Design, Simulation, and Economic Evaluation of a 6.5 kVA Solar Photovoltaic System for Demand-Side Energy Control in a Nigerian Residential Facility

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ABSTRACT

This paper presents the design, hourly simulation, and techno-economic evaluation of a 6.5 kVA hybrid solar photovoltaic (PV) system designed for demand-side energy control (DSM) at a residential facility in Redemption City, Mowe, Ogun State, Nigeria. Rather than sizing PV components from first principles, the study verifies the technical adequacy of a fixed, commercially available equipment set — a 6.5 kVA hybrid inverter, a 51.2 V/200 Ah (10.24 kWh) lithium-ion phosphate (LFP) battery pack, and six 650W N-type bifacial monocrystalline modules (3.9 kWp total) — against an audited residential load. An energy audit established a solar-supported connected load of 2,234 W and a daily energy demand of 20.144 kWh, while two water heaters and two microwave ovens (5,400 W combined) were deliberately segregated onto the utility grid as a demand-side control measure. An hourly energy-balance simulation model was developed in place of licensed commercial PV design software to evaluate system performance under sunny-day, cloudy-day, and consecutive low-irradiance conditions, incorporating a DSM scheme that scheduled the flexible air-conditioning load to coincide with peak solar generation hours. With DSM active, the system met 100% of the daily demand on a representative day with zero grid import, compared with 4.76 kWh of grid import on the same day without DSM — a 100% reduction in short-term grid dependency attributable to load scheduling alone. On an annual basis, the array is estimated to yield 5,816.7 kWh (specific yield 1,491.5 kWh/kWp/year; performance ratio 0.78 inclusive of a 10% bifacial gain), covering 79.1% of the 7,352.6 kWh annual solar-supported load, with the residual 1,615.2 kWh/year (22.0%) supplied from the grid even under active DSM. Economic evaluation of the ₦4,216,300 installed system indicates a simple payback period of 4.9 years, a discounted payback of approximately 8 years at a 12% discount rate, a positive net present value of ₦2,211,978 over a 20-year life, an internal rate of return of about 19.9%, and a levelized cost of energy of approximately ₦49.6/kWh — roughly one-third of the ₦150/kWh blended grid/generator avoided-cost benchmark. The system is estimated to avoid approximately 4.02 tonnes of CO_2 emissions annually. The results demonstrate that deliberate load segregation, prioritization, and time-shifting can substantially extend the effective utility of a modestly sized, budget-constrained hybrid solar PV installation without full energy self-sufficiency, offering a replicable, economically attractive pathway for residential solar adoption in high-insolation but grid-constrained regions such as southwestern Nigeria.

Keywords: solar photovoltaic system; demand-side management; bifacial solar module; lithium-ion phosphate battery; hybrid inverter; hourly energy-balance simulation; techno-economic evaluation; levelized cost of energy

INTRODUCTION

Background

Nigeria's electricity supply industry continues to grapple with a wide gap between installed generation capacity and power actually delivered to consumers: installed capacity exceeds 13,000 MW, yet average available grid power routinely falls below 4,000 MW as a result of gas supply shortages, transmission and distribution bottlenecks, and an ageing national grid prone to system collapse. Residential consumers in peri-urban and satellite-town developments — such as Redemption City in Mowe, Ogun State — are particularly exposed to prolonged outages and unscheduled load shedding, driving continued reliance on petrol and diesel generating sets that are costly, noisy, and environmentally damaging [1]. This reliance on inefficient fuel- and diesel-powered backup generation entails substantial recurring costs, noise nuisance, and greenhouse gas emissions relative to solar photovoltaic alternatives, reinforcing the case for cleaner residential energy solutions in Nigerian housing [2].

Redemption City lies within the southwestern high-insolation belt of Nigeria along the Lagos–Ibadan Expressway corridor, receiving an appreciable year-round solar resource that makes solar photovoltaic (PV) generation a technically and economically attractive complement to grid electricity. Recent advances in bifacial PV cell technology, which harvest sunlight from both the front and rear surfaces of the module, have improved specific energy yield relative to conventional monofacial panels of equal power rating [3,4]. In parallel, lithium-ion phosphate (LFP) battery chemistry has displaced lead-acid technology in residential solar storage owing to its higher usable depth of discharge, longer cycle life, and superior thermal stability [5,6]. Modern hybrid inverters further simplify system design by integrating maximum power point tracking (MPPT) charge control, battery management interfacing, and automatic grid-transfer switching within a single unit.

The mere selection of high-quality hardware does not, however, guarantee an efficient or reliable installation. Residential loads vary considerably in power rating, duty cycle, and criticality: refrigeration and lighting must be continuously available, air-conditioning is flexible and schedulable, while resistive water-heating and microwave loads draw very high instantaneous power for short durations and are best excluded from a modestly sized system. This deliberate management of loads at the point of consumption — demand-side management (DSM) — is central to achieving a cost-effective and technically reliable residential solar PV system, particularly where the PV array and battery capacity are fixed by budget or equipment availability rather than freely sized to match total household demand [7,8].

Problem Statement and Objectives

Most published Nigerian residential PV studies size system components freely against an assessed load using tools such as HOMER Pro or PVsyst [9,10,11], rather than beginning from a fixed, pre-specified set of commercial components and evaluating, through simulation, how demand-side control measures can bridge any resulting capacity gap. Few studies explicitly quantify the performance implications of combining modern bifacial modules and LFP storage with a structured DSM strategy within an hourly simulation framework using verifiable manufacturer datasheet parameters. This study addresses that gap.

The specific objectives of the study are to: (i) verify the technical adequacy of a pre-specified 6.5 kVA hybrid inverter, 10 kWh LFP battery pack, and 3.9 kWp bifacial PV array against an audited residential load; (ii) design a three-part demand-side energy control strategy comprising load segregation, prioritization, and scheduling; (iii) develop and apply an hourly energy-balance simulation model to quantify system performance with and without DSM under varying irradiance conditions; and (iv) conduct a techno-economic and environmental evaluation of the resulting system.

Scope and Contribution

The study is confined to a single residential case-study site (Redemption City, Mowe, Ogun State, approximately 6.80°N, 3.43°E) and to the specific TAICO hybrid inverter, TAICO T-ONE LFP battery, and Jinko Solar bifacial module products named in the design. The principal contribution is a replicable methodology for verifying the adequacy of fixed, commercially available components against an assessed residential load, combined with an explicit, quantitatively evaluated DSM strategy and an hourly energy-balance simulation framework that does not depend on licensed commercial PV design software.

LITERATURE REVIEW

Solar Resource and Residential PV Deployment in Nigeria

Published assessments consistently place daily solar radiation in southwestern Nigeria in the range of 3.5–5.5 kWh/m², distinctly lower than the 6–7 kWh/m² typical of far-northern locations, owing to coastal humidity and atmospheric haze [12,13,14,15]. Akinsipe, Moya, and Kaparaju [9] used mathematical modelling and HOMER simulation to design an off-grid PV system for a residential building in Jos, north-central Nigeria, illustrating the standard load-based sizing approach against which the fixed-component verification methodology of the present study can be contrasted. Oyedepo, Adekeye, Leramo, Kilanko, and Babalola [11] surveyed 150 residential buildings across three local government areas of Lagos and used HOMER Pro to size PV systems and estimate the levelized cost of electricity, providing empirical residential load-profile data broadly consistent with the appliance categories audited in the present study. Ohanu [10] sized a standalone PV system for a three-bedroom residence in Obollo-Nsukka and found that, for the specific case examined, the LCOE of the standalone system exceeded the prevailing grid tariff, underscoring the sensitivity of PV economics to local energy audit assumptions, avoided-cost rates, and battery replacement costs — a sensitivity the present study address through its LCOE and NPV analysis. A related study of demand-side management applied to rural loads in Ibadan [16] found that applying DSM techniques ahead of system sizing reduced daily consumption by over half, reinforcing the value of DSM as a design-stage intervention rather than an afterthought, which is the central premise of the present study.

Closer to the present case-study area, Folorunso, Olusanya, and Fasipe [17] modelled and experimentally monitored a 5 kVA solar PV generation system at Bells University of Technology, Ota, in the same Ogun State corridor as Redemption City, recording sun irradiance, module temperature, and PV output voltage at 5-minute intervals over a representative measurement period. Their results confirmed that panel output voltage declines as module temperature rises above the panel's rated nominal operating temperature, and that instantaneous power output is not solely determined by irradiance but by the joint interaction of irradiance and temperature on cell efficiency. This locally generated Ogun State evidence directly supports the temperature-and-irradiance-sensitive performance ratio and bifacial-yield assumptions adopted in the sizing verification of the present study (Sections 3.6 and 5.4), and underscores the value of adaptive, climate-responsive design for solar PV systems deployed within this specific geographic corridor.

