# A novel smart grid architecture that facilitates high RES penetration through innovative markets towards efficient interaction between advanced electricity grid management and intelligent stakeholders

H2020-GA-863876

# Final version of advanced market aware OPF algorithms

## Deliverable D5.3

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# Glossary of Acronyms

**Project management terminology**

| Acronym | Definition |
|---|---|
| D | Deliverable |
| HLUC | High Level Use Case |
| MS | Milestone |
| WP | Work Package |
| UCS | Use Case Scenario |

**Technical terminology**

| Acronym | Definition |
|---|---|
| ATP | Automated Trading Platform |
| API | Application Programming Interface |
| DB | Data Base |
| DESS | Distributed Energy Storage System |
| DG | Distributed Generation |
| DLEM | Distribution Level Energy Market |
| DLFM | Distribution Level Flexibility Market |
| DN | Distribution Network |
| DSO | Distribution System Operator |
| EC | European Commission |
| ESP | Energy Service Provider |
| FM | Flexibility Market |
| FMO | Flexibility Market Operator |
| FMCT | Flexibility Market Clearing Toolkit |
| FSP | Flexibility Service Provider |
| GenCo | Generation Company |
| GUI | Graphical User Interface |
| KER | Key Exploitable Result |
| KPI | Key Performance Indicator |
| LFM | Local Flexibility Market |
| LMO | Local Market Operator |
| LMP | Locational Marginal Price |
| MO | Market Operator |
| OPF | Optimal Power Flow |
| PCC | Point of Common Coupling |
| RES | Renewable Energy Sources |
| SOB | Shared Order Book |
| SOC | State of Charge |
| SOCP | Second Order Cone Program |
| SVC | Static VAR Compensator |
| S/W | Software |

| | |
|---|---|
| TLMP | Transmission Locational Marginal Price |
| TN | Transmission Network |
| TSO | Transmission System Operator |

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# Document History

This deliverable includes the final version of the mathematical models, research problem formulations, algorithms, and performance evaluation results for the support of the of the efficient interaction between network operators and markets. Network-aware market clearing algorithms are presented that will also be integrated in the FLEXGRID's Flexibility Market Clearing Toolkit (FMCT).

**Table 1 Document History Summary**

| Revision Date | File version | Summary of Changes |
|---|---|---|
| 06/05/2021 | v0.0 | Draft ToC circulated among all WP5 partners. |
| 07/10/2021 | v0.1 | All partners commented on the draft ToC structure. |
| 09/10/2021 | v0.2 | Final ToC version has been agreed and writing task delegations have been provided to all involved partners. |
| 28/10/2021 | v0.3 | All partners contributed their 1st round inputs to the 1st draft version. |
| 10/11/2021 | v0.4 | 1st draft version has been compiled and reviewed by DTU. |
| 15/11/2021 | v0.5 | All WP5 partners reviewed the 1st draft and sent their comments to DTU. |
| 17/11/2021 | v0.6 | DTU addressed all comments from WP5 partners and sent the 2nd draft version for internal review by AIT. |
| 24/11/2021 | v0.7 | AIT made a thorough review and requested for changes to enhance the quality of the deliverable. |
| 28/11/2021 | v0.8 | DTU addressed all comments from the internal review process and forwarded the final version to the coordinator. |
| 01/12/2021 | Final | Coordinator (ICCS) made final enhancements/changes and submitted to ECAS portal |

# Executive Summary

This report is an official deliverable of the H2020-GA-863876 FLEXGRID project that describes the final version of advanced market aware optimal power flow (OPF) algorithms developed within WP5. **The focus of this document is on FLEXGRID High Level Use Case #1 (HLUC_01), which primarily focuses on network aware market clearing of distribution level flexibility markets.** Specifically, the algorithmic modelling approach of Use Case Scenarios UCS 1.1, UCS 1.2, and UCS 1.3 are detailed in this deliverable. The developed algorithms are implemented in the Flexibility Market Clearing Toolkit (FMCT) in the FLEXGRID ATP. The intended user of the FMCT is the Flexibility Market Operator (FMO) at the distribution network (DN) level. Furthermore, a methodology and implementation for creating FlexRequests (i.e. quantity vs. price bid curves) is laid out in this deliverable, where the intended user is the Distribution System Operator (DSO). Finally, a comparative analysis between several Distribution Level Flexibility Market (x-DLFM) architectures is conducted with several interesting results that can also be seen as recommendations for regulatory bodies and policy makers in the EU area.

Chapter 1 gives a brief introduction of the market design options and motivates the design choices. Chapters 2 and 3 follow a similar structure in order to present the WP5 research results in a coherent manner. Chapter 2 details continuous and Chapter 3 auction-based flexibility market clearing algorithms for each one of the three UCS. In each subchapter, we present:

- Problem statement, related state-of-the-art and summary of FLEXGRID contributions
- System models
- Problem formulations
- Algorithmic solutions
- Simulation setup and performance evaluation results
- Conclusions and lessons learned

The presented UCS 1.1, UCS 1.2, and UCS 1.3 are market clearing problems and thus the problem statements are largely similar in Chapters 2 and 3, while algorithmic solutions differ substantially. Chapters 2.2 and 3.2 address UCS 1.1, the "distribution network aware flexibility market clearing via FLEXGRID ATP". To this end, a Distribution Level Energy Market (DLEM) clearing algorithm is presented that matches energy FlexOffers and energy FlexRequests while respecting the physical network constraints. Chapter 2.3 and 3.3 address UCS 1.2 ("market-based local congestion management using FLEXGRID ATP in distribution networks using output from AC-OPF model calculation as dynamic input for ATP") and UCS 1.3 ("market-based local voltage control using FLEXGRID ATP in distribution network operation). To this end, a Distribution Level Flexibility Market (DLFM) clearing algorithm is presented that matches active/reactive power reserve FlexOffers and active/reactive power reserve FlexRequests (UCS 1.2/1.3), while respecting the physical network constraints. Chapter 4 presents a methodology for the DSO to create network-aware FlexRequests. Chapter 5 discusses the possible DLFM integration with existing TN-level day-ahead energy, reserve, and near-real-time balancing markets. Chapter 6 concludes the WP5 research work and presents the most important lessons learned.

# 1 Introduction

## 1.1 Description of High-Level Use Case #1 and interaction with the FLEXGRID system as a whole

Flexibility Markets in the distribution network (DN) level can reduce cost for grid upgrades and enhance integration of distributed renewable energies, e.g., by in-/decreasing flexible consumption in cases of high/low renewable infeed in the grid. In this deliverable, design options for flexibility markets and respective mathematical algorithms of the proposed DN-level flexibility markets (DLFM) are presented and simulation results from case studies are compared to identify key performance indicators (KPIs) for flexibility markets.

In FLEXGRID, different design options of flexibility markets are developed for the efficient operation of these novel markets. State-of-the-art of flexibility markets and clearing algorithms have been described in previous D2.1 [1]. In this deliverable D5.3, the final versions of advanced distribution level flexibility market (DLFM) clearing algorithms for the FMO's efficient market operation are developed. The algorithms described in this deliverable address the high-level use cases of FLEXGRID. More details on the high-level use cases of FLEXGRID can be found in detail in Section 4 of D2.1 [1], D5.1 [2], and D5.2 [3]. **The focus of this deliverable is on high-level use case 1 (HLUC_01).**

HLUC_01 focuses on FLEXGRID ATP's operation and its interaction with incumbent markets, e.g., day-ahead wholesale market, and the underlying physical network operation (cf. interaction between markets' and networks' operation). The initial idea is based on NODES business model in collaboration with Nord Pool Consulting (NPC) aiming at defining and developing advanced mathematical models and research algorithms to clear Distribution Level Flexibility Markets (DLFMs) taking into account physical network constraints. Three use case scenarios (UCS) are presented in this deliverable, see Table 2:

**Table 2 Use Case Scenarios detailed in this deliverable**

| Nr. | Name | Goal of the Use Case | Lead |
|---|---|---|---|
| UCS_01 | Distribution network aware flexibility market clearing via FLEXGRID ATP | The FMO wants to clear an energy market, i.e., DLEM, with Offers and Requests from different ESPs, while ensuring that the resulting power flows are feasible for the network. | DTU |
| UCS_02 | Market-based local congestion management using FLEXGRID ATP in distribution networks using output from AC-OPF model calculation as dynamic input for ATP | The FMO wants to clear an active power reserve market, i.e., DLFM, with FlexRequests from the DSO and FlexOffers from different ESPs, while ensuring that the resulting power flows are feasible for the distribution network. | DTU |
| UCS_03 | Market-based local voltage control using FLEXGRID ATP | The FMO wants to clear a reactive power reserve market, i.e., DLFM, with FlexRequests from the DSO and | DTU |

| | | | |
|---|---|---|---|
| | in distribution network operation | FlexOffers from different ESPs, while ensuring that the resulting power flows are feasible for the distribution network. | |

## 1.2 Summary of state-of-the-art solutions for the market clearing challenges

The aim of market clearing is to establish operating points for all market players that try to maximize some objective, commonly the social welfare. For auctions, optimal power flow (OPF) is used, and for continuous markets, power flow (PF) checks are used to run a network-aware market clearing that considers the distribution network with its line limitations, voltage bounds, and transformer limits. The (O)PF can determine how much flexibility can be cleared safely without violating network constraints.

Different types of OPF exist; the most accurate is a full AC-OPF, which captures all relevant network quantities, including reactive power, losses, voltages, and voltage angles. However, the AC-OPF is a non-convex problem, which implies that the global optimum is not guaranteed to be found. Therefore, the scientific literature has developed several approximations of the full AC-OPF.

The simplest approximation is the DC-OPF which ignores voltage magnitude, reactive power, and losses, but results in a linear problem, which is easy to solve. More accurate approximations are, e.g., the BranchFlow method or the DistFlow, which are second order cone programming (SOCP) relaxations of the AC-OPF. The LinDistFlow is a linear approximation of the DistFlow and is detailed in chapters 2.3 and 3.3.

The main goal is to use a convex relaxation of the AC-OPF, including line constraints, losses, voltage, and reactive power. This model should be general enough so that it can be used for different applications (e.g., market clearing, identification of flexibility needs by the DSO, verification of a given dispatch, etc.).

We carried out a comparison of different SOCP formulations in [4]. Among the methods compared, the one introduced in [5] showed the most promising results for active distribution grids and general radial networks. The AC-OPF is first augmented with additional constraints and then relaxed. For practical applications, however, a more scalable approach like DC-OPF or LinDistFlow are more relevant, and therefore are adopted in the algorithms of this deliverable. The objective function can be adjusted depending on the intended use of the model:

- Maximization of the social welfare, which is commonly used for market clearing problems such as UCS 1.1, UCS 1.2, and UCS 1.3.
- Minimization of costs, e.g., flexibility procurement cost
- Minimization of voltage deviations
- Minimization of congestions
- Empty objective function to evaluate the feasibility of a given dispatch (PF)

This model can be enhanced to help decision making for the DSO, by including the possibility to shed part of the load or curtail renewable energy infeed in case of infeasible dispatch. This is modelled by adding slack variables in the constraints for line capacity and voltage limits, associated with a high penalty cost in the objective function.

## 1.3 Summary of research problems and FLEXGRID's research innovation

Following the survey work [4], [5] from both academic and industrial perspectives, FLEXGRID WP5 addresses the following three major research problems:

1) UCS 1.1: The FMO wants to efficiently clear (a set of) FlexRequests and FlexOffers for energy that maximize social welfare while considering network constraints
2) UCS 1.2: The FMO wants to efficiently clear (a set of) FlexRequests and FlexOffers for active power reserve that maximize social welfare while considering network constraints
3) UCS 1.3: The FMO wants to efficiently clear (a set of) FlexRequests and FlexOffers for reactive power reserve that maximize social welfare while considering network constraints

The main research problem addressed in this deliverable is the inclusion of physical network constraints into the market clearing. To approach this problem, a variety of network modelling choices, as well as market design choices have to be made. There exist several design choices that affect the modelling and ultimately the efficiency of the market. An overview of relevant design parameters is listed in [6], while the relevant parameters for the FLEXGRID algorithm are described here.

*Sequence of Market Gate Closure:* FLEXGRID's deliverable D5.1 [2] discussed three major options for market clearing sequences between the transmission and distribution level. In the proactive P-DLFM, the distribution level market clears before the transmission level. In the interactive I-DLFM, the distribution level market clears jointly in iterative information exchange with the transmission level. In the reactive R-DLFM, the distribution level market clears after the respective transmission level market has been cleared. In this deliverable, we focus on the R-DLFM, since it allows us to explore market clearing algorithms in depth and decouple them from the processes on transmission level. Additionally, the R-DLFM is the most likely market sequence to be implemented since it easily can be adopted into the existing market and regulatory framework.

*Auction vs. Continuous Clearing:* A part of the flexibility market clearing could be auction based such as day-ahead flexibility market, using the AC-OPF as presented in Section 3.1 of D5.1 [2]. However, moving closer to real-time, it could become more relevant to have a continuous market. Instead of a market clearing considering all bids and clearing once and for all, this model would be continuously matching bids. This is often the case for today's intraday markets in EU area.

*Pay-as-bid (discriminatory pricing) vs. Pay-as-clear (uniform pricing):* In continuous trading, pay-as-bid is the only available pricing mechanism. It matches FlexOffers and FlexRequests, if the offer price is lower than or equal to the request price. In that case, the bid that was placed earliest sets the price. With the uniform pricing rule, all participants in a given price zone are cleared with pay-as-clear, i.e., all participants receive the same market clearing price (MCP). In auctions, both types of pricing mechanisms are possible.

*Technology Neutrality and Market Horizon:* Today, the central market displays various types of market horizons; from futures and forwards (10 years) to real-time (5min) markets, and ex-post (1-14 days after delivery) settlement. Long-term flexibility procurement, i.e., a year or longer, would facilitate the planning and investment process of distribution system operators (in collaboration with upstream TSO). Short-term flexibility procurement, however, would promote/incentivize the access of small-scale flexible loads, storage assets, and variable renewable energy sources to participate in the market (DLFM).

*Product Standardization:* In the highly liquid wholesale markets (day-ahead and intraday), standardized products are traded today; energy per unit of time, e.g., MWh/h. However, with the event of allowing block bids, the standardization has suffered. On the extreme ends, a market cannot trade fully standardized products only, or trade any possible sub-characteristic of bids. Naturally, a standardized product would achieve higher liquidity. On the other hand, non-standardized products may give special incentives to, e.g., superfast ramping resources or resources in an effective location in the grid, which is related to the following point.

*Location Attribute:* With the consideration of distribution network constraints, the location of an FSP becomes a vital characteristic. It may decide whether the FSP's bid (i.e., FlexOffer) has a higher effectiveness to solve a grid problem and therefore, it is cheaper to solve a grid problem with a flexibility that is in a favorable location. An unfavorable location of the resource could even lead to disqualification of the resource due to infeasible power flows. The more local, and therefore closer to the arising problem, a grid problem is solved, the more effective the solution would be. The disadvantage of high locational resolution is that local market power may be exercised (as for example shown in [7]). On the other hand, the larger the zone, the more liquidity and market competition can be expected.

*Summary and Justification:* An illustration of the discussed market design choices is shown in Figure 1. In the scope of D5.3, we focus on two extremes of the design space: a *uniform price auction of standardized products* on the one end (shaded in blue), and a *discriminatory continuous clearing of non-standardized products* on the other end (shaded in yellow). We include a location attribute in the bids, but allow bids from different locations to match, as long as these transactions do not violate network constraints (i.e., if they pass the network check detailed in chapter 2.4). We do not impose strong assumptions on the market horizon. Based on the literature, e.g., [6], we recommend implementing auctions for longer market horizons and continuous clearing for shorter market horizons.

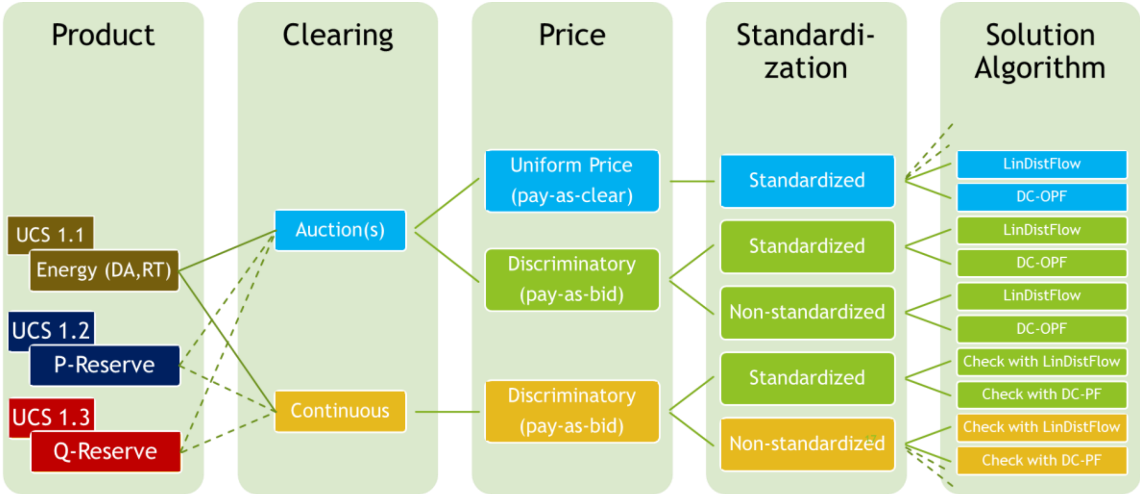


**Figure 1 Summary of market (DLEM/DLFM) design choices**

The solution algorithms are explained in **Error! Reference source not found.** and **Error! Reference source not found.**. Building onto the intermediate version in D5.2, this deliverable presents both *continuous market clearing algorithms (Chapter 2)* and *auction-based clearing algorithms (Chapter 3)* for energy (UCS 1.1 in Chapters 2.2 and 3.2) and reserve (P-reserve/Q-reserve in UCS 1.2/1.3 in Chapters 2.3 and 3.3).

## 1.4 Summary of FLEXGRID's research impact on today and future market operator business

FLEXGRID develops advanced market clearing models and algorithms for the proposed Distribution-Level Flexibility Markets (DLFM). Sophisticated OPF and PF models are developed, which aim to generate effective market signals to FlexSuppliers and FlexBuyers using locational information and ensuring feasible power flows.

## 1.5 Scope of this Deliverable

This document provides the final version of the network-aware market clearing algorithms for DLFM. This deliverable is final in the sense that it includes both continuous and auction-based market clearing algorithms for all three concerned use case scenarios. This includes energy (UCS 1.1 in Chapters 2.2 and 3.2) and reserve (P-reserve in UCS 1.2 and Q-reserve in UCS 1.3 in Chapters 2.3 and 3.3) market clearing. In contrast, deliverable D5.2 focused only on continuous market clearing algorithms for these three use case scenarios.

## 1.6 Structure of this Deliverable

This document provides the final description of the network-aware market clearing algorithms for DLFM that clears energy (UCS 1.1), active power reserves (UCS 1.2) and reactive power reserves (UCS 1.3). Additionally, Chapter 4 presents a method to compute network aware FlexRequests. It further provides possible integration approaches of the x-DLFM into existing markets in Chapter 5. A brief conclusion is provided in chapter 6.

# 2 Continuous network aware market clearing algorithms via FLEXGRID ATP

The focus of this chapter is on addressing the research problem of FLEXGRID's HLUC_01 with continuous market clearing algorithms. In this chapter, continuous market clearing algorithms for UCS 1.1, UCS 1.2, and UCS 1.3 are detailed, where the FMO continuously clears a distribution level market under consideration of network constraints.

## 2.1 Problem statement, related state-of-the-art and FLEXGRID research contributions

The existing electricity markets do not consider the constraints of local distribution networks, leading to a sub-optimal use of these networks (or else greater need for over-provisioned grid infrastructures that cost too much in the long term). As the penetration of distributed energy resources connected to the distribution network increases, it becomes necessary to introduce a market which considers the distribution networks, their constraints, and the location of the flexible resources. This could in turn reduce the costs for the whole system, and enable the integration of renewable energy sources, while providing an alternative to distribution network upgrade.

One way to deal with a high penetration of distributed energy resources is to implement a local energy market. In the literature, we can find three groups of local energy markets [8]:

- Peer-to-peer (P2P) markets [9]
- Centralized markets, run by a flexibility market operator (FMO) [10]
- Markets where participants can either trade directly among each other or through a FMO [10]

The novelty of the FLEXGRID's approach is that the FMO clears the market under full consideration of network constraints, i.e., including line ratings, reactive power limits, and voltage bounds. Moreover, the active participation of the DSO and FSPs is considered with a continuous market setup.

The increasing penetration of distributed energy resources motivates the creation of new market tools aimed for the DSO. Having access to the flexibility of those distributed resources would enable DSOs to operate their networks in a more secure manner, by reducing the occurrence of line congestions through the activation of flexibility. To do so, the network constraints must be included in the model. Usual modeling approaches either ignore the network [12] [13] [14] [15], or if they include the local flexibility scheduling in distribution power flow calculations, they assume that the DSO and the FMO form one entity [16] [17] [18] [19]. In that case, decisions about flexibility procurement and activation are made considering requirements of DSO to solve congestion issues. However, the legal framework may (and, in the EU, currently does) not allow the DSO to act as the market operator.

In this chapter and in the context of FLEXGRID, we propose continuous LFM clearing algorithms targeted at real-time markets, with the FMO as a separate agent. The conceptual design of a LFM that is cleared by an independent FMO entity and that explicitly considers network constraints is a novelty.

## 2.2 UCS 1.1 - DLEM for energy

### 2.2.1 System model

In UCS 1.1, we consider a Flexibility Market Operator (FMO), who clears a local energy market after (i.e., R-DLEM) the transmission level commitments have been cleared. This means that some of the local generators and loads may already have committed parts of their energy to the wholesale transmission level (i.e., day-ahead energy market). The FMO runs a market where FlexRequests and FlexOffers are matched, provided that no distribution network constraint is violated. Without loss of generality and within FLEXGRID's context, we assume that the full network model of the DSO is known to the FMO, as well as the active and reactive power setpoints committed in the wholesale transmission level market (i.e. day-ahead energy market). The aim of the FMO is to maximize social welfare by matching all bids that result in feasible power flows. In this section, we detail a continuous pay-as-bid DLEM market clearing algorithm (yellow choice path in Figure 2), while section 3.2 details an auction-based pay-as-clear DLEM market clearing algorithm (blue choice path in Figure 2).

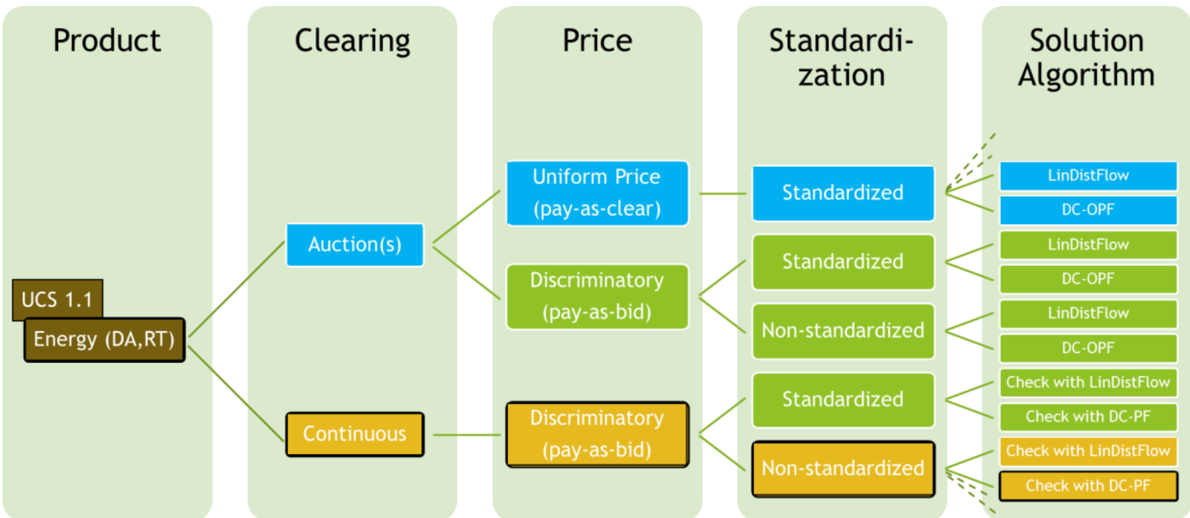


**Figure 2 Market design choices for distribution level energy market (DLEM)**

### 2.2.2 Problem Formulation

#### *2.2.1.1 Bids*

Actors submit a bid as FlexRequest (from the DSO) or FlexOffer (from the FSP) for energy in MWh/h in either upward (generation increase / demand decrease) or downward (generation decrease / consumption increase) direction. The bid (FlexOffer or FlexRequest respectively) is composed of:

- Bid ID: Unique identifier
- Volume in MWh/h
- Price in €/MWh
- Regulation: up (1) or down (0)
- Location ID: e.g., node or DSO area

- Time target: for which time period(s) the bid applies
- Time stamp: indicates when the bid was submitted
- Type: The type is E for energy bids in a DLEM (optional)
- Block: Whether the bid is a block bid or not. If so, the FMO assigns a block indicator to the linked bids

#### *2.2.1.2 Shared Order Book*

Incoming, non-matching bids are placed in a shared order book (SOB), available to all market participants, until they are cleared with a matching bid. There is one SOB for FlexRequests and one SOB for FlexOffers. The SOBs are visible to all market participants, both DSO and ESPs. They contain all the attributes of the bids and are sorted:

- First, by price: For FlexRequests the bid with the highest price comes first and for FlexOffers, the bid with the lowest price comes first.
- Second, by time stamp: For two bids with the same price, the bid with the earlier time stamp is matched first.

