

Research Article

Techno-economic Optimization of PV-battery-diesel Systems for Reducing Diesel Use at Eleven Off-grid Telecom Sites in Niger

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Abstract

Remote off-grid telecommunication sites in Niger depend heavily on diesel generation, leading to high fuel use, operating costs, and direct emissions. This study evaluates site-specific photovoltaic (PV)-battery-diesel retrofit configurations for eleven operational sites using measured baseline data, analytical component sizing, and hourly hybrid optimization of multiple energy resources (HOMER) Pro simulations over one year. Technical performance, generator dispatch, diesel use, lifecycle economics, sensitivity to diesel price and total capital expenditure (CAPEX), and avoided direct CO₂ emissions are assessed jointly. Rather than representing the network with one typical site, the analysis retains the measured differences in electrical demand, solar resource, storage requirement, generator operation, and investment cost across all eleven sites. Across the portfolio, annual diesel consumption decreases from 161,749.75 to 34,757 L, a 78.5% reduction, while cumulative generator runtime falls by 82.4%. Aggregate annual operating expenditure (OPEX) decreases from approximately USD 302,159 to USD 88,259, yielding savings of about USD 213,899/year. Site-level payback periods range from 1.83 to 8.12 years; all configurations have positive net present value (NPV), and their internal rates of return (IRR) range from 10.7% to 54.8%, exceeding the 8% discount rate. Positive aggregate NPV is retained under $\pm 20\%$ variations in diesel price and total CAPEX. Avoided diesel use corresponds to approximately 340.3 tCO₂/year. Overall, the results show that site-specific hybridization can substantially reduce diesel dependence while retaining generator backup and favorable investment performance.

Keywords

Battery Energy Storage, Diesel Fuel Reduction, Homer Pro, Off-Grid Telecommunications, Pv-Battery-Diesel Hybrid Systems, Techno-Economic Optimization

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1. Introduction

Remote telecommunication sites require a continuous and dependable electricity supply because even short interruptions can affect network availability and service quality. At sites without grid access, diesel generators backed by batteries remain a common solution because they are dispatchable and familiar to operators. Their drawbacks, however, are substantial: fuel must be transported and stored, maintenance is frequent, operating costs remain high, and combustion adds directly to local emissions [1].

These drawbacks are amplified when generators spend long periods at partial load. Under such conditions, fuel use does not fall in proportion to electrical output, and maintenance problems can become more frequent [2]. This has encouraged the use of PV-diesel and PV-battery-diesel configurations for remote base sites in Africa and elsewhere [3, 4].

Earlier studies showed that adding PV generation can lower the long-term energy cost of remote telecommunication systems [5, 6]. More recent work has incorporated lithium-ion batteries and multi-component optimization, showing that the outcome depends strongly on the load profile, solar resource, storage capacity, and system configuration [7, 8]. Further studies on telecommunication energy systems likewise indicate that hybrid renewable configurations can reduce reliance on conventional power sources and improve economic and environmental performance, although the magnitude of these benefits remains strongly dependent on-site conditions and system design [9-11].

The present work follows a published assessment of the same eleven ATC Niger sites. That earlier study reported electrical loads of 0.84-3.94 kW, annual diesel consumption of roughly 10,340-23,787 L per site, generator load factors of only 21-39%, and appreciable losses in generation, storage, and AC/DC conversion [12]. Those field observations define the baseline against which the proposed retrofit is evaluated here.

Niger has favorable solar conditions. Site-specific daily global horizontal irradiation ranges from approximately 3.29 to 7.39 kWh/m²/day, consistent with the country's high solar potential reported in previous assessments [13, 14].

Component assumptions also matter over the project lifetime. Lithium-ion batteries are sensitive to cycling intensity

and depth of discharge (DoD) [15, 16]. PV derating and storage efficiency directly affect energy yield and sizing [14-16]. HOMER-based studies commonly account for unmodeled field losses through aggregate derating factors [20].

In practice, diesel displacement in a hybrid telecommunication power system depends on how site load, PV yield, storage capacity, and generator dispatch interact, not on PV capacity alone. The practical question is whether a site-specific PV-battery-diesel retrofit can reduce diesel use well beyond the 35% benchmark while retaining generator backup and acceptable investment performance. Unlike an analysis based on a single representative site, the present approach preserves the measured differences in load, solar production, diesel dependence, storage requirement, and investment cost across all eleven operating sites.

The analysis therefore combines technical sizing and hourly dispatch with lifecycle economics and direct operational emissions. This makes it possible to examine the portfolio as a whole while also showing how technical performance, diesel displacement, operating costs, investment indicators, sensitivity to diesel price and CAPEX, and direct CO₂ reductions differ from one site to another.

2. Materials and Methods

2.1. Study Area and Baseline Energy Architecture

The study covers eleven off-grid telecommunication sites in the Agadez, Maradi, Tahoua, and Tillabéri regions of Niger. The same sites were characterized in a previously published baseline assessment [12]. The site characteristics and operating data reported there are reused here solely to define the pre-retrofit reference case for the hybrid-system analysis. The sites are Tafadek, Tchintaborak, Inabangaret, Guidan Douchi, Dafaoua, Sabon Guida, Bangoutaweye, Borgo, Danga & Sewan, Dingazi Banda, and Fandou Mayaki. Figure 1 shows their geographical distribution, and Table 1 reproduces the corresponding coordinates. The existing installations combine diesel generators, a nominal 48-V DC battery bank, AC/DC rectifiers, an energy bay, and the telecommunications load.

Table 1. Geographical coordinates of the eleven investigated telecommunication sites.