Bifacial Photovoltaic Technology

Bifacial modules capture reflected and diffuse irradiance on their rear surface in addition to direct irradiance on the front, yielding a measurable energy gain over monofacial modules of equivalent rating. Global-scale modelling by Sun, Khan, Deline, and Alam [4] found bifacial gains below 10% at low ground albedo (0.25) but as high as 30% where albedo is raised to 0.5 with elevated mounting. A systematic review by Yakubu and colleagues [3] reports typical gains in the range of 8–30% depending on mounting configuration, tilt, and orientation, while field studies in temperate and tropical climates have reported gains from about 5% at a low-latitude soil site [18] to 15–17% at a large-scale, high-albedo installation in the United Kingdom [19]. The present study adopts a conservative 10% bifacial gain assumption, consistent with typical rooftop-mounted, moderate-albedo residential installations and toward the lower-middle of the range reported in the literature.

Battery Energy Storage Technologies

Lead-acid batteries historically dominated residential solar storage owing to low upfront cost, but tolerate only 30–50% depth of discharge (DoD) before significant degradation, and offer a comparatively short cycle life of 300–600 cycles. Lithium iron phosphate (LFP) batteries have since emerged as the preferred residential chemistry owing to a superior safety profile, long cycle life (typically 3,000–8,000+ cycles depending on DoD and manufacturer), and integrated battery-management protection [5,6,20]. Comparative reviews consistently find LFP chemistry to outperform lead-acid on usable DoD, cycle life, round-trip efficiency, and total cost of ownership over the battery lifetime, despite a higher upfront cost per kilowatt-hour, reinforcing the LFP battery selection adopted in this study.

Hybrid Inverter Technology

A hybrid inverter integrates DC-to-AC conversion, solar MPPT charge control, battery management, and automatic transfer switching between solar, battery, and utility sources within a single unit. Modern hybrid inverters typically provide multiple selectable operating priorities (solar, battery, and utility priority) and programmable load-output relays, features that make them particularly well suited to implementing demand-side management strategies at the point of installation, since the inverter itself can prioritize specific load circuits during periods of constrained solar or battery availability.

Demand-Side Management in Residential Solar PV Systems

Demand-side management (DSM) encompasses strategies applied at the consumer end of the supply chain to influence the timing, magnitude, and priority of load consumption. Palensky and Dietrich [7] provide an early and widely cited classification of DSM techniques spanning energy efficiency, time-of-use scheduling, and demand response. Zhou and colleagues [21] and Nasir and colleagues [8] review residential DSM and load-scheduling techniques in the smart-grid context, noting that most schemes combine load prioritization, peak shaving, and time-shifting rather than relying on a single measure — an observation consistent with the combined load-segregation, prioritization, and scheduling strategy adopted in this study. In the specific context of residential solar PV, DSM is most valuable where installed generation and storage capacity is constrained relative to potential household demand, as is typically the case for cost-conscious residential installations [22,23]. Commonly applied residential DSM strategies include: load segregation of high-power, short-duration, non-deferrable loads; load prioritization of critical, essential, and flexible circuits; load scheduling (time-shifting) of flexible high-power appliances to periods of peak solar generation; and peak shaving of simultaneous appliance start-up. These strategies are complementary, and the most effective residential DSM schemes typically combine two or more of them, as adopted in the present study through the joint application of load segregation (water heaters and microwave ovens kept permanently on the grid), load prioritization (critical loads protected at low battery state of charge), and load scheduling (air-conditioning use aligned with solar generation hours).

Economic Evaluation Methods for Renewable Energy Projects

Techno-economic evaluation of distributed renewable energy projects conventionally combines simple payback period, net present value (NPV), internal rate of return (IRR), and levelized cost of energy (LCOE) as complementary figures of merit [24,25,26]. LCOE expresses the discounted lifecycle cost of a generating asset per unit of discounted lifetime energy output and is widely used to benchmark the cost-competitiveness of different generation technologies and system configurations [27], while NPV and IRR more directly capture the profitability of the specific investment under a given discount rate and cash-flow profile. The present study applies all four indicators in combination, consistent with recommended practice for small-scale distributed PV project appraisal.

Summary and Research Gap

The reviewed literature confirms that (i) southwestern Nigeria possesses a moderate but reliable solar resource suitable for residential PV deployment; (ii) bifacial panel technology and LFP battery storage offer measurable performance and lifecycle advantages over older PV and storage technologies; and (iii) demand-side management, though extensively studied in the general smart-grid literature, is comparatively under-addressed in Nigerian residential PV sizing studies, most of which optimize component capacity freely rather than beginning from fixed commercial hardware. This study addresses that gap by combining a fixed-component design-verification approach, an hourly energy-balance simulation model with explicit DSM logic, and a comprehensive techno-economic evaluation, using named, currently available commercial components and a specific, previously unstudied case-study location.

MATERIALS AND METHODS

Research Design and Study Area

This study adopts an analytical, simulation-based design methodology structured around a fixed set of pre-specified commercial components rather than free component sizing. The methodology comprises five stages: (i) site and load characterization; (ii) verification of the technical adequacy of the specified inverter, battery, and PV array against the assessed load; (iii) design of a demand-side energy control strategy; (iv) development of an hourly energy-balance simulation model; and (v) techno-economic and environmental evaluation. The case-study site is a residential facility within Redemption City, a planned residential estate in Mowe, Obafemi-Owode Local Government Area, Ogun State, Nigeria (approximately 6.80°N, 3.43°E), lying within the southwestern tropical rainforest belt in close proximity to the Lagos coastal corridor. The site experiences a tropical wet-and-dry climate with a rainy season from approximately April to October and a dry, harmattan-influenced season from November to March, and a daily solar radiation profile in the lower-to-middle portion of the 3.5–5.5 kWh/m² range typically reported for southern Nigeria.

Load Assessment and Load Segregation Methodology

An energy audit was conducted to identify all electrical appliances within the facility, and each appliance was classified as either solar-supported (connected to the hybrid inverter output) or grid-exclusive (permanently connected to the utility grid, bypassing the solar system), consistent with the demand-side control philosophy of the study. Appliances were assigned to the grid-exclusive category where their instantaneous power draw was disproportionately high relative to their duty cycle — specifically, short-duration, high-power resistive loads such as water heaters and microwave ovens — since including such loads on a modestly sized 6.5 kVA/10 kWh system would require substantial oversizing of the inverter and battery bank to accommodate infrequent but very high peak demand. For each solar-supported appliance, power rating, quantity, and average daily hours of use were recorded and used to compute total connected load and total daily energy demand.

Sizing Verification Methodology

Rather than sizing components from first principles, the study verifies the adequacy of the pre-specified inverter, battery pack, and PV array against the assessed load using the following standard relations.

Inverter Capacity Verification

The real-power capability of the inverter is computed from its apparent power rating and an assumed operating power factor:

$$P_{\mathrm{real}}\ (\mathrm{W}) = S_{\mathrm{inverter}}\ (\mathrm{VA}) \times \cos\phi \qquad (1)$$

where S_{inverter} is the rated apparent power of the inverter (VA) and $\cos\phi$ is the assumed inverter operating power factor. The estimated instantaneous surge demand, accounting for the soft-start inrush of inverter-type air-conditioning compressors and conventional refrigerator compressors, is computed as:

$$S_{\mathrm{surge}} \approx \Sigma(n_i \times P_i \times k_i) \qquad (2)$$

where n_i is the quantity, P_i the steady-state rating, and k_i a soft-start multiplier applied to each high-inertia appliance category (typically 2× for inverter-type compressors and 3× for conventional compressors), with non-motor loads assumed to draw their steady-state rating. The estimated surge demand is compared against the inverter's rated apparent power to confirm adequate start-up headroom.

PV Array Configuration Verification

Total installed PV array capacity is computed as:

$$P_{PV}\ (Wp) = N_{module} \times P_{module,rated} \qquad (3)$$

where N_{module} is the number of modules and $P_{module,rated}$ is the rated power per module at Standard Test Conditions. Modules are arranged in a series–parallel configuration such that the resulting string voltage and current fall within the input voltage and current limits of the inverter's built-in MPPT charge controller:

$$V_{OC,string} = N_s \times V_{OC,module} \qquad I_{SC,array} = N_p \times I_{SC,module} \tag{4}$$

where N_s is the number of modules per series string and $N_p$is the number of parallel strings.

