

Techno-Economic Sizing and Optimization of a Grid-Connected Photovoltaic Electric Vehicle Charging Station Using HOMER: A Case Study of Palestine

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Abstract: - The rapid growth of electric vehicle (EV) adoption has intensified the need for cost-effective and sustainable fast-charging infrastructure. Integrating photovoltaic (PV) systems with electric vehicle charging stations (EVCSs) offers significant environmental and economic advantages; however, proper system sizing and techno-economic optimization are critical to ensure feasibility and long-term performance. This paper presents a comprehensive techno-economic sizing and optimization study of a grid-connected photovoltaic-based fast electric vehicle charging station using HOMER Pro software.

A real case study located in Hebron, Palestine, is investigated due to its high solar potential and increasing EV charging demand. The proposed charging station is designed to supply an average EV load of approximately 7 MWh/day. A detailed load assessment is conducted, followed by optimal sizing of the PV system, power converters, and grid interaction strategy. The analysis includes land utilization requirements, energy balance evaluation, and economic performance indicators such as Net Present Cost (NPC), Levelized Cost of Energy (LCOE), and renewable energy penetration.

Simulation results indicate that a 1.75 MW photovoltaic system meets the charging demand through optimal sizing, achieving a PV penetration exceeding 100% and permitting substantial surplus energy export to the utility grid during periods of high solar irradiance. The levelized cost of PV generation is found to be approximately 0.034 USD/kWh, and the blended levelized cost of the delivered EV charging service, inclusive of grid backup, is approximately 0.072 USD/kWh, both well below the 0.20 USD/kWh grid tariff, demonstrating strong economic viability compared to conventional grid-supplied charging stations. The outcomes confirm that PV-based fast EV charging stations, when properly sized and optimized, represent a sustainable and economically attractive solution for future transportation infrastructure. The underlying sizing problem is further formulated as an explicit cost-minimization program; its solution algorithm is examined analytically, closed-form sensitivity relationships for the discount rate, PV derating factor, and grid sellback price are derived and validated against the simulation outputs, and a stochastic model of EV arrivals is proposed as a probabilistic complement to the deterministic load profile.

Key-Words: - Electric vehicle charging station; Photovoltaic systems; Techno-economic analysis; HOMER Pro; System sizing; Renewable energy integration; Grid-connected microgrid; Optimization algorithms; Sensitivity analysis; Stochastic demand modeling

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1 Introduction

The rapid global penetration of EVs has intensified the demand for reliable, high-power, and sustainable charging infrastructure. Fast EVCSs, particularly those rated above 50 kW, introduce significant power demand, which can lead to voltage fluctuations, increased peak load, and power quality issues when supplied exclusively by the utility grid [1]. As a result, integrating renewable energy sources (RES), especially PV systems, into EV charging infrastructure has emerged as an effective strategy to

enhance sustainability, reduce grid stress, and lower operational costs [2].

Photovoltaic-based EV charging stations offer the advantage of on-site renewable generation, enabling partial or full coverage of charging demand during peak solar hours. However, the intermittent nature of solar energy and the stochastic behavior of EV charging demand impose challenges on system planning and sizing [3]. An undersized PV system may fail to meet charging requirements, leading to excessive grid dependency, while oversizing results in

increased capital cost and underutilized assets. Therefore, accurate load assessment, optimal system sizing, and techno-economic evaluation are critical steps for the practical deployment of PV-based EV charging stations [4].

Recent research has focused extensively on the control and operation of renewable-powered EV charging systems, addressing aspects such as power flow control, voltage regulation, and fast-charging dynamics [5]. Nevertheless, system-level planning and economic feasibility studies, particularly those based on real geographic locations and realistic EV demand profiles, remain comparatively limited. Techno-economic analysis provides decision-makers with essential indicators such as NPC, LCOE, renewable penetration level, and land utilization requirements, which are vital for investment and implementation planning [6].

Hybrid Optimization Model for Electric Renewables (HOMER) software has become one of the most widely adopted tools for the techno-economic design and optimization of grid-connected and off-grid renewable energy systems. HOMER enables the evaluation of multiple system configurations by simulating long-term energy balance while considering component costs, resource availability, and operational constraints [7]. Its application to EV charging infrastructure allows the assessment of different PV-grid penetration scenarios, energy exchange with the grid, and long-term financial performance under realistic operating conditions [8].

This paper presents a techno-economic sizing and optimization study of a large-scale, grid-connected photovoltaic-based electric vehicle fast charging station. The study is based on a real case study in Hebron, Palestine, characterized by high solar irradiance and growing EV adoption. Using HOMER Pro software, the proposed system is optimally sized to meet an average daily EV charging demand of approximately 7 MWh/day. The analysis includes EV load assessment, PV system sizing, inverter configuration, land utilization requirements, and comprehensive economic evaluation.

The main contributions of this paper are as follows:

1. Development of a realistic EV charging load model based on expected EV and electric bus demand.
2. Optimal sizing of a 1.75 MW grid-connected PV system for fast EV charging using HOMER.
3. Detailed techno-economic evaluation, including NPC, LCOE, PV penetration, and grid energy exchange.

4. Practical insights into land utilization and deployment feasibility for large-scale PV-based EV charging stations.
5. Explicit mathematical formulation of the sizing problem as a constrained cost-minimization program, together with an analysis of the algorithm HOMER Pro uses to solve it.
6. Closed-form sensitivity analysis of the levelized cost indicators with respect to the discount rate, PV derating factor, and grid sellback price, complemented by a proposed stochastic model of EV arrivals.

The results demonstrate the economic viability and sustainability benefits of integrating photovoltaic systems with fast EV charging infrastructure, providing a valuable reference for planners, utilities, and policymakers aiming to accelerate renewable-powered transportation.