Region	Site	Latitude (°N)	Longitude (°E)
Agadez	Tafadek	17.38519	7.957051
Agadez	Tchintaborak	15.67674	7.392430
Agadez	Inabangaret	17.90276	6.050560
Maradi	Guidan Douchi	13.30700	7.691750

Region	Site	Latitude (°N)	Longitude (°E)
Tahoua	Dafaoua	14.13550	5.061500
Tahoua	Sabon Guida	13.92920	5.904000
Tillabéri	Bangoutaweye	14.12347	1.844806
Tillabéri	Borgo	13.66917	3.033389
Tillabéri	Danga & Sewan	14.49458	1.904250
Tillabéri	Dingazi Banda	14.18142	2.551000
Tillabéri	Fandou Mayak	13.89056	2.896111

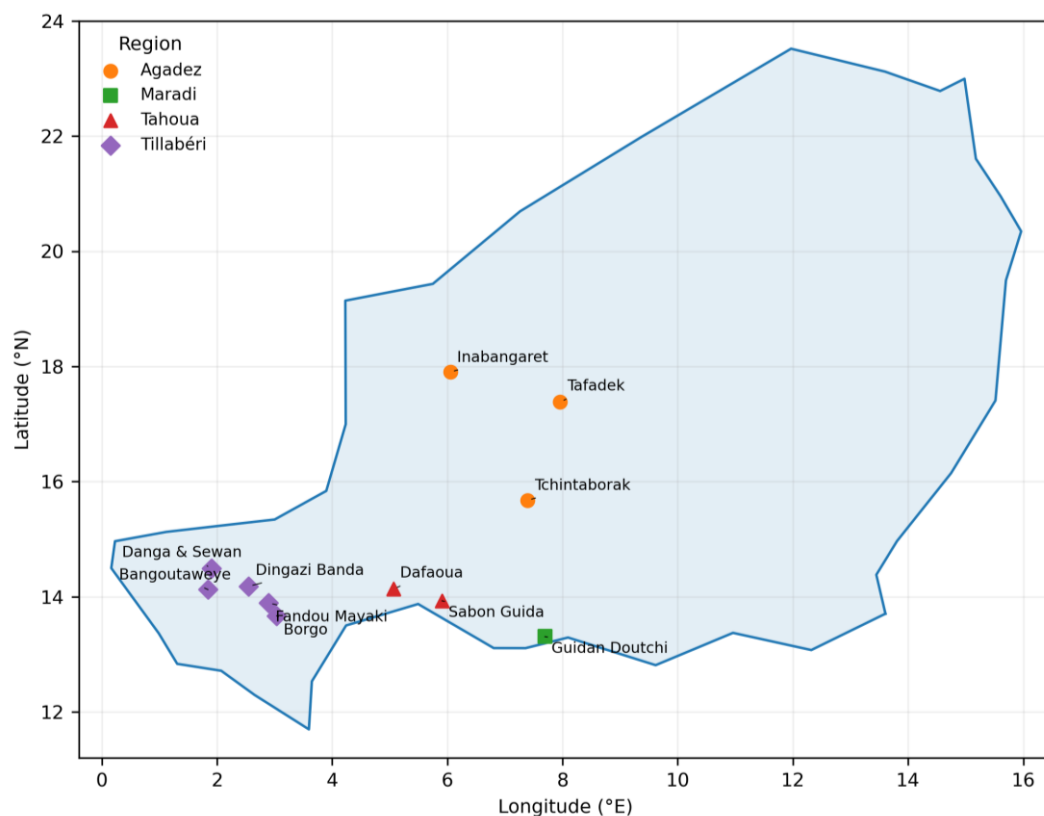


Figure 1. Location of the eleven investigated off-grid telecommunication sites in Niger. Site coordinates are those reported in Table 1.

The installed generator sets are rated at either 20 or 22 kVA. Each site uses 24 series-connected 2-V battery cells, giving a nominal 48-V DC bus, with existing lead-acid capacities of 600 or 800 Ah. Baseline electrical loads were derived from DC voltage and current records acquired by the Galooli remote monitoring system in August 2025. Mean power was de-

rived from these records, and daily energy demand was calculated for continuous 24-h operation. These equipment characteristics and operating data are retained as the pre-retrofit baseline; the retrofit analysis does not re-estimate them. Table 2 summarizes load, daily energy demand, generator runtime, and annual diesel consumption.

Table 2. Baseline electrical load, daily energy demand, generator runtime, and annual diesel consumption.

Site	Load (kW)	Daily energy demand (kWh/day)	Baseline generator runtime (h/day)	Baseline diesel consumption (L/year)
Tafadek	3.84	92.16	13.40	13,008.60

Site	Load (kW)	Daily energy demand (kWh/day)	Baseline generator runtime (h/day)	Baseline diesel consumption (L/year)
Tchintaborak	2.83	67.92	11.33	10,340.45
Inabangaret	2.26	54.24	13.15	12,001.20
Guidan Doutchi	1.55	37.20	14.40	10,512.00
Dafaoua	3.94	94.56	18.78	17,136.75
Sabon Guida	2.60	62.40	17.00	19,607.80
Bangoutaweye	2.40	57.60	23.71	13,585.30
Borgo	2.08	49.92	19.57	23,787.05
Danga & Se-wan	2.76	66.24	21.33	16,662.25
Dingazi Banda	0.84	20.16	15.75	10,347.75
Fandou Ma-yaki	3.04	72.96	13.71	14,760.60

2.2. Baseline Diesel Consumption

For each site, daily diesel consumption was estimated from the measured generator operating time and the corresponding hourly fuel-consumption rate:

$$C_d = C_h \times T_g \quad (1)$$

where C_d is daily diesel consumption (L/day), C_h is the generator fuel-consumption rate (L/h), and T_g is generator runtime (h/day). Annual fuel use was then obtained from:

$$C_a = C_d \times N_d \quad (2)$$

where C_a is annual diesel consumption (L/year) and N_d is the number of operating days in the year. A diesel price of USD 1.30/L (XOF 734/L) was used in the economic analysis. This price includes transport and associated services under the ATC Niger supply arrangement. A site-specific hourly fuel-consumption rate was used for each generator; no single portfolio-wide rate was imposed.

2.3. Hybrid-System Design and Sizing

2.3.1. Proposed PV-Battery-Diesel Architecture

Figure 2 illustrates the proposed retrofit architecture and its renewable and backup power-flow paths.

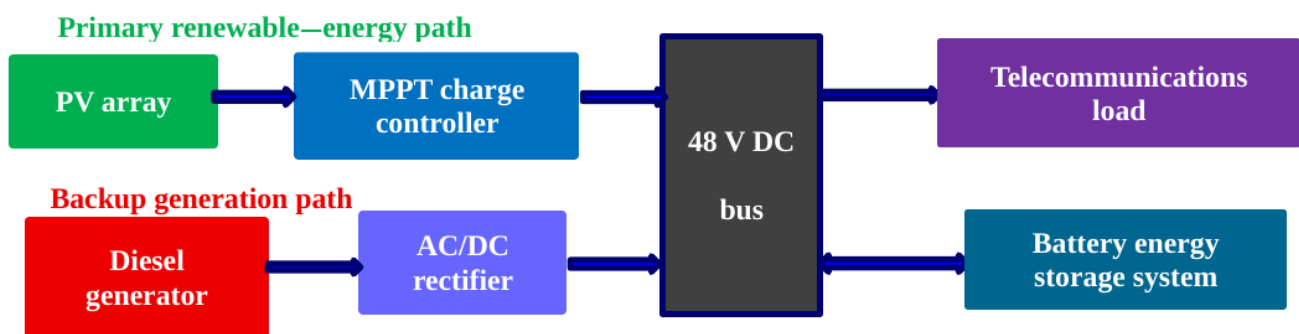


Figure 2. Proposed PV-battery-diesel energy architecture for the investigated telecommunication sites.

