

Development of an Optimal Solar PV Compensation Model Integrating Dynamic Tariff Pricing for Maximized Techno-Economic Impact

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ABSTRACT

Well-structured policies and clear financial mechanisms are essential for fostering a stable and competitive renewable energy market. In Malaysia, solar PV compensation schemes have evolved since 2011 to offer competitive renewable energy rates. Due to limited financial benefits, the initial Net-Energy-Metering (NEM) scheme attracted low participation. Subsequently, NEM 2.0 and NEM 3.0 were introduced to enhance incentives and accelerate rooftop solar adoption. However, the effectiveness of NEM 3.0 in providing attractive compensation remains limited. Furthermore, quantitative evaluations of compensation schemes integrated with dynamic tariffs such as Enhanced Time-of-Use (ETOU) and System Marginal Price (SMP) are still lacking. This study formulates solar PV compensation scheme models namely Self-Consumption (SELCO), NEM 2.0, and NEM 3.0 that integrate dynamic tariff pricing to maximize prosumers' techno-economic performance. An Institute of Higher Learning (IHL) operating under a commercial flat (C1) tariff is used as the case study. Results show minimal variation in bill savings under the flat tariff, attributed to uniform hourly energy rates and identical monthly Maximum Demand (MD) charges. Sensitivity analysis shows that NEM 2.0 with larger PV capacity delivers the best financial performance, achieving the highest Internal Rate of Return (IRR), Lowest Levelized Cost of Electricity (LCOE), and shortest payback period. Under dynamic ETOU pricing, the IHL's existing PV system achieved cost savings of 33–39% compared to grid-only consumption. Furthermore, higher proportions of deferrable load significantly reduced MD, with a 40% deferrable load scenario yielding an average 18% reduction. These findings empower prosumers and guide policymakers on solar incentive reforms.

1. Introduction

As global temperatures rise and energy demand surges, the transition to sustainable energy has never been more critical. Solar PV has emerged as a key player in limiting greenhouse gas emissions and reducing reliance on fossil fuels. Recognized in 2015, the Paris Agreement highlights three (3) key enabling technologies for achieving the 1.5°C climate target which are Electric Vehicles (EVs), Energy Storage Systems (ESS), and solar PV [1]. With rapid technological innovation and strong government support, the global shift toward the adoption of clean energy is being spurred. In Malaysia, the government is responsible for driving the adoption and development of solar energy through a variety of initiatives. These include fiscal incentives, supportive policies and regulations, interactive green taxes, low-interest loans, solar leasing programs, research grants, and public awareness campaigns. Together, these initiatives have cultivated an environment conducive to the growth of solar energy. The key to this progress is the Malaysian National Energy Transition Roadmap (NETR), which plays a crucial role in advancing Malaysia's energy transition and reducing greenhouse gas emissions through a diverse energy mix. The NETR aims to gradually increase the share of renewable energy, targeting 31%

by 2025, 40% by 2035, and 70% by 2050. By 2050, it aims to achieve a 32% reduction in GHG emissions relative to the 2019 baseline, reaching 4.3 MtCO₂eq per capita [2]. Over the past decade, Malaysia's grid-connected solar PV installations have experienced significant expansion, boasting a compound annual growth rate of 48%. This growth has seen the capacity rise from 0.1GW to 2.6GW [3].

For solar PV adoption to remain sustainable, consumer incentives must be both compelling and competitive. At the same time, well-structured policies play a crucial role in preventing market and price distortions. A comprehensive analysis by Dusonchet and Telaretti [4] examined how policy support influenced the growth of solar PV across Germany, France, Italy, Greece, and the United Kingdom (U.K). Their findings highlighted that elevated electricity prices, along with proactive renewable compensation mechanisms, significantly contributed to increased Internal Rate of Return (IRR) and Net Present Value (NPV) for solar PV investments. While early PV deployment in Europe was largely driven by administratively set Feed-in Tariff (FIT) schemes, more recent empirical studies and regulatory assessments indicate a gradual transition toward market-oriented support mechanisms such as competitive auctions, corporate

power purchase agreements (PPAs), and market-linked remuneration models [5-7]. During this transition, Pyrgou et al., [8] highlighted that maintaining the sustainability of such frameworks requires periodic evaluations of capital, operational, and investment costs to ensure they remain aligned with a country's specific renewable energy surplus. These policy developments aim to improve the integration of variable renewable energy into electricity markets while maintaining investment attractiveness and supporting system flexibility.

Further studies have explored hybrid compensation approaches. In Italy, Poconi et al., [9] demonstrated that combining FIT incentives with energy efficiency investments could significantly lower government subsidy expenses. Subsequently, several European countries implemented hybrid compensation schemes combining NEM and FIT to support solar PV expansion. While foundational studies by Ramírez et al., [10] emphasized that tailoring compensation schemes based on system type, location, and tariff structures enhances economic viability. Recent regulatory analyses for the 2024–2026 period emphasize the need for compensation frameworks that balance consumer incentives with equitable cost recovery across the grid [11]. Traditional NEM schemes have been criticized for potentially shifting system costs to non-prosumers and introducing operational challenges to distribution networks, thereby motivating the transition toward cost-reflective mechanisms such as Contracts for Difference (CfD) and net billing models [12]. As a result, optimizing prosumer benefits while maintaining system fairness remains a key policy challenge.

The effectiveness of these compensation schemes is largely determined by the price signals provided by the grid. However, conventional flat electricity tariffs do not reflect temporal variations in demand and supply, thereby limiting incentives for load shifting and demand-side flexibility. While such tariffs remain dominant in several regions due to regulatory simplicity and consumer protection considerations, their effectiveness in supporting high solar PV penetration is constrained. Existing studies under flat tariff structure primarily focus on economic feasibility and system sizing, demonstrating cost reductions through solar PV integration but with limited consideration of temporal optimization [13-16]. Conversely, dynamic pricing mechanisms including Time-of-Use (TOU), Critical Peak Pricing (CPP), and real-time tariffs have been shown to enhance system efficiency by aligning consumption patterns with generation profiles and reducing peak demand charges [17-19]. However, the economic superiority of dynamic tariffs is highly context dependent. Their effectiveness relies on the presence of sufficient load flexibility, enabling consumers to shift demand in response to price signals. In practice, constraints such as operational inflexibility in commercial facilities, regulatory limitations, and the persistence of demand charges may reduce the achievable benefits. Furthermore, while cross-country studies suggest positive outcomes under dynamic pricing frameworks, direct comparisons must be interpreted cautiously due to differences in market structures, tariff regulations, and energy pricing mechanisms. Despite these limitations, the increasing integration of variable renewable energy sources necessitates a transition toward more cost-reflective tariff designs. In this context, the interaction between compensation mechanisms (e.g., NEM, SELCO) and tariff structures (flat versus dynamic) remains insufficiently explored. This is particularly true in emerging markets such as Malaysia, where the interaction between compensation mechanisms and tariff structures under varying demand conditions requires further investigation.

