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Economic viability of decentralised battery storage systems for single-family buildings up to cross-building utilisation

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ABSTRACT

Due to the great cost decrease of photovoltaics as well as battery storage, especially in the segment of decentralised home storage, the number of grid-connected battery-supported photovoltaic systems being installed in recent years is steadily increasing. However, the scientific community has intensively discussed that lithium-based battery storage systems cannot yet be operated economically in most cases. This paper addresses the level to which the cost of lithium battery storage needs to decrease in order to be economically viable. For this purpose, the economic viability of battery storage systems in single-family buildings, multi-apartment buildings and across-buildings is analysed on the basis of a linear optimisation model and the method of the internal rate of return. The utilisation of the storage system is optimised for different battery and photovoltaic capacities on the basis of generation and consumption. The internal rate of return method is used to compare the savings resulting from the reduced consumption from the electricity grid with the investment costs and the operation and maintenance costs. In order to be able to estimate the influence of the most important parameters a sensitivity analysis is also carried out. The analysis concludes that, depending on the combination of capacities of photovoltaics, battery storage and in relation to the load profile, the battery storage costs would have to drop by at least 85% in order to generate a certain predefined return over a depreciation period of 25 years. Furthermore, the more different load profiles can be covered directly with photovoltaic electricity, e.g. in a multi-apartment building or across buildings, the less electricity needs to be stored and this reduces the benefit and the utilisation of the battery storage and therefore the specific investment costs must further decrease. Another conclusion that emerges from the sensitivity analysis is that the electricity price and the spread between the electricity price and the feed-in tariff have the greatest influence on the investment costs and profitability. Due to limited space for photovoltaics and simultaneously high consumption, self-consumption is already quite high with cross-building utilisation and can no longer be increased to the necessary extent by the battery storage system, which is why the investment costs must also be lower. The novelty of this paper lies in particular in the fact that it deals with the target costs of battery storage systems in various scenarios for certain rates of return. The analyses in this paper are intended to provide a deeper understanding of the framework conditions for the economic operation of a battery storage system in the aforementioned scenarios. However, this paper does not take into account alternative sources of income other than savings on grid consumption. The possibility of time-variable (grid) tariffs, for example, is also not considered in detail in this paper and should be analysed further in future work.

1. Introduction & motivation

If we look at the development of photovoltaics in recent years and take into account the ambitious climate goals not only of the European Union but also worldwide, it becomes clear that photovoltaics will be of major importance in the coming decades. In addition to the use of ground-mounted- and agricultural photovoltaics, building-integrated and building-mounted photovoltaic systems will play a major role. Since additional land sealing should be avoided, these systems offer a great opportunity, especially in new buildings, but also in renovations, to optimally use the already built-up and existing surface potential. In addition, the electricity generated should be consumed as locally or regionally as possible in order to use the capacities efficiently, relieve the distribution grids and reduce the resulting losses.

However, since photovoltaics is a fluctuating generation capacity, it must also be ensured that electricity demand and supply are brought

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into balance. There are several flexibility strategies for this. In addition to the curtailment of the surplus, the adaptation of consumption through load shifting and import and export, there is also the option of storing the surplus photovoltaic electricity in a decentralised manner using battery storage. Especially for the increasing number of prosumers, this appears to be a favourable option for consuming as much photovoltaic electricity as possible.

As the economic viability of storage systems is also heavily dependent on the structure of electricity prices, this paper will focus specifically on Europe and the situation in Austria. Due to new EU-regulations like the Directive on common rules for the internal market in electricity ((EU) 2019/944), see [1] as well as the revised Renewable Energy Directive (2018/2001/EU), compare [2] it is now also possible not only to supply single-family buildings with self-generated photovoltaic electricity, but also to include tenants of multi-apartment buildings and to supply entire blocks or regions and merge them into energy communities. The Directive on common rules for the internal market in electricity ((EU) 2019/944) therefore addresses new regulations that allow consumers to actively participate in all markets, individually or in the context of citizen energy communities, whether through generation, consumption, sharing or sale of electricity, or through the provision of flexibility services with demand response and storage, see [3].

In addition, the revised Renewable Energy Directive (2018/2001/EU) aims to strengthen the role of renewable energy self-consumers and renewable energy communities. EU countries should therefore ensure that they can participate on an equal footing with large participants in the available support schemes, see [3]. The core objective of this work is the economic evaluation of decentralised battery storage systems that are installed in different constellations to increase the self-consumption of prosumers, and thus also to minimise the electricity purchase costs from the grid. The prosumer's question of "how much" a storage system may actually cost in order to meet certain economic expectations will be addressed in the following analyses. The situation in single-family buildings, multi-apartment buildings as well as across properties is addressed, since different scales and different legal frameworks come into play here. For this purpose, the difference in cash flow of a pure PV system compared to a PV storage solution with a given annual return is evaluated and the maximum possible investment costs are calculated via a linear optimisation model, with the aim of minimising the costs for electricity purchase, and a subsequent economic evaluation via the internal rate of return method. These investment costs are then compared to actual investment costs and necessary future cost reductions are analysed.

From the literature, it is known that battery storage is currently uneconomical under most conditions (compare Section 1.1), but the question of how the investment costs may be in different scenarios in order to be operated economically has not been answered in depth to date.

The major new contribution of this paper to the topic of the economic viability of battery storage is to show exactly under which framework conditions (electricity price, feed-in tariff, given rate of return) which investment costs may arise for a battery storage system in different application areas in addition to a photovoltaic system. So precisely the answer to the question of the prosumer "how much" a battery storage system may cost in order to generate a certain rate of return. In addition, to the authors' knowledge, no work has yet analysed how far the investment costs of battery storage systems would have to drop in order to be operated profitably under different conditions. The analysis in this paper is intended to provide prosumers with an indication of whether battery storage is cost-effective and a sense of the extent to which investment costs need to fall in order for an investment to be considered reasonable.

1.1. Literature review

As already outlined in the introduction, battery storage is a practical solution to store the surplus of decentralised photovoltaic systems and thus also to increase self-consumption or to relieve the electricity grid, e.g. through peak shaving or load shifting in general. Due to the huge photovoltaic boom in recent years, the topic of decentralised storage is also intensively discussed in the literature. The spectrum ranges from the economic efficiency of storage in single-family buildings to office buildings, taking into account different types of tariffs, the performance of components and the provision of ancillary services. Initially, it were still lead batteries that were considered for the analysis. In the meantime, however, lithium-based batteries dominate. A general outlook on the economic evaluation of storage and its future prospects in the electricity market and also its value for the society is presented by [4] and [5]. After a comprehensive literature review and simulations, [6] conclude that decentralised battery storage can already be operated profitably in 2014. However, only lead–acid batteries are considered in this study and not lithium-ion batteries, as in this paper. Lead–acid batteries have significantly lower investment costs, but need to be replaced more often and have significantly lower efficiency. The study is only representative to a limited extent for this paper, but it shows the technological change that has taken place in the last eight years. In different regions, the profitability of battery storage systems varies significantly. In [7] the economics of battery storage systems in California are analysed and it is concluded that the economic benefit is hardly justifiable but can make sense for security of supply. The same finding was made by [8] and [9], who analysed the economic viability of PV-storage systems in Thailand and Australia. [10] state that the net present values of most of the PV-battery configurations are very low and therefore households will invest into standalone PV installations instead. The paper by [11] focuses on regional differences, through use cases in Germany and Australia, as well as through different operating strategies such as maximisation of self-consumption, feed-in damping and mixed integer programming with the objective function of minimising electricity costs. On the one hand, the authors conclude that battery storage cannot be operated economically under the assumptions made and, on the other hand, that there are indeed differences in battery lifetime with the various operating strategies. Feed-in damping appears to be the most advantageous for battery life. [12] combine dispatchable load components as well as batteries and conclude that load shifting through domestic hot water as well as smart AC units are much more profitable than battery storage systems due to their high investment costs.

[13] find that investment costs and electricity tariffs are the primary drivers of economic viability, while building load size is the most important factor in determining solar-plus-storage size in commercial buildings. In contrast, [14] conclude that in Switzerland for some user groups PV-storage systems are already profitable and will become more profitable until 2050, while the optimal size of the battery system increases. In [15], the economic viability of PV storage systems is assessed using three different locations in the United States via the method of levelized costs of electricity (LCOE). Battery storage is presented as an alternative to net metering or bidirectional metering and to increase self-consumption. The authors conclude that under optimal dimensioning and assumed retail electricity prices, PV storage systems are indeed economically viable. The electricity production costs are between \$0.11/kWh and \$0.15/kWh, which is slightly below the procurement costs. The greatest sensitivity in the economic viability is the investment costs of both PV and storage systems, as well as the use of the Investment Tax Credit, which was included here. ITC reduces the tax burden in the first year of operation, which can even lead to an economic profit in the most favourable case. A similar approach was taken by [16]. In this paper, however, the levelised costs of use are calculated (i.e. no feed-in to the electricity grid, pure self-consumption) and compared to the retail electricity price for different

household types and sizes of PV storage systems and six different countries in Europe (Cyprus, France, Greece, Italy, Portugal, Spain). The authors conclude that grid parity cannot be achieved under the current framework conditions in the countries without reducing the costs of the components and therefore battery storage systems are not an economic solution. The two papers by [11] and [17] deal with the degradation of battery storage under different operating conditions and different technologies while [18] also includes the costs due to the full load cycles of the battery. [19] analysed forecast-based operation strategies and conclude, that this strategy is able to increase battery lifetime, decrease curtailment and therefore also decrease costs by up to 12%. The paper by [17] concludes that time-of-use tariffs have a negative impact on the battery life due to the higher depth of discharge (DoD) and the higher state of charge (SOC). In addition, when operating as a backup, it is advised not to leave the battery 100% fully charged. Furthermore, lower temperatures as well as overdimensioning and the associated lower DoD rate have a favourable effect on the service life. The degradation of the battery storage is also depicted in the current paper using a simple, linear model of the decrease in capacity per cycle. Several papers deal with ancillary services like voltage or frequency regulation, power quality as well as peak load shaving and battery storage systems in smart systems, see [20], [21], [22] and [23]. These papers analyse different aspects of ancillary services and conclude that while battery storage can provide such services, it can only be operated profitably under certain scenarios and battery life can also suffer, and that regulatory frameworks and incentives need to be put in place. A broader approach to the integration of renewable energies and their options is taken in the two papers by [24] and [25] where the focus is not only on battery storage, but also on sector coupling and various technologies such as electric vehicles, heat pumps and hydrogen-powered vehicles and their efficient utilisation. As can be seen from the review of the literature, there are many different opportunities, and the topics analysed in the field of battery storage are very diverse. A majority of the papers conclude that lithium-based battery storage is currently still not economically viable. However, it is assumed that the costs will be significantly reduced in the next few years (see [26]) and that battery storage can play a major role in the integration of renewable energies. In order to be able to provide services for the electricity grid, however, sufficient regulatory framework conditions still need to be created.

