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# Deliverable D3.5

## Report on optimal allocation framework for dispatching flexibility

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## Version History

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| 0.02 | 2021.10.15 | Second draft |
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| 0.04 | 2021.10.29 | Final version |

# List of abbreviations

| Abbreviation | Definition |
|---|---|
| BESS | Battery energy storage systems |
| BRP | Balancing responsible parties |
| DER | Distributed energy resource |
| DR | Demand response |
| DSO | Distribution system operator |
| ECs | Energy clusters |
| EV | Electric vehicles |
| FSP | Flexibility service providers |
| FSPs | Flexibility service providers |
| HP | Heat pumps |
| LFM | Local flexibility market |
| LMP | Locational marginal prices |
| P2P | Peer to peer |
| P2P | Peer to peer |
| PV | Photovoltaic |
| TE | Transactive energy |
| WS | Wholesale |

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## Project overview

FlexiGrid is an innovation project funded by EU's largest research and innovation program, Horizon 2020.

The project will create an enabling architecture for small and medium Distribution System Operators (DSOs) to unlock flexibility resources. Through a cross-sectoral integration and optimisation of resources, especially those arising from coupling between different energy sectors, as well as demand response using charging schemes for electric vehicles (EVs) or storage, DSOs will be able to meet the future capacity shortage with flexibility and updating old systems with smart technology.

In FlexiGrid, organisations from all over Europe cooperate to leverage digital and smart grid technologies at the grid edges. The project will deliver IoT platforms, peer-to-peer and peer-to-pool marketplaces, vehicle-to-grid, power-to-heat, and power-to-gas solutions, as well as innovative business models.

FlexiGrid will equip DSOs with advanced tools to enhance the observability and controllability of distribution networks while demonstrating both pool-based and peer-to-peer market mechanisms. Furthermore, implementing these market mechanisms in the project's demos will be facilitated by a flexible DSO-Customers coordination platform for efficient real-time trading of energy and grid services between market actors.

The overall objectives of FlexiGrid are:

• **To develop an integrated architecture** for flexibility measures and electricity grid services provided by electricity storage, vehicle charging, power-to-heat, demand response, and variable generation to enable additional decarbonisation.

• **To define, test, deploy and demonstrate markets and market mechanisms** that incentivise flexibility, in particular for mitigating short-term and long-term congestions or other problems in the distribution network such as voltage issues

• **To drive cooperation** between DSOs, transmission system operators (TSOs), consumers and generators by defining market interactions, facilitating the integration of wholesale and retail markets and cross-sector interactions

• **To deploy smart grid technologies** to enable the architecture and markets, bringing actors together to participate as distributed energy sources, driving increased resilience of the electricity grid, increased system security, greater observability, higher automation and improved control of the grid

• **To enable future technical and commercial innovation** by identifying barriers to innovation, developing pathways to regulatory and policy reform, developing business models, and through strategic collaboration.

## Consortium

# Executive Summary

This deliverable is part of WP3 “integrated process for observability, flexibility determination and dispatch”. The emphasis of this deliverable is to develop an optimal allocation framework for dispatching flexibility. The deliverable presents the need and benefit of flexibility services based on international experiences. The framework for dispatching flexibility follows different aspects of direct control based on real-time (data-driven) monitoring mechanisms, day-ahead scheduling optimisation, as well as optimal allocation and dispatch of local flexibility. The grid congestion and voltage rise problem can be detected and solved at the local community level without interaction with the distribution system operator. A direct control algorithm has been developed that calculates dispatch setpoints for PV inverters with the aim to solve transformer overloading and voltage rise issues. In addition, an indirect optimisation-based control algorithm has been developed to assist the distribution system operator to select the optimal flexibility offered while satisfying technical requirements and minimising the energy cost. Finally, a bi-level optimisation model for allocation and dispatch of local flexibility is presented. The distribution system operators can use the model to allocate technically and economically available flexibility from the flexibility service providers connected at the distribution grid and define the optimal flexibility price for both flexibility procurers and flexibility service providers.

# 1. Introduction

The rapid increase of distributed energy resources (DER) in the distribution grid brings new challenges for the DSO, e.g., reversed power flow, potential voltage band violations. On the other hand, some of these DER and the quickly progressing digitalisation of grid infrastructure enable new services for the DSO called "flexibility services" (FSs). FlexiGrid is developing models, concepts, tools, and market designs to enable flexibility for future distribution grids related to the high penetration of variable renewable energy. The DSO needs to maintain the distribution system operating within save operation parameters (e.g. by voltage control, congestion management) in any circumstance. However, the violation either from the generation side (i.e., wind or solar) or from the demand side (i.e., electric vehicles, heat pumps) creates new challenges for the grid.

Within FlexiGrid (task 3.1), the project team developed grid monitoring and risk assessment methods. Furthermore, other technical solutions DERs control (task 3.2) and market solutions such as tariff agreements, flexibility market (tasks 3.3, 3.4) have been developed. Also, (within WP2 in this project), novel market mechanisms are developed. Finally, the report connects those methods/models to develop an optimal allocation and dispatch of FSs.

This report focuses on developing an optimal resource allocation framework for flexibility services. Flexibility is the ability to deviate from the planned operation schedule [1] purposely. Then, two different control methods, indirect and direct control, will be adopted to control this ability:

- Direct control: the devices (i.e., heat pump, EV, PV) will be controlled by direct control signals. These signals will be calculated based on the grid operation status. For example, a voltage rise control algorithm will measure the feeder voltage and calculate the new control references for the PV inverter depending on the terminal voltage level
- Indirect control: there is no direct control signal that will be sent to devices. However, this is a response of users to the financial incentive such as energy tariffs or energy prices

Also, the framework for dispatching flexibility will be developed in different time resolutions. A day-ahead scheduling and real-time control will be deployed. In this sense, the indirect control method will be used for day-ahead scheduling for the local flexibility market. However, to solve grid-oriented challenges in real-time, a direct control method is used.

## 1.1. International experiences

Flexibility plays an essential role in the distribution system operation. It can solve not only technical problems (e.g., voltage, frequency control, losses reduction) but also economic issues (e.g., buying with lower energy prices).

Table 1.1 presents several commercial and research projects related to FSs. Furthermore, the concept of the LFM, the roles and responsibilities in the local market, and the value of the local market are surveyed in [2]. In general, the LFM is a marketplace that enables sellers and buyers to trade energy or flexibility. Figure 1.1 shows the overview of the flexibility value chain. The flexibility resources offered by prosumers can be used as FSs for portfolio optimisation, congestion management, or balancing services.

Table 1.1: Some projects related to flexibility services.

| No. | Project | Location | Note |
|---|---|---|---|
| 1 | Piclo [3] | UK | Commercial |
| 2 | IESO [4] | Canada | Commercial |
| 3 | Enera [5] | Germany | Commercial |
| 4 | CoordiNet [6] | Spain/Sweden/Greece | R&D and Pilots |
| 5 | PlatOne [7] | Sweden/Hungary | R&D and Pilots |
| 6 | Clue | Austria/Germany/Sweden | R&D and Pilots |
| 7 | SmartNet [8] | Italy/Denmark/Spain | R&D and Pilots |
| 8 | FlexiGrid [9] | Sweden/Turkey/Switzerland/Bulgaria | R&D and Pilots |

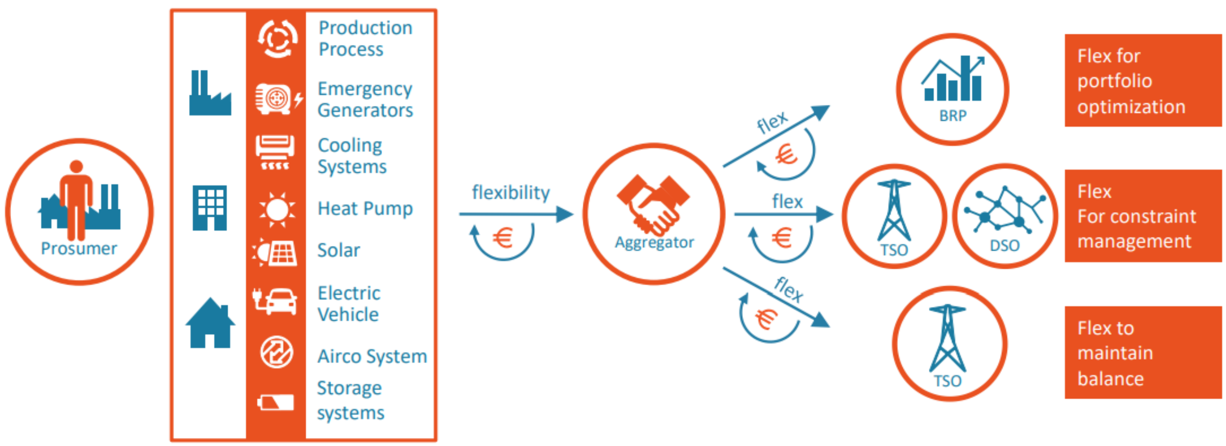



Figure 1.1: The flexibility value chain [1].

Via the local market, different buyers or procurers will buy energy services or FSs. For example, the DSO will buy FSs to solve grid congestions, voltage control, or loss minimisation. On the other hand, the Balancing Responsible Parties (BRP) are responsible for grid balancing services. Thus, BRPs could procure flexibility for optimising the energy portfolio and minimising the energy difference.

Table 1.2: Examples of commercial and research projects related to FSs [10].

| Uses of flexibility | DSO | Supplier | Asset owner | Customer |
|---|---|---|---|---|
| Reduced energy cost | | | | X |
| Avoided distribution capacity | X | | X | X |
| Avoided transmission capacity | X | | X | X |
| Peer-to-Peer services income | X | | X | X |
| Distribution services income | X | X | X | X |
| Transmission services income | | X | X | X |
| Avoided infrastructure investment | X | | | |
| Avoided generation capacity | X | | X | X |
| System balancing services | | X | X | X |
| Avoided losses | X | X | X | X |
| Wholesale trading | X | X | | |
| Market price reduction | X | X | | X |
| Avoided generation capacity cost | X | | X | |

The energy providers or sellers in the local market can participate directly or indirectly on behalf of end-users. For example, the aggregator collects all flexibility amounts from different flexibility providers and then uses them as a product to serve the needs of associated stakeholders. Also, the local energy communities' operators can act as sellers, helping the DSOs in congestion management.

Lastly, the local market operators play a crucial role in the deployment of the LFM. These act as managers of the market receiving bids, solving the market-clearing problem, quantifying energy resources and activating flexibility. Grid operators (including DSOs), as well as independent third-party companies, could take on the responsibility of LFM operation.

Table 1.2 summarises the benefits when flexibility comes to market. It depends on the type and aim of the local market. In the Table, the DSO, supplier, asset owner, and customer are included.

## 1.2. Local flexibility services

The increased net load uncertainty due to the rising integration of renewable energy resources will also increase the flexibility needs of grid operators [11]. Mobilising local FSs could reduce the need for operating expensive and fossil-fuel-based generators during infrequent high-peak periods. Such generators are also preferred due to their short ramp-up/downtimes, and grid operators opt to have them committed at least at their minimum output for this purpose. Utilising local FSs from distributed resources such as battery energy storage systems (BESS), which also have a short ramp-up/downtime, could accelerate the decommissioning of these generators. Local FSs could also help mitigate the volatility in locational marginal prices (LMPs) caused by energy imbalances resulting from intermittent generation [12]. DSOs usually deem FSs as less reliable than network reinforcement/expansion. However, flexibility solutions can be available more quickly than any network upgrades with lower capital expenditures. Moreover, even if the DSO is not the procurer of the local FSs, s/he can still act as the intermediate responsible party for technical validation of FSs traded in day-ahead or intra-day markets and procured by the TSO [13].

Below is a description of some of the local FSs that have been proposed in the literature. Depending on the type of FS, different computation methods for assessing flexibility metrics or the value of flexibility might be applied. The FSs can be classified into two main categories: 1) demand-side FSs and 2) grid-side FSs.

### *1.2.1. Demand-side FSs*

These FSs are offered by resources at the end-user level. Figure 1.2 depicts two types of demand-side flexibility products: baseline and capacity limitation. The baseline FS (FS-B) has been extensively used in most recent literature, e.g., [11] and [14]. The baseline profile of a FSP could, for example, be its optimal energy schedule. Any deviation from this profile is defined as a flexibility amount. The capacity limitation FS (FS-C) is innovative, and its main advantage over the baseline FS is that it is not prone to manipulation [15]-[16]. The flexibility amount in FS-C is calculated as the difference from the imported power of the flexibility provider from an upper capacity limit, which can, for example, be the capacity at the connection point.