The system combines a PV array, lithium-ion battery storage, MPPT charge controllers, a 48-V DC energy bay, high-efficiency rectifiers, and the existing diesel generator. Available PV power supplies the load first; surplus production charges the battery, which covers subsequent shortfalls. The diesel generator remains available for periods when PV generation and stored energy are insufficient.

The PV array feeds the 48-V DC bus through dedicated MPPT charge controllers, whereas the diesel generator is connected through the AC/DC rectifier stage. The selection and sizing of the main components are described below.

2.3.2. PV Sizing

Initial PV sizing targeted a contribution equal to 35% of the daily electrical demand at each site, corresponding to the minimum diesel-reduction benchmark established for the retrofit assessment. The target daily PV energy was written as:

$$E_{PV} = 0.35E_j \quad (3)$$

where E_{PV} is the target daily PV production (kWh/day) and E_j is the site daily energy demand (kWh/day). The corresponding peak PV capacity was estimated from:

$$P_{PV} = \frac{E_{PV}}{GHI \times \eta_{sys}} \quad (4)$$

where PPV is the required PV capacity (kWp), GHI is the site-specific daily global horizontal irradiation (kWh/m²/day), and η_{sys} is the preliminary overall derating factor. A value of 0.75 was used at this sizing stage to account for aggregate field losses [17]. The calculated capacities were then adjusted to practical commercial configurations. The resulting component sizes are reported in Table 3. Commercial configurations used 425-Wp monocrystalline modules: 18 modules (7.65 kWp, reported as 7.7 kWp) at ten sites and 27 modules (11.475 kWp, reported as 11.5 kWp) at Dafaoua.

2.3.3. MPPT Charge-Controller Selection and Sizing

Eltak Flatpack2 48/3200 HE Solar controllers (Part No. 241119.650) were selected to interface the PV arrays with the 48-V DC bus in accordance with ATC technical requirements. Each unit is rated at 3.2 kW, includes maximum power point tracking, and was represented with a peak conversion efficiency of about 97%.

Two 3.2-kW controllers were assigned to each 7.65-kWp array, providing 6.4 kW of rated MPPT output. Dafaoua uses three controllers, providing 9.6 kW for its 11.475-kWp array. The resulting PV-to-controller power ratio is approximately 1.20 in both configurations; this modest DC oversizing improves controller utilization below peak irradiance while allowing limited peak-power clipping.

2.3.4. Battery Sizing

Lithium-ion storage was selected because it combines high round-trip efficiency with good suitability for repeated cycling in renewable-energy applications [18-19]. The required storage capacity was estimated as:

$$C_{Bat} = \frac{E_{stock}}{DoD \times \eta_{Bat}} \quad (5)$$

The number of commercial battery units was then obtained from:

$$N_{Bat} = \frac{C_{Bat}}{C_{unit}} \quad (6)$$

where E_{Stock} is the required stored energy, DoD is the allowable depth of discharge, η_{Bat} is battery efficiency, and C_{unit} is the nominal energy of one battery unit. Preliminary sizing assumed a DoD of 75% and a round-trip efficiency of 95%. Depending on the site, the modeled storage capacity ranged from 24 to 48 kWh. At the preliminary sizing stage, the energy to be stored was set equal to the target daily PV energy in Equation (3). A nominal 12-kWh commercial battery unit was used, and the calculated number of units was rounded up to the next integer.

For annual simulation, a more conservative operational DoD of 65% was used. Keeping the sizing and operating DoD separate limits routine battery utilization during dispatch and reflects the well-established effect of deeper cycling on lithium-ion aging [15, 16, 21].

2.3.5. Energy-Bay Selection

The selected energy bay was a Delta ODPS 2900B-48-6 telecom DC power system. It operates on a nominal 48-V DC bus and provides 16.2 kW of rated output, which is sufficient for the telecommunications load, battery charging, and integration of the PV and diesel subsystems.

AC/DC conversion is provided by Delta DPR 2900B-48 rectifier modules. Each module is rated at 2.9 kW and has a manufacturer-reported peak efficiency of approximately 96.4% [22]. For the HOMER Pro simulations, this stage was represented by a rounded conversion efficiency of 97%.

2.3.6. Diesel Generator Configuration

The existing 20-22 kVA diesel generator sets were retained rather than replaced or resized. At a power factor of 0.8, these ratings correspond to about 16-17.6 kW of active power. In the hybrid configuration, the generator is no longer the primary source; it is called only when the combined PV and battery supply cannot meet the telecommunications demand.

HOMER Pro was configured with a minimum generator loading of 58%, following ATC technical recommendations. This setting was intended to reduce the prolonged low-load

operation observed in the baseline systems, where generator load factors were only 21-39% [12]. Such operation is also associated with poorer fuel efficiency and greater maintenance concerns [2].

Table 3 brings together the component sizes obtained from the preceding design steps; these configurations were then used as inputs to the HOMER Pro simulations.

Table 3. Site-specific component configurations used as inputs to the HOMER Pro simulations.

Site	PV array (kWp)	MPPT output (kW)	Battery storage (kWh)	Energy-bay output (kW)
Tafadek	7.7	6.4	48	16.2
Tchintaborak	7.7	6.4	36	16.2
Inabangaret	7.7	6.4	36	16.2
Guidan Douthi	7.7	6.4	24	16.2
Dafaoua	11.5	9.6	48	16.2
Sabon Guida	7.7	6.4	36	16.2
Bangoutaweye	7.7	6.4	36	16.2
Borgo	7.7	6.4	24	16.2
Danga & Sewan	7.7	6.4	36	16.2
Dingazi Banda	7.7	6.4	24	16.2
Fandou Mayaki	7.7	6.4	36	16.2

2.4. Simulation and Performance Assessment

2.4.1. HOMER Pro Model

Figure 3 shows the component topology used in the HOMER Pro model.