As part of efforts to restructure Malaysia's electricity grid for greater solar PV integration, compensation schemes have been periodically revised to remain practical for both electricity providers and prosumers. The framework began with the FIT scheme and evolved into more dynamic models such as NEM, SELCO, NEM 2.0, the e-bidding FIT, and most recently, NEM 3.0. A thorough empirical evaluation of electricity tariffs is necessary to identify competitive compensation rates for renewable energy and to ensure a sustainable and balanced approach to cost allocation among prosumers. In Malaysia the recent NEM 3.0 compensation scheme involves more advanced pricing structure with the inclusion of Net Offset Virtual Aggregation (NOVA) mechanism that adopting a real-time wholesale pricing i.e., average System Marginal Price (SMP) for energy export. The NOVA mechanism comprises two (2) categories i.e., A and B. The only thing that distinguishes between these categories is Category B adopting the concept of Virtual Net Metering (VNM) while Category A deploying the same concept as NEM. Given that NEM 3.0 adopts SMP based export compensation, it is essential to examine how this dynamic pricing mechanism influences techno-economic performance, technological feasibility, environmental outcomes, and consumer behavior.

Against this backdrop, existing research on compensation schemes in Malaysia remains limited. A recent study by Razali et al., [20] proposed a compensation model integrating NEM with TOU, replacing the existing flat tariff for residential prosumers. Previously, the same researchers conducted a comparative analysis on financial returns and cost savings for NEM residential prosumers [21]. On the other hand, Subramani et al., [22] performed a techno-economic assessment of solar PV and energy storage sizing for commercial consumers, identifying optimal configurations to achieve MD reduction, thereby lowering electricity costs under the NEM 2.0 and TOU tariff framework. Tan et al., [23] compared the cost benefits of FIT versus the older NEM model, concluding that NEM offered slightly higher savings by reducing MD charges, whereas FIT generated savings through total energy sell-back to the grid. However, with FIT no longer being an option in Malaysia, this comparison is no longer applicable. Notably, a critical gap in the literature remains, as the quantitative performance of NEM 3.0 within the solar PV energy trading framework has yet to be comprehensively studied.

As compensation policies continue to evolve, in-depth research is essential to identify the most beneficial scheme for prosumers while ensuring cost-effective and efficient energy utilization. To address the identified research gap, this study develops three solar PV compensation scheme models, namely SELCO, NEM 2.0, and NEM 3.0, to evaluate prosumer economic viability and energy usage profiles. A commercial institution of higher learning (IHL) under the C1 electricity tariff is selected as the representative case study. The analysis further examines the financial implications of each model under different pricing mechanisms, including the recently introduced ETOU tariff structure.

This study makes three (3) main contributions to the literature on Malaysian solar PV compensation schemes. First, it provides a quantitative techno-economic evaluation of SELCO, NEM 2.0, and NEM 3.0 within a combined commercial-scale modeling framework, with particular emphasis on the financial implications of SMP based export compensation under NEM 3.0. Second, it integrates the tariff with deferrable load models to examine how demand-side flexibility influences electricity cost and MD reduction in a commercial institutional setting under the C1 tariff. Third, the study performs a simultaneous assessment of electricity bill savings, energy

import-export behavior, MD reduction, and long-term investment performance through Net Present Cost (NPC), LCOE, IRR, Return on Investment (ROI), and payback period. These contributions provide broader insight into the interaction between compensation design, tariff structure, and load flexibility, while offering practical guidance for both prosumers and policymakers.

2. Methodology

Fig. 1 shows the flowchart outlining the research methodology employed in this study. Using HOMER Grid software, three (3) distinct solar PV compensation scheme models (i.e., SELCO, NEM 2.0, and NEM 3.0) were initially developed and systematically assessed for different solar PV system capacities. Additionally, the study further considers different electricity tariff structures, such as flat rates, real-time SMP, and ETOU. To ensure both regulatory compliance and practical relevance, each model was evaluated based on the design parameters outlined by the Malaysian Energy Commission (EC) for grid-connected solar PV systems. The objective of the simulations was to optimize both technical and economic performance, including peak shaving, lower NPC and LCOE, higher ROI and IRR, and shorter payback periods.

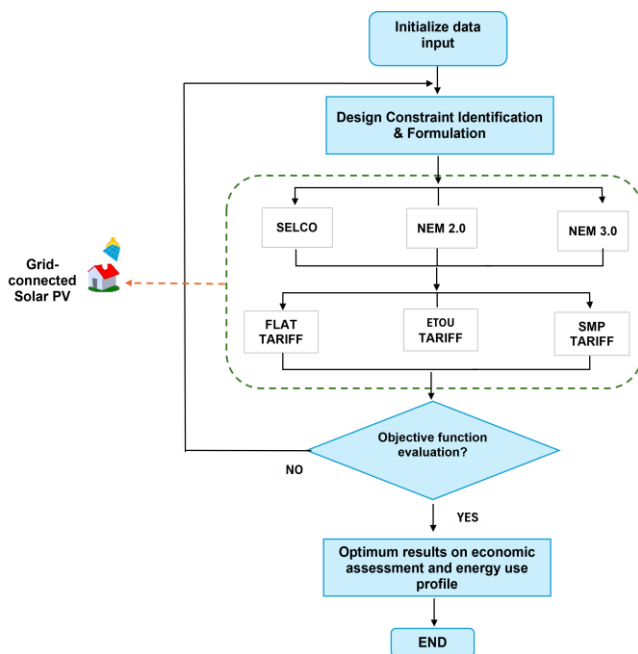


Fig. 1 Methodological research flowchart.

2.1 Identifying Grid-Connected Solar PV Project

This study relies on real, measurable data, considering both the technical and economic aspects of solar PV systems, as well as energy usage patterns at IHL located in Permatang Pauh, Penang, Malaysia. Fig.2 presents a top-down view of the grid-connected solar PV system, which supplies electricity to key facilities including academic buildings, administrative offices, student hostels, the health center, and the library. The system has an installed capacity of 3,651 kWp, operates under the NEM 2.0 compensation scheme, and comprises a total of 18,400 solar panels. Based on recorded data, the site generates an average of 14,783.065 kWh of solar energy per day. It is also situated in a high solar potential zone in Malaysia, with yearly solar irradiation values ranging from 1,785 kWh/m² to 1,890 kWh/m² [24]. Given the focus on grid-connected solar PV systems, this study evaluates NEM 2.0, NEM 3.0, and SELCO to identify the most suitable solar PV compensation scheme within energy market trading arrangements.