1.2. Structure of the work

The paper is structured as follows. In chapter two, both the main input parameters such as electricity price and feed-in remuneration, battery parameters and the structure and methodology of the linear PV storage optimisation model as well as the methodology of the economic evaluation are presented. Chapter three provides the results of the impact of battery storage on self-consumption as well as on coverage. Based on these evaluations, the economic feasibility is analysed for single-family homes, multi-apartment homes and on a cross-building level based on additional possible investment costs and necessary cost reductions compared to actual storage costs. The fourth chapter concludes with an interpretation of the results and an outlook on future research and analysis needs.

2. Method and data input

For reasons of readability, this paper distinguishes in the units between €/kWh and c/kWh and €/kWh$_{storage}$. The first two are used for electricity prices and feed-in remuneration. The latter for the investment costs of the battery storage.

Table 1
Electricity price & feed-in remuneration.

Parameter	Value
Electricity price	15 c/kWh
Tariff structure	Flat tariff
Feed-in remuneration	6 c/kWh

2.1. Retail electricity price & feed-in remuneration

Two of the most important parameters for assessing the economic viability of battery storage systems, apart from the investment costs, are the electricity price and the feed-in remuneration. The electricity price composition as well as the level of electricity prices vary significantly in Europe, therefore it is not possible to extrapolate per se from the electricity price to the economic efficiency of battery storage systems. Fig. 1 shows the level of retail electricity prices for average households in the range between 2500 kWh and 5000 kWh electricity consumption per year.

The strong increase in electricity prices in the last months of 2021 and in the first quarter of 2022 is not directly considered in this paper, but the sensitivity analysis addresses the question of how a change in the electricity price level affects the economic viability of battery storage. As can be seen in Fig. 1, electricity prices in Europe vary between 10 c/kWh and 30 c/kWh.

The level of the electricity price does not necessarily reflect the share of the electricity price that can actually be used to evaluate the savings from self-consumption by the battery storage system. Depending on the country, there are different regulations and not all components of the electricity price, such as fixed and capacity-related components of the grid tariffs as well as taxes and other fixed levies, can be included in the economic evaluation of self-consumed PV electricity. In some countries there are fixed and capacity-related components, e.g. in the grid tariff, which cannot be taken into account. In this work, it is assumed that the applied electricity price only includes the components that can also be used to calculate the savings from self-consumption.

In this paper, the electricity price is assumed to be 15 c/kWh in the baseline scenario. Flat tariffs are currently still the predominant tariff structure, although more and more flexible tariffs are also being offered. For the analyses in this paper, constant electricity prices and non-dynamic tariffs are assumed.

In Austria, for example, the feed-in remuneration, i.e. the remuneration paid by an energy supplier for the purchase of surplus PV electricity, has been 3–7 c/kWh in recent years. In other countries, the feed-in remuneration can be higher or lower, but will tend to be based on the current market value of the PV electricity. The variation of the feed-in remuneration is also considered in the sensitivity analysis, whereas subsidies are not taken into account in this paper.

The parameters for the economic calculation are summarised in Table 1.

2.2. Battery parameters

Due to the simple modular expandability, battery storage systems are a good solution for decentralised use. In recent years, lithium-based battery storage systems have become the most popular choice for decentralised use, compare [26], also due to the increasing market caused by e-mobility. Lithium batteries can be charged and discharged with an efficiency of about 95%, which corresponds to an overall efficiency of about 90%. This efficiency level is also assumed for the following analyses, compare [27] and [28]. As the battery storage system is charged and discharged almost daily and no long downtimes without charging and discharging are to be expected, self-discharge was not taken into account in the model for the sake of simplicity. [29] points out that lithium batteries are mainly charged with an IUa

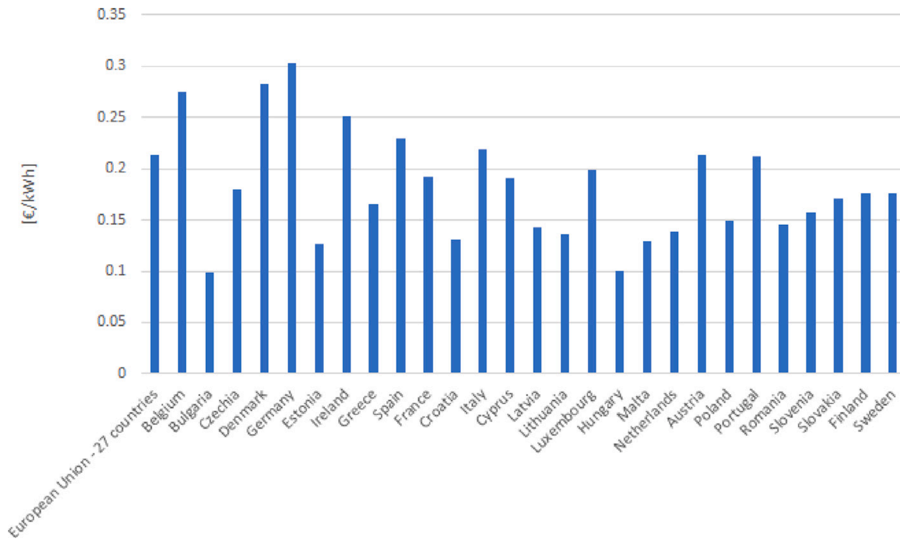

Fig. 1. Retail electricity price in EU 27 member states in 2020, Data source: Eurostat.

Table 2
Battery parameters.

Parameter	Value
Charge & discharge efficiency	95%
Maximum charge/discharge power	10 kW
Depth of Discharge (DoD)	80%
Number of full-load cycles	3000

charging strategy: First, the battery is charged with constant current until the state of charge reaches the value of 80%. Secondly, the battery is charged with constant voltage until the state of charge reaches 100%. In the first phase, the charging power is assumed to be constant. This charging curve is also assumed in the model to obtain a charging curve as realistic as possible. In this analysis, a maximum charging power of 10 kW and a maximum possible depth of discharge of 80% is assumed. This means that 80% of the gross capacity can actually be used for photovoltaic surplus storage. For reasons of comparability, the maximum discharge power was set at 10 kW for all three scenarios. A typical size for single-family buildings would be 3,5 kW. However, the outcomes for self-consumption and self-sufficiency do not change, so it was decided to use the same value for all scenarios. Cycling stability is assumed to have a realistic value of 3000 in this analysis. The definition of cycle lifetime is assumed to be reached in this paper when the battery storage can only provide 80% of its original capacity. The yearly degradation of the battery storage system was then linearly interpolated so that the battery storage system still has a capacity of 80% of the initial capacity when it is replaced. The basic battery parameters used in this paper are outlined in Table 2

The cost of a battery storage system has also dropped significantly in recent years, as outlined in [26]. In 2022, the average specific investment costs for a 1 kWh storage unit are around 1300 $€/\mathrm{kWh}_{battery}$ and for a 10 kWh storage around 1000 $€/\mathrm{kWh}_{battery}$. As can be seen from Fig. 2, the specific costs are decreasing, especially in the segment up to 10 kWh. The cost degression flattens out significantly thereafter and, especially for large storage units above 100 kWh, the specific costs drop only slightly.

The data comes from C.A.R.M.E.N E.V. from 2022 [30], which publishes an annual market comparison for the German market. The costs outlined are average end user costs for stationary battery storage systems including inverters and all other components including profit margin. The costs in this paper hardly comparable with costs for battery storage systems in the electromobility sector. Even though e-mobility can certainly be seen as a key driver for stationary battery storage systems, the development of storage costs in the automotive sector cannot be transferred one-to-one to stationary operation. It depends heavily on which components are taken into account in the reported costs (cells, packaging, charge control, thermal management, installation, inverters, etc.) and what is left out. Incidentally, this does not only apply to the comparison between stationary systems and batteries for the automotive sector, but there are also major differences between stationary systems as to which components are taken into account and which are not. A detailed comparison between the costs of stationary battery storage and battery storage for electromobility and the comparison of different sources can be found in [31].

2.3. Energetic calculation

To calculate the economic efficiency of the battery storage, a linear optimisation model was developed in Matlab using the YALMIP toolbox and the Gurobi solver, with the aim of minimising the costs of purchasing electricity for different load profiles. The optimisation model thereby performs calculations with a temporal resolution of a quarter of an hour. This is a model that optimises the utilisation of the PV-storage combination for different PV and storage capacities.

The objective function, see Eq. (1), is as follows:

$$\begin{aligned} min \sum_t (q_t^{grid_{battery}} + q_t^{grid_{demand}}) * c_t^{electricitypurchase} \\ -(q_t^{PV-feed-in} + q_t^{battery-feed-in}) * p_t^{feed-inremuneration} \end{aligned} \quad (1)$$

with

$q_t^{grid_{battery}}$ = Stored electricity from the grid at time t [kWh]
$q_t^{grid_{demand}}$ = Coverage of the load profile from the grid [kWh]
$c_t^{electricitypurchase}$ = Electricity price [c/kWh]
$q_t^{PV-feed-in}$ = Direct feed-in to the grid [kWh]
$q_t^{battery-feed-in}$ = Feed-in from the battery to the grid [kWh]
$p_t^{feed-in-remuneration}$ = Feed-in remuneration [c/kWh]

The basic structure of the optimisation model is shown in Fig. 3.

Taking into account real global horizontal irradiance data from Vienna in 2010, the direct, diffuse and reflected irradiance on any inclined surface is calculated according to the isotropic diffuse irradiance model, taking into account the degree of clarity. Based on this irradiation, the power output of the photovoltaic modules is determined, taking into account the location, the orientation, the installation angle

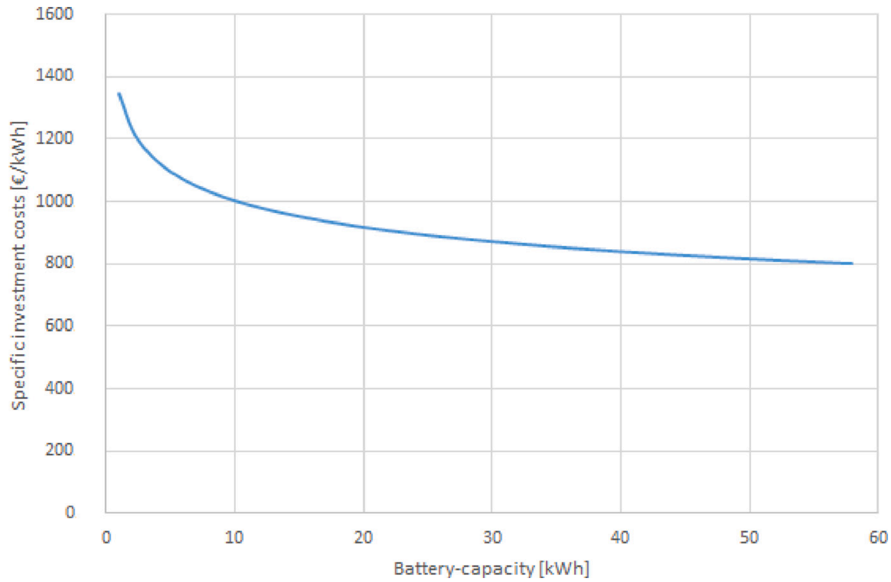

Fig. 2. Specific investment costs for lithium based batteries in 2022, w/o VAT [€/kWh$_{battery}$].
Data source: C.A.R.M.E.N EV.

and the ambient temperature, and serves as input for the optimisation model. Further input parameters for the optimisation model are the capacity of the PV system, the capacity and efficiency as well as the charging curve of the battery storage as well as the electricity price, tariff structure and feed-in remuneration. Miscellaneous load profiles can also be fed into the optimisation model. The optimisation model then calculates a cost-minimum solution to cover the load profile via the PV system, the battery storage and the electricity grid. In principle, the optimisation model is given the option of charging the storage from the grid and feeding electricity back to the grid. However, this is only relevant for variable tariffs, as with a flat tariff it is always more cost-efficient to either feed in directly or to cover the load profile directly from the grid due to the storage losses. The output parameters of the optimisation model are the energy flows between the PV system, the battery storage, the electricity grid and the load profile and, derived from this, the rate of self-consumption, the rate of self-sufficiency, the self-consumption savings and the feed-in revenues as well as the costs of purchasing electricity from the grid.

