


Article

Integrated Modelling of Decentralised Energy Supply in Combination with Electric Vehicle Charging in a Real-Life Case Study

Georg Göhler ^{1,*} , Anna-Lena Klingler ¹, Florian Klausmann ¹ and Dieter Spath ²

¹ Fraunhofer IAO, Fraunhofer Institute for Industrial Engineering, 70569 Stuttgart, Germany; anna-lena.klingler@iao.fraunhofer.de (A.-L.K.); florian.klausmann@iao.fraunhofer.de (F.K.)

² Institute of Human Factors and Technology Management (IAT), University of Stuttgart, 70569 Stuttgart, Germany; dieter.spath@iao.fraunhofer.de

* Correspondence: georg.goehler@iao.fraunhofer.de

Abstract: Intelligent integration of decentralised energy resources, local storage and direct consumption are key factors in achieving the transformation of the energy system. In this study, we present a modular simulation concept that allows the planning of decentralised energy systems for buildings and building blocks. In comparison to related studies, we use a simulation model for energy planning with a high time-resolution from the perspective of the energy system planner. In this study, we address the challenges of the grid connection in combination with an increasing number of electric vehicles (EV) in the future. The here developed model is applied for an innovative building block in Germany with a photovoltaic (PV) system, a combined heat and power (CHP) unit, battery storage and electric vehicles. The results of the simulation are validated with real-life data to illustrate the practical relevance and show that our simulation model is able to support the planning of decentralised energy systems. We demonstrate that without anticipating future electric vehicle charging, the system configurations could be sub-optimal if complete self-sufficiency is the objective: in our case study, the rate of self-sufficiency of the net-zero energy building will be lowered from 100% to 91% if considering electric vehicles. Furthermore, our simulation shows that a peak minimising operation strategy with a battery can prevent grid overloads caused by EV charging in the future. Simulating different battery operation strategies can further help to implement the most useful strategy, without interruption of the current operation.



Citation: Göhler, G.; Klingler, A.-L.; Klausmann, F.; Spath, D. Integrated Modelling of Decentralised Energy Supply in Combination with Electric Vehicle Charging in a Real-Life Case Study. *Energies* **2021**, *14*, 6874. <https://doi.org/10.3390/en14216874>

Academic Editor: Heejin Cho

Received: 27 September 2021

Accepted: 17 October 2021

Published: 20 October 2021

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Keywords: decentralised energy system; self-consumption; modelling; real-life demonstration; electric vehicles; stationary battery

1. Introduction

The European energy system is currently undergoing a profound transformation that will persist for several decades. The transformation includes increasing use of renewable energy sources, which is accompanied by decentralisation of energy production and storage. This trend allows a more active participation of formerly passive energy consumers, which in turn leads to the necessity of more integrated planning of energy systems and building development. This development is further driven by the EU Directive on Energy Performance of Buildings that specifies that by the end of 2020, all new buildings must be nearly zero-energy buildings (nZEB) [1,2]. In these buildings, high insulation reduces the energy demand to a minimum. The remaining energy required to supply the building is usually renewable energy generated onsite [3].

Under current political framework conditions, this decentralised energy production and its onsite consumption, so-called self-consumption, is particularly profitable for building owners in countries with high energy purchasing prices and low costs of renewable electricity production [4]. In the future, falling costs for PV systems and storage

technologies for the enhancement of self-consumption could further drive the market development of decentralised energy production. Moreover, various technologies, such as flexible loads and storage technologies, can be used to improve self-sufficiency or to limit peak loads. Already, there exists a vast number of possible systems, which can be adapted to each individual case. From previous research, we know that the selection of components and their configuration in a decentralised energy system are influenced by exogenous and endogenous factors. Energy models therefore refer to financial factors, non-financial aspects, such as the consumers' attitude towards the system, policy framework and technology factors.

For the vast majority of households, the decision to invest in a decentralised energy system depends mainly on the economic efficiency, which is primarily driven by the investment costs of the system components and energy prices (see Section 3.3) [5–7]. In addition to the electricity price, costs for the grid connection can potentially be reduced with decentralised energy systems [8].

Besides economic efficiency, non-financial factors also play an important role with regard to investing in green technologies [9]. Homeowners are motivated by their environmental awareness [10–14], a high rate of self-sufficiency [15–17] as well as an interest in innovative technologies [18].

As far as the political framework conditions are concerned, there are various funding programmes to support decentralised energy systems. In Germany, the feed-in remuneration [19] and funding programmes, for example for the purchase of a battery storage system [20], play a decisive role. In Germany, feed-in remuneration for PV is 9.59 ct/kWh [21]. The remuneration for CHP electricity can be paid either via the “Renewable Energy Sources Act (EEG)” or the “Combined Heat and Power Act (KWKG)”. While the remuneration for CHP up to 50 kW_{el} under the KWKG is 8 ct/kWh for feed-in and 4 ct/kWh for self-consumption [22], feed-in remuneration rises to 13.32 ct/kWh (status March 2017) under the EEG, but only if renewable fuel (e.g., biogas) is used [23]. For both technologies, however, feed-in remuneration is significantly lower than end-consumer electricity prices of currently 30 ct/kWh [24,25]. Therefore, high rates of self-consumption are generally an indicator of a good economic performance. Furthermore, high rates of self-sufficiency are generally seen as an indicator for social acceptance [26].

Another important aspect to consider are technological factors that are available for a sustainable energy supply. Technologies composing a decentralised energy system can generally be grouped into technologies that produce electric energy and heat and technologies that enable a better balance between generation and consumption on site, such as stationary batteries or flexible household appliances. Besides the flexibility potential, batteries can be used for efficient peak load reduction and thus reduce the load on the public grid [27]. The household's electricity consumption is generally increased by substituting other forms of energy consumption with electricity, so-called electrification. In addition to stationary batteries, electric vehicles can be used as flexible consumers, for example to increase the proportion of self-sufficiency. In terms of their contribution to aligning on-site electricity generation and consumption, only limited potential is identified: For private charging, the EV is usually plugged in in the afternoon, thus adding to the already existing evening load peak [28].

The variety of these exogenous factors that influence the systems' performance results in a high complexity, in particular since there are various links between different technologies [29]. With these developments, it is increasingly challenging for building owners and planners to successfully integrate user demands for a reliable and economic energy supply, renewable energy production and regulatory requirements.

