

Techno-Economic Feasibility Analysis of Solar-Powered Electric Vehicle Charging Infrastructure in Mbeya City, Tanzania

Gerald K. Rukanda*, Isaka J. Mwakitalima, Maria A. Kiheya and Mateso S. Ntinyako

Department of Electrical and Power Engineering

Mbeya University of Science and Technology, P.O Box 131, Mbeya, Tanzania

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ABSTRACT

Reliable and affordable charging infrastructure is critical to the transition to electric mobility in Tanzanian cities. This study compares three grid-connected charging pathways for Mbeya City: solar PV and grid, battery storage and grid, and solar photovoltaic (PV) and battery storage and grid using hourly HOMER Grid simulation, Excel validation, and sensitivity analysis. The modelled demand was 729.8 kWh/day (266.4 MWh/year), with a peak of 130.83 kW at 18:00 for one charging point. Solar and Grid delivered the best economic performance, with CAPEX of \$83,983, net present cost of \$117,948, LCOE of \$0.034/kWh, annual utility-bill savings of \$15,891, 5.34-year simple payback, 6.5-year discounted payback, and 18.56% IRR. It maintained zero unmet load, supplied approximately 40% renewable energy, and reduced gross grid-related CO₂ emissions by 45.8 t/year (50.5%). Solar, storage and grid increased the renewable fraction to approximately 90% and reduced CO₂ emissions by 33.4 t/year (36.8%), but its NPC rose to \$1.486 million because battery cycling and replacement costs dominated lifecycle expenditure. Sensitivity analysis showed that tariff, EV demand, PV cost, solar resource, inflation, and battery cost materially affect viability. The results support Solar and Grid as the most defensible first-stage architecture for Mbeya, with storage added selectively where resilience or peak-management benefits justify its lifecycle cost.

*Corresponding author's e-mail address: geraldso96@gmail.com (Rukanda, G.K.)

1.0 Introduction

The decarbonisation of urban transport increasingly depends on charging infrastructure that is reliable, affordable, and compatible with local power-system conditions. EV charging stations are therefore increasingly treated as integrated energy nodes that interact with the utility grid, local demand, and renewable generation (Mastoi *et al.*, 2022; Alrubaie *et al.*, 2023a).

Solar photovoltaic integration can reduce daytime grid purchases and lifecycle emissions, while battery storage can shift part of the solar resource toward later charging periods. Previous studies compare grid-only, PV-assisted, and PV-BESS charging pathways, but their economic ranking depends strongly on local tariffs, load timing, component costs, and grid-export rules (Bhatti *et al.*, 2016; Hossain & Cho, 2026).

For African cities, electric two- and three-wheelers are particularly relevant because they support short urban trips and paratransit services at lower capital cost than four-wheel EV fleets. This makes solar-supported charging for three-wheelers a realistic transition pathway for intermediate cities where mobility demand is growing but infrastructure budgets remain constrained (Ayeter *et al.*, 2023; Himabindu *et al.*, 2024).

Mbeya City is a relevant case because Tanzania has substantial photovoltaic potential and identified PV hot spots suitable for solar-based infrastructure planning (Oyebamiji & Hayangah, 2025) (Aly *et al.*, 2017). Charging-station architecture affects PV sizing, converter loading, storage requirements, and grid exchange (Chandra Mouli *et al.*, 2016). Multi-resource designs may improve flexibility and wider economic benefits, although their additional storage and converter costs can materially alter lifecycle economics (Yang *et al.*, 2021; Hafez & Bhattacharya, 2017).

Although several studies have examined photovoltaic-powered electric vehicle (PV-EV) charging systems in Asia, Europe and North America, limited evidence is available for intermediate cities in sub-Saharan Africa. Existing PV-EV charging studies provide useful technology and optimisation frameworks, but they do not resolve the Mbeya-specific

combination of an evening-dominant charging peak, Tanzania T2 tariff structure, local solar resource, and the comparative lifecycle performance of PV-grid, battery-grid, and PV-battery-grid pathways under one consistent hourly model. In addition, local studies rarely report the complete set of economic, reliability, grid-exchange, and emissions indicators needed to reproduce the system ranking.

Novelty and objective. This study addresses that gap by combining a Mbeya-specific hourly charging profile with site solar data and HOMER Grid optimisation, then comparing the three architectures using a common economic and environmental accounting framework. The contribution is the simultaneous location-specific comparison of load timing, optimised component sizing, net present cost (NPC), levelised cost of energy (LCOE), payback, grid purchases and sales, and CO₂ impacts for a secondary Tanzanian city. The objective is to identify the architecture that is technically feasible and economically defensible for staged urban e-mobility deployment.

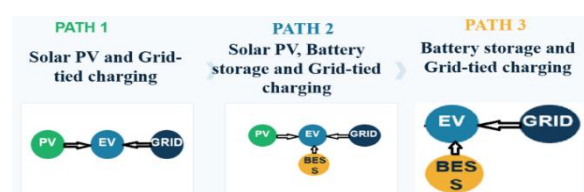
2.0 Materials and Methods

2.1 Techno-Economic Case-Study Design

The study uses a comparative techno-economic case-study design. Three pathways are evaluated: (i) Solar PV and Grid-tied charging; (ii) Battery Storage and Grid-tied charging; and (iii) Solar PV, Battery Storage and Grid-tied charging. The same hourly load and utility tariff are applied to all pathways so that differences arise from the energy-system architecture rather than from different demand assumptions. This scenario-based comparison is consistent with feasibility studies of PV-based charging stations (Sierra *et al.*, 2020) and (Buestan-Morales *et al.*, 2024). The three charging pathways are illustrated in Figure 1.

Figure 1

Three System Configurations for Techno-Economic Assessment



2.2 Site, Data Sources, and Site-Selection Procedure

Mbeya combines useful solar potential with growing demand for urban mobility, and three-wheelers and repeat-route fleets are relevant early e-mobility segments. The study reference point is 8.8936° S, 33.4762° E, within the municipal geographic context reported by the Mbeya City Council profile (GWF CORE, 2026.). The adopted annual mean solar irradiance is 4.97 kWh/m²/day, with a monthly range of 4.06-5.72 kWh/m²/day; these values are consistent with photovoltaic suitability reported for the southern highlands (Mwasenga& Kamoleka Mlela, 2024) and location-specific irradiation evidence (Mwasenga& Kamoleka Mlela, 2024). The adopted monthly average temperature range is 15.2-19.7°C (Mbeya Climate: Weather Mbeya & Temperature by Month, n.d.), while the November-April rainy season and May-October dry season agree with regional climate analyses (Mwakalila, 2014). Table 1 summarizes the resource data adopted for Mbeya City.

