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Moumouni Guero Mohamed

Mohamed.moumouni@uddm.edu.ne

Université de Maradi

Prodjinonto Vincent

Université d'Abomey-Calavi

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Reliability-Adjusted Profitability of a Rural PV-Wind Hybrid Mini-Grid: Reconciling Dispatch Uncertainty with Discounted Cash-Flow Analysis in the Niger Sahel

Moumouni Guero Mohamed^{1,2,3*}, Prodjinonto Vincent²

¹Department of Mechanical and Energy Engineering, POLYTECH Maradi, Dan Dicko Dankoulodo University of Maradi, BP 465 Maradi, Republic of Niger

²Laboratory of Energetics and Applied Mechanics, University of Abomey-Calavi, Abomey-Calavi, Republic of Benin

³InnovaTech-Smart Energies, Consulting and Expertise Firm, Maradi, Republic of Niger

* **Correspondence:** Moumouni Guero Mohamed, Mohamed.moumouni@uddm.edu.ne

Email addresses: Moumouni Guero Mohamed, Mohamed.moumouni@uddm.edu.ne; Prodjinonto Vincent, prodjinontov@yahoo.com

ORCID: Moumouni Guero Mohamed, 0000-0002-4183-8972

Abstract

Background Rural PV-wind hybrid mini-grids are routinely assessed for profitability under an assumption of uninterrupted dispatch that a full annual simulation may not support. This study tests that assumption for a 38.5 kW photovoltaic-wind hybrid mini-grid designed for Tafaghatt, a rural village in Niger's Maradi region, by carrying two dispatch estimates of the same configuration, one built on representative days and one on a full stochastic year, through a single 15-year discounted cash-flow model. Sized against a surveyed demand of 160 kWh/day, it pairs 28.5 kWp of photovoltaics and a 10 kW turbine with 240 kWh of lithium iron phosphate storage, and delivers an estimated 64,123 kWh/year at an assumed tariff of 350 F CFA/kWh, consistent with prevailing off-grid rural tariff practice.

Results Total investment is 120,000,000 F CFA, of which only 19.3% covers generation equipment. The base case returns a levelized cost of 306 F CFA/kWh generated, a net present value of 21,586,792 F

CFA at a 10% real discount rate, an internal rate of return of 13.07% and a discounted payback in year 11. Little of this survives the quantities the study does not observe. Normalized to energy delivered rather than generated, the levelized cost rises to 336 F CFA/kWh, and to 395 F CFA/kWh under the companion study's 15.0% annual loss-of-power-supply probability, where the net present value turns negative (−16,968,806 F CFA) and the return falls to 7.42%. Repricing the battery bank at the published lithium-ion benchmark, or lowering collection to 85%, each turns it negative on its own. At constant capacity, demand growth adds nothing: the plant already sells all it generates.

Conclusions Bankability rests on three quantities the design study did not measure: storage cost, dispatch reliability and revenue collection. All three are measurable before an investment decision, and an assessment that reports the span between two dispatch readings, rather than a verdict with a caveat attached, is what a financier or regulator needs. For comparable Sahelian schemes the scope for improvement lies in the non-generation cost bundle and in a tariff calibrated against measured willingness to pay rather than cost recovery alone.

Keywords: Techno-economic analysis, Discounted cash flow, Loss-of-power-supply probability, Dispatch reliability, Hybrid PV-wind mini-grid, Rural electrification, Rural energy policy, Tariff design, Niger Sahel

Background

A rural electrification project can be technically sound and still fail. What ultimately decides its fate is whether the revenue it generates can recover the initial outlay, cover the bills that keep it running, and reward capital at a rate investors find acceptable. Stand-alone renewable hybrid mini-grids in the Sahel face this test in its sharpest form: steep upfront capital costs collide with sparse populations and modest household incomes, making rural electrification a far more delicate economic proposition than anything found in cities or on the national grid [1,2]. The stakes are considerable at continental scale too: mini-grids are now regarded as the least-cost option for connecting a large share of the roughly half a billion people who still lack electricity access worldwide, most of them in Sub-Saharan Africa, yet the sector's bankability still hinges on getting this revenue-versus-cost balance right at the level of each

individual village scheme [3]. That balance is not a purely financial question. It is struck inside a national regulatory framework that fixes how tariffs may be set, and against household incomes that determine what those tariffs can actually recover, so a profitability verdict for a Sahelian mini-grid is only meaningful once the tariff regime and the affordability constraint behind it are stated alongside the discount rate.

A fair amount of research has by now looked at how PV-wind hybrid systems perform financially in rural electrification schemes across Africa, Asia and Latin America, usually settling on the levelized cost of energy (LCOE) as the yardstick of choice. The numbers, though, swing widely depending on local resource quality, system size and how much grid-connection infrastructure gets folded into the cost base. In Mongo, Chad, a PV-wind-battery configuration comes in at 0.185 USD/kWh [4]; a PV-wind-diesel-battery setup powering a telecommunication station in northeast Algeria reaches 0.214 USD/kWh [5]; Morocco's eastern Sahara manages as little as 0.0383 USD/kWh with a PV-wind-pumped-hydro-storage configuration, helped by an already-existing hydro-storage asset that pulls the levelized cost down [6]; and a dynamically optimized PV-wind system serving an Ethiopian community lands at 0.28 USD/kWh [7]. Outside Africa the spread is just as wide: a solar-biomass microgrid in Brazil reports 0.03-0.05 USD/kWh [8], while a PV-dominated island microgrid in the Comoros sits at 0.563 USD/kWh [9]. A rural microgrid planning study in Uttarakhand, India, combining PV, wind, diesel and battery storage, arrives at a broadly similar cost structure for its chosen configuration [10]; meanwhile a multi-criteria assessment (AHP, TOPSIS, EDAS, PROMETHEE II) covering hybrid microgrids across several Asian least-developed countries finds that pushing up the PV share, provided storage backs it up, consistently drives down both the levelized cost and the environmental footprint [11]. What emerges from all of this is less a single number than a lesson: the LCOE is hostage to site-specific logistics, resource quality, and just how much of the distribution network gets counted in the bill.

The system examined here is a 38.5 kW PV-wind hybrid mini-grid earmarked for Tafaghatt village, in the Aguié department of Niger's Maradi region, sized through a deterministic least-favorable-month method [12] calibrated against a 160 kWh/day demand target (the configuration is restated in the

Methods: 28.5 kWp of photovoltaic capacity, one 10 kW wind turbine and a 240 kWh LiFePO₄ battery bank). A technically sound design, however, only answers half the question that matters to the people who have to fund it: what ultimately decides whether such a scheme gets built, and stays built, is whether it pays for itself. Five objectives structure the analysis that follows: first, building a complete investment cost breakdown covering both the generation system and its low-voltage distribution network; second, computing the levelized cost of energy and setting it against the chosen electricity tariff; third, running the discounted cash-flow method to obtain the project's net present value, internal rate of return and payback period; fourth, pressure-testing all of these indicators through a multi-parameter sensitivity analysis spanning cost, demand and reliability inputs; and fifth, reconciling this discounted cash-flow-based profitability case against a companion annual stochastic dispatch-reliability estimate for the same configuration [13]. What distinguishes the present analysis is not that dispatch is simulated, since hourly simulation is standard practice in this literature and several of the studies cited above rely on it, but that two dispatch estimates of the same configuration, one built on representative days and one on a full stochastic year, are carried through to the same discounted cash-flow model and are shown to straddle the sign change of the net present value. The question this paper puts to the field is therefore not whether a mini-grid can be simulated, but how far a profitability verdict travels when the dispatch record beneath it is replaced.

This paper is the profitability-focused installment of a three-part assessment of the Tafaghatt system, and its contribution is deliberately bounded relative to the other two. The technical sizing exercise itself, the choice of a 75%/25% PV-wind energy split, the least-favorable-month sizing method and the resulting 38.5 kW configuration, was established and validated on its own technical merits in a companion paper [12] and is treated here as a fixed input rather than re-derived. A second companion paper [13] examines the same configuration from a different angle again, reconstructing an explicit hour-by-hour representative year of 8,760 hours with stochastic day-to-day solar and wind variability and a 15% photovoltaic soiling derate, and reporting an annual renewable fraction of about 85% together with an annual loss-of-power-supply probability of 15.0% concentrated in the July-September

monsoon window. Those parameters are the whole of what the present paper borrows from it, and they are restated here so that the figure carried through the cash-flow model below can be audited without recourse to the companion text. What this paper adds on top of both is the discounted cash-flow and sensitivity framework itself: the levelized cost of energy, net present value, internal rate of return and payback indicators, the nine-scenario tariff-discount-rate grid, the capacity-constrained demand-growth and multi-parameter tornado analyses, and an explicit reconciliation of the profitability case against the stochastic dispatch findings of [13]. The three papers accordingly answer three distinct questions about the same village-scale system, whether it is correctly sized, whether it pays for itself, and whether it performs reliably once realistic year-round resource variability is taken into account, and the revenue-adjusted analysis reported below exists specifically to connect the second question to the third rather than leave them as separate, disconnected readings of the same case.

Methods

System configuration and study area

The system placed under the microscope here is a 38.5 kW PV-wind hybrid setup (28.5 kWp of photovoltaic field, a 10 kW wind turbine, a 240 kWh LiFePO₄ battery bank and two 10 kW hybrid inverters) earmarked for electrifying Tafaghatt village (13.65° N, 7.71667° E) in the Aguié department of Niger's Maradi region. This configuration was obtained through a deterministic least-favorable-month sizing exercise [12], run against the site's decadal (2012-2021) solar and wind resource record with a fixed 75%/25% PV-wind energy split, and it is sized to cover a daily demand of 160 kWh, with an estimated annual renewable electricity generation of 64,123 kWh.

The 160 kWh/day figure was established during this same design-phase field visit. The demand assessment was conducted by the InnovaTech-Smart Energies team during a two-week field survey in March 2024, covering approximately 120 households and the main community facilities, including the market, school and health center. Data were collected through household and institutional interviews, a count of planned connections, and an inventory of the main electrical appliances and their expected

daily operating hours. The individual estimates were then aggregated to obtain the total daily electricity demand of 160 kWh/day. It is treated throughout this study as the principal aggregate demand input against which the system was sized and its profitability assessed (and its profitability assessed in the subsections that follow). Several methodological limits of this survey should be stated plainly: it was conducted in a single dry-season wave (March 2024) rather than repeated across seasons; no formal margin of error or confidence interval was computed for the resulting demand estimate; no coincidence (simultaneity) factor was applied across households' simultaneous appliance use; and the ratio of the roughly 120 households surveyed to the village's total household count is not reported here. These are acknowledged gaps in the demand assessment, not resolved quantities, and a reader seeking to reproduce this study's sizing exercise would need to fill them independently. The dispatch simulation described below discusses the scope and limits of this aggregate approach relative to a fully disaggregated end-use load survey.

