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leafs

Integration of Loads and Electric Storage Systems into advanced Flexibility Schemes for LV Networks

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Integration of Loads and Electric Storage Systems into advanced Flexibility Schemes for LV Networks

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Abbreviations

aFRR	automatic Frequency Restoration Reserve
AMIS	Automated Metering and Information System
BEA	Building Energy Agent
BESS	Battery Energy Storage System
BMS	Battery Management System
BVES	Bundesverband Energiespeicher
CAPEX	Capital Expenditures
CEC	Citizen Energy Community
CEMS	Customer Energy Management System
CLS	Controllable Local System
DCF	Discounted Cash Flow
DC	Data Concentrator
DER	Distributed Energy Resources
DG	Distributed Generation
DSO	Distribution System Operator
EDGA	Express Grid Data Access
EPEX	European Power Exchange
ESS	Energy Storage System
EV	Electric Vehicle
HIL	Hardware-in-the-loop
LCOS	Levelized Costs of Storage
LEC	Local Energy Community
Li-ion	Lithium Ion
LV	Low Voltage
ICT	Information & Communication Technology
IEC	International Electrotechnical Commission
NPV	Net Present Value
O&M	Operations & Maintenance
OLTC	Onload Tap Changer
OPEX	Operational Expenditures
PCC	Point of common Coupling
P-HIL	Power Hardware-in-the-loop
PHS	Pumped Hydro Storage
PLC	Powerline Communication
PV	Photovoltaics
PV-BESS	PV Battery Energy Storage System
R&D	Research & Development
REST	Representational State Transfer
RTE	Round-trip efficiency
RTU	Remote Terminal Unit

SCADA	Supervisory Control and Data Acquisition
SDEL	Solar Discounted Electricity Load
SGAM	Smart Grid Architecture Model
SLVG-C	Smart Low Voltage Grid Controller
SoC	State of Charge
TCP	Transmission Control Protocol
TRL	Technology Readiness Level
VAT	Value Added Tax
VPP	Virtual Power Plant
WACC	Weighted average Costs of Capital
XMPP	Extensible Messaging and Presence Protocol

Executive Summary

Today, a visible flexibility potential (e.g. domestic hot water boilers, heat pumps) is already available in low voltage (LV) power grids. With the further implementation of photovoltaic plants (PV) and corresponding PV battery energy storage systems (PV-BESS), the rollout of electric vehicles (EV) and further electrification of heating and cooling supply, this potential will increase in the upcoming years. Concepts and products are currently implemented to activate and utilize this flexibility potential to improve profitability for consumers by providing additional system services (e.g. provision of control reserves) and/or by participating in the electricity market (e.g. utilization of dynamic energy prices). Due to common control signals an increase of simultaneity and thus higher power peaks can be expected. With a certain penetration of these components and concepts, negative impacts on the local distribution grid are likely if insufficient measures are implemented within the grid domain.

Although a market driven activation of flexibility (without consideration of the local grid) is already offered by some market players in Austria, a grid friendly activation for local grid services has yet to be developed. Therefore, the objectives of the project *leafs* were to develop and analyse a wide range of flexibility activation concepts for loads and energy storage systems (ESS) in LV grids under consideration of local grid boundary conditions (voltage band, equipment loading). Accordingly, the activation of flexibility was analysed from two perspectives:

1. A negative impact of market driven flexibility activation on the local distribution grid should be avoided.
2. A positive impact on the local distribution grid through a corresponding grid friendly flexibility activation should be generated.

All in all, four different concepts were defined and analysed in the project. These four concepts reflect the variety of possible approaches to activate flexibility in a grid friendly way.

1. **Separate control of customer assets**: Flexible components at the customer premise are dynamically parametrized for grid friendly operation by the DSO. Activation for market services is done by a third-party over a separate communication channel.
2. **Combined control of customer assets**: The DSO dynamically parametrizes flexible components for grid friendly operation and transmits signals for market-based operations. The DSO does not act as market participant but as an infrastructure provider for communication and control of flexible components.
3. **Combined control of utility assets**: Flexibility is created by implementation of central components (a central BESS in this case). This component can be used by customers and is fully integrated into the control system of the local utility ensuring a grid friendly operation and allowing for provision of additional services.
4. **Monetary incentive**: Grid friendly activation of flexibility is achieved through a monetary incentive provided by the DSO to the customers. The customer receives the incentive when he/she shifts consumption to times of high local PV generation to relieve the local grid.

These four flexibility activation concepts were specified in detail, implemented and validated in different field trials. Regulatory, socio-economic and economic assessments were carried out to complement these field trials to give a comprehensive overview of the matter.
In a first step, a general assessment of existing and future flexibilities was performed. In this regard, the potential of existing flexibility options was evaluated, and future flexibilities in different rollout scenarios assessed. The following results were obtained based on this baseline assessment:

- **Existing flexible load potential**: An analysis of existing flexibility showed that up to 20% of all connected loads of a DSO are flexible loads with an interruptible supply contract, accessible to the DSO. This is a considerable amount (e.g. 190 – 270 MW in the supply area of *Energienetze Steiermark GmbH*). However, strong seasonal variations exist, and this load power is available for a rather short period of time.
- **Future flexibility potential**: For future developments, a large-scale survey was conducted within the project which consisted of about 13,450 participants. The results of the survey showed that consumers are interested in technologies such as PV and PV-BESS. About 30 % of all participants are planning to install an electric heating system in the future and about 24 % are considering the possibility of purchasing an EV in the upcoming years. With that, it is expected that the future flexibility potential in LV grids will increase visibly in the coming years.
- **Grid impact of flexible loads**: Measurements taken from more than 100 transformer substations showed that currently, in approximately 25% of all networks, the peak load is a result of coordinated switching schemes (in this case the ripple control of the DSO). Similarly, conducted simulations showed that the peak load can be significantly increased due to a common, market-based control signal in single grids. Therefore, it is expected that market driven flexibility activation will have an impact on LV grids in the future.
- **Future EV integration**: Due to high power levels and the possible large number, EVs will be of special interest for future rollout of flexible components. Large-scale simulations for defined rollout scenarios on all grids of two DSOs showed a high impact of coordinated charging of EV with high simultaneity on future grid reinforcement costs. Additional simulations showed that the implementation of flexible EV integration strategies (e.g. utilisation of BESS or P(U) measures for EV charging) could reduce the grid reinforcement efforts significantly (between 46% and 80% in the supply area of *Netz Oberösterreich GmbH* and 38% to 70% in the supply area of *Salzburg Netz GmbH*). This effect depends on multiple factors such as the parametrization of the function and the feasible amount of allowable power reduction which would be the subject of further investigations. As a result, planning guidelines of the participating DSOs were partly adapted to prepare for the expected EV rollout. With these adapted planning guidelines, a future EV rollout can be handled more smoothly.
- **Future PV integration**: PV is already widely installed in LV grids. It is expected that this trend will continue in the future. For that, a rollout scenario, derived from the Austrian climate and energy strategy *#mission2030*[1] objectives, was implemented

[1] https://mission2030.info/

and analysed with regards to grid reinforcement requirements in large-scale simulations. Moderate reinforcement requirements will be necessary for the two participating DSOs (*Netz Oberösterreich GmbH* and *Salzburg Netz GmbH*). Measures like Q(U), P(U), together with probabilistic grid planning, increase the hosting capacity in the grid significantly.
Another measure analysed was the limitation of grid feed-in to 70% of the PV peak power. Simulations showed that the energy and thus the economic losses are on average very small (<1 %) if significant self-consumption is present. This limitation will also result in a stimulus for the optimisation and increase of the self-consumption for consumers. However, such an approach does not apply to PV systems without any local consumption which feed all generated energy into the grid. Finally, it has to be stressed that such a measure is meaningful in grids where hosting capacity limits are reached. In LV grids with low penetration of PV a limitation of PV feed-in does not have a visible positive impact on the grid. All in all, unnecessary curtailment should be avoided. Therefore, a feed-in restriction should be coupled with existing system stability controls, e.g. voltage control.

The first two of the four flexibility activation concepts focused on the implementation of six residential PV-BESS with extended functions to act in a grid friendly way and provide additional market services. Different setups varying in communication infrastructure, control functions and equipment were implemented in the municipalities Eberstalzell and Köstendorf. The following results were obtained:

- **Activation effort**: Technically it was proven that flexibility can be activated and controlled by the DSO in various ways. However, depending on the setup the effort to access and remote-control flexible components can be significant and thus must be compared with the benefits produced. Relevant aspects which increased costs in the project were attributed to the high number of components and their significant integration effort. This effort had to be invested due to a lack of interoperability, complexity of parametrisation and missing tools to find errors in the system. Additionally, it must be considered that a smart meter rollout is a base requirement for dynamic and coordinated control schemes to be able to recognize corresponding voltage band variations and grid congestions. Consequently, a future implementation of a dynamic control of flexible components through the DSO (beyond existing ripple controls) would require much stronger standardisation, robust and automated control, available interfaces, strong interoperability and long-term reliability. As long as these prerequisites are not provided, control devices and functions used to avoid violation of grid boundary conditions are required to be simple (at best autonomous) and easy to implement (Plug & Play) or alternatively, only be applied to systems of a certain size.
- **Economic benefit**: Market driven activation of flexibility for both PV-BESS as well as flexible loads poses a rather small economic benefit under current market conditions. In some cases (especially within spot markets) the revenues per used PV-BESS cycle are lower than the induced cost which results in a decrease in the return on investment of the complete system. Thus, the main operation strategy of PV and central BESS mostly aims at the increase of self-consumption of PV generation which currently offers the highest revenue option. Even this operation strategy exhibits economic feasibility (even with corresponding subsidies) only in some cases.

However, consumers do not always make decisions based on purely economic parameters and the price of BESS is expected to decrease even further in the future.

- **Power-based grid tariff for customers**: It has been shown that a possible power-based grid tariff component might create a new operation strategy for flexibility, especially PV-BESS. With an implementation of such a grid tariff scheme the economic feasibility of these systems could improve. Currently, such power-based grid tariff schemes are under discussion by the Austrian regulator under the term *Tarife 2.0*[2].
- **Forecasting requirements**: Advanced control schemes to increase grid friendliness significantly improve with forecasting of generation and/or load. Thus, forecasting quality has a visible impact on the control scheme. Activities have shown that both load and generation forecasts exhibit visible deviations from the actual measured power value, which makes optimizing a single system for self-consumption and grid friendliness more challenging to achieve.

The third concept developed in the project was the implementation of a so-called community BESS. This system functions similarly to a PV-BESS but for multiple customers, installed as a central BESS in the LV grid. The installed BESS has a capacity of 100 kWh, and 100 kW of charge and discharge power. The system is installed in the municipality of Heimschuh, Styria and is located at a critical node in the local LV grid. The system implements an additional voltage control scheme and can provide additional market services. The following results were obtained:

- **Community storage implementation**: It has been proven that an implementation of a community storage system with a central BESS is technically possible. The system increased the PV self-consumption of the customers in the same ranges as residential PV-BESS and was tested in operation for 1 ½ years without any considerable outages and interruptions. The integration into the SCADA[3] system of the local DSO exhibited no problems. However, a significant development effort for was necessary as these systems are not yet available as an off-the-shelf product.
- **Active voltage control with a central BESS**: Additionally, the system can provide active grid voltage control including reactive and active power management. These functions could add to the economic benefits of the system. The prerequisite for this service is the optimal placement of the BESS in the grid. Depending on the structure of the local grid and generation and load patterns, reactive power control is sufficient most of the time when the grid voltage necessitated voltage control. Hence, the available capacity of the BESS is fully accessible to the customers for almost all the time. With that, BESS can be added to the DSO’s toolbox (grid reinforcement is the most common tool), as a new measure to increase the hosting capacity of local grids.
- **Additional market services with a central BESS**: Simulations and analyses showed that an additional participation in the day-ahead market and provision of secondary control power does not generate a visible economic benefit for the system. Field trials proved the technical feasibility but also showed a visible impact onto the local grid voltage when the system is fully activated for market-based services. The

[2] https://www.e-control.at/marktteilnehmer/strom/netzentgelte/tarife-2-0

[3] Supervisory Control and Data Acquisition

latter is a consequence of the circumstance that the system was installed at a critical node that is not optimal for providing significant amounts of active power for market participation.

- **Multi-Use of the central BESS**: It has been shown in the project that the use of storage for multiple purposes (e.g. community storage, voltage control and additional market service) can improve the economics of the system. This is an important consideration since BESS are still considered to be a very cost-intensive technology.
- **Costs of BESS**: As equipment cost reductions are currently significant (e.g. during the project duration a system cost reduction of about 30% was achieved for PV-BESS and central BESS), BESS come closer to an economic operation at implemented subsidy schemes and common operation strategies. Assuming for example a further decrease of BESS costs, it can be expected that the number of PV-BESS and central BESS will rise in the coming years and thus, a grid friendly design of self-consumption increasing operation strategies should be implemented.
- **Consumer perspective on community storage systems**: Compared to distributed PV-BESS, a central BESS exhibits certain advantages such as no installation effort and space requirements for the participating customers as well as synergies between customers which allow a more effective usage of the battery capacity. Results of the conducted customer survey showed that customers with PV systems are highly interested in joining a community storage system, however, there are existing concerns with regards to forming a community with other customers when there is no intermediate organisation which plays the role of a mediator.
- **Tariffs for community storage**: The project showed that grid tariffs (which were given during the project - especially for delivering stored electricity back to the customers) have a strong negative cashflow impact for the central BESS operator. Only at significantly reduced grid tariffs an economic operation for such systems, at current electricity market and storage price conditions, is possible. According to information from the Austrian regulator such a tariff allowing for local energy exchange may be introduced in the near future in the frame of the Austrian implementation of the new electricity market guideline [1] in the *Clean Energy for all Europeans* package. This would also make the community storage scheme, developed in the project, competitive to residential PV-BESS. Additionally, it has to be mentioned that with a large-scale rollout of such a community storage scheme the distribution of grid fees might change to the disfavour of grid users who are not able to participate in such a community concept.
- **Ownership of storage**: Operating a central BESS for multiple use-cases (including voltage control) implies an interaction and integration with the DSO. Different models of operation and ownership models exist which also include a DSO ownership and operation of the BESS. This is the most preferable scheme for the DSO, owing to its responsibility to provide a highly reliable network to the customer. A regulatory analysis showed that there is currently no explicit regulation in the Austrian framework as to whether a DSO is allowed to own and operate an ESS. The new European Electricity Directive covers this topic in detail and defines specific cases in which a DSO might be allowed to own and operate an ESS. However, a final statement can only be provided after the directive is adopted by national law.

The project had a strong interaction with end customers. This included a dedicated field trial (the fourth flexibility activation concept followed in the project), analysing the responsiveness of customers to incentives. Customers received a certain amount of money, a so called *Sonnenbonus,* to shift consumption to coincide with times of high local generation. The following findings were obtained from this field trial:

- **End customer responsiveness**: The *Sonnenbonus* field trial in Eberstalzell showed that end customers are willing to shift their high consumption periods to coincide with high local generation, when offered a monetary incentive. 94 % of all households participating in a post field trial survey stated that they want to continue using this approach. Thus, there is a future potential for customer related flexibility activation which includes time-of-use tariff models.
- **End customer flexibility potential**: While the *Sonnenbonus* field trial shows that end customers are willing to activate flexibilities, it also showed that there is a limitation in load shifting when considering larger household appliances. Customers attempted to shift their use of loads such as dishwashers and washing machines by implementation of simple automation processes such as timer switches. The corresponding effect on the local low voltage network was very small. However, on average an increase of 5 % in energy consumption was observed in times the bonus was available. Despite the low impact of the bonus incentive on the local grid the reduction of the simultaneity factor could have a positive impact on medium and high voltage networks. This, however, was not subject of the project and should be further investigated in future projects.
- **Costs for the incentive**: The cost saving benefit of the *Sonnenbonus* per kWh was set to a very high level for the field test in order to identify whether customers were willing to participate in such a scheme. Thus, identifying the minimum cost saving threshold was not the aim of the project. Therefore, the results of the scalability analysis calculations show that the costs for the activation of demand flexibility via the tested *Sonnenbonus* in Upper Austria would drastically[4] exceed the achievable grid cost savings. A cost neutral time of use tariff however could possibly produce the same result with minimal additional cost. The necessary level of compensation is a case for further study.
- **End customer information**: Many customers participating in the field trial did not invest a high level of interest in the actual amount of monetary bonus received (this information was displayed in the app). This indicates that monetary incentives alone may not trigger changes in consumption patterns but also other factors (i.e. consuming more renewable, local power) are relevant too. Additionally, survey participants indicated that it is not necessary to provide detailed reports of their consumption on a regular basis. Despite this, participants agreed that the frequency of reporting should be more than once per year.

In summary, the project was able to show the real-world applicability of grid friendly flexibility activation in low voltage grids with those four different flexibility activation concepts. Combining all activities in the project a comprehensive picture of this topic was produced.

[4] If bonus payments of 10.8 €/a and customers are chosen for a period of 40 years, the net present value of cost exceeds the achievable net present value of benefits by factor 58. Such payments represent the lowest median values within the Sonnenbonus demo case in Eberstalzell. Thus, it seems unreasonable to cover the evident monetary losses by subsidies.

1 Introduction

The *leafs* project evaluated the effects of increased consumer and energy market driven utilization of energy storage systems (ESS) and load flexibility on low voltage (LV) power distribution grids. New technologies and operation strategies were developed which enable the optimal use of distribution grid infrastructure through the activation of available flexibilities using direct or indirect control schemes operated by the local distribution system operator (DSO) or via the implementation of monetary based customer incentives. Flexibility, in the context of this project, is defined as the active alteration of the system power level and/or a shift in time.

The project aimed to allow for an increase in the number of possible customers with distributed energy resources. This should be achieved with minimum network reinforcement costs as well as achieving a higher self-consumption level for customers operating their own distributed generation (DG) unit. This, in turn, lead to the increase of overall benefits for the energy system by allowing the cost effective and efficient integration of increasing shares of electricity from renewable DG.

1.1 Structure of the Report

In order to provide an overview of this report the structure is briefly described. Chapter 1 introduces the *leafs* project and its background, including a summary of the project objectives. Chapter 2 describes the project methodologies and assessment activities conducted during the project. Thereafter, Chapter 3 presents the results obtained from the technical, economic, socioeconomic and regulatory analysis. Finally, Chapter 4 provides an overview of the conclusions and recommendations for future developments and activities derived from the project findings.

1.2 Scope of Work

Significant changes can be expected in the way in which consumers will behave from a power distribution grid perspective. Today, network planning (layout and dimensioning of distribution grid infrastructure and equipment) is based on statistical assumptions and historic data for load and generation behaviour over time.

Network planning approaches might have to change since new technologies such as distributed ESS and EVs can be operated in a flexible way. Also, existing components such as heat pumps and domestic hot water boilers can be operated in such a flexible way. Aggregation of this flexibility, by virtual power plant (VPP) operators, can result in market-driven load profiles based on price signals with potentially high synchronous behaviour in a given distribution segment. Without active consideration of the local distribution system limits, the likelihood of thermal overload in grid equipment or voltage band violations may increase and thus should be avoided. In contrast, the use of flexible components allows for the potential to relieve these constraints of the power grids and thereby allow for a higher penetration of DG.

1.3 Focus Areas of the Project

Based on the scope of work, further developments, which extend past the currently available state-of-the-art technologies, were necessary. Therefore, the project *leafs* proactively developed technologies and operation strategies to

a. allow for a grid friendly activation of flexibility for market services while ensuring that violations of defined grid boundary conditions are avoided.
b. use the existing flexibility to increase the possible penetration of distributed generation - especially photovoltaic (PV) - in LV grids.

Implementation and activation of this flexibility can be achieved in many different ways and through different stakeholders. Within the project four flexibility activation concepts were analysed in detail and validated in separate field trials. Each concept focused on different components and communication setups which are outlined as follows:

1. **Separate control of customer assets**: In the field trial area Eberstalzell, Upper Austria, grid friendly operation of flexible components - in this case PV-battery energy storage system (BESS) - is achieved through direct control of single components by the DSO. The grid integration approach focuses on the limitation of the operational window of the PV-BESS according to the local grid conditions. Additionally, the DSO can set parameters of the PV-BESS to ensure a grid friendly operation of the system. A market signal to activate the flexibility is provided by a third party – in this case over the cloud-based system of the PV-BESS manufacturer.
2. **Combined control of customer assets**: In the field trial area Köstendorf, Salzburg, both grid control signals as well as possible market services are transmitted by the DSO to a local energy management system in each participating household. The DSO acts as an infrastructure provider but not as a market participant and provides all automation and communication infrastructure. A market participant can gain access/control via the DSO's infrastructure.
3. **Combined control of utility assets**: In this case flexibility is created at a central point in the grid, directly accessible by the DSO. For that, a central BESS of 100 kW/100 kWh was installed in a LV feeder in the field trial area Heimschuh, Styria. Flexibility services such as increasing of PV self-consumption are offered to local customers by the system operator which is integrated into the utilities' control system.
4. **Monetary incentives for end customers**: Flexibility can be activated not only through direct control of components but also through monetary incentives. In the field trial area Eberstalzell, Upper Austria, end customers received a bonus when consuming more energy in times of high PV generation in the local distribution grid. A smartphone app informed the participating customers of the availability of the bonus. Extensions of this test focused on the additional active control of customer assets (in this case domestic hot water boilers) through the DSO.

The number of approaches in the project reflect a variety of possible flexibility activation concepts in LV networks. The assessment of this variety allows also for the development of more generic pattern descriptions.
All defined concepts pose specific advantages and disadvantages and are viable future setups as shown in Table 1. The viability of each concept depends on the existing infrastructure of the local DSO, interfaces of the components and the desired services for the grid and market. A summary of the single concepts is given in Table 1. A detailed overview of the individual field trials based on these concepts can be found in Section 2.3.

Table 1: Qualitative comparison of flexibility activation concepts analysed in the project

	Separate control of customer assets	**Combined control of customer assets**	**Combined control of utility assets**	**Monetary incentive**
Interfaces	The component requires two interfaces for each market control and grid control	The component requires only one interface for both market and grid control		Activation signals are communicated through a smartphone app or arbitrary website
Infrastructure	Depending on the control channel a local control infrastructure is required in the substation. Future implementations might also use an internet connection for communication		Components are usually integrated directly into the control infrastructure of the DSO/utility	Server systems to integrate customers in the incentive scheme and information infrastructure
Interaction between grid and market	Grid limitations are communicated to each component. These limitations have to be relayed to the market participant to allow for determination of the availability of the component	Limitations due to the activation for market services can be already determined before communicating to the component.		A combined market and grid signal could be transmitted. If separate signals are transmitted conflicts might arise.
Relevance	This setup is very likely since a lot of component manufacturers are able to control their products remotely	This setup requires proper interfaces between the DSO, market participants and the components. This inherits a significant implementation effort	Especially for larger systems this setup is interesting. This includes community ESS but no small-scale systems such as PV-BESS	Incentives do not necessarily trigger a predictable behaviour of end customers. Hence, planning with such an approach is hard.

1.4 Alignment to the Program

The project *leafs* was well aligned to the funding research program. It covered all three objectives defined in the program scope. The contributions to the defined goals are described as follows.

Goal 1: Contribution to the fulfilment of the climate and technology-political targets

leafs analysed the effects of increased utilization of ESS as well as load flexibility on distribution grids taking into consideration existing solutions concerning generation flexibility. The project's aim was to proactively tackle the challenges concerning the massive integration of renewables driven by the European and Austrian political targets. Through the flexibility activation concepts, solutions and technologies developed within the project, the integration of PV into LV networks can be improved by incorporating feasible control algorithms for flexibility provision. By considering grid friendly behaviour via controls and flexible tariffs, the perpetuation of the high quality of supply in Austria can be ensured which is a strategic objective for Austria.

Goal 2: Increase the affordability of sustainable energy and innovative energy and mobility technologies

leafs delivered the basis for cost-efficient and thus affordable integration of PV, ESS and flexible loads (e.g. EV, heat pumps and domestic hot water boilers) into the network by introducing solutions considering both technology and system perspectives. The cost effectiveness achieved through the utilization of virtual storages as well as direct storage was analysed as an alternative solution to minimize the requirement/need for electricity network reinforcement at LV grid level. More specifically, the economic benefits provided by different services (partly driven by monetary incentives) in combination with ESS and flexibility available from loads and DG on consumers (prosumer), DSO and market participant level were investigated. Thus, the project indicated an improvement in the affordability of integrating sustainable energy and related technological solutions at residential level as well as in LV networks as an alternative in order to minimize network reinforcement.

Goal 3: Build up and secure technology leadership, strengthen international competitiveness

Through the investigation of grid friendly flexibility provision, the market potential for different market players was illustrated. Thus, research institutions, industry and DSOs worked closely together in the project. The project enabled the contributing partners to offer their developed technologies and future commercialized services and products not only in Austria but also on the international market. This was further emphasised through performance of the replicability and scalability analysis within the project. Other Austrian DSOs provided their support by participating in joint workshops which promoted discussions of possible methods/solutions to increase the competitiveness of Austrian technology and system solution providers in the area of grid coupled electric energy storage and load flexibility.

1.5 Methodological Approach

leafs followed a robust technology development approach covering simulation, laboratory assessment and field validation. To integrate this approach into a comprehensive analysis, three central activities were combined as shown in Figure 1.

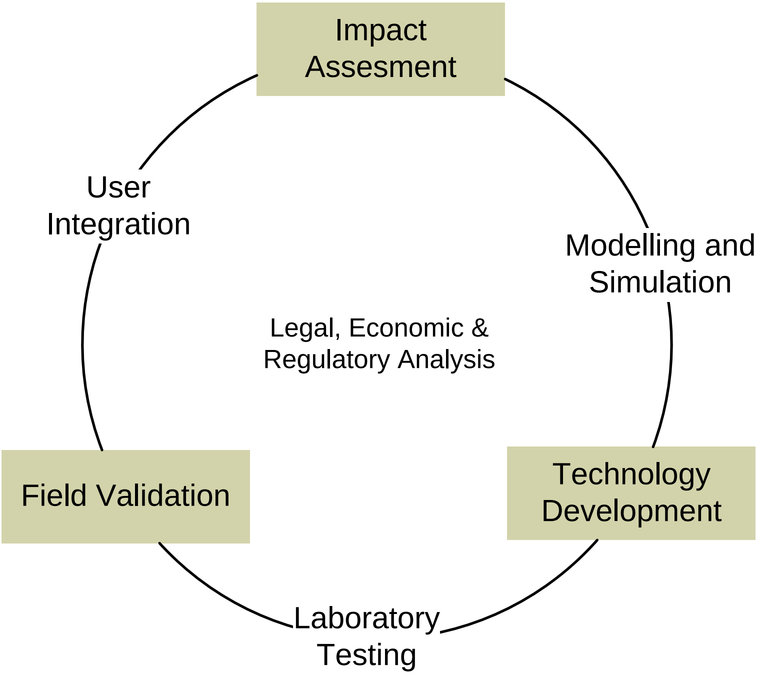


Figure 1: The three central methodological steps of the leafs project and their means of interaction

Solutions for flexibility activation by the local DSO for better grid integration of renewables and market service provision were developed (technology development) and evaluated with extensive simulations and laboratory trials. The developed solutions and operation strategies were implemented and validated in different field trials. Simulations with representative sets of model networks, flexibility potential assessments and surveys among relevant end customer groups were carried for an extensive impact assessment. To produce a comprehensive overview extensive economic, regulatory and socio-economic assessments complement the described activities. All activities and their respected methods are described in detail in the following sections.

1.5.1 Modelling and Simulation

Component Simulations

For the development of the different storage controllers multiple simulation models were implemented. These models allowed for dynamic and transient network simulations to be performed on different levels of component detail. The models include the ability to conduct simulations on both direct current (DC) coupled systems and alternate current (AC) coupled systems. The base setup of one of the developed models is provided in Figure 2. The model includes all relevant hardware components of a real BESS including PV and local loads.

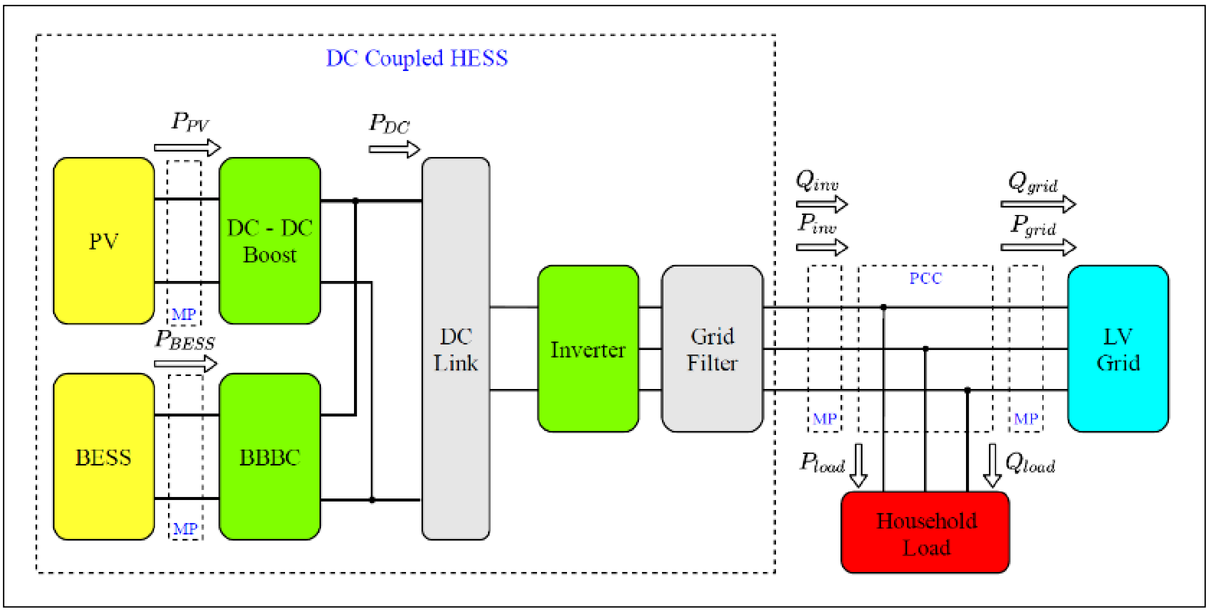


Figure 2: Schematic of DC coupled PV-BESS tied to the LV grid

In conjunction with the implementation of the system models, the corresponding control schemes were developed. Additional sensitivity studies were carried out to find the most suitable control parameters for single operation schemes.

Grid Simulations

For each of the three field trial regions, detailed grid simulations were carried out to develop and assess the performance of the defined control mechanisms and operation strategies. The simulations were conducted over a simulation period of one year and the operational profiles from the market simulations were used within the simulations.

Market Simulations

The market simulations provided the basis for the economic assessment (see Section 1.5.6) and the impact assessment on the distribution grid. In these simulations, each prosumer was able to (but did not necessarily) operate a PV system, a PV-BESS, flexible and inflexible loads and pursued a certain operation strategy to maximize his own economic benefit. This resulted in annual revenues or rather avoided costs per prosumer which were an input for the economic assessment. As a result, the optimized operation of storage systems and flexible loads resulted in market driven prosumer load profiles.

Development of Load Profiles

To reach the aim of performing long term grid simulations for an entire year (with a time resolution of one minute), suitable consumption/load profiles as input for the power flow calculations were prepared. Concerning power profiles for households, there was no suitable measurement data for this duration with the required resolution available for the required

number of customers. Therefore, these load profiles were generated by the load profile generator developed by the *Technical University of Vienna* within the *aDSM* project[5].
After obtaining the first simulation results for the reference scenario of each grid, the simulation results were compared to the existing measurement data obtained from the field tests that is summarised in Table 2.

Table 2: Available data from field test regions for validating the synthetic load profiles

Device or Type: Resolution / duration	Eberstalzell	Köstendorf	Heimschuh
Measurement data received over Modbus from local devices	Transformer P, Q, U: ~1-second / less than one year	Transformer P, Q, U: ~1-second / several years	BESS: P, Q, U, …: ~1-second / less than one year
Measurement data from Smart-Meter: EGDA measurements	Voltage from ~20 critical nodes in the grid: ~5-minute / less than one year	Voltage from ~20 critical nodes in the grid: ~5-minute / several years	Power from grid customers and feeder voltage: ~1-minute / less than one year
Historical data from Smart-Meter: Metering Data	4Q-powers from selected customers: 15-minute / several years	4Q-powers from selected customers: 5-minute / one year	4Q-powers from selected customers and feeder: 15-minute / less than one year

The analysis showed reasonable similarity between the measured and the synthetic load profiles. Hence, it can be assumed that the simulation results provided meaningful conclusions regarding the current and the future status of the stability of LV networks in the given context, notwithstanding the acknowledgement of some minor drawbacks.

1.5.2 Technology Development

As one of the main pillars of *leafs,* the technology development included the controller development, interface development and their implementation in the respected devices.

Controller Development & Implementation

The controllers applied in the field were developed in a co-simulation approach as visualized in Figure 3. The actual controller is implemented on the target hardware while the rest of the components, including all relevant control infrastructure is simulated. In this regard, a significant reduction in the development effort was achieved since specific aspects of the control infrastructure were taken into consideration directly at the beginning of the development process.

[5] FFG Project-Nr. 834612

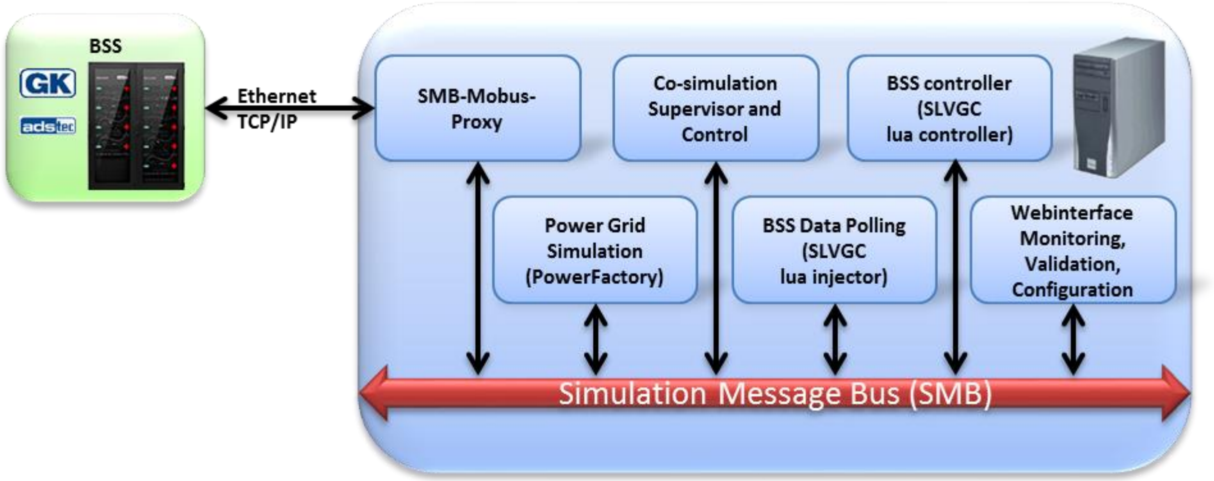


Figure 3: Schematic visualization of the co-simulation approach for controller development

Interface Development

To allow for the provision of flexibility, proper communication interfaces are required. Thus, for a dynamic control of distributed assets (DG, flexible loads) the DSO needs to connect to those units for (re-)parametrization and remote control. To enable these corresponding interfaces protocol, interoperability has to be ensured. Within *leafs* a multitude of communication channels such as AMIS-PLC[6], Modbus TCP[7] & Modbus - RTU[8], IEC 60870–5–104, XMPP[9] and REST[10] were in use. For the communication between the DSO and the components, these communication channels were based on a local communication architecture (all relevant components should be located in the local grid). For market interaction, an architecture based on a central server system was analysed.

Some components had the required interfaces already implemented while others needed to be adapted. The following list gives an overview of required interfaces for the most relevant components:

- **PV-BESS – Local grid control signal**: To communicate with the PV-BESS locally for grid control, a *ModBus-TCP* based communication infrastructure was implemented. This communication is based on the *SunSpec*[11] specification. *SunSpec* defines a standardized set of values and registers based on so called models which allow for setting values in the PV-BESS or reading data from the PV-BESS. In this case the *SunSpec* models 123 (Immediate Controls) and 124 (Basic Storage Controls) were implemented to allow for local grid control. With this set of values, it is possible to define limits for active power feed in, the battery and others. Additionally, it is possible to send active and reactive power set points to the PV-BESS. With that the *SunSpec* implementation was sufficient for the implementation of certain grid friendly operation

[6] Advanced metering and information system powerline communication
[7] Transmission Control Protocol
[8] Remote Terminal Unit
[9] Extensible Messaging and Presence Protocol
[10] Representational State Transfer
[11] https://sunspec.org/

strategies. Additionally, it is an enabler for the scalability and transferability of the implementation as *SunSpec* is a widely used quasi-standard for PV systems and PV-BESS.

- **PV-BESS - Market signal**: A remote provision of the market signal is possible over the cloud of project partner Fronius (*Fronius Solar.Web*). This implementation was already available from the project *EStore-M*[12] and was used in *leafs*. A formal prioritisation criterion between market and grid was implemented and successfully tested.
- **Central BESS**: The central BESS has a Modbus-TCP based communication interface which was integrated with the local controller. Also, the BESS was integrated into the SCADA system of the DSO. This was accomplished over IEC 60870–5–104 using an automation component as firewall to separate the ICT[13] infrastructure of the central BESS from the ICT system of the DSO. Besides transfer of the most important operating data (state of charge (SoC), power flow, battery status, etc.) and the possibility to remotely switch off the BESS in case of problems within the grid was also implemented.
- **Smart Home Systems**: The smart home systems which were to be installed in Eberstalzell provide a large variety of interfaces to single components. In this case the partners did not actively develop certain interfaces. The integration of components would have to be implemented by the participating customers in the field trial themselves.
- **Domestic Hot Water Boilers**: To control the hot water boilers, the existing ICT infrastructure of the smart meter system (AMIS) was used. This communication is based on powerline (PLC) and allows to address individual boilers or complete groups.

1.5.3 Laboratory Testing

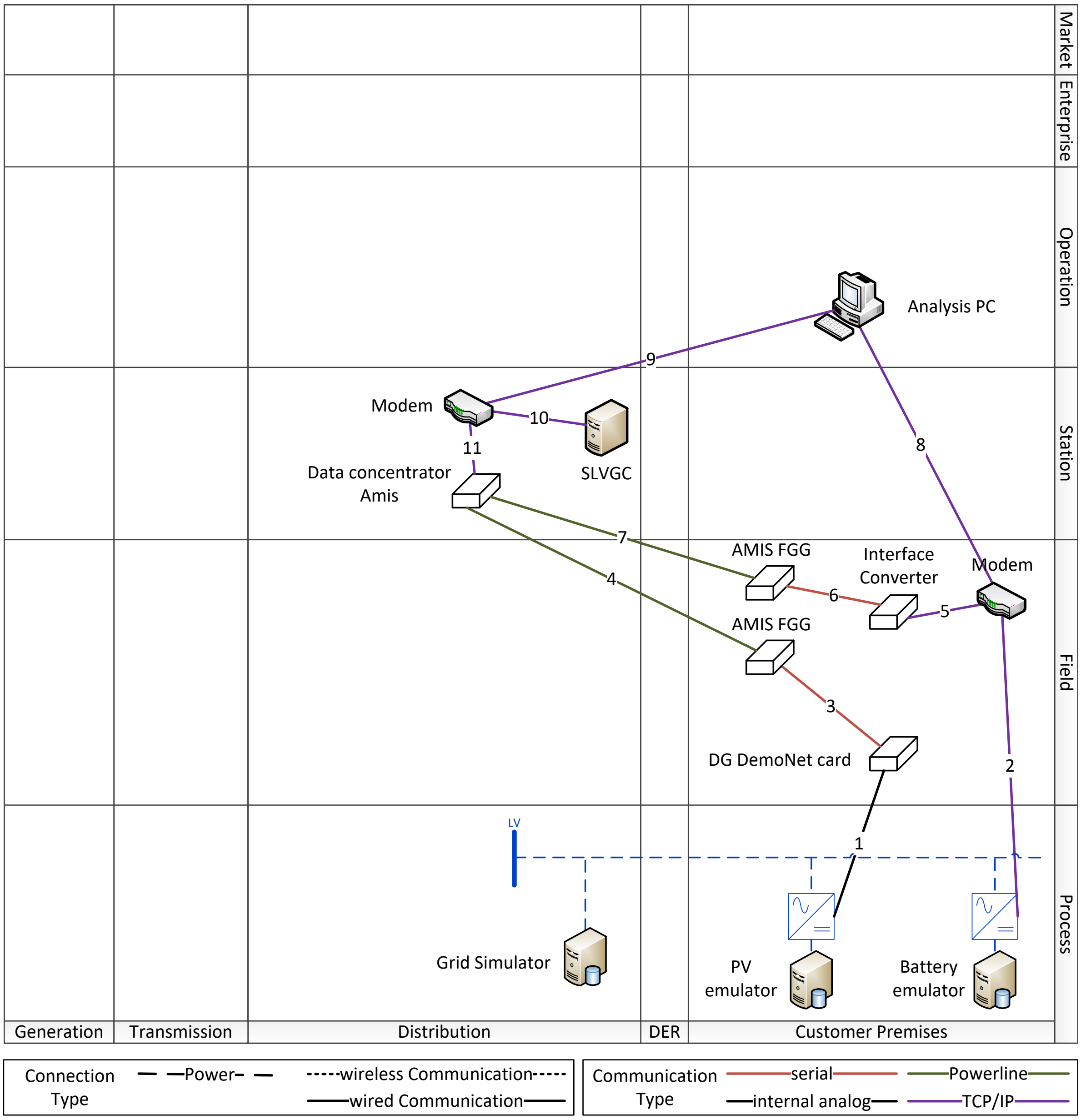
Before the rollout in the field, complete system tests were performed in the *AIT SmartEST* laboratory for the developed components and operation strategies. During these tests, the complete ICT system was recreated incorporating all relevant components that are also installed in the field test. The tests focused on both the residential PV-BESS and central BESS setup in the field trials.