Table 1
Resource Data for Mbeya City

Indicator	Value
Coordinates	8.8936° S, 33.4762° E
Solar irradiance	4.97 kWh/m ² /day annual mean
Monthly range	4.06–5.72 kWh/m ² /day
Monthly average temperature range	15.2–19.7°C
Climate pattern	Rainy Nov–Apr and Dry May–Oct

Four categories of input data were used: solar-resource data, EV charging-demand data, technical component data, and economic data. Solar inputs comprised irradiance and ambient temperature; demand inputs comprised the hourly charging profile; technical inputs described PV, battery, inverter/converter, and operational limits; and economic inputs covered component capital/replacement costs and the T2 electricity tariff. This structure follows the input categories commonly used in PV-EV charging feasibility studies (Himabindu *et al.*, 2021; Himabindu *et al.*, 2024; Buestan-Morales *et al.*, 2024). Table 4 provides a city-scale planning allocation, whereas the HOMER simulation used the aggregate hourly station load summarised in Section 2.4.

Charging-station areas were screened using accessibility, demand concentration, land suitability, solar exposure, and proximity to existing electrical infrastructure (E. Seilabi *et al.*, 2024). Site visits to count stopping and passing vehicles were used as exploratory planning inputs.

2.2.1 Field Reconnaissance and Sampling Clarification

The field component is treated as purposive, non-inferential reconnaissance rather than a statistically sampled interview survey. The five-site vehicle observations/planning counts in Table 3 total 3,943 three-wheelers and were used only to characterise mobility concentration, stopping/parking activity, accessibility, and site suitability. Oral interviews were not used to generate numerical HOMER inputs because the preserved records do not contain a defensible participant roster, stakeholder-category counts, a structured questionnaire, or response-frequency data. Accordingly, no interview-derived percentages or inferential statistics are reported. For future validation, the field protocol should prospectively record sample size and stakeholder strata such as drivers/operators, terminal or site managers, utility/municipal personnel, and nearby businesses or landholders, and should triangulate structured responses with measured charging demand and grid data.

2.2.2 Site-Selection Decision Rule

Table 3 presents the distribution of three-wheelers across the five proposed charging locations in Mbeya City, which were counted at each location. For preliminary field-survey design, approximately 65% of the vehicles stop or park within the selected site areas, while 35% pass through without stopping. This resulted in stopping/parking counts of 2,563 vehicles and passing counts of 1,380 vehicles.

The five planning candidates in Table 4 were Iyela Old Airport, Iganjo-Ikhangha, MUST-Iyunga, Uyole Bus Terminal, and Sisimba/Ruanda. For the detailed case analysis, MUST-Iyunga was selected as the reference planning node for simulation in HOMER Grid with 4 MW of solar capacity (18.18% of the city allocation), 11.471 MWh/day of planning load, an estimated 2022

population of 98,473, and 717 allocated three-wheelers as shown in Table 4 which present Data inputs and planning variables. The preliminary technical design parameters for the MUST-Iyunga site are summarised in Table 5.

2.2.3 Data-Validation Procedure

Geographic and solar-resource values were cross-checked against the sources cited above, while the charging profile and economic outputs were checked against the HOMER Grid simulation. The report gives 729.8 kWh/day average electric energy consumption, 22.2 MWh/month, 266.4 MWh/year, and a maximum demand of 130.83 kW on March 6 for one charging point.

2.2.4 Electric Three-Wheeler Technical Characteristics

The TRÍ E2 was adopted as the representative electric three-wheeler for the Mbeya City charging-demand analysis because the vehicle has been introduced and tested in Tanzania and its design incorporates operational feedback from local drivers (TRI | SOLUTIONSplus, n.d.). The vehicle is equipped with an 8 kWh lithium iron phosphate battery and a 4 kW electric motor, provides more than 100 km of driving range per charge, and has a maximum speed of approximately 55 km/h. A full charge requires approximately five hours using the onboard charging system (Bolt, TRÍ, & Watu Partner to Empower Drivers with Electric Three-Wheeler Pilot Program in Tanzania - CleanTechnica, n.d.). These characteristics are suitable for urban passenger transport and provide a practical basis for estimating charging demand across the proposed Mbeya charging locations. Table 2 shows the technical specifications of the representative electric three-wheeler for charging-demand reconciliation. The representative TRÍ E2 has an 8 kWh battery, more than 100 km driving range, and an approximately five-hour full-charge time. Two full-equivalent charges per day were used only for city-scale planning, corresponding to 16 kWh

per allocated vehicle per day and 63.088 MWh/day for the 3,943-vehicle planning fleet. This planning envelope is distinct from the final station-scale HOMER load of 729.8 kWh/day. For the MUST-Iyunga planning node, 729.8 kWh/day is approximately 6.36% of the 11.472 MWh/day planning allocation. The 130.83 kW peak is obtained directly from the maximum hourly load in the HOMER profile at 18:00 on March 6 for one charging point and is not a charger nameplate rating. Individual trip distance and charging frequency were not independently imposed in the final HOMER run; their combined effect is represented by the aggregate hourly station-load profile.

