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Intelligent control of household Li-ion battery storage systems

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Abstract

The increase in electricity prices along with a decrease in the price of storage systems has led to a rapid expansion of the PV-battery home storage system market. In order to be economically viable PV-storage systems must fulfil certain performance criteria, and the system control strategy has a large impact on the overall system performance.
At KIT the performance of 20 commercially available PV-battery systems has been evaluated based on several criteria, one of these is intelligent control. A detailed study of the relationship between battery ageing and control strategy of 6 of these systems with NMC-based cells is part of the evaluation. It is shown that an intelligent control strategy can prevent calendar ageing. How large the effect is obviously depends on the dimensioning of the system and the sensitivity of capacity fade at different SOC levels. It is observed that a difference in battery lifetime caused by calendar ageing of up to 1.5 years is possible.
In order to complement these results it is interesting to also consider the effects of intelligent control strategies (or the lack thereof) on the PV power fed into the grid. The feed-in of PV power to the grid is often regulated by law, and if the battery is fully charged too early in the day the system operator is forced to throttle the PV-system during the midday peak. An intelligent charging regime with accurate load and generation forecasts can prevent this, but could also lead to a reduction in self-sufficiency if the prediction is incorrect. It is shown that between 62 kWh and 104 kWh per year are lost due to the reason that most storage systems don't possess a charging strategy to prevent throttling of the PV-generator.
Since the effects of battery ageing and unwanted PV throttling are not independent it is useful to evaluate them in parallel and in combination with results on battery and system efficiency. The goal is to determine the economic impact of intelligent control and the resulting interplay between each of these factors.

Keywords: PV-Battery Home Storage Systems; Performance; Intelligent Controle Startegy; Battery aging, PV throttling

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1. Introduction

Efficient and economic energy storage technologies are key elements for a sustainable future energy supply. Attractive and economical applications can be established if we succeed in providing persistent and cost-efficient storage systems for electrical energy.

While the electricity prices for households in Germany have increased by around 66 % [1] since 2005, prices of household storage systems (storage capacity of less than 10 kWh) have declined by 43 % during the last four years [2]. This has led to a rapid expansion of the PV-battery home storage system market in Germany.

Nevertheless there are several critically important aspects affecting the performance and, as a consequence, the commercial viability: the system design and dimensioning [3]–[5], the level of development of the system control software [6]–[8] and the calendar and cycle life of the battery and electronic components [9].

The system control strategies as well as the efficiency of different components have a large impact on the overall system performance [6]–[8], [10], [11]. For this reason, over 20 commercially available PV-battery systems with a usable storage capacity of between 2 kWh and 6 kWh are currently being analyzed with respect to different performance criteria. The present work focuses on the system control strategy and its effect on the system performance.

The system control software should be regulated in such a way as to maximize the self-supply ratio. At the same time, the underlying algorithms must ensure the longest possible operational lifespan of the battery; in particular the various electrochemical processes that take place during the operation of a lithium-ion battery must be taken into account. According to Munzke et al. [7] one concrete example of this is that excess energy should not be stored in the battery right at the start of the day, but rather only after midday, since most lithium-ion batteries age faster when their state of charge (SOC) is high [12]. This is mainly true for days when the excess energy is higher than the possible amount of energy which can be stored within the battery.

Therefore a vital component of the software is its ability to predict both the energy needs of the customer as well as the energy supplied by the PV-array throughout the day. In essence one needs to be able to predict the load as well as the available power to deduce how the system should best be regulated in order to increase profitability.

Peak-shaving can also increase the overall system profitability in cases where the maximum power that can be fed into the grid is limited by law to for example 70 % of PV peak power: during times of high PV production the predictive control system ensures that the excess energy is stored without having to throttle the PV-generators.

These factors require serious brainpower in the control system, since one has to decide in advance when and with what power the battery should be charged or discharged in order to simultaneously maximize self-supply and ensure a long battery life or store excess energy within the battery to prevent that the PV generators have to be throttled.

Tests revealed that only 25 % of the systems tested already possess a fully developed control strategy. The strategy of many systems is just to increase the amount of self-consumption, which results in the strategy represented by Figure 1. While 40 % of the advanced systems need online data, the other 60 % possess an offline prediction [7].

The present work quantifies the effect of intelligent predictive control, as well as the resulting interplay between PV throttling and battery ageing due to controlled charging. Although one would like to minimize both of these effects it is not always the case that a reduction in ageing is accompanied by a reduction in losses due to PV throttling.

Since the different effects are not independent the goal is to study the interplay between each aspect as well as the relationship to system efficiency. The overall economic viability of storage systems depends on various factors and the goal is to examine more closely the effects of intelligent control software, thus complementing other studies based on simulation or those that look at different aspects like cell ageing in an isolated context like Keil et al. [12].

2. Methodology

2.1. Input data

To find out whether the commercial home storage systems possess any sort of intelligent and/or predictive charging/discharging algorithm, they are tested within a hardware-in-the-loop environment similar to the measurements described in the efficiency guidelines [13]. The measurements are done for typical reference days with measured solar PV data from KIT with a time resolution of one second and load curves for single-family households which can be generated based on the VDI 4655 reference profiles [14]. The tests were performed with an annual electricity demand of between 3500 kWh and 4800 kWh, which corresponds to between 2 and 5 inhabitants per household. The resulting household load profiles have a time resolution of one minute. The PV data comes from the 1 MW PV plant at KIT north campus, located at 49.1° N, 8.44° E, which corresponds to climate zone TRY12 in the VDI 4655 classification system. Table 1 shows an overview of the test configurations.

Table 1: Test configurations

	Test 1	Test 2	Test 3
Load data	VDI 4655 - TRY 12 [14]	VDI 4655 - TRY 12 [14]	Data from household 14 of one week in summer, from the project „ADRES-CONCEPT“ [15]
Annual electricity demand - inhabitants per household	4200 kWh - five inhabitants	4200 kWh - five inhabitants	~ 3500 kWh
PV data	Different days around the year according to the reference days	Different days around the year according to the reference days	7 summer days
PV-plant size	3.5 kWp	4.8 kWp	3.5 kWp

By testing all 10 different reference days of the VDI 4655 and using the corresponding frequency of each day of climate zone TRY12, the results can be extrapolated for the whole year.

In addition to that, tests were performed using the same PV data from summer and measured load data of different households. These data stem from one week of measurements, in summer, from the project „ADRES-CONCEPT“, and have a time resolution of one second [15].

