Using electrical energy storage in residential buildings – Sizing of battery and photovoltaic panels based on electricity cost optimization

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Using electrical energy storage in residential buildings – sizing of battery and photovoltaic panels based on electricity cost optimization

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Abstract

The popularity of small-scale residential energy production using photovoltaic power generation is predicted to increase. Self-production of electricity for self-consumption has become profitable mainly because of high-distribution costs and taxes imposed by the service providers on commercially produced electricity or because of the subsidies which reduce installation costs. Electrical energy storage can be used to increase the self-consumption potential of photovoltaic power. Additionally, electrical energy storage can lead to other benefits such as demand response or avoiding high load peaks. In this study, the profitability and sizing of a photovoltaic system with an associated electrical energy storage are analyzed from an economic perspective. The novel theory of sizing for profitability is presented and demonstrated using case studies of an apartment building and detached houses in Finland. To maximize the benefits, several alternative models for electricity metering and pricing are used and compared. The results demonstrated that the optimal size of the photovoltaic system could be increased by using electrical energy storage and suitable electricity pricing. This could lead to an increasing amount of photovoltaic production in the residential sector. Additionally, it is possible that when all the incentives are taken into account, electrical energy storage in combination with photovoltaic power generation would be more profitable than photovoltaic power generation alone. Photovoltaic power generation also increased the profitability of electrical energy storage, which could mean that the implementation of electrical energy storage in the residential sector could likewise increase.

Keywords: Cost optimization; Energy community model; Energy storage; Photovoltaic; Residential building; Self-consumption

1. Introduction

Electrical energy storage systems (EESS) could solve many problems in future electricity generation and distribution [1]. The use of renewable energy resources must increase rapidly in the near future in order to mitigate climate change. Renewable energy generation is often weather dependent (e.g., solar and wind power), which leads to rising needs for flexibility in the whole energy system. Flexibility in electrical energy systems can be increased in many ways. The intelligent use of electric devices as well as the implementation of EESS can introduce some of the required flexibility. EESS are very adaptable because there are various available solutions which possess different features. It is possible to choose the most suitable EESS solution a particular purpose.

Residential buildings are an important factor in the development of new flexible power systems. A significant part of annual electricity consumption is residential. For example, in Finland, annual

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electricity consumption was 85.2 TWh in 2016, and approximately 26.4% (22.5 TWh) of this was in housing [2]. Household appliances were responsible for about 36.4% (8.2 TWh) of the annual domestic electricity consumption, and the rest was consumed in heating spaces, domestic water, and saunas [3]. High flexibility in the load profiles of residential buildings makes them interesting targets for the application of demand response. The timing of load-use can easily be changed without significant loss of comfort. There are, however, still a lot of loads for which time of use cannot change. Customers' load profiles change a lot, and in the worst cases, load peaks accumulate at the same times for multiple customers. By applying intelligent control, this accumulation can be avoided. Using EESS, it is possible to implement demand response operations so that customers do not sense any significant loss of comfort, without instituting changes in the customer's consumption.

Electricity generation will become more distributed in the future, and to reduce the distribution losses and costs of distribution, it is a reasonable approach to produce energy on-site, where the consumption occurs. Small-scale electricity generation, for example, photovoltaic (PV) power generation, plays an important role in nearly zero energy buildings, where the consumed energy is compensated for by self-production [4]. Renovations of old residential buildings are important in reducing housing-related emissions. In Finland, there are many apartment buildings that were built in the 60s, 70s, or 80s, and their energy efficiencies are poor [5]. It is possible to increase the building's energy efficiency by applying such measures as adding insulation and changing space heating to heat pump–based systems. Old buildings consume a lot of energy despite being renovated, so on-site energy production is also needed. When the electrical energy is produced on-site, it incurs none of the losses associated with electricity distribution. Additionally, the decrease in the total amount of distributed energy could reduce the need to reinforce the grid in future if the load profile can be controlled intelligently, by EESS, for example.

Although EESS could be used to solve many of the problems associated with power systems, they are not yet widely used because of the high attendant cost and poor profitability. The battery energy storage system (BESS) is an EESS in which the storage technology is based on batteries. In the last decade, the price of lithium-ion batteries has fallen rapidly, and this trend is expected to continue [6]. The falling cost of batteries makes them a more interesting solution and increases the attendant profitability. When lithium-ion (Li-ion) battery prices fall and demand rises, mostly due to the increasing demand of the electric vehicle industry, there is a concern that rising lithium prices could in turn increase the costs of Li-ion batteries. The market price of lithium has only a minimal impact on the consumer price of Li-ion batteries, so the fall in the price of batteries could be expected to continue [7]. Another way to increase profitability is to maximize the benefits of EESS, and this is a very interesting research target. In this study, the term BESS is used when referring to batteries. When the case is generalized to include other storage technologies, for example, supercapacitors or flow batteries, the term EESS is used.

The current profitability of EESS both with and without PV in Finnish households is slow, but with a good control system and suitable development of electricity prices, it could become profitable in the future [8]. Power-based distribution tariff structures will increase the profitability of EESS if the pricing structures and the customer's load profiles are suitable [9]. Global study results all appear to be similar, but each country possesses its own special features; the electricity pricing structures and the production profiles of PV depend on geographic location.

In Finland and other Nordic countries, PV production occurs mostly in summer, when the production can be even higher than in Central Europe, because of long days and colder weather [10]. Germany and Italy are the main producers of PV energy in the European Union. Germany is very similar to Finland; the benefits of EESS are associated with Time-of-Use (ToU) tariffs, the increase in self-consumption, and possible dynamic tariffs with load limits [11].

Previous research projects have presented various results for the profitability of PV and EESS, which include some of the following published findings. Surplus PV production can be used to power domestic water heaters or air conditioning, which are more profitable than BESS alone [12]. It could be profitable to use community energy storage (CES) to store surplus energy from rooftop PV production within the residential building group [13]. The results of paper [14] showed that no significant differences could be detected in profitability and benefits between household energy storage (HES) and CES system architecture.

High PV penetration can cause an over-voltage problem [15]. This can be solved using BESS, which is typically connected in parallel with PV, and a control schedule which is locally administered by the HES. Voltage control schemes do not address the primary needs of the BESS owner. An economically-optimal control strategy may have been implemented with a time-dependent grid supply limit, which can lead to an over-voltage problem [16].

Increasing the site self-consumption of PV-generated power is the most common control aim of a BESS installation. Study [17] shows that although this control does decrease the total amount of power exported to the grid from the PV system, the PV power production peaks stay equally as high as without an installed BESS. This outcome is probable if the BESS is not controlled using smart systems. Using a forecast of PV production and household consumption in the control system, it becomes possible to decrease the impact on the grid caused by the PV production supply peaks. Residential buildings are good candidates for increasing self-consumption using BESS because the consumption usually occurs in different time of the day than the high PV production. For example, in commercial buildings, high consumption usually occurs during the daytime, when the PV production also peaks. Thus, the profitability of increasing self-consumption in commercial buildings using BESS is not as attractive [18].

To maximize the techno-economic benefits of BESS, it is important to correctly size the PV and BESS according to the customers' load profile [19]. Sizing a BESS with grid-connected PV is usually done by choosing the PV size first and then optimizing the capacity of the BESS. An example is presented in [20], where the sizing is done for a solar power plant. The same kind of sizing is done in [21], utilizing the Improved Harmony Search Algorithm, and in [22] for a rooftop solar power plant. This often leads to poor profitability of the BESS, but the results depend strongly on how the PV is sized. The sizing of PV systems has been demonstrated in [23] for Northern European conditions, in [24] by utilizing the mixed integer optimization model, and in [25] for a commercial building. In some cases, it was found that using BESS could increase the profitability of PV if the size of PV was increased [26]. This paper evaluates the profitability of PV with associated EESS and the process of sizing them accordingly. A different approach is used in this case which was not used in previous studies, however, since the EESS is sized first.

Residential buildings were chosen as the research target because the PV production profiles and building consumption profiles typically differ significantly. Apartment buildings form an energy community, where the local PV and EESS system benefit all the customers in the community. Local energy communities have been raised as an option in the EU clean energy package as a means to improve efficient energy management [27]. Previous papers have not commonly studied residential buildings while taking into account the differences between apartment buildings and detached houses.

A comprehensive analysis of the electricity pricing scheme and its effects on PV and EESS sizing has not previously been done. The aim of this study is to research how electricity pricing affects the profitability of PV and EESS. The research has been done from the perspective of the Nordic electricity market environment, especially within the Finnish context, but the results can be generalized for other global context by taking environmental differences into account.

The remainder of this paper is divided into six sections. Section 2 presents a theoretical analysis of optimal PV and BESS sizing from a techno-economic perspective considering different BESS control incentives. Section 3 introduces the simulation model, which is used in various case studies. Section 4 includes the input data from the consumption of residential customers, electricity price data, weather data, and data for PV production. Section 5 presents the results of simulation cases, which demonstrate the theory in practice. The discussion is presented in Section 6, and the conclusions of the paper in Section 7.

2. Sizing of PV and EESS in residential buildings

2.1. Introduction to the effects of electricity pricing and metering on the sizing of PV and EESS

The electricity pricing structure affects the sizing of PV system and EESS. Different countries, energy retailers and distribution system operators (DSO) possess multiple structures for electricity pricing and for accelerating the implementation of renewable energy generation. In this paper, electricity pricing structures, as used in Finland, or as presented in various research papers, are used. Different kinds of possible pricing structures, which affect the sizing of PV and EESS, are introduced in this chapter. Direct prices and structures are presented along with case studies later in the paper. However, the main pricing guidelines which affect sizing, are presented here.

Commonly-used incentives for PV are feed-in tariffs, ToU pricing, and net metering [28]. In many high PV–penetration countries, the implementation of PV is sped up with feed-in tariffs, which means that the customer receives a constant remuneration price for the total amount of generated PV energy (c/kWh) fed back into the grid. The problem with this approach is that feed-in tariffs encourage customers to acquire large PV system which can lead to high levels of power fed back into the grid supply. This can lead to problems in the distribution system. The feed-in tariff also requires extra metering so that all produced energy can be measured before self-consumption. In many countries, feed-in tariffs are slowly being abandoned; for example, Finland has no feed-in tariff for PV. For these reasons, the feed-in tariffs have been left outside of the scope of this study.