Table 2
Technical Specifications of the Representative Electric Three-Wheeler

Technical parameter	Specification
Vehicle model	TRÍ E2 electric three-wheeler
Application	Passenger/public-transport electric three-wheeler
Propulsion system	Battery electric
Electric motor rated power	4 kW
Battery technology	Lithium iron phosphate (LFP)
Battery capacity	8 kWh
Driving range	>100 km per full charge
Maximum vehicle speed	55 km/h
Full charging time	Approximately 5 h using on-board charger
Approximate average charging power	≈1.6 kW
Battery warranty	2,000 cycles
Display	Fully digital
Rear-view assistance	Rear camera
Suspension	Heavy-duty suspension
Charging method	Plug-in/on-board charging
Proposed daily full-equivalent charging cycles for this study	2 cycles/day
Battery energy per EV per day in the study	16 kWh/day
Number of EVs considered	3,943
Total nominal fleet battery demand	63.088 MWh/day

Table 3

The Distribution of Three-Wheelers across the Five Proposed Charging Locations in Mbeya City

S/N	Site	Survey date	Survey period	Stopping /parking	Passing without stopping	Total observations	Approx. road distance from Kabwe stand (km)	Estimated EV three-wheeler travel time at urban operating speed of 25–30 km/h
1	Iyela Old Airport	02-02-2026	06:00–19:00	932	502	1,434	3.5	7–9 min
2	Iganjo–Ikhanga	03-02-2026	06:00–19:00	582	314	896	12.0	24–29 min
3	MUST–Iyunga	04-02-2026	06:00–19:00	466	251	717	10.0	20–24 min
4	Uyole Bus Terminal	05-02-2026	06:00–19:00	350	188	538	10.9	22–26 min
5	Sisimba/Ruanda	06-02-2026	06:00–19:00	233	125	358	5.0	10–12 min
Total				2,563	1,380	3,943		

Table 4

Data Inputs and Planning Variables

Site	Solar capacity (MW)	Allocated number of three wheelers (EV)	Allocated load (MWh/day) (EV x 2 x8kWh)	Estimated population served*2022	Capacity share of energy (%)
Iyela Old Airport	8	1,434	22.944	196,946	36.37
Iganjo–Ikhanga	5	896	14.336	123,092	22.72
MUST–Iyunga	4	717	11.472	98,473	18.18
Uyole Bus Terminal	3	538	8.608	73,855	13.64
Sisimba/Ruanda	2	358	5.728	49,237	9.09
Total	22	3,943	63.088	541,603	100

Table 5

Technical Design Parameters for MUST Site

Component	Type	Recommended rating
Solar PV plant	N-type TOPCon bifacial	4 MWp
Battery type	Lithium Iron Phosphate(LFP/LiFePO ₄)	17.68 MWh
PV inverter	Central inverter/MPPT	4.5 MVA
Converter	DC/DC	150kW for one shared(5min)
Converter	DC/AC	22kW for one shared(30min)

2.3 System Architecture and Dispatch Logic

An hourly energy-balance framework is used to match PV generation, storage operation, charging demand, and grid support. At each time step, PV serves the charging load first; available surplus can charge the battery, while residual demand is supplied from storage and/or the grid subject to component limits. This dispatch structure is consistent with PV-EV charging studies (Sierra *et al.*, 2020). Bidirectional converter operation and battery energy shifting follow the same physical logic used in integrated charging-station power management (Wang *et al.*, 2020). The three architectures were simulated in HOMER Grid, with Excel used only for transparent post-processing, comparison tables, validation checks,

and sensitivity calculations (Buestan-Morales *et al.*, 2024).

The technical parameters adopted in the HOMER Grid simulation for MUST–Iyunga charging station are summarised in Tables 5a–5d. The modelled system comprises a 4 MW ABB PVS800-1000 generic photovoltaic system, 18 units of 1 MWh lithium-ion battery storage providing a total nominal storage capacity of 18 MWh, a 4.4 MW bidirectional AC/DC converter, and 22 charging points of 150 kW and 22 charging points of 50 kW Level 3 on-demand for large and small EV chargers, providing a combined charging capacity of 4.4 MW.

The photovoltaic system was modelled with a 96% derating factor and a 25-year lifetime, while

the battery had a minimum state of charge of 20%, 90% round-trip efficiency, and a 15-year lifetime. The converter was modelled with 98% inverter and rectifier efficiencies. These parameters were used as the principal technical inputs for the hourly techno-economic simulation and system optimisation. PV degradation was represented by the 96% derating factor in a 25-year lifetime. Battery degradation was represented through the 90% round-trip efficiency in a 15-year calendar life.

2.3.1 Reproducibility and Optimisation Boundary

The analysis was evaluated at hourly resolution over a 25-year project horizon. The 4 MW PV, 18 MWh battery-bank, 4.4 MW converter, and charger ratings in Tables 5a–5d describe the engineering design envelope/component configuration used for the detailed MUST–Iyunga case and should not be interpreted as the final least-cost architecture. For economic comparison, the exported HOMER optimisation recommends 4.4 MW PV for Solar and Grid, one 1 MWh battery for Storage and Grid, and one 1 MWh battery for Solar, Storage and Grid. PV losses were represented by a 96% static derating factor with a 25-year PV life; no separate annual PV degradation curve was applied. Battery operation used 20% minimum SOC, 90% round-trip efficiency, and a 15-year calendar life, while the converter used 98% inverter/rectifier efficiency and a 15-year life. HOMER ranked feasible architectures by minimum lifecycle NPC subject to hourly energy balance, component limits, SOC constraints, and complete load service.

Figure 2 illustrates the schematic configuration of the proposed grid-connected PV–battery EV charging station. The system consists of a grid connection, an AC bus, a bidirectional AC/DC converter, a DC bus, a solar PV system, battery storage, and an AC EV charging load. Solar PV generates DC electricity that can supply the system through the DC bus, while surplus energy can be stored in the battery for later use. The bidirectional converter enables power exchange between the DC and AC buses, allowing the battery and PV system to support the AC charging demand while maintaining grid interaction. When solar and battery power are

insufficient, the utility grid supplies the required charging demand. Conversely, excess renewable energy can be managed through the interconnected buses.