This ensures that the incoming bid is matched at the best available price, so the social welfare is the highest possible for each match.

#### *2.2.1.3 Matching*

Bids are matched according to price, time-priority, and the absence of line congestions. The matching algorithm has the following heuristic properties:

- **Automatic process**: It is triggered when a bid is added or updated
- **Pay-as-bid pricing**: Each participant gets the price of the standing bid, i.e., earliest bid of the two matching bids.
- **Best price**: A FlexRequest can only match with a FlexOffer with a price that is inferior or equal. If several orders meet this requirement, the priority goes to the one with the best price (highest price for a FlexRequest and lowest price for a FlexOffer).
- **First-come-first-served principle**: If there are two orders with the same price, the priority goes to the one that was submitted first.
- **Network check**: A network check is performed to ensure that the activation of the bids would not result in congestions.
- **Partial execution of single bids**: If an order is only partially matched, the rest of the bid remains and is entered into the corresponding SOB. Owing to the network check requirement, it is especially important to allow partial matching of the bids. In this way, the volume of two bids can match up to the point where their activation would result in a congestion.
- **All-or-Nothing (AoN) for block bids**: Block bids can only be fully accepted or fully rejected.

It is vital to note that the location of the bids does not need to match, i.e., FlexOffer and FlexRequest *can* be located at different buses. This means that – if accepted - flexibility can be procured from a distant bus and transported through the network to where it is required without causing congestions.

#### 2.2.1.4 Network Check

The network check is based on a baseline energy dispatch that is established by either previous markets (e.g., day-ahead energy market) or by an estimation of load and generation at each bus (based on, e.g., commonly available data of similar days and hours and load forecasting). The baseline energy dispatch must be known or estimated in order to extract active and reactive power setpoints under normal operation.

Then, the network check considers the baseline dispatch, as well as all previously matched bids. For the DLEM, the DC power flow algorithm is implemented as the first step towards the inclusion of network constraints in a continuous market clearing algorithm. The main reasons for this choice are that the DC power flow is simpler, and thus more transparent for the market players, and faster, with computing time being a critical element for continuous markets. More complex power flow approximations may be used but will come at the cost of increased computational effort.

#### 2.2.1.5 *Quantity update algorithm with DC power flow for single bids*

With the DC power flow algorithm, power flows are calculated with the help of power transfer distribution factors (PTDFs). PTDFs are linear sensitivities linking power injections with line flows (for more details about their calculation, see [19]). PTDFs are fixed for a given network. In particular, the power flow $P_{ij}$ in the line between bus $i$ and $j$ is linked to the power $P_m$ injected at bus $m$ by the PTDF factor of line $ij$ for an injection of power at the slack bus $k$ and retrieval of the same quantity in bus $m$, $PTDF_{ij,km}$ by:

$$P_{ij} = X_m PTDF_{ij,km} P_m \tag{2.1}$$

The maximum power flow variations, in both directions, can then be evaluated as:

$$\Delta P_{ij}^{max,+} = P_{ij}^{max} - P_{ij} \tag{2.2}$$
$$\Delta P_{ij}^{max,-} = -P_{ij}^{max} - P_{ij} \tag{2.3}$$

where $\Delta P_{ij}^{max,+}$ and $\Delta P_{ij}^{max,-}$ are the maximum power flow variations respectively from $i$ to $j$ and from $j$ to $i$, and $P_{ij}^{max}$ is the line capacity. Finally, we use that the change in the power flow of line $ij$ associated with a power injection at bus $m$ and equivalent withdrawal at $n$ can be obtained as:

$$\Delta P_{ij} = \left(PTDF_{ij,kn} - PTDF_{ij,km}\right)\Delta P_{mn} \tag{2.4}$$

Algorithm 1 describes how to evaluate the maximum quantity that can be traded for an injection in bus $m$ and retrieval in bus $n$:

**Algorithm 1 DLEM quantity update algorithm for UCS 1.1 with DC power flow**

```
Data: request_bus, offer_bus, Quantity
if up_regulation then
      m = offer_bus;
      n = request_bus;
else if down_regulation then
      m = request_bus;
      n = offer_bus;
for all the lines ij in the distribution system do
```

```
        Calculate P_ij = X_m PTDF_ij,km P_m
        Calculate ΔP_ij^max,+ = P_ij^max − P_ij
        Calculate ΔP_ij^max,− = − P_ij^max − P_ij
        Calculate Quantity_max that can be injected in bus m and retrieved
        in bus n, taking into account the direction of the flow: ΔP_mn^max =
        (PTDF_ij,kn − PTDF_ij,km) / ΔP_ij^max
        Update Quantity to be lower than or equal to Quantity_max;
return Quantity
```

### 2.2.1.6 Quantity update algorithm with DC Power Flow for block bids

Similar to the single bids, block bids should be matched with the best available requests. However, due to the AoN condition, we have to ensure that all the single offers included in the block bid can be fully matched before setting a match. To prioritize seniority, older requests should be temporarily assigned to the block bid and stored until its complete match is possible. To be fair across all incoming offers, however, the requests assigned to a block bid should still be available in their order book, in case a new matching offer appears before the match with the block bid becomes effective. Then, if a temporary match with a block bid is partially or completely cancelled, the requests order book should be immediately revisited looking for a new match for the remaining offer. Furthermore, every match that occurs while the block bid is not fully matched changes the line flows and can, thus, technically limit the match of the block bid. Therefore, network constraints should be constantly checked to guarantee that the temporary matches with the block bid are still feasible.

To avoid this tedious process, we store all the possible matches with the single offers involved in the block bid as candidates, until there are enough candidate requests to fully match it. After meeting this condition, it may happen that some parts of the block bid have several candidates to match with. To determine which one(s) to choose we run an optimization problem, considering all the possible matches with the single offer concerned. This way, we can select the request(s) that lead to the highest social welfare respecting network constraints. The optimization problem is a linear program (LP) formally defined as follows:

$$\min_{\mathbf{x}} \lambda_{b,t}^{\mathrm{U}} P_{b,t}^{\mathrm{U}} + \lambda_{b,t}^{\mathrm{D}} P_{b,t}^{\mathrm{D}} - \sum_{r \in \mathcal{R}_b} \left( \lambda_{r,t}^{\mathrm{U}} P_{r,t}^{\mathrm{U}} + \lambda_{r,t}^{\mathrm{D}} P_{r,t}^{\mathrm{D}} \right) \tag{2.5}$$

$$\text{s.t.} \quad P_{n,t}^{\mathrm{S}} - \sum_{r \in \mathcal{R}_n} \left( P_{r,t}^{\mathrm{U}} - P_{r,t}^{\mathrm{D}} \right) - \sum_{m \in \Omega_n} \left( b_{n,m} \left( \delta_{n,t} - \delta_{m,t} \right) \right) = 0, \forall n \in \mathcal{N}, n \neq n_b \tag{2.6}$$

$$P_{n_b,t}^{\mathrm{S}} + P_{b,t}^{\mathrm{U}} - P_{b,t}^{\mathrm{D}} - \sum_{r \in \mathcal{R}_{n_b}} \left( P_{r,t}^{\mathrm{U}} - P_{r,t}^{\mathrm{D}} \right) - \sum_{m \in \Omega_{n_b}} \left( b_{n_b,m} \left( \delta_{n_b,t} - \delta_{m,t} \right) \right) = 0 \tag{2.7}$$

$$-P_{n,m}^{\mathrm{lim}} \leq b_{n,m} \left( \delta_{n,t} - \delta_{m,t} \right) \leq P_{n,m}^{\mathrm{lim}}, \qquad \forall n \in \mathcal{N}, m \in \Omega_n \tag{2.8}$$

$$0 \leq P_r^{\mathrm{U}} \leq P_r^{\mathrm{Umax}}, \qquad \forall r \in \mathcal{R} \tag{2.9}$$

$$0 \leq P_r^{\mathrm{D}} \leq P_r^{\mathrm{Dmax}}, \qquad \forall r \in \mathcal{R} \tag{2.10}$$

$$\delta_{\mathrm{ref}} = 0 \tag{2.11}$$

where $\mathbf{x} = \left\{ P_{r,t}^{\mathrm{U}}, P_{r,t}^{\mathrm{D}}, \delta_{n,t} \right\}$.

The objective function (2.5) seeks to minimize total costs, given the cost of the offer in question, and the sum of the costs of the requests that constitute the complete match. The decision variables are $P_r$, the energy fulfilling request $r$ and $\delta_{n,t}$ the voltage angle at node $n$. The price and the quantity bid for the single offer $b$ contained in the block bid $k$ are given in $\lambda_{b,t}$ and $P_{b,t}$. The information about the requests are $\lambda_{r,t}$, the price of the request $r$ and $\mathcal{R}_b$, the set of candidate requests to match with $b$. The superscript $\mathrm{U}$ stands for upward and $\mathrm{D}$ for downward.

The nodal balance at the node where the block bid is located, $n_b$, is represented in (2.7), whereas (2.6) applies for the rest of the nodes, contained in the set $\mathcal{N}$.
$P_{n,t}^{\mathrm{S}}$ is the initial setpoint of node $n$ at time period $t$ and $\mathcal{R}_n$ is the set of requests located at node $n$. The last term of both equations refers to the energy flows from or to the node, with $\Omega_n$ being the sets of nodes connected to $n$. These flows are calculated using the susceptance of the line, $b_{n,m}$, and the voltage angle difference of the connected nodes $n$ and $m$.

Constraint (2.8) guarantees that the energy flow through each line respects its capacity limit $P_{n,m}^{\mathrm{lim}}$ in both directions. Constraints (2.9) and (2.10) make the amount of energy traded for each request positive and equal or lower than the quantity bid, $P_r^{\mathrm{max}}$. Finally, the last constraint (2.11) sets the voltage angle $\delta$ at the reference node.

As the optimization problem is solved separately for each single offer composing the block bid, subscript $t$ corresponds to the time target for the given single offer $b$. Since $b$ has only one direction, upward or downward, the terms in the opposite direction are disregarded along the whole problem.

The entire process carried out to match block bids is described in Algorithm 2. In case the possible match is between single bids, or there is only one candidate request for the single offer of a block bid, we use the PTDF method to check network constraints rather than solving this optimization problem, in order to reduce computational complexity.

**Algorithm 2 Block bids matching algorithm for UCS 1.1**

```
Data: Quantity_bid
for each offer of the block bid do
    if there is just one possible match then
          Calculate Quantity_max following Algorithm 1;
          if Quantity_max = Quantity_bid then
              Save potential match and move to the next offer;
          else
              if Quantity_max < Quantity_bid and Quantity_max > 0 then
                  Store the request as a candidate match and exit;
    else if there are multiple possible matches then
        Solve (2.5)-(2.11) to determine the best match;
        if feasible then
            Save potential match and move to the next offer;
        else
            Store the requests as candidates and exit;
if there is a potential match for each offer of the block bid then
    Set a match;
    Update the Setpoint;
return Setpoint, match
```

### 2.2.3 Algorithmic Solution

Finally, an incoming bid is matched following the heuristic matching algorithm illustrated in Figure 3.

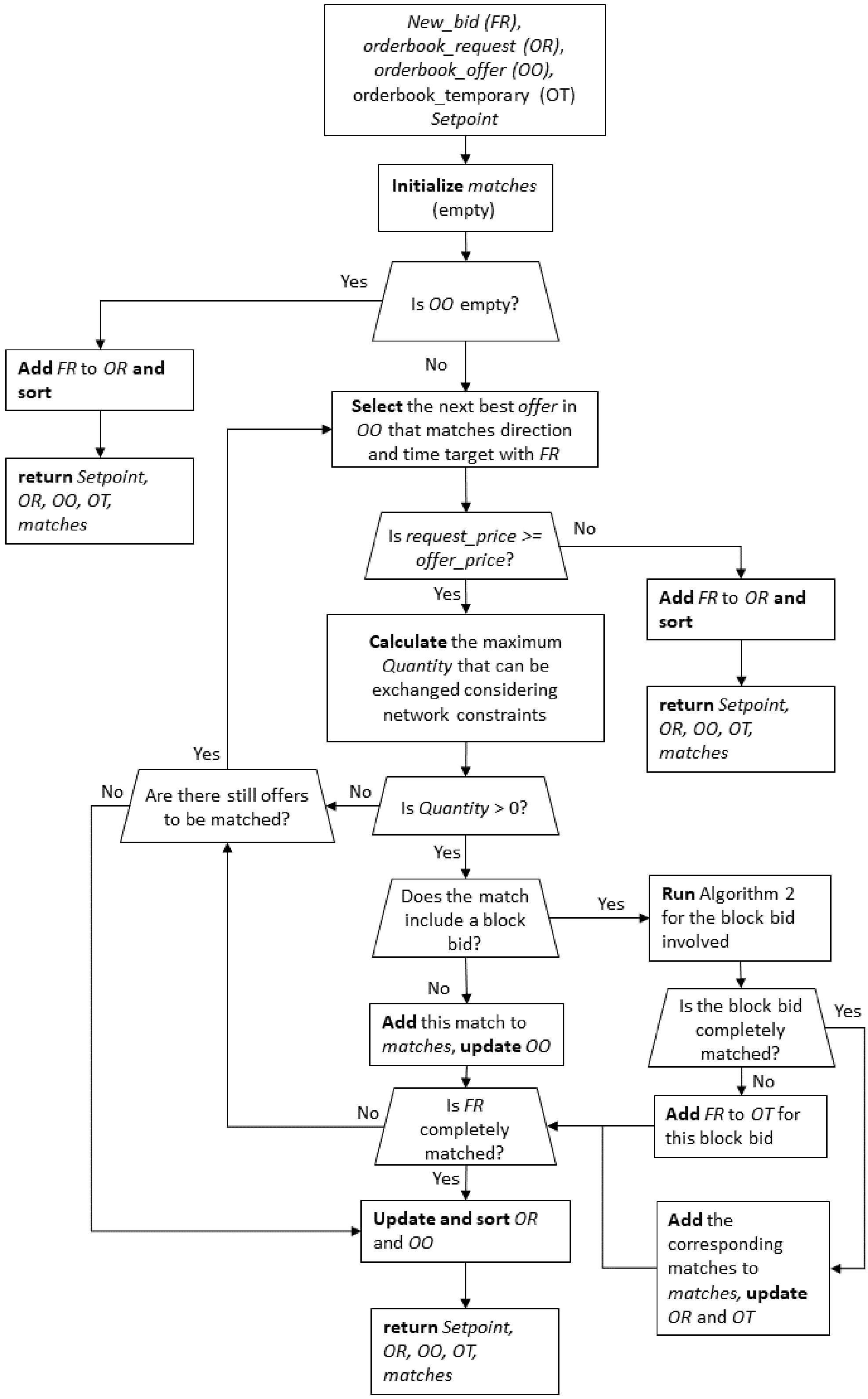


**Figure 3 Heuristic approach to UCS 1.1 DLEM continuous clearing with an incoming request**

Similarly, an incoming offer is matched following the heuristic matching algorithm illustrated in Figure 4 Heuristic approach to UCS 1.1 DLEM continuous clearing with an incoming offer

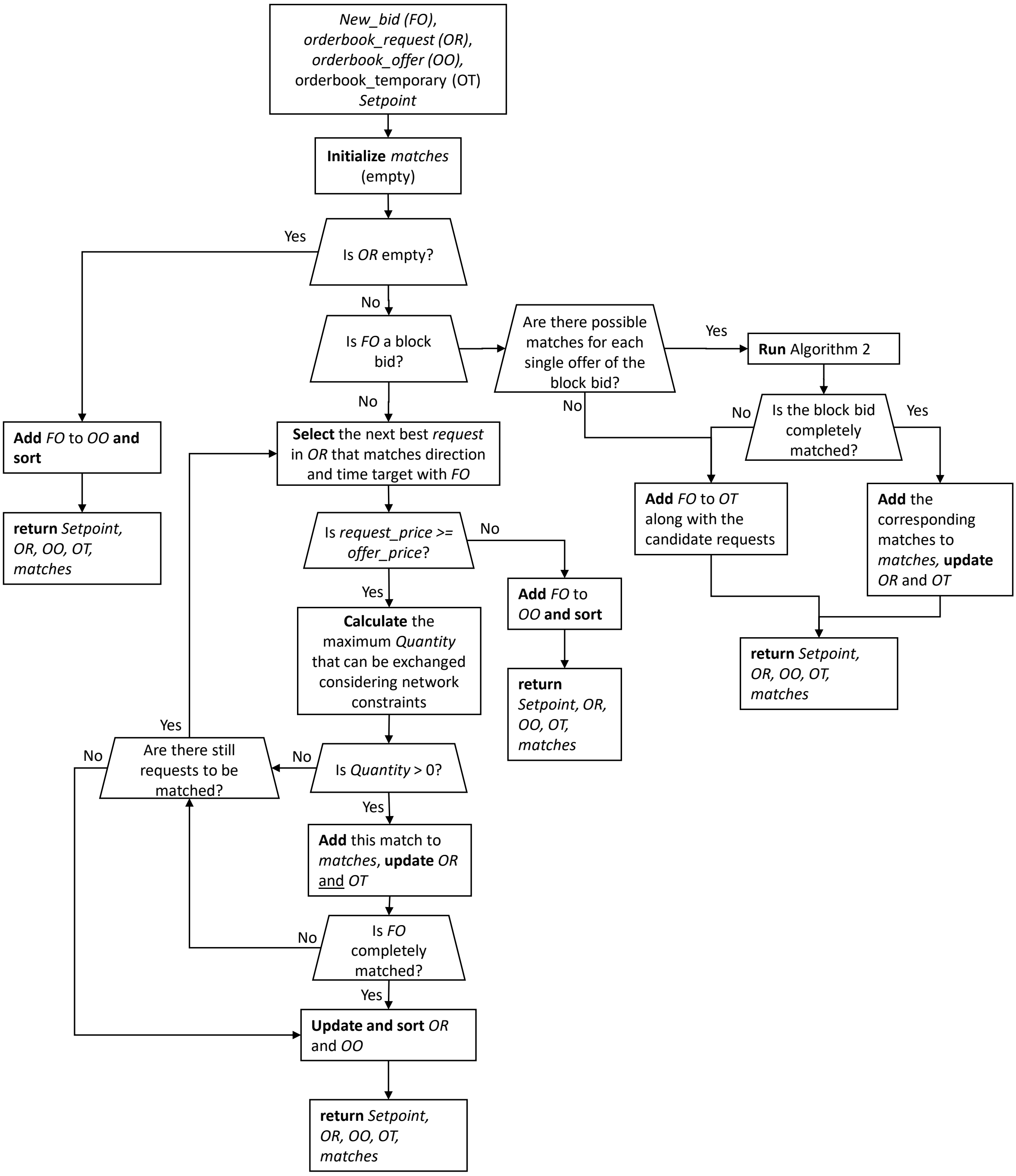


**Figure 4 Heuristic approach to UCS 1.1 DLEM continuous clearing with an incoming offer**

As a result of this continuous clearing model, single bids are matched with the best available option at the time of their submission, and block bids are matched with the set of the best options available at the moment when the full match of the block bid is possible. For all matches, the proposed market clearing guarantees that network constraints will be satisfied.

## 2.3 UCS 1.2 and UCS 1.3 - DLFM for power reserves

### 2.3.1 System model

In UCS 1.2, we consider an FMO that clears a local *active* power *reserve* market, and, in UCS 1.3, we consider an FMO that clears a local re*active* power *reserve* market after (R-DLFM) the transmission level commitments have been cleared. This means that some of the local generators and loads may already have committed parts of their energy and/or reserve to the wholesale transmission level (TN-level day-ahead energy market and TN-level reserve market). The FMO runs a continuous pay-as-bid market where FlexRequest from the DSO and FlexOffers from FSPs are continuously matched and accepted, or otherwise added to the orderbook. When the prices match, a network check is performed in order to ensure that no network constraint is violated. Without loss of generality and within FLEXGRID's context, we assume that the full network model of the DSO is known to the FMO, as well as the active and reactive power setpoints committed in the wholesale transmission level market. The aim of the FMO is to maximize social welfare by matching all bids that result in feasible power flows.

Here, the novelty of FLEXGRID's algorithmic approach is that the FMO clears the market continuously and under full consideration of network constraints, i.e., including line ratings, reactive power limits, and voltage bounds. A second contribution is that this algorithm ensures that any combination of reserve *activation* (in real-time after the clearing) is feasible for the network, opposed to current approaches, where one feasible reserve activation suffices.

The market design choices detailed in this subchapter are circled in black in Figure 6.

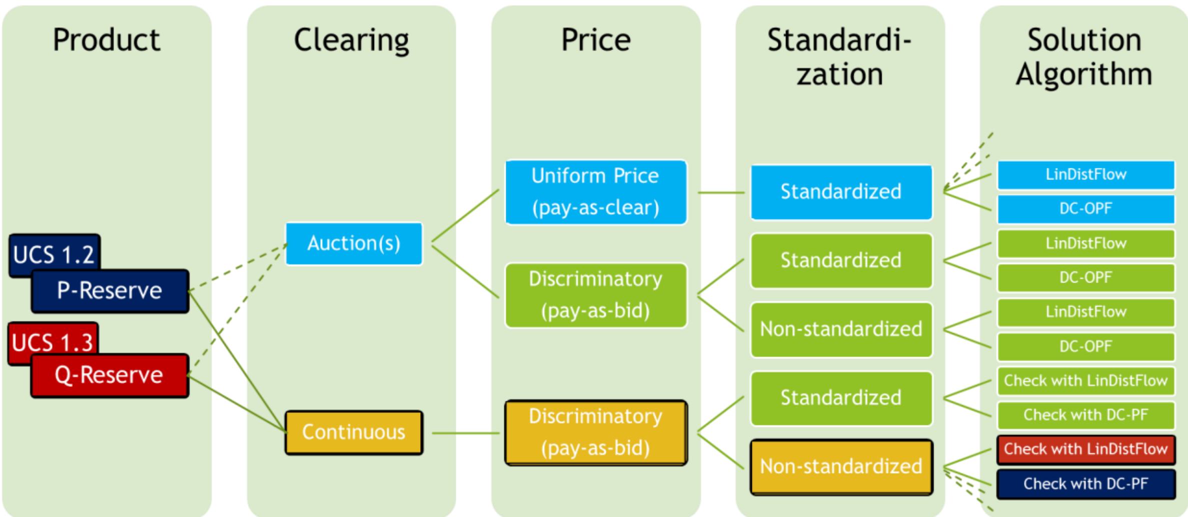


**Figure 5 Market design choices for reserve DLFM in UCS 1.2 and UCS 1.3**

### 2.3.2 Problem formulation

The FMO aims to clear the DLFM while ensuring a feasible operating point for the distribution network (DN). For this, the DSO must provide crucial network data. The task of the FMCT in UCS 1.2 an UCS 1.3 is to find feasible market transactions that respect the physical limits of the DN while maximizing social welfare within the given network constraints.

#### 2.3.2.1 Bids

Actors submit a bid as FlexRequest or FlexOffer for power reserve capacity (availability) in either upward or downward direction. The bid (FlexOffer or FlexRequest respectively) is composed of:

- Bid ID: Unique identifier
- Volume in MW/h
- Price in €/MW
- Regulation: up (1) or down (0)
- Location ID: e.g., node or DSO area
- Time target: for which time period(s) the bid applies
- Time stamp: indicates when the bid was submitted
- Type: The type is P for active power and Q for reactive power reserve bids in a DLFM

FlexRequests can specify whether they are conditional or unconditional. Market actors seem to be in a position to estimate whether their FlexRequest will be activated in the real-time operation with high probability (certainty) or not. A request tagged as unconditional is expected to be activated with certainty, unlike a request tagged as conditional. For instance, an unconditional reserve bid for active power can be understood as an energy bid, since the unconditional power activation over a given activation time interval corresponds to energy.

#### 2.3.2.2 Shared Order Book

Incoming, non-matching bids are placed in a shared order book (SOB) until they are cleared with a matching bid. There is one SOB for FlexRequests and one SOB for FlexOffers. The SOBs contain the attributes of the bids and are sorted:

- First by price: For FlexRequests the bid with the highest price comes first and for FlexOffers, the bid with the lowest price comes first.
- Second, by time stamp: For two bids with the same price, the earliest comes first.