Net metering can be implemented on two different levels. A net metering scheme usually requires the customer's entire energy supply to the grid and their consumption to be calculated together. The customer benefits from all produced energy regardless of their consumption level. This type of total net metering obviates the need for a local EESS to increase self-consumption and thus removes the incentive and makes the use of EESS unprofitable [29]. Total net metering can lead to the same problems as those associated with the feed-in tariff because it provides incentive to supply all surplus energy to the grid when customer's total amount of energy supply keep lower than total consumption. Total net metering is not used in Finland and is therefore excluded from this study. Net metering is also sometimes applied as a summation of hourly consumption and energy supply to the grid. Traditionally, grid supply and consumption are measured separately using separate meters. Using a bi-directional meter for hourly net metering, the consumption per hour is measured and the customer is charged per measurement. Hourly net metering removes the incentives for EESS operations which take less than an hour but makes for easier evaluation of PV profitability and sizing. Metering practices vary between countries and DSOs; in Finland, most DSOs use hourly net metering. In this paper, all calculations are made using hourly net metering.

One easy way to influence a customers' consumption is to use ToU pricing, where the price of electricity varies with time. The price can change once a day or even every hour. The price is typically higher when the consumption of the whole power grid is higher. PV production typically peaks at approximately midday, and the highest consumption peaks usually occur in the evening. ToU pricing thus provides an incentive for demand response operations. In Finland, customers with access to self-production can make a contract with the energy retailer in which the retailer will buy surplus energy. Market-price-based real-time pricing is often used in this scenario. The hourly price is determined using an hourly day-ahead spot-price for the region of Finland within the Nordic electricity market [30]. Energy retailers, who can be competitive, apply their own margin that they take off the grid supply price and add to the purchase price. Additionally, value-added tax (VAT) is added to the purchase price. This kind of pricing is used in this study as a market-price-based tariff.

In countries like Finland, where energy retailers and DSOs are separate entities, a distribution tariff provides the biggest incentive for EESS with PV. Another incentive is the electricity tax, which does not have to be paid by small-scale producers (under 100 kVA) in Finland. The electricity tax and distribution price are included in the electricity purchase price, but not in the grid supply price. Therefore, it represents a significant difference between these prices. The electricity tax with a strategic stockpile fee for typical residential customers is 2,253 c/kWh plus 24% VAT in Finland [31].

There are multiple structures available for pricing the distribution fee. The basic model consists of the basic charge (€/month) and the volumetric charge (c/kWh), which are commonly used in Finland. Another model is the ToU, in which the volumetric charge varies between day and night. Larger customers command pricing structures. In these, a part of the basic and volumetric charges are replaced by the demand charge (€/kW). The demand charge could be implemented in various ways, for example, power usage to be charged could be taken as the highest average hourly power usage of a sliding year or the three highest power usages of a sliding year. Recently, there has been discussion about how power tariffs could also be implemented for small-scale residential customers. Because part of the profitability of residential PV comes from the volumetric charge, there is a concern that the profitability of PV will decrease if power tariffs are introduced. However, the demand charge provides a new incentive for EESS use [9].

Customers in apartment buildings have separate electricity contracts for each apartment. Their consumption is typically so low that the opportunity to participate in demand response or any energy-saving operation is very limited. These kinds of operations in apartment buildings are typically implemented via their common electricity use, for example, elevators, lighting, and heating. It is possible to change the common metering when the customers of an apartment building form an energy community. Along with this change, PV and EESS can be utilized for the benefit of the entire building and its customers. This change can cause some legislative problems. In countries like Finland, however, it is still a possibility if every customer accepts the conditions. Of course, customers have the option of leaving the community if it is their desire [32]. This approach could lead to problems in the sharing of benefits and costs among customers. Different types of solutions have been developed for this scenario, such as presented in [33]. The energy community model is presented later in this paper.

2.2. Sizing of PV panel array

The size of the PV panel array is limited by physical and economic factors. Physical boundaries such as roof area can limit the PV array size, but for the purposes of this study, the sizing is done only from an economic perspective. The aim is to find the size of the PV which maximizes the profit. To maximize the profit, first the annual cost savings have to be determined. Fig. 1 shows the basic principle of dependence between the annual cost savings and the PV nominal power. The wide red curve C shows this dependence. It consists of two straight lines and the curvature between them. Line A ($y = ax+f$) was fitted using linear regression: when all energy produced was self-consumed, it compensated for the energy purchase. The annual cost savings came from the purchase price of electricity, including distribution fees and taxes. Line B ($y = bx+g$) was fitted using linear regression when all produced energy was fed back into the grid, and the annual cost savings came from the sale of energy and thus from its selling price. The variables in Fig. 1 are presented in table 1.

At some point, as the PV size increases, the produced energy can no longer all be self-consumed, and the production of surplus energy begins (point c, h in Fig. 1). If the PV continues to increase in size from this point, the production increase associated with the increased size of the PV array becomes surplus energy (after point e, j in Fig. 1). Slope b depends on the electricity grid supply price and slope a depends on the electricity purchase price. Changes between points c, h and e, j are not linear, and the customer's load profile determines how the line curves.

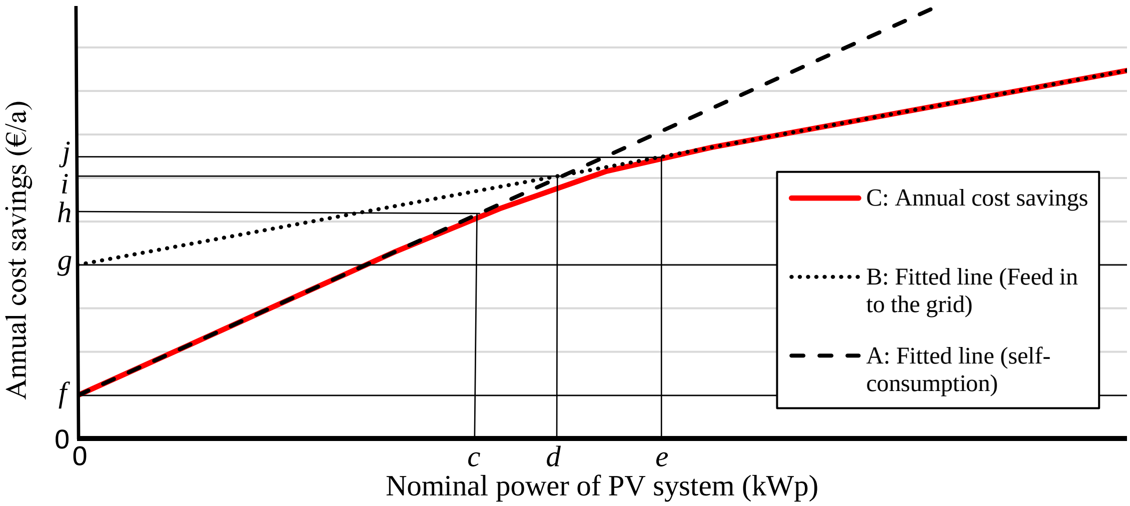

Fig. 1. *Annual cost savings dependence on nominal PV power.*

Table 1. Variables in Figs. 1, 3 and 4.

Variable	
a	Slope of line *A* ($y = ax+f$)
b	Slope of line *B* ($y = bx+g$)
c	Nominal power of PV after which energy starts feeding back into the grid
d	Crossing point of lines *A* and *B* (Nominal power of PV) and optimal size of PV
e	Nominal power of PV after which all extra energy is fed back into the grid
f	Constant term of line *A* ($y = ax+f$)
g	Constant term of line *B* ($y = bx+g$)
h	Maximum annual cost saving when all produced energy is self-consumed
i	Crossing point of lines *A* and *B* (Annual cost saving)
j	Maximum annual cost saving at maximum self-consumption
k	Maximum profit of PV
m	Optimal size of PV with EESS
n	Maximum profit of EESS

Using real data from customers, a very large PV array size is typically needed to reach the real point *e*. However, this may actually be impossible because only a small part of the increased production is timed to coincide with periods of high consumption, e.g., in the evening. Yet it is reasonable to accept that thereafter, point *e* is the point at which an increase in self-consumption becomes negligible. The width of the gap between *c* and *e* also depends on the customer's load profile. If the shape of the curve of the customer's load profile is similar to the PV production profile curve, the gap between *c* and *e* becomes small and the change between the lines becomes dramatic because an increase in PV array size also has a similar effect during the day. If the customer's load profile curve differs from the shape of the PV production profile curve, the gap between *c* and *e* becomes wider because the increasing PV production can supply the load during the mornings and evenings, even if the midday load is already supplied. Fig. 2 shows a sample profile curve for a typical customer's load and three PV production profiles (PV 1, PV 2, and PV 3) for different sizes of PV array. All PV production using profile PV 1 is used on-site to supply the customer's load (green area in Fig. 2). When the size of PV array increases (profiles PV 2 and PV 3), the midday surplus

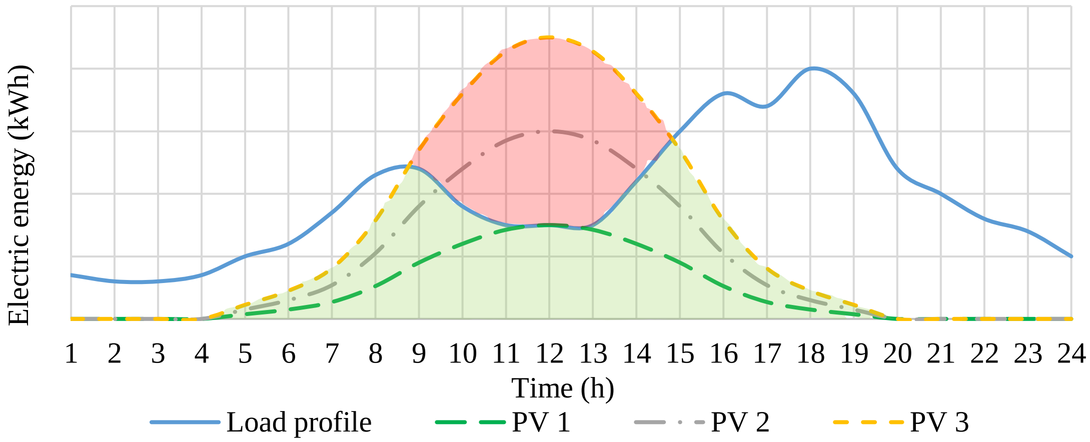

Fig. 2. *Typical load profile of customer and three PV production profiles from different sizes of PV.*

production (red area in Fig. 2) must be fed back onto the grid, but increases in morning and evening production can still be used on-site.

