Platone

PLATFORM FOR OPERATION OF DISTRIBUTION NETWORKS

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PLATform for Operation of distribution NEtworks

D5.5 v1.0

Use Case 2 Demonstration Report

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Abstract

This document contains a demonstration report on the second use case successfully applied in the German demonstration trial of the H2020 Platone project. Further, it contains a performance evaluation based on Key Performance Indicators (KPI), a description of a coordination scheme for central and decentral organized flexibilities and evaluates the customer engagement.

Keyword list

Smart Grids, Decentral Flexibility Management, Virtual Power Plants, Energy Community, Battery Storage, Local Balancing, System Operator Coordination

Executive Summary

"Innovation for the customers, innovation for the grid" is the vision of project Platone - Platform for Operation of distribution grids. Within the H2020 programme "A single, smart European electricity grid", Platone addresses the topic "Flexibility and retail market options for the distribution grid". Modern power grids are moving away from centralised, infrastructure-heavy transmission system operators (TSOs) towards distribution system operators (DSOs) that are flexible and more capable of managing diverse renewable energy sources. DSOs require new ways of managing the increased number of producers, end users and more volatile power distribution systems of the future. Platone is using blockchain technology to build the Platone Open Framework to meet the needs of modern DSO power systems, including data management. The Platone Open Framework aims to create an open, flexible and secure system that enables distribution grid flexibility/congestion management mechanisms, through innovative energy market models involving all the possible actors at many levels (DSOs, TSOs, customers, aggregators). It is an open-source framework based on blockchain technology that enables a secure and shared data management system, allows standard and flexible integration of external solutions (e.g. legacy solutions), and is open to integration of external services through standardized open application program interfaces (APIs). It is built with existing regulations in mind and will allow small power producers to be easily certified so that they can sell excess energy back to the grid. The Platone Open Framework will also incorporate an open-market system to link with traditional TSOs. The Platone Open Framework will be tested in three European field trials and within the Canadian Distributed Energy Management Initiative (DEMI).

In WP5 of the Platone project, Avacon with the support of the consortium, has conceptualized, implemented and successfully integrated a decentral Energy Management System (EMS) prototype, named Avacon Local Flex Controller (ALF-C) to control small scale flexible assets located in local low-voltage grid sections. The ALF-C applies SCADA / ADMS functionalities to provide services to DSO, TSO and grid customers (communities). Its functionalities create more transparency of generation, consumption and the status of the grid. It applies a local balancing scheme that integrates small scale flexible assets and enables monitoring and control features. In a wider concept of grid operation by system operator (SO), the ALF-C displays a prototype of an automized, semi-autonomous edge computing energy management instance, as part of a decentral flexibility management mechanism that follows the edge computing paradigm. It enables SOs to extend their flexibility portfolio by building a bridge to the increasing number of untapped dormant flexible assets located in LV-networks in order to increase the grid hosting capacity for renewable energy and reduce power peaks in distribution network.

In the German trial of the H2020 Platone project, Avacon conceptualises, develops and implements an energy management system, ALF-C, as part of the Platone Framework. It is tested in a community with 89 households that have a significant volume of roof top photovoltaic (PV) generation that often exceeds local generation. This community is representative of future generation and consumption characteristics. A large community battery energy storage (CBES) is installed in the community to model future flexible power and storage potential provided by domestic battery storages operated by households.

With Use Case (UC) 2, Avacon implements a balancing scheme that aggregates the flexibility portfolio of a community into a single source of flexibility. This flexibility is able to provide a constant value of power exchange at the grid connection point according to request set by DSO, TSO or market participants. This is achieved by implementing a balancing algorithm in collaboration with RWTH Aachen. The algorithm initiates charging and discharging of batteries in the community so that the power exchange equals the external request.

The results of a performance evaluation based on KPI show that the balancing scheme responsiveness, significantly less than 5 minutes, and the accuracy of execution with a standard deviation of 5.3 kW (8%) meets the targeted value set in D5.2. However, further improvements of the balancing scheme beyond the requirements of the project and current regulations could be achieved with shorter control cycles. Further, Use Case 2 implements basic technical requirements for LV-grids and energy communities to provide flexibility to DSO, TSO and market participants, e.g. for alleviation of grid congestions. The allocation of flex activation in future markets might take place as contractual agreements, regulated schemes for SOs or market-based approaches. However, the current German legislation lacks incentives to foster flexibility markets. A major challenge for the cost-efficient activation of flexibilities is the coordination of centrally and decentrally organized flexibilities. A potential solution might be the application of a SO coordination scheme. In this context, the ALF-C has to apply a prioritization

mechanism, in case multiple requestors trigger the ALF-C to provide flexible power at the same time. The prioritization mechanism implemented in the demonstrator follows the prioritization scheme of the grid traffic light concept proposed by the BDEW. The evaluation of the prioritization has been tested successfully in UC 2.

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1 Introduction

The project "PLATform for Operation of distribution Networks – Platone" aims to develop an architecture for testing and implementing a data acquisition system based on a two-layer Blockchain approach: an "Access Layer" to connect customers to the Distribution System Operator (DSO) and a "Service Layer" to link customers and DSO to the Flexibility Market environment (Market Place, Aggregators, …). The two layers are linked by a Shared Customer Database, containing all the data certified by Blockchain and made available to all the relevant stakeholders of the two layers. This Platone Open Framework architecture allows a greater stakeholder involvement and enables an efficient and smart network management. The tools used for this purpose will be based on platforms able to receive data from different sources, such as weather forecasting systems or distributed smart devices spread all over the urban area. These platforms, by talking to each other and exchanging data, will allow collecting and elaborating information useful for DSOs, transmission system operators (TSOs), Market, customers and aggregators. In particular, the DSOs will invest in a standard, open, non-discriminatory, blockchain-based, economic dispute settlement infrastructure, to give to both the customers and to the aggregator the possibility to more easily become flexibility market players. This solution will allow the DSO to acquire a new role as a market enabler for end users and a smarter observer of the distribution network. By defining this innovative two-layer architecture, Platone strongly contributes to aims to removing technical and economic barriers to the achievement of a carbon-free society by 2050 [1], creating the ecosystem for new market mechanisms for a rapid roll out among DSOs and for a large involvement of customers in the active management of grids and in the flexibility markets. The Platone platform will be tested in three European trials (Greece, Germany and Italy) and within the Distributed Energy Management Initiative (DEMI) in Canada. The Platone consortium aims to go for a commercial exploitation of the results after the project is finished. Within the H2020 programme "A single, smart European electricity grid" Platone addresses the topic "Flexibility and retail market options for the distribution grid".

The Platone platform will be tested in three European trials (Greece, Germany and Italy) and within the DEMI in Canada. The Platone consortium aims at a commercial exploitation of the results after the project concludes. Within the H2020 programme "A single, smart European electricity grid", Platone addresses the topic "Flexibility and retail market options for the distribution grid".

In WP5 of the Platone project Avacon implements a decentral Energy Management System (EMS) prototype in a local low voltage (LV) grid representative for a rural community with significant photovoltaic energy generation. This EMS is called Avacon Local Flex Controller (ALF-C) and it can provide decentral SCADA / ADMS functionalities for DSO, TSO and customers. The principle of the ALF-C follows the edge computing paradigm. The functionalities enable automatized monitoring of low-voltage networks and local balancing mechanisms to foster the integration of renewable energy generation an increase the efficiency of existing grids.

This report is dedicated to Use Case 2 of the German demonstrator. In this use case the balancing scheme applied by the ALF-C prototype controls the community battery energy storage (CBES) prototype in such a way that a constant value of power exchange at the medium voltage (MV)/LV grid connection point is achieved that equals the requested power exchange set by external requestors. As part of the use case, a prioritisation mechanism is implemented and tested. The ALF-C enables the Energy Community to achieve and maintain the requested power exchange at the MV/LV grid connection point. Furthermore, the ALF-C is also able to plan demands in a schedule-based control plan a day ahead.

1.1 Task 5.4

Deliverable 5.5 is the result of Task 5.4 "Field Test Design and Execution", that aims for an in-depth analysis of the demonstration results performed based on Key Performance Indicators (KPI) applied to the field test setup implemented in Task 5.5. "Installation and operation of field test equipment". Further, this deliverable is the result of Task 5.3.2 "Coordination of local balancing with flexibility demands in higher level networks" aiming to define a coordination scheme for the allocation of decentral and central organized flexibility.

1.2 Objectives of the Work Reported in this Deliverable

The objective of this deliverable is to exemplify the implemented coordination scheme for external flexibility request and to describe a general theoretical approach of a coordination scheme for centrally and decentrally organized flexibility in distribution grids. Further, this deliverable evaluates the demonstration results of the UC 2 balancing and coordination scheme implemented in the demonstrator performed based on demonstrator specific KPIs. Further, this deliverable contains an evaluation of the customer recruitment process based on common KPI. Based on the collected results, lessons learned and the implications on future operation are described.

1.3 Outline of the Deliverable

Chapter 2 describes the motivation and objects of the UC 2 demonstration report. Chapter 3 describes the current legal situation in Germany in terms of flexibility schemes for System Operators (SO). Chapter 4 describes how the implemented solution (ALF-C) prioritizes flexibility requests. In chapter 5 a prioritization scheme for the activation of flexibility within a community is conceptualized. Chapter 6 describes a coordination scheme for SO in case of market-based flexibility activation. Chapter 7 evaluated the demonstration results of UC 2 based on common and project KPI. Further the chapter evaluates the success a customer recruitment based on common KPI. Chapter 7 summarizes the conclusions and lessons learned.

1.4 How to Read this Document

This document provides relevant experiences and lessons learned from the use case demonstration and describes a coordination scheme for central and decentral organized flexibility. A first draft of concept of the solution design and technical specification of the WP5 IT architecture (ALF-C) is provided in H2020 Platone Deliverable D5.1 [2]. A detailed description of use cases and KPIs for the evaluation of the use case data and measurement results is provided in D5.2 [3]. However, updates of KPI definitions are described in this deliverable. Common KPI are defined in D1.2 [4]. More information about the dependencies of this work package with the others is described in D9.5 [5] since it lists all tasks and dependencies of all work packages. Further information about relevant legal and regulatory legislation can be read in D1.3 [6].

2 Motivation and Objectives

In times of increasing distributed renewable energy resources (DER) and increasing renewable generation in distribution networks, the German distribution system operators (DSO) have to spend much more effort to keep the electricity grid within its technical limits and avoid overloads on lines and transformers. Especially DSOs operating in rural and suburban areas are affected by the growth in numbers of rooftop photovoltaic systems (PV) and have therefore no other choice, but to replace and upgrade existing transformers.

The peak feed-in also causes the voltage to rise along the feeder and the lines, requiring the DSO to add more feeders and reinforce existing lines in the grid. In some areas these effects can be countered to some degree with the deployment of voltage regulating distribution transformers and proactive reactive power management. But the cumulative feed-in of PV in rural networks remains a big challenge for DSOs. Being at the forefront of the German energy transition, Avacon has been challenged by a fast growth of decentral energy generation. Particularly in the rural regions, Avacon is managing low- and medium voltage networks that are exporting a significant surplus of locally produced energy.