2.2. Test criteria

The following criteria are used to quantify the level of intelligence of the storage system control software of the systems under test: (a) the success of delayed charging in reducing the time spent at high SOC levels, (b) the ability to shave the midday peak and (c) whether prediction errors lead to the battery not being fully charged so that the user's self-sufficiency is unnecessarily reduced.

Throughout the whole test the power, current and voltage are measured at different points of measurement as described in the efficiency guidelines [13].

In Munzke et al. [7] an approach is described which uses the measured battery voltage ($U_{\mathrm{BAT,act}}$) to evaluate the success of delayed charging (criterion (a)). As the battery chemistry as well as the module topology of the batteries is known the mean cell voltage can be calculated. For further evaluation the voltage range from the minimum to the maximum cell voltage is divided into 25 and 200 intervals. This is done separately for the different cell chemistries. While in Munzke et al. [7] only the measured battery voltage during operation is used to determine the SOC of the systems, the current work also takes the ohmic resistance ($R0_{\mathrm{BAT}}$) as well as the current ($I_{\mathrm{BAT,act}}$) flows from and to the battery into account (see Equation (1)). The calculated open circuit voltage (OCV) of the battery can then be used to calculate how much time the battery spends in each interval. In this way the OCV and therefore the SOC of the battery ($U_{\mathrm{BAT,OCV}}$) during operation can be determined.

$$U_{\mathrm{BAT,OCV}} = U_{\mathrm{BAT,act}} + I_{\mathrm{BAT,act}} * R0_{\mathrm{BAT}} \tag{1}$$

The most common cell chemistries within the study are NMC and LFP. Regarding the shape of the OCV/SOC curve it is easier to determine the SOC via the OCV of NMC than LFP based batteries. The evaluation that follows therefore focusses on 6 PV-storage systems (labelled A...F) with batteries based on NMC chemistries.

The ohmic resistance of each battery ($R0_{\mathrm{BAT}}$) is measured for several SOC (25 %, 50 %, 75 % and 90 %) by using a charge pulse for 20 s with half of the possible nominal power. The nominal charge power of each system is determined according to the efficiency guidelines [13]. The ohmic resistance values of 25 % and 50 % SOC as well as of 75 % and 90 % SOC are quite similar for all systems under evaluation. Therefore, for all further calculations a mean value of the resistance at 25 % and 50 % was used for all SOC values smaller than 60 % and a mean value of the resistance at 75 % and 90 % for all SOC values higher than 60 %.

The measured $R0_{\mathrm{BAT}}$ for the different systems under evaluation varies between 13.6 mΩ and 168.1 mΩ depending on the SOC and the system (see Table 2).

Table 2: Measured ohmic resistance of the batteries

		System A	System B	System C	System D	System E	System F
R0 of the battery /mΩ	SOC < 60 %	85.2	19.2	168.1	20.2	14.4	15.0
	SOC > 60 %	78.2	15.6	152.3	19.8	13.6	14.4

As the module topology of the batteries is known, the ohmic resistance per cell of each system can be calculated (see Table 3). The determined values vary between 1.2 mΩ and 4.2 mΩ, which are just a little bit higher than the ohmic resistance of pouch and hard case cells which were determined by single cell measurements. Nevertheless the measured values are considered valid, as the battery management system is also a part of the battery module, which can result in an increase in the ohmic resistance.

Table 3: Minimum and maximum values of the measured ohmic resistance

		SOC < 60 %	SOC > 60 %
Ohmic resistance per cell /mΩ	Minimum measured value of all systems	1.3	1.2
	Maximum measured value of all systems	4.2	3.9

The second criterion (b) to evaluate the control strategy is its ability to shave the midday peak, in the sense that the PV generators do not have to be throttled. That could be the case if the maximum power that is allowed to be fed into the grid by law would be limited to 70 % of PV peak power (3.5 kWp). As a consequence the maximum grid feed in power would be 2.45 kW. This is for example the case in Germany due to the renewable energy law (EEG).

PV energy which is neither used within the household nor charged within the battery is fed into the grid as excess energy ($E_{\mathrm{EX\ AC}}$). As the feed-in limitation of the 6 systems under evaluation is not active the cut excess energy ($E_{\mathrm{EX\ AC,t}}$), where the excess power ($P_{\mathrm{EX\ AC}}$) exceeds 70 % of the PV peak power ($P_{\mathrm{PV\ kWp}}$), can be calculated according to Equation (2). In the same way Equation (3) can be used to determine the excess energy ($E_{\mathrm{EX\ AC,t,y}}$)which would need to be throttled for the measurements according to the test criteria (Test 1 and 2).

$$E_{\mathrm{EX\ AC,t}} = \sum(P_{\mathrm{EX\ AC}} - P_{\mathrm{PV\ kWp}} * 70\ \%) \quad (2)$$

$$E_{\mathrm{EX\ AC,t,y}} = \sum_{\mathrm{all\ ref,d}} \sum (P_{\mathrm{EX\ AC}} - P_{\mathrm{PV\ kWp}} * 70\ \%) * n_{\mathrm{ref,d}} \quad (3)$$

$$\left.\right\} \quad P_{\mathrm{EX\ AC}} > P_{\mathrm{PV\ kWp}} * 70\ \%$$

$n_{\mathrm{ref.\ d}}$ represents the number of reference days per day type for region 12 (Karlsruhe) of the VDI 4655 classification. If the household would just be equipped with a PV-system without storage, the maximum allowed AC PV power would already be 2.45 kW. To determine the energy losses due to a direct throttling of the PV-generator Equation (4) can be used.

$$E_{\mathrm{PV\ AC,t}} = \sum_{\mathrm{all\ ref,d}} \sum (P_{\mathrm{PV\ AC}} - P_{\mathrm{PV\ kWp}} * 70\ \%) * n_{\mathrm{ref,d}} \qquad P_{\mathrm{PV\ AC}} > P_{\mathrm{PV\ kWp}} * 70\ \% \quad (4)$$

The third criterion, whether prediction errors lead to the battery not being fully charged so that the user's self-sufficiency is unnecessarily reduced, is evaluated by a comparison between the usable charge capacity of the storage system and the energy charged within the battery during day time. One indicator is if the energy charged within the battery during day time is lower than the usable storage capacity and grid feed-in still takes place the same day. The size of the power electronics as well as a slow response time of the system on changes in PV or load or an inaccurate estimation of the state of charge of the battery might also lead to a battery not being fully charged at the end of the day. Therefore in addition a qualitative analysis of the charge behaviour is needed to determine if prediction errors lead to the battery not being fully charged.

