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Forecast of Rooftop PV Adoption in Thailand

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ABSTRACT

As the interest in rooftop photovoltaic (PV) systems has increased in Thailand, it is necessary to evaluate issues on grid integration and policy impacts. This study establishes a systematic approach to forecasting annual PV adoption that is necessary to analyze PV impacts of future actions in Thailand. A "Customer-adoption Model" was selected to forecast PV adoption until 2036. The payback period is the main indicator for addressing total PV adoption in 2036 and the Bass diffusion model is used to address annual PV adoption for four customer groups (residential scale, small general service, medium general service, and large general service). The two main parameters, buyback rate and PV installation cost reduction, are included to forecast PV adoption for eight scenarios. Under the assumption of a two percent annual PV cost reduction and no buyback rate, Thailand's solar PV goal can be achieved in 2025, instead of 2036. Also, in 2036, PV is expected to constitute about 9%–14% of the energy basis of the overall system. Thai utilities should not only focus on total PV adoption but also consider annual PV adoption, since utilities need to prepare their power systems and staffs before hosting PV every year.

Keywords: PV adoption; Forecast; Rooftop PV; Solar PV; Thailand

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1. Introduction

Renewable energy for electricity, especially from solar PV, has been of interest in Thailand due to several drivers, including a decrease in PV installation costs and an increase in supportive policies, such as a fixed Feed-in Tariff (FiT) scheme. As of now, Thailand's long-term Alternative Energy Development Plan 2015–2036 (AEDP 2015) includes targets of a 30-percent share of renewable energy in final energy consumption in 2036 and also has specific targets for each type of renewable. Focusing on solar PV (ground-mounted PV and rooftop PV), Thailand has set a target of 6,000 MW to be achieved by 2036. According to the public data of Thailand's Energy Regulatory Commission (ERC), the total installed capacity of PV is approximately 3,211 MW as of 2017[1], which means that about 2,800 MW is left to meet the AEDP's goal.

At this point, the Thai government tends to pay attention to new rooftop PV installations more than to ground-mounted PV. In 2016, a new rooftop PV support scheme was announced with a shift from the FiT scheme to a self-consumption scheme. This means that rooftop PV electricity needs to be self-consumed first and excess generation to the grid may be compensated at a defined buyback rate. However, there has been only a self-consumption pilot project without compensation for excess electricity injected back into the grid. The Thai government will launch a new support policy for rooftop PV based on an evaluation of the pilot project with compensation for excess electricity at a defined buyback rate, but the details of the upcoming support policy are not yet confirmed [1].

There are many concerns from stakeholders, especially utility companies, about the technical and economic impacts of a large adoption of rooftop PV on power systems. These concerns may slow down the adoption of the new policy, so one possible way to create a more supportive environment is to examine the benefits and costs of PV, the implications for utility business models and planning, and electricity rate structures, as has been done in many studies [2-10].

In order to perform such analysis, it is necessary to forecast rooftop PV adoption for each year. However, apart from the long-term goal of solar PV, Thailand still lacks annual forecasts of rooftop PV to address stakeholders' planning and policy implications precisely.

This study forecasts PV[2] adoption and focuses on the four customer groups of Thailand's two power distribution utility companies: The Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA). MEA is responsible for Bangkok and two neighboring provinces (Nonthaburi and Samut Prakarn) while PEA is responsible for the remaining provinces of Thailand. Also, the forecasts of PV adoption by the areas of MEA and PEA have been summed up to address the whole country. In addition, PV forecasts have been made for eight scenarios by varying the buyback rate of excess PV generation and the percentage of cost reduction of annual PV installation.

2. Background

Existing methods to address renewable generation potential have been done for several aspects, as illustrated in Fig. 1 [11]. The largest potential is the resource potential, which is the amount of physical energy content available from resources, such as the sun's radiation for solar energy. Technical potential focuses on actual geographic land-use and system

[1] About 188 MW for rooftop PV (6%) and 3,023 MW (94%) for ground-mounted solar PV.

[2] In this paper, "PV" represents rooftop PV systems of small size (i.e. less than or equal to 1 MW) installed on customers' roofs and connected to the distribution grid.

performance constraints while economic potential considers not only land-use availability and system performance but also the economic feasibilities of renewable energy investments. The last type is market potential, which takes into account current or future market factors, such as regional competition with other resources, policy implementations, and barriers. This paper focuses mainly on an economic evaluation of the potential of PV, together with the effects of policy development.

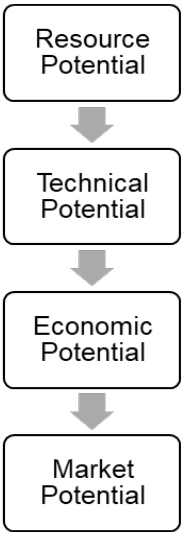


Fig. 1. Types of renewable generation potential (Adapted from [11]).

The rate of PV adoption depends on several drivers according to Mills et al. [12], who classifies the drivers of PV deployment into four groups: PV economics, public policies, customer preferences, and macro factors. First, customer economics can be affected by many factors, such as PV installation costs, PV performance, government policies, electricity prices, and new business models (i.e. third-party power purchase agreements). Second, PV policies include several options (i.e. tax incentives, net metering, renewable portfolio standards (RPS)) offered by the government. Third, customer preferences are based mainly on how many customers intend to install PV systems because either peer influence (word-of-mouth) or heterogeneity (different people have different thresholds for adopting a new technology) exists [13-15]. Finally, macro factors, such as economic growth, load growth, and oil and gas prices, also influence PV deployment.

The current literature on forecasting PV adoption is normally addressed by three stakeholders: research institutes, industry experts, and utility companies. The first two stakeholders usually adopt bottom-up customer-adoption models. In contrast, utility companies often use top-down models by assuming an end point of PV or examining historical data [15].

According to utility planning studies in the U.S. [12], as summarized in Table 1, PV forecasts are categorized into five approaches: customer-adoption modeling, program-based approaches, stipulated forecasts, historical trends, and miscellaneous approaches.

Table 1. Methods for forecasting PV (Adapted from [12]).

Method	Definition
Customer-adoption modeling	Uses adoption models based on consumer decision-making and several factors, such as PV economics and performance
Program-based approach	Assumes incentive program deployment targets as PV forecast
Stipulated Forecast	Assumes endpoint of PV deployment usually without additional details for forecasts
Historical Trends	Extrapolates from historical data based on current PV installation

	costs
Miscellaneous	Uses the judgments of planners

Customer-adoption modeling is one of the most comprehensive PV forecasting methods and provides a bottom-up framework based on historical PV deployment, technical potential, PV economics, and end-user behaviors. The key benefit of this method is to remodel PV forecasts according to various scenarios and updated assumptions. American utility planners, such as Northwest Power and Conservation Council (NWPCC), PacifiCorp (PAC), Pacific Gas & Electric (PG&E), Puget Sound Energy (PSE), and Western Electricity Coordinating Council (WECC), have adopted this approach to forecasting PV deployment [12], as have several other studies, such as those by the National Renewable Energy Laboratory (NREL), which used the Solar Deployment System (SolarDS) [16] and the Distributed Generation (dGen) models [17]. However, this method does have some disadvantages, such as uncertain assumptions having to be made.

Generally, customer-adoption modeling consists of three steps: (1) evaluating the maximum technical potential, (2) addressing PV adoption based on PV economics (willingness-to-adopt), and (3) assessing PV deployment over a time frame [12]. For the first step, the technical potential could be addressed in various ways. For instance, PSE, PAC, and PG&E evaluated technical potential on the basis of available roof space using average floor space, average number of floors, and number of customers [12]. WECC assumed that 50 percent of customers would be able to install PV (4 kW for residential and 50 kW for commercial customers) [18].

For the second step, the willingness-to-adopt curve is a relationship between PV economics (i.e. simple payback period) and market share (as a percentage of technical potential). This relationship can be ascertained by customer surveys or simulation models. For example, in the work of R.W. Beck [19], the willingness-to-adopt curve was developed from a customer-adoption model (SolarSim) by averaging curves from Navigant Consulting and curves based on heat pump adoption [20], as shown in Fig. 2. This curve (green line) has been adopted by some utilities for planning studies, such as PG&E's 2014 BPP [12].

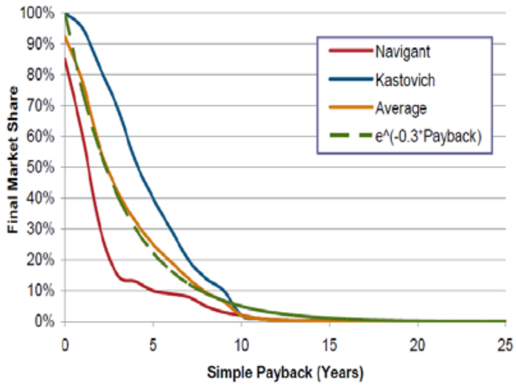


Fig. 2. The relationship between final market share and simple payback period [19].