The optimisation model is then applied for single-family buildings, multi-apartment buildings as well as for cross-building optimisation. Due to the different sizes of PV and battery storage and the differences in the load profiles, where a certain pooling effect is expected especially for multi-apartment buildings as well as for cross-building solutions, differences in self-consumption as well as in the self-sufficiency should become apparent, which then also have an impact on the maximum possible investment costs of battery storage.

In the following analyses, the cost-minimal solution for different PV storage combinations is outlined.

2.4. Economic calculation

The method of the internal rate of return (IRR) is used in this paper to evaluate the economic viability of a battery storage system. The IRR is an interest rate at which the net present value (NPV) becomes exactly zero within the calculation period. This implies that the investment costs are exactly equal to the discounted cash flow, see Eq. (2).

$$NPV = -I_0 + \sum_{t=1}^{T} \frac{C_t}{(1+IRR)^t} = 0 \tag{2}$$

with

NPV = Net present value (€)
I_0 = Initial investment costs (€)
C_t = Cash flow at time t (€)
IRR = Internal rate of return
T = Calculation period (a)

The higher the internal rate of return, the more profitable an investment is. The internal rate of return can be used for investments of different types so investments or projects can be evaluated on the same basis. When comparing investment options with similar parameters, the investment with the highest internal rate of return is considered the most economically viable. In principle, the weighted average cost of capital (WACC) is the benchmark for the IRR. The weighted average cost of capital is thereby composed of the cost of equity and the cost of debt and is weighted according to its share, see [32]. If the internal rate of return is higher than the weighted cost of capital, the investment in a battery storage system is considered economically viable. In the economic calculation, a conservative value for the expected return of 5% was selected for all scenarios for reasons of comparability. However, it is generally the fact that different investors also have different return expectations (which tend to be significantly higher) and the amortisation periods can also be significantly shorter. The aim of the economic analysis is to quantify the additional benefit of the battery storage system compared to a pure photovoltaic system and to calculate the maximum investment costs of such a battery storage system, taking into account a given internal rate of return, whereby additional savings due to increased self-consumption as well as the replacement of the battery storage system after the cycle life or, if reached first, the calendaric life are taken into account.

To identify the maximum additional investment costs of battery systems to be profitable, compared to a standalone PV-system, for households as well as for multi-apartment buildings and across-buildings, the calculation is done as shown in Eq. (3) to Eq. (5)

$$NPV = -I_{Battery_{tot}} + \sum_{t=1}^{T} \frac{\Delta C_t}{(1+IRR)^t} = 0 \tag{3}$$

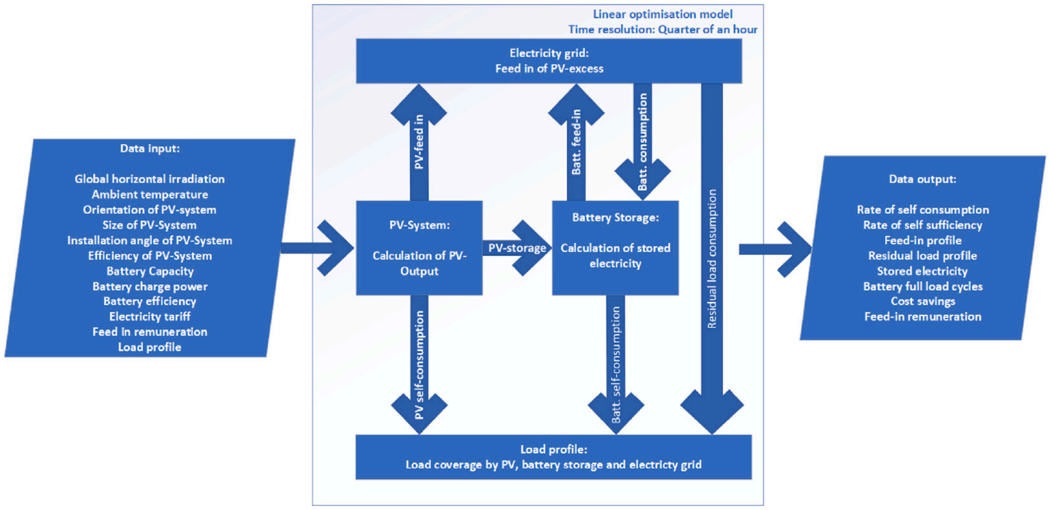

Fig. 3. Structure of the optimisation model.

$$I_{Battery_{tot}} = \sum_{t=1}^{T} \frac{\Delta C_t}{(1+IRR)^t} \tag{4}$$

$$I_{Battery} = \frac{I_{Battery_{tot}}}{1+0.7*(1+IRR)^{-t_c}} \tag{5}$$

with

NPV = Net present value (€)

$I_{Battery_{tot}}$ = Overall investment costs (initial + rebuy) (€)

$I_{Battery}$ = Maximum additional investment costs at given IRR (€)

ΔC_t = Difference cash flow with battery storage and without battery storage (€)

IRR = Internal rate of return

t_c = Year of the battery storage replacement (a)

T = Calculation period (a)

In order to calculate the maximum possible investment costs, including the additional investment in a battery storage system during the calculation period, Eq. (2) is slightly transformed. Eq. (3) is similar to Eq. (2) with the exception that only the difference of the cash flow with and without battery storage (ΔC_t) is used. Eq. (4) is now transformed so that the discounted cash flow is equal to the total investment costs (initial + rebuy). The additional costs of the rebuy (replacement of the storage due to end of life) are assumed to be only 70% of today's costs, regardless of the time of the additional investment. These additional investment costs are discounted depending on the timing of the investment and are then taken into account in Eq. (5), where the maximum additional investment costs are calculated. The calculation period is assumed to be 25 years, as this also corresponds to the lifetime of the photovoltaic system.

As mentioned before, ΔC_t is the difference in cash flows (cost savings + feed-in revenue - operation and maintenance (O&M) costs) in year t with and without battery. Here, C_t strongly depends on the amount of self-consumed PV electricity ($q_t^{self-consumption}$), household electricity prices ($c_t^{electricitypurchase}$), feed-in remuneration ($p_t^{feed-in}$) and the amount of PV electricity fed into the grid ($q_t^{feed-in}$).

$$C_t = q_t^{self-consumption} * c_t^{electricity-purchase} + q_t^{feed-in} * p_t^{feedin} - O\&M_t \tag{6}$$

Table 3 points out the parameters for the economic evaluation of the baseline scenario:

In this paper, a replacement (rebuy) of the battery storage system is assumed approximately in the middle of the entire calculation period of 25 years. In principle, the battery storage system's lifetime depends, among other things, on the number of full cycles completed. However, the simulations have shown that an average of around 250 cycles per year are completed in all scenarios and relevant capacities, which is why, for the sake of simplicity, a cycle dependency was not taken into account and the replacement was assumed to take place in the middle of the calculation period. The costs for replacing the battery storage system include all costs and not just the costs for the battery cells, as in the worst-case scenario it must also be assumed that the inverter and other components will also have to be replaced at some point during the calculation period.

Table 3
Economic parameters baseline scenario.

Parameter	Value
Electricity costs	15 c/kWh
Feed-in remuneration	6 c/kWh
IRR	5%
Replacement date	13a
Cost of replacement	70% of actual costs
Calculation period	25a

3. Results

3.1. Single-family buildings

The situation for single-family houses is shown in Fig. 4. A rooftop photovoltaic system is installed with a southern orientation and an installation angle of 30°. This is the energetically optimal orientation for maximum photovoltaic energy production in the geographical location of Central Europe. The battery storage system is additionally installed in the building as a wallbox either directly connected to the photovoltaic system using the inverter of the PV system or as a dedicated system with its own inverter for coupling with the AC system of the building. The photovoltaic system as well as the battery storage can then supply various appliances in the building with PV electricity. An average electricity consumption of 4000 kWh/a is used for both the energy and the economic calculation, and the load profile is accordingly scaled. Both temperature data and irradiation are used from the year 2010, as this year represents an average weather year. The summary of the parameters used is shown in Table 4, all other parameters are applied as outlined in the previous chapters.

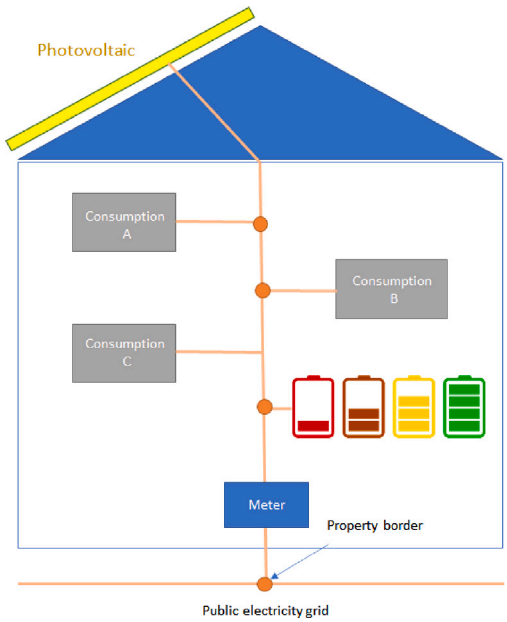

Fig. 4. Schematic configuration in a single-family building.

Table 4
Parameters for single-family buildings.

Parameter	Value
PV-System	
Orientation	south
Installation angle	30°
Size	1 – 14 kWp
Battery System	
Charge/Discharge Power	10 kW
Size	0 – 14 kWh
Load profile	
Type of profile	Standardised H0
Consumption	4000 kWh/a

3.1.1. Energetic calculation

The energy calculation of the rate of self-consumption as well as the rate of self-sufficiency for a single-family building was calculated using a standardised H0 load profile and results are presented in Figs. 5 and 6. A standard load profile, such as the H0 profile for households/single-family buildings, is a representative load profile that maps the typical course of the electrical power consumed. It is used to forecast and balance the actual load profile at a point in the grid (market location) without recording power measurement. The H0 profile represents an averaging of many different consumers in the household consumption group. This averaging can lead to deviations in terms of self-consumption share and coverage compared to individual profiles, and accordingly also for the investment costs of the battery storage system. Nevertheless, this profile can be used to make statements for an average household.