Even the change from only on-site consumption (line *A* in Fig. 1) to surplus power supply to the grid (line *B* in Fig. 1) is not dramatic; the most dramatic change occurs when the nominal power of PV is *d*. The annual cost saving *i* along with its associated PV size depends on the magnitude of the change between lines *A* and *B*. The constant term *f* of line *A* indicates the annual cost benefit without PV, which can come from incentives other than increasing self-consumption. Examples of these other incentives include decreasing peak power usage or the application of market-price-based control.

The investment costs associated with PV depend mostly on its nominal power (€/kWp), but there is also, for example, some of the initial installation costs do not depend on the nominal power. For this reason, the total investment price per kWp can decrease as the number of installed panels increases. However, in reality, the PV investment cost is not directly proportional to its size. In sizing PV, it is assumed that the price per kWp is constant. This supposition is valid when the size of any change is small, and the cost of the panels is large compared with the installation costs. To evaluate the profitability of PV, the benefits and the costs have to be compared. The benefits are calculated using the annual cost savings (€/a) in Fig. 1, so the PV costs also have to be estimated using yearly costs (€/a). The investment costs for PV can be roughly estimated so that they are evenly distributed over the lifetime of the PV system.

Fig. 3 shows the basic principle of comparing the annual costs of PV and the annual cost savings, which are lines A and B in Fig. 1. If the slope of the PV cost line is lower than slope *a* (as in Fig. 1) but higher than slope *b* (as in Fig. 1), the highest annual profit *k* comes with the nominal power *d* of PV. This is the basic principle used for sizing PV systems. If the slope of the PV cost line is lower than slope *b*, PV is always profitable and only physical or legislative boundaries should limit its size; if the slope of the PV cost line is higher than slope *a*, the use of a PV system of any size is not profitable. In a real situation, the annual profit is lower than *k*, caused by a non-ideal change between lines *A* and *B*. For this reason, the ideal size of the PV system is slightly lower than *d*. Available sizes of a commercial PV system is discrete, so the customer can invest in a system which size is smaller than *d*. When referring to PV in this paper, the size d is referred to as the optimal size.

2.3. EESS use for demand response operations

The use of EESS for demand response (DR) operations has been unprofitable due to its high investment costs and low economic incentives [8]. Li-ion batteries are the main solution for residential EESS because of their high efficiency, long lifetime, and small physical size in relation to its capacity [8, 19]. In previous years, the price of Li-ion batteries has fallen rapidly [6]. At the same time, the volatility of the electricity price has increased, therefore increasing the attractiveness of DR [34].

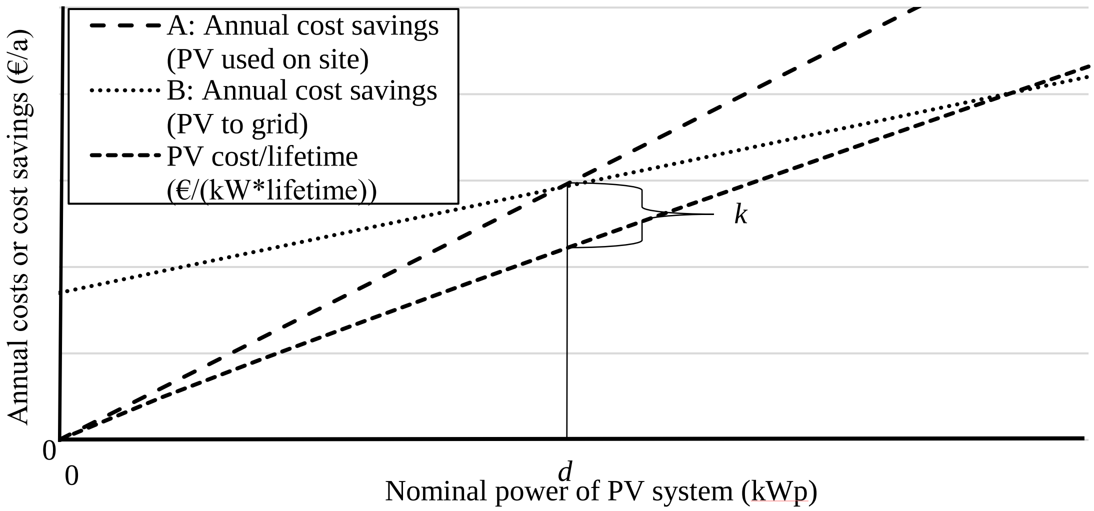

Fig. 3. *The basic principle of PV sizing.*

Additionally, the novel structures of distribution tariffs can include new incentives for using EESS for DR [9], so it would be meaningful to research the use of EESS for DR.

The timing of electricity use is modified in DR operations, for example, using the washing machine at night or switching off the electric heating during peak hours. These operations can cause a loss of comfort for the customers, such as a decrease in room temperature or a delay in household operations like washing clothes. Using EESS, it is possible to implement DR without any loss of comfort. In DR operations, EESS discharges when the aim is to decrease consumption, and charges when it is possible to allow the level of consumption to increase. The use of EESS for DR is an operation which is the reverse of the delayed use of electric devices. Delayed use decreases consumption and can be implemented immediately without prior planning, but the use of EESS to decrease peak powers must be planned in advance because the necessary energy should be available in the EESS.

The sizing of EESS for DR operations is based on the load profile of the customer [8]. If the income from DR depends on the amount of shifted load (c/kWh), the maximum income depends on the amount of the load during response hours. These kinds of incentives include, for example, market-price-based dynamic tariffs or ToU tariffs. A suitable EESS size would approximately match the customer's average load during high-cost periods because the load can roughly be fully supported using this size EESS. Theoretically, if the EESS size increases any further, the increase in annual cost saving, which is dependent on the capacity of EESS, starts to drop off and the profit starts to decrease.

With power-based tariffs, the optimal size of the EESS depends on the difference between peak power (hourly average maximum power) and the level of normal daily peaks [9]. It is possible to lop off individual high peaks, which are not daily, repetitive occurrences, using the EESS. Additionally, the structure of the power-based tariff affects the sizing of the EESS. If the power charge is directly proportional to the peak power (€/kW), the EESS can be sized for the full range of the peak difference, but if the structure includes some step boundaries, they could limit the size of EESS.

2.4. EESS with PV in residential buildings

The annual profit generated by PV also depends on the nominal power of the PV system. This dependence can be shown when the PV cost line from Fig. 3 is projected onto the horizontal axis, as shown in Fig. 4. In the other words, the profit can be calculated by removing the costs from the savings. The shape of the curve depends on many variables, but Fig. 4 shows the basic principle of the phenomenon. The highest annual profit *k* comes with the nominal power *d* of the PV system. Using EESS, it is possible to increase the on-site use of produced energy. When the load is lower than the PV production (the red area in Fig. 2), the storage is charged, and when the load is higher, the storage is discharged. This increases the constant term g of line B and can also increase the slope of B. These changes lead to an increase in the optimal PV size (PV + EESS). The new optimal size of PV with EESS is m and the increase in annual profit from PV with EESS is n.

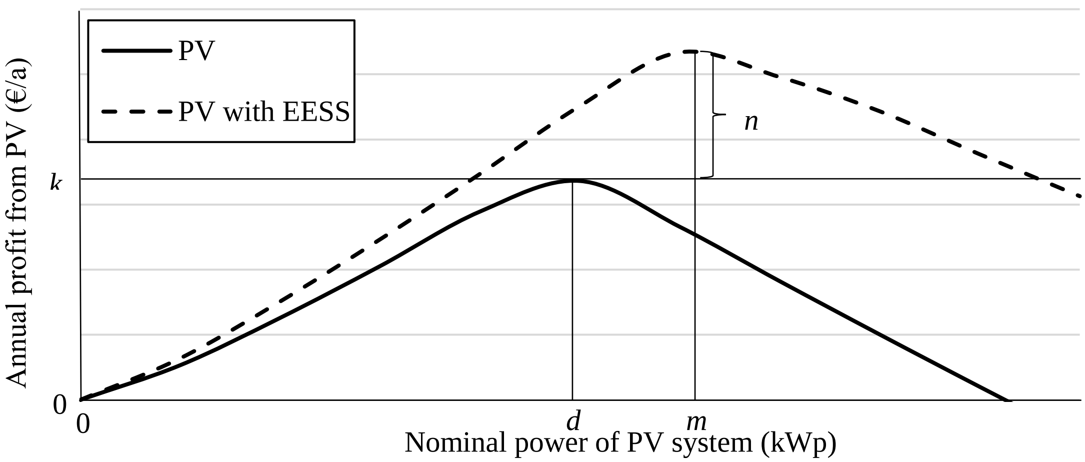

Fig. 4. The basic principle of PV sizing.

The evaluation of PV and EESS profitability and sizing of these is slightly complicated by the fact that it can be done based primarily on PV or EESS. Either the PV or EESS sizing must be performed first. When the size of PV increases as a result of using EESS, the investment cost associated with PV also increases. However, the part of the increasing annual profit that results from the increased size of the PV or from the use of EESS is still unknown. If only the profitability of EESS was under investigation, its annual profit can be seen to be nearly constant for any PV size which is higher than m. In this case, the annual profit from the EESS is higher than n (i.e., the difference between the curves in Fig. 4). When the optimal PV size is applied in this paper, the annual profit from the PV is k with a nominal power for the PV system which is d or higher. The annual profit from EESS is n for the optimal size of EESS. When the EESS is involved in the building's energy system along with PV, the aim in sizing the PV system is to find the nominal power m, as in Fig. 4. The problem with multi-objective optimization is that the optimized variables affect each other. Often, the PV has been sized before the EESS, and the sizing of the EESS is thus based on a constant PV size. In this study, the aim is to size the PV and EESS together.

2.5. Evaluation of profitability

The annual profit and internal rate of return (IRR) is used to evaluate the profitability of PV and EESS in this study. The payback period is usually used to evaluate the profitability of PV or EESS as in [35]. The payback period confirms whether the investment was profitable and how long it will take to begin generating profit. This period is not an informative variable for identifying the total profit or for situations in which different applications are being compared.

