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DEVELOPMENT OF A COST-OPTIMAL POWER SUPPLY FOR RURAL NAMIBIA: AN OEMOF-BASED CASE STUDY OF TSUMKWE

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Summary

This study addresses the critical electrification gap in Sub-Saharan Africa by optimising a standalone mini-grid for *Tsumkwe*, Namibia. Using the *Open Energy Modelling Framework*, a single-stage optimisation identifies the least-cost energy mix by minimising the Levelized Cost of Electricity over the project lifetime. Solar photovoltaics, wind, biomass-fired combined heat and power, battery storage, diesel generation and grid connection are evaluated on an equal footing, with diesel permitted to compete freely as an investment option rather than excluded from consideration a priori. Results show that a moderate expansion of the existing 304 kW_P PV array by roughly 200 kW_P, without any battery extension, is the least-cost configuration. The existing diesel genset is retained, but its dispatched share of demand falls to a small residual fraction, and no additional diesel capacity is selected despite being available to the solver. Grid connection to the nearest national grid point, 82 km away, is likewise available at its own cost in the same optimisation and is not selected. This configuration reduces lifetime CO_2 emissions by 81.8 % relative to optimally operating the existing infrastructure alone, with cost and emissions reduced together rather than traded off. The annualised cost of the PV expansion is more than three times outweighed by the value of the diesel fuel it displaces, a simple payback of roughly 3.5 a. A comparable saving is available immediately and without any new investment: Dispatching the existing infrastructure as the model shows it optimally could be operated, rather than as historically observed, is worth a similar order of magnitude in avoided diesel fuel alone.

Keywords: Mini-Grids, Rural Electrification, OEMOF, LCoE, Techno-Economic Analysis, Sub-Saharan Africa

Field of application for the findings: Rural energy planning and decentralised infrastructure development

Addressed audience: Energy policy makers, energy utilities, and renewable energy researchers

1. Introduction

The global challenge of universal energy access is most acute in Sub-Saharan Africa (SSA), where a significant portion of the population remains without modern electricity services (The World Bank, 2024). While the global electrification rate has reached above 90 % (IEA et al., 2025, p. 15), the deficit in SSA continues to widen, accounting for 85 % of the global population without access (IEA et al., 2025, p. 115). In sparsely populated countries like Namibia, where the population density is only four people per square kilometre (The World Bank, 2023), traditional grid extension is often expensive and technically challenging.

Solar hybrid mini-grids have emerged as a primary technology for rural electrification, providing a decentralised alternative to extending the power grid. The economic viability of these solutions has been enhanced by a sharp decrease in the price of PV technology over the last years (IRENA, 2025, p. 4). Consequently, PV-based decentralised infrastructures – alongside complementary renewable resources such as wind and biomass – have become an increasingly cost-competitive alternative to fossil-fuel-based development pathways for expanding energy access in African countries, creating a growing design space of technology combinations.

Beyond basic lighting, mini-grids enable essential social services – vaccine refrigeration, digital education and productive energy use. Namibia's high solar irradiation levels favour solar-based electrification, yet the country operates only three officially recognised community mini-grids nationwide against a 45 % national electrification rate (Mehta et al., 2025, p. 2,3). Existing mini-grid systems suffer from degradation due to maintenance deficits and shifting demand (Institute of new Energy Systems (InES), 2024, p. 9), necessitating computational tools for systematic optimisation and planning.

Tsumkwe has been the subject of repeated technical assessment, reflecting successive stages of its own hybrid system: From the original commissioning study (Azimoh et al., 2017) through mid-life performance reviews (Hoeck et al., 2022; Lwakatare et al., 2024) to the most recent operational and comparative analyses (Mehta et al., 2025; Kaluwa and Bekker, 2025; Katende et al., 2026).

This paper is organised as follows: Section 2 introduces the *Tsumkwe* case study and the resulting research questions. Section 3 formalises the Levelized Cost of Electricity (LCoE)-based optimisation methodology and its *Open Energy Modelling Framework* OEMOF implementation. Section 4 documents the input data. Section 5 presents the reference scenario, the cost-optimal configuration, a grid-extension scenario and a sensitivity analysis. Section 6 discusses implications, limitations and transferability. Section 7 concludes with recommendations.

2. *Tsumkwe*: The Case Study Area

The settlement of *Tsumkwe*, located in the north-eastern region of Namibia, serves as a case study for this investigation. *Tsumkwe* is home to approximately 4,000 residents from diverse ethnic backgrounds. The settlement's remote location – approx. 700 km from the capital, *Windhoek* – makes connection to the national electricity grid economically challenging. Current infrastructure includes primary and secondary schools, a clinic, and a police station, all of which rely on a stable power supply (Mehta et al., 2025, p. 6).