Laboratory Testing of residential PV-BESS

Tests with the residential PV-BESS were carried out focusing on the ICT infrastructure of the PV-BESS. Figure 4 shows the setup of the PV-BESS in the field trial in Eberstalzell. The relevant components of this setup were implemented or simulated in the laboratory to pre-validate the functionality and communication setup for the field trial. With this setup, it was possible to test the whole communication chain from the centrally operated *Smart Low Voltage Grid Controller* (SLVG-C) “on the top” via PLC “down to” the individual customer’s PV inverter and PV-BESS. Figure 4 shows the interconnection and the connection type of all

[12] https://www.scch.at/de/das-projekte-details/estore-m
[13] Information & communication technology

components relevant for providing the control functionality required for the field tests, with the exception of the transformer control components.



1… Internal measurement signal
2, 5, 8, 9, 10, 11…MobBUS TCP SunSpec
3, 6…ModBUS RTU
4, 7…Powerline DLC CX1

Figure 4: Hardware connection scheme of components relevant for the field test setup in Eberstalzell as tested in the laboratory (except transformer control components)

The three main goals of the laboratory tests included:

- Ensure the successful transmission of set values from the SLVG-C to the PV-BESS *Fronius Energy Package (*including *Fronius Symo Hybrid inverter)* via *ModBus SunSpec* with corresponding local interfaces and gateways.
- Test the provision and realisation of market signals from the PV-BESS manufacturer's online portal *Fronius Solar.web* to the storage system and ensure that

the grid control takes precedence over the market participation in case of conflicting set values.

- Ensure the correct transmission of set values from the SLVG-C to the legacy PV-inverters as it was realised in the *DG DemoNet Smart LV Grid* project.

Several issues were identified and solved during the laboratory tests. These issues would have required a significantly higher amount of effort to resolve if they had been identified after implementation in the field test region. E.g. several adaptations of the technical addressing between the grid controller SLVG-C and the PLC connection element (AMIS data concentrator (DC)) were necessary to overcome problems with the IEC 60870–5–104 interface between SLVG-C and DC. Also, the addressing of the *Modbus* registers had to be adapted, which was relatively simple under laboratory conditions.

In the field trial area Köstendorf, the SLVG-C communicates with the Building Energy Agent (BEA) that forwards commands from the SLVG-C after internal optimisation and prioritisation to the specific household appliances. Since this communication channel is already established in the field test region available from the preceding project, it was not necessary for an overall test that incorporates the complete field test infrastructure. Therefore, the only communication channel that is new in the *leafs* project is the one from the BEA to the *Fronius Symo Hybrid.* This interface was tested in laboratory tests. Some issues with data acquisition in the BEA from the software drivers could be identified and fixed.

PV-BESS Battery Emulation

To increase testing efficiency and reduce testing efforts, a lithium ion (Li-ion) battery emulator was implemented using a Power Hardware-in-the-Loop (P-HIL) approach. The implementation represents both the physical behaviour of the battery as well as the battery management system (BMS) and its communication interface as given in Figure 5. Whereas the implementation of the physical behaviour can be done with parametrized generic battery models, the implementation of the BMS and especially the communication interface is specific for each system under test. The work showed that a single cell can be characterised and used in a model representing multiple cells (1,024 in this case). With this developed approach, the generation of battery models of specific products can be significantly simplified. The validation against an equivalent real battery system showed that the physical representation by the battery emulator is sufficient to replace the real battery characteristics for system testing as given in Figure 6.

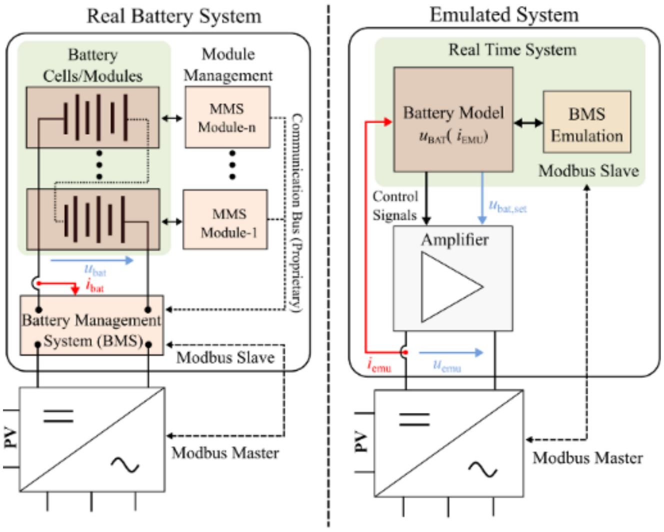


Figure 5: Basic setup of a real battery system and the implemented emulator

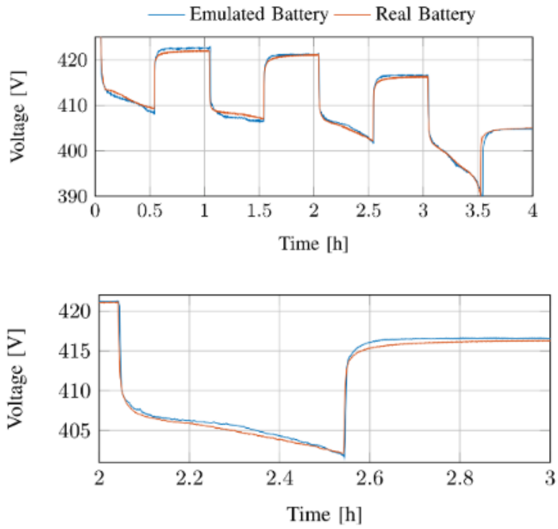


Figure 6: Battery stack voltage during four discharging and charging cycles (upper figure) and detailed view of one discharge cycle (lower figure)

Hardware-in-the-loop Testing for Asymmetric Operation of the Inverter

Flexibility could also be achieved by operating the PV-BESS in an unsymmetrical way. However, the AC power stage concept currently used in Fronius inverters has no power flow on the neutral conductor (unless the PV-BESS is not operated in backup power mode). This type of grid-tied topology allows for higher intermediate circuit voltages and thus a higher efficiency in symmetrical feeding operation. The connected neutral conductor is only used for measuring and the supply of the inverter (and in backup power mode to supply an unbalanced load). Therefore, asymmetrical feeding with zero sequence is not possible in grid-tied mode. Based on the hardware design for the next generation of *Fronius* inverters, an analysis on additional hardware costs as well as the effects on efficiency and service life was carried out for asymmetric feed-in. To ensure that efficiency is sustained at a high level at balanced feeding on high power levels, a concept with an internally switchable neutral conductor was designed, so that the output stage can be adapted dynamically depending on the requirements.

The existing output control algorithm of the current three-phase inverters was adapted to improved controllability of the separated sequences (positive, negative and zero). The new control was successfully simulated using a Hardware in the Loop (HIL) system from *Typhoon HIL* with inverters without active neutral for positive and negative sequence and with active neutral conductors (currently only the *Fronius Symo Hybrid* inverter) including the zero sequence.

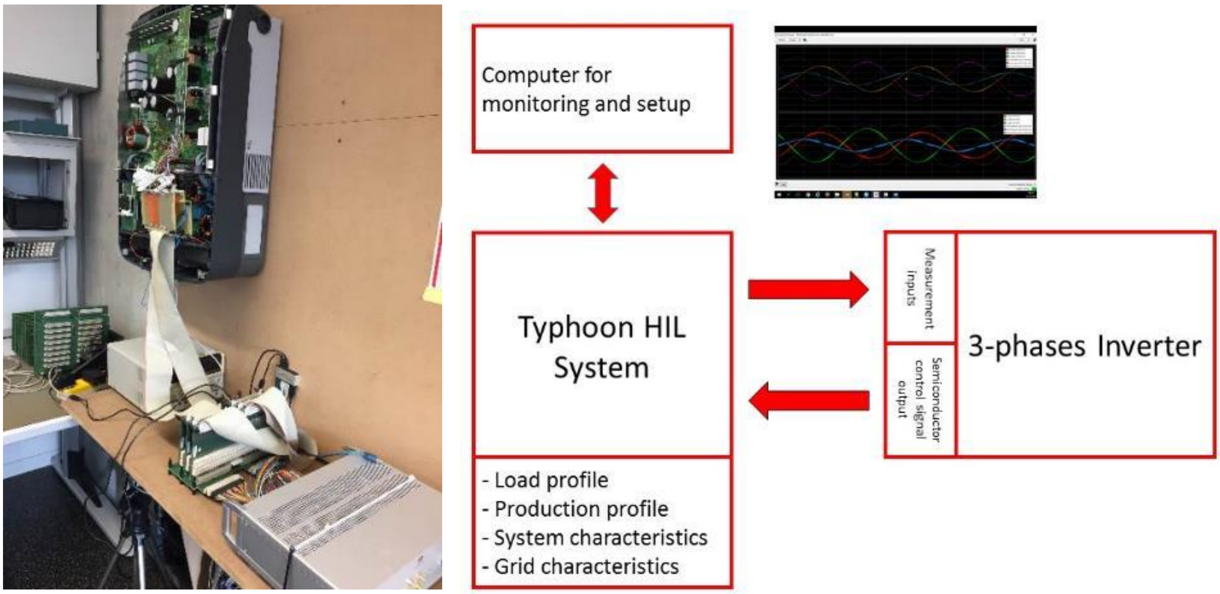


Figure 7: HIL Setup (left) and HIL concept (right)

Laboratory Testing of the central BESS

To pre-validate the functionality of the central BESS, different tests were carried out in the laboratory. These tests focused on the one hand on basic tests including the assessment of the datasheet specifications, determination of the basic dynamic behaviour of the system, efficiency evaluations, assessment of the operational window and other tests. On the other hand, specific tests were carried out to assess the correct functionality of the developed controller in different situations not reproducible in the field (e.g. overvoltage). Special focus was given to the external controller which incorporates the functionalities for providing a community storage system for several customers, local voltage control and remote control for market participation. Therefore, the controller calculates the active and reactive power set value for the BESS's inverter and supervises the state of the battery (for details see Section 2.3.3). For the development of the controller, the BESS had to be tested in detail to obtain fundamental parameters for the external controller in terms of timings, delays and operational limitations. Hence, the central BESS was installed in the *AIT SmartEST* laboratory as shown in Figure 8.

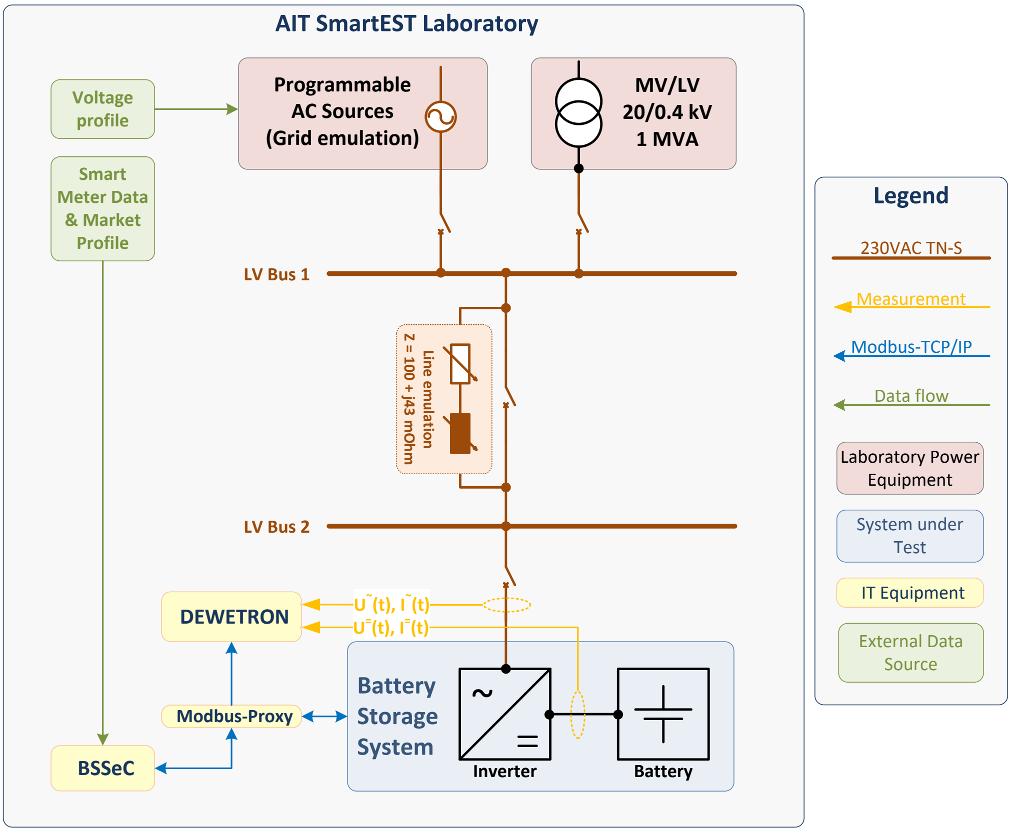


Figure 8: Laboratory overview for testing the central storage system

Figure 9 shows the system as it was set up in the *AIT SmartEST laboratory*. Based on the laboratory setup and operation, the relevant system characterisations (efficiency patterns, dynamic behaviour) were obtained, such that they could be used for the implementation in the simulation models.

Figure 9: Central storage system for the field trial in Heimschuh setup in the AIT SmartEST Laboratory – full system (left) and inner setup of inverter (right)

Initially, the BESS was connected without line impedance emulation and thus the voltage sensitivity at the connection point did not reflect the same conditions within the field test. Thereafter, the line impedance emulation was activated and tests concerning the controller stability in terms of voltage control were performed (see Figure 10).
Prior to field deployment, the proper functionality of the overall controller of the central BESS was tested on the target hardware which controlled the BESS connected to the programmable AC source (with active line emulation) and was monitored for several days. For this test, synthetic household power profiles and market signal profiles were fed into the system to simulate field test conditions.
Additionally, the most relevant system parameters were determined and where necessary, a corresponding assessment procedure was developed. The primary assessment procedure focused on the charging and discharging cycle times of the battery according to the PV-BESS efficiency guideline published by the *Bundesverband Energiespeicher* (BVES) [2] and as shown in Figure 10.

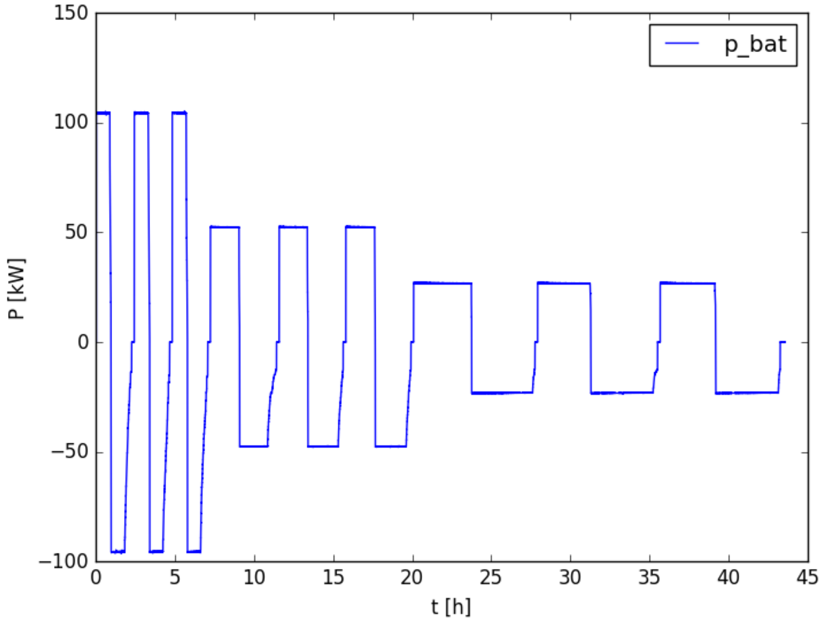


Figure 10: Battery power timeline during the round-trip efficiency (RTE) tests

1.5.4 Field Validation

The developed concepts and operation strategies were implemented and evaluated in separate field trials. The field validation included development of testing scenarios and executing them in the field. Each field trial that was implemented, focused on a specific validation scheme to assess the flexibility activation scheme (see Section 2.3 for details).

1.5.5 User Integration

A deeper understanding of the end-user perspective on increased utilisation of ESS, load flexibilities, and other smart grid-based products and services was a central focus in the *leafs* project. The assessment of end-user's interest in and willingness to adopt new technologies and operation strategies was analysed from two different perspectives with the aim of complementing the technical, economic, and regulatory analyses of *leafs*. The two perspectives were:

I. A field trial in the Upper Austrian village of Eberstalzell in which an incentive scheme was implemented to test whether households are willing to shift their electricity consumption to times which coincide with high generation of electricity from local PV plants (see Section 2.3.4 for details)
II. A large-scale survey was conducted within the federal states of Salzburg, Styria and Upper Austria to gain a deeper understanding of households' perspectives on novel products, services, and other opportunities made possible by smart grids.

In order to implement these two perspectives, an end user integration process was designed and an implementation strategy which focused on the recruitment of household customers and the installation of different communication channels with all customers who joined in one of the activities. In order to achieve the goals derived by perspectives I and II, the integration process included the development of incentive schemes, customer data protection frameworks and trouble-shooting strategies.

Survey of End-User

Overall, 13,450 households took part in a large-scale survey conducted in *leafs*. The questionnaire focused on five unique topics: Sociodemographic indicators and household equipment, ownership of and interest in PV technology, PV-BESS and community energy storage systems, information provision and electric mobility. Relevant indicators are shown in Table 3.

Table 3: Survey indicators

	Upper Austria	Salzburg	Styria
Type of survey	online survey		
Survey tool	typeform.com		
Participation mode	by email invitation only		
Invitation emails sent	16,758	14,412	140,801
Responses	2,129	1,070	10,251
Response rate	14.2%	8.5 %	8.0 %
Selection criteria	10,000 PV owners, 6,758 randomly chosen	4,005 customers with PV 10,407 randomly chosen customers	140,801 (all customers whose email address was known)
Incentives	5 Smart home management systems	30 different non-energy related prices	An e-Bike (1st price), 4 coupons for a smart home management system
Time period or duration	22.04.-04.06.2018	07.05.-22.05.2018	21.01.-05.02.2019
Additional information for participants	https://www.leafssurvey.com/oberoesterreich.html	https://www.leafssurvey.com	https://www.leafssurvey.com/steiermark.html

The survey contained questions in five main categories:

1. **Sociodemographic indicators and household equipment**: This section contains a wide range of questions targeting household composition and living situation. This section also focused on identifying the use of high load devices and their heating systems.
2. **Ownership of and interest in PV technology**: The survey questions related to PV cover motivational aspects (e.g. the reasons for adopting PV solutions), experiences with owning a PV including operational costs, future plans when public subsidies run out as well as the households' interest in community-owned PV installations.
3. **Electricity storage system**: Similar to the PV questions, information about ownership and usage of ESS was gathered. Here, the focus was not only on residential PV-BESS, but also on centralised community BESS and how households perceive them.
4. **Information provision**: There was high interest in identifying the type of information concerning electricity consumption customers desire, how they prefer to receive it and in which granularity and frequency.
5. **Electric mobility**: Questions related to EV ownership and charging behaviour were formulated and households asked about their interest in community-owned charging facilities.

By conducting such a large-scale survey among customers of the grid operators *Salzburg Netz GmbH*, *Energienetze Steiermark GmbH* and *Netz OÖ GmbH,* the goal was to gain a deeper understanding of the factors that drive households' energy-related decisions.

The results of this survey provided a detailed understanding of the status of consumer devices, as well as their perceptions toward technologies such as PV and EV. Moreover, data on future plans regarding the respective technologies was collected. In addition, the household acceptance of receiving information related to their electricity consumption including the kWh consumed or related costs and CO_2 emission level was investigated. The collected empirical basis provided insights not only on the current status but also on the potential future development of consumer attitudes, acceptance and interests in the energy related technologies and electricity consumption, which can be used for provision of novel services and further development of smart grids.

1.5.6 Legal, Economic & Regulatory Analysis

These activities complemented the technical developments and the socio-economic analysis in the project. With that a comprehensive overview of the topic at hand was made available.

Economic Assessment

The economic assessment within the project followed the goal to analyse actor specific business cases (mainly cost / revenue ratings) for each defined operation strategy. Therefore, all investments of each solution were calculated as yearly cost (annuities) considering a specific evaluation period as well as interest and price change rates.

The evaluation period depends on the component with the longest service life. If batteries together with a PV system are evaluated, a calculation period of 20 years was chosen. If batteries or flexibility in the sense of grid components are rated, an evaluation period of 40 years was implemented according to the technical lifetime of many grid assets.

For long periods price changes for recurring payments have to be considered. The price change rate indicates how much the payments in the following period are higher or lower than the payments in the period before.

The capital related costs of implemented systems include cost of acquisition, fixed maintenance costs and replacement investments. Added to this are costs for installing the systems. The installation costs vary, depending on whether it is a new installation or a replacement investment. Planning costs are usually negligible for small systems as they are mostly built according to standards.

For system components which exceed the evaluation period under review, the residual values were determined. For components that needed to be replaced during the period, replacement costs were considered.

The operational costs include costs of maintenance and inspection as well as losses and insurance. Also, it is necessary that implemented systems must be inspected within the calculation period at intervals of several years. On a yearly basis, these operational costs were added to the annuity of capital expenditures for each evaluated solution.

In order to compare costs to achievable revenues, the revenue results of market related optimization (see Section 1.5.1) were used. A variation of uncertain parameters (mainly the revenues) identified actor specific risks for further utilization of storage devices or other flexibility activation mechanisms.

Regulatory Analysis

Legal, economic and regulatory analyses were performed for all solutions and provided additional inputs for the final simulation-based investigation of replicability and scalability of the solutions. The defined setups and operations strategies were analysed towards their applicability in the current regulatory framework. The identified critical points were analysed, and possible action plans elaborated to streamline the regulation of flexibility, improve incentives and reduce system complexity in ways consistent with the goals of the EU energy policy. Based on the analysis, workshops and the results from the field trials specific grey areas in the regulatory framework in context of the project activities were collected and described.

1.5.7 Impact Assessment

The third main pillar of the project was the impact assessment. The objective was to provide a holistic picture extending beyond the implemented concepts and conducted field trials. This included potential assessments, analysis of possible rollout scenarios and outreach to relevant stakeholder groups.

Flexibility Potential Assessment of flexible Loads

The existing flexibility potential with regard to interruptible loads within the LV networks of *Netz Oberösterreich GmbH* and *Energienetze Steiermark GmbH* was analysed. Based on historic consumption data, a detailed energy evaluation with regards to interruptible tariffs was carried out for the whole supply area of both DSOs to finally determine a daily averaged power curve for relevant interruptible loads. This investigation included:

1. **Theoretical Assessment**: The investigation included the pre-selection of interruptible load groups based on their relevance regarding presumed flexibility potential and annual energy consumption. This approach was refined by using standard load profiles and custom load profile measurements with a resolution of 15 minutes. Based on these calculated power curves, the unknown installed plant capacity of interruptible loads was determined. The daily power curve represents a first attempt towards a detailed power balance and was determined for the service area of three selected substations.
2. **Switching trials**: Flexible load actuation was carried out in the chosen substations in April in Upper Austria and in June in Styria. In both switching trials the test was carried out on a workday as this represents the majority of days. Several additional ripple control commands were sent to the devices in order to evaluate their influence on the transformer's load profiles at the selected substations.
3. **Potential assessment**: The results of these analyses were used to make a projection of existing flexibility for the whole grid. In the first step, the results of the switching trials were compared to the theoretical assessment to be able to calculate different concurrence-factors for different typical days of a year. These factors were matched with the installed transformer capacity of all substations to calculate the potential for the whole grid.

Additionally, out of the submitted project scope *Salzburg Netz GmbH* also provided a flexibility analysis. It focused on the determination of the load flow of a specific command group in a primary substation, by performing a series of Off/On switching actions during the active time and recording of the corresponding step responses of the system.

Flexibility Potential Assessment for PV-BESS

A dedicated analysis method for the assessment of residential PV-BESS was developed with the focus of assessing the existing flexibility potential. This method included the analysis of the **efficiency**, **effectiveness** and **utilization** of PV-BESS:

- **Effectiveness**: The degree of increase of the local consumption in relation to the local generation and the storage was analysed.
- **Utilization**: A detailed analysis of the usage of the PV-BESS system with regards to the full cycles, distribution of storage power and state of charge was performed.
- **Efficiency**: Methods for the assessment of energy losses in the power conversion system and the battery are provided.

With these characteristics, a comprehensive analysis of the entire systems was achieved and the impact of providing flexibility through the use of the PV-BESS could be evaluated. The methodology used was evaluated over a set of 51 systems. Measurement data was provided by project partners and by *Land Steiermark*, who collected data in the course of the Styrian subsidy framework for PV-BESS.

Scalability Analysis

The objective of this activity was to evaluate the impact of large-scale integration of PV, PV-BESS and flexible loads on LV networks under several different conditions. The focus of the scalability analysis was based on all LV networks within the supply area of the DSOs *Salzburg Netz GmbH* and *Netz Oberösterreich GmbH*. This includes a total of 14,614 networks with a total of 42,000 feeders and 1,998,000 connection points.
Scenarios were developed to reflect the future rollout of relevant technologies such as PV and EVs:

1. **EV rollout**: A complete rollout of EVs in the two supply areas was assumed. This implies that every household owns one EV. Different charging powers and simultaneity factors were analysed representing different charging approaches. Details on the scenario can be found in Section 3.1.7.
2. **PV rollout**: A rollout scenario of PV based on current political targets (*#mission2030*) was defined. The overall targeted generation capacity was broken down to the supply areas of the two DSOs *Salzburg Netz GmbH* and *Netz Oberösterreich GmbH* including a relevant distribution of the PV plants into the different network levels. For both DSOs the rollout scenario represented at least an increase of the generation capacity by the factor of 10. Details on the scenario can be found in Section 3.1.7.

In each of these scenarios various measures were analysed regarding the grid reinforcement requirements (line reinforcements and transformer upgrades). These scenarios incorporated advanced grid functions such as P(U), Q(U), limitation of feed-in power (as described in Section 2.2.3), a grid friendly operation of PV-BESS as defined in Section 2.2.2 and the implementation of central BESSs used to avoid voltage band violations as described in Section 2.2.4. The impact of market driven activation of flexibility with a high simultaneity was analysed. With that, the concepts elaborated and analysed in *leafs* were scaled up to the complete supply area of the DSOs giving a specific focus to the impact on the LV distribution grids.
Based on load flow calculations of all networks, all scenarios were assessed and compared with regards to the overall grid reinforcement costs. As such, the specific grid reinforcement of the two DSOs including equipment characteristics and reinforcement schemes were applied.

Stakeholder Integration

The results of the project were shared with other Austrian DSOs (not participating in the project) and the Austrian regulatory agency for energy. The objective was to obtain additional perspectives on the project results and discuss replicability and transferability of the concepts.

2 Project Concept

As described in Section 1.3 the project is organised around four different flexibility activation concepts to control flexible components for grid and market services. The following sections describe the concepts analysed in the project in detail. First, a generic description of the *leafs* system architecture is given, the individual developed grid integration functions are introduced and, lastly, all field trials and related assessment activities are described.

2.1 System Architecture

A system architecture enabling grid friendly activation of flexibility based on a coordinated voltage control scheme, developed in the project *DG DemoNet Smart LV Grid* [3], was implemented. This system architecture simplistically describes the degrees of flexibility activation for grid services and/or market-based services. This architecture spans across all the flexibility activation concepts (see Section 2.3) of the project.

2.1.1 Grid Integration Concept

The control scheme used in the project *DG DemoNet Smart LV Grid* covers multiple voltage control setups for PV generation installed in households in combination with on-load tap-changing transformers (OLTC) in the substation as well as EV charging stations (see Figure 11). Overloading of DSO equipment (cables, lines, transformers) was avoided by complying with the corresponding network planning process prior to the connection of the flexible units and enabling their control functions.

Figure 11 shows the concept of the developed grid integration approaches of the system architecture. ESS, especially central BESS and residential PV-BESS as well as flexible loads are newly added to the existing approach as they are the primary devices used for current and future flexibility. The existing voltage control function *P(U)* was conceptually extended for bidirectional operation for ESS and for loads such as EVs separately. A new function to limit the operational window of the system was added. The limitation of the inverter's active power and / or the battery charging / discharging power is done depending on the actual or expected status of the grid (given as *x%* in Figure 11). *Q(U)* and *P(U)* represent existing grid integration functions which integrate seamlessly with the approach defined in the *leafs* project.

The functions can be either set once (Level 1 and Level 2) or can be reconfigured dynamically (Level 3) in combination with a central grid controller. Due to the increase of simultaneity caused by a common control signal, overloading of DSO equipment such as transformers, lines and cables might arise. Therefore, it is vital that the grid control scheme takes this into consideration during the planning process and is adapted accordingly.

	DG DemoNet Smart LV Grid control scheme		Addition in leafs	
	MV/LV Tap Changer	PV System (no battery)	PV Battery & Grid Storage	Flexible Loads
Level 0	U_{busbar} = const	-	-	-
Level 1	U_{busbar} = const	Q(U), P(U)	Q(U), P(U), x%	P(U), x%
Level 2	Field sensors	Q(U), P(U)	Q(U), P(U), x%	P(U), x%*
Level 3/4	Field sensors	$Q(U)_{DYN}$, $P(U)_{DYN}$	$Q(U)_{DYN}$, $P(U)_{DYN}$, $x\%_{DYN}$	$P(U)_{DYN}$, $x\%_{DYN}$*

*Flexible loads do need a local control for the consideration of grid requirements
x% = Reduction of the active power in % of nominal power

Figure 11: Overview of the defined grid integration levels of the system architecture

With this approach, the project *leafs* enhances and further develops existing grid integration approaches. This extension leads to the following additional benefits:

- while the control concept of *DG DemoNet Smart LV Grid* is limited to customers with a PV system, the control scheme in *leafs* allows all customers to participate and act in a grid friendly way.
- with a coordinated approach to reduce the load and the associated network congestion of the local low voltage grid, upstream grid levels could be also relieved.

To use the concept above, a grid state has to be generated using field sensors, mainly voltage data generated by the smart meters as well as active and reactive power data measured in the transformer station. That means that for similar approaches during regular grid operation the planned smart meter rollout must be completed. This is due to limited availability of alternative methods to obtain measurement data from LV networks.

2.1.2 Concept for Market Participation and Provision of System Services

An integration concept for the economic optimisation of a customer's energy costs (possibly including loads, generation and/or storage) or a dedicated plant (generation and/or storage) in the grid was developed. Three separate steps are defined, which require different integration approaches:

1. **Step 1**: The first step represents (economic) benefits for the customer. This includes autonomous applications for economic optimisation, which can be implemented without active communication to a market platform or connection to an aggregator or VPP operator. The most relevant application is local consumption of PV but could also include (residual) peak generation reduction[14] and (residual) peak load reduction in the future.

[14] The new version of the Austrian grid interconnection requirements which are applicable as of 1.8.2019 cater for this measure.

2. **Step 2**: The second level incorporates market-based services that can be provided in an autonomous (predefined) way, such as (droop control based) primary frequency control. That means that the control signal can be generated locally (i.e. based on a local frequency measurement). An active communication is required to activate or deactivate the service locally, but no permanent connection is required to provide the service.
3. **Step 3**: Besides participation on the spot market, which includes provision of balancing power and provision of secondary and tertiary control, an active communication channel to an aggregator or VPP-operator is required.

Functions for Step 1 and Step 3 were analysed in-depth and tested in the field within the project. It was decided that functions for Step 2 are not analysed in detail as the number of possible applications is limited to primary frequency control and this application infers with basic operation strategy of the BESS and PV-BESS.

Operation Strategies for Flexibility based in the customer premises

For flexibility located at the customer level, six different operation strategies, including corresponding incentives and penalties were analysed and the impact of BESS and flexible loads on the prosumer and the distribution system evaluated. These operation strategies include:

1. **Maximisation of self-consumption**: This represents the typical PV-BESS operation strategy in networks without net-metering or feed-in restrictions. In this operation strategy, fixed prices as well as remuneration per kWh feed in of generated PV are assumed. Power-based grid tariffs are not considered in this operation strategy.
2. **Minimisation of procurement costs**: Instead of a fixed electricity price, a flexible price for end customers with a ¼ h resolution is considered. The electricity price applied is the German/Austrian European Power Exchange (EPEX) Spot intraday closing price of 2016.
3. **Minimisation of procurement power**: In this operation strategy an annual power-based grid tariff of 40 EUR/kW is assumed. With that the influence of PV-BESS and flexibilities on procurement power pricing can be evaluated.
4. **Minimisation of PV curtailment**: A feed-in limitation of 70 %[15] of the peak power of the PV system into the grid is assumed. The optimisation tries to avoid a possible curtailment of PV feed-in above this limit by increasing the self-consumption in times of high PV generation.
5. **Minimisation of PV feed-in power**: An annual power-based tariff for grid feed-in, equivalent to the power-based tariff as described above, is set to 40 EUR/kW to test a method to reduce the feed-in power of single customers.
6. **End customer incentive**: An incentive called *Sonnenbonus* of 10 ct/kWh is available in times of high PV generation in the grid.

The objective was always to minimise costs for each prosumer. Further, in every moment the grid procurement and feed-in of all prosumers are aggregated to describe the overall change of power levels.

[15] This value of 70% feed-in limit was chosen by the project partners but could be also set higher or lower.

Operation Strategies for the central BESS

Along with the assessment of customer owned flexibility, the following services were analysed for the central BESS. The number of services is lower and different applications are available:

1. **Maximisation of self-consumption**: Several customers share a common BESS to increase their local consumption of PV. Energy to be charged and discharged by the BESS is transmitted over the local distribution grid. Grid fees and taxes play a vital role in this concept and are analysed in detail.
2. **Provision of automatic frequency restoration reserve (aFRR)**: In times of low PV generation, the BESS could participate in other markets. The participation on the aFRR market was evaluated, while applying the standard grid fees of grid level 7. In case of activation, the storage unit buys or sells the required energy on the intraday market.
3. **Participation in the spot market**: The participation on the day-ahead market was evaluated, while applying the standard grid fees of grid level 7, as well as the pumped hydro storage (PHS) tariffs.

2.1.3 Approach for Interaction between Market & Grid

A core aspect of the project is that a market or system-based activation of flexibility must not lead to voltage band violations or DSO equipment (transformers, cables, lines) overloading. Conflicts between the market and the local grid arise when there are local grid congestions at a time when a market service requires a higher grid feed-in or consumption. In case of such a conflict, the grid requirements supersede the market requirements. From this perspective, the power limitation of flexible components given by the DSO always has the highest priority and market requirements can be fulfilled within those given constraints. (e.g. P_{grid}^{limit} = 5 kW and P_{market} = 3 kW). This must be considered when implementing corresponding interfaces and functions in flexible components.

These limits could be set dynamically based on state estimations but also only once based on existing usage patterns (e.g. the highest simultaneity of customers is approximately 3 kW). However, the limitations should be given in a way to allow activating as much flexibility as possible in the grid.

2.2 Grid Integration Functions

As described in Section 2.1.1 multiple grid integration functions have been developed and tested in *leafs*. This covers both reactive and active power control dependent on the local voltage situation. In comparison to the functions developed in *DG DemoNet Smart LV Grid,* the functions consider the bidirectional operation of central BESS and residential PV-BESS as well as functions for flexible loads.

Along with the grid integration functions implemented in *DG DemoNet Smart LV Grid* the functions in *leafs* are implemented for all three phases equally. Additionally, tests have been carried out to operate a PV-BESS in an unsymmetrical way (see also Section 1.5.3 and Section 3.1.4) to cover the local load per phase. With this configuration, an active

improvement of the local voltage band usage would be possible. The PV-BESS used in the project is able to operate in this way, however, a corresponding necessity to implement the function could not be identified in the project.
The grid functions can be executed in coordination and combination with other equipment such as the local OLTC. A detailed description of the single grid control schemes applied in each field trial can be found in Section 2.3.

2.2.1 Dynamic Component Operation Limits

The BESS operation is limited by setting operational constraints within the system. These constraints can be either set statically or can be dynamically adjusted by a centrally operated grid controller. Examples for operational constraints are:

a. Setting the charging power of the battery (P_{max}^{bat}): This can be useful to avoid peak PV infeed during midday on sunny summer days because the battery was fully charged before the occurrence of peak generation. If the charging power is limited, the charging process is lengthened, and the PV peak generation can be reduced – depending on the individual relation between nominal PV infeed power, battery capacity and battery power.

b. Setting the discharging power of the battery (P_{min}^{bat}): This can be useful to avoid the reduction of storing actual PV infeed into the battery (or even battery discharging despite PV infeed) initiated by a market participation. This condition can have a negative impact on the grid state if PV infeed is already high.

c. Setting the maximal infeed power of the inverter (P_{max}^{inv}): This can be useful since it is well known that high PV infeed close to nominal PV infeed power typically only occurs a few hours per year, and a curtailment during these comparable short time periods will not lead to a significant loss of energy. As a consequence, the DSO does not have to plan for the grid to be capable of hosting the full nominal power of the PV which enables an increase in hosting capacity or alternatively, savings in grid reinforcement costs. This function is also meaningful, if applied to the point of common coupling (PCC). With that the local consumption of the customer can be regarded in the limitation of the inverter output.

d. Setting a charging offset for the battery (P_{offset}^{bat}): This implies that charging of the battery starts when PV infeed increases a threshold – PV infeed below the threshold is not charged but fed into the grid: This can be useful to effectively reduce the typical PV infeed peak during midday: If the weather forecast for the current day is known, then the expected PV infeed energy for this day can be estimated. If this value is significantly bigger than the storage capacity, a time delay of battery charging is obtained through the activation of the charging offset function which will clip the PV infeed curve and thus have significant positive effects on grid voltage.

This list makes no claim to be exhaustive, but it shows the most interesting operation limitations that were analysed within the *leafs* project. Figure 12 shows the behaviour of the battery and inverter during constrained conditions when the PV infeed curve represents that of a sunny summer day without household load. The first graph shows the unconstrained behaviour of a PV and a full battery before midday and a high PV infeed peak as consequence. The second graph shows the effect of applying P_{max}^{inv} only, the third the effect of applying P_{max}^{bat} only, and the fourth the combination of both limitations. The second row of graphs show the implementation of P_{offset}^{bat} both with and without the combinations of limitations.

This approach could also be applied to flexible loads such as PV powered hot water boilers. The intention for doing this is - similar to the ESS - to reduce the PV infeed peak during midday. However, it should be noted that that flexible loads do not necessarily implement a corresponding function or that corresponding interfaces are defined.

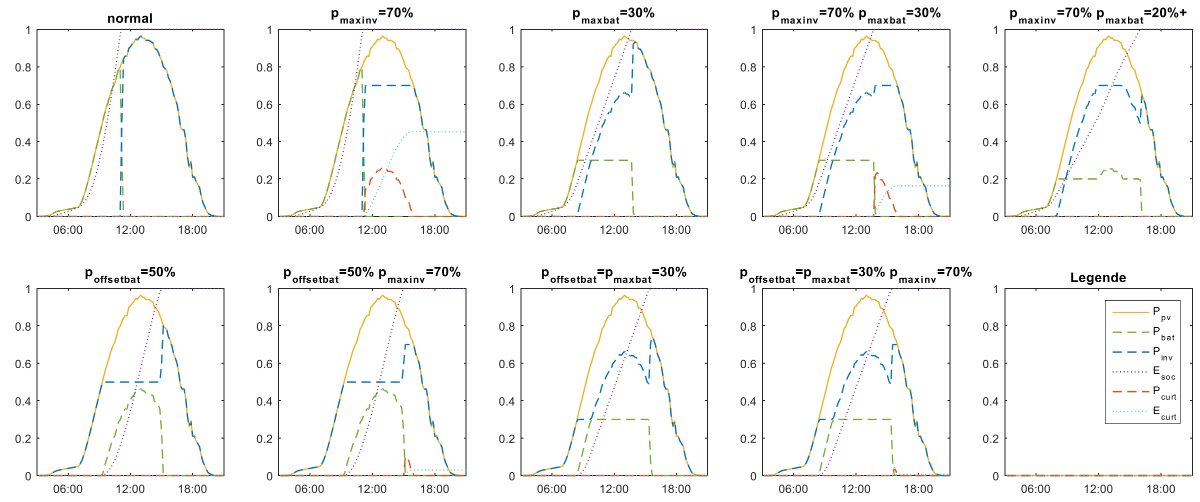


Figure 12: Examples for storage system operation with different operational strategies and limitations

The specific control approach applied to the PV-BESS in the field trial is as follows: The existing iterative control of the PV-inverter's Q(U) characteristic curve (developed in *DG DemoNet Smart LV Grid*) in times of a high voltage range in the grid[16], remains the primary control action in times of voltage problems in the grid. In a second step, if the Q(U) curve reached its limits, the active power control, P(U), of the ESS is activated.

In this way, battery charging and discharging power is limited. This first step of this control is the combination of an dynamic control used in combination with a Q(U) function. Figure 13 shows that the maximum discharging power (P_{min}^{bat}) is reduced in step-by-step increments to zero, so that in times of high grid voltage, the DSO can be sure that an ESS will not discharge (e.g. to compensate for household demand or to serve on markets). This second step is followed by a third step where the ESS is forced to charge. This forced charging increases stepwise until the discharge limitation reaches the nominal charging power. At this point, all ESSs have to charge their battery to maximal power according to their current potentials. In summary, at the end of the control iterations, the DSO can be sure that all PV inverters will contribute their whole reactive power potential to decrease high grid voltages and all PV-BESSs will charge their battery until the capacity limit is reached.

[16] meaning the difference between the highest and the lowest voltage in the grid, which in practise will probably occur on different feeders, but the highest and lowest voltage can also be located at the same node which indicates a high phase unbalance.