Figure 2

Schematic Configuration Arrangement of the Charging Station

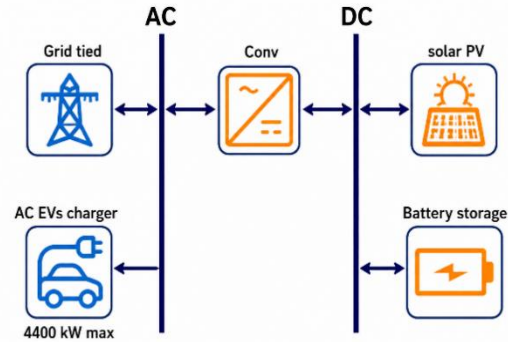


Table 5a

Technical Specifications of the Solar PV Module

Parameter	Specification
Manufacturer	ABB
Model	ABB PVS800-1000
Total modeled PV capacity	4,000 kW (4 MW)
Rated component capacity	1,000 kW
Total capital cost	US\$2,764,000
Replacement cost	US\$0
O&M cost	US\$300/year
Project/component lifetime	25 years
PV derating factor	96%
Temperature coefficient	−0.4100%/°C
Nominal operating temperature	45°C
PV efficiency	17.30%

Table 5b

Battery Energy Storage Specifications

Parameter	Specification
Battery model	Generic 1MWhLi-ion
Number of battery units	18
Nominal capacity per unit	1,000 kWh (1 MWh)
Total nominal battery capacity	18 MWh
Nominal voltage	600 V
Nominal capacity	≈1,670 Ah per unit
Round-trip efficiency	90%
Maximum charging current	≈1,670 A
Maximum discharge current	≈5,000 A

Parameter	Specification
Initial state of charge	100%
Minimum state of charge	20%
Lifetime	15 years
Lifetime throughput	17,680,000 kWh
Total capital cost	US\$2,068,560
Total replacement cost	US\$2,068,560
O&M cost	US\$200/year

Table 5c

Bidirectional Converter Specifications

Parameter	Specification
Component	AC/DC bidirectional converter
Model	Generic large, free converter
Rated capacity	4,400 kW (4.4 MW)
Capital cost	US\$220,000
Replacement cost	US\$220,000
O&M cost	US\$100/year
Converter lifetime	15 years
Inverter efficiency	98%
Rectifier relative capacity	100%
Rectifier efficiency	98%
Operating modes	DC-to-AC and AC-to-DC

Table 5d

EV Charging-Station Specifications

Parameter	Specification
Component	EV charging station
Charger model	Highway Charger (Level 3, On-Demand)
Charger output power	150 kW per charger
Number of chargers for large EV of 150kW	22
Number of chargers for large EV of 50kW	22
Maximum installed charging power	4.4 MW
Charging price	US\$0.06/kWh
Large EV proportion	50%
Large EV maximum charging power	150 kW/EV
Large EV average charging duration	15 min
Small EV proportion	50%
Small EV maximum charging power	50 kW/EV
Small EV average charging duration	15 min

2.4 Mathematical Formulation Used for Modelling

The hourly HOMER Grid simulation was represented using energy-balance, battery-state,

economic, and emissions relationships. These equations define the physical constraints and performance indicators used to compare the three charging pathways.

2.4.1 Hourly Energy Balance

At each simulation time step, the power supplied by the PV system, utility grid, and battery discharge must equal the EV charging demand, battery-charging power, system losses, and exported power (Leone, Peretti, *et al.*, 2022).

$$P_{PV}(t) + P_{grid}(t) + P_{bat,dis}(t) = P_{EV}(t) + P_{bat,ch}(t) + P_{loss}(t) + P_{exp}(t) \quad (1)$$

where $P_{PV}(t)$ is PV power generation, $P_{grid}(t)$ is grid power import, $P_{bat,dis}(t)$ is battery discharge power, $P_{EV}(t)$ is EV charging demand, $P_{bat,ch}(t)$ is battery charging power, $P_{loss}(t)$ represents system losses, and $P_{exp}(t)$ is surplus power exported to the grid.

2.4.2 Battery Energy Balance

The battery energy stored at time t was determined from (Aksan *et al.*, 2024).

$$E_{bat}(t) = E_{bat}(t-1) + \left(P_{bat,ch}(t)\eta_{ch} - \frac{P_{bat,dis}(t)}{\eta_{dis}} \right) \Delta t \quad (2)$$

where $E_{bat}(t)$ is the battery energy at time t , η_{ch} is the battery charging efficiency, η_{dis} is the discharge efficiency, $E_{bat}(t-1)$ is the stored energy at the previous time step, and Δt is the simulation time step.

2.4.3 Battery State of Charge

The battery state of charge (SOC) was calculated as (Cao *et al.*, 2025).

$$SOC(t) = SOC(t-1) + \frac{E_{bat}(t) - E_{bat}(t-1)}{E_{rated}} \quad (3)$$

subject to:

$$SOC_{min} \leq SOC(t) \leq SOC_{max} \quad (3a)$$

where E_{rated} is the rated battery-storage capacity, $SOC(t)$ is the battery state of charge at time t , $SOC(t-1)$ is the state of charge at the previous time step. The lower SOC_{min} limit prevents excessive battery discharge and supports battery lifetime, and maximum limits to prevent excessive battery overcharging.

2.4.4 Economic Formulation

2.4.4.1 Net Present Cost

The total net present cost (NPC) over the project lifetime was calculated as (Leone, Longo, *et al.*, 2022).

$$NPC = C_{cap} + \sum_{y=1}^N \frac{C_{net}(y)}{(1+r)^y} - \frac{S_N}{(1+r)^N} \quad (4)$$

where C_{cap} is the initial capital cost, $C_{net}(y)$ is the net annual cost in year y , S_N is the salvage value at the end of the project, r is the real discount rate, and N is the project lifetime in years.

2.4.4.2 Levelised Cost of Energy

The levelised cost of energy (LCOE) was determined as (Alhazmi, 2025).

$$LCOE = \frac{\sum_{y=1}^N \frac{C_{total}(y)}{(1+r)^y}}{\sum_{y=1}^N \frac{E_{EV}(y)}{(1+r)^y}} \quad (5)$$

where $C_{total}(y)$ represents the total annual system cost in year y , and $E_{EV}(t)$ is the EV charging energy supplied during year y is the discount rate, denotes the project year, and N is the total project lifetime.

2.4.4.3 Simple Payback Period

The simple payback period (SPP) relative to the baseline system was calculated as (Karmakar *et al.*, 2025).

$$SPP = \frac{I_{prop} - I_{base}}{O_{base} - O_{prop}} \quad (6)$$

where I_{prop} and I_{base} are the initial investment costs of the proposed and baseline systems, respectively, while O_{prop} and O_{base} are their corresponding annual operating costs.