#### 2.3.2.3 Matching

Bids are matched according to price, time-priority, and the absence of line congestions. The matching algorithm has the following heuristic properties:

- **Automatic process**: It is triggered when a bid is added or updated
- **Pay-as-bid pricing**: Each participant gets the price of the standing bid, i.e., earliest bid of the two matching bids.
- **Best price**: A FlexRequest can only match with a FlexOffer with a price that is inferior or equal. If several orders meet this requirement, the priority goes to the one with the best price (highest price for a FlexRequest and lowest price for a FlexOffer).
- **First-come-first-served principle**: If there are two orders with the same price, the priority goes to the one that was submitted first.
- **Network check**: A network check is performed to ensure that the activation of the bids would not result in congestions.
- **Partial execution**: If an order is only partially matched, the rest of the bid remains and is entered into the corresponding SOB. Owing to the network check requirement, it is

especially important to allow partial matching of the bids. In this way, two bids can match up to the point where their activation would result in a congestion.

It is vital to note that the location of the bids does not need to match, i.e., FlexOffer and FlexRequest *can* be located at different buses.

#### *2.3.2.4 Network Check*

The network check is based on a baseline energy dispatch that is established by either previous markets (e.g., day-ahead energy market) or by an estimation of load and generation at each bus (based on, e.g., commonly available data of similar days and hours and load forecasting). The baseline energy dispatch must be known or estimated in order to extract active and reactive power setpoints under normal operation.

Then, the network check considers the baseline dispatch, as well as all previously matched bids. For the DLEM, the DC power flow algorithm is implemented as the first step towards the inclusion of network constraints in a continuous market clearing algorithm. The main reasons for this choice are that the DC power flow is simpler, and thus more transparent for the market players, and faster, with computing time being a critical element for continuous markets. More complex power flow approximations may be used but will come at the cost of increased computational effort.

- *Check Procedure:* Behold, this is a market for flexibility reserves. Thus, there is no guarantee that the procured reserves will be activated. Rather, we need to ensure that accepted reserve bids can be activated without causing any congestion. A discussion on how to achieve feasible solutions at both the market clearing stage and during real-time activation is available in [20]. Several setups can be considered but the only way to make sure that the activation would not lead to line congestions is to test the activation of all combinations of accepted bids with the new bid under check.
- *Unconditional Requests*: The bids in the order book are re-evaluated once unconditional requests are matched, since unconditional (energy) bids offset the baseline dispatch.

#### *2.3.2.5 Multi-period model & block bids*

Several market sessions can be accessed at any point in time. Each bid must specify to which session it is submitted (target time). This setup allows for block bids, covering more than one market interval. Block bids requiring complete matching of the entire block and are exempt from partial matching.

### 2.3.3 Algorithmic solution

The algorithmic solution differs between UCS 1.2 and UCS 1.3. The objective with the choice of algorithms is to obtain sufficient accuracy while ensuring computational tractability. For UCS 1.2, it can be argued that a DC power flow is sufficiently accurate. However, for UCS 1.3, a better approximation of the AC power flow is required. Here, the LinDistFlow algorithm is implemented.

#### 2.3.3.1 UCS 1.2 – DLFM for active power reserves

Assuming DC power flow, the power flows are calculated with the help of the power transfer distribution factors (PTDFs). PTDFs are linear sensitivities linking power injections with line flows (for more details, see [19]). In particular, the power flow $P_{ij}$ in the line between bus $i$ and $j$, is linked to the power $P_m$ injected at bus $m$, by the PTDF factor $PTDF_{ij,km}$ of line $ij$ for an injection of power at the slack bus $k$ and retrieval of the same quantity in bus $m$, by:

$$P_{ij} = X_m PTDF_{ij,km} P_m \tag{2.12}$$

The maximum power flow variations, in both directions, can then be evaluated as:

$$\Delta P_{ij}^{max,+} = P_{ij}^{max} - P_{ij} \tag{2.13}$$
$$\Delta P_{ij}^{max,-} = -P_{ij}^{max} - P_{ij} \tag{2.14}$$

where $\Delta P_{ij}^{max,+}$ and $\Delta P_{ij}^{max,-}$ are the maximum power flow variations respectively from $i$ to $j$ and from $j$ to $i$, and $P_{ij}^{max}$ is the line capacity. Finally, we use that the change in the power flow of line $ij$ associated with a power injection at bus $m$ and equivalent withdrawal at $n$ can be obtained as:

$$\Delta P_{ij} = \left(PTDF_{ij,kn} - PTDF_{ij,km}\right)\Delta P_{mn} \tag{2.15}$$

Algorithm 3 describes how to evaluate the maximum quantity that can be traded for an injection in bus $m$ and retrieval in bus $n$:

**Algorithm 3 DLFM quantity update algorithm for UCS 1.2 with DC power flow**

```
Data: request_bus, offer_bus, Quantity
if up_regulation then
      m = offer_bus;
      n = request_bus;
else if down_regulation then
      m = request_bus;
      n = offer_bus;
for all the lines ij in the distribution system do
      Calculate P_ij = X_m PTDF_ij,km P_m
      Calculate ΔP_ij^max,+ = P_ij^max − P_ij
      Calculate ΔP_ij^max,− = − P_ij^max − P_ij
      Calculate Quantity_max that can be injected in bus m and retrieved
      in bus n, taking into account the direction of the flow: ΔP_mn^max =
      (PTDF_ij,kn − PTDF_ij,km) / ΔP_ij^max
      Update Quantity to be lower than or equal to Quantity_max;
return Quantity
```

Finally, an incoming bid is matched following the algorithm detailed in Algorithm 3. In case of a match with an unconditional request, the matching algorithm runs again on the bids in the SOBs. The full hierarchical matching flow chart is illustrated in Figure 6.

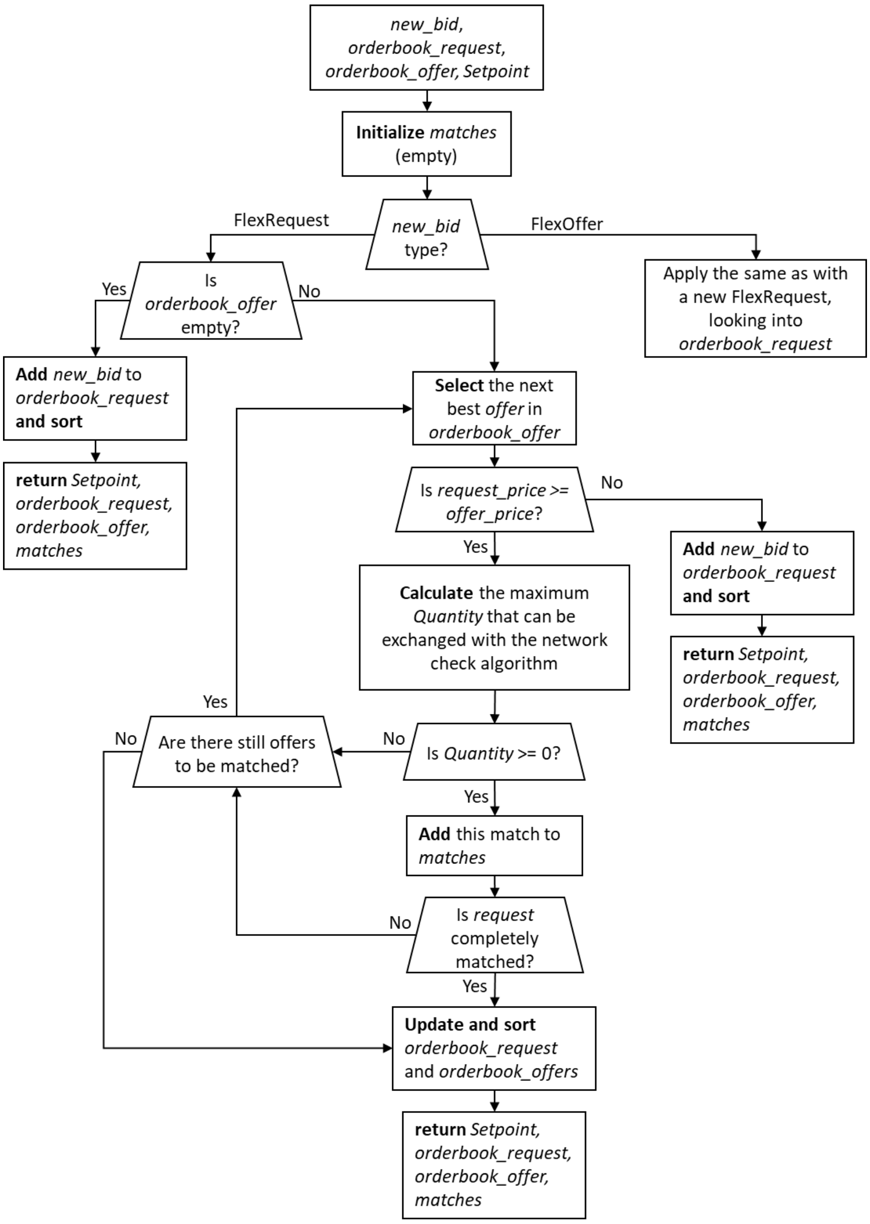


**Figure 6 Heuristic approach to UCS 1.2 DLFM continuous active power reserve clearing**

#### *2.3.3.2 UCS 1.3 – DLFM for reactive and active power reserves*

In order to also clear *reactive* power reserves for voltage management in UCS 1.3, a more accurate power flow approximation is required. Here, we use the linear approximation of the DistFlow algorithm. LinDistFlow is a linearized approximation of the non-convex AC power flow [22]. In LinDistFlow, the line flow losses are neglected which ultimately allows to derive linear power flow equations. Unlike in DC power flow, the reactive power flow and voltage magnitude are part of the LinDistFlow. The LinDistFlow formulation is given in equations (4.1) to (4.3).

$$P_{i+1} = P_i - P_{L,i+1} \tag{2.16}$$

$$Q_{i+1} = Q_i - Q_{L,i+1} \tag{2.17}$$

$$V_{i+1}^2 = V_i^2 - 2(r_i P_i + x_i Q_i) \tag{2.18}$$

Where, $P_i$ and $Q_i$ are the net real and reactive power flow in branch $i$ shown in Figure 7. $P_{L,i+1}$ and $Q_{L,i+1}$ indicates the real and reactive demand at node $i+1$ and $V_i$ is the voltage magnitude in node $i$.

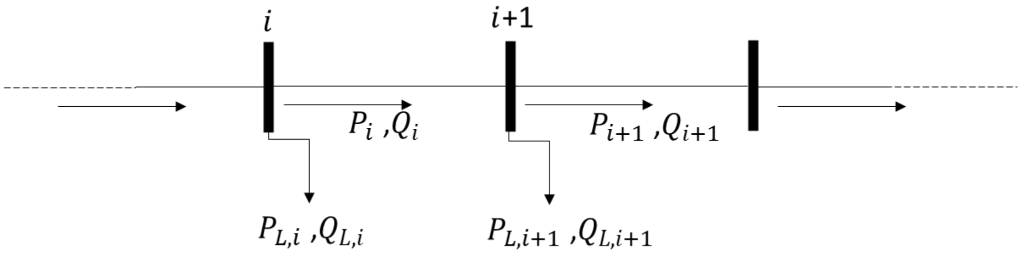


**Figure 7 One line diagram of a radial network**

When any network constraint violation is identified by the LinDistFlow network check algorithm, the quantity will be reduced by a small margin and the process will be repeated. Just as in Chapter 3, the network check algorithm will also look for any combination of accepted requests that could cause line flow congestion or voltage violation before accepting a match. This makes sure that the activation of all combinations of the accepted bid would not lead to a network issue. The order book's bids are re-evaluated once unconditional requests are matched, as they modify the power dispatch.

An incoming bid is matched following the algorithm depicted in Figure 8 In case of a match with an unconditional request, the matching algorithm runs again on the bids in the SOBs.

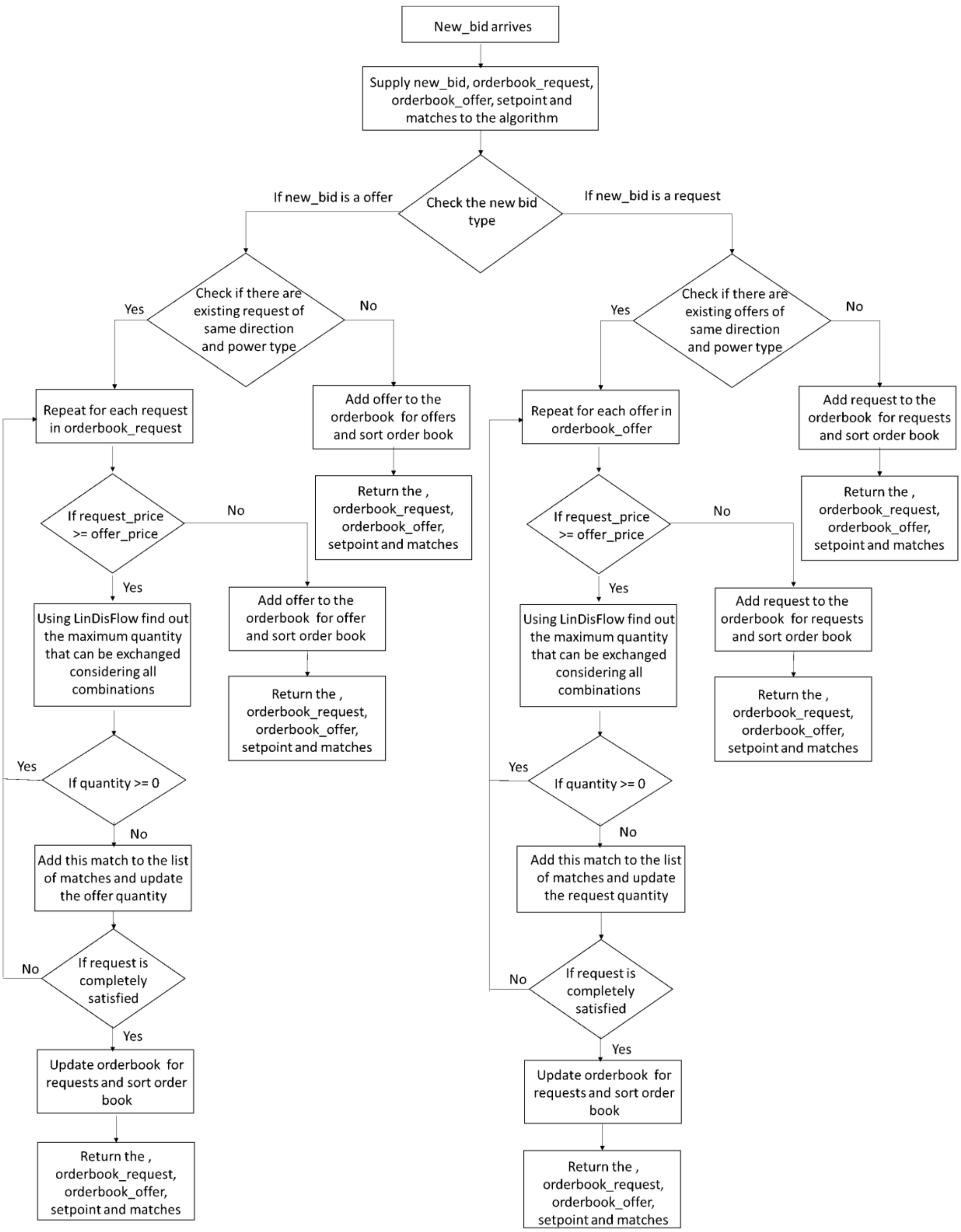


**Figure 8 Heuristic approach to UCS 1.3 DLFM continuous reactive and active power reserve clearing**

## 2.4 Simulation setup and performance evaluation results

In this subchapter, the results of the network-aware market clearing in UCS 1.1 and UCS 1.3 are evaluated with respect to the reference case of network-unaware market clearing. The clearing of only active power reserves in UCS 1.2 can be considered a special case of UCS 1.3 and is thus not explicitly presented here.

### 2.4.1 Simulation setup

We evaluate our algorithms on part of a real DN which was provided by bnNETZE within FLEXGRID.

The reference (*ref*) scenario is detailed in the following: The radial 81-bus system is modified in order to represent a future with some renewable penetration and EV penetration. To that end, the setpoints of the system are modified to increase the loads; 87% of all loads have 3kW and 13% of all loads have 4kW. We assume that the baseline dispatch (initial setpoint) is known and results in non-zero values of energy-not served (ENS) and curtailment. For simplicity and to demonstrate our approach, we consider one time period of one hour, and a power factor $\cos(\phi) = 0.95$. Additionally, we add three wind farms with an installed capacity of 0.2 MW, 0.1 MW, and 0.2 MW respectively.

The cost of curtailment is assumed $C^{curt}$ =60 €/MWh, the value of lost load is $C^{VOLL}$ =200 €/MWh. Reserve activation costs are assumed 0 in a first step, since we consider that the flexibility providers have no operational expenses or opportunity cost. FlexRequest and FlexOffers are generated since there is no DLFM today from which data can be fetched. FlexRequests for energy are priced at 70 €/MWh for up- and 40 €/MWh for down-regulation. FlexRequests for reserves are priced at 70 €/MWh for up- and 40 €/MWh for down-regulation. FlexOffers are priced randomly between 25 €/MW and 35 €/MW sampled from a uniform distribution.

The key KPIs are detailed below:

- The cumulative **procured flexibility** in MWh (UCS 1.1) or MW (UCS 1.2 and UCS 1.3)
- The total **energy-not served** ($E^{ENS}$) in MWh
- The total **curtailed energy** ($E^{curt}$) in MWh
- The **DSO cost**, i.e., flexibility procurement cost which corresponds to the DSO expense in the flexibility market and is obtained using the market clearing price and the DSO expense during the real-time dispatch (curtailment, energy not served and flexibility activation).
- The **DSO cost reduction** can be obtained by comparing the respective UCS result to the business-as-usual (BAU), i.e., no flexibility market.
- The **social welfare**, which is composed of several parts.
    - The **total surplus of participants** (FlexBuyer and FlexSupplier) calculated as the difference between the utility of the accepted FlexRequests and the cost of the accepted FlexOffers (assuming that all participants bid their true utility/cost).
    - The **cost of energy not served** computed by $\sum E^{ENS} \cdot C^{VOLL}$
    - The **cost of curtailment** computed by $\sum E^{curt} \cdot C^{curt}$
- The **cost reduction** can be obtained by comparing the respective UCS result to the business-as-usual (BAU), i.e., no flexibility market.

The social welfare is calculated as:

$$SW = \sum\left(\lambda_i^{R+} - \lambda_i^{O+}\right)E_i^{f+} + \left(\lambda_i^{R-} - \lambda_i^{O-}\right)E_i^{f-} - \lambda^{ENS}E_i^{ENS} - \lambda^{curt}E_i^{curt} \tag{2.19}$$

Where the first two parts correspond to the FlexSuppliers surplus, the third part is the cost for ENS, and the last part is the cost of curtailment.

Since the results are sensitive to key assumptions and input parameters, we conduct sensitivity analyses with respect to three key parameters:

- RES penetration: In the reference scenario, we assume a low-RES penetration (*ref)* with 3 wind turbines. The *midRES* scenario includes 6 wind turbines, and the *highRES* scenario includes 9 wind turbines in the distribution network.
- Liquidity: In the reference scenario, we assume sufficient liquidity (*ref)* scenario where FlexOffers has a higher aggregate volume than FlexRequests. We compare this to a scenario with insufficient liquidity (*lowLiq*) which inevitably results in curtailment and/or ENS.
- EV penetration: In the reference scenario, we assume a relatively low load (*ref*). We compare this to a future system with high EV penetration or other load growth (*highLoad*).

The reference (*ref*) scenario corresponds to the combination of *low-RES*, *sufficient Liquidity*, and *low-Load* scenarios. The business as usual (BAU) case corresponds scenarios without any flexibility market. The next subchapter presents the results of these sensitivity analyses with a change of only one parameter at a time.

### 2.4.2 Performance evaluation and KPIs

Three different RES penetration scenarios are simulated. They key KPIs for the RES penetration scenarios are compared to the respective BAU in Table 3 (UCS 1.1) and Table 4 (UCS 1.3) respectively.

**Table 3 KPIs for continuous DLEM case study (UCS 1.1)**

| KPI | BAU *ref* | DLEM *ref* | BAU *midRES* | DLEM *midRES* | BAU *highRES* | DLEM *highRES* |
|---|---|---|---|---|---|---|
| Flexibility [MWh/h] | 0 | 0.059 | 0 | 0.468 | 0 | 0.878 |
| ENS $E^{ENS}$ [MWh/h] | 0 | 0 | 0 | 0 | 0 | 0 |
| Curtailment $E^{curt}$ [MWh/h] | 0.059 | 0 | 0.468 | 0 | 0.878 | 0 |
| DSO Cost [€/h] | 3.54 | 2.36 | 28.08 | 18.72 | 52.68 | 35.12 |
| Cost reduction for DSO [€/h] | - | 1.18 | - | 9.36 | - | 17.56 |
| Social Welfare [€/h] | -3.54 | 0.543 | -28.08 | 3.59 | -52.68 | 6.723 |
| -Total surplus of participants | 0 | 0.543 | 0 | 3.59 | 0 | 6.723 |
| -Cost of ENS | 0 | 0 | 0 | 0 | 0 | 0 |
| -Cost of Curtailment | 3.54 | 0 | 28.08 | 0 | 52.68 | 0 |

**Table 4 KPIs for continuous DLFM case study (UCS 1.3)**

| KPI | BAU *ref* | DLFM *ref* | BAU *midRES* | DLFM *midRES* | BAU *highRES* | DLFM *highRES* |
|---|---|---|---|---|---|---|
| Flexibility [MW/h] | 0.00 | 0.12 | 0.00 | 0.49 | 0.00 | 0.90 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Flexibility [kVAr/h] | 0.00 | 0.32 | 0.00 | 0.42 | 0.00 | 0.68 |
| ENS $E^{ENS}$ [kW/h] | 0.02 | 0.00 | 0.01 | 0.00 | 0.01 | 0.00 |
| ENS $Q^{ENS}$ [kVar/h] | 0.07 | 0.00 | 0.11 | 0.00 | 0.17 | 0.00 |
| Curtailment $E^{curt}$ [kW/h] | 0.10 | 0.00 | 0.48 | 0.00 | 0.89 | 0.00 |
| Curtailment $Q^{curt}$ [kVar/h] | 0.25 | 0.00 | 0.31 | 0.00 | 0.51 | 0.00 |
| DSO Cost [€/h] | 4.76 | 17.04 | 20.09 | 35.68 | 36.94 | 57.47 |
| DSO cost reduction [€/h] | - | -12.28 | - | -15.59 | - | -20.53 |
| Social Welfare [€/h] | -4.76 | 2.10 | -20.09 | 5.32 | -36.94 | 8.94 |
| - Total surplus of participants | 0.00 | 2.10 | 0.00 | 5.32 | 0.00 | 8.94 |
| -Cost of ENS | 0.66 | 0.00 | 0.45 | 0.00 | 0.45 | 0.00 |
| -Cost of Curtailment | 4.10 | 0.00 | 19.64 | 0.00 | 36.49 | 0.00 |

The most relevant KPIs are visualized in Figure 9 for UCS 1.1 and in Figure 10 for UCS 1.3. In Figure 9 (UCS 1.1), the social welfare with the flexibility market is higher than without it, and this difference increases with increasing RES penetration. The DSO cost increases with increasing RES penetration, but remains lower with the DLEM than in the BAU. In the BAU, curtailment increases with RES penetration. In the DLEM scenarios, the otherwise curtailed energy is entirely covered with flexibility.

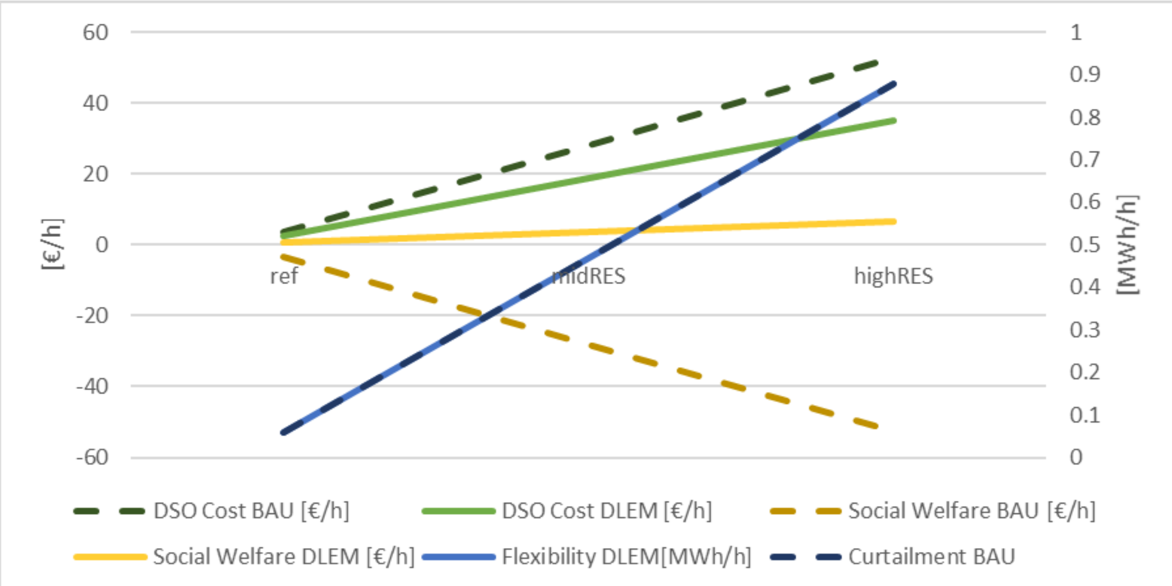


**Figure 9 Results of continuous DLEM (UCS 1.1) compared to BAU, for different RES penetration scenarios**

In Figure 10 (UCS 1.3), similar trends are observed. However, opposite to UCS 1.1, the DSO cost increases with increasing RES penetration but is here remains lower with the DLEM than in the BAU. This is because the voltage deviations the DLFM case are not financially penalized which makes for an unfair comparison. Similar to UCS 1.1, in the BAU, curtailment increases with RES penetration. In the DLFM scenarios, the otherwise curtailed energy is entirely covered with flexibility.