To address these challenges Avacon aims to implement an extensive concept of a decentralized energy management system, respecting the principle of subsidiarity of energy supply in MV and LV networks, by applying the edge computing paradigm. The aim of the concept is to increase the resilience of distribution networks against additional stress on lines and transformers, caused by the increasing share of renewable generation and increasing demand from loads. The concept shall enable the implementation of a more efficient grid congestion management and increase the hosting capacity of the existing distribution network for renewable energy through innovative grid management mechanism involving small scale non-regulated flexibility. The decentral flexibility management concept shall consist of multiple redundant and semi-autonomous energy management systems for flexibilities connected to the LV grid.

As an intermediate target and core of the German demonstrator in Platone, Avacon aims to implement the ALF-C, a prototype of an edge computing energy management system that builds a platform to aggregate DER located in low voltage levels to a single source of flexibility ("virtual power plant"). The flexibility portfolio managed by the ALF-C shall involve batteries and demand-side flexibility owned by households, local energy communities or industry and other untapped flexibility. The flexibility portfolio may consist of domestic household battery storage systems, operated in combination with rooftop photovoltaic system, heat pumps, night storage heater, electric heaters, used for domestic heating, or charging stations for electric vehicles (EVs). The decentral flexibility management concept foresees the ALF-C to be operated in secondary substation, which builds the grid connection point of the MV and LV grid. The ALF-C aggregates all DER of a low voltage network, connected to the same LV/MV to a single source of flexibility. The decentral approach aims to implement multiple benefits to the DSO, since it:

- enables the DSO to monitor generation and consumption, which enables the DSO to monitor the grid status in the low voltage levels in close to real time,
- improves efficiency of congestion management through the involvement of untapped local small scaled flexible assets into the flexibility management portfolio of the DSO,
- increases the security of distribution grid operations against external human made hazards and cyber-attacks through redundant and distributed, rather than centralized, grid management instances and
- allows the DSO to provide services such as the energy management to households, to form renewable energy communities or citizen energy communities, aiming to practice collective self-consumption or improve self-consumption of local generated energy.

Since the allocation of flexibility activation in future distribution networks will be managed by both central and partially decentral flexibility management systems, coordination schemes to ensure a safe and reliable energy supply are required. Such a coordination scheme would need to be implemented on multiple level, as described in this document.

With Use Case 2, Avacon aims at implementing a balancing scheme that enables local LV grids or energy communities to provide a constant set value of power at the MV/LV grid connection point upon an accepted request from a DSO, a TSO or a market participant. The balancing schemes apply algorithms, developed by RWTH Aachen, that use the battery storages in the grid and try to compensate power fluctuations of the community.

3 Current Legal Situation of Flexibility Activation available to System Operators in Germany

The following chapter gives an overview of the current legal situation related to flexibility mechanisms available to SOs in Germany. The chapter begins with a description of the Traffic Light Concept of the German Federal Association for Energy and Water Management, “Bundesverband der Energie- und Wasserwirtschaft” (BDEW), that highlights the prioritization for flexibility activation. The flexibility activation schemes are described and categorized into regulated flexibility activation, non-regulated flexibility activation and market-based flexibility activation.

3.1 BDEW Traffic Light Concept

The BDEW has proposed the smart grid traffic light concept [7] which defines how market participants and DSOs will interact in case of grid congestions in the distribution grid. It further describes the state of the grid and gives an indication of which measures should be applied to stabilize the grid through grid congestion alleviation. The green phase indicates that the distribution grid is not affected by congestion. Market Participants are free to trade and exchange flexibility. During a red phase the stability of the grid is threatened by unforeseen congestions, whereas the yellow phase is a transition phase between green and red. Table 1 gives an indication of which schemes for flexibility activation the DSO and TSO have to apply. The table further displays, which coordination schemes might be applicable during each traffic light state in the future, which are elaborated in the following sections.

Table 1: BDEW Traffic Light Concept

Priority	Requestor	Content	BDEW-Traffic Light	Status of Congestion	Scheme for Flexibility Activation	Upstream Coordination Scheme Stage 1
1 – Highest Priority	DSO, TSO	Flexible power is needed to solve real time congestions leading to exceeding technical limits and overload of network equipment.	Red	Real-time	Feed-in Management (Redispatch)	Direct
2 – Medium Priority	DSO, TSO, Marked	Congestions in the network will be forecasted by DSO or TSO and will be solved with the procurement of flexibilities via market actions and contraction for flexibility provision. Interactions take place between SO and market participants.	Yellow	Predicted	Redispatch (cost based) Schemes for marked based flexibility activation	SO Coordination Scheme
3 – Low Priority	Marked	Flexibility request that are not intended to solve critical grid status. Markets are	Green	No congestion predicted	Schemes for marked based flexibility activation	ALF-C Prioritization Scheme

		allowed to trade and activate system or market relevant flexible assets to contribution to the integration of fluctuating feed-in or demand.				

3.2 Regulated and Non-Regulated Flexibility Activation

The §12 of the German Renewable Energy Act, "Erneuerbare Energien Gesetz" (EEG), states that the DSO is obliged to connect all sources of renewable energy that so wishes to its network and is obliged to ensure that its network provides enough hosting capacity to accommodate all energy that is produced [8]. This includes the obligation to optimize, expand and reinforce the network when required. However, the investments in additional network capacity cannot always keep up with the growth of decentral generation. To keep the grid in a safe operating condition, the DSO has the right and the obligation to use various grid-related countermeasures, tools and techniques to resolve grid congestions. This includes for example central reactive power management, decentral reactive power management, voltage regulating transformers, high temperature conductors, advanced grid operation strategies.

The German Energy Industry Act, "Energiewirtschaftsgesetz" (EnWG), sets the guideline principle related to the measures and tools to be applied by SO to ensure a safe and reliable power supply in case of grid congestions in §13 (1) 1 [9]. It states that grid switching measures must be prioritized over market-based approaches for flexibility activation or via the activation of grid reserves. If these approaches are not sufficient, the last option for the DSO is to curtail the renewable generation. The following paragraphs summarize the current flexibility mechanisms applied by German DSOs in accordance with the current regulation.

Feed-In Management, "Einspeisemanagement", is the reduction of the feed-in of renewable generators by the DSO. It is only applied as the very last option for resolving unpredicted grid congestion, indicated by the red traffic light phase. According to §13 (2) of the EnWG, it is only applicable if all other grid related measures have failed to resolve a forecasted grid congestion. This mechanism is also applied in case of an immediate unpredicted congestion. The technical realisation is based on legacy technologies. The system in many networks is based on a ripple control signal, e.g., for photovoltaic and wind turbines. The control command from a DSO is handed over to a communication service provider who broadcasts the ripple control signal via a radio signal across the entire service area. Upon receiving this signal, the DERs stop electricity generation. Plant operators affected by the feed-in management are reimbursed for their lost revenue in accordance with §15 of the EnWG.

Redispatch – Redispatch describes the adjustment of power feed-in for congestion management. According to §13 (1) 2 EnWG, German TSOs must resolve network congestions in the transmission grid. To prevent an impending grid congestion, the generation of a power plant before the forecasted grid congestion, e.g., on a line, will be adjusted accordingly. At the same time, the generation of previously inactive power plants behind the grid congestion is increased. Therefore, the application of redispatch requires a forecast of generation and consumption and grid load flow analysis to determine potential congestion to be solved in the yellow traffic light phase. The legal basis for congestion management (redispatch and feed-in management) has been introduced with the Grid Expansion Acceleration Act, "Netzausbaubeschleunigungsgesetz" (NABEG) [10]. Since October 2021, German DSOs are encouraged to improve their congestion management on the distribution level by applying a redispatch mechanism in the yellow traffic light phase (forecasted congestion) instead of applying feed-in management. This new mechanism is named "Redispatch 2.0" and involves all renewable generating DER with a generation capacity exceeding 100 kW and other DERs, if the assets are equipped with a radio or ripple control receiver and are already integrated into the DSO control scheme.

Demand Response: The Demand Response is a non-regulated flexibility mechanism. The European directive 2012/27/EU Art. 15 (4) states that "Member States shall ensure the removal of those incentives (…) that might hamper participation of demand response, (…)" as well as improve customer participation in demand response [11]. In Germany, these requirements are codified in §14a EnWG, which states that "Network operators are obliged to offer a discount on grid charges for those customers who offer controllability and flexibility to the system operator". It further states that the details of this flexibility scheme remain to be defined in a statutory law which is yet to be finalized. Until then, however, historic flexibility- and control-mechanisms are used under EnWG §14a.

The most common among these historic control mechanisms is a DSO-controlled switching of storage heaters that once applied to double-tariff customers. The affected customers receive a discounted energy tariff during off-peak hours. These tools were conceived in an era before the German energy system underwent unbundling, so the discount would apply to the combined retail price and grid fee. The distribution system operator would determine the discount and retain control over the definition and switching of peak and off-peak windows. Today, energy retailers and grid operators are unbundled so that the retail share of a customer's energy does not necessarily reflect the old double tariff model. However, under §14a EnWG the grid operator is still granting a grid charge discount in exchange for controllability and is still using the same systems to carry out the tariff switching, even though it might not have any effect on the retail side. The contractual agreement states that the DSO defines the preferred charging times, guaranteeing a sufficient number of hours to cover customers energy demand. In practice, DSO usually have fixed charging windows during the night that amount to 8 hours of charging time. During these hours, the customers heating device would charge up with thermal energy and release the heat throughout the following day. On particular cold days and in some regions, DSOs might also activate heaters for additional heating periods during the day to cover high demand.

Heat pumps on the other hand have not been around in large numbers when the first installation of the double-tariff scheme took place in the 1960s and 1970s, so they are less burdened with historic flexibility mechanisms. Taking into account customer expectations for comfort and the capabilities of the devices, today's agreement between DSOs and customers under §14a EnWG states that the DSO, has the right to interrupt the heat pumps operation for up to 2 hours and up to 3 times per day.

