

Load-Flow Assessment of Federal University of Technology, Akure 11 KV Distribution Network for Solar PV Integration

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ABSTRACT

The increase in electricity demand of Nigerian universities, with an epileptic public grid, has created interest in integrating solar photovoltaic (PV) generation into distribution networks. This study presents a load-flow assessment of the 11 kV/0.415 kV distribution network of the Federal University of Technology, Akure (FUTA). Hourly load data for a month were compiled using digital smart meters for 20 distribution substations across three campus operating states, namely Academic Session, Examination Period and Academic Break, and used to derive 24-hour aggregate load profiles, substation demand factors and a system diversity factor. A single-line model of the FUTA network, comprising a 7.5 MVA grid intake transformer, a 4 MVA (2 x 2 MVA) solar PV interconnection scheme feeding an 11 kV PV Integration Bus, and a battery energy storage system (BESS), was analysed in ETAP. The assessment combines (i) a stringent PV-islanded snapshot case for the instrumented Obanla precinct segment and (ii) an extended Newton-Raphson load-flow sweep across thirteen time-segmented solar-irradiance scenarios (0-900 W/m²) combined with the three measured campus load profiles, so that PV performance is characterised across varying irradiance and demand rather than at a single operating point. The aggregate campus peak demand was 2778.1 kW at 11:00 hrs during the Academic Session (load factor 0.742), 2203.9 kW at 14:00 hrs during the Examination Period (load factor 0.680), and 1610.8 kW at 20:00 hrs during the Academic Break (load factor 0.520), with a near-unity system diversity factor of 1.000-1.013 in all states, indicating strongly coincident substation peaks. In the PV-islanded case, the two solar transformers jointly delivered approximately 485.2 kW and 423.4 kVAR to the PV Integration Bus, of which 253.8 kW reached the two instrumented busways; a power-balance calculation at the PV Integration Bus shows that ohmic (transformer and cable) losses account for less than 20 kW of the residual 231.4 kW, with the remainder attributable to reactive absorption and to power routed toward the unmonitored third busway (BusWay9) and reserve/BESS-charging capacity rather than to unexplained loss. Across the extended irradiance sweep, network voltage remained within the conventional $\pm 10\%$ (0.90-1.10 pu) statutory tolerance band except for a brief dip to 88.13% at SEMS Bus 2 during the low-irradiance (10%) ramp of the Academic Session, and the SEMS and CERAD distribution transformers were found to operate above rated capacity (up to 176.6% and 141.6% respectively) at every PV penetration level, confirming a pre-existing capacity constraint unrelated to the PV scheme. Active-power losses rise sharply at low irradiance, from 0.0136 MW (no PV) to 0.464 MW at 10% irradiance during the Academic Session peak window, before falling back to 0.0239 MW at 90% irradiance, underscoring the need for coordinated reactive-power management during PV ramp-up. The implications for PV hosting capacity, voltage regulation, transformer loading margins and battery dispatch strategy are discussed, and a phased, feeder-prioritised PV/BESS integration plan is recommended.

Keywords: Load flow analysis, solar photovoltaic integration, distribution network, demand factor, diversity factor, ETAP simulation.

INTRODUCTION

Reliable electricity supply remains a persistent challenge for public institutions in Nigeria, where frequent grid

outages and voltage instability disrupt academic, research and administrative activities. The Federal University of Technology, Akure (FUTA) draws bulk power from the national grid through a dedicated intake substation and redistributes it through an internal 11 kV network to more than twenty distribution substations serving hostels, lecture theatres, laboratories, staff quarters and commercial outlets on campus. In order to reduce dependence on the grid and on diesel back-up generation, the university has installed a grid-tied solar PV plant, interconnected at 11 kV through a dedicated PV Integration Bus, together with a battery energy storage system (BESS) intended to firm up the intermittent solar output.

The introduction of embedded generation into a distribution network originally designed for unidirectional power flow from the grid changes the network's steady-state operating characteristics. Voltage profiles, transformer and feeder loading, and fault levels can all be affected, and the extent of the impact depends on the PV plant's location and capacity relative to the local load. A rigorous load flow assessment is therefore necessary to confirm that the existing network can accommodate the additional generation without violating voltage or thermal limits, and to establish the practical PV hosting capacity of the network.

This study addresses that requirement for the FUTA distribution network by combining two complementary data sources: (i) metered 24-hour load profiles for 20 distribution substations across three representative operating states of the university calendar; and (ii) an ETAP one-line power flow model of the core Obanla precinct of the network, in which the PV plant and BESS are interconnected, used to examine bus loading and power flow under a grid-open, PV-islanded operating case. The specific objectives are to: (a) characterise the diurnal and session-dependent load behaviour of the network; (b) quantify substation-level demand factors and the overall system diversity factor; (c) evaluate, through load flow simulation, the ability of the installed PV/BESS scheme to supply the instrumented network segment; and (d) identify existing network constraints and recommend a technically sound PV/BESS integration strategy.

Load flow (power flow) analysis is the fundamental steady-state study used to determine bus voltage magnitudes and angles and the active/reactive power flowing in every branch of a network for a specified generation and load condition. Distribution networks are typically radial with a high resistance-to-reactance ratio, which limits the direct applicability of transmission-oriented solvers such as the classical Gauss-Seidel and Newton-Raphson formulations and has motivated dedicated radial and iterative approaches, alongside commercial distribution-simulation packages, for distribution-level studies (Zdiri *et al.*, 2023). Commercial platforms such as ETAP remain widely used in industry and academia for distribution load flow, short-circuit and stability studies because they combine a Newton-Raphson-based solver with a graphical one-line environment that mirrors as-built network topology; ETAP-based studies of high-voltage and distribution substations have been used to identify under-voltage conditions and to test corrective measures such as shunt capacitor banks (Kamble and Rewatkar, 2017), and integrated ETAP/single-line-diagram approaches have similarly been applied to optimise load-current analysis and voltage-profile visualisation in a typical power system model (Mehtre and Dubey, 2024).

A growing body of work has examined the effect of embedding solar PV generation in distribution networks. Studies that model renewable sources within the load flow problem of low-voltage radial networks report that appropriately sized and sited PV can improve voltage profile, reduce losses and mitigate reverse power flow, while poorly sized PV can have the opposite effect (Zdiri *et al.*, 2023). ETAP-based studies on modified IEEE bus systems with PV integration show that inverter-based generation reduces the real and reactive power drawn from synchronous sources and can improve transient voltage stability, provided adequate reactive support is available at the point of interconnection (Yustika *et al.*, 2026; Upadhyay and Jamnani, 2022). Quasi-dynamic, time-domain load flow studies that incorporate a full daily solar irradiance profile further show that although DC-side voltage deviation from PV variability can be modest, AC-side bus voltage deviation can be considerably larger, underscoring the value of studying PV integration across the complete daily load-generation cycle rather than at a single snapshot (Mashavave *et al.*, 2025). At the planning level, hosting-capacity studies using probabilistic and learning-assisted load flow methods are used to determine the maximum PV capacity a feeder can absorb without breaching voltage or thermal constraints, reinforcing the case for a feeder-by-feeder, demand-informed approach to PV siting (Ly *et al.*, 2025).