For the third step, addressing the annual PV adoption rate can be accomplished using a theoretical technology diffusion model that can produce an S-diffusion curve of the cumulative adoption rate. The S-curve consists of four stages: startup, growth, maturation, and decline. The Bass diffusion and Fisher-Pry models have normally been used to address annual PV adoption. The former model, used by PG&E and WECC, relies on both the internal and external influences while the latter, used by PAC, considers only the internal [21]. Several other studies on PV forecasting have also used the Bass diffusion model [15-17, 22].

While Thailand has a stipulated forecast of solar PV (AEDP's goal), the country still lacks more comprehensive forecast methods. This study, then, selected customer-adoption modeling as a forecast method in order to take customer economics of rooftop PV investment into account. The customer-adoption modeling used in this paper was adjusted based on resource availability in Thailand. Thus, we (1) used a number out of each customer group as the technical potential, (2) adopted R.W. Beck's equation (a green line in Fig. 2) as the willingness-to-adopt relationship, and (3) selected the Bass diffusion model to address annual PV adoption. The limitations of this model are discussed in Section 5.

3. Data and Methods

This section first describes the study's data and assumptions, such as selected load profiles by customer groups, selected scenarios, PV compensation schemes, and the technical, economic and financial assumptions, used as the inputs into our forecasting model and the System Advisor Model (SAM), developed by NREL to address performance and financial models for renewable energy projects, including PV. Then, we present the method used to forecast PV adoption in Thailand using customer-adoption modeling.

3.1 Data and Assumptions

3.1.1 Customer Groups and Modeled Load Profiles

The selected customer groups of the areas of MEA and PEA are residential scale (RES)[3], small general service (SGS)[4], medium general service (MGS)[5], and large general service (LGS)[6]. These four groups account for about 99 percent of the total utility customers and load served in 2016. Each group can subscribe to various options of electricity tariffs. We selected one tariff class for each customer group according to the highest share of customer subscription as of December 2015 and the highest potential to install PV, as summarized in Table 2.

Table 2. Details of selected customer groups.

Customer Group	Electricity Tariff	Code
Residential Scale (>150 kWh/month)	Block rate	RES
Small General Service (<12 kV for MEA and <22 kV for PEA)	Block rate	SGS
Medium General Service (12–24 kV for MEA and 22–33 kV for PEA)	TOU rate	MGS
Large General Service (12–24 kV for MEA and 22–33 kV for PEA)	TOU rate	LGS

We determined the PV capacity of each customer group by defining a percentage of annual peak load. For RES and SGS, PV capacity was assumed to be 5 kW, which represents 100% of peak load. For MGS and LGS, PV capacity was assumed to be 100 and 1,000 kW, respectively, which represents 50 percent of

[3] Residential scale is categorized into two main subgroups according to monthly consumption: less than 150 kWh/month and more than 150 kWh/month.

[4] Small general service means customers with a maximum of 15-minute integrated demands of less than 30 kW through a single Watt–hour meter.

[5] Medium general service means customers with a maximum of 15-minute integrated demands from 30 to 999 kW and the average energy consumption for three consecutive months through a single Watt–hour meter not exceeding 250,000 kWh per month.

[6] Large general service means customers with a maximum of 15-minute integrated demands more than 1,000 kW or the average energy consumption for three consecutive months through a single Watt–hour meter exceeding 250,000 kWh per month.

the peak load for each group. The selections of the PV sizes were based on consulting with the stakeholders and reflected PV installations in Thailand in terms of roof space and customer characteristics (i.e. income). Then, the 8760-hourly load profiles of each customer group in MEA and PEA areas were modified to meet the mentioned conditions by increasing their magnitudes with the same load shape. Table 3 represents the installed PV capacity of each group and the modeled load profiles. Comparing the load shapes between MEA and PEA for each customer group, there is no major difference in terms of load shapes. Only the magnitudes are different. Typically, SGS, MGS, and LGS experience peak loads at about noon while RES experiences peak load in the evening. Generally speaking, the load profiles of SGS, MGS, and LGS are well aligned with the PV production shapes.

3.1.2 Scenarios

We forecasted PV adoption in Thailand using different scenarios, which are summarized in Fig. 3. We also selected a PV compensation scheme (net billing) since this scheme was being considered by the Thai government as of September 2017 [1]. Under this scheme, PV electricity is first self-consumed and excess generation is credited as monetary units to offset hourly electricity bills at a defined buyback rate. At the time of writing (November 2018), the government was considering setting the buyback rate to lower than or equal to the wholesale rate [1]. Thus, this study assumed the buyback rate to be between nothing (0 THB/kWh) and the average wholesale rate (2.6 THB/kWh[7]). Apart from various buyback rates, we also assumed the annual percentage of PV installation cost reduction to be 4 percent for the maximum case and 2 percent for the minimum case. This determination was based on consultations held with stakeholders in the country, as this reduction would better reflect the feasibility of PV investment with possible future trends. We set the time frame of the analysis to cover the period between the time of writing (2018) and the end of the AEDP plan (2036).

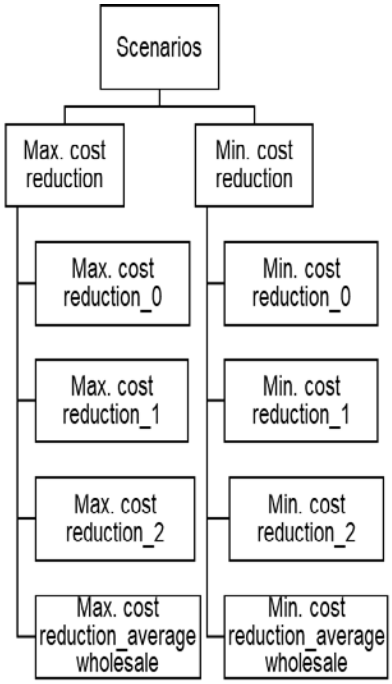


Fig. 3. Selected scenarios in this analysis. (Code meaning: percentage of annual PV installation cost reduction_buyback rate in THB/kWh[8]).

3.1.3 Assumptions

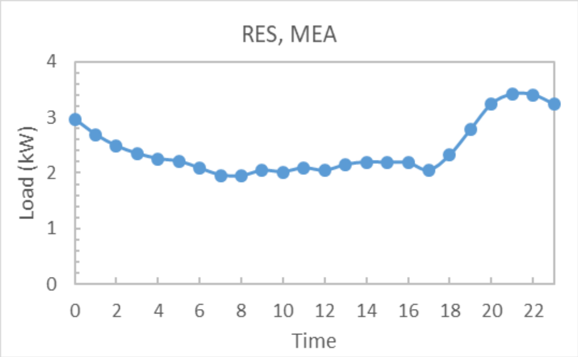
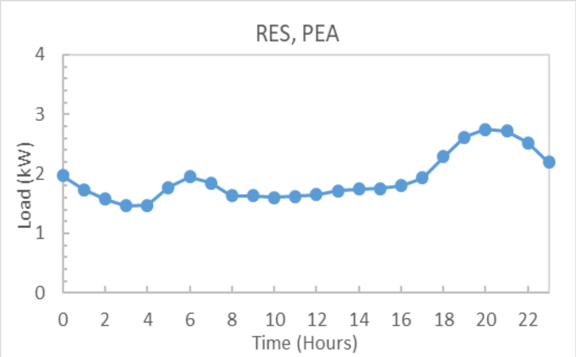
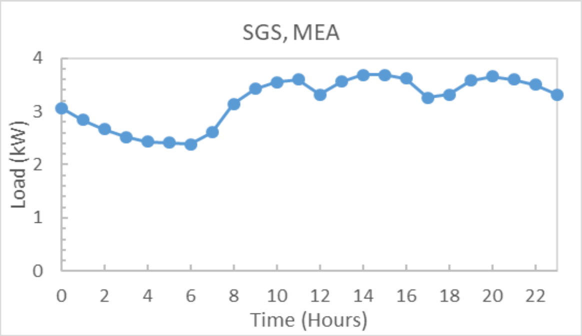
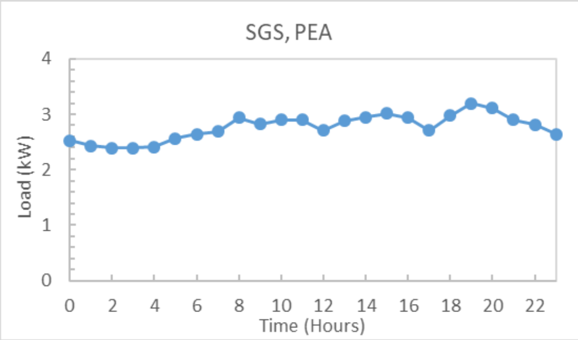
This section discusses all assumptions used in the analysis.

