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Customer economics of residential PV–battery systems in Thailand

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ABSTRACT

The currently high upfront costs of batteries and the low retail electricity prices of households make investments in PV–battery systems not yet economically feasible. However, the experiences/learning curves of renewable generation technologies lead to the assumption that battery prices will rapidly decline with increasing diffusion. Furthermore, projected retail electricity rates are expected to increase with rising electricity demand. This study investigates the returns to residential customers using PV–battery systems under decreasing battery prices in Thailand. The impacts of four additional parameters have been included. The analysis is based mainly on net present values (NPV) and levelized costs of electricity (LCOE). The results show that battery size and its cost, and retail rate design have significant impacts on the returns, whereas buyback incentives for excess electricity have the lowest impact. In addition, to increase the power system flexibility by using PV–battery systems, the Thai government should provide the appropriate financial support, by which the savings incurred by the grid extension investments compensate for the costs.

1. Introduction

Renewable electricity plays an important role in alleviating concerns about climate change and in increasing energy security. Solar photovoltaic (PV) power is one of the promising technologies in the market. In Thailand, the majority of PV adoption comes mainly from utility-scale systems, as discussed in the GIZ publication [1]. In the third quartile of 2017, the cumulative installed capacity of PV was approximately 3200 MW,[1] of which 95% was utility-scale, ground-mounted solar systems, whereas the remaining 5% was rooftop PV (both small and large scale).

The Thai government has recently begun promoting self-consumption rooftop PV systems. One example of such support is the pilot project of the self-consumption of solar power generation with PV launched in 2016 by the Ministry of Energy. Until now, the electricity generated by rooftop PV systems was consumed on-site and any excess PV electricity was not compensated. Because the residential loads in Thailand peak at night, when rooftop PV cannot generate electricity, the amount of excess PV generation is high during the day. Some studies have proposed compensation schemes for the excess generation. Such schemes, e.g.net-billing, are discussed in Tongsopit et al. [2] and Chaianong et al. [3] Even though these schemes are expected to increase the profitability of rooftop PV investment, they increase the imbalance between load and generation profiles and the need for network investments. On the other hand, the inclusion of batteries into PV systems could shift the loads or contribute to reduced generation capacities during peak time. Furthermore, such inclusion mitigates the loads in the grids, producing less demand and less feed-in of solar power, and thereby reducing the necessity to invest in grid extensions or enforcements.

With a PV battery system, the consumption and generation patterns may differ considerably. As discussed in the Sandia report [4], there are various battery applications in power systems, starting from the generation system to the end user/utility customer. With PV systems, one of the most valuable battery applications for utility customers is “Renewable Energy Time-shift” for reducing the

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[1] Thailand's total generation capacity as of 2017 is 42,433 MW based on the statistical database of Energy Policy and Planning Office (available online: https://goo.gl/3rar2t).

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intermittency of PV and solving the mismatch between load demand and PV production, together with a demand-side management approach, which stores PV electricity in a battery for later consumption when electricity demands are high. In addition, when almost all PV electricity is self-consumed, the policy supports for excess generation may not be necessary, and so, would help to reduce government spending.

Because of the high upfront costs of battery installation, residential PV–battery systems in Thailand are hardly deployed. However, many studies [5–10] have forecasted a reduction in battery technology costs, which would increase the use of batteries together with PV systems. Apart from battery costs and their expected decline, there are some factors, such as retail rate subscriptions, subsidies/incentives, and system sizes that affect the economic feasibility of PV–battery systems.

This research evaluates the customer economics of grid-connected residential PV–battery systems in Thailand and assesses when they would be able to compete with the PV-only systems or grid electricity. Battery costs and other parameters, including battery sizes, retail rate subscriptions, and subsidies/incentives, are expected to have an impact on the returns on residential PV–battery investment, and so, were included in this analysis. This study also investigates if the reduced investment expenditures for grid extensions could compensate for additional spending by the Thai government to support payments (subsidies) for the batteries.

This paper focuses on residential customers because this customer group is expected to show the highest percentage of PV adoption in the future, as discussed in Chaianong et al. [11], and would tend to have a considerable mismatch between the load and PV production profiles.

The remainder of this paper is structured as follows. Section 2 reviews the relevant literature. Section 3 explains the data, assumptions, and methodology of this research. Section 4 discusses the customer economic results of residential PV–battery systems. Section 5 summarizes the key findings and their implications.

2. Literature review

The customer economics of PV–battery systems are influenced by a number of factors. Hoppmann et al. [12] reviewed various articles addressing the economics of PV–battery systems from the customer's perspective. The varied input parameters include PV sizes, battery sizes, technology costs, subsidies, and electricity prices. The main selected output parameters are the cost of electricity and some financial indicators, such as net present value (NPV), payback period (PB), and internal rate of return (IRR). Similarly to the idea of this research, some studies, such as [13,14], simulated the results by assuming that household battery may increase the self-consumption ratio of PV systems because household battery could reduce the amounts of electricity (1) fed back to and (2) purchased from the grid. Moreover, since the feasibility of battery investment is not yet attractive because of high capital costs for batteries, Braun et al. [13] investigated the additional results to address the reduction of battery costs for future situations.

Li et al. [15] also studied the techno-economics of grid-connected residential PV–battery systems in Kyushu, Japan. The results show that the self-consumption ratio can increase by installing a household battery. The customer demand, PV production profile, and battery size are the main factors that must be well designed to achieve the best performance. The self-consumption ratio is higher when the battery size is bigger and becomes saturated. The optimum residential PV–battery systems can also reduce grid electricity peaks. Focusing on economic feasibility, the authors used NPV to compare the effects of direct battery subsidies and found that the subsidies were necessary to increase the economic feasibility of an investment. Furthermore, increasing the electricity price and decreasing the PV–battery cost could make such an investment more attractive. Similarly to Quoilin et al. [16], the authors addressed the self-consumption performance and the customer economics of residential PV–battery systems in European countries (the UK, France, and Portugal) and found that, to achieve 100% of PV self-consumption, there are two possible options: (1) oversizing the PV system and (2) installing a battery together with the PV system. The self-consumption performance was found to be a non-linear function of PV and battery size. Moreover, battery cost reductions and indirect subsidies (retail prices) were the two main factors affecting the economic feasibility of home PV–battery systems.

Nottrott et al. [17] simulated a linear programming routine to find an optimal energy storage dispatch pattern for minimizing demand change under a time-of-use scheme at a Californian campus. The NPV was also analyzed for finding an installed battery cost that would make an investment feasible. The results showed that investments in Li-ion batteries would be financially feasible at 400 USD/kWh or approximately 40% of 2011 market prices.

On the basis of the Thai context, Thirakiat and Tongsopit [18] studied the economic feasibility of PV–battery systems of small general service customers in Thailand. The authors compared the feasibility of a current time-of-use (ToU) rate and a special ToU rate, which was designed according to international electricity tariff reviews. The current ToU consists of an on-peak period and an off-peak period, whereas the special ToU was designed to have three periods (on-peak, regular, and off-peak). The on-peak of the special ToU is higher than that of the current ToU and the off-peak of the special ToU is lower than that of the current ToU, whereas the regular rate is in-between the rates of these two periods. The special ToU can increase the economic feasibility of PV–battery systems in Thailand; hence, the appropriate retail rate designs are necessary to promote PV–battery systems in the country.

The economic feasibility has been addressed as the indicator for evaluating the attractiveness of PV investments in Thailand and other countries [2,3,19-23]. This study represents a new approach to analyzing the benefits of PV–battery systems from the customer's perspective by considering important parameters, which are retail rate subscriptions, subsidies/incentives, system sizes, and system cost reductions, as discussed above. This approach also foresees the future situation of battery investment in Thailand to inform relevant stakeholders of the next generation of distributed energy.