In the Nigerian context, several studies have examined solar PV and hybrid microgrid deployment on university campuses as a response to grid unreliability. Feasibility and sizing studies using tools such as HOMER Pro report that campus PV/battery systems can supply the bulk of institutional energy needs, with PV energy fractions reported as high as 88% of annual demand for one Nigerian university case, alongside a multi-year investment payback period (Ogbikaya and Iqbal, 2022; Idemudia and Jimoh, 2024). A more recent techno-economic study of a wind-solar-battery microgrid for a Nigerian university campus reported a 74.3% renewable energy fraction and a diversity factor of 0.60 between two campus load centres with complementary daily usage patterns, underscoring how load coincidence directly shapes the achievable renewable-energy fraction and required generation/storage capacity (Adenle and Akinpelu, 2026). Related work has applied machine-learning-based demand forecasting and load-shedding techniques on a Nigerian university campus (Oyinlola and Oluseyi, 2025), reported field-measured load-demand and emissions data from a Nigerian private university's diesel-PV-grid hybrid power station (Zarma et al., 2023), reviewed PV-based microgrid concepts and sizing strategies for electrification more broadly across Nigeria (Nta *et al.*, 2024), demonstrated real-time field-measurement-based microgrid sizing methodology for a Nigerian test-bed installation (Alagbu *et al.*, 2022), and mapped hybrid-energy-system deployment trends across Nigerian institutional and urban settings, noting that grid-connected PV-battery hybrids are emerging as the most viable configuration for university campuses (Adeyeye and Mbohwa, 2026). These studies consistently identify accurate load characterisation as a prerequisite for correctly sizing embedded PV and storage assets.

Demand factor and diversity factor are well-established, complementary distribution-planning indices. Demand factor is the ratio of the actual maximum (peak) demand of a system, or part of a system, to its total connected (installed) capacity, and is always less than or equal to unity, reflecting the fact that connected loads are rarely all active simultaneously at full rating. Diversity factor, by contrast, is the ratio of the sum of the individual maximum demands of the constituent parts of a system to the coincident maximum demand of the system as a whole; it is normally greater than unity because individual loads do not all peak at the same time, and a value close to unity signals strong coincidence between sub-load peaks. Probabilistic treatments of diversified transformer and feeder loading confirm that the diversity factor is itself time- and probability-dependent, and utilities use it, together with the demand factor, to right-size transformers, feeders and, increasingly, embedded generation and storage assets relative to actual rather than nameplate demand (Heydt, 2023). This study applies these indices to the FUTA network alongside an ETAP-based power-flow case study, combining planning-level statistical load characterisation with an operational-level steady-state simulation of the PV/BESS interconnection — a combined treatment that, to the authors' knowledge, has not previously been reported for this network.

MATERIALS AND METHODS

Study Area and Network Description

Under existing supply conditions, FUTA receives power from the Leo Junction 132/33 kV transmission substation, which is equipped with two 60 MVA and one 30 MVA power transformers. At the campus injection substation, the voltage is stepped down from 33 kV to 11 kV through a 7.5 MVA transformer, and the 11 kV network is distributed across campus via a single-busbar switchboard with ring-main-unit switches, through three main feeders, Obaekere, Obanla I and Obanla II all supplying twenty distribution substations across academic, administrative, residential and commercial load centres as shown in Figure 1 and a centralised solar PV plant generating at 0.66 kV is stepped up to 11 kV through two 2 MVA transformers and interconnected at the same busbar, with battery storage for output firming; four synchronised diesel generator sets of 2×1.5 MVA, 2×1.3 MVA as shown in Figure 2, are also part of the university's broader hybrid-supply plan.