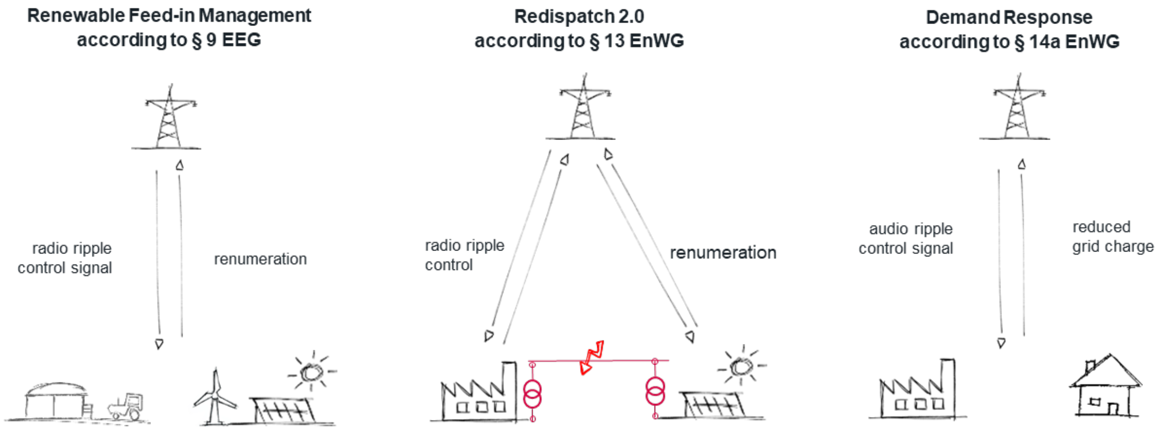

Figure 1: Scheme for Flexibility Activation

Table 2: Flexibility Mechanisms in Distribution Networks and involved Flexibility Types

	P_{DER} > 100 kW		P_{DER} <= 100 kW; >30 kW		P_{DER} <= 30 kw	
Asset Type	**Generators**	**Loads**	**Generators**	**Loads**	**Generators**	**Loads**
Feed-In Management §9 Renewable Energy Act (EEG)	Renewable Generators, Batteries, Cogeneration Plants	-	Renewable Generators, Cogeneration Plants	-	PV, if equipped with ripple controller	-
Redispatch §13 Energy Industry Act (EnWG)	Renewable Generators, Batteries, Cogeneration Plants	-	Renewable Generators, which are already controlled by DSO	-	Renewable Generators, which are already controlled by DSO	-
Demand Response §14a Energy Industry Act (EnWG)	-	Heat Pumps Night Storage Heaters Electric Heaters		Heat Pumps Night Storage Heaters Electric Heaters		Heat Pumps Night Storage Heaters Electric Heaters

3.3 Market-Based Flexibility Management

DSOs use flexibility primarily to alleviate grid congestions. The EU Regulation 2019/943 on the internal market for electricity states that the “dispatching of power-generating facilities and demand response shall be non-discriminatory, transparent and … market based”, which also applies to redispatch mechanisms [12]. However, Germany has submitted an action plan to the European Commission in order to be exempted from a market based redispatch until 2025 and to apply a cost-based redispatch 2.0.

Since the German Incentive Regulation (Anreizregulierungsverordnung, ARegV) which incentivises system operators to invest in grid infrastructure does not foresee the recovery of costs caused by market-based approaches for congestion management, flexibility markets have not yet matured in Germany [13]. However, in several European and German projects, market-based flexibility procurements have been successfully tested and their advantages and disadvantages investigated. Examples for projects are comax[1], enera[2], ENKO[3], WINDNODE[4], DARE[5], flexgrid[6], NODES[7], iPower[8], FlexEnergy[9] and pebbles[10].

As the market-based congestion management provides a potential scheme to incentivise owners of small-scaled asset to provide flexibility to the DSO, a coordination scheme for activation of flexibilities is required. The market-based congestion management requires four process steps (Figure 2):

1.) The Flexibility provider (FP) forecasts the availability and amount of flexible power that can be provided by its assets and places offers accordingly on the flexibility market. Flexibility bid offers submitted by the FP may consist of price-volume pairs and should be related to a specific geographical or grid topology related areas for a given period of time, e.g., 15 minutes[11].

2.) The SO applies generation and load forecast for their respective grid and applies load flow analysis to determine grid constraints and the necessary amount of flexibility needed for alleviation per grid or market area.

3.) Before placing bids on the market, system operators apply a coordination mechanism to ensure a cost-efficient flexibility activation.

4.) The SO places bids on the market according to their needs with respect to the restrictions of the coordination scheme.

[1] https://en.comaxtek.com/
[2] https://projekt-enera.de/
[3] https://www.enko.energy/enko2-0/
[4] https://www.windnode.de/
[5] https://www.dare-plattform.de/da-re-plattform-startet-mit-ersten-nutzern/
[6] https://flexgrid-project.eu/
[7] https://nodesmarket.com/
[8] https://ipower-net.weebly.com/
[9] https://www.flexenergy.ch/de/projekte/
[10] https://pebbles-projekt.de/
[11] The submission takes place by various providers, each are certified for the market participation, e.g., by the SO. The flexibility provided by FP might come from a large portfolio of different asset types, such as heat pumps, domestic stationary batteries, mobile batteries (e-vehicle), electric heaters, etc. The flexibility can be provided by a single source of flexibility or from an aggregated portfolio, such as an energy community.

Figure 2: Principle for Market Based Flexibility Management

The legal basis for market-based congestion management mechanism is §13 (1) 2 EnWG. German SOs are obliged to make use of market-based measures, in particular in case of balancing power (TSO) to maintain system stability and contractually agreed interruptible loads (TSO and DSO). The application of marked-based flexibility activation is only allowed during the yellow traffic light phase for the management of predicted grid congestions and if the DSO is not able to resolve the congestion problems with its own assets, e.g., through grid switching, §13 (1) 1 EnWG. This mechanism aims at resolving local grid congestion by the activation of flexibility provided by voluntary market participants and without the curtailment of renewable generation.

However, at the current stage there are no mature flexibility markets in Germany offering flexibility assets for market-based congestion management to the DSO. Nevertheless, the concept of flexibility markets has potential to provide benefits to DSO and grid customers. The concept is based on the incentive of grid customers to actively offer flexibility to grid operators against remuneration. While the grid customers benefit from the remuneration for the provision of flexible power without impending comfort to the DSO, the DSO benefits from the broader pool of flexible assets, allowing more efficient alleviation of local grid congestions during the yellow traffic light phase.

4 Current State of Flexibility Activation in the German Demonstrator

In the German demonstrator, Use Case 2 aims at testing flexibility activation. The field test setup consists of a community located in the low voltage network in the distribution grid made up of about 89 households with 19 PV systems with an installed generation capacity of approximately 340 kW. The community is linked with the MV-grid along a single MV/LV grid connection point (smart secondary substation). In the LV grid of the community a community battery energy storage (CBES) with an installed capacity of 330 kW and 777 kWh storage capacity connected to the LV busbar of the MV/LV feeder. The storage is able to provide bi-directional flexibility 24/7. Additionally, 5 households with a roof top PV system have been equipped with battery storages adding 30.7 kWh of storage capacity for PV self-consumption in the field.

The Use Case 2 balancing logic aims at enabling energy communities to react on external power requests. An energy management system called ALF-C, developed within the scope of the German Demonstrator, is used to activate local flexibility and balance flex demands or feed-in according to the community load demand. Further, ALF-C is able to process and prioritize external flexibility requests. It can then achieve and maintain the requested value of power exchange at the MV/LV grid connection point. The computed setpoint is processed in a soft-real-time control cycle that is applied every 15 minutes. The algorithm has been implemented together with RWTH Aachen. The main targets for the ALF-C are to achieve the calculated setpoint at the grid connection point between LV/MV grid, to maintain the calculated setpoint for the requested time, and to follow current standards, such as the BDEW traffic light concept.

A core feature of the ALF-C is the aggregation of small-scaled flexibilities in the LV grid into a single source of flexibility. The ALF-C is designed to execute one request at a time. In the event of multiple simultaneous requests, as is possible in Use Case 2, a prioritization mechanism must be applied. The implemented prioritization logic follows the principle of the grid traffic light concept proposed by the BDEW. Hence, the algorithm requires additional information to be provided with each external request that enables the ALF-C to prioritise accordingly. This information are the priority of the requestor, see Table 3, and the timestamp of request submission.

Table 3: Prioritization of Flexibility Requestors

Requestor	Prioritisation
TSO	1
DSO 1	1
DSO 2	2
Aggregator 1	3
Aggregator 2	3
Energy Community	4

In case of two or more requests submitted with the same prioritisation running in the same 15-minute cycle, the request that was submitted the earliest will be executed. Table 3 shows an overview of how demands of certain requestors are prioritised within the ALF-C. The lower the integer, the higher the prioritisation of the respected requestor.

To demonstrate the approach of the ALF-C to schedule requests, Figure 3 shows an example of various requests submitted to the ALF-C at different times during a 12-hour period. The black dot indicates the time of submission while the bar is the actual timeslot for which flexibility is requested for. The hatched area in the bar shows the actual time the request was performed. In Figure 3 the following can be seen. During the first hour, two requests are submitted at the same time. One is prioritised very high (prioritisation 1 by a TSO) and demands a specific power exchange for 3 hours. The other submitted request is prioritized very low (prioritisation 5 by the energy community) and demands a power exchange for 12 hours. The TSO requests supersede the request of the energy community.

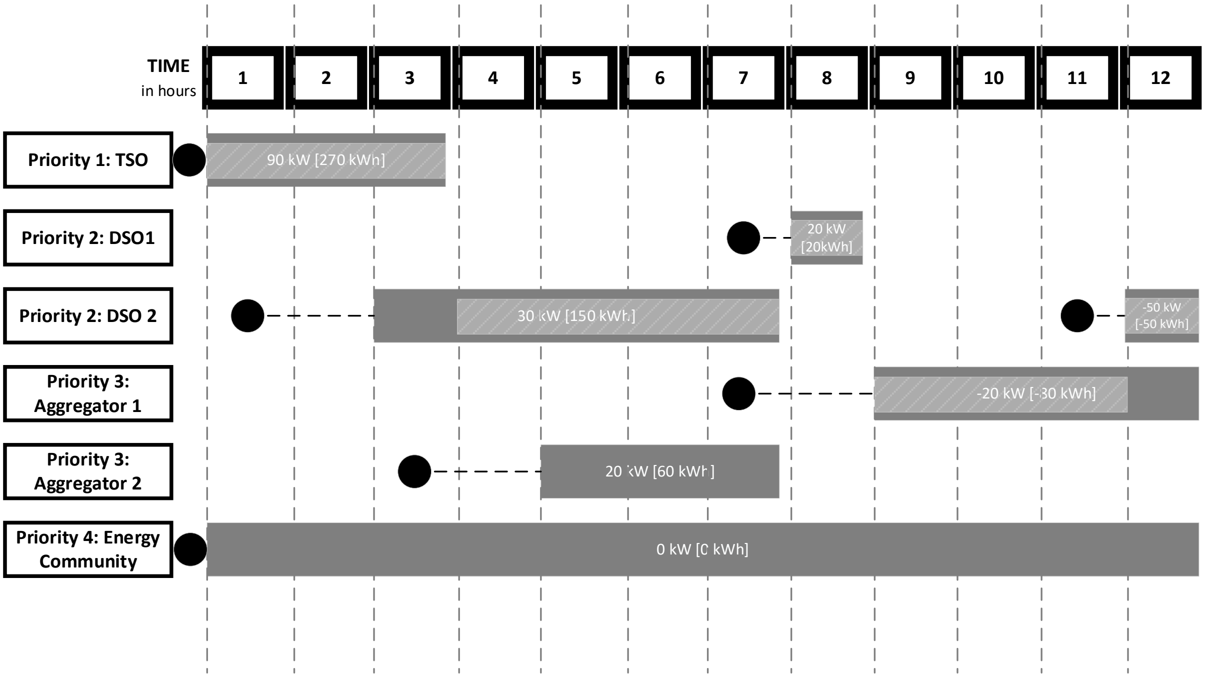

Figure 3: Incoming Requests for the ALF-C

During the first hour another request with a prioritization 2 is submitted by DSO 2 and demands a power exchange over 5 hours. At hour 3, a request with prioritization 3 in demanding a power exchange for 3 hours is submitted by aggregator 1. According to the BDEW traffic light concept, the request made by DSO 2 should not be executed in the first demanded hour because the TSO request is still active. Once the TSO request is completed, the DSO 2 requests is executed. On the other hand, the request made by aggregator 2 with prioritization will never executed since its timespan always overlaps with the previously submitted and higher prioritized requests.