Existing studies mostly focus on the operation of decentralised energy systems, which can follow various objectives, such as the improvement of the economic case of the decentralised energy systems, the benefit for the overall systems or a combination of both. Since it is mostly the most economic option for decentralised energy system operation, most existing operation algorithms aim to increase self-consumption rates, e.g., Laurischkat and

Jandt [30], Gudmunds et al. [31] and Munkhammar et al. [28]. Other operation algorithms focus on peak load limitation by demand response [32] or shedding of load to maintain the system's stability [33]. With these types of peak load limitation strategies, the load on the public grid can be reduced and a potential grid expansion can be avoided.

While a stationary battery is seen as the most common flexibility option, more recent studies additionally consider the option to transfer electricity from the EV back to the grid (so-called vehicle-to-grid) [31,34]. The market uptake of electric vehicles therefore increases the number of flexible entities in the decentralised energy system and thus the complexity of the operation algorithm. In addition, the calculations need to be performed with a high time-resolution in order to model the operation of decentralised energy systems in a realistic way. In particular, EV charging processes with high charging powers and correspondingly large fluctuations have to be modelled with small time steps. Laurischkat and Jandt [30], for example, use a quarter-hourly resolution, while Rascon et al. [35] simulate in one-minute steps. These requirements can lead to high computing times, in particular if an optimisation model is chosen [36]. Many scholars therefore chose simulation models with a pre-defined heuristic for the operation of the decentralised energy system flexibilities [37–39].

In summary, we find that an abundance of energy models exist, which cover various aspects of decentralised renewable production as well as flexible consumption. However, the market uptake of electric vehicles increases the number of flexible entities in the decentralised energy system and thus its complexity. Especially the high number of electric vehicles in the future, are a concern to existing infrastructure, such as the grid connection, and is therefore an additional challenge to the planning process of buildings. Even though the need for planning tools with high time resolution addressing these challenges exist, the perspective of building planners is rarely focused in current literature. The objective of this paper is therefore to demonstrate integrated planning of the energy supply of a building block, while considering cost and robustness to future developments. Additionally, we develop a modular and fast simulation model, whilst achieving plausible results in comparison with real-life data. Thus, the model is designed for a first rough planning from the perspective of the energy system planner. In order to simulate the charging processes of the electric vehicles in the best possible way, we use a high time resolution (1-min steps).

The remainder of this paper is structured as follows: We first present a modular simulation concept that allows the planning of decentralised energy systems for buildings and building blocks considering the introduced factors (Section 2). In a case study of a real-life building block, different scenarios of energy systems are simulated and the results are analysed in regard to the impact on the economic efficiency of the decentralised system and the available connection to the public grid (Section 3). Furthermore, the simulated effects and conclusions are verified with recorded data of a real-life case-study. Finally, the results are discussed and conclusions are drawn in Sections 4 and 5.

2. Methodology

The core of the model used in this study is to determine the battery operation and load management of the charging infrastructure for a given objective (right part of Figure 1). The battery operation and load management are determined based on simulated or given load profiles for electricity and heat generation and consumption (left and middle part of Figure 1). For the representation and evaluation of the energy system and electric mobility, we developed a simulation model. With a simulation model, the complex relationships between electric vehicles and the resulting load peaks can be analysed precisely. For the model presented in this study, we used a time-resolution of one minute. In this case, the computation time was 101.5 s (with CPU 4x 2,9 GHz dual core).

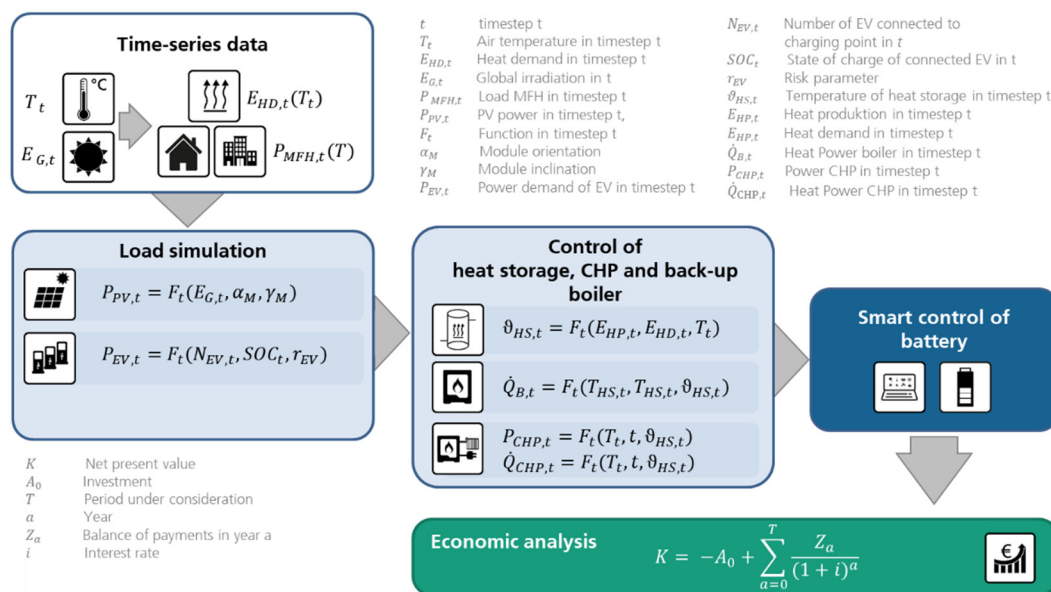


Figure 1. Overview of the developed simulation model of decentralised energy systems. Based on time-series data in minute resolution (**upper part**), the power output of PV is simulated as well as EV charging. The control of CHP, heat storage and back-up boiler is modelled as a simple heuristic (**central part**). Smart control of battery and charging infrastructure can be simulated with different objectives (**right part**). The simulation results are an input for the subsequent economic analysis (**lower part**).

In particular, the planner of the energy system can compare and evaluate different system configurations and parameter variations in a short amount of time, without compromising the temporal resolution.

In the following, the input data and model simulation are described in more detail. For better understanding, we focus on the description of the most essential modelling components and core parts of the algorithm.

2.1. Time-Series Data

The most important input for the model simulation are yearlong time-series data of power and heat production or consumption with a high time-resolution. The applied data needs to be recorded for an entire year to include seasonal effects in particular for the fluctuating PV power, and the weather-dependent heat demand [40]. The application of individual data is necessary as well as a high time-resolution to avoid the effect that possible mismatches between power production and consumption are evened out by aggregation [41,42]. We generally use data with a time-resolution of one minute. In the cases where data was only available in a lower resolution (e.g., temperature and solar insolation data), we interpolated between available data points. For this purpose, we use the “Piecewise Cubic Hermite Interpolating Polynomial (PCHIP)” from Matlab in order to accurately interpolate the data [43]. In this study, the individual electricity consumption profiles for the individual households are taken from [44]. To assess the heat demand for residential and commercial areas, we use the standard load profile method from the “Federal Association of the German Gas and Water Industry (BGW)” and “Association of Local Utilities (VKU)”, based on gas consumption profiles [45]. This method is based on the annual total heat demand, the respective temperature of the considered day (here: “Test Reference Year (TRY)” data), and a sigmoid function for the distribution over the year and daily profiles in hourly resolution. A characteristic profile is assigned to each day, classified into winter, summer, transition period and working day, Saturday, Sunday and public holiday. These typical day profiles are then assembled to a yearlong time-series considering the outdoor temperature and irradiation. Meteorological data are taken from the TRY provided by the Federal Office for Building and Regional Planning [46].