2 System Description and EV Load Assessment

2.1 Proposed System Configuration

The proposed EVCS is designed as a grid-connected photovoltaic-based system intended to support high-power fast EV charging while minimizing dependency on the utility grid. The overall configuration integrates two PV farms, a centralized DC bus, multiple DC fast-charging units, and a bidirectional grid interface. This hybrid architecture enables both energy import from and export to the utility grid depending on real-time generation and load conditions.

The system comprises two PV farms rated at 1 MW and 0.75 MW, respectively, resulting in a total installed PV capacity of 1.75 MW. Each PV farm is interfaced through a dedicated DC-DC boost converter, while a 1000 V DC bus serves as the main energy distribution backbone for fast EV charging units and grid interaction. The utility grid provides supplementary power during periods of low solar generation and absorbs surplus PV energy during high irradiance conditions.

Figure 1 illustrates the overall architecture of the proposed EV charging station. The system integrates dual photovoltaic farms connected to a common DC bus through DC-DC boost converters. Fast EV chargers are supplied directly from the DC bus, reducing power conversion stages and improving system efficiency. A bidirectional inverter enables seamless interaction with the utility grid, allowing excess photovoltaic energy to be exported while

ensuring uninterrupted charging during periods of insufficient solar generation.

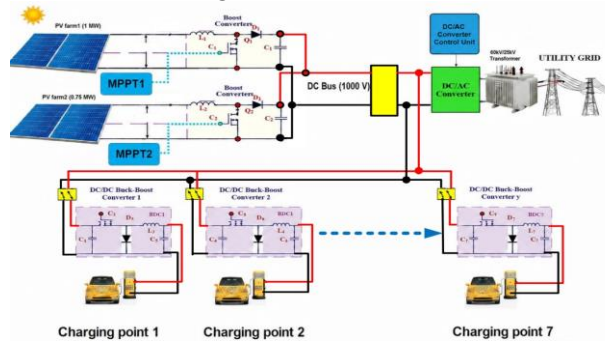


Fig. 1: Schematic configuration of the grid-connected PV-based electric vehicle charging station. "Source: created by the authors"

2.2 EV Charging Demand Estimation

Accurate estimation of EV charging demand is a fundamental step in the techno-economic sizing of the proposed system. The charging station is designed to serve both passenger electric vehicles and electric buses, reflecting realistic urban charging scenarios. The daily energy demand is analytically derived based on the number of vehicles, battery capacities, and assumed initial state of charge (SoC) upon arrival [9].

The analysis assumes that vehicles arrive at the station with an average initial SoC of 30% and are charged up to full capacity. This assumption aligns with typical urban driving patterns and fast-charging behavior [10]. Based on the thesis methodology, the charging facility is assumed to serve 182 passenger EVs and 7 electric buses per day.

The corresponding energy demand is computed as follows:

1. Passenger EVs: $182 \text{ vehicles} \times 35 \text{ kWh} \approx 6,370 \text{ kWh/day}$
2. Electric buses: $7 \text{ buses} \times 91 \text{ kWh} \approx 637 \text{ kWh/day}$

The resulting total daily charging demand is approximately 7,007 kWh/day, which serves as the primary load input for system sizing and HOMER-based optimization.

2.3 Load Profile Characteristics

The temporal distribution of EV charging demand exhibits distinct daily, seasonal, and annual variations, which significantly influence renewable energy utilization and grid interaction [11]. Peak charging activity is observed during morning and evening hours, corresponding to daily commuting patterns [12]. Seasonal variations are also evident due to changes in transportation activity and weather conditions.

Figure 2, Figure 3 and Figure 4 present the daily, seasonal, and annual EV charging demand profiles

used in this study. The daily profile highlights peak demand during typical commuting hours, while the seasonal and annual profiles illustrate longer-term variations in charging behavior. These load characteristics play a crucial role in determining the optimal photovoltaic system size and the extent of grid dependency

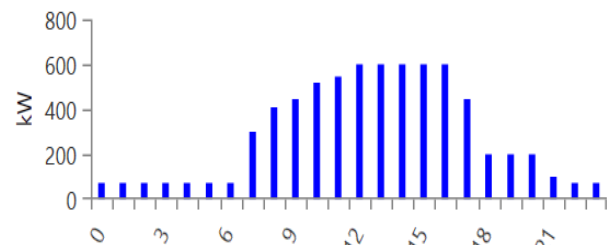


Fig. 2: Daily electric vehicle charging load profile of the proposed EVCS. "Source: created by the authors"

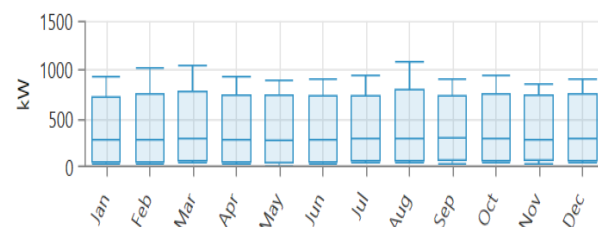


Fig. 3: Seasonal variation of EV charging demand. "Source: created by the authors"

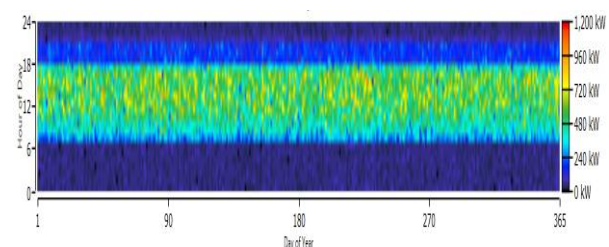


Fig. 4: Annual load profile of the electric vehicle charging station. "Source: created by the authors"

2.4 Implications for System Sizing

The derived EV load profile confirms the necessity for a large-scale photovoltaic system capable of delivering high energy output while maintaining system reliability. The significant daily energy demand of approximately 7 MWh/day justifies the selection of a 1.75 MW PV system, ensuring adequate coverage of charging requirements during peak solar periods and economic feasibility over the project lifetime.