The hybrid mini-grid was commissioned in 2012 – at the time of commissioning one of the largest hybrid mini-grid systems in sub-Saharan Africa (Azimoh et al., 2017, p. 14) – and was subsequently extended in 2014 and 2016 (Lwakatare et al., 2024, p. 10). In its present configuration, it comprises a 304 kW_P PV array (202 kW_P from 2012 plus a 102 kW_P extension in 2016), a lead-acid battery bank of 3,000 kW h nominal capacity (1,600 kW h usable), and a 300 kV A diesel genset. The original installation comprised 650 kV A – two 150 kV A units and one 350 kV A unit (Hoeck et al., 2022, p. 515; Azimoh et al., 2017, p. 9) – of which only a single unit remains operational. The three most recent assessments consistently report its rating as 300 kV A (Mehta et al., 2025, p. 6; Kaluwa and Bekker, 2025, p. 2; Katende et al., 2026, p. 264). The present study adopts this figure without reconstructing the intervening replacement history. The two ground-mounted PV fields and the battery building form the renewable backbone of the existing system (cf. figure 1).

Because different studies were conducted at different points along this stepwise expansion, the reported specifications diverge accordingly: Earlier studies report the smaller initial figures, while more recent ones describe the present configuration (cf. table 1). The present study adopts the values in the last row (cf. table 1). The existing assets are treated as sunk, so only newly built capacity is priced.

Tab. 1: Reported technical specifications of the *Tsumkwe* mini-grid across the literature.

Source	PV in kW_P	Battery nom. / usable in MW h	Diesel generator in kV A
Azimoh et al. (2017, p. 9)	202[a]	0.77 / –	650
Hoeck et al. (2022, p. 515)	202[a]	0.77 / –	650
Lwakatare et al. (2024, p. 10)	304[b]	3.0 / –	350
Mehta et al. (2025, p. 7)	304[b]	2.4 / –	300
Kaluwa and Bekker (2025, p. 2)	304[b]	2.4 / 1.6	300
Katende et al. (2026, p. 264)	304[b]	3.0 / 1.6	300
This study	304	3.0 / 1.6	300

[a] As-built 2012 configuration, before both battery extensions (1,140 kW h in 2014, 1,070 kW h together with the 102 kW_P PV extension in 2016).
[b] Post-2016 configuration (including the 102 kW_P PV and battery extension).

Over time, however, the system has faced several operational failures: Dust accumulation and insufficient maintenance progressively reduced PV output (Mehta et al., 2025, p. 20), while generator-PV-synchronisation issues caused unscheduled interruptions (Azimoh et al., 2017, p. 18). Most consequentially, overheating of the battery storage room, where temperatures reached up to 50 °C, led to accelerated chemical degradation and

Fig. 1: Aerial view of the existing *Tsumkwe* hybrid mini-grid: The 202 kWP (2012, yellow overlay) and 102 kWP (2016, red overlay) ground-mounted PV fields and the building housing the battery storage (blue overlay). Source: *Institute of new Energy Systems* (InES), TH Ingolstadt. Edited for annotation and to remove extraneous foreground elements.

capacity loss (Institute of new Energy Systems (InES), 2024, p. 17). Coupled with rising energy demand, these failures forced the settlement to rely increasingly on expensive and polluting diesel generation. The current study seeks to provide a data-driven optimisation roadmap to restore and expand this system sustainably.

Although *Tsumkwe* is currently off-grid, the national electricity grid has recently been extended to *Mangetti Dune*, located approximately 82 km away (Lwakatare et al., 2024, p. 14). This development raises a critical research question: *Is it economically more viable to extend the grid infrastructure to Tsumkwe or to rehabilitate and optimise the existing decentralised mini-grid?* The present study directly addresses this trade-off by simulating a grid-extension scenario against a full off-grid technology optimisation, evaluating solar PV, wind, biomass CHP, battery storage and diesel generation as candidate expansion options.

3. LCoE-Based Optimisation Methodology

The methodology utilises OEMOF, specifically the `oemof.solph` library, to perform a single-stage cost optimisation of the *Tsumkwe* mini-grid system. OEMOF is an open-source Python framework that represents energy systems as directed graphs of nodes and edges, allowing for modular and transparent modelling (Hilpert et al., 2018; Krien et al., 2020; OEMOF Community, 2026). The primary objective is the minimisation of the LCoE, formalised below (cf. equation 1).

3.1 Mathematical formulation

The LCoE is the constant unit price in USD/(kW h) that, applied to every kilowatt-hour supplied over the project lifetime, recovers all capital and operating expenditures discounted to the base year. The LCoE is the ratio of the discounted life-cycle expenditure to the discounted electricity supplied (Kost et al., 2024, p. 37; Short et al., 1995, p. 47),

$$\mathrm{LCoE} = \frac{I_0 + \sum_{t=1}^{T} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{T} \frac{M_t}{(1+i)^t}}, \tag{1}$$

where I_0 is the initial investment expenditure, A_t the annual total cost in year t, comprising fixed and variable operation and maintenance (O&M) expenditure and fuel, M_t the electricity supplied in year t, i the real discount rate and T the economic lifetime. In the multi-technology system each asset is evaluated over its own lifetime T_n (cf. table 2) and the discounted expenditures are summed across assets. The denominator is deliberately the *served* demand rather than gross generation. Under the PV surplus of the optimised system – where total

PV generation, existing plus new, exceeds annual demand by roughly 24 % (cf. section 5.2) – normalising by generation would credit curtailed, valueless energy and understate the true supply cost.