PV profitability is often evaluated using the levelized cost of electricity (LCOE), as in [36]. This is the price of generated electricity and can be calculated by dividing the entire lifetime cost of the generation system by the amount of electricity generated over its lifetime. Levelized cost of electricity is a good measure to use when the aim is to compare energy sources or to research whether PV production is more profitable than purchasing energy from the grid. When EESS is combined with PV, the use of LCOE is questionable, because there is a risk that the uncertainty of the results will increase due to different lifetimes associated with PV panels, power electronics, and the battery system.

An effective variable in the evaluation of profitability is the IRR (see, e.g., [37]). It is a good variable to use when different solutions are being compared, but it is also sensitive to changes in investment costs. Investment costs are difficult to estimate in this kind of study, so critical evaluation is required. However, all profitability evaluation methods must first be evaluated for annual cost benefits: Figs. 1 and 3 show how annual electricity savings are estimated. From this, it is also possible to calculate annual profit when the annual investment costs are reduced from the annual savings.

3. Simulation model

3.1. Basic structure of the simulation model

The simulation model consists of a control system and battery model as described in previous studies, such as in [8]. The control works on two levels: hourly and continuously. The hourly control determines the most profitable move for the following hour. In reality, the control decisions are based on load forecasting, PV production forecasting, and the state of the EESS. In these simulations, the principle is the same, but the load and production forecasts are based on the actual load and production, which correspond to the ideal forecasts. The actual load and production are used to avoid errors caused by forecasting errors. The aim of the continuous control is to execute the objective provided by the hourly control. When using ideal forecasts and the consumption data of average hourly consumption, the importance of continuous control is minimal. However, it becomes important in situations where the EESS reaches full charge or is completely discharged at some point within the hour. The type of EESS could be variable, but in the simulations used in this study, the focus was on BESS because it is a commonly used solution in this scale of application.

3.2. BESS model

The type of BESS used in the model is a Li-ion battery with a lithium iron phosphate (LFP, LiFePO4) cell-type and a graphite negative electrode. This type of battery is suitable for residential use because of its long cycle and calendar lifetime and good safety features [38]. The BESS system and its connection to the building's electricity network are shown in Fig. 5. The BESS is controlled via an inverter, which requires information from all other components of the system. The battery converter includes a charge controller and the solar panel converter includes the PV controller.

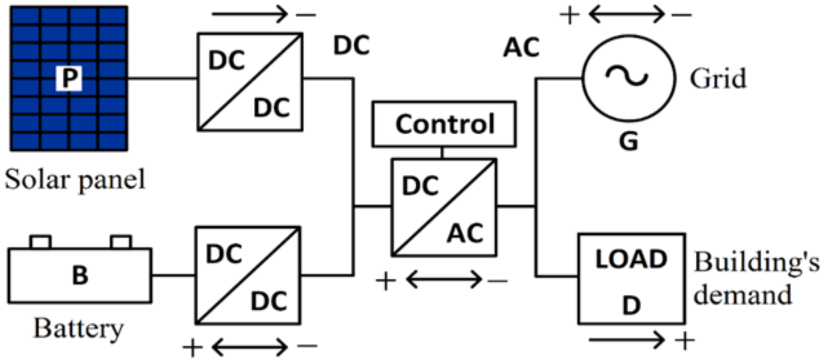

Fig. 5. BESS components and connection to building's electricity network [8]

Modelling of the BESS state is based on the state of charge (SOC), as shown in equation (1):

$$SOC_t = 100\frac{E_t}{E_{\max}} = 100\frac{B_{eff}B_t}{E_{\max}} + SOC_{t-1}, \tag{1}$$

where E_t is the amount of stored energy at time t and E_{max} is the maximum capacity of the BESS. The SOC at time t is SOC_t and SOC_{t-1} is the SOC of the previous time step. Variable B_t is the energy transfer to or from the energy storage and B_{eff} is the efficiency of the transfer. The positive and negative directions of current flow, if they are possible, are shown in Fig. 5.

The modeling of losses in BESS is based on the efficiencies of its components. To simplify, the losses are assumed to be the same in both directions, even though in reality, the charging and discharging losses are not identical. When the average losses are estimated in both directions, it gives a good approximation of overall losses because the use of BESS is cyclic. In this study, the efficiency of the inverter η_{inv} was 98% and the DC-converter efficiency η_{dc} was 99%. Thus, the energy transfer efficiency between the network and the storage was 97% and the energy transfer efficiency between the PV and the battery is 98%. BESS losses occur mainly in the converters and in the battery itself [38]. Battery losses increase when the SOC is low or very high [39]. For this reason, the SOC limits of the battery were set at 25-95%. When the battery was not completely charged or discharged, charging losses depended almost linearly on the charging current I_c, assuming that the internal serial resistance R_b was constant. [39]. In this case, the charging efficiency η_c can be calculated using equation (2):

$$\eta_c = 100\frac{V_b - I_c R_b}{V_b}, \tag{2}$$

where V_b is the nominal voltage of the battery. The efficiency B_{eff} in (1) can be obtained by multiplying the efficiencies η_{dc}, η_{inv}, and η_c. The energy transfer of storage B_t is calculated by multiplying the charging current I_c with the charging voltage V_c, which can be calculated using equation (3):

$$V_c = V_b - I_c \cdot R_b. \tag{3}$$

The battery consists of cells, which are series or parallel connected (as required), so that a suitable capacity and voltage are produced. In simulations, the internal serial resistance value of one modelled cell was 0.026 Ω, the cell voltage was 3.3 V, and the capacity of one cell was 2.5 Ah [26]. The maximum output power of the battery could be expressed using C-rate, which is the battery’s ratio of maximum power and capacity. In this study, the C-rate 0.7 C was used because it was the most profitable C-rate employed for this type of use [9]. The effect of BESS and PV on the customer’s electricity cost was modelled using equations from the grid perspective. The energy taken from the grid or the supply fed back into the grid (G) was determined using a model based on the energy transfer between the BESS, the building’s demand D and production. This was determined by the three options. When the battery was charged, the energy transfer between the building’s network and the grid could be represented using equation (4):

$$G = \begin{cases} \dfrac{B_t - P_{dc}}{\eta_{inv}} + D, & \| P_{dc} < B_t \\ -\eta_{inv} \cdot (P_{dc} - B_t) + D, & \| P_{dc} \geq B_t \end{cases} \tag{4}$$

where P_{dc} is self-produced PV energy after the converter stage but before the inverter. The equation depends on whether the charged energy comes from the PV, or if it also needs to be supplied by the grid. The third option is to discharge the BESS. This can be calculated using equation (5):

$$G = \eta_{inv} \cdot (-B_t - P_{dc}) + D \tag{5}$$

3.3. Control of BESS

To minimize the costs of electricity, control of the BESS based on economic incentives is introduced in [8]. The main incentive comes from the difference between the purchase price and the grid supply price. For this reason, the main task of the control system is to avoid supplying electricity to the grid if possible. The level of the BESS SOC must be low before the instances when production is higher than consumption. At the beginning of every hour, the control system calculates the optimal

BESS-use profile for the next 18 hours based on the forecasted loads and production. If there are times when production is higher than the consumption, the control discharges the BESS before these times so that there is space left to accommodate the surplus energy. The control strategy for increasing energy self-consumption is very simple and the frequency of use of the BESS depends on the size of the PV system.

Another incentive for the use of BESS is the power-based price component of the distribution tariff, if one is involved. A control strategy used to decrease the maximum hourly average power has been presented in [9]. This type of BESS use is the reverse of the approach which increases self-consumption because the SOC must be high before the hour in which the BESS is required to decrease the load. Additionally, the highest load and production peaks do not usually happen in the same day, nor even in the same season. Therefore, these two control tasks are not mutually exclusive.

Because the load profiles of customers vary, there are many situations where the BESS is not needed to increase self-consumption or decrease maximum peak power. During these downtimes, BESS can be utilized for other purposes. The third incentive is the ToU pricing, which is less effective in term of profitability than the previous two incentives [9]. In this study, the ToU tariff of the energy retailer was similar to real-time pricing, where the price changes hourly based on day-ahead market prices. Customers may also have another ToU structure in the DSO's tariff, with two constant prices per day: daytime price (7–22) and nighttime price (22–7). These tariffs present an incentive for customers to shift loads out of the high-price hours to low-price hours. For this reason, the control system uses market-price-based controls, which have been introduced in [8]. An effective control algorithm can be based on hour-pairs, such as the lowest price hour and the highest price hour of the optimization period (18 hours). The control aims to charge and discharge BESS during these hours if the price difference is so high that the benefit outweighs the losses caused by using BESS or if the other incentives do not prevent it. Few rules are added for improving the control algorithm presented in [8] and the peak power decrease algorithm presented in [9]. If a possible power peak was imminent, the control system fully charged the BESS during the three previous hours, and if it was forecast that surplus energy would be produced, the control system discharged at least the forecasted amount of surplus energy from the BESS before surplus energy was produced.

3.4. Simulation of PV production

The PV production model used to model the performance of a tilted solar panel is based on the global solar irradiance components. These are namely the direct beam $G_{b,i}$, the diffuse component $G_{d,i}$ and the reflected component $G_{r,i}$. The model of global solar irradiance based on geographic location is introduced in [41]. In this study, the PV power plant is assumed to be in Tampere; its azimuth angle is 0° and it is tilted at a 45° angle. Global irradiance is the sum of irradiance components $G_i = G_{b,i} + G_{d,i} + G_{r,i}$. Beam irradiance can be modeled accurately if the conditions of the sun are assumed to be constant. Beam irradiance can be calculated using $G_{b,i} = G_b \cos \theta_i / \sin \alpha_s$, where G_b is the horizontal beam irradiance, θ_i is the angle of incidence onto the surface based on the azimuth angle of the sun, and α_s is the solar elevation [42]. For an isotropic sky, the diffuse irradiance on a tilted surface can be calculated using $G_{d,i} = G_d (1 + \cos \beta)/2$, where G_d is the horizontal diffuse irradiance and β is the angle of inclination of the panel. The reflected irradiance can be calculated using $G_{r,i} = \rho_g\, G\, (1 - \cos \beta)/2$, where ρ_g is the average reflectance of the ground and G is the horizontal global irradiance, which is used because both the beam and the diffuse irradiance are assumed to reflect isotropically.