To evaluate the impact of the system control strategy on system performance, its influence is compared to the one of system efficiency. According to Munzke et al. [16] the system efficiency (for Test 1 and 2) can be calculated with Equation (5).

$$Eff_{\mathrm{SYS}} = \frac{\sum_{\mathrm{all\ ref.\ d}} \left((E_{\mathrm{SC,d}} + E_{\mathrm{FI,d}}) * n_{\mathrm{ref.\ d}} \right)}{\sum_{\mathrm{all\ ref.\ d}} \left(E_{\mathrm{PVS,DC,d}} * n_{\mathrm{ref.\ d}} \right)} * 100\ \% \tag{5}$$

$E_{\mathrm{SC,d}}$ is the energy directly consumed by the system operator per day, $E_{\mathrm{FI,d}}$ is the energy fed into the grid per day and $E_{\mathrm{PVS,DC,d}}$ is the energy yield of the PV plant per day.

2.3. Systems under evaluation

Table 4: Systems under evaluation

	System A	System B	System C	System D	System E	System F
Usable storage capacity /kWh	4.3	3.8	2.1	5.2	4.9	4.0
Nominal storage capacity /kWh	4.4	5.0	2.0	5.5	6.4	5.0
Rated PV output power /kW	4.2	5.0	3.7	5.0	4.6	5.0

Table 4 shows an overview of the systems under evaluation with NMC based batteries. While the usable storage capacity was determined after the efficiency guidelines for home storage systems, the rated PV output power as well as the nominal storage capacity stem from the datasheets of the different systems. The shown usable storage capacity is usable discharge capacity.

3. Results

To get a better understanding how different control strategies can look like, Figure 1 and 2 represent different control strategies as they are already described by Munzke et al. [7], [17]. In both cases the battery is not big enough to store all of the surplus energy supplied by the installed PV-panels. In the case shown in Figure 1 the batteries are charged much faster than in the one shown in Figure 2. Even though the useable storage capacity of system C (Figure 2) is only 43 % of system E (Figure 1), it is fully charged 3.00 hours to 4.25 hours after system E stops charging. The test was done with the test configuration Test 3 described in Table 1. As a consequence, system C only spends 0.75 hours to 2.00 hours instead of 4.75 hours fully charged.

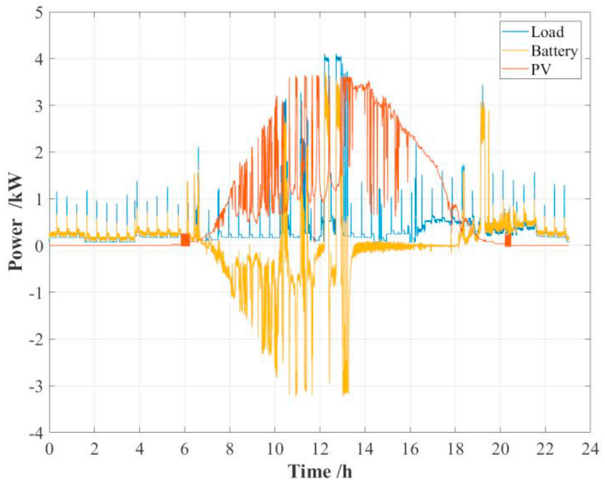

Figure 1: Measurement data for a transition day: example of a system that does not seem to have an intelligent charging algorithm – system E

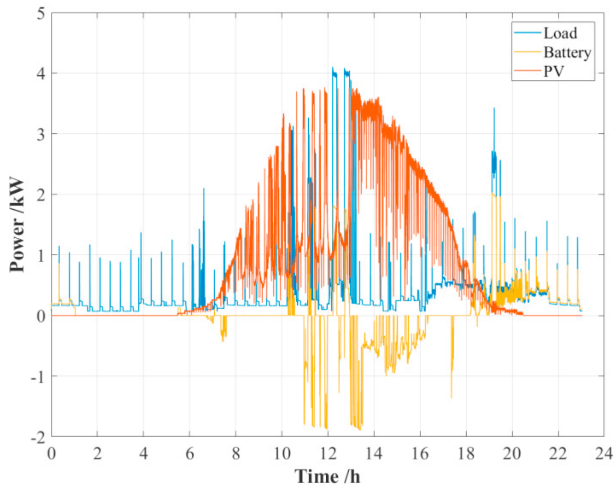

Figure 2: Measurement data for a transition day: example of a system that displays intelligent behavior regarding its battery charging algorithm – system C

3.1. Calendar aging

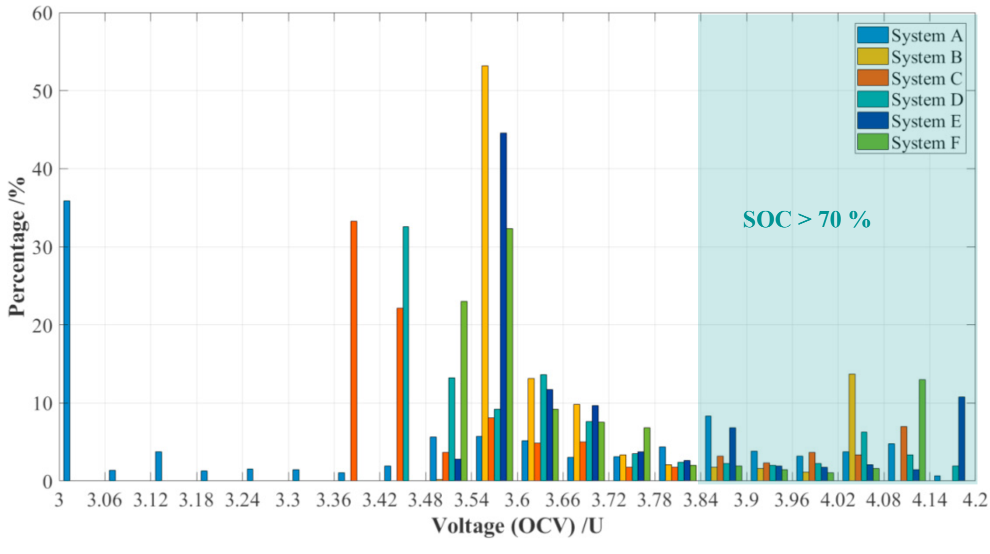

Figure 3: Distribution of the OCV extrapolated for a whole year for System A…F (Test 1)

Figure 3 shows the distribution of the OCV for the 6 different systems (A to F) under test. The measurements were done according to the test criteria (Test 1) and extrapolated for a whole year. For NMC, an SOC higher than 70 % corresponds to an open circuit voltage of around 3.84 V. In addition to that Figure 4 shows a more detailed distribution of the OCV between 3.84 V and 4.2 V. While an SOC higher of 80 % corresponds to an OCV of around 3.945 V, 90 % correspond to around 4.05 V. As a consequence all voltage levels higher than 3.945 V represent an SOC higher than 80 % and all voltage levels higher than 4.05 V represent an SOC higher than 90 %.