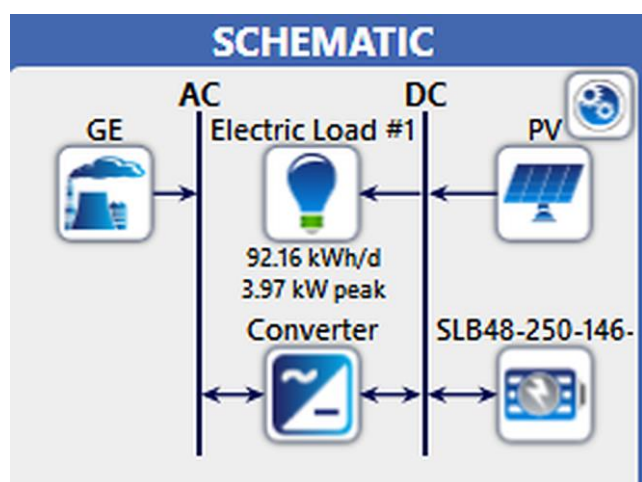


Figure 3. Representative HOMER Pro schematic of the simulated PV-battery-diesel system for the Tafadek site.

The HOMER Pro model included the PV array, battery storage, existing diesel generator, power-conversion stage, and continuous telecommunications load. Figure 3 presents the Tafadek configuration as an example; the same model structure was used for the other sites, with their respective load and component values from Tables 2 and 3 [23].

The eleven sites were evaluated using the same simulation procedure to enable direct comparison. For each site, the measured load and baseline generator data in Table 2, the component sizes obtained from the analytical sizing in Table 3, and the local solar-resource profile were entered into HOMER Pro. The model was run at hourly resolution for one year. Annual PV production, generator runtime, diesel consumption, and battery operation were then used in the economic and environmental assessments. Using identical model settings across sites while retaining site-specific load, solar resource, and component sizing ensured that differences in performance reflected site conditions rather than methodological differences.

Site-specific solar-resource profiles corresponding to the coordinates in Table 1 were used in the annual simulations. A PV derating factor of 0.80 represented the combined effects of temperature, soiling, wiring, and mismatch because temperature was not modeled as a separate variable, consistent with HOMER Pro practice and previous HOMER-based PV studies [20, 23]. Battery round-trip efficiency was set to 95% [18-19]. Operational DoD was set to 65%, minimum generator loading to 58%, and AC/DC conversion efficiency to 97%.

The annual PV-to-load energy ratio was calculated as:

$$R_{PV/load} = \frac{E_{PV,annual}}{E_{load,annual}} \times 100 \quad (7)$$

where $E_{PV,annual}$ is annual simulated PV production (kWh/year) and $E_{load,annual}$ is annual site demand (kWh/year). The ratio is an annual energy-balance indicator, not the renewable fraction or the share of load supplied directly by PV. It can therefore exceed 100% when annual PV production is greater than annual electricity demand.

The annual diesel-fuel reduction was calculated as:

$$R_{diesel} (\%) = \left(\frac{C_{baseline} - C_{optimise}}{C_{baseline}} \right) \times 100 \quad (8)$$

where $C_{baseline}$ and $C_{optimized}$ are the annual diesel consumptions before and after the retrofit, respectively.

2.4.2. Economic Model

Economic performance was evaluated using capital expenditure (CAPEX), operating expenditure (OPEX), annual operating-cost savings, simple payback period, net present value (NPV), internal rate of return (IRR), and a derived LCOE proxy. In both cases, OPEX comprised annual diesel-fuel and maintenance costs based on the site-specific cost schedule used in the project model. For consistency with the present retrofit analysis, baseline OPEX was recalculated using the diesel price, exchange rate, and maintenance-cost assumptions adopted here. The resulting monetary values therefore differ slightly from those in the earlier baseline paper, while the underlying operating data remain unchanged.

All values originally reported in West African CFA francs (XOF) were converted to US dollars (USD) using the average USD/XOF exchange rate for August 2025, the period in which the field data were collected. The exchange rate used throughout the analysis was USD 1 = XOF 563.06. The currency conversion changes only the reported monetary values; dimensionless indicators such as IRR and time-based metrics such as payback are unaffected.

$$C_{fuel} = C_{gen} \times C_u \quad (9)$$

where C_{gen} is annual diesel consumption (L/year) and C_u is the unit diesel price (USD/L). Annual cash flow was taken as the reduction in OPEX between the baseline and hybrid cases:

$$CF = OPEX_{before} - OPEX_{after} \quad (10)$$

Total CAPEX, expressed as an equivalent present capital cost, was calculated from the initial equipment cost, installation cost, and present value of replacement expenditure over the project lifetime. Equipment costs cover the PV modules, MPPT charge controllers, mounting structures and junction

boxes, lithium-ion batteries, the energy bay and rectifiers, and other balance-of-system components. Thus:

$$CAPEX_{total} = CAPEX_{equip} + CAPEX_{inst} + CAPEX_{repl} \quad (11)$$

The equipment acquisition cost is given by:

$$CAPEX_{equip} = C_{PV} + C_{MPPT} + C_{ST} + C_{BAT} + C_{EB} + C_{BOS} \quad (12)$$

where C_{PV} , C_{MPPT} , C_{ST} , C_{BAT} , C_{EB} , and C_{BOS} denote the costs of the PV modules, MPPT controllers, solar structures and junction boxes, lithium-ion batteries, energy-bay/rectifier equipment, and other balance-of-system components, respectively.

Installation costs included the PV array, battery system, and energy-bay/rectifier installation and were calculated as:

$$CAPEX_{inst} = C_{PV,inst} + C_{EB,inst} + C_{BAT,inst} \quad (13)$$

Replacement CAPEX accounts for components whose service life is shorter than the assumed project lifetime and is discounted to present value:

$$CAPEX_{repl} = \sum_{j=1}^m \frac{C_{repl,j}}{(1+r)^{t_j}} \quad (14)$$

where $C_{repl,j}$ is the replacement cost of component j , t_j is its replacement year, and r is the discount rate.

Under the equivalent-present-cost convention, the simple payback indicator was calculated as:

$$Payback = \frac{CAPEX_{total}}{CF} \quad (15)$$

The discounted analysis used an 8% discount rate and a project lifetime of 20 years. Annual operating-cost savings were treated as constant real cash flow; taxes, financing, general inflation, and residual value were not modeled:

$$NPV = -CAPEX_{total} + CF \left[\frac{1 - (1+r)^{-N}}{r} \right] \quad (16)$$

The reported IRR was obtained as the rate for which NPV becomes zero under the same equivalent-present-cost convention:

$$0 = -CAPEX_{total} + CF \left[\frac{1 - (1+IRR)^{-N}}{IRR} \right] \quad (17)$$

A configuration was considered economically attractive

when NPV was positive and IRR exceeded the assumed 8% discount rate.