3.1.3.1 Technical Assumptions

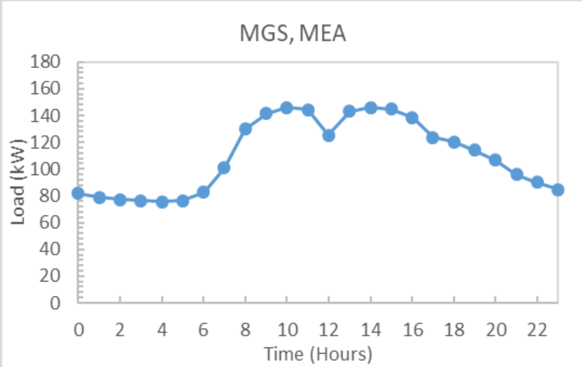
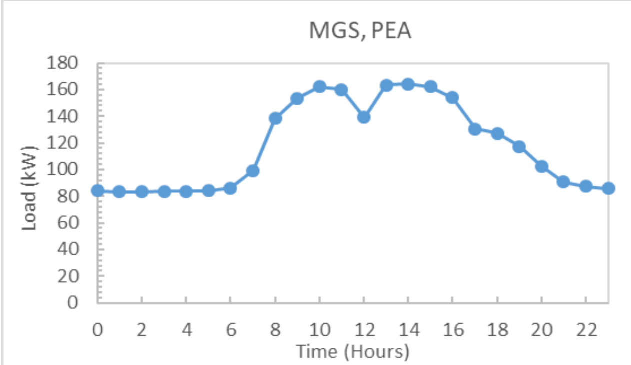
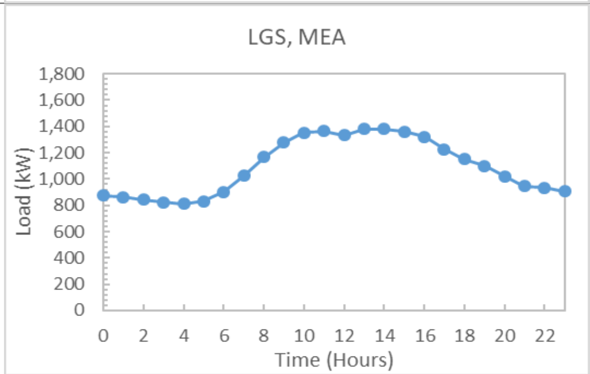
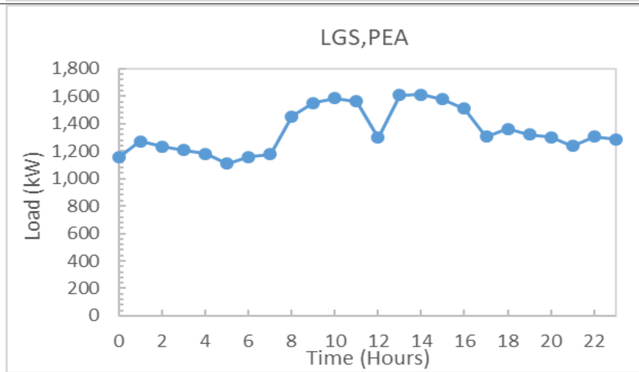
[7] Used weighted average wholesale rate at 69–115 kV. A fuel adjustment charge (Ft) was included as of September–December 2017 (–0.0071 USD/unit).

[8] Buyback rates of 0, 1, 2, and 2.6THB/kWh would be 0, 0.03, 0.06, and 0.07 USD/kWh (exchange rate: 35 THB/USD).

Table 3. PV capacity and modeled load profiles.

Group	PV capacity (kW)	PV capacity as % of annual peak load	Modeled load profiles (MEA) (Average day in 2015)[9]	Modeled load profiles (PEA) (Average day in 2015)
RES	5	100		
SGS	5	100		

[9] This means an average day (an average of each hour of load profile in a day) rather than a peak day.

Group	PV capacity (kW)	PV capacity as % of annual peak load	Modeled load profiles (MEA) (Average day in 2015)[9]	Modeled load profiles (PEA) (Average day in 2015)
MGS	100	50		
LGS	1,000	50		

The technical assumptions (Table 4) were mainly selected according to SAM's default values for a given module type [23], except for orientation, tilt, and azimuth, which were taken on the basis of the location of the PV system, which is Thailand.

Table 4. Technical assumptions.

System Parameters	Input
System Size (kW)	5,5,100, and 1,000 for RES, SGS, MGS, and LGS
Module Type	Crystalline Silicon
Module Efficiency (%)	15.9
DC to AC Ratio	1.1
CEC Weighted Inverter Efficiency (%)	96.65
Array Type	Fixed Open Rack
Tilt (Latitude) (degrees)	13.7
Azimuth (Facing South) (degrees)	180
System Losses (%)	14
Ground-to-coverage Ratio (GCR)	0.3
System Lifetime (years)	25
Degradation Rate (%)	0.5

3.1.3.2 Economic and Financial Assumptions

The economic and financial assumptions as well as other assumptions are summarized in Table 5-Table 9.

Table 5. PV installation cost (based on Thailand's PV market as of November 2017).

System cost (USD/W)	RES	SGS	MGS	LGS
System cost (USD/W) [10]	1.43	1.43	1.29	1.00
Operating and Maintenance costs[11] **(USD/year)**	143	143	286	1,429
Insurance costs (% of installed cost)	0.25			
Interconnection costs (USD)	–	–	2,857	2,857

[10] Inverter was assumed to be replaced every 11 years. The inverter cost is around 17% of system cost.

Table 6. Financial parameters (based on Thailand's market).

Financial Parameters	Input
Debt fraction (%)	0 for RES and SGS[12] 70:30 for MGS and LGS
Debt term (%)	6.97
Debt years (years)	12
Inflation rate (%)	1.5

Table 7. Retail rates (public data of MEA and PEA[13])).

(1) *Residential scale with block rates (RES)*

Block rate	Rate
1–150 units (USD/kWh)	0.092
151–400 units (USD/kWh)	0.121
Over 400 units (USD/kWh)	0.126
Fixed charge (USD/month)	1.0920

[11] Operating and maintenance costs (cleaning, safety, repair, etc.) include costs related to ensuring PV remains in good and safe conditions while performing satisfactorily.

[12] The 0% debt was assumed because selected RES and SGS customers are high-demand customers compared to other customers in the same group. This means they should have high household income and be able to install rooftop PV within this condition.

[13] Fuel adjustment charge (Ft) is not included. Ft is -0.0045 USD/unit as of September–December 2017. Value Added Tax (VAT) of 7% is also not included

(2) Small general service with block rates (SGS)

Block rate (Voltage level<12 kV)	Rate
1–150 units (USD/kWh)	0.092
151–400 units (USD/kWh)	0.121
Over 400 units (USD/kWh)	0.126
Fixed charge (USD/month)	1.0920

(3) Medium general service with TOU rates (MGS)

TOU rate (Voltage level=12–24 kV)	Rate
On-peak (USD/kWh)	0.120
Off-peak (USD/kWh)	0.075
Demand charge (USD/kW)	3.798
Fixed charge (USD/month)	8.921

(4) Large general service with TOU rates (LGS)

TOU rate (Voltage level=12–24 kV)	Rate
On-peak (USD/kWh)	0.120
Off-peak (USD/kWh)	0.075
Demand charge (USD/kW)	3.798
Fixed charge (USD/month)	8.921

Table 8. Number of customers as assumed technical potential in this analysis (public data of MEA and PEA as of 2016).

Number of customers	MEA	PEA
RES	3,062,576	16,739,341
SGS	517,300	1,539,077
MGS	22,524	72,446
LGS	2,324	6,396

Table 9. Other parameters (based on historical data and Thailand's Power Development Plan (PDP 2015–2036)).

Other Parameters	Input
Real retail growth rate (% per year)	1.89

3.2 Method

The methodology used here to forecast PV adoption in Thailand is summarized in Fig. 4 and consists of (1) payback period calculation, (2) maximum market share determination, and (3) annual PV adoption determination.

Fig. 4. Steps to forecast PV adoption in Thailand.

3.2.1 Payback Period (PB) Calculation

Payback period is the time required in years to recover the cost of investment. We selected SAM to calculate the payback period of the PV project for each customer group of the areas of MEA and PEA. The main inputs are discussed in Section 3.1.3. In SAM, the payback period is simple payback period and calculated using a non-discounted cash flow. The simple payback period is the first point in time when cumulative cash flow (the summation of annual cash flow) changes from negative to positive value. The annual cash flow can be addressed as follow:

$$\text{Annual cash flow (USD)} = \text{Annual cost (USD)} + \text{Value of energy generated by system (USD)} \quad (3.1)$$

3.2.2 Maximum Market Share (Willingness-to-adopt) Determination

For this step, we applied the relationship between the payback period and maximum market share of PV to obtain the levels of maximum PV adoption for each customer group in MW. According to R.W. Beck [19], the fraction of customers willing to adopt a technology is a function of simple payback time (PB), as shown by the following equation.

$$\text{Maximum market share} = e^{(-0.3\times \text{payback time})} \quad (3.2)$$

We converted a percentage of the willingness-to-adopt into total PV adoption (in MW) by multiplying by the total number of customers as assumed technical potential and assumed the typical PV sizes on the basis of the customer groups, as illustrated in Fig. 5.