Several models have been developed to model diffuse solar irradiance. The Perez All-Weather Sky Model is the best model to use with the conditions associated with Finland, but if the solar panels are tilted toward the south, the Reindl model is superior [42]. The panels used in this study are tilted to south, hence the Reindl model is used. The Perez model is introduced in [43] and the Reindl model in [44]. Additionally, the Reindl model is considered one of the best diffuse solar irradiance models as noted in [45]. The ratio of the horizontal diffuse irradiance and the horizontal global irradiance in the Reindl model is based on the brightening factor k_T. In practice, the brightening factor depends on the cloudiness of the sky. Given that the actual cloudiness varies, cloudiness probabilities are used instead. The model for cloudiness probability in Finland is presented in [46] and is utilized in this study. The simulation model is stochastic because of the use of probabilities to model the variability of cloud cover in every simulation.

The average reflectance has two constant values in simulations for the year. During the winter season (December–April), the average reflectance is taken to be $\rho_g = 0.58$, which corresponds to the reflectance of snow. At other times of the year, it is taken to be $\rho_g = 0.24$, which corresponds to the reflectance of dark roof materials and deciduous trees, which are the assumed materials directly adjacent to the solar panels.

The PV production (P_{PV}) can be calculated using equation (5), where P_{STC} is the nominal power in standard test conditions (STC), β_P is solar cell power temperature coefficient (0.006), T_c is the solar cell temperature and T_{STC} is the standard solar cell test temperature (25ºC) [42]. The verification coefficient C_v is added to the equation so that the simulation model for PV production can be verified with real measurements from PV systems.

$$P_{PV} = C_v P_{STC} G_i \left(1 - \beta_P (T_c - T_{STC})\right) \tag{5}$$

The same PV production simulation model was used in [8], where it was verified by comparing model values to real values as measured from polycrystalline silicon PV cells. The result was that the model systematically generated values that were too high, leading to the necessity of setting C_v to 0.85. The reason for this could be that the temperature of the solar cell was too low in the model or that the physical solar panels' efficiency was decreased, caused by the aging of the cells, soiling of the panels, or not accounting for shade in the model. Additionally, this is affected by the type of solar cell used for verification. The verified simulation model generated realistic data for PV production.

4. Initial data and energy community model

4.1. Consumption data

Two case studies were used in this study. Case study 1 was an apartment building for which the consumption data covered four years (2013–2016), including hourly energy consumption measured using an AMR meter. The load data for individual apartments and for the building were separate; the load data for the building consisted of such items as common space lighting, the elevator, and the electrical heating load. Case study 2 consists of a total of 12 detached houses located near the Tampere area. The data was also measured using modern AMR meters. The measurements spanned two years (2014–2015). In simulations, the first year of data represented the comparison year, and the EESS and PV were assumed to be installed at the beginning of the second year. In the apartment building for instance, the simulation was performed over three years and for one year in the detached houses.

In case study 1, the study object, "Tammela" (see e.g., [5]), is the apartment building in central Tampere. The building was constructed in 1980 and has been widely renovated to increase energy efficiency. There are 56 electrical network connection points: the building's electricity, 54 apartments, and a business premises. This kind of large apartment building consumes a lot of energy for warming. Before the renovation, all warming energy had been purchased from the city's district heating network. An exhaust air heat pump (60 kW) was installed in 2014 to increase energy efficiency. The total amount of purchased energy decreased by 41% per year after this installation. The amount of purchased district heating energy has decreased by 66% overall, significantly decreasing energy costs. However, electricity usage has simultaneously increased by 26% (from 170 MWh to 215 MWh per year), even though there was an extensive electricity-saving renovation which included changing old lighting over to LED lighting. The highest annual electricity load peak for the building has also increased significantly. The hourly average maximum power was approximately 50 kW in 2013 and 70 kW in 2016 (40% increase). These kinds of energy-saving renovations will become more common as efforts to decrease energy consumption and to prevent climate change become more popular, but this actually caused an increase in electricity demand and highlighted the need to strengthen the electricity grid.

In case study 2, the study subjects were selected from a group of 1525 customers so that the electricity usage behavior varied widely, but they were all still typical detached house customers. More accurate data from selected customers is presented in Table 2, which shows the annual consumption and average hourly maximum power. Additionally, the percentage of winter consumption from December to February and the hour of day when consumption was most likely to be highest are shown.

Table 2. Study group of detached house customers

Customer	Annual consumption (MWh)	Hourly average maximum power (kW)	Winter consumption (Dec – Feb) (%)	Average of highest consumption hour
1	26.9	11.4	40.2	23
2	20.9	8.9	35.0	23
3	9.7	8.3	39.4	22
4	6.7	4.6	40.0	23
5	23.6	16.5	36.6	20
6	7.8	11.0	28.5	17
7	14.1	9.4	35.1	23
8	14.7	8.9	31.3	20
9	21.2	11.5	33.7	22
10	15.6	8.4	35.9	6
11	10.4	6.0	37.0	23
12	14.5	7.2	38.6	9
Average	15.5	9.3	35.9	19

4.2. Energy community model

For legislative reasons, in apartment buildings in Finland, the production of PV can be utilized practically only for the building’s own load, not for individual apartment loads. Each apartment has its own electricity contracts with the energy retailer and the DSO. Energy produced by a PV system owned by the housing company is not profitable in apartments because small-scale energy producers can sell surplus energy only to the grid. If this surplus energy is sold to the grid and some apartments purchase it from the grid at the same time, the apartment owner has to pay a distribution fee to the DSO, as with all other electricity vendors. Using EESS makes it even more complicated because apartments cannot use stored energy from a PV system owned by the housing company, for example, unless the housing company has purchased it from the grid. So, in practice, the EESS and PV can be utilized only to supply the loads of individual apartment buildings if the metering is implemented in a typical way. It is also possible that the individual apartment owner could install PV and EESS for their own use, but they can utilize them only to supply their particular apartment’s load. The basic principle of the energy community model and the present model are shown in Fig. 6.

EESS and PV could be utilized for the whole building’s load only if the energy community model is used. In this case the building forms an energy community and makes only common contracts with the energy retailer and the DSO. All combined electricity (from the building and the apartments) purchased from the grid or supplied to the grid is measured using one meter. Legally, every customer must retain the option to select their own energy retailer, however, this can lead to problems. The energy community model is possible only if all apartment owners accept this model and retain the option of resigning from the community. The apartment building’s energy community forms such a large unit that it is possible to choose a low-voltage power distribution tariff, which is typically only provided to small industrial customers. It includes a power-based charge component, which could increase the profitability of the EESS [9].

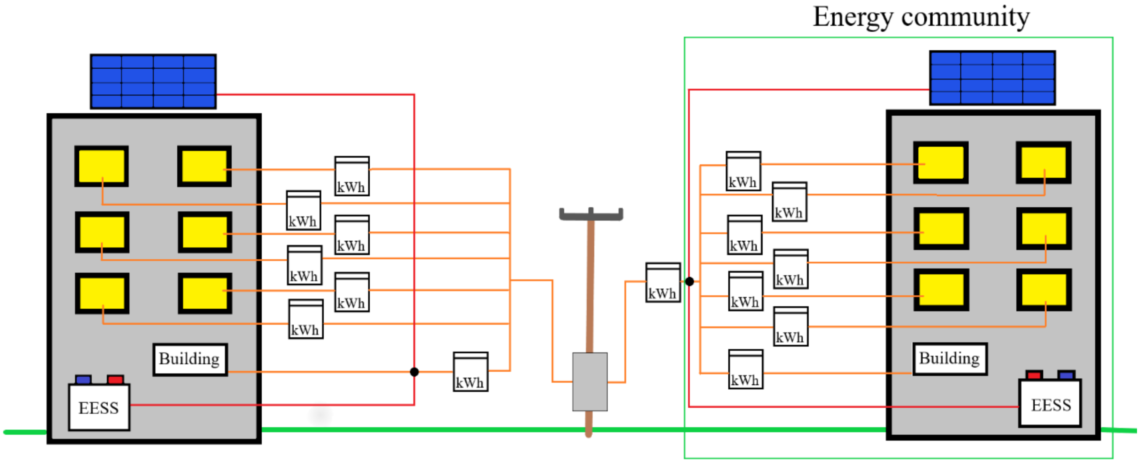

Fig. 6. Apartment building using the energy community model (right) and a typical model (left).

4.3. Electricity price data

In all calculations presented in this paper, the energy retailer tariff has been used, which is a dynamic market-price-based tariff based on day-ahead area prices for Finland in the Nordic electricity market [30]. The energy retailer margin used in the model is 0.25 c/kWh, which is typical in Finland.

The distribution tariff depends on the case type. For case study 1, the low-voltage power tariff was used. To study the benefits of the energy community model, the general tariff was also used. It is the simplest of distribution tariffs and includes only a basic charge and a constant volumetric charge. The low-voltage power tariff includes the basic charge and volumetric charge along with a two-time ToU structure and a power charge. To define the monthly power charge, the highest power peak in the previous 12 months was used, calculated as an average of the two highest monthly hourly power peaks. The charge components are introduced in Table 3.

Table 3. Alternatives for the distribution tariff in a case study of an apartment house (Case 1) [47]

Tariff	Basic charge €/month	Volumetric charge c/kWh (7-22)	Volumetric charge c/kWh (22-7)	Power charge €/kW/month
General 3x(25A–63A)	3.98	5.98	5.98	
General 3x(>63A)	25.73	5.98	5.98	
Low-voltage power	213.18	4.52	3.97	2.58

Different tariff structures and prices were used in the detached houses case study (case study 2) because the houses were located in different DSO areas and power-based tariffs were not commonly used for domestic customers. Study prices were used here, as presented in [47] and [48], which were calculated for the same DSO area as the area in which the detached houses were located. Tariff components are shown in Table 4, including taxes. In the power-based tariff (simply termed “Power” hereafter), the power-based component is charged based on the highest hourly average power usage for the month. Weightings of the power charge component were calculated theoretically, and charge components of the power-based tariff represented total corresponding costs. If the DSO were to shift to power-based tariffs for small customers, in practice the power charge component might be lower and the other components higher.