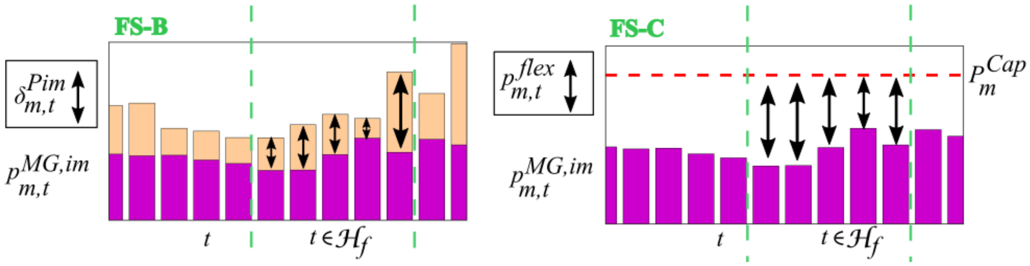



Figure 1.2: Illustration of two demand-side FSs: FS-B and FS-C.

### 1.2.2. Grid-side FSs

The most typical example of these services is network reconfiguration. Network reconfiguration is the change in the network's topology, which is achieved by modifying the status of circuit-breakers or switches. With this FS, a part of the load can be shifted from one feeder to another, thus altering the demand at both feeders. Although this FS does not incur capital expenditures as high as network infrastructure upgrades, they are still more expensive than demand-side FSs [17].

## 1.3. Report outline

The report is organised as follows: first, the introduction will outline and summarise the report. Different services will be developed in the concept of direct or indirect control. The grid congestion and energy cost will be considered, enabling the DSOs to manage congestion at a minimised cost. Further, a bi-level optimal allocation and dispatch will be developed.

Moreover, in chapter 2, a self-adaptive control for grid congestion is developed. The input is taken from deliverable D3.1 on network observability and risk assessment. A data-driven model based on the smart meter data is trained for transformer loading monitoring. The model is developed as a local community function, which mitigates the distribution networks' transformer overloading and voltage rise issues. The control actions are taken from the local community's level, and the control signal will be sent to the PV inverter, called the direct control method. The self-adaptive control will be tested with the IEEE European 55 bus network.

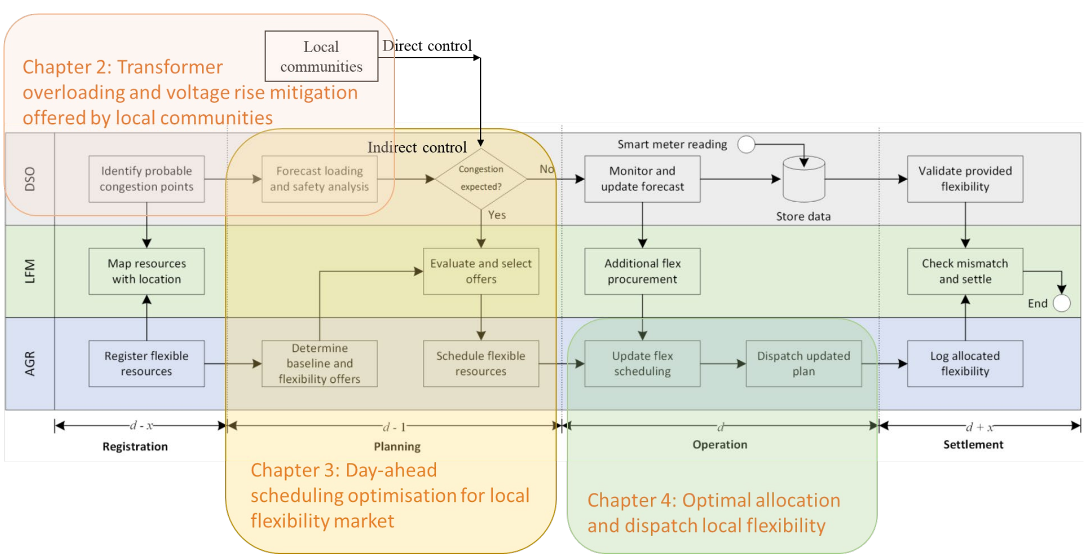



Figure 1.3: The structure of the report.

As opposed to the concept described in chapter 2, a day-ahead scheduling optimisation model is developed in chapter 3. First, based on different flexibility offers and grid operating conditions (e.g., technical and economic aspects), DSOs need to decide on a day-ahead schedule. Then, an optimised decision-making method is needed for the DSO to control the load to solve technical and economic problems. In this chapter, the flexibility energy resources are controlled based on a market-based mechanism. Then, this method is called indirect control. This chapter will use the concept of peer-to-pool for the LFM, which was delivered in D2.3.

In chapter 4, a resource allocation optimisation model, which enables the coordination between DSO and flexibility providers, is developed. The model will result in a more realistic calculation of flexibility and flexibility prices that dispatches this amount. The modified 33-bus radial distribution network will be used for testing the algorithm. In the end, the amount of flexibility with their price and location will be defined.

Finally, the report will end with the conclusion, discussion, and recommendation addressed in chapter 5. Furthermore, the connection between this work and other demonstration WPs will be addressed.

The connection of different chapters in this report is shown in Figure 1.3. This is based on the procuring flexibility framework (reported in deliverable D3.3: process design for flexibility procurement and dispatch). The local flexibility market (LFM) enables the use of flexibility from DERs for different services such as grid-oriented and market-oriented services.

# 2. Transformer overloading and voltage rise mitigation offered by local communities

At the community's level, flexibility can be offered by changing generation/consumption profiles (load profile or generation profile). In this chapter, the grid congestion solving by local communities is developed and discussed. With the rapid increase of DERs into the distribution system, the power flow in the system is changed from one direction to bidirectional. The reverse power that comes from residential-scale PV systems poses a technical challenge of voltage rise. In the worth case, when the voltage at the connecting point of PV rises over 1 pu. The on-off switching of the PV unit is activated to protect the PV system. Then, the distribution network will lose an amount of energy from the PV system.

Several methods have been proposed to address this problem [18]–[21]. In [18], an overvoltage mitigation method is proposed with droop-based active power curtailment. By computing different set points for the droops, the model offers an equal power curtailment. Further, a power quality management function was developed in [19], which increased network hosting capacity and managed the network voltage rise problem. Authors in [20] proposed a method that regulates the voltage within an acceptable operating range and maximises the PV generation capacity. The method is based on the local voltage and power measurements, which do not rely on global communication. Recently in [21], adaptive coordination of sequential droop control for PV inverters has been developed to mitigate the voltage rise problem. The method proposed a fair power curtailment while avoiding curtailing a significant PV power by using reactive power absorb. However, it could bring a transformer overloading issue.

In this chapter, the transformer overloading and voltage rise issues are solved by the direct control concept. That means the local communities can actively detect the problem and dynamically change their operating conditions to solve the problems. In this case, the DSOs do not need to take any actions until the local communities cannot keep the voltage magnitude and transformer loading in the safe operating range.

## 2.1. Problem formulation

Figure 2.1 shows the IEEE European 55 bus network. This is a three-phase network that is fed by a 250 kVA, 11 kV/0.4kV distributed transformer. The network has a radial topology with 55 residential users with single-phase connections which consist of 21 houses in Phase A, 19 houses in Phase B, and 15 houses in Phase C, respectively. Furthermore, the household is connected with the rooftop PV system. The rated power of the PV system varies randomly from 4.28 kWp to 6.25 kWp [10], which is collected from the real residential PV in the Netherlands.

$$|\Delta V| \approx \frac{(|P_L| - |P_G|)R + (|Q_L| - |Q_G|)X}{|V^*|} \tag{2.1}$$

The one-year transformer loading profile is presented in Figure 2.2. It can be seen that the transformer loading is very high in the period from mid-April to mid-August. On some days, the loading is over 100%. As a result, the transformer temperature will be increased, corresponding to the overload percentage. Therefore, it will increase failure and reduce the lifetime of the transformer in long-term operation. For more detail, Figure 2.3 shows the one-day transformer loading in July. It can be seen from the Figure; the loading percentage is increased at around mid-day. The reason is due to the high-power injection from the PV system. It is noted that the PV system is controlled by local control, named sequential droop control

[21]. The Q-V and P-V droop control mitigate the voltage rise problem in radial systems with high PV penetration. The ideal is whenever the voltage is higher than a pre-defined value, and the Q-V droop control is used to calculate the reactive power, which can be absorbed by PV inverters. The voltage difference between sending and receiving buses can be reduced using reactive power, following the equation (2.1). In that, $V^*$ is the receiving end voltage, $P_L/Q_L$ donate the receiving end bus local power consumption, and $P_G/Q_G$ are the local power generation from PV systems. As a result, the voltage rise problem can be solved while maintaining the large amount of active power injection from household PV. However, in the mid-day, while keeping the active power generation and reactive power absorb from PVs, there is two power flow of active and reactive power through the transformer. As a result, this can cause the transformer to overload. In Figure 2.3, the transformer loading is overloaded up to around 108% from 10:30 AM to 2 PM. This can reduce the transformer lifetime. In the following sections, we will explain the concept of local communities which can detect the problem and change their power setpoints to solve the problem.

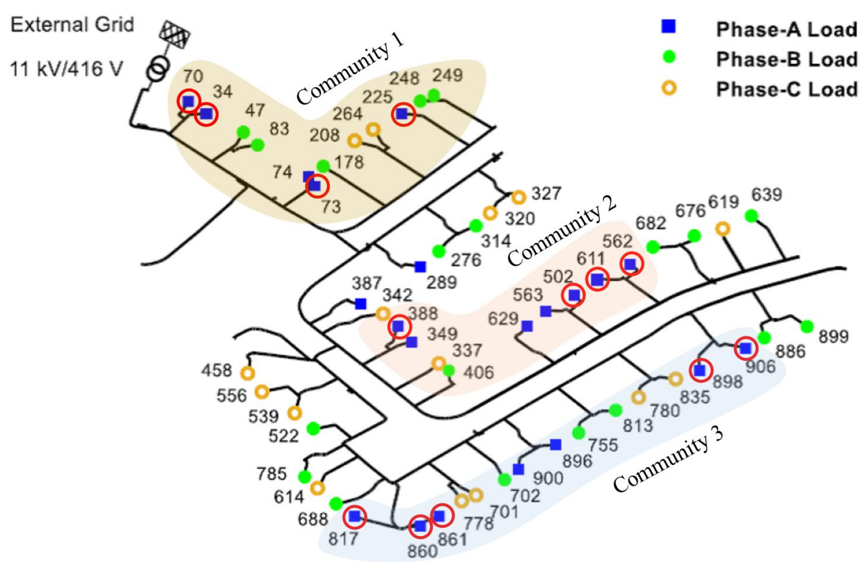



Figure 2.1: The IEEE European 55 bus network.

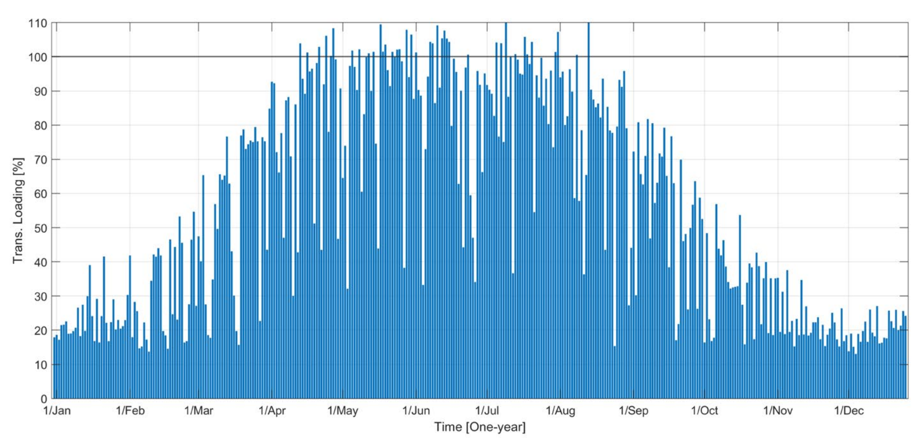



Figure 2.2: One-year transformer loading.