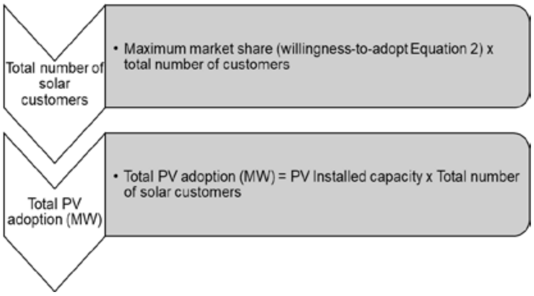


Fig. 5. Steps for calculating total PV adoption in MW.

3.2.3 Annual PV Adoption Determination

The annual additional PV adoption for each scenario was addressed using the technology adoption curve, also known as the Bass diffusion model, of which the equations are summarized below. The shapes of the curves are discussed in Section 4.1. We assumed that 90 percent of the maximum market share of PV (from Section 3.2.2) was achieved at the end of AEDP (the year 2036) by adjusting the values of p and q, which are 0.0038 and 0.35, respectively, and in the range of their typical values as given by various studies [16, 17, 21, 24].

$$F(t) = \frac{1 - pe^{-(p+q)t}}{1 + \frac{q}{p}e^{-(p+q)t}} \quad (3.3)$$

$$f(t) = \begin{cases} F(t), & t = 1 \\ F(t) - F(t-1), & t > 1 \end{cases} \quad (3.4)$$

$$A(t) = M\ F(t) \text{ and } a(t) = M\ f(t) \quad (3.5)$$

Where:

M is potential market or maximum market share (total PV adoption of each customer group; in MW).

f(t) is portion of M that adopts at time t.

F(t) is portion of M that have adopted by time t.

a(t) is adoptions at time t (additional PV installation at time t; in MW).

A(t) is cumulative adoptions (cumulative PV installation ; in MW).

p is innovation coefficient (external influence, i.e. advertising).

q is imitation coefficient (internal influence, i.e. word-of-mouth).

The current PV installation in the country as of 2017, as summarized in Table 10, was taken as the starting point. The current rooftop PV installation was about 6% of total solar PV installation in Thailand. At this step, according to the customer-adoption model, annual PV adoption, as well as maximum PV adoption in Thailand, from 2018 to 2036 were formulated.

4. Results and Discussion

4.1 Results

In this section, the results of calculating the payback period for each customer group (RES, SGS, MGS, and LGS) of both MEA and PEA are presented. Then, the forecast of PV adoption of each scenario addressed by the proposed method for the MEA and PEA areas, as well as the overall adoption for the whole country, are discussed.

Table 10. Current PV installation as of 2017 (Adapted from [25] and public data from the Energy Regulatory Commission in Thailand).

PV Installed Capacity (MW)	RES	SGS	MGS	LGS	TOTAL
MEA	11.6	11.6	16.9	37	**77.1**
PEA	16.6	16.6	24.3	53.1	**110.6**
GRAND TOTAL					**188.3**

Note: Due to public data limitation of small-scale PV installed capacity, it was assumed that RES and SGS installed capacity are equal to each other.

4.1.1 Payback Periods

The payback periods of the PV installations in the MEA and PEA areas are summarized in Table 11 under the set of assumptions discussed earlier. Additionally, the differences between the payback periods of each customer group, which have the same PV sizes, in the MEA and PEA areas are due to different load profiles, as shown in Table 3. It is also worth noting that there is almost no difference between payback periods of LGS in MEA and PEA area even though load profiles are different. This is because LGS customers were assumed to install the same PV size and have larger demand than PV production. The same amount of power is generated by PV and consumed by LGS. Thus, the same payback period is resulted. Different load profiles do not matter.

For the MEA and PEA areas, the payback periods of RES are sensitive to the buyback rate due to the fact that the load and PV production profiles are not well aligned. Therefore, there is some excess PV electricity flowing back to the grid. Hence, a higher buyback rate leads to a shorter payback period for RES. In contrast, for SGS, MGS and LGS, the payback periods are insensitive to the buyback rates, since the load profiles are well aligned with the PV production profiles, leading to less excess PV electricity. Therefore, the levels of the buyback rate do not affect the payback periods of MGS and LGS. For example, the Year 1 payback period of RES in the MEA area ranges from 9.3–11.7 years, depending on the level of the buyback rate while the Year 1 payback period of MGS in the MEA area is 8 years for all levels of the buyback rate.

Focusing on the payback period at the end of AEDP with the assumption of PV installation cost reduction over time, unlike the level of the buyback rate, the reduction leads to shorter payback periods for all customer groups. The payback periods at the end of AEDP are about 2–3 years for all customer groups under the assumption of an annual PV cost reduction at 4% and about 2–5 years at 2%.

4.1.2 Forecast of Maximum PV Adoption at the end of AEDP

After addressing the payback period of each scenario, the percentages of maximum market share were addressed using Equation 3.2. Table 12 shows the percentages of the maximum market shares of PV adoptions in the MEA and PEA areas by customer group. When considering the levels of the buyback rate, the percentages of the maximum market shares are different for RES under different buyback rates but not for SGS, MGS and LGS for the same

Table 11. Payback periods of PV installations of MEA and PEA areas.

(a) MEA

Payback period (years)	Buyback = 0 THB/kWh			Buyback = 1 THB/kWh (0.03 USD/kWh)			Buyback = 2 THB/kWh (0.06 USD/kWh)			Buyback = 2.6 THB/kWh (0.07 USD/kWh; average wholesale rate)		
	Year 1	The end of AEDP (Max. cost reduction)	The end of AEDP (Min. cost reduction)	Year 1	The end of AEDP (Max. cost reduction)	The end of AEDP (Min. cost reduction)	Year 1	The end of AEDP (Max. cost reduction)	The end of AEDP (Min. cost reduction)	Year 1	The end of AEDP (Max. cost reduction)	The end of AEDP (Min. cost reduction)
RES	11.7	2.8	3.9	9.8	2.7	3.8	9.5	2.7	3.8	9.3	2.6	3.7
SGS	8.8	2.3	3.4	8.8	2.3	3.4	8.7	2.3	3.3	8.7	2.3	3.3
MGS	8.0	2.2	3.2	8.0	2.2	3.2	8.0	2.2	3.2	7.9	2.2	3.2
LGS	6.1	1.7	2.4	6.1	1.7	2.4	6.1	1.7	2.4	6.1	1.7	2.4

(b) PEA

Payback period (years)	Buyback = 0 THB/kWh			Buyback = 1 THB/kWh (0.03 USD/kWh)			Buyback = 2 THB/kWh (0.06 USD/kWh)			Buyback = 2.6 THB/kWh (0.07 USD/kWh; average wholesale rate)		
	Year 1	The end of AEDP (Max. cost reduction)	The end of AEDP (Min. cost reduction)	Year 1	The end of AEDP (Max. cost reduction)	The end of AEDP (Min. cost reduction)	Year 1	The end of AEDP (Max. cost reduction)	The end of AEDP (Min. cost reduction)	Year 1	The end of AEDP (Max. cost reduction)	The end of AEDP (Min. cost reduction)
RES	13.4	3.2	4.6	12.5	3.1	4.4	11.6	2.9	4.2	9.8	2.9	4.1
SGS	9.0	2.4	3.4	8.9	2.4	3.4	8.9	2.4	3.4	8.8	2.4	3.4
MGS	7.9	2.2	3.2	7.9	2.2	3.2	7.9	2.2	3.2	7.9	2.2	3.2
LGS	6.1	1.7	2.4	6.1	1.7	2.4	6.1	1.7	2.4	6.1	1.7	2.4

Table 12. Percentages of maximum market shares of PV adoption in MEA and PEA areas.