Cost data collection

Equipment costs (PV modules, inverters, batteries, the wind turbine, protection devices and copper busbars) were pulled together from supplier quotations gathered during the design phase. For the distribution side (low-voltage poles, cabling, household meters), we relied on itemized connection and network-extension quotes from NIGELEC, the national utility, drawn from comparable monophasic and triphase rural connections. The feasibility-study, site-preparation and labor costs, meanwhile, cover the resource assessment campaign, the civil works, and the installation of both the generation plant and the village-wide low-voltage network needed to reach individual households as well as the market, the schools and the health center. A separate capital-contingency line, the replacement-cost provision reported in Table 2, was budgeted at the design stage to cover projected spares and mid-life component replacement, inverters, charge controllers and protection gear as well as the battery bank, over the 15-year project horizon; The economic analysis framework below clarifies how this upfront budgeting line relates to the battery-replacement cash outflows tracked explicitly in the discounted cash-flow schedule.

Economic analysis framework

The profitability analysis leans on the discounted cash-flow (DCF) method, applied over a 15-year project lifetime with the base-case parameters listed in Table 1. Every monetary figure is given in F CFA, the currency in which the underlying investment and revenue data were originally compiled, with US-dollar equivalents in parentheses, converted at 573 F CFA/USD, roughly the prevailing XOF/USD rate in mid-2026 [14]. The analysis is conducted in constant mid-2026 terms: neither the tariff nor the operation-and-maintenance cost is escalated over the horizon, and the discount rate is accordingly a real rate, so that a nominal reading of these results would require inflating the cash flows and the discount rate consistently. Three further conventions bound what the indicators can mean, and are stated here rather than left implicit. The project is treated as fully equity-financed, with no debt service, taxation, depreciation allowance or working-capital requirement, so the internal rate of return reported below is a project return and not an equity return. Revenue is computed on energy delivered, with no allowance for technical losses on the low-voltage network, non-technical losses or arrears; because the collection rate is not observed at this site, it is carried instead as an explicit sensitivity parameter. And no salvage value is credited at the end of year 15, although the photovoltaic field, the wind turbine and the distribution network have service lives well beyond the horizon and the battery bank replaced in year 10 retains roughly five of its seven years of nominal service life at the end of the project horizon, worth about 0.9 million F CFA in present value. The last convention is conservative with respect to project value; the first two are not.

Table 1 Base-case parameters of the profitability study

Parameter	Value	Unit
Total installed capacity	38.5	kW
Estimated annual renewable electricity generated	64,123	kWh/year
Initial investment cost (CI)	120,000,000	F CFA

Electricity tariff (base case)	350	F CFA/kWh
Annual O&M cost (3% of CI)	3,600,000	F CFA/year
Battery replacement cost (year 10)	4,500,000	F CFA
Discount rate (base case)	10	%
Project lifetime (n)	15	years

The 350 F CFA/kWh tariff is set in line with the tariff-fixing principles established by Niger's own regulatory framework for off-grid rural electrification: Décret n°2019-406/PRN/ME (26 July 2019), which governs autonomous off-grid rural electrification projects under the national PERAN program, and Décret n°2017-796/PRN/ME (6 October 2017), which approves NIGELEC's tariff methodology and end-user tariff structure [2,15,16]. As of the most recent published regulatory diagnostic, however, Niger's decree framework establishes the principle that tariffs must reflect production costs without yet specifying a detailed, mini-grid-specific tariff-calculation methodology [17]; the 350 F CFA/kWh figure retained here therefore reflects NIGELEC's prevailing off-grid rural practice rather than a codified mini-grid tariff schedule, a documented regulatory gap that this study flags rather than resolves. The 3% O&M assumption sits comfortably within the conservative range reported in the renewable-cost literature [2]. A single battery replacement is scheduled in year 10. Lithium iron phosphate cells rated for several thousand cycles at an 80% depth of discharge would, at roughly one cycle per day, outlast the 15-year horizon on cycle count alone. The year-10 replacement adopted in this study is therefore driven by calendar ageing under sustained high-temperature operating conditions rather than by cycle count. Experimental studies have shown that elevated storage temperatures accelerate the calendar ageing of LiFePO₄ batteries, including over the 40–55 °C range investigated under controlled conditions [18]. This temperature range is used here as an ageing-stress reference and not as a measured battery-enclosure temperature at the Tafaghatt site. The ten-year replacement is consequently treated as a conservative planning assumption, and its cost is varied explicitly in the sensitivity analysis. Regarding the relationship between this replacement and Table 2's upfront replacement-cost provision (10,738,962 F CFA), two accounting conventions could in principle be used.

Approach A treats the initial investment CI as covering only generation, storage and distribution hardware, with every future replacement, the battery included, entered as an explicit, separately discounted cash outflow in the DCF schedule (Table 4) and in the LCOE numerator (Eq. 1, term $C_{repl,t}$). Approach B instead folds a lump-sum replacement reserve into CI itself, treating it as a pre-funded book provision rather than a future cash event. This study adopts Approach A throughout: Table 4's net cash flow is reduced in year 10 by the actual battery cost, and Eq. (1) discounts that same cost back to year zero as a separate term added to CI. Table 2's replacement-cost provision line is accordingly not a duplicate of that outflow; it is a broader capital-budgeting contingency, covering projected spares for inverters, charge controllers and protection equipment across the 15-year horizon, disbursed on an as-needed basis outside the scheduled battery replacement modeled explicitly in the DCF. No cost item is therefore subtracted twice between Table 2 and Table 4.

Levelized cost of energy formulation

The LCOE captures the average cost of producing a single kilowatt-hour over the project's entire lifetime: initial investment, discounted operating costs and discounted replacement costs are added together, then divided by the discounted lifetime energy production:

$$LCOE = \frac{CI + \sum_t \frac{C_{repl,t}}{(1+r)^t} + C_{O\&M} \times F_{an}}{E_{an} \times F_{an}} \quad (1)$$

where CI is the initial investment, $C_{repl,t}$ the replacement cost incurred in year t, $C_{O\&M}$ the annual operation and maintenance cost, E_{an} the annual energy production, r the discount rate and F_{an} the annuity discount factor over the project lifetime n:

$$F_{an} = \frac{1 - (1+r)^{-n}}{r} \quad (2)$$

Net present value and internal rate of return

Net present value (NPV) works by summing every year's discounted net cash flow, $CF_{net}(t)$, across the project's lifetime and then subtracting the initial investment:

$$NPV = \sum_t \frac{CF_{\text{net}}(t)}{(1+r)^t} - CI \quad (3)$$

Here $CF_{\text{net}}(t)$ is simply the annual revenue (production times tariff) minus O&M costs, with a further deduction for the battery replacement in year 10. A positive NPV means the project is creating value over and above the return capital demands. The internal rate of return (IRR), meanwhile, is whatever discount rate r^* drives the NPV exactly to zero:

$$NPV(r^*) = 0 \quad (4)$$

Since Eq. (3) behaves nonlinearly in r , we obtained the IRR by numerically solving Eq. (4) directly, root-finding on the exact discounted cash-flow series, rather than settling for the cruder two-point linear interpolation between trial discount rates, which we use here only as a rough, first-order check before refining numerically. By convention, a project counts as profitable once its IRR clears the discount rate used in the NPV calculation.

Payback period indicators

We computed two payback indicators that complement each other. The simple, non-discounted version ignores the time value of money altogether, but it is quick to compute and gives a decent order-of-magnitude read:

$$\text{Payback}_{\text{simple}} = \frac{CI}{CF_{\text{net}}} \quad (5)$$

The discounted payback period, by contrast, is simply the first year in which the cumulative discounted cash flow crosses into positive territory: in other words, the year the investment is fully recovered once present value is accounted for. It can be read straight off the year-by-year cumulative discounted cash-flow series in Table 4.

Tariff and discount-rate sensitivity design

The electricity tariff and the discount rate are, of the two, the most uncertain inputs to this whole analysis (one hostage to future tariff policy, the other to the cost of capital and country risk), so we ran a sensitivity analysis crossing three tariff scenarios (300, 350 and 400 F CFA/kWh) with three discount rates (8, 10 and 12%), nine combinations in total, recomputing the NPV and IRR for each.

Energy balance and hourly dispatch simulation

Two figures for the village's electricity needs appear side by side in this study: a surveyed average daily demand of 160 kWh, collected during the design-phase field survey, and an estimated annual renewable electricity generation of 64,123 kWh. Taken literally as a constant year-round load, 160 kWh/day would sum to 58,400 kWh/year, so the generation figure exceeds this theoretical baseline by about 9.8% (Table 7). This margin should not be read as idle overcapacity: it is the buffer that closes three gaps a single annual energy total cannot show on its own, the mismatch between when the sun and wind actually generate and when households, the market, the schools and the health center actually draw power; the round-trip losses inherent to charging and discharging the battery bank and to DC-AC inversion; and a short reserve against cloudy-day production shortfalls. Table 7 makes this distinction explicit, separating the generated-output estimate from the energy actually delivered to the load, which the shortfall-free dispatch result ties directly to the surveyed demand baseline. A fully disaggregated end-use load survey, with a per-household appliance census, a measured coincidence factor and a multi-season sampling design capable of supporting a formal margin of error, fell outside the cost-data scope of this techno-economic study, which accordingly treats the 160 kWh/day figure as its principal aggregate demand input, with the attendant reproducibility limitations noted above; the diurnal load shape used below is illustrative of typical rural West African mini-grid consumption patterns [3] and is used here to test dispatch adequacy, not to substitute for a full load census.

To test whether the 9.8% margin is in fact sufficient, rather than merely assumed to be, we built an hourly dispatch simulation and ran it over representative 24-hour days for both the dry season (October-April, average irradiance 6.05 kWh/m²/day, average wind speed 4.75 m/s) and the wet season (May-September, average irradiance 4.85 kWh/m²/day, average wind speed 4.15 m/s, including two daily cloud-transient events that cut PV output by 45-50% for an hour each, representative of Sahelian monsoon convective cloud cover). PV output was modeled from the array's rated capacity through a system derating factor of 0.92 (soiling, temperature and mismatch losses) and an inverter efficiency of 0.95; the annual generation figure of 64,123 kWh used throughout this study

is an AC figure at the inverter output, already net of both, so that the 9.8% margin over the demand baseline covers battery round-trip losses and the cloud-transient reserve only. Wind output was modeled from a Weibull-distributed wind resource (shape parameter $k \approx 1.76$) carried through the published power curve of the Aeolos-H 10 kW horizontal-axis turbine: a two-bladed, direct-drive permanent-magnet machine of 7.5 m rotor diameter, cut-in 2.5 m/s, rated 10 m/s and survival 50 m/s, at a 30 m hub height [19]. One consequence of using the manufacturer curve rather than a generic one must be stated plainly. Integrated over the site's seasonal Weibull distributions, that curve yields an annual capacity factor of 0.166, against the 0.204 adopted in the design study [12]; the corresponding wind yield is 14,514 rather than 17,870 kWh/year, which would lower total annual generation to 60,766 kWh and the margin over the demand baseline from 9.8% to 4.1%. We retain the design study's generation figure so that the three papers in this series remain mutually consistent, and carry the discrepancy explicitly, as a parameter of the tornado analysis and as a declared limitation. The battery bank, 240 kWh nominal of lithium iron phosphate at 48 V, was tracked hour by hour with a round-trip efficiency of 90%, deliberately below the 95% this chemistry typically achieves so that the dispatch check errs on the conservative side, and with a minimum state of charge fixed at 20% of nominal capacity (192 kWh usable, an 80% depth of discharge appropriate to lithium iron phosphate), never allowed to fall below this floor or exceed the nominal ceiling. The two representative-day load profiles, the hourly dispatch model and the discounted cash-flow model described in this section are available from the corresponding author on reasonable request. The adequacy metric is the loss of power supply probability,

$$LPSP = \frac{\sum_{h=1}^{24} E_{\text{unmet},h}}{\sum_{h=1}^{24} D_h} \quad (6)$$

where $E_{\text{unmet},h}$ is the hourly shortfall between demand D_h and the power actually available from PV, wind and the battery once the state-of-charge floor is respected, summed over the 24 hours of the representative day. $LPSP = 0$ means every hour of demand is served; $LPSP > 0$ flags hours in which the generation-storage combination falls short.

