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Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: A case of Indonesia's urban residential households

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ABSTRACT

This study explores the potential of grid-connected rooftop photovoltaic (PV) systems in terms of how they can be better planned and utilised by understanding possible trade-offs between cost and reliability while acknowledging challenges to utility supply security in the context of emerging economies. The study particularly examines the implications of unserved energy targets, PV capacity, and billing deduction factors on grid-connected rooftop PV's trade-offs in terms of total net present cost and unserved energy. This study considers four residential household segments in Indonesia's urban area as a case study, with four cases applied in each segment representing scenarios on PV capacities and billing deduction factors. Using HOMER software, the analyses highlight the role of cost components in trade-offs involving potential PV capacity cases. Systems with maximum PV capacity exhibit cheaper total net present costs than those of half PV capacity within the same unserved energy. While the optimisations pushed PV capacity up to the maximum size across all unserved energies, higher unserved energy resulted in lower grid capacity required to meet demand associated with the system's maximum unserved energy limit. This study provides residential customers and stakeholders with insights to better plan and implement grid-connected rooftop PV systems and policies.

Credit author statement

Yusak Tanoto: Conceptualisation, Methodology, Data preparation, Simulation, Formal analysis, Visualisation, Writing – original draft, Writing – review & editing.

1. Introduction

The utilisation of solar photovoltaic (PV) systems has increased significantly in recent years, with global capacity growth reaching 1.2 TW by 2022 [[1–3]]. In several emerging economies and jurisdictions, the installation of rooftop solar PV has witnessed significant growth [[4–8]]. Grid-connected rooftop PV is a feasible option for providing electricity in residential households in many urban areas [9]. Installing grid-connected rooftop PV is simpler, cheaper, and requires almost no maintenance compared to hybrid systems [10]. Adopting low-cost, green technologies like PV can reduce CO_2 emissions and support sustainable energy transition [[11,12]]. However, when choosing grid-connected rooftop PV, customers consider various factors, including the system's performance expectations, socio-environmental beliefs, and price-value beliefs, among others [13].

Rising electricity prices in developed countries like Australia, the Netherlands, Germany, and many others have fuelled the adoption of residential rooftop PV systems along with the growth in capacity. However, it is worth noting that rooftop PV development in emerging economies has been influenced by both economic and technical factors. Increasing electricity rates and challenges utilities face in providing a reliable power supply, particularly in urban distribution networks, have contributed to the rise of rooftop PV in these countries.

It is of importance to pay special attention to the low reliability of urban distribution networks [14]. This is particularly essential for households choosing the appropriate size of rooftop PV components. A grid-connected system without any capacity shortage, representing excellent reliability, would require a larger supply capacity to meet high peak loads during a short period. This, of course, would come at a higher cost. On the other hand, a smaller and less expensive system may meet a reasonable portion of the load while allowing for some capacity shortage.

Many studies have investigated different aspects of the techno-economic feasibility of rooftop solar PV systems in the context of emerging economies and developing countries. These studies have primarily focused on grid-connected residential applications and have used

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various techniques and tools. Some studies have concentrated on system planning through simulations, while others have evaluated the performance of installed systems, either at a single location or across several sites.

Gabr et al. [10] assessed the techno-economic feasibility of a grid-connected rooftop PV system in Egypt, considering the ongoing electricity retail prices and net-metering policy applied to three types of housing rates with different demand levels. They used HOMER (Hybrid Optimisation of Multiple Energy Resources) software [15] to measure the net present value of energy cost, payback period, and bill savings. Laib et al. [16] evaluated the performance of a grid-connected solar PV system and its energy balance in Algeria. The authors developed a Matlab-Simulink model to optimise, rationalise, and implement energy-saving approaches to evaluate the system's energy performance and balance.

Dondariya et al. [17] predicted the performance of grid-connected rooftop PV systems in Ujjain, India. The authors compared PV*SOL [18], PVGIS [19], SolarGIS [20], and SISIFO [21] to analyse system performance in terms of energy generation, performance ratio, and solar fraction. Mohammadi et al. [22] analysed the impact of different tracking options on the potential of grid-connected PV development in Iran using RETScreen software [23]. Jesus et al. [24] proposed Solar-Energy, a new optimisation tool for the techno-economic analysis of PV microgeneration. The authors conducted a techno-economic analysis of grid-connected PV systems in Brazil, providing decision-making indicators such as net present value, modified internal rate of return, discounted payback period, and sensitivity analysis of key techno-economic parameters. In another study, Al Garni et al. [25] assessed the optimal design of grid-connected PV by considering various PV tracking systems applied in Makkah, Saudi Arabia. The authors used HOMER to examine the horizontal axis, vertical axis, and a two-axis tracking system. Earlier study by Lau et al. [26] analysed the pricing mechanism for grid-connected PV projects in the residential sector of Malaysia by evaluating the impact of component costs, feed-in tariffs, and carbon taxes using HOMER.

Duman and Güler [27] assessed the economic feasibility of 5 kW grid-connected solar PV in nine provinces of Turkey. Using HOMER, the study evaluated the discounted payback period, internal rate of return, and profitability index, and found that the system would not be feasible in two provinces under the practiced feed-in tariff. Bakhshi and Sadeh [28] examined the economic feasibility of grid-connected rooftop PV systems in Iran. They used PVsyst software [29] to estimate the annual energy generation of a 5-kW peak system in different cities. Their analysis included Net Present Value (NPV), Internal Rate of Return (IRR), payback period (PP), and Levelised Cost of Energy (LCOE), and employed a dynamic feed-in tariff strategy. Similar indicators, i.e., NPV, LCOE, IRR, and static PP and dynamic PP, were used by Xin-gang and Yi-min [30] in building a cost-benefit model to evaluate the economic performance of China's rooftop PV industry. Meanwhile, Orioli and Gangi [31] considered the effects of time variation on the PP assessment of grid-connected rooftop PV systems in Italy.

Li et al. [9] conducted a study to evaluate and compare the techno-economic performance of grid-connected rooftop PV systems and other alternatives in five climate zones in China using HOMER. The study found that grid/PV systems were the most cost-effective option among all the studied systems, and Kunming is the most economical among other regions. Tomar and Tiwari [32] discussed the feasibility of grid-connected rooftop PV for three residential households. The authors used HOMER to simulate the impact of feed-in tariffs/net metering along with a tariff-of-day policy in New Delhi, India. They concluded that systems without energy storage are technically and economically viable for decentralised households. An earlier study by Pillai et al. [33] developed an economic evaluation methodology to assess the near-term benefits of grid-connected residential PV systems in the United Kingdom and India. The authors developed a metric called 'Prosumer Electricity Unit Cost' (PEUC) and used it to examine the effects of solar input, financial mechanisms, and demand profiles in the near-term time frame of the project.

While studies focusing on single household analysis or involving multiple sites have provided useful insights for stakeholders regarding the potential techno-economic impacts of grid-connected rooftop PV and its deployment opportunity, less explored, however, has been the impacts of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors. In particular, there has been little attention of the potential trade-offs between system reliability and costs.

This paper aims to explore the potential benefits of grid-connected rooftop PV in terms of how the systems can be better planned and utilised through understanding possible trade-offs between system reliability and cost while also recognising the challenges to utility supply security in the context of emerging economies. While system reliability and efficiency of residential rooftop PV can be enhanced by incorporating other technologies such as wind or diesel, gas, and energy storage [34], this paper focuses on the grid-connected PV systems in urban households in emerging economies. In particular, this study suggests a method for incorporating billing deduction factors in HOMER optimisation while taking into account the implications of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors on the assessment of cost-reliability trade-offs. The city of Surabaya, Indonesia, is considered a case study.

Despite high-level supportive legislation, rooftop PV has only seen modest deployment in Indonesia mainly due to non-technical barriers and challenges, such as missing permits, lack of regulatory certainty, lack of alignment and synchronisation of implementing regulations, project bankability issues, and cost burden for PLN (Perusahaan Listrik Negara, i.e., Indonesia's state-owned electricity company that is solely responsible for electricity generation, transmission, and distribution) as the sole off-taker, among others [[35–37]].