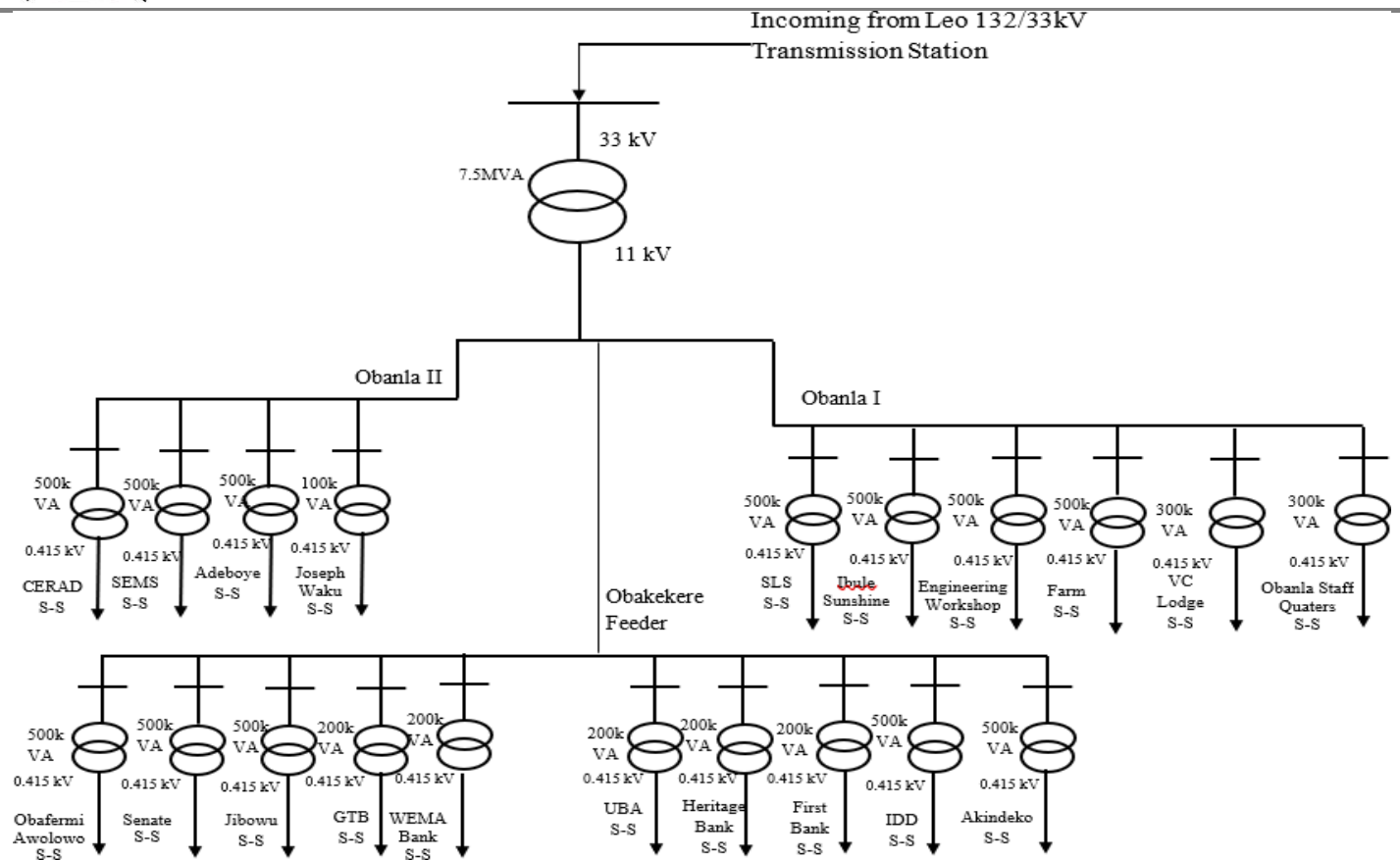


Figure 1. Single-Line Diagram of the Existing FUTA Sub-Distribution Network

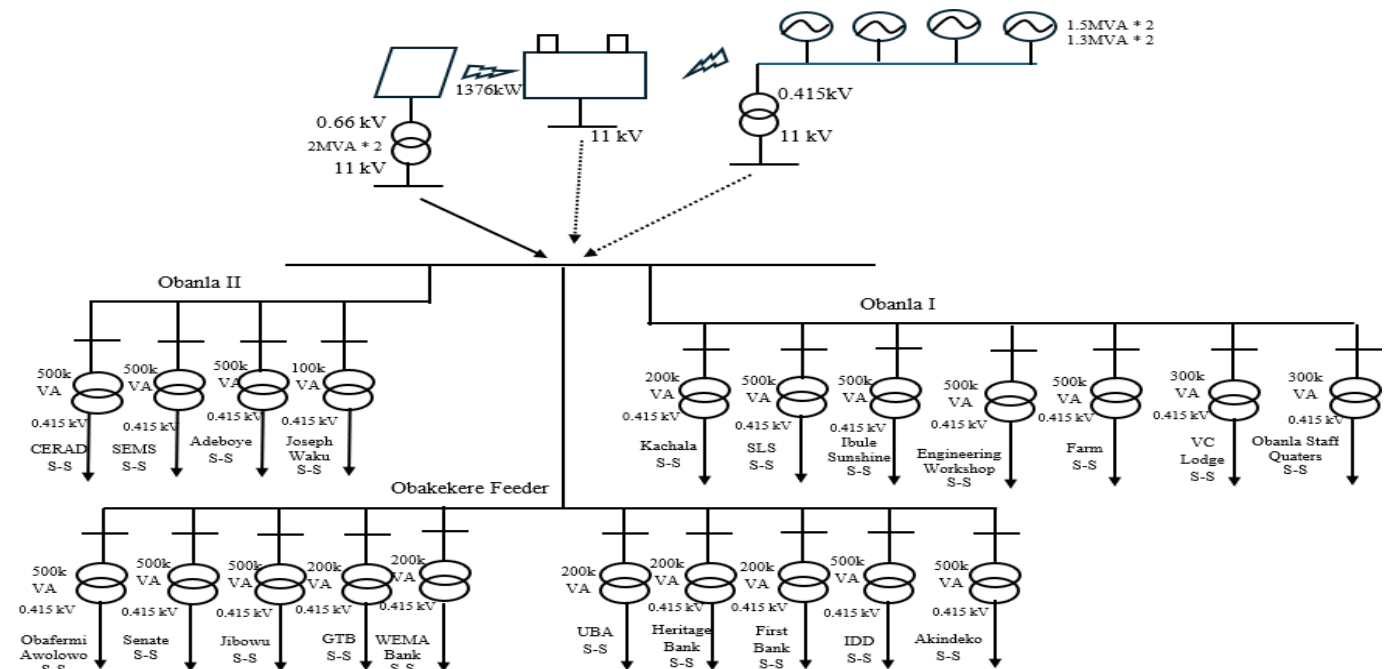


Figure 2: Single-Line Diagram of the Proposed FUTA Sub-Distribution Network Integrated with a Hybrid Solar PV–Diesel Generation and Energy Storage System

Data Collection

Hourly real-power load data, from 00:00 h to 23:00 h over 30 days, were compiled using calibrated digital smart meters for the 20 distribution substations under three operating states that reflect the university calendar:

The Academic Session, the Examination Period and the Academic Break. For each state and substation, the installed transformer capacity was also recorded, permitting calculation of substation- and system-level demand indices.

Demand Factor and System Diversity Factor.

The demand factor (DF) of each substation was computed as the ratio of its metered peak demand within a given operating state to its installed transformer capacity as shown in Equation 1 in line with standard distribution-planning practice:

$$P(t) = \frac{E(t)}{\Delta t} \quad (1)$$

where $P(t)$ is the active power demand in kW at interval t , $E(t)$ is the energy consumed during that interval in kWh , and Δt is the measurement interval (1 hour).

The load factor (LF), which indicates how effectively a substation's or the system's installed capacity is utilised over time, was computed using Equation 2:

$$LF = \frac{E_{total}}{P_{peak} \times T} \quad (2)$$

where E_{total} is the total energy consumed over the observation period in kWh , P_{peak} is the maximum observed hourly demand in kW , and T is the total duration of observation (hours).

The demand factor (DF) of each substation, the ratio of its metered peak demand to its installed transformer capacity, was computed using Equation 3:

$$DF = \frac{P_{max}}{P_{installed}} \quad (3)$$

where P_{max} is the observed peak demand (kW) and $P_{installed}$ is the total rated (nameplate) capacity of the substation transformer (kW).

The system diversity factor (DF_v), which assesses the degree of simultaneity between individual substation peak demands and the coincident system peak, was computed using Equation 4:

$$DF_v = \sum \frac{P_{individual\ peak}}{P_{group\ peak}} \quad (4)$$

where $P_{individual\ peak}$ is the sum of the individual peak demands of the 20 substations (each evaluated at its own peak hour, irrespective of the operating state) and $P_{group\ peak}$ is the coincident peak demand of the aggregated 20-substation system. A diversity factor greater than unity indicates that individual substation peaks do not occur simultaneously.