3. Methodology

This study is categorized into two main sections: (1) base analysis and (2) impacts of policies and battery sizes, as illustrated in Fig. 1. Both technological and economic outputs were simulated with the System Advisor Model (SAM), which is a performance and financial model developed by the U.S. National Renewable Energy Laboratory (NREL) for renewable energy projects.

All PV generation is self-consumed first and any excess generation is stored in a battery from 8 a.m. to 3 p.m., then discharged to serve load. Any additional electricity demand is met by grid electricity. For the PV size, the PV capacity was assumed to be 5 kW on the basis of stakeholder consultation. PV installation in the country was reflected in terms of residential roof space and customer characterizations (i.e. income). Moreover, the comparison between annual 5 kW PV production and annual load consumption (PV-to-load ratio) is well-aligned with the study of Chaianong et al. [3] Focusing on battery type and size, Li-ion batteries were selected for this analysis. The size was determined by calculating the total

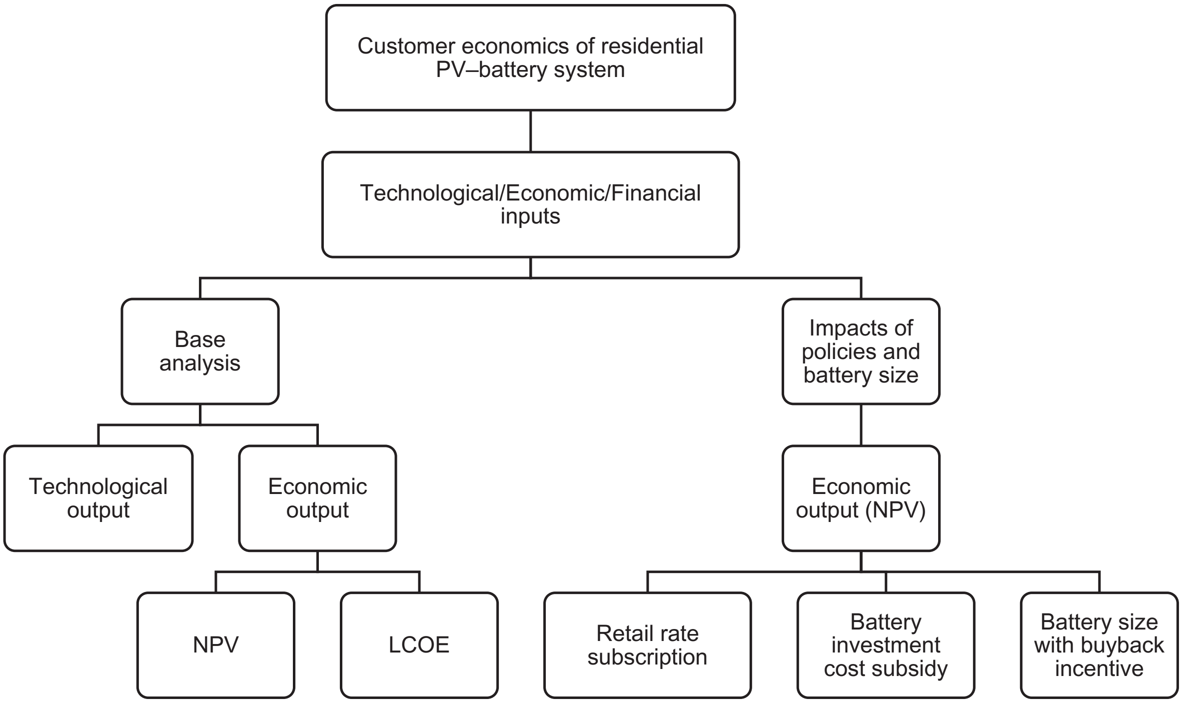


Fig. 1. Overview of calculation model (NPV is net present value and LCOE is levelized cost of electricity).

yearly PV surplus generation of a 5 kW PV-only system, which was assumed to be about 50% of maximum battery capacity for installation in the base analysis. The calculated battery size of 6.5 kWh was also considered from the point of view of market availability.

For the base analysis, the customer economics of residential PV–battery systems in Thailand were analyzed on the basis of a range of current battery costs from 500–1000 USD/kWh and an annual percentage of battery cost reduction of 4–12% to take battery price uncertainty into account.[2] The two main output parameters are (1) net present value (NPV) and (2) levelized cost of electricity (LCOE), as expressed by Equations (1) and (2), respectively. The NPV was selected to represent the project's feasibility, as the NPV gives a return benefit in currency and takes the time value of money into account while the LCOE was used to compare the PV–battery electricity price and grid electricity price. The NPV and the LCOE were calculated individually from SAM for the period of 2018–2036 stipulated by Thailand's Alternative Energy Development Plan (AEDP 2015).

$$\mathrm{NPV} = \sum_{0}^{n} \frac{C_n}{(1+i)^n} - C_0 \tag{1}$$

Where:

NPV is net present value (USD)
C_0 is initial capital cost (USD).
C_n is annual cash flow at time n (USD).
i is discount rate (%).
n is period of analysis (25 years).

$$\mathrm{LCOE} = \frac{C_0 + \sum_1^n \frac{C_n}{(1-i)^n}}{\sum_1^n \frac{Q_n}{(1-i)^n}} \tag{2}$$

Where:

LCOE is levelized cost of electricity (USD/kWh).
C_0 is initial capital cost (USD).
C_n is annual cost (USD).
Q_n is energy generated by the system in year n (kWh).
i is discount rate (%).
n is period of analysis (25 years).

The impacts of the four parameters were also taken into account: (1) retail rate subscriptions, (2) battery investment subsidies, (3) battery sizes, and (4) buyback incentives,[3] as explained in Table 1. In fact, battery sizes and buyback incentives were considered together and the other assumptions in the calculation remain the same.

First, for retail rate subscriptions, the default rate is a block rate as used in a base case. A current residential ToU rate[4] is also applied to compare between these two current residential retail rates in Thailand. Additionally, a sensitivity analysis of different retail rate designs is also included (a fixed flat rate[5] and potential options of

[2] Current battery costs and annual percentages of battery cost reduction were taken from international markets (anonymous battery companies) as of August 2018 and from the literature on battery cost forecasts [5–10].

[3] Buyback incentive means the specific rate at which distribution utilities buy excess PV electricity from residential customers who have installed PV or PV–battery systems.

[4] Basically, residential customers in Thailand have two options (normal block rate and on/off-peak rates). The normal block rate does not take the time period into account, on/off-peak rate does. The customers are charged more during the on-peak period. On-peak period includes Monday–Friday from 9 a.m. to 10 p.m.) and off-peak period includes Monday–Friday from 10 p.m. to 9 a.m., Saturday, Sunday, and official holidays (See Table 6 for details).

[5] The concept was adopted from a regulated rate of Singapore's Energy Market Authority and the flat rate was assumed to be the highest tier of current Thai residential block rate (0.122 USD/kWh; see Table 6).

Table 1
Four selected parameters.

Parameters	Base Analysis	Impacts of policies and battery sizes
Retail rate subscriptions	Normal block rate	On/off-peak rate (ToU rate) and fixed flat rate
Battery investment subsidies (%)	0% every year	30% for the first 10 years; 20% for the remaining years
Relative battery capacities (kWh battery/kW PV)	1.3 (6.5 kWh/5 kW)	0.2–2
Buyback incentives (USD/kWh)	0	Average wholesale rate = 0.07 USD/kWh (2.6 Thai baht/kWh)

Table 2
Technological assumptions.