On the customer side, on the other hand, the decision regarding whether to implement grid-connected rooftop PV or rely solely on electricity from the utility grid, in many cases, has not been supported by sufficient knowledge of techno-economic aspects, particularly on reliability and cost implications due to different system settings and regulations. In addition, lack of product knowledge, complicated permit requirements, and perception of expensive systems were identified as the main barriers to adopting rooftop PV for households [38].

This paper offers a new perspective on the ongoing rooftop PV studies from a techno-economic standpoint. It introduces the concept of reliability-cost trade-offs that may arise due to different energy targets and the resulting variations in PV system sizes. These trade-offs are particularly relevant in emerging economies given the level of reliability and associated costs can vary significantly. The paper models unserved energy targets by accounting for potential capacity shortages on the supply side.

The paper is organised as follows. Section 2 provides a brief overview of the current status of solar PV deployment, with a focus on rooftop solar PV systems in Indonesia. Section 3 explains methods used in this study, including an overview of the simulations, input data, and modelling assumptions. Results and discussions are presented in Section 4. Finally, the conclusion of the paper is presented in Section 5.

2. Brief status of rooftop solar PV deployment for residential households in Indonesia

The potential for rooftop solar PV systems in Indonesia is immense due to the country's vast solar irradiation coverage and large market [39]. Despite this, the development of residential rooftop PV systems has been slow. As of October 2022, 75 % of the 6,261 PLN customers who installed rooftop PV were residential customers with mostly on-grid systems [40]. The residential sector has installed rooftop PV with a total capacity of 15.2 MW, representing approximately 22 % of the total rooftop capacity for all PLN customers [41]. The Java-Bali area has the largest share of the national rooftop PV capacity, accounting for around 80 % in 2021 [42].

There are challenges to the slow deployment of residential rooftop PV in Indonesia that are currently affecting all PLN customers. Some of these challenges have been acknowledged in the PLN Electricity Supply Business Plan (RUPTL) 2021–2030 [43]. These include: 1) several PLN electricity networks are currently not prepared to handle distributed renewable energy-based generation due to oversupply conditions caused by decreased demand; 2) there will be a need for PLN to add more generation plants to increase system flexibility if there is a relatively massive penetration of rooftop PV; and 3) there will be additional investment costs in generation control and forecasting, dispatch system, and grid code enforcement [[44,45]]. While the challenges may delay large-scale PV deployment, oversupply of system capacity, including from coal-fired power plants, can present an opportunity to provide the grid with increased flexibility [[46,47]].

Through the Ministry of Energy and Mineral Resources (MEMR), the Indonesian government has made efforts to encourage the implementation of rooftop solar PV. This includes the issuance of Ministerial Regulation No. 49/2018, revised by Ministerial Regulation No. 26/2021 [48]. These regulations aim to achieve a rooftop PV capacity of 3.6 GW. Although the revised regulation is seen as a positive step, especially regarding the recognition of 100 % export of electricity back to the PLN grid, implementation has been challenging.

As the grid operator, PLN is hesitant to approve applications for rooftop PV installations up to the maximum allowable capacity quota per customer due to oversupply and financial issues, mainly caused by the ongoing take-or-pay scheme derived from the Power Purchase Agreement (PPA) of large quantities of coal-based electricity from Independent Power Producers (IPP). To address the situation, MEMR has consulted with stakeholders to discuss various options, focusing on revising Ministerial Regulation No. 26/2021. Due to the current oversupply situation, rooftop PV users will most likely not be allowed to export electricity to the PLN grid, according to the newly revised regulation that has yet to be published [49].

Despite the positive efforts on the regulatory framework, the ongoing 35 GW coal power plant mega-project started in 2015 has become a problem for Indonesia's energy transition. The unchanging plans for additional coal power plants, which are not yet built, are arguably seen as one of the main barriers that hinder the massive development of PV, including rooftop systems – that require a comprehensive solution. While the share of coal in electricity generation is expected to decrease from around 56 GW–40 GW, the capacity of coal-fired power plants is proposed to increase by 13 GW in the RUPTL 2021–2030. It has come to light that there are still plans to construct coal power plants in 2027, as per the 2015–2019 PPA [50].

3. Methods

In this study, HOMER software is used to model grid-connected rooftop solar PV systems. Possible system sizes with various load profiles are simulated, as are their economic parameters, such as total Net Present Cost (NPC) and Cost of Energy (COE). Four different daily load profiles for residential households with electricity contracts of 2,200 V-Ampere (VA), 3,500 VA, 5,500 VA, as well as 6,600 VA have been created. Fig. 1 depicts these load profiles.

While a preliminary survey has been carried out to obtain the load profiles (as shown in Fig. 1) owned by different households in different locations in Surabaya – to represent different residential customer segments – this study considers only one location to allow the same solar irradiation data to be used in all simulations. It should be noted that all load profiles surveyed, as shown in Fig. 1, are for weekdays. Nevertheless, weekend patterns for most residential segments show similar base load values to weekdays but have slightly higher peak load, over a short period, than weekdays. One thing to note is that the surveyed load profiles have ruled out the impact of the Covid-19 pandemic which has

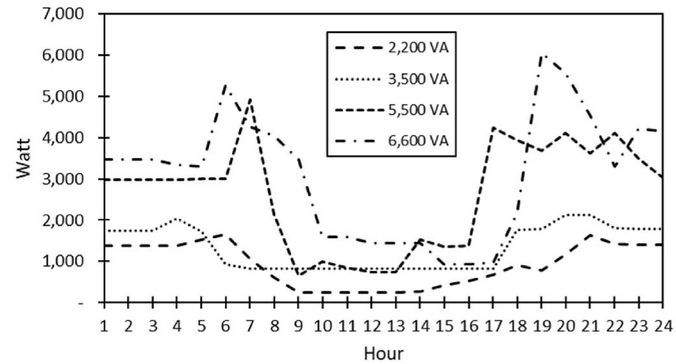

Fig. 1. Surveyed hourly based daily load profile for four residential households.

recently subsided, where people spent more time at home due to restrictions on outdoor activities or working from home.

Meanwhile, Table 1 shows several loading parameters for all residential segments, including the base load, maximum (peak) load, demand factor, and load factor. The demand factor is defined as the maximum demand divided by the connected load. The load factor is the ratio of average to maximum load for a 24-h period.

As shown in Table 1, the surveyed households have a fairly low to medium range of demand factors and relatively low load factors, i.e., around 0.5–0.6. This, however, is a typical household situation in many Indonesian urban areas, including Surabaya. Between 7 a.m. and 4 p.m., demand for electricity falls because most people spend their days outside their homes studying or working. Furthermore, with the exception of refrigerators, electricity has not been used for kitchen appliances. While gas is commonly used in stoves and ovens, microwaves are uncommon in Indonesia.

3.1. Solar resource data

Surabaya has huge untapped potential for rooftop PV. Located on the east coast of the Java Sea, Surabaya is Indonesia's second-largest urban area of around 300 km^2 and has relatively high solar resources. According to a World Bank report that selected a geographical site of -7.32° ($7^\circ 19'$) South Latitude and 112.68° ($112^\circ 40'$) East Longitude, the long-term average daily Global Horizontal Irradiation (GHI) in Surabaya has reached 5.29 kWh/m^2 [29], higher than Indonesia's average daily GHI of 4.8 kWh/m^2. Fig. 2 presents the map of daily and yearly long-term averages of GHI values in Indonesia, including Surabaya, from 1999 to 2018 [51].

HOMER allows users to enter GHI and/or Clearness Index [52] values using one of the two possible approaches, i.e., by downloading GHI and/or Clearness Index values from HOMER or by obtaining the NASA/MERRA2 hourly-based datasets of GHI and/or Clearness Index from the NREL National Solar Radiation Database (NSRDB) viewer [53]. While the first approach allows users to directly obtain 'ready to use' monthly average values of GHI and/or Clearness Index by specifying the location's latitude and longitude, the second approach lets users explore the data using the following steps: (1) entering the location's latitude and longitude; (2) selecting available datasets; (3) selecting appropriate

Table 1
Loading parameters for all surveyed residential households.