Load Flow Simulation in ETAP

The FUTA distribution system was modelled in ETAP using the recorded utility data. Two complementary load-flow analyses were performed. The first is a PV-islanded adequacy case with a single, stringent operating snapshot in which the instrumented Obanla I and Obanla II loads were supplied solely from the solar PV plant with the grid incomer breaker open, used to test the stand-alone adequacy of the PV plant. The second was an extended, thirteen-scenario irradiance sweep in which the PV unit was modelled as a generator (PV) bus with a specified active-power injection and a regulated voltage magnitude, subject to inverter reactive-power capability limits; when the reactive-power limit is reached, the bus is automatically converted to a PQ bus to reflect realistic inverter operating constraints. This second analysis was combined, in turn, with each of the three measured campus load profiles (Academic Session, Examination Period, Academic Break), the PV performance was evaluated jointly across varying generation and demand rather than at a single operating point and shown in Figure 3.

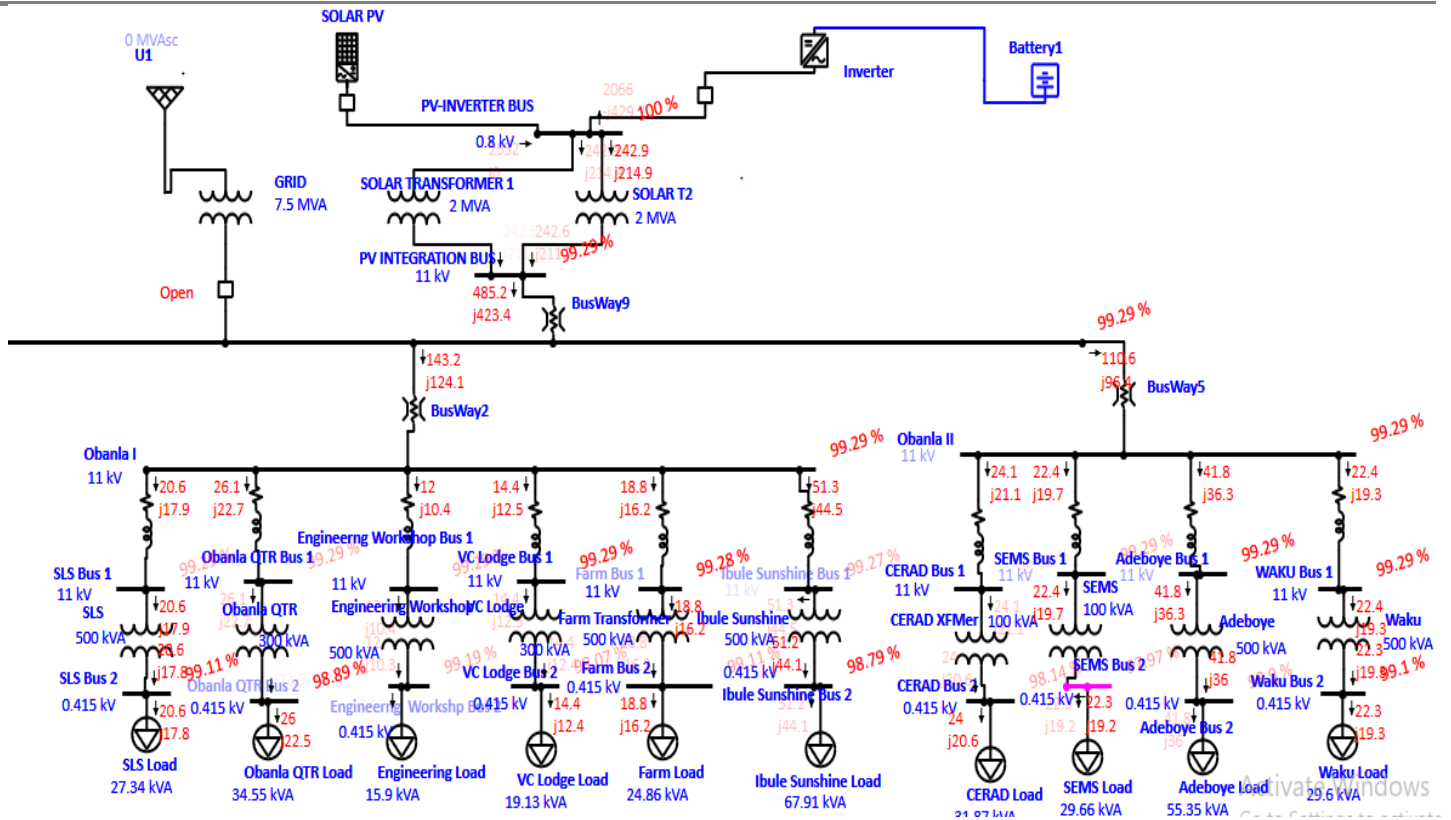


Figure 3. Simulated Single-line Diagram of FUTA Network Obanla, using ETAP.

Newton-Raphson load-flow analysis, as in Equations 5-8, were used for the active power, reactive power, active-power loss and reactive-power loss respectively, consistent with established practice for distribution and embedded-generation studies (Mashavave *et al.*, 2025; Yustika *et al.*, 2026).

$$P_i = V_i \sum_{j=1}^n V_j (G_{ij} \cos(\delta_i - \delta_j) + B_{ij} \sin(\delta_i - \delta_j)) \quad 5$$

where P_i is the injected active power and Q_i (Equation 6) the injected reactive power at bus i ; V_i and V_j are the voltage magnitudes at buses i and j ; δ_i and δ_j are the corresponding voltage phase angles; G_{ij} and B_{ij} are respectively the real (conductance) and imaginary (susceptance) components of the i - j element of the bus admittance matrix; and n is the total number of network buses.

$$Q_i = V_i \sum_{j=1}^n V_j (G_{ij} \sin(\delta_i - \delta_j) - B_{ij} \cos(\delta_i - \delta_j)) \quad 6$$

The model comprises the 7.5 MVA grid transformer, the two 2 MVA solar step-up transformers, the 11 kV PV Integration Bus, the inverter-coupled BESS, the 11 kV busways (BusWay2, BusWay5, BusWay9) and the downstream substation transformers and loads. Total active- and reactive-power losses on the network branches were determined using the Equations 7 and 8.

$$P_{loss} = \sum_{k=1}^n I_k^2 R_k = \sum_{k=1}^n \frac{|S_k|^2}{|V_k|^2} R_k \quad 7$$

$$Q_{loss} = \sum_{k=1}^n I_k^2 X_k = \sum_{k=1}^n \frac{|S_k|^2}{|V_k|^2} X_k \quad 8$$

where P_{loss} and Q_{loss} are the total active and reactive power losses; I_k is the current through line segment k ; R_k and X_k are the resistance and reactance of line k ; S_k is the apparent power on line k ; V_k is the sending-end voltage magnitude of line k ; and n is the total number of network line segments.