An interesting observation is the split of active and reactive power reserves. In the *ref (i.e., lowRES)* scenario, reactive power reserves are predominantly procured. The higher the RES penetration, the more active power reserves and less reactive power reserves are procured in the studied distribution network.

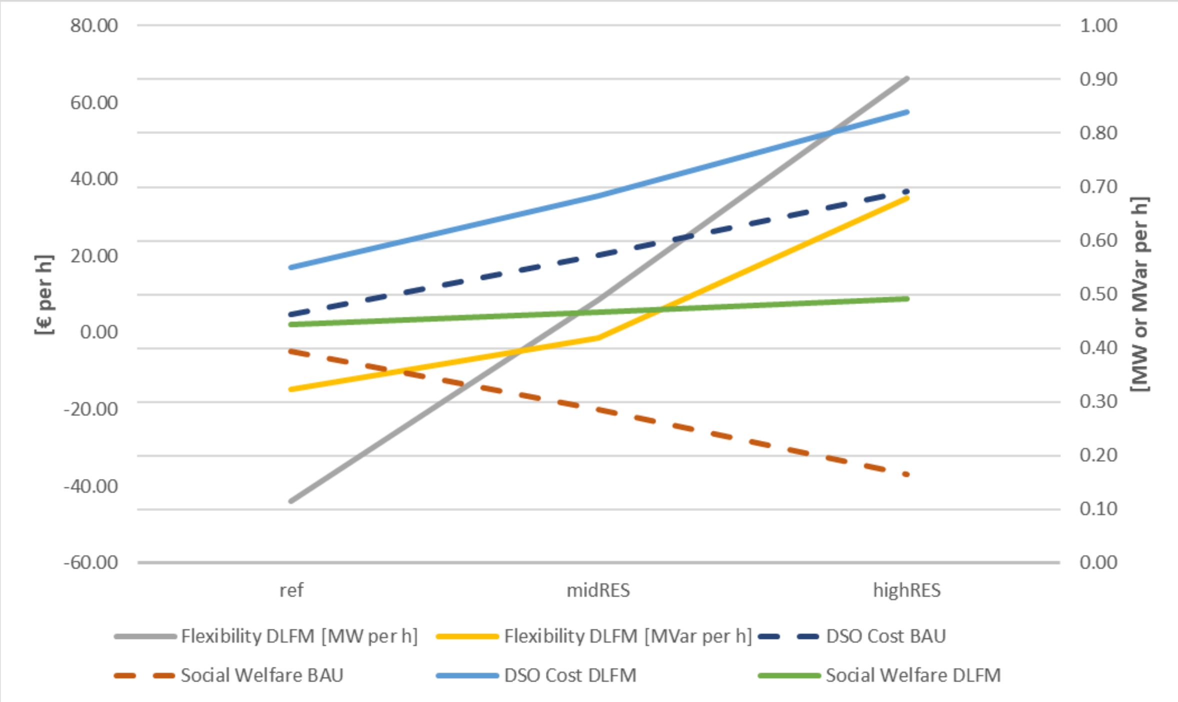


**Figure 10 Results of continuous DLFM (UCS 1.3) compared to BAU, for different RES penetration scenarios**

Furthermore, a scenario with insufficient liquidity and one with high load is simulated. The key KPIs for these scenarios are compared to the respective BAU in Table 5 (UCS 1.1) and Table 6Table 4 (UCS 1.3) respectively.

**Table 5 KPIs for continuous DLEM case study (UCS 1.1)**

| **KPI** | BAU *ref* | DLEM *ref* | DLEM *lowLiq* | BAU *highLoad* | DLEM *highLoad* |
|---|---|---|---|---|---|
| Flexibility [MWh/h] | 0 | 0.059 | 0.049 | 0 | 0.646 |
| ENS $E^{ENS}$ [MWh/h] | 0 | 0 | 0 | 0.636 | 0 |
| Curtailment $E^{curt}$ [MWh/h] | 0.059 | 0 | 0.01 | 0.01 | 0 |
| DSO Cost [€/h] | 3.54 | 2.36 | 2.56 | 127.7 | 25.82 |
| Cost reduction for DSO [€/h] | - | 1.18 | 0.98 | - | 101.88 |
| Social Welfare [€/h] | -3.54 | 0.543 | -0.227 | -127.7 | 5.037 |
| Total surplus of participants | 0 | 0.543 | 0.373 | 0 | 5.037 |
| Cost of ENS | 0 | 0 | 0 | 127.1 | 0 |
| Cost of Curtailment | 3.54 | 0 | 0.6 | 0.6 | 0 |

**Table 6 KPIs for continuous DLFM case study (UCS 1.3)**

| **KPI** | BAU *ref* | DLFM *ref* | DLFM *lowLiq* | BAU *highLoad* | DLFM *highLoad* |
|---|---|---|---|---|---|
| Flexibility [MW/h] | 0.00 | 0.12 | 0.10 | 0.00 | 0.69 |
| Flexibility [kVAr/h] | 0.00 | 0.32 | 0.09 | 0.00 | 0.51 |
| ENS $E^{ENS}$ [kW/h] | 0.02 | 0.00 | 0.00 | 0.67 | 0.00 |
| ENS $Q^{ENS}$ [kVar/h] | 0.07 | 0.00 | 0.00 | 0.37 | 0.00 |
| Curtailment $E^{curt}$ [kW/h] | 0.10 | 0.00 | 0.01 | 0.03 | 0.00 |
| Curtailment $Q^{curt}$ [kVar/h] | 0.25 | 0.00 | 0.23 | 0.14 | 0.00 |
| DSO Cost [€/h] | 4.76 | 17.04 | 7.25 | 28.29 | 44.04 |
| DSO cost reduction [€/h] | - | -12.28 | -2.49 | - | -15.75 |
| Social Welfare [€/h] | -4.76 | 2.10 | 0.52 | -28.29 | 7.31 |
| Total surplus of participants | 0.00 | 2.10 | 1.09 | 0.00 | 7.31 |
| Cost of ENS | 0.66 | 0.00 | 0.16 | 27.27 | 0.00 |
| Cost of Curtailment | 4.10 | 0.00 | 0.41 | 1.03 | 0.00 |

## 2.5 Conclusions and lessons learned

After communicating FLEXGRID UCS 1.1, 1.2, and 1.3 scientific results to both academic and industrial communities, we have come up with a short list of lessons learned that could be further investigated in future R&D initiatives. Table 7 summarizes research and business-related insights for each one of the lessons learned.

**Table 7 Lessons learned from UCS 1.1, 1.2, and 1.3 with continuous clearing**

| **Lesson learned** | **Research & Business insights** |
|---|---|
| The benefits of continuous vs. auction-based clearing are not generalizable. Advantages exist depending on the geographical context, surrounding market frameworks, regulation, market participants etc.<br>The only general conclusion is that continuous clearing is preferred on short-term markets, whereas auctions are preferred in long-term markets. | Real-time markets are likely to use continuous clearing. The longer the market lead time, the better the argument for an auction-based market. |
| Some countries (e.g., Germany) are headed down a policy path that involves heavy regulation and requirements from local flexibility assets. This may prevent the formation of local flexibility markets since flexibility is implicitly traded via regulatory frameworks rather than voluntary market transactions. | The business case depends on the specific geographical context and may vary with the regulation that is in place. |
| In the underlying distribution network, reactive power reserves are predominantly needed with | It is not generalizable whether active or reactive power are more significant. The |

| | |
|---|---|
| low RES penetration, while active power reserves become more important the higher the RES penetration becomes. | answer may depend on the specific network and RES penetration levels. |
| Locational Marginal prices (LMPs) can send transparent price signals and investment incentives, but can be quite complex to compute. The difficulty arises from, e.g., inclusion of block bids in auctions, or from the use of continuous clearing. | If LMPs are not available, alternative means of investment signals should be established that can transparently communicate the need for local FlexAssets at a given network node or DSO area. |
| Ideally, the DLEM/DLFM would be integrated into transmission network level markets. | The advantage of such integration is reduced balancing cost from a system perspective. The disadvantage is that it requires increased data exchange and computational power. |

# 3 Auction based network aware market clearing algorithms via FLEXGRID ATP

This chapter deals with the research problem of FLEXGRID's HLUC_01. In this UCS, we consider the problem of an FMO that wants to clear a network aware flexibility market auction to manage congestions in the distribution network.

## 3.1 Problem statement, related state-of-the-art and FLEXGRID research contributions

The existing electricity markets do not consider the constraints of local distribution networks, leading to a sub-optimal use of these networks. As the penetration of distributed energy resources connected to the distribution network increases, it becomes necessary to introduce a market which considers the distribution networks, their constraints, and the location of the flexible resources. This could in turn reduce the costs for the whole system, and enable the integration of renewable energy sources, while providing an alternative to distribution network upgrade.

One way to deal with a high penetration of distributed energy resources is to implement a local energy market. In the literature, we can find three groups of local energy markets [8]:

- Peer-to-peer (P2P) markets [9]
- Centralized markets, run by a flexibility market operator (FMO) [10]
- Markets where participants can either trade directly among each other or through a FMO [11]

It is easier to consider the network constraints in a centralized approach, where only the FMO has access to the information about the network parameters. The integration of distribution network constraints is necessary to ensure that line congestions and voltage deviations are avoided. However, at distribution level, the DC Power Flow approximation is not as accurate anymore as on transmission level. An AC Power Flow, on the other hand, gives an exact representation of such system, at the cost of non-linear equations. For these reasons, FLEXGRID considers approximations that provide a suitable trade-off between computational complexity and a satisfying representation of the line flows. While, for UCS 1.1 and UCS 1.2., a DC power flow may suffice, it is essential to include both active and reactive power for UCS 1.3.

There has been a lot of interest for convex relaxation of AC-OPF in the last years. Detailed surveys are available in [23], [24], and [25]. Some widely used relaxations are:

- Semi-Definite Programming (SDP)
- Quadratically Constrained Programming (QC), a particular case of SDP
- Second Order Cone Program (SOCP), a particular case of QC

There is generally a trade-off between the tightness of the relaxation (i.e., how small the resulting superset is) and the computational time. In practice, time limits are dictated by the respective market gate closure time and clearing price announcement. SDP and QC are tighter than SOCP but they take longer to solve [26] [27] [28] [29].

In FLEXGRID, we focus on the DSO role in the local market to avoid congestions and voltage deviations. The novelty of the FLEXGRID's approach is that the FMO clears the market under full consideration of network constraints, i.e., including line and transformer ratings, reactive power limits, and voltage bounds.

## 3.2 UCS 1.1 - DLEM for energy

### 3.2.1 System model

In this UCS, we consider a Flexibility Market Operator (FMO), who clears a local energy market after (i.e., R-DLEM) the transmission level commitments have been cleared. This means that some of the local generators and loads may already have committed parts of their energy to the wholesale transmission level (i.e., day-ahead energy market). The FMO runs a market where FlexRequests and FlexOffers are matched, provided that no distribution network constraint is violated. Without loss of generality and within FLEXGRID's context, we assume that the full network model of the DSO is known to the FMO, as well as the active and reactive power setpoints committed in the wholesale transmission level market. The aim of the FMO is to maximize social welfare by matching all bids that result in feasible power flows.

After section 2.2 detailed a continuous pay-as-bid DLEM market clearing algorithm (yellow choice path in Figure 9Figure 2), this section details an auction-based pay-as-clear DLEM market clearing algorithm (blue choice path in Figure 9Figure 2).

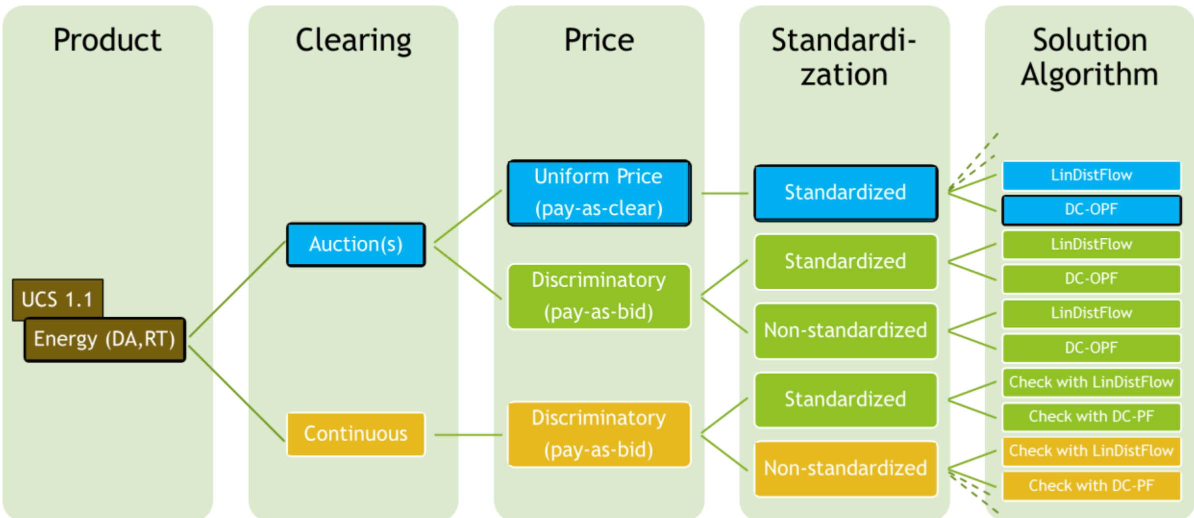


**Figure 10 Market design choices for distribution level energy market (DLEM) auction**

### 3.2.2 Problem Formulation

#### *3.2.2.1 Bids*

Actors submit a bid as FlexRequest (from the DSO) or FlexOffer (from the FSP) for energy in MWh/h in either upward (generation increase / demand decrease) or downward (generation decrease / consumption increase) direction. The bid (FlexOffer or FlexRequest respectively) is composed of:

- Bid ID: Unique identifier
- Volume in MWh/h

- Price in €/MWh
- Regulation: up (1) or down (0)
- Location ID: e.g., node or DSO area
- Time target: for which time period(s) the bid applies
- Time stamp: indicates when the bid was submitted (optional for auction)
- Type: The type is E for an energy bid in a DLEM
- Block: Whether the bid is a block bid or not. If so, the FMO assigns a block indicator to the linked bids

Note that we include here the possibility to have FlexOffers that span over more than one time period. These block bids are defined as single bids linked to each other. They are submitted at the same time and location; they can have different quantities and prices.

#### *3.2.2.2 Multi-period model*

Auction-based markets clear once for each time period, considering all the bids submitted for it. The market clearing is formulated as a multi-period optimization problem. It clears multiple time periods at once with the objective to obtain the highest social welfare for the entire time horizon of the market.

Many electricity markets introduce integer constraints in their formulation to enable participants to better describe their preferences when bidding. In our case, the problem is a mixed integer linear program (MILP), since it accounts for block bids by using binary variables.

#### *3.2.2.3 Network Check*

The network check is implemented implicitly as a set of constraints in the optimization problem that depends on the OPF approximation. The choice of OPF depends on the intended KPI trade-offs. For instance, a DC-OPF is convex, relatively simple and fast, while the non-convex AC-OPF takes longer to solve is not guaranteed to find the global optimum. Therefore, we propose to use a simple and scalable DC-OPF for UCS 1.1. We have used the DC-OPF as the first step towards the inclusion of network constraints in a market clearing auction. Two main reasons for this choice are that the DC-OPF is simpler, and thus more transparent for the market players, and faster, with computing time being a critical element for short-term markets.

#### *3.2.2.4 Pricing*

When market clearing is formulated as a linear optimization problem, the clearing price/s can be derived from the dual variables of the balance equation/s. However, when including integer variables, the pricing is not so straightforward.

We analyze five different pricing methods that can be implemented in this LFM:

- Side-payment
- Convex Hull Pricing (ConvHP)
- Paradoxically Rejected Bids (PRB)
- Vickrey–Clarke–Groves (VCG)
- Pay-as-bid

The first three use the dual variables of the optimization problem to derive uniform prices, whereas the last two propose other solutions for the pricing.

The dual variables of a MILP are obtained by solving it in two steps:

1. Solve the optimization problem and obtain the optimal value for all the integer variables.
2. Solve again the same optimization problem but fixing the integer variables with their optimal values obtained in the previous step. It is now a linear problem in which dual variables are easily derived.

In our case, the disadvantage of fixing the binary variables is that both the objective function and the constraints, all the terms associated with block bids will be parameters instead of variables. Therefore, the cost of the block bids will no longer be included in the price formation. This implies that some market participants may end up with a negative profit, so some adjustments are needed to compensate for it.

##### *3.2.2.4.1 Side-payment*

In the US, market operators compensate the negative profit of the players using uplift mechanisms. They consist of side-payments outside the market clearing. To recover these payments, the operator usually distributes the additional costs in a fair way among the buyers, but the way of proceeding depends on the market.

The uplift payments guarantee cost recovery for the market players and even revenue adequacy for the market operator.

In [30], the authors develop a model of an auction-based market which incorporates side-payments to ensure the above-mentioned properties. However, this is achieved at the expense of market efficiency since this mechanism implies deviations from the market outcome.

##### *3.2.2.4.2 Convex Hull Pricing*

One way of calculating side-payments is through the ConvHP. This method identifies uniform market prices that minimize the total side-payments needed, through the aggregate cost function. Several market operators in the US use it, but through approximations to address the computational challenge in an accessible way, as proposed in [31].

In [32] the formulation, analysis, and implementation challenges for ConvHP in electricity markets are discussed. Its authors conclude that this method is not preferred over the common ones, since simple pricing schemes achieve similar benefits, being more practical and transparent.

##### *3.2.2.4.3 Paradoxically Rejected Bids*

Alternatively, in Europe, instead of using uplift payments, there are PRB. These are non-convex bids, e.g., block bids, which fits the market according to the uniform prices computed, but they are rejected.

In a situation where a bid incurs negative profits, but its price is in line with the clearing price, it is paradoxically rejected. Then the algorithm is run again without that bid until all the participants' costs are recovered. This leads to a sub-optimal market result since social welfare is not maximized. However, the mechanism complies with the revenue adequacy for the market operator.

##### *3.2.2.4.4 Vickrey–Clarke–Groves*

Leaving aside the use of dual variables, the VCG auction is another mechanism proposed to price the market. In [33], the authors state that it is the only mechanism being efficient and incentive compatible. It maximizes social welfare while making it optimal for each participant to bid its true value.

First, the market clears to maximize social welfare and then the price of the transactions is determined. This is not the initial bidding price, but the marginal harm caused to the other participants, which is better than or equal to the original price. Thus, it is more profitable for the players to bid truthfully regardless of other bidders. The marginal harm is calculated considering the best combination of bids excluding the participant under consideration since the mechanism is defined assuming that there is a feasible solution when a player is removed [34].

##### *3.2.2.4.5 Pay-as-bid*

Finally, there is a pricing rule that can be applied to all the markets, which is pay-as-bid. It is the simplest mechanism since each participant gets or pays according to their initial bid. In this way cost recovery and revenue adequacy are ensured. In fact, the market operator ends up with a surplus. In addition, market players can increase their profit by over bidding, so this mechanism does not promote incentive compatibility.

### 3.2.3 Algorithmic Solution

The auction-based clearing is built as a mixed integer linear program (MILP), since it accounts for block bids using binary variables. These variables represent the acceptance ratio of the block bids, with 1 standing for acceptance and 0 for rejection. The aim of the auction-based configuration is to achieve the maximum social welfare for the whole market time horizon. Due to the AoN acceptance condition of the block bids, all the time periods are cleared at once. The following problem can be solved by a MILP solver:

$$\min_{\mathbf{x}} \sum_{t \in \mathcal{T}} \Bigg[ \sum_{o \in \mathcal{O}} \left( \lambda_{o,t}^{\mathrm{U}} P_{o,t}^{\mathrm{U}} + \lambda_{o,t}^{\mathrm{D}} P_{o,t}^{\mathrm{D}} \right) + \sum_{k \in \mathcal{K}} \left( AR_k \sum_{b \in \mathcal{B}_k} \left( \lambda_{b,t}^{\mathrm{U}} P_{b,t}^{\mathrm{U}} + \lambda_{b,t}^{\mathrm{D}} P_{b,t}^{\mathrm{D}} \right) \right) - \sum_{r \in \mathcal{R}} \left( \lambda_{r,t}^{\mathrm{U}} P_{r,t}^{\mathrm{U}} + \lambda_{r,t}^{\mathrm{D}} P_{r,t}^{\mathrm{D}} \right) \Bigg] \tag{3.1}$$

$$
\begin{aligned}
\text{s.t.}\quad & P_{n,t}^{\mathrm{S}} - \sum_{r\in\mathcal{R}_n} \left(P_{r,t}^{\mathrm{U}} - P_{r,t}^{\mathrm{D}}\right) + \sum_{o\in\mathcal{O}_n} \left(P_{o,t}^{\mathrm{U}} - P_{o,t}^{\mathrm{D}}\right) \\
& \quad + \sum_{k\in\mathcal{K}_n} \left( AR_k \sum_{b\in\mathcal{B}_k} \left(P_{b,t}^{\mathrm{U}} - P_{b,t}^{\mathrm{D}}\right) \right) - \sum_{m\in\Omega_n} \left( b_{n,m}\left(\delta_{n,t} - \delta_{m,t}\right)\right) = 0, \\
& \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}
\end{aligned} \tag{3.2}
$$

$$
\sum_{o\in\mathcal{O}} P_{o,t}^{\mathrm{U}} + \sum_{k\in\mathcal{K}} AR_k\, P_{k,t}^{\mathrm{U}} - \sum_{r\in\mathcal{R}} P_{r,t}^{\mathrm{U}} = 0, \qquad \forall t \in \mathcal{T} \tag{3.3}
$$

$$
\sum_{o\in\mathcal{O}} P_{o,t}^{\mathrm{D}} + \sum_{k\in\mathcal{K}} AR_k\, P_{k,t}^{\mathrm{D}} - \sum_{r\in\mathcal{R}} P_{r,t}^{\mathrm{D}} = 0, \qquad \forall t \in \mathcal{T} \tag{3.4}
$$

$$
-P_{n,m}^{\lim} \le b_{n,m}\left(\delta_{n,t} - \delta_{m,t}\right) \le P_{n,m}^{\lim}, \qquad \forall n \in \mathcal{N}, m \in \Omega_n, \forall t \in \mathcal{T} \tag{3.5}
$$

$$
0 \le P_{r,t}^{\mathrm{U}} \le P_{r,t}^{\mathrm{Umax}}, \qquad \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{3.6}
$$

$$
0 \le P_{r,t}^{\mathrm{D}} \le P_{r,t}^{\mathrm{Dmax}}, \qquad \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{3.7}
$$

$$
0 \le P_{o,t}^{\mathrm{U}} \le P_{o,t}^{\mathrm{Umax}}, \qquad \forall o \in \mathcal{O}, \forall t \in \mathcal{T} \tag{3.8}
$$

$$
0 \le P_{o,t}^{\mathrm{D}} \le P_{o,t}^{\mathrm{Dmax}}, \qquad \forall o \in \mathcal{O}, \forall t \in \mathcal{T} \tag{3.9}
$$

$$
AR_k \in \{0,1\}, \qquad \forall k \in \mathcal{K} \tag{3.10}
$$

$$
\delta_{\mathrm{ref},t} = 0, \qquad \forall t \in \mathcal{T} \tag{3.11}
$$

with $\mathbf{x} = \left\{P_{r,t}^{\mathrm{U}}, P_{r,t}^{\mathrm{D}}, P_{o,t}^{\mathrm{U}}, P_{o,t}^{\mathrm{D}}, \delta_{n,t}, AR_k\right\}$.