The load assessment presented in this section forms the foundation for the HOMER-based optimization process discussed in the subsequent section, where technical constraints and economic indicators are jointly evaluated.

3 Photovoltaic System Sizing and HOMER Optimization Framework

3.1 Photovoltaic System Sizing Methodology

The sizing of the photovoltaic (PV) system is carried out to ensure reliable coverage of the electric vehicle charging demand while achieving economic feasibility over the system lifetime [13]. Based on the load assessment presented in Section 2, the proposed EV charging station requires an average daily energy supply of approximately 7,007 kWh/day. Given the high solar potential of Hebron, Palestine, a PV-dominant solution supported by grid interaction is selected.

The PV sizing process follows an analytical approach considering average peak sun hours, system derating factors, and long-term operational efficiency. Using conservative assumptions for system losses and solar resource variability, the required PV capacity is determined to be approximately 1.75 MW. This capacity is sufficient to meet the EV charging demand during peak irradiance periods while allowing surplus energy export to the utility grid.

Table 1 and Table 2 present the electrical and mechanical specifications of the selected 355 W monocrystalline PV module used in the proposed system. These parameters are essential for determining the number of modules, string configuration, inverter selection, and overall land utilization requirements. The module selection ensures high efficiency and compatibility with large-scale grid-connected applications.

Table 1. Electrical characteristics of the selected PV module

Condition	Parameter	Value
STC	Peak Power	355 W
	Max Power Voltage	38.7 V
	Max Power Current	9.17 A
	Open Circuit Voltage	47.0 V
	Short Circuit Current	9.69 A
	Module Efficiency	18.1%
	Power Tolerance	+0 W to +5 W

"Source: created by the authors"

3.2 PV Farm Configuration and Land Utilization

To enhance system reliability and operational flexibility, the total PV capacity is divided into two separate farms rated at 1 MW and 0.75 MW, each associated with an independent inverter. This dual-inverter configuration provides improved redundancy, facilitates maintenance, and allows partial operation during component outages [14].

A total of 4,930 PV modules is required to achieve the desired installed capacity. The land utilization analysis accounts for module dimensions, tilt angle, inter-row spacing to avoid shading, maintenance walkways, inverter placement, and electrical infrastructure.

Table 2. Mechanical characteristics of the selected PV module

Parameter	Specification
Solar Cells	Monocrystalline 156 × 156 mm (6 inches)
Cell Orientation	72 cells (6 × 12)
Module Dimensions	1984 × 998 × 25 mm (78.1 × 39.3 × 0.984 inches)
Weight	28 kg (62 lb)
Front Glass	2.5 mm (0.10 inches), High Transmission, AR Coated, Heat Strengthened Glass
EVA	White
Back Glass	2.5 mm (0.10 inches), Heat Strengthened Glass
Frame	Frameless
Junction Box (J-Box)	IP67 or IP68 rated
Cables	PV Technology Cable 4.0 mm ² (0.006 in ²)
Cable Length (Portrait)	140 / 285 mm (5.5 / 11.2 inches)
Cable Length (Landscape)	1400 / 1400 mm (55.1 / 55.1 inches)
Connector	MC4 Compatible (Amphenol H4/UTX - 1500V)
Fire Type Rating	Type 13

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Table 3 summarizes the land utilization requirements of the proposed photovoltaic system. The total area required is approximately 17,812 m², corresponding to about 1.78 hectares. The analysis confirms that the PV system can be realistically deployed within urban or semi-urban settings, making it suitable for practical EV charging infrastructure implementation

3.3 Formal Optimization Problem Formulation

To move beyond a purely simulation-based treatment, the sizing problem addressed by HOMER Pro in Sections 3.1–3.2 is stated here explicitly as a constrained cost-minimization program. The decision vector is $x = [Y_{PV}, Y_{conv}]$, where Y_{PV} and Y_{conv} denote the rated capacities (kW) of the photovoltaic array and the bidirectional power converter. A battery

capacity was included in the original HOMER search space (Table 4) but is not retained as a free decision variable here, since the optimal solution reported in Table 5 sets it to zero; its removal is a corner-solution outcome of the optimization rather than a modelling simplification.

The objective is to minimize the net present cost of the system over the project lifetime $N = 25$ years:

$$\min \text{NPC}(x) = C_{\text{cap}}(x) + \sum^N [C_{\text{op}}(x,t)/(1+i)^t] - S(x)/(1+i)^N \quad (1)$$

Table 3. Land utilization and configuration summary for the 1.75 MW PV system

Section	Component	Specification / Calculation	Value
System Capacity	Total System Power	–	1,750 kW
	Modules	355W (1.98m × 1.0m)	–
	No. of Modules Required	1,750,000W ÷ 355W	4,930 modules
Electrical Configuration	String Configuration	20 modules per string	–
	Total Strings	4,930 ÷ 20	247 strings
Sub-array Allocation	1 MW Inverter	1,000,000W ÷ 355W ÷ 20	141 strings
	0.75 MW Inverter	750,000W ÷ 355W ÷ 20	106 strings
Physical Layout	Modules per Row	100 m row length	50 modules
	Rows for 1 MW Inverter	(141 × 20) ÷ 50	57 rows
	Rows for 0.75 MW Inverter	(106 × 20) ÷ 50	43 rows
Space Requirements	Panel Area	4,930 × 1.98 m ²	9,761 m ²
	Row Spacing	(57 + 43) × 0.69 m × 100 m	6,900 m ²
	Walkways	1 m every 10 rows → 10 × 100 m × 1 m	1,000 m ²
	Inverter Space	1 MW: 15 m ² , 0.75 MW: 12 m ²	27 m ²
	Combiner Boxes	0.5 m ² per 20 modules → 247 × 0.5 m ²	124 m ²
Total Land Area	–	Sum of all above	17,812 m ² (~1.78 hectare)
	Layout Dimensions	–	~133 m × 134 m