Fig. 2 The existing IHL grid-connected solar PV systems.

2.2 System Modeling and Data Availability

The grid-connected system configuration used in this case study is shown in Fig. 3, which comprises solar PV modules, a DC–AC converter, the utility grid, and IHL as the load. The PV array generates electricity in direct current (DC), which is converted into alternating current (AC) by the inverter to ensure compatibility with both the load and grid requirements. This configuration enables a dual operational mode where electricity generated by the PV system can directly supply the IHL loads, while any surplus energy is exported to the grid. Conversely, when PV generation is insufficient, the system draws additional electricity from the grid to meet demand. The arrangement highlights the importance of the DC–AC converter not only in power conversion but also in maintaining voltage, frequency, and phase synchronization for stable integration with the grid.

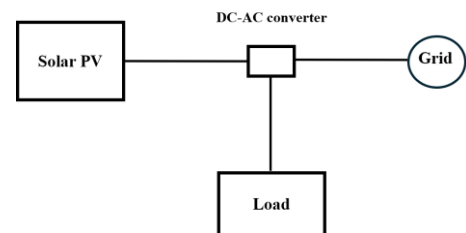


Fig. 3 Grid-connected solar PV system configuration.

Hourly load demand for an entire year is anticipated using HOMER Grid's software, which operates on a two-day look-ahead algorithm to optimize predictive accuracy. Its selection is based on its comprehensive features that combine techno-economic optimization with sensitivity analysis, all within a single platform. This enables accurate assessments of tariff scenarios and system sizing strategies. This study utilizes electricity consumption data from IHL's 2019 utility bills, with load values directly extracted from the institution's utility meter. As per the Internal Performance Measurement and Verification Protocol (IPMVP), the utility meter's error is considered negligible (assumed to be zero), ensuring data accuracy. In order to establish a baseline for analysis, electricity consumption data was collected prior to the installation of the solar PV systems. This allows for a detailed assessment of the site's load characteristics. The IHL annual load profile depicted in Fig. 4(a) demonstrates significant variability driven by its diverse operational activities. Energy demand reaches its highest levels during active academic semesters, while semester breaks and seasonal changes lead to noticeable fluctuations in consumption patterns. An alternative approach to evaluating load behavior is the use of load duration curves, which rearrange consumption data in descending order and normalize it relative to the peak demand. Fig. 4 (b) indicates that the load neared its peak value of 3,737 kW for only a limited number of hours annually, consistent with the recorded annual average MD.

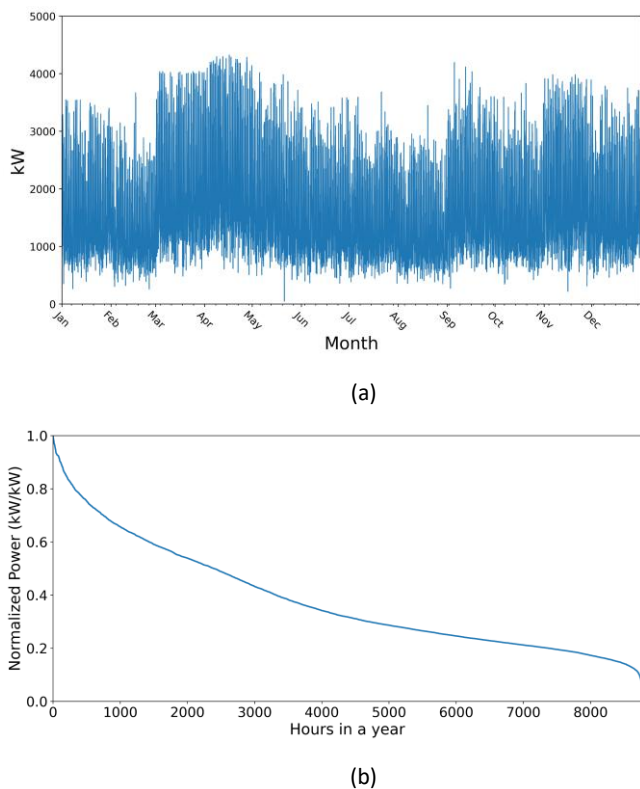


Fig. 4 (a) IHL annual load profile and (b) IHL load duration curve.

As stipulated by the Malaysian Energy Commission (EC), solar PV inverters under the SELCO, NEM 2.0, and NEM 3.0 schemes are recommended to operate within 75% to 100% of the consumer's maximum demand (MD) capacity [25]. Accordingly, the on-site AC inverter output has been designed at 2,803 kW (75%) to align with this guideline. To analyze the model's responsiveness to varying input parameters, a sensitivity analysis on PV system sizes was conducted for all compensation schemes and tariff structures, as shown in Table 1. The PV system capacity was modified to provide an additional 25%, 50%, and 75% beyond the current installed capacity at IHL.

Table 1 Selection of sensitivity variables.

Annual load met by PV	PV (kW)	Inverter (kW)
On-Site	3,651	2,803
+25%	4,564	3,504
+50%	5,477	4,205
+75%	6,389	4,905

2.3 Technical and Economic Consideration

To ensure accurate simulation results, additional data on the technical and financial parameters of the solar PV system are incorporated. Table 2 details the technical specifications, reflecting the real-world on-site installation. The simulation assumes a 21-year lifespan for solar PV panels, with inverters requiring replacement every 15 years [26]. Pricing estimates, based on expert industry insights, suggest a capital expenditure (CAPEX) ranging from RM 2 million (USD 431,220) to RM 2.5 million (USD 539,025) per megawatt (MW) [27]. The financial parameters used in the simulation are summarized in Table 3. This study adopts a nominal discount rate of 6%, while a real discount rate of 4% is applied based on a 2% inflation rate. In Malaysia, the interest rates for solar PV project loans may vary depending on the lending institution and specific loan terms. The nominal discount and inflation rates employed were derived from average figures published by Bank Negara Malaysia [28]. The discount and inflation rates are crucial for solar PV viability, with the discount

rate reflecting risk and opportunity cost through present value calculations for future cash flows. Conversely, the inflation rate impacts both costs and revenues by accounting for changes in the prices of goods and services over time. The Capital Allowance (CA) serves as a tax incentive for solar PV investors, enabling them to offset depreciation losses on business assets. Under Malaysia's CA framework, investors receive a 20% allowance in the first year and an Annual Allowance (AA) of 14% for the subsequent six (6) years.