2.4.4.4 Discounted Payback Period

The discounted payback period was defined as the first year n in which cumulative discounted project cash flow becomes non-negative.

$$DPP = \min \left\{ n: -I_0 + \sum_{y=1}^n \frac{CF_y}{(1+r)^y} \geq 0 \right\} \quad (7)$$

where I_0 is the initial investment and CF_y is the net project cash flow in year y .

2.4.5 Emission Reduction

Annual carbon-dioxide emission reduction was calculated as (Leone, Longo, *et al.*, 2022)(Karmakar *et al.*, 2025).

$$\Delta E_{CO_2} = E_{CO_2,ref} - E_{CO_2,prop} \quad (8)$$

The percentage reduction was obtained from:

$$\eta_{reduction} = [(E_{CO_2,ref} - E_{CO_2,prop}) / E_{CO_2,ref}] \times 100\% \quad (9)$$

where $E_{CO_2,ref}$ represents emissions from the reference system and $E_{CO_2,prop}$ represents emissions from the proposed charging configuration.

2.4.6 Optimisation Criterion

HOMER Grid ranked feasible system configurations by minimising lifecycle net present cost while satisfying the hourly energy balance, battery SOC limits, component operating limits, and the charging-demand requirement.

$$\min NPC(P_{PV}, E_{rated}, P_{conv}) \quad (10)$$

2.5 Economic Factors

The adopted T2 tariff is: \$0.078/kWh energy charge, \$6.0016/kW demand charge, and \$5.70/month fixed charge as shown in Table 6. The 25-year HOMER cash flows are consistent, within rounding, with an 8% nominal discount rate and 2% inflation, equivalent to a real discount rate of 5.88% [$r = (1.08/1.02) - 1$].

Table 6

Economic Parameters

Electricity purchase (tariff T2)	Value
Energy charge	0.078 \$/kwh
demand charge	6.0016 \$/kw
Fixed charge	\$5.70/month

Economic-validation assumptions. The financial boundary is a project-level comparison: no debt-service schedule, grant, subsidy, tax credit, or carbon-credit revenue was added unless already embedded in the exported HOMER cash flows. The 25-year cash-flow reconstruction uses the stated 8% nominal discount rate and 2% inflation, equivalent to a 5.88% real discount rate. These assumptions are retained for reproducibility and explain the high lifecycle cost of storage-containing pathways.

2.6 Uncertainty and Sensitivity Analysis

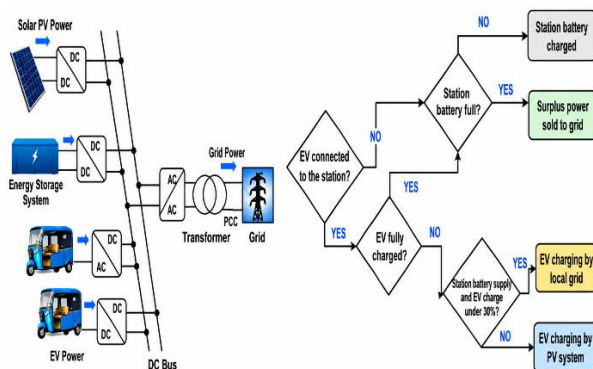
To quantify uncertainty, screening sensitivities were applied around the final HOMER baseline: T2 tariff $\pm 20\%$, PV capital cost $\pm 20\%$, annual solar resource $\pm 10\%$, EV demand $\pm 20\%$, inflation of 0%, 2%, and 5% at an 8% nominal discount rate, and battery capital cost $\pm 20\%$ for storage-containing pathways. The values in Table 8 are one-at-a-time Excel post-processing sensitivities

of the final HOMER cash flows; component sizes were not re-optimised in each sensitivity case. The analysis therefore quantifies financial exposure around the optimised configuration rather than changes in optimum component size.

2.7 System Architecture and Simulation Logic

Figure 3 illustrates the simulation and energy-management logic adopted for the proposed grid-connected PV-battery electric three-wheeler charging station. Solar PV generation is supplied to a common DC bus, where it can directly support EV charging or charge the station battery through appropriate DC/DC converters. The DC bus is interconnected with the utility grid through a bidirectional AC/DC converter and transformer. The control algorithm first determines whether an EV is connected to the charging station. In the absence of an EV charging request, available PV generation is used to charge the station battery until its maximum state of charge is reached, after which excess electricity is exported to the grid. When an EV is connected, the controller assesses its charging status and the availability of stored energy. If the EV still requires charging and the station battery is depleted while the EV state of charge is below 20%, the grid supplies the required charging power. Otherwise, available solar PV energy is prioritised for EV charging. The control strategy therefore coordinates PV generation, battery storage, EV demand, and grid interaction to improve renewable-energy utilisation while maintaining charging availability.

Figure 3
System Architecture and Simulation Logic



3.0 Results

The HOMER simulation quantifies the charging demand as 729.8 kWh/day, 22.2 MWh/month,

and 266.4 MWh/year. The maximum coincidence demand is 130.83 kW on March 6, with the peak-day profile reaching this value at 18:00 for one charging point, as shown in Figure 4. The evening maximum confirms the temporal mismatch between solar production and charging demand: PV can reduce daytime grid use, but evening adequacy requires grid support and/or energy storage.

Figure 4
Peak-Day Load Profile

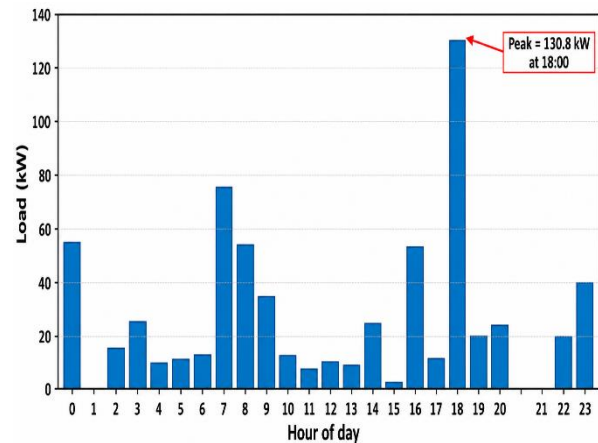


Figure 5 presents the pathway-specific operating plots. They show distinct operational roles rather than a single universally superior architecture. Solar and Grid reduce daytime grid purchases and export substantial surplus PV energy; Battery and Grid provide peak shaving without renewable generation; and Solar, Storage and Grid combine PV and storage but incur greater battery cycling. Table 7 consolidates the quantitative indicators so that the architecture ranking does not depend on visual inference from the figures alone.