The decision variables are the installed capacities P_n^{cap} and the hourly dispatch $P_n(t)$ of the investable assets in $\mathcal{N}$ (PV, wind, CHP, battery extension, diesel extension, grid connection); $\mathcal{N}$ also contains the existing PV array, battery bank and genset, for which $I_{0,n} = 0$ and P_n^{cap} is fixed. Dispatch of the existing diesel genset is likewise a decision variable in every scenario, though its capacity is fixed rather than optimised, exactly as for the existing PV array and battery bank (cf. section 5.1). Since the served demand is exogenous and identical across all configurations, the discounted denominator is a fixed constant (cf. equation 1). Minimising the LCoE is therefore equivalent to minimising its numerator, the total discounted life-cycle cost, which constitutes the objective function,

$$\min_{P_n^{\mathrm{cap}},\, P_n(t)} \sum_{n\in\mathcal{N}} \left(I_{0,n} + \sum_{t=1}^{T_n} \frac{A_{n,t}}{(1+i)^t} \right), \tag{2}$$

subject to the energy-balance, capacity and storage constraints stated below, and solved as a mixed-integer linear programme (MILP) over the hourly index set $\mathcal{T}$ of a representative meteorological year. Here $I_{0,n}$ is the investment expenditure of asset n (its specific cost times P_n^{cap}) and $A_{n,t}$ its annual cost in year t, comprising fixed O&M (proportional to P_n^{cap}) and the variable cost of the optimised dispatch $P_n(t)$, assumed constant over the lifetime T_n (cf. table 2). Each asset is annuitised over its own technical lifetime T_n, with no residual value at any cut-off. The 20-year period T used for the headline comparison is a separate reporting horizon for cumulative CO_2 totals, decoupled from the annuity itself (cf. table 3). This matters most for the grid scenario, whose 40 a medium-voltage (MV) line lifetime exceeds T twofold but is annuitised on this longer basis (cf. section 5.3).

For each time step $t \in \mathcal{T} = \{1, \dots, 8760\}$ the energy balance at the alternating-current (AC) bus must hold,

$$\sum_{n\in\mathcal{N}^+} P_n(t) = D(t) + P^{\mathrm{ch}}(t) + P^{\mathrm{exp}}(t) + P^{\mathrm{exc}}(t), \tag{3}$$

where $\mathcal{N}^+$ denotes the supply-side flows (generators, battery discharge, grid import), $D(t)$ the electrical load demand, $P^{\mathrm{ch}}(t)$ the battery charging power, $P^{\mathrm{exp}}(t)$ the export to the central grid (where applicable) and $P^{\mathrm{exc}}(t)$ a non-priced excess slack. The state of charge $E(t)$ of the battery follows

$$E(t+1) = (1-\delta)\, E(t) + \eta_{\mathrm{ch}}\, P^{\mathrm{ch}}(t)\, \Delta t - \frac{P^{\mathrm{dis}}(t)}{\eta_{\mathrm{dis}}} \Delta t, \tag{4}$$

with the discharging power $P^{\mathrm{dis}}(t)$, the time-step length $\Delta t = 1$ h, the self-discharge rate δ, which is set to zero here, and the one-way charge/discharge efficiencies $\eta_{\mathrm{ch}} = \eta_{\mathrm{dis}} = 0.927$ (round-trip efficiency 86 %, Ralon et al., 2017, p. 102), applied to both the existing and the extension battery. Capacity bounds $0 \le P_n(t) \le P_n^{\mathrm{cap}}$ and state-of-charge bounds $E^{\min} \le E(t) \le E^{\max}$ are enforced. For the existing lead-acid bank these bounds reflect an installed nominal capacity of 3,000 kW h and a usable capacity of 1,600 kW h after thermal degradation, imposed through an effective lower state-of-charge bound $E^{\min}/E^{\max} = 1 - 1600/3000 \approx 0.47$, i.e. a usable depth of discharge of about 53 %. A Loss-of-Power-Supply Probability of LPSP = 0 % is imposed as a hard constraint, i.e. unmet load is not permitted at any time step. Lifetime CO_2 emissions are evaluated post-optimisation from technology-specific operational or life-cycle factors, applied to each technology's dispatched or generated electricity over the reporting period T: 48 g/(kW h) of new PV generation (Schlömer et al., 2014, p. 1335), 90 kg/(kW h) of newly installed battery capacity, within the range reported by Emilsson and Dahllöf (2019, p. 6), 400 g/(kW h) of grid-imported electricity (Electricity Control Board (ECB), 2025, p. 58) and 266.5 g/(kW h) of diesel fuel energy (Quaschning, 2024). The latter is a fuel-based factor and is therefore applied to the fuel input rather than to the electrical output. Dispatched diesel electricity is converted to fuel energy through an assumed average generator efficiency of $\eta_{\mathrm{Diesel}} = 0.35$, giving an effective 761 g/(kW h) of diesel-generated electricity. The corresponding factors for wind and biomass CHP (Schlömer et al., 2014, p. 1335) do not affect any reported figure, as neither technology enters a reported configuration. Consistent with their treatment as sunk assets, the existing PV array and battery bank are assigned no life-cycle emissions in any scenario. The diesel genset is treated differently in this respect: its operational emissions are counted in full whenever it is dispatched, regardless of whether the dispatched capacity is existing or newly built, since fuel combustion is an ongoing environmental cost independent of the genset's capital history.