Parameter	Residential household segments			
	2,200 VA	3,500 VA	5,500 VA	6,600 VA
Base load	240 Watt	820 Watt	657 Watt	935 Watt
Maximum load	1,655 Watt	2,127 Watt	4,915 Watt	6,056 Watt
Demand factor	0.53	0.32	0.48	0.43
Load factor	0.56	0.63	0.53	0.51

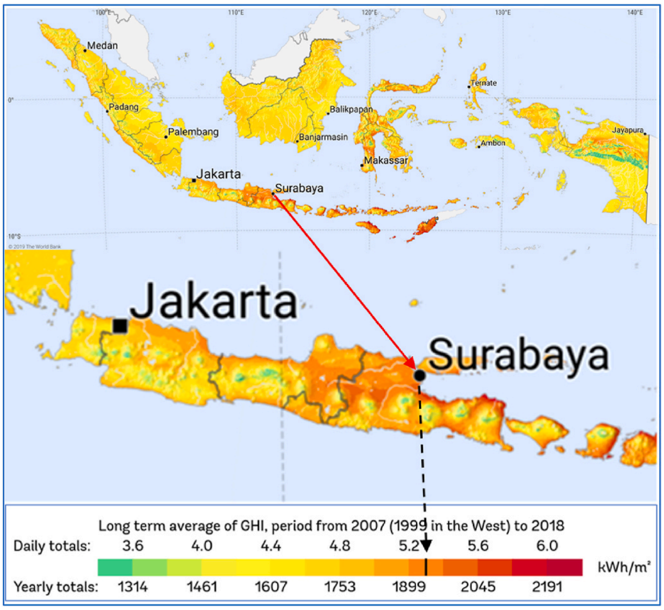

Fig. 2. A map showing daily and yearly long-term average GHI (kWh/m^2) in Indonesia and Surabaya [51].

attributes; (4) selecting year(s); (5) selecting time interval of the data; (6) selecting data formatting options; (7) typing an email for receiving the data; and (8) submitting the request.

While obtaining the GHI and/or Clearness Index data from the NREL NSRDB data viewer website may provide users with flexibility and options of getting the preferred data granularity (10-min, 30-min, or 60-min time intervals for Asia, Australia, and Pacific regions during 2016–2020), HOMER detects the time step of the imported data file based on the number of lines. If, for example, the imported data file contains 8,760 lines, HOMER assumes it contains hourly data. Subsequently, HOMER will convert the data into monthly averages, i.e., a single value for each month. Users, however, should first convert the GHI from hourly-based W/m^2 into daily-based kW/m^2 for a particular year before importing the data into HOMER. In addition, if the year selected on the NREL data viewer website is more than one specific year, users must produce an average value for each time step within all considered years.

This study applies the first approach, i.e., downloading the 'ready to use' GHI and Clearness Index data for a location having a South Latitude of 7°19′ and an East longitude of 112°47'. While the considered latitude in this study is slightly different from that in Ref. [51], the location provides an average daily GHI of 5.26 kWh/m^2, similar to that in Ref. [51]. Table 2 presents numerical values of the monthly average GHI, and Clearness Index obtained for this study, while Fig. 3 shows how

Table 2
Monthly average GHI and clearness index for the specified location.

Month	Clearness index	Global Horizontal Index (kWh/m^2/day)
January	0.45	4.84
February	0.46	4.97
March	0.48	5.05
April	0.52	5.09
May	0.56	5.00
June	0.57	4.82
July	0.59	5.10
August	0.60	5.62
September	0.61	6.21
October	0.56	5.96
November	0.50	5.34
December	0.48	5.13
Average	0.53	5.26

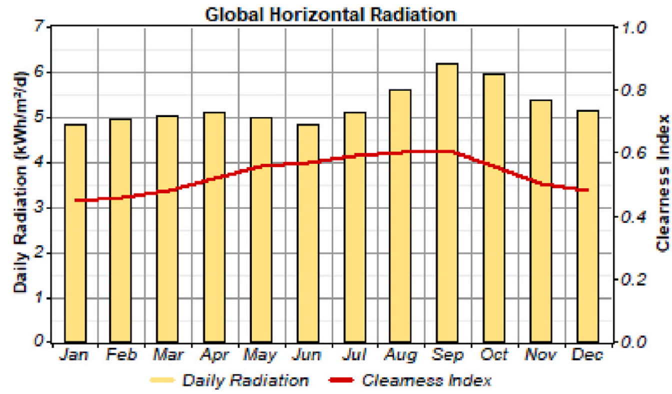

Fig. 3. HOMER visualisation of monthly average GHI and Clearness Index for the specified location.

HOMER depicts the values graphically.

3.2. Reliability-cost trade-offs

The cost-reliability trade-offs in the context of residential grid-connected rooftop PV analysis should demonstrate to customers the importance of understanding the options available and their possible two-sided impacts. This impact may be caused by different PV sizes that customers may consider due to budget or other constraints, such as daytime power requirements and supply reliability. In contrast to the load profiles of commercial buildings in general, which have relatively flat loads during the day, the load profiles for all surveyed households, as shown in Fig. 1, can provide more options to all customers, particularly considering the shape of a deep valley from 7 a.m.–4 p.m. However, there are different consequences for installing any PV size that suits their needs and limitations, not just only maximising the size allowed by regulations up to the contracted amount of power.

The cost-reliability trade-off analysis in this study is based on the maximum annual capacity shortage values assigned to the simulation. HOMER uses the term 'maximum annual capacity shortage' to express the system's reliability constraint. It defines the total capacity shortage as the total amount of capacity shortage throughout a year, expressed in kWh/year. The value is used to calculate the capacity shortage fraction. This fraction is a ratio between total capacity shortage and total electric load, expressed in kWh/year. The simulated systems may end up with a situation where there is an unmet load or unserved energy when the electrical load exceeds the supply. Therefore, the total unmet load and the unmet load fraction can be calculated accordingly. This study applies 0 %, 5 %, 10 %, and 15 % of the maximum annual capacity shortage (or maximum unserved energy). Hereafter, the paper uses the term 'maximum unserved energy' as the system reliability constraint and 'unserved energy' as the result of system reliability.

3.3. System modelling, economic parameters, and assumptions

This study assesses the grid-connected rooftop PV systems for residential households by using HOMER software to model system configurations for four residential household segments with their associated load profiles in the urban area of Surabaya, Indonesia, as a case study. The complete model consists of an electricity grid, the household's loading pattern, and the main components consist of PV array and converter. While much of the simulations are performed in HOMER, this study takes into account the implications of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors on the assessment of cost-reliability trade-offs.

In particular, this study suggests a method for incorporating billing deduction factors in HOMER optimisation since the software does not account for billing deduction cases in its direct calculations. In HOMER, varying sell-back rates for energy sold to the grid can be used to account for various billing deduction factors. To simulate a billing deduction factor of 65 %, for instance, the model multiplies the amount of electricity sold to the grid by 65 % of the electricity full rate for customers.

This study examines four load profiles corresponding to the four residential customer segments. Simulations are performed for each load profile, considering the electricity export deduction factor. The applicable kWh export deduction factor determines the proportion of kWh exported to the grid that can be used as a factor for reducing electricity bills. This study uses two different billing deduction factors, i.e., a 65 % deduction factor according to Ministerial Regulation No. 49/2018 and a 100 % deduction factor according to Ministerial Regulation No. 26/2021. The first deduction factor shows that only 65 % of the kWh exported to the grid is permissible for customers to reduce electricity bills. The second factor indicates that the customer can use all kWh exported to the grid to reduce the amount of kWh purchased from the grid.

In HOMER, these two conditions can be treated differently. HOMER calculates the total energy charge without net metering, i.e., using the 65 % deduction factor, by multiplying the total energy purchased from the grid by the electricity rate applicable to that household segment minus the amount of electricity sold to the grid times the applicable sell-back rate. Using a 100 % deduction factor (net metering), HOMER calculates the total energy charge by multiplying the amount of net kWh purchased from the grid by the electricity rate that applies to the household segment.