Table 2 Solar PV input parameters.

Parameters	Value
Solar PV cost / Brand	RM 3,800/kWp / Longi Solar, 435 W
Solar PV lifetime	21 years
Inverter cost / Brand	RM 500/kW / Sungrow
Inverter lifetime	15 years
PV conversion efficiency	20%

Table 3 Financial parameters declared in simulation.

Parameters	Value
Parameters	Value
Discount rate	6%
Inflation rate	2%
Project Lifetime	21 years

Malaysia's commercial electricity tariff structure is classified into three categories: low voltage (Tariff B), medium voltage (Tariff C1), and medium voltage with peak/off-peak pricing (Tariff C2). These tariffs are charged at a flat rate based on kilowatt-hour (kWh) used. As the IHL operates as an educational institution, the C1 commercial flat tariff is applied for its monthly electricity bill calculations [29]. HOMER Grid allows the incorporation of time-dependent tariff inputs through its advanced grid configuration. In this study, the ETOU tariff is implemented using predefined time-scheduled rates to represent peak and off-peak pricing variations. In addition, dynamic export compensation under NEM 3.0 is modeled by incorporating one year of SMP data as a time-series input, thereby reflecting temporal variations in wholesale electricity pricing. To capture the potential economic advantages of time-based pricing structures, the analysis incorporates both the ETOU tariff and real-time SMP rates. These structures allow electricity prices to vary hourly and by day of the week. Table 4 outlines the trading prices used across all models and schemes, while Fig. 5 details the ETOU tariff structure.

Table 4 Energy trading pricing at different tariffs and compensation schemes.

Parameters	Flat Tariff		ETOU Tariff	
	Grid Price RM/kWh	Sell-back Price RM/kWh	Grid Price RM/kWh	Sell-back Price RM/kWh
SELCO	0.365	0	ETOU	0
NEM 2.0	0.365	0.365	ETOU	ETOU
NEM 3.0	0.365	Real-time SMP ¹	ETOU	Real-time SMP ¹

¹ subject to real-time wholesale prices for SMP



Fig. 5 ETOU rate structure for weekdays and weekends.

To represent consumer-side demand response under the ETOU tariff structure, Deferrable Loads (DL) were modeled in HOMER software. DL refers to non-critical loads that can be rescheduled to align with periods of excess electricity generation. In this study, scenarios with 20%, 30%, and 40% of the total load modeled as deferrable were tested to simulate different levels of consumer load-shifting behavior to assess potential electricity cost reductions under solar PV deployment. In Malaysia's Single Buyer (SB) energy market, the SMP serves as the wholesale real-time electricity tariff. As part of the New Enhanced Dispatch Arrangement (NEDA) mechanism, the government authorized the SB to facilitate electricity procurement from generators that is not covered by Power Purchase Agreement (PPA)/ Service Level Agreement (SLA) agreements. The SMP is derived from the highest bid submitted by a marginal generator, excluding renewable energy sources during each half-hour dispatch period.

Table 5 summarizes the 2020 SMP wholesale electricity data used in the simulation [30]. Statistical analysis indicates that the SMP ranges from a minimum of 0.1483 RM/kWh to a maximum of 0.3999 RM/kWh, with a standard deviation of 0.04536 RM/kWh. The relatively small standard deviation reflects that SMP rates are generally stable and centered near the average. Although the SMP values used in the simulation represent the historical distribution observed in 2020, future wholesale electricity prices may vary due to market conditions, fuel price fluctuations, and policy adjustments. From a qualitative sensitivity perspective, higher SMP values would increase the export revenue under the NEM 3.0 scheme, thereby improving its financial attractiveness relative to the other compensation models. Conversely, lower SMP levels or increased price volatility could reduce the predictability of export revenues for prosumers. Similarly, escalation of retail electricity tariffs would further strengthen the economic advantage of compensation mechanisms based on retail-rate offset, particularly NEM 2.0. Therefore, the comparative results presented in this study should be interpreted within the context of the current tariff assumptions, while recognizing that future tariff reforms and wholesale market dynamics may influence the long-term economic outcomes of the evaluated schemes.

Table 5 Annual variation of wholesale SMP rates.

Descriptive Statistics	Rate (RM/kWh)
Min	0.1483
Max	0.3999
Average	0.24802
Standard deviation	0.04536

2.4 Objective function and system constraint

This study assesses objective functions across three (3) compensation schemes (i.e., SELCO, NEM 2.0, and NEM 3.0) under three (3) distinct tariff structures: flat, ETOU, and wholesale real-time SMP. Using RM 0.365 as the flat tariff rate, energy consumption bills are derived from equations (1) and (2). For the purpose of this analysis, the energy billing formula excludes ancillary charges, including the 1% late payment fee, 1.6% Renewable Energy Fund contribution, surcharges related to power factor performance, and penalties associated with connected load violations.

$$E_{bill_{flat_{tariff}}} = \begin{cases} SELCO_{net_{charge}} = (E_{cons} - E_{imp}) \times RM\ 0.365_{flat\ tariff} \\ NEM\ 2.0_{net_{charge}} = (E_{imp} - E_{exp}) \times RM\ 0.365_{flat\ tariff} \\ NEM\ 3.0_{net_{charge}} = (E_{imp} \times RM\ 0.365_{flat\ tariff}) - (E_{exp} \times SMP_{tariff}) \end{cases} \quad (1)$$

$$E_{bill_{ETOU_{tariff}}} = \begin{cases} SELCO_{net_{charge}} = (E_{cons} - E_{import}) \times ETOU_{tariff} \\ NEM\ 2.0_{net_{charge}} = (E_{imp} \times ETOU_{tariff}) - (E_{exp} \times ETOU_{tariff}) \\ NEM\ 3.0_{net_{charge}} = (E_{imp} \times ETOU_{tariff}) - (E_{exp} \times SMP_{tariff}) \end{cases} \quad (2)$$

Except for the SELCO scheme, all flat tariff compensation models adopt a net metering approach, where the energy balance is computed monthly based on the difference between imported and exported electricity. In comparison, the ETOU scheme deploys real-time metering to capture dynamic import and export values on an hourly basis.