(a) MEA

Maximum market share (%)	**Buyback = 0 THB/kWh**			**Buyback = 1 THB/kWh (0.03 USD/kWh)**			**Buyback = 2 THB/kWh (0.06 USD/kWh)**			**Buyback = 2.6 THB/kWh (0.07 USD/kWh; average wholesale rate)**		
	Year 1	**The end of AEDP (Max. cost reduction)**	**The end of AEDP (Min. cost reduction)**	**Year 1**	**The end of AEDP (Max. cost reduction)**	**The end of AEDP (Min. cost reduction)**	**Year 1**	**The end of AEDP (Max. cost reduction)**	**The end of AEDP (Min. cost reduction)**	**Year 1**	**The end of AEDP (Max. cost reduction)**	**The end of AEDP (Min. cost reduction)**
RES	3%	44%	31%	5%	45%	32%	6%	45%	32%	6%	46%	33%
SGS	7%	49%	37%	7%	50%	37%	7%	50%	37%	7%	50%	37%
MGS	9%	51%	38%	9%	51%	38%	9%	51%	38%	9%	51%	38%
LGS	16%	60%	48%	16%	60%	48%	16%	60%	48%	16%	60%	48%

(b) PEA

Maximum market share (%)	**Buyback = 0 THB/kWh**			**Buyback = 1 THB/kWh (0.03 USD/kWh)**			**Buyback = 2 THB/kWh (0.06 USD/kWh)**			**Buyback = 2.6 THB/kWh (0.07 USD/kWh; average wholesale rate)**		
	Year 1	**The end of AEDP (Max. cost reduction)**	**The end of AEDP (Min. cost reduction)**	**Year 1**	**The end of AEDP (Max. cost reduction)**	**The end of AEDP (Min. cost reduction)**	**Year 1**	**The end of AEDP (Max. cost reduction)**	**The end of AEDP (Min. cost reduction)**	**Year 1**	**The end of AEDP (Max. cost reduction)**	**The end of AEDP (Min. cost reduction)**
RES	2%	38%	26%	2%	40%	27%	3%	41%	29%	5%	42%	29%
SGS	7%	49%	36%	7%	49%	36%	7%	49%	36%	7%	49%	36%
MGS	9%	51%	39%	9%	51%	39%	9%	51%	39%	9%	51%	39%
LGS	16%	60%	48%	16%	60%	48%	16%	60%	48%	16%	60%	48%

reasons as for calculating the payback period. For example, the percentages of the maximum market share (Year 1) range from 2% to 5% for RES in the PEA area while for all customer groups at the end of AEDP with an assumption of a 4% PV cost reduction and to about 30%–50% at 2%.

The maximum forecast of PV adoption (MW) at the end of AEDP (in 2036) was calculated, as illustrated in Fig. 5. Table 13 shows the maximum forecasts of PV adoption (in MW) based on different scenarios in the areas of MEA, PEA, and the country overall. For MEA, the forecast of PV adoption is in the range of 7,483–7,827 MW and 5,946–6,256 MW for the maximum and minimum cost reductions. For PEA, the forecast of PV adoption is in the range of 25,345–28,778 MW and 18,668–21,671 MW for the maximum and minimum cost reductions. For the country overall, the forecast of PV adoption is in the range of 32,828–36,605 MW and 24,614–27,927 MW for the maximum and minimum cost reductions. The varying ranges of forecasted PV adoption are due to the different levels of the buyback rate. Higher buyback rates and percentages of PV cost reduction lead to shorter payback periods and higher PV adoptions by each customer group.

The forecasts of PV adoption in the PEA area are significantly higher than in the MEA area due to the larger number of potential customers. Averaging all scenarios, the forecast of PV adoption in the PEA area accounts for 77% while those in MEA account for 23% of the country overall. Comparing the forecast of PV at the country level to the electricity generation projected for 2036, in the maximum cost reduction case, the shares are about 12%–14% of the projected electricity generation while for the minimum case the shares are about 9%–11%.

4.1.3 Annual PV Adoption

The next step is to calculate the annual PV adoption using the Bass diffusion model. The annual additional and cumulative PV adoptions at buyback rates of 0 and 2.6 THB/kWh of the areas of MEA, PEA, and the country overall are shown in Figs. 6, 7, and 8, respectively.

The bell curves represent the annual additional PV adoption and the S-curves represent the cumulative PV adoption. At the beginning of PV adoption, there are few early adopters but after PV markets have become well known, the payback periods become shorter and the government starts supporting policies such as compensation schemes for excess generation and tax incentives to help decrease investment costs. The number of new adopters increases considerably and peaks at about the year 2032 before there is a saturation of PV adoption.

RES has the highest shares of PV adoption at the end of AEDP due to a large number of potential customers, but for Year 1, MGS and LGS account for the highest shares due to current PV installations that have been integrated into the calculation at the starting point. Table 14 summarizes the percentages of PV shares of the customer groups of the areas of MEA, PEA, and the country overall. For instance, at the end of AEDP in the maximum cost reduction case, the percentages of PV adoption for RES, SGS, MGS, and LGS in the country overall are 64%, 10%, 11%, and 15%, respectively. These are not significantly different from those in the minimum cost reduction case.

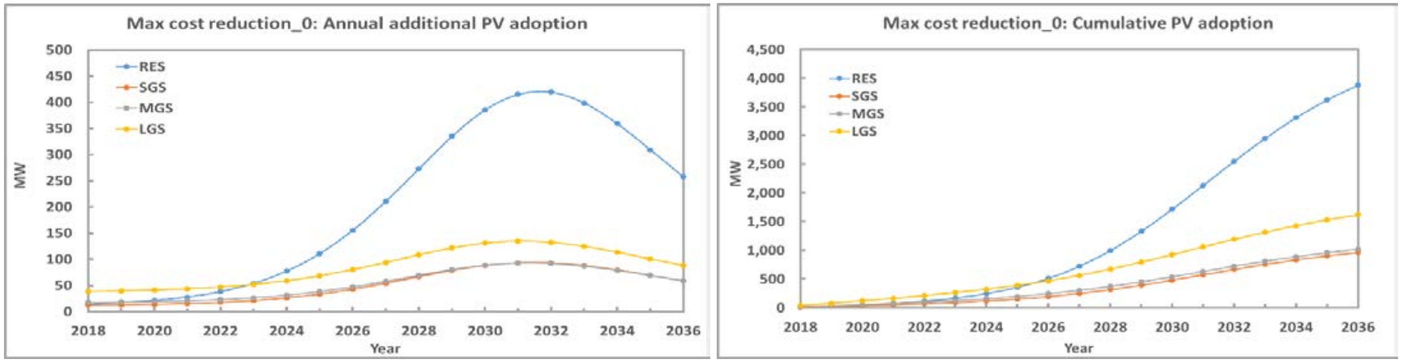
Considering the different buyback rates for the maximum and minimum cost reduction cases, the differences in the annual PV installations of each customer group is not significantly high (see Fig. 6(a) and (b), for example). In contrast, when comparing the different percentages of PV cost reductions, the maximum cost reduction case has a higher annual PV adoption for all customer groups (see Fig. 6(a) and (c), for example).

Table 13. Maximum forecast of PV adoption at the end of AEDP (in 2036).

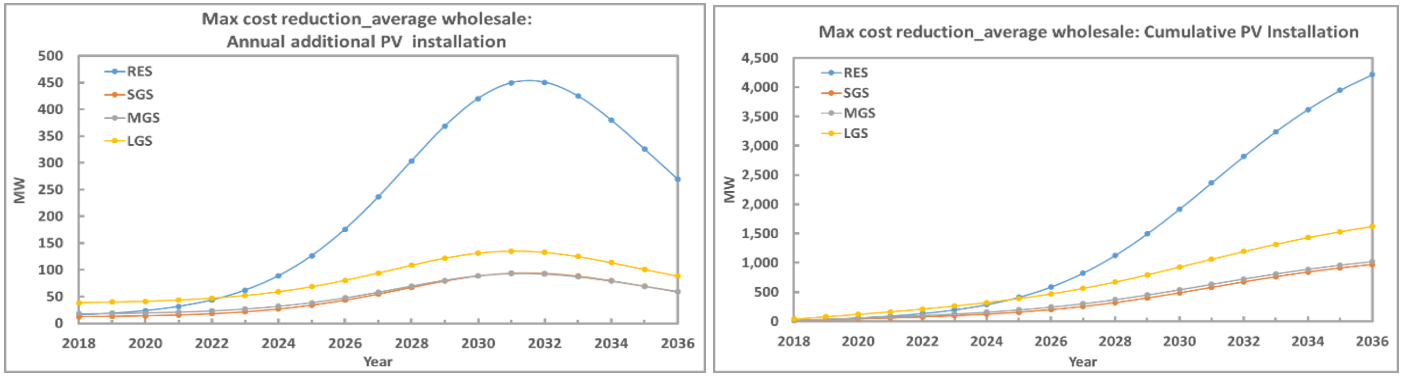
	Maximum forecasts of PV adoption (MW)							
	Max. cost reduction_0	**Max. cost reduction_1**	**Max. cost reduction_2**	**Max. cost reduction_ average wholesale**	**Min. cost reduction_0**	**Min. cost reduction_1**	**Min. cost reduction_2**	**Min. cost reduction_ average wholesale**
MEA	7,483	7,618	7,749	7,827	5,946	6,066	6,185	6,256
PEA	25,345	26,688	28,003	28,778	18,668	19,836	20,984	21,671
Country overall	32,828	34,306	35,752	36,605	24,614	25,902	27,169	27,927
% PV adoption (country level; energy basis)[14]	12.4%	13.0%	13.6%	13.9%	9.3%	9.8%	10.3%	10.6%

Note: In early 2019, Thai government announced the buyback rate of 1.68 THB/kWh as available in ERC's webpage. Thus, the forecast of PV adoption is in between the case of buyback rate of 1 and 2 THB/kWh. For the country overall, it is in between 34 to 36 GW for Max. cost reduction scenario and 26-27 GW for Min. cost reduction scenario.