For the comparative levelized-cost calculation, the capital recovery factor was first determined from:

$$CRF = \frac{r \times (1+r)^N}{(1+r)^N - 1} \quad (18)$$

The simplified levelized-cost indicator was then calculated as:

$$LCOE_{\text{proxy}} = \frac{CRF \times CAPEX_{\text{total}} + OPEX_{\text{hybrid}}}{E_{\text{load,annual}}} \quad (19)$$

where CRF is the capital recovery factor, $CAPEX_{\text{total}}$ is the total investment cost, $OPEX_{\text{hybrid}}$ is annual operating expenditure after optimization, and $E_{\text{load,annual}}$ is annual electricity demand. This value is used only for comparison among sites and is not presented as a direct lifecycle LCOE output from HOMER Pro.

2.4.3. Environmental Performance Assessment

Direct CO₂ savings were estimated from the reduction in annual diesel use following the fuel-based emission-factor approach described in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories [24]. The avoided emissions

were calculated as:

$$\Delta CO_2 = \frac{(C_{\text{baseline}} - C_{\text{optimized}}) \times EF_{CO_2}}{1000} \quad (20)$$

where ΔCO_2 is the avoided annual CO₂ emission (tCO₂/year) and EF_{CO_2} is the diesel emission factor, taken as 2.68 kg CO₂/L.

2.5. Energy Management Strategy for the Optimized Systems

The operating logic used after optimization gives priority to PV generation and uses the battery as the short-term energy buffer. When PV output is below the load, the battery supplies the deficit as long as V_{bat} remains above 48.5 V. Reaching 48.5 V starts the diesel generator, which normally stops once battery voltage rises to 57 V during charging. Between 04: 00 and 09: 00, the stop threshold is reduced to 53 V so that battery capacity remains available for the expected morning PV production. If the generator fails, the battery continues to feed the telecommunications equipment; non-priority loads are shed at 46 V and the battery is isolated at 43.5 V.

This dispatch logic makes the generator a backup source rather than the default supply. The 58% minimum-loading condition applied separately in HOMER Pro is intended to avoid inefficient low-load generator operation during simulated dispatch. The operating sequence is summarized in Table 4.

Table 4. Operating sequences of the energy-management strategy.

Operating condition	Energy-management sequence	Generator status
PV production $\geq$ load	PV supplies the load; surplus PV charges the battery.	OFF
PV production < load and $V_{\text{bat}} > 48.5$ V	PV + battery supply the load; the battery covers the power deficit.	OFF
$V_{\text{bat}} \leq 48.5$ V	Diesel generator starts; generator + PV supply the load and the battery is re-charged.	ON
$V_{\text{bat}} \geq 57$ V	Normal charging cycle completed; diesel generator stops.	OFF
04: 00-09: 00 and $V_{\text{bat}} \leq 48.5$ V	Generator starts but is stopped at 53 V to preserve battery charging capacity for the forthcoming solar period.	ON $\rightarrow$ OFF
Generator failure	Battery supplies the active load; non-priority loads are shed at 46 V and the battery is isolated at 43.5 V.	FAILED / PROTECTED

3. Results

3.1. Technical Performance of the Optimized Systems

Across the eleven sites, annual PV production ranged from 13,877 to 22,372 kWh.

At nine sites, annual PV production remained below annual demand; Guidan Douchi and Dingazi Banda were the two exceptions. Table 5 gives the numerical results together with generator runtime and annual diesel consumption.

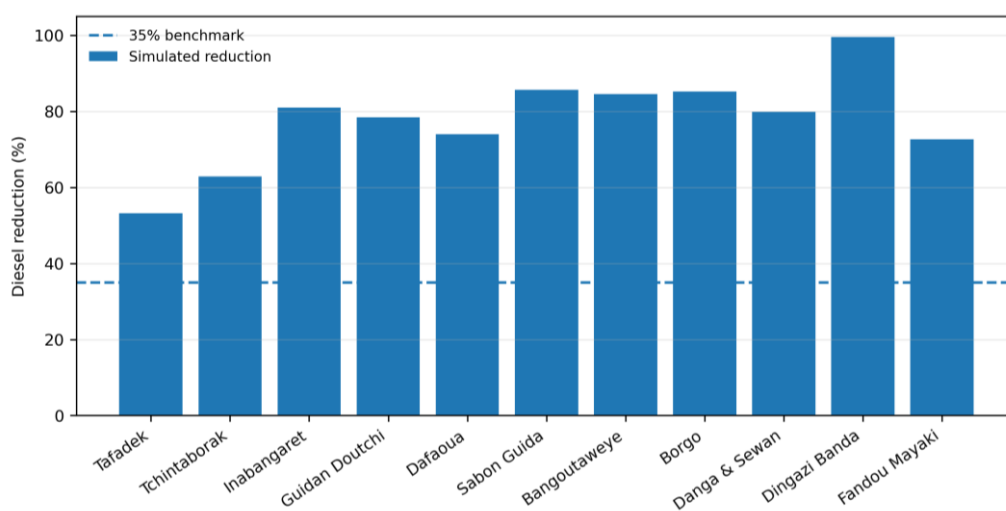
Table 5. Annual HOMER Pro simulation results for the optimized PV-battery-diesel systems.

Site	Annual load (kWh/year)	PV production (kWh/year)	Generator runtime (h/year)	Diesel consumption (L/year)	PV-to-load ratio (%)
Tafadek	33,638.4	14,992	2,178	6,089	45
Tchintaborak	24,790.8	13,877	1,249	3,841	56
Inabangaret	19,797.6	14,992	740	2,276	76
Guidan Douthi	13,578.0	14,455	737	2,267	106
Dafaoua	34,514.4	22,372	1,447	4,450	65
Sabon Guida	22,776.0	14,979	1,006	2,813	66
Bangoutaweye	21,024.0	14,745	681	2,094	70
Borgo	18,220.8	14,745	1,138	3,500	81
Danga & Sewan	24,177.6	14,745	1,200	3,355	61
Dingazi Banda	7,358.4	14,745	14	43	200
Fandou Mayaki	26,630.4	14,745	1,310	4,029	55

The annual PV-to-load ratio ranged from 45% at Tafadek to about 200% at Dingazi Banda. Values above 100% at Guidan Douthi and Dingazi Banda simply mean that annual PV production exceeded annual demand; they should not be read as renewable fractions above 100%. Generator runtime varied from 14 h/year at Dingazi Banda to 2,178 h/year at Tafadek, while annual diesel consumption ranged from 43 to 6,089 L.