2.2. Load Simulation

Since the market uptake of EVs is still in an early stage in Germany, the available charging data is limited. In this study, we simulate EV charging therefore based on the users' mobility behaviour (for more details see [47]). The number of vehicles, the battery size, the consumption, the charging power, the charging efficiency and the state of charge (SOC) is defined for each vehicle at the beginning of the simulation. Dependent of the plug-in probabilities of the EVs at the charging points, different SOC-dependent distributions for four different risk classes are defined: The risk classes "always plugged in", "safety", "normal" and "risk-taking" can be assigned to each vehicle individually.

Based on these inputs, the state of charge of an individual electric vehicle $SOC_{EV}(t)$ is calculated for each time step t as follows:

$$SOC_{EV}(t) = \begin{cases} \min(SOC_{EV}(t-1) + \Delta t \cdot P_{EV}(t); C_{Batt, EV}) & \forall s = 1 \\ SOC_{EV}(t-1) - d_{\Delta t} \cdot c_e & else \end{cases} \quad (1)$$

with $d_{\Delta t}$ the distance that is travelled by the EV during the time period Δt . c_e denotes the average electricity consumption of the EV over 100 km, and P_{EV} the charging power of the available charging infrastructure. s is a (0;1)-vector, which takes the value 1 to indicate a connection of the EV to a charging point. If load management is considered, P_{EV} is a function of t . $C_{Batt, EV}$ is the EV's battery capacity.

The PV production is based on the model from Patel [48] and is not described in detail in this study.

2.3. CHP, Back-up Boiler and Heat Storage

In this study, we define the efficiency of the CHP by the thermal and electrical rated output \dot{Q}_{CHP} and P_{CHP} and the gas input \dot{Q}_{Gas} [49]:

$$\eta = \frac{P_{CHP} + \dot{Q}_{CHP}}{\dot{Q}_{Gas}} \quad (2)$$

As many CHP manufacturers provide the rated output for full and half load, e.g., KW Energie GmbH & Co. KG [50], a linear approximation can be applied to model the throttling of the CHP to any value for the electrical output of the plant. In this study, we operated the CHP at 100% without throttling. Additionally, we considered a ramp-up time to avoid constant on and off switching of the system. For the electrical output, the ramp-up is formally described as follows:

$$P_{CHP, el}(t) = \left(1 - e^{-\frac{t}{T}}\right) \cdot P_{CHP, el} \quad (3)$$

with the considered time constant $T = \frac{t_{ramp}}{2.3025}$. This time constant was determined specifically for this CHP model. For the electrical ramp-up, set $t_{ramp} = 2$ min, so that 90% of the power is reached after two minutes. In comparison, the thermal output takes eight minutes ($t_{ramp} = 8$ min) to reach 90% of the rated power. Additionally, a minimum running time over the year can be taken into account optionally.

The back-up gas boiler is generally used whenever the heat production of the CHP \dot{Q}_{CHP} is insufficient to keep the heat storage at a temperature level of 70 °C. The thermal output of the boiler is calculated as described in Equation (5). $\dot{Q}_{MFH, max}$ thereby describes the maximum heat demand of the households, k is the partial load factor, calculated as follows:

$$k = \frac{\vartheta_{storage, on} - \vartheta_{storage}(t)}{\vartheta_{storage, on} - \vartheta_{storage, full load}} \quad (4)$$

$$\dot{Q}_B(t) = \begin{cases} (\dot{Q}_{MFH, max} - \dot{Q}_{CHP, max}) \cdot k & \forall \vartheta_{WS} \leq 70 \text{ °C} \\ 0 & else \end{cases} \quad (5)$$

Since the efficiency of a boiler is lower in partial-load operation, we adjusted the efficiency according to [51]. In this model, the switch-on control of the CHP and the boiler and thus $\dot{Q}_{CHP}(t)$ and $\dot{Q}_B(t)$ is based on the SOC, respectively the storage temperature, of the heat storage.

The heat storage is represented as follows: the storage temperature $\vartheta_{storage}(t)$ at time step t is calculated as a function of the storage temperature $\vartheta_{storage}(t-1)$ at time step $t-1$, the net heat flow $\dot{Q}_{storage}(t)$ (Equation (6)), the density ρ and heat capacity c of the heat transfer medium and storage volume $V_{storage}$ (Equation (7)).

$$\dot{Q}_{storage}(t) = \dot{Q}_{CHP}(t) + \dot{Q}_B(t) - (\dot{Q}_{MFH}(t) + \dot{Q}_{loss}(t)) \quad (6)$$

$$\vartheta_{storage}(t) = \vartheta_{storage}(t-1) + \frac{\dot{Q}_{storage}(t)}{\rho \cdot c \cdot V_{storage}} \quad (7)$$

2.4. Battery Operation Strategies

In this study, the stationary battery is the central element of load control and the means to increase self-consumption or limit the peak load of the building block. We look at two different battery operation strategies: a self-consumption maximising strategy as well as a strategy that minimises the peak load on the public grid. Both strategies have the option to include forecasted electricity production and consumption data.

We implemented the battery control as a heuristic approach that charges and discharges the battery as long as the SOC stays within the battery's capacity limits, which are set with the bounds SOC_{min} and SOC_{max} :

$$SOC_t = \begin{cases} SOC_{t-1} + P_{Batt,t} \cdot \eta & \forall SOC_{min} \leq SOC_{t-1} \leq SOC_{max} \\ SOC_{t-1} & else \end{cases} \quad (8)$$

with the battery load $P_{Batt,t}$ that equally stays within set bounds P_{min} and P_{max} :

$$P_{Batt,t} = \min\{\max\{P_{target,t}; P_{min}\}; P_{max}\} \quad (9)$$

The desired battery load $P_{target,t}$ depends on the battery operation strategy. To increase self-consumption, the battery is to be charged as soon as excess electricity is produced, and thus

$$P_{target,t} = P_{PV,t} + P_{CHP,t} - P_{MFH,t} - P_{EV,t} \quad (10)$$

In this study we neglected self-discharging of the battery storage.