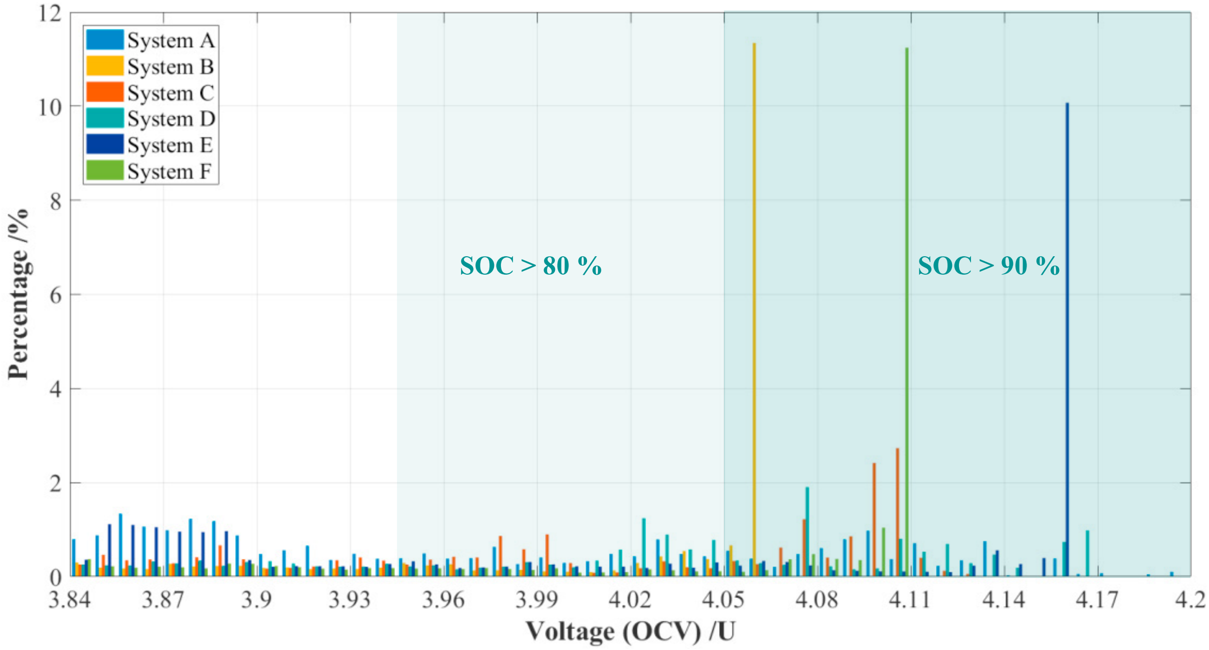

Figure 4: Distribution of the OCV between 3.84 V and 4.2 V (70 % to 100 % SOC) extrapolated for a whole year for System A…F (Test 1)

Table 5: Percentage of time spent at a measured voltage higher than 3.945 V and 4.05 V for the systems A…F

			System A	System B	System C	System D	System E	System F
Percentage of time spent at a voltage (OCV) (extrapolation for a whole year – Test1)	OCV	> 3.945V	13.3	15.3	14.6	14.2	16.7	18.5
		< 3.945V	86.7	84.7	85.4	85.8	83.3	81.5
Percentage of time spent at a voltage (extrapolation for a whole year – Test1)	Measured voltage	> 3.945V	13.4	15.2	14.6	14.2	16.7	16.1
		< 3.945V	86.6	84.8	85.4	85.8	83.3	83.9
Percentage of time spent at a voltage (OCV) (extrapolation for a whole year – Test1)	OCV	> 4.05 V	7.1	12.0	9.4	8.1	13.3	14.1
Percentage of time spent at a voltage (summer week – Test 3)	OCV	> 3.945V	Missing data	36.1	32.4	37.9	46.8	42.0
		< 3.945V		63.9	67.6	62.1	53.2	58.0

Table 5 shows the extrapolated results of the percentage of time which the storage systems spent at a voltage higher than 3.945 V and 4.05 V (SOC > 80 % and SOC > 90 %) calculated by using either the determined OCV or only with the measured voltage as described in Munzke et al. [7]. Both results are similar or even equal, due to the reason that the work focuses on high SOC stages where the current to and from the battery is rather small.

Even though system C is the smallest within the evaluation, it spends the least amount of time at voltage levels higher than 3.945 V during summer days (see Table 5), i.e. it spends the least amount of time at a high SOC level in summer. However this is not the case when comparing the values for the whole year – due to its lower capacity it spends the highest percentage of time at high SOC levels in winter. The same trend is described in Munzke et al. [7]. System A, whose storage capacity is higher than that of system D but less than some of the others, spends the least amount of time at voltage levels higher than 3.945 V during the whole year. A qualitative analysis of the measurement results shows that only two of the five systems (A and C) show an intelligent charging strategy.

Due to different depth of discharge windows the lowest as well as the highest measured voltage of the batteries for each system differ from each other (see Figure 3 and 4). By limiting the depth of discharge (DOD), especially in the upper SOC level (voltage level), calendar ageing caused by high SOC levels can also be reduced. A comparison between the nominal and the usable storage capacity also shows, that the DOD, especially of the systems B and F which do not poses an intelligent charging strategy is limited. Nevertheless these systems spend more time at a SOC higher than 80 % and 90 %.