At hour 7, two requests with different prioritizations are submitted at the same time by DSO 1 and aggregator 1. One request should be executed in the following hour 8 lasting 1 hour and the other should start in hour 9 and last for 4 hours without any overlap between each. However, in hour 11 a higher prioritized request is submitted by DSO 2 for an hour is being performed. Figure 3 shows that the lowest prioritized request (priority 5) of the energy community, which demands a power exchange of 0 kW, is overlapped during the whole 12-hour period and will not be executed at all.

The scenario described above was tested in the German field-trial. The figure below (Figure 4) shows the actual power exchange at the grid connection point (green) during these 12 hours and the power exchange that would have happened if there would have been no request (grey). In addition, the requested power exchange setpoints are drawn including their values.

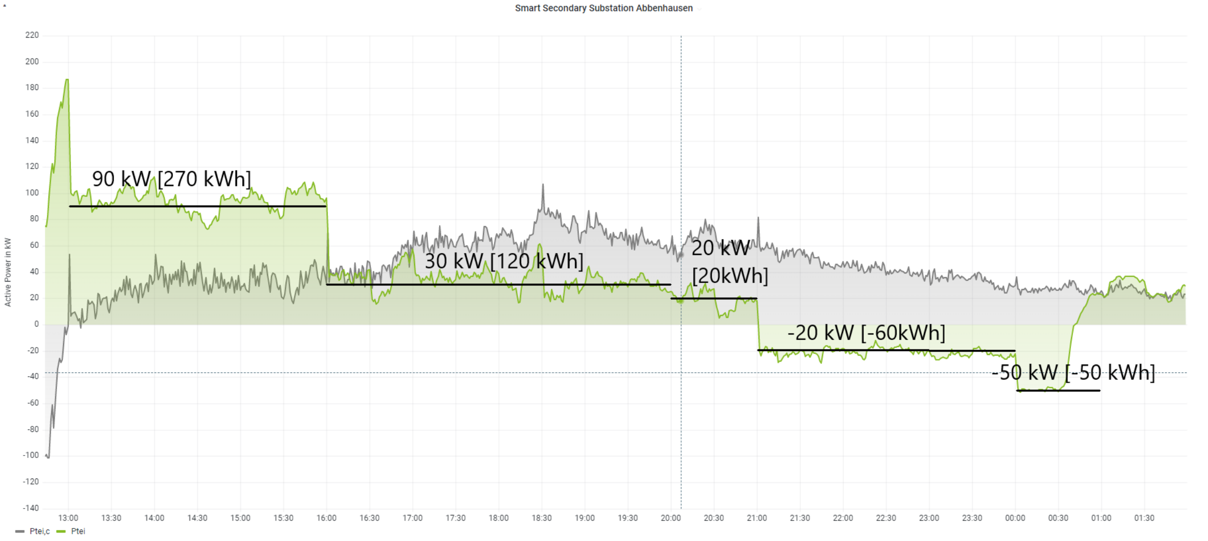

Figure 4: Measured Power Exchange at Grid Connection Point

The measurements show that during the first decision making, the higher prioritized TSO request (90 kW) is performed for 3 hours. Then the request with prioritization 2 by DSO 2 (30 kW) was executed an hour later than requested because of the time overlap with the TSO request. The prioritization 3 request, by aggregator 2, was never activated. After that, the prioritization 2 request by DSO 1 (20 kW) was executed for the demanded hour. Next, the prioritization 3 request by Aggregator 1 (-20 kW) was active but got interrupted by a prioritization 2 request (-50kW) by DSO 2. This request was fulfilled for only the half of the demanded time since the necessary available flexibility could not be provided.

Note that at no time was the request by the energy community (0 kW) active. This shows that the ALF-C can comply with the required coordination schemes when prioritising requests.

5 Procedure Flexibility Activation in Local LV Grids

The aggregation of a local LV grid or community to a single source of flexibility enabling features such as those targeted in UC 2 must follow certain coordination principles. Namely, in case the flexibility portfolio of a community consists of a large number of different asset types. The principles are framed by regulatory, legal and societal aspects as well as technical characteristics. In this chapter the principle of flexibility activation of assets located in a local LV grid or community are described on a theoretical basis. First an overview of regulatory, legal and societal requirements is given. Then a principle for a coordination of flexibility activation is proposed referring to the ALF-C.

5.1 General Requirements

Requirements set by the regulator

The EU Regulation on the internal electricity market (2019/943) states in Article 12 regarding dispatching of generation and demand response and article 13 on redispatch, that the activation of generators or flexible loads „shall be based on objective, transparent and non-discriminatory criteria” [12]. As a consequence, the following principles are implemented:

- The grid service area of the DSO is clustered into several switching groups “Abschaltgruppen”, in case of demand response assets. In case of renewable generators, the assets are clustered into curtailment groups. The assignment logic of an asset into an asset group is based on network topology aspects. Each group consists of assets, which have the same grid-related sensitivity on a congestion area or grid connecting transformers.
- A sufficient number of groups have been established to enable a gradual load reduction in sufficiently small increments, while the individual shutdown groups have similar power values.
- Assets are controllable on remote via a one-way radio signal or ripple control signal.
- Within each cluster, assets are activated by applying a “rolling” or “rotating” mechanism, which means that with each activation of the clusters different assets are activated. This mechanism shall ensure that over the course of a year asset owners are equally affected by the activation.

However, a deviation from the mechanism might be necessary, e.g., in case of system critical situation or technical restriction.

Characteristics of Domestic Batteries / Small Scale Batteries

Domestic batteries < 100 kW are considered as flexible load decreasing PV feed-in through demand shifting. From a technical perspective, batteries can provide bi-directional flexibility and can as such be considered as flexible load and source of feed-in. However, the current legislation does not incentivise households to provide bi-directional flexibility, since feed into the grid is remunerated with a small rate and charging from the grid is priced with standard charges, including all grid fees and taxes, regardless of whether this action helps alleviate congestion. Consequently, a lack of commercial offers and use cases for flexibility in-front-of-the-meter has led customers to put emphasis solely on maximizing individual self-consumption. This shows how the regulation deals with residential batteries but also in the dimensioning of storage systems for private use. Therefore, for households it is more profitable to operate a domestic battery storage in combination with a roof-top photovoltaic system to practice self-consumption within the household. To respect this legal situation and to avoid financial disadvantages to asset owners, batteries are only considered as flexible loads in the field test, able to reduce the PV feed-in.

Regulations on Photovoltaic System (Household)

§11 of the EEG states that DSOs are obliged to take electricity as a priority which means that the curtailment of roof-top photovoltaic systems can only be applied as the very last step, if no other measures provide enough flexibility or in case it is required in order to maintain a safe and reliable energy supply (red traffic light phase – real time congestion) [8]. Consequently, there is no chance for PV curtailment in the green and yellow traffic light phase.

Characteristics of Flexible Loads (Demand Response)

Demand response assets can be made accessible to the DSO for control through contractual agreements. Also, small scaled flexible heaters, used for generation of domestic heating such as night storage heaters or heat pumps fall in this category. Taking into account customer's expectation for comfort and the capabilities of the devices, today's agreement between DSO and customer under §14a EnWG states that Avacon has the right to interrupt the heat pumps operation for up to 2 hours, up to 3 times per day.

Storage heaters are generally triggered via clock timers or sound wave ripple control. The heaters are triggered to consume electricity from the grid in most cases between 10 p.m. to 6 a.m. The time might change according to contractual agreements between the DSO and customers. One key learning Avacon has gathered in the H2020 project InterFlex[12] is that storage heaters come in a much wider variety than expected. Depending on manufacturer, year of installation and policy of the distribution company at the time of installation, storage heaters can range in thermal capacity and charging strategy. The most common types are start-loading devices, which simply begin to charge until full once the DSO signal reaches the customer. The second most common are reverse charging devices, which follow a complex logic to delay charging such as to finish charging at the time of anticipated end of the charging slot. Practical experience of InterFlex has shown very clearly, that reverse charging storage heaters require a much more complex control algorithm.

Since the availability of these asset types is limited to specific clock times, a complex algorithm is required and have a direct effect on the customers comfort, these asset type should be activated in the last step.

5.2 ALF-C - Prioritization of Asset Types

As consequence of the given regulation, technical characteristics and social aspects described in this section. The activation of flexibility located within an energy community or LV grid section will be prioritized as shown in Table 4.

Table 4: Overview of Asset prioritization

Asset Type	Priority	Flexibility Type	Flexibility Type	Expected Time of Availability
Community Battery Storage				
	1	Battery	Bi-Directional Flexibility	24h/7d
Battery				
	2	PV battery (one directional)	Flexible load	9 a.m. – 5 p.m.
	3	Bi-Directional Battery	Flexible Load and Generator	**As Load:** 9 a.m. – 2 p.m. **As Generator:** 2. p.m. – 9 a.m.
Flexible Load				
	4	Electric Car	Interruptible Load (Demand Shifting)	8 p.m. to 5 a.m.
	5	Night Storage heater	Interruptible Load (Demand Shifting)	10 p.m. – 6 a.m.
	6	Heat Pump with water tank	Interruptible Load	24/7 (maximum 3 * 2h)

[12] https://www.interflex.de/de/index.html

	7	Heat Pump direct heating	Interruptible Load	24/7 (maximum 3 * 2h)
	8	Electric Heating	Interruptible Load	24/7 (maximum 3 * 2h)
Photovoltaic				
	9	Household roof-top system	Curtailment	9 a.m. – 5 p.m.

Rotating Activation

To fulfil the legal requirement to not discriminate asset owners through the activation of flexibility, a rotating scheme has to be applied. Independently from a given traffic light phase the mechanism is intended to apply an objective mechanism for the activation of flexibility within a community. The aim is that each asset from the asset portfolio managed by the ALF-C is statistically activated with the same frequency (number of activation) considering the availability. Conversely, this means that the mechanism is intended to ensure an equal effect by control measures for all assets in the portfolio of the community.

Table 5 shows an example how a rotating activation of LV grid assets can be used for flexibility activation. The first two columns show the number of requests and the requested amount of power that is received by the ALF-C. For convenience the prioritization of the received requests is not considered in this example. The second line illustrates one asset per column with its available flexibility capacity. Since not all assets share the same dimensions, the available flexibility capacity varies. The rotation mechanism dispatched the request sequentially to the available assets. If the full capacity of an asset is not used, it is reserved for the following request. In this example the community consists of 6 households and received 9 requests. The first request of 7 kW is dispatched to the first 3 assets (2 kW, 2 kW and 3 kW). The second request is dispatched to the following two assets (Asset 4 and Asset 5) and so on. This procedure enables an equal use of flexibility providing assets. The last request shows that one request can also be dispatched to all assets in the community.