3.2 OEMOF implementation

The *Tsumkwe* energy system is modelled as a single electricity bus onto which all generation, storage and demand components feed (cf. figure 2). Wind turbines and biomass CHP units are each represented by four discrete, commercially available unit sizes rather than a continuously scalable capacity, so that the solver selects a specific technology size endogenously instead of an arbitrary fractional rating. The optional MV grid connection is modelled as a capacity investment that, once made, permits bidirectional import and export up to a shared, symmetric capacity limit, reflecting that a single physical line serves both directions.

The capacities of the PV extension and of the battery extension enter as continuous investment variables, whereas the wind turbine size, the CHP unit selection and the build decision for the grid connection are binary. This combination of continuous sizing and discrete unit selection renders the underlying problem a MILP. `oemof.solph` assembles the MILP automatically from the component graph and passes it to the open-source `HiGHS` solver, which is installed and executed locally on a standard workstation. A comparable annuity-based `oemof.solph` approach was applied by Reiner Lemoine Institut (RLI) (2024) to off-grid scenario planning in Uganda, supporting the methodological transferability of this framework within the SSA context. The solver is invoked with a relative MIP-gap tolerance of MIPGap = 5 % and a 900 s time limit. Across the nine runs reported here – three scenarios and six sensitivity variants – HiGHS required between 16 s and 125 s of solution time, and between 69 s and 182 s including model assembly and result processing. Every run terminated at the root node with a certified 0 % gap, so each reported configuration is a proven global optimum rather than merely a near-optimal solution within the prescribed tolerance.

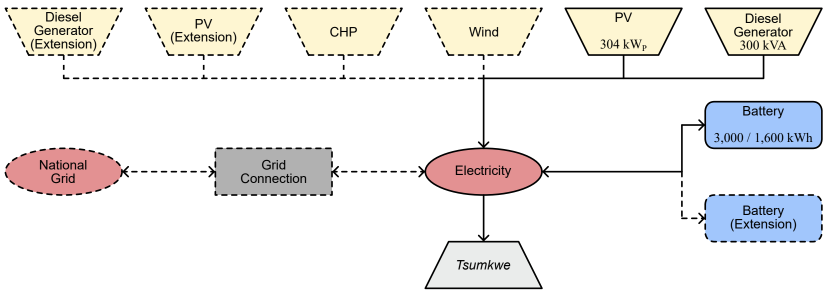

Fig. 2: Topology of the *Tsumkwe* mini-grid. Following standard OEMOF visual conventions, `oemof.solph` *Sources* (PV, wind, CHP, etc.) are drawn as trapezoids, the central *Bus* as an ellipse, the *Converter* (grid connection) as a rectangle and the *GenericStorage* (battery) as a rounded rectangle. The existing diesel genset is part of the optimisation graph and freely dispatchable at its fuel cost, on the same footing as the existing PV array and battery bank (cf. section 5.1); new diesel capacity is an additional, separately costed investment option. Solid borders mark existing infrastructure (dispatchable but not investable), dashed borders indicate new investment options evaluated by the optimiser.

4. Input Data and Parameters

The model integrates high-resolution input data, including hourly meteorological time series (solar irradiance and wind speed) and real consumption profiles measured in *Tsumkwe*. PV yield is derived from PVGIS-SARAH3 (European Commission, Joint Research Centre, 2025) for the meteorological reference year 2021, simulated for a fixed-tilt array (tilt 25°, oriented due north to face the equator, as appropriate for a Southern-Hemisphere site). Wind speeds at 80 m hub height are derived from the NASA POWER reanalysis via the standard power-law correction from 50 m (NASA Langley Research Center (LaRC), 2025). The annual mean wind speed at the site is $\bar{v} = 6.1\ \mathrm{m/s}$, which lies below the economic threshold for commercial onshore turbines.