No Time-of-Use (TOU) rate and demand charge is applied to Indonesian residential sector customers. The electricity rate for households with a 2,200 VA power contract (R1) is IDR 1,444.70 per kWh, while households with power of 3,500 VA or above (R2/R3) are charged IDR 1,699.53 per kWh [[54,55]]. Assuming the exchange rate is IDR 15,000 per USD 1, this gives us USD 0.096 per kWh for 2,200 VA customers and USD 0.113 per kWh for 3,500–6,600 VA ones. The simulation, therefore, applies different electricity rates between 2,200 VA and higher segments.

The simulation also accounts for demand uncertainty by allowing for up to 5 % day-to-day variability, i.e., the standard deviation in the sequence of daily averages, and up to 5 % time-step-to-time-step variability, i.e., the standard deviation in the difference between the hourly data and the average daily profile, depending on the contract. This configuration results in a higher peak load than the surveyed households have. For example, a 2,200 VA household with 22 kWh/day and a peak load of 1.65 kW is simulated to have a peak load of 2.1 kW due to the 5 % day-to-day and time-step-to-time-step variability. Aside from that, electricity demand is assumed to remain constant over the PV's lifetime. The complete system configuration models for all households in HOMER is illustrated in Fig. 4.

3.3.1. Solar PV array and converter

Since the effect of temperature on the PV array is not considered, HOMER calculates the power output generated by the solar PV array P_{PV} according to the following equation.

$$P_{PV} = Y_{PV} \times f_{PV} \left(\frac{G_T}{G_{T,STC}} \right) \tag{1}$$

where Y_{PV} is the rated capacity of the PV array (kW), f_{PV} is the derating factor (%), G_T is the solar radiation incident on the PV array in the current time step (kW/m^2), and $G_{T,STC}$ is the incident radiation at standard test condition (1 kW/m^2).

In HOMER, the rated capacity of the PV array Y_{PV} is specified by users as one of the input variables to Eq. (1). Users can either enter at least one size of solar PV module and the capital cost associated with that particular size, for example, 2 kW, or in fractions, for example, 0.1 kW PV. If the second option were selected, the user must enter several PV module capacities in multiples of 0.1 kW–2 kW or up to the maximum capacity considered. HOMER simulates possible supply configurations to meet hourly-based energy demand and displays the system's Y_{PV} in the simulation results. Therefore, if users enter Y_{PV} as fractions, the number of solar PV arrays N_{PV} can be obtained using the following equation.

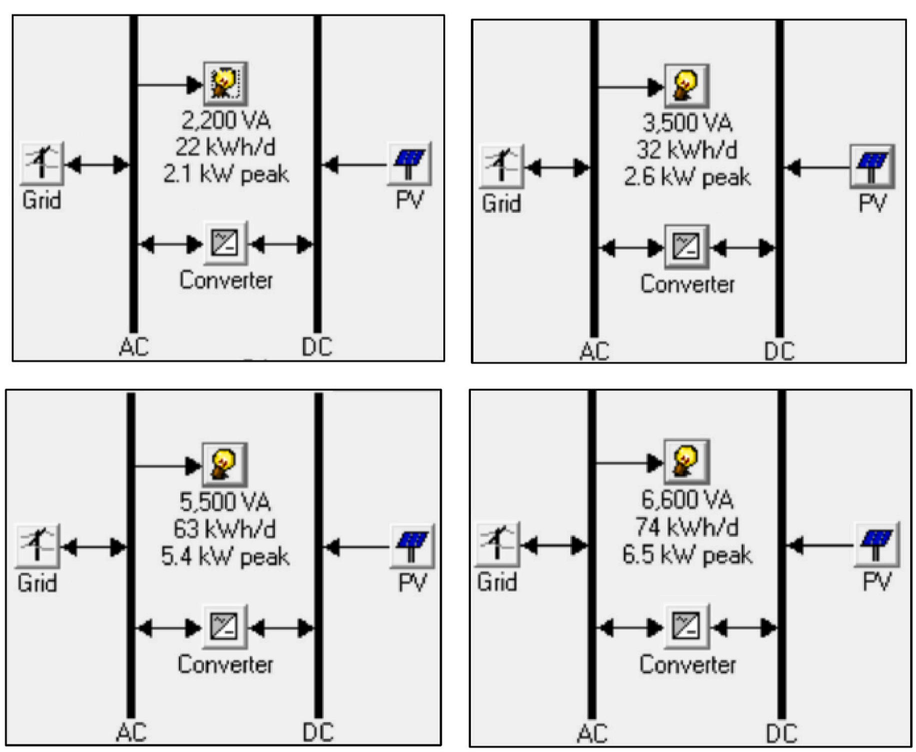

Fig. 4. HOMER system configurations for residential households with 2,200 VA and 3,500 VA (top left to right), households with 5,500 VA and 6,600 VA (down left to right) electricity contracts.

$$N_{PV} = \frac{calc\_Y_{PV}}{frac\_Y_{PV}} \tag{2}$$

where cal_Y_{PV} is the calculated system's rated capacity of the PV array (kW), and $frac\_Y_{PV}$ is the fraction of the rated capacity of the PV entered by users (kW).

HOMER models a converter, or better known as an inverter, to convert DC electricity generated by solar PV arrays to AC electricity by considering the user-specified efficiency η of the inverter side. HOMER calculates the performance of a converter on an annual basis according to the following equation.

$$\eta = \frac{kWh/year_{in}}{kWh/year_{out}} \tag{3}$$

where $kWh/year_{in}$ is the DC electricity generated by PV arrays (kWh/year), and $kWh/year_{out}$ is the AC electricity produced by inverter (kWh/year).

The expected converter life is 15 years, with 90 % efficiency on the inverter side and 85 % efficiency on the rectifier side. The converter-rated capacity candidates can be slightly higher than the solar PV capacity specified in the simulation search space, as HOMER does not consider the power factor of the load. Capital and replacement costs of the 1 kW converter are assumed to be USD 400 (IDR 6,000,000) [56] and USD 380 (IDR 5,700,000), respectively, without annual O&M costs. Capital and replacement costs are assumed to increase linearly concerning size.

This study assumes capital and replacement costs for the 0.1 kW peak PV module in Indonesia to be USD 50 each (equal to around IDR 750,000) [57], and no annual Operating and Maintenance (O&M) costs for the PV arrays. The cost of additional or replacement modules is assumed to increase linearly. The derating factor is considered 80 %, and the ground reflectance is supposed to be 20 %. Given an expected lifetime of 25 years, the PV arrays are installed without tracking. The slope is specified in the same degree as the location's latitude, 7.3°, while the azimuth is set at 180° (due North).

3.3.2. System economic

This study considers a project lifetime of 25 years and assumes an annual interest rate of 5 %. Other important assumptions include system fixed capital cost and system fixed O&M cost. Considering the current total installed cost of solar PV for the Indonesian residential sector, i.e., USD 1,000/kW peak (IDR 15,000,000/kW peak) [[58,59]], and the cost of solar PV modules and converters, the system fixed capital cost and the fixed O&M cost are set at USD 200 (IDR 3,000,000) [60] and USD 20/year (IDR 300,000/year), respectively.

In HOMER, the economic feasibility of the systems can be assessed by using total Net Present Cost (total NPC), Cost of Energy (COE), and operating costs. The total NPC, expressed in USD, is used in economic analysis to show the system's life cycle cost. It is calculated as follows.

$$C_{NPC} = \frac{C_{ann,tot}}{CRF(i, R_{proj})} \tag{4}$$

$$CRF(i, N) = \frac{i(1+1)^N}{(1+i)^N - 1} \tag{5}$$

where $C_{ann,tot}$ is total annualised cost (USD/year), CRF is capital recovery factor, i is interest rate (%), and R_{proj} is project lifetime (year).