3.2. Diesel-Fuel Reduction and Generator Operation

Diesel use declined at every site after hybridization. Across the portfolio, consumption fell from 161,749.75 to 34,757 L/year, saving 126,992.75 L/year, or about 78.5%.

**Figure 4.** Site-specific diesel-fuel reduction achieved by the optimized systems relative to the 35% benchmark.

The size of the reduction differed markedly by site. Dingazi Banda achieved the largest relative decrease (99.6%). Sabon Guida, Borgo, Bangoutaweye, and Inabangaret also exceeded 80%, whereas Tafadek had the smallest reduction at 53.2%. The site-level values are compared with the 35% benchmark

in Figure 4.

Every site exceeded the 35% diesel-reduction benchmark. Generator runtime fell in parallel, from a cumulative 66,477 h/year in the baseline case to about 11,700 h/year after optimization, a decrease of approximately 82.4%. Figure 5 shows

the change for each site.

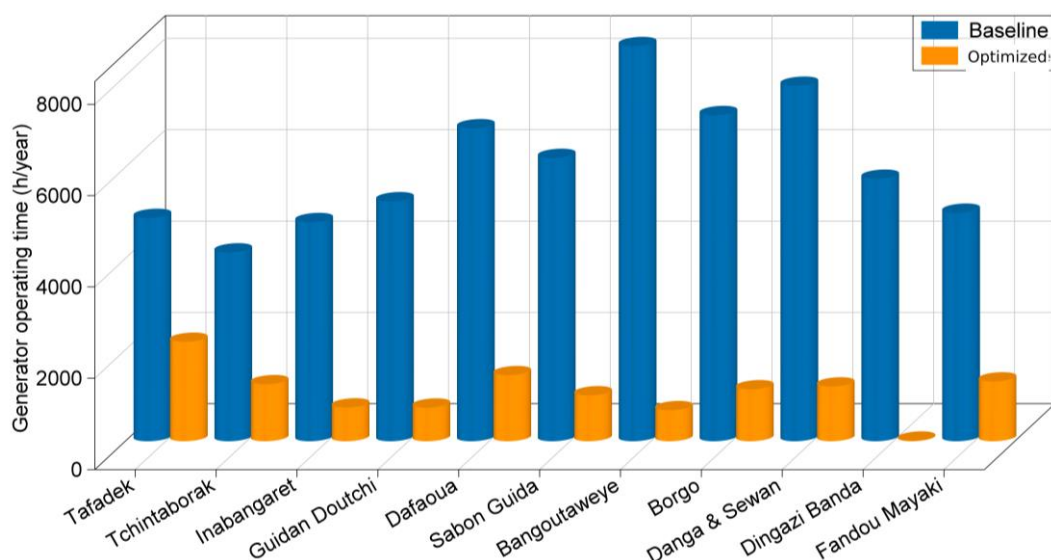


Figure 5. Annual diesel-generator operating hours before and after optimization across the eleven telecommunication sites.

3.3. Techno-Economic Performance

The economic effect was also substantial. Aggregate annual OPEX fell from approximately USD 302,159 in the baseline

case to USD 88,259 after optimization, giving annual savings of about USD 213,899. The combined CAPEX for the eleven retrofits was approximately USD 789,322. Site-level indicators are reported in Table 6.

Table 6. Site-specific techno-economic indicators of the optimized PV-battery-diesel systems. OPEX and savings are in USD/year; CAPEX and NPV are in USD; LCOE proxy is in USD/kWh.

Site	OPEX before	OPEX after	OPEX savings	CAPEX	Payback (yr)	NPV	IRR (%)	LCOE proxy
Tafadek	22,263	12,224	10,039	81,547	8.12	17,018	10.7	0.610
Tchintaborak	20,164	9,429	10,735	72,059	6.71	33,340	13.8	0.676
Inabangaret	23,106	6,671	16,435	72,059	4.38	89,302	22.4	0.708
Guidan Douthi	19,149	6,166	12,983	62,572	4.82	64,896	20.2	0.924
Dafaoua	34,793	10,502	24,291	87,704	3.61	150,787	27.5	0.563
Sabon Guida	34,577	7,746	26,831	72,059	2.69	191,369	37.2	0.662
Bangoutaweye	29,237	6,350	22,886	72,059	3.15	152,641	31.6	0.651
Borgo	43,105	8,828	34,277	62,572	1.83	273,968	54.8	0.834
Danga & Sewan	31,872	8,726	23,145	72,059	3.11	155,186	32.0	0.664
Dingazi Banda	19,850	2,726	17,124	62,572	3.65	105,555	27.1	1.237
Fandou Mayaki	24,043	8,891	15,152	72,059	4.76	76,709	20.5	0.610

Note: Aggregate values were calculated from unrounded site-level data; minor differences may therefore arise from rounding.

Payback ranged from 1.83 years at Borgo to 8.12 years at Tafadek. Sabon Guida, Danga & Sewan, and Bangoutaweye

also returned comparatively short payback periods.

All eleven sites produced positive NPV over the 20-year project lifetime. NPV ranged from USD 17,018 at Tafadek to

USD 273,968 at Borgo, while IRR ranged from 10.7% to 54.8%. Every IRR exceeded the 8% discount rate (Figure 6).

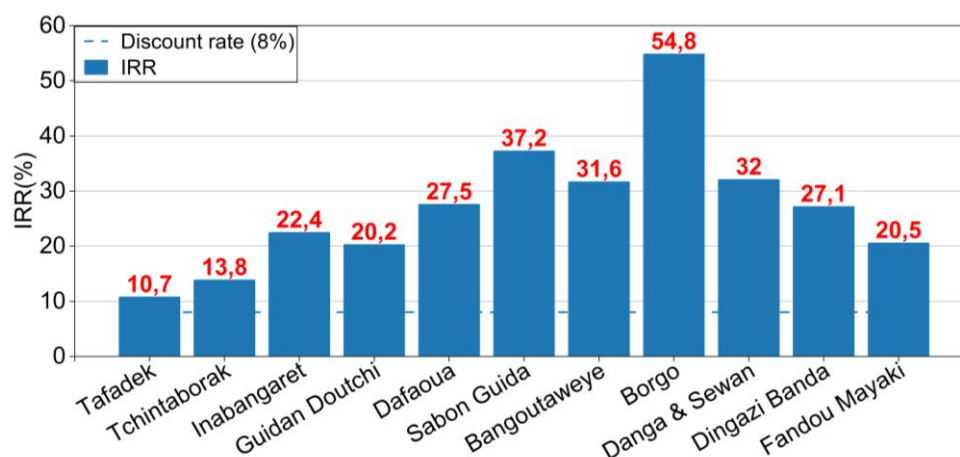


Figure 6. Internal rate of return of the optimized PV-battery-diesel systems compared with the 8% discount rate.