Different combinations of battery storage and photovoltaic system sizes are considered. Both the capacity of the photovoltaic system and the battery storage are related to an annual consumption of 1000 kWh/a. This makes it illustrative insofar as it is relatively easy to estimate the rate of self-consumption as well as the rate of self sufficiency for a known electricity consumption. With an annual electricity consumption of 5000 kWh/a and an installed PV size of 5 kWp, this means a specific PV output of 1 kWp/MWh. This configuration provides a rate of self-consumption of just over 36% and a rate of self-sufficiency of 40%. If a battery storage system with a capacity of 5 kWh is also installed, which corresponds to a specific capacity of 1 kWh/MWh, the

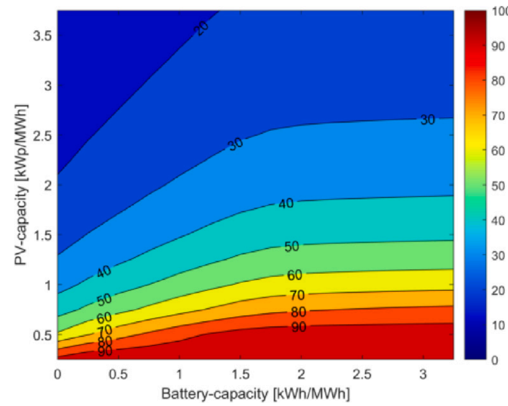

Fig. 5. Rate of self-consumption for different combinations of PV-capacity and battery-capacity related to an annual consumption of 1000 kWh/year [%].

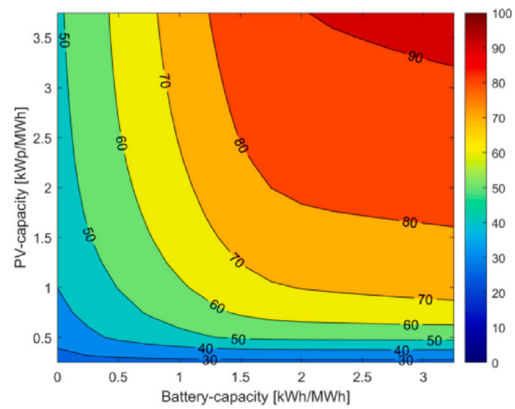

Fig. 6. Rate of self-sufficiency for different combinations of PV-capacity and battery-capacity related to an annual consumption of 1000 kWh/year [%].

rate of self-consumption increases to about 54% and the degree of self-sufficiency rises to about 59%, i.e. 41% of the electricity consumption still has to be purchased from the grid. A specific battery capacity of more than 1.5 kWh/MWh results in only minor advantages in terms of self-consumption. Self-sufficiency also increases significantly less from this battery capacity, as the storage system can no longer be fully discharged at night. Levels of self-sufficiency over 90% can only be achieved with very large specific PV outputs of over 3.5 kWp/MWh and large specific battery sizes of over 2.5 kWh/MWh. In this range, however, the rate of self-consumption is relatively low and large amounts of electricity must be fed into the grid or curtailed.

3.1.2. Economic calculation

As already pointed out in Section 2.4, the method of the internal rate of return is used, whereby the internal rate of return is specified, a cash flow is calculated from own consumption and feed-in as well as the annual operation and maintenance costs, and the resulting maximum investment costs of a battery storage system are derived. These costs are then compared to the actual costs in order to analyse necessary cost reductions.

3.1.2.1. Baseline scenario. The baseline scenario is the initial reference point for the following calculations and sensitivity analyses with regard to electricity price, feed-in tariff, expected annual return and lifetime of the battery storage. The parameters for the baseline scenario are presented in the section below as a recapitulation. An electricity price of 15 c/kWh and a feed-in remuneration of 6 c/kWh are assumed. In addition, a real rate of return of 5% per year is assumed for the

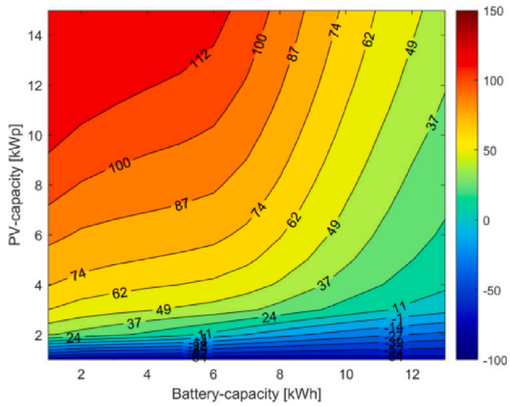

Fig. 7. Maximum additional investment costs (target costs) for different PV and battery capacities, single-family building [€/kWh$_{battery}$].

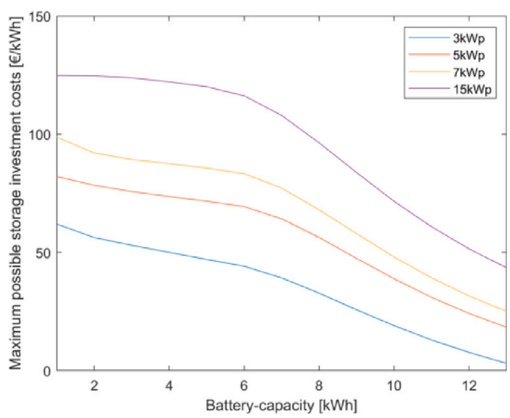

Fig. 8. Maximum additional investment costs (target costs) for selected PV and battery capacities, single-family building [€/kWh$_{battery}$].

calculation of investment costs. A change of the battery storage, after the end of the lifetime of the initial battery storage, is assumed in the middle of the calculation period of 25 years. This is also plausible insofar as the battery storage in a household typically performs about 250–300 full load cycles per year at a depth of discharge of 80% in a typical configuration. Assuming a cycle stability of 3000 full load cycles lifetime, this means a replacement approximately in the middle of the calculation period. The parameters of the calculation are summarised in Table 3.

Figs. 7 and 8 show the results of the calculations for the H0 load profile graphically. In Fig. 8, only selected combinations of PV and storage capacity have been outlined for the sake of visual clarity.

From Fig. 7 it can be deduced, that the calculated specific investment costs of the battery storage range between 120 €/kWh$_{battery}$ and −75 €/kWh$_{battery}$, depending on the size of the battery storage and the PV system. For small PV systems, where self-consumption is already high, the additional benefit of the battery storage is non-existent. In this segment, the additional investment costs are correspondingly also negative, as the operational costs exceed the additional benefit. The maximum specific investment costs may occur where large photovoltaic systems are combined with small battery storage systems. The additional benefit of the battery storage is highest there, as a large surplus prevails and the storage is thus best utilised. In addition, Fig. 8 illustrates a slight downward bend at around 6–7 kWh battery capacity. This is the range in which an additional kilowatthour of battery storage only brings a small additional benefit in terms of increasing self-consumption, compare Fig. 5.

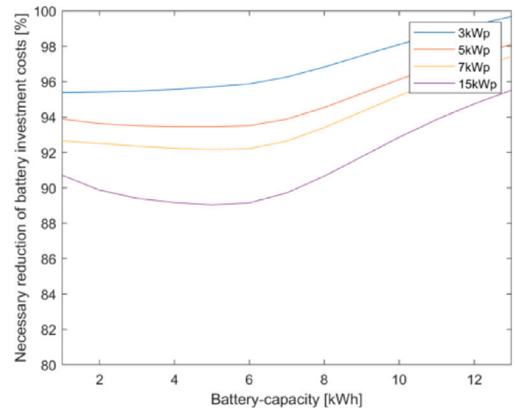

Fig. 9. Necessary cost reduction compared to investment costs in 2022 [%].

Table 5
Parameter sensitivity analysis.

Parameter	Value
PV-capacity	5 kWp
Battery capacity	7 kWh
Electricity price	15 c/kWh
Feed-in remuneration	6 c/kWh
IRR	5%
Battery lifetime	13a
Variation of Parameters	−50% to +50%

If the calculated investment costs are compared with the actual investment costs of a battery storage system pointed out in Fig. 2, it becomes clear that the investment costs still have to decrease significantly in order to be economically viable.

As depicted in Fig. 9, the necessary cost reduction ranges from about 89% for a 15 kWp PV system and a 6 kWh battery storage to about 99% for a 3 kWp PV system and a 13 kWh battery storage. This result demonstrates that, under the assumptions made, battery storage is still far too expensive.

3.1.2.2. Sensitivity analysis. The baseline scenario shows that a battery storage system is not economically viable compared to actual investment costs. How the economic viability and the associated investment costs develop if the input parameters are varied will be discussed in the following chapter. In doing so, electricity prices, feed-in tariffs, expected annual returns and the lifetime of the battery are varied and the effects on the additional investment costs are analysed.

For reasons of clarity of the sensitivity analysis, only a typical combination of PV and battery storage capacity is considered. The initial parameters are summarised in Table 5.

The results of the sensitivity analysis are presented in Fig. 10.

The sensitivity analysis was conducted in such a way that one parameter was adjusted at a time, while all other parameters were kept constant. Fig. 10 clearly illustrates that the electricity price has the greatest influence on the maximum additional investment costs. When varying the parameters by +−50%, the electricity price shows the largest gradient. The feed-in remuneration impacts the economic viability of the battery storage system the second most, compared to the case without battery storage. The expected annual return and the lifetime of the battery storage system play a subordinate role in the sensitivity analysis. Fig. 10 reveals that halving the electricity price to 7.5 c/kWh would make the battery storage system obsolete. The additional investment costs are clearly negative in this scenario. The significantly lower amount of self-consumption savings from battery storage compared to the pure PV system means that battery storage should cost nothing in the self-consumption-optimised case and that