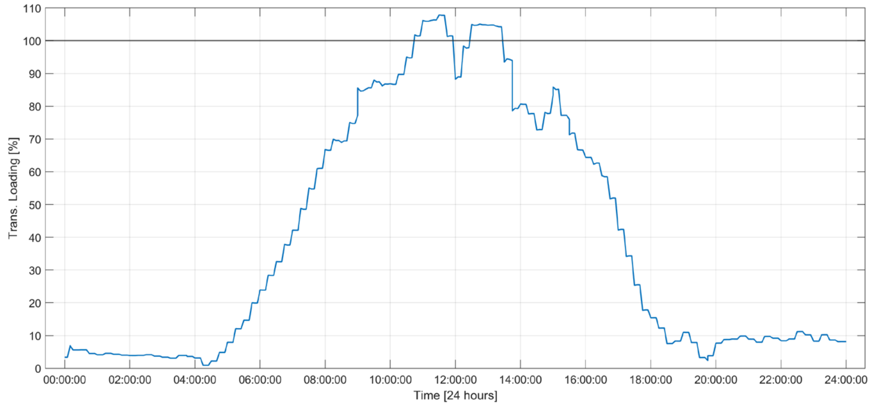



Figure 2.3: The transformer loading.

## 2.2. Self-adaptive control architecture

As described in section 2.1, there is a close relationship between the voltage rise and transformer overloading issues. Therefore, in this section, a self-controlled architecture is developed to solve the voltage rise problem while minimising the transformer overloading. The term "self-controlled" refers to the active control action from the local energy communities, which can detect the overloading issues by using a data-driven model and subsequently change their operation setpoints. Our recently accepted paper [22] developed an XGboost model to enable the transformer loading estimation using limited information in the distribution system. The paper shows the high correlation between transformer loading and voltage magnitude at connected points of households. The framework of the data-driven approach for transformer congestion monitoring is shown in Figure 2.4. This framework includes two main building blocks as follows:

- Model preparation: a comprehensive procedure for transformer loading estimation is executed involving data pre-processing and machine learning model fitting and evaluation. The main outputs of the procedure are a reduced set of smart meters identified as input data sources and the best-performing machine learning algorithm for the regression model.
- Model deployment: data from the selected SMs is collected and fit into the tuned, trained model given by the model preparation stage to estimate the transformer loading. The transformer congestion, subsequently, can be identified.

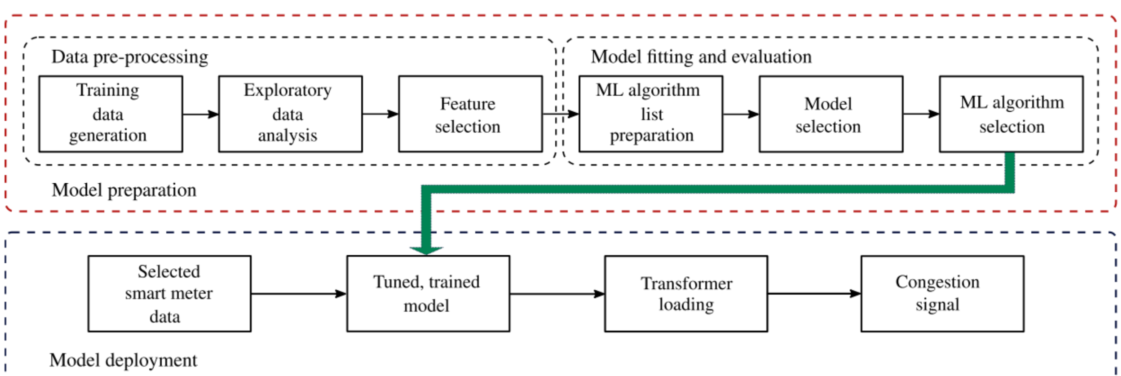



Figure 2.4: Methodological framework.

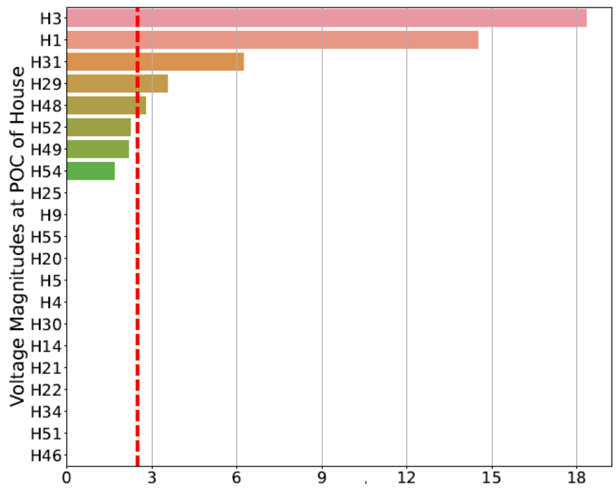



Figure 2.5: The feature importance analysis.

Further, feature importance analysis shows that the transformer loading highly depends on the voltage magnitude of some houses. It means that, by using a limited set of household voltage values, the model can effectively estimate the transformer loading status. As can be seen from Figure 2.5, there are 8/21 houses in Phase A that have a high correlation with the transformer loading status. These are the house number (H3, H1, H31, H29, H48, H52), corresponding to the buses (70, 34, 611, 562, 860, 898) in Figure 2.1. Also, three different communities are defined. Therefore, by exchanging the voltage magnitude, the transformer loading can be estimated.

Each PV is controlled using local droop control, and the active and reactive power setpoints are calculated using the following equations:

For Q calculation (where $\overline{Q}_i$ is the maximum reactive power output, $V_i^{tP}$ is the threshold level of active power curtailment, and $V_i^{gQ}$ is the threshold level for reactive power injection, $V_i^{aQ}$ is the threshold of reactive power absorption):

- If $\underline{V} \leq V_i < V_i^{gQ}$:

$$Q_i^{\text{net}} = \overline{Q}_i \frac{(V_i^{gQ} - V_i)}{(V_i^{gQ} - \underline{V})} \tag{2.2}$$

- If $V_i^{gQ} \leq V_i \leq V_i^{aQ}$

$$Q_i^{\text{net}} = 0 \tag{2.3}$$

- If $V_i^{aQ} < V_i \leq V_i^{tP}$

$$Q_i^{\text{net}} = -\overline{Q}_i \frac{(V_i - V_i^{aQ})}{(V_i^{tP} - V_i^{aQ})} \tag{2.4}$$

- If $V_i^{tP} < V_i \leq \overline{V}$

$$Q_i^{\text{net}} = -\overline{Q}_i \tag{2.5}$$

For P calculation (where $P_i^{\text{MPP}}$ is the maximum power point):

- If $\underline{V} < V_i \leq V_i^{tP}$:

$$P_i^{\text{net}} = P_i^{\text{MPP}} \tag{2.6}$$

- If $V_i^{tP} < V_i < \overline{V}$:

$$P_i^{\text{net}} = P_i^{\text{MPP}} - P_i^{\text{MPP}} \frac{(V_i - V_i^{tP})}{(\overline{V} - V_i^{tP})} \tag{2.7}$$

- If $V_i \geq \overline{V}$:

$$P_i^{\text{net}} = 0 \tag{2.8}$$

The set of equations from (2.2) to (2.8) can be summarised in Figure 2.6. If the PV voltage reaches the reactive power threshold $V_i^{aQ}$ (at the point (1)), the PV will start absorbing reactive power to reduce the voltage in the grid. However, if the voltage still increases and go over the $V_i^{tP}$ (at point (2), which is the threshold level of active power curtailment), the PV injection from PV will be decreased.

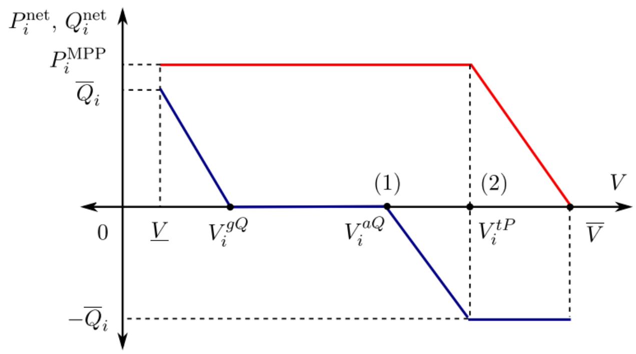



Figure 2.6: The sequential droop control.

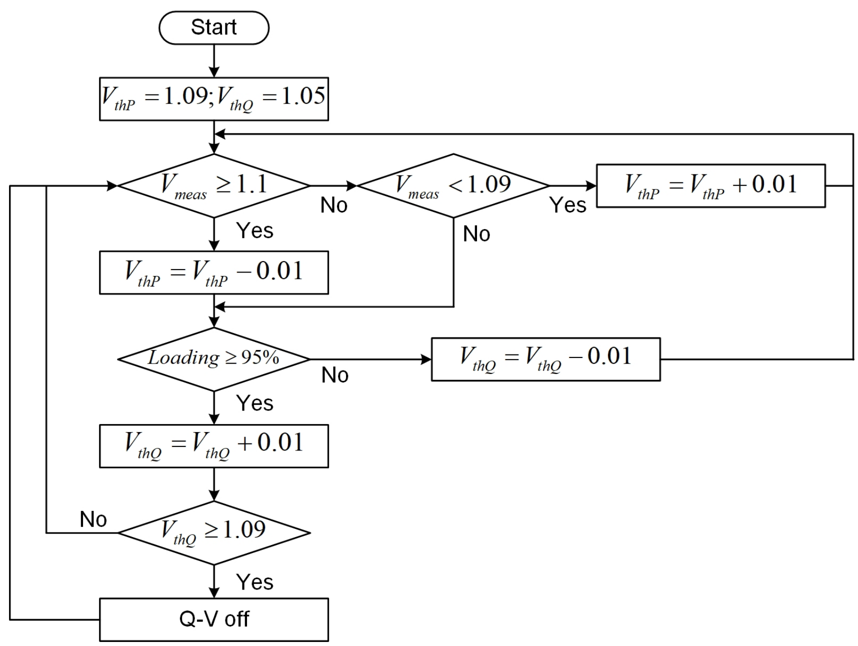



Figure 2.7: Self-adaptive control.

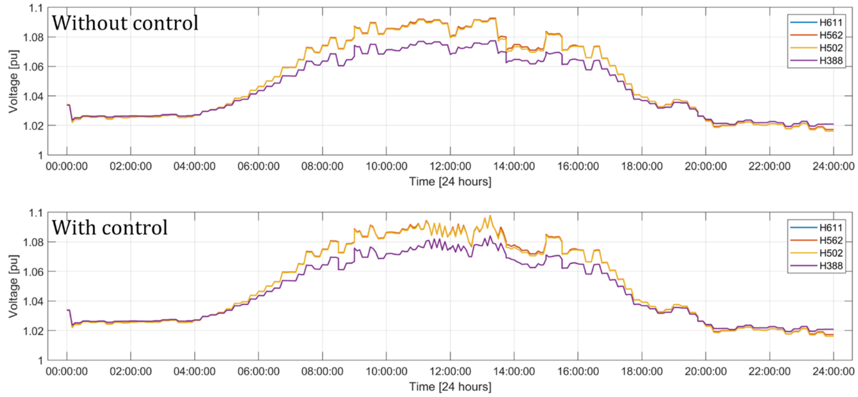



Figure 2.8: Voltage profile of some houses at community 2 in case of with and without control.

A self-adaptive control is developed on the higher control layer to monitor the transformer loading and mitigate the voltage rise issues. Figure 2.7 shows the control diagram of the proposed control. The control is based on the voltage magnitude of the critical bus in each community (the house near the end of feeders) and the estimated transformer loading status to adaptive increase or decreases the setpoint of active curtailment and reactive power absorption. The active power injection needs to be curtailed whenever the voltage exceeds the operation limit of 1.1 pu. Together with the voltage control, the transformer loading is monitored, the overloading limit is set at 95%. If the loading is higher than the limit, then the threshold of Q absorption is increased, which means the PV will reduce the reactive power absorption.

## 2.3. Simulation and results

The concept of self-adaptive control is applied in the IEEE European 55 bus network. The distribution network is built in MATLAB/Simulink, and the control is developed using S-Function. Figure 2.8 shows the voltage profile of four different houses in community 2 (with a higher voltage in three communities). We compare the result in two cases - with and without self-adaptive control (local control is used in both cases). The voltage profile is controlled in the safe operation range of 0.9 pu to 1.1 pu. Then, it can be concluded that the voltage rise issue is mitigated by using only the local sequential droop control. Also, in this community, house 502 has a higher voltage profile. Thus, it is used as the input for self-adaptive control.

The transformer loading in the case of with and without control is shown in Figure 2.9. During the mid-day, the loading percentage increases due to the active power injection and reactive power absorption. As can be seen from the Figure, the overloaded transformer period (over 100%) is effectively reduced by using the self-adaptive control. Figure 2.10 and Figure 2.11 show the absolute value of active power injection and reactive power absorption of house 502 in community 2. As shown in Figure 2.11, the reactive absorption increases following active power injection when the loading percentage is still under the threshold. In the case of transformer overloaded, the threshold for reactive power absorption is increased (the point (1) in Figure 2.6 is moved to the right) to reduce the absorbed reactive power. As a result, the reactive power absorption decreases to zero to prevent the transformer from overloading. However, the transformer is still overloaded, meaning that the active power injection needs to be reduced. Figure 2.10 shows that the active power injection is not equal to the maximum power point corresponding to the overloaded transformer period. At this time, the active power injection is increased up to the maximum power point.