Battery Bank Autonomy Verification

Usable battery capacity is computed from the rated capacity and the manufacturer-specified maximum depth of discharge:

$$C_{usable}\,(kWh) = C_{rated}\,(kWh) \times DoD \tag{5}$$

and the resulting battery autonomy for the non-deferrable (critical and essential) portion of the solar-supported load is:

$$Autonomy\ (days) = \frac{C_{usable}}{E_{non} - AC,daily} \tag{6}$$

where $E_{non} - AC, daily$ is the daily energy demand of all solar-supported loads excluding the flexible air-conditioning load.

Demand-Side Energy Control Strategy Design

The demand-side control strategy comprises three complementary measures. Load segregation excludes the two water heaters and two microwave ovens permanently from the solar system, keeping them on the utility grid at all times. Load prioritization ranks solar-supported loads as critical (refrigeration, essential lighting), essential (fans, television), and flexible/deferrable (air-conditioning), with automatic or manual shedding of lower-priority circuits should battery state of charge (SOC) fall below a defined threshold. Load scheduling (time-shifting) deliberately aligns operation of the flexible air-conditioning load with the 10:00–16:00 window of peak solar generation, with limited evening operation permitted from battery reserves where available, reflecting realistic residential comfort-cooling patterns. This scheduling approach is evaluated quantitatively against an unmanaged (“without DSM”) evening/night schedule in Section 5.

Hourly Energy-Balance Simulation Methodology

An hourly energy-balance simulation model was developed, in the absence of licensed commercial PV design software, to evaluate dynamic system performance. For each hour t, PV generation is estimated from the hourly fraction of daily peak sun hours (PSH) applied to the rated array capacity, adjusted for performance ratio and bifacial gain; hourly load is drawn from the appliance duty-cycle schedule; and the battery state of charge is updated according to the energy balance:

$$SOC(t) = SOC(t-1) + \frac{\eta_{cha} \times (E_{PV(t)} - E_{load(t)})}{C_{rated}} \times 100\% \tag{7}$$

subject to a maximum SOC of 100% and a minimum allowable SOC of 20% (corresponding to the manufacturer's specified 80% maximum depth of discharge), where η_{cha} is the assumed battery round-trip efficiency (0.95). Where the instantaneous energy balance is negative and the battery SOC would fall below its minimum allowable level, the shortfall is drawn from the grid as grid import. Three simulation scenarios were evaluated: a representative sunny day ($PSH = 5.5\,kWh/m^2/day$), a representative cloudy day ($PSH = 3.9\,kWh/m^2/day$), and three consecutive cloudy days, to assess battery depletion and grid-dependency behaviour under sustained low-irradiance conditions. A fourth, comparative scenario evaluated DSM effectiveness on a representative annual-average day ($PSH = 4.8\,kWh/m^2/day$), simulated once with the air-conditioning load scheduled to solar hours and once with an unmanaged evening/night schedule. A fifth scenario extended the simulation across the full twelve-month PSH profile of the study location to estimate annual grid-import requirement with DSM active.

Performance Evaluation Metrics

Expected monthly PV energy yield is estimated as:

$$E_{month} = PSH \times P_{PV\,(kWp)} \times PR \times (1 + BG) \times Days \quad (8)$$

where PSH is the monthly average daily peak sun hours (kWh/m²/day), P_PV is the array capacity (kWp), PR is the system performance ratio, BG is the bifacial energy gain, and Days is the number of days in the month. Specific yield, capacity factor, and solar fraction are computed as:

$$Specific\ Yield\ (kWh/kWp/yr) = \frac{E_{annual}}{P_{PV}} \quad (9)$$

$$Capacity\ Factor\ (\%) = \frac{E_{annual}}{P\_PV \times 8{,}760} \times 100 \quad (10)$$

$$Solar\ Fraction\ (\%) = \frac{E_{annual,PV}}{E_{annual,load}} \times 100 \quad (11)$$

where E_{annual} is the estimated annual PV energy yield (kWh) and $E_{annual,load}$ is the total annual solar-supported load demand (kWh).

Economic and Environmental Evaluation Methodology

System economic viability was evaluated using standard techno-economic indicators. The simple payback period is:

$$Simple\ Payback\ Period\ (yr) = \frac{C_0}{CF_{annual}} \quad (12)$$

where C_0 is the total initial capital cost and CF_{annual} is the annual cost saving from energy displaced from the grid/generator. Net present value over the assumed n-year system economic life at discount rate r is:

$$NPV = -C_0 + \sum_{t=1}^{n} \left(\frac{CF_t}{(1+r)^t} \right) \quad (13)$$

with the internal rate of return (IRR) computed as the discount rate at which NPV equals zero. The levelized cost of energy is:

$$LCOE = \frac{C_0 + \sum O\&M\ Costs}{\sum Lifetime\ Energy\ Generated} \quad (14)$$

Annual cost savings were computed as the value of energy displaced from the grid/generator at a blended avoided-cost rate representative of the combined cost of grid electricity tariffs and diesel generator fuel typically incurred by Nigerian residential consumers (₦150/kWh). Annual operation and maintenance costs were assumed at 1.5% of capital cost per year, and lifetime energy generation was derated by 5% to account for module degradation over the 20-year assumed economic life at a 12% discount rate, representative of prevailing Nigerian lending rates for small-scale energy projects. Environmental benefit was evaluated as the reduction in carbon dioxide (CO_2) emissions:

$$Annual\ CO_2\ Reduction\ (kg) = E_{displaced\,(kWh)} \times EF\ (kg\ CO_2/kWh) \quad (15)$$

where $E_{displaced}$ is the annual energy displaced from grid/generator sources and EF are a blended emission factor of 0.7 kg CO_2/kWh, representative of the combined grid and diesel-generator emission intensity typical of Nigerian residential electricity supply.

SYSTEM DESIGN AND COMPONENT SPECIFICATION

Three pre-specified major components form the basis of the design: a TAICO 6.5 kVA hybrid inverter, a TAICO T-ONE series wall-mounted LFP battery pack rated 10 kWh, and six units of 650 W N-type bifacial monocrystalline solar panels manufactured by Jinko Solar. Tables 1–3 present the manufacturer-specified technical characteristics of each component, drawn from published product literature [28,29,30].

Hybrid Inverter

Parameter	Specification
Model reference	TAICO Hybrid Series (6.5 kVA class)
Rated output power	6,500 VA / 6,500 W
Nominal DC (battery) voltage	48 V
Built-in MPPT solar charge controller capacity	≈ 7,800 W (oversized relative to AC rating for cloudy-day headroom)
PV input voltage range	125–500 VDC
MPPT efficiency	≥ 98%
Output waveform	Pure sine wave
Operating modes	Solar priority, battery priority, utility priority
AC input for grid/generator charging	Yes (auto transfer)
Battery compatibility	Lithium (LFP), tubular, sealed/flooded lead-acid
Protection features	Overload, over-temperature, short-circuit, reverse polarity
Warranty	5 years (manufacturer-typical)

Table 1. TAICO 6.5 kVA hybrid inverter — technical specifications

LFP Battery Pack

Parameter	Specification
Model reference	TAICO T-ONE Series (S10000)
Battery chemistry	Lithium-ion phosphate ($LiFePO_4$ / LFP)
Nominal voltage	51.2 V
Rated capacity	200 Ah
Rated energy	10.24 kWh
Maximum depth of discharge (DoD)	80%

Usable energy (at 80% DoD)	8.19 kWh
Cycle life	> 6,000 cycles at 80% DoD
Round-trip efficiency (assumed)	95%
Battery management system (BMS)	Integrated smart BMS with touch-screen display
Communication	Multi-protocol (CAN/RS-485) for inverter compatibility
Ingress protection	IP64
Operating temperature range	–20°C to +60°C

Table 2. TAICO T-ONE 10 kWh LFP battery pack — technical specifications

Bifacial PV Module

Parameter	**Specification**
Model reference	Jinko Solar JKM650N-78HL4-BDV (Tiger Neo, N-type)
Rated power ($P_{max,STC}$)	650 Wp
Cell technology	N-type TOPCon monocrystalline, bifacial, dual-glass
Module efficiency (STC)	23.25%
Maximum power voltage (V_{mp})	48.33 V
Maximum power current (I_{mp})	13.45 A
Open-circuit voltage (V_{OC})	57.60 V
Short-circuit current (I_{SC})	14.10 A
Bifaciality coefficient	80% ± 5%
Temperature coefficient of P_{max}	−0.29 %/°C
Dimensions	2,465 × 1,134 × 30 mm
Weight	34.0 kg
Product / linear power warranty	12 years / 30 years

Table 3. JinkoSolar 650 W bifacial panel — technical specifications

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Load Assessment and Load Segregation

Table 4 presents the energy audit of appliances designated for solar supply. The DC standing-fan wattage was not explicitly specified in the original site inventory; a representative rating of 60 W per unit, typical of commercially available residential DC standing fans in Nigeria, was assumed.