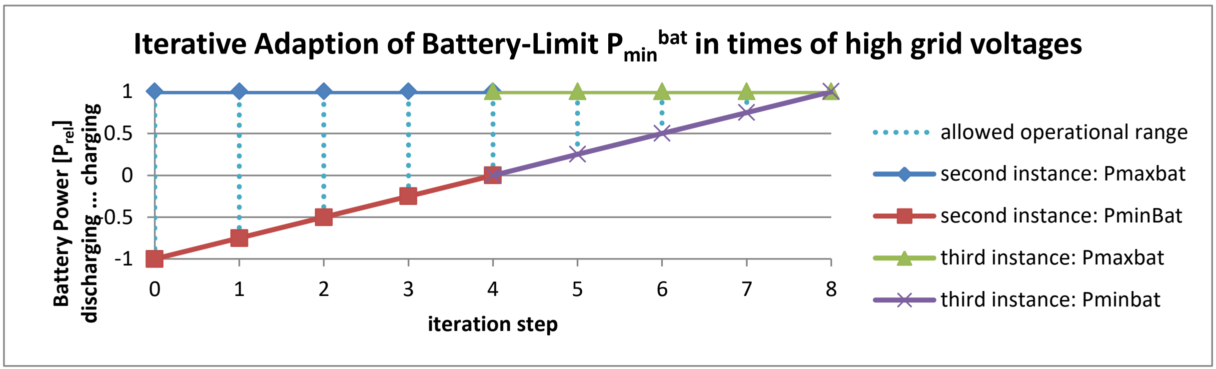


Figure 13: Control approach to iteratively reduce the battery discharging limit as an integration approach for PV-BESS

To parametrise the permissible charging power, a day-ahead weather forecast is provided to the centrally operated grid controller. According to this forecast, the controller calculates a BESS charging limit for all storages in the grid for each day in the morning (meaning that BESS charging is limited during times of good weather forecasts and battery charging remains unconstrained during times of bad weather forecasts). This battery charging limit (P_{max}^{bat}) is broadcast to all PV-BESSs in the morning and remains valid for the whole day. This limit is enforced either on a single customer or even a group of aggregated customers (as done in the field trial in Eberstalzell – see Section 2.3.1).

2.2.2 Grid Consumption and Feed-in Limits

Another approach is to limit the consumption and feed-in of PV-BESS, BESS and flexible loads from and to the grid. Compared to the component limitation described in Section 2.2.1, this approach does not target a single component but rather, the feed-in and consumption at the point of common coupling (PCC). Such an approach is already implemented in the German subsidy program for PV-BESS [4]. The advantage of this approach is that local load is taken into consideration automatically. This limit can be either enforced on a single customer or even a group of aggregated customers.

2.2.3 Bidirectional P(U) Function

According to current Austrian interconnection requirements [5], generators in Austria must implement a P(U) to avoid overvoltage. In *leafs* this function was extended for PV-BESS and flexible loads to additionally avoid under voltage. The function scheme for the different components and its integration into a coordinated control scheme are described below.

PV-BESS

A PV-BESS is able to reduce grid feed-in or even actively charge the battery in situations of high voltage. It is also able to reduce the charging power or even actively discharge the battery in times of low voltage. A function implementing all these functional parameters was applied in the field trial in Köstendorf. The specific implementation is as follows: The existing iterative control of the PV-inverter's *Q(U)* characteristic curve in times of high voltage range (developed in the *DG DemoNet Smart LV Grid* project) remains the first control action in times of voltage problems in the grid. In a second step, if the Q(U) control reaches its limits, the active power control is activated: This is also an iterative control shown in Figure 14, where the dead-band of the default P(U) characteristic curve that is configured at all participating systems is reduced to zero step-by-step. This control process can be applied to BESS to force charging in times of high grid voltages and force discharging in times of low grid voltages.

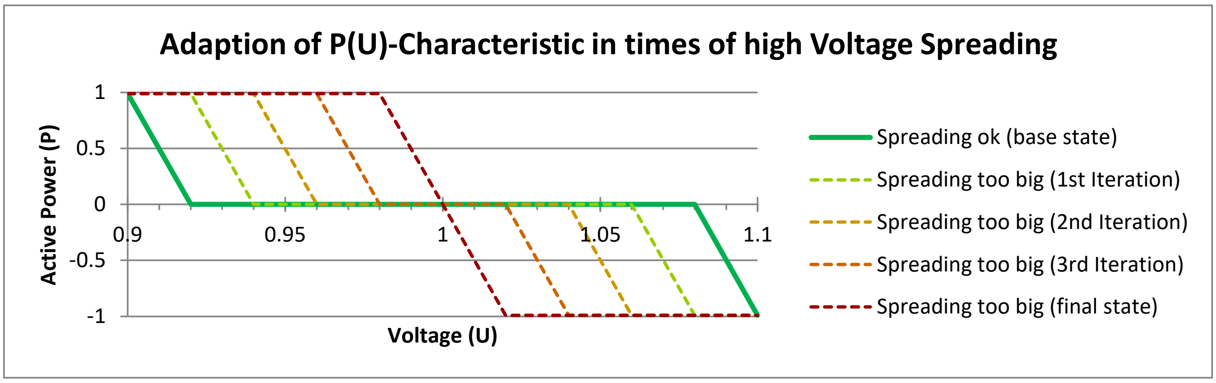


Figure 14: Control approach to iteratively reduce the dead-band of the P(U) characteristic as integration approach for PV-BESS

Flexible loads

In a case of high penetration of flexible components in certain feeders, boundary conditions might be violated in the future due to the high simultaneity of the single components' behaviour. Basic solutions like *P(U)* for under voltage do exist, however, clear boundary conditions on how to implement and use them are not available in the current regulatory framework (see also Section 3.3). A corresponding P(U) function as defined above was applied to controllable loads to offer operational flexibility. In this sense, the characteristic curve is applied in a way that consumption is suggested in the region of the negative slope (in times of high grid voltages) and obviated in the region of the positive slope (in times of low grid voltages) while in the dead-band region the controllable load can operate freely and unconstrained.

A P(U) characteristic for EVs was evaluated in *leafs* in extensive simulations. The charging station measures the local voltage and reduces the charging power when a certain voltage threshold is reached. In this case the EVs start to reduce the charging power at 94 % of the nominal voltage and limits to 6 A at 90 % of the nominal voltage, below 90 % charging is switched off.

2.2.4 Dynamic Voltage Control Function

For larger ESS, where one system has a visible impact on the local grid, a dynamic voltage control function was developed. This is a third possibility in addition to static or dynamic setting of characteristic curves or operational windows to implement a specific and dynamic control as grid integration approach. Such a controller sets the active and reactive power behaviour of the BESS inverter based on an individually adaptable control strategy. The framework conditions and operational requirements for such a controller dependfist on the individual requirements of the storage behaviour and the underlying control as well as the impact of the system onto the local grid. The voltage control scheme has the following characteristics:

- **Controller cycle**: An update cycle of 20 seconds was implemented. The controller measures the voltage for 14 seconds and then updates the reactive and active power setpoints accordingly. Thereafter, the controller waits for 6 seconds before it starts measuring the voltage again as the BESS needs about this time to reach the desired setpoints.
- **Steady state control**: As a consequence of the 20 seconds control cycle, voltage flicker and voltage transients are not controlled because the purpose of the control is a smooth and slow voltage control.
- **Impact estimation**: The controller accounts for its own impact on the grid. For that, the local grid impedance was calculated and implemented in the voltage control scheme.
- **Voltage control in two stages**: The controller starts with reactive power control. When this first step is insufficient, the controller starts to charge or discharge the battery.
- **Bidirectional control**: The controller implements voltage control for over and under voltage problems.
- **Dead band**: The voltage control is activated only when the given voltage limits are violated. As long as the voltage is within the dead-band between the voltage limits, voltage control is completely inactive.
- **Subordinate controls**: The controller tries to realise the active power set values given by the subordinate controls for self-consumption and market participation with reactive power control if the realisation of the active power set value would cause voltage violation. If reactive power control is not sufficient, the voltage controller curtails the subordinate controls.
- **Standby loss optimisation**: If grid voltages are visibly within limits, and the active power set value of the subordinate controls is small enough, the controller sets the whole BESS into standby mode to reduce inverter standby losses. At the end of the 15-minute metering time interval, the controller reactivates the BESS and provides the accumulated energy demand of the subordinate controls with a high active power set value to recover the energy not provided during standby.

2.3 Field Trial Description

As described in the introduction, the four flexibility activation concepts developed in the project were validated in different field trials. Each of the participating three DSOs provided one or more field trial locations suitable for testing. Table 4 gives an overview of the developed flexibility activation concepts and functions implemented for grid and market application for each of the individual field trial regions. Due to the different hardware setups and system configurations, each field trial site followed a different integration approach unique to its situation. The following sections describe in more detail the integration approach of the individual field trial sites.

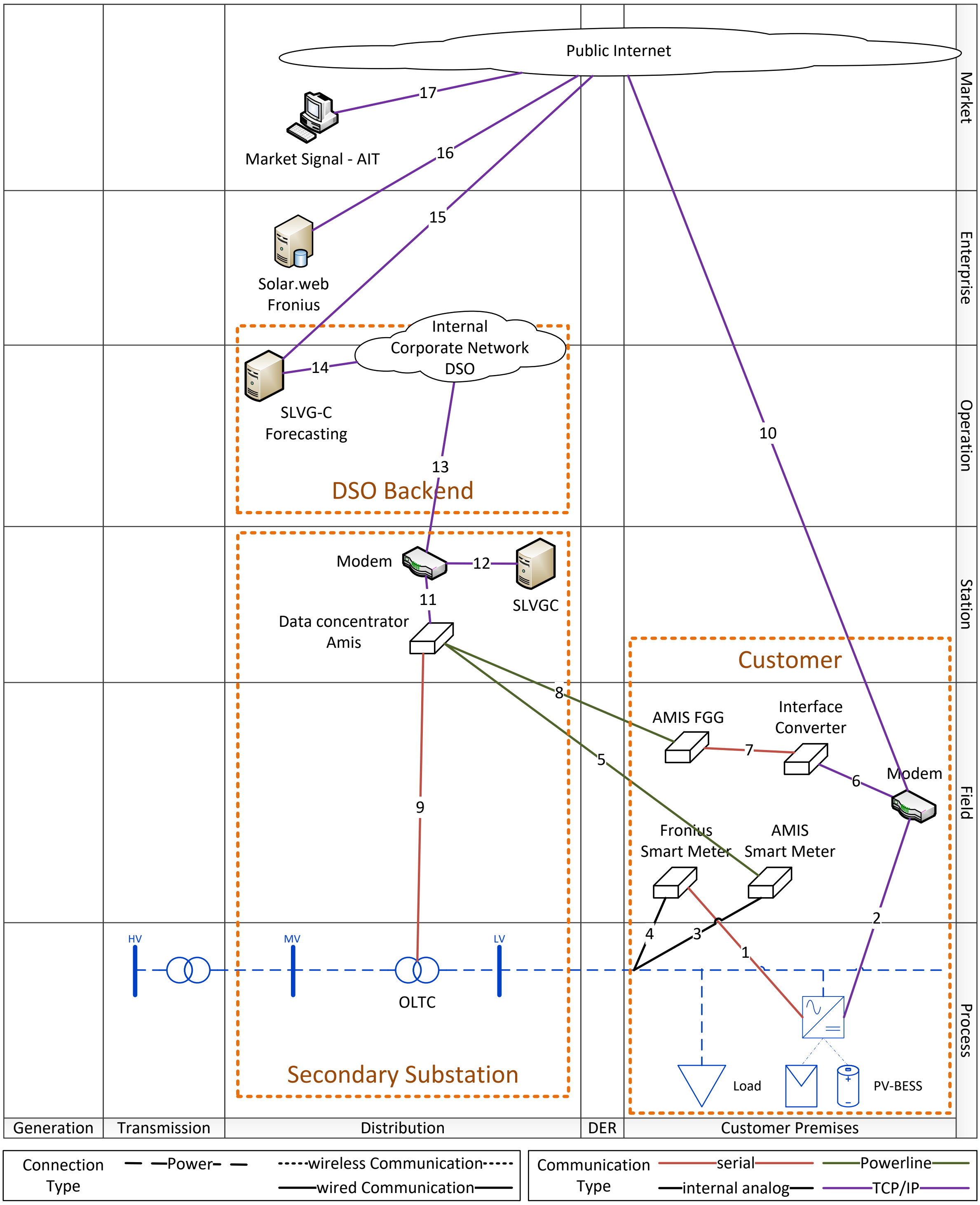
Table 4: Overview and comparison of local field trial implementations based on the different flexibility activation concepts

Flexibility activation concept	Separate control of customer assets	Combined control of customer assets	Combined control of utility assets	Monetary incentive	
				without active control of customer assets	extension with active control of customer assets
Field trial site	Eberstalzell & Littring	Köstendorf	Heimschuh	Eberstalzell	Eberstalzell
Flexible Component	PV-BESS	Customer Energy Management System and PV-BESS	Central BESS	No direct control of components	Domestic Hot Water Boilers
Grid integration approach (see Section 2.2)	$X\%_{DYN}$	$P(U)_{DYN}$	Q(U) + P(U)	Incentive to reduce ($P_{soll} >> P_{ist}$) in times of high local generation	$P_{on/off}$
Market Signal Provision	Third Party (in this case over *Fronius Solar.web*)	DSO (SNG) – not as market player but as an infrastructure provider	DSO (ENS) – not as market player but as an infrastructure provider for communications and controls	None	None

2.3.1 PV-Battery Energy Storage Systems in Eberstalzell

The direct access to flexible loads and ESS is analysed in this activity. Reduced bandwidth of communication with narrow band power line communications was of specific interest in this field trial. With that, no additional communication infrastructure was required. The PV-BESS is directly accessible by the DSO but is owned by the end customer.

The local DSO (*Netz Oberösterreich GmbH*) communicates with the PV-BESS over power line communication (PLC). The main limitation of this communication is a limited bandwidth. The flexibility activation concept is chosen based on these limitations. In this case, an operational window of the PV-BESS is set by defining the allowed maximum battery charging limit based on local weather forecasts (see Section 2.2.1 for details). The market signal is not provided by the DSO but by a third party. Thus, the PV-BESS receives the market signal over the cloud service called *Fronius Solar.web*. The market signal takes the local limitation given by the DSO into consideration. The setup, in the sense of a market signal provided by a third party, is expected to occur in the future as system manufacturers currently have facilities and infrastructure to control their systems remotely. The complete setup is visualized in Figure 15.



1, 7, 9…ModBUS RTU
2, 6…MobBUS TCP SunSpec
3, 4…Internal measurement signal
5, 8…Powerline DLC CX1
2, 10, 16, 17…REST Service
11, 12…IEC 60870-5-104
13, 14, 15…HTTP

Figure 15: Field trial setup in Eberstalzell/Littring visualized in the Smart Grid Architecture Model (SGAM)

For the field trials with PV-BESS in Eberstalzell and Littring the following preparations were necessary:

- **Smart meter rollout**: A smart meter rollout was conducted in the complete area to measure all customers accordingly (see also Section 2.3.4).
- **Power quality measurements**: In all substations additional measurement infrastructure for power flow measurements was installed.
- **Communication infrastructure**: For the communication of the single components itself only the modification of the *Modbus* protocol implemented in the AMIS components had been necessary.
- **Component interfaces**: An interface to the PV-BESS was implemented communicating via PLC on the one side and via *ModBus SunSpec* (see also Section 1.5.2) on the other side. A gateway was developed and implemented for this test.

Three residential PV-BESS were installed at the customer premises in Eberstalzell. The customers were pre-selected by *Netz Oberösterreich GmbH* based on calculations where the PV-BESS would create a corresponding leverage in self-consumption.

Figure 16: Implemented PV system together with the PV-BESS at the customer premise

The function described in Section 2.2.1 was implemented in the local grid controller (SLVG-C). To establish a dynamic reactive power droop control functionality, the set values calculated at the central SLVG-C have to be transmitted via PLC to the PV inverters in the grid and implemented by the inverters.

To demonstrate the overall feasibility of the system architecture, it was decided to introduce a four-day-schedule that is permanently repeated. In this four-day-schedule, a different operational strategy was active for the whole day, so every four days the same operational strategy becomes active. This daily mixing of operation strategies assures that the operational strategies are equally in operation and experience all typical grid conditions depending on season, weather and day of the week (working day or weekend).

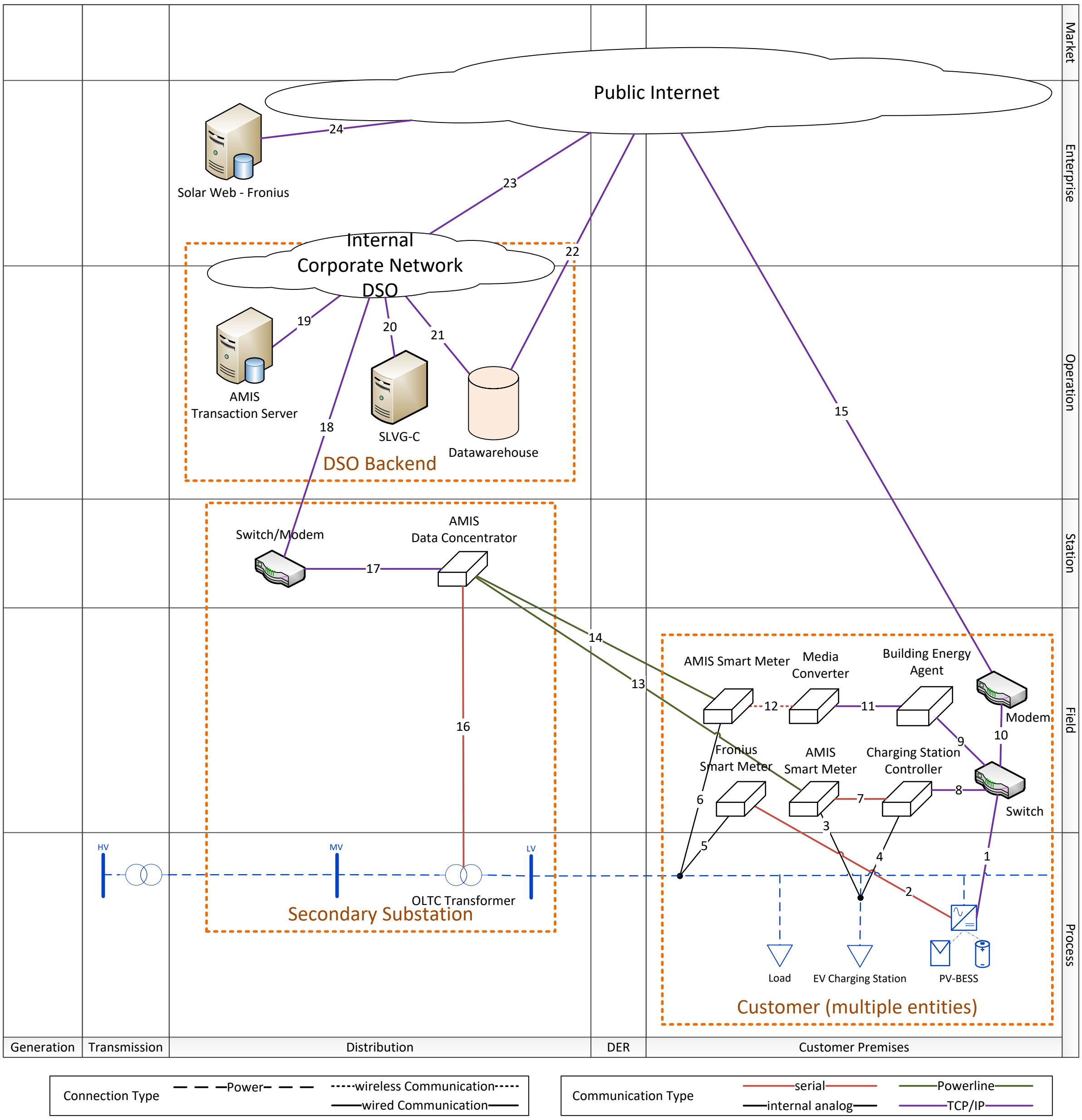
2.3.2 PV-Battery Energy Storage Köstendorf

The aggregation of flexible components and provision of flexibility through a costumer energy management system (CEMS) was validated in a field trial in Köstendorf (*Salzburg Netz GmbH*). In this case, the local DSO assumes the role of the aggregator and provides both the market signal and the setpoints for the local voltage control. The DSO does not act as a market participant but as an infrastructure operator who provides communication and control infrastructure. Broadband communication is used to communicate with the Building Energy Agent (BEA), a CEMS, which is installed in each participating household as interface to the flexibility resources. The BEA controls both the PV-BESS and the EVs in those households. With this setup, the operational window is restricted dynamically depending on the local $P(U)_{DYN}$ (see Section 2.2.3 for details). The functionality was implemented in the CEMS which distributes the limitations between the PV-BESS and the EVs. Given the current developments, this is a probable configuration in the future.

The DSO has no direct connection to individual components in the building (customer premise according to SGAM) and communicates only with the CEMS (in this case the BEA). The home automation system automatically coordinates the operation of a small pool of flexible components (e.g. one PV-BESS and one EV) and schedules the provision for flexibility. The communication infrastructure relies on broad band communication which allows fast control of single entities. Figure 18 shows the setup of the field trial site in Köstendorf including the setup of the central controller.

Five PV-BESSs were installed in 2014 (see **Fehler! Verweisquelle konnte nicht gefunden werden.** for an example) and the participants received a compensation for their availability for testing throughout the project (for the duration of the project, they were allowed to make use of the e-mobility for free and received a one-time subsidy payment for the PV-BESS). Additionally, flexible loads e.g. e-mobility rolled out during the preceding project *DG DemoNet Smart LV Grid* and made available with small adaptions of the intelligent charging stations (project participants received them at a reduced price as a compensation for any negative effects).

Figure 17 PV-BESS installed in Köstendorf



1, 9…MobBUS TCP SunSpec
2, 16…ModBUS RTU
3, 4, 5, 6…Internal measurement signal
7…IR-probe 1107 (EN61107)
8…LS Public x3.0

1, 10, 15, 24…REST Service
11…M-Bus
12…w-M-Bus
13, 14…Powerline DLC CX1
17, 18, 19, 20… IEC 60870-5-104
21, 22, 23…HTTP

Figure 18: Field trial setup in Köstendorf visualized in SGAM

Data belonging to project participants is transferred via the BEA situated in a non-controllable environment within the household of the customers. Figure 19 shows how data is transferred to and from the SLVG-C. To secure this data transmission and allow individual communication and characteristics with every BEA, the protocol XMPP is used in its own network segment for transmitting the data to a centralised server. This centralised server further transfers the data to the database using a REST-service.

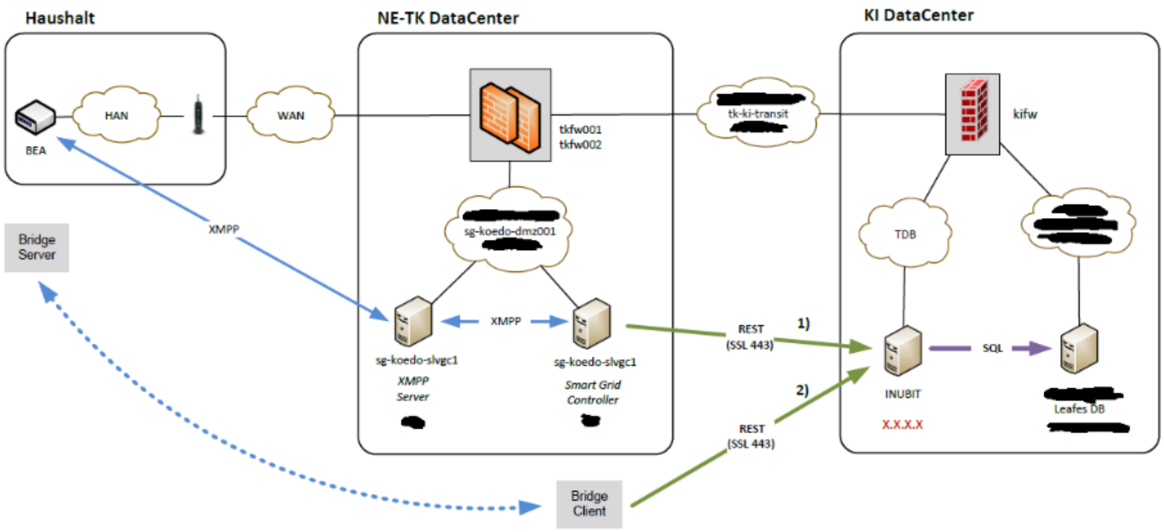


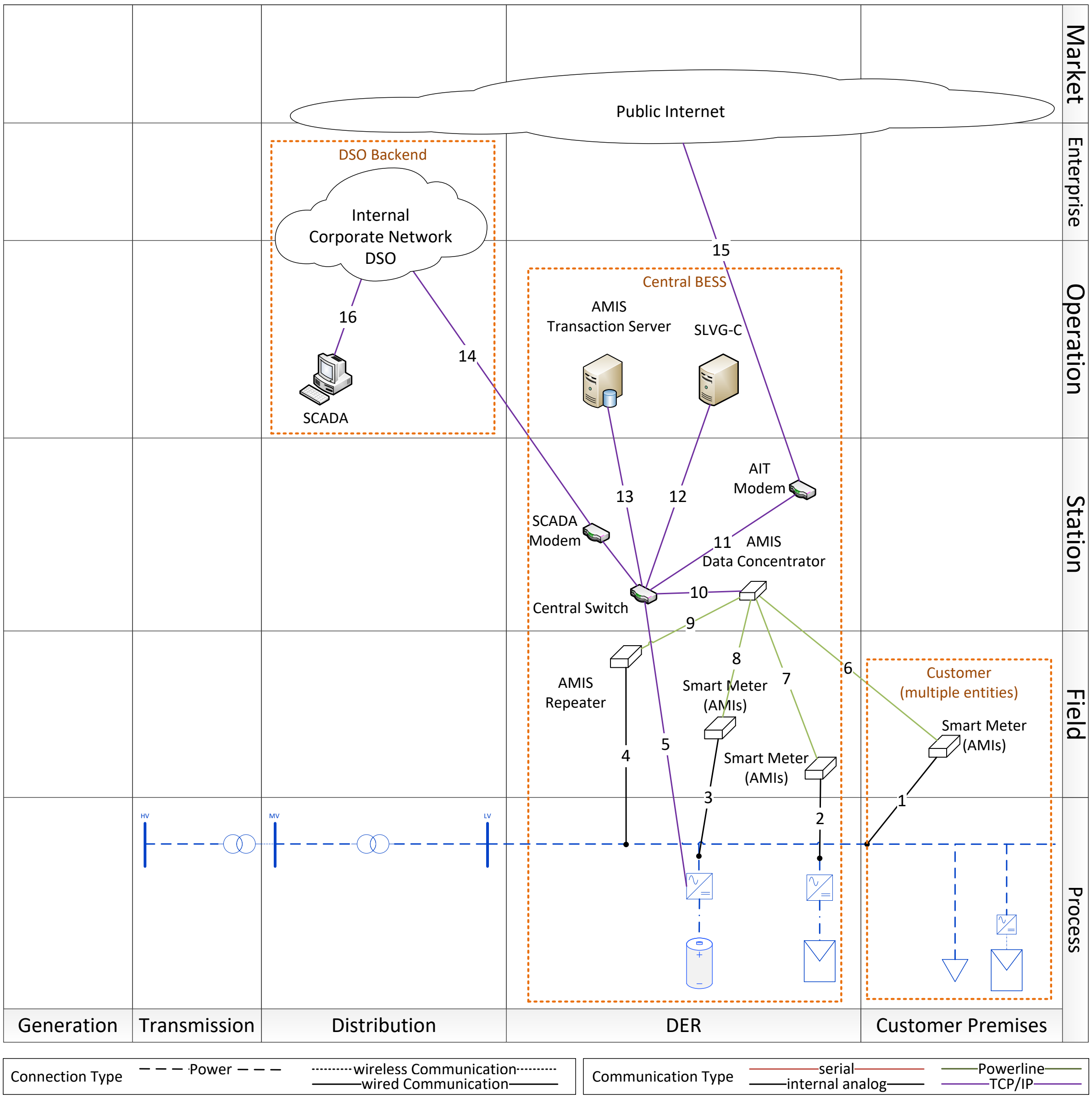
Figure 19: Secure Data transmission via XMPP

Additional measurement infrastructure for the system analysis was installed. The central component for collecting data is an upgraded smart meter. While a standard unit is only able to collect and transmit measurement data every 15 minutes, the upgraded version used in Köstendorf was able to collect and transmit measurement data of voltage, as well as active and reactive power in the form of 2.5-minute mean values. This allows a more detailed analysis concerning the impact of a high penetration rate of e-mobility and using flexible loads in combination with ESS.

2.3.3 Central Battery Energy Storage System

A central BESS with a nominal power of 100 kW was installed in the grid of Heimschuh (*Energienetze Steiermark GmbH*). The system is operated as a community storage system for multiple end customers connected in the local grid and implements an active voltage controller. Additional system services or market participation was made possible through remote control capabilities.

The testbed in Heimschuh covered one low voltage feeder supplying several customers. Six ff these customers agreed to participate in the field trial. The feeder is connected to a secondary substation with independent voltage regulation via OLTC connected to the bus bar. The BESS is installed at a critical node in the grid so that it is able to provide additional active grid support. The BESS itself is built in a modular way and was acquired by the DSO at the beginning of the project. The schemata of the whole setup can be seen in Figure 20.



1, 2, 3, 4…Internal measurement signal
5…ModBUS TCP
6, 7, 8, 9…Powerline DLC CX1
10, 12, 13…IEC 60870-5-104
11, 15…HTTP
14, 15…IEC 60740-5-101

Figure 20: Heimschuh System architecture visualized in SGAM

The central BESS needs to collect generation and consumption patterns from all participating customers online in order to provide the virtual home storage service and generate the power setpoint. For that, no special equipment at customer level was needed – a smart meter that is polled regularly was sufficient. Basic measurement values are generated by the local smart meters and transmitted via PLC. Therefore, a real-time control approach is not possible, since it takes up to one minute for all data to be transmitted. However, field test experiences proved that a real-time approach is not necessary, since the error caused by the time delay of the averaging and transmission of the measurement values is negligible. Nevertheless, significant efforts were made to achieve a relatively fast and reliable communication over PLC to optimise control quality.

The control algorithm considers local consumption of PV, voltage control and market participation and was tested over a period of 18 months in the field. An overview of the controller is given in Figure 21.

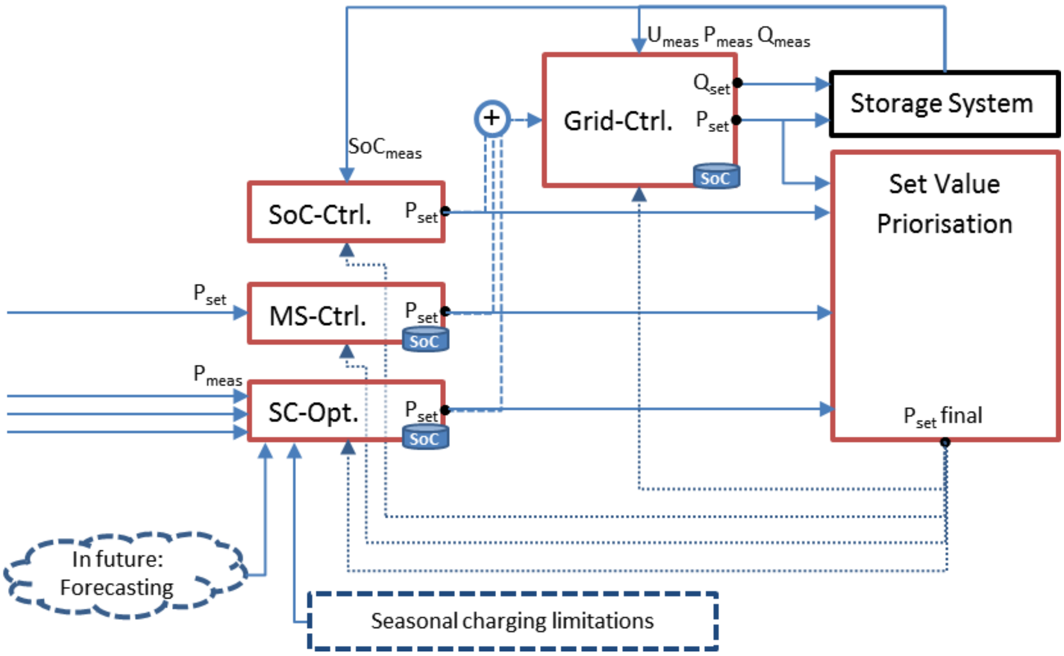


Figure 21: Schematic component diagram from the battery controller in Heimschuh

Due to its nominal power and the position in the grid (i.e. at the end of a LV feeder) the central BESS has a significant impact on the local voltage level. Therefore, it is not sufficient to use voltage control approaches as implemented for PV-BESS. The BESS control implements a dynamic voltage control approach including both reactive (*Q(U)*) and active power (*P(U)*) control (see Section 2.2.4 for details). Simultaneously, this voltage control provides the limitation of the operational window of the BESS.

Significant attention was given to the internal State of Charge (SoC) calculation of the individual customers as well as the consideration for the losses generated by the BESS. Additionally, it has been considered that the SoC of a BESS is a calculated value which might suddenly jump due to BESS-internal estimation errors.

For the housing of the central BESS, a so-called Urban Box was used which is depicted in Figure 22. This is a wooden box which was designed for multipurpose applications.

Figure 22: Installation of the UrbanBox for the central storage system

Before implementing the BESS in the field, it was tested in the *AIT SmartEST laboratory*. The BESS showed several faulty behaviours that had to be solved by the BESS manufacturer through several software updates, hardware changes and finally a complete revise in the case of a return of the complete system to the BESS manufacturer. After testing the BESS and the controller unit, the BESS, including the inverter, was moved from the lab facility of AIT in Vienna into the *UrbanBox* in Heimschuh. A festive event was organized at the opening ceremony of the system. This event is depicted in Figure 23 and received considerable media attention. The *UrbanBox* with the entire BESS system installed is depicted in Figure 24.

Figure 23: The festive opening of the Urban Box in Heimschuh

Figure 24: Inside view of the Urban Box: Inverter (left), Battery (centre), controller (right)

The communication with the central control room and the SCADA system of *Energienetze Steiermark GmbH* was implemented so that all changes of the parameters and all outages of the central BESS could be detected remotely. Figure 25 shows the storage system as seen in the control centre of the DSO.

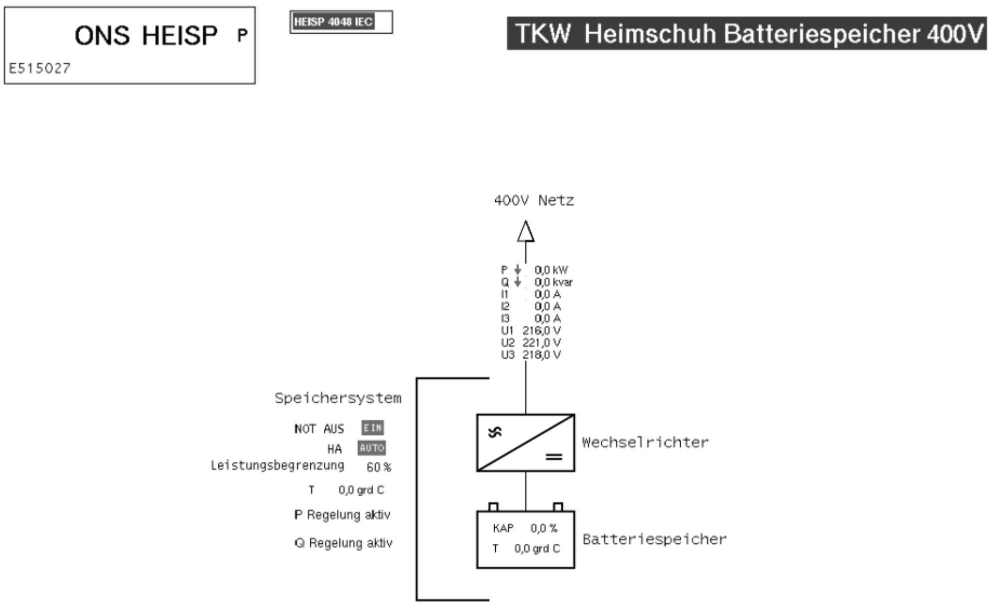


Figure 25 The leafs central BESS as seen in the SCADA of Energienetze Steiermark GmbH

After installation, an open loop operation was carried out as a first step where the controller was used to calculate all the initial setpoints and parameters for the BESS. After the investigation of the results of the open loop control scheme was completed, the closed-loop operation was then initiated during October 2017.

2.3.4 Monetary Incentive for End Customers

One of the main goals of the *leafs* project aimed to quantify the effect of load shifting within the residential sector on the local electricity grid. Previous research in this area was restricted due to the lack of smart metering infrastructure, which was necessary for the continuous monitoring of the effects of load shifting trials or was limited to a very short period and only a few pricing events. Due to these limitations, the trials did not provide a solid empirical basis for investigation of load-shifting potential of households during times of high generation from PV power plants. Eberstalzell was, therefore, an optimal test bed for a load shifting trial, due to the available smart metering infrastructure and high number of residential PV generators.

In this regard, a straightforward research question was formulated: Is there a significant load shifting potential on the household level that can be utilised via financial incentives when the grid is highly stressed? An innovative incentive and bonus scheme, called *Sonnenbonus*, was set up and tested in a 12-month field trial in which 184 households (24.5 % of all households) in Eberstalzell participated. The households which participated in the field trial were offered a bonus of 10 ct/kWh when they adapted their consumption to the current levels of locally generated PV electricity. Throughout the field trial period, a large set of data was collected, including 15-minute load profiles of all participants, as well as demographic data about the households. This data was used to assess the load shifting effect initiated by the *Sonnenbonus*.

The participants downloaded the *SonnenmonitorApp* (see below) and allowed the app to access their smart meter data. The field trial tested the *Sonnenbonus* approach, which sent a message over the *SonnenmonitorApp* to participants stating that during certain times of the following day their electricity price will be reduced by 10 ct/kWh (i.e. the variable part of the grid tariffs at grid level 7 in Eberstalzell). *Sonnenbonus* messages were sent out via an app based on the following criteria, where hour-long time slots would receive the bonus-price discounts if:

I. the average solar irradiation over one hour is predicted to be greater than the threshold of 600 W/m^2 and
II. there are at least two consecutive hours where this threshold is exceeded.

The criteria above were evaluated based on information obtained for weather forecasts. Messages of active bonus times were sent out one day ahead at 16:00 if the weather forecast predicted that the above criteria would be met. This process was completed automatically each day throughout the study period, and thus directly linked a financial incentive for changing household electricity consumption with predicted weather conditions. The algorithms for this weather forecast evaluation were developed using the programming language *Python*. *GreenPocket GmbH* programmed the necessary REST-API[17] that translated the outcome of the *Python* script into a push message that was then automatically sent to the participants.

The first *Sonnenbonus* was sent out on April 11th 2018 and the last *Sonnenbonus* was active on March 31st 2019.

[17] REpresentational State Transfer, Application Programming Interface

End customer App for *Sonnenbonus*

The *SonnenmonitorApp* is based on a product of the German software development company *GreenPocket GmbH*. The basic set-up and functionalities of the app were extended in the Horizon 2020 project *PEAKapp*[18], which is coordinated by *Energieinstitut at the Johannes Kepler University Linz* and which had been tested together with *Energie AG OÖ* in this project. A major aspect of the *PEAKapp* field trial was integrating the app in the *Energie AG OÖ* internal system and to achieve the high standard of security and safety that *Energie AG OÖ* demands from all external software products.

Using the existing app was therefore a feasible solution. As the *PEAKapp* project had a different research scope than *leafs*, several adaptions were necessary. Firstly, the app was branded to match the cooperate identity of *Netz Oberösterreich GmbH*, such that the delivery of *Sonnenbonus* messages could be displayed via push notifications. These notifications show the user an overview of their account status based on a history of *Sonnenbonus* compliance. Thus, a history of *Sonnenbonus* usage and the accumulative costs savings achieved by the user is clearly shown. Thirdly, the automatic algorithm and the REST-API were developed, programmed and integrated into the app system. Finally, an instruction video was made and uploaded to *Youtube*[19] to assist the field trial participants and demonstrate the functionalities the app has to offer.

The *SonnenmonitorApp* not only displays the *Sonnenbonus* messages but also shows daily, weekly, monthly and yearly electricity consumption for all meters installed, several benchmarks and included a serious game in which the users collected points[20] based on how accurately they predicted their electricity consumption for the next day. The most relevant visualisations and notifications are shown in Figure 26.