2.5. Economic Analysis

As part of the planning tool, the economic efficiency of the individual components and the overall system was analysed. In this study, electric vehicles and charging infrastructure were not considered, since vehicle and building owners are different identities. However, the electricity consumption of the charging processes was included in the economic efficiency analysis. We used the net present value method to evaluate the investment.

The net present value K , which is used for a comparison of different variants, is calculated as follows [52]:

$$K = -A_0 + \sum_{a=0}^T \frac{Z_a}{(1+i)^a} \quad (11)$$

A_0 is the total investment in euro, Z_a represents the payment balance per year, T is the period under consideration and i the discount rate.

3. Results

To show the benefit of model simulation for the planning and operation of decentralised energy systems, and to validate the here presented modelling approach, we intro-

duce the following case study that was conducted within the project “SmaLES@BW” [53]. In this demonstration project, an energy system was planned and built within a residential building block with five multi-family houses and a common underground car park. Two of the houses include commercial areas. This decentralised energy system includes the generation of electricity and heat with 20 kW_p PV systems, a CHP unit (73 kW_{th}, 33 kW_{el}) and a 284 kW gas boiler, energy storage consisting of a 5000 litre hot water tank and a 67 kWh (usable capacity) lithium-ion battery system, as well as the integration of a charging infrastructure (30 × 11 kW-charging points) for electric vehicles (see Figure 2). The overall system was demonstrated at the Federal Garden Show 2019.

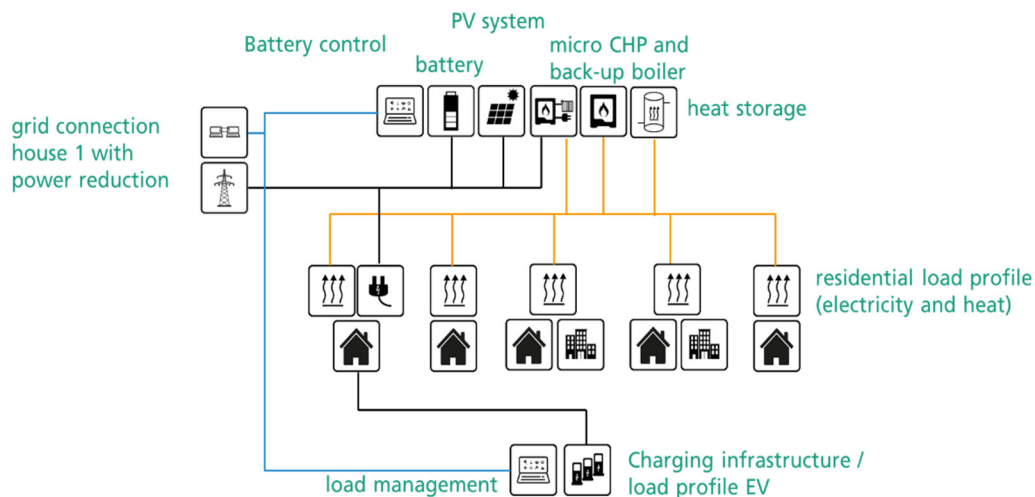


Figure 2. Simulated building block with five multi-family houses, including two with commercial areas, 20 kW_p PV and 67 kWh battery system, CHP (73 kW_{th}, 33 kW_{el}), 5000l hot water tank, charging infrastructure with 30 × 11 kW-charging points, and connection to the public low voltage grid [53].

For regular operation, it was decided by the project owner that only house 1 would be connected to the electricity generation from CHP, while all five houses were connected to the heat supply. House 1, which is connected to the power generation system, also supplies the common parking lot, which is equipped with a flexible charging infrastructure. Residents can easily connect their charging unit via a prepared distribution rail that allows a maximum of 30 charging stations. Furthermore, three of the other houses are equipped with a PV system. In our case study, we analysed house 1 since the entire electricity production, the electric consumption of EVs and the heating consumption is connected to house 1 (see Table 1). Although the charging infrastructure and heating system can be used by all residents of the entire building block, the supply is only provided via house 1.

For our study, we simulated various system scenarios (see Table 2) that would be possible in the considered building block in order to draw general conclusions on the rate of self-sufficiency, self-consumption and necessary grid connection. As argued above, a high rate of self-consumption is an indicator of a good economic performance, while a high rate of self-sufficiency generally fosters social acceptance. Table 2 lists five possible system scenarios (S1 to S5) that all consist of a PV system with 20 kW_p and a micro CHP with 73 kW_{th} and 33 kW_{el}. To analyse the benefit of a stationary battery storage, the 67 kWh battery was added in the scenarios S2, S4 and S5. Furthermore, to account for future electric mobility, S3, S4 and S5 additionally contain 30 EVs, which are able to charge with 11 kW each. S4 and S5 differ only in the battery operation strategies that either maximise self-consumption (max. SC) or minimise the peak load of the overall building block (min. PL).

Table 1. Overview of system components and parameters of the simulated building block (cf. Figure 2).

Parameter/System Component	Unit	House 1 + EV + Heat
Number of dwellings		13
Living area	m ²	1471
Hot water demand	kWh/a	528,000
Electricity demand	kWh/a	54,000
Grid connection	kW	62
PV system	kW	20
CHP (thermal power)	kW	73
CHP (electrical power)	kW	33
Back-up boiler	kW	284
Hot water tank	l	5000
Battery (capacity)	kWh	67
Battery (power)	kW	50
Number of parking lots		92
Number of charging points		30

Table 2. Overview of considered system scenarios in the building block. The considered battery operation strategies either maximise self-consumption (max. SC) or minimise the peak load on the grid connection (min. PL).

System Scenarios	(S1)	(S2)	(S3)	(S4)	(S5)
PV	✓	✓	✓	✓	✓
CHP	✓	✓	✓	✓	✓
EV			✓	✓	✓
Batt.		✓		✓	✓
EV			30 × 11 kW	30 × 11 kW	30 × 11 kW
Battery strategy		max. SC		max. SC	min. PL

In the following, we first discuss the results of one particularly interesting scenario (S4), and subsequently compare the different scenarios from a technical and economic perspective.

3.1. Load Simulation Results with a PV + CHP + Battery + EV System (Scenario S4)

Figure 3 shows the load simulation results for scenario S4 (see Table 2) in the form of average day profiles from Monday to Sunday. The figure illustrates the importance of the EV charging profiles: with their high electricity consumption, EVs cause the highest load peaks with over 40 kW on Fridays. Moreover, the electricity consumption varies between weekdays and in particular between weekdays and weekend days, when the commuting trip is not necessary. The figure further displays the battery charging. With the self-consumption maximising operation strategy, charging mostly occurs in late evening hours when excessive CHP power is produced.