The hourly load profile is the most sensitive input of the model and was therefore based on empirical, on-site measurements rather than synthesised from population proxies. The dataset comprises 8,760 hourly time steps recorded throughout the calendar year 2021, collected by the InES research team at TH Ingolstadt as part of an on-site monitoring programme and shared with the authors for this study (Mehta et al., 2025; Institute of new Energy Systems (InES), 2024). The measurements resolve both essential consumers (clinic, primary and secondary schools, police station, residential lighting and refrigeration) and non-essential or productive uses connected to the mini-grid. The annual electricity consumption sums to approximately 632 MW h, jointly covered by the existing PV, battery and diesel assets (cf. section 2). The diesel generators alone supplied 404 MW h of this in the reference year 2021, around 64 % of demand. Optimal dispatch of the same existing assets, as established in section 5.1, reduces this to 35.6 %, a reduction of 178,933 kW h/a, worth approximately 67,995 USD per year in avoided diesel fuel at no capital cost. This is an upper bound rather than an immediately realisable saving. Part of the gap reflects operational constraints – forecast uncertainty, maintenance windows, staffing – that the model's perfect-foresight dispatch does not capture. A further part is physical: Measured generation in 2021 (432 MW h PV plus 404 MW h diesel) exceeds metered demand by 204 MW h, whereas the model, applying the same 86 % round-trip efficiency to the degraded lead-acid bank as to a new one, loses only 26 MW h to storage and curtailment. Conversion and auxiliary losses of that magnitude cannot be recovered by rescheduling alone, so the operational lever is smaller than the raw difference suggests.

Tab. 2: Selected techno-economic input parameters for the *Tsumkwe* optimisation. Units are given per value. Values originally denominated in EUR were adopted at parity (EUR ≈ USD).

Asset	CAPEX	Fixed O&M	Var. cost	T_n
PV (new)[a]	1,378 USD/kW_P	18.0 USD/(kW_P a)	—	24 a
Wind turbine[a]	1,489 USD/kW	60.0 USD/(kW a)	—	25 a
Biomass CHP[b]	2,500 USD/kW	75 USD/(kW a)	0.005 USD/(kW h)	30 a
Battery extension[c]	350 USD/(kW h)	3.59 USD/(kW h a)	—	15 a
Grid extension (MV line)[d]	30,000 USD/km	150 USD/(km a)	0.14 USD/(kW h)	40 a
Diesel genset[e]	500 USD/kW	15.0 USD/(kW a)	0.380 USD/(kW h)	15 a

[a] Source: Allington et al. (2022, p. 14)
[b] Sources: Allington et al. (2022, p. 14) and Reiner Lemoine Institut (RLI) (2024, p. 88)
[c] Sources: Ralon et al. (2017, p. 77) and Reiner Lemoine Institut (RLI) (2024, p. 89). Round-trip efficiency 86 % applies to both batteries (cf. section 3).
[d] Grid extension CAPEX according to Lwakatare et al. (2024, p. 14), who report 30,000 USD/km to 40,000 USD/km for SSA and adopt the lower bound. Fixed O&M is set to 0.5 % of CAPEX (own assumption), a flat annual base charge of 5,000 USD/a for the connection point is added (own assumption). Grid lifetime and connection capacity are own assumptions.
[e] Diesel genset CAPEX and fixed O&M according to Keskinis et al. (2025, p. 22). The variable cost follows from the fuel price and generator efficiency stated in section 4: at a lower heating value of 9.8 kW h per litre and $\eta_{\text{Diesel}} = 0.35$ this gives 0.380 USD/(kW h). Existing lead-acid bank and new lithium iron phosphate extension are operated as separate subsystems (no cell-level mixing).

The profile combines a broad daytime plateau, driven by institutional and commercial consumers, with a pronounced evening peak, rather than the sharp morning-and-evening double peak of purely residential SSA settlements (cf. figure 3). Seasonal variation is moderate: The monthly mean load ranges from 62 kW (May) to 85 kW (November) around an annual mean of 75 kW. Because demand-side dynamics drive both the required storage size and the dispatch behaviour, the use of an empirical on-site profile is critical for the validity of the cost optimisation. Synthetic profiles based on per-capita averages would misrepresent this institutional daytime plateau and the evening peak, and with it the cost-optimal split between PV, storage and dispatchable generation.

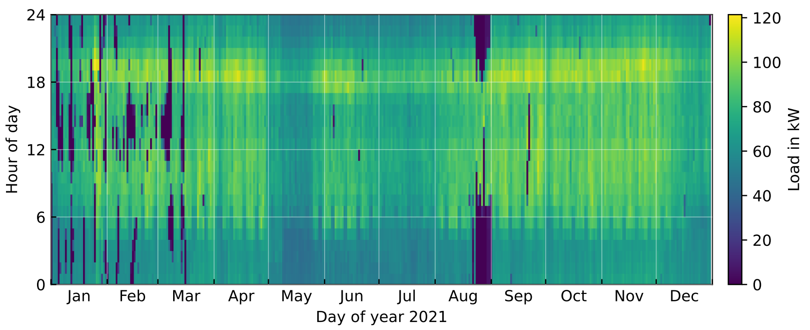

Fig. 3: Carpet plot of the hourly *Tsumkwe* load profile for the reference year 2021. The evening peak (around 18:00–21:00) averages 88 kW and reaches at most 121 kW, above the daytime plateau (roughly 08:00–17:00, 80 kW on average, driven by institutional and commercial consumers) and the nocturnal base load (around 60 kW between 01:00 and 05:00). The diurnal pattern is stable across the year. The scattered dark vertical bands – concentrated in January–March, with a sustained gap in late August – mark data gaps or supply interruptions in the underlying measurement record.