S/N	Appliance	Qty	Unit rating (W)	Total power (W)	Hrs/day	Energy (Wh/day)
1	Plasma television (52 W)	2	52	104	6	624
2	DC standing fan	2	60	120	10	1,200
3	Table-top refrigerator	2	75	150	24	3,600
4	Inverter air-conditioner (1 HP)	2	850	1,700	8	13,600
5	Lighting (total household bulbs)	1	160	160	7	1,120
	TOTAL (SOLAR-SUPPORTED LOAD)			2,234		20,144

Table 4. Solar-supported load schedule

From Table 4, the total connected solar-supported load is 2,234 W and total daily energy demand is 20,144 Wh/day (≈ 20.144 kWh/day). The two inverter air-conditioning units alone account for 1,700 W (76.1%) of connected load and 13,600 Wh/day (67.5%) of daily energy demand, making air-conditioning the dominant and most critical load to manage under the demand-side control strategy of Section 4.6.

S/N	Appliance	Qty	Unit rating (W, assumed)	Total power (W)	Remarks
1	Water heater	2	1,500	3,000	Excluded from solar system — permanently on grid
2	Microwave oven	2	1,200	2,400	Excluded from solar system — permanently on grid

Table 5. Grid-exclusive load schedule (not connected to the solar system)

The water heaters and microwave ovens were deliberately excluded from the solar PV system because their combined instantaneous demand (5,400 W) alone exceeds the real-power capacity of the 6.5 kVA inverter, and their short-duration, high-power resistive/inductive draw would impose disproportionate surge stress on the inverter and rapid, deep discharge events on the battery bank relative to the modest energy they would displace from the grid. Retaining these loads on the grid is therefore both a technical necessity and a deliberate demand-side control decision for a system of this capacity.

Sizing Verification Results

Applying Equation (1) at an assumed inverter power factor of 0.8, the real-power capability of the specified inverter is $P_{real} = 6{,}500 \times 0.8 = 5{,}200\ W$. Comparing this against the total connected solar-supported load of 2,234 W (Table 4), the inverter operates at only about 43% of its real-power capacity under normal steady-state conditions, leaving a comfortable margin of approximately 2,966 W (57.0%) for starting surges. Applying Equation (2) with a soft-start multiplier of 2× for the two inverter-type air-conditioning compressors and 3× for the two refrigerator compressors, the estimated instantaneous surge demand is $(2 \times 850 \times 2) + (2 \times 75 \times 3) + (104 + 120 + 160) = 4{,}234\,W$, comfortably within the inverter's 6,500 VA rating and confirming adequate headroom for simultaneous appliance start-up.

Applying Equation (3), the total installed PV array capacity is $P_{PV} = 6 \times 650 = 3{,}900\,Wp\,(3.9\,kWp)$. Given the inverter's specified 125–500 VDC MPPT input voltage range (Table 1) and the module's rated V_{mp} of 48.33 V and V_{OC} of 57.60 V (Table 3), the six modules were arranged in two parallel strings of three series-connected modules per string. Applying Equation (4): $V_{OC,string}$ = 3 × 57.60 = 172.8 V, $V_{mp,string}$ = 3 × 48.33 = 144.99 V, $I_{SC,total}$ = 2 × 14.10 = 28.2 A, $I_{mp,total}$ = 2 × 13.45 = 26.9 A. These values fall comfortably within the inverter's MPPT input voltage range and well within the ≈ 7,800 W built-in MPPT controller capacity ($172.8\,V \times 28.2\,A \approx 4{,}873\,W$ at open-circuit conditions), confirming that the six-panel array configuration is fully compatible with the specified hybrid inverter.

Applying Equation (5), the usable energy of the battery pack at its rated 80% maximum DoD is $C_{usable} = 10.24 \times 0.8 = 8.19\,kWh$. Excluding the flexible air-conditioning load, the daily energy demand of the non-deferrable (critical and essential) solar-supported appliances — refrigerators, fans, television, and lighting — is $E_{non} - AC, daily = 624 + 1{,}200 + 3{,}600 + 1{,}120 = 6{,}544\,Wh/day = 6.544\,kWh/day$. Applying Equation (6), the resulting battery autonomy for these non-deferrable loads, absent solar charging, is $Autonomy = 8.19\,/\,6.544 \approx 1.25\,days$, which is considered adequate for a grid-backed hybrid system in which the inverter's automatic grid-transfer function provides continuity of supply beyond this period.

Protection and Safety Devices

The design incorporates DC string fuses rated at 1.5 × I_{SC} per string (≈ 21 A); DC and AC Type II surge protection devices (SPDs); a DC isolator switch between the PV array and inverter and an AC isolator between the inverter and the household distribution board; miniature circuit breakers sized to the current rating of each protected circuit; a dedicated earthing and bonding system for the PV array frame, inverter chassis, and battery enclosure; and the integrated battery management system within the LFP battery pack, providing over-charge, over-discharge, over-current, and thermal protection. These provisions follow accepted low-voltage installation and PV module qualification practice [31,32].

Indicative Bill of Engineering Measurement and Evaluation (BEME)

S/N	Item description	Qty	Unit cost (₦)	Total cost (₦)
1	Jinko Solar 650 W N-type bifacial panel	6	110,500	663,000
2	TAICO 6.5 kVA hybrid inverter	1	900,000	900,000
3	TAICO T-ONE 10 kWh LFP battery pack (S10000)	1	1,700,000	1,700,000
4	Mounting structure, DC/AC cables, combiner/isolators	1	250,000	250,000
5	Protection devices (MCBs, SPD, earthing)	1	120,000	120,000
6	Installation, labour and commissioning	1	200,000	200,000

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7	Contingency (10%)	1	—	383,300
	TOTAL ESTIMATED COST			4,216,300

Table 6. Indicative bill of engineering measurement and evaluation

The figures in Table 6 are indicative estimates based on prevailing Nigerian market rates for the named components at the time of the study and are subject to variation with market conditions, currency exchange rates, and import duties.

RESULTS AND DISCUSSION

Solar Resource Data for the Study Location

Estimated monthly average peak sun hour (PSH) values for Redemption City, Mowe, were derived by adjusting published solar radiation data for southwestern Nigeria to reflect the location's proximity to the humid Lagos coastal corridor, which typically yields slightly lower irradiance than inland southwestern locations such as Ibadan. The adopted monthly PSH values range from 3.9 kWh/m²/day in July (peak rainy season) to 5.5 kWh/m²/day in February and December (dry/harmattan season), with an annual average of 4.8 kWh/m²/day, consistent with the 3.5–5.5 kWh/m²/day range generally reported for southern Nigeria [12,13].

Hourly Simulation Results

Representative Sunny Day (PSH = 5.5 kWh/m²/day, DSM Active)

Table 7 presents the simulation for a representative sunny (dry-season) day at 2-hourly intervals (the complete hourly profile is plotted in Figure 1), with DSM active and a starting battery SOC of 95%. Total PV generation for the day was 18.40 kWh against a total load of 20.14 kWh.

Hour	PV gen. (kWh)	Load (kWh)	SOC start (%)	SOC end (%)	Grid import (kWh)
00:00	0.00	0.27	95.0	92.4	0.00
02:00	0.00	0.27	89.7	87.1	0.00
04:00	0.00	0.27	84.5	81.8	0.00
06:00	0.00	0.15	78.8	77.3	0.00
08:00	1.21	0.15	81.8	91.6	0.00
10:00	2.10	1.85	100.0	100.0	0.00
12:00	2.42	1.95	100.0	100.0	0.00
14:00	2.10	1.85	100.0	100.0	0.00
16:00	1.21	0.15	98.7	100.0	0.00
18:00	0.00	0.31	100.0	97.0	0.00
20:00	0.00	0.53	92.9	87.7	0.00

21:00	0.00	2.23	87.7	65.9	0.00
22:00	0.00	2.23	65.9	44.1	0.00
23:00	0.00	0.43	44.1	39.9	0.00

Table 7. Simulation summary — representative sunny day (with DSM, 2-hourly intervals)

The battery bank reaches full charge (100% SOC) by mid-morning (09:00–10:00) and remains fully charged throughout the peak air-conditioning operating window (10:00–16:00), served directly by PV generation. The battery discharges through the evening to supply the scheduled evening air-conditioning use (21:00–22:00) and other essential loads, ending the day at 39.9% SOC with zero grid import required.