Extended sensitivity analysis: demand growth and multi-parameter tornado diagram

The nine-scenario grid described above varies only the tariff and the discount rate. Three further exercises broaden the picture. First, we relaxed the constant-demand assumption. Because the base case already books revenue on the plant's entire annual generation, demand growth cannot be monetized at constant installed capacity: energy delivered is capped at 64,123 kWh/year whatever the demand trajectory. The growth analysis is therefore built on the surveyed demand baseline of 58,400 kWh/year, which leaves 9.8% of headroom before the plant saturates, and delivered energy in year t is taken as the smaller of $E_{base} (1 + g)^t$ raised to the power $(t - 1)$ and E_{an} , for $g = 0, 2$ and 5% per year, with the tariff, the discount rate, the replacement schedule and the operation-and-maintenance cost held at their base-case values and the last of these deliberately not indexed to delivered energy. We report the saturation year, the cumulative unserved demand and the resulting indicators. A second variant relaxes the capacity constraint itself: generation capacity is scaled once, at the outset, by the factor needed to serve the year-15 demand with the same 9.8% margin, at the implicit capacity cost of 361.8 F CFA per annual kilowatt-hour derived from the generation-equipment line of Table 2 (23,200,000 F CFA for 64,123 kWh/year), with the operation-and-maintenance cost and the battery replacement cost scaled by the same factor. Installing the whole expansion in year 1 overstates its cost relative to a staged build-out, so this variant is a lower bound on the value of growth. Second, we built a one-at-a-time tornado diagram over nine parameters. Annual energy production and the tariff enter as a single revenue parameter, since the net present value is linear in their product and separating them yields two arithmetically identical rows. The nine parameters are revenue (+/-20%), CAPEX (+/-20%), the battery bank unit cost (the design-phase quotation against the lithium-ion industry benchmark of 209 USD/kWh reported by [3]), the discount rate (8 to 12%), the annual loss-of-power-supply probability (0 to 15%), the revenue collection rate (100 to 85%), the operation-and-maintenance rate (+/-20%), the wind capacity factor (0.204 as adopted in the design study against 0.166 obtained from the manufacturer power curve) and the battery replacement cost (+/-20%). For the CAPEX row, operation-and-maintenance cost is held at its base-case value rather than rescaled as

3% of the perturbed capital cost, so that the row isolates the effect of the initial investment without double-counting a relationship the O&M row tests independently. Demand growth is not included, because at constant capacity it produces no spread. Since the net present value is linear in revenue, capital cost and operating cost, this decomposition is exact rather than approximate; what it cannot capture is joint variation, and a full Monte Carlo treatment remains a natural extension. Third, because the battery bank unit cost proves material and rests on a single design-phase quotation, we report a dedicated scenario in which both the battery bank acquisition cost and its scheduled replacement cost in year 10 are scaled proportionally to three published lithium-ion benchmarks, while all other model inputs are held at their base-case values. This treatment preserves consistency between the initial battery investment and the replacement expenditure over the 15-year project horizon.

The three exercises are reported in the order introduced here.

Revenue adjustment for annual dispatch shortfall

Every profitability indicator obtained in the base-case analysis assumes that the mini-grid serves the full demand baseline, consistent with the shortfall-free result returned by the two representative-day dispatch check described in the Methods. A companion study reconstructing a full 8,760-hour stochastic year for the same 38.5 kW configuration finds an annual loss-of-power-supply probability of 15.0%, concentrated in the July-September monsoon window [13]. Because a two-day snapshot cannot capture multi-day monsoon shortfall runs, and because every revenue-based profitability indicator in this study is a direct function of how much of the demand baseline is actually served and billed, we test this discrepancy quantitatively here rather than leaving it as a qualitative caveat.

The adjustment is applied to the surveyed demand baseline itself, $E_{\text{served}} = E_{\text{base}} \times (1 - \text{LPSP}_{\text{annual}})$, with $E_{\text{base}} = 58,400 \text{ kWh/year}$ (Table 7) and $\text{LPSP}_{\text{annual}} = 15.0\%$ from [13], rather than to the higher, generation-based revenue proxy used as an upper bound in the results below ($E_{\text{an}} = 64,123 \text{ kWh/year}$), since the demand baseline is the more conservative and better-justified basis for a revenue estimate once shortfall is taken into account. All other base-case parameters, tariff, discount rate, O&M rate, battery replacement schedule and cost, and CAPEX, are held at their Table 1 values, and the same

discounted cash-flow model (Eqs. 3-5) is applied to the resulting net cash flow. Because the levelized cost of energy (Eq. 1) is a cost-of-generation metric normalized to the plant's annual output rather than to billed demand, it is unaffected by this adjustment and is not recomputed. To isolate the two effects at play, a switch from the generation-based revenue proxy to the demand baseline on one hand, and the annual shortfall itself on the other, results are reported for three cases: the published base case ($E_{an} = 64,123$ kWh/year, generation-based), an intermediate demand-baseline case with no shortfall ($E_{base} = 58,400$ kWh/year), and the revenue-adjusted case ($E_{served} = 49,640$ kWh/year, LPSP = 15.0%). The three bases are carried through the same cash-flow model and compared in the Results. The tornado analysis additionally reports this same shortfall as an eighth, one-at-a-time tornado parameter, isolating its effect from the revenue-proxy switch tested here.

Declaration of AI use

This manuscript was prepared with the intellectual contributions of the authors to the study design, data analysis, interpretation of results, and scientific content. Grammarly and ChatGPT were used to assist with grammatical refinement and reference formatting. During the revision phase, an AI assistant (Anthropic Claude) was also used to restructure the manuscript to conform to the journal's format and to partially verify the reference list. All model assumptions, input data, interpretations, and conclusions are those of the authors, who have verified every reported figure and assume full responsibility for the accuracy, integrity, and final content of the manuscript.

Results

Investment cost breakdown

Of the total 120,000,000 F CFA investment ($\approx 209,400$ USD), 77,600,000 F CFA, or 64.7%, falls under a single line that bundles four distinct categories: the feasibility and resource-assessment study, site preparation and civil works, installation labor, and the low-voltage distribution infrastructure itself. The share attributable to the distribution network alone is not separated in the design-phase cost file,

and this bounds what can be inferred from it: the finding Table 2 supports is that non-generation costs dominate the capital budget, not that the distribution network alone does. For reference, the World Bank mini-grid market outlook puts the distribution grid at about 14% of total mini-grid capital cost on average [3], so the 64.7% line here is either an outlier attributable to a scattered settlement pattern and landlocked logistics, or an artefact of aggregation, and the data at hand cannot separate the two. Generation equipment (PV modules, inverters, the battery bank and the wind turbine) accounts for 23,200,000 F CFA (19.3%), a capital-contingency provision for future component replacement, spares for inverters, controllers and protection gear beyond the scheduled battery replacement already tracked explicitly in the discounted cash-flow schedule (Methods), takes up 10,738,962 F CFA (8.9%), and the remaining distribution hardware, cables, protection devices, poles, meters and busbars, makes up the balance of 8,461,038 F CFA (7.1%) (Table 2, Fig. 1).

Table 2 Breakdown of the initial investment cost

Cost item	Amount (F CFA)	Share (%)
Feasibility study, site preparation & labor	77,600,000	64.7
Hybrid inverters (× 2)	9,000,000	7.5
Capital contingency for spare parts and component replacement	10,738,962	8.9
Electric poles (PBA 9 m)	5,465,084	4.6
PV modules (57 × 500 Wp)	5,700,000	4.7
LiFePO4 battery bank (240 kWh)	4,500,000	3.7
Wind turbine (10 kW)	4,000,000	3.3
Cables (3φ-1φ)	1,829,694	1.5
Circuit breakers (× 3)	660,000	0.6
Electricity meters (× 4)	302,760	0.3
Copper busbar	203,500	0.2

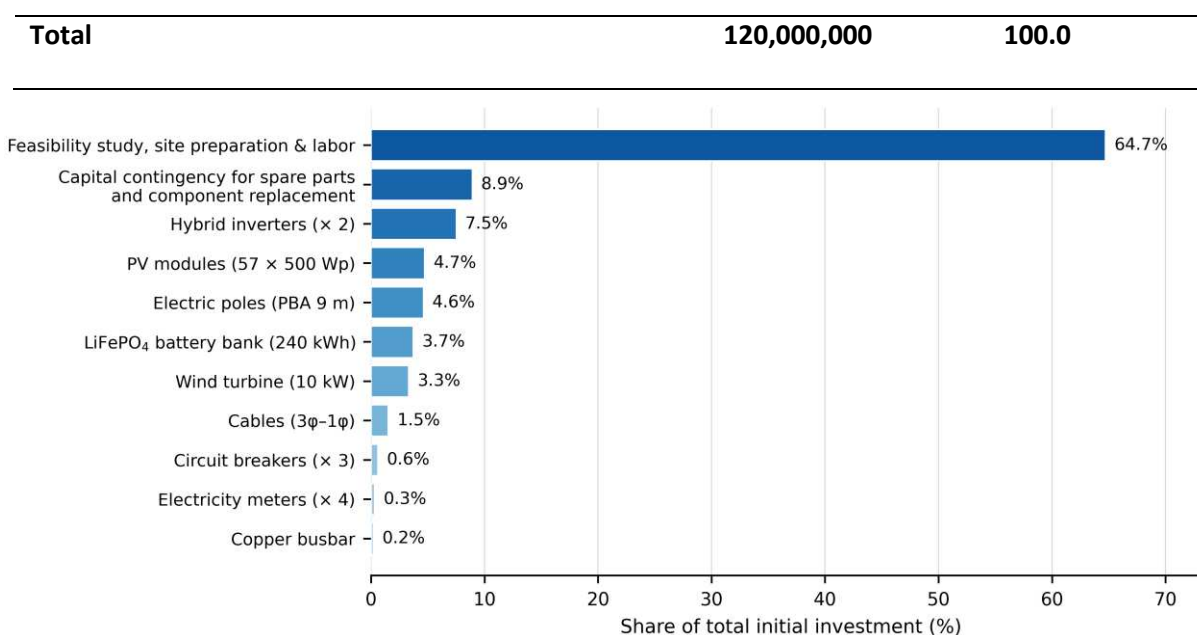


Fig. 1 Breakdown of the initial investment cost. Total investment = 120,000,000 F CFA.