In the aspect of economic efficiency, each model will be evaluated based on the lowest NPC and LCOE, higher ROI and IRR and shortest payback year. The IRR serves as a key indicator for investors, providing a measure of the project's expected profitability relative to the capital deployed. On the other hand, the LCOE facilitates direct comparisons with prevailing grid tariffs, thereby offering a benchmark for assessing whether renewable energy systems have achieved cost parity with conventional power sources. Equation (3) below is used to calculate the ROI for each model project's lifespan.

$$ROI = \frac{\left(\sum_{t=0}^{R_{life}} C_{f,base} - C_f \right)}{R_{life}(C_0 - C_{0,ref})} \quad (3)$$

Throughout the project's lifespan, the net cash flow is represented by C_f with $C_{f,base}$ indicating the annual cash flow for the base system. The initial investment is denoted by C_0 where $C_{0,ref}$ represents the capital cost for the base system. R_{life} denoted as project's lifespan. In HOMER grid software, the term base system commonly denotes the initial or reference setup of the energy system under analysis. This base system acts as a point of comparison for assessing and evaluating alternative scenarios or configurations.

HOMER Grid determined the LCOE using the formula shown in equation (4). The term $Cost_{annual\ total}$ (RM/yr) denotes the annualized total NPC derived using the Capital Recovery Factor (CRF). Meanwhile, the total energy served, represented by E_{serve} (kWh/yr), accounts for the electricity delivered to the main AC load, E_{load} , along with any surplus photovoltaic (PV) energy exported to the grid, $E_{grid\ sale}$.

$$LCOE = \frac{(Cost_{annual,total})}{(\sum E_{serve})} = \frac{CRF \times (C_{PV} + C_{inv} + O\&M_t - Grid_{sale})}{E_{load} + E_{grid\ sale}} \quad (4)$$

The initial capital cost for PV, inverter, operation and maintenance cost, and grid sale are represented as C_{PV} , C_{inv} , $O\&M_t$ and $Grid_{sale}$ respectively. The CRF formula is shown in equation (5) with t equal to 21 years project's lifespan and r is the annual real discount rate (%). For modeling consistency, electricity tariff structures and compensation mechanisms are assumed to remain constant throughout the 21-year project lifetime. This assumption enables a controlled comparison between compensation schemes, although actual tariff adjustments or policy revisions may influence long-term economic outcomes. The r has been assumed to be 4%, based on the average rates typically offered by financial institutions in Malaysia. This assumption provides a practical benchmark for evaluating project viability under relatively stable borrowing conditions and moderate investor risk.

$$RF(i, N) = \frac{i(1+r)^t}{((1+r)^t - 1)} \quad (5)$$

Fig. 6 illustrates the cash flow diagram of the solar PV system over its 21-year project lifetime. This diagram encompasses the initial cost, incentives, O&M expenses, as well as the costs associated with inverter replacements every 15 years and battery replacements after 15 years.

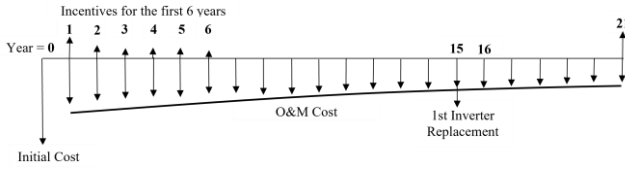


Fig. 6 Discounted cash flow diagram for solar PV system.

The Discounted Cash Flow (DCF) method is favored over nominal cash flow because it offers a more precise depiction of the project's financial performance, considering variables such as inflation, costs, and benefits. In this diagram, the initial cost calculation includes expenses for PV panels, inverters, BESS, integration, and installation, sourced from local practitioners and systems installed in IHL.

The NPC serves as a comprehensive metric, encompassing all expenditures incurred over the lifetime of a system, subtracted by any income generated within that same period. The costs include various elements such as the initial costs of PV modules, inverters, and capital expenses, along with ongoing operation and maintenance expenses, as well as replacement costs. Additionally, grid electricity tariff charges are factored into the calculation, with revenue from grid sales constituting a significant component on the income side [31]. The payback period for renewable energy project is a crucial metric in assessing its financial viability and ROI. The solar PV only project only may benefit a shorter payback period but could lack in advantages provided by energy storage capabilities. Equation (6) facilitates the calculation.

$$\text{Payback Period} = \frac{C_f}{C_o} \quad (6)$$

Each grid-connected solar PV model is designed to meet identical technical and operational constraints across various compensation schemes and tariff structures. As outlined in the SEDA Malaysia Grid-Connected PV System Design Course, equation (7) establishes that the standard derating factor (k) for Malaysian solar PV systems ranges from 0.75 to 0.8 for crystalline modules and from 1.0 to 1.30 for thin-film modules [25].

$$P_{nom_{inv}} = k \times P_{array_{stc}} \quad (7)$$

Before running the simulation, the constraint regarding the percentage of solar PV array power output has been set as equation (8). This constraint dictates that with sufficient spare capacity, the solar PV system must be capable of serving the load even if the array output suddenly decreases to 80%. Additionally, to ensure that the system is not overcommitting its generated power to external sources, equation (9) is adhered to. It defines the amount of power being exported from the solar PV system should not exceed the total power generated by the system.

$$80\% \leq \%PV_{output} \leq 100\% \quad (8)$$

$$P_{pv_export} \leq P_{pv_generated} \quad (9)$$

As defined in NEM 2.0 and NEM 3.0, equations (10) and (11) describe the requirements for bidirectional energy trading. For solar PV systems, the power for grid import shall not exceed the IHL unmet load power, as demonstrated by equation (12). The consumption energy in equation (13) is defined as the difference between energy imported from the grid and energy exported to the grid, plus solar energy production for the solar PV system.

$$E_{imp} = \begin{cases} 0 & , E_{load} \leq E_{pv} \\ E_{load} - E_{pv} & , E_{load} > E_{pv} \end{cases} \quad (10)$$

$$E_{exp} = \begin{cases} 0 & , E_{load} \geq E_{pv} \\ E_{pv} - E_{load} & , E_{load} < E_{pv} \end{cases} \quad (11)$$

$$P_{grid_{import}} \leq P_{unmet_{load}} \quad (12)$$

$$E_{cons} = E_{imp} - E_{exp} + E_{pv} \quad (13)$$

Sales Capacity (SC), measured in kW, is another constraint factored into the model. NEM 2.0 and NEM 3.0 set SC to its maximum, as both operate under a similar energy trading mechanism. In contrast, SELCO enforces an SC of zero (0), prohibiting the sale of surplus solar PV energy.