HOMER defines COE as the average cost per kWh produced by the system. It is calculated by dividing the total annualised cost by the total electricity produced including total grid sales as follows.

$$COE = \frac{C_{ann,tot}}{E_{prim,AC} + E_{grid,sales}} \tag{6}$$

where $E_{prim,AC}$ the total electricity produced by all components of the system in a year, and $E_{grid,sales}$ is the total grid sales (electricity sold to the grid).

Operating costs, expressed in USD/year, are the sum of the annual O&M costs, and annualised replacement cost minus annualised salvage value. For grid-connected systems, it includes the annualised cost of electricity purchased from the grid minus electricity sold to the grid. While the term operating costs is useful in providing the user with some insights into the contribution of these types of costs on the total NPC and typically decreases at higher unserved energy, this study rules out the term operating costs in the analysis due to the focus of this study on analysing the possible trade-off between the system cost, which is already well represented by the total NPC, and unserved energy.

3.3.3. Scenarios and cases

This study considers two main scenarios in the simulation regarding the selection of solar PV-size candidates. The first scenario is called Maximum-PV-Capacity (MPVC). This basically refers to the maximum PV capacity a customer can install, i.e., up to the power (VA) contracted by a household, as per Ministerial Regulation No. 26/2021. For example, a household with 2,200 VA contracted power can install PV panels up to 2.2 kW peak capacity. In this case, the simulation considers up to 2.2 kW peak PV capacity in 0.1 kW PV arrays. This scenario considers PV sizes of up to 3.5 kW peak, 5.5 kW peak, and 6.6 kW peak for households with 3,500 VA, 5,500 VA, and 6,600 VA, respectively. HOMER simulates these size candidates and the fraction of electricity purchased from the grid. The optimisation will result in a system configuration with the least total NPC and other alternatives that exhibit higher total NPC.

The second scenario is called Half-PV-Capacity (HPVC). Under this scenario, simulations use up to half the maximum allowable PV capacity. For example, simulations for possible system configurations for a 2,200 VA household consider up to 1.1 kW peak capacity in 0.1 kW PV arrays. Other simulations for households with 3,500 VA, 5,500 VA, and 6,600 VA are carried out considering PV capacity of up to 1.75 kW peak, 2.75 kW peak, and 3.3 kW peak, respectively. This scenario is based on the low load during the day for all households, i.e., between 7 a.m. and 4 p.m. This study assesses the total NPC from both MPVC and HPVC scenarios for all household segments.

This study considers up to four cases for each household segment, i.e., 100%-MPVC, 100%-HPVC, 65%-MPVC, and 65%-HPVC. In this regard, either 100 % or 65 % refer to the applicable deduction factor according to the regulations mentioned earlier in Section 2. In other words, there are two cases for each scenario. The MPVC scenario consists of 100%-MPVC and 65%-MPVC, while the HPVC scenario consists of 100%-HPVC and 65%-HPVC.

4. Results and discussion

Tables 3-6 highlight the main results regarding important techno-economic aspects for all the cases considered in a 2,200 VA household. In the 100%-MPVC cases (see Table 3), the total NPC has reached USD 9,175 for 0 % maximum unserved energy (no-unserved energy) and has declined to USD 7,987 or 13 % for up to 11 % simulated unserved energy. As for no-unserved energy, the total NPC has increased to USD 10,031, USD 10,371, and USD 10,661 for the 65%-MPVC (see Table 4), 100%-HPVC (see Table 5), and 65%-HPVC cases (see Table 6), respectively.

All the total NPC of 100%-MPVC is found to be the cheapest among other cases considering all unserved energy. From the simulations, it is revealed that the total NPC of 100%-MPVC with no-unserved energy is USD 9,175, cheaper than the total NPC of 65%-MPVC with 7 % unserved energy and of HPVC cases with 11 % unserved energy. The simulation results have implied potential benefits of rooftop PV installation up to the maximum permitted capacity and concerning a 100 % billing deduction scheme for households with 2,200 VA, considering different options regarding unserved energy, installed capacity, and percentage of

Table 3
Simulation results for 2,200 VA: 100%-MPVC.

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	2.2	1.5	1.8	1,900	9,175	0.081	33	0
5	2.2	1.5	1.4	1,900	8,796	0.081	34	4
10	2.2	1.5	1.3	1,900	8,446	0.080	35	7
15	2.2	1.5	1.2	1,900	7,987	0.079	36	11

Table 4
Simulation results for 2,200 VA: 65%-MPVC.

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	2.2	1.5	1.8	1,900	10,031	0.089	33	0
5	2.2	1.5	1.4	1,900	9,652	0.088	34	4
10	2.2	1.5	1.3	1,900	9,302	0.088	35	7
15	2.2	1.5	1.2	1,900	8,842	0.088	36	11

Table 5
Simulation results for 2,200 VA: 100%-HPVC.

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	1.1	1.0	1.8	1.150	10,371	0.092	19	0
5	1.1	1.0	1.4	1.150	9,987	0.092	20	4
10	1.1	1.0	1.3	1.150	9,636	0.091	21	7
15	1.1	1.0	1.2	1.150	9,177	0.091	21	11

billing deduction.

As shown in Table 3 to Table 6, renewable energy's contribution to electricity generation has reached 33–36 % share in the cases of MPVC and 19–21 % share in the cases of HPVC within the range of 11 % unserved energy. As expected, reducing the installed capacity of PV modules to half the maximum allowable capacity will decrease PV penetration in the systems.

The optimisation results presented in Table 3 to Table 6 also provide customers with another insight into the potential role of the system cost components in shaping the cost-reliability trade-off. While the initial capital costs are of course found to be lower in HPVC cases compared to those in MPVC due to less PV array involved, i.e., USD 1,150 versus USD 1,900, it is found that the total NPC of MPVC cases are found to be cheaper than those of HPVC cases within the same unserved energy.

From the simulation results in 100%-MPVC cases, for example, it is found that 4 % unserved energy is equal to 283 kWh/year of unmet electricity, while 7 % and 11 % unserved energies are equal to 542 kWh/year and 881 kWh/year, respectively. On the other hand, the total NPC of this particular case has shown a noticeable decrease of around USD 350 – USD 450 for every 3–4% additional unserved energy.

Tables 7–10 shows the trade-offs between the total NPC, as expressed in annual total cost (USD/year), and unserved energy (kWh/year) of all simulations for a 2,200 VA household. The optimisation results show cheaper total annual costs as unserved energy increases. In addition, MPVC cases have shown more affordable yearly costs due to fewer energy charges (electricity bills) spent by the customers compared to those of HPVC.

It is of importance to observe the simulation results in terms of a range of shares of energy charge to the total (annual) cost of the systems. As presented in Table 7 to Table 10, all optimisation results in MPVC cases have shown lower shares of energy charge to the (annual) total cost compared to those in HPVC ones. It is found that the averaged shares of energy charge to the total cost are 70 % and 74.6 % for 100%-MPVC and 65%-MPVC, respectively, versus 83.9 % and 84.3 for 100%-HPVC and 65%-HPVC, respectively.

As the finding compares MPVC and HPVC scenarios, it highlights the potential benefits of higher PV penetrations in reducing the energy charge component's share of the total annual cost within the same unserved energy range. In this regard, the lower applicable billing deduction factor indicates the smaller revenue that a customer can expect within the same scenario, which, of course, has an impact on the higher portion of energy charge in the total annual cost. While this paper highlights particular results for a 2,200 VA surveyed household, similar implications as obtained in Table 7 are also expected to occur for other households considered in this study, given the similarity of the households' daily load profiles.

Figs. 5 and 6 depict the cost-reliability trade-offs in terms of total NPC versus unserved energy for all cases in 2,200 VA and 3,500 VA, as well as 5,500 VA and 6,600 VA households, respectively. From the simulation results presented in Figs. 5 and 6, the total NPC of 100%-MPVC cases is the cheapest in every unserved energy. The finding indicates a comparative benefit of on-grid rooftop PV systems installing

Table 6
Simulation results for 2,200 VA: 65%-HPVC.