Figure 5 forms an operational comparison set in which the panels jointly compare PV/grid power flow and battery state-of-charge behaviour across the three architectures. Figure 6 forms the corresponding economic-comparison set, while Table 7 provides a consolidated numerical comparison.

Figure 5

The Pathway-Specific Operating Plots

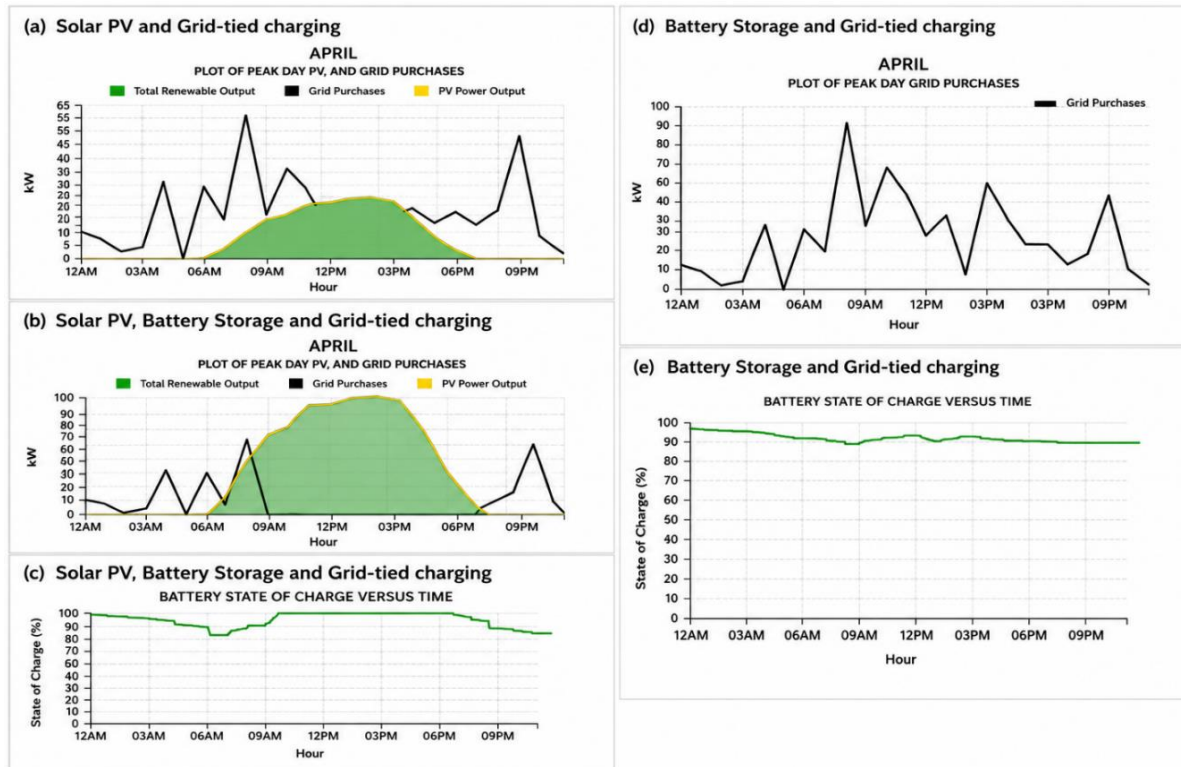


Figure 6a presents the cost-and-savings comparison. CAPEX is \$83,983 for Solar and Grid, \$116,797 for Storage and Grid, and \$138,817 for Solar, Storage and Grid. Annual utility-bill savings are \$15,891, \$1,996, and \$4,651, respectively. When annual operating and replacement costs are included, annual total savings are \$15,741 for Solar and Grid, -\$1,128 for Storage and Grid, and -\$85,825 for Solar, Storage and Grid. The negative annual total savings in the storage-containing pathways indicate that their lifecycle operating/replacement burden exceeds the annual bill savings under the modelled assumptions.

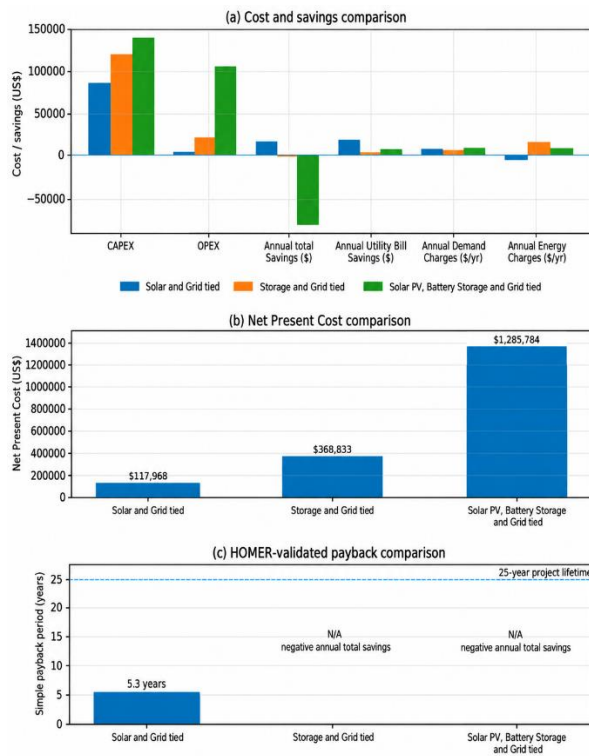
Figure 6b shows the present net cost (NPC) comparison. Solar and Grid has the lowest NPC at \$117,948 and the lowest LCOE at \$0.034/kWh. Storage and Grid has an NPC of \$368,833 and an LCOE of \$0.199/kWh, whereas Solar, Storage and Grid has an NPC of \$1,485,784 and an LCOE of \$0.800/kWh. The base-case values are NPC \$237,457 and LCOE \$0.128/kWh; therefore, Solar and Grid is the least-cost architecture for the simulated load and tariff.