Investment and operating costs for the generation and storage assets, with their sources, are summarised in table 2; the resulting PV CAPEX (1,378 USD/kW_P) is at the optimistic end of the plausible range. The diesel fuel price is set to 1.30 USD per litre, slightly below the 1.62 USD per litre reported by GlobalPetrolPrices.com (2026). Wind generation is derived from the swept rotor area (5,064 m^2) and rated power of the LeitWind LTW80 (LeitWIND AG/SpA, 2024) with a constant power coefficient of 0.5, capped at rated power – an assumption favourable to wind and therefore conservative with respect to its rejection – and biomass CHP units follow the Re2 Energy gasifier portfolio (Re2 Energy GmbH, 2024).

5. Results

Three scenarios are compared in this section. The reference scenario reflects *Tsumkwe*'s existing infrastructure. The cost-optimal configuration allows new investment across all technologies, including diesel. The grid-extension scenario assumes the existing PV, battery and diesel assets are phased out entirely (cf. table 3).

Tab. 3: Comparison of the reference scenario, the cost-optimal configuration, and grid extension with existing assets phased out.

Parameter	Reference	Cost-optimal	Grid extension
PV, existing (in kW_P)	304	304	—
PV, new (in kW_P)	—	198	—
Battery, existing (nominal / usable, in kW h)	3,000 / 1,600	3,000 / 1,600	—
Battery, new (in kW h)	—	—	—
Diesel dispatched (in % of demand)	35.6	3.0	—
Diesel, new capacity built (in kW)	n/a	0	n/a
Grid connection	no	no	yes
Annualised system cost (in USD/a)	106,333	51,225	249,159
LCoE (in USD/(kW h))	0.168	0.081	0.394
Cost saving vs. reference (in %)	—	51.8	−134.3
Lifetime CO_2 emissions, 20 a (in t)	3,430	626	5,057
Annual CO_2 emissions (in t/a)	171.5	31.3	252.8
Specific intensity (in g/(kW h))	271	49.5	400
CO_2 reduction vs. reference (in %)	—	81.8	−47.4

5.1 Reference scenario

The reference scenario establishes what *Tsumkwe*'s existing infrastructure costs when dispatched optimally, with no new investment permitted. The existing 304 kW_P PV array and 3,000 kW h battery (1,600 kW h usable) are available at zero capital cost, being already paid for. The existing 300 kV A diesel genset is likewise available at zero capital cost, carrying only its ongoing fixed O&M and fuel cost whenever dispatched. It is modelled with an active-power limit of 300 kW, which is never binding in any scenario.

Under optimal dispatch of the existing assets alone, diesel supplies 35.6 % of annual demand, with PV and the existing battery covering the remainder. This yields an annualised cost of 106,333 USD/a, a reference LCoE of 0.168 USD/(kW h). The associated lifetime CO_2 emissions are 3,430 t CO_2 (171.5 t/a, a specific intensity of 271 g/(kW h)).

5.2 Cost-optimal configuration

Allowing new investment alongside the existing, freely dispatchable assets, the model determines that an additional 198 kW_P of PV should be installed, increasing total PV capacity to approximately 502 kW_P. No battery extension is selected, since the existing bank's usable capacity is sufficient once diesel can absorb the residual gap. Although additional diesel capacity is a genuine investment option in this scenario, the solver did not invest in further genset capacity, since the existing 300 kW genset alone comfortably covers the reduced residual role diesel plays here. Wind and biomass CHP are not selected either. Local wind speeds are low ($\bar{v}$ = 6.1 m/s), and biomass CHP's capital cost (Allington et al., 2022, p. 14) is too high relative to its output to compete with PV. Grid extension is not selected either. Offered at its own cost alongside every other option, and with the annualised line cost independent of the connection capacity actually built, the 82 km connection to *Mangetti Dune* does not enter the least-cost solution. Mehta et al. (2025, p. 6) note in addition that the existing 200 kV A extension to *Mangetti Dune*, commissioned in 2022, is already insufficient for Tsumkwe's demand, so a realistic connection would require reinforcement upstream of the line costed here – making the figure in section 5.3 a lower bound. Diesel is reduced to 18,945 kW h/a, 3.0 % of annual demand. Total PV generation, existing plus new, then exceeds annual demand by 24 %, of which 15.0 % is curtailed in the optimum.