[18] GA #695945

[19] https://bit.ly/2Vyfzol

[20] During the field test, the collected points had no other function than to show the user his or her own increase or decrease in prediction accuracy. In future applications, these points could be used to e.g. trade them for customer loyalty products

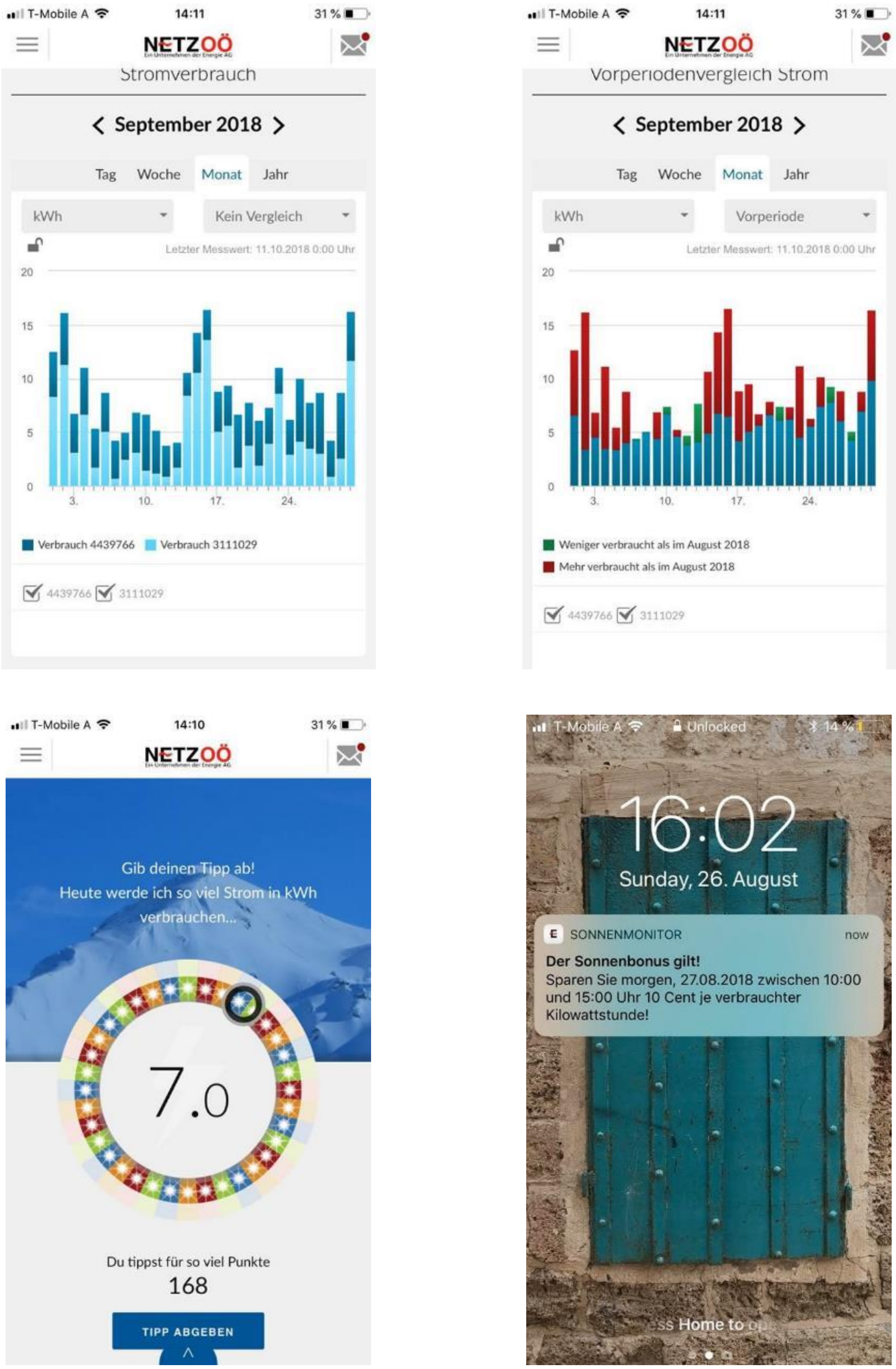


Figure 26: Example pages of the SonnenmonitorApp, the household's daily electricity consumption in one month (the different colours represent different meter in the household) (upper left) and comparison of consumption between two consecutive months (upper right) (here September 2018 values are compared with August 2018 values), the game, in which users made a bet on their next day consumption and gained points for accuracy (lower left), push notification showing the Sonnenbonus time slot (lower right)

Energiemonitor Eberstalzell

To inform customers about the project and the ongoing field trials, an information monitor (*Energiemonitor Eberstalzell*) was developed, prepared and coordinated with the municipal administration. Additional communication and information measures to inform the citizens of Eberstalzell were developed. The *Energiemonitor Eberstalzell* (see Figure 27 and Figure 28) shows the electricity demand and the solar electricity locally generated by PV systems in the whole community area of Eberstalzell. The raw data of the area's power demand is collected from each transformer station on a daily basis. To get the amount of solar electricity generated, a PV test plant is used to determine the current utilisation ratio of all PV plants in the area.

Figure 27: Energiemonitor Eberstalzell - Dashboard view

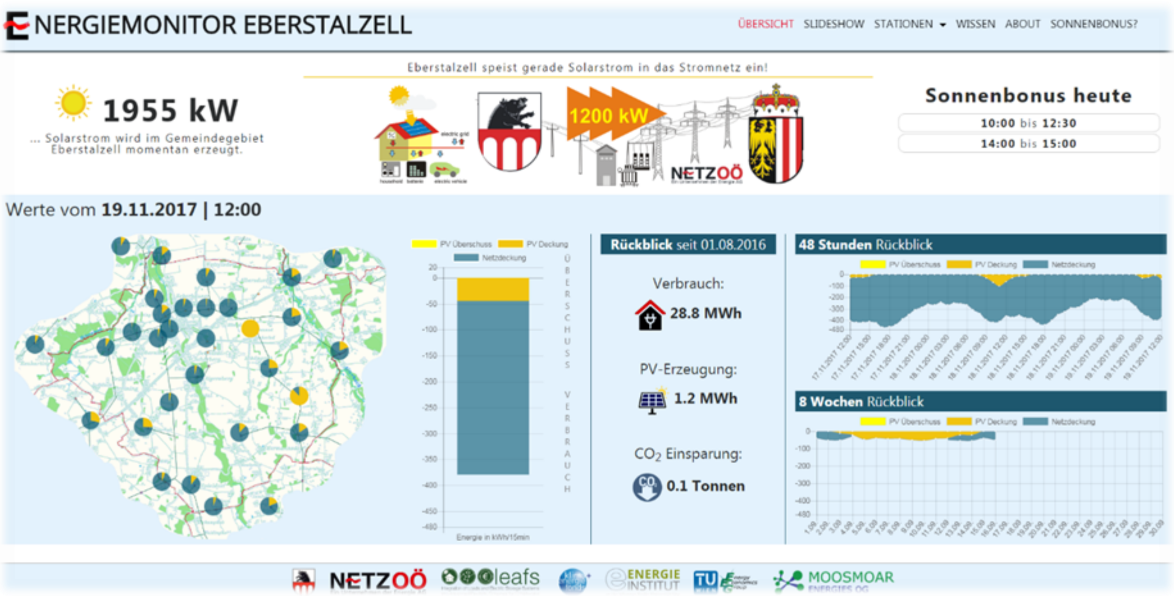


Figure 28: Energiemonitor Eberstalzell - Transformer station view

2.3.5 Advanced Ripple Control Tests

In order to achieve a balanced load and thus an efficient operation of the electricity grids, possibilities are sought to shift loads between the times of day without negatively affecting the comfort of the respective household. For this reason, two distinct field trials were carried out.

Ripple Control Adaption based on existing Systems

An attempt was made in November and December 2017 in some households of the city of Steyr to shift electrical loads from night time to day time by means of ripple control signals. To this end, the charging behaviour of selected households with electric hot water boilers was adjusted such that that they were supplied with electricity between 15:00 and 16:00 in addition to the agreed night-time electricity times from 02:00 to 06:00. This means that the hot water boilers of the selected households were given the opportunity to recharge to their pre-set target temperature between 15:00 and 16:00 on an off-routine basis. This additional charging time in the afternoon results in the fundamental possibility of automatically shifting the electrical load from night hours to day hours, but this can only be done to a relevant extent if the temperature in the boiler at 15:00 is sufficiently below the target value to be able to absorb required amounts of energy.
Before the set up was implemented in the system, several preparatory measures had to be implemented in the operating system. The most time consuming of these measures was the adaption of the smart metering system. For the standard use of the existing ripple control system, no broadcast commands for delimited subgroups of certain meters are implemented (specified switchgear of one switch group). However, such an adaption would be required, not just in the smart metering system but also in the billing system (prevalent SAP). To avoid complications generated by such an adaption, the trial set up was not done with an automatic ripple control signal but via manual switching.

***Sonnenbonus* Extension with Ripple-Control**

As customers do not have the possibility to change the behaviour of large flexible loads, the *Sonnenbonus* test was extended to switch flexible loads automatically with the existing ripple control system. Electrical loads with an interruptible tariff have a load switching device LSG (Lastschaltgerät). To switch these loads automatically – with an approval of the customers – it was necessary to develop software, which is able to operate automatically the relay of the LSG for these interruptible loads during the timeframe of the *Sonnenbonus*. Therefore, no customer interaction is necessary and larger flexible loads can be activated when required.
For the grid operator, the key premise was that the customer does not experience any reduction of comfort during this field trail. To guarantee this, the hot water boiler was also recharged during the normal operating hours between 22:00 and 06:00. After the field trial the interruptible tariff with the normal switching times was re-activated.
A software program was written by *Netz Oberösterreich GmbH* to switch on domestic hot water boilers in times when the *Sonnenbonus* was available. The program was implemented, and a trial carried out during the first months of 2019 in Eberstalzell.

3 Results and Conclusions

The following sections describe the results produced by the project based on the activities described in Chapter 2. The description of the results is divided into technical, economic, regulatory and socio-economic aspects. The reason for the adopted structure is due to the synergies/similarities between the individual field trials and flexibility activation concepts assessed in the project. Figure 29 summarizes the main groups of results divided into the for defined categories

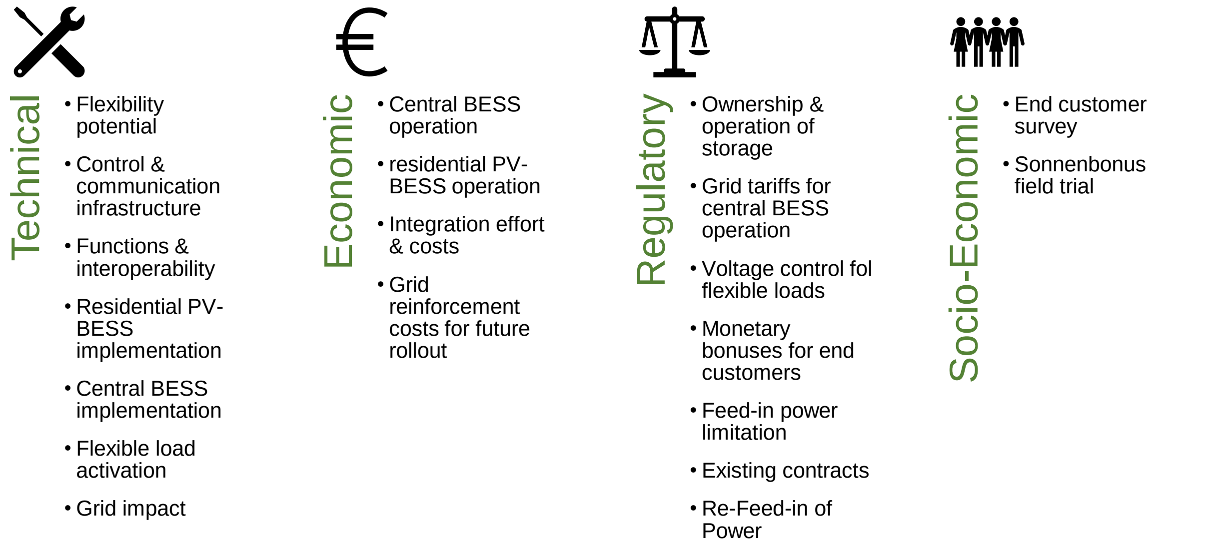


Figure 29: Overview of main result groups in the project

3.1 Technical Results

The following section summarises the results from a technical perspective. This includes relevant technical developments, assessments and technical simulations. The results incorporate a wide variety of various areas which include an assessment of the technical flexibility potential, the communication and control infrastructure, to the single components to and an assessment of the grid impact.

3.1.1 Flexibility Potential

As described in Section 1.5.7, the potential of flexibility of relevant components was analysed. In this analysis, existing flexible loads and residential PV-BESS were considered.

Flexible Loads

Up to 20% of the metering points of the participating DSOs in the LV grids are flexible loads with an interruptible grid tariff. Additional flexible loads which exist, but do not have a separate metering point, are not documented by the DSOs. Flexible loads include a variety of components and different tariff models. The most relevant components which see a flexibility-related grid tariff are domestic hot water boilers and heat pumps. Investigations and practical switching tests at certain substations (as described in Section 1.5.7) showed a technically accessible flexibility potential of about 130 MW in the supply area of *Netz Oberösterreich GmbH* and 179 – 236 MW in the supply area of *Energienetze Steiermark GmbH*. Seasonal variations exist due to different usage patterns of the flexible loads (thermal demand). The existing technical flexibility potential in Upper Austria equates to approximately 60% of the PV capacity installed and 7% of the peak load. An increase of this share in the future, driven by a further electrification of thermal loads and EVs, is expected.

The geographic distribution of flexible loads in the supply area of *Netz Oberösterreich GmbH* is given in Figure 30 which shows the theoretical flexibility potential represented by honeycombs of a diameter of 5 km. For honeycombs marked in grey, no customer data for flexible loads was available. The obtained representation clearly reflects the geographical situation in Upper Austria's supply area. In particular, the southern region is strongly characterised by rural and sparsely populated regions, alpine landscape and therefore a large area exhibits no flexibility potential. The majority of high potential honeycombs relate to urban areas such as Steyr, Schärding, Gmunden and Vöcklabruck. The supply areas of non-participating DSOs (Linz, Wels and Ried) are represented by uncoloured honeycombs and is included for indicative purposes.

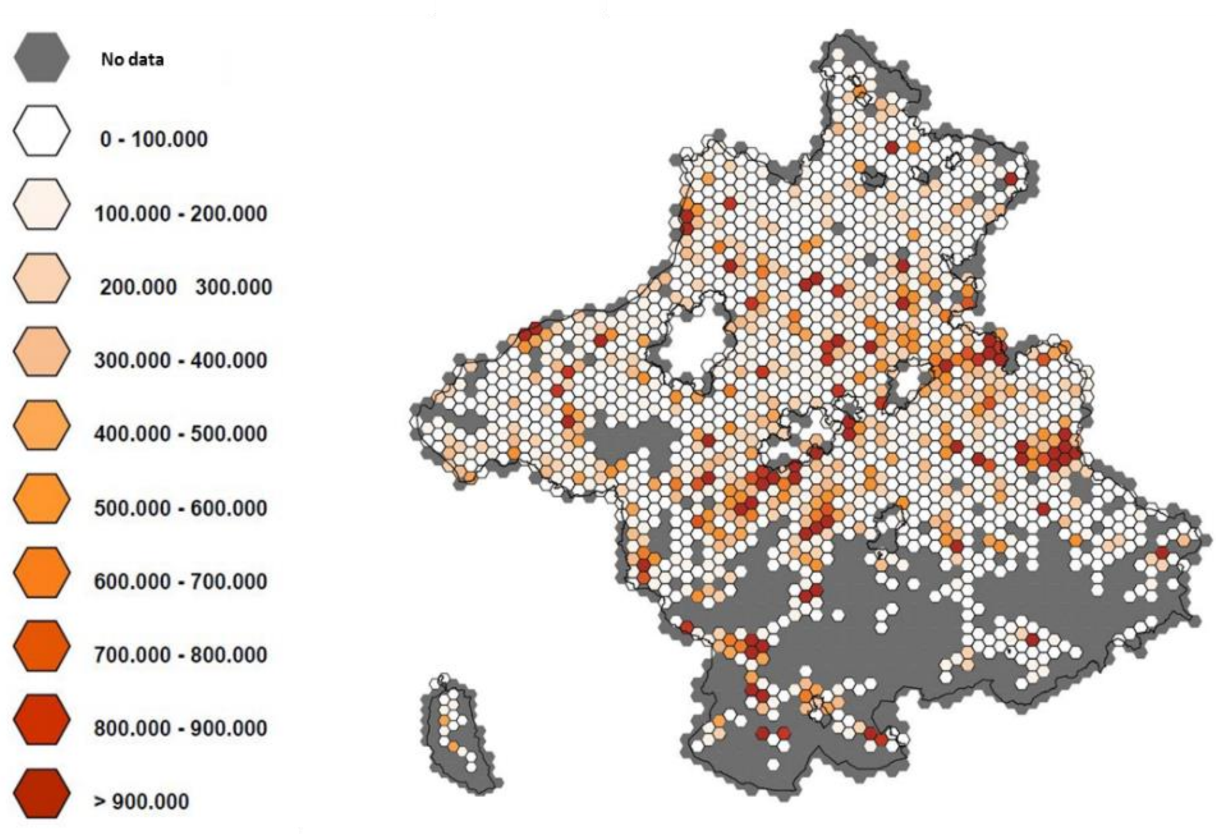


Figure 30: Annual flexibility potential in [kWh] in the supply area of Netz Oberösterreich GmbH

The flexibility potential is not only theoretical, since it has been proven to be achievable over the existing ripple control infrastructure. However, this achieved flexibility potential is based on the maximum value which realistically cannot be sustained for long durations of time. The results are based on switching tests conducted between 22:00 – 06:00 on one workday in April in Upper Austria and consider mainly storage water heaters and storage heating systems.

A mathematical equation representing the power decay of flexible load behaviour for the selected switching group (in this case hot water boilers which are activated between 02:00 and 06:00 – or also called the 4h-group) was defined using the measurements obtained from the networks in Upper Austria. The validation of the calculated decay curves was made by carrying out a ripple control experiment for this specific customer group as given in Figure 31. During this field experiment, customers assigned to the selected 4h-group were alternately switched on and off by modifying the relevant ripple control signal.

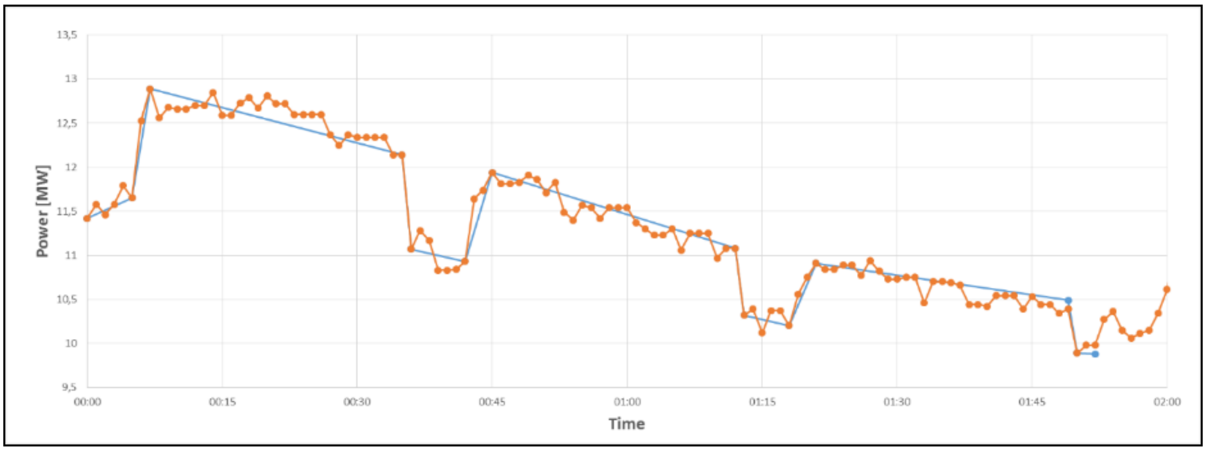


Figure 31: Step-response ripple control experiment for primary substation Ranna

There are limitations regarding the activation of this flexibility potential. First, the customer's comfort should not be reduced, and the basic application not disturbed (e.g. provision of hot water). Second, there might be limitations due to existing regulatory/constitutional rights of customers which prohibit the DSO from activating the flexible loads at different times than in the past (see Section 3.3.7). Furthermore, the impact of activating these flexibilities on the LV grids has to be assessed. This is due to the fact that it is possible that the peak power in certain LV grids may increase due to simultaneous switching of these additional loads (see Section 3.1.7). Additionally, the energy suppliers are required to be informed about the additional switching so that they are able to adapt their balance group forecasts accordingly.

Residential PV-BESS

The analysis of 51 installed residential PV-BESS (see Section 1.5.7) showed that such systems are discharged to their operational minimum values between 25 % and 75 % of their yearly operation. The average time the systems are completely discharged is 45 % but with a strong seasonal variation. Thus, there is scope that these devices could be used for additional operation strategies other than PV self-consumption especially during the winter months from November to February, as well as in the night between 00:00 and 06:00. The overall flexibility potential for residential PV-BESS systems is currently low, since an estimation by the university of applied sciences *FH Technikum Wien* shows there were only approximately 4,000 systems installed in Austria at the end of 2017 [6]. The utilisation of a PV-BESS depends on the load patterns (annual demand, demand profile), generation and the battery capacity. To assess the usability of a specific PV-BESS for additional flexibility provision, an assessment based on historical monitoring data and the system size of each plant is recommended.

Figure 32 and Figure 33 show an example of the utilisation of one selected system. It is clearly shown that the system has the capacity to be used for additional services in the winter months between 00:00 and 7:00.

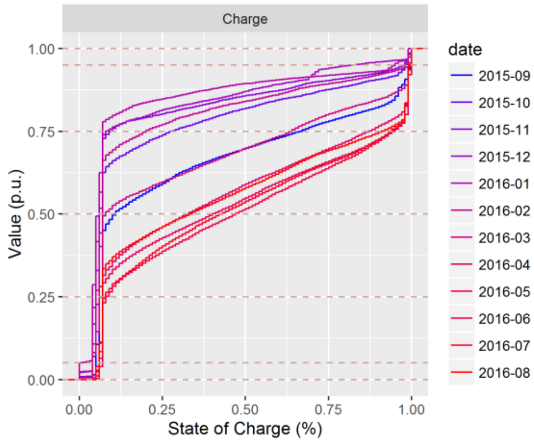


Figure 32: Monthly distribution of the state of charge (SoC) as a load duration curve in p.u. (0-1) of the complete analysis period

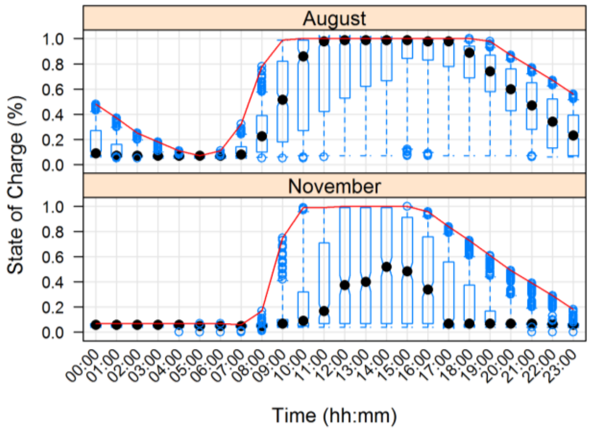


Figure 33: Daily distribution of the state of charge (SoC)

In Figure 34 the probability distribution of the State of Charge (SoC) for a system for each hour per month is shown where each tile represents an hour of the day for each month. The annotations indicate the probability of the PV-BESS being completely discharged. Therefore, the given system can be utilised for additional services (e.g. provision of system services, market-based charging) from October to March from the evening (about 22:00) to the morning without interference of the primary application.

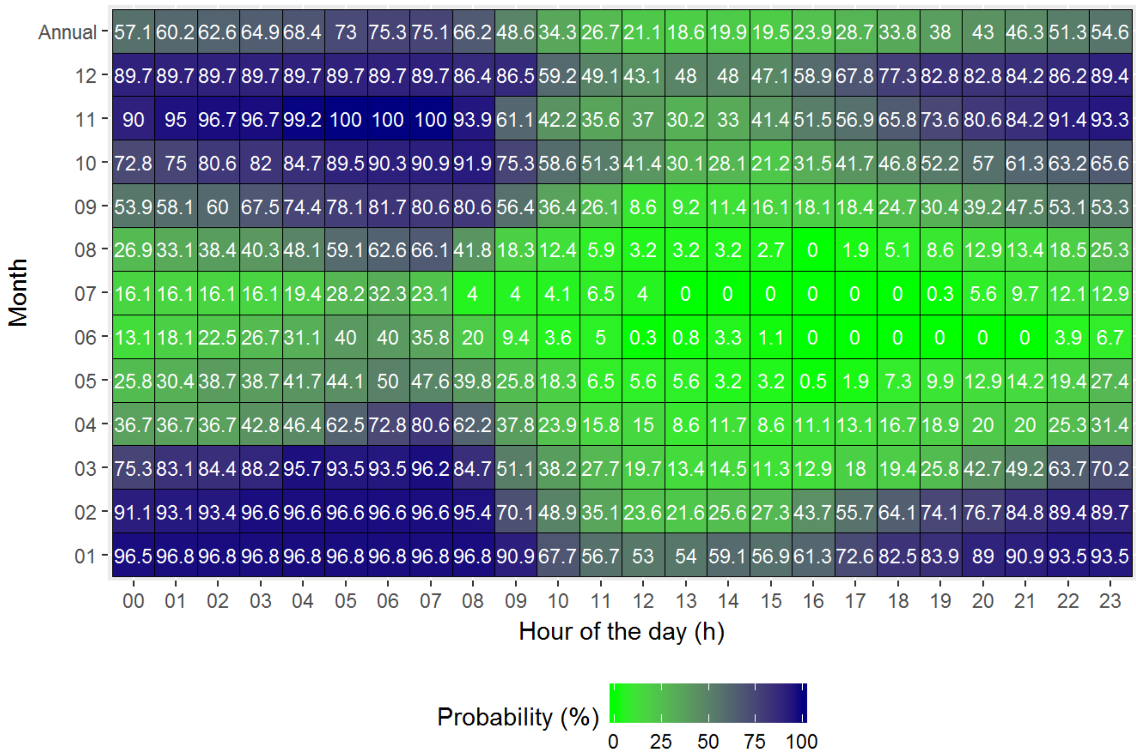


Figure 34: Probability of fully discharged PV-BESS (in hourly/monthly clusters)

Figure 35 shows the annual percentile of complete discharge of all 51 analysed systems. The graph relates the discharge time to the generation power and local demand as well as the battery capacity. The red line represents a relation of annual PV generation and demand of 1:1. Above the line the annual generation is higher than the annual demand and below vice versa. With that it can be seen that the influence of the relation between generation and demand is more significant than the battery capacity. The impact of the battery size on the total discharge time is in some cases visible but not that significant.

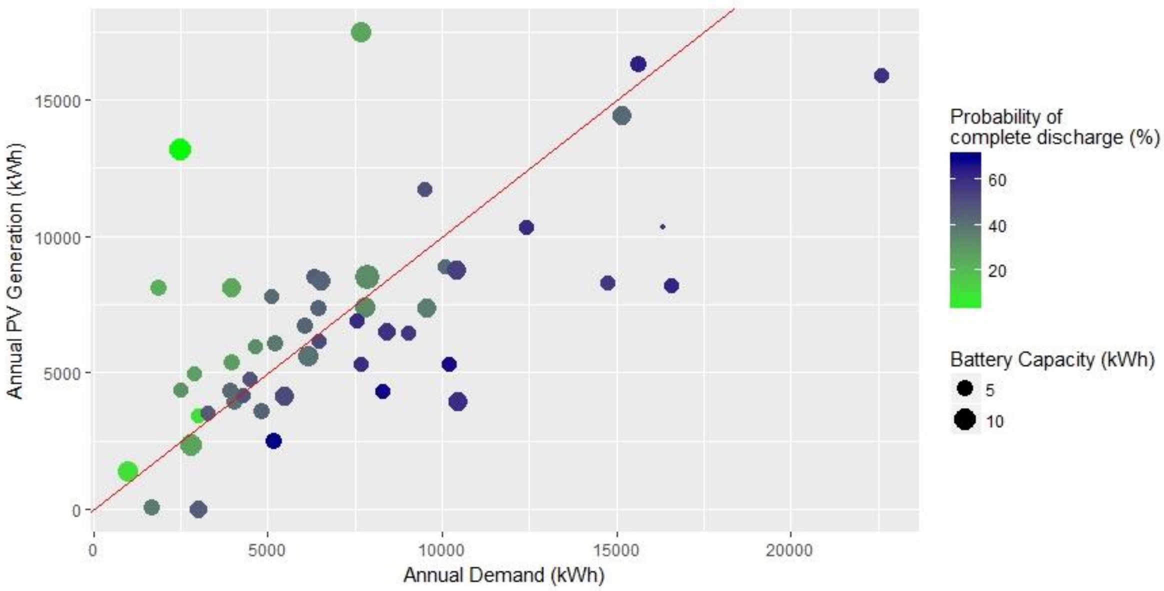


Figure 35: Annual discharge percentile with regard to the PV system size, local demand and battery capacity

3.1.2 Control & Communication Infrastructure

One core aspect of the project was the coordinated and dynamic control of distributed and centralised flexibilities in the LV grid. To achieve such a functionality, it was necessary to implement the corresponding communication and control infrastructure. The following sub sections describe the infrastructure setups investigated in the project. This list claims not to be comprehensive but merely reflects the possibilities and infrastructure of the participating DSOs.

Utilisation of DSO Smart Metering Infrastructure

Activation and operational parametrisation can be achieved through the utilisation of the DSO smart meter infrastructure. Depending on the communication system, bandwidth limitations are evident, as described in Section 3.1.3. This infrastructure allows for different functions and applications:

1. Measurement values for grid control are inherently available through the use of measurements of the individual smart meters.
2. Currently it is possible to execute advanced ripple control mechanisms over the existing Smart Meter system of *Netz Oberösterreich GmbH*. This allows for dedicated activation of flexible loads in the distribution grid.
3. With a corresponding gateway installed at the customer premise, dedicated control commands can be distributed to individual components. This approach was developed in the project *DG DemoNet Smart LV Grid* and extended in *leafs*.

Future developments, such as the *Controllable Local System* (CLS) interface, currently under development in Germany, might increase the role of the smart meter system by incorporating it as the central communication and control device in the distribution grid.

Utilization of DSO IT-Network Infrastructure

If the DSO also functions as an internet service provider, it is possible that this existing infrastructure is used for flexibility activation and grid control. This situation can be found in the supply area of *Salzburg Netz GmbH*. A communication infrastructure was implemented utilizing the local internet network: A *Building Energy Agent* (BEA) was installed in all participating households and is owned and operated by the DSO (see also Section 2.3.2). A separated broadband connection allows for fast and direct communication from the central Smart Low Voltage Grid Controller (SLVG-C) to the individual households and its associated flexible components. However, the infrastructure of the DSO is considered to be critical, hence, it is necessary to apply all security standards of the DSO to the system. The resulting effort in the project was significant which might have an impact on the economic feasibility of such a system without utilizing synergies with other applications. During the project, running 40 setups took approximately 8 man-hours per week. In addition to a high implementation effort, a high level of system reliability is required. This includes low effort of Operations and Maintenance (O&M) as well as longevity. In comparison, a tariff contactor ("Schütz" in German language) has a lifespan of about 10 to 20 years with very low O&M costs. The overall costs for such a system are likely to decrease by reaching a higher technology readiness level (TRL) and implementing the solution into a CEMS.

Utilisation of Third-Party Infrastructure

Flexible components can be also remotely controlled by a third party. This is currently the subject of multiple developments and first products by different system manufacturers in Europe. In *leafs* the *Fronius Solar.web* was used to remotely control the residential PV-BESS in Eberstalzell. With this concept, the direct power control commands in form of a time schedule for the next few hours can be transmitted over the internet which facilitates the *Fronius* infrastructure and interfaces. The field trials in *leafs* were done to simulate the market connection of the system but no grid control was performed over this infrastructure.

As a future alternative to the PLC interface to the BESS at field level, the communication channel between the inverter manufacturer’s cloud system and the BESS could be utilized. A first implementation of such a setup can be found under the current interconnection requirements in California (*Rule 21*). The DSO domain would communicate to this system at server level. Within the project, this channel was utilized for the market domain operation strategies only. It was improved towards commercial maturity, lab tested and successfully deployed to the field test setting. Functional developments included the time scheduling of active (BESS) power. This communication channel could be efficiently utilised for any grid-related or market-based control of the local device (in this case PV-BESS) in future scenarios. However, considerations of cyber security must be taken into consideration and implemented accordingly, as using third party systems to control system components might pose major (cyber-)security risks.

3.1.3 Functions & Interoperability

The project has shown that all flexibility activation concepts can be implemented from a technical perspective (see Section 2.3 for a description of a field trial overview). However, depending on the setup, this activation inherits a significant effort from the DSO side as corresponding interfaces, protocols, components and functions have to be available. The following aspects regarding the control and communication infrastructure were derived in the project.

Component Interoperability

Interoperability between single components must be established: Significant unforeseen effort was caused by communication issues during the implementation of all three field trials. As an example, the protocol (IEC 60870–5–104) between the grid control device (SLVG-C) and the onload tap changer (OLTC) is described.

After the *DG DemoNet Smart LV Grid* project the former OLTCs in Eberstalzell and Littring were replaced with another type from a different manufacturer. The specifications of the communication interface of this new type also contained the IEC 60870–5–104 protocol. Unfortunately, the used protocol stack of the OLTC was not fully implemented according to the standard, causing a nonstandard behaviour in the case of receiving certain data frames from the SLVG-C. Despite the manufacturers attempts to resolve these problems by creating a compliant interface, the nonstandard behaviour persisted. Only after the installation of additional hardware and software components the successful communication between the OLTC and SLVG-C was achieved. Later in the project a replacement of the control component in the OLTC in Littring (Eberstalzell) led to another failure of the communication with the grid controller. Significant effort and several onsite inspections were necessary resolve the problem which was caused by false software configuration, which occurred during the replacement of the control component of the OLTC.

This incident showed that efficient analysis methods and close interoperability between single components from different vendors are currently unavailable. A successful rollout of grid friendly flexibility activation requires efficient analysis tools in order to be cost effective.

Communication Functionality

In Upper Austria, the communication channels used to transmit local measurement values and limitation factors required by the components relating to temporary grid restrictions, was implemented via PLC. In order to achieve this connection, the communication channel used by the existing smart meter system was used. Thus, four different data streams were active on this system:

- **Metering values**: The daily power consumption of all customers is transmitted once per day. This is the core functionality of the metering system which is integrated into the standard operating processes of the DSO.
- **Load profile measurement**: For the *Sonnenbonus* trial the 15-minute load profiles of 192 customers are measured and transmitted once a day to a central database.
- **Advanced Ripple Control System**: Centrally coordinated load and tariff switching via PLC based load switching devices at customer premises for the day-to-day operation of the DSO were active
- **Local control**: Grid supporting functions of PV systems and PV-BESS were set by the SLVG-C (located in the secondary substation) in the two LV distribution grids. Measurement values were transmitted multiple times per day via Express Grid Data Access (EDGA). A broadcast system was implemented to address all components in the grid at the same time.

After activation of the local control to the three additional functionalities, partial loss of communication and problems with data transmission occurred. Significant effort had to be invested to find a solution to run all four services simultaneously. Communication of the SLVG-C had to be limited to day times and the participating components of the field trial.

A conducted analysis to find the source of the problem at hand inherited significant complexity and effort. In a first step, the parametrisation of the four functionalities had to be analysed separately and in conjunction with each other. In a second step, the problem had to be localised in terms of identifying affected system devices (smart meter, data concentrator, SLVG-C, backend database). In a third step the solution had to be defined, developed and implemented. As the problems had been caused by the reduced quality of the physical transmission media “power line”, (high noise levels, high attenuation, changing in the time

domain) the testing of the solution required several optimisation cycles in the field environment.
One of the main findings from these activities was that the extension of the existing infrastructure does require a considerable amount of effort along with the implementation of effective and efficient tools for testing, analysis and fault detection.

3.1.4 Residential PV-BESS Implementation

The project has shown that PV-BESS can be used to provide both market and grid services. As described in Section 3.1.2, existing protocols and interfaces were used to achieve this. The following sections highlight the main results from the field trials with the residential PV-BESS.

Execution of local grid Signals

The PV-BESS used in the project implements all functions required for grid integration, including voltage control with active and reactive power control. Additional functions to introduce a power reduction were implemented during the project based on the *SunSpec* Models 123 (Immediate Controls) and 124 (Basic Storage Controls). The possibility to use existing specifications already adopted by some manufacturers increases the likelihood of a future implementation significantly.
The extension of the grid integration functions to PV-BESS did not require significant effort since these systems are currently considered as generators and thus the grid interface (related inverter) already contains a large number of the required functions. However, it has to be considered that control approaches for achieving Level 2 – 4 (see Section 2.1.1) entail relevant technical and economic efforts (see Section 3.1.2 and Section 3.2.3 for details) which might have a significant negative impact on the economic feasibility for coordinated grid control of such components.
Various field trials were carried out to validate such a functionality in the context of grid applications. The objective of the test in Eberstalzell was to limit the battery charging power to charge the battery over a longer period and thus to reduce the grid feed-in power of the PV-BESS (see Section 2.2.1 for details).
Figure 36 shows the State of Charge (SoC) during the day of the three installed systems at days of normal operation in comparison with days where an active battery charging limit is implemented. The limitation of the battery charging power has a visible impact on the operation on the Plant 1 and the battery is fully charged later than on days without any battery charging limit. It can also be seen that there are days where the battery is not fully charged. This can be either a deviation in the forecast of the PV generation, a deviation in the local load or a possible required optimization of the algorithm. An improvement of the algorithm is necessary to ensure that all excess PV generation is stored to the full extent of the battery capacity when possible.
Without a battery charging limit the PV-BESS is fully charged at about 11:30 (median value). With a battery charging limit in place the battery is only fully charged at 16:00. This indicates a visible reduction of the peak PV power feed-in to the grid during midday.

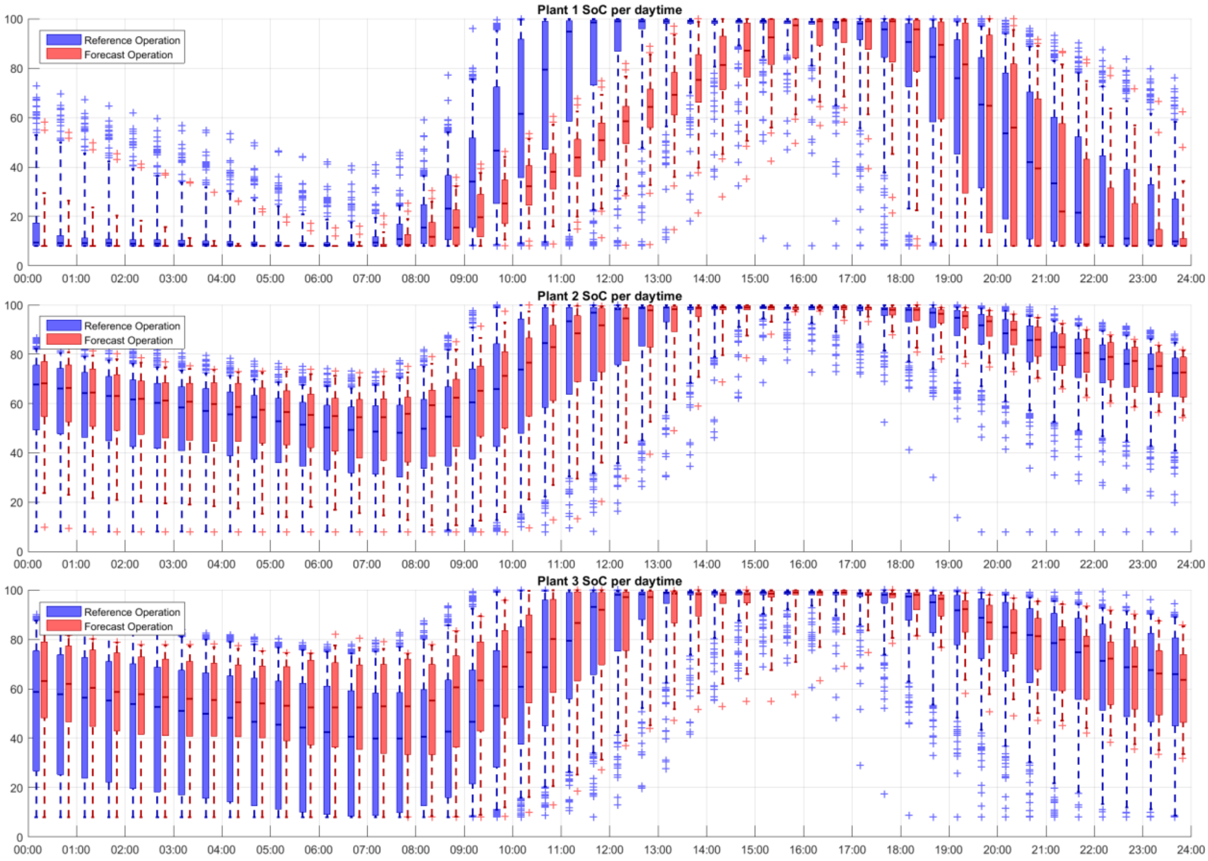


Figure 36: Distribution of the State of Charge in the three test plants in Eberstalzell and Littring with and without a forecasting-based battery charging limit applied

An improved overview of the impact can be given by analysing the feed-in power of the PV-BESS to the grid which is shown in Figure 37. It can be observed that the feed-in power is reduced for all three systems on days with a battery charging limit in place. When considering the reference operation, the default operation mode can be clearly seen. Between 10:00 and 11:00 the systems are fully charged, and the feed-in power rises visibly within a short time. On days where a battery charging limit is active, the feed-in power rises steadily but at a lower level. The maximum feed-in power was reduced to values ranging from 4% to 21%. It can also be seen that there is a large bandwidth of feed-in power based on the local generation and demand.