Alt text: Horizontal bar chart showing each cost item as a share of the 120,000,000 F CFA initial investment, dominated by the combined feasibility study, site preparation and labor line at 64.7%.

Annual revenue and net cash flow

At the chosen tariff of 350 F CFA/kWh, the estimated annual renewable electricity generation of 64,123 kWh translates into annual revenue $R_{an} = 64,123 \times 350 = 22,443,050$ F CFA ($\approx 39,168$ USD). This treats the full generated output as billed consumption across the mini-grid's complete customer base (households, market, school and health center), a planning-stage proxy adopted in the absence of a full end-use metering study; Table 7 shows this generation figure sits 9.8% above the 58,400 kWh/year surveyed-demand baseline that the dispatch simulation confirms is served without shortfall, so revenue computed this way should be read as an upper-bound planning estimate rather than a metered billing figure. Subtract the annual O&M cost of 3,600,000 F CFA and the recurring net cash flow comes to $CF_{net} = 18,843,050$ F CFA per year ($\approx 32,885$ USD/year), dropping to 14,343,050 F CFA in year 10, when the battery replacement eats into the total (Table 3).

Table 3 Annual revenue and net cash flow in the base case

Item	Value (F CFA/year)	Value (USD/year)
Annual energy production	64,123 kWh	n/a
Gross annual revenue	22,443,050	39,168
Annual O&M cost	3,600,000	6,283
Net cash flow (regular years)	18,843,050	32,885
Net cash flow (year 10, after battery replacement)	14,343,050	25,032

Base case: tariff 350 F CFA/kWh, discount rate $r = 10\%$. USD equivalents are converted at 573 F CFA/USD.

Levelized cost of energy

Plugging $r = 10\%$ and $n = 15$ years into Eq. (2) yields an annuity factor $F_{an} = 7.606$, while the present value of the single battery replacement (year 10, Eq. 1) comes to 1,734,945 F CFA. The LCOE (Eq. 1) then works out as:

$$LCOE = \frac{120,000,000 + 1,734,945 + 3,600,000 \times 7.606}{64,123 \times 7.606} \approx 306 \text{ F CFA/kWh} \quad (7)$$

That is roughly 0.53 USD/kWh. One qualification governs how the figure may be read. The levelized cost is normalized to the plant's annual generation and is therefore a cost per kilowatt-hour generated, whereas the tariff is a price per kilowatt-hour billed; the two are directly comparable only if all generated energy is delivered and billed. Normalized instead to the energy actually served, the levelized cost rises to 336 F CFA/kWh under the surveyed demand baseline of 58,400 kWh/year and to 395 F CFA/kWh under the 15% annual loss-of-power-supply scenario examined below, the latter above the 350 F CFA/kWh tariff. The base-case margin between levelized cost and tariff is therefore an upper bound on the operating margin the project can actually earn, and both normalizations are reported side by side in Table 10 rather than the first on its own.

Net present value and cash-flow trajectory

Discount the 15-year net cash-flow series at $r = 10\%$ and sum it (Eq. 3), and the result is a net present value of $NPV = 21,586,792 \text{ F CFA}$ ($\approx 37,673 \text{ USD}$): proof that the project generates value over and above what the discount rate demands. Table 4 and Fig. 2 trace the year-by-year path of the cumulative discounted cash flow, which crosses into positive territory between years 10 and 11, while Fig. 3 sets the nominal cash flows against the discounted ones, making the single dip from the year-10 battery replacement clearly visible.

Table 4 Discounted cash-flow schedule of the project over 15 years

Year	Net CF	Discounted CF	Cumulative NPV
1	18,843,050	17,130,045	-102,869,955
2	18,843,050	15,572,769	-87,297,186
3	18,843,050	14,157,062	-73,140,124
4	18,843,050	12,870,057	-60,270,067
5	18,843,050	11,700,052	-48,570,015
6	18,843,050	10,636,410	-37,933,605
7	18,843,050	9,669,464	-28,264,141
8	18,843,050	8,790,422	-19,473,719
9	18,843,050	7,991,293	-11,482,426
10	14,343,050	5,529,867	-5,952,560
11	18,843,050	6,604,374	651,814
12	18,843,050	6,003,976	6,655,791
13	18,843,050	5,458,160	12,113,951
14	18,843,050	4,961,964	17,075,915
15	18,843,050	4,510,876	21,586,792

All values in F CFA at a discount rate $r = 10\%$. The minus sign (-) denotes a negative cumulative NPV.

Year 11 is the first year in which the cumulative NPV turns positive (discounted payback).

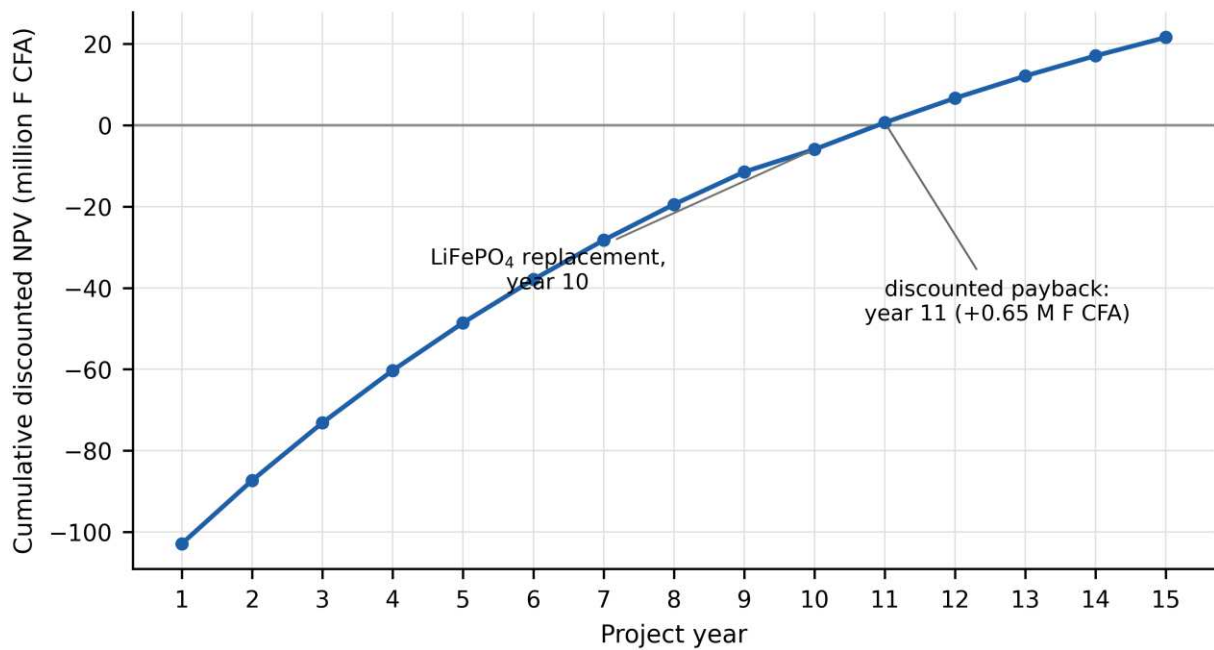


Fig. 2 Evolution of the cumulative discounted net present value. Discount rate $r = 10\%$.

Alt text: Line chart of the cumulative discounted net present value from year 1 to year 15, crossing from negative to positive between years 10 and 11.

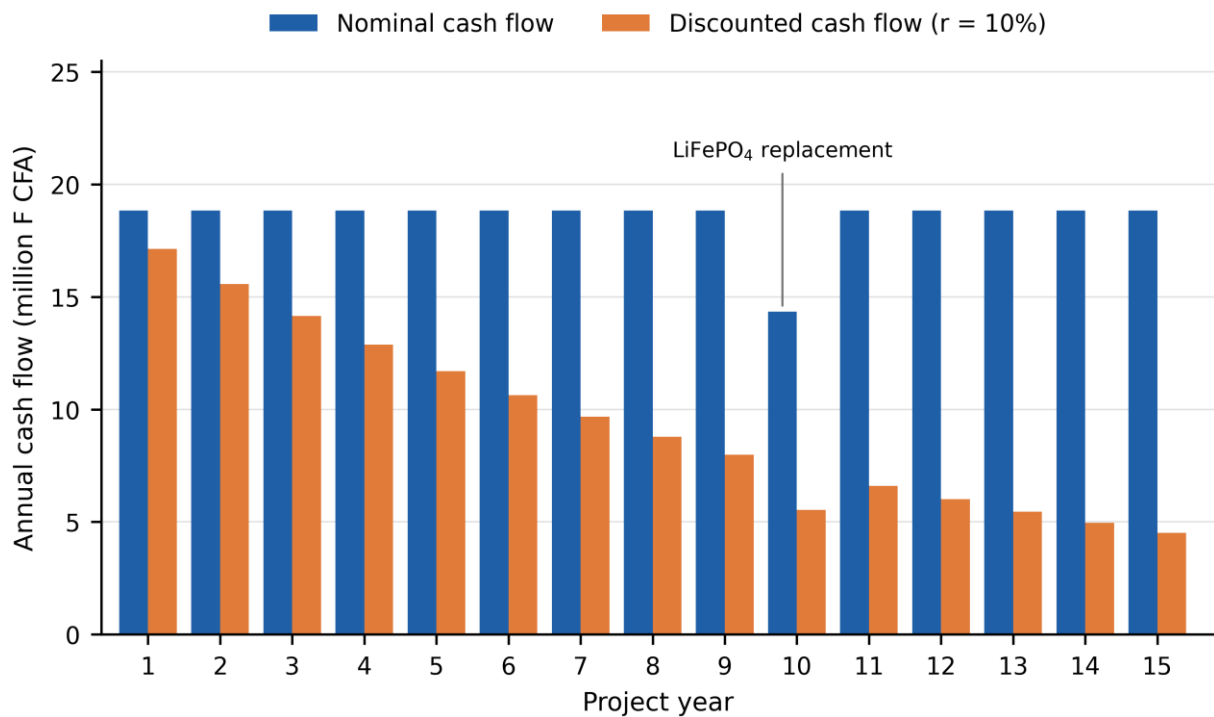


Fig. 3 Annual nominal and discounted cash flows over the 15-year project life

Alt text: Bar chart comparing nominal and discounted annual cash flows over the 15-year project life, with both series dipping in year 10 for the battery replacement.

Internal rate of return

Solving Eq. (4) numerically on the exact 15-year discounted cash-flow series yields an internal rate of return of $IRR = 13.07\%$. That clears the 10% real discount rate by nearly three points. It is a project return computed on a fully equity-financed basis, not an equity return, and it is reported here without comparison to a published band of rural mini-grid returns, since no source we were able to verify reports one on a comparable basis. Fig. 4 traces the exact $NPV(r)$ curve from which this IRR is read.