Table 5: Example of Rotating Flexibility Activation

		Asset Number					
ALF-C Request (Demand) to be dispatched		**Asset - 1**	**Asset - 2**	**Asset - 3**	**Asset - 4**	**Asset - 5**	**Asset - 6**
Request Number	**Amount (kW)**	**Available Flex Capacity (kW)**					
		2 kW	**2 kW**	**3 kW**	**2 kW**	**4 kW**	**1 kW**
Request 1	7 kW	2	2	3			
Request 2	6 kW				2	4	
Request 3	1 kW						1
Request 4	4 kW	2	2				
Request 5	8 kW			3	2	3	
Request 6	2 kW					1	1
Request 8	8 kW	2	2	3	1		
Request 9	11 kW	2	2	1	1	4	1

6 Upstream Coordination Schemes for Flexibility Activation

The previous chapter described how flexibility activation in the LV grid can be coordinated to aggregate flexibility to a virtual power plant providing flexibility according to external request. However, the activation of flexibility in LV levels of the distribution network on request of a higher voltage SO, e.g., for grid congestion management, have an immediate impact on power flows in higher voltage grid levels, operated by third party DSOs. A coordination scheme for flexibility activation involving relevant SOs ensures a cost-efficient activation of flexibility and ensures a safe and reliable energy supply. This chapter describes challenges flexibility activation across multiple voltage and describes consequences and outlines an approach for a SO coordination scheme.

6.1 Design of Transmission grid in Germany

Transmission grids and the HV and MV grids in the distribution network generally display a meshed grid topology (Figure 5). Each change of a generator feed-in power or load demand leads to a change of the load flow in higher voltage level network (upstream networks) and consequently leads to a changing power flow on lines and transformers. As a result of the changing power flows, the voltage might increase or decrease significantly or high currents might occur, exceeding technical limits on lines or transformers.

As shown in Figure 5, TSOs and DSOs are operating different service areas located in different voltage levels. The activation of flexibility by a SO of an asset located in service areas of another SO (SO cross-voltage level activation) might lead to side-effects in the grid of the other SO. The risks of the cross-voltage level activation happen as a result of missing information of the grid operated by another operator. The missing information can be:

- Technical limits and capacity restrictions of lines and transformers or other grid assets
- Sensitivity, which describes the relative rate of power deviation (e.g., active power) to be measured at a grid connection point, in case feeding asset is ramped up or ramped down located in another grid section. For example, ramping up or ramping down of assets located the transformer T3/4 lead to a changing load flow along transformer T2/2 and T2/1. The relative value of change (sensitivity) depends on the technical characteristics of connecting lines and transformers (e.g. resistance).
- Network status, current network load to evaluate available free capacity. To keep a stable and reliable grid and to ensure a cost-efficient activation of market-based flexibility during the yellow phase of the BDEW traffic light concept, SO must inform and ask for permission in case of the cross-voltage level activation of flexibility. For this purpose, a coordination scheme must be implemented.

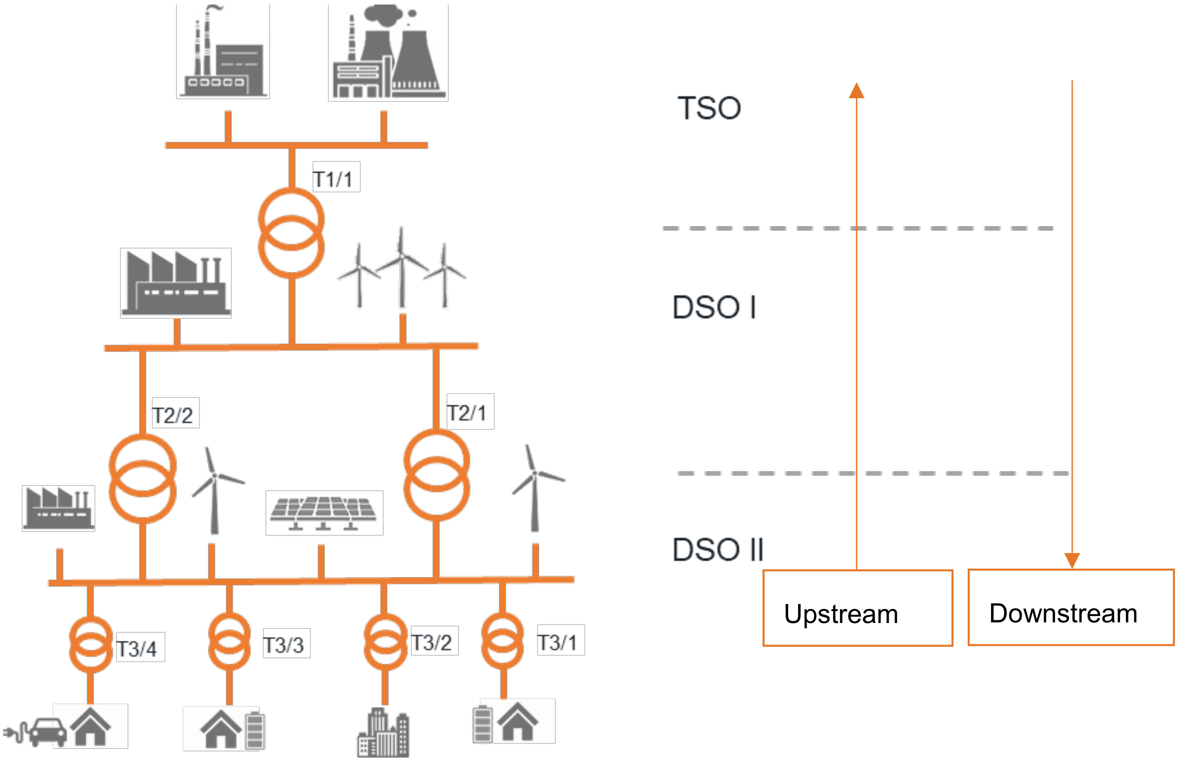

Figure 5: Outline - Common Grid Topology

Due to the potential risks and cost-efficiencies, a market-based congestion management with non-regulated flexibilities requires a coordination scheme with partly de-centrally and partly centrally organized flexibility management. Since the ALF-C has to be seen as an aggregation platform clustering all DER behind a single MV/LV feeder (e.g., T3/4, T3/3, T3/2, T3/1 Figure 5), to single source of flexibility, the solution design of coordination scheme has to consider interference of flexibility activation on different grid levels. It can be described as an upstream coordination mechanism or a downstream coordination mechanism.

The upstream coordination mechanism describes the coordination of requests for flexibility activation to alleviate congestion in higher voltage levels of the distribution network. Depending on the approach of flexibility activation, market-based or non-market-based, the coordination scheme requires the involvement of different actors and consequently coordination schemes.

The downstream coordination mechanism coordinates the activation of DER located behind a MV/LV grid connection point (community or grid section). In case of the ALF-C, all DER are aggregated into a single source of flexibility balanced by the ALF-C. The downstream coordination mechanism coordinates the activation of DER located within a community or grid section. The balancing scheme in UC 2 balances the flexibility within the community in such a way that a requested flexibility (setpoint), which sets the power exchange at the MV/LV grid connection point, is achieved and maintained. The balancing mechanism compensates for unpredictable fluctuations resulting from volatile generation and consumption.

6.2 System Operator Coordination Process

The system operator coordination process (SOCP) is a proposed coordination approach for the market-based activation of flexibilities, e.g., market-based congestion management. The coordination has to be accomplished before SOs place their bids on the market. Since the decentral flexibility management concept foresees the ALF-C as a decentral edge device to monitor and balance small-scaled assets in LV-grids, the ALF-C does not have the necessary data to evaluate the potentially negative effects flexibility requests have on the other layers of the grid. Therefore, this coordination scheme has to be implemented on higher grid managing instances, e.g., MV or HV grid.

An exemplary SOCP will be applied in the German redispatch 2.0 scheme. Additionally, in German research projects funded by the BMWi[13] SINTEG[14] research program, several approaches of a SOCP for market-based congestions management have been tested. In the most extensive constellation, as shown in Figure 6 the process involves three parties:

1.) the TSO, operating the extra-high-voltage transmission system,
2.) the DSO Level I, operating the high-voltage distribution system and
3.) the DSO Level II, operating the medium-voltage and low-voltage distribution system.

Each TSO and DSO operates lines and transformers in its service area and is responsible for ensuring a safe and reliable energy supply. This includes the prediction and management of congestions and classification of the grid status according to the BDEW traffic light concept. To that end, the SOs must determine congestions, based on generation and load forecasts as well as a forward network security calculation and has to determine the required amount of power to ramp up or ramp down, point of time and duration of the activation.

For a market-based activation of flexibility for congestion alleviation, the system operators coordinate the activation as follows:

1) The upstream SO (e.g., TSO is upstream of DSO I, DSO II is upstream of DSO II) informs its downstream SO about the amount of power to be procured via the marketplace and notifies its congestions.
2) The downstream operator processes this information and returns applicable capacity restrictions, which describe the maximum amount of power that the upstream operator is allowed to procure.
3) The initially requesting SO converts its demand into procurement bids for flexibility and submits it to the marketplace within the limits of the given restriction.

A SO coordination process must ensure informational transparency between system operators when applying market-based congestion management and cross-voltage-level activation of flexibility. The coordination has to take place before SO place their bids (flexibility request) on the market-platform. An exemplary coordination process is displayed in Figure 6.