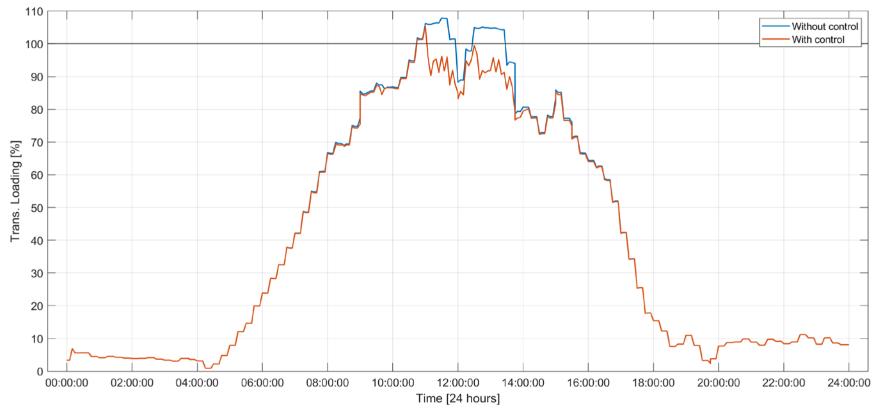



Figure 2.9: The transformer loading in case of with and without control.

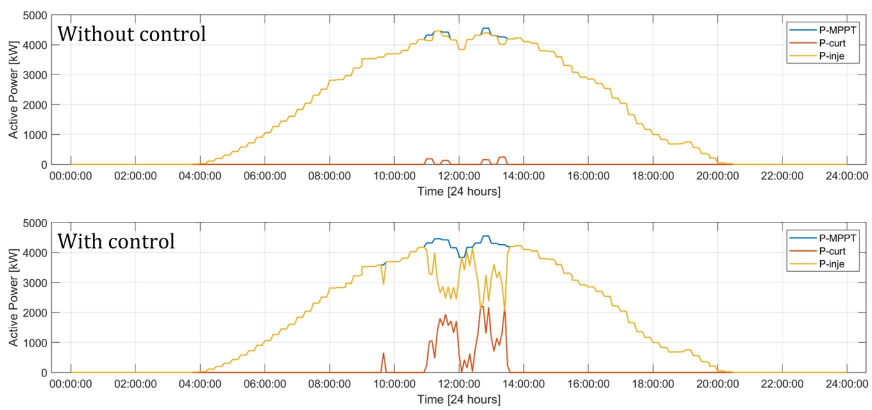



Figure 2.10: Active power of House 502 in case of with and without control.

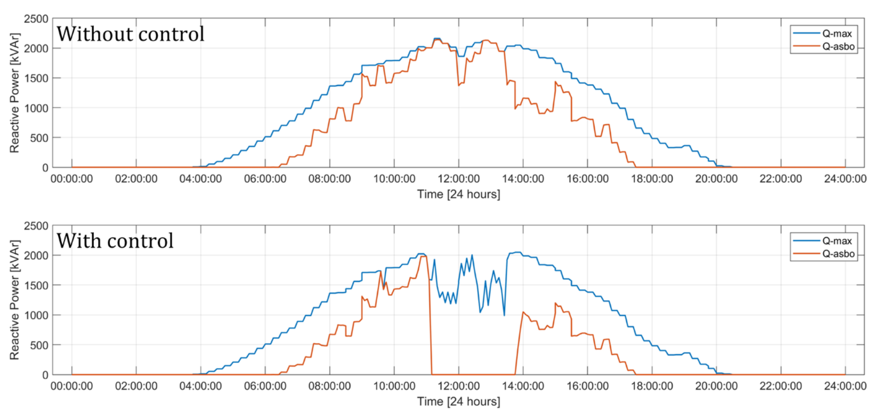



Figure 2.11: Reactive power of House 502 in case of with and without control.

# 3. Day-ahead scheduling optimisation for local flexibility market

The energy shift towards sustainable and integrated electricity systems foresees an increased deployment of distributed renewable generation sources and energy-demanding appliances, such as photo-voltaic panels (PV), heat pumps (HP), and electric vehicles (EV). These distributed energy resources (DERs) transform the energy landscape with new electricity production, usage, and storage. This transition creates the need for new bottom-up control approaches, where greater involvement is dedicated to regional DSOs, active customers, and prosumers [23]. One pathway may be to develop demand response (DR) programs and active control mechanisms in distribution networks, raising privacy concerns and scalability challenges [24], [25]. Thus, a further step towards transactive energy (TE) systems is necessary, where economic and control mechanisms allow balancing demand and supply dynamically, using value as the key operational parameter [24], [26].

Additionally, the European Commission expresses the need to adapt network operation rules for a more flexible market structure. This requires a more dynamic and local marketplace. As a result, various flexible energy resources are incorporated on the intra-day operation while still enabling the involved actors to establish some commitments in advance, for example, by day-ahead trades. Hence, LFM seems promising to create a transactive DR platform where prosumers are engaged to trade energy while supporting the regional scopes (e.g., neighbourhood area) of the distribution network and offering service enhancement for the DSO. As outlined in [24], [25], [27], the LFM offers various advantages: greater amount of self-generated electricity consumed locally, alleviating transport losses and reducing the risk of reverse power flow at medium voltage substations; opportunities for local economies, which provide ways for local companies and regional businesses to develop, advancement of smart grids and digitisation of the networks. However, the LFM creates an open research question from the DSO perspective on optimally deploying flexibility control and procurement methods in regular operation, with uncertain congestion events and complex integration schemes.

Earlier works propose direct DR approaches that enable control and curtailment of local generation and local loads or by varying tap levels at the secondary transformer side [28], [29]. On the other hand, indirect approaches motivate prosumers with incentive- and price-based demand response programs [30]. The study in [24] demonstrates an integrated approach in simulated operation, where market-based DR optimisation is combined with direct load curtailment methods. The findings conclude that the integrated approach effectively prevents overloading events while maintaining appropriate supply in the network. TE frameworks and flexibility markets were recently adopted to create dynamic and efficient energy allocation contracts. Research in [31], [32] extends the wholesale (WS) energy markets, where the TSO can obtain balancing resources, and local resources are aggregated through micro-markets to offer FSs for bidding in the day ahead WS markets. Novel studies lean towards more innovative arrangements beyond the pool-based or auction-based local markets - peer-to-peer (P2P) trading and exchange among energy communities [33]. Various P2P trading scenarios under different techno-economic circumstances are studied in [34], concluding that scheduling load shifting appliances improve savings. However, the P2P context is highly dependent on profiles of involved participants and flexible devices, where the optimal solution is defined by individual trade-offs between self-sufficiency and surplus electricity generation for trades.

This research presents an LFM mechanism where DSOs can improve system security and efficiency. The LFM facilitates flexibility independently from energy, balancing needs, or grid conditions according to a specific location. Moreover, the LFM models a decision-making process to operationalise the flexibility and communication flow between local system operators and the aggregators acting on behalf of end-users. The proposed mechanism ultimately improves system operation efficiency, increases market participants' economic gains, and realises the full potential of household-level flexibility value. The contributions of this paper can be outlined as follows:

- We are proposing an elementary LFM with a trading platform that describes participating actors' interactions.
- Simulating a real distribution grid segment operating under proposed day ahead LFM structure with single DSO and multiple aggregators.
- Developing the market-based deterministic optimisation of decision-making scheduling flexibility resources and solving grid issues from the system operator's perspective.

## 3.1. Local flexibility market

This analysis adopts the flexibility market definition as the platform for purchasing and selling flexibility concerning a delimited geographical area served by distribution feeders (single or radial) such as a neighbourhood. As the main market commodity, we consider the flexibility that can be procured from the local end customers and clusters of DERs. Furthermore, we define flexibility as the active management of distribution system asset profiles adapting to system balance and grid power flows. Regulation upwards, or positive flexibility, is associated with an increased generation or decreasing demand, whereas downward or negative flexibility represents the decrease in the generation or increasing demand. Hence the prosumers can be either an energy sink or an energy source from the grid operator's perspective. For instance, the DSO will submit a positive request for specific flexibility amount in case they encounter grid issues and need the prosumers to decrease their energy consumption.

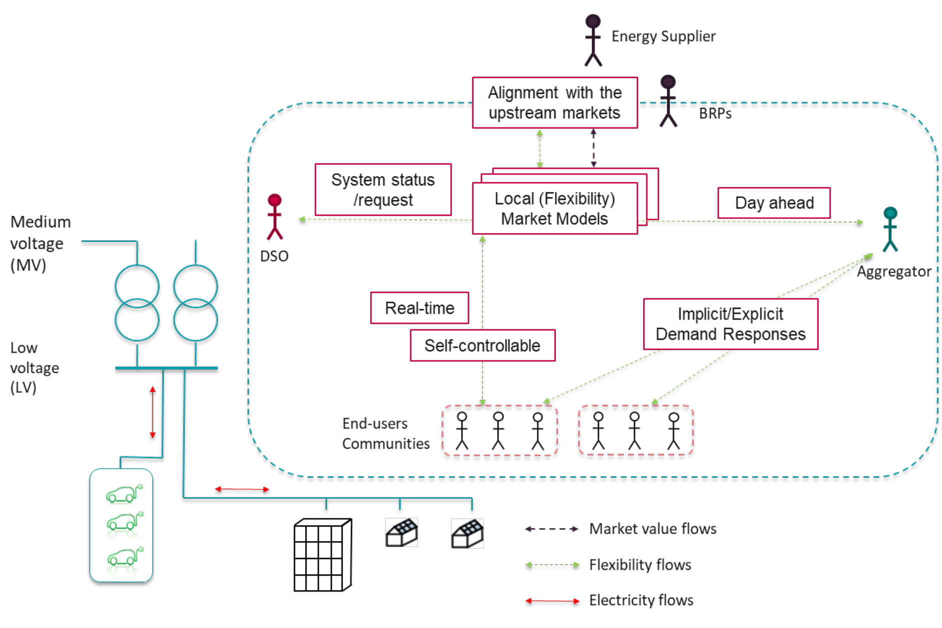



Figure 3.1: Diagram of the participation areas of the proposed LFM actors.

In this work, we take the perspective of the DSO and focus on the medium to low voltage substation transformer loading optimisation as the main intent of flexibility procurement. Considering the grid-oriented service, we propose an LFM that is cleared a day ahead of the delivery day, where the DSO can realise the expected needs for flexibility. The DSO functioning in the area spanned by the LFM is the single buyer, while multiple Aggregator agents compete to sell the flexibility they can provide. Areas of operation for each participating agent are indicated in the LFM overview scheme in Figure 3.1. Accordingly, the end customers, and potentially energy communities or medium-scale RES units, sign contracts with the Aggregators, who act as flexibility providers on their behalf. This way, the flexibility resources at the demand side are specified, including the amount of shiftable or curtailable power, the price of using it, the specific constraints regarding household and comfort preferences, the time of day, frequency of flexibility deployment, etc. The consumer comfort levels (regarding temperature and heat-pump settings, for instance) and the profitability levels (regarding saved energy costs) are assumed to be balanced within contractual agreements with the aggregating actors. The framework is realised by adopting hierarchical agent-based control, where each household has a governing agent device connected to the aggregator's network. It acts as an interface for the prosumers to input the preferences, while the aggregator coordinates the contracted prosumers using dynamic price and control signals via the household agent. Each controllable smart device and DG unit within the households could also be equipped with a device agent governing their optimal operation and actuating the load shifts. Further detailed descriptions of the agent-based demand repose mechanism can be found in [24].