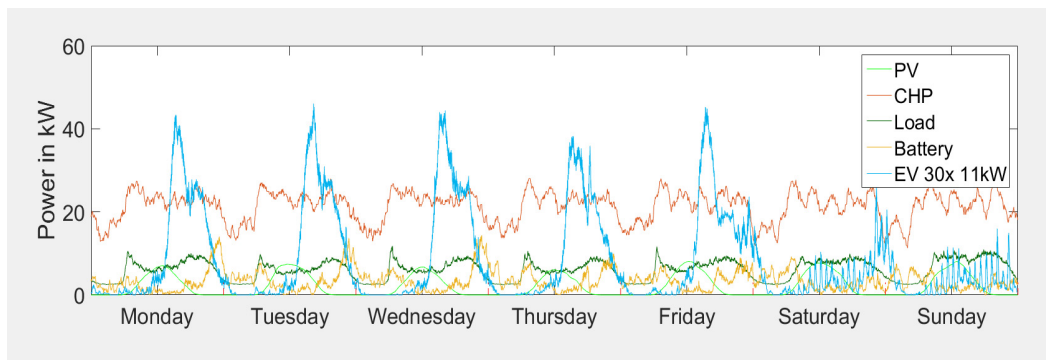


Figure 3. Load simulation results for scenario S4 with a self-consumption maximising battery operation strategy. Average day profiles from Monday to Sunday for CHP (orange) and PV (dark blue) power production, household (green) and EV (blue) power consumption, battery charging (yellow).

The resulting power exchange with the public grid is depicted in Figure 4. Over the year, the different characteristics of the CHP and PV power plants become apparent: the cold season is dominated by excess electricity production of the CHP that is operated with a heat-controlled strategy. The summer season shows dynamic fluctuations between times with high CHP and PV overproduction and EV charging events that cannot be supplied solely with self-produced power and power from the battery storage.

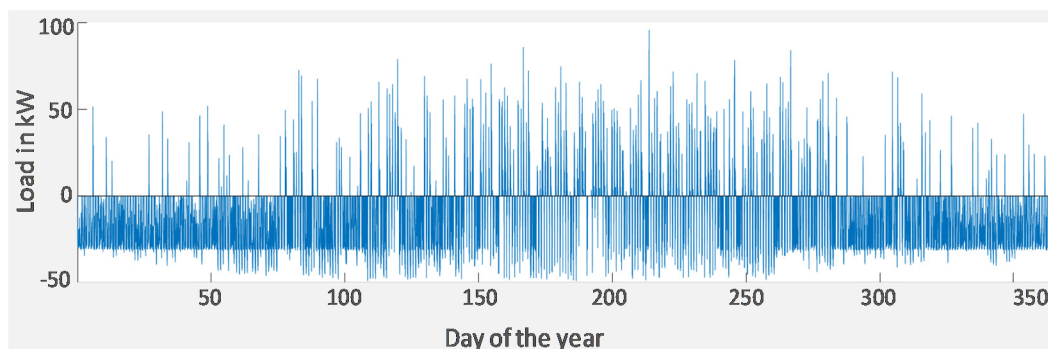


Figure 4. Grid load simulation results for scenario S4 with a self-consumption maximising strategy over the year. Feed-in to the grid is negative on the y-axis, purchase positive.

Over the course of the year, 210 MWh of electricity is produced onsite with PV and CHP from which 115 MWh are self-consumed, resulting in a self-consumption ratio of 55%. With an onsite electricity demand of 127 MWh, however, the self-sufficiency ratio amounts to 91% and the target of zero-energy consumption is missed. The reason is that the mismatch between electricity demand and production, in particular the peak demand of EV charging, cannot be resolved with the installed battery. Figure 5a depicts the state-of-charge over the simulated year in a histogram. We calculated with the usable capacity at this point and therefore set the SOC limits to 0% and 100%. It shows that for most times during the year, the battery was fully charged. However, in extended periods of time, the battery was empty and could thus not supply the electricity demand. We calculated 395 events in which the battery was empty, which is more than once a day. Emergency charging from the grid during off-peak periods could prevent the battery from being completely discharged. Furthermore, the battery power is not sufficient to supply the EV charging infrastructure in peak times. Figure 5b illustrates the battery loads and shows that the battery reached its discharging power limits.

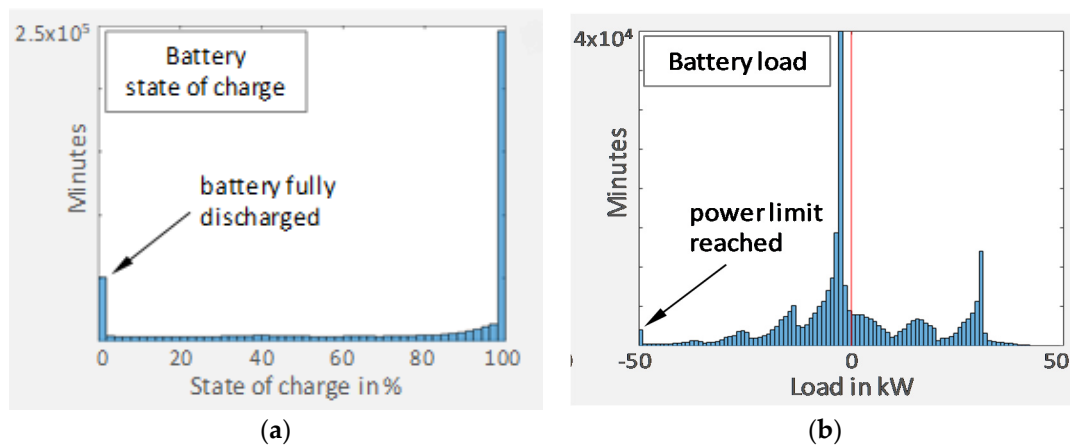


Figure 5. Time allocation of the state of charge (a) and battery power (b) in the simulation year. Battery capacity and battery power reach their limits.

The presented results show that with a high utilisation of the battery, capacity and power limits can be reached and shortages occur. In the investment decision for a storage system, we see the trade-off between a high self-sufficiency rate and high battery utilisation. To achieve 100% self-sufficiency, battery and generation components would have to be greatly oversized.