Parameters	Inputs
PV	
PV size (kW)	5
Module Type	Standard (Crystalline Silicon)
Nominal Efficiency (%)	15
Module Cover	Glass
Temperature Coefficient of Power (%/Celsius)	−0.47
DC to AC ratio	1.1
Inverter Efficiency (%)	96
Orientation	Facing South
Array Type	Fixed Open Rack
Tilt (degrees)	13.7
Azimuth (degrees)	180
System Losses (%)	14.08
Battery	
Battery type	Li-ion
Battery size (kWh/kW)	6.5
Battery charge period	8 a.m.-3 p.m.
Battery discharge period	After 3 p.m.

ToU that are currently not in force[6]). Second, battery investment subsidies were assumed to be 30% in the first 10 years, as is the case in Germany [24], and assumed to be 20% for the remaining years. Third, relative battery capacity was also discussed in Refs. [7,15] as the ratio of battery size in kWh to PV size in kW, which ranges from 0.2 to 2 in this study. Last, the buyback incentives were determined as an average wholesale rate, which was taken from the weighted average wholesale rate at a voltage level of 69–115 kV as of 2017, which is the rate for distribution utilities that buy electricity from a generation/transmission utility in Thailand. Moreover, the Thai government is considering an average wholesale rate as a buyback incentive for surplus PV electricity at the time of writing this study [25].

All assumptions are, then, summarized in Tables 2–6. The technological assumptions, including weather data,[7] were selected mainly on the basis of SAM's default values for a given PV module and battery type [28]. Also, some technical parameters (system size, orientation, tilt, azimuth angle) were addressed according to country-specific contexts. Economic and financial parameters were taken with respect to Thailand's market.

Apart from these assumptions, a load profile of residential customers is needed to perform the analysis. The hourly average residential load profile was collected from the Metropolitan Electricity Authority (MEA), which is the distribution utility that is responsible for Bangkok and two neighboring provinces (Nonthaburi and Samut Prakarn). We also selected the sub-group of the residential load profiles that had a monthly consumption greater than 150 kWh/month, since such customers were expected to install PV–battery systems. This load profile was scaled to meet the

[6] The potential options of ToU include: (1) increasing on/off peak charges by 10% and 15% with same on/off peak time, (2) shortening on-peak period from 9 a.m.-10 p.m. to 9 a.m.- 4 p.m. & 9 a.m.- 6 p.m. with same on/off peak charges, and (3) including carbon dioxide (CO_2) price into on/off peak chargesTotal CO_2 price = (CO_2 price; USD/g) x (CO_2 intensity of power sector; g/kWh).The reginal CO_2 price was assumed to use in the calculation based on World Energy Outlook 2018 [26] (8 USD/tonne in 2018 and 27 USD/tonne in 2036; it was estimated to decrease linearly within the analysis period).The CO_2 intensity was obtained from Energy Policy and Planning Office of Thailand and predicted linearly based on current data/policy and historical trend [27] (570 g/kWh in 2018 and 364 g/kWh in 2036).

[7] Hourly weather file in the SAM database for the weather of one year in Thailand.

Table 3
Residential installed PV and other costs (based on Thailand's market) for residential scale (Exchange rate: 35 THB/USD throughout the analysis).

PV installation costs	
PV installation costs (USD/W)	1.43
Other costs	
Operating and maintenance costs (USD/year)	142.86
Insurance costs (% of installation costs)	0.25

Note: (1) Inverters (which constitute about 17% of PV installation costs) were assumed to be replaced every 11 years; (2) PV installation cost reductions were assumed to be 4% per year as elaborated in Ref. [11]; (3) Operating and maintenance costs (cleaning, safety, repairs, etc.) include costs related to ensuring that PV remains in good and safe conditions while performing satisfactorily.

Table 4
Battery installation costs (based on international market and literature).

Battery costs	
AC battery costs (USD/kWh) (Replacement in year 11)	500-1000
Battery cost reductions per year (%)	4–12

Note: An AC battery is a DC battery with an AC battery inverter.

Table 5
Financial parameters (based on Thailand's market) for residential scale.

Financial Parameters	
Inflation rate (%)	1.5
Real discount rate (%)	2.89

Table 6
Retail rates.

(a) Residential scale with block rates[a]	
Block rate	Rate
1–150 units (USD/kWh)	0.088
151–400 units (USD/kWh)	0.116
Over 400 units (USD/kWh)	0.122
Fixed charge (USD/month)	1.092
(b) Residential scale with time-of-use (ToU) rate	
ToU rate (Voltage level < 12 kV)	Rate
On-peak (USD/kWh)	0.161
Off-peak (USD/kWh)	0.071
Fixed charge (USD/month)	1.092

Note: (1) ToU tariffs are classified by on-peak (Monday–Friday from 9 a.m. to 10 p.m.) and off-peak (Monday–Friday from 10 p.m. to 9 a.m., Saturday, Sunday, and official holidays); (2) nominal retail growth rate is 1.89% according to historical data and Thailand's Power Development Plan (PDP 2015–2036).
[a] The retail growth rate was also applied to all sensitivity cases of rate design.

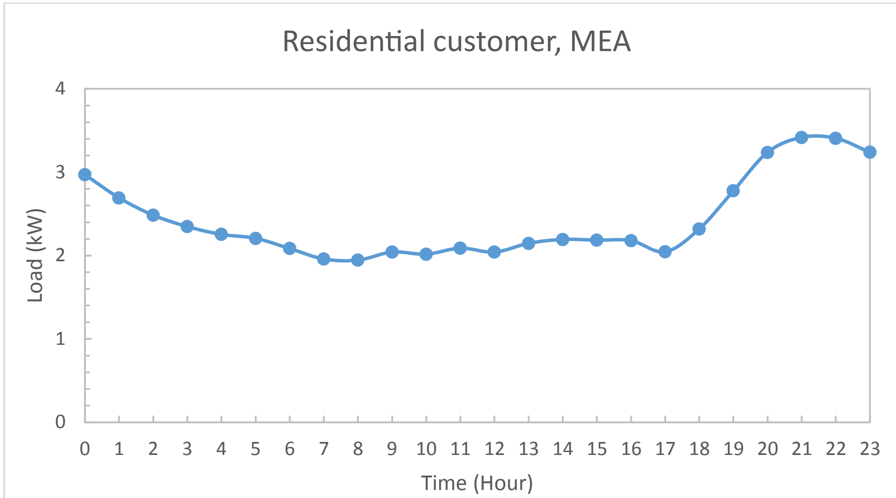


Fig. 2. Scaled hourly residential load profiles (Average day in 2015).

appropriate PV-to-load ratio as discussed in Ref. [3]. The scaled hourly load profile representing an average day in 2015 is shown in Fig. 2.

4. Results and discussions

4.1. Base analysis

First, the technical analysis is discussed to visualize the flow of electricity, as illustrated in Fig. 3. The PV system was simulated on the basis of Fig. 3(a) to generate electricity during the day to serve load. Since there is a mismatch between the residential load profile (blue line in Fig. 3 (a)) and PV production (orange line in Fig. 3 (a)), some of the surplus PV production was assumed to be stored in a battery while the remainder was exported to the grid. The battery was assumed to be charged from a PV–battery system only from 8 a.m. to 3 p.m. Thus, the electricity from the grid to the battery was zero at all times (see Fig. 3 (b) for battery dispatch patterns). It is also worth noting that the PV generation was simulated to meet load first before the battery was charged. After that, the electricity from the battery was simulated to serve load after 3 p.m., as shown by the orange lines in Fig. 3. In addition, the percentage of simulated battery efficiency was about 90%, implying that there were some electricity losses in the battery.