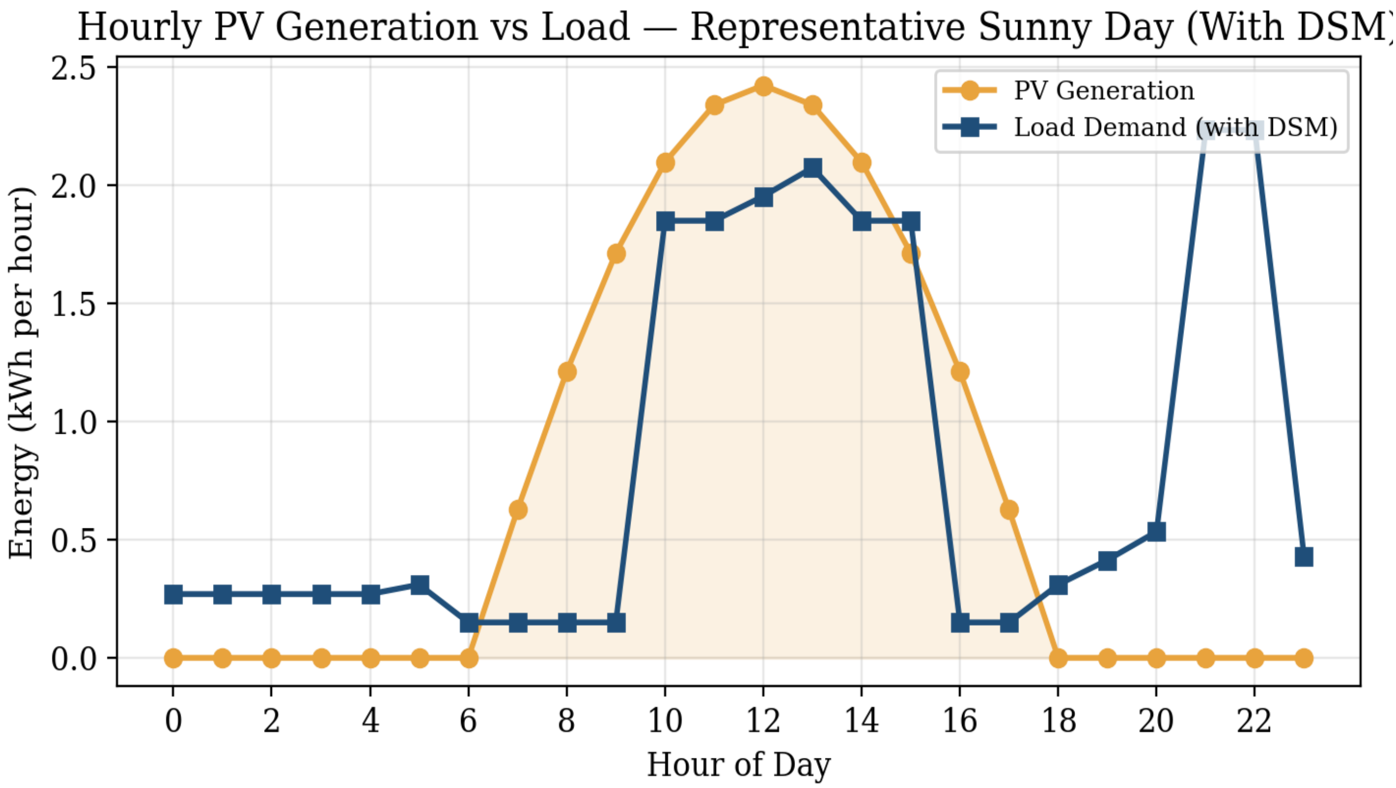

Figure 1. Hourly PV generation versus load demand — representative sunny day (with DSM)

Representative Cloudy Day (PSH = 3.9 kWh/m²/day, DSM Active)

For a representative cloudy (peak rainy-season) day, with DSM active and a starting SOC of 95%, total PV generation was 13.05 kWh against a total load of 20.14 kWh. Despite the reduced generation, the battery bank — starting from a high SOC — absorbs the shortfall for this single cloudy day, ending at 24.2% SOC with zero grid import required. This result is, however, sensitive to the starting SOC, as demonstrated in the multi-day scenario of Section 5.2.4.

DSM Effectiveness Comparison on a Typical Day (PSH = 4.8 kWh/m²/day)

To quantify the benefit of the demand-side control strategy, a representative annual-average day (total PV generation 16.06 kWh) was simulated twice from an identical starting SOC of 90%: once with the air-conditioning load scheduled to coincide with peak solar hours ("with DSM") and once with the air-conditioning load operating on an unmanaged evening/night schedule typical of uncontrolled residential use ("without DSM"). Table 8 summarizes the outcome of the two simulations.

Indicator	With DSM	Without DSM
Total PV generation (kWh)	16.06	16.06
Total load (kWh)	20.14	20.14
Air-conditioning operating window	10:00–16:00 (+ limited evening use)	18:00–02:00 (unmanaged)
Minimum SOC reached	96.0% (never critical)	20.0% (minimum allowable)
End-of-day SOC	39.9%	20.0%
Grid import required (kWh)	0.00	4.76

Table 8. Demand-side management effectiveness — typical-day comparison

The contrast between the two scenarios is striking. With demand-side control active, the air-conditioning load is served directly by PV generation during 10:00–16:00, the battery ends the day at a healthy 39.9% SOC, and zero grid import is required. Without demand-side control, the air-conditioning units instead operate from 18:00 to 02:00, a period during which little or no PV generation is available; the battery is driven down to its minimum allowable SOC of 20% by 21:00, and the system requires 4.76 kWh of grid import to sustain the load through the remainder of the night. This represents a 100% reduction in grid dependency on this representative day when the demand-side control strategy is applied, and preserves a substantially higher battery SOC margin, which is expected to reduce battery cycling depth and extend service life.

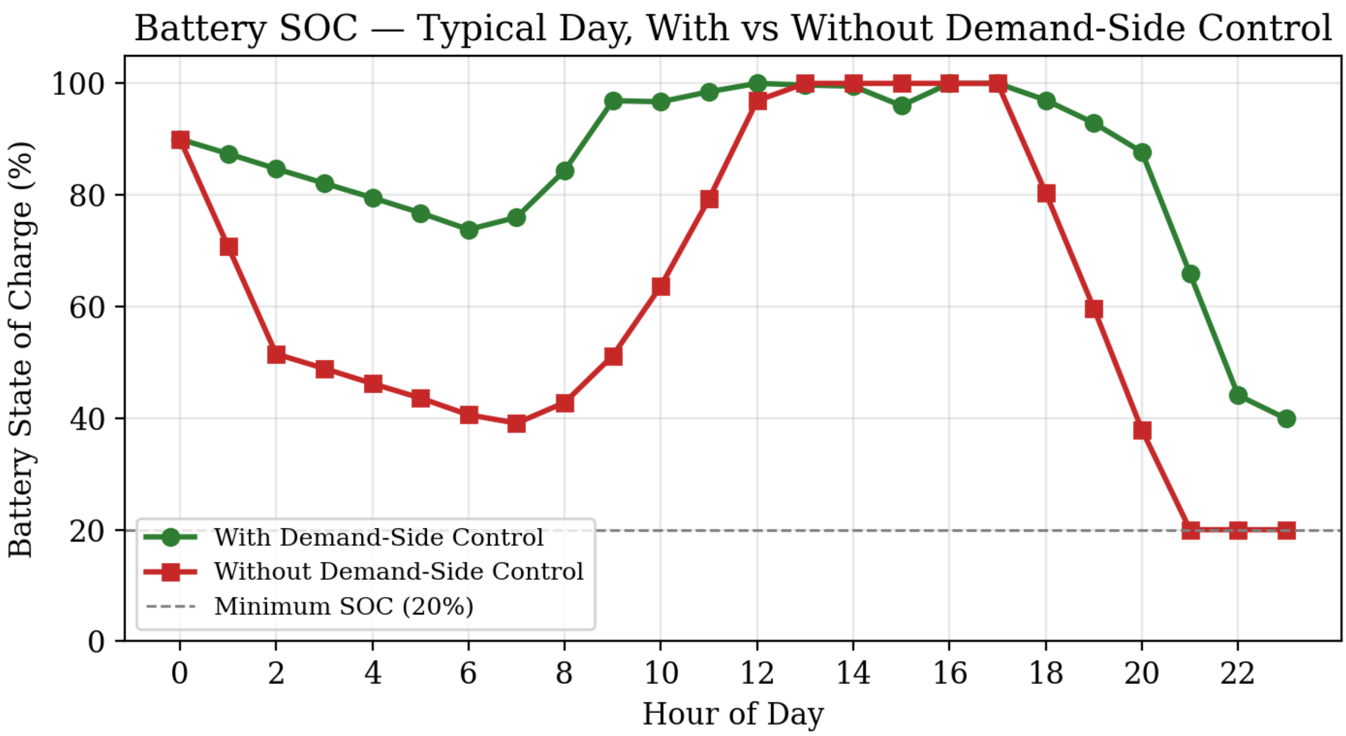

Figure 2. Battery SOC profile — typical day, with vs without demand-side control

Battery Depletion Under Three Consecutive Cloudy Days (DSM Active)

To evaluate system behaviour under sustained low-irradiance conditions, three consecutive cloudy days (PSH = 3.9 kWh/m²/day each) were simulated in sequence, with DSM active throughout and a starting SOC of 95% on Day 1.