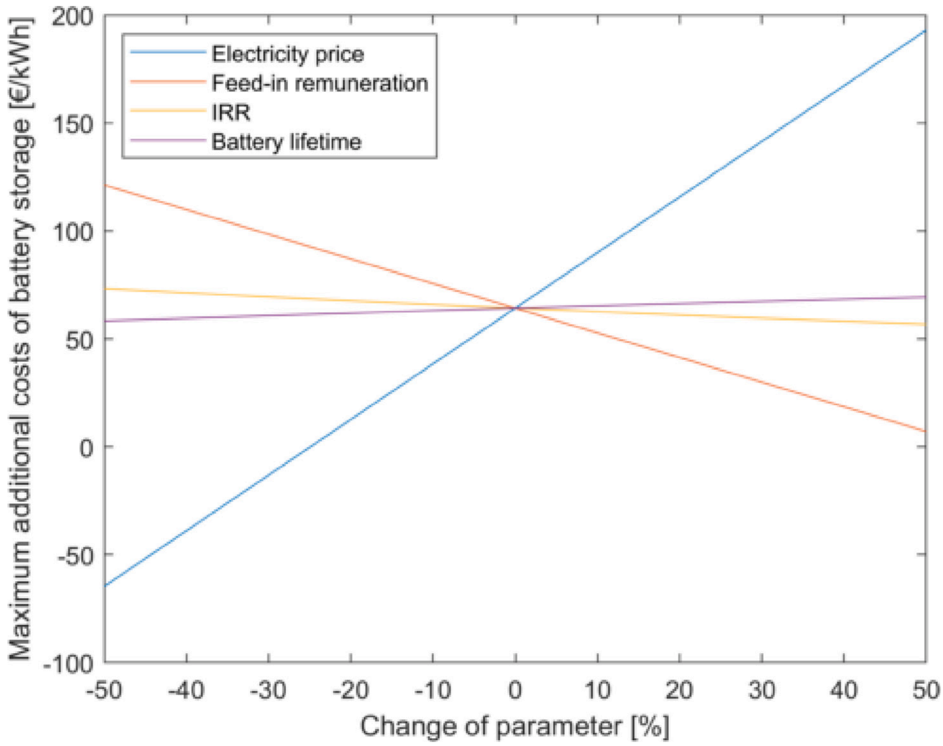

Fig. 10. Sensitivity analysis for additional storage investment costs [€/kWh$_{battery}$].

the operating costs exceed the resulting benefits. An increase in the electricity price by 50% to 22.5 c/kWh leads to a significant increase in the maximum possible investment costs of the battery storage system compared to the initial value. The maximum possible investment costs increase from about 64 €/kWh$_{battery}$ to just under 200 €/kWh$_{battery}$ for the previously specified configuration. Although an increase in the electricity price has a positive effect on the possible specific investment costs of the battery storage system, these would nevertheless have to fall by 82% in order to be operated economically.

An increase in the feed-in remuneration has a negative impact on the economic viability and thus also on the maximum possible investment costs. The increase in the feed-in remuneration makes the feed-in economically more attractive and since more electricity is fed into the grid with a pure photovoltaic system, the cash flow increases significantly more than with the PV-storage combination. The higher the feed-in tariff in relation to the electricity price, the lower the maximum possible investment costs can be. An increase of the feed-in remuneration to 9 c/kWh leads to maximum possible investment costs of only just under 7 €/kWh$_{battery}$, while a halving to 3 c/kWh would mean investment costs of about 120 €/kWh$_{battery}$.

The analysis of the expected annual return (IRR) shows a slightly lower impact on the result. The analysed range varies from 2.5% to 7.5% expected annual return over a calculation period of 25 years. Increasing the expected rate of return decreases the additional investment costs of the battery storage from about 64 €/kWh$_{battery}$ to about 57 €/kWh$_{battery}$. Decreasing the interest rate leads to an increase of the investment costs to 73 €/kWh$_{battery}$. The analysis of the sensitivity of the battery storage lifetime is of the same order of magnitude, but in the opposite direction. In the baseline scenario, it is assumed that the battery storage needs to be replaced in the middle of the calculation period. An earlier replacement, i.e. after 6.5 years, leads to a slight reduction of the possible investment costs to 58 €/kWh$_{battery}$, a later replacement after 19.5 years leads to additional investment costs of 69 €/kWh$_{battery}$.

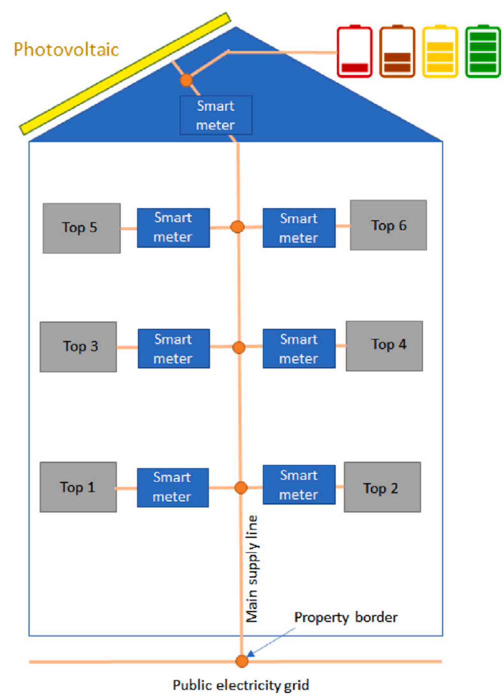

Fig. 11. Schematic configuration in a multi-apartment building.

3.2. Multi-apartment buildings

The situation in multi-apartment buildings is shown in Fig. 11. As with single-family houses, a rooftop photovoltaic system with a southern orientation and an installation angle of 30 is simulated. Since the legal/regulatory framework for the distribution of PV electricity within the building is implemented differently in each country, this

Table 6
Parameters for multi-apartment buildings.

Parameter	Value
PV-System	
Orientation	south
Installation angle	30°
Size	1 – 41 kWp
Battery System	
Charge/Discharge Power	10 kW
Size	0 – 51 kWh
Load profile	
Type of profile	measured household
Overall consumption	20,000 kWh

paper specifically addresses the situation in Austria. A photovoltaic system may (even in urban, densely built-up areas where roof/building areas are directly adjacent to each other) only be physically connected to one multi-apartment building or to one main electrical line if there are several main lines in a building. The participating beneficiaries in the PV system then do not have to pay grid fees for the self-generated and used electricity in the building and are therefore clearly favoured. The same applies to a battery storage system if it is only used for one building. The situation is different if it is to be used across-buildings, see Section 3.3. In order to participate in such a shared generation system, however, several contracts are necessary to ensure correct calculation and allocation of the energetic shares by the grid operator.

The calibration of the simulation model for multi-apartment buildings can be found in Table 6. Since the actual distribution in the building is simulated here, this is not performed using individual H0 profiles due to the simultaneity, but instead calculated with measured load profiles. For this purpose, 10 household profiles were stochastically selected from a pool of over 70 measured (anonymous) household load profiles, which are used in this use-case and which are scaled with different annual electricity consumptions.

3.2.1. Energetic calculation

The distribution of photovoltaic electricity within the building depends on the chosen method. In Austria, both a static and a dynamic distribution scheme can be chosen. The dynamic distribution key, on the one hand, which has a temporal resolution of a quarter of an hour, is based on the actual consumption at time t of a participating household in relation to the sum of the consumption of all participating households at time t. The static distribution key, on the other hand, is determined in advance and is based, for example, on the investment sum of the individual households and can only be changed by contractual agreement. If, for example, another household joins or a household leaves, the distribution key must be redefined. The static key at the same time provides the advantage of simple allocation, but also the disadvantage that within the building, the unused share of one participant cannot be used by another. With the dynamic model, however, this is possible. As a result, the rate of self-consumption within the building is also significantly higher. The disadvantage is the more complicated accounting. In the following calculations, the battery storage is also integrated into the dynamic key and thus all participants are given the opportunity to store their respective surpluses. The dynamic distribution within the building is calculated as in Eq. (7):

$$PV_{Top_n}(t) = PV_{generation}(t) * \frac{Load_{Top_n}(t)}{\sum_{n=1}^{N} Load_{Top_n}(t)} \tag{7}$$

with

$PV_{Top_n}(t)$ = Share of PV generation at time t of a participating household (kWh)

$PV_{generation}(t)$ = PV generation at time t (kWh)

$Load_{Top_n}(t)$ = Load of a participating household at time t (kWh)

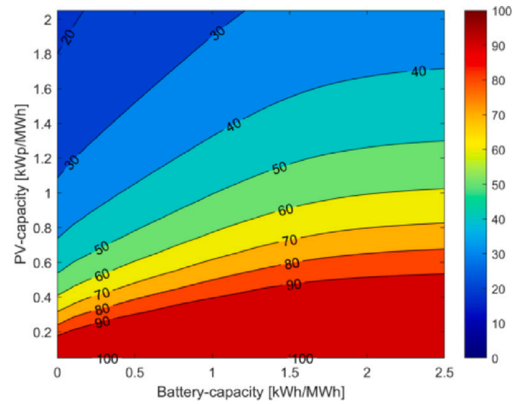

Fig. 12. Rate of self-consumption for different combinations of PV-capacity and battery-capacity related to an annual consumption of 1000 kWh/year, multi-apartment building [%].

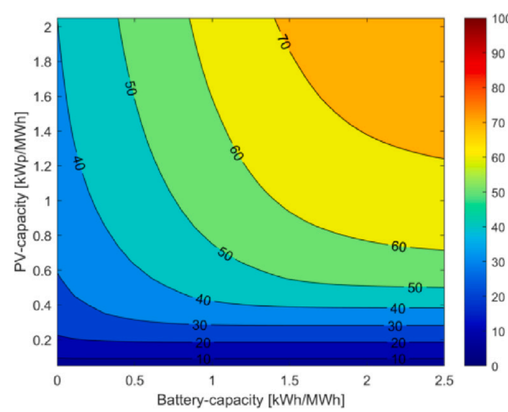

Fig. 13. Rate of self-sufficiency for different combinations of PV-capacity and battery-capacity related to an annual consumption of 1000 kWh/year, multi-apartment building [%].

N = Number of participating households (1)

Figs. 12 and 13 show the rate of self-consumption as well as the rate of self-sufficiency for multi-apartment buildings related to a yearly electricity consumption of 1 MWh/a.

Due to the dynamic distribution of the photovoltaic electricity generated, a large amount can also be used directly in the building. With a total consumption of 20,000 kWh in the building and a photovoltaic output of 20 kWp, this results in a rate of self-consumption of about 33%. This rate of self-consumption results for 10 different measured household load profiles, scaled with an annual consumption of 1000 kWh/a to 4000 kWh/a with an average electricity consumption of 2000 kWh/a across all profiles. The rate of self-sufficiency within this configuration is around 34%. If a battery storage with a gross capacity of 20 kWh is installed, the rate of self-consumption increases to about 50% and the rate of self-sufficiency to about 54%. However, the rate of self-consumption and the rate of self-sufficiency also depend on the composition of the load profiles. If there is a high daytime consumption in the building, this can increasingly be covered by the PV system. Many different load profiles also lead to an increase in the share of self-consumption. Especially if there are not only residential apartments in the building, but possibly also a commercial business or a charging station for electric vehicles is integrated into the dynamic distribution key.

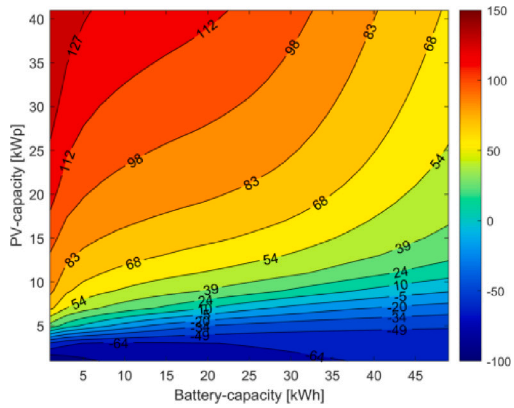

Fig. 14. Maximum additional investment costs (target costs) for multi-apartment buildings for different PV and battery capacities and an annual consumption of 20,000 kWh/a [€/kWh$_{battery}$].