Transformer loading, reported as a percentage in the Results, was obtained from the apparent power at the transformer terminals using Equation 9 and expressed as a fraction of the transformer's rated apparent power

using Equation 10.

$$S = \sqrt{P^2 + Q^2} \quad 9$$

$$L_T = \frac{S_T}{S_{T \text{ rated}}} \times 100\% \quad 10$$

where S is the apparent power, P and Q the active and reactive power at the transformer terminals, L_T is the percentage transformer loading, S_T the transformer's operating apparent power and $S_{T \text{ rated}}$ its rated (nameplate) apparent power. Finally, to close the power balance at the PV Integration Bus and quantify, rather than only qualitatively describe, the disposition of the power leaving the PV plant, Equation 11 was used.

$$P_{PV \text{ out}} = P_{bus \text{ way } 2} + P_{bus \text{ way } 5} + P_{bus \text{ way } 9} + P_{loss \text{ network}} \quad 11$$

where $P_{PV \text{ out}}$ is the combined active power delivered by the two solar transformers to the PV Integration Bus; $P_{bus \text{ way } 2}$ and $P_{bus \text{ way } 5}$ are the active powers received at the two instrumented busways; $P_{bus \text{ way } 9}$ is the active power routed toward the third, unmonitored busway of the model (including any reserve held for BESS charging); and $P_{loss \text{ network}}$ is the aggregate transformer and cable loss between the PV Integration Bus and the downstream busways.

The corresponding reactive power balance was obtained by replacing each active power term above with its reactive power counterpart and $P_{loss \text{ network}}$ with $Q_{loss \text{ network}}$ from Equation 7 and 8.

Time-Segmented Solar Irradiance Scenarios

To determine the PV performance under varying irradiance rather than at a single operating point, a time-segmented irradiance profile comprising thirteen (13) scenarios was incorporated into the extended load-flow sweep, as shown in Table 1. This scenario presents a realistic weather conditions across a 24-hour period, ranging from night-time (0 W/m²) to peak clear-sky conditions (900 W/m²); for each scenario the PV output was adjusted proportionally to irradiance while the installed PV capacity was held constant. Load-flow analysis was performed for every irradiance scenario in combination with each of the three measured load profiles, and upon convergence, bus voltages, branch currents and power flows were extracted to compute transformer loading and technical losses. This combined sweep directly addresses the limitation of assessing PV performance from a single PV-islanded snapshot.

Table 1. Time-Based Solar Irradiance Scenarios (0-24 Hours)

Time Band	Scenario	Irradiance (W/m ²)	Description
0-5 hrs	S1	0	No solar generation
6-10 hrs	S2	100	Very cloudy and early sun
6-10 hrs	S3	300	Normal morning
6-10 hrs	S4	500	Clear late morning
11-16 hrs	S5	100	Heavy cloud
11-16 hrs	S6	300	Cloudy
11-16 hrs	S7	500	Partly cloudy
11-16 hrs	S8	700	Clear
11-16 hrs	S9	900	Very clear sky (peak)
17-19 hrs	S10	100	Cloudy evening

Time Band	Scenario	Irradiance (W/m ²)	Description
17-19 hrs	S11	300	Normal
17-19 hrs	S12	500	Clear early evening
20-24 hrs	S13	0	No solar generation

RESULTS AND DISCUSSION

Twenty-Four-Hour Aggregate Load Profile

Figure 4 plots the aggregate system-level demand curve, obtained by summing the hourly demand of all 20 substations, for each of the three operating states, together with the peak demand, its hour of occurrence, the minimum demand, its hour of occurrence, the average demand and the resulting load factor for each state and Table 2 shows the twenty-four-hour aggregate load-profile statistics by operating state. The Academic Session records the highest system peak of 2778.07 kW, occurring at mid-morning exactly 11:00 hrs, consistent with concurrent lecture, laboratory and hostel loading. The Examination Period peak was 20.7% lower than the Academic Session peak and occurs later in the day at 14:00 hrs, reflecting a shift in campus activity toward afternoon and evening reading and reduced laboratory usage. The Academic Break exhibited the lowest peak of 1610.75 kW, 42% below the Academic Session peak, and, notably, its peak occurred in the evening at 20:00 hrs rather than at midday, consistent with a residential and security dominated baseline load in the absence of teaching activity. The load factor declines progressively from 0.742 for the Academic Session to 0.680 for the Examination Period and 0.520 for the Academic Break.