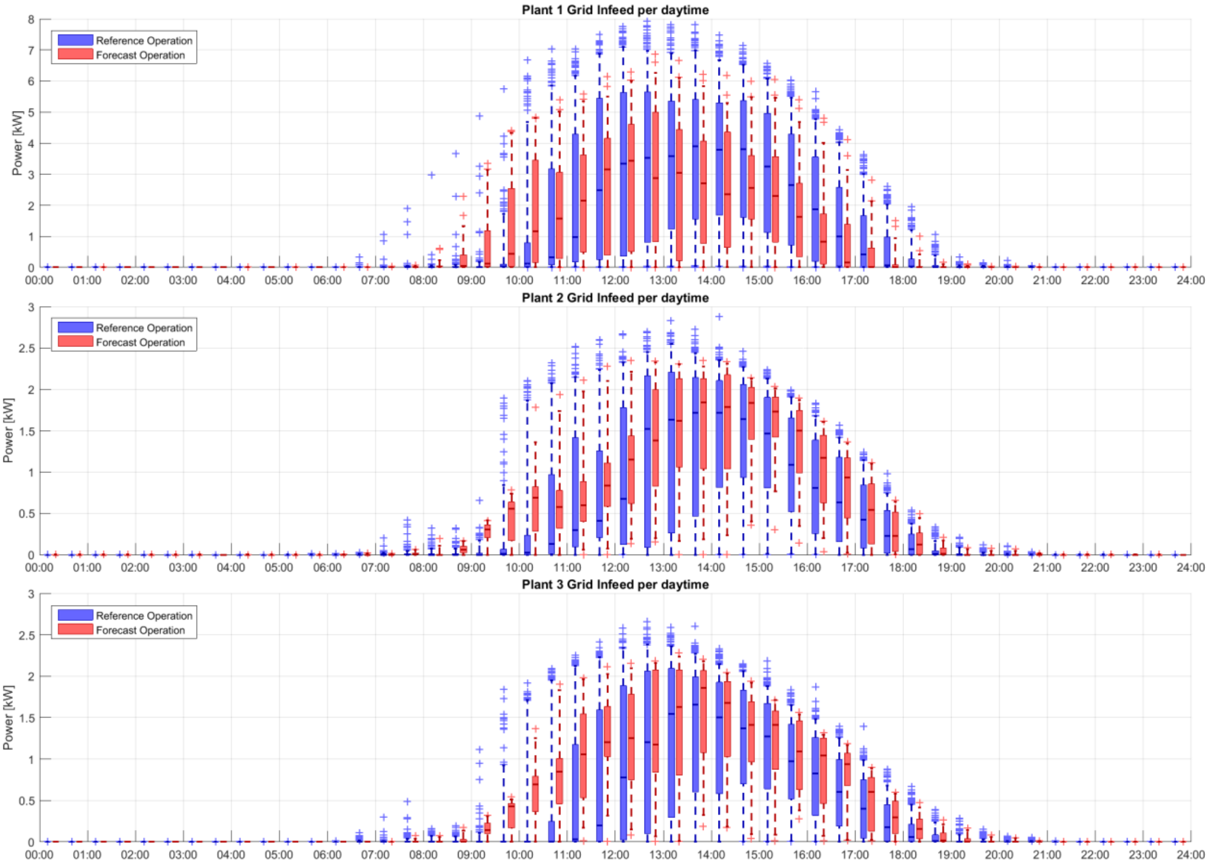


Figure 37: Distribution of grid feed-in power in the three test plants in Eberstalzell and Littring with and without a forecasting-based battery charging limit applied

Plant 1 is located in a different LV grid than Plant 2 and Plant 3. For Plant 1, the validation period was significantly longer as problems with the infrastructure could be resolved sooner. This can be also noted in Figure 36 as only days in the summer were available where the systems have a high SoC in the morning.

Execution of a Market Signal

The PV-BESS used in the project can receive, process and execute a remote market signal provided through the cloud system of the manufacturer over the internet (*Fronius Solar.web*). Internally, the PV-BESS continuously determines its operational window following the market signal without any violation of grid boundary conditions resulting from the grid signal. When implementing a function like this in other systems, the correct prioritisation needs to be ensured (see also Section 2.1.3). The grid signal does not provide a specific setpoint but a maximum operational window. The PV-BESS can operate freely within these boundaries.

Local and temporary grid restrictions must be considered and communicated back to the cloud system of the manufacturer. With that, the market participant can estimate the available flexibility capacity.

To test the setup, a scenario was constructed, were large amounts of wind and hydro generation during the night necessitates flexible loads in a medium voltage grid. Figure 38 shows the effects of this scenario on the SoC of the three installed PV-BESS. During the time between 01:00 and 02:00 (grey area in Figure 38) the storage system should not be discharged in order to cater for the load consumption because during this time it is expected that the households consume directly from the grid. This can be seen in Figure 38 on the nights of the 27th, 29th and 31st of July where the SoC remains constant or slightly rises[21] during the time of 01:00 to 02:00. During the other nights the PV-BESS was either already completely discharged (30th of July) or the market signal was not active (28th of July and 1st of August). Figure 38 also indicates that the PV-BESS are able to provide the flexibility required in the proposed scenario. The benefit of this approach is that, depending on the capacity per household, sufficient flexibility is available in a grid.

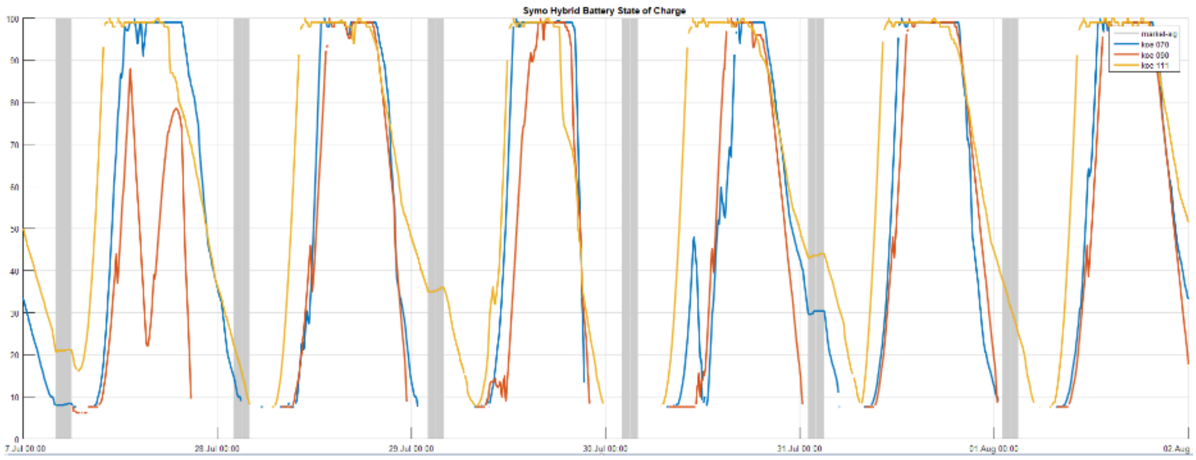


Figure 38: Flexibility through interrupted discharging of storage units

Unsymmetrical Operation

As described in Section 1.5.2 deliberate unsymmetrical operation of grid-tied PV-BESS can have a positive impact on the grid. However, such a feature is currently not on the market and neither is it required by the national regulatory framework. Moreover, it would lead to higher equipment costs (approximately 3 to 5 %) and to increased conversion losses (resulting in a reduced efficiency of approx. 0.2 percentage points for the reference inverter platform). Certain electrical components of the converter would age faster due to increased stress. Overall, product lifespan could also be affected. Nevertheless, future grid support functions could be improved by considering the state of each phase. However, the participating grid operators do not see a strong necessity to implement the functionality now. The need for phase accurate power compensation is currently also lacking in international markets.

Based on the calculation for costs, lifespan and efficiency, *Fronius* decided not to implement asymmetric operation (beyond backup power) into the current production of inverters. However, the discussion in the *leafs* consortium showed that the demand for such functions could increase in the future, so *Fronius* intends to integrate an asymmetric operation mode into the next generation of inverters as a default.

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[21] The increasing SoC can be explained with internal correction of the SoC value - within the BMS of the PV-BESS as a consequence of battery cell balancing that starts when battery gets idle.

3.1.5 Central BESS Implementation

The project has shown that the technical implementation of a community BESS, with additional voltage control and remote control for market services, is possible. Furthermore, the project has shown that such a system allows for synergies between customers and additional services to the DSO. The following sections summarise the most relevant aspects.

Technical Suitability

In a first step the system was tested in the AIT laboratory to assess the applicability of the defined operation strategies. The following aspects have been analysed:

- **Battery round trip efficiency (RTE) for determining the capacity:** The specified capacity of 100 kWh was available at the specified nominal power of 100 kW.
- **Step response:** The inverter's current operational point was changed significantly, and the system's response time and the transient responses were observed. The results from this test significantly affected the design of the controller. The inverter was able to realize any set value within a time span of around 7 seconds.
- **Inverter's P-Q-Diagram:** The inverter's P-Q-diagram was analysed by sending various set values – valid and invalid ones – to the system and observing its behaviour. (Since the system's apparent power limitation is 100 kVA, a set value of 90 kW and 90 kVAr would be an example of an invalid set value). The inverter was able to deliver the specified 100 kVA in all combinations of active and reactive power with an additional limitation to +/- 86 kVAr reactive power. The inverter realized all invalid set values by bringing them into the inverter's defined P-Q-Diagram.
- **Inverter's accuracy of set value realization within the P-Q-Diagram:** A time series of active and reactive power set values were defined that bring the system in significantly different operating states in all four quadrants of the P-Q-Diagram (charging/discharging and generating/consuming active power). The inverter was able to realize the given set values independently of the previous and the new system state with a high level of accuracy. Slight inaccuracies occurred during times of very low power factors (e.g. a set value of 0 kW and 70 kVAr).
- **Efficiency of the inverter:** The system was charged and discharged at different power rates and different battery voltages to determine the inverter's efficiency and the standby losses. A very simple linear model was able to approximate the efficiency of the inverter high accuracy. According to this linear model, the inverter losses consist of a power-independent "standby-loss" of around 1.4 kW and a power dependent "operation-loss" of around 2.5% of the input/output power.
- **Round-trip Efficiency:** Round trip efficiency (RTE) tests at different charging/discharging powers were performed (see Figure 10) to determine the battery's efficiency that is visualised in Figure 39. Battery efficiencies between 95.5% and 98% depending on the power of charging and discharging were obtained. Additionally, the round-trip efficiency including the inverter was evaluated. Efficiencies between 85% and 87.6% depending on the charge/discharge power were established.

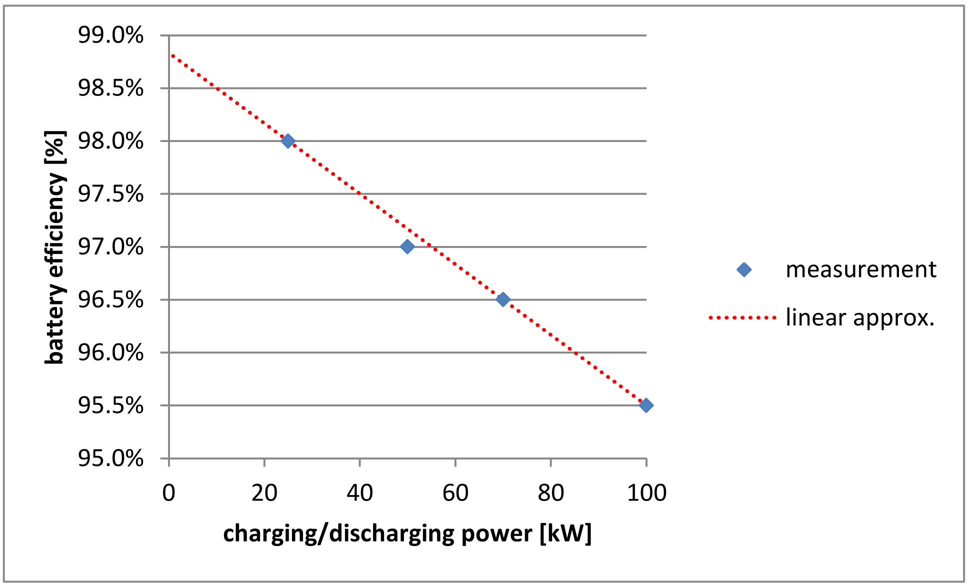

Figure 39: Battery efficiency measured at different charging / discharging power levels

Sizing of Power and Capacity

The more residential customers share a central BESS the less specific power and capacity per customer are required due to effects of (non-)simultaneity. In case of the accumulated consideration of six prosumers with nine PV installations in the pilot town of Heimschuh, the excess PV generation was reduced by 11 % in comparison to the case where these specifications were treated separately (both scenarios calculated and compared in simulations). The simultaneity effects are only applicable for the total annual energy, but not in terms of maximum power.

When ten or more customers participate, the service can be offered to approximately 10% more customers. This effect is one of the benefits compared to residential PV-BESS. A community BESS should therefore include a larger number of customers (at best > 10) to increase synergetic effects and cost-efficiency.

Community Storage Operation

From October 2017, the central BESS has been operational as a community storage system. Figure 40 shows the energy values per month for one customer:

- The bright red area (load) shows the complete consumption, the dark red area (CON) shows the consumption including the self-consumption of the PV without storage and the dark red area with the dashed line (CON + ST) shows the grid consumption consideration the self-consumption of PV with the storage system.
- The bright green area shows the overall PV generation of the customer (generation), the PV grid infeed considering self-consumption is shown in the dark green area (INF) and the feed-in including the storage operation in the dark green area with the dashed border (INF + ST).
- The dark blue bars show the contribution of the central BESS to reduce infeed and consumption (ST CON/INF) and the bright blue bars theoretical storage operation without any limitation on capacity (EGDA CON/INF).

- The dark yellow bars show the direct consumption without storage (direct CON) and the bright yellow bars with storage (direct CON + ST).

It can be seen that both consumption and infeed are reduced visibly by the storage system.

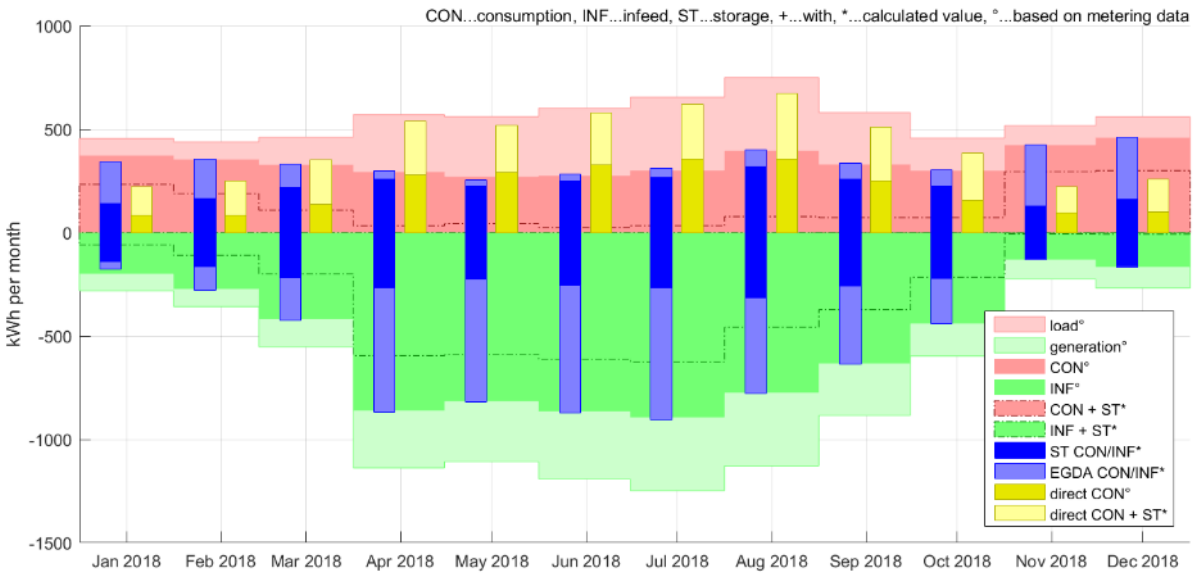

Figure 40: Energy values of a customer distributed in generation (green areas) and demand (red areas) and storage operation (blue bars) showing operation without storage (bright areas) and with storage (dark areas) as well as direct consumption (yellow bars)

Figure 41 shows the self-consumption rate of this customer with and without storage. The darker fields show the values without storage and brighter fields with storage. Also in this visualization, a significant impact of the storage can be seen.

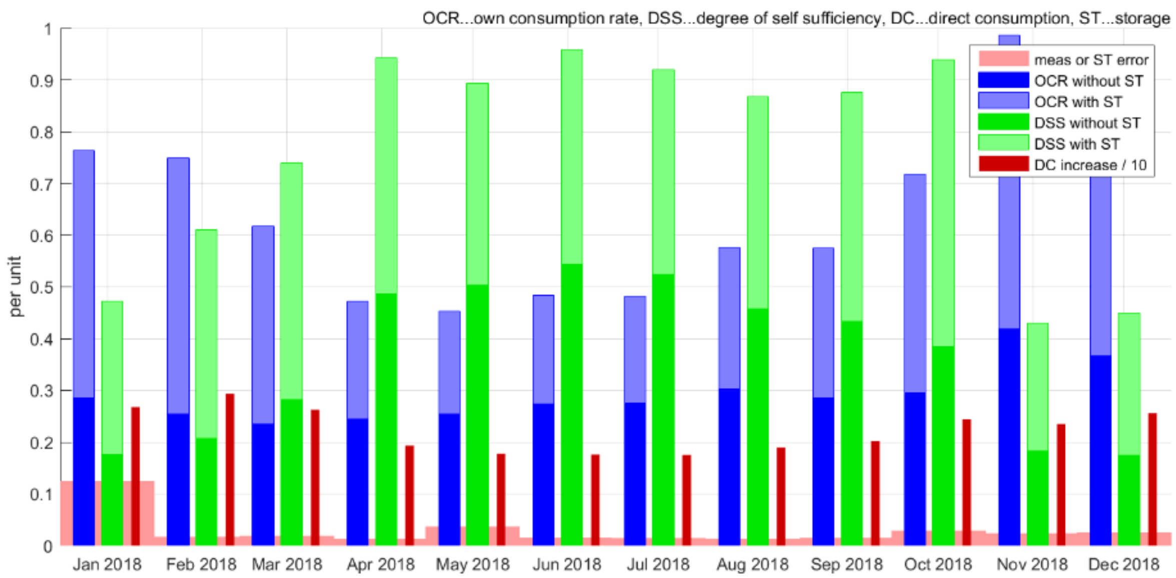

Figure 41: Self consumption per month of one customer participating in the field trial

At the beginning, a total six customers participated in the test. However, due to an inadequate relation between generation and demand and thus no need for storage, two customers were removed from the field trial.

Table 5 shows the remaining customers and their changes in behaviour in terms of energy consumption and feed-in during the initial test period until July 2018. The grid consumption is reduced by values between 1,082 and 1,543 kWh or 30 and 48 % (representing subtractions of the values in Table 5). The grid feed-in is reduced between 1,088 and 1,548 kWh or 16 % and 36 %. This represents values which are equal to normal PV-BESS systems.

Table 5: Grid consumption and grid feed-in with the community storage system – initial test phase

Customer	1	2	3	4
Grid consumption without BESS in kWh	2,897	2,207	1,771	1,713
Grid consumption with BESS in kWh	1,402	664	575	631
Reduction of grid consumption with BESS in %	52	70	68	63
Grid feed-in of PV without BESS in kWh	-5,452	-4,384	-7,356	-2,991
Grid feed-in of PV with BESS in kWh	-3,955	-2,836	-6,158	-1,903
Reduction of grid feed-in with BESS in %	27	35	16	36

Table 6 shows the residual grid consumption and feed-in from August 2019 to December 2019. In this period the capacity for the individual customers were improved. This was achieved by either reducing or increasing the capacity to find the optimal capacity value when considering the requirements of the customer. It has to be noted, that the consumption and generation is lower during this period when the improved capacities are implemented.

Table 6: Grid consumption and grid feed-in with the community storage system – improved capacities

Customer	1	2	3	4
Grid consumption without BESS in kWh	2,267	1,923	1,642	1,218
Grid consumption with BESS in kWh	1,198	831	722	529
Reduction of grid consumption with BESS in %	47	57	56	57
Grid feed-in without BESS in kWh	-3,059	-2,153	-4,682	-1,618
Grid feed-in with BESS in kWh	-1,995	-1,065	-3,764	-939
Reduction of grid feed-in with BESS in %	35	51	20	52

Voltage Control

The central BESS provided voltage control based on reactive and active power (see Section 2.2.4 for details). The central BESS ensures that a voltage level of 240 V is not exceeded. Figure 42 shows the daily activation time of the voltage controller of the central BESS over a period of twelve months. The BESS voltage control was activated nearly every day, also in the winter months from December to March. In most cases, only reactive power is used to keep the local voltage within the defined boundaries.

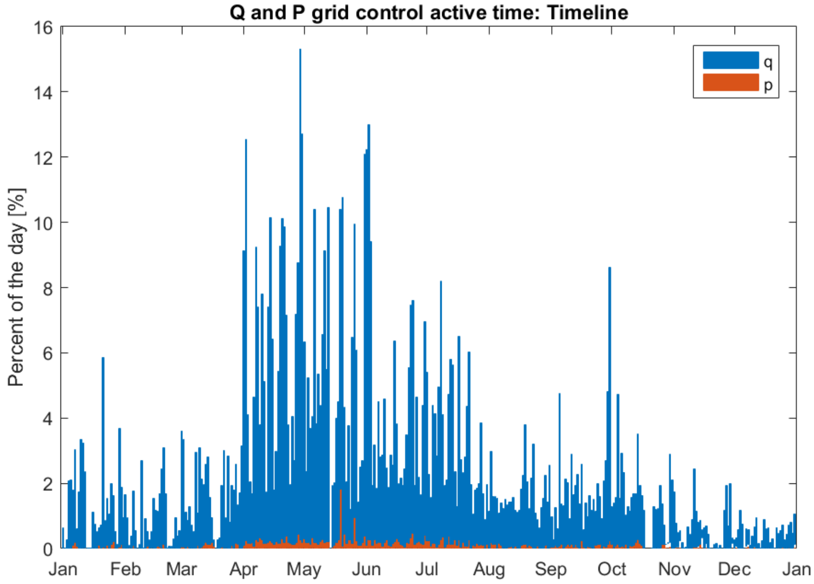

Figure 42: Active control time for P and Q control for voltage control

The qualitative analysis as given in Figure 42 is also reflected in Figure 43 which shows the duration curves of the percentage per day where the central BESS has activated voltage control with either active and reactive power. It can be seen that in this case the voltage control targets can be achieved most of the time with reactive power control.

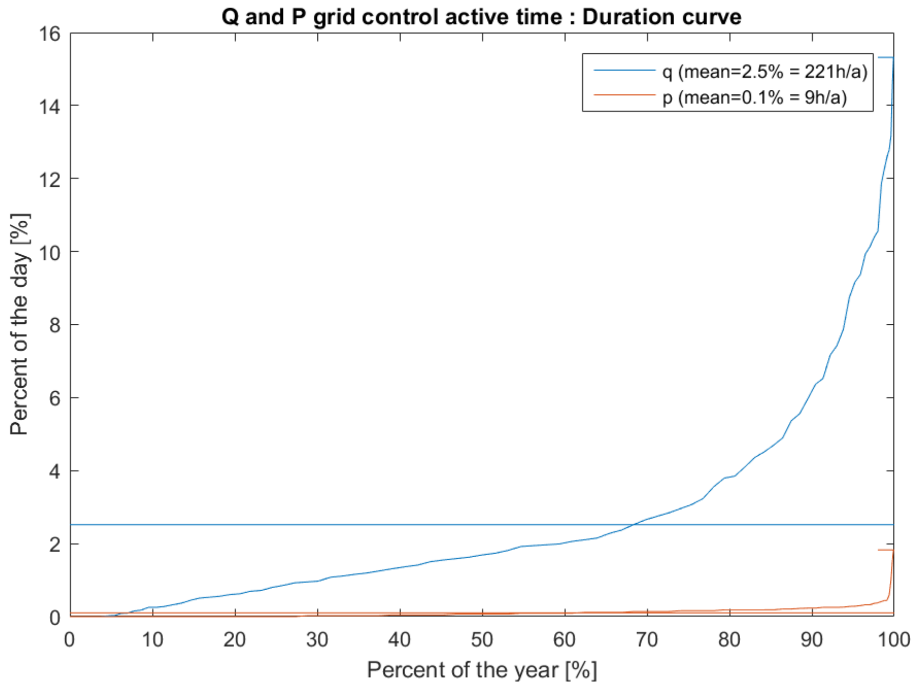

Figure 43: Duration curve of percentage per day (as given in Figure 42) were the BESS was operated with reactive power as a first step and active power as the second step

The voltage controller operates in two distinct operation modes. The first mode is to bring voltage in the local grid back into boundary conditions when the voltage limit violation is caused by another component in the grid. The second mode avoids any negative effect of the central BESS on the grid due to its own operation. Figure 44 shows the voltage band at the central BESS during the field trial. The effect of the central BESS on the grid can be clearly seen. It has to be noted that the voltage values outside of the allowed voltage band occured only a very minor part of the time. During these times the central BESS is able to keep the voltage within the defined boundary conditions. The significant larger part of the time the voltage control avoids a negative impact of the central BESS on the local grid.

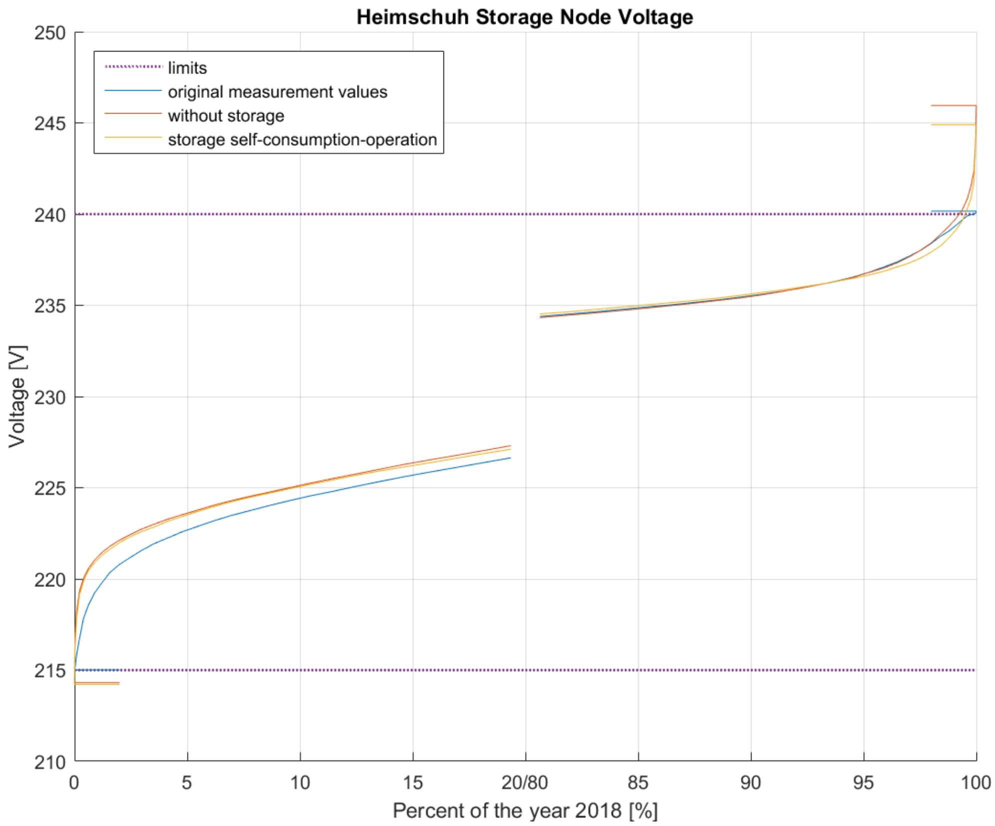

Figure 44: Voltage band the central BESS in Heimschuh with and without storage operation

From the figures, the following aspects can be deducted:

1. The BESS operates mainly with reactive power (approximately 66 hours without self-consumption and 44 hours with self-consumption mode active) for avoiding voltage band violations caused in the grid. Thus, the DSO might not need the BESS capacity after all to achieve the desired effect on grid voltage. It is also noted that the BESS avoided negative impact of its own operation on the grid. All in all, the active control duration was about 221 hours and the duration of the active power control was only about 9 hours. With that the system can be utilised for other operations strategies such as the community storage functions for a significant portion of time. However, a general statement cannot be derived from this field trial. In other grid situations the need for active power and storage capacity might be higher. If only reactive power would be required, a BESS would most likely not be the most cost-efficient solution.
2. Reserving capacity for the DSO seems to be an inefficient approach. It is considered to be more efficient when the DSO acquires full control in times when it is required, and that the BESS implements the community storage functions in a grid friendly way.

3. Since the costs for BESS capacity ratings are significantly higher than for power ratings, a BESS could be an economically viable solution under corresponding boundary conditions. However, more detailed investigations have to be carried out to validate this.
4. Compared to a solution based on active and reactive power controls in distributed generators, the central BESS can be placed at the location where it has the highest impact on the grid. Additionally, problems of fairness of distribution of voltage-based power reduction between customers would not arise.

Market Service Provision

Investigations from an economic perspective have shown that a spot marked participation of such a central BESS does not make sense (see Section 3.2.1). Therefore, an implementation of a market-based test cycle was not conducted. However, a validation cycle was introduced where the real-world applicability was tested. Figure 45 highlights an example where this market-based validation cycle was active. The BESS is charged and discharged twice a day based on a hypothetical market signal which can be seen in the lower part of the figure. The middle part shows the combined BESS operation including local voltage control and self-consumption. The upper part shows the voltage levels in the local grid. The impact of the market-driven operation can be seen very clearly with lower voltage levels during charging and higher voltage levels during discharging.

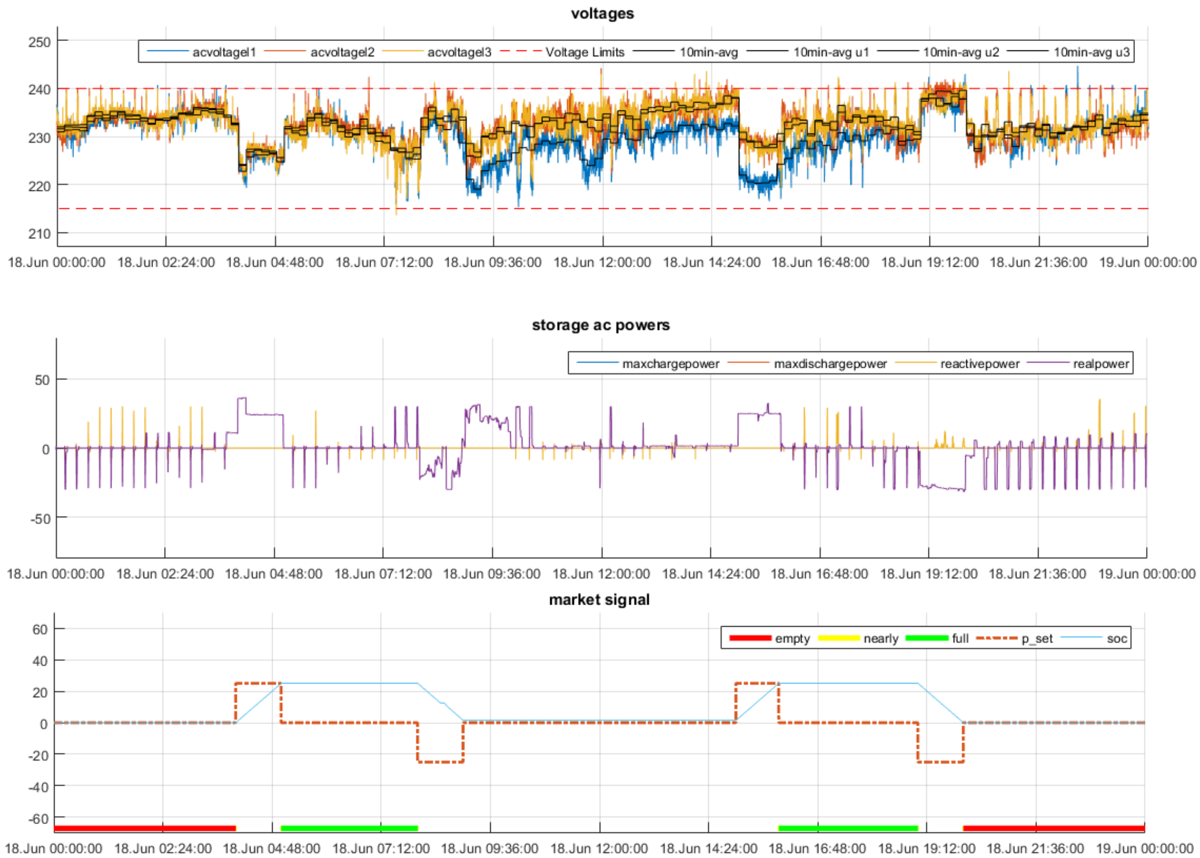

Figure 45: Example operation day of the central BESS with a market-based charging and discharging algorithm

3.1.6 Flexible Load Activation

Field trials in the project showed that an activation of flexibility in loads such as domestic hot water boilers is possible. However, certain limitations and barriers were identified as described in the following sections.

Interfaces & Grid Functions

Flexible loads do not implement such a set functionality of grid integration functions as generation units do. In future developments the ability to avoid under voltage will be relevant, especially for EVs (see Section 3.1.7). If all participating flexible loads implement grid integration Level 1 (see Section 2.1.1), a certain share of possible future complications can be solved (see Section 3.1.7 for details). However, there are flexible loads (EVs, heat pumps, domestic hot water boilers) which are activated, by a third party for market services, without any consideration of the local grid or interaction with the local DSO.

Advanced Ripple Control based on existing Systems

As described in Section 2.3.5 a dedicated field trial was carried out in the city of Steyr to shift flexibility of existing domestic hot water boilers to operate during the day. Table 7 shows the results of the field trial. For example, the consumption at night during the test phase without the additional 15:00 to 16:00 charge (Σ 195,096.5 kWh) is 5.3 times higher than during the day hours (Σ 36,669.8 kWh). In contrast, this factor is only about 3 if the boiler recharge operation is initiated between 15:00 and 16:00 via a ripple control command signal. In any case, this shows that a certain degree of load shift is achievable when the 15:00 to 16:00 recharging is implemented.

Table 7: Descriptive evaluation of day and night consumption

	Value	Consumption Night [kWh]	Consumption Day [kWh]	Difference Night - Day [kWh]
	Time	22:00-06:00	06:00-22:00	-
Without 15:00 – 16:00 charge	Sum[1]	195,096.5	36,669.8[4]	145,313.5
	Mean[2]	2.74	0.56	2.21
	Median[3]	2.15	0.00	1.92
With 15:00 – 16:00 charge	Sum[1]	112,661.7	44,397.1	59,732.1
	Mean[2]	2.42	1.05	1.41
	Median[3]	1.55	0.00[5]	0.83
Total	Sum[1]	307,758.2	81,066.9	205,045.6
	Mean[2]	2.62	0.75	1.89
	Median[3]	1.92	0.00	1.53

[1] Sum shows the cumulated energy quantity of all households in the final data set during the specified periods (e.g. households consumed a total of 195,096.5 kWh during the night hours in the test phase without load demand from 15:00 to 16:00).
[2] Mean shows the average consumption of a household (for example, a household consumed an average of 1.05 kWh in the daytime hours in the test phase during the 15-16 charging),
[3] Median shows the maximum consumption of at least 50% of households in the period (for example, at least 50% of households had no consumption at all (= 0 kWh) in the daytime hours during the test phase with 15:00 – 16:00 charge).
[4] Consumption should be 0 kWh for this period. However, a firmware upgrade in this period triggered recharging during daytime. Additionally, some base meters may have been erroneously included in the test.
[5] A median of 0 means that more than 50% of the boilers had no energy uptake in this period. For the period with day time recharging this is most likely explained by problems regarding the receipt of the steering signal by the majority of meters.

Subsequently it was therefore examined whether the observed load shift of about 0.8 kWh per household (difference of the mean values without and with 15:00 – 16:00 charge; 2.21 - 1.41 = 0.80 kWh) is to be regarded as significant or whether this could also be due to chance.

In addition to the determination of actual load shift potentials by hot water boilers, the data suggest possible further correlations. For example, the average consumption of a household in the trial phase without charge between 15:00 – 16:00 hours was lower than in the subsequent phase with charge between 15:00 – 16:00 hours. This could possibly indicate that the operation of the boiler becomes somewhat less efficient due to the afternoon recharging. However, for the same households, the data was recorded in chronological order: while the no charge phase took place between 15:00 and 16:00 at the beginning of November 2017, the trial phase with afternoon charging took place towards the end of November / beginning of December. In this sense, factors such as holidays in the respective observation period, weather, and similar variables would have to be corrected before comprehensive conclusions could be drawn.

***Sonnenbonus* with Ripple-Control**

As described in Section 2.3.5, automation experiment adjusting the hot water boilers activity to the discounted times was organized in the period from 1st of February until the 5th of February and from 1st of March until the end of the field tests. The results of this experiment are given in Table 8. While for three of the eight households that took part in the experiment, the consumption during discounted times was significantly higher than the average consumption in the sample, for one household it was lower. There is no consumption data for the remaining boilers for the times when the boiler trial was ongoing (February and March).

Table 8: Hot water boiler results

Boiler	Consumption during discounted times [kWh]	Average consumption of all households without boilers in the discounted times [kWh]	Difference [kWh]
B1	170.84	94.15	76.69
B2	141.50	94.15	47.35
B3	154.69	94.15	60.54
B4	11.63	94.15	-82.52

3.1.7 Grid Impact

The impact of the different measures and concepts on the grid was assessed in a broad range analysis including simulations and field trials. The following sections describe the main results.

Peak Generation in Low Voltage Grids

Figure 46 illustrates duration curves of the accumulated load profiles of simulated 103 prosumers in Eberstalzell and Köstendorf for different operation strategies (see Section 2.1.2). In the baseline scenario (blue line), prosumers do not operate storage systems or flexible loads and thus cannot respond to any market signals. The peak load of the distribution grid segment at the substation roughly equals 330 kW and PV generation exceeds total consumption in about 760 h per year and must be transferred to a higher grid level. The operation strategy *max. self-consumption* (red line) has only minor effects on the duration curve. The annual peak load does not decrease, but a higher share of PV generation can be utilized within the grid segment. Thus, excess PV generation only has to be transferred to higher grid levels in roughly 400 hours per year.

In case the prosumers are exposed to time variable electricity prices and aim to minimise their electricity procurement cost, the annual peak load in the distribution grid increases drastically (yellow line). This is caused in the high simultaneity of increased load during times of low electricity prices. By limiting the PV feed-in power at 70% of the installed PV capacity of each individual prosumers, flexible loads and charging of storage systems is shifted in times of peak generation (purple line). Thus, the total PV generation can be utilised locally and is not transferred to higher grid levels. Finally, an operation strategy that strives to minimise the procurement power of each prosumer individually, hardly decreases the peak load at the substation. This is because of a lack in simultaneity of the peak loads of the individual prosumers.

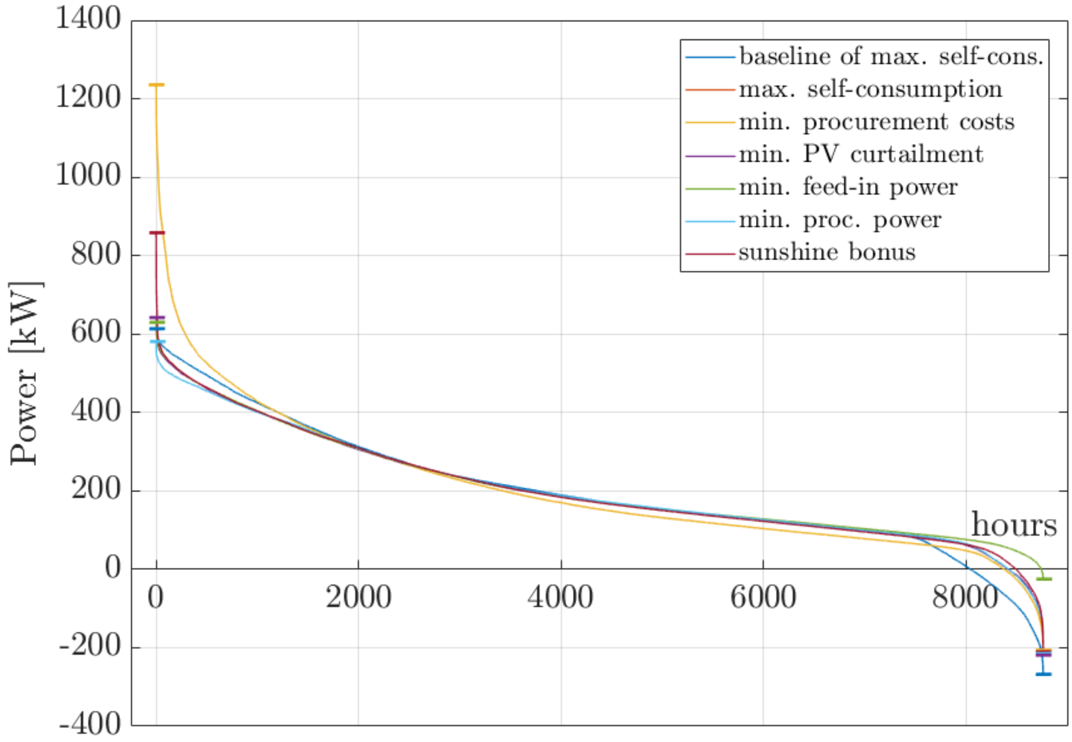

Figure 46: Duration curve of accumulated load flow at the substation of the distribution grid segment (Eberstalzell)

The total power flows from the operation strategies are compared with a baseline scenario where no flexible loads and no BESS are available. It shows that all applied operation strategies have a positive effect on the total feed-in power. In the baseline scenario, the maximum feed-in is 49 % of the installed PV power. When BESS and flexible loads are applied the maximum feed-in power reduces below 39 % of the baseline. The introduction of a feed-in power fee leads to a reduction to 4 % compared to the installed PV power in the operation strategy to *minimise PV curtailment.* The curtailment of PV generation is 18 % in terms of generated energy.

Table 9: Maximum feed-in power in % of installed PV power

baseline	max. self-cons.	min. proc. costs	min. PV curtail.	min. feed-in power	min. proc. power	Sonnen-bonus
49.44 %	35.93 %	38.15 %	34.63 %	4.26 %	37.59 %	37.96 %

Table 10: Change of maximum procurement power compared to baseline scenario

baseline	max. self-cons.	min. proc. costs	min. PV curtail.	min. feed-in power	min. proc. power	Sonnen-bonus
100%	+5 %	+101 %	+4 %	+2 %	-6 %	+40 %

By applying controllable BESS and flexible loads to the prosumers, PV curtailment is avoided for each of the other cases. Additionally, a feed-in limitation of 70 % of installed PV power has no negative effect on the optimisation. In real-life, these results might vary since the BESS might not incorporate any optimisation functions based on generation and load forecast (see Section 3.1.4 for details on operation of PV-BESS).