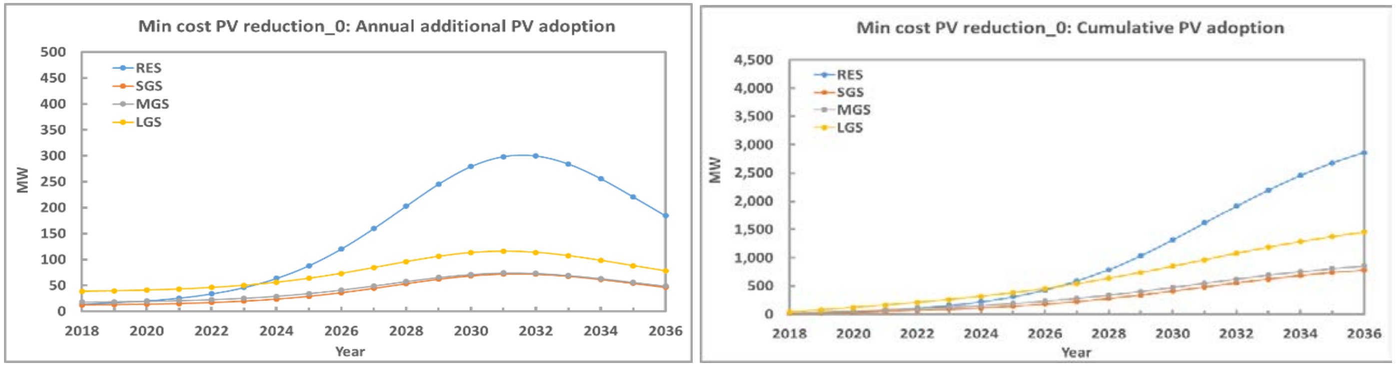
[14] Compared to the electricity generation projected for 2036, which is 355,536 GWh. Calculations were based on electricity generation in 2017 (183,581 GWh) and 3.54% growth, which was determined from the historical growth rate in the last 10 years.



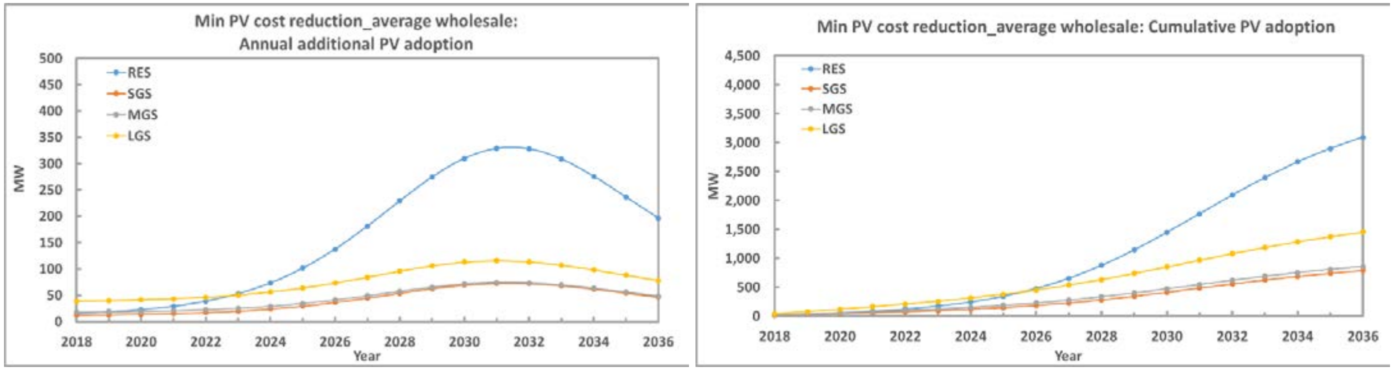
(a) Max. cost reduction_0



(b) Max. cost reduction_average wholesale



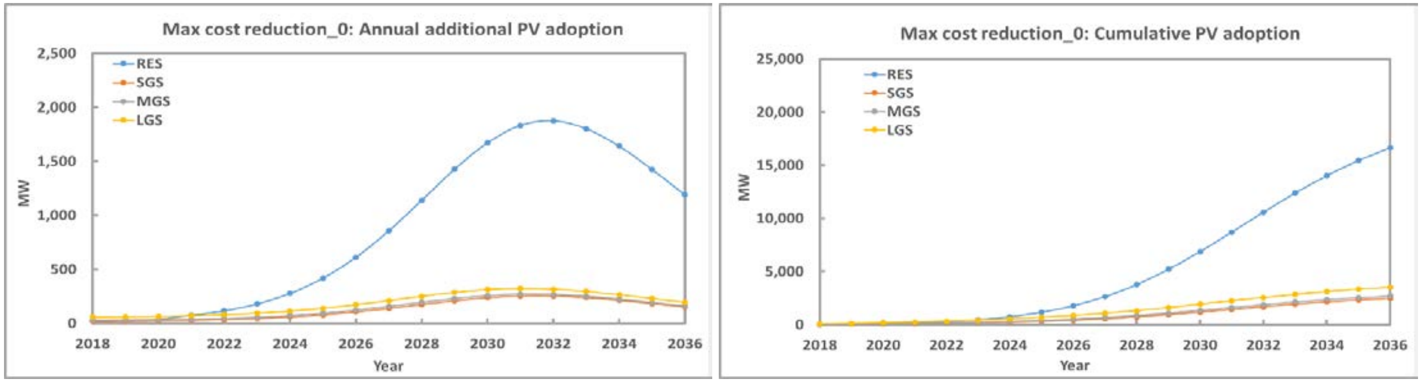
(C) Min. cost reduction_0



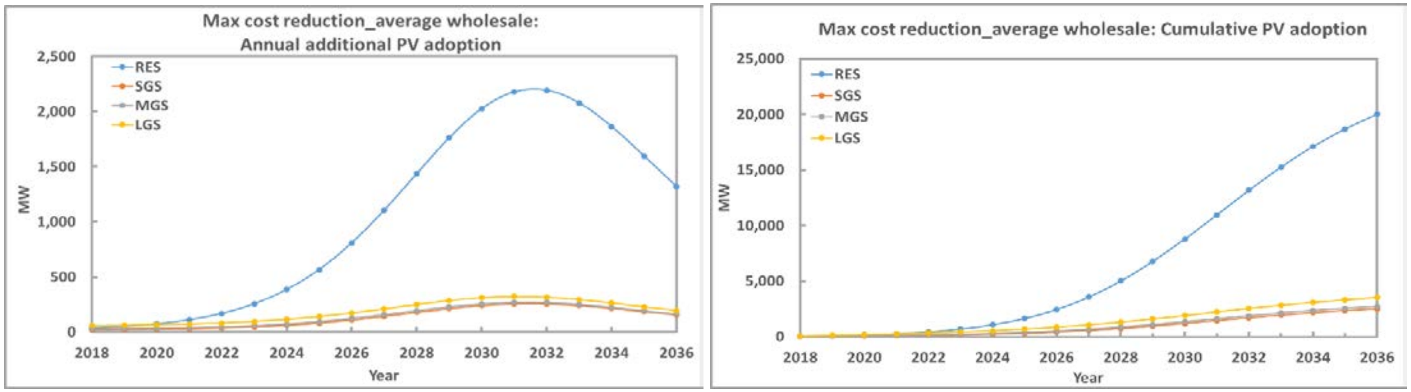
(d) Min. cost reduction_ average wholesale

Fig. 6. Annual additional PV adoption and cumulative PV adoption in the MEA area at buyback rates of 0 and 2.6 THB/kWh.[15] (Left: Annual additional PV adoption. Right: Cumulative PV adoption).

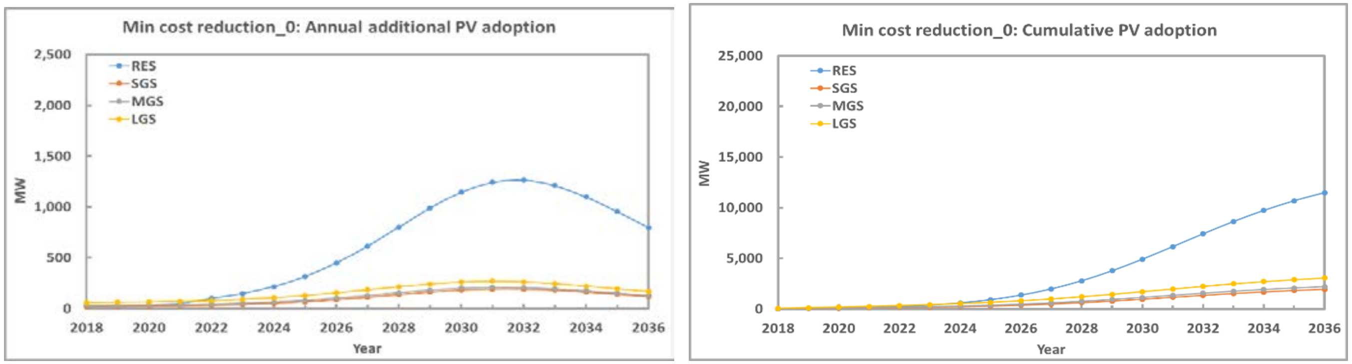
[15] To avoid complexity, only the minimum and maximum levels of the buyback rate are shown.