Table 4. Alternatives for the distribution tariff in the detached houses case study (Case study 2) [47]

Tariff	Basic charge €/Month	Volumetric charge c/kWh	Power charge €/kW/Month
General 3x25A	13.66	6.09	
Power	4.74	3.51	7.23

4.4. Investment cost of BESS and PV

The actual investment cost of BESS depends on many things, such as the type of system, BESS manufacturer, and power retailers. Installation and maintenance also contribute to the costs, so accurate investment costs are difficult to estimate. The investment costs for Li-ion-based BESS were studied; the results in [22] state that in 2015, the LFP cell prices were in the 200–350 €/kWh range, and the projected price for 2020 ranged from 100 to 200 €/kWh. The cost of the required power electronics was in the 100–150 €/kW range in 2015, and it is assumed that it will reach approximately 80–110 €/kW in 2020 [49]. Power electronics can be partly combined with the PV system, so these costs could be divided between the PV and BESS. The total costs of the BESS can be roughly estimated, including investment and maintenance costs, ranging from 200 to 400 €/kWh. The calendrical lifetime of the LFP-based BESS is approximately 15 years, as presented in [50].

The investment costs for the PV system (€/kWp) strongly depend on its size. The relative costs of small-scale PV power plants are high in relation to larger systems. A PV system under 10 kWp can cost over 2000 €/kWp [4]. Over 40 kWp, the PV systems can cost approximately 1300 €/kWp in Finland [51]. The PV system costs used in this study included the costs of power electronics and some installation and maintenance costs and ranged from 1500 to 2100 €/kWp. The lifetime of a PV system is approximately 30 years (see [51]), and it is recommended that the power electronics be replaced or upgraded once in a PV system's lifetime.

5. Simulation results for case studies

5.1. Case 1: Apartment building

Table 5 shows a comparison of the annual electricity costs of an apartment building based on the distribution tariff using the energy community model with a low-voltage power tariff and with a general tariff. The comparison was made over four years (2013–2016). The building's electricity supply main fuse was 3x125A and each apartment's main fuse was 3x25A. In Table 4, *general* signifies general tariffs with typical contracts, where every apartment pays its own basic charges. The energy community model was used along with a low-voltage power tariff. The average annual saving in distribution fees was 1 419 €, and this together with the savings derived from not having to pay the energy retailer's basic charge, compensated for the extra costs associated with using the energy community model, e.g., billing.

Table 5. Distribution fees of the apartment building with different tariff structures

	2013	2014	2015	2016	Average
General	10 431	11 373	13 121	13 984	12 227
Low voltage power	9 206	10 097	11 569	12 360	10 808
Annual savings	1 225	1 275	1 552	1 623	1 419

Simulations using various sizes of PV system as show in Fig. 1 were performed for three years (2014–2016), with 50 different sizes of PV system modelled for each year. Based on these data points (results of simulations), lines *A* and *B* were fitted using linear regression. The results of the simulations and fitted lines are shown in Fig. 7. The optimal size *d* of the PV system (see Fig. 1) was approximately 31 kWp. This is a practical upper limit for the size of PV without incorporating BESS. The actual optimal size of the PV system was lower, caused by the curving cost line of the PV before the intersection point.

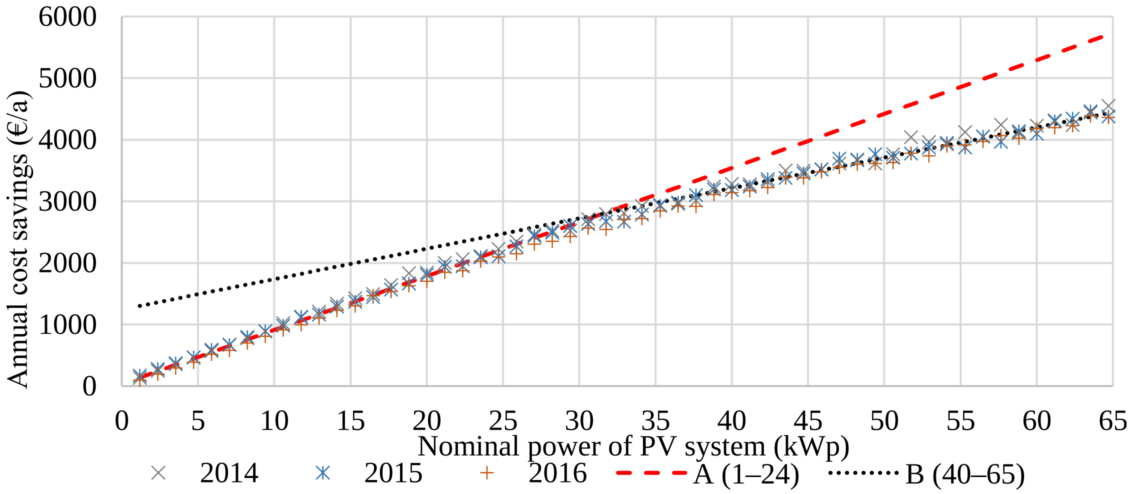

Fig. 7. Cost simulation for apartment building using various sizes of PV system (Fig. 1). Line *A* is the result of a linear regression performed on data points between 1–24 kWp nominal power of PV system and line *B* that of between 40–65 kWp.

The same kind of simulation as shown in Fig. 7 was performed using various sizes of BESS, resulting in "optimal" PV system sizes (*d* in Fig. 1) for various sizes of BESS, and annual cost savings for the "optimal" PV system size (*i* in Fig. 1) using various sizes of BESS. These result points were fitted using linear regression, as presented in Fig. 8. The annual cost savings associated with the use of PV and the "optimal" size of the PV both increased when the capacity of the BESS increased. With the studied BESS sizes (0–99 kWh), the increase could be assumed to be linear, meaning that the PV system size could increase without limitations imposed by the increasing BESS capacity. When a customer purchases PV along with BESS, the BESS can be sized first, based on the available investment resources, and the PV can then be sized based on the size of the BESS.

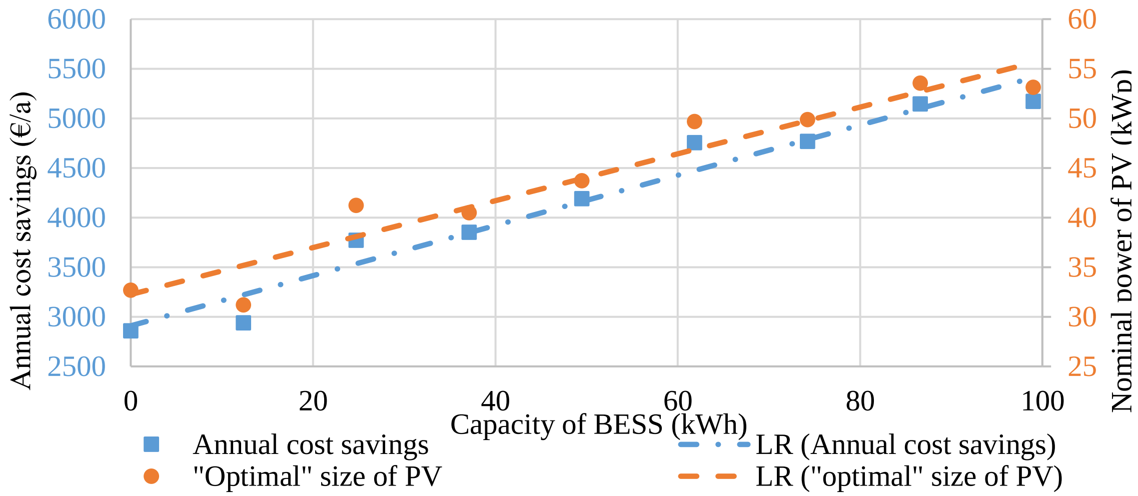

Fig. 8. Effect of BESS on annual cost savings from PV and "optimal" size of PV.

In the following comparison, the BESS was assumed to be 25 kWh. When the energy community model was not used and the general tariff was applied, the annual profits from PV and BESS were low, as presented in Fig. 9. In all cases, the profit was higher without BESS than with it. The optimal PV size (*d* in Fig. 4) was between 13 and 27 kWp if BESS was not used. These values were slightly lower than the "optimal" sizes shown in Fig. 8, as theoretically predicted. Accurate optimal PV size depends on the investment prices for PV and BESS. Using BESS increased the optimal size of the PV system (*m* in Fig. 4) to a range of 20–41 kWp, but the annual profit dropped lower than without the BESS (*n* in Fig. 4 is lower than the cost of the BESS). However, the shapes of the profit curves agree with the theory discussed in Section 2, and the required characteristics can be found from the curves.

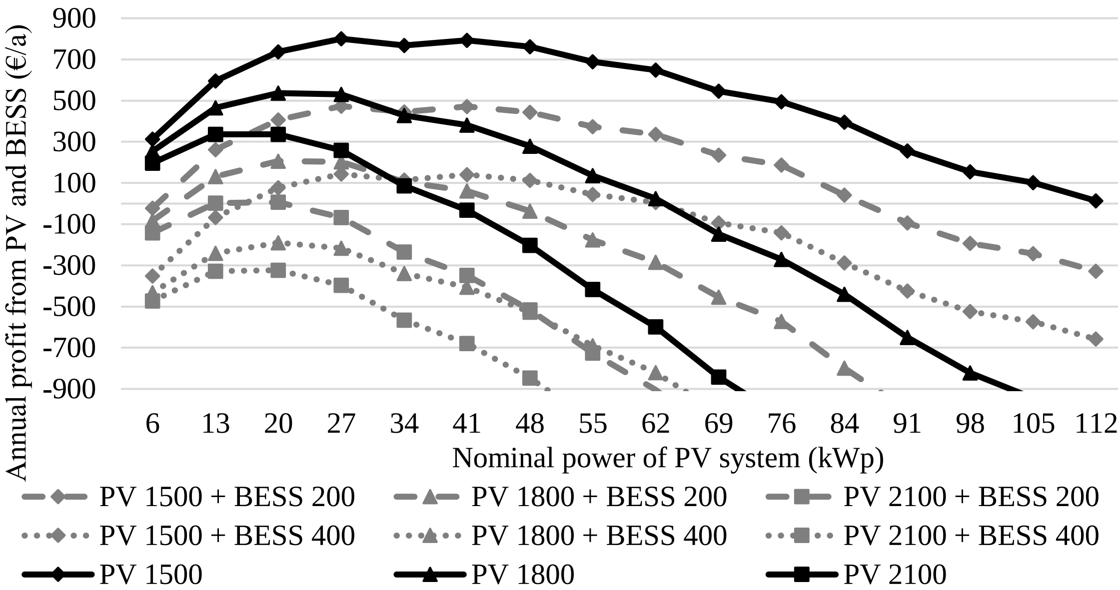

Fig. 9. Annual profit from various sizes of PV system both with and without 25 kWh BESS when the general tariff was applied. Three alternatives for PV investment prices (1500, 1800, and 2100 €/kWp) and two alternatives for BESS investment price (200 and 400 €/kWh) are presented.