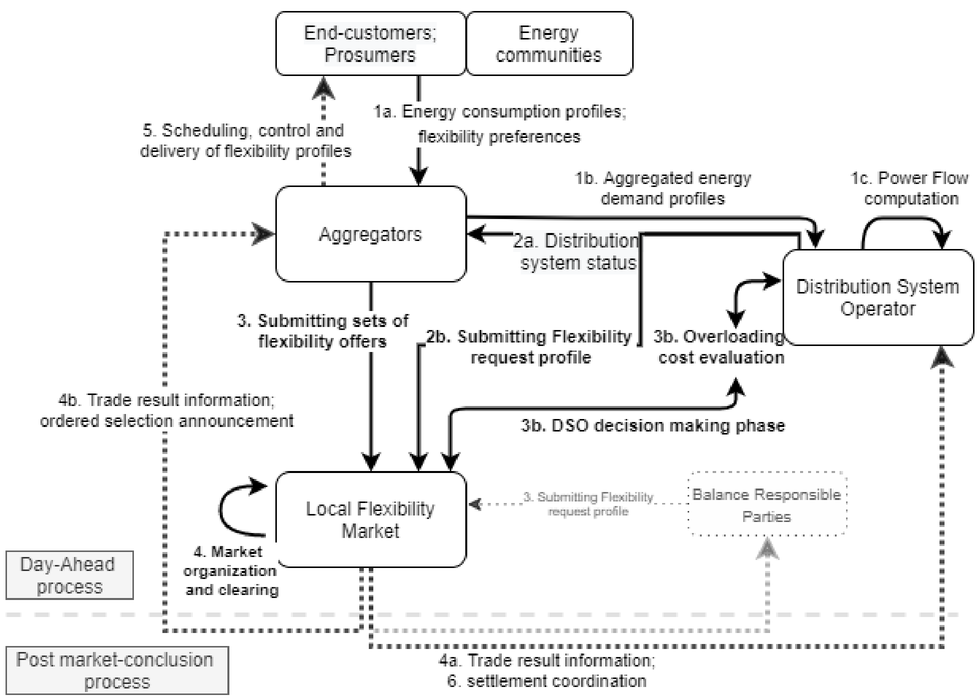



Figure 3.2: Diagram of the sequential interaction between participating actors in the LFM.

*In Figure 3.2, the dashed lines represent processes following the closure and clearing of the LFM platform. Note: The BRP actors have the opportunity to submit flexibility requests to the LFM to mitigate their anticipated unbalances. However, their interactions are represented in grey colour as the BRPs are not considered to participate in the analysed LFM platform*

The proposed LFM is organised for 24 hours ahead of the delivery time, with a resolution of 1 hour. Initially, the profiles of prosumers are analysed by the aggregator and supplied to the system operator. Next, DSO determines the need for flexibility for the entire settlement period and poses the flexibility request to the market platform. In response, Aggregators pose their offered flexible schedules and the corresponding prices. Finally, based on the submitted offers, the DSO must perform the decision analysis to select the most (economically and technically) optimal flexibility schedule.

In the following list, the operational stages, numbered and illustrated schematically in Figure 3.2, are described in detail:

- 1a; 1b; 1c; DSO executes risk and contingency analysis and power flow computations for the concerned grid segments. To investigate the violations of operational limits of the grid assets, DSO might use their historical measurements and estimated loading data models, the information supplied by the aggregators, estimates, and weather forecasts.
- 2a; 2b; If DSO analysis predicts operation violations or risks, they send a flexibility request profile to the LFM platform, seeking to mitigate the risks. For every scheduled time unit, DSO assigns either a positive or zero amount of requested flexibility. Moreover, the DSO submits additional information to the LFM participants: type of risk encountered, the location where flexibility is needed, and the general system status.
- 3; Aggregators collect available flexibility profiles from contracted prosumers (for the concerned location and time of day) and compute their aggregate offers. They submit these offers to the LFM, incorporating the amount and direction of flexibility for each scheduled time unit. It has to be noted that Aggregators offer flexibility aligned to the requested DSO profile (e.g., requested and offered positive flexibility indicate the need and opportunity to decrease the consumption).
- 3b; Here, the DSO enters the decision-making phase. The models or functions employed here aid the DSO in translating the anticipated load, offering flexibility, and deciding which resource to procure or which trade-off to select. Given small or short overloading at the transformer and depending on the set of constraints, the decision-making mechanism may choose to allow the overloading. While the constraints are different for individual flexibility frameworks, they are generally defined by the asset degradation and the value of flexibility, such as the market price and the flexibility resource availability.
- 4a; 4b; 5; Finally, resulting trades are announced, and other participants are informed. Competing Aggregators could use this information to their advantage, employing algorithmic learning techniques to improve bidding strategies and the rate of successful flexibility trades. However, this is out of the scope of this paper.
- 6; Finally, the LFM single-day period is concluded, and settlements are coordinated by the market operator according to the delivered schedules.

## 3.2. Mathematical model description

### *3.2.1. Methodology and assumptions*

This analysis assumes that the LFM consists of several Aggregators, a single DSO, and an independent market operator. Flexibility resources comprise the prosumer load profiles and controllable or shiftable devices (including smart appliances, HPs, PV, and storage sources such as EVs or batteries). The prosumers are assumed to be motivated by minimising their energy costs, realised by the financial compensation defined by the Aggregator contract they engage in. It is further assumed that DSO aims to manage the grid as efficiently as possible, maintaining security and operating at minimum costs. The main Aggregator objective is to generate profit by trading flexibility. To model the operation of the LFM, we assume the DSO is facing overloading issues during the day at the distribution transformer. Thus, the DSO seeks to modulation the apparent power at the feeder connections to limit the transformer loading level. Taking this assumption allows neglecting the location aspects of the needs for flexibility essential for other issues the DSO may face, such as voltage band violations.

Moreover, it is assumed that the LFM platform operates with hourly resolution profiles, and bids are cleared for the entire scheduling horizon. To ensure that the clearing and delivery of newly agreed flexibility profiles do not cause further grid problems, the DSO is assumed to compute power flow calculations for the combination of suitable flexibility offers. Moreover, while the household and flexible device load profiles were generated using measured factual data, the aggregators' flexibility was generated manually, based on expected behaviour strategies. The manual generation enables the problem to capture the stochastic modelling and reflect the uncertainty that the aggregators face when creating flexibility offers.

### *3.2.2. Optimisation problem*

The set of all time units within the day ahead schedule is defined by $N_t$Indexed by t to refer to specific time units. The set of Aggregators is defined by $N_a$, indexed by a to refer to each Agg. It is assumed that Aggregators submit flexibility offers, which are collectively defined in the set $N_a^P$ for each a. During each time period t and Pa profile, the quantity of flexibility offered by the Aggregators is defined as $q_{a,t}^{P_a}$. The price in each period t of the offered profile for Agg a is denoted by $p_{a,t}^{P_a}$. The request by DSO is defined as $G_d^t$ for each time period. Moreover, the Aggregators are assumed to trade only a single profile out of their offers. Hence a binary selector variable $\beta_a^{P_a}$ is used to indicate whether the specific profile of the specific Agg has been selected. The optimisation problem from the perspective of the DSO can be formulated as the minimisation of flexibility costs in the following way:

$$minC_{da} = \sum_{t \in N_t} G_{da}^t \tag{3.1}$$

Subject to:

$$G_{da}^t = \sum_{a \in N_a} \sum_{P_a \in N_a^P} \beta_a^{P_a} [p_{a,t}^{P_a} \cdot q_{a,t}^{P_a}], \forall t \in N_t \tag{3.2}$$

$$Q_d^t \leq \sum_{a \in N_a} \sum_{P_a \in N_a^P} [\beta_a^{P_a} . q_{a,t}^{P_a}], \forall t \in N_t \tag{3.3}$$

$$1 = \sum_{P_a \in N_a^P} \beta_a^{P_a}, \forall a \in N_a \tag{3.4}$$

$$\beta_a^{P_a} = [0,1], \forall a \in N_a, , \forall P_a \in N_a^p \tag{3.5}$$

The optimisation objective is to establish the most economical combination of flexibility profiles for the day-ahead market. The binary variable $\beta_a^{P_a}$ is not dependent on time, which implies the orders are selected for the whole scheduling period. In the objective function equation (3.1), $G_{da}^{t}$ represents the cost of flexibility in each time period in the day ahead (da). The sum in equation (3.2) provides costs of the entire 24-hour scheduling program, taking the selected price and quantity pairs in the $\left[p_{a,t}^{P_a} \cdot q_{a,t}^{P_a}\right]$ product. Moreover, the constraint described by equation (3.3) enforces that the final procured flexibility matches or exceeds the flexibility which the DSO has requested. Finally, the constraint in equations (3.4) and (3.5) ensures that only a single profile of the submitted set for each aggregator is selected.

## 3.3. Simulation and result

The proposed flexibility market modelling methodology is tested in a case study, based on a factual distribution grid segment, consisting of a low voltage (0.4kV) residential area network, supplied by 400 kVA, 10kV/0.4kV distribution transformer with 115 busses and 183 loads in total. The schematic structure of this network is shown in Figure 3.3.

It is observed that household loading profiles are distinctly varying; hence it is necessary to analyse whether they can be clustered according to their trends and consumption levels, as the clusters can be organised and managed by the Aggregators in the LFM, offering different levels and products of flexibility to the DSO. Based on the yearly energy consumption from the smart-meter-equipped households, three clusters have been identified, characterised by annual consumption: up to 3000kWh, up to 5000kWh, and consuming up to 7500kWh. Furthermore, these clusters were used to compute mean profile vectors, extrapolated with the log-normal distribution to generate additional household yearly load profiles. The resulting profiles are shown in Figure 3.4, with three clusters outlined with solid lines.

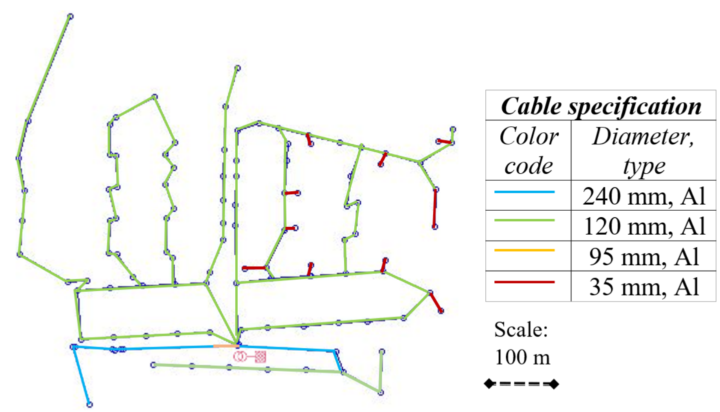



Figure 3.3: Selected low voltage distribution network segment.

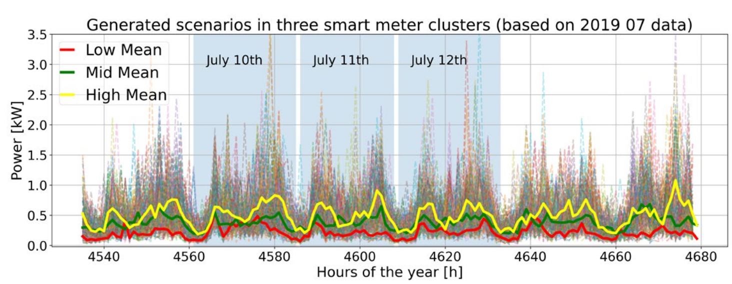



Figure 3.4: Generated household load profiles within three identified clusters, classified by yearly energy consumption.

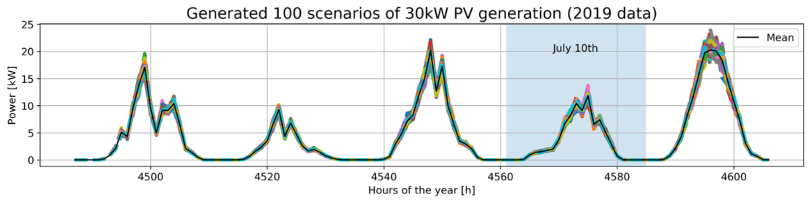



Figure 3.5: Generated hourly PV profiles, corresponding to 7th-12th July 2019.

The PV generation was modelled based on actual data of 10 operational 30kWp PV plants. In total, 100 additional yearly profiles are created, taking the mean value vector and standard deviation of the initial set, generating values for each hour according to the normal distribution function. Of this set, the five days in summer are represented in Figure 3.5, where the generated 100 PV profiles and their corresponding mean level can be seen. Finally, the household load profiles were considered the base load for each node in the analysed segment. Next, 40 households in the grid were assumed to have EV charging installed. The charging power was assumed to range from 3kW to 8kW, integrated from earlier demand response programs that model the charging based on driving distance and charging times. Also, 60 households were assumed to own rooftop PV installations, ranging from 4kWp to 7kWp. For simplification purposes and to assume an uncertain flexibility quantification, the flexibility offers are generated manually for the simulated daily periods. Each Agg is assumed to offer two flexibility profiles; hence a total of 6 offers is available. The first Agg, managing the prosumers with PV, is assumed to shift load towards the middle of the day, while the remaining Aggregators are assumed to undertake more conservative bidding strategies. However, all the Aggregators are assumed to shift demand to the night hours (exploiting shiftable loads such as washing machines, freezers, and heating devices). For the construction of this benchmarking case, the flexibility was priced by assigning the WS energy market hourly price to simulate the functionality of the LFM decision-making and subsequently analyse different impacts of the pricing schemes. The hourly dynamic price signals were obtained for the Lithuanian market from the NordPool day-ahead auction market online database for the specific days in 2019. Finally, the 60 highest-consuming households with EV charging were assigned to Agg Nr.1. The 60 households of middle consumption level were assigned to Agg Nr.2. The remaining 63 prosumers were allocated to the Agg Nr.3.

