s−1 as a bankable hub-height turbine input. What this paper cannot support is a procurement decision: the load is synthesised, the turbine curve is generic, and the prices are not quotations.

Conclusion

Within the assumed single-year resource series, synthesised critical load, generic turbine curve, screening costs and 1,350-point design grid, the feasible least-cost supply at a 1% LPSP limit is 320 kW of photovoltaics, 800 kWh of storage and 40 kW of diesel, at 0.190 USD kWh−1 and a 91.4% renewable fraction. The same wind product gives capacity factors of 4.8% at 10 m and 19.2% at 50 m; a 10 m mean should not be used as hub-height input for this site. Under a 200 kW photovoltaic cap, wind enters the feasible optimum in the explored space and the levelised cost rises to 0.215 USD kWh−1. Diesel-only supply remains the costly reference at 0.351 USD kWh−1 and 505 t CO2 yr−1. Future work requires interval-metered load, multi-year or mast-calibrated wind, a manufacturer turbine curve and vendor quotations before any investment decision.

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