Day	End-of-day SOC (%)	Grid import required (kWh)
Day 1	24.2	0.00
Day 2	20.0 (minimum)	6.81
Day 3	20.0 (minimum)	7.25

Table 9. Battery depletion summary — three consecutive cloudy days

While the battery bank can absorb a single day of below-average irradiance without grid assistance provided it begins from a high SOC, sustained cloudy conditions over two or more consecutive days deplete the battery to its minimum allowable SOC, after which the hybrid inverter's grid-backup function becomes essential to maintain uninterrupted supply to the solar-supported loads. This confirms the appropriateness of the hybrid, rather than fully off-grid, system configuration specified for this project, and underscores the continuing importance of grid backup even with an effective demand-side control strategy in place.

Estimated Monthly and Annual PV Energy Yield

Applying Equation (8) with P_PV = 3.9 kWp, PR = 0.78, and a 10% bifacial energy gain, Table 10 presents the resulting monthly energy yield estimates for the designed system.

Month	PSH (kWh/m²/day)	Daily yield (kWh)	Days	Monthly yield (kWh)
January	5.4	18.07	31	560.2
February	5.5	18.40	28	515.3
March	5.2	17.40	31	539.4
April	4.9	16.40	30	491.9
May	4.6	15.39	31	477.2
June	4.1	13.72	30	411.6
July	3.9	13.05	31	404.6
August	4.0	13.38	31	414.9
September	4.3	14.39	30	431.7
October	4.7	15.73	31	487.5
November	5.1	17.07	30	512.0
December	5.5	18.40	31	570.5
TOTAL / AVERAGE	4.8	15.94	365	5,816.7

Table 10. Estimated monthly PV energy yield for the designed system

The system is estimated to generate a total of 5,816.7 kWh annually, an average of about 15.94 kWh/day. Energy yield peaks in December and February (18.40 kWh/day) during the dry season, and dips in July (13.05 kWh/day) during the peak of the rainy season.

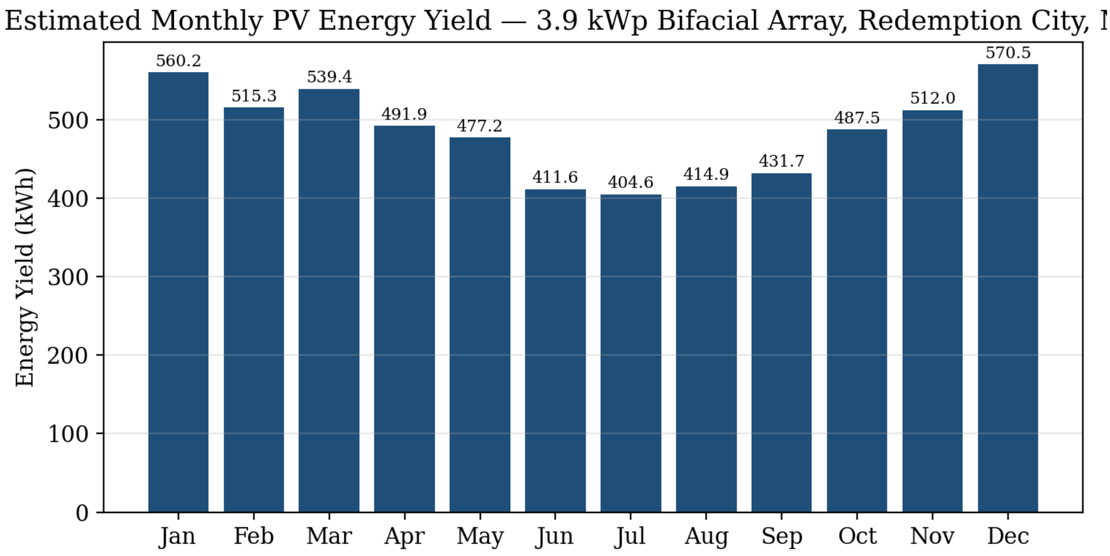

Figure 3. Estimated monthly PV energy yield — 3.9 kWp bifacial array

Specific Yield, Capacity Factor and Performance Ratio

Applying Equation (9): Specific Yield = 5,816.7 / 3.9 ≈ 1,491.5 kWh/kWp/year. This value falls within, and toward the upper end of, the typical 1,200–1,600 kWh/kWp/year range reported for well-designed PV systems in tropical regions, reflecting the additional energy contribution of the bifacial modules used in this design. Applying Equation (10): Capacity Factor = 5,816.7 / (3.9 × 8,760) ≈ 17.0%, consistent with, and slightly above, values typically reported for fixed-tilt monofacial PV installations in similar tropical locations (15–19%), reflecting the incorporated bifacial energy gain.

Solar Fraction and Load Coverage

The annual solar-supported load demand is 20.144 kWh/day × 365 days ≈ 7,352.6 kWh/year. Applying Equation (11): Solar Fraction = (5,816.7 / 7,352.6) × 100 ≈ 79.1%. This indicates that, on an annual energy-balance basis, the 3.9 kWp bifacial PV array alone supplies approximately 79.1% of the total solar-supported load, with the balance requiring either battery-stored solar energy carried over from other periods or grid backup. This finding is independently corroborated by the hourly simulation results of Section 5.2.

Annual Grid Dependency: With and Without Demand-Side Control

Extending the hourly simulation methodology of Section 3.5 across the full twelve-month PSH profile of Table 10, with the demand-side control strategy active throughout, the estimated annual grid-import requirement was computed month by month, as summarized in Table 11.

Month	**Grid import required (kWh)**
January	69.6
February	57.6
March	93.5
April	119.2
May	153.4
June	197.6

July	224.7
August	214.4
September	177.9
October	143.3
November	100.1
December	63.8
ANNUAL TOTAL	1,615.2

Table 11. Estimated monthly and annual grid import requirement (with demand-side control)

The annual grid-import requirement of 1,615.2 kWh represents approximately 22.0% of the total annual solar-supported load of 7,352.6 kWh, closely corroborating the 20.9% shortfall (100% − 79.1%) computed independently from the simple annual energy-balance method of Section 5.5. This close agreement between the two independent estimation approaches — the aggregate annual energy balance and the detailed hourly simulation — lends confidence to the overall performance assessment. Grid dependency is highest during the peak rainy-season months of June to September, when solar irradiance is lowest, and lowest during the dry-season months of November to February. As demonstrated in Section 5.2.3, the demand-side control strategy is highly effective at reducing this grid dependency: on a representative typical day, grid import fell from 4.76 kWh (without DSM) to 0 kWh (with DSM), a 100% reduction, underscoring the material value of the demand-side control measures designed in this study.

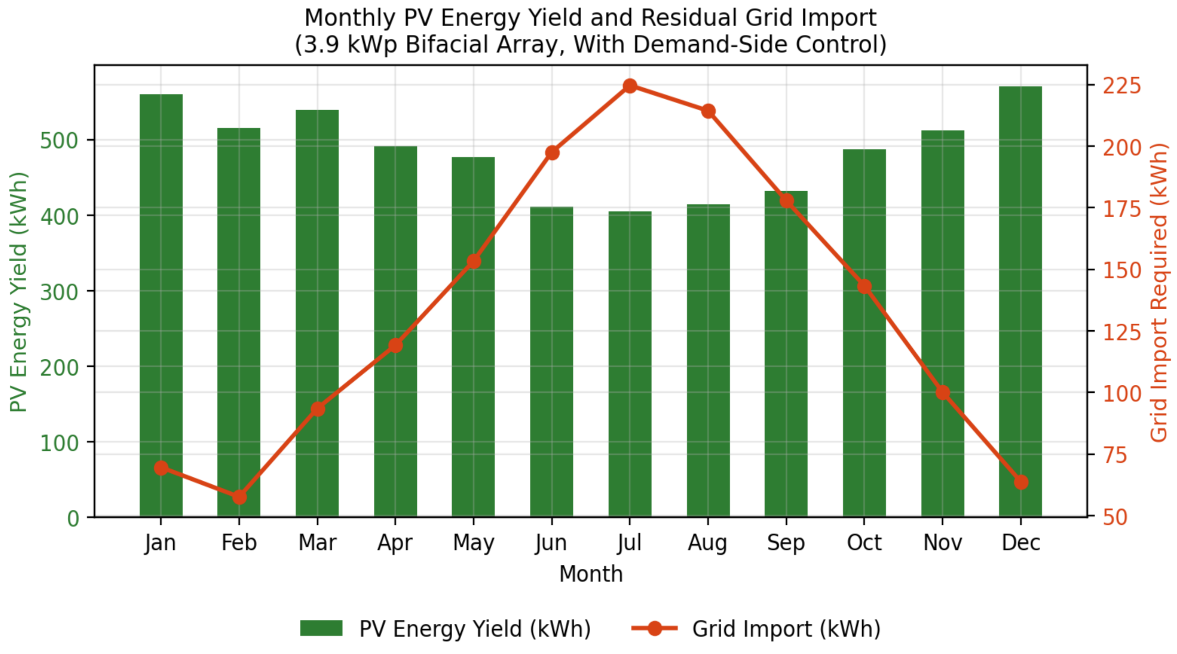

Figure 4. Monthly PV energy yield and residual grid import required, with demand-side control active (derived from Tables 10 and 11)