Two days were selected in the analysed year (January 2nd, 2019, for the winter day and July 10th for the summer day) to represent the varying levels in demand in PV generation and subsequently to contrast the needs for flexibility in the distribution grid. Furthermore, to exemplify the different operation conditions, it was assumed that during colder environment temperatures, the DSO operated the MV/LV transformer up to 300kW (having a limit rating of 400kVA). At the same time, during the warmer summer days, the DSO seeks to maintain the loading below 200kW of active power transfer.

Considering the day in January, Figure 3.6 and Figure 3.7 show the network load and flexibility requirement results. This is the fundamental outcome of the first stage undertaken by the DSO, specifically the power flow computation to identify potential grid issues (such as asset overloading) and gauge the need for LSs, posing the requested profile to the LFM platform. It is observed that considering the desired operation limit of 300kW, the transformer is overloaded during evening peak hours, and the maximum flexibility requested by the DSO results to be nearly 40kW for consumption reduction, around 19:00. The collective energy profiles for contracted prosumers for each considered aggregator are shown in Figure 3.8.

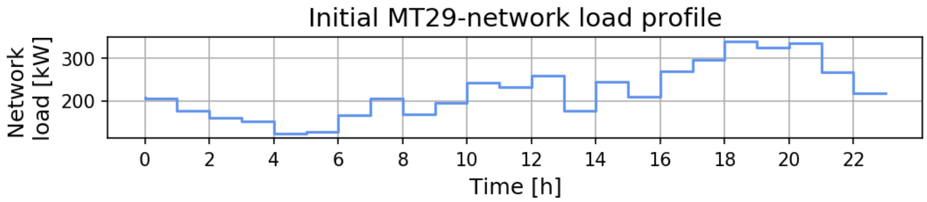



Figure 3.6: Initial network load profile for January 2nd, 2019.

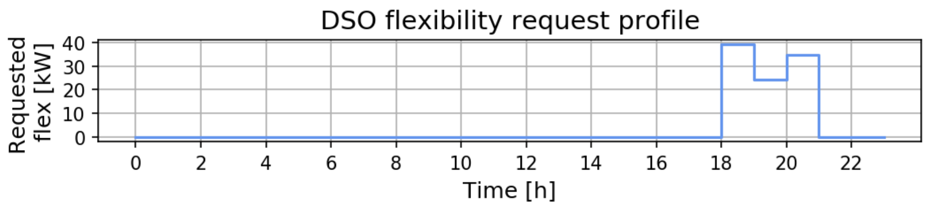



Figure 3.7: Requested DSO flexibility profile for January 2nd, 2019.

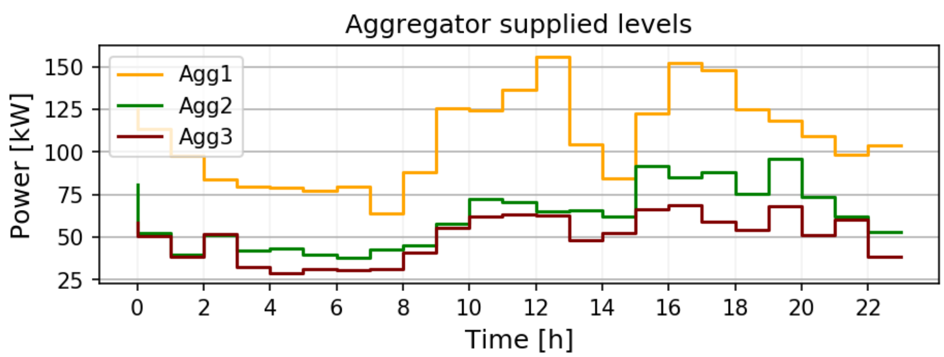



Figure 3.8: Energy profiles for the consumers and prosumers within each Aggregator cluster, shown for January 2nd, 2019.

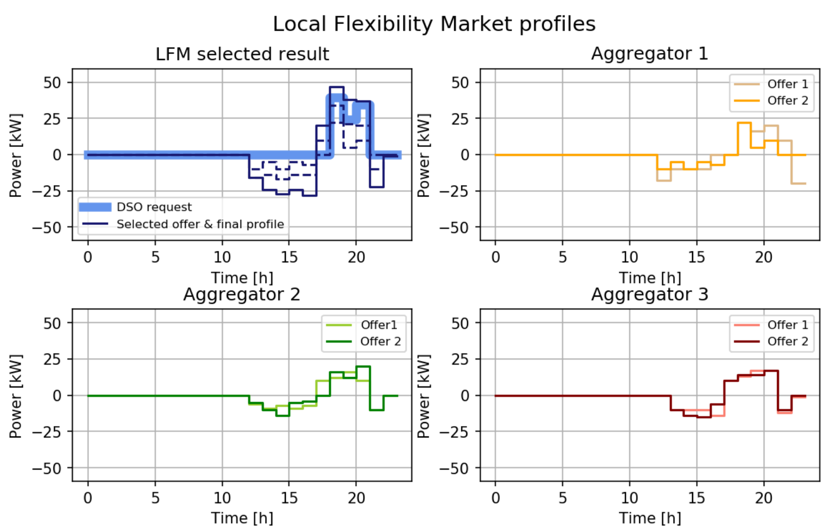



Figure 3.9: Local Flexibility Market operation outcomes, with offered and selected flexibility profiles for January 2nd, 2019

Based on anticipated prosumer energy profiles and the requested flexibility, the Aggregators create offer bids, presented in yellow, green, and red colours in Figure 9. The optimisation problem result is shown in the top-left blue subplot of Figure 3.9, where it is seen that the flexibility needs for the winter evening peak are met and exceeded. At the same time, the aggregators scheduled the shiftable loads to consume at earlier hours and one hour after the congested peak.

Considering the summer day in July, the network segment load profile is different due to the in-feed from the rooftop PV installations. Results show that, in addition to the morning peak around 7:00, the network is lightly loaded during the sunny hours of the day. However, a steep increase is observed in the evening, exemplified by the 50kW expected overload and requested flexibility around 21:00. Based on the type of contracted prosumers, Agg1 can offer the largest shift of power to the earlier hours, increasing the local consumption of solar generation and providing flexibility during congested evening periods. Furthermore, it is observed that morning peak hour demand can be adjusted by each aggregator relatively quickly, while during the evening, aggregator offers are just meeting the DSO request exactly.

# 4. Optimal allocation and dispatch local flexibility

Most studies on flexibility dispatch assume that the feasibility region that determines the available flexibility at a given time is only based on technical limits, e.g., actual technical limits of the flexible resources or other operation limits set by the flexibility procurer. However, this assumption ignores the limitations imposed on this feasibility region by the economic operation targets of the flexibility providers. This chapter presents a bilevel optimisation model to allocate and dispatch local flexibility provided by energy clusters (ECs) to minimise the DSO's cost due to the peak power tariff. This optimisation model enables the coordination between DSO and flexibility service providers (FSPs), i.e., the ECs, which results in a more realistic calculation of the flexibility amount and the flexibility price that dispatches this amount, as both the technical and the economic capabilities of the FSPs are considered. The model incorporates the AC power flow equations and the technical limits of the distribution grid and the operational targets of the ECs and determines the flexibility price, the amount of flexibility, and the location of flexibility amounts (location of ECs that provide each amount).

## 4.1. Mathematical Formulation for the DSO Optimization Problem (Upper Level)

The DSO procures local flexibility to minimise its peak power cost. The peak power cost is calculated using a fixed power tariff. It should be noted that reducing the peak power cost in its daily operation could also benefit the DSO long term, leading to reduced capacity subscription fees. In the mathematical formulations below, the parameters are represented by names starting with upper case letters, while the variables with names start with lower case letters.

### 4.1.1. Objective Function

The objective to minimise the peak power cost and the cost of procuring ECs' flexibility is given as

$$\min \mathrm{f}^{\mathrm{UL}} = \mathrm{c}^{peak} + \mathrm{c}^{\mathrm{flex}}, \tag{4.1}$$

where $c^{peak}$ is the peak power cost and $c^{flex}$ is the flexibility cost. In addition,

$$p_{s,t}^{dev} \geq P_{s,t}^{TSO,sch} - p_{s,t}^{SS}, \qquad \forall t \in \mathcal{H}, \forall s \in \mathcal{S}_i$$
$$p_{s,t}^{dev} \geq -P_{s,t}^{TSO,sch} + p_{s,t}^{SS}, \qquad \forall t \in \mathcal{H}, \forall s \in \mathcal{S}_i$$

and

$$c^{peak} \geq \Lambda^{peak} p_{s,t}^{SS}, \qquad \forall t \in \mathcal{H}, \forall s \in \mathcal{S}_i, \tag{4.2}$$

is used to compute $c^{peak}$, where $\Lambda^{peak}$ is the power tariff adjusted to fit the duration of the scheduling horizon, as this is a monthly fee paid to the TSO in practice. The variable $p_{s,t}^{SS}$ denotes the active power transfer from the transmission grid to the distribution grid through the boundary bus $s$ between the two connected systems at time step $t$. The subset $\mathcal{S}_i \subseteq \mathcal{N}$, where $\mathcal{N}$ is the set of the distribution grid buses, contains all the buses s of the distribution grid that are also boundary buses. The set of time discretisation steps, i.e., the scheduling horizon, is denoted $\mathcal{H}$.

### 4.1.2. AC Power Flow Equations

The LinDistFlow equations (4.6)-(4.15) model the linearised lossless AC power flow according to the convex branch flow model [35], which is derived after applying voltage angle relaxation and disregarding the capacitance and the line losses.

$$-\sum_{m\in\mathcal{M}_i}\left(p_{m,t}^{EC,im} - p_{m,t}^{EC,ex}\right) - P_{i,t}^{L} + \sum_{s\in\mathcal{S}_i} p_{s,t}^{SS} + \sum_{j\in\mathcal{F}_i}\left(p_{ji,t} - p_{ij,t}\right) = 0, \forall \mathrm{t} \in \mathcal{H}, \forall i, j \in \mathcal{N}, \tag{4.3}$$

$$-q_{s,t}^{SS} - Q_{i,t}^{L} - \sum_{m \in \mathcal{M}_i} Q_{m,t}^{EC} + \sum_{j \in \mathcal{F}_i} \left(q_{ji,t} - q_{ij,t}\right) = 0, \forall t \in \mathcal{H}, \forall i, j \in \mathcal{N}, \tag{4.4}$$

$$v_{j,t} - v_{i,t} + 2\left(p_{ij,t}R_{ij} + q_{ij,t}X_{ij}\right) = 0, \forall t \in \mathcal{H}, \forall i \in \mathcal{N}, \forall j \in \mathcal{F}_i, \tag{4.5}$$

$$v_{i,t} \leq V^{max} \text{ and } v_{i,t} \geq V^{min}, \forall t \in \mathcal{H}, \forall i \in \mathcal{N}, \tag{4.6}$$

$$v_{i,t} = V^{SB}, \ \forall t \in \mathcal{H}, \forall i \in \mathcal{S}_i, \tag{4.7}$$

$$p_{ij,t} = 0, \ \forall t \in \mathcal{H}, \forall i \in \mathcal{N}, \forall j \notin \mathcal{F}_i \tag{4.8}$$

$$p_{ij,t} = 0, \ \forall t \in \mathcal{H}, \forall i \in \mathcal{N}, \forall j \notin \mathcal{F}_i \tag{4.9}$$

$$q_{ij,t} = 0, \ \forall t \in \mathcal{H}, \forall i \in \mathcal{N}, \forall j \notin \mathcal{F}_i, \tag{4.10}$$

$$p_{ij,t} + p_{ji,t} = 0, \ \forall t \in \mathcal{H}, \forall i \in \mathcal{N}, \forall j \notin \mathcal{F}_i, \tag{4.11}$$

$$q_{ij,t} + q_{ji,t} = 0, \ \forall t \in \mathcal{H}, \forall i \in \mathcal{N}, \forall j \notin \mathcal{F}_i. \tag{4.12}$$

The variables $p_{m,t}^{EC,im}$ and $p_{m,t}^{EC,ex}$ denote the power imported/exported to/from an EC. The variables $v_{i,t}$ and $p_{ij,t}/q_{ij,t}$ refer to the square of voltage magnitude of bus $i$ and the active/reactive power flow from bus $i$ to bus $j$. The parameters $R_{ij}/X_{ij}$ and $V^{SB}$ line resistance/reactance, and square of voltage at the reference boundary bus. The parameters $P_{i,t}^{L}$and $Q_{i,t}^{L}$ represent the active and reactive power demand, respectively.