Fig. 10 shows the results from the energy community model when the low-voltage power tariff was applied. The profits generated using the energy community model in Fig. 10 were higher than without using it as shown in Fig. 9. Another notable difference was that the profits were higher with BESS than without it when the size of the PV system increased. However, the theory of PV sizing as presented in Section 2 remained valid when applying the energy community model and low-voltage power tariff. When the price of PV was 1500 €/kWp, the annual profit decreased very slowly as the size of the PV system rose above the optimal value. This indicated that this price was near the lower limit of the validity area of the theory. Further decreases to the PV price lead to increases to the annual profit together with increasing PV size. This is not the desired type of optimization.

The results from Figs. 9 and 10 are summarized in Table 6, which shows the optimal sizes of PV systems and the annual profits generated using these optimal sizes. From Table 6, it can be seen that PV was more profitable with the energy community model than without, and the profit increased when BESS was used, as long as the price of BESS was low. The price limit of BESS, in terms of its profitability, was 300–400 €/kWh depending on the price of PV. Additionally, the optimal PV size increased by 7–18 kWp while using BESS with the energy community model. The optimal size of PV increased by 21–39 kWp over the optimal PV size for the basic case.

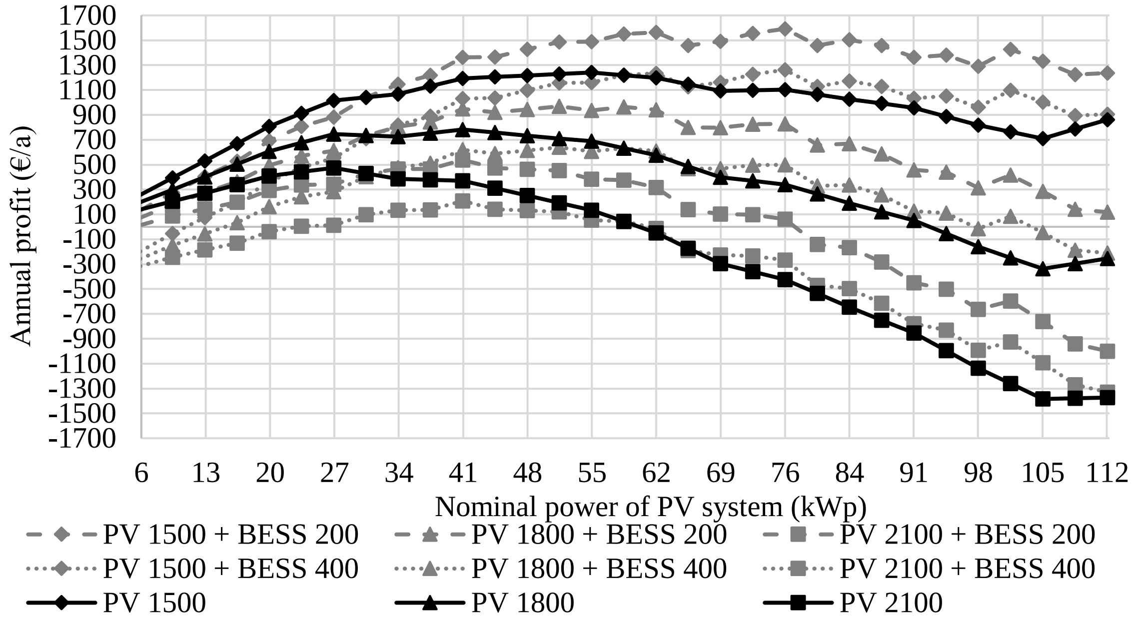

Fig. 10. Annual profit from various sizes of PV system both with and without 25 kWh BESS, when the energy community model with the low-voltage power tariff is applied. Three alternatives for the PV investment price (1500, 1800, and 2100 €/kWp) and two alternatives for the BESS investment price (200 and 400 €/kWh) are presented.

Table 6. Optimal sizes of PV with various PV prices and annual profits

	Basic		Energy community model	
	Optimal size of PV (kWp)	Annual profit (€/a)	Optimal size of PV (kWp)	Annual profit (€/a)
PV 1500	27	803.40	55	1240.69
PV 1800	20	536.62	41	782.40
PV 2100	20	336.62	27	474.16
PV 1500 + BESS 200	27	473.40	62	1563.85
PV 1800 + BESS 200	20	206.62	59	962.93
PV 2100 + BESS 200	20	6.62	41	538.08
PV 1500 + BESS 400	27	143.40	62	1233.85
PV 1800 + BESS 400	20	-190.04	59	632.93
PV 2100 + BESS 400	20	-323.38	41	208.08

The calculated values for the IRR are shown in Fig. 11. The very high values of IRR, noted in cases without a BESS and with only a small PV system, were caused by an assumed constant price component for PV. In real cases, a very small PV system size would be more expensive in terms of relative cost when compared with a larger PV system size. In this study, the price per kWp was assumed to be constant, which increased IRR for small PV system sizes. However, if the PV system sizing was performed using IRR, the optimal PV system size was slightly lower than in the profit study. In sizing PV and BESS, the customer must decide which of the following characteristics are more important: higher profits or higher IRR.

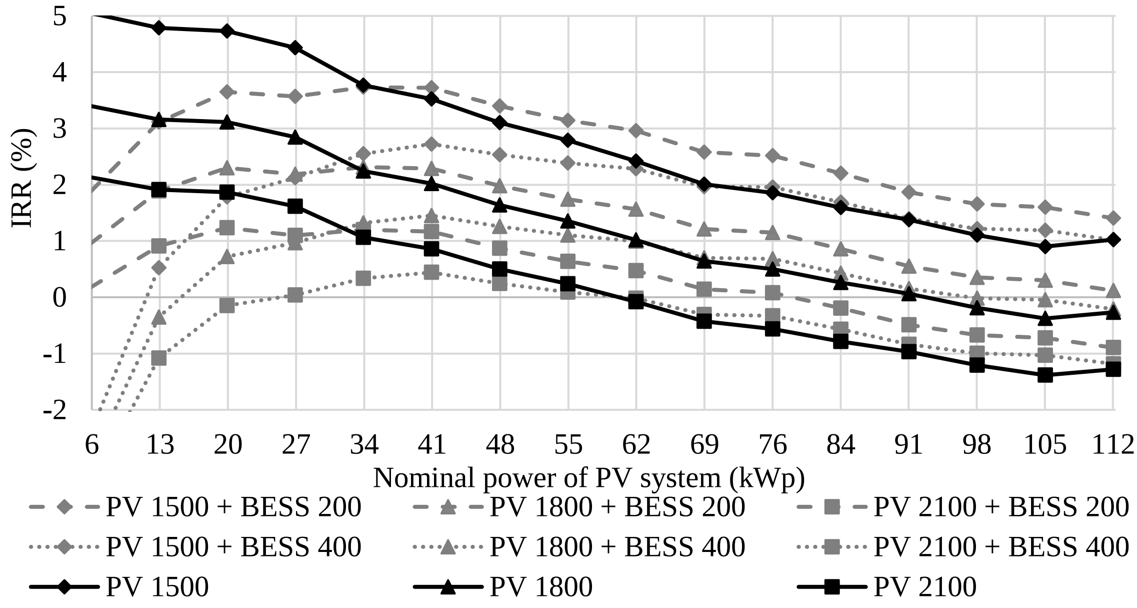

Fig. 11. IRR of PV and BESS investments. Three alternatives for the PV investment price (1500, 1800 and 2100 €/kWp) and two alternatives for the BESS investment price (200 and 400 €/kWh) are presented.

5.2. Case 2: Detached houses

PV size optimization using various sizes of BESS was performed for detached house customers, as presented in Section 2. Evaluation was performed using two different tariff structures: power and general tariff. The results of the optimization are shown in Fig. 12, where the results were averaged over the study group of 12 customers. With a small BESS size (0–2kWh), the "optimal" size of the PV system behaved contrary to the theory. The "optimal" size of the PV system decreased when the capacity of BESS increased. This was caused by chosen simulation step size, which in this case was the PV step size of 3 kWp. When the "optimal" PV size was very low, as in this case, the fitting of line *A* was performed using only two or three points, which could cause this kind of error. However, after the BESS capacity reached 4 kWh, the behavior of the PV system size began to agree with the theory. While applying the power tariff, the "optimal" size of the PV system was 1–2 kWp higher than while applying the general tariff. When the BESS capacity increased over 6 kWh, the increase

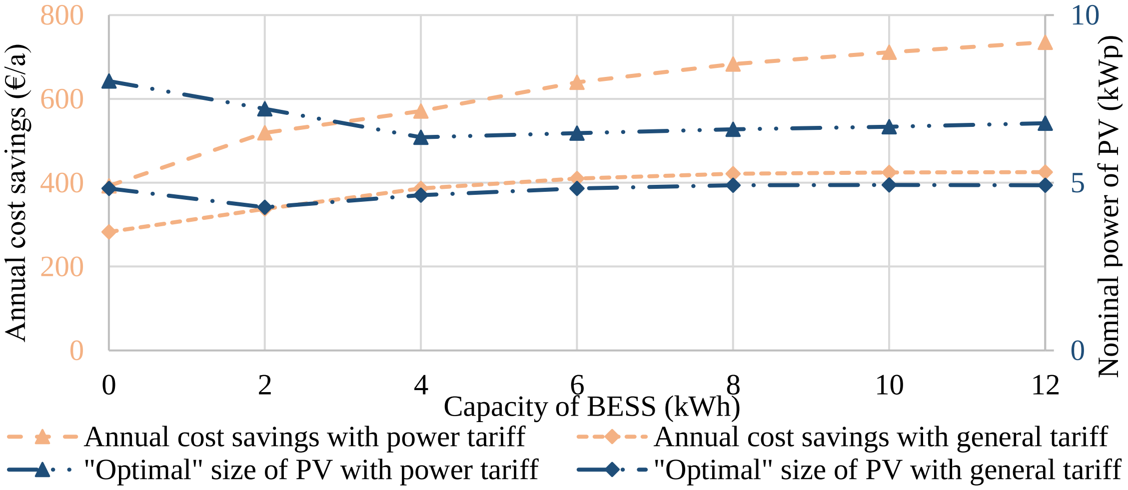

Fig. 12. Sizing of the PV system using various sizes of BESS.

in annual cost savings began to demonstrate a decreasing trend. Thus, after this was identified, BESS sizes of only 4 and 6 kWh were used. Previously, the optimal size of a BESS for a detached house customer either with or without PV was optimized at approximately 4–6 kWh [8-9].