The objective function (3.1) minimizes the cost of trading flexibility. It considers all the single offers $\mathcal{O}$, block offers $\mathcal{K}$, and requests $\mathcal{R}$ submitted for all the time periods $\mathcal{T}$. The decision variables are $P_r$, the energy fulfilling request $r$, $P_o$, the energy fulfilling offer $o$, the acceptance ratio $AR_k$ of the block bid $k$, defined in (3.10), and $\delta_{n,t}$ the voltage angle at node $n$. The price and the quantity bid for the single offer $b$ contained in the block bid $k$ are given in $\lambda_{b,t}$ and $P_{b,t}$. The other prices are $\lambda_{r,t}$, the price of the request $r$ and $\lambda_{o,t}$, the price of the offer $o$. The superscript $\mathrm{U}$ stands for upward and $\mathrm{D}$ for downward.
The first and the third term of the objective function refer to the cost of single offers and requests. The second term is the sum of the cost of all single offers contained in block bid $k$, $\mathcal{B}_k$, multiplied by the acceptance ratio.

The first constraint (3.2) is the nodal balance, including a term for the block bids and considering all the offers located at each node $\mathcal{O}_n$ and $\mathcal{K}_n$. $P_{n,t}^{\mathrm{S}}$ is the initial setpoint of node $n$ at time period $t$ and $\mathcal{R}_n$ is the set of requests located at node $n$. The last term of both equations refers to the energy flows from or to the node, with $\Omega_n$ being the sets of nodes connected to $n$. These flows are calculated using the susceptance of the line, $b_{n,m}$, and the voltage angle difference of the connected nodes $n$ and $m$. Constraints (3.3) and (3.4) ensure that offers match with requests both upwards and downwards.

Constraint (3.5) guarantees that the energy flow through each line respects its capacity limit $P_{n,m}^{\lim}$ in both directions. The energy accepted per bid is limited in (3.6) – (3.9), where $P^{\max}$ is the total quantity bid. Finally, the last constraint (3.11) sets the voltage angle $\delta$ at the reference node.

Solving this optimization problem, we determine which bids are accepted and for which quantity in order to achieve the highest social welfare respecting network constraints.

## 3.3 UCS 1.2 and UCS 1.3 - DLFM for power reserves

### 3.3.1 System model

In this UCS, we consider a Flexibility Market Operator (FMO), who clears a local *active* power *reserve* market after (R-DLFM) the transmission level commitments have been cleared. This means that some of the local generators and loads may already have committed parts of their energy and/or reserve to the wholesale transmission level. In UCS 1.2, we consider an FMO that clears a local *active* power *reserve* market and, in UCS 1.3, we consider an FMO that clears a local re*active* power *reserve* market after (R-DLFM) the transmission level commitments have been cleared. This means that some of the local generators and loads may already have committed parts of their energy and/or reserve to the wholesale transmission level. The FMO gathers all FlexRequests and FlexOffers for a given timeframe. At gate closure, no further bids are accepted and the network-aware auction-based market clearing algorithm runs. The aim of the FMO is to maximize social welfare by matching all bids that result in feasible power flows. Without loss of generality and within FLEXGRID's context, we assume that the full network model of the DSO is known to the FMO, as well as the active and reactive power setpoints committed in the wholesale transmission level market. The different algorithms are shown in Figure 11.

Here, the main novelty of FLEXGRID's algorithmic approach is that the FMO clears the market under full consideration of network constraints, i.e., including line ratings, reactive power limits, and voltage bands.

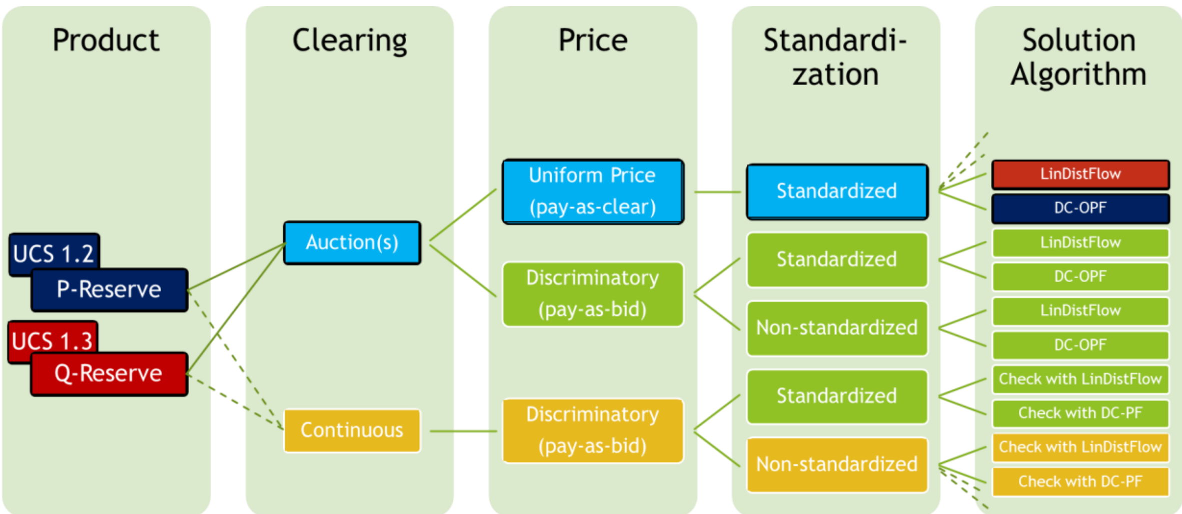


**Figure 11 Market design choices for reserve DLFM auction in UCS 1.2 and UCS 1.3**

### 3.3.2 Problem formulation

The FMO that aims to clear the DLEM while ensuring a feasible operating point for the distribution network (DN). For this, the DSO must provide crucial network data. The task of the FMCT is to find feasible market transactions that respect the physical limits of the DN, while maximizing social welfare within the given network constraints.

#### 3.3.2.1 Bids

Actors submit a bid as FlexRequest (from the DSO) or FlexOffer (from the FSP) for active or reactive power reserve capacity (availability) in either upward or downward direction. The bid (FlexOffer or FlexRequest respectively) is composed of:

- Bid ID: Unique identifier
- Volume in MW/h
- Price in €/MW
- Regulation: up (1) or down (0)
- Location ID: e.g., node or DSO area
- Time target: for which time period(s) the bid applies
- Time stamp: indicates when the bid was submitted (optional for auction)
- Type: The type is P for active power and Q for reactive power reserve bids in a DLFM

#### 3.3.2.2 Multi-period model

Auction-based markets clear once for each time period, considering all the bids submitted for it. The market clearing is formulated as a multi-period optimization problem. It clears multiple time periods at once with the objective to obtain the highest social welfare for the whole time horizon of the market.

#### 3.3.2.3 Network check

The network check is implemented implicitly as a set of constraints in the optimization problem that depends on the OPF approximation. The choice of OPF depends on the intended KPI trade-offs. For instance, a DC-OPF is convex, relatively simple, and fast, while the non-convex AC-OPF takes longer to solve is not guaranteed to find the global optimum. Therefore, we propose to use a simple and scalable DC-OPF for UCS 1.2, and a more accurate LinDistFlow for UCS 1.3. Other network models can be considered in the future.

#### 3.3.2.4 Guarantees for activation

When considering a reserve market, we do not know which reserves will need to be activated in real time. In order to guarantee that the activation of the procured reserves will be feasible, all possible combinations of FlexRequests should be considered. The market clearing problem would then be solved for each of the combinations, and the final accepted bids would be all the bids that are accepted in any of the problems solved as so. However, this procedure would come with a high computational cost. Considering all combinations of FlexRequests could also end up being very expensive for the DSO. One solution would be for the DSO to define which combinations of FlexRequests should be covered. Another solution would be to have low reserve payments and high activation payments.

### 3.3.3 Algorithmic solution

#### 3.3.3.1 UCS 1.2 – DLFM for active power reserves

The aim of the auction-based configuration is to achieve the maximum social welfare for the whole market time horizon:

$$\min_{\mathbf{x}} \sum_{t\in\mathcal{T}} \left[ \sum_{o\in\mathcal{O}} \left(\lambda^{\mathrm{U}}_{o,t} P^{\mathrm{U}}_{o,t} + \lambda^{\mathrm{D}}_{o,t} P^{\mathrm{D}}_{o,t}\right) - \sum_{r\in\mathcal{R}} \left(\lambda^{\mathrm{U}}_{r,t} P^{\mathrm{U}}_{r,t} + \lambda^{\mathrm{D}}_{r,t} P^{\mathrm{D}}_{r,t}\right) \right] \tag{3.12}$$

$$\text{s.t.} \quad P^{\mathrm{S}}_{n,t} - \sum_{r\in\mathcal{R}_n} \left(P^{\mathrm{U}}_{r,t} - P^{\mathrm{D}}_{r,t}\right) + \sum_{o\in\mathcal{O}_n} \left(P^{\mathrm{U}}_{o,t} - P^{\mathrm{D}}_{o,t}\right) - \sum_{m\in\Omega_n} \left(b_{n,m}\left(\delta_{n,t} - \delta_{m,t}\right)\right) = 0, \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \tag{3.13}$$

$$\sum_{o\in\mathcal{O}} P^{\mathrm{U}}_{o,t} - \sum_{r\in\mathcal{R}} P^{\mathrm{U}}_{r,t} = 0, \quad \forall t \in \mathcal{T} \tag{3.15}$$

$$\sum_{o\in\mathcal{O}} P^{\mathrm{D}}_{o,t} - \sum_{r\in\mathcal{R}} P^{\mathrm{D}}_{r,t} = 0, \quad \forall t \in \mathcal{T} \tag{3.16}$$

$$-P^{\mathrm{lim}}_{n,m} \le b_{n,m}\left(\delta_{n,t} - \delta_{m,t}\right) \le P^{\mathrm{lim}}_{n,m}, \quad \forall n \in \mathcal{N}, m \in \Omega_n, \forall t \in \mathcal{T} \tag{3.17}$$

$$0 \le P^{\mathrm{U}}_{r,t} \le P^{\mathrm{Umax}}_{r,t}, \quad \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{3.18}$$

$$0 \le P^{\mathrm{D}}_{r,t} \le P^{\mathrm{Dmax}}_{r,t}, \quad \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{3.19}$$

$$0 \le P^{\mathrm{U}}_{o,t} \le P^{\mathrm{Umax}}_{o,t}, \quad \forall o \in \mathcal{O}, \forall t \in \mathcal{T} \tag{3.20}$$

$$0 \le P^{\mathrm{D}}_{o,t} \le P^{\mathrm{Dmax}}_{o,t}, \quad \forall o \in \mathcal{O}, \forall t \in \mathcal{T} \tag{3.21}$$

$$\delta_{\mathrm{ref},t} = 0, \quad \forall t \in \mathcal{T} \tag{3.22}$$

with $\mathbf{x} = \left\{P^{\mathrm{U}}_{r,t}, P^{\mathrm{D}}_{r,t}, P^{\mathrm{U}}_{o,t}, P^{\mathrm{D}}_{o,t}, \delta_{n,t}\right\}$.

The objective function (3.12) minimizes the cost of trading flexibility. It considers all the offers $\mathcal{O}$, and requests $\mathcal{R}$ submitted for all the time periods $\mathcal{T}$. The decision variables are $P_r$, the energy fulfilling request $r$, $P_o$, the energy fulfilling offer $o$ and $\delta_{n,t}$ the voltage angle at node $n$. The prices are $\lambda_{r,t}$, the price of the request $r$ and $\lambda_{o,t}$, the price of the offer $o$. The superscript $\mathrm{U}$ stands for upward and $\mathrm{D}$ for downward.

The first constraint (3.13) is the nodal balance, considering all the offers located at each node $\mathcal{O}_n$. $P^{\mathrm{S}}_{n,t}$ is the initial setpoint of node $n$ at time period $t$ and $\mathcal{R}_n$ is the set of requests located at node $n$. The last term of both equations refers to the energy flows from or to the node, with $\Omega_n$ being the sets of nodes connected to $n$. These flows are calculated using the susceptance of the line, $b_{n,m}$, and the voltage angle difference of the connected nodes $n$ and $m$. Constraints (3.15) and (3.16) ensure that offers match with requests both upwards and downwards.

Constraint (3.17) guarantees that the energy flow through each line respects its capacity limit $P^{\mathrm{lim}}_{n,m}$ in both directions. The energy accepted per bid is limited in (3.18) – (3.21), where $P^{\mathrm{max}}$ is the total quantity bid. Finally, the last constraint (3.22) sets the voltage angle $\delta$ at the reference node.

Since this is a reserve procurement problem, we do not know the volume of real-time activation at the time of market clearing. Therefore, this problem has to be solved for each combination of FlexRequests and all the bids accepted through this process are retained. In this case, $\mathcal{R}$ would be a subset of all requests, containing only the combination of requests under evaluation in the specific scenario. Fortunately, these clearing problems can be solved in parallel such that the solution time remains practical. However, a large number of subproblems require large computational power, especially for large networks.

In state-of-the-art reserve clearing, the real-time activation is therefore ignored, which allows the formulation of a deterministic problem.

#### 3.3.3.2 UCS 1.3 – DLFM for reactive and active power reserves

In order to capture voltage band and reactive power reserve bids, an auction based optimal power flow algorithm which uses the LinDistFlow network model is used which is capable of clearing both active and reactive power reserves at the same time. LinDistFlow is a linearized approximation of the non-convex AC power flow [28], the network model is found in Chapter 2.3.3.2.

The objective of the action-based market clearing algorithm is to maximise social welfare. The optimization problem is formulated as follows:

$$max \sum_{t\,\in\,T}\left(\sum_{r\,\in\,R_t} \lambda_r p_r - \sum_{o\,\in\,O_t} \lambda_o p_o\right) \tag{3.23}$$

*s.t.*

$$\sum_{r\,\in\,R_t^U} p_r = \sum_{o\,\in\,O_t^U} p_o \qquad \forall\ t\ \in T \tag{3.24}$$

$$\sum_{r\,\in\,R_t^D} p_r = \sum_{o\,\in\,O_t^D} p_o \qquad \forall\ t\ \in T \tag{3.25}$$

$$0 \leq\ p_o\ \leq\ P_o \qquad \forall\ o\ \in O \tag{3.26}$$

$$0 \leq\ p_r\ \leq\ P_r \qquad \forall\ r\ \in R \tag{3.27}$$

(3.1) - (3.6)

where T denotes the time periods under consideration. $R_t$ and $O_t$ are the sets of requests and offers respectively with the superscript U denoting upward and D denoting downward bids. $\lambda_r$ and $\lambda_o$ denotes the price of request r and offer o respectively and, $p_r$ and $p_o$ indicates the quantify of request r and offer o accepted with maximum capacity of $P_r$ and $P_o$.

Constraints (3.24) and (3.25) guarantee the total quantity of accepted upward and downward requests is equal the total amount of accepted upward and downward offers, respectively. Constraints (3.26) and (3.27) guarantee the accepted bid is within their respective limits.

Since this is a reserve procurement problem, we do not know the volume of real-time activation at the time of market clearing. Therefore, this problem has to be solved for each combination of FlexRequests, as detailed in the previous subchapter.

## 3.4 Simulation setup and performance evaluation results

In this subchapter, the results of the network-aware market clearing in UCS 1.1 and UCS 1.3 are evaluated with respect to the reference case of network-unaware market clearing. The clearing of only active power reserves in UCS 1.2 can be considered a special case of UCS 1.3 and is thus not explicitly presented here.

### 3.4.1 Simulation setup

The simulation setup for the case study is the same as in chapters 2.4.1. The difference is that, here, we present the KPIs for the auction clearing of DLEM (UCS 1.1) and reserve clearing (UCS 1.3).

### 3.4.2 Performance evaluation and KPIs

Three different RES penetration scenarios are simulated. They key KPIs for these scenarios are compared to the respective BAU in Table 8 (UCS 1.1) and Table 9 (UCS 1.3) respectively.

**Table 8 KPIs for auction DLEM case study (UCS 1.1)**

| **KPI** | BAU *ref* | DLEM *ref* | BAU *midRES* | DLEM *midRES* | BAU *highRES* | DLEM *highRES* |
|---|---|---|---|---|---|---|
| Flexibility [MWh/h] | 0 | 0.059 | 0 | 0.468 | 0 | 0.878 |
| ENS $E^{ENS}$ [MWh/h] | 0 | 0 | 0 | 0 | 0 | 0 |
| Curtailment $E^{curt}$ [MWh/h] | 0.059 | 0 | 0.468 | 0 | 0.878 | 0 |
| DSO Cost [€/h] | 3.54 | 2.36 | 28.08 | 18.72 | 52.68 | 35.12 |
| Cost reduction for DSO [€/h] | - | 1.18 | - | 9.36 | - | 17.56 |
| Social Welfare [€/h] | -3.54 | 0.857 | -28.08 | 5.824 | -52.68 | 10.498 |
| Total surplus of participants | 0 | 0.857 | 0 | 5.824 | 0 | 10.498 |
| Cost of ENS | 0 | 0 | 0 | 0 | 0 | 0 |
| Cost of Curtailment | 3.54 | 0 | 28.08 | 0 | 52.68 | 0 |

**Table 9 KPIs for auction DLFM case study (UCS 1.3)**

| **KPI** | BAU *ref* | DLFM *ref* | BAU *midRES* | DLFM *midRES* | BAU *highRES* | DLFM *highRES* |
|---|---|---|---|---|---|---|
| Flexibility [MW/h] | 0.00 | 0.12 | 0.00 | 0.49 | 0.00 | 0.90 |
| Flexibility [kVAr/h] | 0.00 | 0.32 | 0.00 | 0.42 | 0.00 | 0.68 |
| ENS $E^{ENS}$ [kW/h] | 0.02 | 0.00 | 0.01 | 0.00 | 0.01 | 0.00 |
| ENS $Q^{ENS}$ [kVar/h] | 0.07 | 0.00 | 0.11 | 0.00 | 0.17 | 0.00 |
| Curtailment $E^{curt}$ [kW/h] | 0.10 | 0.00 | 0.48 | 0.00 | 0.89 | 0.00 |
| Curtailment $Q^{curt}$ [kVar/h] | 0.25 | 0.00 | 0.31 | 0.00 | 0.51 | 0.00 |
| DSO Cost [€/h] | 4.76 | 14.94 | 20.09 | 30.43 | 36.94 | 53.05 |
| DSO cost reduction [€/h] | - | -10.18 | - | -10.34 | - | -16.11 |
| Social Welfare [€/h] | -4.76 | 2.10 | -20.09 | 5.31 | -36.94 | 8.94 |
| Total surplus of participants | 0.00 | 2.10 | 0.00 | 5.31 | 0.00 | 8.94 |
| Cost of ENS | 0.66 | 0.00 | 0.45 | 0.00 | 0.45 | 0.00 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Cost of Curtailment | 4.10 | 0.00 | 19.64 | 0.00 | 36.49 | 0.00 |

The most relevant KPIs are visualized in Figure 12 for UCS 1.1 and in Figure 13 for UCS 1.3. In Figure 12 (UCS 1.1) the social welfare with the flexibility market is higher than without it, and this difference increases with increasing RES penetration. The DSO cost increases with increasing RES penetration but remains lower with the DLEM than in the BAU. In the BAU, curtailment increases with RES penetration. In the DLEM scenarios, the otherwise curtailed energy is entirely covered with flexibility.

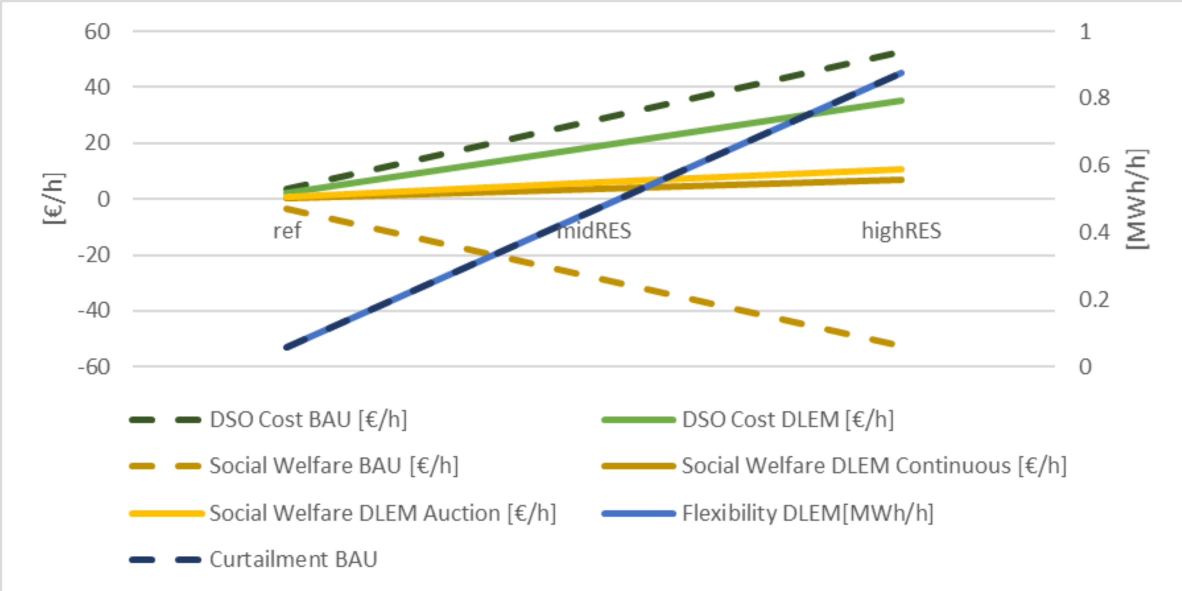


**Figure 12 Results of auction based DLEM (UCS 1.1) compared to BAU, for different RES penetration scenarios**

In Figure 10 (UCS 1.3), similar trends are observed. However, opposite to UCS 1.1, the DSO cost increases with increasing RES penetration but is here remains lower with the DLEM than in the BAU. This is because the voltage deviations the DLFM case are not financially penalized which makes for an unfair comparison. Similar to UCS 1.1, in the BAU, curtailment increases with RES penetration. In the DLFM scenarios, the otherwise curtailed energy is entirely covered with flexibility.

As in the continuous clearing, the split of active and reactive power reserves is analysed. In the *ref (i.e., lowRES)* scenario, reactive power reserves are predominantly procured. The higher the RES penetration, the more active power reserves and less reactive power reserves are procured in the studied distribution network.

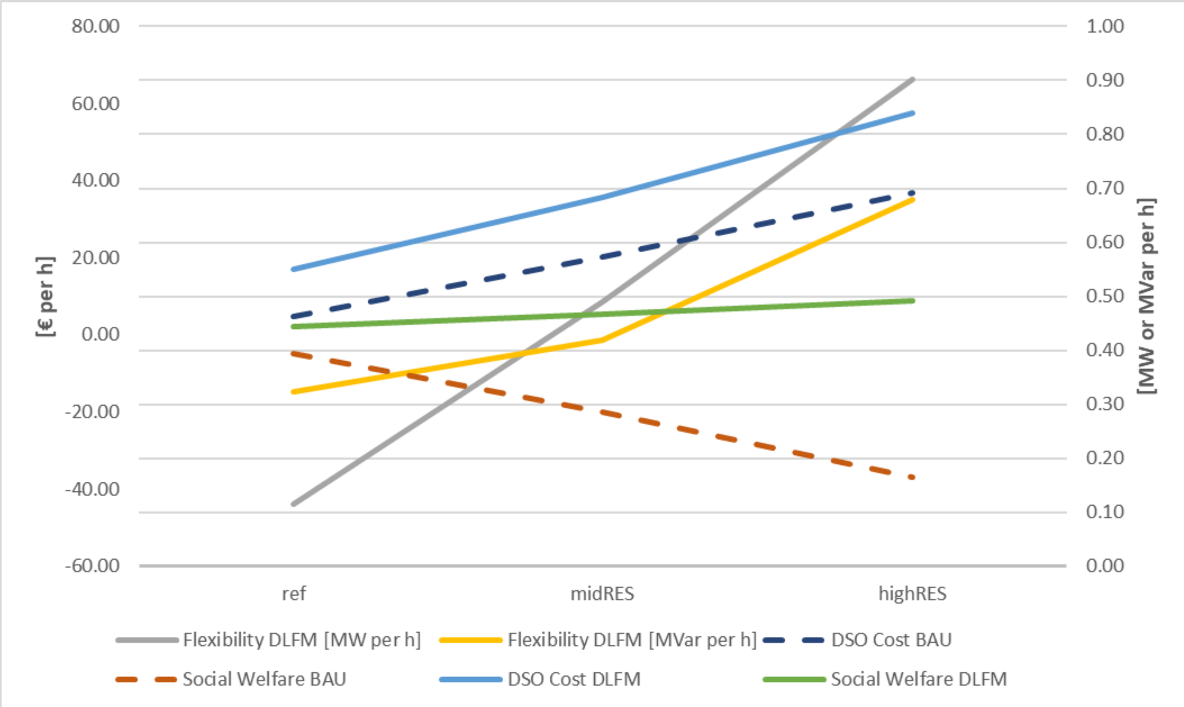


**Figure 13 Results of auction based DLFM (UCS 1.3) compared to BAU, for different RES penetration scenarios**

In Figure 12 and Figure 13, the social welfare of the auction-based algorithm is compared to the social welfare of the continuous clearing algorithm. The results show that social welfare is higher when using the auction-based algorithm. This is consistent with the theory, since only the optimization based auction can maximize social welfare, while the continuous market relies on heuristic sets of rules to clear the market.