Keil et al. [12] performed measurements of calendar ageing for different cell chemistries, their results for NMC show a higher capacity fade (CF) at SOC levels greater than 60 % to 70 %. A CF of 1 % to 3 % at a SOC between 0 % and 70 % and 5 % to 6 % between 70 % and 100 % SOC is found over a period of 10 months, where measurements were performed at 25 °C. An increase of the temperature to 40 °C and 50 °C shows a higher increase of the CF for a SOC of 80 % to 100 %. For the following evaluations this trend together with Equation (6) is used to calculate the annual CF (CF_y) due to calendar ageing as well as the end of life (EOL) of the batteries that is only caused by calendar aging. 80 % relative capacity is defined as the end of life criterion. As a CF of 5 % to 6 % per year is rather high for batteries used within PV-storage systems, a sensitivity analysis is proposed.

$$CF_{\mathrm{y}} = \frac{t_{\mathrm{OCV}>3.945}}{t_{\mathrm{total}}} * CF_{\mathrm{SOC\ 80\ \%-100\ \%}} + \frac{t_{\mathrm{OCV}<3.945}}{t_{\mathrm{total}}} * CF_{\mathrm{SOC\ 0\ \%-80\ \%}} \qquad (6)$$

Figure 5, 7 and 9 represent the effect of a different capacity fade at different SOC levels. The results were calculated using Equation (6) and a variation of the CF for all SOC levels lower (1.0 %, 1.3 %, and 2.0 %) as well as higher (1.0 % - 6.0 %, 1.3 % - 6.0 % and 2.0 % - 6.0 %) than 80 % SOC. The calculated lifetime of the systems under test differ from each other as a function of the percentage of time spent at an OCV higher ($t_{\mathrm{OCV}>3.945}$) than 3.945 V and as a consequence a SOC higher than 80 %. The higher the CF at a SOC higher than 80 % is, the more important it is to reduce the time spent at high SOC levels. It can be seen that system A shows the least capacity fade per year in all three scenarios. As a consequence the battery lasts the longest until it reaches a relative capacity of 80 %, i.e. its end-of-life (see Figure 5, 7 and 9).

If the CF per year at a SOC higher than 80 % reaches 5.5 % per year, the difference in lifetime caused by calendar ageing varies between 0.55 years and 1.59 years depending on the capacity fade per year at a SOC lower than 80 %.

The cumulative economized grid supply cost over the lifetime of the storage system $K_{\mathrm{GC,e}}$ can be calculated using Equation (7),

$$K_{\mathrm{GC,e}} = CL * E_{\mathrm{BAT\ dischg,DC,y}} * Eff_{\mathrm{PE\ dischg,y}} * (K_{\mathrm{E,SC}} - K_{E,FI}), \qquad (7)$$

where CL is the lifetime of the PV-storage systems due to calendar ageing, $E_{\mathrm{BAT\ dischg,DC,y}}$ is the energy discharged during the whole year (measured on the DC side of the inverter), $Eff_{\mathrm{PE\ dischg,y}}$ is the mean discharge efficiency of the path BAT2AC (inverter) during one year, $K_{\mathrm{E,SC}}$ are the costs for electricity consumed from the Grid (0.29 €/kWh) and $K_{\mathrm{E,FI}}$ is the current feed-in tariff (0.122 €/kWh). $K_{\mathrm{GC,e}}$ are costs which would occur if the battery would not be able to supply the load of the household. The longer the lifetime of the battery is, the more costs can therefore be avoided. As a consequence the less ageing occurs, the more grid supply cost over the lifetime of the storage system can be economized. If the electricity is provided by the battery storage system instead of the grid, costs that would occur for electricity consumed from the grid are avoided. As the usable storage capacity of the different systems under study varies between 2.1 kWh and 5.2 kWh, a different amount of energy is discharged from the batteries during one year. The annual discharge energy of the largest system is nearly double the discharge energy of the smallest system. Using the real discharge energy of each system would therefore give no answer to the question of the influence of the control strategy on performance. Therefore a mean value for the annual energy discharged from a battery is calculated with Equation (8).

$$E_{\mathrm{BAT\ dischg,DC,y}} = -32.241 * Capa_{\mathrm{BAT}}^{2} + 390.63 * Capa_{\mathrm{BAT}} + 0.5576, \qquad R^2 = 0.9423 \qquad (8)$$

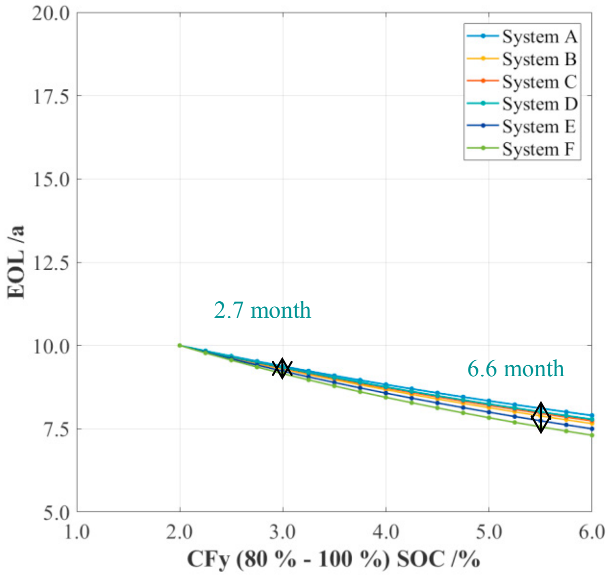

Figure 5: Lifetime of the battery within a PV-storage system due to calendar ageing calculated with a capacity fade per year of 2.0 % for SOC levels between 0 % and 80 % and a variation of 2.0 % - 6.0 % for SOC levels between 80 % and 100 %

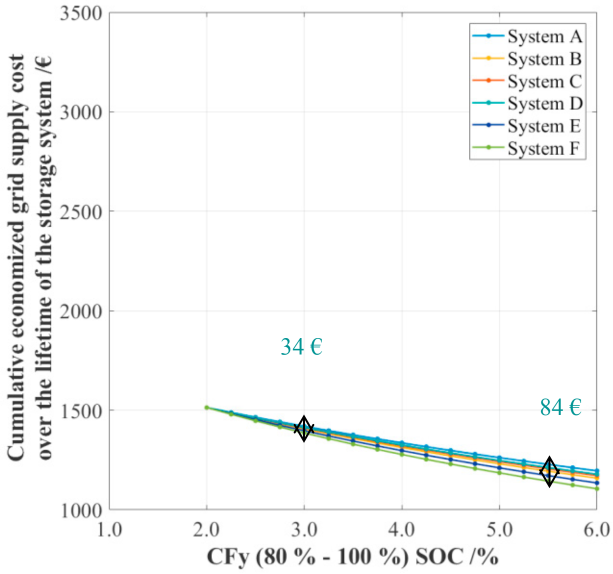

Figure 6: Cumulative economized grid supply cost over the lifetime of the storage system of the different PV-storage systems due to calendar ageing calculated with a capacity fade per year of 2.0 % for SOC levels between 0 % and 80 % and a variation of 2.0 % - 6.0 % for SOC levels between 80 % and 100 %