Annual profits were calculated using a 1500 €/kWp PV system price, because it was the highest price while still retaining a positive annual profit without using BESS. The price of BESS was chosen as 300 €/kWh in calculations because it was the median of the range, and the comparison was easier using a constant price. Calculated annual profits are shown in Fig. 13. The profitability while applying a power tariff and BESS was much higher than while applying the general tariff, even if the profitability of the PV alone was lower with the power tariff than with the general tariff.

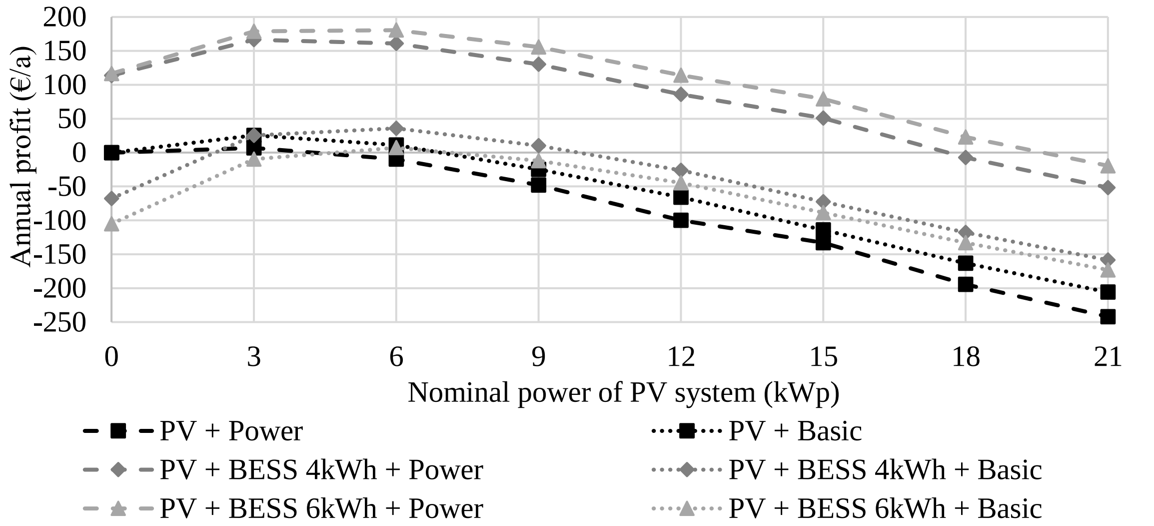

Fig. 13. Annual profit from PV and BESS with power or general tariff, with an investment cost of PV of 1500 €/kWp and an investment cost of BESS of 300 €/kWh.

The IRR while applying various investment prices for PV (1500–2100 €/kWh) and BESS (200–400 €/kWh), with the power tariff and a 6 kWh BESS, is shown in Fig. 14. Also shown are the IRR of a PV investment, with 1300 €/kWp of PV while applying a power and a general tariff for

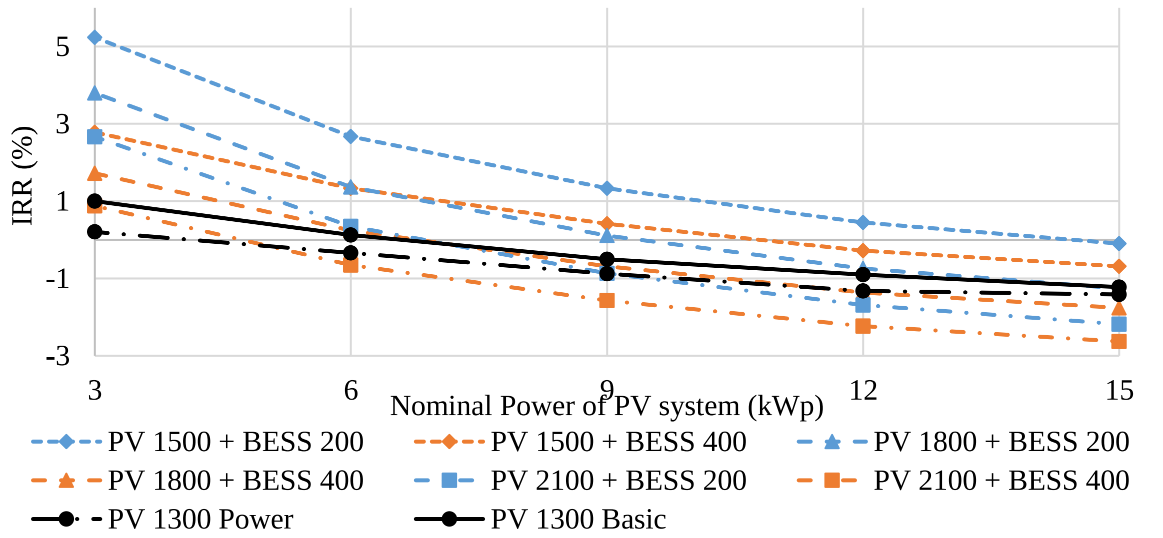

Fig. 14. IRR of PV and BESS investment for detached house customers with various investment prices of PV and BESS when power tariff is used, and IRR of PV investment with the power and general tariffs.

comparison. The results were averaged over the study group. The investment price of 1300 €/kWp was used because it was the highest investment price corresponding to a positive IRR. This indicated that the price of PV must decrease in the future so that PV without BESS becomes profitable for average customers without any subsidies, if the pricing remains the same in the future. Using power tariffs decreased the profitability compared with a general tariff if the BESS was not used, but with BESS, the profitability increased significantly. The IRR was highest with a small PV system (e.g., 3 kWp) and it decreased when the PV system size increased. The price of BESS had a more significant effect on IRR than that of PV.

6. Discussion

During the last few years, PV systems have been installed more often in apartment buildings. The pricing model and sizing, nowadays, leads to a very limited PV system size. Currently, with typical contracts and general distribution tariffs in the studied apartment building, the optimal PV size was found to be 20–27 kWp depending on the investment price for PV. This nominal power corresponded to about 30–40% of the building's annual maximum power usage. In practice, actual PV system size is lower because it was best to avoid generating surplus energy. Using EESS did not increase the profits using the present model. If the apartment building began to apply the energy community model and the low-voltage power tariff was selected, the optimal size of the PV system could increase by 21–39 kWp. This expansion of PV system would produce roughly an additional 19–35 MWh per year in Finland, which is all emission-free solar power. This amounts to approximately 8–21% of the annual consumption of the apartment building.

For detached house customers, PV profitability is very limited. A very small PV system size could be profitable if the investment price of PV is low. When the general distribution tariff is changed to the power-based tariff, the profitability of PV decreases. Photovoltaic production used for self-consumption becomes less profitable when the volumetric price of the tariff decreases. The power-based tariff incentivizes the use of BESS, increasing its profitability significantly. A decrease in power taken from the grid and stored surplus production are mutually exclusive operations for the BESS, so the same BESS can be used for both incentives. It is also possible to apply Market-price-based control to earn extra savings. This makes the combination of PV and BESS very profitable if they are sized correctly. Optimal PV size could be increased by using BESS, but in detached houses, the potential for this is much lower than in apartment buildings. This is caused by a higher basic consumption and different distribution tariff structures. In detached houses, the weight of the power-based component is higher and volumetric charges do not include a two-time ToU structure. However, the potential for increasing the amount of BESS installed along with PV is very high, which could open new business opportunities for service providers.

In reality, the load and PV production forecasts for EESS control are not as ideal as shown in the simulations performed in this study. Forecasting errors can affect a decrease in annual savings. It is possible that the EESS is fully discharged when discharging is required to offset load increases that have not been forecasted, for instance. These problems could be avoided with accurate forecasts. Ideal forecasts were used in this study because the varying forecasting errors, the amount by which they could affect the results, and the effect itself were different for different customers. With ideal forecasts, the upper boundary of the results can be calculated. The effects of forecasting errors have been studied in [9], for example. In future, verification of the model and the results will be performed using a real battery system.

7. Conclusions

This paper introduces sizing methods for photovoltaic system and electrical energy storage system from an economic perspective. The most important result suggested that the sizing of the storage is profitable if performed first so that the photovoltaic sizing can be based on the chosen storage size. The electrical energy storage size depends mainly on variables other than the size of photovoltaic system (e.g., load profile and pricing structure), and the sizing of the photovoltaic system depends mainly on the size of the storage and the load profile. Verification of the sizing model was performed in Finland, but the same model can be utilized in other environments as long as the details of the local electricity pricing structures are accounted for. The main study object was an apartment building which has made several changes to improve its energy-efficiency. As a result, the maximum electrical load increased significantly even though the total amount of consumed energy decreased. Through the use of electrical energy storage, this could have been avoided.

A commonly-used photovoltaic sizing method which does not take into account the energy community model leads to a very limited sizing of the photovoltaic system. If the internal rate of return is used in the sizing, the size of the chosen photovoltaic panel array could be very small. In this paper, increasing the profitable size of the photovoltaic system has been investigated. The energy community model and low-voltage power tariff could increase the profitable size of the photovoltaic system. Using this model, the use of electrical energy storage along with a photovoltaic system also became profitable when the benefit from photovoltaic system and the storage system could be utilized simultaneously. Using electrical energy storage with a photovoltaic system can overcome the problematic effects on the power grid caused by increasing the number of grid-connected photovoltaic plants. In the long term, this could decrease the costs incurred by the distribution system operator and could lead to lower customer electricity prices.

A change to the power-based distribution tariff decreases the profitability of photovoltaic systems because the volumetric charge decreases. If a new incentive, which accounts for electrical energy storage control, is rolled out, the profitability of storage in conjunction with a photovoltaic system could increase significantly. This could increase the implementation of electrical EESS in detached houses.

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