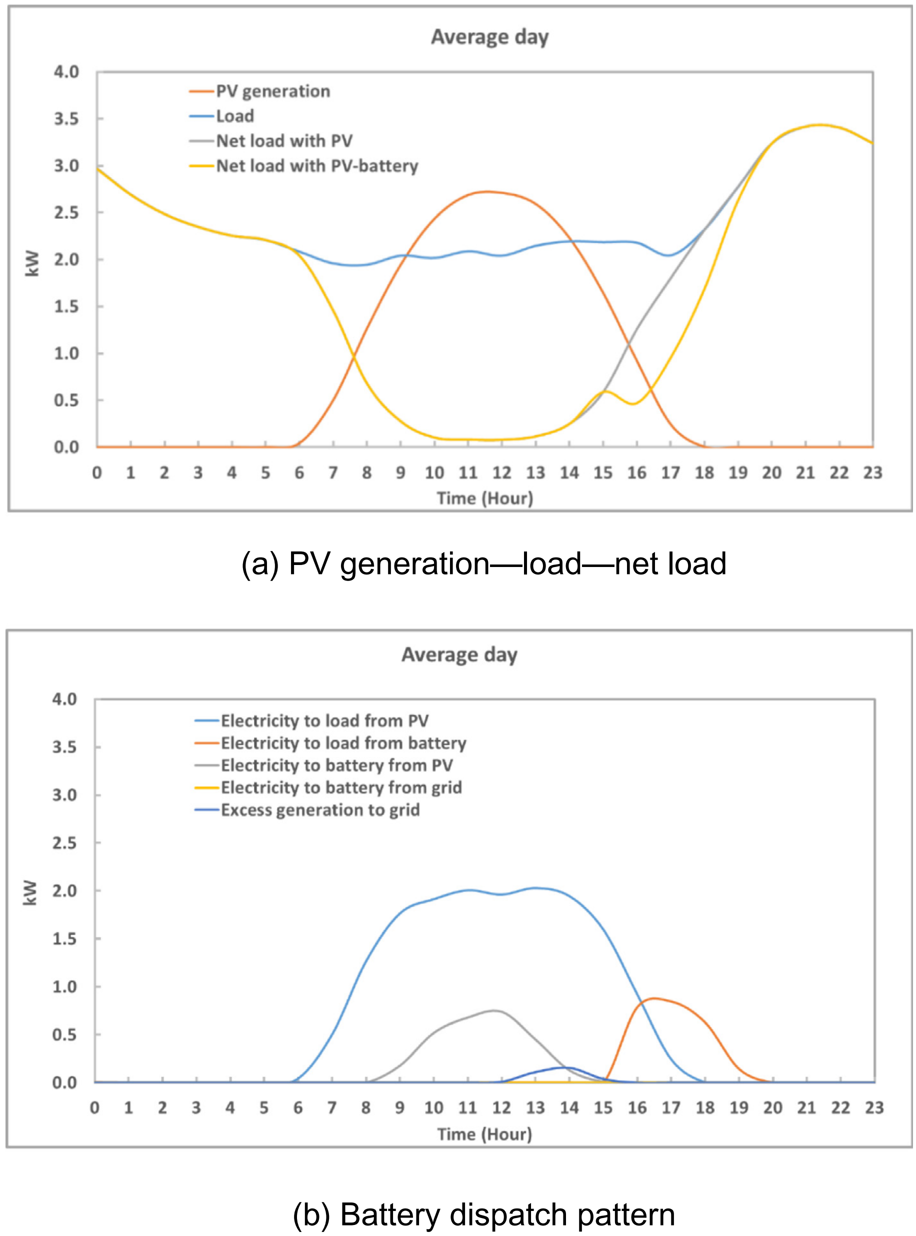
Fig. 4 also illustrates the flow of electricity as discussed above. The percentage of self-consumption is 97% while the percentage of surplus electricity to the grid is 2% and the remaining 1% is for battery loss. Self-consumed electricity comes mainly from PV production (87%) while about 13% is from battery discharges. When comparing the net load of a PV-only system (grey line in Fig. 3 (a)) and the net load of a PV–battery system (yellow line in Fig. 3 (a)), the difference occurs at about 3 p.m. onward when the battery starts discharging electricity to serve load. Therefore, it is noticeable from the results that the use of a battery could (1) increase the self-consumption ratio (from 84% to 97% of total electricity generation from PV) and (2) decrease the amount of surplus electricity fed to the grid (from 16% to 1% of total electricity generation from PV).

Next, the economic analysis of the base analysis is discussed. As was stated, NPV and LCOE are the two main output parameters. The NPV and LCOE results of installations in different years from 2018 to 2036 are presented in Fig. 5-Fig. 6, respectively. The NPV of the residential PV–battery system can be negative or positive and in 2018, it ranges from −2900 to 2600 USD according to the assumptions about the battery costs and their reductions per year. Thus, it is worth noting that the battery costs and their reductions are one of the important factors affecting the feasibility of PV–battery investments. Moreover, in 2021, the NPVs are all positive even for the highest battery costs and lowest percentages of annual battery cost reductions. The NPVs range from about 660–5800 USD with the battery costs assumed to be about 340–890 USD/kWh. The NPV becomes higher over time, implying that the residential PV–battery system investment becomes more feasible because of lower PV–battery installation costs and the expected increase in the retail rate, as had been assumed in this analysis.

The NPV of the residential PV–battery system was also compared to the NPV of the residential PV-only system. It is worth noting that the PV cost was assumed to be about 1.4 USD/W and its reduction was assumed to be at 4% per year. Thus, the NPV of the residential PV-only system has a specific value, rather than a range of values, for each year. Fig. 5 shows that when considering from NPV, PV–battery systems can compete with PV-only systems starting in 2029 at some levels of battery costs (i.e. the minimum cost is about 120 USD/kWh and its reduction is 12%). However, when battery costs are lower, a PV–battery system is expected to compete with a PV-only system at various levels of battery cost. Thus, residential prosumers would become interested in investing in battery systems together with PV installations.

Apart from NPV, LCOE is also presented in Fig. 6 to compare the PV–battery system costs to grid electricity costs in order to illustrate when PV–battery electricity can reach grid parity. As for now, the LCOEs of PV–battery systems range from 0.15 to 0.21 USD/kWh while the average retail rate is 0.10 USD/kWh. At all levels of battery costs and their reductions, the LCOEs of the PV–battery systems are still not able to reach grid parity, i.e., the LCOEs are higher than the grid electricity price, even though there are some levels that make NPV positive, as discussed above. This is because the NPV calculation includes the dynamic changes in retail rate over a period of analysis that makes NPV positive from 2021 onward while the competitive LCOE is reached later.

When the PV–battery system is cheaper, its LCOE can compete with the grid electricity price from 2026 onward. The minimum LCOE and grid electricity price in 2026 are expected to be 0.13 USD/kWh when the battery cost is about 180 USD/kWh. It is also worth noting that, from 2031 onward, the LCOE is lower than the



(a) PV generation—load—net load

(b) Battery dispatch pattern

Fig. 3. Electricity profiles from residential PV–battery systems (Average day).

projected grid electricity price under all assumed conditions to help ensure that PV–battery systems can become feasible as compared to projected grid electricity price and a PV-only system when the battery price is about 100 USD/kWh, which would require more than 10 years from now, depending on current battery costs and annual cost reductions.

4.2. *Impacts of policies and battery sizes*

As stated in the Methodology section, four parameters (retail rate subscriptions, battery investment subsidies, battery sizes, and buyback incentives) were selected for the impact analysis for an understanding of how NPV would change from the base analysis.