The economic case for this expansion rests on a direct comparison of the investment against what it displaces, avoiding any need to value the pre-existing infrastructure. The new PV capacity costs 23,284 USD/a to build and maintain – capital annuity plus its own fixed O&M – and displaces 206,295 kW h/a of diesel generation relative to the reference scenario, worth 78,392 USD/a in avoided fuel at the assumed diesel price. This is more than three times the annualised cost of the investment itself, corresponding to a simple payback of approximately 3.5 a on the PV investment alone. The system-wide LCoE reported in table 3 (0.081 USD/(kW h)) follows from the same underlying costs but should be read only as a summary figure alongside this incremental result, since it still depends on how the pre-existing assets are valued (cf. section 6).

Ecologically, the cost-optimal configuration reduces lifetime CO_2 emissions by 81.8 % relative to the reference, from 3,430 t to 626 t CO_2 over 20 years (171.5 t/a to 31.3 t/a), a specific intensity of 49.5 g/(kW h) against 271 g/(kW h) for the reference. Of the residual 31.3 t/a, roughly half (16.9 t/a) is the embodied life-cycle burden of the new PV itself and only 14.4 t/a is combustion. Cost and emissions are reduced together rather than traded off against one another.

5.3 Grid extension

This scenario tests grid connection under the assumption that the existing PV array, battery bank and diesel genset are retired at end of life and not renewed, so the entire load must be served by a new 82 km medium-voltage connection to *Mangetti Dune* (grid-line CAPEX and fixed O&M cf. table 2, energy import priced at an assumed local grid tariff of 0.14 USD/(kW h)). All other new investment (PV, wind, biomass CHP, battery, diesel) is available but priced out, isolating grid as the only supply option once nothing is inherited.

The resulting annualised cost is 249,159 USD/a (LCoE 0.394 USD/(kW h)) – 134.3 % above the reference and roughly 4.9 times the cost-optimal configuration. The comparison is unfavourable on ecological grounds as well: At *Tsumkwe*'s assumed grid emission factor, full reliance on grid import without any local generation results in 5,057 t CO_2 over 20 years, 47.4 % above the reference and the highest lifetime emissions of any scenario examined. Grid extension is therefore the least favourable pathway on both criteria.

5.4 Sensitivity analysis

To assess robustness against future market developments, PV CAPEX is varied by ±20 % and the optimisation is repeated. The annualised system cost, relative to the reference, remains reduced by between 48.3 % (+20 % PV CAPEX, 181 kW_P new PV, diesel 3.9 % of demand) and 55.6 % (−20 % PV CAPEX, 206 kW_P, diesel 2.6 %). The PV-dominant configuration with a small residual diesel share is retained throughout, and neither grid extension nor new diesel capacity is selected in any variant. Battery CAPEX was varied over the same range and leaves configuration and cost unchanged to within solver tolerance: no extension is selected at any price tested, the existing bank's usable capacity already covering the diurnal shift PV requires.

The baseline adopts a discount rate of 5 %, treated as a sensitivity parameter since no single rate is prescribed for the Namibian off-grid context. Varying it between 3 % and 8 % – the upper bound matching the rate assumed by Lwakatare et al. (2024) for the same site – moves the optimised LCoE from 0.075 USD/(kW h) to 0.090 USD/(kW h), a cost reduction relative to the reference of between 55.3 % and 46.4 %.

6. Discussion

Within the assumptions adopted here, the cost-optimal and the ecologically preferable configuration coincide. A moderate PV expansion, no new storage, and a small residual diesel share reduce both cost and emissions. This capital-investment result is complemented by a zero-capital one of comparable magnitude: optimally dispatching the existing infrastructure alone, without building anything new, would already have cut diesel use by close to half relative to historical 2021 operation (cf. section 4). Investment and operational improvement are complementary levers here, not substitutes, and the latter carries no financing risk.

Three independent points of comparison support the results. First, the measured 2021 diesel share of 64 % of demand matches the 65 % reported by Kaluwa and Bekker (2025, p. 5) from an independent assessment of the same plant, confirming the input dataset. Second, and despite an entirely different tool chain (HOMER Pro rather than `oemof.solph`) and a different objective formulation, their cost-optimal model selects 180 kW of additional PV and reduces the diesel contribution to 1.77 % of annual demand, against the 198 kW_P and 3.0 % found here – a close agreement on the central recommendation. The two studies differ on storage: Kaluwa and Bekker (2025) add 1,200 kW h of lithium-ion capacity where the present model adds none, which follows directly from the different treatment of the residual gap. Here the already-paid-for genset may fill it at fuel cost alone (0.380 USD/(kW h)), which is cheaper than annualised new storage at any point in the battery price range tested (cf. section 5.4). Third, the reference LCoE reported here (0.168 USD/(kW h)) is of the same order as their N$3.53–4.45/kWh (approximately 0.19 USD/(kW h) to 0.24 USD/(kW h)).