"Source: created by the authors"

where $C_{\text{cap}}(x)$ is the total capital cost, $C_{\text{op}}(x,t)$ is the net operating cost in year t (PV and converter O&M plus the cost of grid purchases net of grid sales

revenue), $S(x)$ is the salvage value, and i is the discount rate. Because O&M costs are level in real terms and grid purchases and sales are treated as level annual quantities under the deterministic load profile of Section 2, $C_{\text{op}}(x,t) = C_{\text{op}}(x)$ is constant in t , so the summation in Equation (1) reduces to an annuity — the step used explicitly in Section 3.7 to isolate the effect of the discount rate on the reported results.

The optimization is carried out subject to:

3. Hourly power balance: $\text{PPV}(x,t) + \text{Pgrid,imp}(t) = \text{PEV}(t) + \text{Pgrid,exp}(t)$ for every simulated hour $t = 1, \dots, 8760$, where $\text{PEV}(t)$ is the EV charging load derived from the profile of Section 2.3.

4. PV output model (Equation 2 below), which fixes $\text{PPV}(x,t)$ as a function of YPV , the derating factor, and the incident solar resource.

5. Converter capacity limit: $|\text{Pconv}(t)| \leq \text{Yconv}$ for every t .

6. Grid interconnection limit: $0 \leq \text{Pgrid,imp}(t), \text{Pgrid,exp}(t) \leq \text{Pgrid,max}$, with Pgrid,max treated as unconstrained in the present case study, consistent with the nominal 999,999 kW grid capacity reported in Table 5.

7. Non-negativity: $\text{YPV} \geq 0, \text{Yconv} \geq 0$.

The PV array itself is modelled internally by HOMER Pro as

$$\text{P}_{\text{PV}}(x,t) = f_{\text{PV}} \cdot \text{Y}_{\text{PV}} \cdot (\text{IT}(t)/\text{IS}) \quad (2)$$

with f_{PV} the PV derating factor, $\text{IT}(t)$ the incident solar radiation in time step t , and $\text{IS} = 1 \text{ kW/m}^2$ the standard test-condition irradiance [7]; this is the form HOMER Pro uses when the temperature dependence of PV output is not separately modelled, as in the present study. The derating factor therefore enters as a direct linear multiplier on the annual energy yield, a property used in the sensitivity analysis of Section 3.7. Because Pgrid,max is effectively unconstrained, the EV load is served in every hour at every feasible x , so the maximum annual capacity shortage is identically zero — consistent with the 100% load service implicit in Table 6, Table 7, Table 8 and Table 9.

This formulation makes explicit what HOMER Pro solves internally as a black box: for each candidate x it runs an hourly simulation of the constraints above and evaluates $\text{NPC}(x)$ via Equation (1), and the optimizer then searches over x for the minimizer. Section 3.4 discusses how that search is actually carried out.

3.4 HOMER Pro Optimization Framework and Solution Algorithm

The techno-economic optimization of the proposed EV charging station is carried out using HOMER Pro

software, which simulates the long-term performance of hybrid renewable energy systems. HOMER evaluates multiple system configurations by considering component costs, solar resource availability, load demand, grid interaction, and economic parameters [15].

The optimization objective is to minimize NPC while satisfying the EV charging demand and operational constraints [16]. The system components considered within the HOMER model include:

- Photovoltaic array
- DC/AC power converter
- Utility grid connection
- Electric vehicle charging load

Figure 5 illustrates the HOMER Pro system representation of the proposed PV-based EV charging station, while Figure 6 illustrates the optimization process implemented by HOMER Pro to identify the most cost-effective configuration. The software performs hourly energy balance simulations over a 25-year project lifetime, enabling the identification of the most cost-effective configuration while maintaining system reliability.

HOMER Pro solves the program of Section 3.3 using one of two internal algorithms [7]. The first is a grid-search (full-factorial) method, which simulates every feasible combination of component sizes drawn from a user-specified discrete search space and ranks the resulting configurations by NPC — the exhaustive procedure historically used by the software. The second, the proprietary HOMER Optimizer, is a derivative-free direct-search algorithm layered on the same hourly simulation engine, which explores the continuous size space more efficiently than exhaustive enumeration without requiring gradient information — a necessary property here, since $NPC(x)$ in Equation (1) is not available in closed form and can only be evaluated by running the hourly simulation of constraints (a)–(e). Both algorithms return the same type of output: a ranked list of feasible configurations, from which the minimum-cost configuration in Table 5 is selected.

Because HOMER's search — by either algorithm — evaluates $NPC(x)$ only through simulation, it offers no formal guarantee of global optimality and returns no gradient or dual information about the solution. For the two-variable search space considered here, this is not a material limitation, and the results are consistent with the closed-form reconciliation of Section 4.4. If the decision space were extended, however — for example to include battery capacity, EV charging schedules as decision variables, or the stochastic demand model proposed in Section 3.8 — the objective would become non-smooth and possibly

non-convex, and population-based metaheuristics such as particle swarm optimization or genetic algorithms, already applied elsewhere to EV charging infrastructure sizing [5], [9], would be a more suitable and scalable alternative to grid search. A systematic comparison against HOMER's built-in optimizer on such an extended problem is identified as a direction for future work rather than pursued here, since it would require dispatch data at a resolution beyond what the present HOMER Pro simulation exports.