### 4.1.3. FSs

Both demand-side FSs that were introduced in Section 1.2.1 were incorporated in the bilevel optimisation problem. When the flexibility product FS-C is used, the term $\mathrm{c}^{\mathrm{flex}}$ of Eq. (4.1) becomes

$$c^{flex} = \sum_{t \in \mathcal{H}_{\mathfrak{f}}} \sum_{t \in \mathcal{M}_i} \pi_{flex}^{Cap} \, p_{m,t}^{flex} = \pi_{flex}^{Cap}\left(P_m^{Cap} - p_{m,t}^{fl,im}\right), \tag{4.13}$$

and the EC imported/exported power are given by

$$p_{m,t}^{EC,im} = p_{m,t}^{im}, \ \forall t \in \mathcal{H}, \ \forall m \in \mathcal{M}_i, \tag{4.14}$$

$$p_{m,t}^{EC,ex} = p_{m,t}^{ex}, \ \forall t \in \mathcal{H}, \ \forall m \in \mathcal{M}_i, \tag{4.15}$$

The positive variables $\pi_{\mathrm{flex}}^{\mathrm{Cap}}$ and $p_{m,t}^{flex}$are the flexibility price and the offered amount of flexibility (average value over $\Delta t$ during the flexibility activation period $\mathcal{H}_{\mathfrak{f}} \subseteq \mathcal{H}$), while $\mathrm{p}_{\mathrm{m,t}}^{\mathrm{fl,im}}$ is the EC's imported power at each time step of the flexibility activation period. Note that the amount of flexibility is calculated in terms of power capacity reduction, i.e., with FS-C the ECs offer an "updated" capacity given by $P_m^{Cap} - p_{m,t}^{flex}$ (see Figure 1.2) to the DSO. The parameter $P_m^{Cap}$ is the upper capacity limit a value that the DSO and the EC operator have to agree upon, e.g., it can be the capacity at the connection point.

When the flexibility product FS-B is used, the term $c^{flex}$ of Eq. (4.1) becomes

$$c^{flex} = \sum_{t\in\mathcal{H}_f}\sum_{m\in\mathcal{M}_i} -\pi^{im}_{flex}\,\delta^{Pim} + \pi^{ex}_{flex}\delta^{Pex}, \quad (4.16)$$

and the EC imported/exported power are given by

$$p^{EC,im}_{m,t} = p^{im}_{m,t} + \delta^{Pim}, \forall t \in \mathcal{H},\ \forall m \in \mathcal{M}_i, \quad (4.17)$$

$$p^{EC,ex}_{m,t} = p^{ex}_{m,t} + \delta^{Pex}, \forall t \in \mathcal{H},\ \forall m \in \mathcal{M}_i, \quad (4.18)$$

where the non-negative variables $\pi^{im}_{flex}/\pi^{ex}_{flex}$ are the flexibility prices and the variables $\delta^{Pim}/\delta^{Pex}$ (where $\delta^{Pim}$ is a non-positive and $\delta^{Pex}$ is a non-negative value) are the procured flexibility amounts, which correspond to the deviation from the baseline power exchange profile. Here, it is the optimal EC energy dispatch $(p^{ex}_{m,t} - p^{im}_{m,t})$ that is considered as the baseline profile, which can be computed by solving the optimal EC energy dispatch problem without integrating any FS.

## 4.2. Mathematical Formulation for the Optimisation Problem of the FSPs (Lower Level)

The lower-level (LL) problem is the optimal energy and flexibility dispatch, which each EC solves. The EC business model used here assumes that the EC is owned and operated by a third-party, which creates income for the EC customers through participation in energy services (e.g., energy arbitrage, peak demand reduction) and FSs [36].

### *4.2.1. Objective Function*

The EC operator seeks to minimise the energy cost of the EC (given by $c^{im}_m - r^{ex}_m$ in Eq. (5.22) where $c^{im}_m$ and $r^{ex}_m$ refer to the energy cost and revenue of the EC) while maximising the income from the FSs provided, denoted by $r^{flex}$:

$$\min f^{LL}_m = c^{im}_m - r^{ex}_m - r^{flex}_m, \quad (4.19)$$

$$\mathrm{c}^{\mathrm{im}}_{\mathrm{m}} = \sum_{\mathrm{t}\in\mathcal{H}} (\Lambda_{\mathrm{t}} + \mathrm{C}^{\mathrm{im}})\mathrm{p}^{\mathrm{EC,im}}_{\mathrm{m,t}}\Delta\mathrm{t}, \quad (4.20)$$

$$r^{ex}_m = \sum_{t\in\mathcal{H}} (\Lambda_t + C^{ex})p^{EC,ex}_{m,t}\Delta t, \quad (4.21)$$

where the parameter $\Lambda_t$is the energy price [euro/MWh], while $\mathrm{C}^{\mathrm{im}}/\mathrm{C}^{\mathrm{ex}}$ denote the distribution grid tariff and reimbursement fee corresponding to the EC imported and exported energy.

### *4.2.2. Power Balance*

An EC connected at bus $m$ with PV and BES systems must satisfy the active power balance at that bus, which is given by Eq. (4.22) $\forall t \in \mathcal{H}$. Note that it is assumed that the BES can inject power both to the EC's consumption points and to the external grid, while it can be charged both with PV power and with power imported from the main distribution grid.

$$P^{PV}_{m,t} + p^{dis}_{m,t} - p^{ch}_{m,t} = p^{EC,ex}_{m,t} - p^{EC,im}_{m,t} + P^{EC,L}_{m,t}. \quad (4.22)$$

In Eq. (4.22), $P^{PV}_{m,t}$, $P^{EC,L}_{m,t}$ and the positive variables $p^{ch}_{m,t}/p^{dis}_{m,t}$ respectively refer to the PV generation, the electric power consumption of the EC customers and the charging/discharging power of the BES.

### *4.2.3. BES Model*

For the BES, the measurement-based model presented in [37] was used. This model assumes a linear relationship between the BES's state-of-energy (SoE) and its power throughput and uses a sampling-based approach considering data from charging/discharging curves to more accurately represent the behaviour of an actual BES. Indeed, the model considers the variable charging/discharging efficiencies of the BES system, which are associated with both internal BES losses and DC/DC converter losses and are usually ignored in typical BES mathematical models used in linear optimisation

### *4.2.4. FSs*

When the FS-C flexibility product is considered, the term $r_m^{flex}$ in Eq. (4.19) becomes

$$r_m^{flex} = \sum_{t\in\mathcal{H}_f} \pi^{Cap}_{flex}\left(P^{Cap}_m - p^{fl,im}_{m,t}\right) \tag{4.23}$$

and the following constraints are added $\forall t \in \mathcal{H}, \forall m \in \mathcal{M}_i$:

$$0 \geq p^{im}_{m,t} - p^{fl,im}_{m,t}, \tag{4.24}$$

$$0 \geq p^{im}_{m,t} - p^{fl,im}_{m,t}. \tag{4.25}$$

The EC imported/exported power $p^{EC,im}_{m,t}/p^{EC,ex}_{m,t}$ are calculated according to Eq. (4.14)-(4.15), where $p^{im}_{m,t} \geq 0$, $p^{ex}_{m,t} \geq 0$. When the flexibility product FS-B is used, the EC imported/exported power are given by Eq. (4.17)-(4.18) while the following constraints are also added $\forall t \in \mathcal{H}, \forall m \in \mathcal{M}_i$:

$$0 \geq -p^{im}_{m,t} - \delta^{Pim}_{m,t}, \tag{4.26}$$

$$0 \geq -p^{ex}_{m,t} - \delta^{Pex}_{m,t}. \tag{4.27}$$

The term $r^{flex}_m$ in Eq. (4.19) becomes

$$r^{flex}_m = \sum_{t\in\mathcal{H}_f} \pi^{ex}_{flex}\,\delta^{Pex}_{m,t} + \pi^{im}_{flex}\delta^{Pim}_{m,t}. \tag{4.28}$$

## 4.3. Bilevel Optimisation

The links between the upper-level (UL) and lower-level (LL) problems (one solved for each EC) are the variables $p^{EC,im}_{m,t}$, $p^{EC,ex}_{m,t}$, $\pi^{FS-C}_{m,t}$, $\pi^{im,FS-B}_{m,t}$, $\pi^{ex,FS-B}_{m,t}$, $p^{flex}_{m,t}$, $\delta^{Pex}_{m,t}$, and $\delta^{Pim}_{m,t}$. The coupling variables between the two levels of optimisation are $p^{EC,im}_{m,t}$ and $p^{EC,ex}_{m,t}$. The UL variables $\pi^{FS-C}_{m,t}$, $\pi^{im,FS-B}_{m,t}$, $\pi^{ex,FS-B}_{m,t}$, which represent the flexibility prices, are parameters to the LL's problem. On the other hand, the flexibility amounts $p^{flex}_{m,t}$, $\delta^{Pex}_{m,t}$, and $\delta^{Pim}_{m,t}$ are LL variables that appear as parameters to the UL problem.

The bilevel optimisation problem is formulated as an equivalent single-level optimisation problem so that it can more easily be solved. This is achieved by replacing the LL problem (provided that it is convex, as is the case here) with its KKT conditions, which are added to the conditions of the UL problem. The Strong Duality Theorem is used to eliminate nonlinearities related to the multiplications of flexibility prices with flexibility amounts, as both these quantities are variables in the single-level problem.

The KKT conditions comprise all the equality and inequality conditions of the primal LL problem, the complementarity slackness (CS) of the primal LL inequalities, and the equality constraints derived from the partial derivatives of the LL Lagrangian function w.r.t. the LL primal variables (these derivatives must be equal to zero). Note that all the primal and dual variables of the LL problem become primal variables of the single-level equivalent problem. The solution of the bilevel optimisation problem yields the flexibility price, the allocation and the amount of flexibility that is dispatched.

## 4.4. Description of Test System, Assumptions, and Parameters of Simulation Studies

The purpose of the simulation studies was to evaluate the dispatched flexibility according to the following key assessment metrics:

1. Allocation
2. Amount
3. Time
4. Cost
5. Value

A standard 33-bus radial distribution grid, which was first presented in [38], was used as the test system of the simulation studies. This network was modified such that three ECs with PV and battery systems are connected at three of its buses (see Figure 4.1). The EC characteristics are found in [39].

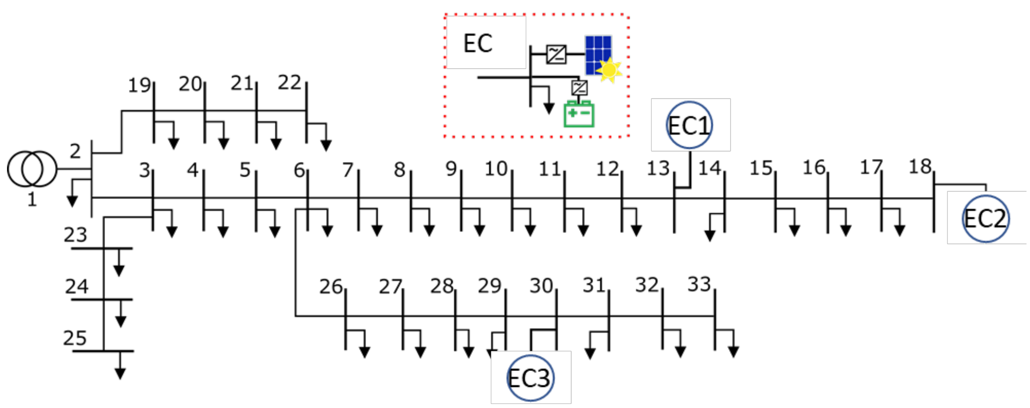



Figure 4.1: The modified 33-bus radial distribution network with three grid-connected ECs.