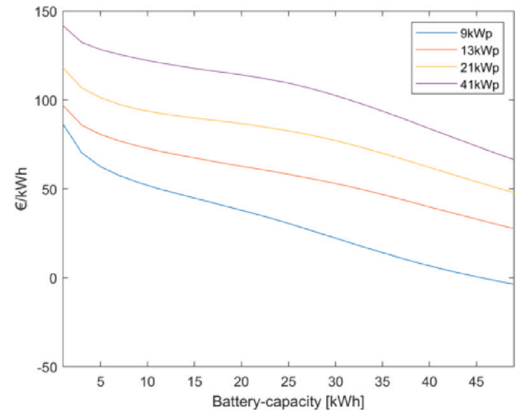

Fig. 15. Maximum additional investment costs (target costs) for multi-apartment buildings for selected PV and battery capacities and an annual consumption of 20,000 kWh/a [€/kWh$_{battery}$].

3.2.2. Economic calculation

As with a single-family building, the following sections illustrate the economic efficiency of a battery storage system in various scenarios for multi-apartment buildings. The parameters for the economic evaluation are also identical and can be taken from Table 3. However, the increased electricity consumption in the building as well as the larger area suitable for Pv installation are specifically addressed and therefore larger combinations of PV and battery storage systems are analysed and compared to the current investment costs.

3.2.2.1. Baseline scenario. In the baseline scenario, an electricity price of 15 c/kWh, a feed-in remuneration of 6 c/kWh and an expected annual return of 5% per year are again assumed. The analysis of the full load cycles has shown that due to the different capacity ratios of the battery storage and the PV system as well as the total annual consumption, a similar behaviour with regard to the number of cycles is shown and therefore it is also assumed that the battery storage must also be replaced in the middle of the calculation period for multi-apartment buildings.

Figs. 14 and 15 show the results of the calculations for an overall annual electricity consumption of 20.000 kWh. The sizes of PV systems and battery storage systems shown here take into account the change in the amount of space available and are also intended to represent the conditions and dimensions exemplarily. With a typical size of 5–7 m^2/kWp, a 40 kWp photovoltaic system would already require between 200 and 280 m^2 of roof space. Realistically, the typical usable roof area of a multi-apartment building (taking into account all distances that must be maintained, e.g. from chimneys and property boundaries) is around 100 m^2, which corresponds to a PV capacity between 14 and 20 kWp.

In the baseline scenario, the maximum possible investment costs are between about 140 €/kWh$_{battery}$ and −75 €/kWh$_{battery}$. The range is roughly the same as for single-family building, but the scale has changed significantly here. Additional costs of 140 €/kWh$_{battery}$ apply here for a 1 kWh storage unit for a PV size of 41 kWp, whereas for a single-family building additional costs of 120 €/kWh$_{battery}$ may occur for 15 kWp and a 1 kWh storage unit. Fig. 15 shows a slight downward bend at a capacity of 30 kWh, which corresponds to 1.5 kWh/MWh. Especially for smaller systems below 5 kWp, where self-consumption is already significantly above 80 percent, additional investment costs are hardly reasonable.

As Fig. 16 depicts, the necessary cost reduction ranges from about 88% for a 41 kWp PV-system and a 20 kWh battery storage to over 100% for a 9 kWp PV-system and with a battery storage capacity of 45kWh or above. This result demonstrates that the investment costs for battery storage under the assumptions made are clearly too high even for multi-apartment buildings. Among typical capacities, battery storage may even cost less than for single-family buildings.

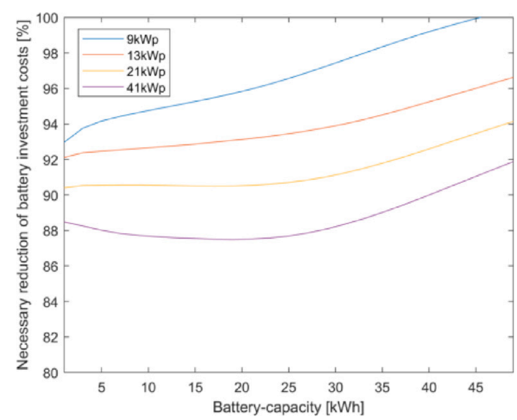

Fig. 16. Necessary cost reduction compared to investment costs in 2022, multi-apartment building [%].

Table 7
Parameter sensitivity analysis multi-apartment building.

Parameter	Value
PV-capacity	15 kWp
Battery capacity	30 kWh
Electricity price	15 c/kWh
Feed-in remuneration	6 c/kWh
IRR	5%
Battery lifetime	13a
Variation of Parameters	−50% to +50%

The primary reason lies in the distribution scheme and in the different load profiles that can be covered. The more different load profiles with different daily consumptions can be supplied, the higher the self-consumption share even without storage. With an optimal distribution key, as assumed here, the maximum possible share can be consumed directly and a much smaller share must be fed into the grid or stored.

3.2.2.2. Sensitivity analysis. As with single-family buildings, the following chapter analyses the effects of a change in the level of the electricity price, the feed-in tariff, the expected return and the lifetime of the battery. The initial parameters for the analysis are outlined in Table 7

The basic characteristics of the sensitivity analysis are, as expected, similar to those for single-family buildings, see Fig. 17. The amount of

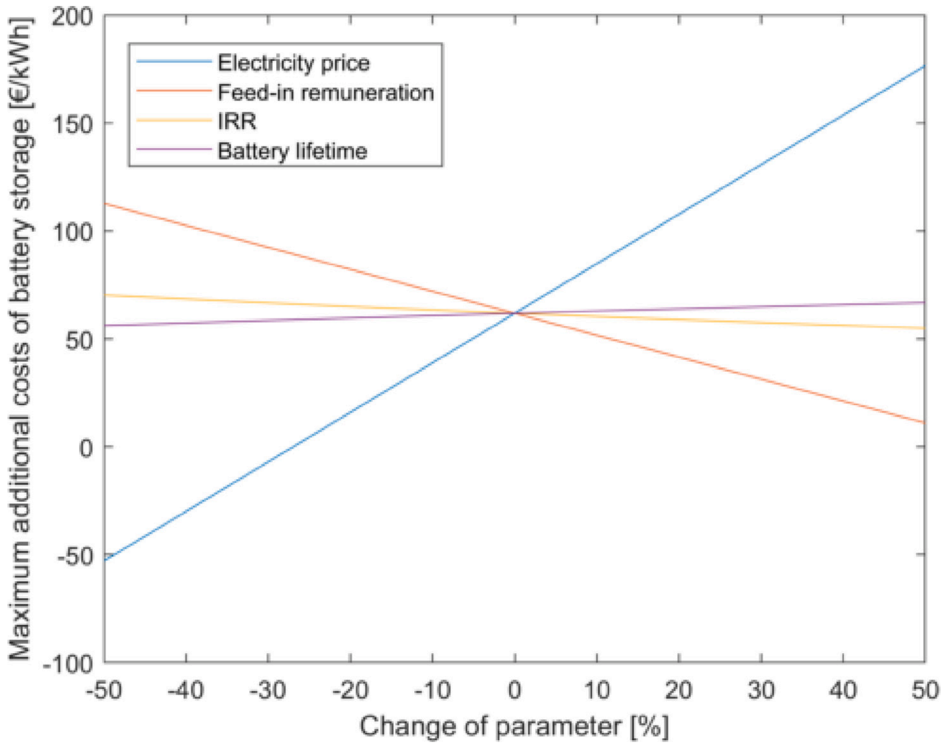

Fig. 17. Sensitivity analysis for additional storage investment costs in a multi-apartment building [$€/\mathrm{kWh}_{battery}$].

additional costs has slightly decreased, mainly due to the optimal distribution of electricity within the building and the coverage of different load profiles. An increase in the electricity price by 50% results in additional potential investment costs of about 176 $€/\mathrm{kWh}_{battery}$ compared to about 200 $€/\mathrm{kWh}_{battery}$ for single-family buildings, whereas a reduction by 50% means negative investment costs of about -53 $€/\mathrm{kWh}_{battery}$, compared to about -60 $€/\mathrm{kWh}_{battery}$. Similar results can be derived for the analysis of the feed-in tariff, the expected annual return as well as for the lifetime of the battery. An increase in the feed-in tariff also has a negative impact on the economic efficiency and thus also on the maximum possible investment costs. An increase in the feed-in tariff to 9 c/kWh leads to maximum possible investment costs of about 11 $€/\mathrm{kWh}_{battery}$, while a halving to 3 c/kWh would mean investment costs of about 113 $€/\mathrm{kWh}_{battery}$. The analysis of the expected annual return (IRR) also shows a lower impact on the result here. An increase in the expected return reduces the additional investment costs of the battery storage from about 62 $€/\mathrm{kWh}_{battery}$ to about 55 $€/\mathrm{kWh}_{battery}$, a reduction in the interest rate leads to an increase in investment costs to 70 $€/\mathrm{kWh}_{battery}$. The analysis of the sensitivity of the lifetime of the battery storage is roughly in the same order of magnitude, but in the opposite direction. An earlier replacement, i.e. after 6.5 years, leads to a slight reduction of the potential investment costs to 56 $€/\mathrm{kWh}_{battery}$, a later replacement after 19.5 years leads to additional investment costs of 66 $€/\mathrm{kWh}_{battery}$.

3.3. Cross-building storage utilisation

An extension of the scenarios already analysed results from the use of battery storage across buildings. In this case, the development of the economic efficiency and the additional maximum investment costs is assessed, if the system boundaries were extended to several buildings. Fig. 18 shows the cross-building use of photovoltaic electricity and battery storage. Battery storage can be used across-buildings to store surplus electricity from one or more photovoltaic systems or other renewable energy systems. For instance, only one photovoltaic system can be installed on a building and cover part of the consumption of both buildings directly or via a battery storage system. This can be a good option, for example, if no photovoltaic system can be installed on the second building due to shading. In the same way, it can also make sense for several differently oriented systems to supply several buildings and for the surplus to be stored and used, for example, at night. The cross-building use poses some challenges, especially with regard to integration and billing. In principle, the decentrally generated photovoltaic electricity can also be used via the public grid through energy communities, whereby grid fees are incurred for that part of the electricity. However, the previous scenarios have already shown that economic viability is difficult to achieve. Additional grid fees would also be incurred for storing the electricity and consumption from the storage facility if it is connected to the public grid. Therefore, it is important to ensure that the battery storage system does not have to be connected to the public grid. In Austria, a reduction of grid fees is provided for renewable energy communities depending on the regional expansion and the grid level used. A distinction is made between local renewable energy communities and regional energy communities. Local energy communities may only use grid levels six and seven, which includes the local low-voltage grid including the transformer station. Regional energy communities can also use the medium-voltage grid, i.e. grid level five and the medium-voltage busbar in the transformer station located on grid level four [33].

Different concessions apply to local and regional communities:

- Local area: The energy prices for the grid usage charge in local EEGs are reduced by 57% compared to standard grid charges.
- Regional area: The energy prices for the grid usage charge in regional EEGs are reduced by 28% for users on grid levels six and seven, and by 64% on grid levels four and five.