In our simulation we find another trade-off between a high self-sufficiency rate and security of supply: in summer, due to the reduced availability of base-load CHP power and the fluctuating availability of PV power, dynamic load changes with high peaks occur (see Figure 6). With up to 96 kW, the necessary electricity purchase from the public grid to supply buildings and EVs cannot be realised with the available grid connection of 62 kW. Over the year, the grid connection is overloaded in 58 instances; see Figure 6 (left side). In the case of exceeding the grid connection, a grid extension is estimated in order to avoid a power failure. The feed-in of excess electricity of maximum 49 kW, on the other hand, is not a problem for the available grid connection (Figure 6, right side). The results show that the battery operation strategy maximising self-consumption and enabling high self-sufficiency rates is unsuitable to secure a sufficient power supply. The sensitivity analysis also demonstrates that with this operation strategy the battery storage would have to be very large in order to completely avoid grid overload. If we increase the battery capacity and power by a factor of 3.6, the grid will be still exceeded 11 times.

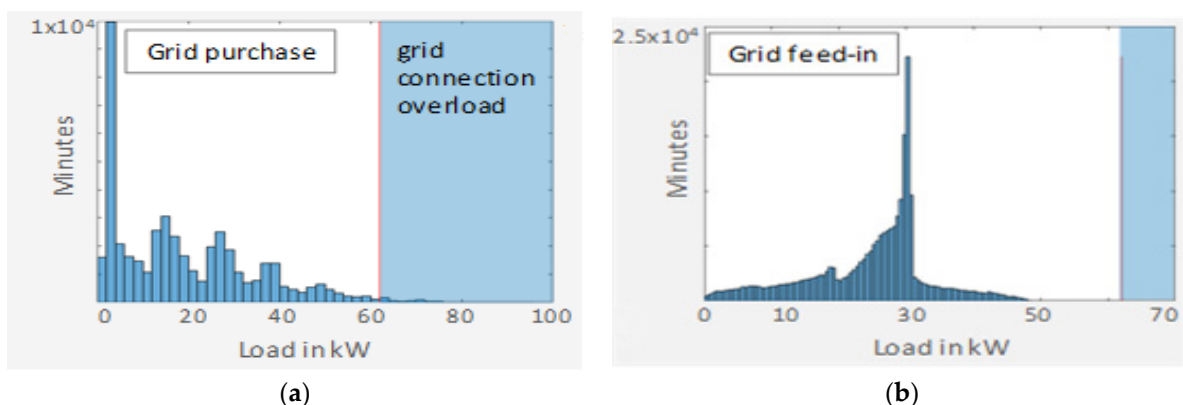


Figure 6. Time allocation for the electricity purchase from the public grid (a) and the feed-in to the public grid (b) in the simulation year. The necessary grid purchase with maximum 96 kW cannot be realised with the available grid connection.

3.2. Comparison of Scenarios

When comparing the different scenarios from a technical perspective for the case study, we find that, even though the PV system and CHP produce, with a total of 209 MWh (PV: 19 MWh and CHP: 190 MWh), much more electricity than the 13 households' consumption of 54 MWh, net-zero electricity demand can only be reached with an electricity storage that matches supply and demand (S1 vs. S2). We present these findings again in Table 3, in terms of self-consumption (r_{SC}) and self-sufficiency (r_{SF}) rates. The table further lists the full cycles of the stationary battery over the entire year. The full cycles are an indication of the battery usage that is usually corresponding with the battery's economics. For the scenario S2, the number of full cycles is relatively small. Our simulation results suggest that for this case a battery of 50 kWh would be sufficient.

Table 3. Overview of considered system scenarios S1 to S5 in the building block.

System Scenarios	(S1)	(S2)	(S3)	(S4)	(S5)
r_{SC}	21%	26%	41%	55%	41%
r_{SF}	82%	100%	67%	91%	68%
full cycles		165		420	2
Grid connection sufficient?	✓	✓	x	x	✓

With 30 EVs, additional electricity needs to be purchased from the grid (see scenario S3 to S5), even though CHP and PV produce enough electricity over the course of the year to supply the EVs' demand. However, the high demand peaks cannot be supplied in every instance.

In our simulation, we additionally analysed whether or not the grid connection of maximum 62 kW is sufficient to supply the load peaks of electricity production and consumption. As can be seen in Table 3, the grid connection is sufficient for the grid feed-in of the CHP and PV electricity production. Even in times with low consumption and high production, the feed-in power never exceeds 49 kW (with 34 kW from the CHP and 15 kW from the PV). However, the peak consumption of the EV charging leads to a grid overload in scenario S3 and S4 (more details in Section 3.3). In scenario S5, we simulated a different battery operation that minimises the peak load on the public grid to see whether the grid overload can be prevented. We found that the new battery operation strategy can successfully lower the supply from the grid to a maximum of 62 kW. It therefore prevents an expensive grid expansion or an unwanted shedding of the EV charging load. However, with his strategy, the self-sufficiency rate decreases to 41%, and the battery usage is very small with merely two full cycles. How the different operating strategies and components affect the economic efficiency is shown in the following section.

3.3. Economic Analysis of the Case Study

In order to compare and evaluate the system scenarios further, an economic analysis is conducted in this section. The input parameters in Table 4 are the basis for the economic analysis.

The economic analysis of the different system scenarios mainly shows the effects of the increase in self-consumption and the introduction of electric vehicles. The increased grid loads inflicted by electric vehicle charging has to be accompanied by either a stationary battery storage or a grid expansion.

If the energy system is considered without electric vehicles there is no economic case for the battery storage, since the grid connection is sufficient and the revenue from an increased self-consumption is comparatively low. However, if 30 electric vehicles are included in the calculations, the scenario with a mainly self-consumption-oriented battery storage (S4) is most economical. Table 5 gives a summary of the economic comparison between the different scenarios.

Table 4. Overview of input parameters for the economic analyses, grouped into general information, investment, operating costs and revenues.

Parameter		Case Study Assumptions					
General	Interest rate in %	1					
	Period under consideration in years	20					
	Electricity price in cent/kWh	30 ^a					
	Rate of increase electricity price	1.5					
Parameter		PV	CHP	Battery	Boiler	Heat Storage	Grid
Investment and operating costs	Investment in EUR	29,640 ^b	86,633 ^c	71,493 ^d	24,887 ^e	7500 ^e	1400 /kVA ^{f,g}
	Maintenance in EUR/a	300 ^h	1975 ^c	1072 ⁱ	373 ^j	-	-
	EEG levy SC (40%) in cent/kWh	2.7 ^k	2.7				
	Fuel price (biogas) in cent/kWh		7.5 ^l		7.5 ^l		
	Rate of increase biogas		1.5		1.5		
Revenues	Feed-in remuneration in cent/kWh	9.59 ^m	13.32 ^k				

(a) [54], (b) [55], (c) [56], (d) [57], (e) [58], (f) [59], (g) [60], (h) [61], (i) [62], (j) [63], (k) [23], (l) [64], (m) [21].