Impact of future PV rollout scenarios on the grid

As described in Section 1.5.7, the rollout scenarios for PV have been evaluated based on all LV networks in the supply areas of *Salzburg Netz GmbH* and *Netz Oberösterreich GmbH*. The political targets for renewable energy development based on the Austrian Energy and Climate Strategy - *#mission2030* - were translated to specific capacity additions for both DSOs on low voltage distribution grids. These capacities were added to the grid models and equally distributed amongst relevant customers. Table 11 gives an overview of the estimated total capacities for the areas owned by both DSOs. These capacities lay foundation for the development of the PV implementation scenario.

Table 11: Overview of PV implementation scenarios

DSO	PV in 2014 in grid level 6, 7	PV derived from targets in the *#mission2030*		
		share	PV total	PV in grid level 6, 7
Salzburg Netz GmbH	44 MW_p	8 %	1.12 GW_p	0.97 GW_p
Netz Oberösterreich GmbH	86 MW_p	10 %	1.4 GW_p	1.2 GW_p

Based on the existing distribution of PV system sizes the future distribution of PV was assumed. Table 12 summarises all relevant assumptions for the implementation of the PV rollout scenario for PV in 2030 and includes relevant grid integration functions.

Table 12 Summary of assumptions for the peak PV generation scenario in 2030

Aspect	*Salzburg Netz GmbH*	*Netz Oberösterreich GmbH*	Description
Scaling of Generation	0.85	0.85	Base simultaneity of PV regarding compensation effects over medium voltage grids

Aspect	Salzburg Netz GmbH	Netz Oberösterreich GmbH	Description
Reactive Power Control	cos φ = 1 / 0.95 / 0.9, Q(U), Q(U) with central BESS		Q(U) is chosen as the standard reactive power control function due to lower network losses compared with a constant cos φ
Active Power Control	inactive, except in the Q(U) + P(U) scenario		To assess the grid reinforcement requirements P(U) is not activated. There is a separate scenario which assess an additional P(U) implementation
Total Installed Capacity	1,120 MW_p	1,400 MW_p	Total power of PV installed in the supply area as described in Table 11
Expected Capacity NE5 and above	145 MW_p	182 MW_p	Large scale PV generation not regarded in this analysis as installed in higher grid levels
Expected Capacity NE6	134 MW_p	168 MW_p	Based on the given distribution of PV systems about 12% of the cumulated PV power is directly connected to NE6
Expected Capacity NE7	840 MW_p	1.050 MW_p	Based on the given distribution of PV systems about 75% of the cumulated PV power is directly connected to NE7
PV system size household	2 kW_p		Based on the distribution of households and other load types in all LV grids according to list of metering points
PV system size industrial	35.5 kW_p		
PV system size agricultural	8.6 kW_p		
PV system size small enterprises	2.4 kW_p		

Figure 47 (lines and cables) and Figure 48 (transformers) show the grid reinforcement requirements for both DSOs and different measures such as reactive power control, different planning approaches and the implementation of central BESS. All diagrams show the PV penetration on the x-axis (labelled in percent of the PV *#mission2030* scenario of 14 GW_p for Austria) and each of the parameters under considerational all LV grids on the y-axes (such as the number of grids to be reinforced). Most diagrams show red lines and blue lines that distinguish between the different planning approaches: In this case, the blue lines show the results when all loads in the grid are scaled by 20% of the maximal load scenario which is an accepted in network planning of certain DSOs in Austria. The red lines show the results when load in the grid is neglected (scaled to 0%) which is also an accepted value amongst certain DSOs in Austria. The different markers indicate different PV reactive power (and active power) control scenarios as defined in Table 13.

Table 13 Description of control strategies for PV integration in the scalability analysis

Symbol	Description
○	No reactive power control
□	Q(U) control for the distributed generators
✳	Constant cos φ of 0.95 for PV
△	Constant cos φ of 0.90 forPV

Symbol	Description
+	Central storage with active and reactive power control (wide area voltage control via active power control with cos φ = 0.9) in addition to PV inverter in Q(U) control mode
▪	Q(U) and P(U) control for distributed generation

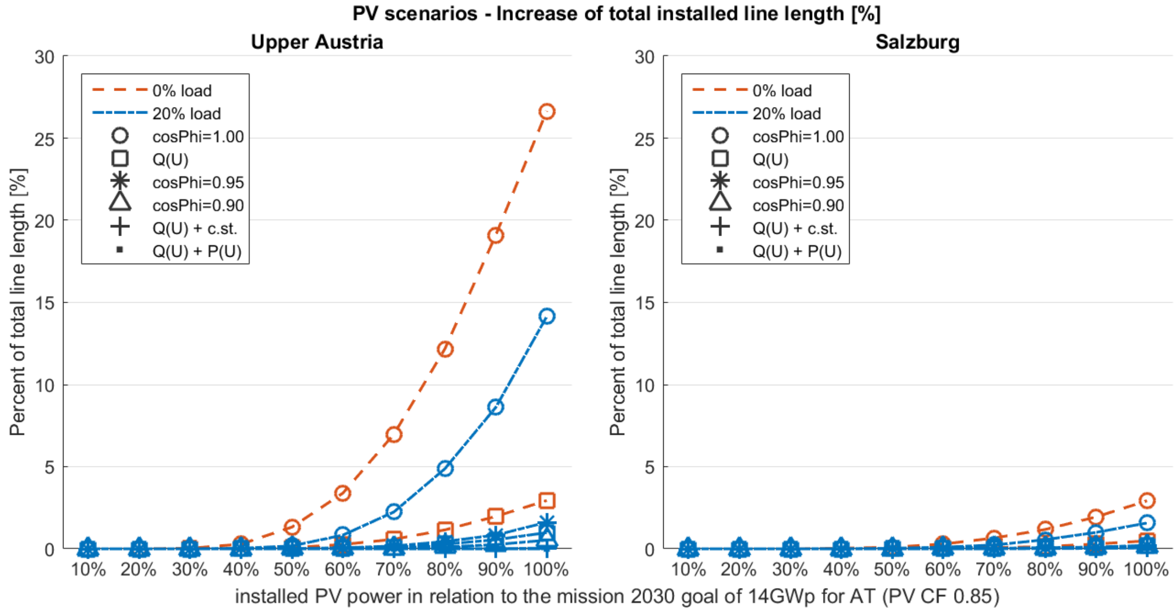

Figure 47: Reinforcement requirements for different PV penetration scenarios: Percentage of affected line length

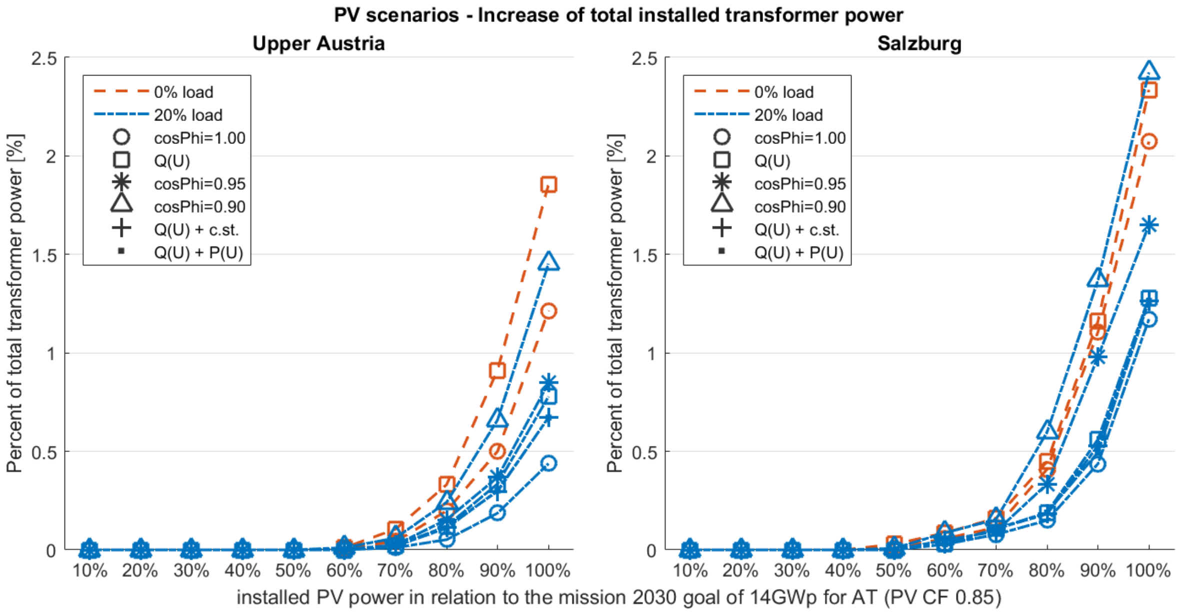

Figure 48: Reinforcement requirements for different PV penetration scenarios: Percentage of affected transformers (increase of total installed transformer power); c.st. = Central Storage

Based on this analysis the following aspects can be derived:

- The grid reinforcement requirement strongly depends on the amount of PV penetration. Results show that minimal grid reinforcement will be necessary in the future when up to 50 % of the PV penetration derived from the *#mission2030* goal is implemented based on the current distribution of PV systems in the LV grids.

Additionally, it should be noted that unevenly distributed PV systems may cause an increase in the reinforcement requirement in networks at lower penetration levels.

- It is possible that 100 % PV penetration can be accommodated in the future based on existing strategic network reinforcement plans. This, however, strongly depends on the timeframe in which the PV systems are implemented.
- For both DSOs, line reinforcement is predominantly necessary due to the violation of voltage constraints and not due to the violation of loading constraints (thermal capacity of power lines or transformers).
- Despite nearly all calculation constraints being equal for both DSOs, grid reinforcement results differ significantly for both DSOs. This is attributed to the different limits set for the for voltage rise constraint (3% for *Netz Oberösterreich GmbH* and 4% for *Salzburg Netz GmbH)*, the different cabling degree (compared to overhead lines) of line assets, cable types of both DSOs and in the difference in ratio between rural and urban grids both DSOs operate.
- In the 100 % PV penetration scenario, 104 transformers have to be upgraded at *Netz Oberösterreich GmbH* and 65 transformers at *Salzburg Netz GmbH* (below 4% of their transformer assets considered in the simulation). Considering the scenario to be realised until 2030, these numbers are very low, making the transformer upgrade a minor challenge.
- In the 100% PV penetration scenario, 585 km of groundwork and line reinforcement have to be done at *Netz Oberösterreich GmbH* and 32 km at *Salzburg Netz GmbH*. The reasons for the significant differences was previously mentioned. While 32 km grid reinforcement at *Salzburg Netz GmbH* is considered as insignificant, 585 km reinforcement required by *Netz Oberösterreich GmbH* is also considered to be relatively low considering the fact that during strategic grid reinforcement more than 100 km of LV lines are reinforced by *Netz Oberösterreich GmbH* every year.
- By assuming one PV-BESS at each PV installation and assuming that the energy exceeding 70% of nominal PV generation is stored in the battery, PV infeed power would be limited to 70% of the nominal power without losing significant amounts of PV generation. This will reduce the necessary grid reinforcement requirement by a factor of 2 to 3 when considering the necessary groundwork and up to a factor of 10 when considering the number of necessary transformer replacements.
- High PV penetrations can be considered as a challenge for some LV grids but the impact on MV grids also has to be considered. However, this was not within the scope of this analysis and shall be subject of future investigations.
- PV infeed is not considered as an ad-hoc challenge that needs to be solved immediately, but rather that solutions be found and implemented timeously since the planning horizon for the power system is around 30 years.
- Central BESS installed in the low voltage grid are able to significantly reduce the grid reinforcement for a future rollout with high power levels and may be an interim measure for single grids if the price decreases further. However, an evaluation of the total required storage capacity was not carried out which is necessary to evaluate the implementation of central storage systems accordingly.

The required grid reinforcement is a result of the developed scenarios and is a reasonable indication of the expected range. However, if the scenario assumptions differ, the results will also differ. It can be expected that in certain grids, the grid reinforcement requirements might be higher or lower due to a different change in system size and distribution. This will be subject of future research activities.

Current Peak Consumption of Low Voltage Grids

An extensive analysis of measurement data obtained from of 131 low voltage grid substations in Upper Austria showed that up to 25 % the peak load is caused by activating flexible loads by existing ripple control patterns and thus produced by the DSO internally. In more than 50 % of the observed grids, the peak load occurs in the afternoon due to normal load, while morning peaks occur only in around 10 % of the observed grids. The number of grids which see a peak load around midday is below 10 %.

The transformer sizing is done based on this peak load. Consequently, peak load reduction by a change of the ripple control patterns would be effective in around 25 % of the grids and therefore it can be considered as a viable solution for the future.

Grid Impact of Flexibility in current Grids

Grid simulations based on the results of the market simulations (see Section 3.2.2) were carried out. The prosumers' residual profiles considered in the market simulations were integrated into the grid simulation models of Eberstalzell and Köstendorf. These LV distribution grids serve three to four times more consumers than prosumers considered in the market simulations. Figure 49 shows an example of the simulation results for the transformer loading for the operation strategy to minimize of procurement costs in Köstendorf. The left part of the figure shows the magnitude and duration of the transformer values exceeding 100% of loading. Most time periods of overloading do not exceed ten minutes. Only a minor part of the overloading periods is 30 minutes or higher. This must be considered when analysing the need for transformer reinforcement since overloading for a short duration does not necessarily harm the transformer. The right side shows the sum of overloading conditions and its distribution over the year. It can be clearly seen that the increased number of overloading occur in the winter months. However, with lower ambient temperatures, the overloading of transformers poses a lesser problem.

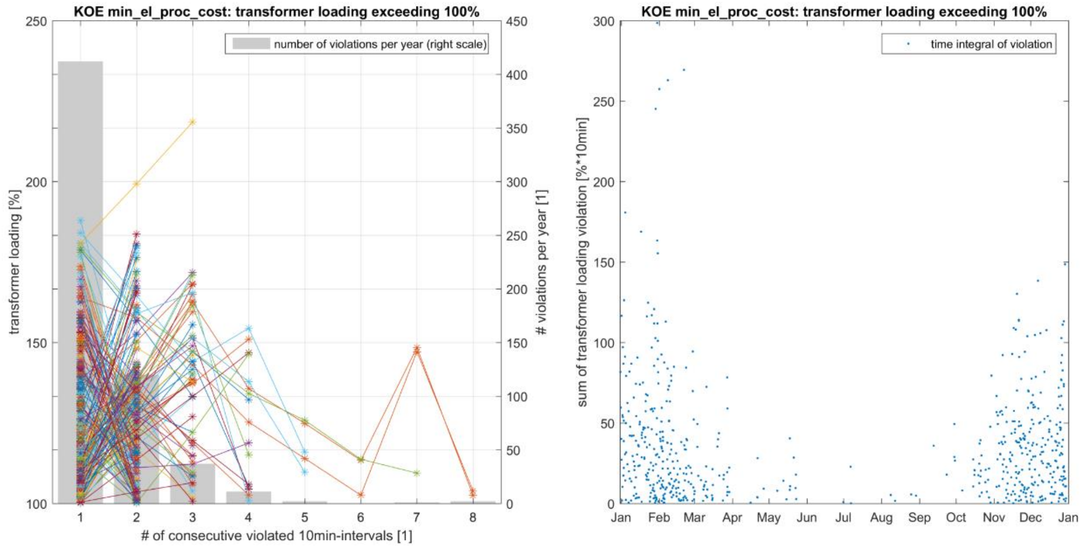

Figure 49: Example of a grid simulation for Köstendorf for minimization of electricity procurement costs

A comparison of the results, as given in Figure 50, was done for both transformer loading, and grid voltage and a more comprehensive overview is possible. The strategy to reduce procurement costs (*min_el_proc_cost*) has the biggest impact on the grid in Eberstalzell and Köstendorf. The lowest voltage is at (Köstendorf) or below (Eberstalzell) the allowed voltage range of the nominal voltage – even if not all customers participate in the scheme. However, this value was only reached a few times during the analysis period of one year. 95 % of the voltage values are in acceptable ranges. Individual values of transformer loading which extend beyond the 100 % of loading were noted but are considered as insignificant since they only occur a few times during the year.

A similar, but not as strong, effect is created by the *Sonnenbonus* (*sunshine_bonus*) if all flexibilities are activated in the grid. Both strategies are based on a common signal for all customers in the LV grid with the potential to increase the simultaneity. Especially for the *Sonnenbonus,* this is concept is very interesting since the main idea is to promote grid friendly behaviour of individual customers. The goal to reduce generation peaks is over-achieved by all the activated flexibility and produces a negative impact onto the local grid.

Increasing the self-consumption (*max_self_consumption*) has no significant impact on the grid compared to the baseline scenario (*baseline*). Limiting the feed-in power to 70% of the nominal power (*min_PV_curtailment*) has a slight positive impact on the grid. In this case it must be considered that not all customers are equipped with PV and the local grids are stable. A stronger impact is observed by introducing a power dependent grid tariff for feed-in which also leads to a higher value of PV curtailment.

The implementation of power dependent grid-tariffs for consumption does have a negligible impact on the grid-voltage and transformer loading. However, a visible effect can only be seen in Eberstalzell.

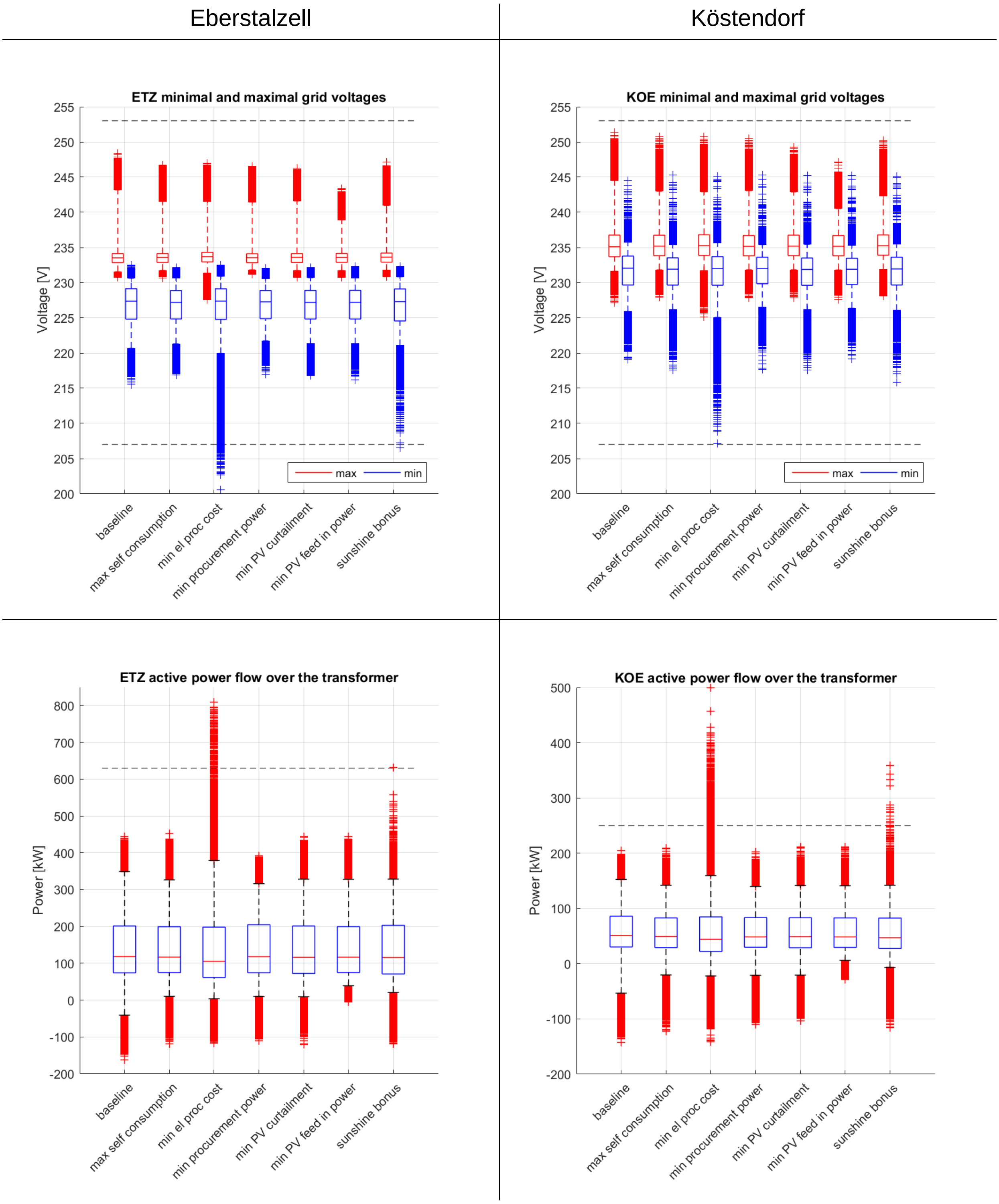

Figure 50: Distribution of values[22] of the impact of the single operation strategies on the LV grids of Eberstalzell (left) and Köstendorf (right) with regards to the grid voltage[23] and transformer loading

[22] The boxplot shows the 0%, 5%, 25%, 50%, 75%, 95% and 100% percentile

[23] The values show the maximum and minimum voltage in each time step of the simulation

Impact of flexible loads rollout on the grid

An extensive simulation analysis of specific LV distribution grids showed that the peak consumption could be doubled due to simultaneous market activation. Thus, the impact of the flexibility activation on the load side is more significant than the impact of the generation side. The reason is that there are a high number of flexible loads installed in the grids and the simultaneity of the single loads is significantly increased. Vice versa, an individual peak load reduction of individual customers does not automatically lead to an overall peak load reduction at the substation due to the low simultaneity of the load patterns.
As described in Section 1.5.7 rollout scenarios for EVs have been evaluated based on all LV networks in the supply areas of *Salzburg Netz GmbH* and *Netz Oberösterreich GmbH*. A complete diffusion of EVs is taken as the base rollout scenario, meaning that one EV per residential and agricultural customer connection is assumed. All relevant calculation parameters are summarised in Table 14.

Table 14: Summary of all relevant assumptions for the PV rollout scenario in 2030

Aspect	Value/Unit	Description
Distribution of EVs	Each domestic (H0) and agricultural (Lx) customer	The consideration of EVs only at H0 and Lx customers creates a “home-charging” scenario.
Charging Power [kW]	3.6 kW / 11 kW / 22 kW	The three charging power values are assumed to be equal for all EVs in each scenario
Simultaneity	0.2 / 0.5	Only one calculation is done for each charging power / simultaneity combination, so simultaneity factors equal scaling factors of charging power
Local Control Strategies	local voltage control via P(U) and via central storage	Both controlled scenarios are decentralised, meaning that only local measurements influence the control process
Centralised / Coordinated Control Strategies	None	Impact of market signals or other centralised or coordinated control schemes were analysed only via variation of simultaneity factors
P(U) Scenario: Active Power Control P(U) Characteristic	P (94 %) = 100 % P (90 %) = 6 A P (<90 %) = 0 %	Reduction of charging consumption starts at 94% of nominal voltage and limits to 6A at 90% of nominal voltage, below charging is switched off
Central Storage Scenario: Storage Placing	Position in feeder: 75 %	Considering the path from the substation to the grid node with the lowest voltage, the storage is installed on 75 % of the way from the substation to the node.
Total number of EVs in the considered grids of *Salzburg Netz GmbH*	200,700	313,335 cars (PKW) were registered 2018 in Salzburg[24], so 303,900 cars[25] are assumed in the supply region of *Salzburg Netz GmbH*
Total number of EVs in the considered grids of *Netz Oberösterreich GmbH*	352,900	933,682 cars (PKW) were registered 2018 in Upper Austria[26], so 575,500 cars[27] are assumed in the supply region of *Netz Oberösterreich GmbH*

24 Page 3 at https://www.statistik.at/web_de/statistiken/energie_umwelt_innovation_mobilitaet/verkehr/strasse/kraftfahrzeuge_-_bestand/index.html
25 97%
26 Page 3 at

Figure 51 (for lines and cables) and Figure 52 (for transformers) show the grid reinforcement requirements for the defined charging powers and simultaneity factors for both DSOs. Different measures such as P(U) and the implementation of central storage systems were analysed, and the grid reinforcement requirements compared. The x-axis shows different charging powers (P [kW]) combined with different simultaneity factors (CF [%]) due to market driven activation. The y-axis shows the requirements of grid reinforcement in relation to the current grid status.

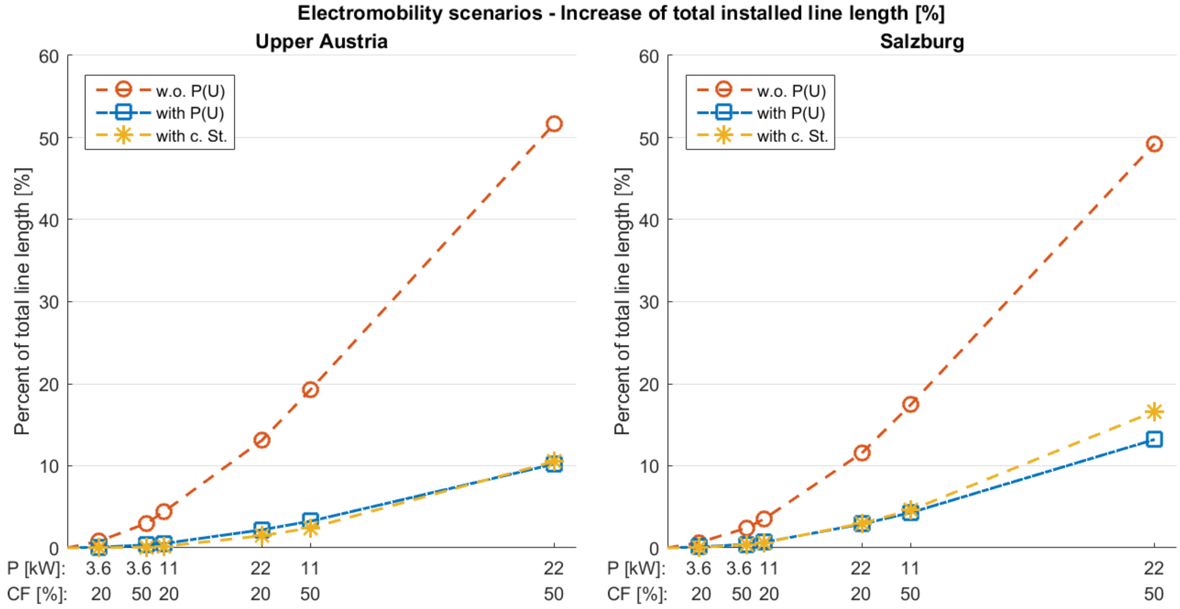

Figure 51: Reinforcement demand of different EV charging scenarios: Percentage of affected lines (length); c. St. = Central Storage

https://www.statistik.at/web_de/statistiken/energie_umwelt_innovation_mobilitaet/verkehr/strasse/kraftfahrzeuge_-_bestand/index.html

[27] 62%

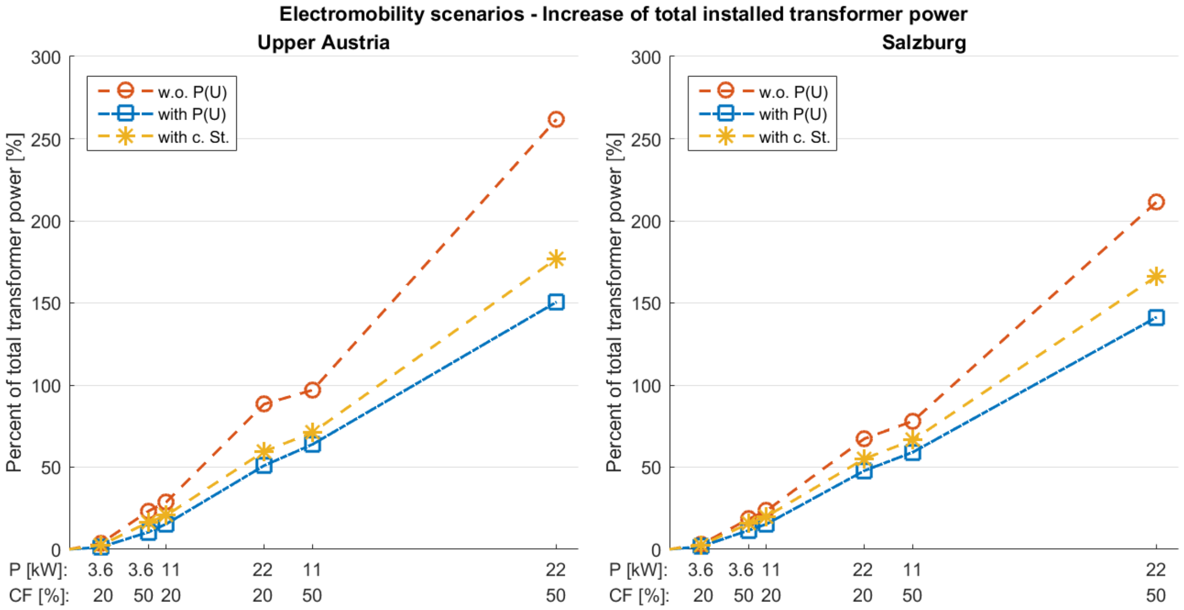

Figure 52: Reinforcement demand of different EV charging scenarios: Percentage of affected transformers (increase of total installed transformer power); c. St. = Central Storage

Based on this analysis the following aspects can be derived:

- The grid reinforcement requirement is highly dependent on the charging power and coincidence factors of the EVs. It is possible that a rollout of EV with low power charging can be supported in the future with existing strategic network reinforcement plans of the DSOs.
- A massive rollout of higher charging power requires significant additional grid reinforcement, meaning that up to 90 % of all analysed grids and transformers or up to 40 % of the installed line length are affected at Netz Oberösterreich GmbH.
- While in the low charging power scenarios less than 10 % of the total line reinforcement requirement is due to network overloading while the remainder is due to voltage violation, higher charging power scenarios lead to 20 – 40 % of line reinforcement demand due to overloading.
- E-mobility in high power charging scenarios can be considered as a challenge not only for LV grids but also for MV grids. However, the MV-grid was not part of the evaluation and further investigations need to be carried out to quantify the impact on MV grids.
- Although a rollout of P(U) control was able to reduce the total grid reinforcement requirements and associated cost (up to 80 %) significantly, reinforcement demand is still extreme in high power charging scenarios. This can be explained by two factors: Firstly, the charging stations P(U) control cannot fully eliminate under-voltage conditions, because it does not consider non-P(U)-curtailed grid load at the end of the feeder. Secondly, P(U) has no capability to avoid line overloading. However, P(U) or flexibility in the charging process in general (in order to keep charging power and simultaneity low), can play an important role to significantly reduce future EV grid integration costs if the regulatory scheme permits its usage.
- Central storage systems are able to reduce grid reinforcement requirements visibly. For the 11 kW scenario with a simultaneity factor of 0.2 a total number of 4,109 systems with a combined power of 92.7 MW would have to be installed in the supply

area of Netz Oberösterreich GmbH. In the supply area of Salzburg Netz GmbH, a total number 899 systems with a combined power of 17 MW would be required. The required storage capacity was not evaluated and should be objective of further investigations.

- The resulting required grid reinforcement for the two DSOs does not differ significantly when compared to the PV scenario. On the one hand, Netz Oberösterreich GmbH allows 6 % voltage drop in LV grids and Salzburg Netz GmbH only 5.5 %. This compensates the higher cabling degree of Salzburg Netz GmbH compared to Netz Oberösterreich GmbH to a certain extend. On the other hand, the scenario assumptions for EV charging led to an especially high reinforcement demand in urban grids (which was not the case in that extend in the PV scenario) and was not restricted to rural grids since the number of EVs scale in a linear with the number of customers whereas PV does not (on multifamily houses less PV per customer can be installed). Therefore, Salzburg Netz GmbH is affected by grid reinforcement with its higher share of urban LV grids more than it was in the PV scenario.
- E-mobility is not an ad-hoc challenge to be solved immediately. Solutions need to be identified and implemented in the near future since the planning horizon for electric grids is around 30 years.

Effect of the *Sonnenbonus* on Grid Voltage

In addition to calculating the load shifting effect of the *Sonnenbonus* (see Section 3.4.2), its effect on power quality measurement was a key factor of interest. To evaluate this effect, measurement data for the time period 10th April 2018 to 11th February 2019, when the *Sonnenbonus* was active, was used and compared to pre-field test values collected in the year 2017. Thereby, the measured phase voltage U_{L1N}, U_{L2N} and U_{L3N} of the installed power quality measurement system were taken from the low voltage grid of the in the community area of Eberstalzell. For the construction of the boxplots shown in Figure 53, the data was subdivided into the effect of the *Sonnenbonus* for

a. the whole community of Eberstalzell and for
b. the busbar at the secondary substation in Eberstalzell.

With this distinction, a statistical analysis was performed to evaluate the effect of the *Sonnenbonus* on power quality. Incomplete measurement data was excluded from this analysis to avoid distortions. The evaluation of the effect from the *Sonnenbonus* (which was valid whenever global solar radiation exceeded 600 W/m² for at least two consecutive hours) a boxplot diagram with modified classification is used.

Boxplots show the median value, the 5 % and the 99 % percentile as well as the minimum (0 %) and the maximum value (100 %). The evaluated 5 % and the 99 % percentile represents the box in the boxplot. The median value is shown as a horizontal line in the middle of the box (5 % and 99 %) and the whiskers indicates the minimum and maximum values. No outliners are shown in the boxplot.

Figure 53 shows the effect of the *Sonnenbonus* on the power quality measurement (voltage) for the whole community of Eberstalzell and at the busbar of the secondary substation of Eberstalzell.

In Figure 53, the two boxplots on the left side show the required voltage band with and without the *Sonnenbonus* in the whole community of Eberstalzell. Comparing the same outer values (≥ 600 W/m² global solar radiation) representing the 99 % percentile, the voltage is about < 1% in contrast to times without *Sonnenbonus*.
With respect to the intended voltage band of 3 %, reserved for decentralised feed-in of e.g. PV generators, in a low voltage network the effect of the *Sonnenbonus* causes an improvement of this reserved voltage band by 33 %.

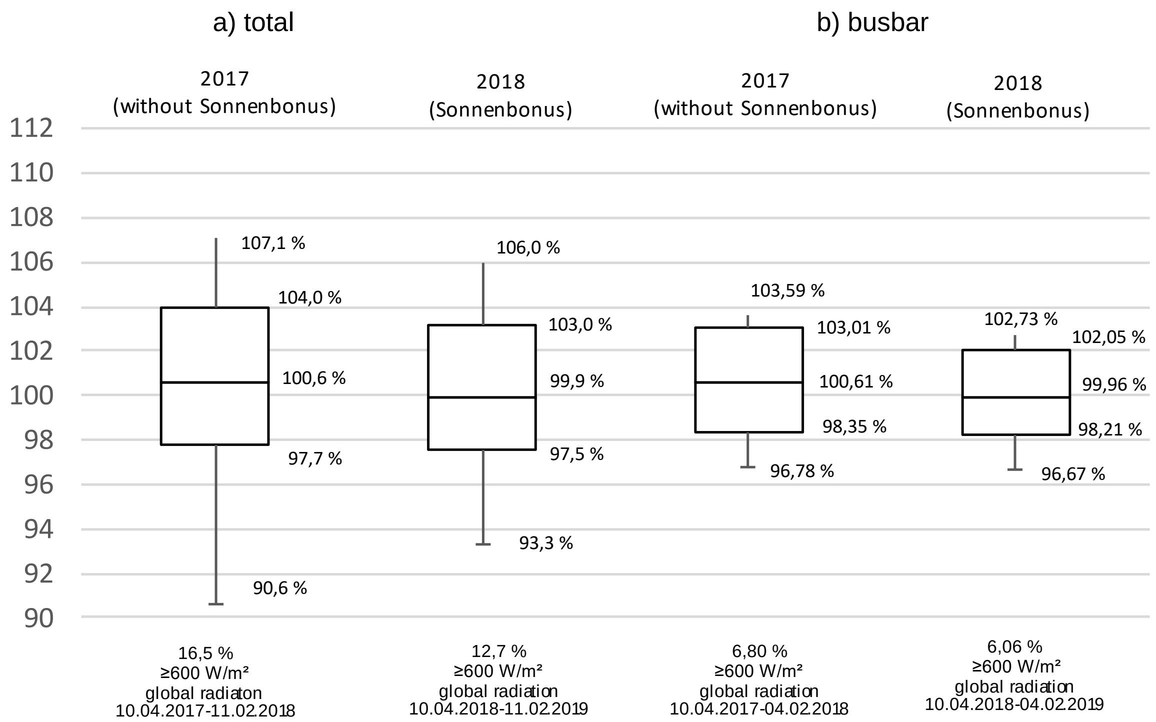

Figure 53: Effect of the Sonnenbonus a) for the whole community of Eberstalzell and b) on the busbar of the secondary substation of Eberstalzell

The two boxplots on the right side in Figure 53 show the voltage band at the busbar in the secondary substation of Eberstalzell. In this analysis, the difference of the 99 % percentile with or without the *Sonnenbonus* is also about 1 %. This situation can be explained by the consideration of voltage fluctuations within the high voltage grid. Thus, an effect of the *Sonnenbonus* on power quality was not detectable.
The *Sonnenbonus* field trial showed several positive effects, most notably the load shifting effect of 5 %, as described above, as well as the overall positive feedback from participants regarding the value of additional information on their electricity consumption pattern. Power quality was not improved as has been shown above. Solutions which create a win-win situation for both the grid operator and the customers should be the primary goal of any real-life customer involvement programs which influence actual grid operation. Future research based on the first (and so far unique) outcomes of the *Sonnenbonus* field trial should therefore be focused on experimenting with the design of the *Sonnenbonus* messages, the criteria when the *Sonnenbonus* is active and potentially, the minimum number of customers required to have an impact on power quality.

3.2 Economic Results

As described in Section 1.5.6, the flexibility activation concepts and the operation strategies in the project are analysed with regards to their economic feasibility. Costs and benefits are assessed and analysed. The following sections describe the most relevant outcomes.

3.2.1 Central Battery Energy Storage System

Costs of a central BESS

Achievable economies of scale effects of larger BESS might lead to lower costs for customers (if it is possible to forward the benefits to the customers to a considerable extent) compared to residential PV-BESS. However, to achieve this, it is necessary to change existing tariff schemes as indicated below. In contrast, positive grid impacts (e.g. avoiding the installation of an OLTC) and thus a financial participation of the DSO must be realised by the central BESS (see Section 3.1.5) in order to significantly reduce overall ESS costs for customers. In return, it is necessary to implement dedicated infrastructure which is not required for residential systems such as concrete foundation, a dedicated housing, laying of cables and metering infrastructure (if not already available). Regarding the total costs (system + installation) of a central BESS, a reduction of 30 % of the BESS was observed during the project term. Furthermore, optimised contracting of the community storage system to customers (considering simultaneity of customer demand and generation) could also have additional positive economic impacts.

Basic economic Feasibility of a Central Storage System

When applying the current grid tariff scheme (applying fees for storing and consumption of electricity) an economic operation of the central BESS as a community storage system is not possible. To allow for an economic feasibility, an adaption of the current tariff scheme for local energy exchange and storage would be necessary (see Section 3.3.2). This is being currently discussed in the context of citizen energy communities (CEC) which are introduced with the new guideline on the electricity market [1].

The extension of currently available pumped hydro storage (PHS) tariffs into grid layer 7 is one part of the proposed solution. For example, instead of approx. 8 ct/kWh (grid tariff + taxes) 0,233 ct/kWh would be applicable for withdrawal of electricity by the BESS from the grid. Accordingly, such new grid tariff regulation options were discussed with the national regulator.

Additionally, a reduced tariff is necessary when energy from the BESS or another local customer is consumed by another customer. This tariff approach is already in preparation by the national regulatory agency (E-Control). By 2020 the Austrian regulator plans to implement a so-called local energy community (LEC)[28] tariff to allow for local energy

[28] The final Clean Energy Package contains two definitions of energy community: Citizen Energy Community (CEC) which is contained in the provisionally agreed recast Electricity Directive, and Renewable Energy Community (REC), which is contained in the recast Renewables Directive. As the project was ended before the

exchange between end customers. The main aspect is that the energy stored in the BESS does not change ownership and remains with the single customers. Thus, it is expected that taxes (VAT, energy tax) and charges (levies for the support of renewable energies) do not arise.

Spot Market Participation of the central BESS

Additional utilisation of the BESS for spot market arbitrage has negative impacts on the economic feasibility (at current market conditions). Two scenarios with different tariffs were analysed:

1. A normal grid tariff including taxes of 8 ct/kWh as described above requires a price spread higher than 80 EUR/MWh to achieve profit. When analysing the optimisation of a BESS with a storage capacity of 100 kWh and perfect foresight, an operational annual revenue of 27 EUR for one year with day-ahead arbitrage is achieved.
2. By applying a PHS grid tariff in 2018 of 0,233 ct/kWh the operational revenue increases to 587 EUR. Investment costs are not considered in those numbers. Therefore, a participation only in the spot market is not economical as the yearly costs of the central BESS are not covered with such revenues. Nevertheless, an analysis in combination with reserve markets is carried out as described below.