Graph Analysis

Figures 1–4 together characterize the temporal behaviour of the designed system across three timescales — hourly, daily, and monthly — and support several consistent observations. First, Figure 1 shows PV generation and load closely tracking one another between 10:00 and 16:00, the window in which the demand-side scheduled air-conditioning load draws directly from concurrent PV output; the battery reaches and holds 100% SOC through this period rather than cycling, indicating that the array is appropriately sized to meet peak midday demand with surplus capacity available for battery replenishment. Second, Figure 2 exhibits two markedly different SOC trajectories for an identical starting condition and total daily load: the DSM trajectory declines gently and predictably through the evening, while the non-DSM trajectory shows a steep double-step decline coincident with the 18:00–02:00 unmanaged air-conditioning window, striking the 20% SOC floor and forcing a sustained grid-import plateau from 21:00 to 23:00. The shape of this second curve — rather than only its end-point — is diagnostic: it shows that uncontrolled load timing does not merely add average grid dependency but concentrates it into a specific overnight period of maximum consumption and minimum PV availability, precisely when a hybrid inverter's grid-transfer function is required regardless of the ostensible annual solar fraction. Third, the monthly PV yield curve of Figure 3 and the grid-import curve of Figure 4 are approximately mirror images of one another: yield peaks in the November–February dry season and troughs in June–August, while grid import troughs in the dry season and peaks in the rainy season, with the crossover points in the two curves (around April–May and October) marking the transitional shoulder seasons in which grid dependency begins to rise or fall most steeply. This inverse but non-identical relationship — grid import does not fall to exactly zero even in the highest-yield months, and does not rise in direct proportion to the yield shortfall in the lowest-yield months — reflects the buffering effect of the battery bank, which absorbs a portion of short-term irradiance variability, and the fixed, DSM-scheduled shape of the daily load profile, which limits how much load can be shifted into any single day's solar window regardless of that day's irradiance.

Battery State of Charge, Autonomy, and Cycling Behaviour

The hourly simulation results of Section 5.2 show that the battery bank, with DSM active, typically completes a shallow daily charge/discharge cycle, ending most days at a healthy SOC of 40% or above, except following consecutive low-irradiance days, when SOC may be driven down to the manufacturer's minimum allowable level of 20%. This pattern of predominantly shallow cycling, punctuated by occasional deeper discharges during extended cloudy periods, is favourable for LFP battery longevity, as it is expected to result in an average cycle depth well below the battery's rated 80% DoD cycle-life test condition, potentially extending the practical service life of the battery pack beyond its rated 6,000-cycle figure [5]. The demand-side control strategy's role in preserving battery SOC margin is therefore expected to yield a secondary economic benefit in the form of extended battery replacement intervals, beyond the direct grid-cost savings quantified in Section 5.9.

Economic Evaluation

Using the indicative total capital cost of ₦4,216,300 (Table 6), and recognizing that the demand-side control strategy enables the system to displace 5,737.4 kWh/year from the grid/generator (the annual solar-supported load of 7,352.6 kWh less the residual annual grid import of 1,615.2 kWh under DSM, from Table 11), annual cost savings were computed at a blended avoided-cost rate of ₦150/kWh: Annual Cost Savings = 5,737.4 × 150 ≈ ₦860,610. Applying Equation (12): Simple Payback Period = 4,216,300 / 860,610 ≈ 4.9 years.

Net Present Value and Internal Rate of Return

Applying a discount rate of 12% over an assumed 20-year system economic life, and treating the annual cost saving of ₦860,610 as a constant annual cash inflow (a simplifying assumption discussed in Section 5.11), Equation (13) gives: $NPV = -\text{₦}4{,}216{,}300 + \Sigma^{t}{}_{=1}{}^{20}\,[\text{₦}860{,}610\,/\,(1.12)^{t}] \approx +\text{₦}2{,}211{,}978$. The positive NPV confirms that the investment is economically viable at the assumed discount rate. The internal rate of return — the discount rate at which NPV equals zero — was computed as approximately 19.9%, comfortably exceeding the 12% discount rate and further confirming the attractiveness of the investment. The discounted payback period, accounting for the time value of money, was computed as approximately 8 years, well within the system's 20-year assumed economic life.

Levelized Cost of Energy

Assuming annual O&M costs of 1.5% of capital cost per year over the 20-year system life, and applying an average lifetime energy derating factor of 5% to account for module degradation, Equation (14) gives:

$$LCOE = \frac{₦4{,}216{,}300 + ₦1{,}264{,}890}{5{,}816.7 \times 20 \times 0.95} \approx ₦49.6/kWh.$$

This LCOE compares very favourably with the assumed blended grid/generator avoided-cost rate of ₦150/kWh, indicating that solar energy from the designed system is roughly one-third the cost of the grid/generator electricity it displaces over the system's economic life — a finding broadly consistent with LCOE comparisons reported for residential and commercial PV systems elsewhere in Nigeria [10,11,33], where LCOE is likewise found to be highly sensitive to local avoided-cost assumptions and site energy audit accuracy.

Economic indicator	Value
Total indicative capital cost	₦4,216,300
Annual cost saving	₦860,610
Simple payback period	4.9 years
Discounted payback period (12%)	≈ 8 years
Net present value (12%, 20 years)	+₦2,211,978
Internal rate of return (IRR)	≈ 19.9%
Levelized cost of energy (LCOE)	≈ ₦49.6/kWh
Blended grid/generator avoided cost	₦150/kWh

Table 12. Summary of economic evaluation indicators

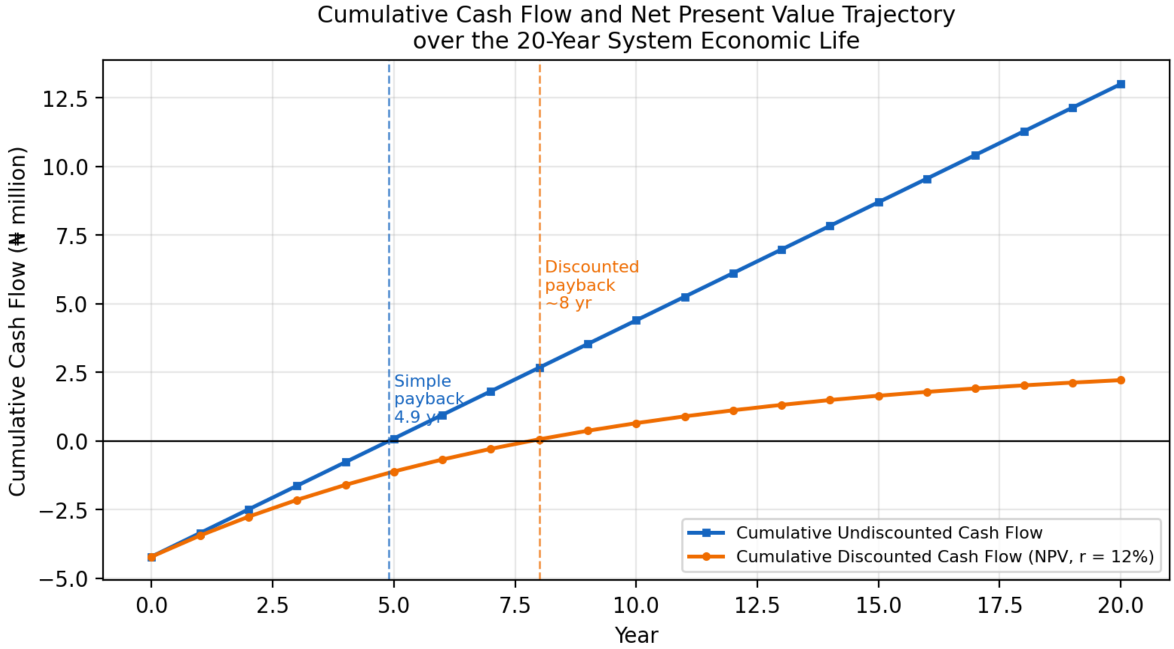

Figure 5. Cumulative undiscounted and discounted (NPV) cash-flow trajectories over the 20-year system economic life, showing the simple and discounted payback points

Figure 5 illustrates the divergence between the undiscounted and discounted cumulative cash-flow trajectories. Both curves cross zero — the payback point — but at different times: the undiscounted curve reaches breakeven at 4.9 years, while the discounted (NPV) curve, which progressively down-weights future cash flows at the 12% discount rate, does not reach breakeven until approximately year 8. The widening gap between the two curves in the later years of the project life reflects the compounding effect of discounting on distant cash flows, and illustrates why the discounted payback period, rather than the simple payback period alone, is the more conservative and informative indicator of investment risk for a 20-year asset.