Table 5. Overview of the economic results of the considered system scenarios S1 to S5 in the building block.

System Scenarios	(S1)	(S2)	(S3)	(S4)	(S5)
CapEx in EUR/a	7433	11,007	9749	12,921	11,007
OpEx in EUR/a	75,849	73,106	86,848	78,054	87,519
Net present value K in million EUR	-1.114	-1.163	-1.458	-1.435	-1.496

Although the battery storage for peak load limitation (S5) completely replaces the necessary grid expansion (see S3 and S4), this operating mode is a little less efficient than S4 in terms of overall economic efficiency. S4 is the most economical, as the grid only needs to be expanded slightly and a significant saving is achieved through the increased degree of self-consumption (see Table 3).

Figure 7 shows the distribution of costs (investment (CapEx) and variable costs (OpEx)) of the individual components and revenues per year. The revenue relates to feed-in remuneration. Please note that S3 to S5 include the electricity consumption of electric vehicles in OpEx, while S1 and S2 do not consider the costs of fuel consumption. Since the cars in this setting are private ones, fuel supply is organised individually, while electricity supply has to be organised by the building owner.

S4 has the highest investment, but also the lowest variable costs. The sum of the investment for the grid connection (EUR 38,372) and the battery storage (EUR 71,493) exceeds with EUR 109,865 the system scenario with pure grid expansion (EUR 46,320) in S3. This means that the battery, which is operated in S4 with self-consumption optimisation, can partially reduce the peak load at the grid connection. The economic case of the battery is primarily based on the increase in the degree of self-consumption.

In order to validate the applicability in practise of the model, the simulation data from scenario S4 is compared with real-life data in the next section.

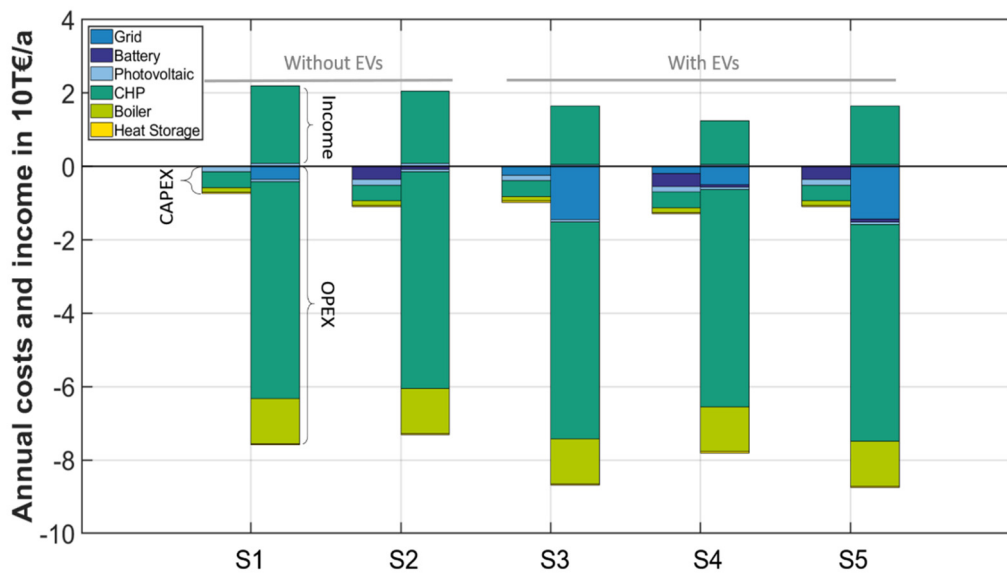


Figure 7. Overview of investment costs (CapEx), operating costs (OpEx) and incomes of the four system scenarios without electric vehicles (S1–S2) and with 30 electric vehicles (S3–S5).

3.4. Model Validation with Real-Life Data

Concerning the validation of the presented model, we had the opportunity to compare the simulated results with the recorded data of the real-life building block. Since the electric vehicles used in the simulation refer to a future scenario and have not yet been charged in the real system, the comparison refers to a simulated basic scenario without electric mobility. The battery storage in real-life demonstration is operated with the self-consumption maximising strategy. For our study, data could be provided for a completely selected year (from May 2019 to April 2020) with a time-resolution of 15 min. In a further step, annual values were generated from the available data in order to compare them with the simulation results. Moreover, net electricity neutrality could not be reached in real life, which may be due to a breakdown of the CHP. Due to technical problems, the CHP plant could not be operated from the end of July until the end of September. Simulated and recorded data are compared in Table 6.

Table 6. Simulated and recorded data for the building block from May 2019 to April 2020.

	Simulation	Real-Life Data	Deviation
Consumption households	54,002 kWh	55,101 kWh	2%
Supply from grid	0 kWh	7108 kWh	n/a
Feed-in to grid	153,116 kWh	136,050 kWh	11%
PV production	19,991 kWh	19,413 kWh	3%
CHP production (el.)	190,427 kWh	165,204 kWh	13%
CHP run time	5771 h	5261 h	9%
Battery efficiency	91.85%	90.16%	2%

The simulation results represent the reality well, and in particular the battery efficiency and the PV production are met very accurately. The higher supply from grid and the lower feed-in (difference: approx. 24 MWh) can be mostly explained by the downtimes of the CHP (difference: approx. 25 MWh), which is also noticeable in a longer runtime.

4. Discussion

The objective of our study was the demonstration of integrated planning of decentralised energy systems with a high share of electric vehicles. The aim was to give an estimation of the technical feasibility and economic efficiency. The validation shows that the results of the simulation are suitable for this planning process. In this way, many different system scenarios, operating strategies and new technologies can be calculated and compared in a short time. Especially for the economic analysis, the results do not have to be exactly the same as real-life data, as balances are drawn up over several years (here: 20 years). In the case study presented here, the installed technologies were selected and pre-defined by the building planner. For a well thought out planning process, however, it would have been better to select the technologies and their capacities based on modelling results. This was not possible in our case and should be considered in further studies.

Further results of our study show that even though the decentralised energy system, with its 33 kW_{el} CHP system and a 20 kW PV system, produces, with 209 MWh in total, significantly more electricity than the 13 considered households' consumption of 54 MWh per year. One hundred percent self-sufficiency can only be reached with additional electricity storage. The battery is used to store PV and CHP power to supply the households at a later point in time (SC maximising strategy) and to minimise the peak load on the public grid (peak load limitation strategy). In the future, electric vehicles will increase residential electricity consumption and thus the rate of self-consumption in buildings. In our case study, we consider 30 electric cars that charge in total 75 MWh over the year with a maximum power of 11 kW. With this setting, the rate of self-sufficiency is lowered to 91%. At the same time, however, self-consumption increases from 26% to 55% (with a self-consumption maximising battery operation strategy) and thus increases the economic benefit of the decentralised energy system.