[13] Federal Ministry for Economic Affairs and Energy, „Bundesministerium für Wirtschaft und Energie“ (BMWi)
[14] SINTEG – „Schaufenster intelligente Energie – Digitale Agenda für die Energiewende“ was a research program funded by the BMWi

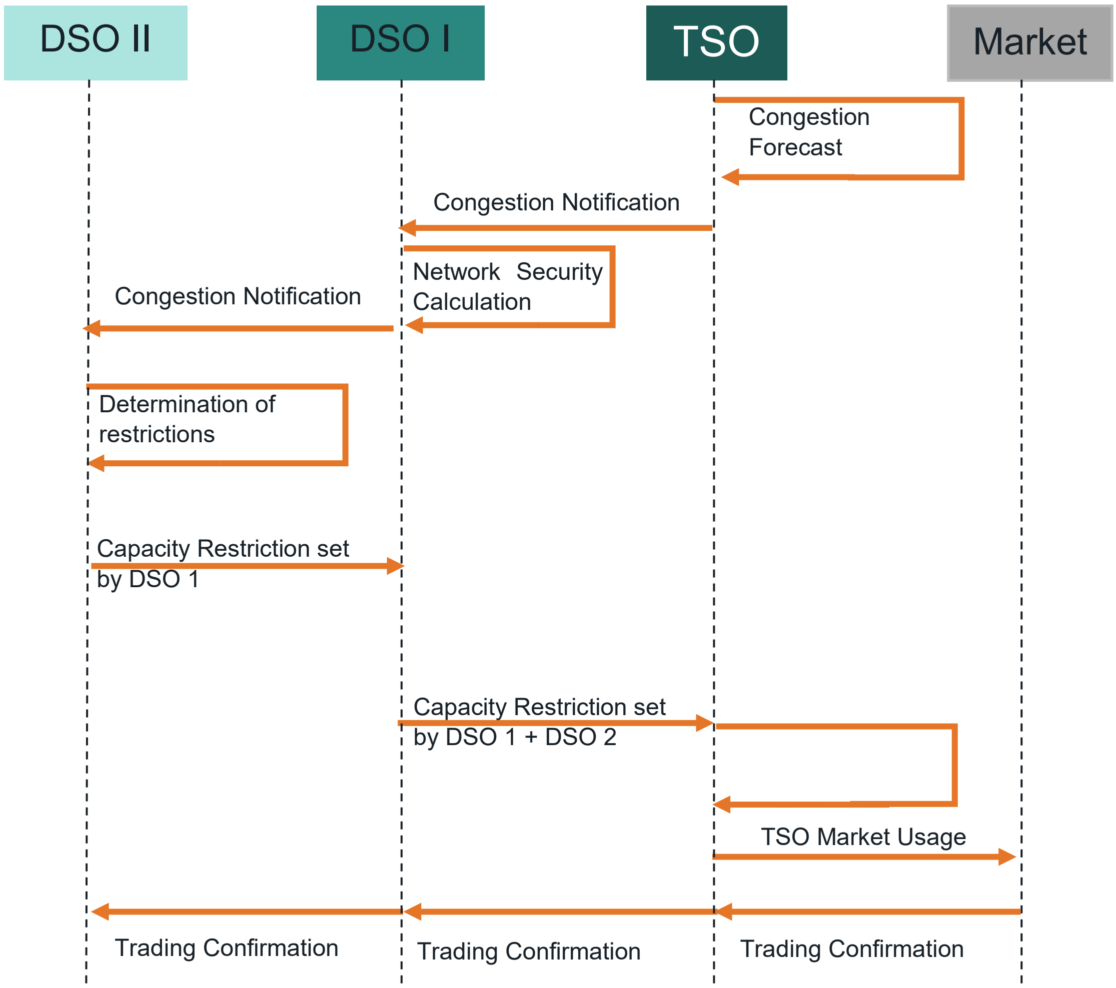

Figure 6: Example - System Operator Coordination Scheme

This example shows the principle of the coordination scheme. It refers to a coordination case, in which three SO are responsible for different voltage levels of the electricity grid, as shown in Figure 5. The example displays the most extensive constellation, at which a TSO is aiming to activate flexibility connected to the medium or low voltage grid operated by DSO II.

In the first step, a top-down request for market-based flexibility activation takes place, followed by a bottom-up approval in the second step. The placement of a request order or bid (request) by the TSO on the market platform requires a congestion forecast by the TSO, to determine flexibility requirements for the alleviation of its own congestions and the approval for activation from all downstream SO (DSO I and DSO II). In this example it is the task of the respective TSO to obtain approval from the downstream network operators. The TSO transmits its requests for flexibility to the downstream DSO I. The request has to be provided in a standardised data format. In this example it is named "congestion notification" (CN). This request must be provided to the downstream network operator within a specific time frame, early enough to give all downstream operators time to respond (e.g., 15-minutes per downstream DSO = 30 minutes in this example), but not too early, so that forecast still provide reliable predictions (e.g., 6 hours). The congestion notification contains relevant information for the procurement of flexibility, such as value of power, starting time of delivery and duration. As shown in the example, after the detection of a grid congestions in the service area of the TSO a CN is sent to the downstream DSO I (HV grid) and DSO II (MV and LV grid). In case of regional flexibility markets the congestions request from the TSO must contain at information about the proposed market area as well as amount of flexibility per 15-minute interval.

The downstream SO (DSO I) determines capacity restrictions (CR) in his service area and communicates restrictions to the upstream network operator. The CR corresponds to the usable capacity bands that must not be exceeded by the upstream SO during the market use. With the provision of the CR to the upstream SO, the downstream SO gives the necessary approval for the procurement. Applied to the shown example this means that the DSO I is obliged to forward the CN to the downstream SO (DSO II) and collect its CR. DSO I checks the restriction set by the DSO II and determines the restriction for his own network based on a network security analysis (load flow analysis). The determined restrictions are then forwarded to the TSO.

Congestion Notification (CN)

The CN provides an overview of required power for activation per grid connecting feeder (market area) to alleviate congestions. The list gives an overview of what an upstream SO is willing to activate/procure in the market. The notification details the intended market areas, flexibility to be procured (MW), starting time, end time and duration for flexibility procurement.

Table 6: Example - Congestion Notification

Market Area	Grid Connecting Transformer	Start Time	End Time	Time Resolution	Capacity Restriction
Primary Substation Engelsborg	HV-1-T121	2022-01-16T22:00 (CET)	2022-01-16T23:30 (CET)	60 Minutes	1 MW
Primary Substation Klanghausen	HV-1-T121	2022-01-16T22:15 (CET)	2022-01-16T22:30(CET)	15 Minutes	2 MW
Primary Substation Weser	HV-1-T122	2022-01-16T22:00 (CET)	2022-01-16T22:15 (CET)	15 Minutes	0,5 MW
Primary Substation Salzgitter AG	HV-1-T121	2022-01-16T23:00 (CET)	2022-01-16T23:15 (CET)	15 Minutes	4 MW

Capacity Restriction (CR)

The CR is a list defining capacity restrictions determined and provided by a downstream SO to the upstream SO. The list details for each grid connecting transformers the maximum transportation capacity. The capacity restriction must not be exceeded through the marked-based activation of flexibility of the upstream SO.

Table 7: Example - Capacity Restriction

Market Area	Grid Connecting Transformer	Start Time	End Time	Time Resolution	Capacity Restriction
Primary Substation Engelsborg	HV-1-T121	2022-01-16T22:00 (CET)	2022-01-17T8:00Z	15 Minutes	20 MW
Primary Substation Engelsborg	HV-1-T121	2022-01-16T22:15 (CET)	2022-01-17T8:00Z	15 Minutes	20 MW
Primary Substation Engelsborg	HV-1-T121	2022-01-16T22:30 (CET)	2022-01-17T8:00Z	15 Minutes	20 MW
Primary Substation Engelsborg	HV-1-T121	2022-01-16T23:00 (CET)	2022-01-17T8:00Z	15 Minutes	15 MW
Primary Substation Engelsborg	HV-1-T121	2022-01-16T23:15 (CET)	2022-01-17T8:00Z	15 Minutes	15 MW

Primary Substation Engelsborg	HV-1-T121	2022-01-16T23:30 (CET)	2022-01-17T8:00Z	15 Minutes	15 MW
Primary Substation Engelsborg	HV-1-T122	2022-01-16T22:00 (CET)	2022-01-17T9:00Z	15 Minutes	10 MW

Market Activation

After the coordination process has been finalized, the requesting SO is allowed to procure flexibility on the market according to the CR. After the market settlement and the day of delivery the DSO must verify, whether the FP has delivered the contractual agreed amount of flexibility. In case of a positive verification the billing process can start.

7 Performance Evaluation

This chapter evaluates the demonstration results of Use Case 2 and the customer engagement process. The evaluation is performed on base of demo specific and common KPIs. Demo Specific targets are designed to specifically evaluate the use case performance. Common KPIs are indicators defined for at least two different Platone demonstrations sites and will enable the assessment of Platone's performance in achieving its overall technical objectives and customer recruitment process. The calculation methodology and target values are described in Deliverable D1.2.

7.1 Evaluation based on Project KPIs

In this section, six key performance indicators (KPI) are evaluated. The first set of two KPIs is defined in deliverable 5.2, Detailed Use Case Descriptions, and focuses on evaluating features of the ALF-C in context of Use Case 2, Flexibility Provision. The responsiveness of the ALF-C to realise a flexibility request within Use Case 2 is evaluated with KPI_DE_05. The degree of accuracy of the realised flexibility request is then evaluated with KPI_DE_06.

7.1.1 KPI 5 - Responsiveness

A key requirement for unlocking the full potential of any energy management system is its responsiveness to flexibility requests. The ALF-C and its connected flexibilities, e.g., battery storage systems, must process and carry out a request deterministically within five minutes. The faster flexibility can be provided, the more valuable and effective for grid-related issues it will be. In deliverable 5.2, the responsiveness is defined as the latency between setting a setpoint in the ALF-C at time t_0 and the point in time when the requested power P' equals the measured power P, $t_{P=P'}$:

$$\text{KPI\_DE\_05} = t_{P=P'} - t_0$$

The target value of this KPI is less than 5 minutes. To evaluate the responsiveness of the ALF-C, it is advantageous to break down the processing of a request into distinct phases first and analyse each individually, see Figure 7.

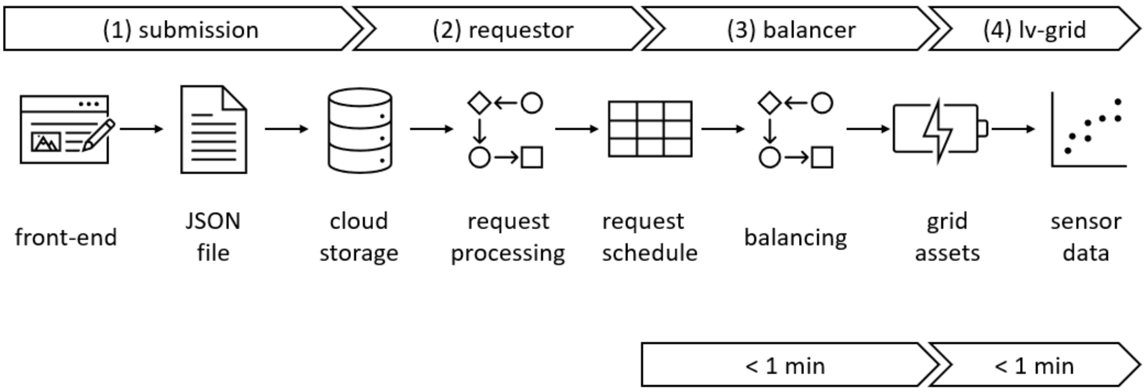

Figure 7: ALF-C Request Processes and Response Times

(1) Each request for the provision of flexibility begins with a submission to the ALF-C. In the current iteration of the ALF-C, a request is created within a front-end web application, then packaged into a single JSON-file and send via HTTP to a cloud storage that is accessible for the ALF-C. The latency of sending a request is considered negligible.

(2) The request-processing module of the ALF-C checks the cloud storage for new requests at a rate of once per minute. Once a new request is detected, it is processed, and its properties are stored permanently in the ALF-C schedule table with a status set to "new". Afterwards, the JSON-file in the cloud storage is moved into an archive folder. The processing time of the requestor-module is less than 5 seconds and thus negligible.

(3) The core modules of the ALF-C operate at a rate of once every 15 minutes, in sync with today's energy market. Within each cycle, the highest prioritised request out of all eligible requests is selected and its status is set to "active". In parallel, the ALF-C gathers the current state of the connected grid assets, e.g., state of charge of batteries. The type of request and the current state of the LV-grid are the input for the balancer to compute a new setpoint for the aggregated grid assets. Following the balancing step, this new setpoint is disaggregated into individual setpoints and sent to the flexibility assets to fulfil the request.