However, several caveats should be acknowledged. The model is based on the meteorological year 2021 and a single-year load profile. The linear formulation approximates inverter and storage efficiencies as constant, neglecting load-dependent variation, and imposes no charge or discharge power limit on the battery, so the modelled dispatch can exceed the C-rate a lead-acid bank would tolerate. Capital, operating and fuel prices are held constant over the 20-year horizon, omitting inflation and energy market dynamics. The optimisation logic, mathematical formulation and constraints are technology- and site-agnostic, so the model can be transferred to other off-grid settlements in Namibia, Botswana, Zambia or beyond by replacing the input data layer (load profile, PVGIS, NASA POWER, local cost data). A site without *Tsumkwe*'s specific inherited assets would need to cost every asset from new, so its least-cost configuration cannot be read directly from the sunk-asset reference adopted here.

7. Conclusion and Recommendations

This study set out to answer whether grid extension or continued, decentralised off-grid operation is the more cost-effective path for *Tsumkwe*. Decentralised operation is preferable to grid extension under every configuration examined, from the reference scenario reflecting today's infrastructure to the cost-optimal expansion identified here. Applying the OEMOF framework with an LCoE-based objective, and allowing diesel to compete freely alongside PV, storage and grid connection as an investment option, the cost-optimal pathway is a moderate PV expansion to approximately 502 kW_P with no new storage, cutting annualised system cost roughly in half and reducing lifetime CO_2 emissions by 81.8 % relative to the reference. Diesel is not eliminated but reduced to a residual 3.0 % of demand, a genuine model output rather than an assumption, since new diesel capacity was available as an investment option and not selected.

The practical implication for Namibian authorities is that grid extension from *Mangetti Dune* should not be pursued, and the existing diesel genset should be retained for its residual dispatch role rather than phased out. Prioritising the 198 kW_P solar expansion identified here offers the most viable path to reducing *Tsumkwe*'s energy costs and emissions at once.

This study does not, however, address what happens as the existing infrastructure reaches the end of its technical lifetime – the diesel genset and original battery installation both date to 2012 (Lwakatare et al., 2024, p. 10), and the battery bank is already thermally degraded. The sunk-asset treatment adopted throughout this study is a reasonable basis for near-term decisions but will not remain valid indefinitely; a dedicated follow-up analysis, once replacement timelines become concrete, should determine which components need renewal and at what capacity. Before any new capital is committed, closing the gap between historical and optimally dispatched operation of the existing infrastructure alone offers a lower-risk, zero-capital starting point. An extended monitoring system, commissioned to validate the dispatch modelled here against actual operation, would help realise this gap and would also provide the operational data a future replacement-sizing analysis requires. This data-driven planning methodology offers rural communities in the region an alternative to fossil-fuel-based grid extension, and contributes to the Namibian National Electrification Policy target of universal household access by 2040 (Government of the Republic of Namibia, 2021).

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AI Statement

During the preparation of this work, the authors used Claude (Anthropic) in order to assist with language and formatting editing and to debug and verify the accompanying oemof.solph simulation code. After using this tool/service, the authors reviewed and edited the content as needed and take full responsibility for the content of the published article.

Nomenclature

Symbol	Description	Unit
LCoE	Levelized Cost of Electricity	USD/(kW h)
I_0	Initial investment expenditure	USD
$I_{0,n}$	Initial investment expenditure of asset n (= 0 for existing assets)	USD
A_t	Annual total cost in year t (O&M, fuel)	USD/a
$A_{n,t}$	Annual cost of asset n in year t (fixed O&M, variable cost, fuel)	USD/a
n	Asset index	—
M_t	Electricity supplied in year t	kW h
i	Real discount rate	—
P_n^{cap}	Installed capacity of asset n	kW
$P_n(t)$	Dispatched power of asset n at time t	kW
$P^{\text{ch}}(t)$	Battery charging power	kW
$P^{\text{dis}}(t)$	Battery discharging power	kW
$P^{\text{exp}}(t)$	Power exported to central grid	kW
$P^{\text{exc}}(t)$	Excess (curtailed) power slack	kW
$D(t)$	Electrical load demand at time t	kW
$E(t)$	State of charge of battery at time t	kW h
E^{min}, E^{max}	Lower / upper SoC bounds	kW h
$\eta_{\text{ch}}, \eta_{\text{dis}}$	Battery charge / discharge efficiency	—
η_{Diesel}	Average diesel-generator efficiency	—
δ	Battery self-discharge rate	1/h
T	Evaluation period: 20 a for CO_2	a
T_n	Economic lifetime of asset n (cf. table 2)	a
t	Hourly time index	—
Δt	Length of one time step	h
$\mathcal{T}$	Set of time steps (1 . . . 8760)	—
$\mathcal{N}$	Set of assets in the objective (investable and existing)	—
$\mathcal{N}^+$	Subset of supply-side flows	—
MIPGap	Relative MIP optimality gap tolerance	%
LPSP	Loss-of-Power-Supply Probability	%
$\bar{v}$	Annual mean wind speed at hub height	m/s

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