4.2.1. *Retail rate subscriptions*

When changing the residential retail rate subscriptions from the normal block rate to on/off-peak rates, the NPV of the PV–battery system is sensitive to the ToU rate, as the NPV is higher than that of the base analysis, as shown in Fig. 7 (all NPVs become positive from 2020 onward), because self-consumed PV electricity is consumed during the on-peak period when the grid electricity price is higher than the average residential block rate, leading to higher NPV under the ToU rate subscription. Moreover, the ToU rate helps the PV–battery system to become positive and able to compete with PV-only systems faster than the rate of the base analysis. It is also worth noting that, with the ToU rate, almost all levels of battery costs and their reductions make the NPV of the PV–battery system higher or equal to the NPV of the PV-only system in 2036, which is not the case for the results of the base analysis.

4.2.1.1. Sensitivity analysis. Apart from the current residential block rate and ToU rate, a sensitivity analysis of retail rate designs were conducted. The results are illustrated in Fig. 8 (a)-(c). Fig. 8 (a)

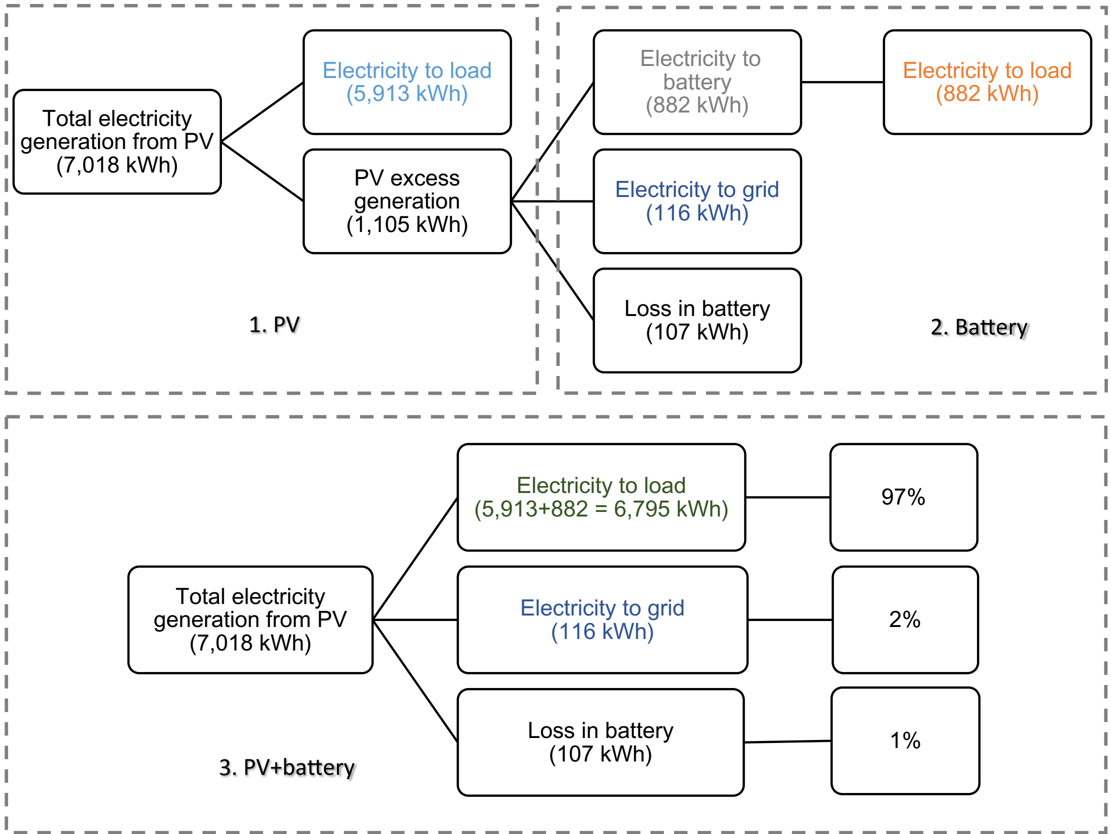


Fig. 4. Flow of electricity in PV–battery system (illustrative). The below box (3. PV + battery) is the integration of two above boxes (1.PV & 2. Battery).

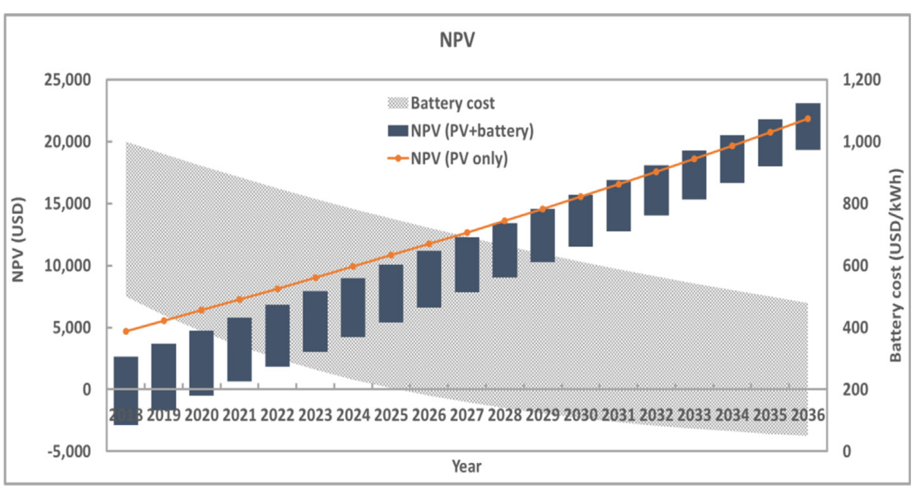


Fig. 5. NPVs of residential PV–battery systems installed in different years from 2018 to 2036 (base analysis).

shows NPVs of a residential PV–battery project installed in different years from 2018 to 2036 by different retail rate designs. Fig. 8 (b) and Fig. 8 (c) show examples of NPVs of a residential PV–battery project installed in 2019 and 2036, respectively. They visualize the impact of different retail rate designs on NPV results. It is found that NPV is sensitive to retail rate designs and the detailed results are summarized as follows.

- There are hardly any differences between block rate and fixed flat rate since the assumed retail rates are not much different.
- Focusing on the sensitivity analysis with different ToU designs:
  - Increasing on/off peak charges significantly affects NPV. Under these conditions, such an investment becomes economically feasible when on/off peak charges increase more than or equal to 10%, even with the high assumed battery cost (i.e. an installed project in 2019- see Fig. 8 (b)).
  - Shortening on-peak period till 6 p.m. does not significantly impact NPV values, but shortening to 4 p.m. has a significant effect. This is because there is a peak of discharge from battery around this time (see Fig. 3 (b)) and NPV decreases since electricity from PV-battery is more expensive than off-peak rates.