The scenario was extended by adding ten more measured load profiles and bringing the total consumption of the buildings to about 40,000 KWh. To account for the increased total consumption, the PV and battery storage capacities were also adjusted.

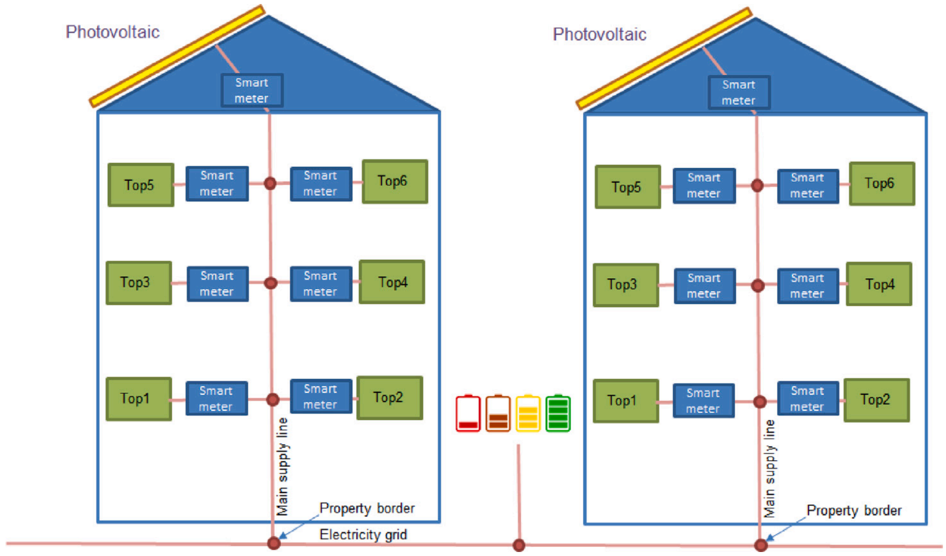

Fig. 18. Schematic configuration of cross-building energy sharing.

Table 8
Parameters for cross-building storage utilisation.

Parameter	Value
PV-System	
Orientation	south
Installation angle	30°
Size	1 – 81 kWp
Battery System	
Charge/Discharge Power	10 kW
Size	0 – 101 kWh
Load profile	
Type of profile	measured household
Overall consumption	40,000 kWh

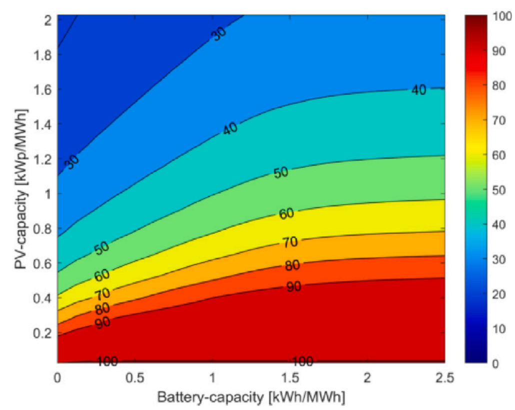

Fig. 19. Rate of self-consumption for different combinations of PV-capacity and battery-capacity related to an annual consumption of 1000 kWh/year, cross-building utilisation [%].

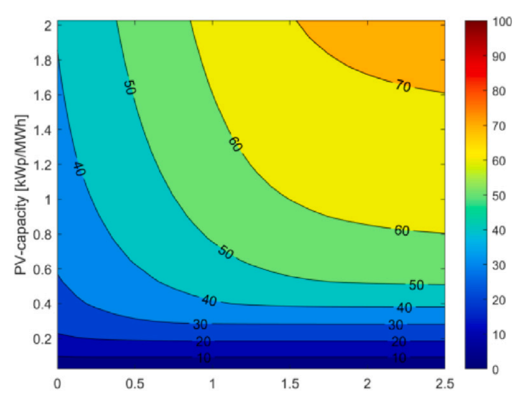

Fig. 20. Rate of self-sufficiency for different combinations of PV-capacity and battery-capacity related to an annual consumption of 1000 kWh/year, cross-building utilisation [%].

Table 8 summarises the parameters for cross-building storage utilisation.

3.3.1. Energetic calculation

The energetic calculation is based on a total electricity consumption of 40,000 kWh per year and 20 different measured, randomly selected household load profiles. As can be seen in Figs. 19 and 20, the different compositions of the load profiles result in marginal differences for the share of self-consumption and the rate of self-sufficiency for PV systems up to a size of 1 kWp/MWh and a battery storage of 1.5 kWh/MWh compared to multi-apartment buildings in Figs. 12 and 13. Only above these values deviations can be observed. In multi-apartment buildings, rates of self-sufficiency of over 70% are already achieved with significantly smaller capacities. Basically, two reasons attribute to this effect. On the one hand, the level of self-sufficiency is already slightly higher for a building-wide calculation compared to a multi-apartment building, even without a storage system, which is why the additional benefit of the storage system increases to a smaller extent. On the other hand, due to the supply of twice as many different measured load profiles and the simultaneity of the load profile peaks, not all peaks can be covered by the battery storage. For this purpose, the charging and discharging capacities would have to be adjusted, which would also lead to higher investment costs for the storage.

Without storage, the self-consumption share at 1 kWp/MWh, which would correspond to a 40 kWp system in this case, is about 32%. With a correspondingly smaller system of only 0.5 kWp/MWh, i.e. 20 kWp, the rate of self-consumption is already over 52%, even without storage. If we assume that two (Wilhelminian-) buildings in Vienna have suitable rooftop areas of about 100 m^2 each and assume an area of 5m^2 per

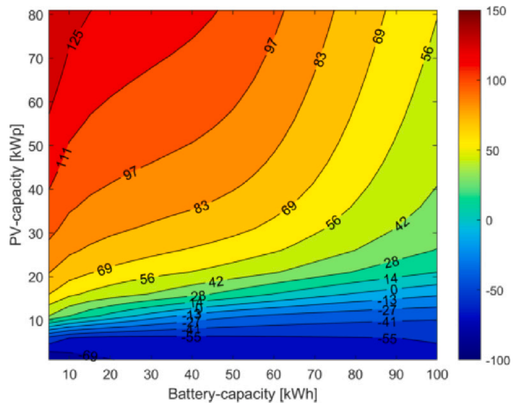

Fig. 21. Maximum additional investment costs (target costs) for cross-building utilisation for different PV and battery capacities and an annual consumption of 40,000 kWh/a [€/kWh$_{battery}$].

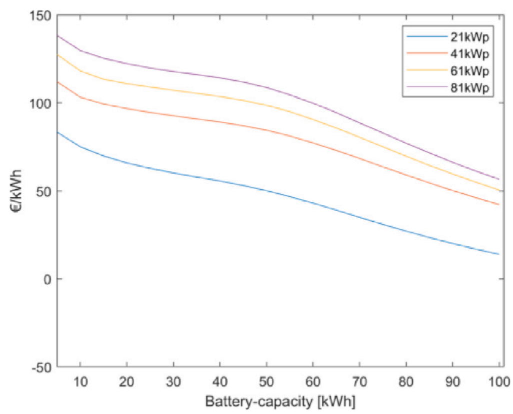

Fig. 22. Maximum additional investment costs (target costs) cross-building utilisation for selected PV and battery capacities and an annual consumption of 40,000 kWh/a [€/kWh$_{battery}$].

kWp, a 40 kWp system is a realistic size. An additional storage unit with a size of 1.5 kWh/MWh, corresponding to 60 kWh, increases the self-consumption to approximately 85%. An increase of just over 30 percentage points. Basically, it can be stated that a battery storage size of 1.5 kWh/MWh for the supply of different household load profiles can be considered ideal in this use case, at least in terms of energy supply.

3.3.2. Economic calculation

As shown in the energy performance assessment, the relative changes in terms of self-consumption and self-sufficiency are only relatively small in some areas compared to multi-apartment buildings. How the different capacities of PV and battery storage affect the additional investment costs is analysed in the following sections.

3.3.2.1. Baseline scenario. Figs. 21 and 22 show the results for an overall annual electricity consumption of 40,000 kWh, PV-capacities between 1 and 81 kWp and storage capacities between 5 and 100 kWh.

As can be seen in the previous use cases, the additional costs depend heavily on the dimensioning of the systems in relation to the yearly electricity consumption. Since the dimensions are different in each use case and different load profiles are used, comparability is not that easy. However, if the investment costs for a 41 kWp system are compared in the case of a multi-apartment building, Fig. 15, and in the case of a cross-building electricity exchange, Fig. 22, it becomes clear that in the latter scenario the costs for the battery storage system must be lower for the same size. The reason for the lower costs is the already increased

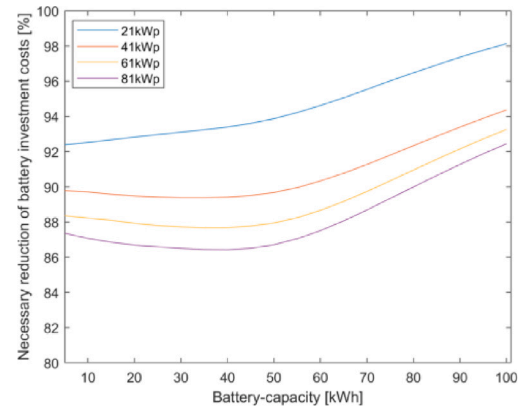

Fig. 23. Necessary cost reduction compared to investment costs in 2022, cross-building utilisation [%].

Table 9
Parameter sensitivity analysis cross-building utilisation.

Parameter	Value
PV-capacity	40 kWp
Battery capacity	60 kWh
Electricity price	15 c/kWh
Feed-in remuneration	6 c/kWh
IRR	5%
Battery lifetime	13a
Variation of Parameters	−50% to +50%

self-consumption due to the different load profiles and the higher yearly total consumption. As a result, the additional benefit of the battery storage system decreases. This becomes also apparent in Figs. 23 and 16, where the respective necessary reduction of the specific investment costs is shown in comparison to the current battery storage costs.

In general, the same order of magnitude can be seen for all three use cases and for the respective realistically feasible capacity combination of PV and battery storage. However, if we compare the same sizes of PV and battery storage as before, the investment costs must decrease further to guarantee the same economic performance if the PV electricity is also distributed or sold to tenants/owners in multi-apartment buildings and if electricity is exchanged between buildings. In the case of cross-property use of the battery storage via the public grid, grid fees for storage or consumption from the storage would also have to be taken into account, which is not the case in this analysis. If this were also taken into account, the investment costs would have to be reduced even further.

As Fig. 23 points out, the necessary cost reduction ranges from about 86% for a 81 kWp PV-system and a 40 kWh battery storage to about 98% for a 21 kWp PV-system and a 100 kWh battery storage system. The previous comparison of a 41 kWp PV system between multi-apartment building and cross-building utilisation is now also illustrated with numbers. If one compares a 41 kWp PV system and a battery storage capacity of 40 kWh, the cross-building use-case must be about four percentage points cheaper, which can be explained by the higher self-consumption without storage.