Figure 6c presents the HOMER payback results. Solar and Grid has a simple payback of 5.3 years, a discounted payback of 6.5 years, and an IRR of 18.56%. HOMER reports no valid simple or discounted payback and no IRR for Storage and Grid or Solar, Storage and Grid because their annual total savings are negative. The previously derived positive magnitudes of 103.54 years and 1.62 years are absolute CAPEX-to-savings ratios and are not valid payback periods; they are therefore excluded from the final economic interpretation.

The consolidated comparison in Table 7 highlights substantial differences in the technical, economic, renewable-energy, and environmental performance of the three simulated charging pathways. Solar and Grid has the lowest CAPEX (\$83,983), NPC (\$117,948), and LCOE (\$0.034/kWh), with annual utility-bill savings of \$15,891, 5.3/6.5-year simple/discouted payback, and an IRR of 18.56%. Storage and Grid has CAPEX of \$116,797, NPC of \$368,833, and LCOE of \$0.199/kWh; although it reduces peak demand, HOMER reports no valid payback because annual total savings are negative. Solar, Storage and Grid has the highest CAPEX

(\$138,817), NPC (\$1,485,784), and LCOE (\$0.800/kWh), and likewise has no valid HOMER payback under the final cash flows. The approximate renewable-energy contribution increases from 0% for Storage and Grid to about 40% for Solar and Grid and about 90% for Solar, Storage and Grid. All pathways provide zero unmet load under grid-supported operation. Relative to the 90.7 tCO₂/year base case, gross grid-import emissions are reduced by approximately 45.8 t/year (50.5%) for Solar and Grid and 33.4 t/year (36.8%) for the hybrid, while Storage and Grid produces essentially no CO₂ reduction.

Figure 6
Comparative Economic Performance



The sensitivity analysis presented in Table 8 evaluates the influence of key techno-economic parameters on the economic performance of the proposed charging configurations. For the Solar and Grid-tied system, changes in the T2

electricity tariff and EV charging demand had a pronounced effect on the payback period, which varied from 6.6 years under the low cases to 4.4 years under the high cases, compared with the base value of 5.3 years.

Variations in PV capital cost also significantly affected project economics, with the payback period ranging from 4.2 to 6.3 years and NPC increasing from approximately \$102.2 thousand to \$133.7 thousand. A $\pm 10\%$ change in solar resource produced a comparatively moderate payback variation of 4.8–5.8 years. Inflation increased NPC from \$112.0 thousand at 0% to \$130.5 thousand at 5%. Battery capital cost had an even greater effect on storage-based configurations, particularly the hybrid of Solar, Storage and Grid system, where NPC ranged from approximately \$1.24 million to \$1.74 million. These results highlight the importance of electricity tariffs, component costs, EV demand, solar availability, and macroeconomic conditions in determining project viability. The sensitivity values were obtained through Excel post-processing of the final HOMER cash flows without re-optimizing component sizes for each case.

Overall, Solar and Grid is the economically preferred pathway under the final HOMER assumptions. Storage and Grid reduces monthly peak demand but does not create enough energy-cost savings to recover its storage investment. The hybrid pathway reduces grid imports and gross CO₂ emissions, but the battery throughput assumption triggers frequent replacements and dominates lifecycle cost. The preferred architecture therefore depends on the decision objective: PV-grid minimises cost, whereas storage can add resilience or peak-management value only if those services justify the additional lifecycle cost.

Table 7
Consolidated Quantitative Comparison of the Three Simulated Charging Pathways

Indicator	Solar and Grid	Storage and Grid	Solar, Storage and Grid
CAPEX (\$)	83,983	116,797	138,817
NPC (\$)	117,948	368,833	1,485,784
LCOE (\$/kWh)	0.034	0.199	0.800
Payback	5.34/6.5 yr	N/A	N/A

Indicator	Solar and Grid	Storage and Grid	Solar, Storage and Grid
IRR (%)	18.56	N/A	N/A
Utility-bill savings (\$/yr)	15,891	1,996	4,651
Grid purchases (MWh/yr)	71.034	143.725	90.779
Grid sales (MWh/yr)	122.796	0	0.046
Unmet load (%)	0	0	0
Renewable fraction	≈40%	0%	≈90%
Gross import CO ₂ (t/yr)	44.9	90.8	57.3
CO ₂ reduction vs base	45.8 t/yr (50.5%)	-0.1 t/yr	33.4 t/yr (36.8%)

Table 8

Sensitivity Analysis of Selected Techno-Economic Parameters for the Simulated Charging Configurations

Sensitivity parameter	Low case	Base case	High case
T2 tariff (-20% / 0% / +20%)	PBP = 6.6 yr	PBP = 5.3 yr	PBP = 4.4 yr
PV CAPEX (-20% / 0% / +20%)	PBP = 4.2 yr; NPC = \$102.2k	PBP = 5.3 yr; NPC = \$117.9k	PBP = 6.3 yr; NPC = \$133.7k
Solar resource (-10% / 0% / +10%)	PBP = 5.8 yr	PBP = 5.3 yr	PBP = 4.8 yr
EV demand (-20% / 0% / +20%)	PBP = 6.6 yr	PBP = 5.3 yr	PBP = 4.4 yr
Inflation (0% / 2% / 5%; nominal discount rate = 8%)	NPC = \$112.0k	NPC = \$117.9k	NPC = \$130.5k
Battery CAPEX, Storage (-20% / 0% / +20%)	NPC = \$337.9k	NPC = \$368.8k	NPC = \$399.8k
Battery CAPEX, Hybrid (-20% / 0% / +20%)	NPC ≈ \$1.24 million	NPC = \$1.486 million	NPC ≈ \$1.74 million

4.0 Discussion

The primary technical issue is the mismatch between daytime PV availability and the 18:00 demand peak. This pattern is consistent with the broader PV-EV literature, in which direct solar charging reduces daytime grid purchases but requires grid support or storage when charging extends beyond sunshine hours (Bhatti *et al.*, 2016). Integrated power management can shift energy temporally (Wang *et al.*, 2020), and comparable feasibility studies likewise show that architecture selection depends on the temporal relationship between PV and EV demand (Sierra *et al.*, 2020). In Mbeya, that mismatch explains why PV reduces energy charges strongly while storage mainly affects demand peaks.