3. Case Study and Analysis of Results

The energy profile depicted in Fig. 7 illustrates the performance of the solar PV system during its first year of operation. It highlights the system's capacity to generate electricity under varying levels of solar irradiance, weather conditions, and AC loads at the IHL. The inverter was sized to accommodate 75% of the average annual MD, leading to an average daily PV production of 14,783.07 kWh. The system demonstrates a strong ability to offset grid purchases, covering between 9% and 75% of the demand during office operations (from 8 am to 5 pm), with the highest contribution observed at peak irradiance. Nevertheless, reliance on the grid remains significant during the early morning and evening when PV generation is limited, resulting in higher levels of grid purchases. Grid sales are relatively minimal, suggesting that most of the PV output is directly consumed on-site. These findings not only provide a clear picture of the daily operational dynamics of the PV system but also highlight the importance of strategic system sizing and demand management in maximizing cost savings and reducing grid dependency.

In addition to the average energy profile, Fig. 8 presents a closer examination of the monthly billing data revealed that the maximum electricity bill reductions at a particular month reached 46% under NEM 2.0, 44% under NEM 3.0, and 42% under SELCO, relative to the grid-only baseline. These peak values were observed during months with high solar irradiance, particularly in March, April, and November, where PV output closely aligned with daytime institutional load demands.

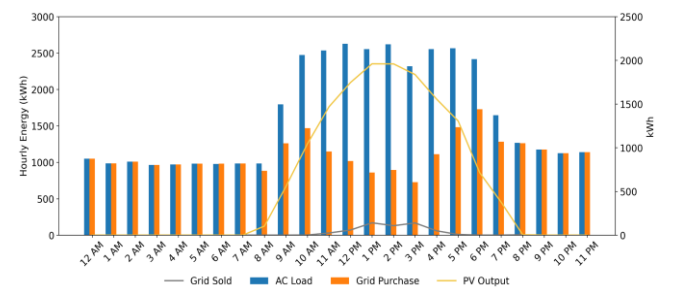


Fig. 7 Year 1 average 24-hour energy profile for on-site solar PV generation.

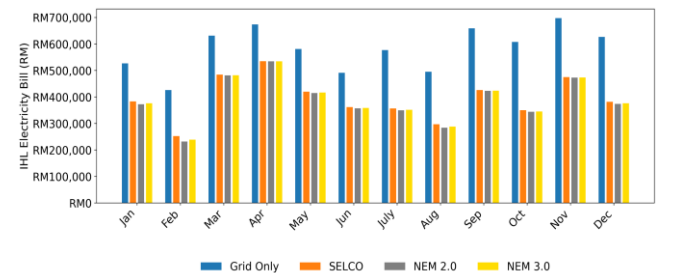


Fig. 8 Monthly electricity bill at various compensation schemes.

The observed variability in monthly savings across different schemes is primarily attributed to the compensation mechanism design. Under NEM 2.0, the one-to-one offset for exported energy enables full retail rate compensation, maximizing the financial return from surplus generation. NEM 3.0, despite offering lower compensation via the SMP rate, still delivers significant savings due to moderate export value and reduced grid dependency. In contrast, SELCO relies solely on self-consumption without export benefits, which limits the extent of savings, especially during low-demand or high-generation periods.

Currently, the installed solar PV system at IHL produces only a minimal amount of excess energy for grid trading. Therefore, further analysis of various solar PV system capacities is essential to assess the impact on the energy usage profile more comprehensively. To address this, a sensitivity analysis of various solar PV capacity percentages under SELCO, NEM 2.0, and NEM 3.0 was conducted to further evaluate their impact on the energy usage profile of both the PV system and IHL, as well as the potential energy savings. Fig. 9 illustrated that as the capacity of the solar PV increases, there is a notable decrease in the electricity bill for IHL. The reduction occurs due to less energy purchased from the grid, facilitated by the increased output capacity of the solar PV system, which can adequately cater to a significant portion of the AC load. This trend is consistently observed across various compensation schemes, with NEM 2.0 demonstrating the highest recorded bill savings, followed by NEM 3.0 and SELCO. At the highest simulated capacity increase (+75%), the annual electricity bill was reduced by approximately 52.31% under NEM 2.0 (from RM 557,116 to RM 265,718), 48.77% under NEM 3.0 (to RM 285,464), and 41.37% under SELCO (to RM 326,584). These values represent average annual savings over a one-year period rather than savings in a specific peak or representative month. The superior performance of NEM 2.0 is largely due to its one-to-one offset mechanism for exported solar energy. On the other hand, NEM 3.0 utilizes an SMP compensation rate which averaged RM 0.24802/kWh during the study period, resulting in a tariff difference of approximately RM 0.1170 compared to NEM 2.0.

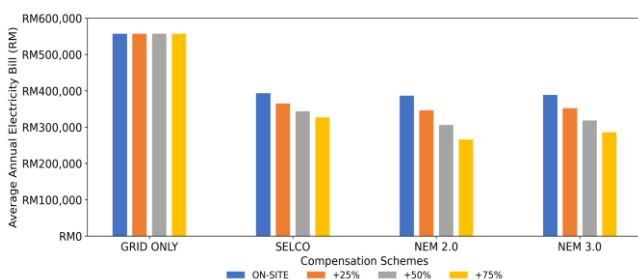


Fig. 9 Average annual electricity bill at various PV capacity and compensation schemes.

Currently, the MD charge for the IHL is set at RM 30.30 per kilowatt, based on the highest recorded demand within a given month. Fig. 10 illustrates the decrease in prosumers' MD when an additional 25%, 50%, and 75% capacity is added to the existing on-site PV installation at the IHL. With an added 75% solar PV capacity (6,389 kW with a 4,905 kW inverter), the system recorded its highest MD reduction, nearly 18%. Due to system sizing, MD curtailment is slightly lower for smaller solar PV adoption. However, the reduction only varies by a minimal 5% from installed solar PV value. The reduction in MD has important implications beyond immediate monthly bill savings.

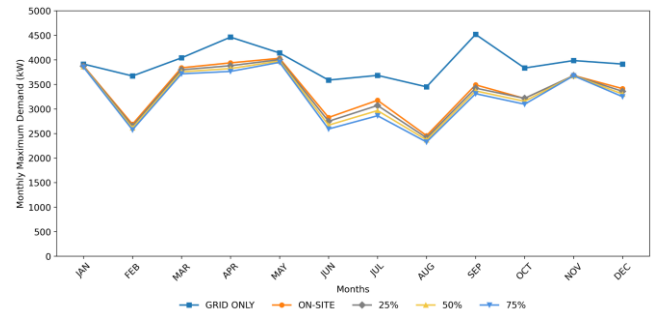


Fig. 10 MD for variation of solar PV array.