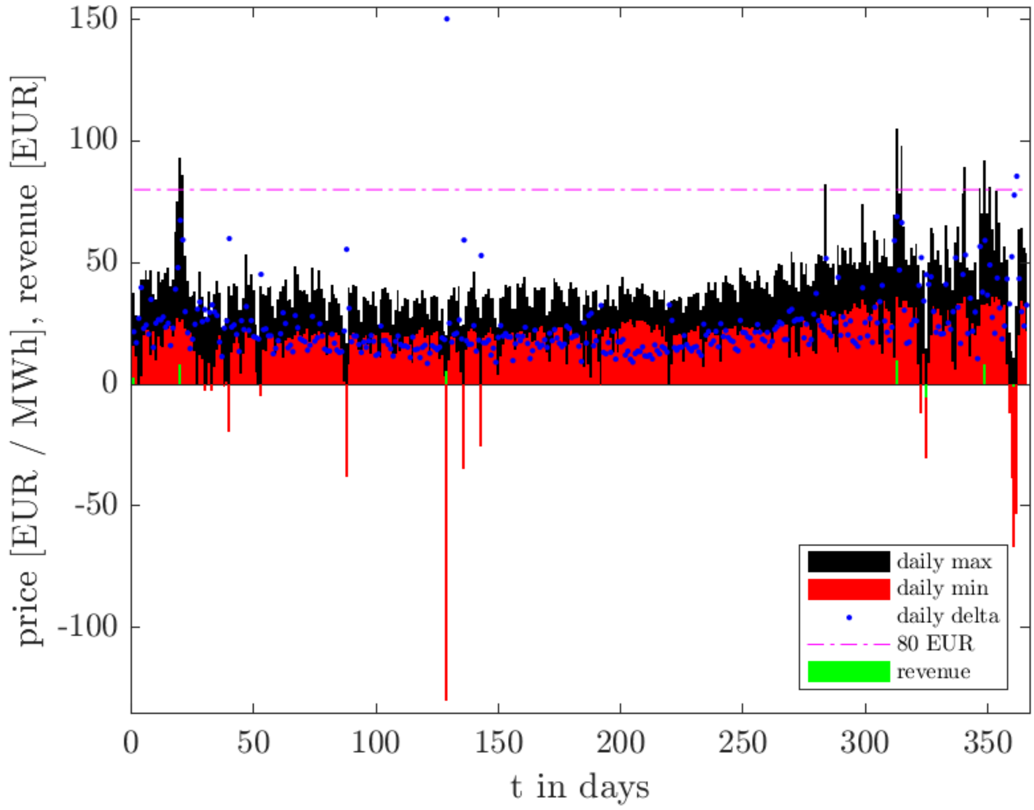

Figure 54: Operation of a 100 kWh storage at EPEX day-ahead arbitrage (year 2016, grid fee + taxes of 80 EUR/MWh)

corresponding directives were issued, the term LEC is used within this document.

Additional remunerated Voltage Control

A dynamic voltage control algorithm including reactive and active power control was implemented (see also Section 2.2.4) to keep the local voltage in the defined voltage band. In case the DSO is willing to pay for this service[29] as a replacement investment for a stronger line or the purchasing of an OLTC where the costs are within the same range, the economic feasibility can be increased significantly. For example, such payments made by the DSO to the storage system operator in Heimschuh could convert an unfeasible business case[30] (losses of approx. 2,000 EUR/a) into a feasible one (profits of approx. 1,200 EUR/a) if no subsidies, storage prices of 2015 (project start) and PHS grid tariffs are applied (see Figure 55). The increased risk of becoming dependent on a third party(system) has to be taken into account and is not part of this calculation.

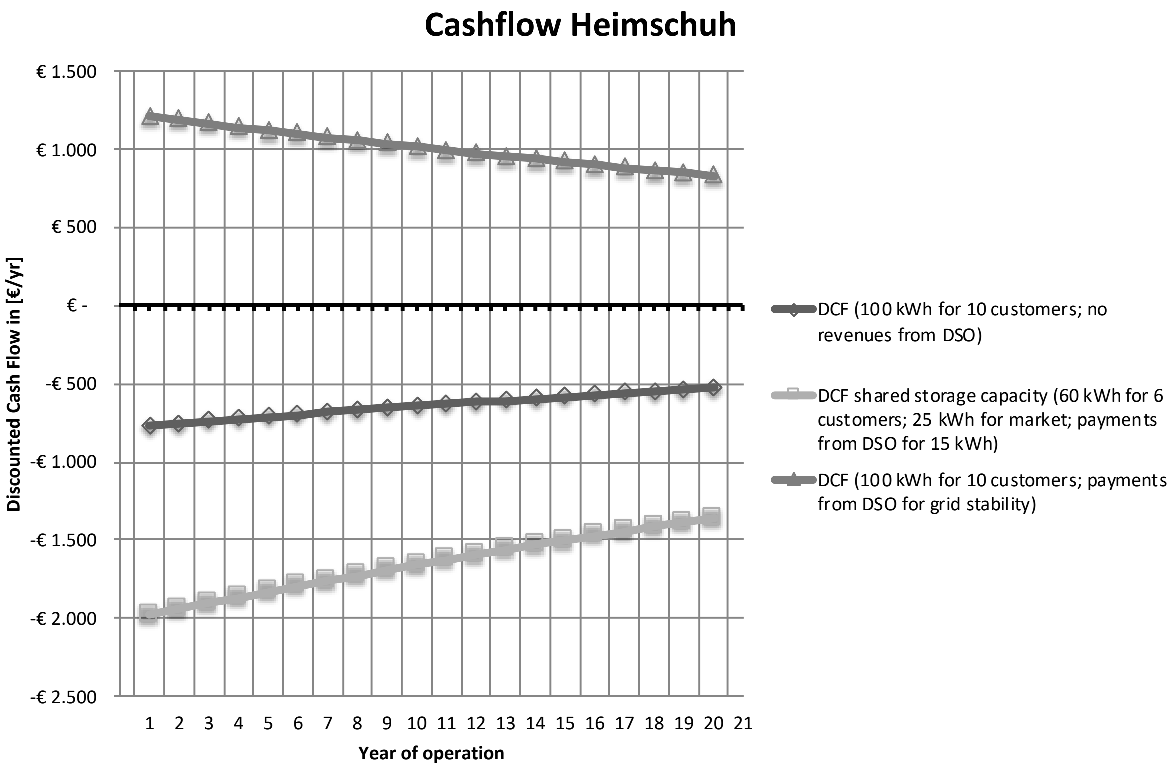

Figure 55: Discounted cash flow (DCF) comparison for the community storage system for analysed business strategies in Heimschuh without subsidies, pumped hydro grid tariffs and varied DSO payments

Provision of Control Reserves

The economic viability of the Heimschuh storage system (100 kW, 100 kWh) on LV distribution grid level with participation in the automatic frequency restoration reserve market (aFRR or SRR (Sekundärregelreserve)) was evaluated. Since the minimum bid size is limited

[29] This scheme is applicable in cases where the DSO has to bear the costs for the grid reinforcements or in situations where a temporary reinforcement is required. In cases where the customers have to pay for the grid reinforcement this scheme is not applicable.

[30] In the business case it is assumed that the customers of the central BESS will yearly pay the same amount to the operator of the central BESS as an own PV BESS would have cost them.

to 5 MW, it is only possible to participate with a 100 kW storage in a bidding-pool with others. Grid tariffs and taxes of 8 ct/kWh are presumed. Additional to day-ahead arbitrage (Figure 54) participation in the intraday market for discharging or charging the BESS in case of aFRR-activation was assumed. The revenue at the aFRR market is of course dependant on the individual bidding strategy. For this optimisation, a “median approach” where a bid with the median annual product price was chosen. The annual operational revenue is 4,100 EUR for the 100 kWh storage system. The optimisation model charged the storage system “for free” with negative aFRR activations and made the most profit by selling it at the intraday market. In Figure 56 a half-day snapshot of the bids, activations and energy flows of the storage system is shown. However, as yearly central BESS costs are significantly higher than achievable revenues as well as the costs for market participation were not considered in the operational revenue, solely implementing this operation strategy seems not economical.

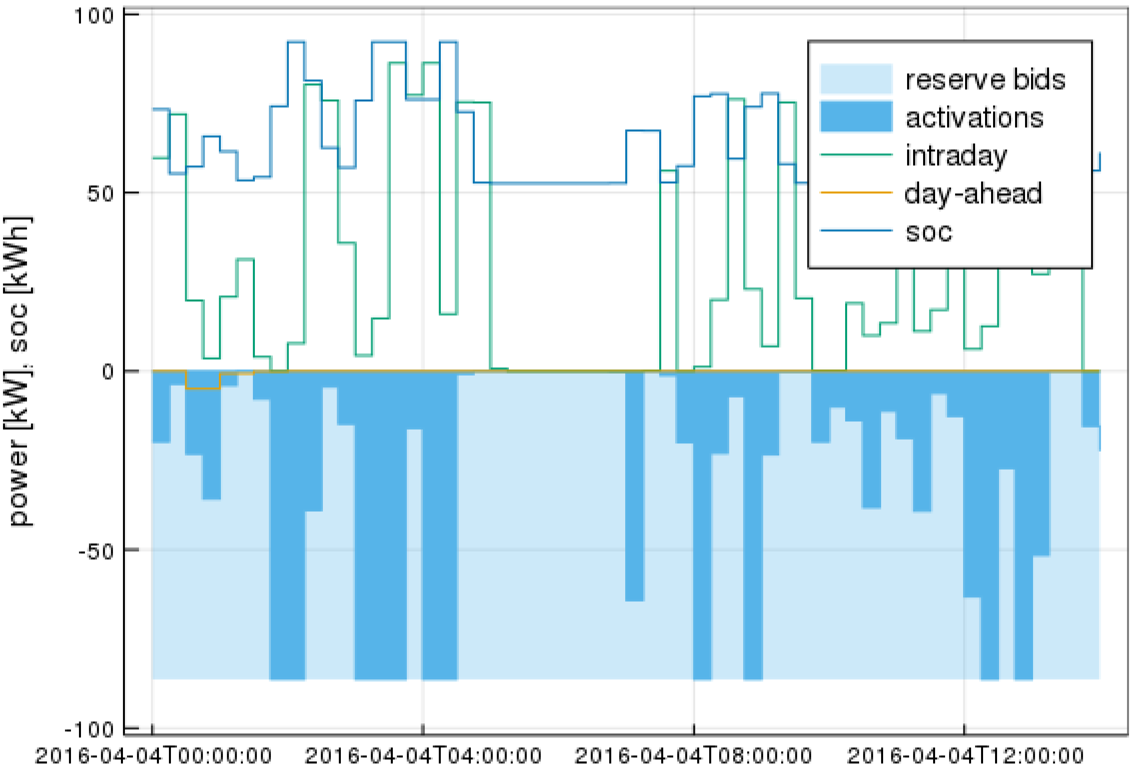

Figure 56: aFRR and Spot-market participation of Heimschuh storage system

3.2.2 Residential PV-BESS

Evaluation of operation strategies

As described in Section 2.1.2, six operation strategies were defined, which facilitate incentives (*Sonnenbonus*), penalties (70%-curtailment, power-based grid tariffs) and energy price structures (flexible energy price) to investigate the impact on prosumers with- and without PV-BESS and flexible loads. In the baseline scenarios, no PV-BESS and flexible loads were considered, whereas in the improved scenario those components were considered. In all scenarios the total loads were 1,150 MWh and the PV generation is 520 MWh.

Some PV energy is consumed directly, while some PV energy is fed into the grid. In Figure 57, the aggregated energy flow of all households in Eberstalzell and Köstendorf for the different operation strategies for one year can be seen. The positive y-axis shows the consumed energy and describes its origin (PV direct use, PV energy stored in the battery, energy procured from the grid and stored, energy procured and used directly) and the losses of the PV-BESS, whereas the negative y-axis shows the feed-in and the curtailed energy.

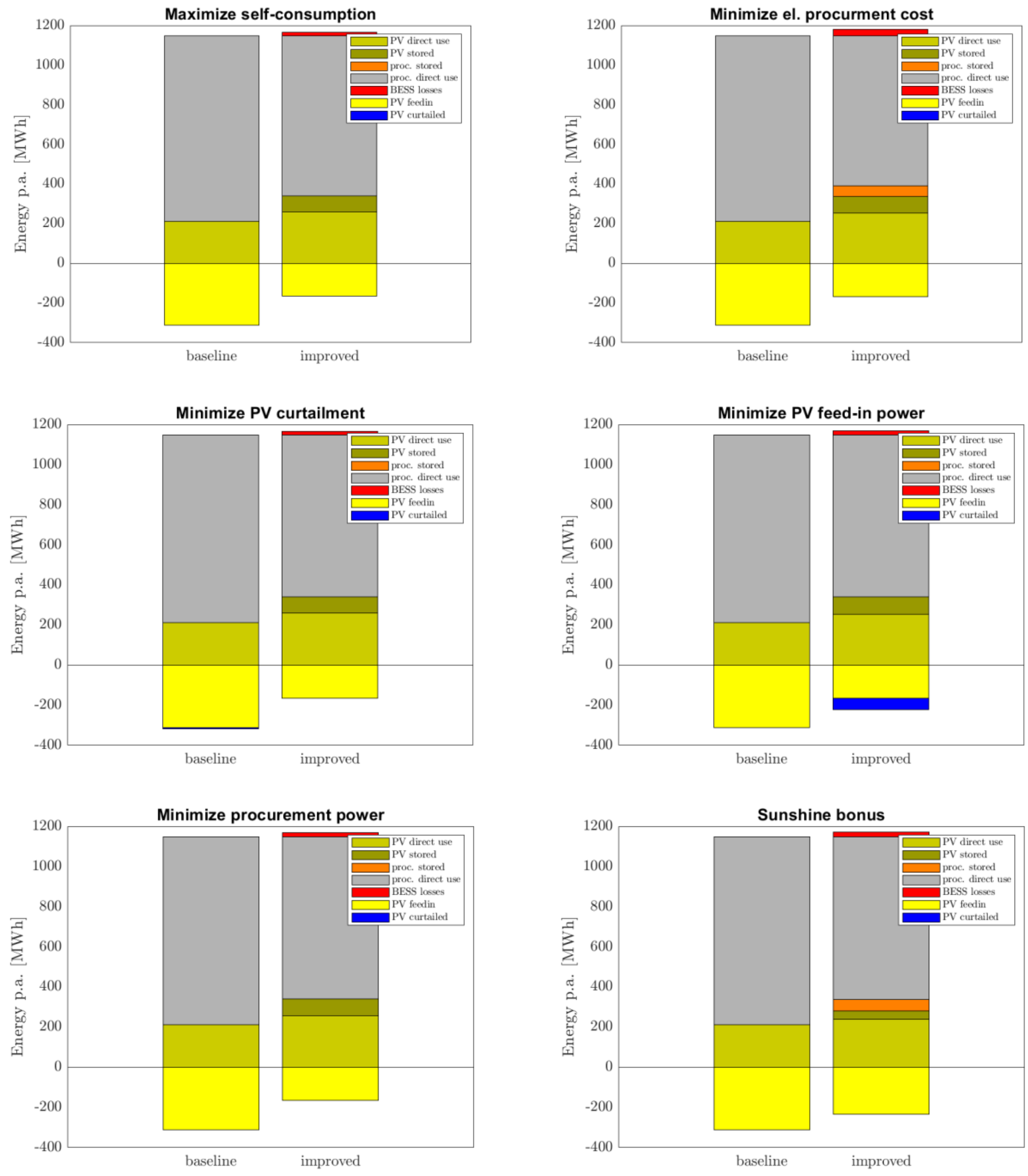

Figure 57: Annual energy flows for different operation strategies

In all operation strategies, the PV-BESS and flexible loads increase self-consumption. In the operation strategies *min. el. Procurement costs* and *Sonnenbonus*, a flexible energy price or a bonus to incentivise consumption was applied. Those are the only two cases where it is economical to charge the PV-BESS from the grid in times of cheap electricity. The operation strategy *min. PV curtailment* permits a feed-in larger than 70% of the PV peak power. This amounts to an average curtailment of 0.76 % (ranging from 0.1 % to 4.3 %) of the total PV-energy in the baseline scenario. In the improved scenario, the flexibilities and PV-BESS consume the excess energy so that no curtailment occurs. The feed-in power pricing in *min. PV feed-in power* leads to curtailment in the improved scenario. Since the PV-BESS cannot store all excess PV generation, it is more economical to curtail it to avoid power-based grid tariffs for grid feed-in.

When the average costs of the baseline scenarios of the different operation strategies are compared to the standard case *max. self-consumption*" (as given in Table 15) an increase in average costs for the strategies which apply penalties like power pricing can be seen. Almost no influence is seen by the 70 % curtailment, since almost no energy exceeds the 70 % PV peak power generation. The *Sonnenbonus* decreased the average costs by less than 30 EUR compared to the strategy *maximize self-consumption*, which shows that less than 300 kWh were procured during the *Sonnenbonus* time. In the operation strategy *min. el. procurement costs* the EPEX day-ahead price of the year 2016 is directly applied for the prosumers which decreases the average costs by 300 EUR compared to the strategy *maximize self-consumption*.

For all improved scenarios, a positive effect on the operational costs is seen. The PV-BESS and flexible loads decrease the average operational costs by 10 % to 18 %. As one can see, a power-based grid tariff has on average a high influence of cost reduction.

Table 15: Average operational costs per prosumer for the operation strategies

Operation strategy	baseline costs [EUR]	improved costs [EUR]	difference total [EUR]	percental change
Maximize self-consumption	1.181	1.065	116	-10%
Minimize el. procurement costs	888	768	120	-14%
Minimize PV curtailment	1.183	1.065	117	-10%
Minimize PV feed-in power	1.351	1.120	231	-17%
Minimize procurement power	1.527	1.251	276	-18%
Sonnenbonus	1.153	1.008	146	-13%

Basic economic Feasibility

All six operation strategies were analysed in a dedicated cost-benefit-analysis. This analysis showed that, at PV-BESS prices considered until late 2018, economic operation of such systems in Austria seemed not given (with some minor exceptions), even though PV-BESS subsidies of 400 EUR/kWh (Upper Austria) or 800 EUR/kWh (Salzburg) were applied.

However, reduction of costs (PV-BESS system price incl. installation) of up to 40 % (e.g. from approx. 1,810 EUR/kWh to approx. 1,080 EUR/kWh for a useable capacity of 4.8 kWh) were observed during the project runtime. Taking into consideration the new subsidy schemes (600 EUR/kWh or max. 30% of investment cost in Salzburg; 300 EUR/kWh for max. 6 kWh for commercial customers in Upper Austria) the economic performance of PV-BESS applying analysed operation strategies significantly increased within the last four years. A high economic performance was seen for the theoretical operation strategy *Minimisation of Procurement Power* and its corresponding parameter assumptions. With the current cost of early 2019, this strategy already achieves an economically viable operation for some of the analysed PV-BESS systems.

Generally speaking, it has to be stressed that other factors such as grid independency, emergency power or self-consumption aspects even further influence the purchase decision of a residential customer positively. If these factors are considered the individual economic performance of PV-BESS may already be given for other operation strategies as well (see Section 3.4.1 for details). However, from a pure micro-economic point of view Levelized Cost of Storage (LCOS), including subsidies of BESS, of about 30 ct/kWh (at 200 yearly cycles) were determined. Compared to a surplus of about 14 ct/kWh for an increase in self-consumption, further visible cost reductions are necessary to achieve economic feasibility with PV-BESS.

As an example, Figure 57 illustrates the revenue optimisation result bandwidth for 37 analysed households (equipped with 4.8 kWh storage systems) in Eberstalzell. These revenues are used to derive resulting cashflows (revenues for the strategy of maximising the self-consumption of locally generated PV electricity via the PV-BESS minus their yearly cost) for minimum (MIN), median (MEDIAN) and maximum (MAX) optimisation results. As can be seen only the maximum revenue optimisation results could lead to a storage utilisation which is close to economic operation at current storage cost and electricity prices in Austria. Very similar results are given for other operation strategies and/or PV-BESS capacities.

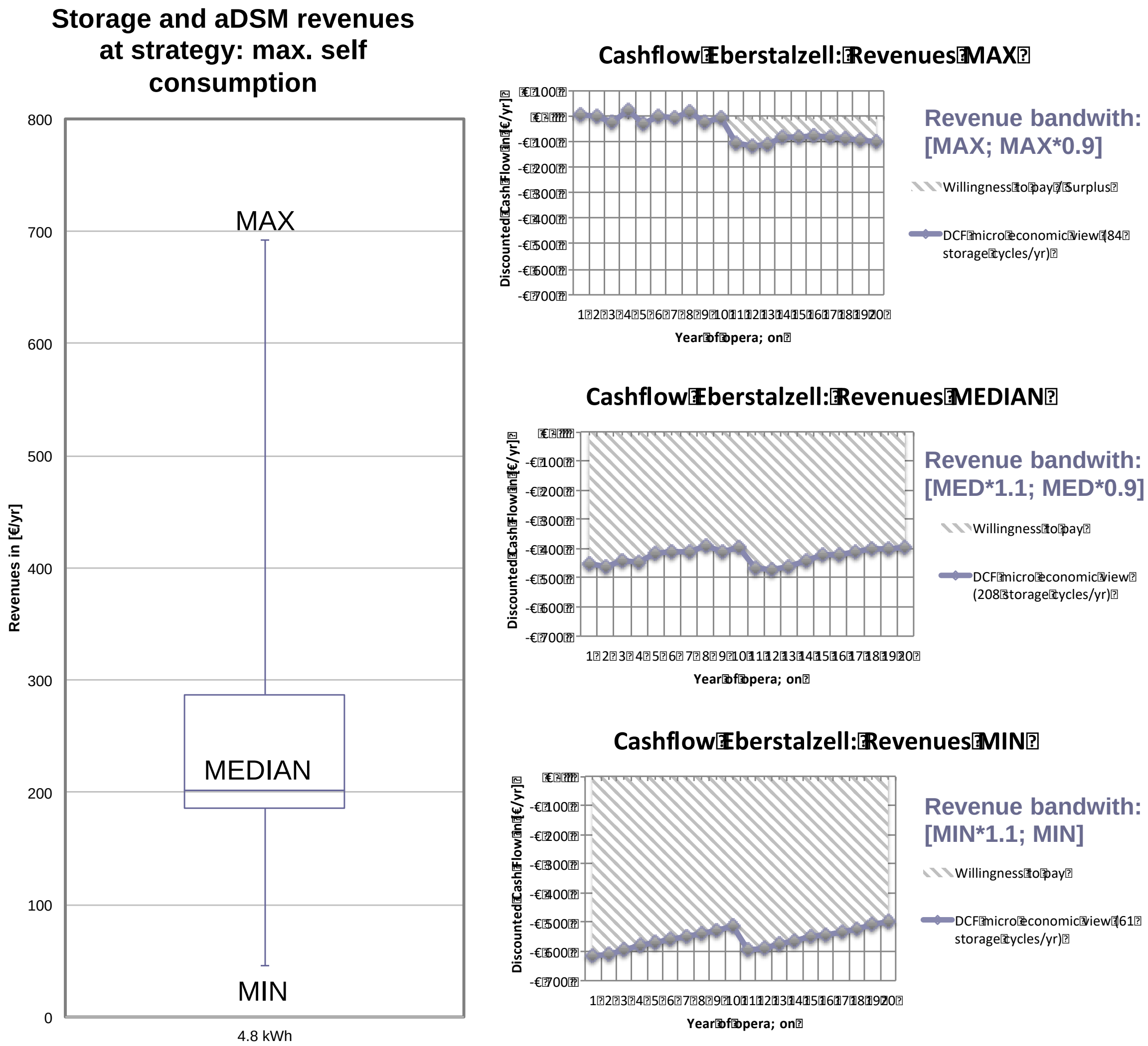

Figure 58: Revenue distribution and cashflow results for 4.8 kWh storage systems in Eberstalzell

Economic Benefit of a grid supporting Operation

In the context of the project, the theoretical grid supporting impact of the *Sonnenbonus* (tested in Eberstalzell) was economically rated. Accordingly, Figure 59 shows the theoretically achievable grid cost savings, if the *Sonnenbonus* was implemented in all low voltage grids within the simulation scenarios of the project. The different bars LOW, MED and HIGH represent different cost scenarios for line reinforcements as defined in Table 17.

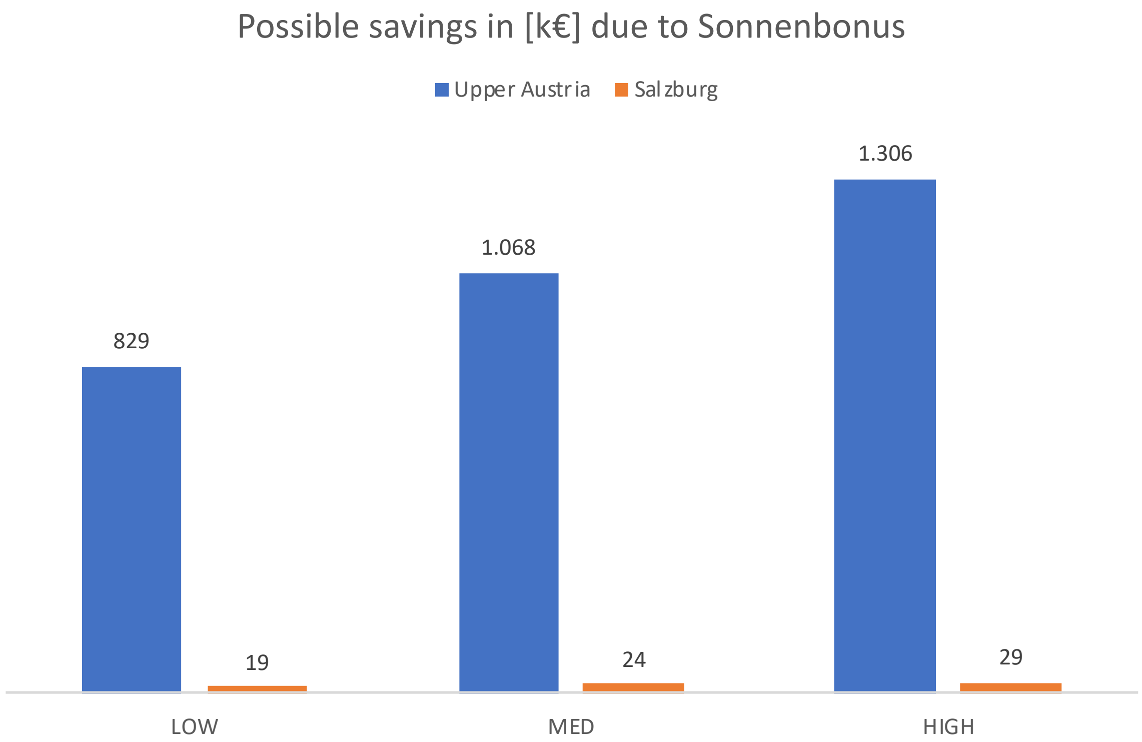

Figure 59: Possible Sonnenbonus related grid cost savings in Upper Austria and Salzburg

Considering the applicable customers, the highest benefits due to the lower requirement of grid reinforcement (1.3 million EUR as Net Present Value) could result in a bonus payment of approx. 3.4 EUR per customer within an evaluation period of 40 years.

On the contrary, if the lowest median value of *Sonnenbonus* payments during the project (1.8 EUR in September 2018) is used for a 6-month period (period with high PV generation) the lowest bonus results in 10.8 EUR per year and customer. Assuming that this yearly bonus motivates the customers for the next 40 years (due to technical lifetime of grid reinforcements) to behave as simulated, the total cost (Net Present Value at a 2 % inflation rate and 4.85 % WACC) per customer would calculate to approximately 200 EUR.

As a result, the calculated *Sonnenbonus* costs (200 EUR per customer for 40 years) lie at factor 58 above calculated grid saving impacts (3.4 EUR per customer). For the Upper Austrian case this would result in financial losses of approximately 75.6 million EUR (NPV within the next 40 years). As a consequence, it seems unreasonable to cover the evident monetary losses by subsidies with the given approach. However, with alternative cost-efficient setups this measure might still become interesting. For instance, a feasible approach would be a cost neutral time-of-use grid tariff.

3.2.3 Integration Effort & Costs

The execution of the project showed that a significant effort is required to implement hardware and interfaces with existing control systems in all three field trials. This includes the complete metering infrastructure (if it is not available), interfaces to the single components and the control systems of the DSOs. This effort must be taken into consideration when applying a corresponding cost benefit analysis. A future rollout of such an intelligent control setup would require significantly lower effort to be cost effective and competitive with other measures. The following sections summarise relevant and hidden costs which arose during the execution of the project.

Costs for Component Interfaces

One relevant interface is the local interface of the distributed assets. In Upper Austria specific attention had to be given to this: when providing data via PLC it is necessary to implement a signal converter to ensure that the signal is compatible and able to communicate with the local device. In the case of Upper Austria this was a converter from PLC to Modbus TCP. When setting up an intelligent control for distributed flexibility costs for such a system, operation and maintenance (O&M) costs have to be taken into account. The investment costs are at about 100 EUR for the RMC-30 Protocol Gateway per device excluding labour costs and annual O&M of about 5 EUR per device. Upcoming security requirements like end-to-end encryption are further adding to these costs but were not regarded in the cost analysis in the project.

Costs for Automation and Control Infrastructure

This includes costs for procurement, installation and operation of controller systems (such as the SLVG-C), communication systems (e.g. data concentrator, repeater) as well as backend systems. A detailed analysis in the project *DG DemoNet Smart LV Grid* was carried out and estimated about 130 EUR/a costs per grid. However, these costs might differ significantly depending on the local automation system and communication infrastructure. Costs such as these have to be taken into consideration for a corresponding cost benefit analysis since they have a negative effect on the economic feasibility.

Additional Costs for Adaption of existing Metering Infrastructure

It has to be taken into consideration that for the control scheme certain measurement values have to be available. If those values are gathered by smart meters a change of the smart meter firmware might become necessary. In some cases that might lead to a necessary official recalibration of the meters. It takes approximately one hour to replace an existing meter of a customer including organisation and travel. Costs such as these have to be taken into consideration for a corresponding cost benefit analysis since they have a negative effect on the economic feasibility.

Costs for Backend Adaption of advanced Ripple Control

Certain smart metering systems as already implemented in Upper Austria include extended switching capabilities, which allow for a more differentiated control of flexible loads. Basically, the whole infrastructure is already available or will be when the smart meter rollout is completed. However, to use the flexibility with this infrastructure, it is necessary to reprogram each metering and switching device. In a pilot project the validation of the correct interaction of all applied technical functions in the grid and at the customers' level is done manually. This effort might exceed the economic benefit gain by using the flexibility. If there is no easy and efficient way to re-program the remote switching configuration for single devices, this measure will not be used in the future.

Efforts for System Analysis

To verify correct operation, the collection and analysis of significant amounts of measurement, metering, and logging data from different components and devices is necessary. For future systems, either this task has to be automated as far as possible, or the components have to configure, integrate and check themselves automatically (plug & play). This is a huge challenge especially because the impact of the applied technical solution on the grid might not be fully predictable in an advanced calculation. Therefore, validation results deviating from the expectations have to be interpreted carefully to answer the question, if there is really a malfunction in the applied solution or if the specifics of the grid are the reason why results are not as expected. As a conclusion, it is not possible to draw a sharp line between correct or incorrect functions of the applied solutions. Furthermore, each DSO will have to find meaningful timing parameters for this validation process meaning that questions like “should the system report anomalies that occur once / twice / over one hour / one day / one week or after one month?” have to be answered individually to keep maintenance efforts low.

Metering Point for Self-Consumption

Increasing the local consumption of PV with flexible loads is only economically viable when there is no usage of the local grid and no corresponding fees, charges and taxes arise (see also Section 3.2.1). This can be achieved either by connecting all loads (flexible loads might be connected at a separate metering point as an interruptible load) and generators to one and the same metering point or by introducing a corresponding measurement scheme as done for community PV (according to § 16a ElWOG 2010 [7]).

Due to historical developments a good share of the flexible loads was connected at a separate metering point with interruptible supply to allow for switching through ripple control. A lower grid tariff and possibly energy price (depending on the supplier contract) is awarded to customers with such components connected as interruptible loads. With decreasing nominal power of those flexible loads (especially heat pumps) and lower feed-in tariff a trend can be seen that customers do not take a separate meter for flexible loads to be able to increase self-consumption and to reduce costs tied to the metering point. This has to be considered for existing setups.

3.2.4 Grid Reinforcement Costs for future Rollout

During the project grid reinforcement cost for PV and EV rollout in Austria (see Section 3.1.7) were evaluated economically. Accordingly, the following cost parameters were implemented. Table 16 shows the generally implemented economic parameters. In this context, it has to be mentioned that the economic evaluation was performed using grid integration simulation results of March 2019.

Table 16 Overview of general economic parameters

Parameter	Value
Inflation rate	2 %
Weighted Average Cost of Capital – WACC (regulated)	4.85 %
Evaluation period (cables and transformers)	40 years

To reflect soil consistency (e.g. stony soil vs. meadow) three cost level scenarios were defined during the project as shown in Table 17.

Table 17 Overview of implemented cost scenarios

Scenario	Cabling costs (incl. digging, installation and surface restoration)	Cost share of cabling material
LOW	50 EUR/m	10 EUR/m
MED	70 EUR/m	10 EUR/m
HIGH	90 EUR/m	10 EUR/m

On asset level the following CAPEX and OPEX values were implemented. It was agreed within the project team, that transformer station upgrades, calculated with CAPEX of 50,000 EUR become necessary, if the new transformer has a capacity which is two capacity classes higher than the original one. Costs for transformers with a capacity higher than 800 kVA (calculated with about 12,000 EUR) were linearly interpolated. The calculation for transformer costs includes the fact, that transformers which are removed because of overload are normally used in another station and not sold for their remaining value (1,000 EUR).

Costs for PV rollout according to *#mission2030*

A comparison of all implemented cost evaluation scenarios in the supply areas of Netz *Oberösterreich GmbH* in Upper Austria and *Salzburg Netz GmbH* in Salzburg is provided by the following figures. For both Upper Austria and Salzburg, the highest PV grid integration costs (between 226 and 360 million EUR in Upper Austria and 11.5 to 17.8 million € in Salzburg) arise if no Q(U) strategy (see “woqu” as blue bars) is implemented. Considering a simultaneity factor of 0.7 (see “woqu_07”; orange bars) significantly reduces the induced cost (bandwidth 114 to 192 million EUR in Upper Austria and 4.9 to 7.7 million EUR in Salzburg) which are however still higher than at a Q(U) strategy (see “qu”; grey bars; bandwidth 42 to 66 million EUR in Upper Austria and 3.9 to 5.2 million EUR in Salzburg) are implemented. Lowest costs are observed if Q(U) combined with a simultaneity factor of 0.7 (see “qu_07”; yellow bars) are considered. In this case the PV grid integration cost bandwidth is between 17 and 28 million EUR (Net Present Value) in Upper Austria as well as 1.3 and 1.8 million EUR in Salzburg.

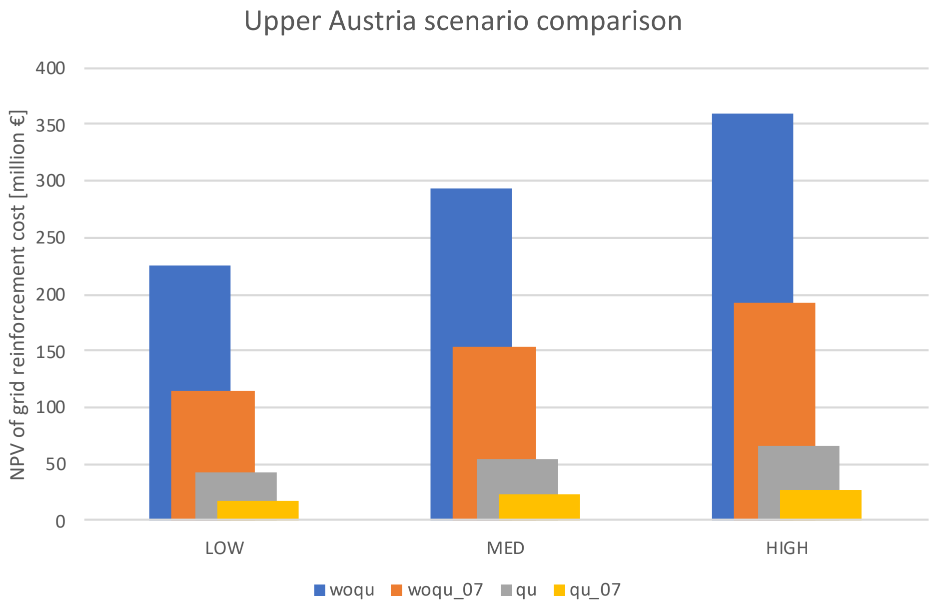

Figure 60: PV grid integration cost - Scenario comparison in Upper Austria (76% of all LV grids of Netz Oberösterreich GmbH considered)

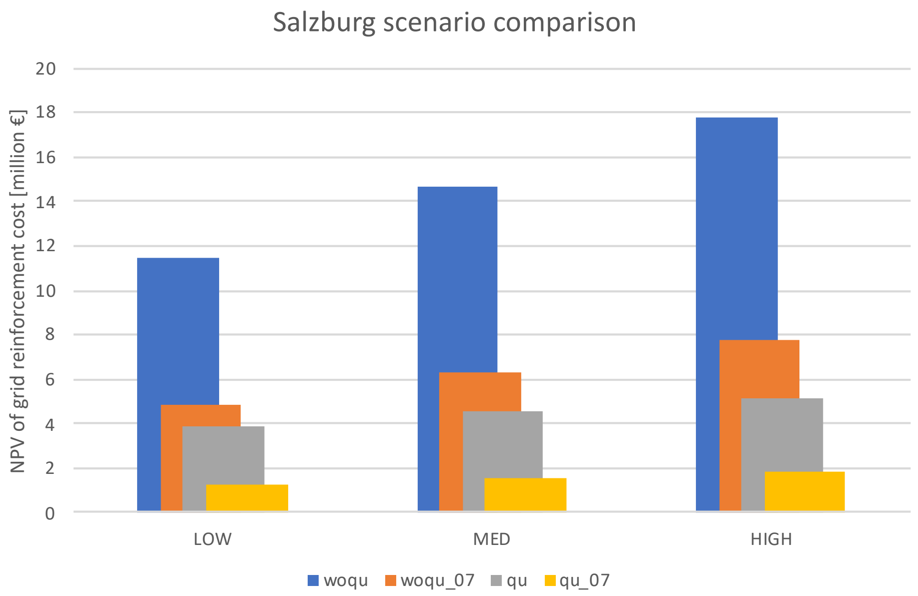

Figure 61: PV grid integration cost - Scenario comparison in Salzburg (54% of all LV grids of Salzburg Netz GmbH considered)

From an economic perspective the implementation of Q(U) strategies once again (see also results of the project *DG DemoNet Smart LV Grid)* result in high grid integration cost savings (about 80% in Upper Austria and 70% in Salzburg) within the simulated LV grids.

On a closing remark is has to be stressed that, depending on the situation, grid reinforcement costs might not arise for the DSO but for the plant operator. In cases of new planned generation plants direct costs for corresponding grid reinforcement in the same voltage level have to be covered by the plant operator. This has to be taken into consideration for future costs of grid reinforcements.

Costs for Rollout of electric Vehicles

Based on the scalability simulation results for EV rollout (see Section 3.1.7) of the project the economic evaluation calculated the grid reinforcement cost with and without P(U) integration strategies. Due to the chosen grid simulation methodology (simulation of peak load flows) it was not possible to derive necessary capacities of simulated central BESS devices. Thus, an economic evaluation of the strategy EV combined with central storage devices was not feasible.

However, the following figures show grid integration cost in Upper Austria and Salzburg for a charging capacity range (3.6 kW to 22 kW) different simultaneity factors (0.2 to 0.5) as well as grid integration cost scenarios (HIGH vs. MED vs. LOW). As can be seen, the results indicate varying cost impacts. For instance, the chosen simultaneity factor highly influences the resulting cost as an increase of the simultaneity factor from 20 to 50 % in all scenarios more than doubles the grid integration cost.

Like the simultaneity factor also the integration strategy has strong cost impacts (see Figure 62). As a result, the implementation of P(U) integration strategies can reduce the grid integration cost between 46 % and 80 % in Upper Austria. Slightly lower reduction possibilities (38 % to 70 %) are given in Salzburg (compare Figure 63).