Furthermore, a scenario with insufficient liquidity and one with high load is simulated. The key KPIs for these scenarios are compared to the respective BAU in Table 10 KPIs for continuous DLEM case study (UCS 1.1)Table 10 (UCS 1.1) and Table 6Table 4 (UCS 1.3) respectively.

**Table 10 KPIs for continuous DLEM case study (UCS 1.1)**

| **KPI** | BAU *ref* | DLEM *ref* | DLEM *lowLiq* | BAU *highLoad* | DLEM *highLoad* |
|---|---|---|---|---|---|
| Flexibility [MWh/h] | 0 | 0.059 | 0.049 | 0 | 0.646 |
| ENS $E^{ENS}$ [MWh/h] | 0 | 0 | 0 | 0.636 | 0 |
| Curtailment $E^{curt}$ [MWh/h] | 0.059 | 0 | 0.01 | 0.01 | 0 |
| DSO Cost [€/h] | 3.54 | 2.36 | 2.56 | 127.7 | 25.82 |
| Cost reduction for DSO [€/h] | - | 1.18 | 0.98 | - | 101.88 |
| Social Welfare [€/h] | -3.54 | 0.857 | 0.1 | -127.7 | 8.512 |
| Total surplus of participants | 0 | 0.857 | 0.7 | 0 | 8.512 |
| Cost of ENS | 0 | 0 | 0 | 127.1 | 0 |
| Cost of Curtailment | 3.54 | 0 | 0.6 | 0.6 | 0 |

**Table 11 KPIs for continuous DLFM case study (UCS 1.3)**

| **KPI** | BAU *ref* | DLFM *ref* | DLFM *lowLiq* | BAU *highLoad* | DLFM *highLoad* |
|---|---|---|---|---|---|
| Flexibility [MW/h] | 0.00 | 0.12 | 0.10 | 0.00 | 0.69 |
| Flexibility [kVAr/h] | 0.00 | 0.32 | 0.09 | 0.00 | 0.51 |
| ENS $E^{ENS}$ [kW/h] | 0.02 | 0.00 | 0.00 | 0.67 | 0.00 |
| ENS $Q^{ENS}$ [kVar/h] | 0.07 | 0.00 | 0.00 | 0.37 | 0.00 |
| Curtailment $E^{curt}$ [kW/h] | 0.10 | 0.00 | 0.01 | 0.03 | 0.00 |
| Curtailment $Q^{curt}$ [kVar/h] | 0.25 | 0.00 | 0.23 | 0.14 | 0.00 |
| DSO Cost [€/h] | 4.76 | 14.94 | 7.25 | 28.29 | 41.02 |
| DSO cost reduction [€/h] | - | -10.18 | -2.49 | - | -12.73 |
| Social Welfare [€/h] | -4.76 | 2.10 | 0.52 | -28.29 | 7.31 |
| Total surplus of participants | 0.00 | 2.10 | 1.09 | 0.00 | 7.31 |
| Cost of ENS | 0.66 | 0.00 | 0.164 | 27.27 | 0.00 |
| Cost of Curtailment | 4.10 | 0.00 | 0.41 | 1.03 | 0.00 |

## 3.5 Conclusions and lessons learned

After communicating FLEXGRID UCS 1.1, 1.2, and 1.3 scientific results to both academic and industrial communities, we have come up with a short list of lessons learned that could be further investigated in future R&D initiatives. Table 12 summarizes research and business-related insights for each one of the lessons learned.

**Table 12 Lessons learned from UCS 1.1, 1.2, and 1.3 with DLFM auction clearing**

| **Lesson learned** | **Research & Business insights** |
|---|---|
| The benefits of continuous vs. auction-based clearing are not generalizable. Advantages exist depending on the geographical context, surrounding market frameworks, regulation, market participants etc. | The only general conclusion is that continuous clearing is preferred on short-term markets, whereas auctions are preferred in long-term markets.<br>Real-time markets are likely to use continuous clearing. The longer the market lead time, the better the argument for an auction-based market. |
| Some countries (e.g., Germany) are headed down a policy path that involves heavy regulation and requirements from local flexibility assets. This may prevent the formation of local flexibility markets since flexibility is implicitly traded via regulatory frameworks rather than voluntary market transactions. | The business case depends on the specific geographical context and may vary with the regulation that is in place. |
| The social welfare is only maximized with the use of auction based OPF algorithms. | The strengths of continuous markets are found in increased liquidity and |

| | |
|---|---|
| Continuous markets are not guaranteed to achieve social welfare maximization and will, in most practical cases, not achieve the optimal social welfare. | stakeholder engagement, not necessarily in social welfare maximization. |

# 4 Creation of a FlexRequest

This chapter deals with the DSO's research problem of the creation of a FlexRequest. There is no specific UCS associated to this research problem. However, the creation of FlexRequests is a prerequisite for a functioning DLFM market, and therefore vital to include in this deliverable. FlexRequests are bids from the DSO which are required inputs for use case scenarios UCS 1.1, UCS 1.2, and UCS 1.3 of this deliverable, as well as for UCS 2.1, UCS 4.1, and UCS 4.2. FlexOffers, on the other hand, are created by ESP or FSPs and their modeling is detailed in use case scenarios UCS 2.1, UCS 2.3 and UCS 4.3.

## 4.1 How to determine the price of a FlexRequest: Techno-Economic Analysis – Network Upgrade vs. Flexibility Procurement

### 4.1.1 Introduction

The occurrence of congestion in the network threatens reliable supply for end-users and generates additional costs for distribution system operators.
In order to reveal such congestion problems and consequently decrease DSO costs, two approaches are considered:

- BAU approach – business as usual, and
- FLEXGRID approach – utilization of flexibility from the existing distribution network (a FlexSupplier solution).

The first approach is well-known as it has been used for decades. The distribution system operator deals traditionally with the mentioned problems by increasing the network capacity, i.e., installation of new MV overhead lines or underground cables, and potential upgrade of transformer substations. The second approach presents trading services from an FlexSupplier. The key strategy of this business model is to enable safe and reliable power system operation while performing balancing services and minimizing DSO costs. We refer to this as the FLEXGRID approach.

### 4.1.2 Methodology

#### *4.1.2.1 Nomenclature*

Sets

| | |
|---|---|
| $b \in B$ | Battery energy storage unit |
| $d \in D$ | Representative day |
| $e \in E$ | Electric vehicle unit |
| $i \in I$ | Photovoltaic unit |
| $s \in S$ | Bus |
| $t \in T$ | Time period |
| $l \in L^{new}, L^{ex}$ | Power line (set of existing and new lines) |

Variables

| | |
|---|---|
| $f_{d,t,l}$ | Power flow through line *l* in period *t* in representative day *d* |
| $p_{d,t,b}^{BES,ch}$ | Charging power of BES unit *b* in period *t* in representative day *d* |
| $p_{d,t,b}^{BES,dis}$ | Discharging power of BES unit *b* in period *t* in representative day *d* |

| | |
|---|---|
| $p_{d,t,e}^{EV,ch}$ | Charging power of EV unit *e* in period *t* in representative day *d* |
| $p_{d,t,e}^{EV,dis}$ | Discharging power of EV unit *e* in period *t* in representative day *d* |
| $p_{d,t,s}^{DSM\downarrow}$ | Power decreased in DSM service at bus *s* in period *t* in representative day *d* |
| $p_{d,t,s}^{DSM\uparrow}$ | Power increased in DSM service at bus *s* in period *t* in representative day *d* |
| $p_{d,t,i}^{PV}$ | Power production of PV unit *i* in period *t* in representative day *d* |
| $p_{d,t,i}^{VOLE}$ | Value of energy not-supplied for PV unit *i* in period *t* in representative day *d* |
| $p_{d,t,s}^{VOLL}$ | Power of loss of load at bus *s* in period *t* in representative day *d* |
| $soc_{d,t,b}^{BES}$ | State of charge of BES *b* in period *t* in representative day *d* |
| $soc_{d,t,e}^{EV}$ | State of charge of EV *e* in period *t* in representative day *d* |
| $\theta_{d,t,l}$ | Voltage angle differences between two connecting buses |
| $x_{d,t,s}^{FLEXGRID\downarrow}, x_{d,t,s}^{FLEXGRID\uparrow}$ | Binary variables for activation of DSM service in down/up direction |
| $x_l$ | Binary variable for investment decision of new line l |
| Parameters | |
| $B_l$ | Series susceptance of line *l* (S) |
| $C_l$ | Total capex and opex cost of new line *l* (€) |
| $C_s^{DSM}$ | Total capex and opex cost of DSM service for each end-user connected at bus |
| $C^{curt}$ | Cost of curtailment (energy not-supplied) (€) |
| $C^{VOLL}$ | Cost of loss of load (energy not served) (€) |
| $D_{d,t,s}$ | Power demand at bus *s* in period *t* day *d* (MW) |
| $F_l^{max}$ | Maximum power rating of line *l* (MW) |
| $M$ | Big enough constant value (-) |
| $P_e^{EV,max}$ | Maximum charging/discharging power of EV unit *e* (MW) |
| $P_b^{BES,max}$ | Maximum charging/discharging power of BES unit *b* (MW) |
| $P_{d,t,i}^{PV}$ | Power production of photovoltaic system *i* in period *t* day *d* |
| $P_s^{load,max}$ | Maximum connecting power at bus *s* (MW) |
| $P_s^{feeder,max}$ | Maximum installed power of line |
| $T_d$ | Weight of representative day *d* |
| $\sigma_{d,t,e}^{EV,ar}$ | Binary value for arriving hour of EV, 1 if EV arrives to connecting point, else 0 |
| $\omega^{FLEXGRID}$ | Percentage of installed DSM service |
| $\theta^{max}$ | Maximum allowed voltage angle |
| $\pi_{d,t}^{DA}$ | Day-ahead prices for each hour *t* in representative day *d* |

#### *4.1.2.2 Methodology description*

The objective function (4.1) minimizes the DSO investment and operation costs. The first item in the objective function presents the cost of line investment, shown by (4.2). The second item presents the whole costs introduced by demand-side management units (4.3). It consists of total CAPEX and OPEX costs for DSM units represented by $C_s^{DSM}$, while the second part presents their benefit performed by providing services at day-ahead prices $\pi_t^{DA}$. The third item of objective function is the cost of lost load (energy not served) presented by (4.4), and the fourth item is the cost of curtailment (energy not supplied) presented by (4.5). The energy-not supplied is energy that could not be delivered due to network restrictions.

*The objective function:*

$$\text{Minimize}\, COST = COST^{line} + COST^{DSM} + COST^{VOLL} + COST^{curt} \tag{4.1}$$

*subject to:*

$$COST^{line} = \sum_{l \in L^{new}} C_l \cdot x_l \tag{4.2}$$

$$COST^{DSM} = \sum_{s \in S} C_s^{DSM} - T_d \cdot \sum_{d \in D} \sum_{t \in T} \sum_{s \in S} \pi_t^{DA} \cdot \left(p_{d,t,s}^{DSM\downarrow} - p_{d,t,s}^{DSM\uparrow}\right) \tag{4.3}$$

$$COST^{VOLL} = T_d \cdot \sum_{d \in D} \sum_{t \in T} \sum_{s \in S} C^{VOLL} \cdot p_{d,t,s}^{VOLL} \tag{4.4}$$

$$COST^{curt} = T_d \cdot \sum_{d \in D} \sum_{t \in T} \sum_{i \in I} C^{curt} \cdot p_{d,t,i}^{curt} \tag{4.5}$$

*Energy balance equation:*

$$\begin{aligned} \sum_{s \epsilon S^{feeder}} p_{d,t,s}^{feeder} + \sum_{i \in M^{PV}} p_{d,t,i}^{PV} + \sum_{l \in M^{line}} f_{d,t,l}^{+} - \sum_{l \in M^{line}} f_{d,t,l}^{-} \\ + \sum_{b \in M^{BES}} p_{d,t,b}^{BES,dis} + \sum_{e \in M^{BES}} p_{d,t,e}^{EV,dis} + p_{d,t,s}^{DSM\downarrow} \\ = p_{d,t,s}^{load} + p_{d,t,s}^{DSM\uparrow} + \sum_{b \in M^{BES}} p_{d,t,b}^{BES,ch} + \sum_{e \in M^{BES}} p_{d,t,e}^{EV,ch} \\ + p_{d,t,s}^{losses} \qquad \forall s \in S, \forall t \in T, \forall d \in D \end{aligned} \tag{4.6}$$

*Flow constraints:*

$$f_{d,t,l} = B_l \cdot \sum_{\{s,m\} \in M^{line}} \left(\theta_{d,t,s} - \theta_{d,t,m}\right) \quad \forall l \in L^{ex}, \forall t \in T, \forall d \in D \tag{4.7}$$

$$-F_l^{max} \leq f_{d,t,l} \leq F_l^{max} \quad \forall l \in L^{ex}, \forall t \in T, \forall d \in D \tag{4.8}$$

$$-\theta^{max} \leq \theta_{d,t,s} \leq \theta^{max} \quad \forall s \in S, \forall t \in T, \forall d \in D \tag{4.9}$$

$$\begin{aligned} f_{d,t,l}^{new} - B_l \cdot \sum_{\{s,m\} \in M^{line}} \left(\theta_{d,t,s} - \theta_{d,t,m}\right) + M \cdot (1 - x_l) \geq 0 \\ \forall l \in L^{new}, \forall t \in T, \forall d \in D \end{aligned} \tag{4.10}$$

$$\begin{aligned} f_{d,t,l}^{new} - B_l \cdot \sum_{\{s,m\} \in M^{line}} \left(\theta_{d,t,s} - \theta_{d,t,m}\right) - M \cdot (1 - x_l) \leq 0 \\ \forall l \in L^{new}, \forall t \in T, \forall d \in D \end{aligned} \tag{4.11}$$

$$-F_l^{max} \cdot x_l \leq f_{d,t,l}^{new} \leq F_l^{max} \cdot x_l, \qquad \forall l \in L^{new}, t \in T, d \in D \tag{4.12}$$

$$-P_s^{feeder,max} \leq p_{d,t,s}^{feeder} \leq P_s^{feeder,max} \quad s \in \{s1\}, t \in T, d \in D \tag{4.13}$$

*Photovoltaic constraints:*

$$p_{d,t,i}^{PV} + p_{d,t,i}^{curt} \leq P_{d,t,i}^{PV} \quad \forall i \in I, \forall t \in T, \forall d \in D \tag{4.14}$$

*Battery energy storage constraints:*

$$p_{d,t,b}^{BES,dis} \leq P_b^{BES,max} \quad \forall b \in B, \forall t \in T, \forall d \in D \tag{4.15}$$

$$p_{d,t,b}^{BES,ch} \leq P_b^{BES,max} \quad \forall b \in B, \forall t \in T, \forall d \in D \tag{4.16}$$

$$soc_{d,t,b}^{BES} = soc_{d,t-1,b}^{BES} + p_{d,t,b}^{BES,ch} \cdot \mu^{ch} - \frac{p_{d,t,b}^{BES,dis}}{\mu^{dis}} \quad \forall b \in B, \forall t \in T, \forall d \in D \tag{4.17}$$

$$soc_{d,t,b}^{BES} \leq SOC_b^{BES,max} \tag{4.18}$$

*Demand side response constraints:*

$$p_{d,t,s}^{DSM\downarrow} \leq \omega^{FLEXGRID} \cdot D_s \cdot x_{d,t,s}^{FLEXGRID\downarrow} \quad \forall s \in S, \forall t \in T, \forall d \in D \tag{4.19}$$

$$p_{d,t,s}^{DSM\uparrow} \leq \omega^{FLEXGRID} \cdot D_s \cdot x_{d,t,s}^{FLEXGRID\uparrow} \quad \forall s \in S, \forall t \in T, \forall d \in D \tag{4.20}$$

$$x_{d,t,s}^{FLEXGRID\downarrow} + x_{d,t,s}^{FLEXGRID\uparrow} \leq 1 \quad \forall s \in S, \forall t \in T, \forall d \in D \tag{4.21}$$

$$p_{d,t,s}^{load} + p_{d,t,s}^{VOLL} + p_{d,t,s}^{DSM\downarrow} = D_{d,t,s} \quad \forall s \in S, \forall t \in T, \forall d \in D \tag{4.22}$$

$$D_{d,t,s} + p_{d,t,s}^{DSM\uparrow} \leq P_s^{load,max} \quad \forall s \in S, \forall t \in T, \forall d \in D \tag{4.23}$$

*Electric vehicles constraints:*

$$p_{d,t,e}^{EV,dis} \leq P_e^{EV,max} \quad \forall e \in E, \forall t \in T, \forall d \in D \tag{4.24}$$

$$p_{d,t,e}^{EV,ch} \leq P_e^{EV,max} \quad \forall e \in E, \forall t \in T, \forall d \in D \tag{4.25}$$

$$soc_{d,t,e}^{EV} = soc_{d,t-1,e}^{EV} + p_{d,t,e}^{EV,ch} \cdot \mu^{ch} - \frac{p_{d,t,e}^{EV,dis}}{\mu^{dis}} + SOC_e^{EV,ar} \cdot \sigma_{d,t,e}^{EV,ar} \quad \forall e \in E, \forall t \in T, \forall d \in D \tag{4.26}$$

$$soc_{d,t,e}^{EV} \leq SOC_e^{EV,max} \quad \forall e \in E, \forall t \in T, \forall d \in D \tag{4.27}$$

$$p_{d,t,i}^{PV}, p_{d,t,i}^{VOLE}, p_{d,t,s}^{load}, p_{d,t,b}^{BES,dis}, p_{d,t,b}^{BES,ch}, p_{d,t,e}^{EV,dis}, p_{d,t,e}^{EV,ch}, p_{d,t,s}^{DSM\downarrow}, p_{d,t,s}^{DSM\uparrow}, soc_{d,t,b}^{BES}, soc_{d,t,e}^{EV} \geq 0 \tag{4.28}$$

The energy balance equation (4.6) presents the sum of all power imported in the bus that is equal to all power exported from the bus. The flow through lines is calculated by (4.7) and constrained by (4.8). The voltage angle is constrained by (4.9). For calculation of flow through new lines, a big M method is used in (4.10) and (4.11), which ensures the linearity of the constraints. The flow at new lines is constrained by (4.12) and the maximum possible power flow at the feeder is constrained by (4.13).

The power production of photovoltaic capacity is presented by (4.14) where the energy not supplied (ENS) is defined. Maximum discharging power of the battery storage is constrained by (4.15) and charging power by (4.16). The state of charge (SOC) of battery in period $t$ is measured by (4.17) and constrained by maximum value in (18). The set of constraints for DSM is presented by (4.19) - (4.23). The power that is decreased by end-users is constrained in (4.19) by maximum percentage allowed, as well as the power that is increased in (4.20). The service performed by the end-user can be arranged only once per period $t$, either for down or up direction. This rule is set by (4.21). If the load is not satisfied, then the value of $p_{d,t,s}^{VOLL}$ is assigned as in (4.22). The constraint for the providing service for up direction is set by (4.23). The last set of constraints are for electric vehicles (4.24) - (4.27). The constraints for maximum discharging/charging power by EV are presented by (4.24) - (4.25). The level of battery charge is determined by (4.26) and it depends on the SOC at arrival. SOC is constrained by their maximum values in (4.27). All non-negative variables are gathered in (4.28).

### 4.1.3 Case study

The case study network is illustrated in Figure 14 and consists of a feeder connected to ten highly loaded end-users. End-users could be both smart buildings and hotels. Each connection point has a smart meter. The photovoltaic systems connected to the feeder have their own battery energy storage systems incorporated. The network has two EV charging points. It is assumed that the number of end-users that own electrical vehicles is going to increase in the future.

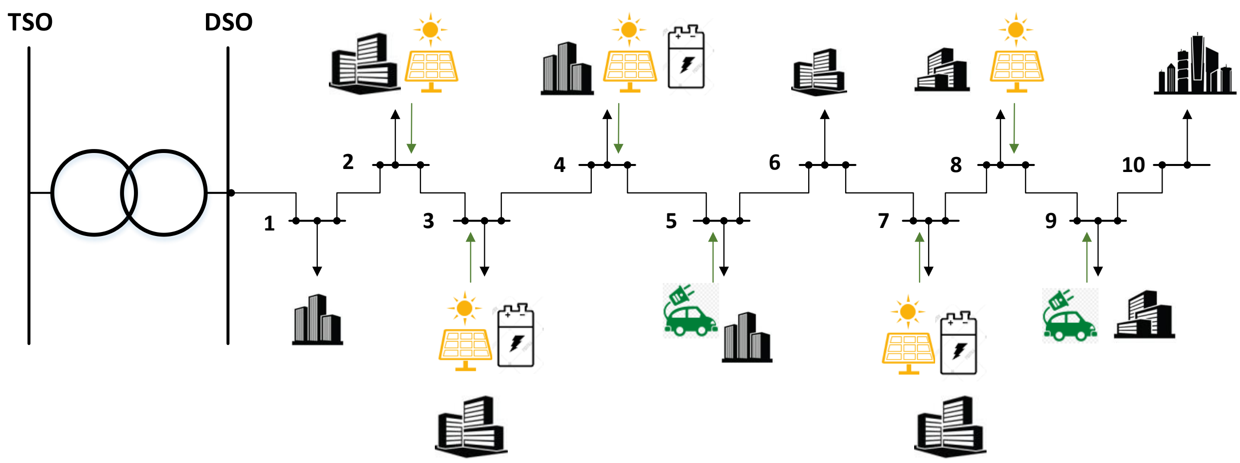

**Figure 14 Network test case**

The network represents power station 110/20 kV to which one feeder is connected. The length of feeder is seven kilometers and consists of 10 line segments. The maximum power of feeder is 11.518 MW, maximum current is 350 A, and nominal voltage is 20 kV. The network assets connected to the feeder are: five PV systems, three battery energy storage systems, and two charging points for electric vehicles. Their characteristics are described in Table 13. Installed power of PV systems is 2 MW connected to the buses 2, 3, 4, 7 and 8. Maximum power of BES converter is 1 MW, while the maximum BES capacity is 2 MWh. This implies means that the period of BES full discharge is two hours. BES units are connected to buses 3, 4 and 7, and operates optimally with PV units. Each EV battery has a maximum power of 0.004 MW, and maximum capacity 0.015 MWh.

**Table 13 Detailed asset data**

| Type | Installed power | Buses |
|---|---|---|
| PV system | 2 MW | 2, 3, 4, 7, 8 |
| BES | 1MW/2MWh | 3, 4, 7 |
| EV | 0.004MW/0.015MWh | 5,9 |

The total demand of all end-users at the feeder is illustrated in Figure 15 . It represents 5 characteristic days in one year: working days - summer, spring, autumn, winter, and the last one presents weekends. Each day has its own weight: winter (65 days), spring (66 days), summer (66 days), autumn (65 days), weekends (104 days). Not only the demand has specific curves, but seasons also have impact on production of solar power plants due to different solar position and imapct on their time of production, as can be seen in Figure 15.

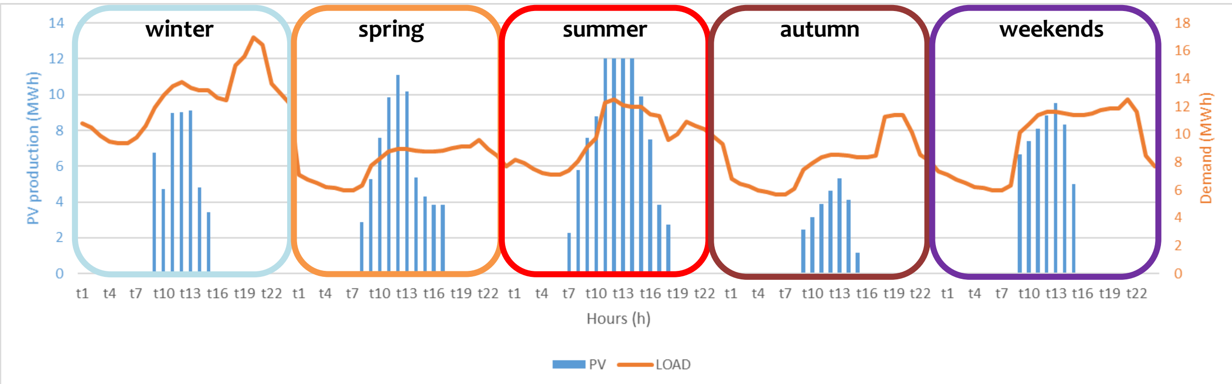


**Figure 15 Total demand of all end-users at feeder and total PV production in the target year**

The length of investment horizon is set to 15 years. TSO/DSO costs are: i) loss of load cost, ii) cost of energy not-served, iii) demand side management installation and service costs, iv) cost of new lines – CAPEX and OPEX, respectively. The input data are presented in Table 14. The VOLL presents total value of lost load in one year for which end-users contributed to security of supply. It means that the DSO needs to cover the cost which was incurred during the period of when end user needs were not satisfied. The value of curtailed energy values the energy that could not be exported to the network due to faults or congestion. DSM installation and service costs are costs of communication connection of DSO and end-users which also incorporates the maintenance during the determined horizon (15 years). Each end-user has its own local energy management system (EMS). Gird reinforcement costs consist of building of new MV bay and building of new line segments. All costs are levelized to the one target year. The DSO losses are measured as 3.3% of total load in the system and are considered as additional consumption in the network.