The derived LCOE proxy varied from USD 0.563/kWh at Dafaoua to USD 1.237/kWh at Dingazi Banda.

3.4. Sensitivity Analysis

Sensitivity was tested by varying diesel price and total CAPEX one at a time to 80%, 100%, and 120% of their baseline values. Diesel-price results are reported in Table 7.

Table 7. Sensitivity of aggregate economic performance to diesel-fuel price variations.

Diesel-price scenario	Annual savings (USD/year)	Aggregate NPV (USD)	Minimum payback (years)	Maximum payback (years)
80% of baseline	180,790	985,701	2.16	9.90
100% of baseline	213,899	1,310,773	1.83	8.12
120% of baseline	247,009	1,635,845	1.58	6.89

Diesel price had the expected effect on the savings generated by the retrofit. At 80% of the baseline price, aggregate annual cash flow fell to USD 180,790 and aggregate NPV to

USD 985,701. At 120%, these values rose to USD 247,009 and USD 1,635,845, respectively. Table 8 reports the corresponding total-CAPEX cases.

Table 8. Sensitivity of aggregate economic performance to total capital expenditure (CAPEX).

CAPEX scenario	Total CAPEX (USD)	Aggregate NPV (USD)	Minimum payback (years)	Maximum payback (years)
80% of baseline	631,458	1,468,637	1.46	6.50
100% of baseline	789,322	1,310,773	1.83	8.12
120% of baseline	947,187	1,152,908	2.19	9.75

With total CAPEX reduced to 80% of baseline, aggregate NPV increased to USD 1,468,637 and site-level payback ranged from 1.46 to 6.50 years. At 120% of baseline CAPEX, aggregate NPV fell to USD 1,152,908 and the payback range widened to 2.19-9.75 years.

Aggregate NPV remained positive in every diesel-price and CAPEX scenario considered.

3.5. Environmental Performance

Lower diesel consumption translated directly into lower combustion-related CO₂ emissions. The annual fuel saving of 126,992.75 L corresponds to approximately 340.3 tCO₂/year of avoided direct emissions. Figure 7 shows the contribution of each site.

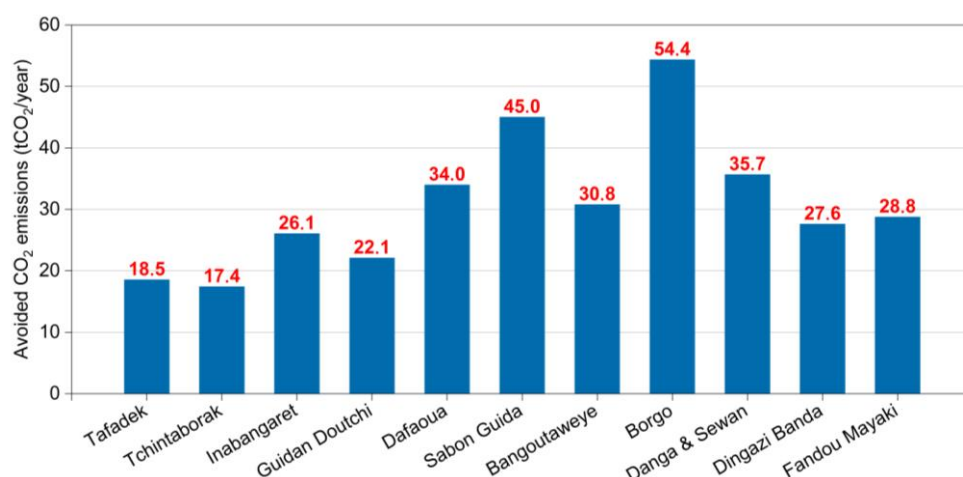


Figure 7. Annual CO₂-emission reductions achieved by the optimized PV-battery-diesel systems across the eleven telecommunication sites.

Avoided emissions ranged from about 17.4 tCO₂/year at Tchintaborak to 54.4 tCO₂/year at Borgo. Sabon Guida ranked second at roughly 45.0 tCO₂/year, followed by Danga & Sewan and Dafaoua.

4. Discussion

4.1. Technical Performance and Diesel-Fuel Reduction

A 78.5% reduction in portfolio diesel use is large enough to change the role of the generator in these systems. Diesel consumption decreased at every site, and Figure 4 shows that all eleven sites exceeded the 35% reduction benchmark. Instead of supplying much of the daily energy, the generator mainly covers periods when solar production and stored energy are insufficient. PV therefore serves the daytime load directly when available, while the battery shifts part of the solar surplus into non-solar hours, in accordance with the energy-management sequence summarized in Table 4. This operating pattern is consistent with hybrid strategies proposed for remote telecommunication supply [1, 5, 7].

The drop in generator runtime is equally important. Figure 5 shows that cumulative generator operating time fell sharply after hybridization, while the baseline assessment found load factors of only 21-39% at the same sites [12]. At such low

loading, specific fuel consumption generally rises and maintenance problems may become more frequent [2]. Applying a 58% minimum-loading constraint in the simulations directly targets this weakness of the existing diesel-dominated architecture.

Recent work on hybrid telecommunication power systems reports diesel reductions of a similar order. A HOMER Pro-optimized system in Nigeria achieved a 91.24% diesel reduction with 100% modeled reliability [8]. Another study showed that PV, lithium-ion storage, and diesel backup can be jointly sized around power availability and lifecycle cost [7]. The absolute values are not directly comparable because the studies differ in load, system boundary, grid context, and design assumptions, but they point in the same direction: substantial diesel displacement is technically achievable. Comparable studies of telecom power systems also report marked reductions in fuel-based generation when renewable supply, storage, and dispatch are jointly optimized [9, 11].