3.5 HOMER Input Parameters and Economic Assumptions

Accurate input data are essential for reliable techno-economic evaluation. The HOMER simulation incorporates realistic solar radiation and ambient temperature data specific to Hebron, Palestine. Economic parameters include capital costs, operation and maintenance expenses, grid electricity tariffs, and financial assumptions.

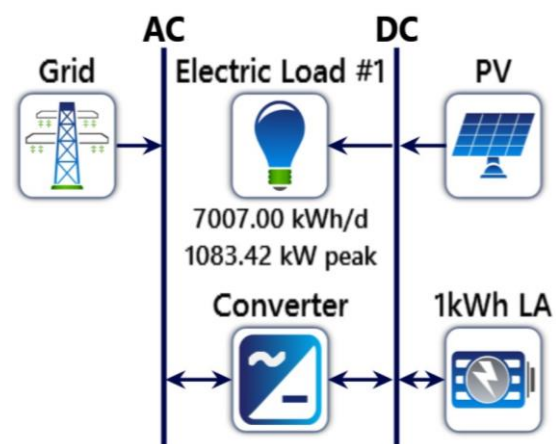


Fig. 5: HOMER Pro model of the proposed PV-based electric vehicle charging station. "Source: created by the authors"

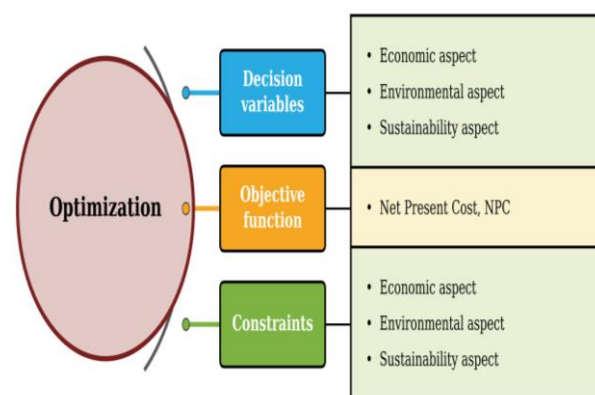


Fig. 6: HOMER Pro optimization process for renewable-based EVCS design. "Source: created by the authors"

Table 4. lists the technical and economic parameters used in the HOMER Pro simulation. The project lifetime is set to 25 years, with a discount rate of 8% and an inflation rate of 2%. These assumptions reflect realistic longterm investment conditions and ensure accurate evaluation of system feasibility

Table 4. HOMER Pro input parameters and economic assumptions

Item	Value
Project Lifetime	25 years
Nominal Discount Rate	8.0%
Expected Inflation Rate	2.0%
Real Interest Rate	5.9%
PV Capital Cost	582.00 (\$/kW)
PV O&M	10.00 (\$/kW)
PV Derating Factor	80%
Battery Capital Cost	300.00 (\$/kW)
Converter Capital Cost	100.00 (\$/kW)
Converter efficiency	95%
Grid Power price	0.2 (\$/kWh)
Grid Sellback price	0.1 (\$/kWh)
The Energy Demand for Electric Vehicles	7,007 (kWh/day)

"Source: created by the authors"

3.6 Optimization Criteria

HOMER ranks feasible system configurations based on techno-economic performance indicators, including NPC, LCOE, renewable penetration, and grid energy exchange. The selected optimal configuration balances investment cost and operational efficiency while maximizing renewable energy utilization.

The optimized system configuration obtained from HOMER is discussed in detail in the subsequent section, where energy balance results and economic performance indicators are analyzed.

3.7 Analytical Sensitivity Framework

This section derives closed-form relationships between three parameters identified for sensitivity analysis — the discount rate, the PV derating factor, and the grid sellback price — and the reported cost indicators and shows in Section 4.4 that these relationships reproduce the values in Table 7, Table 8 and Table 9 to the precision reported there. Numerical results are evaluated in Section 4.6.

For a level annuity over the project lifetime N at discount rate i , the capital recovery factor is

$$CRF(i, N) = i(1+i)^N / [(1+i)^N - 1] \quad (3)$$

so the annualized value of a one-time capital expenditure C_{cap} is $C_{cap} \cdot CRF(i, N)$; because level real annual cash flows annualize to themselves, the

annualized value of a level annual operating cost is that cost unchanged. This decomposition follows directly from the annuity reduction of Equation (1) noted in Section 3.3.

The photovoltaic array is the only NPC component with both a capital and an O&M term, so its leveled cost of energy is

$$LCOE_{PV}(i, f_{PV}) = [C_{PV, cap} \cdot CRF(i, N) + C_{PV, O\&M}] / EPV(f_{PV}) \quad (4)$$

where $CPV, cap = YPV \cdot cPV$ ($YPV = 1,753$ kW, $cPV = 582$ \$/kW, Table 4), $CPV, O\&M = YPV \cdot cO\&M = 17,530$ \$/yr, and $EPV(f_{PV})$ is the annual PV energy yield. Equation (2) shows that EPV scales linearly in the derating factor f_{PV} to first order, holding the irradiance profile and temperature effects fixed, so

$$EPV(f_{PV}) \approx EPV,0 \cdot (f_{PV}/f_{PV,0}) \quad (5)$$

with base case $f_{PV,0} = 80\%$ and $EPV,0 = 2,848,503$ kWh/yr (Table 6).