**Table 14 Input planning parameters [[1]]**

| Type of cost | |
|---|---|
| Value of lost load ($C^{VOLL}$) | 1,500 €/MWh |

[1] VIMSEN Project FP7 ICT-619547, Final proposed VIMSEN business models and pricing policies, 2016

| | |
|---|---|
| | 3,000 €/MWh |
| Value of curtailed energy($C^{curt}$) | 1,000 €/MWh |
| DSM installation and service costs ($C_s^{DSM}$) | 16,700 €/EMS (capex)<br>14,293 €/EMS (opex)<br>30,993.00 €/EMS (total) |
| Grid reinforcement costs ($C_l$) | 204,000 €/unit (MV bay)<br>50,700 €/km/line segment (capex)<br>34,050 €/km/line segment (opex) |
| Discount rate ($r$) | 8 % |
| Investment horizon | 15 years |

Due to a lot of unpredictable future realizations described in the previous chapters of this study, this analysis considers three scenarios: i) *SLOW*, ii) *MEDIUM*, iii) *FAST* energy transitions, as shown in Table 15. Each scenario considers changes in load, EVs penetration, PV capacity, level of DSM flexibility. The level of DSM flexibility is measured as a percentage of variable demand of each end-user, and in BASIC scenario it is presented with possibility of 10 % of flexible demand. This variable demand is called up-DSM service, when the end-user consumes more energy than it was scheduled and down-DSM service, when the end-user decreases its consumption. The percentage increase of the *SLOW*, *MEDIUM, and FAST* scenarios with respect to today's reference (*BASIC* scenario) is summarized in Table 15.

**Table 15 Energy transition scenarios**

| | Load | EV | PV | DSM flexibility level |
|---|---|---|---|---|
| ***SLOW*** | 7.5% | 45% | 60% | 7.5% |
| ***MEDIUM*** | 12% | 57% | 91.5% | 15% |
| ***FAST*** | 22.5% | 75% | 120% | 30% |

### 4.1.4 Results

The BASIC scenario shows results according to the input data presented in Figure 15. Results are for two assumptions: i) VOLL 1500 €/MWh, ii) VOLL 3000€/MWh. The investment results are shown in Table 16 and Table 20. They show investment into new line segments in the BAU approach and procured amount of flexible energy in the FLEXGRID approach with comparison to non-investment case (no investment in new lines and DSM service). The main difference between these two approaches is that BAU approach only considers investment into new line segments and has non-flexible demand, while FLEXGRID approach only considers flexible demand as DSM service – demand side response to deal with the congestion in the feeder. BES, PV, and EV are operated in both approaches.

#### *4.1.4.1 Results – VOLL 1500 €/MWh*

The results show that in the *SLOW* scenario, due to occurrence only few periods of loss of load, which in total amounts 373.87 MWh, the investments result only in adding two new line segments. While in FLEXGRID approach and by an increase of 7.5% of flexible demand of each end-user, the value of loss of load is decreased to 184.52 MWh (-58.99%). Total procured flexible energy in this case is 15,263 MWh. All demand is satisfied in MEDIUM scenario, which sets value of loss of load to zero. In this scenario, even 4 line segments are invested in BAU approach, while FLEXGRID approach uses 15,263 MWh of flexible energy. As the percentage of flexible demand increases (+15% in comparison to BASIC scenario), the procured flexible energy increases. The highest procured flexible energy is obtained in FAST scenario resulting with total amount of 38,095 MWh.

**Table 16 Investment results assuming VOLL 1500 €/MWh**

| | Loss of load (MWh) | | Investments (# line segments) | Flexible energy ($p^{FLEXGRID}$) (MWh) |
|---|---|---|---|---|
| | **BAU** | **FLEXGRID** | **BAU** | **FLEXGRID** |
| *BASIC* | 514.61 | 449.96 | 1 | 8,149 |
| ***SLOW*** | 373.87 | 184.52 | 2 | 15,263 |
| ***MEDIUM*** | 0 | 0 | 4 | 22,452 |
| ***FAST*** | 213.29 | 0 | 3 | 38,098 |

**Table 17 Operation results assuming VOLL 1500 €/MWh**

| | BAU benefit ($TB^{BAU}$) (€) | FLEXGRID benefit ($TB^{FLEXGRID}$) (€) | Δ benefit (€) | Aggregators' additional price ($\boldsymbol{AP^{FLEXGRID}}$) (€/MWh) |
|---|---|---|---|---|
| ***BASIC*** | 2,151,092 | 2,243,424 | + 92,332 | 11.33 |
| ***SLOW*** | 4,380,603 | 4,921,551 | + 540,948 | 35.44 |
| ***MEDIUM*** | 6,205,442 | 6,215,190 | + 9,748 | 0.43 |
| ***FAST*** | 10,027,800 | 10,351,310 | + 323,510 | 8.49 |

The aggregators' markup price $MP^{FLEXGRID}$ is calculated as in equation (4.29) by using the obtained operational benefits from Table 17.

$$MP^{FLEXGRID} = \frac{TB^{FLEXGRID} - TB^{BAU}}{p^{FLEXGRID}} \qquad (4.29)$$

The benefits are calculated with respect to the BAU case for each scenario, respectively. The aggregators' markup price is defined as the maximum price that the DSO would be willing to pay on top of the day-ahead price in order to ensure feasible operation and avoid network investment. The highest markup price is obtained in the *SLOW* scenario, 35.44 €/MWh. The reason is that flexibility providers are enabled to cover these relatively low periods of unsatisfied demand (189.35 MWh more than BAU approach) and increase their profit by providing the DSM service. However, with investment into more lines, the DSM service is less attractive. This statement is confirmed with results obtained in the *MEDIUM* scenario, with a markup price of 0.43 €/MWh for DSM service, where 4 line segments are installed).

The time series results of the *SLOW* scenario are presented for the BAU approach in Figure 16, and for the FLEXGRID approach in Figure 17. The DA-market price is shown by the yellow dotted line.

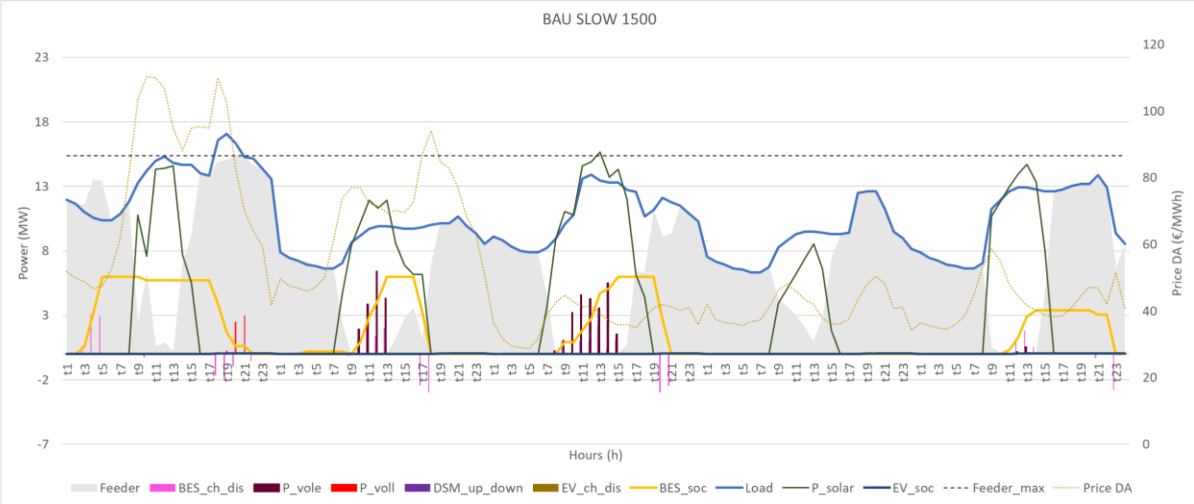


**Figure 16 Time series in BAU SLOW approach**

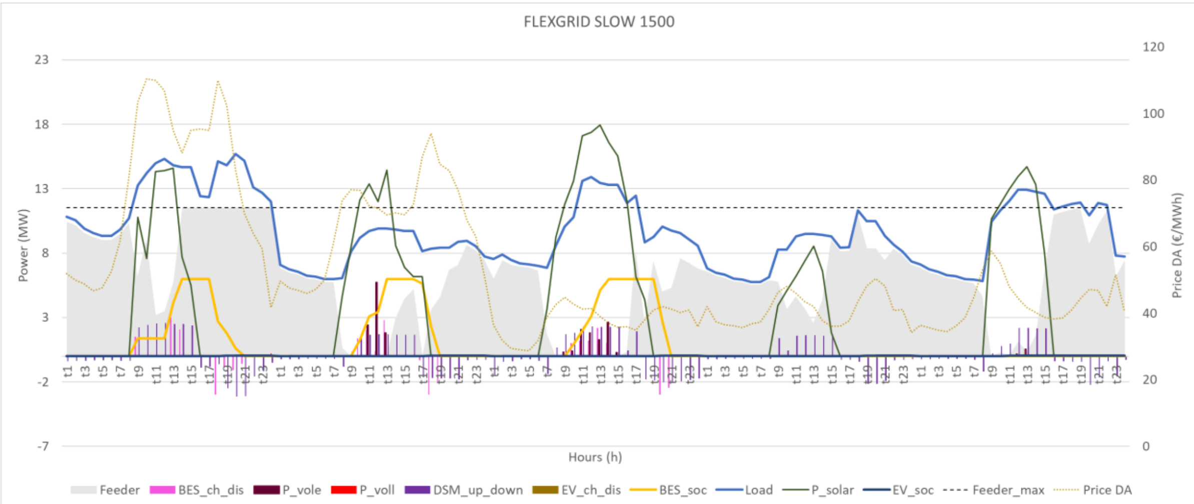


**Figure 17 Time series in FLEXGRID SLOW approach**

The amount of loss of load for one winter day are presented in Table 18. The gray area shows the total feeder power flow. The maximum feeder power in the BAU approach is 15.39 MW because of a network upgrade with 2 line segments. Due to high solar production in the middle of day, there are periods of self-supplying. Furthermore, the BES is charged in these periods, and actively helps remove congestion in evening hours, especially in winter, spring, and summer days respectively.

**Table 18 ENS in Day 1 (winter period) assuming VOLL 1500 €/MWh - in FLEXGRID SLOW scenario**

| ENS ($p_{d,t,s}^{VOLL}$) | t16 | t17 | t19 | t20 | t21 | t22 | t23 | t24 |
|---|---|---|---|---|---|---|---|---|
| **BAU** | - | - | 0.261 | 2.482 | 3.009 | - | - | - |
| **FLEXGRID** | 0.004 | 0.088 | - | - | 1.103 | 0.268 | 0.941 | 0.435 |

The operation asset results of *MEDIUM* scenario are presented for BAU approach in Figure 18, and for FLEXGRID approach in Figure 19. The maximum feeder power in BAU approach is 19.63 MW because of update of the network with 4 line segments. BES operation is now also more represented in Day 5 (weekend) with charging during the day and discharging in periods of higher loads in hours 19 and 23. The state of charge of the battery is presented with yellow line. However, BES activity is lower in the FLEXGRID approach than in the BAU approach, since DSM provides a higher share of the flexibility in the FLEXGRID approach.

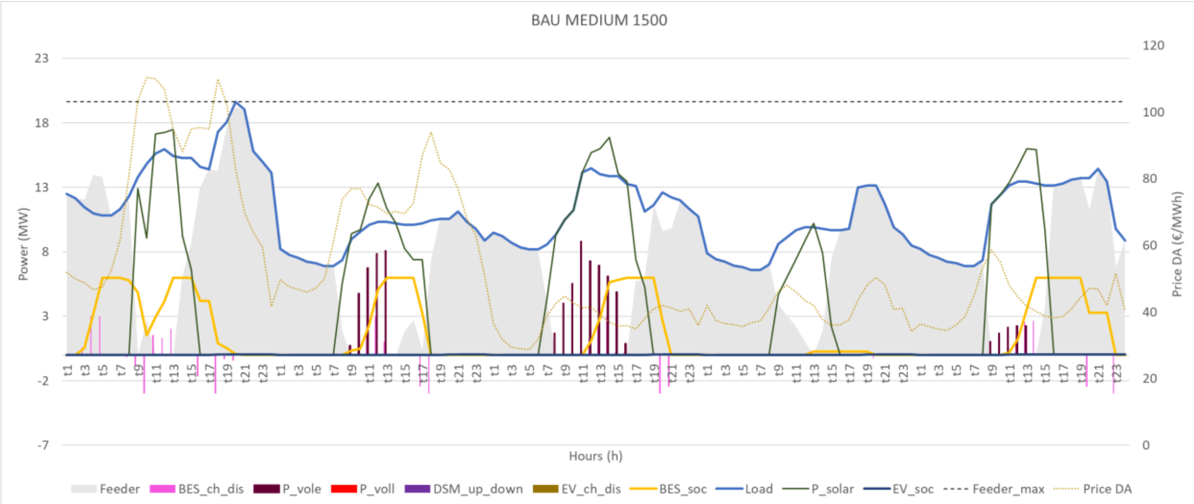


**Figure 18 Time series in BAU MEDIUM approach**

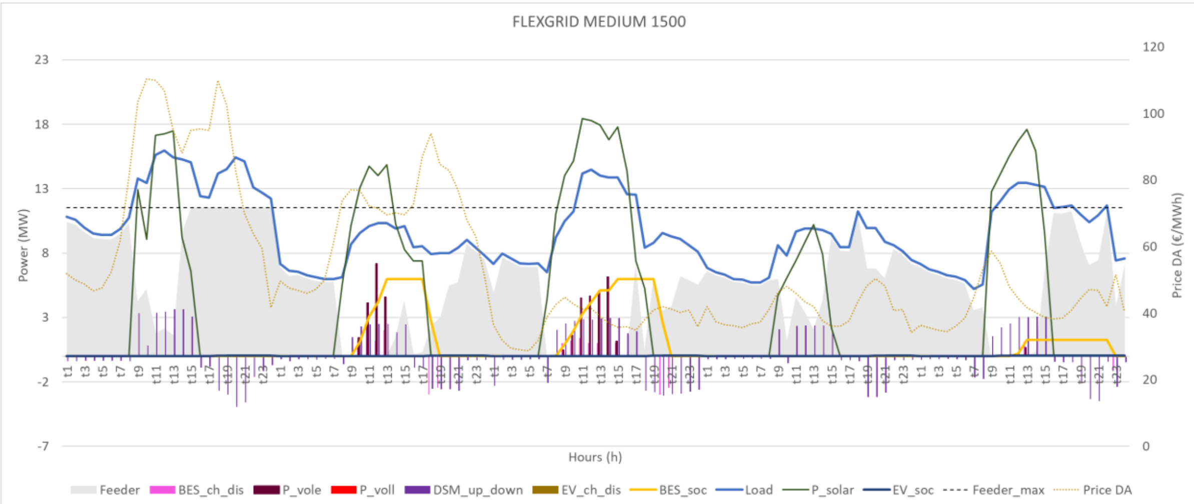


**Figure 19 Time series in FLEXGRID MEDIUM approach**

The time series results of the *FAST* scenario are presented for BAU approach in Figure 20, and for FLEXGRID approach in Figure 21. The maximum feeder power in BAU approach is 18.96 MW because of update of the network with 3 line segments. The BES is now also active in Day 4 (autumn) in BAU approach due to growing production of PV system.

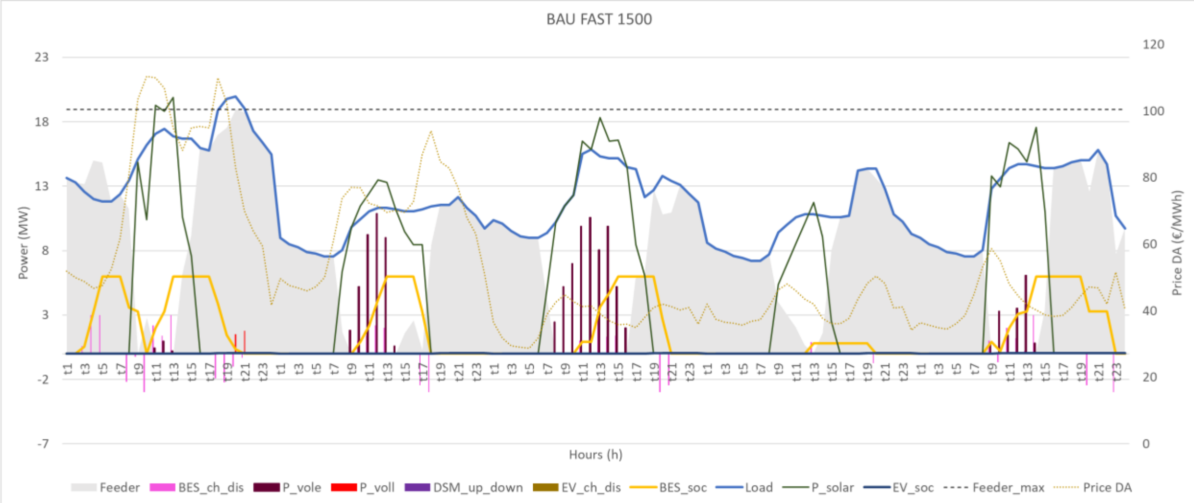


**Figure 20 Time series in BAU FAST approach**

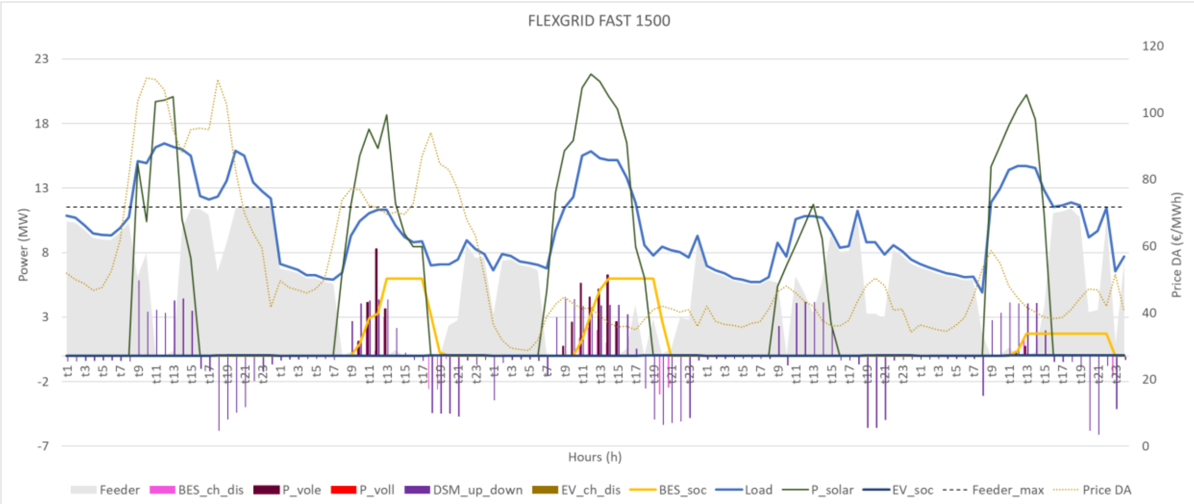


**Figure 21 Time series in FLEXGRID FAST approach**

#### *4.1.4.2 Sensitivity analysis of level of DSM flexibility*

Sensitivity analyses are performed in the *SLOW* and *FAST* scenarios in order to investigate for which percentage of flexible demand the DSO is willing to give an incentive (markup price) to providers. In the BAU approach *SLOW* scenario in Figure 22, the DSM service starts to be paid the markup price at 15% of flexible demand, and the highest additional price is achieved with 17.5% of flexible demand. On the other side, in the *FAST* scenario in Figure 23, DSM service start to be attractive at 25% of flexible demand which is at the same time the highest additional price obtained for this scenario.

**Table 19 Sensitivity analysis to percentage of flexibility in power system provided by flexible demand**

| DSM flexibility level (%) | Markup price (€/MWh) | |
|---|---|---|
| | *SLOW* | *FAST* |
| 5 | -458.46 | -1285.06 |
| 10 | -112.12 | -334.04 |
| 13 | -30.91 | -182.19 |
| 15 | 6.41 | -127.56 |

| | | |
|---|---|---|
| 16 | 20.25 | -105.54 |
| 17.5 | 35.44 | -75.71 |
| 20 | 32.06 | -38.49 |
| 25 | 25.89 | 12.74 |
| 30 | 21.64 | 11.22 |
| 35 | 18.63 | 9.64 |
| 40 | 16.25 | 8.49 |

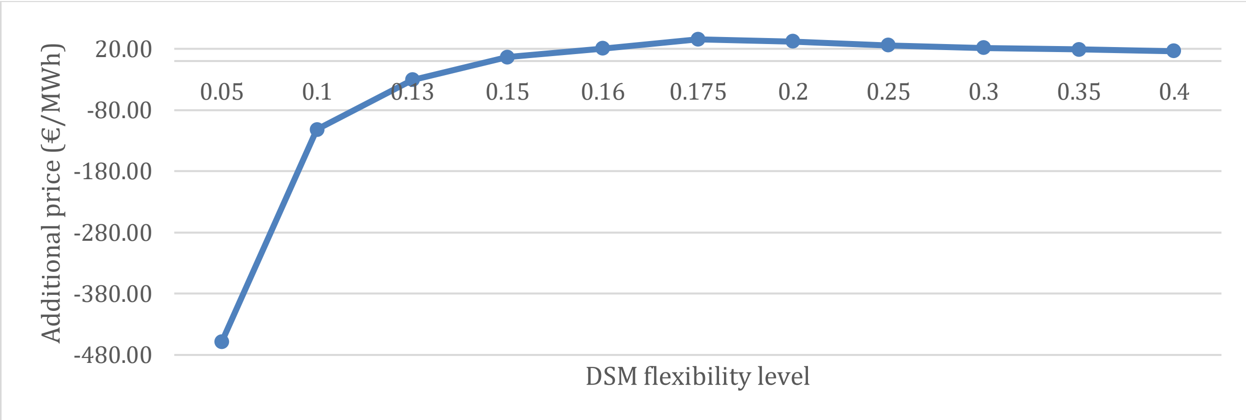


**Figure 22 Sensitivity of markup price (€/MWh) to DSM flexibility level in FLEXGRID SLOW approach**

By increasing the percentage of flexible demand after the peak price is obtained, the additional prices are decreased. The reason for this is that, after all DSO costs associated to VOLL are recovered (in case of peak markup price), there are no additional "revenues" (from DSO point of view) that would drive markup price.

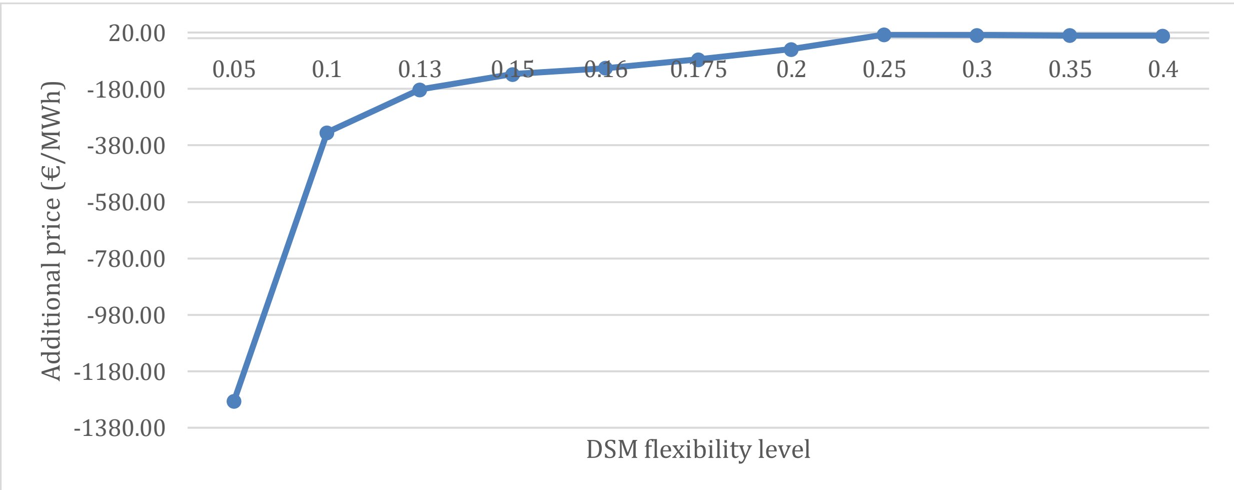


**Figure 23 Sensitivity of markup price (€/MWh) to DSM flexibility level in FLEXGRID FAST approach**

#### *4.1.4.3 Results – VOLL 3000 €/MWh*

This section provides results considering VOLL 3000 €/MWh. The results in Table 20 show that in the *BASIC* scenario, due to occurrence only few periods of loss of load, which in total amounts 68.99 MWh for BAU approach, the investments are resulted in adding two new line segments. While in FLEXGRID approach and by using 10% of flexible demand of each end-user, the value of loss of load is 454.56 MWh. Total procured flexible energy in this case is 8,128 MWh. All demand is satisfied in *SLOW* and *MEDIUM* scenarios for BAU approach, which sets value of loss of load to zero. In these scenarios, even 3 line segments are invested in *SLOW* scenario and 4 line segments in *MEDIUM* scenario. On the other side, in FLEXGRID approach loss of load amounts in 185.69 MWh in *SLOW* scenario, while uses 14,000 MWh of flexible energy. Moreover, *MEDIUM* scenario does not have any loss of load, while using 22,452 MWh of flexible energy (+60.37% in comparison to *SLOW* scenario). Generally, as the percentage of flexible demand increases in comparison to BASIC scenario, the procured flexible energy increases on all scenarios. The highest procured flexible energy is obtained in *FAST* scenario resulting with total amount of 39,003 MWh.