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	1.1	1.0	1.8	1,150	10,661	0.094	19	0
5	1.1	1.0	1.4	1,150	10,277	0.094	20	4
10	1.1	1.0	1.3	1,150	9,926	0.094	21	7
15	1.1	1.0	1.2	1,150	9,467	0.094	21	11

Table 7
Trade-offs between annualised total cost and unmet energy for a 2,200 VA household.

Scenario	Unserved energy (%)	Unmet energy (kWh/year)	Annual energy charge (USD/year)	Annualised total cost (USD/year)	Share of energy charge to total cost (%)	Averaged share of energy charge to total cost (%)
100%-MPVC	0	0	481	651	73.8	70
	4	283	454	624	72.8	
	7	542	429	599	71.6	
	11	881	396	567	69.8	
100%-HPVC	0	0	624	736	84.8	83.9
	4	287	597	709	84.2	
	7	546	572	684	83.6	
	11	886	539	651	82.8	
65%-MPVC	0	0	541	712	75.9	74.6
	4	283	515	685	75.2	
	7	542	490	660	74.2	
	11	881	457	627	72.9	
65%-HPVC	0	0	645	756	85.3	84.3
	4	287	617	729	84.6	
	7	546	592	704	84.1	
	11	886	560	672	83.3	

Table 8
The cost per watt of PV installed capacity with 0 % maximum unserved energy.

Household	The cost per watt of PV installed capacity ($/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	4.17	4.56	9.43	9.69
3,500 VA	4.20	4.53	9.68	9.74
5,500 VA	5.55	5.93	12.34	12.54
6,600 VA	5.39	5.71	12.02	12.12

Table 9
The cost per watt of PV installed capacity with 5 % maximum unserved energy.

Household	The cost per watt of PV installed capacity (USD/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	3.99	4.39	9.08	9.34
3,500 VA	4.00	4.34	9.30	9.36
5,500 VA	5.24	5.62	11.75	11.95
6,600 VA	5.06	5.39	11.36	11.46

Table 10
The cost per watt of PV installed capacity with 10 % maximum unserved energy.

Household	The cost per watt of PV installed capacity (USD/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	3.84	4.23	8.76	9.02
3,500 VA	3.71	4.05	8.71	8.77
5,500 VA	4.91	5.29	11.11	11.31
6,600 VA	4.78	5.10	10.78	10.88

maximum PV capacity permitted combined with higher billing deduction factors (here is 100 %) over other configurations. Moreover, there is a relatively large difference in total NPC between the 100%-MPVC cases and the 65%-MPVC cases concerning all unserved energies up to a 15 % maximum annual unserved energy constraint, while insignificant differences of the total NPC are found between those in the 100%-HPVC cases and the 65%-HPVC cases, particularly in 3,500 VA and 6,600 VA households.

Residential customers can further estimate one of the important indices for rooftop PV installation decision-making, i.e., the cost per MWh consumed (USD/MWh). Using 100%-MPVC cases in a 2,200 VA household as illustrations, and given the cost is the total NPC, as presented in Fig. 9, the costs per MWh consumed during the project lifetime for 0 %, 4 %, 7 %, and 11 % unserved energies are USD 37.19/MWh, USD 36.70/MWh, USD 36.22/MWh, and USD 35.54/MWh, respectively, provided the total MWh consumed over the 25-year project lifetime are 246.68 MWh, 239,68 MWh, 233.20 MWh, and 224.73 MWh, respectively for the associated unserved energies.

From this particular analysis, it is found that, despite a considerably large difference in terms of total NPC between the system with no-unserved energy and that with the poorest reliability (USD 1,188 difference), the cost per MWh figures have shown a relatively small gap of cost difference during the project lifetime, i.e., USD 1.65/MWh, between no-unserved energy and 11 % unserved energy.

In addition to merely exploring and comparing economic parameters such as total NPC, the share of energy charge to total annual cost, and COE, it is also of interest to assess the potential economic impact of the systems in terms of cost per watt of PV installed, i.e., through exploring which households exhibit the lowest cost per watt of PV installed capacity. The cost per watt of PV installed can be used as one of the indicators for customers in deciding the capacity of PV to be installed

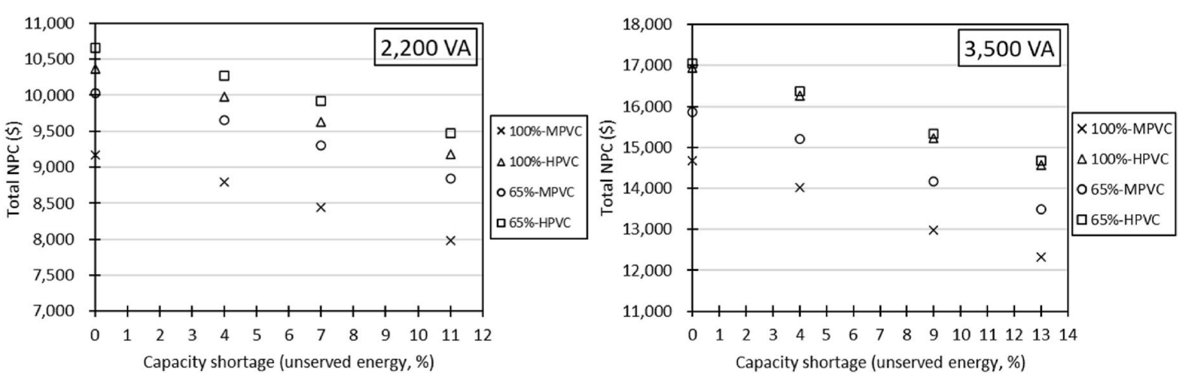

Fig. 5. Total NPC versus unserved energy in all cases for 2,200 VA (left) and 3,500 VA (right).

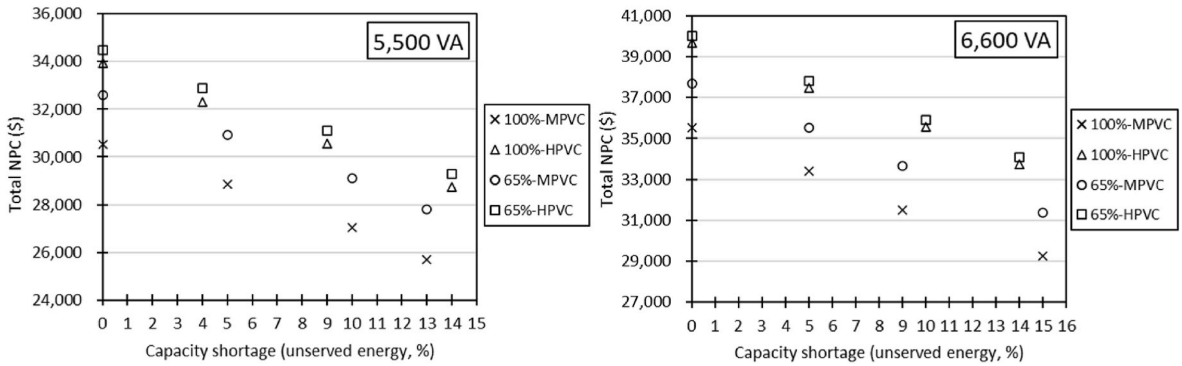

Fig. 6. Total NPC versus unserved energy in all cases for 5,500 VA (left) and 6,600 VA (right).

while considering possible techno-economic scenarios, including the potential impact of applicable billing deduction factors and a range of different unserved energy.

The lowest cost per watt of PV installed capacity can be obtained for all scenarios by comparing the total system cost (total NPC) with the PV installed capacity. Table 8 presents variations in cost per watt of PV installed capacity for all the optimisation results of 100%-MPVC and 65%-MPVC, as well as 100%-HPVC and 65%-HPVC given no-unserved energy (0 % maximum unserved energy), while Tables 9–11 present variations of the cost per watt of PV installed capacity considering 5 %, 10 %, and up to 15 % maximum unserved energy, respectively.