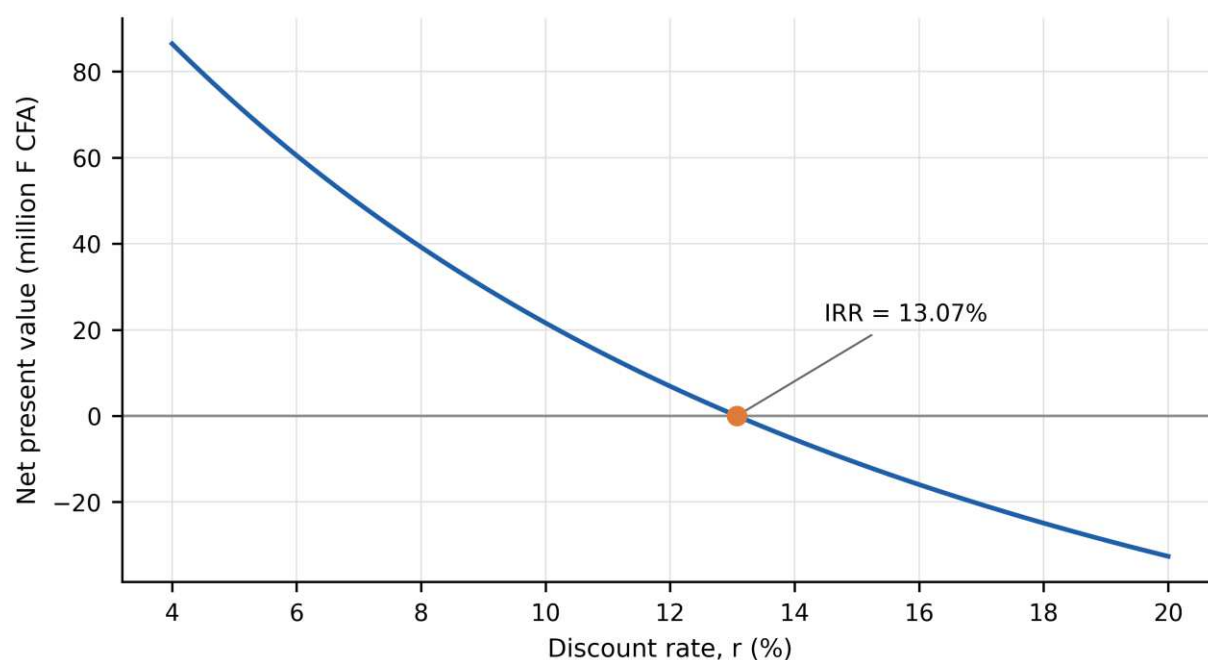


Fig. 4 Net present value as a function of the discount rate. The internal rate of return is the discount rate at which the curve crosses zero (13.07%).

Alt text: Line chart of net present value as a function of the discount rate, showing the curve crossing zero at the internal rate of return of 13.07%.

Payback period

The simple payback period (Eq. 5) works out to $CI/CF_{net} = 120,000,000/18,843,050 \approx 6.4$ years; as noted in the Methods, we report it only as a secondary, discounting-free indicator, since it ignores both the time value of money and every cash flow realized after break-even. The discounted payback, read off Table 4, is the indicator we treat as decisive: it lands in year 11, the point at which the cumulative discounted cash flow first turns positive (+77,548 F CFA). In present-value terms, then, the investment pays for itself four years before the 15-year horizon closes, leaving a comfortable window in which the project simply generates value.

Tariff and discount-rate sensitivity

Table 5 and Fig. 5 lay out the NPV and IRR for all nine tariff-discount-rate combinations. Seven of the nine keep the project profitable (NPV positive, IRR above the discount rate), including the harshest test at the base tariff itself (350 F CFA/kWh, $r = 12\%$: NPV = +6.9 M F CFA). Profitability only breaks down once the tariff drops to 300 F CFA/kWh alongside a discount rate of 10% or above (NPV of -2.8 and -14.9 million F CFA at $r = 10\%$ and 12% , respectively); at that tariff the IRR (9.59%) slips just under the 10% reference rate. As expected, the IRR itself does not move with the discount rate for a given tariff, since it is an intrinsic property of the cash-flow series, running from 9.6% at 300 F CFA/kWh, up to 13.1% at 350 F CFA/kWh, and 16.3% at 400 F CFA/kWh.

Table 5 Sensitivity of the NPV and IRR to the electricity tariff and the discount rate

Tariff (F CFA/kWh)	NPV, $r=8\%$	NPV, $r=10\%$	NPV, $r=12\%$	IRR
300	11.8	-2.8	-14.9	9.6%
350 (base case)	39.2	21.6	6.9	13.1%
400	66.6	46.0	28.7	16.3%

NPV values are given in million F CFA. The IRR depends only on the tariff, since it is an intrinsic property of the cash-flow series.

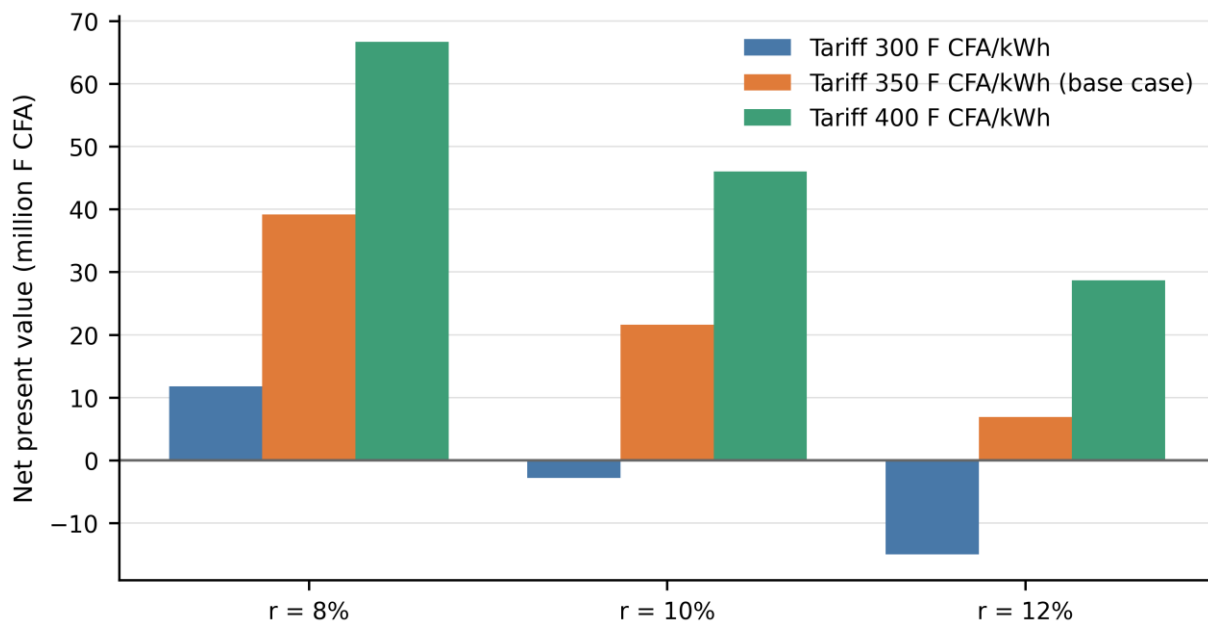


Fig. 5 Sensitivity of the NPV to the electricity tariff and the discount rate. Nine combinations of three tariffs (300, 350 and 400 F CFA/kWh) and three discount rates (8, 10 and 12%).

Alt text: Grouped bar chart of net present value across nine tariff and discount-rate combinations, showing profitability holding for all but the lowest tariff at higher discount rates.

Synthesis of profitability indicators

Table 6 Synthesis of the base-case profitability indicators of the Tafaghatt hybrid mini-grid

Indicator	Value	Verdict
Initial investment (CI)	120,000,000 F CFA ($\approx$ 209,400 USD)	Input
LCOE (per kWh generated)	306 F CFA/kWh ($\approx$ 0.53 USD/kWh)	< tariff per kWh generated ✓
NPV ($r = 10\%$, $n = 15$ yr)	21,586,792 F CFA ($\approx$ 37,673 USD)	NPV > 0 ✓
IRR	13.07%	IRR > r ✓
Simple payback	$\approx$ 6.4 years	$\ll$ 15 years ✓
Discounted payback	Year 11	4 years of residual value ✓

Base case: tariff 350 F CFA/kWh, $r = 10\%$, $n = 15$ years.

Energy balance reconciliation and dispatch simulation results

Table 7 reconciles the two demand figures used throughout this study and summarizes the hourly dispatch simulation described in the Methods. The 64,123 kWh/year production figure exceeds the

58,400 kWh/year theoretical constant-load baseline by 9.8%, and the hourly simulation confirms this margin is what it takes to serve the load without shortfall: the reference design (28.5 kWp PV, 10 kW wind, 240 kWh LiFePO4 battery) records no unmet hour on either the dry-season or the cloud-affected wet-season representative day, with the battery state of charge troughing in the pre-dawn hours of the wet-season day and staying comfortably above the 20%-of-nominal floor throughout. The margin is therefore fully accounted for: it funds the round-trip conversion losses and the short-duration cloud-transient reserve, rather than sitting idle as spare capacity.

Table 7 Energy balance reconciliation and hourly dispatch simulation results

Parameter	Value
Surveyed average daily demand	160 kWh/day
Theoretical annual demand (constant load, 365 days)	58,400 kWh/year
Estimated annual renewable electricity generated	64,123 kWh/year
Estimated conversion, dispatch-margin and reserve allowance	5,723 kWh/year (8.9% of generated output; an energy-balance share, unrelated to the capital-contingency share of the same rounded percentage in Table 2)
Estimated electricity delivered to load / billed basis (= surveyed demand, confirmed shortfall-free)	58,400 kWh/year
Coverage ratio (production / theoretical demand)	1.098 (+9.8%)
LiFePO4 nominal / usable capacity (SOCmin = 20% of nominal)	240 kWh / 192 kWh
Unmet hours, dry-season representative day	none over 24 h
Unmet hours, wet-season representative day (incl. 2 cloud transients)	none over 24 h

Demand growth under a capacity constraint

480 Table 8 reports what demand growth is actually worth to this project once the plant's own capacity is
481 respected, and the answer is not the one a growth scenario is usually expected to give. Because the
482 base case already books revenue on the entire annual generation of 64,123 kWh, growth adds exactly
483 nothing at constant installed capacity: whatever the trajectory, delivered energy cannot exceed what
484 the plant produces. Measured instead from the surveyed demand baseline of 58,400 kWh/year, which
485 leaves 9.8% of headroom, growth is worth something only until the plant saturates, and it saturates
486 quickly, in year 6 at 2% annual growth and in year 3 at 5%. The net present value rises from 6,351,434
487 F CFA under flat demand to 16,852,636 F CFA at 2% and 18,955,052 F CFA at 5%, with the internal rate
488 of return moving from 10.93% to 12.36% and 12.66%. But the whole gain is earned in the first few
489 years, and beyond saturation the growth path converts into unserved demand rather than revenue,
490 64,790 kWh cumulatively at 2% and 306,869 kWh at 5% across the horizon (Fig. 6).