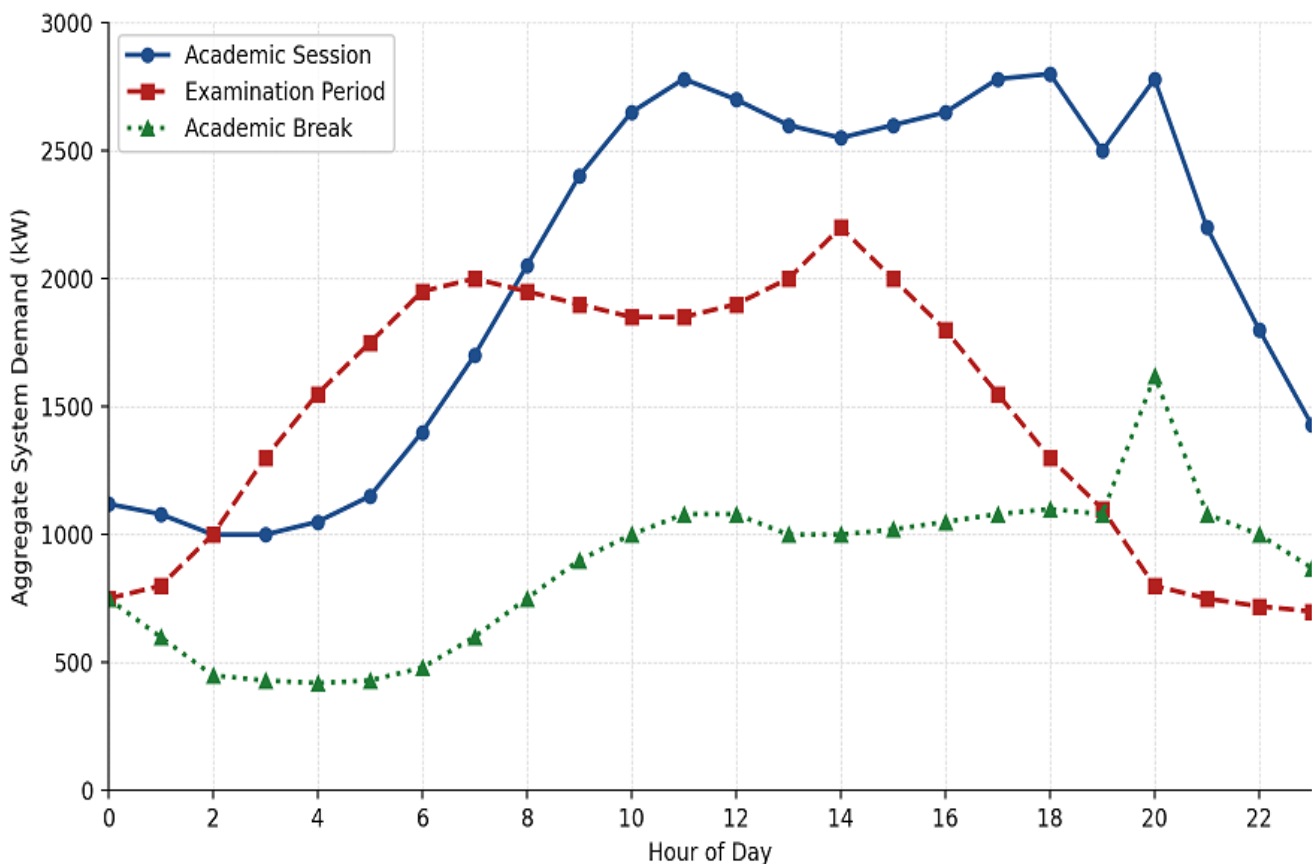


Figure 4. Aggregate 24-hour system demand curves for the FUTA distribution network (20 substations) under the Academic Session, Examination Period and Academic Break operating states.

Table 2: Twenty-Four-Hour Aggregate Load Profile Statistics by Operating State

Operating State	Peak Demand (kW)	Peak Hour	Minimum Demand (kW)	Off-Peak Hour	Load Factor
Academic Session	2778.07	11:00	977.16	03:00	0.742
Examination Period	2203.88	14:00	702.64	23:00	0.680
Academic Break	1610.75	20:00	382.21	05:00	0.520

Substation Demand Factor

Figure 5 presents the installed capacity, peak demand and demand factor of each of the 20 substations across the three operating states. Demand factors range broadly from about 0.09 for the Engineering Workshop during the Academic Break to 1.862 for CERAD during the Academic Session. Most substations showed DF well below unity, in the 0.15-0.8 range, indicating that their installed transformer capacity provides adequate margin above metered peak demand; commercial and banking substations (GTB, WEMA, First Bank, UBA, Heritage) showed comparatively high but sub-unity demand factors of 0.4 to 0.8 even during the Academic Break, reflecting their less session dependent, near-continuous operation. The CERAD substation is the notable exception, its demand factor exceeds unity in all three operating states (1.862 in the Academic Session, 1.436 in the Examination Period and 0.844 in the Academic Break) which meant that, its metered peak demand exceeds its nameplate installed capacity (90 kW) for two of the three states. This indicates that the CERAD transformer is undersized relative to actual demand and is a pre-existing network constraint independent of the solar PV scheme. It should be prioritised for capacity upgrade or load transfer regardless of the PV integration programme, since an overloaded local transformer will continue to limit reliability of supply to CERAD even after PV is commissioned upstream.

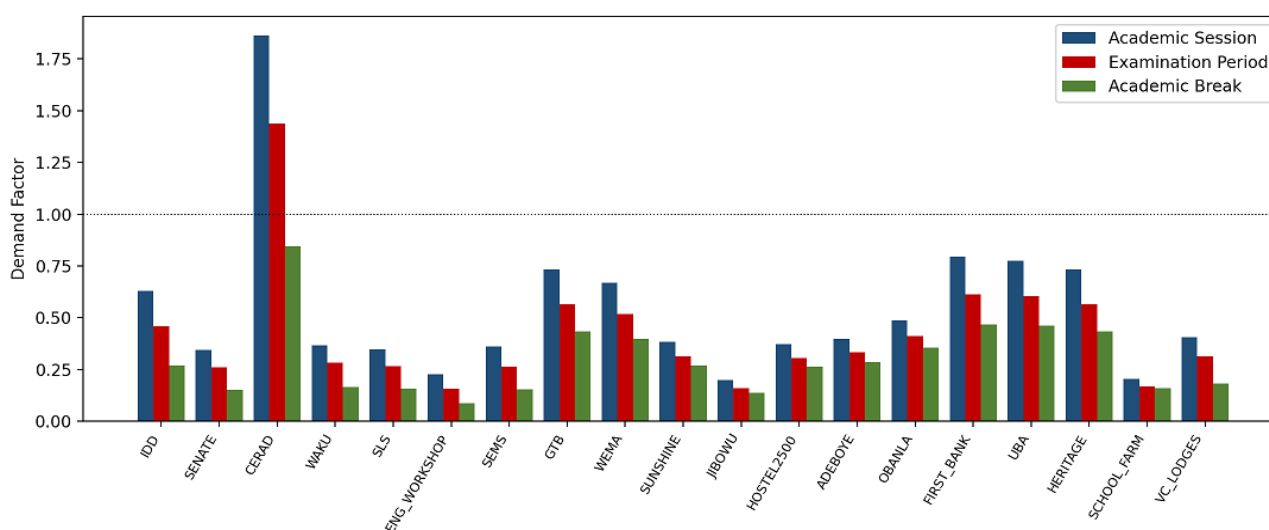


Figure 5. Substation factors across the Academic Session (AS), Examination Period (EX) and Academic Break (AB) operating states. The dotted line marks the unity demand factor (DF = 1)

System Diversity Factor

Table 3 presents the system diversity factor computed from the sum of individual substation peaks for each operating state. The system diversity factor is close to unity in all three operating states (1.013, 1.002 and 1.000, respectively) and equals exactly unity during the Academic Break. A diversity factor near unity indicates that individual substations tend to reach their own peak demand at, or very close to, the hour at which the whole-campus demand also peaks; that is, the substation load profiles are strongly time-coincident rather than diverse.