The final economic results do not support a universal claim that the hybrid pathway is the best solution. Solar and Grid is the least-cost option, with NPC \$117,948, LCOE \$0.034/kWh, 5.3-year simple payback, and 18.56% IRR. Storage and Grid improve peak shaving but has substantially higher lifecycle cost. The hybrid reduces gross grid imports and increases renewable contribution, but its NPC reaches \$1.486

million because battery cycling and replacement costs dominate. This trade-off is consistent with literature emphasizing the flexibility advantages of PV-BESS systems (Alrubaiie *et al.*, 2023; Buestan-Morales *et al.*, 2024; Hossain & Cho, 2026), but the present results demonstrate that flexibility does not guarantee minimum lifecycle cost.

The final HOMER cash flows are -\$1,128/year for Storage and Grid and -\$85,825/year for Solar, Storage and Grid; consequently, HOMER returns N/A for their payback and IRR. Only Solar and Grid produces a valid positive payback (5.3 years simple and 6.5 years discounted). Operationally, the hybrid can still provide higher renewable contribution, lower gross grid imports, solar-energy shifting, and resilience value, but these services must be economically valued before storage can be justified.

For Mbeya, the practical early market remains electric three-wheelers and repeat-route urban fleets, which are among the most feasible early e-mobility segments in African cities (Ayetor *et al.*, 2023). The final model suggests a staged strategy: use PV-grid charging first where daytime load and grid access are adequate, then

add storage where outage resilience, peak-demand control, or future tariff structures create a quantified value stream. The environmental results reinforce this distinction: Solar and Grid reduces gross grid-related CO₂ emissions by 45.8 t/year (50.5%) relative to the base case, while Solar, Storage and Grid reduces them by about 33.4 t/year (36.8%). The sensitivity results show that tariff, PV cost, solar resource, demand growth, inflation, and battery cost can materially change the financial margins, so architecture selection should be revisited as local conditions change.

5.0 Conclusion

This study demonstrates that grid-connected solar charging is technically feasible and economically attractive for the Mbeya City case, but the preferred architecture depends on the balance between lifecycle cost, renewable-energy contribution, grid interaction, and operational flexibility. Among the three simulated pathways, Solar and Grid achieved the strongest lifecycle performance, with CAPEX of \$83,983, NPC of \$117,948, LCOE of \$0.034/kWh, simple and discounted payback periods of 5.34 and 6.5 years, an IRR of 18.56%, and annual utility-bill savings of \$15,891. It maintained zero unmet load, contributed approximately 40% renewable energy, and reduced gross grid-related CO₂ emissions by 45.8 t/yr (50.5%) relative to the base case. Storage and Grid provided peak-shaving capability but remained economically weak, with NPC of \$368,833 and no meaningful CO₂ reduction. Solar, Storage and Grid achieved the highest renewable fraction of approximately 90% and reduced gross CO₂ emissions by 33.4 t/yr (36.8%), but its NPC increased to \$1.486 million and LCOE to \$0.800/kWh because battery cycling and replacement costs dominated lifecycle expenditure. Sensitivity analysis further showed that electricity tariff, EV demand, PV cost, solar resource, inflation, and battery cost materially affect project viability; for the Solar and Grid pathway, the tested cases produced payback periods of approximately 4.2–6.6 years. These findings confirm that technical flexibility alone does not determine the preferred charging architecture. This interpretation is consistent with the established technical rationale for PV-EV

charging (Bhatti *et al.*, 2016), PV-BESS flexibility (Alrubaie *et al.*, 2023), and the need for location-specific techno-economic assessment (Hossain & Cho, 2026). Under the assumptions evaluated, Solar and Grid is therefore the most defensible first-stage deployment option for Mbeya City, while battery storage should be introduced selectively where resilience, peak-demand management, or weak-grid support has a clearly quantified value.

6.0 Recommendations

Based on the final economic and sensitivity results, Mbeya City should adopt a staged deployment strategy in which Solar PV and Grid-tied charging is prioritised at high-demand nodes such as terminals, depots, commercial corridors, and institutional centres. System capacity should be determined from measured hourly charging demand and site-specific solar availability rather than from city-scale planning capacity alone. This approach is consistent with PV-EV charging principles (Bhatti *et al.*, 2016) and recognizes electric two- and three-wheelers as practical early e-mobility segments in African cities (Ayetor *et al.*, 2023). Battery storage should not be treated as a compulsory component; it should be added only where a site-specific business case demonstrates sufficient value from peak-demand reduction, outage resilience, solar-energy shifting, or weak-grid operation. Such selective use of storage is consistent with the flexibility benefits of hybrid charging systems (Alrubaie *et al.*, 2023; Hossain & Cho, 2026).

Before large-scale implementation, future projects should validate session-level EV charging profiles, site irradiance, battery cycling and lifetime throughput, operation and maintenance costs, replacement schedules, grid-export compensation, and distribution-network constraints (Sierra *et al.*, 2020; Rashid *et al.*, 2024). Because the sensitivity analysis shows that tariff, component cost, solar resource, demand growth, and inflation can materially change payback and NPC, HOMER optimisation should be rerun whenever these inputs change significantly. Utilities and city planners should also evaluate time-of-use tariffs, transparent export rules, concessional financing, local maintenance capability, and modular capacity

expansion to improve bankability and avoid oversizing. The recommended implementation pathway is therefore Solar and Grid first, followed by modular storage only when its additional services justify the lifecycle cost (Alrubaie *et al.*, 2023; Hossain & Cho, 2026).

This study is limited by aggregate HOMER and field records, which do not capture individual EV travel, charging sessions, or statistically representative interview data. Economic results are also sensitive to low O&M assumptions and repeated battery replacements. Future work should collect session-level mobility data, validate local cost and battery assumptions, use measured solar data, assess grid constraints, and test scenarios.

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9.0 Declaration of Conflict of Interest

The authors declare that there is no conflict of interest regarding the publication and presentation of this work. The research was conducted independently for academic purposes, and the authors have no financial, commercial, or personal relationships that could have influenced the study design, analysis, interpretation, or conclusions.

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