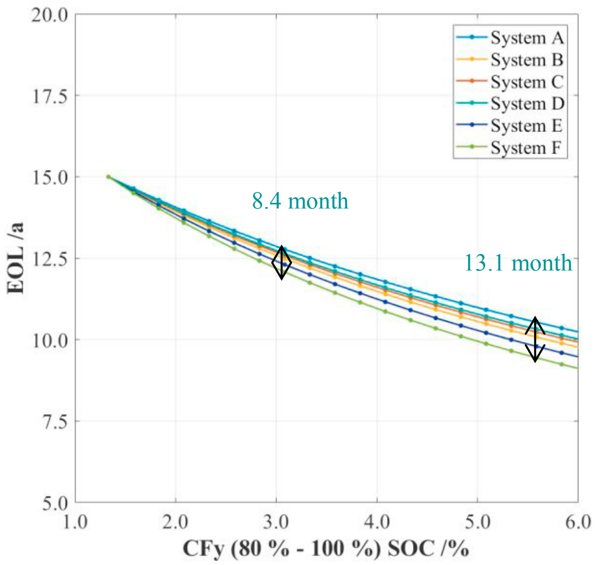

Figure 7: Lifetime of the battery within a PV-storage system due to calendar ageing calculated with a capacity fade per year of 1.3 % for SOC levels between 0 % and 80 % and a variation of 1.3 % - 6.0 % for SOC levels between 80 % and 100 %

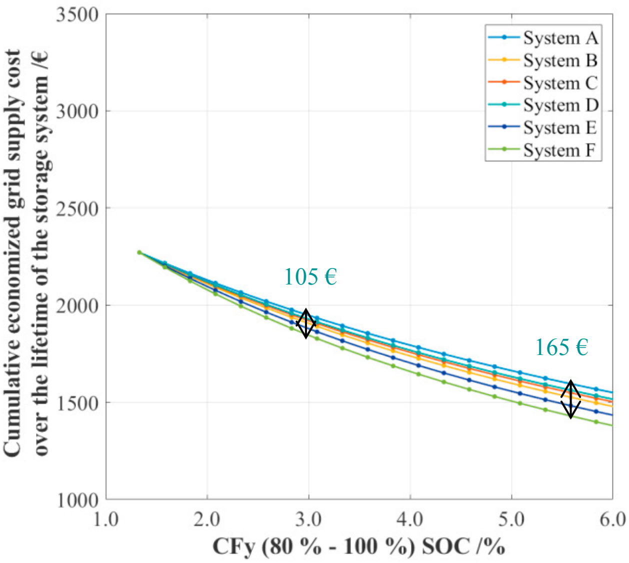

Figure 8: Cumulative economized grid supply cost over the lifetime of the storage system of the different PV-storage systems due to calendar ageing calculated with a capacity fade per year 1.3 % for SOC levels between 0 % and 80 % and a variation of 1.3 % - 6.0 % for SOC levels between 80 % and 100 %

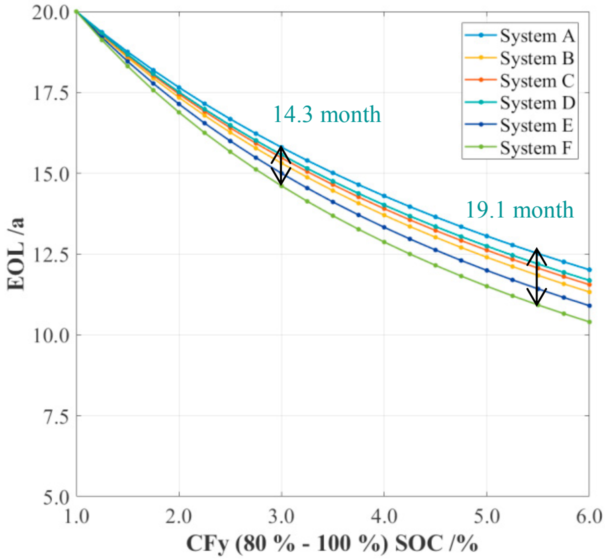

Figure 9: Lifetime of the battery within a PV-storage system due to calendar ageing calculated with a capacity fade per year of 1.0 % for SOC levels between 0 % and 80 % and a variation of 1.0 % - 6.0 % for SOC levels between 80 % and 100 %

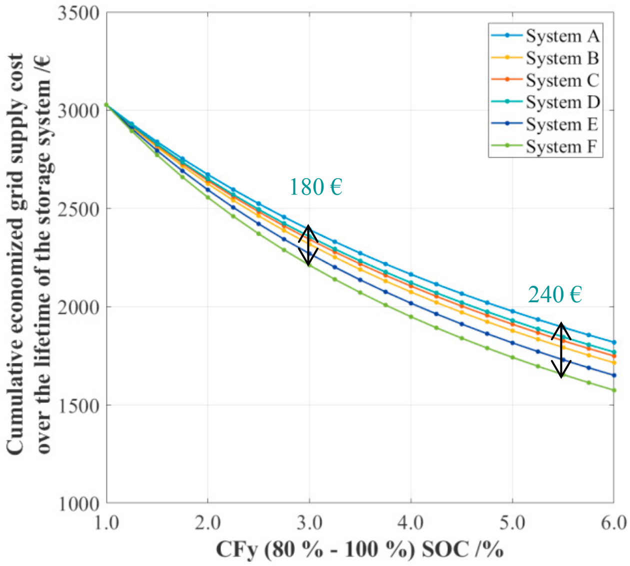

Figure 10: Cumulative economized grid supply cost over the lifetime of the storage system of the different PV-storage systems due to calendar ageing calculated with a capacity fade per year 1.0 % for SOC levels between 0 % and 80 % and a variation of 1.0 % - 6.0 % for SOC levels between 80 % and 100 %

Equation (8) is derived from the results of all systems under evaluation with battery efficiencies higher than 93 %. A second degree polynomial function is used to find a correlation between the energy discharged during the whole year and the usable battery capacity of the different systems. As battery capacity ($Capa_{\mathrm{BAT}}$) the mean usable battery capacity (4.1 kWh) of the 6 systems is determined. The mean discharge energy therefore results in 1060 kWh per year. As a simplification the permanent reduction of the usable storage capacity during battery lifetime is not taken into account. The mean discharge efficiency of the path BAT2AC is chosen to be 85 %. If the CF per year at a SOC higher than 80 % reaches 3.0 % per year, the difference in the cumulative economized grid supply cost over the lifetime of the storage system varies between 34 € and 180 € (and between 84 € and 240 € at 5.5 %) depending on the capacity fade per year at an SOC lower than 80 % (see Figure 6, 8 and 10). If no feed-in tariff would exist, the cumulative economized grid supply cost over the lifetime of the storage system would increase. For a CF per year of 3 %, at a SOC higher than 80 % the cumulative economized grid supply cost would vary between 58 € and 311 € (and between 145 € and 415 € at 5.5 %) again depending on the capacity fade per year at an SOC lower than 80 %.