491 The second panel of Table 8 relaxes the capacity constraint. Scaling generation capacity to follow the
492 year-15 demand costs 7,411,907 F CFA at 2% growth and 22,734,413 F CFA at 5%, at the implicit
493 capacity cost derived in the Methods, and once that capital and the associated operating and
494 replacement costs are carried, the net present value settles at 7,349,462 and 4,965,128 F CFA
495 respectively, with internal rates of return of 10.94% and 10.51%, barely above the discount rate. The
496 planning implication is the opposite of the conventional one: for a mini-grid sized tightly against a static
497 surveyed demand, growth is not a free source of upside. It is either foreclosed by the capacity ceiling
498 or paid for with capital that consumes most of the revenue it unlocks. Sizing decisions and growth
499 expectations therefore have to be taken together at the design stage, not sequentially.

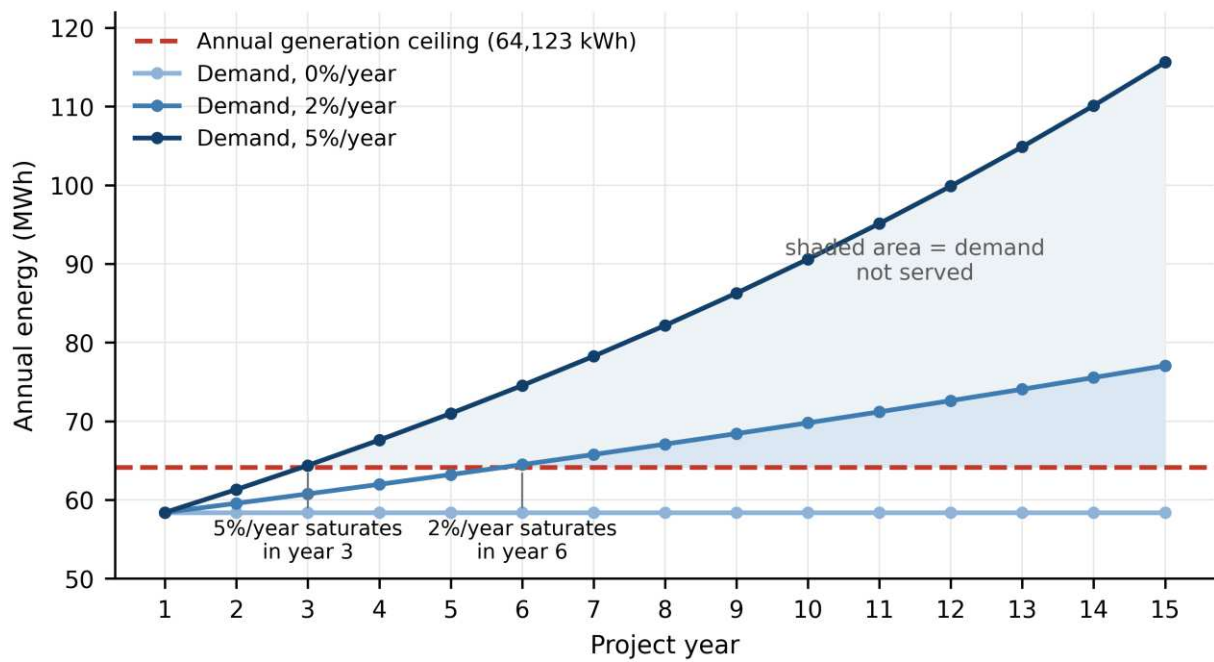


Fig. 6 Demand growth against the annual generation ceiling. The shaded areas show demand that cannot be served at constant installed capacity.

Alt text: Line chart of annual demand under 0, 2 and 5% growth against a horizontal generation ceiling of 64,123 kWh, with the gap above the ceiling shaded as unserved demand.

Table 8 Sensitivity of the NPV and IRR to the annual demand-growth rate

Scenario	Additional CAPEX (F CFA)	Saturation year	Cumulative unserved demand (kWh)	NPV (F CFA)	IRR (%)
Constant capacity, 0%/year (flat demand)	0	not reached	0	6,351,434	10.93
Constant capacity, 2%/year	0	6	64,790	16,852,636	12.36
Constant capacity, 5%/year	0	3	306,869	18,955,052	12.66

Capacity scaled to	7,411,907	–	0	7,349,462	10.94
year-15 demand,					
2%/year					
Capacity scaled to	22,734,413	–	0	4,965,128	10.51
year-15 demand,					
5%/year					

506 *Revenue basis for the constant-capacity panel is the surveyed demand baseline of 58,400 kWh/year,*
507 *capped at the annual generation of 64,123 kWh/year. Discount rate $r = 10\%$, tariff 350 F CFA/kWh. In*
508 *the capacity-scaled panel, generation capacity, operation-and-maintenance cost and battery*
509 *replacement cost are all scaled once at the outset by the factor required to serve the year-15 demand*
510 *with the same 9.8% margin.*

511 **Multi-parameter tornado diagram**

512 Table 9 ranks the nine parameters described in the Methods by the net present value spread each
513 produces. Revenue, the product of annual generation and tariff, dominates at 68,281,449 F CFA; it is
514 reported as a single parameter because the net present value is linear in that product, so that treating
515 generation and tariff separately produces two arithmetically identical rows. CAPEX follows at
516 48,000,000 F CFA. The third rank is the one that matters most for how this study should be read:
517 repricing the battery bank and its scheduled replacement cost from the design-phase quotation to the
518 published lithium-ion industry benchmark moves the net present value by 33,587,897 F CFA, more
519 than the discount rate at 32,313,734 F CFA and more than the annual dispatch shortfall and the
520 collection rate, each worth 25,605,543 F CFA. The operation-and-maintenance rate follows at
521 10,952,754 F CFA, the wind capacity factor at 8,936,763 F CFA, and the battery replacement cost, when
522 varied independently by +/-20% around its quoted value, remains last at 693,978 F CFA. Demand
523 growth does not appear at all: at constant capacity it produces no spread. Two readings follow. First,
524 the ranking is dominated by inputs the study measures rather than by inputs it assumes, since revenue

and capital cost both outweigh the discount rate, which is the parameter techno-economic studies most often foreground. Second, and less comfortably, three of the five parameters ranked immediately below CAPEX, namely the battery unit cost, the annual shortfall and the collection rate, are quantities this study does not observe directly. Together they span 84,798,984 F CFA of net present value, nearly four times the base-case value itself. The base case is therefore best understood as one point inside a wide and largely unmeasured region, rather than as a central estimate with narrow error bars.

Table 9 Tornado-diagram ranking of NPV sensitivity to nine parameters

Rank	Parameter	NPV spread (F CFA)
1	Revenue (annual generation $\times$ tariff), $\pm 20\%$	68,281,449
2	CAPEX, $\pm 20\%$	48,000,000
3	Battery bank unit cost, quotation to 209 USD/kWh benchmark	33,587,897
4	Discount rate, 8% to 12%	32,313,734
5	Annual LPSP, 0% to 15%	25,605,543
5	Revenue collection rate, 100% to 85%	25,605,543
7	O&M rate, $\pm 20\%$	10,952,754
8	Wind capacity factor, 0.204 to 0.166	8,936,763
9	Battery replacement cost, $\pm 20\%$	693,978

Discount rate $r = 10\%$, tariff 350 F CFA/kWh. Each parameter is varied one at a time with all others held at their base-case values. Demand growth is omitted because at constant installed capacity it produces no spread. Ranks 5 are tied.

Revenue-adjusted profitability under a realistic annual loss-of-power-supply scenario

Table 10 compares the base case used throughout the base-case analysis with the two alternative readings introduced in the Methods. Moving from the generation-based revenue proxy ($E_{\text{an}} = 64,123$ kWh/year) to the demand baseline alone ($E_{\text{base}} = 58,400$ kWh/year), with dispatch still assumed shortfall-free, already lowers annual revenue from 22,443,050 to 20,440,000 F CFA, compresses the

net present value at the base discount rate from 21,586,792 to 6,351,434 F CFA, and brings the internal rate of return down from 13.07% to 10.93%, only just above the 10% discount rate used throughout this study; the discounted payback shifts from year 11 to year 14. Applying the companion study's annual loss-of-power-supply probability of 15.0% on top of that baseline [13] lowers served and billed energy further, to 49,640 kWh/year, and annual revenue to 17,374,000 F CFA. Under this revenue-adjusted case, the net present value turns negative, –16,968,806 F CFA, the internal rate of return falls to 7.42%, below the discount rate, the simple payback lengthens to 8.7 years, and the discounted payback is not reached at all within the 15-year project horizon. The levelized cost of energy, 306 F CFA/kWh, is identical across all three cases, since it is computed from the plant's annual generation rather than from billed demand (Methods).

Table 10 Profitability indicators under three alternative revenue bases

Indicator	Base case (Ean = 64,123 kWh/yr)	Demand baseline, no shortfall (Ebase = 58,400 kWh/yr)	Revenue-adjusted, LPSP = 15.0% (Eserved = 49,640 kWh/yr)
Annual revenue (F CFA)	22,443,050	20,440,000	17,374,000
Net cash flow, ordinary year (F CFA)	18,843,050	16,840,000	13,774,000
Net cash flow, year 10 (F CFA)	14,343,050	12,340,000	9,274,000
Net present value at r = 10% (F CFA)	21,586,792	6,351,434	–16,968,806
Internal rate of return (%)	13.07	10.93	7.42

Simple payback	6.4	7.1	8.7
period (years)			
Discounted payback	11	14	not reached within 15
period (years)			years
Levelized cost per	306	306	306
kWh generated (F			
CFA/kWh)			
Levelized cost per	306	336	395
kWh delivered (F			
CFA/kWh)			

551 *Discount rate $r = 10\%$, tariff 350 F CFA/kWh.*

552 This does not mean the system is poorly designed. The technical adequacy demonstrated by the
553 dispatch simulation, which records no unmet hour on either representative dispatch day, and the
554 profitability case built on top of it, both hold under the assumption that year-round dispatch
555 performance matches the two representative days actually modeled. What Table 10 shows is that the
556 investment case is not robust to the alternative, and arguably more realistic, annual stochastic
557 estimate obtained independently in the companion study [13]: roughly two fifths of the profitability
558 erosion (15,235,358 of 38,555,598 F CFA) comes from replacing an upper-bound revenue proxy with
559 the surveyed demand baseline, and the remaining three fifths from the shortfall itself. Tested in
560 isolation, on the same one-at-a-time footing as the other eight tornado parameters, this shortfall alone
561 ranks fifth of nine drivers of project value, level with the revenue collection rate and below both the
562 battery bank unit cost and the discount rate: material, but not the single dominant risk when
563 considered on its own. Closing the gap between the two dispatch methodologies, rather than treating
564 either one as definitive, is accordingly a precondition for treating this assessment as a bankable
565 investment case rather than an indicative estimate. The Discussion returns to this point.