Table 4.1: EC characteristics

| | Point of Connection | Peak Load Consumption (kW) | PV Capacity (kWp) | Energy to power ratio (kWh/kW) |
|---|---|---|---|---|
| EC1 | Bus 13 | 60 | 43.1 | 17.2/14.4 |
| EC2 | Bus 18 | 90 | 64.7 | 25.9/21.6 |
| EC3 | Bus 30 | 200 | 334.8 | 134.9/111.76 |

The bilevel optimisation problem is solved day-ahead, i.e., the dispatch period is 24 hours, and $\Delta t = 1$ hour. The flexibility activation period was limited between 15:00-20:00, which is within the flexibility activation period requested from small to medium-sized companies that act as FSPs in [39]. The optimisation model was developed using Pyomo, which was implemented in the Python programming language, which is free and open source. Therefore, it is expected that the optimisation tool for optimal allocation and dispatch of flexibility will be easily integrated into any local web-based control system of a DSO or the Flexi-Grid IoT platform. The Python script and modules that were used for the simulation results presented in the next section could be easily modified to use the demonstration site's model parameters and input data. After this, the only other requirement for the demonstration of the optimisation tool is to add the code that will build the communication interface with the control platform, e.g., commands to read/write data through web application programming interfaces (APIs).

## 4.5. Simulation Results

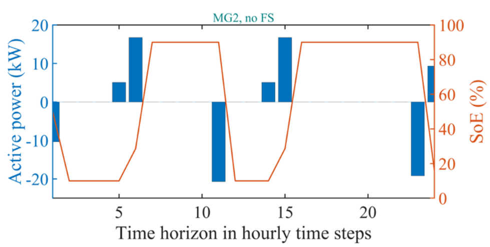
This section presents the simulation results with FS-B and FS-C . The case where no FSs are offered by the ECs is used as a benchmark case to assess the values of flexibility and the changes in the power exchanges with the main grid and power outputs of the flexibility resources.

### *4.5.1. Allocation, Amount, and Time of Flexibility Dispatch*

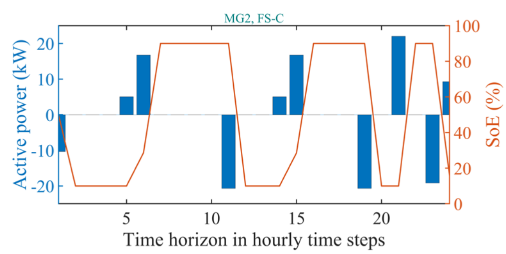
In FS-C all three ECs offered flexibility, and the amount and time of their flexibility dispatch can be seen in Table 4.2. On the contrary, with FS-B, no flexibility was dispatched. The time step of the flexibility dispatch is also illustrated in Figure 4.2, which shows the dispatch of the BES of EC2 with FS-C and without FSs, and in Figure 4.3, which shows the active power exchange of the same EC with the main distribution grid. As can be seen, an additional discharge half-cycle is added to provide the flexibility at hour 18:00-19:00 (time step 19).

Table 4.2: Amount and time of flexibility dispatch in FS-C

| | Flexibility Amount (kW) | Time Steps of Flexibility Dispatch |
|---|---|---|
| EC1 | 24 | 19 (18:00-19:00) |
| EC2 | 21 | 19 (18:00-19:00) |
| EC3 | 107 | 19 (18:00-19:00) |



(a)



(b)

Figure 4.2: The BES dispatch in EC2 when a) no FSs are implemented and b) when the EC offers FS-C.

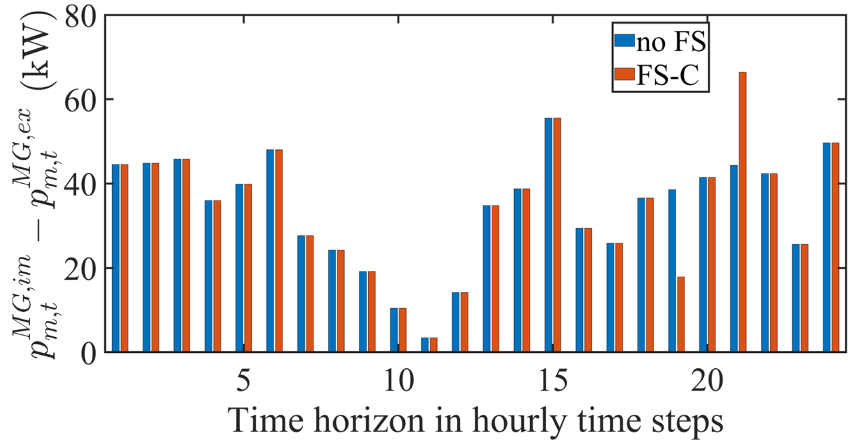



Figure 4.3: The power exchange of EC2 with FS-C and without FSs.

### 4.5.2. Cost and Value of Flexibility

In the studied example, FS-B did not benefit either the ECs or the DSO, as no amount of flexibility was dispatched. In FS-C, although flexibility was dispatched, it is not straightforward whether this offers value to the DSO or the ECs. That is because the flexibility value of FS-C depends on the choice of the parameters $\mathrm{P}_{\mathrm{m}}^{\mathrm{Cap}}$ which are affected by the configuration of all connected grids, and they should be customised for each specific test system. In the bi-level formulation, these parameters are eliminated. Therefore, this FS was implemented as the addition of a penalty to the OF of the FSPs and an income from the payment of this penalty to the objective function of the DSO in Case D (to understand this, set $P_m^{Cap} = 0$ to Eq. (5.16) and (5.26)). Performing a sensitivity analysis of $P_m^{Cap}$ it was shown that when $P_m^{Cap}$ was set to be equal to 25% of the capacity at the ECs' connection points, the DSO, EC1, and EC2 had a daily economic value of flexibility of 0.2%, 0.8%, and 1.8%, respectively, of their total daily operation cost. EC3, however, had an increased cost. Considering that the installed BES capacity at each distribution grid corresponded to a conservative future scenario of BES deployment, it is possible that with the integration of more BESs, this FS-C could offer an even higher economic value and potentially benefit all connected systems.

## 4.6. TSO-DSO coordination

The model for allocation and dispatch of flexibility, which was presented in this chapter, is a local ancillary services model without any TSO-DSO coordination and where the DSO has the priority to utilise the local flexibility. TSO-DSO coordination could be introduced with common FSs markets or coordinated flexibility dispatch on both systems. There is, however, another scheme with TSO-DSO coordination, where the DSO has full control of the operation and flexibility dispatch within its own distribution grid. This scheme assumes shared balancing responsibility between the TSO and the DSO, and this is achieved through the agreement on a power exchange schedule at the TSO-DSO interface [40]. Compliance with the schedule at boundary TSO-DSO buses imposes a very hard constraint on the operation of both systems, which may lead to sub-optimal solutions or even to points of infeasibility.

The proposed bi-level model of this chapter can be extended to consider the shared balancing responsibility scheme with TSO-DSO coordination. To avoid infeasibilities, however, it is suggested that instead of a adding a constraint, the objective function could be modified to penalise the power mismatch i.e., the deviation from the scheduled power exchange at the TSO-DSO interface. The objective function of the problem becomes:

$$\min \mathrm{f}^{\mathrm{UL,exch}} = \Pi_{\mathrm{exch}}^{\mathrm{TSO}} \sum_{s\in\mathcal{S}_i} \sum_{t\in\mathcal{H}} \left| P_{s,t}^{TSO,sch} - p_{s,t}^{SS} \right| + \mathrm{c}^{peak} + \mathrm{c}^{\mathrm{flex}}, \tag{4.29}$$

where the first term is the cost of deviation from the scheduled power exchange $P_{s,t}^{TSO,sch}$ at the boundary bus $s$. This is calculated by multiplying a penalty $\Pi_{\mathrm{exch}}^{\mathrm{TSO}}$ with the deviation from the scheduled power exchange given by $\left|P_{s,t}^{TSO,sch} - p_{s,t}^{SS}\right|$. Since the term $\left|P_{s,t}^{TSO,sch} - p_{s,t}^{SS}\right|$ is non-linear, another term is introduced to represent this deviation, i.e., the variable $p_{s,t}^{dev}$. Eq. (4.29) is being replaced by and Eq. (4.30) s.t. (4.31)-(4.32), which are introduced to linearise Eq. (4.29).

$$\min \mathrm{f}^{\mathrm{UL,exch}} = \Pi_{\mathrm{exch}}^{\mathrm{TSO}} \sum_{s\in\mathcal{S}_i} \sum_{t\in\mathcal{H}} p_{s,t}^{dev} + \mathrm{c}^{peak} + \mathrm{c}^{\mathrm{flex}} \tag{4.30}$$

$$p_{s,t}^{dev} \geq P_{s,t}^{TSO,sch} - p_{s,t}^{SS}, \qquad \forall t \in \mathcal{H}, \forall s \in \mathcal{S}_i, \tag{4.31}$$

$$p_{s,t}^{dev} \geq -P_{s,t}^{TSO,sch} + p_{s,t}^{SS}, \qquad \forall t \in \mathcal{H}, \forall s \in \mathcal{S}_i, \tag{4.32}$$

# 5. Conclusions & discussion about the limitation of the deliverable and further prospects

The focus of the work presented in this report was to develop a framework for optimal allocation and dispatch of flexibility. This framework was based on the flexibility procurement and dispatch process presented in the deliverable D3.3. In addition, international experiences related to FSs and the interactions among different actors involved in an LFM were discussed to paint a clear picture of how the proposed framework could be utilised in a real-world application.

The framework is a package of control and optimisation tools, including (1) a direct self-adaptive control algorithm that calculates dispatch setpoints for PV inverters with the aim to solve transformer overloading and voltage rise issues; (2) an indirect optimisation-based control algorithm aimed to assist the DSO to select the optimal flexibility offers satisfying technical requirements and minimising the energy cost; and (3) a bi-level optimisation model for allocation and dispatch of local flexibility, which the DSO can use to allocate technically and economically available flexibility from the FSPs connected at the distribution grid and define the optimal flexibility price for both flexibility procurer and FSPs.

The direct control algorithm monitors the transformer overloading based on a data-driven model, which uses limited data from different local communities. The algorithm calculates the new signal for local droop control of PV inverters whenever the loading percentage exceeds the limit. In addition to this, the self-adaptive control also monitors, and addresses voltage rise problems. Thus, direct control can be used by local grid operators to dispatch flexibility for grid-oriented challenges.

The indirect control receives as input offers from flexibility resources and solves an optimisation problem which yields the day-ahead scheduling of these resources that minimises the energy cost of the DSO. Thus, indirect control can be used by DSOs to dispatch flexibility for both market- and grid-oriented challenges. Both direct and indirect control helps DSO to control the safe operate distribution grid. However, other controllable devices in the distribution network can also support the grid, such as EV or heat-pump. Also, the advanced model predictive control, which is developing in task 3.2, can be used to predict the network state in future. Thus, the optimal control can be calculated.

The bi-level optimisation model for allocation and dispatch of local flexibility can be used to investigate the appropriate incentives for both the DSO and the FSPs regarding their participation in LFMs. The simulations studies assumed that the DSO procured flexibility to minimise the peak power cost of the distribution grid and the FSPs, i.e., the connected ECs, offered FSs to reduce their energy cost (their income from offering FSs would be subtracted from their energy cost). The flexibility was dispatched in hourly time steps for the next day ahead. The comparison between the two flexibility products that were tested, i.e., FS-B and FS-C, as well as the comparison of these FSs with the case where no FSs were offered, demonstrated that FS-C could provide incentives for both the DSO and the ECs, as they both had value from the FS. More studies with different BES sizes should be conducted to explore additional values of flexibility offered with either FS. Nevertheless, this optimisation tool gives valuable info about the benefit of implementing an LFM run by a DSO. The bi-level model could easily be modified to be tested with higher time resolution (i.e., intra-hour dispatch of flexibility). However, it should be noted that the high computation time will introduce limitations, which can only be addressed by reducing the optimality gap, i.e., by potentially accepting sub-optimal solutions.

The developed control and optimisation tools presented in this deliverable will be further used in the demonstration activities of this project. Specifically, they could be used to:

- Demonstrate the controllability and dispatchability of local resources that will be used to offer FSs (task 5.3). These demonstration activities are related to the test cases TC 5.2 (“Control of energy storage for flexibility provision”) and TC 5.3 (“Control of Solar PV for voltage control”), as described in D5.1.
- Demonstrate the use of available flexibility to offer FSs (task 5.3). For this purpose, the bi-level optimisation model presented in Chapter 4 will be used to demonstrate test case TC 5.4: “Flexibility exploitation for service provision”, which was described in D5.1. In addition, the optimisation model might integrate different objective functions for demonstration purposes or even price signals obtained from demonstrations of WP6.
- Demonstrate close-to-real-time flexibility provision and real-time clustering of virtual distribution grids (task 5.3).
- Define the Key Performance Indicators (KPIs) to evaluate the results of the demonstration activities in task 5.3. This evaluation process is a part of task 5.4.
- Demonstrate the interaction of grid operators with LFMs. The developed models of D3.5 can be used to design the bidding strategies and pricing mechanisms, which will be demonstrated in task 6.3 and evaluate in task 6.4.

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