3.2. Evaluation of the ability to cut the midday peak

In the test with Test criteria 1 none of the systems showed an intelligent charging algorithm which prevents throttling of the PV-generator. To test whether a limitation of the feed-in power would lead to a different charging regime, system A, B, D and E were tested with an excess power limitation. But none of them showed changes in their charging regime. System C is the only one which starts to charge the midday peak within the battery as soon as more PV power is available (summer day) as power can be converted by the storage system from DC to AC. The measurements were done with a PV-plant size with 4.8 kWp (test criteria Test 2). The interesting fact is the change in the charging behaviour from a charge strategy that avoids calendar ageing to a charge strategy which is able to cut the midday peak.

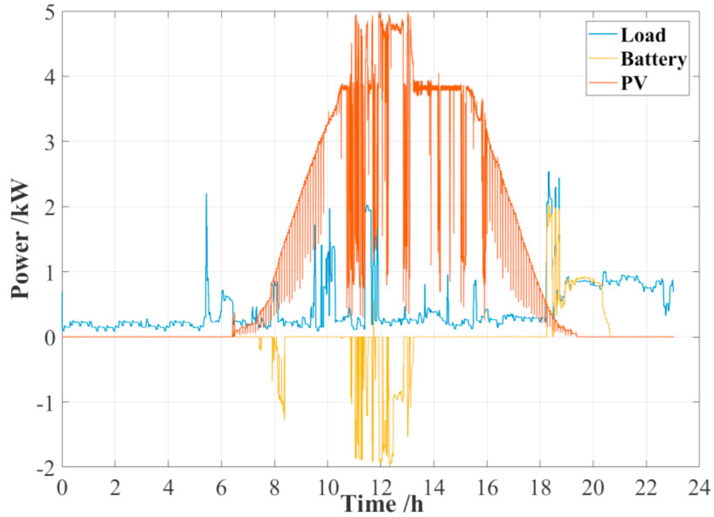

Figure 11: Measurement data for a transition day: example of a system that is able to charge the midday peak within the battery – System C

Table 6: Lost Energy due to potential throttling of the PV-generator (test criteria Test 1 – 3.5 kWp PV)

	System A	System B	System C	System D	System E	System F
Usable storage capacity /kWh	4.3	3.8	2.1	5.2	4.9	4.0
System efficiency /%	85.4	83.9	94.1	85.5	81.5	86.2
Lost electricity per year due to potential throttling of the PV generator (70 % of kWp PV) /kWh	73.2	76.4	59.2	83.3	61.7	104.2
Monetary losses per year due to potential throttling of the PV generator (70 % of kWp PV) /€	8.9	9.3	7.2	10.2	7.5	12.7
Maximum lost electricity during one day due to potential throttling of the PV generator (70 % of kWp PV) /kWh	0.9	1.0	0.6	1.3	0.9	1.3
Lost electricity per year due to potential throttling of the PV generator (50 % of kWp PV) /kWh	244.2	297.5	289.2	303.1	259.6	350.4

By using Equation (3) the excess energy which would need to be throttled for the different systems is calculated and shown in Table 6.

As a reference the excess energy which would need to be throttled of a system without storage is calculated according to Equation (4). Throttling the PV-generator directly to 70 % of the installed PV peak power would lead to energy losses of 335 kWh per year. Whereas limiting the excess power of the household to 70 % of the installed PV peak power would only lead to energy losses of 146 kWh per year (see Equation (3)). The current feed-in tariff is 0.122 €/kWh. Electricity which is provided by the system operator itself leads to less grid consumption. Therefore the self-consumed electricity is rated with 0.29 €/kWh (electricity price for a German household). Lost electricity due to potential throttling of the PV-generator in a case of limiting the excess power to 70 % of the installed PV peak power (with and without storage system) only leads to less electricity fed into the grid. The losses per year for the different systems can be found in Table 6.

For all systems under test, the electricity which would need to be cut off is only less than a third of the electricity which would be cut off in a system without storage system. While the usable storage capacity of system D and E is nearly the same, the lost electricity due to potential throttling of the PV-generator of system E is 26 % less than of System D. The main reason in this case is the system efficiency which is calculated according to Equation (7). Nevertheless the evaluation shows that the system operator only loses between 7.5 € and 12.7 € per year.

For all systems within this evaluation the batteries are big enough to store the throttled PV energy if charging would take place during peak production. The maximum PV energy that would need to be stored within the battery during the midday peak, so that no throttling takes place during the whole year is 1.63 kWh.

If the maximum power which is allowed to be fed into the grid would be limited to 50 % of PV peak power the lost amount of electricity due to potential throttling of the PV-generator would increase (e.g. Germany KfW funding program 275). As a consequence the importance to charge the battery when PV production is high gets more important [18]. The lost electricity per year increases to up to 350 kWh per year (system F). For the systems under evaluation this results in losses between 5.6 % to 8.0 % of the annual produced PV energy (DC). Weniger et al. [18] show similar results from simulations. The simulated losses vary between 5 % and 13 % of produced PV energy depending on the load profile. For the 6 systems the monetary losses would than increase to 29.8 € to 43.9 € per year.

3.3. Prediction errors

All 6 systems show a grid feed-in even on days when the battery is not fully charged at the end of the day. In most cases that is due to the reason that the size of the power electronics is smaller than the possible charge power, that the response time of the system on changes in PV or load is slow or that the estimation of the state of charge of the battery is inaccurate. The energy fed into the grid instead of charged within the battery therefore has a range of 6 kWh to 87 kWh per year, which leads to losses between 1 € to 11 € per year. To calculate the economic losses the energy fed into the grid instead of being charged within the battery is multiplied by 0.29 €/kWh minus 0.122 €/kWh.

As the mentioned aspects also have an influence on battery charging, prediction errors are difficult to quantify. Therefore it is done with the help of a qualitative analysis. None of the two systems which have an intelligent charging algorithm shows prediction errors. The tests were done by measuring the same reference day two or three times in a row. If the tests would be done by alternating rainy and sunny days the results might look different. Further measurements and evaluations need to be done to verify this.

4. Discussion and Conclusion

A new method to determine calendar ageing of a storage system during operation is proposed. The method can be used for batteries with NMC-based cells. A constant measurement of the battery voltage and current are needed as well as of the ohmic resistance of the battery and the module topology. This method is considered as more accurate. Nevertheless a simplification as it was proposed by Munzke et al. [7] gives similar results.