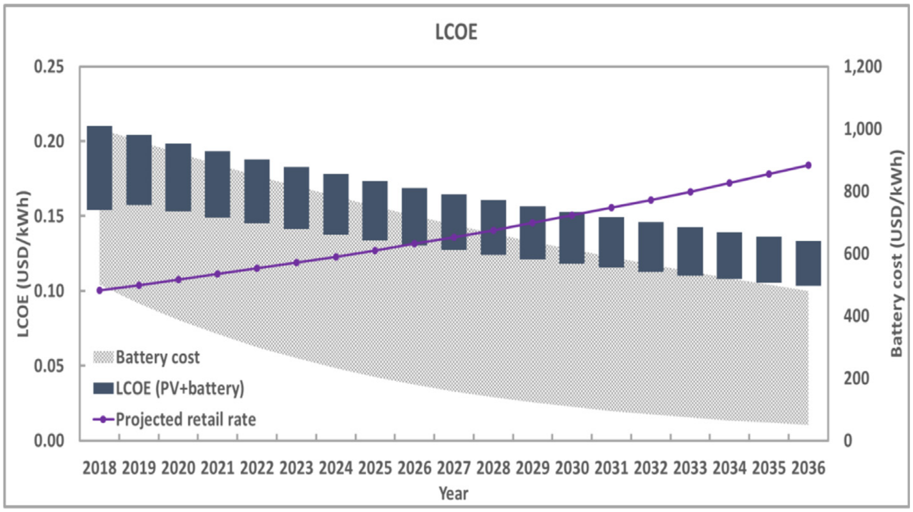


Fig. 6. LCOEs of residential PV–battery systems installed in different years from 2018 to 2036 (base analysis).

 ○ Including CO_2 price increases NPV more than the current ToU case but still less than on/off peak charges (of 10% and 15%).
- Overall, ToU rate performs better than block rate and fixed flat rate, even when adjusting the on-peak period to 9am-4pm. Increasing ToU energy charges (either in terms of CO_2 price or fixed percentage) can positively affect NPV values.

4.2.2. *Battery investment subsidies*

Battery investment subsidies were assumed to be 30% for the first 10 years, later decreasing to 20% for the remaining years to help increase NPV significantly from the base analysis, which has no battery investment subsidies, as seen in Fig. 9. Even in 2018, almost all levels of battery costs can make NPV positive. Moreover, starting from 2019, PV–battery systems will be able to compete with PV-only systems at low battery costs and high reductions. As with the ToU rate, almost all levels of battery costs and their reductions allow the NPVs of PV–battery systems compete with PV-only systems in 2036 because the investment subsidies bring the battery system costs down to make investments more economically feasible.

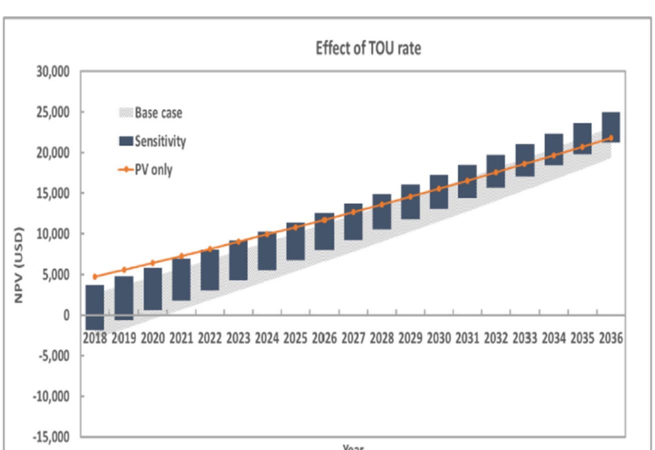
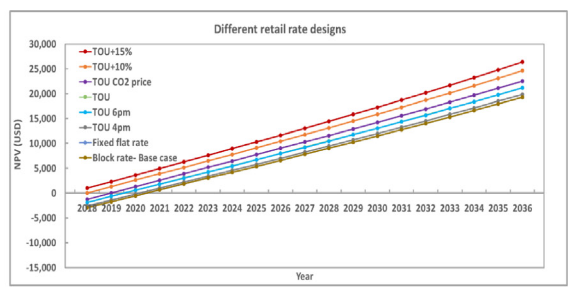


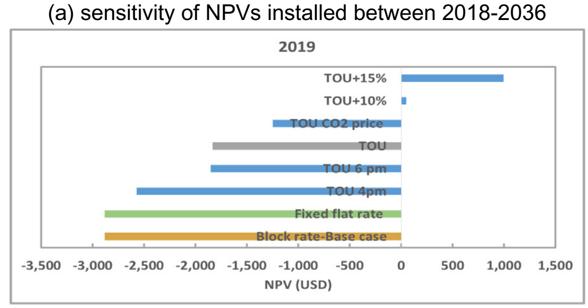
Fig. 7. Effect of ToU rate on NPV of residential PV–battery systems installed in different years from 2018 to 2036.

4.2.3. *Battery system sizes with buyback incentives*

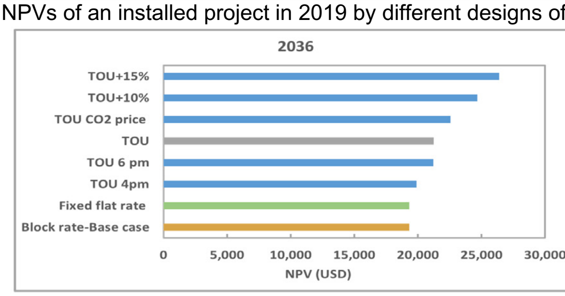
Battery size is another important parameter that needs to be considered. In this section, the relative battery capacity (kWh of



(a) sensitivity of NPVs installed between 2018-2036



(b) NPVs of an installed project in 2019 by different designs of rates



(c) NPVs of an installed project in 2036 by different designs of rates

Fig. 8. Effect of different retail rate designs on NPV of residential PV–battery systems. Note: for the case of highest battery cost and lowest its cost reduction (current battery cost = 1000 USD/kWh with 4% cost reduction annually). (a) sensitivity of NPVs installed between 2018 and 2036. (b) NPVs of an installed project in 2019 by different designs of rates. (c) NPVs of an installed project in 2036 by different designs of rates.

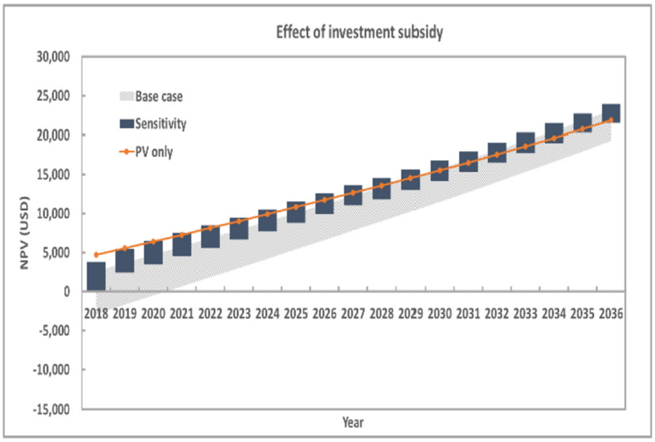


Fig. 9. Effects of battery investment subsidies on NPV of residential PV–battery systems installed in different years from 2018 to 2036.

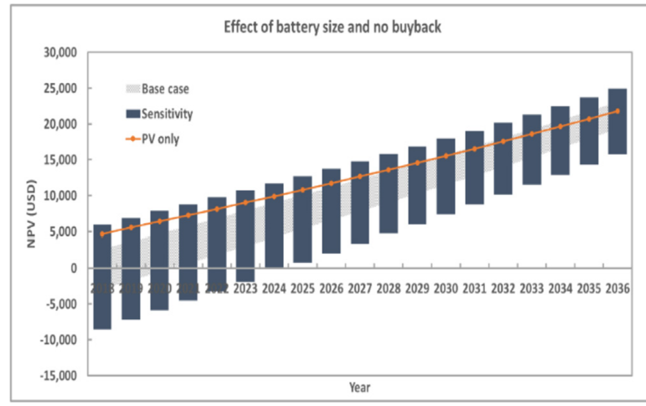


Fig. 11. Effect of battery size without buyback incentive on NPV of residential PV–battery systems installed in different years from 2018 to 2036.

battery/kW of PV) was varied from 0.2 to 2. First, Fig. 10 shows the self-consumption ratios of PV–battery systems under various battery system sizes. The self-consumption ratio is the ratio of total self-consumed electricity to total electricity generation from a PV–battery system. With a PV-only system, the self-consumption ratio is 84%. Ranging the relative battery capacity to PV size, it was found that the self-consumption ratios are between 87% and 98%. Even under the largest battery size, the self-consumption ratio cannot reach 100% because of some electricity losses in the battery during the charging/discharging processes. The self-consumption ratio increases because PV electricity can be stored in a battery and consumed later. Thus, there is almost no excess electricity fed back to the grid. The excess generation ratio drops from 16% when there is no battery to 0.01% when the relative battery capacity is 2. As discussed earlier for the base analysis, these results also confirm that the use of batteries can increase the self-consumption ratios and decrease the excess electricity from the PV system to the grid.