Because Equation (4) excludes the cost of grid backup, it understates the actual cost of delivering EV charging service. A second, complementary indicator — the blended leveled cost of the EV energy service — is defined as the total system annualized cost divided by the annual EV load actually served, $L = 2,557,555$ kWh/yr (Section 2.2):

$$LCOE_{EV}(i, p_{sell}) = [(C_{PV, cap} + C_{conv, cap}) \cdot CRF(i, N) + C_{PV, O\&M} + C_{grid, net}(p_{sell})] / L \quad (6)$$

where $C_{grid, net}(p_{sell}) = p_{buy} \cdot E_{grid, purchase} - p_{sell} \cdot E_{grid, export}$ is the net annual cost of grid interaction, $p_{buy} = 0.20$ \$/kWh is fixed (Table 4), and $E_{grid, export}$ is estimated from the annual energy balance of Table 6 as $E_{grid, export} \approx EPV,0 + E_{grid, purchase} - L = 1,268,255$ kWh/yr. The corresponding marginal relationship, $\partial C_{grid, net} / \partial p_{sell} = -E_{grid, export}$, is exact and independent of the hourly dispatch, and is used directly in Section 4.6 to evaluate the sellback-price sensitivity as a perturbation around the exact reported baseline.

3.8 Stochastic Extension: Probabilistic EV Arrival and Charging Demand Model

Section 2.2 models EV charging demand deterministically, using a fixed vehicle count and a fixed 30% arrival state of charge (SoC). This section proposes such an extension analytically, as a complement to not a replacement for the deterministic HOMER simulation, since re-running HOMER against a stochastic load profile lies outside the scope of the present study.

Passenger EV arrivals are modelled as a non-homogeneous Poisson process with rate $\lambda_{EV}(t)$, $t \in [0, 24)$ h, shaped to reproduce the two-peak

morning/evening commuting pattern already reported in Figure 2, and normalized so that

$$\int_0^{24} \lambda_{EV}(t) dt = 182, \quad (7)$$

the deterministic daily passenger-EV count of Section 2.2; electric-bus arrivals are modelled analogously with $\int \lambda_{bus}(t)dt = 7$. The arrival SoC of the i -th vehicle, S_i , is modelled as a Beta-distributed random variable, $S_i \sim \text{Beta}(3,7)$, which has mean $E[S_i] = 3/(3+7) = 0.30$ — matching the deterministic assumption of Section 2.2 — with a standard deviation of about 14% to represent realistic driver-to-driver variability. Under the paper's own assumption of charging to full capacity, the average usable battery capacities implied by the stated 35 kWh and 91 kWh session-energy figures are $CEV = 35/(1-0.30) \approx 50$ kWh and $C_{bus} = 91/(1-0.30) \approx 130$ kWh, so the energy delivered to vehicle i is $E_i = C_i(1-S_i)$.

The total daily energy demand is the compound sum $D = \sum E_i$ over the random number of arrivals given by the Poisson processes above. For a compound Poisson sum of independent marks,

$$E[D] = 182 \times 50 \times 0.70 + 7 \times 130 \times 0.70 = 6,370 + 637 = 7,007 \text{ kWh/day}, \quad (8)$$

which recovers the deterministic value of Section 2.2 exactly — confirming that the static profile used for HOMER sizing corresponds to the mean of the proposed stochastic model rather than an arbitrary point estimate. The corresponding variance, $\text{Var}[D] = 182 \cdot \text{Var}[CEV(1-S)] + 7 \cdot \text{Var}[C_{bus}(1-S)]$, is strictly positive, and is the substantive content the deterministic profile omits: on higher-demand days the system of Table 5 draws more heavily on grid backup rather than failing to serve load, since the grid interconnection constraint of Section 3.3 is effectively unconstrained. A chance-constrained reformulation of Section 3.3, sizing YPV so that $P(D > D_{\text{design}}) \leq \varepsilon$ for a small target exceedance probability ε , in place of sizing to the mean demand would extend this framework into the design process itself; this is left as a natural next step, well suited to the metaheuristic solution methods discussed in Section 3.4, since the resulting objective is no longer available as a simple deterministic simulation output. Formal treatments of Poisson-process arrivals at EV charging infrastructure, on which the present formulation draws, are given in [17].

4 Simulation Results and Techno- Economic Analysis

4.1 Optimal System Configuration

The HOMER Pro optimization process identifies the most cost- effective configuration that satisfies the

electric vehicle charging demand while minimizing NPC. The optimal system consists of a 1.75 MW photovoltaic array, a bidirectional DC/AC converter, and a grid connection acting as a backup and energy export interface. Although battery storage was initially considered, the optimization results demonstrate that grid connectivity provides superior economic performance for the selected site and load profile.

Table 5. presents the optimal system configuration selected by HOMER Pro. The results confirm that a gridconnected PV configuration without battery storage achieves the lowest NPC while ensuring reliable supply to the EV charging station. The grid effectively complements solar generation during nighttime and lowirradiance conditions

Table 5. Optimal system configuration obtained using HOMER Pro

Component	Name	Size	Unit
PV	Generic flat plate PV	1,753	kW
System converter	System Converter	965	kW
Grid	Grid	999,999	kW

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4.2 Energy Production and Renewable Penetration

The annual energy production analysis reveals that the photovoltaic system is the dominant energy source for the EV charging station. The 1.75 MW PV plant generates approximately 2.85 GWh annually, covering a significant portion of the charging demand. Excess PV energy is exported to the grid during periods of high irradiance, enhancing overall system efficiency.

Table 6 illustrates the annual energy contribution of the photovoltaic system and the utility grid. The PV system supplies approximately 74.5% of the total energy demand, while the remaining 25.5% is imported from the grid. This high renewable penetration highlights the effectiveness of photovoltaic integration in reducing grid dependency

Table 6. Annual energy production and contribution of PV and grid sources

Component	Production (kWh/yr)	Percent (%)
Generic flat plate PV	2,848,503	74.5
Grid Purchases	977,307	25.5
Total	3,825,810	100

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4.3 Monthly Energy Exchange with the Grid

The interaction between the EV charging station and the utility grid varies significantly throughout the year due to seasonal solar irradiation patterns. During high-irradiance months, the station exports surplus energy, whereas grid imports dominate during winter months and nighttime operation.