Table 3. System Diversity Factor by Operating State

Operating State	Sum of Individual Peaks (kW)	System (Coincident) Peak (kW)	Diversity Factor
Academic Session	2814.4	2778.1	1.013
Examination Period	2207.5	2203.9	1.002
Academic Break	1610.8	1610.8	1.000

This is consistent with a campus dominated by a shared institutional schedule of lecture timetables, meal times, evening study and residential patterns rather than a mix of independently timed industrial, commercial and residential loads. The practical implication is that the conventional planning benefit of diversity is the ability to size shared infrastructure below the sum of individual peaks which is minimal on this network, and that embedded PV generation, being itself governed by a single shared solar-irradiance schedule.

ETAP Load Flow and PV Integration Results

Table 4 summarises the key steady state power flow results extracted from the ETAP one-line diagram for the PV-islanded scenario, in which the grid incomer breaker was opened and the instrumented segment operated solely on solar generation. With the grid disconnected, the two 2 MVA solar transformers together delivered approximately 485.2 kW and 423.4 kVAR to the 11 kV PV Integration Bus. Against an installed PV with the inverter capacity of roughly 800 kW, this output corresponds to about 60% of rated capacity, indicating the plant was generating well below its maximum at the simulated instant.

From the PV Integration Bus, this power split along two monitored paths: 143.2 kW and 124.1 kVAR flowed toward BusWay2 which is serving the Obanla I cluster, while 110.6 kW flowed toward BusWay5, serving the Obanla II cluster, a combined 253.8 kW. This compares to a summed metered LV load of 336.2 kVA across the ten instrumented substations in this segment. The BESS (Battery1) and its inverter were de-energised throughout this case, confirming that battery dispatch was not active during the simulated scenario; PV generation alone was sufficient to supply the instrumented Obanla I and Obanla II loads in islanded mode at the time the snapshot was captured.

Table 4. Principal Steady-State Power-Flow Results, PV-Islanded Case

Network Element	Rating / Reading	Remark
Grid intake transformer	7.5 MVA	Incomer breaker open; 0 MVA _{sc} contribution from the grid in this case
Solar Transformer 1 (PV)	2 MVA; ≈ 242.9 kW / j214.9 kVAR	Approximately half of total PV output in this case
Solar T2 (PV)	2 MVA	Combines with Solar Transformer 1 at the PV Integration Bus
PV Inverter Bus	0.8 kV; ≈ 800 kW installed inverter/array rating	LV side of the PV interconnection
PV Integration Bus	11 kV; ≈ 485.2 kW / j423.4 kVAR delivered	Combined output of the two solar transformers
BusWay2 (Obanla I)	143.2 kW / j124.1 kVAR received	Supplies SLS, Obanla Qtrs, Eng. Workshop, VC Lodge, Farm, Ibule Sunshine
BusWay5 (Obanla II)	110.6 kW received	Supplies CERAD, SEMS, Adeboye, Waku

Network Element	Rating / Reading	Remark
BESS (Battery1) + Inverter	De-energised / not dispatched	Available as a planned/standby asset in this case
Combined instrumented load	253.8 kW / 336.2 kVA (10 metered LV loads)	≈52% of the 485.2 kW delivered at the PV Integration Bus

Quantitative Power Balance at the PV Integration Bus

Applying the power-balance framework of Equation 11 to the values in Table 4, the PV Integration Bus and the power reaching the two instrumented busways with an explicit, quantitative reconciliation. The active-power balance will become

$$P_{PV\ out} - P_{bus\ way\ 2} - P_{bus\ way\ 5} = 485.2 - 143.2 - 110.6 = 231.4\ kW,$$

so the residual term $P_{bus\ way\ 9} + P_{loss\ network}$ that must be accounted for is 231.4 kW. This residual can be bounded rather than left speculative. At the PV Integration Bus, the apparent power delivered is $S = \sqrt{485.2^2 + 423.4^2} \approx 644.0$ kVA against a combined solar-transformer rating of 4 MVA, i.e. it was only about 16% loading. At this loading fraction, standard transformer loss behavior, copper (I^2R) loss scaling with the square of the loading fraction, plus a broadly load-independent core or iron loss which implies combined losses in the two 2 MVA solar transformers on the order of 8-12 kW, and 11 kV feeder-cable I^2R losses for the short Obanla-precinct runs, at the currents implied by 644 kVA at 11 kV (≈ 33.8 A), of a similar order of magnitude. Summing these two together gave an estimated network ohmic loss, $P_{loss\ network}$, of approximately 15-20 kW which is far too small to the 231.4 kW. Table 5 sets out this reconciliation explicitly for the reactive-power split for BusWay5 which was not separately reported in the original ETAP readout but estimated from the power factor recorded at BusWay2 (143.2 kW, 124.1 kVAR, $pf \approx 0.755$).

Table 5. Power Balance at the PV Integration Bus, PV-Islanded Case

Component	P (kW)	Q (kVAR)
PV Integration Bus output	485.2	423.4
BusWay2 (Obanla I)	143.2	124.1
BusWay5 (Obanla II)	110.6	≈96.0*
Subtotal delivered to instrumented busways	253.8	≈220.1*
Estimated network ohmic loss ($P_{loss, network}$)	≈15-20	≈10-15
Residual: BusWay9 / reserve and BESS-charging capacity	≈211-216	≈188-193

Bus Voltage Profiles across PV Penetration Levels

To move beyond the single PV-islanded snapshot, the thirteen-scenario irradiance sweep was run, grid-connected, against all three load profiles. Table 6 reports bus-voltage magnitudes, expressed as a percentage of nominal, for the Obanla-precinct buses at the 11-16 hrs peak window, for the no-PV baseline and three representative PV penetration levels (10%, 50% and 90% irradiance) during the Academic Session, together with the corresponding minimum system voltage recorded during the Examination Period and Academic Break.