4.2. Site-to-Site Variability and Hybrid-System Design

Performance varied widely from one site to another even though the overall architecture was the same. The site-specific component sizing in Table 3 and the simulated annual energy balances in Table 5 show that a common architecture does not

produce the same result at every site. Residual diesel use depends on how annual demand, PV production, storage capacity, and dispatch interact. Dingazi Banda is the clearest example: its annual PV production is about twice the annual demand, leaving very little generator use. Tafadek sits at the other end of the range, with a much larger residual generator contribution because demand is high relative to PV production.

The PV-to-load ratio is useful for comparing these energy balances, but it is not a direct renewable fraction. A site can produce more PV energy over a year than it consumes and still require storage or generator support because production and demand do not coincide perfectly in time. The resulting site-to-site differences support tailored sizing rather than a single standard configuration for the whole portfolio [3-8].

4.3. Economic Performance and Investment Attractiveness

Under the assumptions used here, all eleven retrofits are economically viable. Table 6 shows positive NPV for every site and quantifies the spread in payback and IRR across the portfolio, while Figure 6 shows that every IRR exceeds the 8% discount rate. At these sites, the modeled operating savings are sufficient to recover the additional capital cost within the project lifetime.

The strength of that business case, however, differs considerably by site. Borgo has the shortest payback and the highest NPV and IRR, whereas Tafadek has the longest payback and the lowest IRR. The contrast reflects the combined effect of baseline diesel dependence, the fuel and maintenance costs that can be avoided, and the investment required at each location. Comparable site-specific behavior has been reported for hybrid telecommunication and other off-grid PV-diesel systems [3, 5, 7, 8, 25, 26]. A broader techno-economic analysis of solar-powered 5G base stations similarly found that investment outcomes depend strongly on irradiance, energy prices, and local deployment conditions [10].

For deployment planning, this means that PV capacity or CAPEX alone is not a sufficient screening criterion. Sites with high baseline fuel expenditure and strong potential for diesel displacement offer the quickest route to cost recovery and would be logical candidates for early retrofit.

4.4. Sensitivity and Robustness of the Economic Results

The sensitivity cases help show how dependent the investment results are on uncertain costs. Tables 7 and 8 quantify the effects of varying diesel price and CAPEX on annual cash flow, NPV, and payback. Lower diesel prices weaken the benefit of displacing fuel and reduce both annual savings and NPV; higher prices do the opposite. CAPEX moves the economics in the reverse direction, with higher total capital cost extending payback and reducing NPV.

Even so, aggregate NPV remained positive throughout the

$\pm 20\%$ range tested for both variables. At portfolio level, the economic result therefore remained positive under these moderate changes in diesel price and investment cost, although sites with longer baseline payback periods are more exposed to adverse assumptions. Similar sensitivity to fuel price and capital cost has been reported in broader PV-diesel-battery studies [25, 26]. A recent HOMER-based analysis likewise reported strong sensitivity to key cost inputs [27].

4.5. Environmental Implications

The reduction in diesel use also lowers direct operational emissions: the portfolio avoids about 340.3 tCO₂/year from diesel combustion. Figure 7 shows that Borgo and Sabon Guida contribute the largest shares because they displace the most fuel. The carbon benefit therefore follows the same site-to-site pattern as diesel reduction, consistent with recent hybrid-energy assessments [8, 25, 26]. Comparable PV studies also link project economics with carbon reduction [28].

This estimate is limited to direct generator emissions. It does not include embodied emissions from manufacturing, transport, replacement, or end-of-life treatment of PV modules, batteries, and power electronics. A lifecycle assessment would be needed to quantify the full carbon balance of the retrofit.

4.6. Study Limitations and Future Work

The analysis has several limitations. The HOMER model uses a continuous 24-h telecommunications load and therefore does not capture short-term traffic-related variations. Battery temperature effects, calendar and cycle aging, PV degradation, and component replacement are simplified rather than represented in full detail, although each can influence long-term hybrid performance [15, 16].

The economic indicators assume constant real annual savings and do not explicitly model taxes, financing structure, residual value, or general inflation. In addition, the sensitivity analysis is limited to independent $\pm 20\%$ changes in diesel price and total CAPEX.

The available simulation outputs also do not support a detailed calculation of unmet load or capacity shortage, so no numerical reliability index is claimed for the optimized systems. Operational continuity is instead supported by retaining the diesel generator as backup and by applying voltage-based dispatch thresholds. Future work should combine measured hourly load profiles with explicit reliability constraints, temperature-dependent battery aging, PV degradation and soiling, replacement schedules, and field validation of the proposed energy-management strategy.

5. Conclusions

This work evaluated site-specific PV-battery-diesel retrofits for eleven remote off-grid telecommunication sites in Niger using measured baseline data and HOMER Pro simulation. At

portfolio level, annual diesel use fell by 78.5% and generator runtime by approximately 82.4%. Aggregate annual OPEX decreased from about USD 302,159 to USD 88,259. All eleven sites returned positive NPV, and every IRR exceeded the 8% discount rate. The annual reduction in diesel use also corresponds to about 340.3 tCO₂ of avoided direct emissions.

The site-level results were not uniform across the network. Demand, PV production, storage, baseline fuel dependence, and retrofit cost combine differently at each site, producing marked differences in residual diesel use and investment return. These differences support a site-specific deployment strategy rather than one standard configuration for the whole portfolio. For remote telecom operators in Niger and similar off-grid settings, the proposed approach provides a practical way to reduce fuel dependence while retaining dispatchable backup capacity.

Abbreviations

AC	Alternating Current
ATC	American Tower Corporation
CAPEX	Capital Expenditure
CRF	Capital Recovery Factor
DC	Direct Current
DoD	Depth of Discharge
GHI	Global Horizontal Irradiation
GLF	Generator Load Factor
HOMER	Hybrid Optimization of Multiple Energy Resources
IRR	Internal Rate of Return
LCOE	levelized cost of electricity
MPPT	Maximum Power Point Tracking
NPV	Net Present Value
OPEX	operating expenditure
PV	photovoltaic
RMS	Remote Monitoring System.

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Author Contributions

Mahamadou Hamidine: Conceptualization, Formal Analysis, Methodology, Validation, Writing – original draft, Writing – review & editing

Chafiani Halidou Goumey: Data curation, Investigation, Methodology, Software

Arifa Warouma: Supervision, Validation, Writing – review & editing

Data Availability Statement

The data that support the findings of this study are available from the corresponding author upon reasonable request, subject to permissions required by ATC Niger.

Conflicts of Interest

The authors declare no conflicts of interest.

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