Using that method and results from Keil et al. [12], it could be observed that a difference in battery lifetime caused by calendar ageing of up to 1.5 years is possible. This observation was done for batteries of 6 storage systems. An intelligent control strategy can therefore prevent calendar ageing. The extent of this effect obviously depends on the dimensioning of the system and the sensitivity of CF at different SOC levels. If the CF per year at a SOC higher than 80 % reaches 5.5 % per year, the difference in lifetime caused by calendar aging varies between 0.55 years and 1.59 years (0.22 years and 1.19 years for 3.0 %) depending on the CF per year at an SOC lower than 80 %. In the same way this causes a difference in the cumulative economized grid supply cost over the lifetime of the storage system between 84 € and 240 € (34 € and 180 € for 3.0 %). The lower the CF at a SOC of less than 80 % is the higher is the influence of the CF at a SOC higher than 80 %. As a consequence the importance of an intelligent control strategy which prevents calendar ageing increases. This is even more important the less usable storage capacity the storage system has.

Due to different depth of discharge windows the lowest as well as the highest measured voltage of the batteries for each system differ from each other (see Figure 3 and 4). By limiting the DOD, especially in the upper SOC level, calendar ageing caused by high SOC levels can also be reduced. As Keil et al. [12] describe an increase of the CF from 70 % and an even stronger increase from 80 % SOC, the DOD would need to be limited by at least 20 % to prevent calendar ageing due to a high SOC (NMC). As a consequence that would result in a reduced usable storage capacity of 20 % and therefore increased storage costs by 20 %.

For a more accurate study of the effect of the control strategy on calendar aging, the usable storage capacity of the systems within the test as well as their DOD should be the same. Different control strategies could also be evaluated on one storage system.

It has to be taken into account that all observations regarding effects on calendar ageing only apply for cell chemistries where ageing is increased at certain SOC levels.

To determine the overall ageing of the batteries, ageing effects caused by cycling would need to be considered as well. On top of that it must be taken into account that calendar ageing itself already reduces the usable storage capacity during battery lifetime and as a consequence the performance and the economic viability of the system. To show this explicitly additional simulations are needed.

As a second criterion, the ability to cut the midday peak preventing the throttling of the PV-generator was evaluated. For the test with the test criteria Test 1 none of the systems showed a control strategy which would prevent throttling of the PV-generator. Only one system showed a change in the charging behaviour from a charge strategy that avoids calendar ageing to a charge strategy which is able to cut the midday peak when operating it with a larger PV-plant (test criteria Test 2). The system starts to change its behaviour as soon as more PV power is available (summer day) as power that can be converted by the storage system from DC to AC.

The lost amount of electricity due to potential throttling of the PV-generator varies between 61.7 kWh and 104.2 kWh per year, which results in economic losses between 7.5 € and 12.7 € per year. Depending on the lifetime of the battery this results in losses between 55 € (7.2 years) and 254 € (20 years) over its whole lifetime. As long as the supposed feed in tariff exists this lies in the same range as the effect of an intelligent control strategy. Without feed in tariff the effect of an intelligent control strategy is higher.

If the maximum power which is allowed to be fed into the grid would be limited to 50 % of peak power the lost amount of electricity due to potential throttling of the PV-generator would increase to 244.2 kWh and 350.4 kWh per year.

Prediction errors could not be observed. Further measurements with an alternation of rainy and sunny days need to be done to verify this.

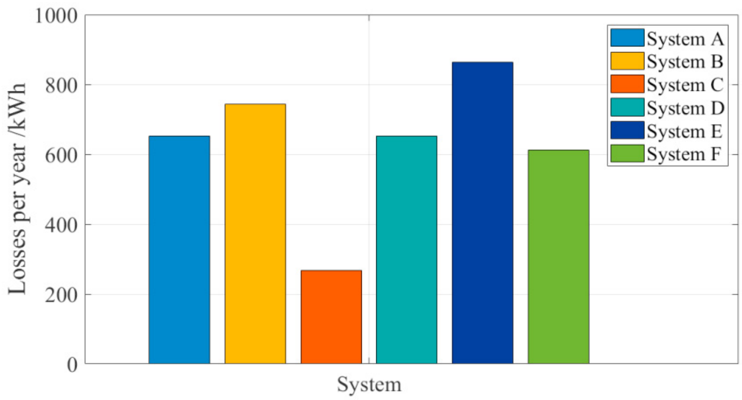

Figure 12: Energy losses for a reference year using test criteria Test 1

To evaluate the impact of the system control strategy on system performance, its influence is compared to the one of system efficiency. The main reason for the losses are conversion losses, battery efficiency losses and standby consumption. As the main focus of this paper lies on the influence of the control strategy on performance, performance losses due to efficiency losses are not discussed in detail here. A deeper evaluation on that topic can be found in [10], [16], [19].

The losses per year of the 6 systems under evaluation are represented in Figure 12. The lost energy would have been partially self-consumed by the potential system operator and the other part would have been fed into the grid. The current feed-in tariff is 0.122 €/kWh, whereas the self-consumed electricity is rated with 0.29 €/kWh. Therefore the losses for the different systems would vary somewhere between 33 € and 77 € for the system with the least efficiency losses and between 105 € and 250 € per year for the system with the highest efficiency losses. Efficiency losses play quite an important role when talking about the performance of PV-storage systems. Over a lifetime of the PV-storage system between 7 years and 20 years they therefore account for losses between 238 € and 1827 €

(7.3 years) to 2106 € and 5007 € (20 years). Losses due to calendar aging are in most cases lower than the one due to efficiency losses. If the feed in tariff declines or would not exist the cumulative economized grid supply cost over the lifetime of the storage system would increase. For a CF per year of 3 %, at a SOC higher than 80 % the cumulative economized grid supply cost would vary between 58 € and 311 € (and between 145 € and 415 € at 5.5 %) again depending on the capacity fade per year at an SOC lower than 80 %. For quite efficient systems the losses would to be in the same range as the ones due to efficiency losses. Nevertheless in most cases they would still be smaller.

As PV-storage systems are just starting to become economic, a longer battery lifetime could always have a quite positive influence [20]. In the current market context such small increases in profitability can make or break the business case for storage. As already mentioned, up to now only 25 % to 30 % of the systems tested possess any kind of intelligent control strategy [7].

Anyhow the expected future increase in the amount of installations in the field make the integration of an intelligent control algorithm, which takes several mentioned aspects into account, all the more important.

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