For every cycle, the ALF-C logs, among other information, the timestamp when the assets acknowledge receiving their new setpoint. This timestamp thus defines the end of the cycle. For Use Case 2, the average processing time of a cycle is, on average, 1 minute and 5 seconds based on the analysis of 1,126 cycles.

(4) After dispatching the setpoints to the respective assets, each asset uses its internal controller to achieve its setpoint. Currently, the only assets connected to the ALF-C is the large-scale battery storage (CBES). All new setpoint given to the CBES are achieved within the 1-minute temporal resolution of the sensor measurements in the secondary substation. It is likely that the CBES internal controller is likely much faster.

In summary, the ALF-C requires about one minute on average to fully process a Use Case 2 request and dispatch the setpoint. It then takes less than 1 minute for the CBES to achieve the given setpoint. This is less than the required 5 minutes. Thus, in the current state of development the ALF-C achieves the desired responsiveness and meets the technical requirements to participate in the secondary reserve market. The KPI_DE_05 must be re-evaluated when the household batteries are installed and connected to the ALF-C, because network communication between the devices could take more time.

7.1.2 KPI 6 - Accuracy of the achievement of a given setpoint

Use Case 2, Flexibility Provision, is a generalisation of Use Case 1, Virtual Islanding: a target value for the active power exchange at a secondary substation is requested. The ALF-C subsequently utilises the flexibility within the LV-grid to achieve the requested setpoint, e.g., by charging or discharging battery storages. This KPI evaluates how accurately the requested energy exchange is achieved.

In deliverable 5.2, KPI_DE_06 is defined as the ratio of the achieved 15-minute average power $\bar{P}_{TEI}$ to the requested power P':

$$\text{KPI\_DE\_06} = \frac{\bar{P}_{TEI}}{P'}$$

However, during the field-test it became clear that this definition is not optimal for evaluating the accuracy of the achieved setpoint. As a ratio, once the nominator or denominator approach a value of 0, the KPI either becomes very small or very large respectively. In the extreme case of zero power exchange required the KPI is not defined mathematically. Additionally, this makes it difficult to compare the KPI for different levels of P'. Instead, an updated definition by taking the absolute difference between both powers is proposed:

$$\text{KPI\_DE\_06} = |\bar{P}_{TEI} - P'|$$

With this definition, near-zero values of either power do not distort the KPI values. Additionally, the KPI values are more comparable for different levels of P'. Note the use the absolute value of the difference to prevent positive and negative values from cancelling each other out in subsequent statistical analysis.

There are two main causes for the ALF-C not reaching the requested energy exchange at the secondary substation:

I. The implementation of the control and balancing mechanism of the ALF-C is inadequate to achieve the requested setpoint, e.g., because of strong fluctuations in power exchanged caused by volatile PV generation. This is what KPI_DE_06 should assess.
II. The ALF-C did not have enough flexibility, i.e., energy from battery storages, available to achieve the requested setpoint. For example, during sunny summer days the battery storages are often fully charged early in the day and thus are incapable of reducing the energy export from the LV-grid to the MV-grid. This cause should not affect this KPI and is instead evaluated in KPI_PR_04.

Hence, only measurements with flexibility available must be considered when computing KPI_DE_06. This is the case when the CBES does not reach its maximum or minimum state of charge (SOC) within a 15-minute cycle. For the period ranging from 2021/11/19 to 2021/12/31, Use Case 2 requests were active on 763 cycles. Of these, full flexibility provided by the CBES was available for 368 cycles—about 48% of the time.

Figure 8 illustrates how KPI_DE_06 requires flexibility to be available as it otherwise loses its meaning. The upper plot shows the active power $\bar{P}_{TEI}$ and the requested setpoint P' during a field-test run with multiple competing requests of Use Case 2 running from 2021/11/29 11 a.m. to 2021/12/21 11 a.m. (UTC). The middle plot shows KPI_DE_06, the difference between requested power and achieved power at the ML/LV grid connection point in the secondary substation. The lower plot shows when the necessary flexibility to achieve the requested power exchange was available, denoted by a value of 1. Conversely, a value of 0 signifies that not enough flexibility was available. As this figure demonstrates, that was the case especially when the Use Case 2 requests asked to export energy, i.e., negative values of P', while the CBES had no charge left. Note, how the KPI increases on 2021/11/30 at 4 p.m. when $\bar{P}_{TEI}$ increase from -100 kW to over 50 kW as the CBES cannot supply the required energy anymore.

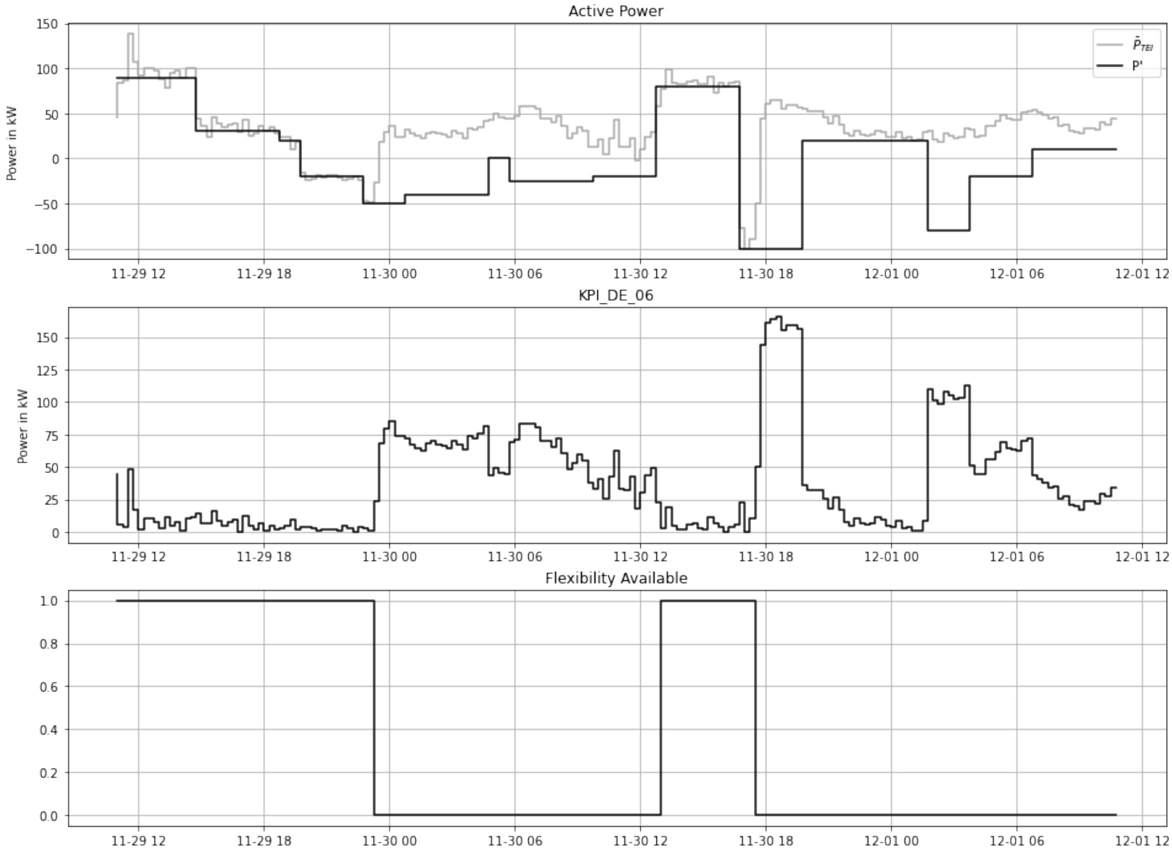

Figure 8: Plot of active power and requested setpoint

Taking the flexibility into account, KPI_DE_06 assess the accuracy of achieving the given setpoint for each 15-minute cycle. For the period under investigation, the mean value of KPI_DE_06 was 5.2 kW with a standard deviation of 6.3 kW. The average absolute value of P' for the period investigated was 64.8 kW. This means that on average an accuracy within 8% of the requested power was achieved. This good degree of accuracy was certainly aided by the fact the volatile PV generation is low during November and December. It is likely that the accuracy, and thus KPI_DE_06, is lower during summer months as unpredictable strong gradients of PV generation within a 15-minute cycles can cause larger differences between requested and achieved power exchange. Hence, KPI_DE_06 should be re-evaluated in the summer.

7.2 Evaluation of Common KPIs

In addition to the ALF-C focused KPIs, four common project KPIs defined in deliverable 1.2, Project KPIs Definition and Measurement Methods, are evaluated. Two common project KPIs assess the availability of flexibility, KPI_PR_03, and the effectiveness of the flexibility, KPI_PR_04.

The remaining project KPI focus on customer participation in the field test. The recruitment rate is evaluated with KPI_PR_013 and the active participations-rate of customers is assessed with KPI_PR_02.

7.2.1 KPI_PR_03 Flexibility Availability

This KPI assesses the availability of the assets that are providing the flexibilities for the ALF-C. At the time of release of this deliverable, the only asset available is the CBES.

In the context of KPI_PR_03 availability is achieved when a communication channel is established. Thus, a direct measure of availability is to check whether datapoints were received by the ALF-C from the CBES, e.g., active power. For this evaluation, 15-minute cycles are considered. The CBES is considered available if during a cycle at least 10 measurement values of active power were received. The KPI is defined as the ration of the number of cycles an asset was available, n_a, over the number of cycles examined, n_0:

$$\text{KPI\_PR\_03} = \frac{n_a}{n_0}$$

The examination period begins on 2021/6/17, after the site acceptance test of the CBES, and ends on 2021/12/31. This period consists of 18,913 cycles. During this period, the CBES was available for 18,704 cycles. Taking the ratio of both values, the uptime of the CBES was 98.89 percent, exceeding the required 80 percent. This shows that the communication between the ALF-C and the CBES is very stable. This KPI must be re-evaluated after the household batteries are installed and integrated into the ALF-C.

7.2.2 KPI_PR_04 Flexibility Effectiveness

This KPI assesses if the flexibility provided by the assets in the LV-grid is sufficient to be effective in steering the grid balance. Effectiveness in this context means that if there is a request for flexibility, this request can be fulfilled by either charging or discharging energy from battery storages.

The computation of this KPI is very similar to KPI_DE_06, which assess the accuracy with which the requested flexibility setpoint is achieved under the condition that flexibility is available. The main difference is that for KPI_PR_04 the availability of flexibility is not a requirement —it is indeed the goal of this KPI to assess the lack of flexibility, i.e., active power.