Larger battery sizes decrease NPV significantly, as shown in Fig. 11 and Fig. 12 because they introduce high capital costs that may not be recoverable. It is also interesting to see that with low battery costs and high-cost reductions, PV with small battery systems can compete with PV-only systems for now because there are low additional battery investments.

Considering the buyback incentives, it was assumed that all excess PV generation would be fed back to the grid and residential customers would either receive nothing or be paid at the average wholesale rate per unit. It was found that buyback incentives had small impacts on NPV, since the buyback rate is not so high and there is a limited amount of excess PV generation. For both cases of with and without a buyback rate, starting in 2024, the NPVs of all system sizes become positive. The buyback rate can increase the NPVs of small battery sizes (i.e. relative battery capacities are 0.2–1) because of the amount of excess PV generation. On the other hand, the buyback rate does not significantly impact NPV when the battery size is large enough to store almost all excess PV generation (i.e. relative battery capacities are more than 1. See Fig. 10 for the amount of excess PV generation).

4.3. Government payment comparison

As mentioned before, the use of a battery with a PV system can address the mismatch between the residential load profile and PV production profile, so a PV–battery system is expected to reduce grid integration costs, since the use of the battery can increase the PV self-consumption ratio. The integration costs are related to power system upgrades and balancing issues to accommodate surplus PV. Furthermore, both battery investment subsidies and buyback

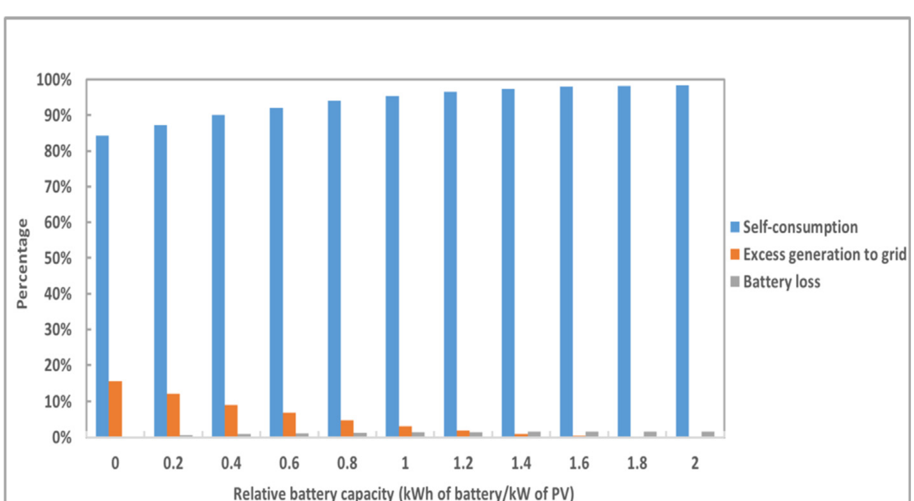


Fig. 10. Self-consumption ratio of PV–battery system with various battery sizes. The relative battery capacity at zero denotes the PV-only system.

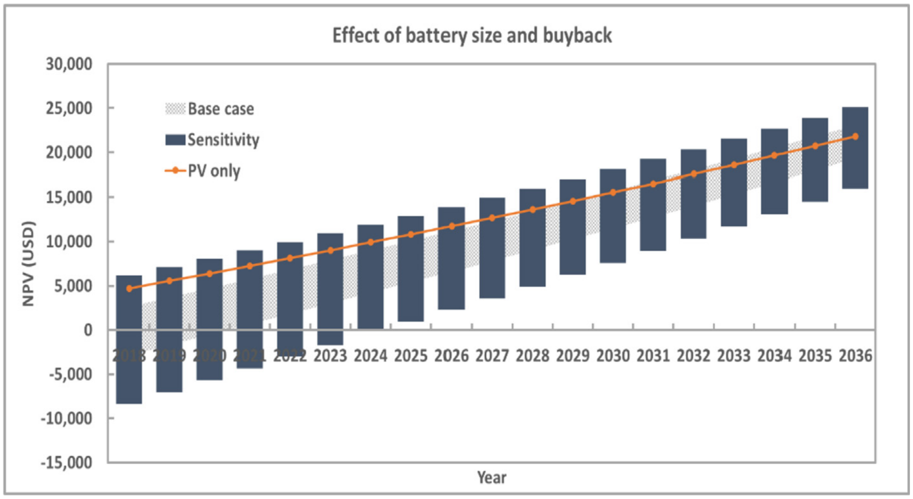


Fig. 12. Effect of battery size with buyback incentive (at an average wholesale rate) on NPV of residential PV–battery systems installed in different years from 2018 to 2036.

Table 7
Comparison of government payments under assumed PV adoptions.

	Payment (USD)	Savings (USD)	Savings (%)
Base (without battery)	114,434,286	–	–
Battery investment subsidy	*Integration cost* = 29,817,384 *Battery investment subsidy* = 22,909,375 to 114,938,957 *Total payment* = 52,726,759 to 144,756,341	−30,322,055 to 61,707,527	−26%–54%
Buyback incentive	*Integration cost* = 29,817,384 *Buyback incentive* = 47,186,345 *Total payment* = 77,003,729	37,430,557	33%

incentives can increase the return on PV–battery investments. This section discusses if the government would be able to save grid integration costs by promoting the use of batteries through investment subsidies and buyback incentives,[8] i.e., if the costs from subsidies and feed-ins are fully compensated for by avoiding the accommodation of PV into the networks.

Table 7 shows the government payments under the (1) normal integration costs of the PV-only system, (2) integration costs of PV–battery systems and battery investment subsidies, and (3) integration costs of PV–battery systems and buyback incentives. It is evident that the PV integration costs are reduced as a result of the batteries. However, the government should subsidize the installations of battery systems; otherwise, the returns would be too low to act as incentives for individual households. It is evident from Table 7 that the government could save money when paying the grid integration costs by increasing the use of PV–battery systems. The savings would depend on the types of subsidies/incentives. For the buyback incentives under all assumptions, the payment savings are 33%. However, for investment subsidies, the savings range from −26 to 54% depending on the current battery costs and their reductions. If the battery costs are too high, the government must pay more to encourage people to install PV–battery systems whose costs would not be higher than the decrease in the grid integration costs.

Table 8 illustrates the government's payment for one household PV–battery system in 2036. This table only aims to depict the payment calculations and grid integration cost savings. The savings depend on the types of subsidies/incentives. For investment subsidies, the subsidy levels depend on current battery costs and their reductions over time. Thus, the payment savings range between 3 and 67% (the savings are all positive in 2036 because of low battery installation costs). On the other hand, for buyback incentives, the incentive levels were assumed to be equal to an average wholesale rate from today until 2036. Therefore, the payment savings are an individual figure of 68%.