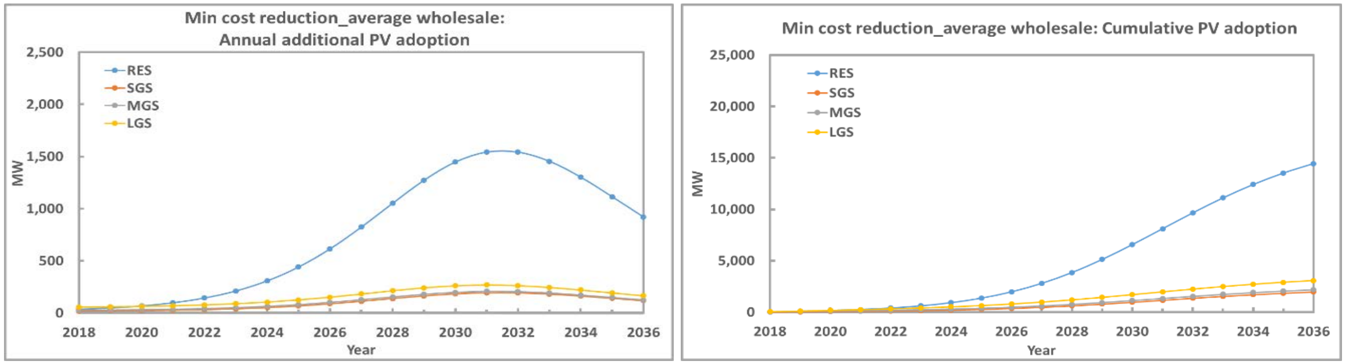
(a) Max. cost reduction_0



(b) Max. cost reduction_average wholesale

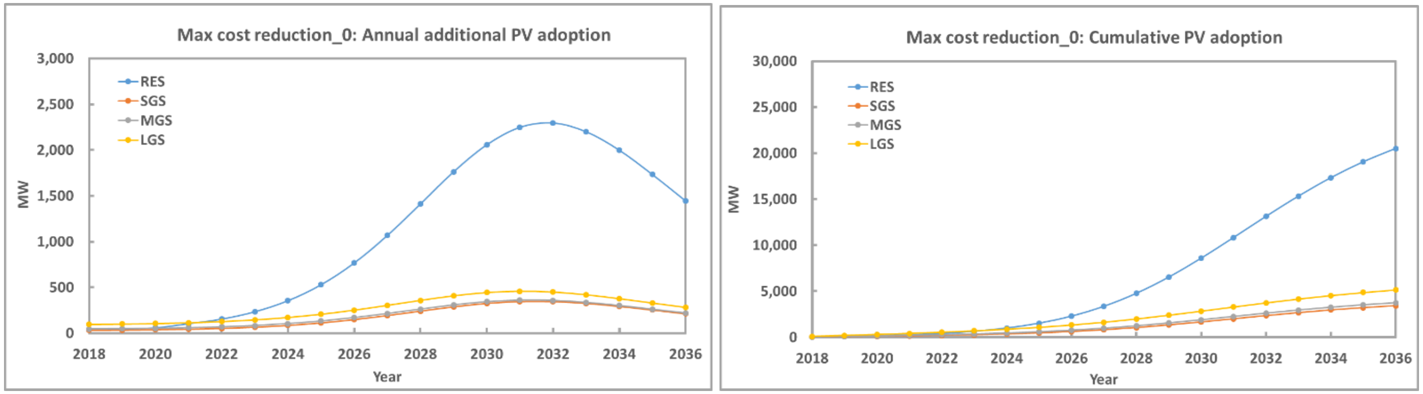


(C) Min. cost reduction_0

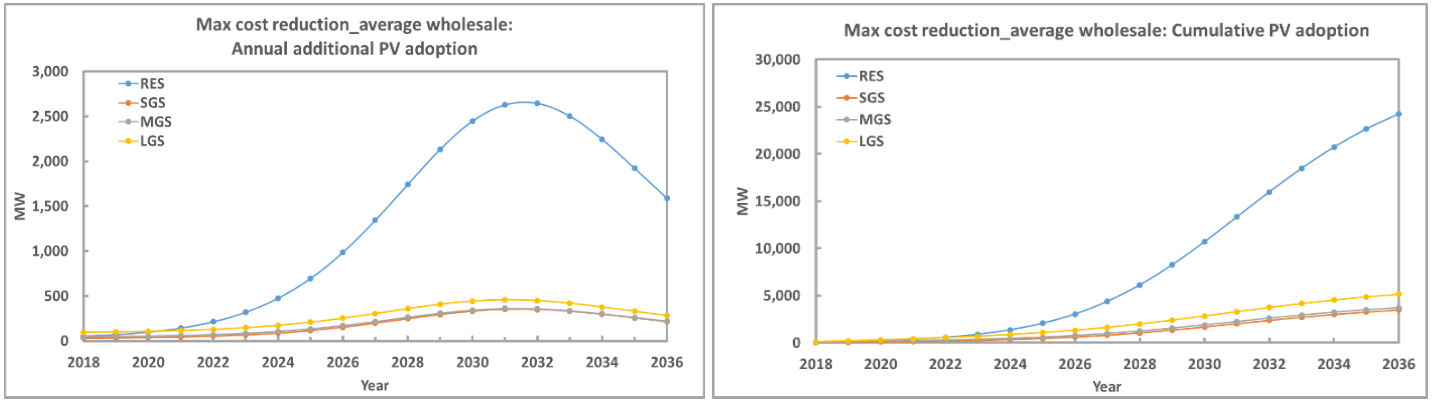


(d) Min. cost reduction_ average wholesale

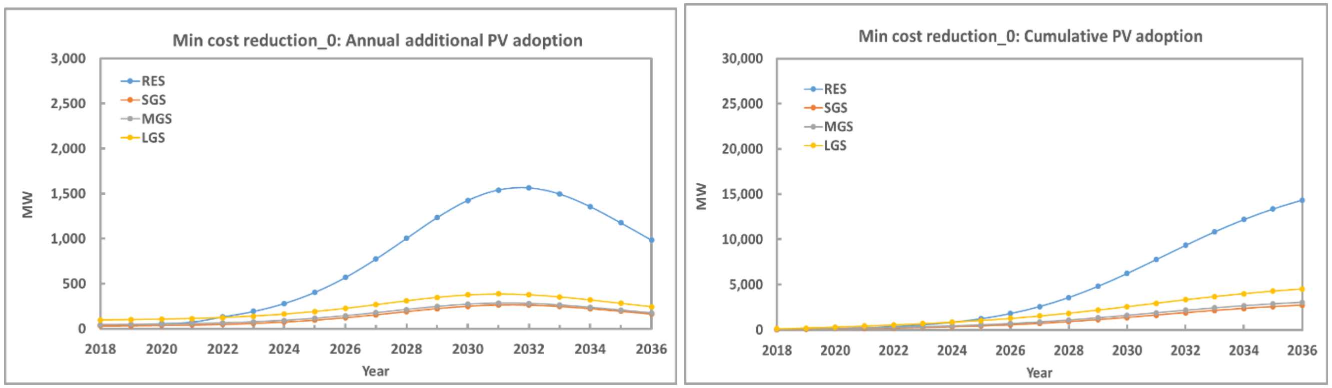
Fig. 7. Annual additional PV adoption and cumulative PV adoption in the PEA area at buyback rates of 0 and 2.6 THB/kWh. (Left: Annual additional PV adoption. Right: Cumulative PV adoption).



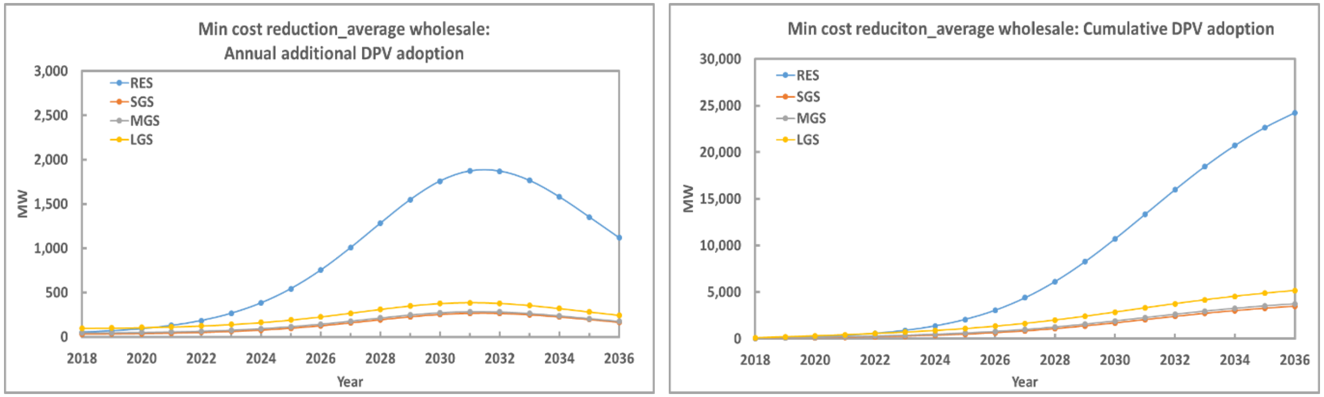
(a) Max. cost reduction_0



(b) Max. cost reduction_ average wholesale



(C) Min. cost reduction_0



(d)Min. cost reduction_ average wholesale

Fig. 8. Annual additional PV adoption and cumulative PV adoption in the country overall at buyback rates of 0 and 2.6 THB/kWh. (Left: Annual additional PV adoption. Right: Cumulative PV adoption).