Similarly, in the original definition the KPI was defined as the ratio of power provided as the ratio of the achieved 15-minute average power $\bar{P}_{TEI}$ to the requested power P':

$$\text{KPI\_PR\_04} = \frac{\bar{P}_{TEI}}{P'}$$

The arguments made with regards to updating the definition of KPI_DE_06 apply to KPI_PR_04. Thus, the updated definition is:

$$\text{KPI\_PR\_04} = |\bar{P}_{TEI} - P'|$$

For the period under investigation, the mean value of KPI_PR_04 was 34.8 kW with a standard deviation of 38.7 kW. Expectantly, these values are much larger compared to KPI_DE_04 because for about half of the cycles not enough flexibility could be provided to achieve the requested setpoint. There are two different view to interpret the results. It could be argued that this shows that the flexibility provided by the CBES should be larger. However, technical and economic constraints put a limit on the size of storages. The other perspective is to re-examine to requested flexibilities in the field test. While the uses cases submitted include many different scenarios to test the algorithms, especially prioritisation of requests, of the ALF-C, they are not necessarily realistic for the season, November to December. It would thus be recommendable to develop and test use case sequences that model more realistic scenarios of future flexibility markets.

7.2.3 KPI_PR_01 Participants' recruitment

The key performance indicator for recruitment of participants was defined to evaluate customer engagement. It is measured by the number of customers contacted for participation (N_{total}) and the number of customers that showed interest in participation (N_{accept}).

$$R = \frac{N_{accept}}{N_{total}} \cdot 100$$

To have a fair customer engagement process, Avacon first engaged to create an understanding of the demo project in the region. For this, all 89 households in the field-test region of Abbenhausen, Twistringen, that were connected to the secondary substation selected for this demonstrator, were informed about the project. The project information included a cover letter with general information, a flyer with project information about our project aims regarding the region and a response card that they could send back if interested in participation including fields with notes. 23.6 % of the households contacted have replied with interest in participating without knowing the terms and conditions yet. Here, different factors need to be considered when evaluating this result. There are households not getting in contact with the demonstrator due to a lack of time in everyday life. There are customers not sending a response because they wait for more information, especially regarding the terms and conditions for actual participation. Also, there are customers who send a response card that shows their interest in participating in hope to get more information. Since experiences from other research projects showed that general interest of customers for participation is low, with response rate averaging around 7%, Avacon expected a response rate not exceeding 20% since within the Platone framework incentives, as discounted household battery storage system can be given to participants.

$$R = \frac{21 \text{ interested customers}}{89 \text{ informed customers}} \cdot 100 = 23.6\%$$

The actual response rate of 23.6% is slightly higher than the expected 20%. 9 of the 21 interested customers had no PV installed, the other 13 have already had PV systems installed and some also already owned a household battery system.

Additionally, Avacon organized an information event to clarify the terms and conditions of the project participation and to give the customers the possibility to ask questions about the project in general and about how a participation would work. Here the range is slightly higher with 27 of the 89 households registering to visit the event under the appropriate Covid-19 restrictions. Four households did not show up.

$$R = \frac{27 \text{ registrations for information event}}{89 \text{ invited customer households}} \cdot 100 = 30.3\%$$

$$R = \frac{23 \text{ attendees (customer households)}}{89 \text{ invited customer households}} \cdot 100 = 25.8\%$$

7.2.4 KPI_PR_02 Active Participation

The key performance indicator for Active Participation shows the proportion of customers that accept to participate in the project (N_{accept}) and customers that are actively participating (N_{active}).

$$R = \frac{N_{active}}{N_{accept}} \cdot 100$$

Due to limited project budget, Avacon could only involve five customers in the project. Avacon sent contracting information to 31 households, attendees of the information event and customers who had shown their interest via response cards before. Nine households accepted the participation by sending back the signed terms and conditions.

$$R = \frac{\text{9 customers willing to actual participate}}{\text{31 informed customers}} \cdot 100 = 29\%$$

Avacon decided to involve the five customers that responded the fastest and checked the technical feasibility. All five customers passed the technical feasibility.

$$R = \frac{\text{5 active customers}}{\text{9 customers accepted to participate}} \cdot 100 = 55.6\%$$

Avacon expected a rate of 70%. The lower rate of 55.6% results from the fact that the German demonstrator, after designing its cost-efficient system, was only able to actively involve five customers due to limited budget. If resource would not have been the limiting factor, eight out of the nine customers would have fulfilled the technical requirements to actively participate. This leads to a rate of 88.9%.

$$R = \frac{\text{8 possibly active customers}}{\text{9 customers accepted to participate}} \cdot 100 = 88.9\%$$

Technical Requirements were, for example, sufficient space for the installation of measurement and control equipment as well as the battery system. Additionally, a communication link to the ALF-C must exist.

8 Conclusion

This section summarizes the key lessons learned and conclusions from the Platone WP 5 Use case 2 application. The lessons learned and conclusions are divided into 3 subject areas according to the content chapters of this deliverable: Use Case 2, customer engagement and coordination of central and decentral managed flexibility. Additionally, the implication on further use case application and future productive implementation are described.

8.1 Lessons Learned

Use Case 2 - The KPI performance evaluation of Use Case 2 showed that:

I. An achieved 99% of flexibility availability (KPI_PR_03) indicates that the implemented field-test setup consisting of an CBES, communication infrastructure, sensors, controllers and the ALF-C balancing scheme provide a high availability. The KPI thus confirms that the implemented field test set setup is sufficient for the evaluation of use case algorithms.

II. The KPI_DE_05 shows that the responsiveness of the ALF-C balancing scheme in combination with the field-test setup has a short latency and meets the requirements of the initially targeted 5 minutes. The dispatching of flexibility request into a measurable power flow value at the MV/LV grid connecting feeder, confirming the execution, takes places in under 2 minutes. The quick responsiveness meets the requirements for prequalification for the participation on secondary control power markets.

III. The main difference between requested setpoint and achieved setpoint of 5.3 kW (8%) measured with KPI_DE_06 shows that the balancing scheme based on a 15-minute control cycle is sufficient for the use case application. However, deviation between requested and measured load exchange at MV/LV grid connecting point during UC 2 application is the result of stochastic and highly dynamic changes of the community load demand and PV generation, especially during daytime. The performance of the ALF-C balancing scheme might be increased through a shorter duration of the control-cycle.

IV. The KPI target values for all KPIs have been achieved and prove the success of the implementation of the ALF-C balancing scheme and the field-test setup. In addition, it has been shown that the set KPI target values were realistic and appropriate.

V. Automation of test runs can save a significant amount of resources and time and improve repeatability. For UC2 testing, the ALF-C interface for triggering requests from external market participants (DSO, TSO, aggregators) was simulated and automated by implementing a so-called runbook. As result, the testing of the ALF-C prioritization algorithm was considerably simplified and less error-prone than manual input via a GUI.

VI. Incoming flexibility requests can only be executed when there is sufficient flexibility storage capacity in the community/LV-grid. When flexibility requests from higher grid management instances (DSO, TSO, market) cannot be fulfilled due to a lack of available flexibility, it would be efficient when a second level (regional) EMS would manage these requests and dispatch them to other energy communities on the same MV feeder.

Customer Engagement

The customer acquisition process had been impeded by COVID-19. The standard process for customer engagement had to be modified. Most exchange of information was done via letters, e-mails or phone calls. It has not been the possible to welcome all 89 households to an information event. All events that have been carried out needed an advanced reservation and a hygiene concept. In total, one Open Day had been carried out to inform the households about the concepts and household battery storages and one information event had been carried out for actual participants.

With the installation of the household batteries, a time shift for consumption behaviour was noticed. Customers reported that they were more aware about using self-produced PV power.

Coordination of central and decentral managed flexibility - The investigation of the current legislation on flexibility schemes for the SO and approaches for a coordination of flexibility activation have pointed out that:

- The BDEW traffic light concept describes an applicable prioritization scheme for the prioritization of flexibility activation measures for alleviation of grid congestions.
- The market-based congestion management (yellow phase) requires a system operator (SO) coordination schemes to ensure a cost-efficient and effective alleviation of congestion and a safe and reliable energy supply.
- Since the regulation lacks a standardized concept for market-based congestion management, currently applied mechanism, such as redispatch 2.0 or concepts implemented in the SINTEG projects, might provide an applicable concept. The coordination scheme has to be implemented on higher grid management instances and not in the ALF-C.
- The ALF-C has to apply a prioritization mechanism to select a single request for execution, e.g., according to the BDEW traffic light concept, in case multiple market participants request flexibility at the same time.

8.2 Implication on forthcoming Application

The KPI evaluations have shown that the initial KPI target values have been achieved. The results point out the successful implementation of the balancing mechanism. In addition, it has been shown that the KPI target values set were realistic and appropriate. However, it must be taken into account that the evaluation is based on a field test setup that has the CBES as the only available flexibility. It also provides bidirectional flexibility. The evaluation the use case performance must also involve household battery storages located in customer households to take into account the complexity of control of decentralized small-scale battery storage system. Further, since household storages are in most cases operated in combination with a rooftop PV system to enable self-consumption, the target of the involvement of domestic storages in the ALF-C balancing scheme is to evaluate the availability of flexibility provided by this type of asset. Avacon has recruited five participating households and implemented necessary hardware components for integration into the ALF-C balancing scheme. The test will be repeated with the involvement of households after the implementation of the communication interface.

8.3 Implication on Future Productive Implementation

The results of the KPI evaluation showed that the ALF-C balancing algorithms is capable to provide flexibility with sufficient responsiveness and accuracy to fulfil DSO, TSO or market request. The algorithms might require improvement in terms of accuracy when it comes to participation of the community in flexibility schemes with high quality demands, such as reserve power markets. Such an improvement might be implemented with shorter control cycle durations, such as 5-minute cycles.

The theoretical analysis of a coordination scheme for centrally and de-centrally managed flexibility has shown that the integration of flexibility, provided by communities, into current flexibility schemes by the DSO lack of standards. Especially the market-based allocation of flexibility requires a well-defined and approved mechanism. The soon-to-be-applied German Redispatch 2.0 mechanism for regulated flexibility may be used as a comparable mechanism. However, the market-based flexibility provided by demand-side should fall under the same cost category as using cost-based supply-side flexibility to create a level playing field and give system operators the most efficient incentives, which requires adaptation of the incentive regulation (ARegV).

9 List of Tables

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12 List of Abbreviations

Abbreviation	Term
ADMS	Advanced Distribution Management System
ALF-C	Avacon Local Flex Controller
BDEW	Bundesverband der Energie- und Wasserwirtschaft
BMWi	Bundesministerium für Wirtschaft und Klimaschutz
CBES	Community Energy Storage System
CN	Congestion Notification
CR	Capacity Restriction
D	Deliverable
DER	Distributed Energy Resources
DSO	Distribution System Operator
EEG	Erneuerbare Energien Gesetz
EMS	Energy Management System
EnWG	Energiewirtschaftsgesetz
FP	Flexibility Provider
GUI	Graphical User Interface
LBES	Local Battery Energy Storage
LV	Low Voltage
MV	Medium Voltage
NABEG	Netzausbaubeschleunigungsgesetz
KPI	Key Performance Indicator
PV	Photovoltaic
SCADA	Supervisory Control and Data Acquisition
SINTEG	Schaufenster intelligente Energie - Digitale Agenda für die Energiewende
SO	System Operator
SOC	State of Charge
SOCP	System Operator Coordination Process
TSO	Transmission System Operator
UC	Use Case
WP	Work Package
SO	System Operator
SOCP	System Operator Coordination Process