As shown in Table 8, the total NPC per watt of PV installed capacity, under 0 % unserved energy, varied from USD 4.14/Watt to USD 12.54/Watt in all cases across all households. The results show similar costs in the MPVC cases concerning 2,200 VA and 3,500 VA households, slightly more than double in the HPVC cases, and similar for 5,500 VA and 6,600 VA households. It is also found that the results are not affected by the applicable billing deduction factors but simply by the PV capacity. Nevertheless, it should be noted that the results obtained in Tables 8–11 are largely influenced by the household's daily electricity load profile and other applied scenarios.

The simulation results in terms of possible system capacity, consisting of grid and PV capacity across all unserved energy in all cases of all households, are depicted in Figs. 7 and 8.

As seen in Figs. 7 and 8, higher unserved energy has resulted in lower grid capacity required by the system to meet the demand according to the system's maximum unserved energy constraint, and the PV capacities are maximised across all unserved energies in different scenarios. Moreover, it is interesting to note that the PV capacities across all MPVC cases are always higher than the grid ones. On the other hand, the grid capacities are mostly higher than those of PV in most HPVC cases, except in 3,500 VA for 9 % unserved energy and beyond. In all cases, the grid capacities have similarly decreased within the unserved energy range. For example, in 2,200 VA (see Fig. 7 left), the grid capacities are found at 1.8 kW, 1.4 kW, 1.3 kW, and 1.2 kW for 0 %, 4 %, 7 %, and 11 % unserved energy, respectively, and similarly in other households.

A sensitivity analysis of the techno-economic factors influencing system performance would benefit stakeholders, particularly residential customers. While focusing on system reliability, this study uses only a 5 % annual interest rate and fixed electricity rates associated with household segments. As a result, the sensitivity variable used in HOMER is maximum annual unserved energy.

Table 11
The cost per watt of PV installed capacity with 15 % maximum unserved energy.

Household	The cost per watt of PV installed capacity (USD/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	3.63	4.02	8.34	8.61
3,500 VA	3.52	3.86	8.32	8.38
5,500 VA	4.68	5.06	10.45	10.65
6,600 VA	4.43	4.76	10.23	10.33

Taking a 2,200 VA household with 100%-MPVC as an example, a graphical sensitivity result depicting possible trade-offs on total NPC versus unserved energy fraction and a sensitivity result of net grid purchases (electricity purchased from the grid minus electricity sold to the grid) versus maximum annual unserved energy are presented in Figs. 9 and 10, respectively. Meanwhile, a sensitivity result of total NPC versus total electricity production is shown in Fig. 11.

Maximum annual unserved energy constraints have varying effects on total NPC, total electricity production, and nett grid purchases. As shown in Fig. 9, total NPC cannot be less than USD 8,500 when unserved energy is kept at or below 6 %. According to Fig. 11, a 10 % unserved energy would result in approximately 9,700 kWh/year of electricity production, which would equal approximately USD 8,500 in total NPC.

Despite possible variations and differences in households' daily loading profiles along with other affecting factors, which, of course, may provide different results and interpretations, this study has sought to explore possible cost-reliability trade-offs in Indonesia's urban residential grid-connected rooftop PV due to three key factors, namely potential unserved energy, PV capacity, and possible billing deduction scheme. The significance of these factors has been shown in the analysis considering different residential household segments, and therefore, should be considered not only by customers who are willing to apply on-grid rooftop PV but also by stakeholders such as government and utility companies according to their role in supporting more grid-connected rooftop PV capacity.

5. Conclusions

This paper explores the potential of grid-connected rooftop PV systems in terms of how they can be better planned and utilised by understanding the possible trade-offs between system reliability and cost while recognising challenges related to electricity supply security in the context of emerging economies. The effects of various unserved energy limits, PV capacities, and billing deduction factors (modelled in HOMER using different sell-back rates) on the systems' techno-economic parameters have been investigated in order to better understand possible cost-reliability trade-offs for total NPC and unserved energy. The analyses are carried out with the help of HOMER, with four different residential household segments in Surabaya, Indonesia, serving as a case study.

In all four cases of each household segment, i.e., 100%-MPVC, 65%-MPVC, 100%-HPVC, and 65%-HPVC, the optimisation results show reliability-cost trade-offs between the total NPC and all unserved energies. Furthermore, the role of cost components in the trade-offs between HPVC and MPVC cases in terms of initial capital costs and total NPC was highlighted in the analyses. The findings revealed a relatively large difference in total NPC for all households between 100%-MPVC cases and 65%-MPVC cases for all unserved energies, while differences

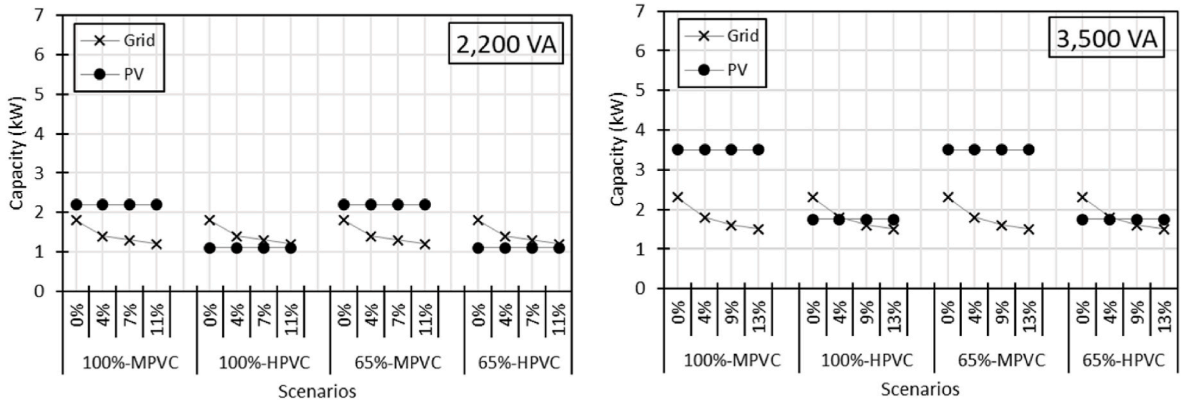

Fig. 7. System capacity across all unserved energies for 2,200 VA (left) and 3,500 VA (right).

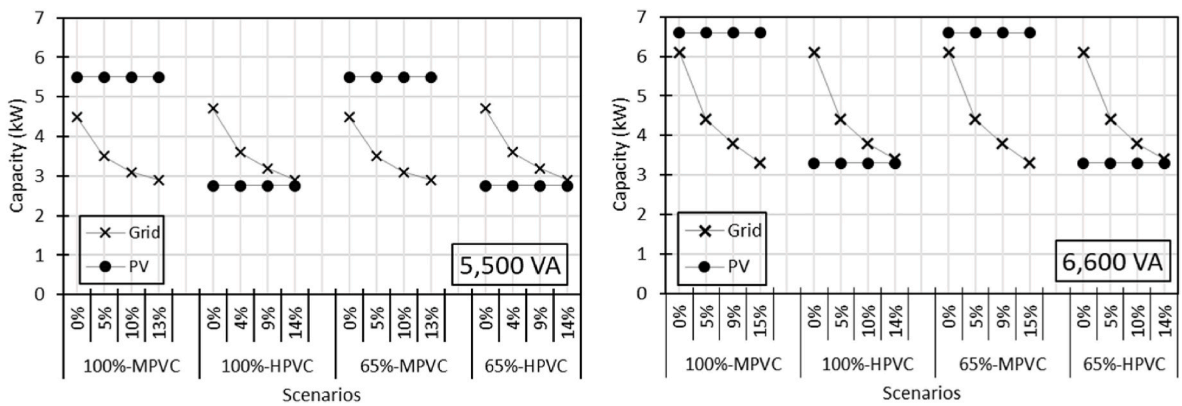

Fig. 8. System capacity across all unserved energies for 5,500 VA (left) and 6,600 VA (right).