Environmental Impact Assessment

Using the annual energy displaced from the grid/generator (5,737.4 kWh/year, Section 5.9) and a blended emission factor of 0.7 kg CO_2/kWh, Equation (15) gives: Annual CO_2 Reduction = 5,737.4 × 0.7 ≈ 4,016.2 kg ≈ 4.02 tonnes/year. Over the projected 20-year system lifespan, this translates to an estimated cumulative CO_2 emission reduction of approximately 80.3 tonnes — a meaningful, if modest-scale, contribution to greenhouse gas emission reduction consistent with the residential scale of the designed system.

Environmental indicator	**Value**
Annual energy displaced from grid/generator	5,737.4 kWh/year
Blended emission factor	0.7 kg CO_2/kWh
Annual CO_2 emission reduction	≈ 4.02 tonnes/year
Cumulative CO_2 reduction (20-year life)	≈ 80.3 tonnes

Table 13. Summary of environmental impact indicators

DISCUSSION OF RESULTS

The results obtained show that the pre-specified 6.5 kVA hybrid inverter, 10 kWh LFP battery pack, and 3.9 kWp bifacial PV array constitute a technically adequate, though not fully self-sufficient, solution for the assessed residential load. On an annual energy-balance basis, the system meets approximately 79% of the solar-supported load directly from solar generation, with the demand-side control strategy — comprising load segregation, prioritization, and scheduling — playing a decisive role in minimizing the residual 21–22% grid dependency and, more importantly, in determining when that grid dependency occurs. The hourly simulation results demonstrate unambiguously that, without demand-side control, the same fixed hardware would require substantially more grid support concentrated in the overnight period and would subject the battery bank to deeper, more frequent discharge cycles, both of which carry direct economic costs in the form of higher electricity/fuel bills and shortened battery service life.

The economic evaluation confirms that, despite the system's inability to achieve full energy self-sufficiency, the investment remains financially attractive, with a sub-5-year simple payback, a positive NPV, an IRR well above the assumed discount rate, and an LCOE substantially below the cost of grid/generator electricity — broadly consistent with, though more favourable than, several comparable Nigerian residential PV studies in which LCOE outcomes were found to be highly sensitive to site-specific load-audit and avoided-cost assumptions [9,10,33]. The environmental analysis further confirms a meaningful, positive contribution to emission reduction, consistent with the general finding in the literature that residential PV adoption in grid-constrained, generator-reliant contexts such as Nigeria yields disproportionately large emission benefits relative to system scale, owing to the high emission intensity of the diesel-generator baseline being displaced [34].

It should be noted that this evaluation relies on several simplifying assumptions — constant annual cash flows with no tariff escalation, a fixed blended avoided-cost rate, representative rather than site-measured solar irradiance data, and an assumed DC standing-fan wattage — which, while reasonable for a project-level feasibility assessment, would benefit from refinement using site-specific metered data, tariff-escalation scenarios, and battery-replacement cost modelling in any subsequent, more detailed engineering study. In addition, the hourly simulation model, while validated internally through the close agreement between its annual grid-import estimate and the independent annual energy-balance calculation (Section 5.6), has not been validated against field-metered performance data from the installed system, which represents the most important direction for further work identified in Section 6.

CONCLUSION

This study has presented the design, hourly simulation, and techno-economic evaluation of a 6.5 kVA hybrid solar PV system for demand-side energy control at a residential facility in Redemption City, Mowe, Ogun State, Nigeria, using a fixed set of pre-specified commercial components: a TAICO 6.5 kVA hybrid inverter, a TAICO T-ONE 10 kWh LFP battery pack, and a 3.9 kWp Jinko Solar bifacial PV array. Sizing verification confirmed the technical adequacy of this configuration for an audited load of 2,234 W connected and 20.144 kWh/day, with two water heaters and two microwave ovens (5,400 W combined) deliberately segregated onto the utility grid. A three-part demand-side control strategy — load segregation, prioritization, and scheduling — was designed and evaluated using a custom hourly energy-balance simulation model, which demonstrated a 100% reduction in grid-import requirement on a representative typical day when the strategy was applied, compared with an unmanaged load schedule. Annual performance evaluation showed an estimated PV energy yield of 5,816.7 kWh/year (specific yield 1,491.5 kWh/kWp/year, performance ratio 0.78 inclusive of a 10% bifacial gain), meeting approximately 79.1% of the annual solar-supported load, with the remainder supplied by grid backup even with demand-side control active. Economic evaluation showed a total capital cost of ₦4,216,300, a simple payback period of 4.9 years, a positive NPV of ₦2,211,978 at a 12% discount rate over 20 years, an IRR of approximately 19.9%, and an LCOE of about ₦49.6/kWh, substantially below the ₦150/kWh blended grid/generator avoided cost. Environmental evaluation estimated an annual CO_2 emission reduction of about 4.02 tonnes.

It is concluded that the pre-specified hybrid inverter, LFP battery pack, and bifacial PV array constitute a technically sound and economically viable solution for the assessed residential load, provided that a deliberate demand-side energy control strategy is implemented alongside the hardware. The system does not achieve full annual energy self-sufficiency, and continued grid backup remains necessary, particularly during the peak rainy season and following consecutive low-irradiance days; however, the demand-side control strategy substantially reduces and reshapes this residual grid dependency in a manner that protects battery health and minimizes cost. The study confirms that appropriately managed demand-side control can meaningfully extend the effective utility of a modestly sized, budget-constrained solar PV installation, offering a practical, replicable, and economically attractive pathway for residential solar adoption in high-insolation but grid-constrained regions of Nigeria and comparable developing-country contexts.

RECOMMENDATIONS

On the basis of the findings, it is recommended that: homeowners and installers working with fixed or budget-constrained solar PV component selections adopt a demand-side energy control strategy — comprising load segregation, prioritization, and scheduling — similar to the one designed in this study, rather than assuming that hardware capacity alone determines system adequacy; high-power, short-duration resistive loads such as water heaters and microwave ovens generally be excluded from modestly sized residential solar PV systems and kept on the utility grid, to avoid disproportionate oversizing of the inverter and battery bank; flexible, high-power loads such as air-conditioning units be scheduled or user-encouraged, wherever practicable, to operate during hours of peak solar generation, to maximize direct self-consumption of solar energy and minimize battery cycling and grid dependency; and, given the residual annual grid dependency identified in this study (approximately 22% even with demand-side control), homeowners retain a reliable grid or generator backup connection rather than pursuing a fully off-grid configuration at this scale of PV array and battery capacity. Future installations and studies should incorporate on-site solar irradiance and module-temperature measurement (e.g., a low-cost pyranometer or reference cell alongside a panel-surface thermocouple) and metered appliance-level load data, where feasible, to refine the representative assumptions used in this study and improve the accuracy of performance and economic projections.

Suggestions for Further Work

Suggested directions for further work include: physical procurement, installation, and field commissioning of the designed system, with metered performance monitoring over at least one full annual cycle, to validate the analytical and simulated performance predictions of this study; incorporation of an automated, microcontroller- or smart-relay-based demand-side control system capable of dynamically scheduling the air-conditioning load based on real-time PV output and battery SOC, rather than the fixed daily schedule assumed here; extension of the economic evaluation to incorporate electricity tariff escalation, foreign-exchange-rate sensitivity, and battery-replacement cost scenarios over the full system lifetime; and comparative techno-economic evaluation of alternative PV array or battery capacity configurations, to determine whether a modest capacity increase would be economically justified by the resulting reduction in grid dependency.

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