In our study, the charging of EVs takes place mostly in evening hours. The possibility of scheduling the charging of EVs to enhance self-consumption or reduce the load peak was not considered since most of the vehicles are not at home during the day. Moreover, the postponement of charging processes affect the vehicles' availability for the next trip, so user's acceptance is essential [65]. However, as suggested by Gnann et al. [66], load scheduling could be an option, if charging at the workplace is encouraged in the future. Furthermore, we did not consider the possibility of bi-directional charging. According to many studies (e.g., Jia et al. [67]; Mohammadi et al. [68]), this could become an option. Although Dubarry et al. [69] note that this additional discharging could reduce the batteries' lifetime significantly. In the future, electric mobility can be generally seen as a significant opportunity for load shifting and load balancing, caused by generation and load fluctuations [70]. Especially if larger batteries are deployed to reduce the range anxiety of EV owners, the Vehicle to Grid (V2G) technology could relieve the grid and even replace stationary battery storages [71].

Concerning the effect of different operation strategies of the stationary battery, we found that the self-consumption maximising strategy succeeds in increasing the onsite-consumed amount of electricity, while at the same time does only reduce the load peak of the EV charging very little. If the battery is operated in a self-consumption maximising strategy, the load peaks of electric vehicle charging violate the grid connection of 62 kW. The grid overloads due to EV charging load peaks can be reduced with a peak load minimising strategy, but with the cost of a reduced self-consumption rate of 41%.

In future research, it should be analysed whether a combined battery operation strategy can both prevent grid overloads as well as increase the self-consumed amount of electricity. An interesting research question would be to investigate the maximum rate of self-consumption that can be reached with the given grid connection. In our study, the grid connection was not sufficient to handle the peak loads caused by the sum of residential load and EV load. However, the overloads of the grid were so small that a simple load throttling could be used to reduce the grid load.

In this study, we focussed on relatively simple battery control mechanisms that were implemented as a heuristic. Up until now, simple control mechanisms are most commonly installed in residential storage systems; however, around 70% use a simple forecasting mechanism based on one week persistency [72]. In the future, forecasting and control algorithms are likely to improve. Therefore, in further research different control mechanisms should be addressed.

The economic analysis shows that in our case study, a battery storage unit improves the economic efficiency of the entire system, but only if electric vehicles are considered. This is due to the fact that with electric vehicles the existing grid connection is not sufficient and grid expansion also generates costs. A further economic factor is the increase of self-consumption, which is especially being promoted by the SC maximising strategy.

In addition to the assessment of self-consumption and self-sufficiency rates, we found that the battery in the considered case study was oversized. We found that a 50 kWh battery would be sufficient. However, if 30 vehicles were to be charged in the car park, the battery would have to be significantly oversized. Even a 241 kWh battery storage could only achieve 97.3% self-sufficiency. Several studies, such as Winkler et al. [73], include the optimisation of the system components' size into the model. An endogenous system configuration could be addressed in further research. However, evidence shows that residential consumers do not always decide on the optimal system size of their investment [4]. In our study, the size of the components was based on that of the real system. However, the model provides the simulation of different component sizes, and the planner is able to compare the scenarios quickly. The advantage is that we are able to consider the requirements of the project developer right from the start.

5. Conclusions

The results of our study show that model simulation can support the planning and operation of decentralised energy systems. The load simulation results show that the decentralised energy system, with its 33 kW_{el} CHP system and a 20 kW PV system, produces, with 209 MWh in total, much more electricity than the 13 considered households' consumption of 54 MWh per year. However, 100% self-sufficiency can only be achieved with additional electricity storage. The grid overloads due to EV charging with a load peak of 96 kW can be reduced with a peak load minimising strategy, but with the cost of a reduced self-consumption rate of 41%. The economic analysis shows that in our case study, a battery storage unit improves the economic efficiency of the entire system from a net present value of EUR −1.458 million to EUR −1.435, but only if electric vehicles are considered.

In our study, we found that the market penetration of electric vehicles and the accompanying increasing electricity demand due to electric vehicle charging will substantially change the requirements of a residential energy system. The simulation of future electric vehicle charging can show possible future needs and thus support energy planners.

Simulating different battery operation strategies can further help to implement a useful control strategy, without interruption to the current operation. In our study, we found that a peak minimising operation strategy can prevent grid overloads caused by electric vehicle charging in the future. Since battery technologies and management continue to improve, future research should address the benefit of vehicle-to-grid and vehicle-to-home for the public grid. Furthermore, our study presents a battery control algorithm based on a heuristic. In future research, more complex battery control algorithms should be included into the energy system modelling. The main objective of our study was to provide a simple model for energy planning from the perspective of the energy system planner. Due to a high time-resolution, we were able to realistically simulate the charging processes of the electric vehicles. In the future, the simulation model will be used as a planning tool in practice.

Regarding the political perspective, we would recommend that incentives for the investment in energy technologies and electric vehicles, such as purchase premiums,

could be linked together. This would promote a more holistic planning of decentralised energy systems.

Author Contributions: Conceptualisation, G.G. and A.-L.K.; Data curation, G.G. and A.-L.K.; Formal analysis, G.G. and A.-L.K.; Funding acquisition, G.G. and F.K.; Investigation, G.G. and A.-L.K.; Methodology, G.G.; Project administration, G.G. and F.K.; Resources, G.G. and F.K.; Software, G.G. and F.K.; Supervision, D.S.; Validation, G.G. and F.K.; Visualisation, G.G., A.-L.K. and F.K.; Writing—original draft, G.G. and A.-L.K.; Writing—review and editing, G.G., A.-L.K. and F.K. All authors have read and agreed to the published version of the manuscript.

Funding: This work has been financially supported by the German Federal Ministry for Economic Affairs and Energy (BMWi) in the context of the project “C/sells” as part of the “Smart Energy Showcases SINTEG” with the grant number “03SIN125” and the Ministry of the Environment, Climate Protection and Energy Sector Baden-Württemberg in the context of the project “SmaLES@BW” as part of the program “Smart Grids and Storages Baden-Württemberg” with the grant number “BWSGD17009”. We are very grateful to DSG Energiekonzepte GmbH for their support and provision of the data.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: The data presented in this study are available on request from the corresponding author.

Conflicts of Interest: The authors declare no conflict of interest.

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