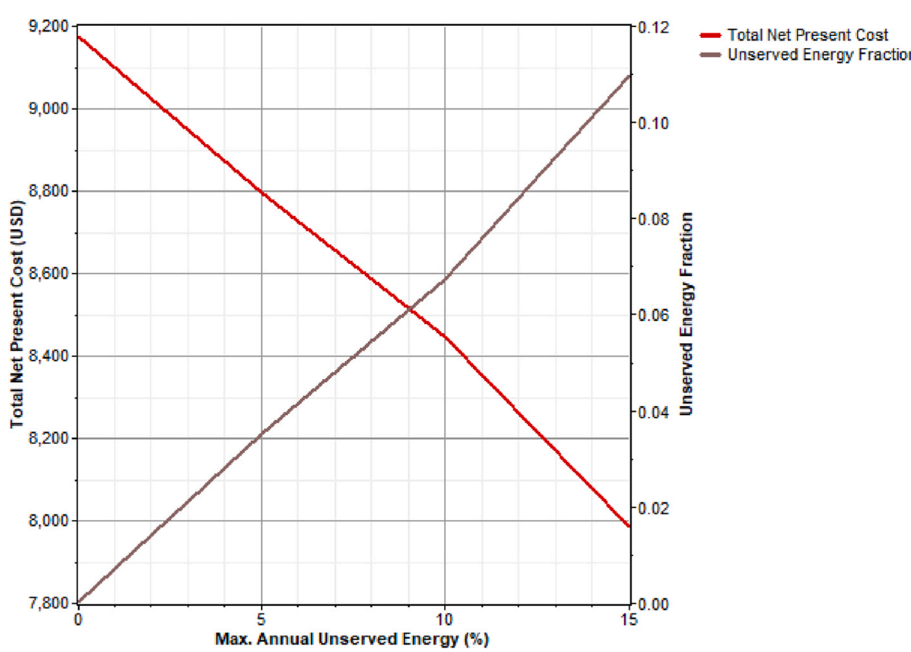

Fig. 9. Sensitivity result of total NPC versus unserved energy fraction in a 2,200 VA household with 100%-MPVC.

between those in 100%-HPVC cases and 65%-HPVC cases are insignificant. The simulation results implied potential benefits of rooftop PV installation up to the maximum permitted capacity and a 100 % billing deduction scheme for households with 2,200 VA, taking into account different options for unserved energy, installed capacity, and billing deduction percentage.

Among the significant results of this study that highlight the benefits of grid-connected rooftop PV are the following: 1) higher renewable

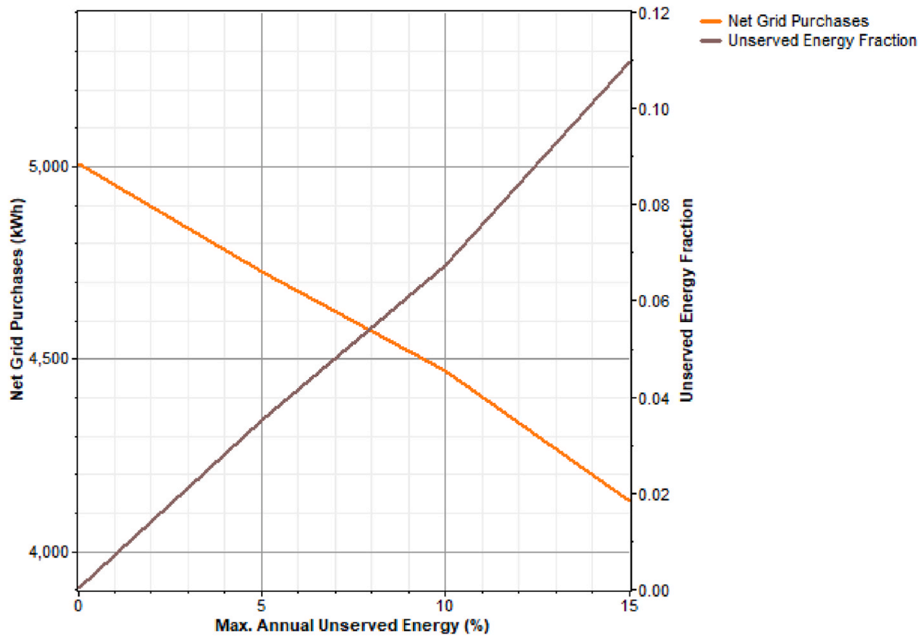

Fig. 10. Sensitivity result of net grid purchases versus maximum annual unserved energy in a 2,200 VA household with 100%-MPVC.

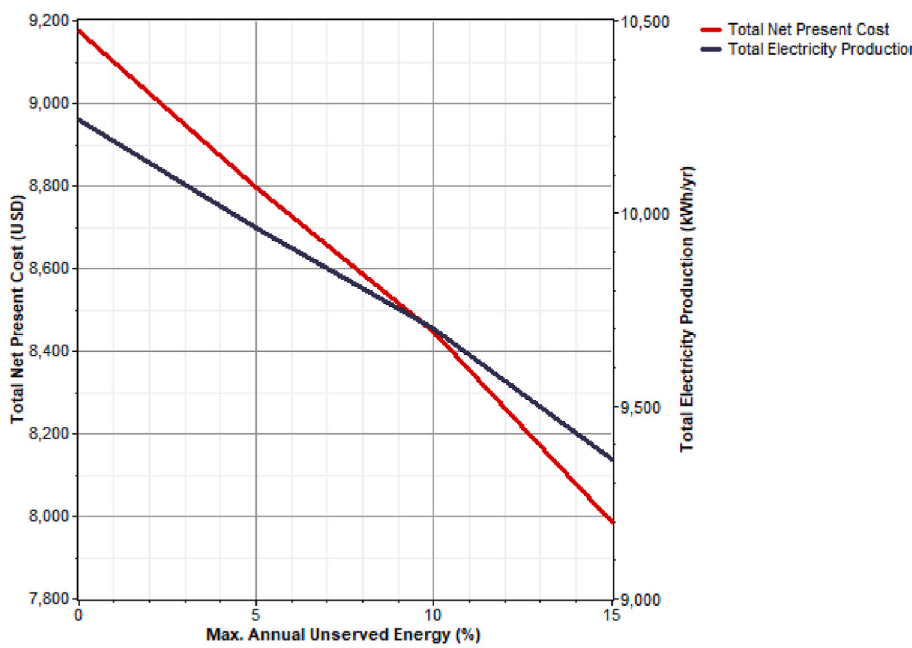

Fig. 11. Sensitivity result of total NPC versus total electricity production in a 2,200 VA household with 100%-MPVC.

energy penetration for MPVC systems compared to HPVC systems regardless of the billing deduction factors; 2) cheaper total NPC are shown by MPVC cases than those of HPVC cases within the same unserved energy; 3) lower shares of energy charge to the annual total cost in MPVC cases compared to those in HPVC ones; and 4) Over the project lifetime, the cost per kWh consumed (USD/MWh consumed) showed only a slight variance between the system with no-unserved energy and the system with the poorest reliability, given 100%-MPVC cases in 2,200 VA as an example; 5) All households with a 15 % maximum limit on unserved energy have the lowest costs per watt of installed PV capacity, and these costs are unaffected by billing deduction factors; 6) based on the system's maximum unserved energy limits, higher unserved energy has led to a decrease in the amount of grid capacity needed by the system to meet demand, and the PV capacities are maximised across all unserved energies in various scenarios; and 7) Sensitivity analyses have revealed a range of impacts of maximum annual unserved energy constraints on various parameters, including total NPC, total electricity production, and net grid purchases.

When it comes to grid-connected rooftop PV, residential customers must be thoughtful, as there are potential trade-offs between cost and reliability. At the same time, attention must be paid to changing regulations that may have an impact on overall profitability. This study's analyses provided important findings and insights not only to the residential customers but also to stakeholders involved in the planning and implementation of rooftop PV policies.

Finally, there is no doubt about the grid-connected rooftop PV's techno-economic potential for accelerating distributed renewable energy penetration. Nonetheless, because rooftop PV deployment appears to be modest, especially in Indonesia, changes to the existing set of regulations are required. More encouraging, innovative policies should be introduced to address the barriers and challenges that customers and the industry face in moving rooftop PV deployment forward.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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