Since MD charges are applied repeatedly over the billing cycle, sustained peak shaving can produce substantial cumulative operating cost reductions over the project lifetime. In addition, lower MD reduces peak stress on the distribution network, improves load factor, and supports more efficient utilization of grid infrastructure. This indicates that MD reduction should be viewed not only as a consumer side economic benefit, but also as a contributor to broader grid efficiency and smart energy management objectives.

Table 6 presents a comparative analysis of energy profiles and financial outcomes across different scenarios, considering various compensation schemes and solar PV capacity sizes. Among the evaluated options, NEM 2.0 with a larger solar PV size emerges as the most profitable, achieving the highest IRR and ROI together with the lowest LCOE, NPC, and payback period, thereby strengthening the project's economic attractiveness for prosumers. This superior performance is driven not only by higher energy savings but also by the favorable one-to-one offset mechanism, through which exported solar PV electricity retains the full retail value of displaced grid electricity. As a result, cumulative cash flow over the 21-year project lifetime is improved. The LCOE of RM 0.3558/kWh under NEM 2.0 is lower than Malaysia's average commercial grid tariff of RM 0.365/kWh, indicating that grid parity has been achieved. At the highest simulated capacity (+75%), NEM 2.0 recorded the lowest LCOE of RM 0.2532/kWh and the shortest payback period of 4.33 years, further highlighting the economic advantage of larger system deployment. In contrast, although NEM 3.0 allows bidirectional energy trading, its SMP-based compensation reduces the value of exported electricity, resulting in weaker and less predictable long-term financial returns despite similar technical energy profiles. At an equivalent capital expenditure (CAPEX) level, SELCO demonstrates the least favorable performance among the evaluated schemes, as restrictions on exporting excess generation significantly limit revenue opportunities and constrain the value of solar PV output to self-consumption.

As Malaysia's solar PV compensation schemes are currently limited to flat tariff consumers, this study extends the analysis by incorporating ETOU rates to explore more comprehensive strategies for optimizing solar PV adoption. The ETOU tariff structure incorporates load management strategies, such as load shifting, which are tailored to consumer-specific electricity usage patterns. In this analysis, a Deferrable Load (DL) component was integrated into the models to simulate load shifting behavior by consumers. Within the HOMER software environment, the DL is prioritized when surplus electricity is available beyond what is required by the primary load. Each compensation model was tested using varying DL levels i.e., 20%, 30%, and 40%, to evaluate the impact of load shifting on electricity cost reduction. In HOMER's advanced grid section, the input parameters for ETOU tariff rates and MD charges were specified to simulate real-time pricing conditions.

Table 6 Comparative of Energy Profile and Financial Results by Scenario.

(a) Energy profile and financial results of 3651 kW PV & 2803 kW inverter at different schemes -> ONSITE									
	Energy Import (kWh)	Energy Export (kWh)	Net Energy (kWh)	CAPEX (RM)	NPC (RM)	IRR (%)	ROI (%)	LCOE (RM/kWh)	Payback (years)
SELCO	9,657,483	0	9,657,483	9.42 mil	75.3 mil	22.5	16.7	0.3680	4.64
NEM 2.0	9,657,483	231,835	9,425,648	9.42 mil	74.1 mil	23.6	17.6	0.3558	4.45
NEM 3.0	9,657,483	231,835	9,425,648	9.42 mil	74.5 mil	23.2	17.3	0.3578	4.51
(b) Energy profile and financial results of 4564 kW PV & 3504 kW inverter at different schemes -> +25%									
	Energy Import (kWh)	Energy Export (kWh)	Net Energy (kWh)	CAPEX (RM)	NPC (RM)	IRR (%)	ROI (%)	LCOE (RM/kWh)	Payback (years)
SELCO	8,787,953	0	8,787,953	11.5 mil	72.4 mil	21.6	15.9	0.3537	4.83
NEM 2.0	8,787,953	628,045	8,159,908	11.5 mil	69.0 mil	23.9	17.9	0.3228	4.39
NEM 3.0	8,787,953	628,045	8,159,908	11.5 mil	70.1 mil	23.1	17.2	0.3279	4.53
(c) Energy profile and financial results of 5477 kW PV & 4205 kW inverter at different schemes -> +50%									
	Energy Import (kWh)	Energy Export (kWh)	Net Energy (kWh)	CAPEX (RM)	NPC (RM)	IRR (%)	ROI (%)	LCOE (RM/kWh)	Payback (years)
SELCO	8,132,603	0	8,132,603	13.6 mil	70.5 mil	20.3	14.7	0.3444	5.12
NEM 2.0	8,132,603	1,238,434	6,894,168	13.6 mil	64.0 mil	24.1	18.1	0.2878	4.35
NEM 3.0	8,132,603	1,238,434	6,894,168	13.6 mil	66.1 mil	22.9	17.0	0.2973	4.57
(d) Energy profile and financial results of 6389 kW PV & 4905 kW inverter at different schemes -> +75%									
	Energy Import (kWh)	Energy Export (kWh)	Net Energy (kWh)	CAPEX (RM)	NPC (RM)	IRR (%)	ROI (%)	LCOE (RM/kWh)	Payback (years)
SELCO	7,630,940	0	7,630,940	15.7 mil	69.4 mil	18.9	13.5	0.3392	5.48
NEM 2.0	7,630,940	2,001,087	5,629,853	15.7 mil	59.0 mil	24.2	18.2	0.2532	4.33
NEM 3.0	7,630,940	2,001,087	5,629,853	15.7 mil	62.4 mil	22.5	16.7	0.2676	4.64

In all modeled compensation schemes, the ETOU rate was applied as the cost for electricity imported from the grid. The pricing for sell-back or energy export adheres to the constraints for each compensation scheme model, SELCO prohibits sell-back to the grid; NEM 2.0 allows sell-back at a one-to-one ETOU rate; and NEM 3.0 uses a real-time SMP rate. To assess cost-saving trends, a baseline model was configured using only grid electricity under the C1 commercial flat tariff, without incorporating any solar PV system. In this context, "no DL" indicates a setup where a 3,651 kW solar PV system is installed at the IHL under the flat tariff category, without the inclusion of deferrable load components.

As illustrated in Fig. 11, the grid-only model incurred the highest average monthly electricity cost at RM 578,421, serving as the baseline for comparison. The integration of solar PV with compensation schemes resulted in substantial cost reductions, with overall savings ranging from approximately 33% to 39% relative to the baseline scenario. The inclusion of DL further improved cost performance across all compensation schemes. Specifically, the 20%, 30%, and 40% DL scenarios consistently show decreasing electricity costs, indicating that increased load flexibility enhances economic efficiency.