566 **Sensitivity to the battery bank cost benchmark**

The tornado diagram ranks the battery bank unit cost third of nine, above the discount rate, the annual dispatch shortfall and the revenue collection rate. Because the battery cost rests on a single design-phase quotation, Table 11 evaluates the effect of repricing both the battery bank acquisition cost and its scheduled year-10 replacement cost against three published lithium-ion benchmarks, while holding all other inputs at their base-case values. The design-phase quotation of 4,500,000 F CFA for 240 kWh of lithium iron phosphate corresponds to 32.7 USD/kWh. Against the most aggressive figure in the reference source, the 150 USD/kWh projected for mini-grid procurement [3], the net present value falls to -759,251 F CFA and the internal rate of return to 9.90%, marginally below the discount rate; against the lithium-ion industry benchmark of 209 USD/kWh the figures are -12,001,105 F CFA and 8.44%; and against the mini-grid average of 605 USD/kWh, -87,454,911 F CFA and 0.05%. The break-even tariff moves correspondingly from 306 F CFA/kWh to between 352 and 529 F CFA/kWh, that is, above the 350 F CFA/kWh tariff assumed throughout in every benchmarked case. Two conclusions follow, and they point in opposite directions. If the design-phase quotation is confirmed on delivery, the gap to published benchmarks is itself a result worth reporting, since it would indicate that regional procurement channels for lithium iron phosphate storage have moved well below what the mini-grid literature assumes, which is plausible given how sharply cell prices have fallen since those benchmarks were compiled. If it is not confirmed, the base-case profitability verdict does not hold. Nothing in the present dataset discriminates between these two readings, and confirming the quotation is accordingly the first verification any investor should require.

Table 11 Profitability under alternative battery bank cost benchmarks

Battery bank unit cost	USD/kWh	Total CAPEX (F	NPV (F CFA)	IRR	Break-even tariff
basis		CFA)		(%)	(F CFA/kWh)
Design-phase	32.7	120,000,000	21,586,792	13.07	306
quotation (Table 2)					

Mini-grid procurement	150	136,128,000	-759,251	9.90	352
projection [3]					
Lithium-ion industry	209	144,241,680	-12,001,105	8.44	375
benchmark [3]					
Mini-grid average [3]	605	198,699,600	-87,454,911	0.05	529

Only the battery bank line of Table 2 is repriced; every other input is held at its base-case value, with $r = 10\%$ and a tariff of 350 F CFA/kWh. Benchmarks are the lithium-ion figures reported by [3], whose mini-grid range is 461-762 USD/kWh. The break-even tariff is the tariff at which the net present value is zero.

Discussion

Cost structure and comparison with the literature

Tafaghatt's base-case levelized cost of 0.53 USD/kWh per kilowatt-hour generated, or 0.59 USD/kWh per kilowatt-hour actually delivered under the surveyed demand baseline, lands toward the upper end of the range reported for comparable Sahelian and African PV-wind hybrid projects: well above the 0.185 USD/kWh recorded in Mongo, Chad [4] and the 0.214 USD/kWh from the Algerian telecommunication station [5], roughly on par with the 0.563 USD/kWh reported for the Comorian island microgrid [9], and far removed from the 0.0383 USD/kWh Morocco achieved with its PV-wind-pumped-hydro configuration, a figure helped enormously by an already-existing hydro-storage asset that slashes capital costs [6]. Whatever the comparison, this is not a story about expensive generation equipment, which claims less than a fifth of total capital expenditure. Beyond that, the cost file does not support a sharper attribution than non-generation costs: the 64.7% line bundles the feasibility study, site preparation, installation labor and the distribution network, while the World Bank mini-grid market outlook puts the distribution grid alone at about 14% of total capital cost on average [3]. The distance between 14% and 64.7% is wide enough to be worth resolving empirically rather than asserting in either direction, and disaggregating that line is the single most useful improvement a follow-up costing exercise could make. What can be said is that the broader pattern of non-generation

cost dominance is well attested for small, dispersed rural mini-grids, a conclusion a rural Nigerien cost-benefit study of a comparable PV-wind-diesel configuration reached as well [1,20]. The same message comes through the wider Sub-Saharan literature: mini-grid techno-economic studies from Cameroon [21], Nigeria [22,23] and a recent multi-country review [24] converge on the finding that once the target is a scattered rural settlement rather than a compact institutional load, distribution and installation costs routinely dominate the capital budget, and a continental-scale costing exercise puts the price tag for universal household electrification across 40 Sub-Saharan African countries by 2030 at several hundred billion dollars precisely because of this distribution burden [25].

Return, sensitivity and the burden of measurement

At 13.07%, the internal rate of return clears the 10% real discount rate by three points. We deliberately refrain from benchmarking it against a published band of rural mini-grid returns, because no source we were able to verify reports one on a comparable basis; what can be said is that it is a project return computed on a fully equity-financed basis rather than an equity return, and that, as the scenarios below show, it is not robust. Comparisons with the wider literature are therefore made on levelized cost rather than on return: the Ethiopian PV-wind system at 0.28 USD/kWh [7], or the Brazilian solar-biomass microgrid at 0.03-0.05 USD/kWh, which benefits from a logistics environment far kinder than the Sahel's [8]. The revised tornado diagram qualifies the original nine-scenario reading: the tariff is an important lever on project viability, but it is not separable from annual generation, and the two together are outranked only by the capital cost. More striking is that the battery bank unit cost, the annual dispatch shortfall and the collection rate together span nearly four times the base-case net present value, which places the burden of proof on measurement rather than on modeling. A similar message turns up elsewhere in the regional literature: in a Malaysian PV-wind farm-electrification study, where the levelized cost (0.34 USD/kWh) stayed below the diesel alternative regardless of financing assumptions [26], and in a Sudanese PV-wind-hydrogen study, where adding hydrogen storage brought the levelized cost down from 0.24 to 0.20 USD/kWh independently of the discount rate used [27]. Closer to home, a Nigerien cost-optimization study of a PV-diesel-generator hybrid

system found that capping the non-renewable share at around 30% of production minimized overall generation cost, broadly consistent with what we find here, where renewables cover the entirety of production at Tafaghatt [28]. A broader look across the region points the same way: a recent review of renewable off-grid mini-grids in Sub-Saharan Africa finds that double-digit returns under realistic tariff assumptions are consistently earned by projects that pair adequate PV-battery sizing with a distribution network scaled tightly to actual demand, rather than by projects betting on any single generation technology to carry project economics on its own [29]. And because West Africa's solar and wind resources are not simply additive, their complementarity across seasons and time of day shapes how much a second-generation technology can realistically buy in reliability terms, a nuance a recent regional resource-synergy assessment brings out clearly and one that the underlying system design for Tafaghatt had to take into account [30].

Affordability and tariff design

A financially sound project is not necessarily a socially viable one, and the question that decides the difference here is whether Tafaghatt's rural households can actually afford 350 F CFA/kWh. The figure follows NIGELEC's prevailing off-grid rural practice and the tariff-setting principles laid out in Niger's PERAN decree and NIGELEC's approved tariff methodology (Methods) [2,15,16], and produces a financially sound project on paper, but Niger's regulatory framework does not yet specify a detailed, mini-grid-specific tariff-calculation methodology, a gap explicitly documented in the most recent published investment-risk diagnostic for the country's renewable energy sector [17]. In the absence of that codified methodology, this study's tariff should be read as a defensible planning assumption grounded in prevailing regulatory practice rather than as a rate set by a published mini-grid tariff order. Beyond the regulatory question, rural incomes in the Maradi region rise and fall with the rains and rain-fed agriculture, and a flat volumetric tariff could still strain the poorest households through the dry season, a pattern documented more broadly for rural Niger, where willingness to pay for electricity access tracks the agricultural calendar closely and tends to sit below urban benchmarks [31]. This points toward tiered or socially adjusted pricing, calibrated to seasonal agricultural income, as a policy

direction worth exploring for the Tafaghatt scheme and comparable Sahelian mini-grids. And the room for maneuver is narrower than it might seem: the sensitivity analysis shows profitability breaking down only once the tariff drops to 300 F CFA/kWh at discount rates of 10% or higher, which leaves little space to lower the tariff without either a capital subsidy (covering part of the distribution-network cost, the bulk of the investment) or a blended structure that cross-subsidizes low-consumption households using revenue from heavier commercial and institutional users such as the market, the lower-secondary school and the health center.

The room for maneuver can be made explicit rather than left as a recommendation. Holding total revenue at the level the base case requires, a two-block tariff must satisfy $f \cdot T_1 + (1 - f) \cdot T_2 = 350$ F CFA/kWh, where f is the share of billed energy consumed by households on a social block priced at T_1 and the balance is billed to commercial and institutional users at T_2 . Table 12 solves this constraint for plausible values. If households account for 60% of consumption, a social block at 250 F CFA/kWh, close to the level at which willingness to pay in rural Niger has been measured [31], requires 500 F CFA/kWh from the market, the lower-secondary school and the health center; a deeper social block at 200 F CFA/kWh requires 575 F CFA/kWh. Whether those upper-block prices are bearable is an empirical question this study cannot settle, and it is precisely the question that decides whether the scheme is socially viable rather than merely financially viable. What the arithmetic does establish is the shape of the trade-off: with generation costs fixed and a margin of only 41 F CFA/kWh between levelized cost and tariff in the base case, every franc removed from the household block must be recovered from a customer base that is small, seasonal and itself income-constrained. A capital subsidy covering part of the non-generation cost, where two thirds of the investment sits, relaxes the constraint considerably more effectively than any redistribution inside the tariff. That is a policy conclusion rather than an engineering one, and it is the one this analysis supports most firmly.

Table 12 Upper-block tariff required for revenue neutrality in a two-block structure

Household share of billed energy	T1 = 200	T1 = 250	T1 = 300
50%	500	450	400

60%	575	500	425
70%	700	583	467

Values are the upper-block tariff T_2 , in F CFA/kWh, required to hold total revenue at the level of a uniform 350 F CFA/kWh tariff, as a function of the household share of billed energy and of the social-block tariff T_1 (also in F CFA/kWh). The construction is revenue-neutral by definition and is intended to expose the structure of the trade-off, not to propose a specific schedule.

Currency and accounting conventions

Every USD figure in this study rests on a single exchange-rate assumption, 573 F CFA/USD, mid-2026, since the F CFA is fixed only against the euro (655.957 F CFA/EUR) and floats freely against the dollar. The dollar figures should therefore be read as rough, order-of-magnitude conversions rather than fixed contractual values, and any future foreign-currency financing would need to build in exchange-rate risk over the full 15-year horizon.