In absolute terms, this means about 82 €/kWh$_{batt}$ as opposed to about 89 €/kWh$_{batt}$, a necessary reduction of about 8%.

3.3.2.2. Sensitivity analysis. Similar results as for single-family buildings as well as for multi-apartment buildings can also be expected for the sensitivity analysis of the cross-building use of the battery storage. The initial parameters are shown in Table 9.

Due to the fact that the PV system is considerably larger in relation to the annual consumption compared to multi-apartment buildings, the

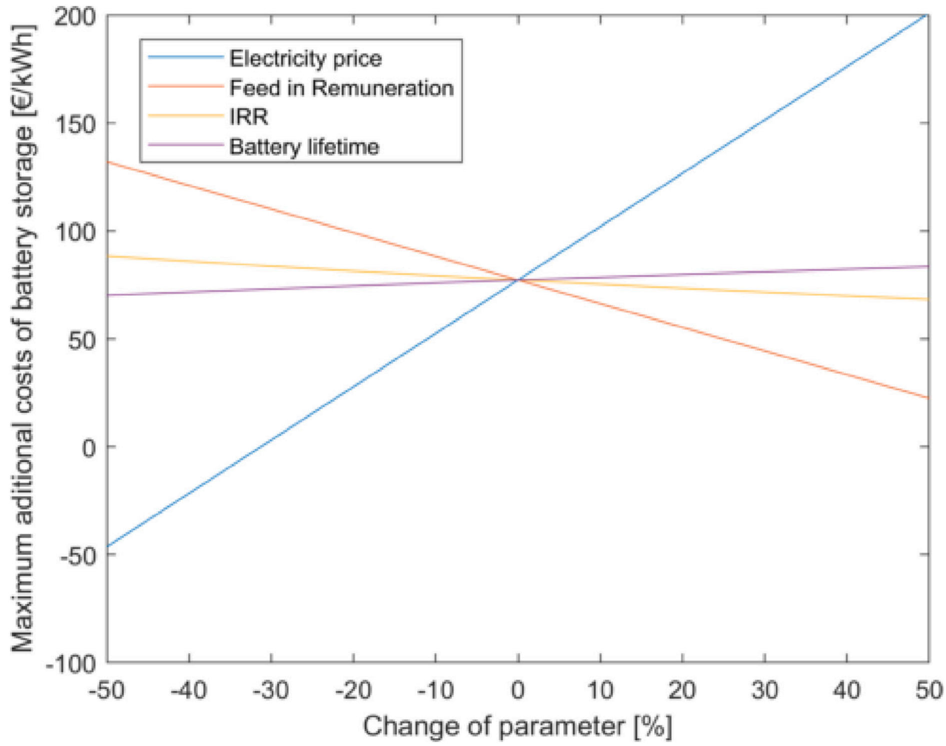

Fig. 24. Sensitivity analysis for additional storage investment costs in cross-building utilisation [€/kWh$_{battery}$].

initial value is also higher at around 77 €/kWh$_{batt}$, see Fig. 24. An increase in the electricity price by 50% leads to additional potential investment costs of about 200 €/kWh$_{batt}$, while a reduction by 50% leads to negative investment costs of just under −50 €/kWh$_{battery}$. Due to the choice of parameters, the sensitivity analysis also shows similar effects for the feed-in remuneration, IRR and battery lifetime as in the other use cases.

For reasons of clarity, only one combination of PV system and battery storage was shown in the sensitivity analysis in all three use cases. For a detailed comparison, all combinations of PV and battery storage would have to be shown. Depending on the choice of the capacity of the PV system and the battery storage, the same basic characteristics will show up, but can differ in terms of the amount.

4. Discussion and conclusion

The novelty of this paper is specifically that it deals with the target costs of battery storage systems in different scenarios. Although there is a lot of discussion in the existing literature about the economic viability of battery storage systems, the authors do not see in any of the papers how the investment costs have to develop in different scenarios so that battery storage systems can operate economically with the expectation of a certain rate of return. However, this is precisely the question addressed in this paper. This work analysed the economically feasible specific investment costs of a battery storage system to obtain a certain annual return under various conditions. Single-family buildings, multi-apartment buildings and cross-building solutions were considered. Furthermore, sensitivity analyses were carried out to show the influence of the level of the electricity price, the feed-in remuneration as well as the expected return and the battery life-time. A southern orientation of the photovoltaic system is assumed throughout the paper, as this is the optimal orientation in terms of energy output. An east–west orientation of the pv-system was not taken into account and should be analysed in a subsequent work.

The main findings of this paper are:

- Specific investment costs need to decrease at least by 85% compared to actual costs
- The electricity price and the spread between the electricity price and the feed-in remuneration have the greatest influence on the result
- If the available photovoltaic areas are limited and consumption is high at the same time, the share of self-consumption is already high — the additional benefit of battery storage diminishes
- The reorganisation of electricity tariffs towards capacity-based tariffs would have a positive effect on economic efficiency and thus on investment costs

From today's perspective and under the assumed framework conditions, it can be clearly concluded that the current investment costs do not allow for the operation of a battery storage system from an economic point of view. This is also in line with the scientific community's discussion.

Even though the costs for battery storage have generally decreased in recent years, see also [26], and currently average about 1350 €/kWh$_{batt}$ for a gross capacity of 1 kWh and about 1000 €/kWh$_{batt}$ for a gross capacity of 10 kWh, see Fig. 2, these investment costs are still too high for storage to be operated economically. In all the use cases analysed, the specific investment costs of battery storage would have to drop by at least 85%. For given load profiles and corresponding annual consumption, the cost reduction depends in particular on the capacity combination of photovoltaics and storage. In the baseline scenario, with relatively small photovoltaic systems for the given load profile, self-consumption already accounts for over 80% to 90% and battery storage only has a very small benefit. The O&M costs already exceed the benefit and the investment costs of the battery storage would have to be negative here to be economically viable. Furthermore, it can be seen in all the use cases that the specific investment costs fall more steeply above a capacity of about 1.5 to 2 kWh/MWh, because the increase in battery capacity only brings a smaller increase in self-consumption as well as in self-sufficiency. As the assumptions regarding electricity consumption and capacities of PV systems and battery storage systems are different in the three scenarios and therefore the cost structure is also different, as well as the different combination of load profiles, a similar picture emerges in relative terms with regard to the necessary cost reduction.

In this paper it is assumed a maximum charging/discharging capacity of 10 kW. This means that the C-rate of the battery also varies depending on the battery capacity. A C-rate is a measure of the rate at which a battery is discharged relative to its maximum capacity. The C-rate also influences the cost of battery storage. A higher C-rate also means higher costs for the battery storage system, as this is also associated with a higher (thermal) load on the battery storage system. Accordingly, a higher charging or discharging rate should also result in a higher cost reduction. The modelling of different C-rates in the evaluation of the costs was not carried out in this paper and should be considered in further work.

As the sensitivity analysis points out, the greatest influence on the investment costs of battery storage systems has the electricity price and the spread between the electricity price and the feed-in remuneration. The higher the assumed electricity price, the higher the self-consumption savings and thus the additional benefit of battery storage. For the economic evaluation of the increase in self-consumption, in countries such as Austria only the variable components of the household electricity prices can be used. Fixed components such as metering fees or renewable electricity flat rates have to be paid independently. In this paper, the level of the electricity price was assumed to only include components that may be taken into account in the evaluation. However, the design and composition of household electricity prices varies from country to country and must be analysed separately. The pure level of the household electricity price is no indication of how self-consumption or the increase in self-consumption can be evaluated. Should grid tariffs change in the next few years from a largely energy-driven tariff to a power tariff, this could be an opportunity for battery storage. Although photovoltaic systems would suffer from such a development, as the share of the electricity price for self-consumption evaluation would decrease, (monetary) incentives could achieve that battery storage systems are used in such a way that power peaks in the load profile are covered and thus less grid capacity is needed. This would have a relieving effect on the electricity grid and a positive effect on the economic efficiency and thus on the possible investment costs of battery storage systems.

Furthermore, the potential of time-variable tariffs and feed-in remuneration should also be analysed in more detail in future papers. The outcome for target cots depend heavily on the design of the tariffs and the extent to which peak prices differ from off-peak prices. Overall, experience shows that the spread between peak and off-peak in dynamic end customer prices is not very high, as the electricity price is made up of the energy tariff, grid tariff and taxes and levies. Nevertheless, higher peak prices can have a positive effect on the necessary reduction in the investment costs of battery storage systems.

However, the calculated specific investment costs also depend strongly on the ratio between the feed-in remuneration and the self-consumption savings. If the feed-in remuneration is relatively high, the benefit of the storage system decreases. Since the difference between self-consumption and feed-in is smaller it becomes more and more attractive to feed the electricity into the public grid instead of storing it. The fact that the battery lifetime has a relatively small influence on the result is based on two aspects. Firstly, it is assumed that the battery storage system will only cost 70% of the actual investment costs when it is newly purchased in x years. On the other hand, due to the methodology the total cash flow remains the same and only the time of replacement varies and is thus divided differently between current and future costs through discounting. Resulting from a relatively small difference in the cash flows without battery storage and with battery storage and the reference to specific costs, the interest rate also has a relatively small influence on the possible investment costs.

In general, the space available for photovoltaics is also somewhat limited. In urban areas, where distribution of photovoltaic electricity in multi-apartment buildings is possible, as is the case in Austria, and specially where different load profiles (e.g. household & commercial) prevail, self-consumption is usually relatively high. In such a scenario, an additional battery storage system is even less economical to operate than in single-family buildings. If the photovoltaic electricity is further distributed beyond the property boundaries, the match between PV-generation and aggregate load profiles with different consumption structures (e.g. high daily consumption, shops, general consumption in multi-apartment buildings, e-mobility) is even higher and thus also the self-consumption share. In addition, there are grid fees for storing electricity that have to be paid. Even if these grid fees vary regionally and only amount to a third of the full grid fees in the near vicinity, they still significantly reduce the maximum arguable investment costs.

In conclusion, the use of decentralised battery storage to increase self-consumption is questionable. If decentralised battery storage systems are already being used in single-family buildings or multi-apartment buildings and across-buildings, they should at least be operated in such a way that they actually have a benefit for the overall electricity system and can thus also generate additional income. However, stationary battery storage competes with other flexibility options such as load shifting, where smart households can adapt their load to generation and increase their self-consumption or electric vehicles as temporary storage. Furthermore power to heat can also be an alternative for battery storage systems. Additionally trading platforms (e.g. e-Friends) where surplus electricity is sold or traded directly to other consumers and prosumers in a peer to peer trading algorithm represent a flexibility option to minimise storage requirements.

CRediT authorship contribution statement

Albert Hiesl: Writing – original draft, Validation, Methodology, Formal analysis, Data curation. **Jasmine Ramsebner:** Writing – review & editing, Formal analysis, Conceptualization. **Reinhard Haas:** Supervision, Visualization, Conceptualization.

Declaration of competing interest

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

Data availability

Data will be made available on request.

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