Figure 7, Figure 8 and Figure 9 depict the monthly energy exchange between the EV charging station and the grid. The results indicate that, during most spring and summer months, energy exported to the grid exceeds energy imports. This behavior confirms that the photovoltaic system is appropriately sized not only to meet EV charging demand but also to contribute surplus renewable energy to the utility grid.

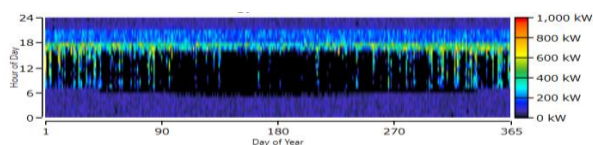


Fig. 7: Monthly energy purchased from the utility grid.

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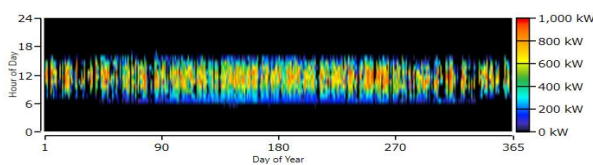


Fig. 8: Monthly energy sold to the utility grid.

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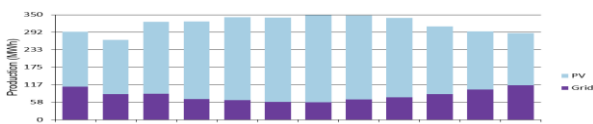


Fig. 9: Monthly energy contribution of PV and grid sources.

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4.4 Economic Performance Evaluation

The economic feasibility of the proposed system is assessed using key performance metrics generated by HOMER Pro, including NPC, LCOE, and annualized system cost [18]. The total NPC of the optimized configuration is approximately 2.38 million USD, which includes capital, operational, and grid energy costs over the 25-year project lifetime.

Table 7, Table 8, and Table 9 summarize the economic performance of the proposed EV charging station. The photovoltaic system constitutes the largest capital investment, while grid purchases account for the majority of operational costs. The obtained levelized cost of energy of approximately 0.034 USD/kWh demonstrates the strong economic

competitiveness of the proposed renewable-based charging station [19].

The PV capital cost in Table 8 follows directly from the optimized PV capacity in Table 5 and the unit cost in Table 4: $1,753 \text{ kW} \times 582 \text{ $/kW} = \$1,020,246 \approx \1.02M , matching Table 7. The real discount rate of Table 4 follows from the nominal rate and inflation rate in the same table: $(8.0\% - 2.0\%)/1.02 = 5.88\% \approx 5.9\%$, giving CRF $(5.88\%, 25) \approx 0.0774$.

Table 7. Overall economic performance indicators of the proposed EV charging station

The electric needs of HaPalmach St 1, Hebron, Palestine are met by a 1,753 kW PV system, which produces 2,848,503 kWh annually. The operating energy costs are currently \$97,740 per year.	
Rated Capacity	1,753 kW
Capital Cost	\$1.02M
Specific Yield	1,625 kWh/kW
PV Penetration	111 %

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Table 8. Net Present Cost breakdown of system components

Name	Capital (US \$)	Operating (US \$)	Replacement (US \$)	Salvage (US \$)	Resource (US \$)	Total (US \$)
Generic flat plate PV	1.02 M	226,619	0.00	0.00	0.00	1.25 M
Grid	0.00	1.04 M	0.00	0.00	0.00	1.04 M
System Converter	96,544	0.00	0.00	0.00	0.00	96,544
System	1.12 M	1.26 M	0.00	0.00	0.00	2.38 M

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Table 9. Annualized cost distribution of system components

Name	Capital (US \$)	Operating (US \$)	Replacement (US \$)	Salvage (US \$)	Resource (US \$)	Total (US \$)
Generic flat plate PV	78,920	17,530	0.00	0.00	0.00	96,450
Grid	0.00	80,210	0.00	0.00	0.00	80,210
System Converter	7,468	0.00	0.00	0.00	0.00	7,468
System (Total)	86,389	97,740	0.00	0.00	0.00	184,128

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Applying this to the PV capital cost annualizes it to \$78,920/yr, exactly matching Table 9; adding the PV O&M cost of $1,753 \text{ kW} \times 10 \text{ $/kW} = \$17,530/\text{yr}$ and dividing by the annual PV yield of 2,848,503 kWh (Table 6) gives $\text{LCOEPV} = (78,920 + 17,530) / 2,848,503 \approx 0.0339 \text{ $/kWh}$, reproducing Table 7 to the precision reported. This confirms that the LCOE quoted in Table 7, the abstract, and the conclusion is specifically the levelized cost of PV generation, not the delivered cost of EV charging service inclusive of grid backup.

The latter, more complete indicator is obtained from Equation (6) using the reported figures directly: dividing the total annualized system cost of \$184,128/yr (Table 9) by the annual EV load actually served, 2,557,555 kWh/yr (Section 2.2), gives $\text{LCOEEV} = 184,128 / 2,557,555 \approx 0.072 \text{ $/kWh}$. This blended figure remains substantially below the flat grid tariff of 0.20 \$/kWh used in Table 4, a 64% reduction, and is the more appropriate basis for comparison with conventional grid-supplied charging, complementing the PV-specific value of Table 7.

4.5 Cash Flow and Financial Sustainability

The long-term cash flow analysis confirms the financial sustainability of the project. Most of the expenses occur during the initial investment stage, while annual operational costs remain relatively stable throughout the project lifetime. Additionally, revenue from energy sales to the grid further improves system economics. Figure 10 presents the resulting distribution of capital and operating costs among the system components, while Figure 11 illustrates the

corresponding project cash flow over the 25-year system lifetime, confirming that the initial capital outlay is progressively offset by operational savings and grid sales revenue.