Dispatch reliability and the limits of this assessment

A caveat on this result deserves to be stated plainly. The absence of unmet hours reported above rests on a dispatch check run over two representative days, one per season, that is 48 of the year's 8,760 hours, rather than on a full year of day-to-day resource variability. It is reported here as an absence of shortfall over the simulated period, and not as an annual probability, because 48 hours cannot support a figure quoted to two decimal places. A companion study of this same 38.5 kW configuration (28.5 kWp PV, 10 kW wind, 240 kWh LiFePO₄ battery) reconstructs a full 8,760-hour representative year with stochastic day-to-day solar and wind variability and a 15% PV soiling assumption, and finds an annual loss-of-power-supply probability of 15.0%, concentrated in the July-September monsoon window [13]. The two figures are not directly comparable, for two distinct reasons. First, the companion study's 15% figure is a soiling-only derating, whereas the 8% factor used in the dispatch check here (Methods) bundles soiling together with temperature and mismatch losses rather than isolating soiling specifically, so only part of that 8% is attributable to soiling and the two percentages do not measure the same loss mechanism. Second, a two-day snapshot cannot capture the multi-day

monsoon-season shortfall run that an annual stochastic reconstruction reveals; together, these two differences account for the gap between the two results. The practical implication is that the levelized cost per kilowatt-hour generated is unaffected, since it is a cost-of-generation metric, but the levelized cost per kilowatt-hour delivered, the net present value and the internal rate of return all are. The revenue-adjusted analysis quantifies how far returns fall once the companion study's annual estimate is taken into account instead: the net present value turns negative and the internal rate of return contracts from 13.07% to 7.42%, below the discount-rate threshold. Reconciling the two dispatch methodologies, ideally within a single annual stochastic model driving both the technical and the economic assessment, remains a priority before this profitability case is treated as bankable rather than as an estimate bounded, as Table 10 shows, between a comfortably profitable reading and a loss-making one.

Limitations and next steps

Seven boundaries bound what this assessment establishes, and they are worth stating together rather than scattered through the text. The demand baseline rests on a single dry-season survey wave of roughly 120 households, without a measured coincidence factor or a stated margin of error, and every revenue figure in the paper is a linear function of that one number. The dispatch check that records no unmet hour covers 48 of the year's 8,760 hours, which is why it is reported as an absence of shortfall over the simulated period rather than as an annual probability, and why the companion study's annual estimate is carried through the cash-flow model rather than set aside. The battery bank unit cost rests on a single design-phase quotation that sits well below published lithium-ion benchmarks, and Table 11 shows what the profitability verdict becomes if those benchmarks are the better guide. The annual generation figure of 64,123 kWh is inherited from the design study; integrating the manufacturer power curve of the specified turbine over the site's wind distribution yields a capacity factor of 0.166 rather than the 0.204 that figure assumes, which would cut total generation to 60,766 kWh/year and the margin over the demand baseline from 9.8% to 4.1%. Reconciling that difference is a task for the design study rather than for this one, but it bears directly on every revenue figure reported here, and

it is carried as a tornado parameter for that reason. Revenue assumes that all delivered energy is billed and collected, with no allowance for technical losses on the low-voltage network, non-technical losses or arrears; the collection rate enters the tornado diagram as a parameter precisely because it is unobserved here. The analysis credits no salvage value at the end of year 15, although the photovoltaic field, the wind turbine and the distribution network have service lives well beyond it and the battery bank replaced in year 10 retains roughly half its service life, worth about 0.5 million F CFA in present value, or 2.5% of the base-case net present value. Finally, one boundary is a matter of framing rather than of data: this study asks whether a given hybrid mini-grid pays for itself, not whether it is the least-cost way of serving Tafaghatt. A comparison against grid extension and against a diesel or PV-diesel alternative, conducted on the same reliability-adjusted basis used here, is the natural next question for a planner and is answered by none of the three papers in this series. Of these seven, only the salvage-value omission is conservative with respect to project value.

Conclusions

Under its base-case assumptions, the 38.5 kW PV-wind hybrid mini-grid designed for Tafaghatt village is financially viable: a levelized cost of 306 F CFA/kWh generated against a 350 F CFA/kWh tariff, a net present value of 21,586,792 F CFA at a 10% real discount rate, an internal rate of return of 13.07% and a discounted payback in year 11 of a 15-year life. An hourly dispatch check over two representative days records no unmet hour in either season. Those figures are the starting point of this paper rather than its finding.

The finding is how little of that verdict survives contact with the quantities the study does not itself measure. Normalizing the levelized cost to energy delivered rather than generated raises it to 336 F CFA/kWh, and to 395 F CFA/kWh once the companion study's 15.0% annual loss-of-power-supply probability is applied, at which point it exceeds the tariff and the net present value turns negative, with the internal rate of return falling to 7.42%. Repricing the battery bank alone at any published lithium-ion benchmark, every other input unchanged, turns the net present value negative as well. So does a revenue collection rate of 85% rather than 100%. And demand growth, usually treated as the upside

that rescues a marginal mini-grid, turns out to be worth nothing at constant capacity, because the plant already sells everything it makes, and to yield barely more than the discount rate once the capacity to serve that growth is paid for. The base case is therefore not a central estimate but the most favorable corner of a wide region, and the three parameters that define that region, storage cost, dispatch reliability and revenue collection, are all measurable before an investment decision is taken. That is the practical recommendation this paper makes.

Two implications follow for comparable Sahelian schemes. First, because roughly two thirds of the capital budget sits outside the generation plant, in feasibility work, civil works, installation labor and the low-voltage network, the main influence on project economics lies in how that bundle is procured and, before that, in disaggregating it finely enough to be managed at all; the present cost file does not permit that separation, and future ones should. Second, a reliability-adjusted profitability assessment is not the same exercise as a profitability assessment with a reliability caveat attached. Carrying two dispatch estimates of the same system through the same cash-flow model shows that they straddle the sign change of the net present value, and it is that span, rather than either endpoint, that a financier or a regulator needs to see. Reconciling the two dispatch methodologies within a single annual stochastic model, disaggregating the non-generation cost line, and confirming the storage quotation are accordingly the three steps that would convert this indicative assessment into a bankable one.

List of abbreviations

CAPEX: Capital expenditure (initial investment cost)

CF_{net(t)}: Net cash flow in year t (F CFA)

C_i: Initial (total) investment cost (F CFA)

C_{o&m}: Annual operation and maintenance cost (F CFA)

C_{repl,t}: Replacement cost incurred in year t (F CFA)

DCF: Discounted cash flow

D_h: Hourly electricity demand (kWh)

786 **E_{an}**: Annual energy production (kWh/year)

787 **E_{base}**: Surveyed demand baseline (kWh/year)

788 **E_{served}**: Demand actually served under a given LPSP (kWh/year)

789 **E_{unmet,h}**: Hourly unmet (shortfall) energy (kWh)

790 **ESMAP**: Energy Sector Management Assistance Program (World Bank)

791 **F CFA**: Franc of the African Financial Community (ISO 4217 code XOF)

792 **F_{an}**: Annuity discount factor over the project lifetime

793 **g**: Annual demand-growth rate (%)

794 **IRR**: Internal rate of return (%)

795 **LCOE**: Levelized cost of energy (F CFA/kWh)

796 **LiFePO₄**: Lithium iron phosphate (battery chemistry)

797 **LPSP**: Loss of power supply probability (%)

798 **LPSP_{annual}**: Annual loss of power supply probability (%)

799 **n**: Project lifetime (years)

800 **NIGELEC**: Société Nigérienne d'Électricité (national electricity utility)

801 **NPV**: Net present value (F CFA)

802 **O&M**: Operation and maintenance

803 **PERAN**: Programme d'électrification rurale autonome hors réseaux (Niger)

804 **PV**: Photovoltaic

805 **r**: Discount rate (%)

806 **R_{an}**: Annual revenue (F CFA)

807 **SOC**: State of charge of the battery bank (%)

808 **T1, T2**: Social-block and upper-block tariff in a two-block structure (F CFA/kWh)

809 **Declarations**

810 **Ethics approval and consent to participate**

811 All methods were carried out in accordance with the relevant institutional guidelines and regulations
812 of the Université Dan Dicko Dankoulodo de Maradi (UDDM), and in accordance with the Declaration
813 of Helsinki.

814 This was a non-interventional, observational study. It collected only aggregate, indicative estimates of
815 expected household and institutional electricity demand, used solely to size the mini-grid, and no
816 individually identifiable data were retained. The survey protocol, together with the applicable ethical
817 review requirements, was submitted to the Ethics and Professional Conduct Committee of UDDM. This
818 Committee operates under the authority of the University's Rectorat and derives its mandate from
819 Decree No. 2013-201/PRN/MEMS/RS of 31 May 2013, approving the Charter of Ethics and Professional
820 Conduct of Niger's Public Universities. Article 29 of that Charter provides for a joint order of the Rectors
821 of Niger's public universities to establish, at each university, the body responsible for overseeing the
822 Charter's application, including the ethical conduct of research carried out under the University's
823 authority. The Committee determined that a study of this kind, non-interventional and anonymized,
824 did not require full ethics review: it posed no more than minimal risk, involved no biomedical or
825 otherwise sensitive procedure, and retained no identifiable personal data.

826 Consent followed the way decisions about shared infrastructure are actually made in Tafaghatt. Before
827 any household was approached, the village chief, who speaks for the community on matters of this
828 kind, gave his authorization for the survey to go ahead. Each household and institutional respondent
829 was then asked, individually and orally in the local language, whether they agreed to take part, after
830 being told what the survey was for and that they could refuse or stop at any point without
831 consequence.

832 No signed consent form was used. Literacy in writing is limited among the surveyed population, and a
833 signed document would have introduced a degree of formality out of step with local practice, more
834 likely to put people off than to protect them. The Committee reviewed this exact procedure, village-
835 level authorization followed by individual oral consent, and found it appropriate for a study of this

kind. The approach follows CIOMS Guideline 9 (2016), which allows an ethics committee to waive the requirement for a signed form in minimal-risk research, provided the investigator can attest that consent was actually sought and given. The corresponding author, who ran the field survey, provides that attestation here: oral consent was obtained from every household and institutional respondent before interview.

No experiments on human or animal subjects were conducted. Individual responses were used only to build the aggregate demand figure reported in the Methods and were not kept in identifiable form beyond that step. No personal, identifiable or sensitive data appears anywhere in this manuscript or its supporting materials.

Consent for publication

Not applicable. This manuscript does not contain any individual person's data, images or other identifiable information.

Availability of data and materials

The datasets and models supporting the conclusions of this article are available from the corresponding author on reasonable request. This applies to the two representative-day load profiles that drive the dispatch simulation, to the hourly dispatch model and the discounted cash-flow model described in the Methods, and to the aggregated meteorological series used to drive the simulation. Both models are implemented in Python 3 without third-party dependencies and reproduce every quantitative result reported in Tables 3 to 12; they can be made available to the editors and to the reviewers for verification at any point during peer review. Part of the underlying cost data, namely the equipment supplier quotations and the NIGELEC connection and network-extension quotes described in the Methods, were obtained under commercial terms from third parties and are not publicly available; aggregated, de-identified versions of these figures can be shared for verification purposes with the permission of the originating parties.

Competing interests

The authors declare that they have no competing interests in relation to the work described in this manuscript.

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Authors' contributions

Moumouni Guero Mohamed contributed to the conceptualization of the study, development of the methodology, formal analysis, investigation, and data curation. He also prepared the original manuscript and contributed to its review and revision. Prodjinonto Vincent provided supervision and validation throughout the study and contributed to the review and revision of the manuscript.

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Authors' information

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