Table 6. Bus-voltage magnitude

Bus	kV	Session, No PV	Session, PV 10%	Session, PV 50%	Session, PV 90%
Grid intake bus (slack)	11	100.00	100.00	100.00	100.00

Bus	kV	Session, No PV	Session, 10% PV	Session, 50% PV	Session, 90% PV
SEMS Bus 2	0.415	90.28	88.13	90.31	90.43
CERAD Bus 2	0.415	93.46	91.37	93.48	93.60
Adeboye Bus 2	0.415	97.21	95.19	97.24	97.35
SLS Bus 2	0.415	97.55	95.52	97.57	97.68
Ibule Sunshine Bus 2	11	97.77	95.75	97.79	97.90
PV Inverter Bus	0.415	100.00	96.33	99.15	99.11

Across all penetration levels, voltage shows a clear and consistent inverse relationship with system load, the weakest voltages were invariably found at the 0.415 kV secondary buses, particularly SEMS Bus 2 and CERAD Bus 2, which carry the heaviest relative transformer loading. SEMS Bus 2 records the most critical voltage depression across all conditions and without PV it registers 90.28% during the Academic Session, at the lower boundary of the conventional $\pm 10\%$ (0.90-1.10 pu) tolerance band, compared with 92.68% during the Examination Period and 96.73% during the Academic Break. With PV at 10% irradiance, voltage at SEMS Bus 2 drops further to 88.13% during the Academic Session which was below the 90% lower limit and confirming that low-irradiance PV transients create a brief but technically critical voltage-depression condition at this bus. At 50% irradiance the voltage recovers to 90.31%, and at 90% irradiance to 90.43%, both marginally above the no-PV baseline. This non-monotonic response reflects reactive-power dynamics and at low irradiance the grid supplies a reactive surge to compensate for the still-small PV active injection, increasing current magnitudes on upstream branches and worsening voltage drop, before the growing PV active injection reduces it at higher irradiance levels. CERAD Bus 2 follows the same pattern, dipping to a minimum of 91.37% at 10% PV before recovering to 93.60% at 90% PV. All 11 kV primary buses, and all buses during the Academic Break, remain at or above 96.7% throughout, confirming that voltage-regulation concern is confined to the most heavily loaded 0.415 kV secondary buses (SEMS Bus 2 and CERAD Bus 2) during the low-irradiance ramp of the Academic Session, rather than being a network-wide compliance issue.

Feeder and Transformer Loading

Table 7 presents the transformer loading percentages for the Obanla-precinct transformers, the grid intake and the two solar transformers, at the 11-16 hrs peak window, across the three operating states and representative PV penetration levels.

Table 7. Transformer Loading (%) for Obanla Precinct, Peak Window (11-16 hrs)

Transformer	Session, No PV	Session, 10% PV	Session, 90% PV	Exam., No PV	Exam., 90% PV	Break, No PV	Break, 90% PV
SEMS	176.6	175.2	176.7	134.4	129.8	59.1	59.1
CERAD	140.7	139.6	140.7	141.6	141.7	62.5	62.5
Adeboye	42.4	42.0	42.4	33.2	33.3	21.2	21.2
Ibule Sunshine	25.1	24.9	25.1	32.1	32.1	19.9	19.9
Obanla Qtr	20.3	20.2	20.3	41.2	41.3	25.8	25.8
SLS	35.6	35.3	35.6	26.8	26.9	11.7	11.7
Grid intake	32.1	169.6	24.8	33.1	24.9	17.6	26.7
Solar T1 / T2	0	351.0	70.7	0	70.7	0	70.7

Without PV integration, active-power losses are low and demand-proportional, the peak no-PV loss of 0.0136 MW (1.36% of peak load, academic session) is notably low for a campus distribution network. With PV

integration at 10% irradiance, losses undergo a dramatic and disproportionate increase, rising to 0.464 MW during the Academic Session peak window with a 3,312% increase over the no-PV baseline. This is caused by high reactive currents flowing through the solar-transformer branches and the grid-bus connection during low-irradiance PV operation, which create large I^2R losses in the solar injection path that far exceed the small loss reductions achieved in downstream branches. As irradiance rises to 30%, losses fall to 0.194-0.195 MW; at 50% to 0.0672-0.0709 MW; by 70% to 0.0321-0.0375 MW; and by 90% to 0.0173-0.0239 MW, a monotonic decline confirming that the loss penalty from PV integration is most severe at low irradiance and diminishes progressively as active-power injection increases. The Academic Break shows the largest relative percentage loss increase at every irradiance level because its no-PV baseline is extremely low (0.0034 MW), so that even a modest PV-induced loss addition appears large in percentage terms; in absolute terms, however, the loss magnitude at a given irradiance level is very similar across all three operating states, since the solar-injection path, not the downstream load, dominates the loss mechanism at low-to-moderate irradiance. These findings underscore the importance of incorporating reactive-power management for example, coordinated inverter reactive control or switched capacitor banks at the PV Integration Bus during PV ramp-up within any energy-management strategy for the network.

CONCLUSION

This paper has presented a load-flow assessment of the FUTA distribution network for solar PV integration, combining a 24-hour, 20-substation load-profile analysis across three campus operating states with both a PV-islanded ETAP snapshot and an extended, thirteen-scenario irradiance sweep of the network. The aggregate campus demand was found to peak at 2778.1 kW during the Academic Session, 2203.9 kW during the Examination Period, and 1610.8 kW during the Academic Break, with load factors of 0.742, 0.680 and 0.520 respectively, and a near-unity system diversity factor of 1.000 to 1.013, indicating strongly coincident substation peaks. The CERAD substation was identified as operating above its nameplate demand factor in two of the three states, flagging a pre-existing capacity constraint independent of PV.

In the PV-islanded case, the installed 4 MVA solar PV interconnection delivered 485.2 kW / 423.4 kVAR, sufficient to supply the instrumented campus electrical loads in a grid-open, islanded mode; a quantitative power balance at the PV Integration Bus showed that ohmic network losses account for less than 20 kW of the 231.4 kW difference between generation and the power reaching the two instrumented busways, with the remainder attributable to unmetered flow toward the network's third busway and to BESS-charging capacity. The extended irradiance sweep showed that network voltage remains within the conventional $\pm 10\%$ tolerance band across almost all operating conditions, with a single, brief exception at SEMS Bus 2 (88.13%) during the low-irradiance ramp of the Academic Session, and that the SEMS and CERAD distribution transformers are overloaded (up to 176.6% and 141.6% of rated capacity respectively) at every PV penetration level, confirming that this constraint is pre-existing and unrelated to the PV scheme. System losses were found to rise sharply at low irradiance from 0.0136 MW to 0.464 MW during the Academic Session peak window before falling back at high irradiance, identifying the PV ramp-up window as the period of greatest technical stress on the network. These findings confirm that solar PV integration is technically viable for at least partial network islanding at FUTA across a realistic range of irradiance and load conditions, while underscoring the need for substation-level capacity remediation at SEMS and CERAD, and for reactive-power compensation during low-irradiance PV ramp-up, ahead of any expansion of the PV/BESS integration programme.

Ethical Approval

This study did not involve human or animal experimentation. Approval for the collection and use of the FUTA distribution network and metering data were obtained from University Management through the Directorate of Works and Services, Federal University of Technology, Akure.

Conflict of Interest

The authors declare that there is no conflict of interest associated with this study.

Data Availability

The load/meter data and the ETAP simulation model used in this study are available from the corresponding author upon reasonable request.

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