It is also worth noting that these calculations are only rough estimations by a specific analysis (as discussed in Footnote 9). The use of a battery can certainly decrease grid integration costs, whereas the type of subsidy/incentive needed depends on several factors (i.e. subsidy/incentive type and level, battery costs, self-consumption ratios, etc.). For example, buyback incentives do matter in this calculation because there is some excess PV generation fed back to the grid. If the battery size is very large (high battery investment costs and high self-consumption ratios), then the buyback incentives do not affect the NPV. Thus, it may be reasonable to provide battery investment subsidies, rather than buyback incentives, to reduce the high upfront costs.

5. Discussion

As seen clearly from the results, the use of a battery can increase the self-consumption ratios of residential PV production, leading to lower feed-in of excess PV generation, which is beneficial to utilities. However, as shown by the base analysis, with current battery

[8] For this calculation, residential PV adoption was assumed to be 4216 MW in 2036 while the annual residential PV adoption can be found in Chaianong et al. [11]. This is the maximum forecast among the eight scenarios of this analysis. Moreover, the integration costs of the PV-only systems were assumed to be 27 USD/kW for generation/transmission/distribution system [29] and the percentage of the integration cost reduction with the inclusion of batteries was 74%, which was calculated from Ref. [30]. All other assumptions remain the same as those of the base analysis.

Table 8
Government payments (for 1 PV–battery system only in 2036).

	Payment (USD)	Savings (USD)	Savings (%)
Base (without battery)	136	–	–
Battery investment subsidy	*Integration cost* = 35 *Battery investment subsidy* = 10–96 *Total payment* = 45–131	5 to 91	3%–67%
Buyback incentive	*Integration cost* = 35 *Buyback incentive* = 9 *Total payment* = 44	92	68%

costs and their projections, PV–battery systems are still not profitable because of the high upfront costs. This is aligned with the study from Germany and Japan [7,31]. However, with decreasing battery installation costs, investments seem to be more economically feasible and can even compete with PV-only systems in some situations. Such situation would happen when the battery price is about 100 USD/kWh, which is also in line with [9] and would require more than 10 years as suggested by the base results.

Looking at the policies and battery sizes, the buyback rate seems to affect NPV less than do other parameters if the battery size is appropriate (i.e. the relative battery capacity (kWh of battery size/kW of PV) is greater than 1; see Fig. 10). The ToU rate can also increase NPV. This is because PV electricity is self-consumed during on-peak period (the on-peak rate is higher than the average block rate in the base analysis). As also discussed in Ref. [18], the high on-peak during daytime and low off-peak during night time lead to high returns on investment of PV-battery system. Thus, it implies the importance of retail rate design as one of the policy options to encourage people to install PV-battery. Moreover, battery size and cost seem to be the most important parameters that can affect returns significantly. It is also obvious from all the analyzed cases that higher changes in NPV occur only at the beginning of the period of analysis. When battery costs can compete with other technologies, all four parameters become less significant.

The implications of results for the relevant stakeholders are summarized below.

- *Residential customers*
  - Batteries help to increase the PV self-consumption ratio.
  - Battery size is also important for affecting the feasibility. Thus, it is necessary for each individual system to size their PV–battery system properly by focusing on the individual load profile and the preferable PV self-consumption level.
  - Even though PV–battery systems are economically feasible, it is uncertain that most residential customers would adopt this new technology because of many reasons. For example, newcomers may prefer to invest in other business options rather than PV–battery systems.
- *Policymakers/government*
  - Since PV–battery system investment is not yet economically feasible, it is necessary to provide some measures (i.e. investment subsidies or buyback incentives) to reduce system costs. After the battery system costs are low enough to compete with grid electricity, such subsidies may not be necessary anymore.
  - It has been proven by the example of government payment calculation that subsidies/incentives for batteries are worth comparing to the PV grid integration costs. The government can save money on paying the PV grid integration costs by supporting the use of PV–battery systems, as discussed in Section 4.3.
- *Utilities and regulators*
  - Batteries help to decrease excess generation that would be beneficial to the grid. However, when residential customers tend to increase their self-consumption, the utilities experience higher revenue losses, which are passed on to ratepayers in terms of increases in retail rates. Therefore, it is necessary for the utilities to compare costs and benefits.
  - There are also some mitigation measures for dealing with the utility death spiral, as discussed in Refs. [32,33]. The regulators may need to revise the electricity tariff structure to truly reflect the cost of electricity in each interval during each day, as retail rate affects the feasibility of PV–battery systems. Moreover, it is worth addressing the motivation of each utility in its pursuit of new business models (changing from traditional cost-of-service to performance-based regulation), as discussed in Ref. [34]. However, it is necessary to consider these mitigation measures in a Thai context (i.e. current laws/regulations) to implement such measures successfully.

6. Conclusions

As battery costs continue to decline, interest in the use of batteries together with rooftop PV is growing. There is a mismatch between the load profiles and PV generation of residential customers in the country. This mismatch can be mitigated by using batteries. This analysis addresses the customer economics of residential PV–battery systems in Thailand and includes an impact analysis of retail rate subscriptions, battery investment subsidies, battery sizes, and buyback incentives.

Because of the high upfront costs of batteries, PV–battery investment is still not feasible and PV–battery costs are still higher than the grid electricity price. However, with declining PV–battery costs and increasing electricity retail rates, residential PV–battery systems are expected to be feasible and able to compete with grid electricity or PV-only systems. Such a scenario would happen when battery installation costs are about 100 USD/kWh (without any financial support), which would take more than 10 years from today, depending on the current battery costs and the actual declines in the costs per year.

According to the impact analysis, the ToU rate helps increase the NPV because the ToU rate increases the amount of bill savings (on-peak retail rates are higher than the average normal block rate). Apart from the ToU rate, battery sizes and their costs are one of the important parameters significantly affecting the feasibility of PV–battery investment and PV self-consumption ratios. Moreover, buyback incentives can help make PV–battery investments attractive when there is excess PV generation.

It is also clear from this analysis that the use of PV–battery systems can reduce grid integration costs. The financial effect is positive, even if the government pay subsidies/incentives to encourage residential customers to install PV–battery systems. This does not apply in the case of high battery investment costs, which call for high investment subsidies. However, the type and level of subsidies/incentives should be considered carefully. If the government would like to encourage residential customers to self-consume their PV electricity fully, it is necessary for them to size their systems appropriately, so buyback incentives would seem to be unnecessary, but battery costs are still a large burden. The government should support investment subsidies to make such investments feasible.

To sum up, it is important for residential customers to size their PV–battery systems appropriately by considering their load profiles and self-consumption levels. Since there is a burden due to the high battery costs, the government should provide financial support to make investments economically attractive. When battery costs are low enough, PV–battery systems can compete with other technologies and supporting measures/subsidies are not required. Moreover, the utilities and regulators in Thailand must conduct major adaptations in their organizations to increase the use of PV–battery systems.

Our study has some limitations that would be interesting for future works to address. First, battery technology was limited to a typical Li-ion battery in the simulation program. There are other battery types and battery efficiency models in the market that were not taken into account. Second, it would be good to model the NPV with individual load profiles, rather than average data, in order to understand how individual load profiles affect NPV. Third, apart from increasing PV self-consumption, batteries also have an energy arbitrage function, i.e. storing grid electricity during off-peak to consume during on-peak when the grid electricity price is higher. With this combination, it is worth seeing how NPV would change. Finally, an assumption about an increase in the retail rate was taken from Thailand's power development plan. This assumption would probably not reflect the actual electricity costs with the increasing rooftop PV systems that would affect the feasibility calculation of PV–battery investments in Thailand.

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