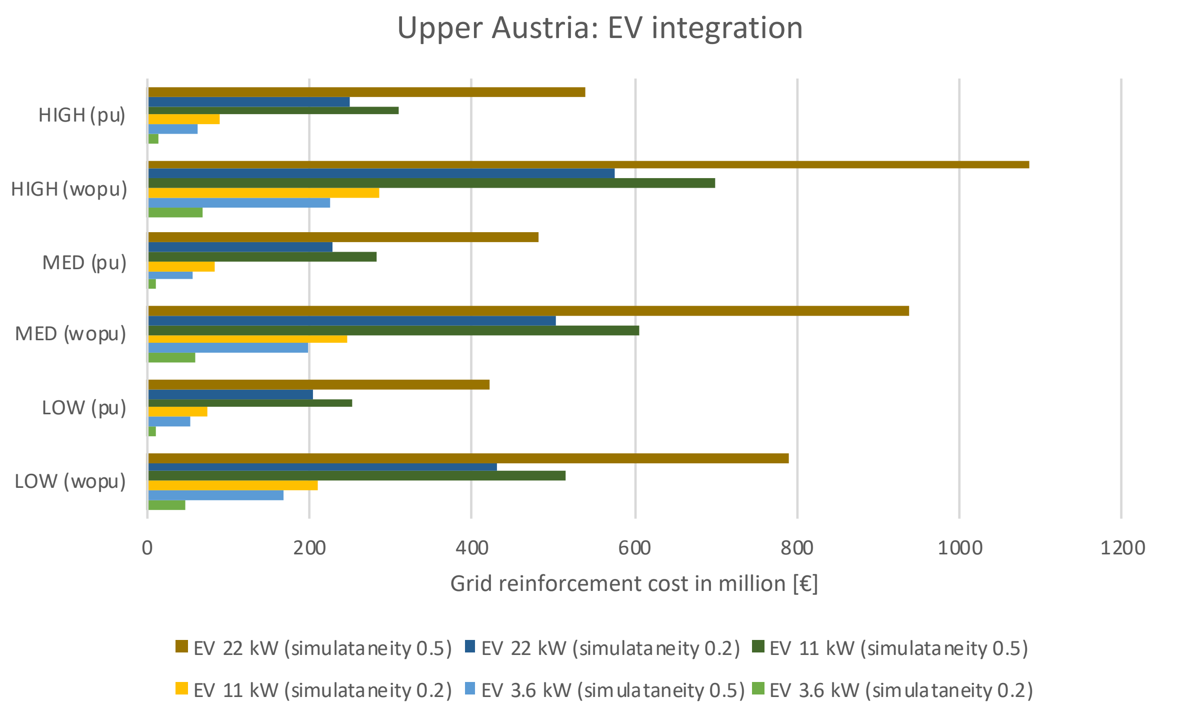

Figure 62: EV grid integration cost in Upper Austria – comparison of all charging scenarios (76% of all LV grids of Netz Oberösterreich GmbH considered)

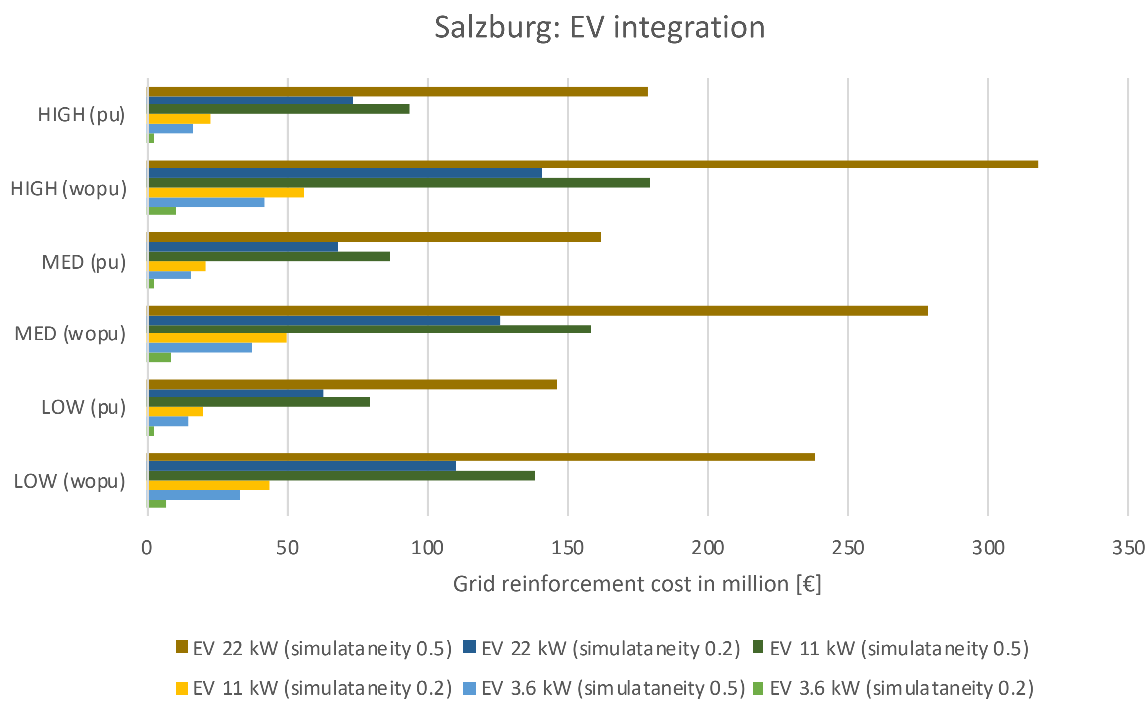

Figure 63: EV: grid integration cost in Salzburg – comparison of all charging scenarios (54% of all LV grids of Salzburg Netz GmbH considered)

3.3 Regulatory Results

As described in Section 1.5.6, the existing legal framework on European, national and regional level was analysed. The analysis conducted showed that the flexibility activation concepts tested in *leafs* can be implemented in the Austrian national context from the regulatory point of view. However, the novelty of these concepts, in terms of the expanding the provision of flexibility to the market domain, raises new coordination issues.
The related EU and Austrian policy, current regulatory framework is still characterised by a number of grey areas with respect to the status and treatment of distributed flexible resources, while different actors in the electricity systems lack adequate incentives for their deployment which are listed in the following sections below.

3.3.1 Ownership & Operation of Storage

The current national regulatory framework does not explicitly regulate whether DSOs are allowed to own and operate ESS. However, the matter is tackled in the current directive in the *Clean Energy Package* by the European Commission [1].
The regulation can be summarised as follows: DSOs are not allowed to own and operate ESS. However, if there is a specific need which is recognised by the national regulator and a market-based procurement is possible, the DSO might be allowed to own and operate an ESS solely for grid purposes. This demand has to be evaluated by the national regulatory agency regularly. Hence, a concluding result will be only available when the definitions of the *Clean Energy Package* are transferred into national law which expected earliest in 2020.

3.3.2 Grid Tariffs for central BESS Operation

The community BESS in Heimschuh was developed based on assumptions for certain tariffs (see Section 3.2.1). This includes tariffs for energy exchange in low voltage grids and a tariff for the BESS operation:

- To make an energy exchange between customers interesting a reduced grid tariff is required. Currently, there is no such tariff scheme implemented in the Austrian regulatory framework. However, the new directive in the *Clean Energy Package* by the European Commission [1] does introduce the concepts of so called citizen energy communities (CEC) and renewable energy communities which needs such a tariff scheme as a basis. Additionally, the Austrian regulator announced that a so-called neighbourhood tariff scheme will be implemented in the near future.
- For PHS a special, reduced grid tariff can be applied. This tariff was also applied in the investigations carried out in the project. However, technology neutral formulation of this specific tariff scheme would clarify the applicability for BESS completely.

3.3.3 Voltage Control for Flexible Loads

Investigations in the project have shown that a P(U) control for EVs has a visible positive impact on future grid reinforcement demand in a given rollout of EVs (see Section 3.1.7). Such a P(U) control is not yet implemented in the Austrian regulatory framework. There are discussions and an effort to introduce such a mechanism in the upcoming version of the Austrian grid interconnection requirements. The following aspects still need to be clarified:

- To what extend such a mechanism can be implemented. This includes voltage levels at which the charge power has to be reduced as well as energy and time periods for how long such a load reduction is allowed. Only with that corresponding planning by the DSO is possible.
- The mechanism is in discussion for EVs but could also be applied to other flexible loads such as heat pumps, domestic hot water boilers or others. Future interconnection requirements might also include these components.
- When implementing such a mechanism it has to be considered that the active power reduction might differ due to the local grid situation. Customers at the end of the feeder at points of higher impedance and a bigger voltage variation will more likely have to reduce charging power compared to customers closer to the local substation. Beside the distribution of power reduction between customers further studies have to carry out to assess the duration of power reduction and its frequency of appearance.

3.3.4 Monetary Bonuses for End Customers

A monetary bonus for grid friendly behaviour of end customers was tested in the project (see Section 3.4.2). From a regulatory point of perspective, it is however unclear how such a bonus is to be tackled as the current tariff system does not provide the possibility of a monetary bonus for grid friendly behaviour. If implemented, a monetary bonus for grid friendly behaviour must be commensurate to achievable savings by grid friendly behaviour, otherwise the cost of the bonus would become an inefficient additional burden to the system. The challenge would be to design a bonus that i. is efficient ii. yields incentive effects and iii. that avoids the possibility of windfall profits.

3.3.5 Feed-in Power Limitation

Extensive simulations in the project showed that a limitation of the feed-in power at the PCC would reduce the grid reinforcement demand for a future rollout of PV significantly and increase the hosting capacity of grids for PV respectively (see Section 3.1.7). With a corresponding local flexibility, the losses due to power reduction can be close to zero.

Currently, DSOs are allowed to specify a certain power limit at the PCC if the hosting capacity limits would be violated. However, the customer is allowed to have a larger nominal generation power installed behind the meter. However, an explicit formulation of a general mechanism of this type does not exist in the Austrian regulatory framework and would have to be discussed with the relevant national stakeholders.

3.3.6 Re-Feed-in of Power

The regulatory implications of charging the battery from the grid (mixed electricity from non-renewable and renewable sources) and feeding it back to the grid were not analysed. Since the DSOs have to report the exact amount of renewable power of each generation type to the regulator ("Herkunftsnachweisdatenbank" in German) this leads to problems when a PV-BESS charges energy from the grid and feeds it back at a later point in time. A possible solution is to use virtual metering points. However, there is no legal obligation for the plant operator to obtain such a virtual metering point. When implementing a corresponding activation of flexibility with PV-BESS, this has to be analysed in detail.

3.3.7 Existing Contracts

From a technical perspective it is possible to control interruptible loads by a DSO. However, contracts with customers might need to be changed as consuetudinary rights of customers for certain off-times ("Sperrzeiten" in German language) for interruptible loads for ripple control might exist. With that, the actual potential for load shifting based on existing infrastructure and contracts might be lower than expected. A more detailed analysis of this matter needs to be performed.

3.4 Socio-Economic Results

The following sections summarise the results from a socio-economic perspective. This includes the *Sonnenbonus* field trial as well as the large-scale survey.

3.4.1 End Customer Survey

As described in Section 1.5.5 a large-scale survey was carried out in the project. The collected empirical basis provides insights not only on the current status but also the potential development of consumer attitudes, acceptance and interests in the energy related technologies and electricity consumption, which can be used for provision of novel services and further development of smart grids. In the following the most relevant results are presented.

Living situation and household equipment

Most of the households in the sample in Styria and Upper Austria are represented by households residing in single-family dwellings. In Salzburg two categories, namely single-family dwellings and double family dwellings have a similar share in the sample, representing 74 % of the sample. Looking at the ownership status, in all the three states most of the respondents own their dwelling – in Upper Austria 94 % of the households, followed by Styria with 81 % and Salzburg with 79 %. Accordingly, the average living space size in the sample is rather big – 142 square meters, which is explained by the significant share of single/double family dwellings in all the three states. Further, looking at the size of the households, a rather homogenous distribution among the three member-states is observed with 2-person households being the dominant category, followed by 3-person households as the second biggest category and 4-person households as the third. On average, the households in the sample have 2.7 residents. Another important characteristic of the households in the context of electricity consumption is the ownership of energy-intensive appliances like dryers, swimming pools and saunas. Although again the overall distribution of share of households owning specific appliances is rather comparable in Upper Austria, Styria and Salzburg, the highest share of dryers (63 %), saunas (36 %) and swimming pools (24 %) were observed in Upper Austrian households.

Adoption of PV

The survey questions related to PV covered motivational aspects, e.g. why was PV installed in the first place, experiences with owning a PV including operational costs, future plans when public subsidies run out as well as the households' interest in community-owned PV installations. Relevant aspects can be found in Table 18.

Table 18: Overview of PV aspects in the survey

	Upper Austria	Salzburg	Styria
Share of PV owners	20 % (420)	40 % (424)	14 % (1,445)
Households (HH) intending to buy PV	Yes: 3 % Maybe: 24 %	Yes: 3 % Maybe: 12 %	Yes: 4 % Maybe: 21 %
HH interested in Community PV	56 %	51 %	-
Number of subsidies (S) claimed by PV owners	1 S: 87 % 2 S: 12 % 3 S: 1 %	1 S: 84 % 2 S: 15 % 3 S: 1 %	1 S: 69 % 2 S: 29 % 3 S: 2 %

The share of PV owners in the sample is the highest in Salzburg with 40% of the sample owning a PV, followed by Upper Austria with 20 % and Styria with 14 % of the sample. Such a high share of PV owners in the sample can be explained by three factors:

I. the selection criteria used by the grid operators when they invited their customers to the survey,
II. a high share of single-family dwellings was represented in the sample and

III. the fact that usually the households that react to an email contact from their electricity provider have a higher level of interest in energy related topics than the average household.

Further on, the highest share of households that consider installing a PV system in the near future is observed in Upper Austria (27 %), followed by Styria (25 %) and Salzburg (15 %). Also, when asking about participation in community PV system a high interest in both Upper Austria and Salzburg was observed.[31] Looking at the factors that are important for respondents in terms of their decision to participate in community PV – increasing the share of renewables turned out to be the top ranked factor considered very important by 65 % of respondents. The next two factors both with a share of 61 % are the absence of personal risks of and clear information on the costs and profits of such an investment. No personal involvement in maintenance and operation is another factor of importance (52 %). Overall, these results confirm a high support and interest of consumers in the increase of renewables. Furthermore, if an investment in such community-owned PV systems is to be implemented most of the households do not want to be involved in the operating activities, while they want to have a clear overview of the related costs and profits. These results serve as in important input in development of business models for community PV.

Electric Vehicle Usage and Experiences

Overall 435 households in the survey own an EV. In Table 19, selected results of the questions related to EVs are presented. It can be seen that 3.7 % of Upper Austrian survey participants own an EV, while the respective number in Styria is slightly lower at 2.9 % and higher in Salzburg at nearly 5 %. For all federal states, this is significantly higher than the actual share of EVs in the federal states which is at roughly 0.4 - 0.5 % (Data from *Statistik Austria*). 22 % in Upper Austria and Styria as well as 28 % in Salzburg consider buying an EV in the coming five years. The survey also asked all households to tell, if they have already gathered information about EVs: more than 70 % said they had. When it comes to public charging facilities, Upper Austrian and Styrian EV owners said that they mostly use charging stations at shopping malls, while in Salzburg more than half of them prefer charging stations at public parking places.

Table 19: Overview of selected indicators for EVs in the survey

	Upper Austria	Salzburg	Styria
Share of EV owners in the sample	3.71 % (n = 79)	4.95 % (n = 53)	2.95 % (n = 303)
Share of EV owners in the federal state (Data from Statistik Austria)	0.4 %	0.5 %	0.4 %
Share of HH intending to buy EV	22 %	28.1 %	22.8 %
Share of HH who have already gathered information about e-cars	76 % (n = 2,050)	71.2 % (n = 1,017)	73.3 % (n = 9,947)
Mostly used public charging stations	Shopping Mall (58 %)	Public Parking (55 %)	Shopping Mall (38 %)

[31] These questions were not part of the Styrian questionnaire.

Considering the current literature on electric mobility showed that main barriers to wider adoption of this technology are costs of EVs and concerns regarding public charging availability [8]. The outcome of the survey confirms these findings: in all three federal states, the driving range was selected as the top reason to not buy an EV. The second most important reason is the actual price of an EV followed by concerns about the public charging infrastructure. For the two top reasons that speak against EVs from the point of view of survey participants, a difference between households living in thinly populated areas and areas of intermediate density compared to households living in a densely populated area can be seen. For the first two groups, driving range concerns are more important than for the third group, the same is true for price considerations. In contrast, household in densely populated areas have more troubles installing private charging points. One possible solution to the second concern is the business model of community charging which represents a mix of a privately-owned charging points and public charging in the sense that it is owned by a group of households who can use it under agreed terms.

Electric heating

The survey also included questions about the currently installed heating system. Here, a rather heterogeneous picture with respect to the share of specific heating systems was observed. For instance, in Styria the three top systems are district heating (20 %), followed by fuel oil boiler (19 %) and natural gas heating (18 %). In Salzburg gas heating takes the first place (19 %) followed by district heating (18 %) and heat pumps (17 %). In Upper Austria, the highest share of household owns biomass heating – 20 % of the sample, followed by fuel oil boilers (19 %) and natural gas heating (18 %).
The survey also included questions asking households if they had plans to update their heating systems within the next few years. 11.4 % of respondents stated that they plan to install a new or updated heating system. According to the data in all the three federal states electric heating (heat pump) is the preferred future heating system which households plan to install, but the responses also show, that 20 - 27 % of households are still undecided about their future heating energy choice.

Interest in PV-BESS

Households equipment with PV-BESS as well as factors that are important in the context of the decision to buy them (Figure 64) were also covered in the *leafs* survey. The highest share of households that own a PV-BESS is observed in Salzburg (8 %). In this federal state we also find the highest share of households who intent to buy a PV-BESS. Upper Austria and Styria have the same distribution of responses with 2 % owning a storage system and 3 % intending to buy one (see Table 20).

Table 20: Selected Indicators for storage units and community storage facilities

	Upper Austria	Salzburg	Styria
Share of storage owners	2 % (n = 48)	8 % (n = 82)	2 % (n = 251)
Households (HH) intending to buy storage	3 % (n = 71)	6 % (n = 69)	3 % (n = 302)
HH interested in community storage	-	-	80 % (n=2,878)

The most important factor influencing the buying decision which was identified as very important by 81 % of respondents is the maximization of self-consumption of self-generated PV electricity followed by energy autarky which was identified as a very important factor by 60 % of the respondents. The factor that turned out to be of least importance according to our survey are the available subsidies – 36 % of households claimed that this factor was not important at all, while only 15 % named this factor very important. The results of the survey show that households that adopted the storage technology are mainly motivated by the desire to increase own consumption and reduce grid dependency while also avoiding potential supply interruptions and black outs (see Figure 64).

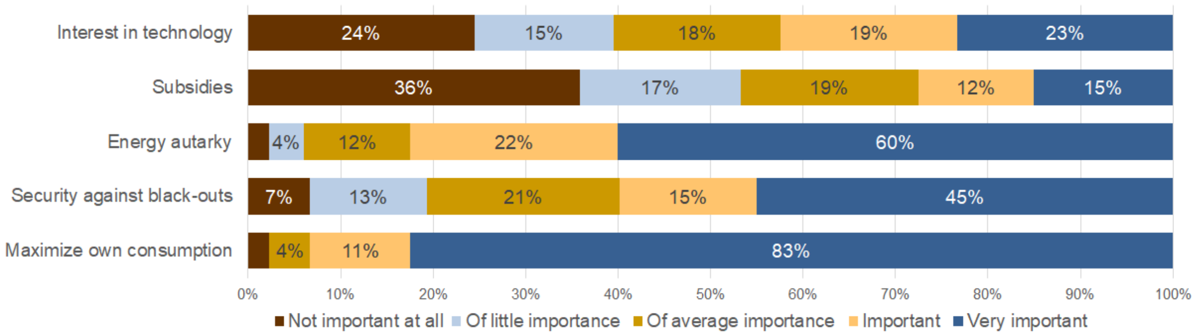

Figure 64: Factors affecting storage system acceptance (n = 269)

Interest in community storage

The survey included questions on the investment in community storage systems. Respondents were asked to rank the importance of factors like the questions on the adoption of community PV (see Figure 65). A similar trend was observed, where most respondents attach high importance to transparency of costs and profits, as well as an increase in renewable and absence of responsibility for the maintenance and operation of the storage system. We observe no significant differences in answers from households living in houses versus those living in apartments.

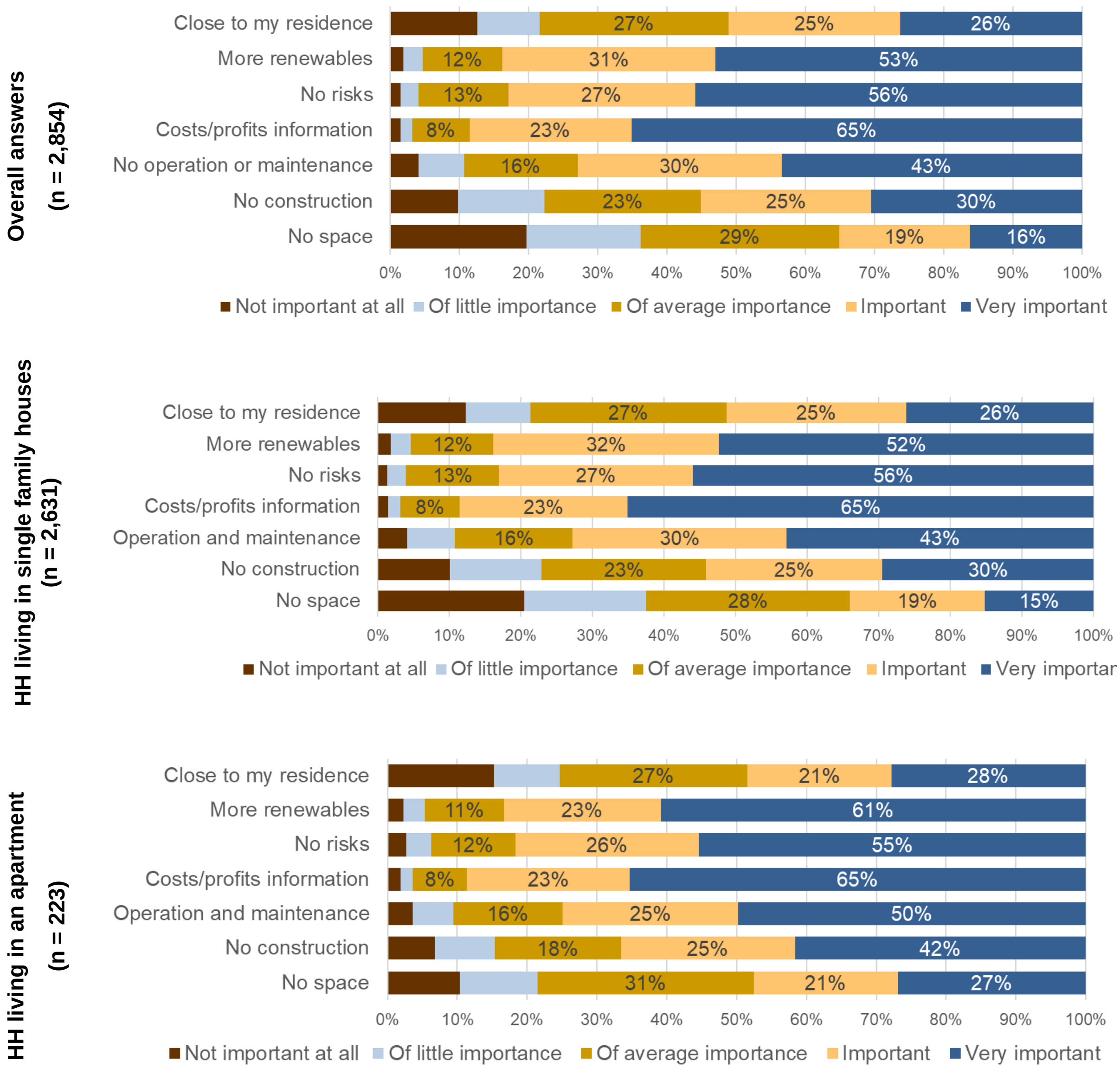

Figure 65: Importance of specific characteristics of community storage facilities to households

Information provision

The survey also investigated, what kind of information about their electricity consumption customers want to get, how they want to receive it and in which granularity (see Figure 66). The information that households want to get in 15-minute intervals is their electricity consumption – expressed by 7 % of respondents in the sample. All the other information including electricity costs are desired by households on daily, monthly, or yearly basis. 27 % of the households would like to receive information on their electricity consumption on a daily basis, same applies to the costs of electricity (20 %). Looking at the information which households would like to receive on a monthly basis – 51 % of the surveyed indicated energy saving tips which is the second most popular option after the electricity consumption.

Comparison with other households turned out to be the least popular type of information for households in the sample with 30 % suggesting that they do not want to receive this information. However, summing up the results of this part of the survey, a high interest of consumers can be observed to receive a detailed information related to electricity consumption.

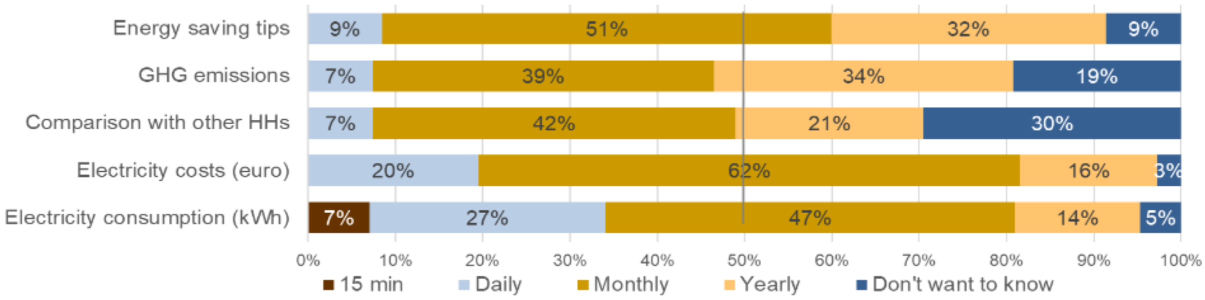

Figure 66: Information provision frequency (n = 13,336), full sample

Community charging concept

The *leafs* survey investigated consumers' attitudes to a community charging concept as well as estimated the importance of the attributes of such charging stations for consumers to participate in it (Figure 67). The households were asked to rank six attributes and choose the most important one, the second most important and the least important that would influence their decision to participate in such a project. Looking at the results, it can be seen that the costs of the charging station were ranked by the majority of households as the most important factor (23 %), the second most important factors were distance to home and flexibility to charge the car at any time (both 20 %), the least important factor chosen by the majority of the respondents was the power of the charging station or the speed of charging (29 %) followed by the possibility to leave the car over night at the charging station (24 %). Further on, the survey analysed the difference in distribution of the attributes' ranks based on the ownership of EVs (see Figure 68). Although in general the distribution of answers looks somewhat similar there are some major differences.

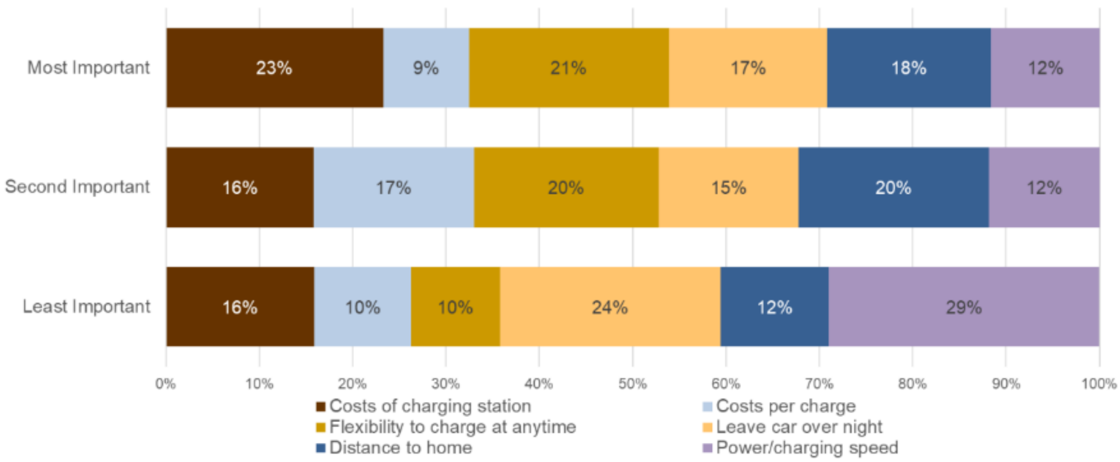

Figure 67: Community charging attributes (n = 3,452)

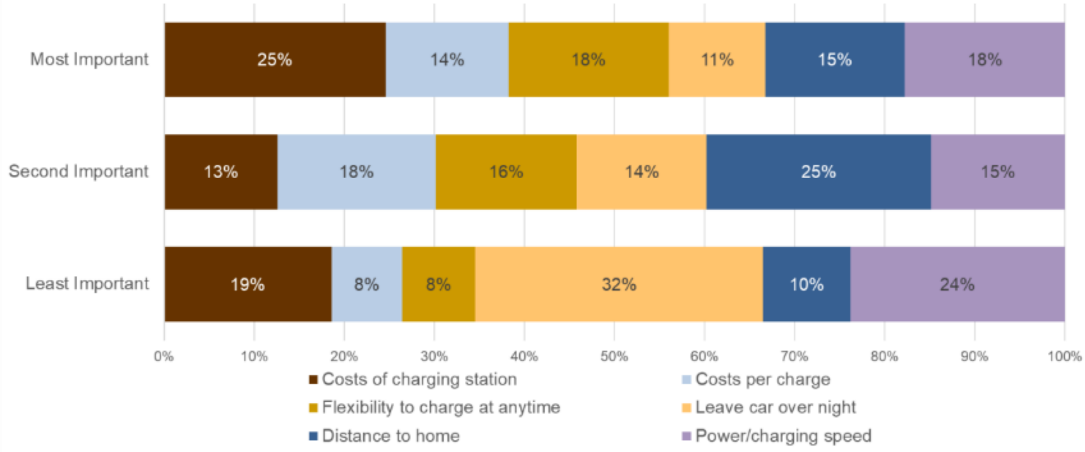

Figure 68: Community charging attributes, EV owners (n = 435)

Compared to households without EVs, households (see Figure 69) that already own an EV attach a higher importance to the power of the charging station, but less importance to the possibility to leave the car overnight. For the second most important factor, the study also observed differences in distribution of ranks of the attributes, but most interestingly in the least important attributes EV owners opted for a possibility to leave the car over night, while the majority of non-owners chose the charging speed as the least important attribute. Such differences in distribution of attributes can be interpreted as empirical evidence of difference between the two groups of consumers which can be explained by differences in socio-demographics partially: early adopters are mainly residing in single family house and have a higher than average income, however the majority of the sample is represented by households residing in single family houses. Another possible explanation is the difference in attitude due to availability of experience[32] which is also found in previous studies suggesting that by having personal experiences with electric vehicles, consumers' perception of driving range and charging location may change.

[32] See, for instance, Anders Fjendbo Jensen, Elisabetta Cherchi, Stefan Lindhard Mabit, On the stability of preferences and attitudes before and after experiencing an electric vehicle, Transportation Research Part D: Transport and Environment, Volume 25,2013, Pages 24-32.

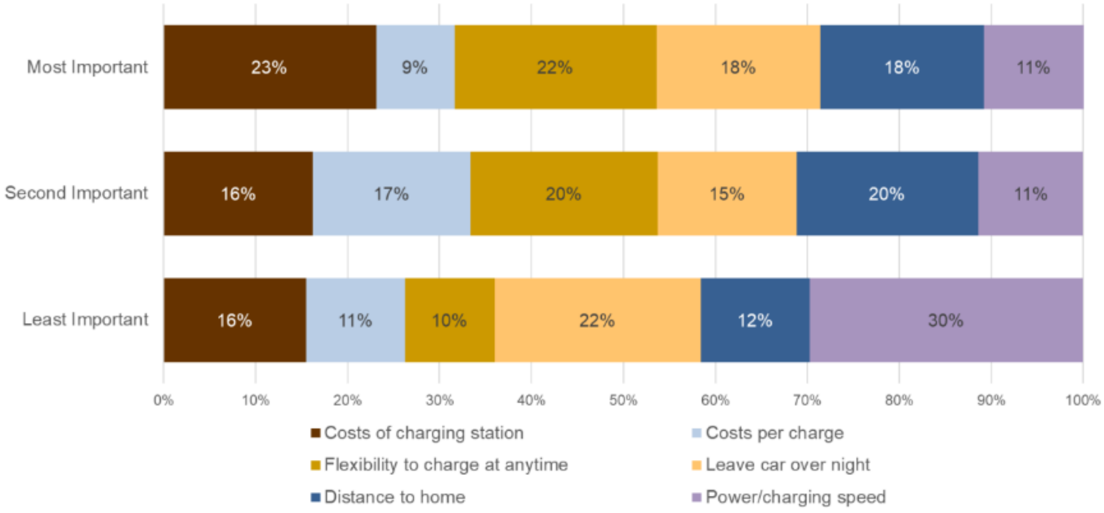

Figure 69: Community charging attributes, no EV (n = 3,017)

3.4.2 *Sonnenbonus* Field Trial

As part of the leafs project, the project aimed at quantifying the effect the potential measure, load shifting in the residential sector, has on the local electricity grid in the Upper Austrian village Eberstalzell (see also Section 2.3.4).

Sonnenbonus Effect on Consumption

The results of this analysis are shown in the following table, for Phase 1[33] of the field test where the *Sonnenbonus* threshold was set to 600 W/m^2. Phase 1 of the field test lasted from April 11st 2018 until February 1st 2019, but after October 1st 2018 no more *Sonnenbonus* were given in Phase 1 because no time periods exceeding the solar threshold based on the solar predictions occurred. Thus, the estimation is completed using the time period April 11st 2018 – October 1st 2018, for Phase 1.

The primary result is that on average the *Sonnenbonus* treatment increases electricity consumption during the bonus time period by 5.2 %. Total household consumption during *Sonnenbonus* times from primary electricity meters was 50,113 kWh. Similarly, the average 15-minute consumption during *Sonnenbonus* times is 0.151 kWh.

Table 21: *Sonnenbonus* Phase 1 estimates

Time	ITT-Effect34	Estimate	Std. Err.
Overall	5.2 %	0.0506***	(0.011)
Sunday	1.4 %	0.0139	(0.018)
Monday	8.2 %	0.0791***	(0.015)
Tuesday	5.8 %	0.0567***	(0.015)
Wednesday	2.0 %	0.0201	(0.013)

[33] Results for Phase 2 of the field test (February-March 2019) are presented in Deliverable 6.1 of the leafs project. Results for this second phase are not statistically significant and are therefore not discussed further in this report.
[34] An ITT (Intent To Treat) effect measures the effective change in the outcome when an attempt is made to apply a treatment to a given individual or population.

Time	ITT-Effect34	Estimate	Std. Err.
Thursday	11.6 %	0.110***	(0.017)
Friday	6.2 %	0.0602***	(0.018)
Saturday	2.2 %	0.0226	(0.017)
Midnight – 7:00	0.0 %	0	(.)
8:00	3.9 %	0.0380*	(0.021)
9:00	6.2 %	0.0599***	(0.016)
10:00	8.0 %	0.0769***	(0.016)
11:00	5.4 %	0.0530***	(0.015)
12:00	3.9 %	0.0379**	(0.015)
13:00	5.1 %	0.0496***	(0.014)
14:00	6.3 %	0.0610***	(0.014)
15:00	2.9 %	0.0290*	(0.016)
16:00	-2.5 %	-0.0255	(0.025)
17:00 – 23:00	0.0 %	0	(.)

* significant at α = 10%, ** significant at α = 5%, *** significant at α = 1%, ITT effect has same significance level as corresponding β1 estimate.

Looking first at the results by day of the week, it can be noted that on weekends the *Sonnenbonus* treatment is much less effective, with a 1 – 2 % estimated treatment effect. In contrast, Thursdays showed the highest treatment effect of an 11.6 % increase in household consumption for times in *Sonnenbonus*. The take-away here is that *Sonnenbonus* treatments have been much more effective at changing household consumption during weekdays than weekends, except for Wednesday, which has low treatment attendance in Austria. This is probably because households are occupied with leisure activities during the weekends when the *Sonnenbonus* is active.

Turning now to focus on the outcome from the hourly specification, it can be noted firstly that the effect of the *Sonnenbonus* cannot be tested during many times of the day since the *Sonnenbonus* is not active when the sun is not strong. *Sonnenbonus* treatments were active between 08:00 and 16:00 during the study. However, the earlier and later timeslots in this range received fewer *Sonnenbonus* treatments, since it was not often that the sun was predicted to be strong during these times.

Thus, there is a difference in treatment intensity between time slots that may cause differences in estimated treatment effects. This could be due either to small sample size concerns, i.e. there were too few *Sonnenboni* given at 16:00 to identify the true effect of the treatment at this time, or a behavioural effect whereby study participants expect, or came to expect, the *Sonnenbonus* during midday times and so were better able to respond to the treatment during these times. Alternatively, it is possible that households are simply unable or unwilling to increase their electricity consumption around e.g. 16:00. For either reason, stronger treatment effects during midday times between 09:00 and 16:00 were observed. Interestingly, the treatment effect at 16:00 is negative and statistically significant, which may be a spurious correlation due to the very low number of *Sonnenboni* that were active at 16:00. However, this may also indicate a load shifting effect, where households are increasing their usage during earlier times and then decreasing their usage in the following hours. Overall, these results are an important and novel contribution to the understanding of consumer behaviour with respect to household demand on electricity produced from renewable sources. Furthermore, if automation would have been enabled in our experiment it is likely that even stronger effects could have been seen. Yet, even without automation households involved in *Sonnenbonus* tests demonstrated a solid potential for load-shifting during times with high production from local solar power plants and showed strong user-engagement in the experiment over a long period of time.

End Customer Perspective

In order to get a better understanding of the findings, all field test participants were asked to share their experiences in the field trial in late March 2019. For that, an online survey was set up and participated were invited via email to complete this survey. In total, 52 households provided answers. The focus of the survey was to investigate the way in which households used the *Sonnenbonus* time slots. From their responses it can be seen that nearly 60 % manually switched on their washing machine and dryer. 23 % of the participants mentioned that they programmed their washing machines, dryers as well as dish washers in such a way that they were automatically switched on during *Sonnenbonus* time slots.

A third of all respondents additionally provided other responses, which shed an interesting light on households' use of the *Sonnenbonus*. The responses vary but have a common theme: appliances with a high load demand were switched on. They charged their EVs, heated their warm water via direct heating rod, baked bread, hoovered, reprogrammed their heat pumps and bought smart sockets. While these responses are not representative, they show that there is a group of households with a high level of understanding when it comes to which appliances need relatively high levels of electricity and who is willing to restructure their daily household life.

Further information collected in the post survey data allowed for an improved understanding of the socio-demographic characteristics of the sample group. For instance, the majority of the post survey respondents (65 %) are working full time and are between 35 to 65 years old. For this group it should have been especially challenging to react to the *Sonnenbonus* treatment, however as stated previously, a behavioural change in terms of electricity consumption of the household during the *Sonnenbonus* times was observed.

Furthermore, it was questioned whether electricity consumption patterns changed only during the implementation of the *Sonnenbonus* or if there was a general focus on the overall consumption of electricity even during the non *Sonnenbonus* times. It has been identified that 50 % of the households have started to become more aware of their electricity consumption and 9 % replaced inefficient household appliances with energy-efficient ones. Moreover, while the majority of the households were satisfied with the available functionalities, some expressed an interest in further functions, for instance, real-time data transmission from the meters in 15-minute intervals. Finally, 94 % of the households who participated in the post-survey said that they would like to continue using the app.

4 Outlook and Recommendations

The project anticipated current topics of public interest quite well. One the one hand, this brings the partners of the consortium into a good situation to continue to work on the results and outcomes of *leafs*. On the other hand, relevant aspects for a future development of the project contents can be given. The following aspects have been identified:

- The community storage system in Heimschuh will be developed further towards a product in the follow-up project *Blockchain-Grid*. Within this project the communication infrastructure is improved by changing to a wireless system with a control scheme based on a distributed blockchain approach. Peer-to-Peer trading between single customers and trading of free grid resources will be possible developing the concepts towards the first local energy community in Austria. The end-user is tightly integrated into the system that includes actual billing of the participating customers.
- The *leafs* project took the scalability analysis of a high number of low voltage grids to a new level. Grid reinforcement requirements were determined based on this highly detailed analysis taking into consideration 14,614 low voltage networks with a total of 42,000 feeders and 1,998,000 connection points. After the conclusion of the project, work will continue for the scalability analysis to determine future impact of different technologies on more detailed level for more distribution system operators.
- Further cost reductions for BESS are expected in the coming years. With that, the economic feasibility of PV-BESS will increase moving them towards an economic breakeven point. When reaching grid parity, such systems will be installed in greater numbers. Thus, a corresponding framework ensuring grid friendly operation and proper system integration and grid tariffs should be developed in the future.
- Grid tariffs, including stronger load power pricing, are in preparation by the Austrian regulator. When implemented, those tariffs could create a new operation strategy for the operation PV-BESS and other flexible loads to reduce the peak load which creates a new value stream. With that economic feasibility of PV-BESS might rise faster than currently expected moving them quicker towards the break-even point.

Beside an outlook on future developments several recommendations are derived from the project:

- Extensive simulations have shown that a P(U)-characteristic for electric vehicles does have a significant impact on the grid reinforcement requirements in future rollout scenarios. It is thus vital to implement such a functionality in EVs and the charging infrastructure. However, further research is required to determine the optimal parametrisation of the function to achieve corresponding results. Of special interest is the equal treatment of all customers connected to a single low voltage feeder. To achieve this, a combination which includes time of use tariff seems to be the most feasible option.
- To rollout new concepts such as the implementation of local grid tariffs, a dedicated community or central -storage tariff and the possibility to provide incentives to Individual customers would be required in the regulatory framework.
- The *Sonnenbonus* trial showed that there is a potential for user driven flexibility activation. However, in order to allow for such a system a cost-efficient remuneration

scheme (i.e. via innovative local grid tariffs) has to be developed. Additionally, a future application potential exists but must include the large flexible loads such as domestic hot water boilers or heat pumps.

- A power-based grid tariff scheme for the individual reduction of power consumed by individual customers does not automatically translate to an overall power reduction in a certain LV voltage grid. To reduce the overall power in the grid the DSO will have to find alternative measures.
- All in all, no control algorithm has been identified (also for CEMS) which actively reduces voltage unbalance. For single phase flexible loads a proper control scheme which takes the phase information into account and is able to actively reduce unsymmetrical loading should be subject in future developments.
- Investigations have shown that the hosting capacity for PV can be increased significantly when feed-in power at the PCC is limited to 70%. For PV plants with significant self-consumption, such a curtailment would cause insignificant energy losses. This, in return reduces the effort to reinforce the local grid significantly when reaching hosting capacity limit in grids. Thus, such a concept should be discussed in the future regulatory or legal framework.
- Concerning flexible loads, no functions are currently implemented (in contrast to generation units) to avoid load related violation of grid boundary conditions such as voltage band violations and overloading of the DSO equipment. Hence, flexible loads should be equivalently treated in the focus of grid integration measures, especially EVs.
- Project results indicate that an increasing penetration of flexible loads and PV-BESS can be expected in the electric grid in the future. These technologies and corresponding grid friendly operation strategies should be taken into consideration in future grid planning and operation schemes.
- There is no efficient way to communicate and to control devices at the customer premises (behind the meter) as there are no standards and a lack of interoperability. Hence, grid supporting functions should be very simple to be implemented and, at best, autonomous in operation to be applicable in as many situations as possible. Additionally, it has to be considered that a smart meter rollout is a base requirement for dynamic and coordinated control schemes in order to be able to recognize corresponding voltage band variations and grid congestions.
- To allow for more complex and coordinated control in an efficient manner, investment and installation costs of such a system have to be visibly reduced, standardisation and interoperability significantly improved, availability and implementation to a wide range of systems ensured, the longevity and robustness improved, parametrisation effort reduced, monitoring concepts adapted, error analysis tools developed, and operation and maintenance costs significantly reduced. Only then, intelligent and coordinated control will be applicable for systems in low voltage grids. To bring such a system to a broad application, further research and development as well as standardisation and completed smart meter rollout, will be required.
- Implementation and operation of coordinated grid control schemes and activation for marked services during normal conditions pose major cybersecurity concerns. Therefore, increased care has to be taken, when implementing such systems, especially when using third party systems.

5 Literature

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