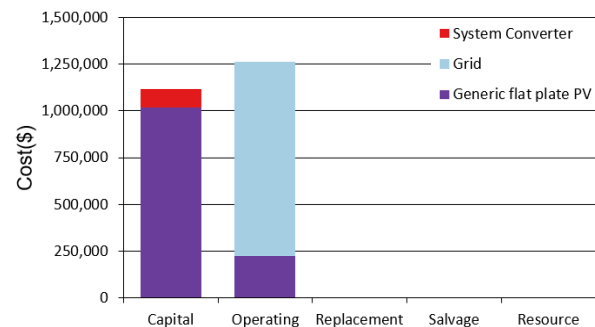


Fig. 10: Distribution of capital and operating costs for the EV charging station.

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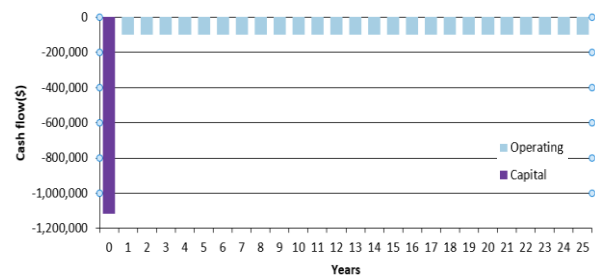


Fig. 11: Project cash flow over the system lifetime.

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4.6 Sensitivity Analysis Results

Table 10. evaluates the closed-form relationships of Section 3.7 at representative low/base/high values of the three parameters. The discount-rate and derating-factor rows use Equations (4)–(5) and reproduce the base-case LCOEPV of Table 7 exactly at the reported base values (8% nominal discount rate, 80% derating factor); the sellback-price row applies the exact marginal relationship of Section 3.7 to the reported base-case system cost of Table 9, so the base-case LCOEEV entry reproduces the 0.072 \$/kWh value derived in Section 4.4 exactly, with the low/high entries obtained from the linear marginal relationship

Two observations follow. First, the PV-specific LCOE is more sensitive to the discount rate than to the derating factor over the ranges considered (+16%/–15% versus +7%/–6%), which is expected since capital recovery, not energy yield, dominates the PV cost structure at this discount rate.

Table 10. Sensitivity of PV-specific LCOE (LCOEPV) and blended EV-service LCOE (LCOEEV) to the discount rate, PV derating factor, and grid sellback price

Parameter/metric	Low	Base	High
Nominal discount rate (%)	6.0	8.0	10.0
→ LCOE (PV-only) (\$/kWh)	0.0289	0.0339	0.0393
→ LCOE (blended) (\$/kWh)	0.0659	0.0720	0.0786
PV derating factor (%)	75	80	85
→ LCOE (PV-only) (\$/kWh)	0.0361	0.0339	0.0319
Grid sellback price (\$/kWh)	0.05	0.10	0.15
→ LCOE (blended) (\$/kWh)	0.0968	0.0720	0.0472

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Second, and less expected, the blended LCOEEV is substantially more sensitive to the grid sellback price ($\pm 34\%$) than to the discount rate ($+9\%/-8\%$): the station's overall economics depend more on the tariff governing exported energy than on the financing terms of the PV investment, a result not visible from the point estimates of Tables 7–9 alone, and which follows from the relatively large exported-energy volume (1,268,255 kWh/yr, about one third of PV production) relative to the capital cost base.

This exported-energy estimate is derived from the annual energy balance of Table 6 rather than from HOMER's hourly dispatch. Consistent with this, the net grid operating cost of \$68,636/yr computed from Equation (6) at the base-case sellback price is within 14% of the \$80,210/yr reported in Table 9, with the residual attributable to the hourly (8,760 time-step) resolution of the HOMER simulation, which captures the precise timing of imports and exports relative to the solar resource information an annual energy balance alone cannot recover. This gap is itself informative: it quantifies the value added by the hourly simulation over an annual-average analytical approximation, directly addressing the concern that HOMER is used here only as an opaque black box.

5 Conclusion

This paper presented a comprehensive techno-economic sizing and optimization study of a grid-connected photovoltaic-based fast electric vehicle charging station using HOMER Pro software. A real case study located in Hebron, Palestine, was investigated to evaluate the feasibility of integrating large-scale PV generation with high-power EV

charging demand under realistic environmental, technical, and economic conditions.

A detailed EV load assessment revealed an average daily charging demand of approximately 7 MWh/day, corresponding to combined passenger EV and electric bus charging requirements. Based on this demand and the local solar resource availability, an optimally sized 1.75 MW photovoltaic system was identified. The HOMER optimization results demonstrated that a grid-connected PV-dominant configuration without battery storage achieves the lowest Net Present Cost while ensuring reliable operation and flexibility. The utility grid effectively complements solar generation during nighttime and low-irradiance periods, while absorbing surplus energy during peak solar hours.

The techno-economic analysis showed that the proposed system achieves a photovoltaic penetration exceeding 100%, enabling significant energy export to the grid. The computed levelized cost of energy of approximately 0.034 USD/kWh confirms the strong economic competitiveness of the proposed charging station when compared to conventional grid-supplied alternatives. In addition, the land utilization analysis verified that the required installation area is practical for deployment within urban or semi-urban environments.

Overall, the results confirm that properly sized PV-based fast EV charging stations represent a sustainable and economically viable solution for supporting the electrification of transportation. The methodology and findings presented in this study provide valuable guidance for planners, investors, and policymakers seeking to develop renewable-powered EV charging infrastructure.

Future work may extend this study by incorporating battery energy storage systems, variable electricity tariffs, and multi-objective optimization frameworks to further enhance system flexibility and economic performance.

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