Table 14. Shares of PV adoption by customer group at the end of AEDP (in 2036).

	Shares of PV adoption (%) (average from all buyback rates)					
	Scenario: Max cost reduction			**Scenario: Min cost reduction**		
	MEA	**PEA**	**Country overall**	**MEA**	**PEA**	**Country overall**
RES	53%	68%	64%	49%	64%	61%
SGS	13%	9%	10%	13%	10%	10%
MGS	13%	10%	11%	14%	11%	12%
LGS	21%	13%	15%	24%	15%	17%

Table 15. Maximum annual additional PV adoption (Refer to Fig. 6-Fig. 8. (Left side)).

	Maximum annual additional PV adoption (MW)	
	Max. cost reduction	**Min. cost reduction**
MEA	737–771	560–591
PEA	2,710–3,032	1,925–2,216
Country overall	3,447–3,800	2,483–2,807

4.2 Discussions

The payback period is an indicator selected to define the PV adoption scenarios. There are options to help shorten the payback period in order to increase PV adoption in the country. Several options for incentives, such as investment tax credits (ITC)[16], can reduce PV installation costs and shorten payback periods for all customer groups. Moreover, purchasing tariffs or buyback rates are also important for making PV investments more attractive to some customer groups, such as residential scale. It is clear that shorter payback periods lead to higher PV adoption. However, in the long run, when PV is able to compete with the retail rates and promote itself in the market, improving the skills of PV installers (i.e. to meet certification standards) and the effective installation of PV projects is also necessary.

As mentioned earlier, about 2,800 MW remains to meet the AEDP goal. This study clearly shows that the AEDP's goal can be achieved even before 2036 without the buyback rate. Applying the PV adoption pattern of Min. cost reduction_0 case revealed that the AEDP's goal would be achieved at the latest by 2025[17].

According to the IEA analysis [26], the 10 percent of total gross maximum technical potential is over 38 GW, while the maximum forecast of PV adoption in 2036 based on PV customer economics in this study is in between 25 and 37 GW. Therefore, the availability of roof area should not be a constraint. Moreover, maximum annual additional PV adoption can be seen in Table 15. Comparing these with the projected peak demand in 2032[18], which is a peak year of PV adoption, the percentages of maximum annual PV adoptions to projected peak demand ranges from approximately 4%–5% for MEA, 5%–9% for PEA, and 5%–8% for the country overall. Although this study does not consider the technical ability on annual grid integration, each utility must understand their system performances and the necessary system upgrades by taking the forecasts of annual PV adoption into account as the limitation of grid ability can lead to a lower actual PV adoption in the country.

As summarized in Table 13, the PV shares at the end of AEDP range from approximately 9%–14% in 2036 (energy basis, country level). According to the IEA's publication [27], if the share of variable renewable energy (VRE)[19] ranges from 3% to almost 15%, it falls into Phase 2, which means that the VRE systems become noticeable in system operations. An important challenge is net load determination by focusing on projected demand and PV output. Moreover, the power development plan needs to be considered with a comprehensive view of new power plants and current operating patterns to accommodate PV. In addition, it is very important to ensure sufficient grid capacity to integrate PV and consider a forecasting system of PV and other VREs in order to maintain the security of supply. Examples of countries that are currently in Phase 2 include Chile, Brazil, New Zealand, Australia, Canada, Sweden, and the Netherlands.

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[16] In Thailand, there is a tax incentive that might be applicable for large-scale rooftop PV investment according to Board of Investment. This incentive would be beneficial for large-scale PV installation by shortening payback period and increasing PV adoption level that would be interesting to address in the future works.

[17] We assume that no ground-mounted PV systems had been installed since the beginning of the period of analysis. If there are installed ground-mounted PV systems, it is possible that the AEDP can be achieved before 2025.

[18] Projected peak demands in 2032 are 14,249 MW, 35,746 MW, and 48,796 MW for the areas of MEA, PEA, and the country overall, respectively. The demands were calculated from the hourly demands in 2017 with the assumption of demand growth at 3.54% according to historical data.

[19] We assume that VREs in Thailand mostly represent PV and exclude current ground-mounted solar PV capacity at about 3,000 MW.

On the basis of a real-market situation (i.e. with higher PV cost reduction), PV shares may grow higher than the numbers forecasted in this study. Therefore, utilities must prepare for an upcoming situation in which high PV adoption may shift the peak time to the evening. Due to the merit-order effect [28-30], this shift will affect wholesale prices such that, at this stage, grid integration and planning issues must be comprehensively considered. There are studies discussing such issues, including [12, 27]. According to the IEA's publication [27], examples of mitigation measures include wholesale price reform to represent new peak hours and increases in power system flexibility (i.e. dispatchable generators, demand-side management, and energy storage). Moreover, forecasts of PV in terms of installed capacity and location (PV hotspots) could significantly help utilities accommodate PV in the grid [12, 27] and also evaluate the value of solar power and the utilities' economic impacts so that the utilities could plan their businesses accordingly.

Important points of discussion are summarized below:

(1) Incentives for PV investments are needed to reduce investment costs until PV can compete in the market;
(2) With high PV adoption, each utility should understand their system performance as well as the necessary system upgrades and staff training;
(3) Grid integration and planning issues must be considered to integrate new power plants and current operating patterns with PV to help maintain system reliability and increase system flexibility;
(4) Forecasts of PV (installed capacities and locations) can help relevant stakeholders to host PV.

4. Conclusions

As there are concerns from relevant stakeholders about the impacts of PV on the grid and utilities in Thailand, it is important to have a method to forecast PV adoption annually (installed capacities and locations) in order to address grid integration-related issues. Our analysis intends to propose a systematic approach to forecasting installed capacities of PV adoption in Thailand. We selected the customer-adoption model because it can represent the relevant parameters, including PV installation costs, rates, and policies, as well as the market performance of PV in Thailand.

The key inputs of this forecasting model are the payback period of PV investment based on characteristics of load profiles and other assumptions about each customer group. Then, the maximum market share of PV was determined using the relationship between the willingness-to-adopt and payback period. The Bass diffusion model was used to address annual PV adoption in terms of the maximum potential for each scenario.

The two main parameters, the buyback rate and PV installation costs, were taken into account to forecast PV for eight scenarios. Reducing PV installation costs can shorten the payback period and increase PV adoption for all customer groups (RES, SGS, MGS, and LGS) while the buyback rate can help increase PV adoption mainly for RES, due to different load profiles. Thus, if the government would like to increase the PV adoption of each specific customer group, it is necessary to understand their load characteristics and the incentives that would encourage customers to adopt PV.

Using the assumptions of annual PV cost reduction's being at 2% and no buyback rate, it is obvious that solar PV's goal of Thailand can be in 2025 well before the end of AEDP in 2036. Also, in all eight scenarios, PV is expected to have shares of approximately 9%–14% in the energy basis of the overall system by the end of AEDP.

It is also important for Thai utilities not only to focus on maximum PV adoption by the end of AEDP but also to consider annual PV adoption in order to prepare their systems before hosting PV each year in the future. It is found that the percentages of maximum annual PV adoption to projected peak demand ranges from approximately 4%–5% for MEA, 5%–8% for PEA, and 5%–8% for the country overall. These results may encourage the utilities to pay attention to their power production plans in order to accommodate PV in the grid, secure the power supply, and understand the values and impacts of PV on their systems to mitigate stakeholder's concerns and help move forward policy support of PV in the country.

To accurately forecast PV adoption in Thailand, the following potential improvements to the forecasting model can be considered:

(1) Identifying a relationship between the willingness-to-adopt and the payback period using a survey approach based on the Thai context, as has been done by [31] for the U.S;

(2) Estimating p and q values in the Bass diffusion model based on the Thai historical data that may better reflect PV technology diffusion in Thailand;

(3) Improving accurate estimates of the rooftop technical potential for each customer group.

(4) Improving the customer-adoption model using agent-based models (ABM) for representing the complexities of customer behavior and technology diffusion, as discussed by [17, 32-33].

(5) Addressing each utility's maximum potential to host PV and the number of required PV installers with respective certification schemes to evaluate whether each scenario can occur in a real situation or not.

(6) There are some conditions that might be interesting to address under the step of payback period calculation (i.e. tax incentive for large-scale customers and loan option for residential customers to invest in rooftop PV). With these conditions, it will affect the level of payback period and PV adoption.

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