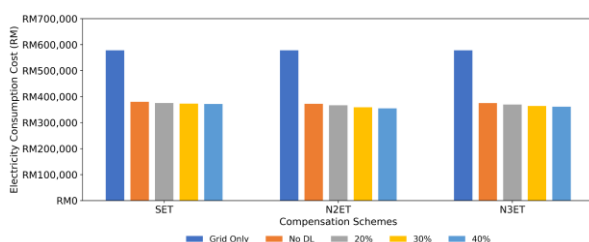


Fig. 11 Average electricity cost comparison at different deferrable load percentages.

However, a closer examination reveals that the marginal cost reduction between successive DL levels is relatively small, particularly between the 30% and 40% scenarios. This suggests reducing returns in economic benefit as DL penetration increases.

Quantitatively, while the initial introduction of DL (from no-DL to 20%) produces a noticeable reduction in electricity cost, further increases in DL contribution result in incremental improvements of only a few percentage points. This indicates that the majority of cost savings is achieved at lower levels of load flexibility, with higher DL penetration contributing limited additional benefit. These findings demonstrate that although demand-side flexibility plays a significant role in reducing electricity costs, its impact is constrained by system characteristics such as load profile alignment, PV generation patterns, and tariff structure. Beyond the economic benefits, the integration of dynamic tariffs and DL supports broader smart grid objectives, including peak demand reduction and improved load factor, thereby enhancing overall grid efficiency and facilitating higher renewable energy penetration.

Fig. 12 illustrates the monthly fluctuations in MD across varying levels of DL integration. The results clearly indicate that

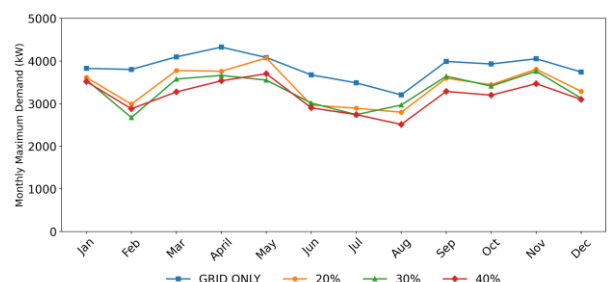


Fig. 12 MD reduction across varying deferrable load percentages.

implementing a 40% DL strategy yields the greatest impact, with an average MD reduction of approximately 18% relative to the baseline grid-only scenario. This reduction is not only statistically significant but also has direct implications for operational cost savings and long-term system planning. Assuming a typical MD value of 4,000 kW in the grid-only case, the 18% reduction equates to a decrease of 720 kW in peak demand. At the prevailing MD tariff rate of RM 30.30 per kW, this translates into a monthly saving of RM 21,816, or approximately RM 261,792 annually.

The seasonal trend shows that months with higher baseline MD (such as April and October) benefit more substantially from DL strategies compared to months with lower baseline MD (such as February and August). This suggests that DL integration is particularly effective in mitigating seasonal peaks, thereby flattening the load profile. These findings highlight the economic and technical benefits of demand-side management, where strategic load shifting can lower electricity expenditure while enhancing grid stability and overall system efficiency.

4. Conclusion

A thorough economic and energy utilization analysis was carried out using HOMER Grid software, providing a clear and comprehensive evaluation of solar PV implementation. The analysis led to the formulation of an optimized solar PV compensation model, integrating dynamic tariff pricing to maximize its techno-economic impacts. Three (3) solar PV compensation scheme models, SELCO, NEM 2.0, and NEM 3.0 were developed to evaluate the commercial consumers' economic and energy usage profiles at flat, ETOU, and real-time SMP tariff rates. Among the models, NEM 2.0 demonstrated the most favorable financial performance, achieving the highest average monthly bill reduction of approximately 46%, followed by NEM 3.0 (44%) and SELCO (42%). The increased revenue certainty is attributed to NEM 2.0's one-to-one offset mechanism, in contrast to the variable SMP rates employed under NEM 3.0. While the SMP based pricing structure aligns with market liberalization goals, it results in heightened variability and lowered revenue predictability for prosumers. Further analysis incorporating ETOU tariffs and varying levels of DL discovered additional savings potential. When 40% of the load was treated as deferrable, the average monthly MD was reduced by 18%, demonstrating the value of load-shifting strategies in reducing overall electricity costs and improving grid-side efficiency. In comparing tariff structures, the findings suggest that ETOU tariffs outperform flat and SMP tariffs when paired with deferrable load strategies, offering greater savings due to time-based energy cost differentiation and reduced MD charges. Overall, combining NEM 2.0 with high DL participation and dynamic tariffs such as ETOU can yield the highest techno-economic impact.

This analysis assumes fixed tariff structures and discount conditions over the 21-year project lifetime to ensure consistent comparison across the evaluated compensation schemes. In practice, future tariff revisions, financing changes, and SMP fluctuations may affect the long-term economic performance of the proposed models. From a qualitative sensitivity perspective, retail tariff escalation would likely enhance the economic attractiveness of compensation schemes that rely on retail-rate offset, particularly NEM 2.0, whereas the performance of NEM 3.0 remains more sensitive to changes in SMP levels and volatility.

Within these modeling assumptions, the finding provides valuable guidance for energy users in selecting the optimal solar PV compensation scheme at the distribution level. It also serves as

a resource for policymakers in designing compensation schemes that are both financially attractive and grid responsive. While NEM 3.0 aligns with market liberalization goals through real-time pricing, its volatility may limit investor confidence. To address this, policymakers should consider introducing mechanisms such as minimum SMP floors, hybrid compensation models or performance-based green incentives to increase uptake. Furthermore, incentivizing load flexibility programs, particularly for commercial and industrial users, could enhance grid reliability while empowering consumer-side participation. While this research focuses on the commercial C1 consumer, future studies are recommended to explore the long-term operational performance of solar PV systems under varying climatic conditions and categories for electricity consumers. Moreover, the assessment of the impact of emerging tariff structures and evolving SMP price dynamics warrants further analysis. The incorporation of battery energy storage systems (BESS) into compensation models can yield deeper insights into maximizing self-consumption and enhancing grid adaptability. In addition, real-world implementation of demand-side strategies should be examined to validate the practicality of DL integration at scale. Policy-level simulations considering carbon pricing or green energy credits could further strengthen the economic case for renewable adoption. Collectively, the results highlight the broader significance of aligning solar PV compensation schemes with Malaysia's Net Zero 2050 commitments, ensuring that financial, technological, and environmental objectives are achieved concurrently.

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