**Table 20 Investment results assuming VOLL 3000 €/MWh**

| | Loss of load (MWh) | | Investments (# line segments) | Flexible energy ($p^{FLEXGRID}$) (MWh) |
|---|---|---|---|---|
| | **BAU** | **FLEXGRID** | **BAU** | **FLEXGRID** |
| *BASIC* | 68.99 | 454.56 | 2 | 8,128 |
| ***SLOW*** | 0 | 185.69 | 3 | 14,000 |
| ***MEDIUM*** | 0 | 0 | 4 | 22,452 |
| ***FAST*** | 0 | 0 | 5 | 39,003 |

Aggregators' additional price presents the price that could be added to the day-ahead price with which the DSM provider was performed the service during the daily operation. The highest addition to day-ahead prices is obtained in *MEDIUM* scenario, only 0.43 €/MWh, presented in Table 21. The reason behind is that for higher VOLL (3000 €/MWh), DSM services are less significant in comparison to BAU approach. System operator intents to increase network capacity more than higher incentivize DSM providers, besides DSM services also covers all load in the system. Moreover, in scenarios when BAU approach covers more loss of load, DSM service are not additionally supported. This is case for *BASIC* and *SLOW* scenarios. Also, with investment into more lines, the DSM service is less attractive. This statement is confirmed with results obtained in *MEDIUM* and *FAST* scenario, only additional 0.43 €/MWh and 0.41 €/MWh for DSM service, where 4 and 5 line segments are installed.

**Table 21 Operation results assuming VOLL 3000 €/MWh**

| | BAU benefit ($TB^{BAU}$) (€) | FLEXGRID benefit ($TB^{FLEXGRID}$) (€) | Δ benefit (€) | Markup price ($\boldsymbol{MP^{FLEXGRID}}$) (€/MWh) |
|---|---|---|---|---|
| ***BASIC*** | 4,247,327.72 | 3,090,099.44 | -1,157,228.28 | -142.38 |
| ***SLOW*** | 8,207,118.39 | 7,653,612.55 | -553,505.84 | -39.54 |
| ***MEDIUM*** | 12,453,199.39 | 12,462,947.39 | +9,748.00 | 0.43 |
| ***FAST*** | 19,015,577.68 | 19,031,511.68 | 15,934.00 | 0.41 |

The operation asset results of *SLOW* scenario are presented for BAU approach in Figure 24, and for FLEXGRID approach in Figure 25. The DA-market price is shown by yellow dotted line, and their values are represented at the right axes of all Figures 18-21. The amount of loss of load for one winter day are presented in Table 22, where the loss of load is only present in FLEXGRID scenario in hours 16-17, and hours 21-24. The gray area shows the feeder power. The maximum feeder power in BAU approach is 18,96 MW because of a network upgrade with 3 line segments. Due to high solar production in the middle of the day, there are periods of self-supplying. Furthermore, the BES is charged in these periods, and actively helps remove congestion in morning and evening hours, especially in winter, spring, and summer days respectively. It is shown by pink bars that present discharging in hours: 10, 18, 20-21 for winter day; 9, 17-18 for spring day; 20-21 for summer day, and 20, 23 for weekend day.

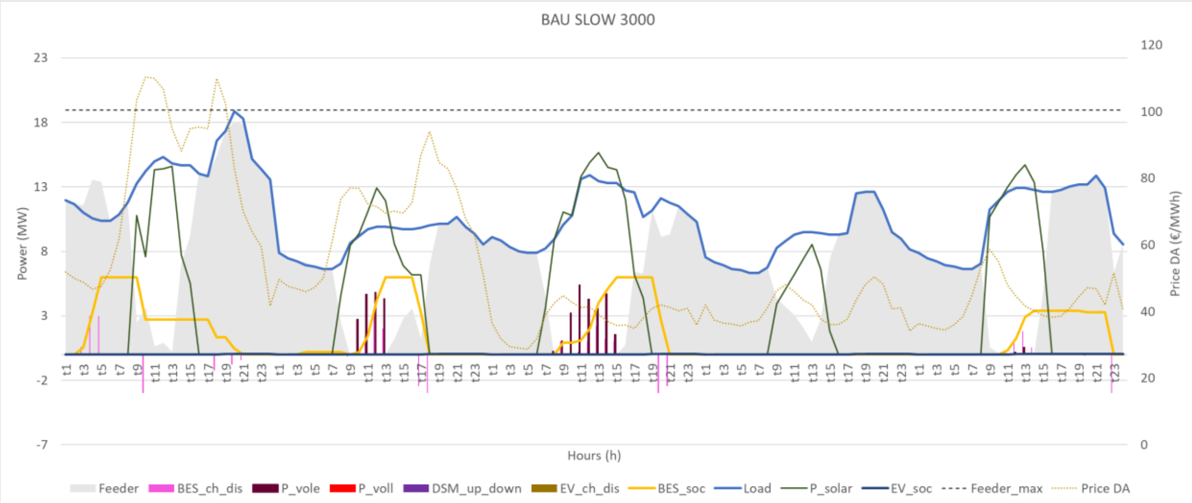


**Figure 24 Time series in BAU SLOW approach**

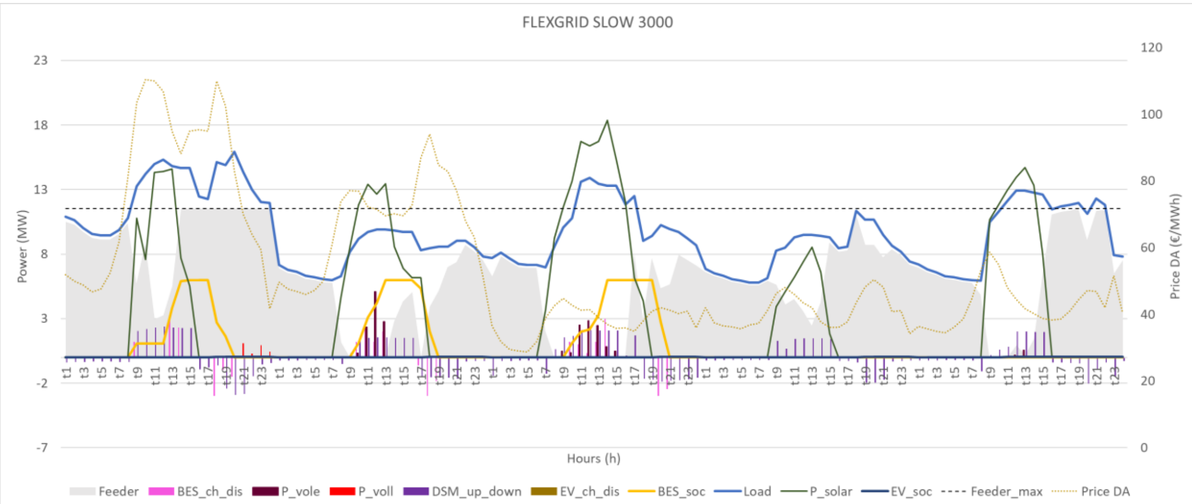


**Figure 25 Time series in FLEXGRID SLOW approach**

**Table 22 ENS on Day 1 (winter period) assuming VOLL 3000 €/MWh - in SLOW scenario**

| ENS ($p_{d,t,s}^{VOLL}$) | t16 | t17 | t19 | t20 | t21 | t22 | t23 | t24 |
|---|---|---|---|---|---|---|---|---|
| BAU | - | - | - | - | - | - | - | - |
| FLEXGRID | 0.004 | 0.095 | - | - | 1.099 | 0.271 | 0.952 | 0.435 |

The time series results of the *FAST* scenario are presented for the BAU approach in Figure 26Figure 20, and for FLEXGRID approach in Figure 27. The maximum feeder power in BAU approach is 21.48 MW because of a network upgrade with 5 line segments. The BES is now also active in Day 4 (autumn) in BAU approach due to growing production of PV system.

FLEXGRID approach activates a lot of DSM service due to even 40% of flexible demand of each end-user. It is interesting that in this all demand is covered due to using a lot of flexibility services from DSM providers (especially during the winter/spring/summer days).

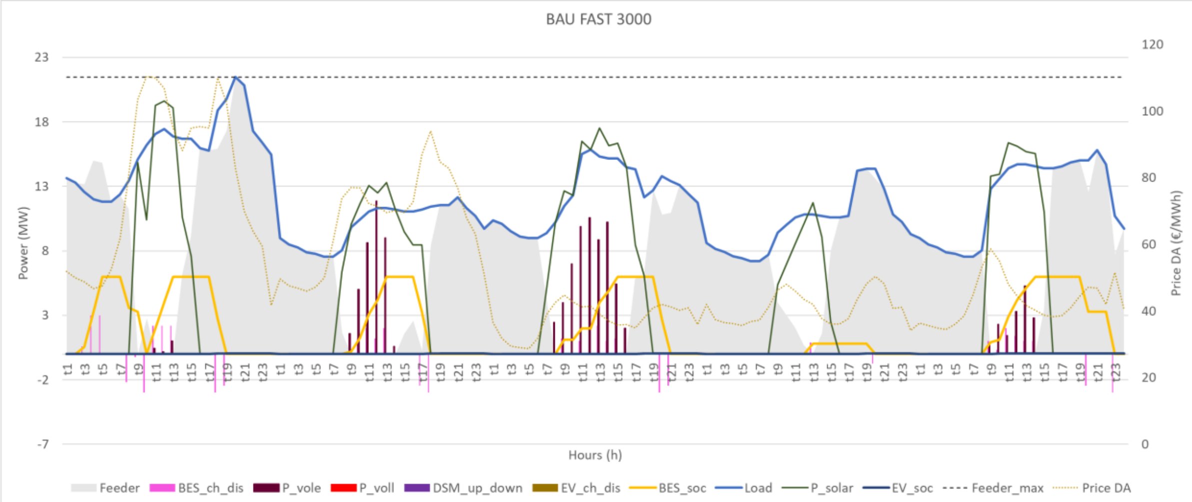


**Figure 26 Time series in BAU FAST approach**

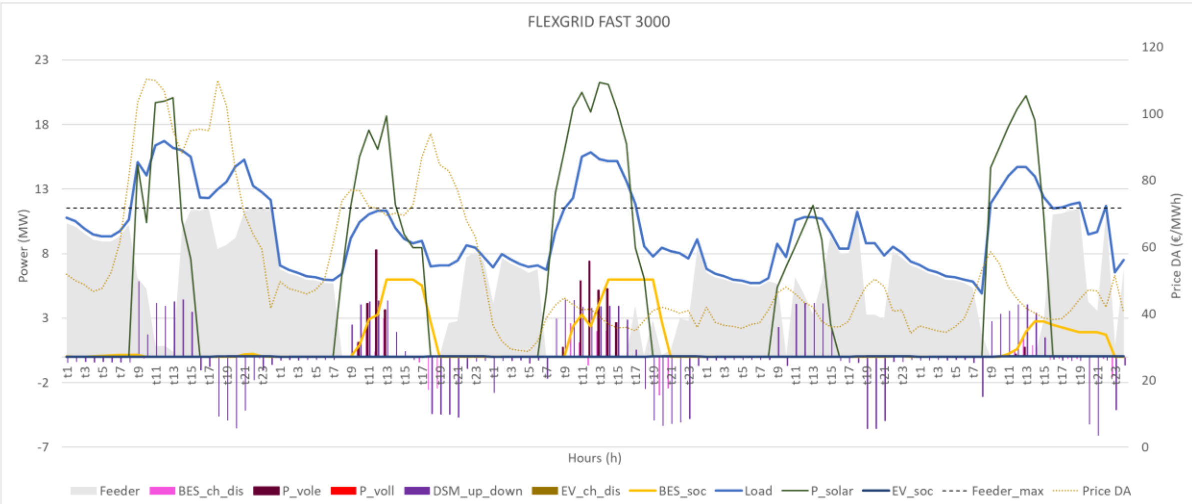


**Figure 27 Time series in FLEXGRID FAST approach**

### 4.1.5 Conclusion

This study provides a techno-economic analysis which develops a model that gives the optimal markup price for flexibility services in modern distribution system network considering electric vehicles, photovoltaic systems, battery energy storage systems, and demand side response providers. The sensitivity analyses show for which cases the flexibility providers are encouraged to provide their services, and in which cases the DSO should rather proceed with the BAU approach. Two different assumptions on the VOLL are used: i) VOLL 1500 €/MWh, and ii) VOLL 3000 €/MWh, and three different expansion scenarios.

In the *SLOW 1500* scenario, the DSM markup price rises up to 35.44 €/MWh, and in the *MEDIUM 1500* scenario to 0.44 €/MWh. In *BASIC 3000* and *SLOW 3000* scenarios DSM services are not attractive at all, while for MEDIUM 3000 and FAST 3000, the DSO is willing to give a low markup price. The BAU approach has higher benefits when the congestion is obvious to occur frequently during the year. Otherwise, the FLEXGRID approach provides higher revenues in the earlier stage of demand growth (*BASIC/SLOW* scenarios for lower VOLL price). The markup price for flexibility provides an incentive to DSM. However, if a higher VOLL is assumed, the results show that the DSO would rather invest in grid upgrades than pay a higher markup price to for DSM service providers.

FLEXGRID ATP uses this result as a first step to obtain the FlexRequest. In the second step, the volume (quantity) of FlexRequests needs to be determined as described in the rest of this chapter.

## 4.2 How to determine the volume (quantity) of a FlexRequest

### 4.2.1 Introduction

While the previous section showed how to determine the price of FlexRequests, we focus here on the quantity that the DSO should ask for in reserve flexibility markets. The question is how to determine such a FlexRequest, which shall consider the network limits and uncertainty?

For network-aware local flexibility markets, the DSO has two options. The transparent option is to share all network data with the flexibility market operator (FMO) which then runs a stochastic market clearing. *This solution has received criticism for* (i) the intractable and *impractical size of the problem* for real life operation and (ii) the *existing legal framework* on data exchange between DSO and FMO. The privacy-preserving option entails the creation of a network-aware FlexRequest by the DSO, which is then used in a deterministic market clearing by the FMO, similar to the transmission-level ancillary services markets currently operating in Europe. This second option is compatible with real world operations, and ensures high transparency for electricity traders, as it does not involve a stochastic market clearing or network constraints. Here, we will thus detail this second option, in which FlexRequests will be created with a stochastic model, and later cleared in a deterministic market.

### 4.2.2 Nomenclature

Sets

| | |
|---|---|
| $n \in \mathcal{N}$ | Bus $n$ |
| $ij \in \mathcal{L}$ | Line connecting origin bus $i$ and destination bus $j$ |
| $t \in \mathcal{T}$ | Time period $t$ |
| $z \in \mathcal{Z}$ | Zone $z$ |
| $o \in \mathcal{O}, r \in \mathcal{R}$ | Offers ($o$) / request ($r$) submitted |
| $o \in \mathcal{O}_t, r \in \mathcal{R}_t$ | Offers ($o$) / request ($r$) submitted for time period $t$ |
| $o \in \mathcal{O}^+_{z,t}, r \in \mathcal{R}^+_{z,t}$ | Upward offers ($o$) / request ($r$) submitted for time period $t$ and zone $z$ |
| $o \in \mathcal{O}^-_{z,t}, r \in \mathcal{R}^-_{z,t}$ | Downward offers ($o$) / request ($r$) submitted for time period $t$ and zone $z$ |

Variables

| | |
|---|---|
| $P_{ij,t}$ | Active power flow in the line between bus $i$ and $j$ at time $t$ |

| | |
|---|---|
| $Q_{ij,t}$ | Reactive power flow in the line between bus $i$ and $j$ at time $t$ |
| $P_{n,t}^{\mathrm{R}}$ | Active power flexibility activation at bus $n$, for time $t$ |
| $Q_{n,t}^{\mathrm{R}}$ | Reactive power flexibility activation at bus $n$, for time $t$ |
| $u_{n,t}$ | Squared voltage magnitude at bus $n$, for time $t$ |
| $\mathrm{P_{n,t}^{R-}}$ | Downward FlexRequest at bus $n$, for time $t$ |
| $\mathrm{P_{n,t}^{R+}}$ | Upward FlexRequest at bus $n$, for time $t$ |
| $\alpha_{n,t}$ | Factor to express the flexibility activation as a linear function of the forecast error at bus $n$, for time $t$ |
| $b_t^F, b_t^P, b_t^Q, b_t^u$ | Matrices that relate the variables for the flexibility, active power, reactive power and voltage respectively to the source of uncertainty $\xi$, for time $t$ |
| $\Omega_{n,t}^{(.)}$ | Uncertainty margins associated with the different uncertain variables |
| $k_{ij,t}^{\mathrm{P}}, k_{ij,t}^{\mathrm{Q}}$ | Auxiliary variables introduced to reformulate some of the chance-constraints, for line $ij$, time $t$ |
| $p_{o/r}$ | Quantity accepted from the corresponding offer ($o$) or request ($r$) |
| Parameters | |
| $P_{n,t}^{\mathrm{inj}}$ | Fixed active power injection at bus $n$, for time $t$ |
| $Q_{n,t}^{\mathrm{inj}}$ | Fixed reactive power injection at bus $n$, for time $t$ |
| $P_{n,t}^{\mathrm{U}}$ | Forecast of the uncertain active power injection at bus $n$, for time $t$ |
| $Q_{n,t}^{\mathrm{U}}$ | Forecast of the uncertain reactive power injection at bus $n$, for time $t$ |
| $R_{ij}$ | Resistance of line $ij$ |
| $X_{ij}$ | Reactance of line $ij$ |
| $K$ | Factor of proportionality between the reactive and the active powers: $K = \sqrt{\frac{1-\cos\phi^2}{\cos\phi^2}}$, where $\cos\phi$ is the power factor |
| $\xi_{n,t}$ | Deviation from the active power injection forecast at bus $n$, for time $t$ |
| $\xi_{\mathrm{tot},t}$ | Total forecast error for time $t$: $\xi_{\mathrm{tot},t} = \sum_{n\in\mathcal{N}} \xi_{n,t}$ , $\forall\, t \in \mathcal{T}$ |
| $\overline{S}_{ij}$ | Rated apparent power of line $ij$ |
| $\underline{V_n}$ | Minimum voltage at bus $n$ |
| $\overline{V}_n$ | Maximum voltage at bus $n$ |
| $\epsilon_{(.)}$ | Violation probability for the corresponding constraint, $\epsilon \in (0,1)$ |
| $A$ | Matrix capturing the linear relation between the uncertainty injections and the power flows in the lines |
| $a_{ij,n}$ | Element of row $ij$ and column $n$ of matrix $A$: $a_{ij,n} = \begin{cases} 1, \text{ if } ij \text{ is part of the path from the slack bus to } n \\ 0, \text{ otherwise} \end{cases}$ |
| $\Gamma$ | Incidence matrix that denotes the connection of each source of uncertainty to the corresponding bus |
| $\beta$ | Parameter introduced to maintain the reliability level of the quadratic chance constraint: $\beta \in (0,1)$ |
| $\lambda_{o/r}$ | Price of the offer $o$ or request $r$ |
| $\overline{P}_{o/r}$ | Quantity submitted for the offer $o$ or request $r$ |

### 4.2.3 Creation of FlexRequests

The need for the DSO to procure flexibility reserves is motivated by the uncertainties in the network operation, and in particular on the power injection at each node. An imperative for the operation of a DSO is to avoid curtailment of producers or load shedding because of distribution network constraints. In order to achieve this, a chance-constrained optimal power flow problem is formulated to determine the quantity and direction of FlexRequests. These FlexRequests should resolve expected problems in the distribution network with high level of reliability, provided that they are matched in the flexibility market they are later submitted in. It is thus a two-stage problem that includes the procurement of flexibility and the subsequent dispatch in real time.

#### *4.2.3.1 Chance-constrained Model*

To represent the network, the LinDistFlow approximation is used [35]. With this linearization of the AC power flow, not only line flows are considered but also voltage magnitudes. This model can thus allow the DSO to formulate FlexRequests more efficiently while maintaining a good level of accuracy. The line flows and voltages are given by:

$$\sum_{jn\in\mathcal{L}} P_{jn,t} - \sum_{nk\in\mathcal{L}} P_{nk,t} = P^{\mathrm{inj}}_{n,t} + P^{\mathrm{R}}_{n,t} + P^{\mathrm{U}}_{n,t}, \quad \forall\, n \in \mathcal{N}, \forall\, t \in \mathcal{T} \tag{4.30}$$

$$\sum_{jn\in\mathcal{L}} Q_{jn,t} - \sum_{nk\in\mathcal{L}} Q_{nk,t} = Q^{\mathrm{inj}}_{n,t} + Q^{\mathrm{R}}_{n,t} + Q^{\mathrm{U}}_{n,t}, \quad \forall\, n \in \mathcal{N}, \forall\, t \in \mathcal{T} \tag{4.31}$$

$$u_{j,t} = u_{i,t} - 2\left(R_{ij}P_{ij,t} + X_{ij}Q_{ij,t}\right), \qquad \forall\, ij \in \mathcal{L}, \forall\, t \in \mathcal{T} \tag{4.32}$$

The active and reactive power balance per node is expressed in (4.30) and (4.31). The voltage drop is given in (4.32).

In the following, we assume that the reactive power injections are proportional to the active power injections.

The main variables of the problem are the upward and downward FlexRequest at each bus (4.33):

$$\mathrm{P}^{\mathrm{R\text{-}}}_{\mathrm{n,t}}, \mathrm{P}^{\mathrm{R+}}_{\mathrm{n,t}} \geq 0, \qquad \forall\, \mathrm{n} \in \mathcal{N}, \forall\, \mathrm{t} \in \mathcal{T} \tag{4.33}$$

The uncertain power injection is defined as: $\tilde{P}^{\mathrm{U}}_{n,t}(\xi) = P^{\mathrm{U}}_{n,t} - \xi_{n,t}$, $\forall\, n \in \mathcal{N}, \forall\, t \in \mathcal{T}$, where $P^{\mathrm{U}}_{n,t}$ is the forecasted value and $\xi_{n,t}$ is the deviation from the forecast at bus $n$, for time $t$. In general, the uncertain variables and parameters can be expressed as $\tilde{Y}(\xi) = Y + \Delta Y(\xi)$, where $Y$ is associated to the forecasted value and $\Delta Y(\xi)$, is the reaction to the forecast error.

Apart from the flexibility requested, all variables of the problem depend on the uncertainty realization. Following this, five chance-constraints are formulated:

$$\mathbb{P}\left(\tilde{P}^2_{ij,t}(\xi) + \tilde{Q}^2_{ij,t}(\xi) \leq \overline{S}^2_{ij}\right) \geq 1 - \epsilon_S, \qquad \forall\, ij \in \mathcal{L}, \forall\, t \in \mathcal{T} \tag{4.34}$$

$$\mathbb{P}\left(\underline{V}_n^2 \leq \tilde{u}_{n,t}(\xi)\right) \geq 1 - \epsilon_V, \qquad \forall\, n \in \mathcal{N}, \forall\, t \in \mathcal{T} \tag{4.35}$$

$$\mathbb{P}\left(\tilde{u}_{n,t}(\xi) \leq \overline{V}_n^2\right) \geq 1 - \epsilon_V, \qquad \forall\, n \in \mathcal{N}, \forall\, t \in \mathcal{T} \tag{4.36}$$

$$\mathbb{P}\left(-P^{\mathrm{R\text{-}}}_{n,t} \leq \tilde{P}^{\mathrm{R}}_{n,t}(\xi)\right) \geq 1 - \epsilon_R, \qquad \forall\, n \in \mathcal{N}, \forall\, t \in \mathcal{T} \tag{4.37}$$

$$\mathbb{P}\left(\tilde{P}^{\mathrm{R}}_{n,t}(\xi) \leq P^{\mathrm{R+}}_{n,t}\right) \geq 1 - \epsilon_R, \qquad \forall\, n \in \mathcal{N}, \forall\, t \in \mathcal{T} \tag{4.38}$$

Equation (4.5) is related to the rated apparent power of the lines. Constraints (4.34) - (4.35) require bus voltages to be within limits. Finally, in (4.36) - (4.8), the predicted flexibility activation is bounded by the flexibility requested. The chance-constrained formulation makes particular sense here, since in practice it is possible for the DSO to occasionally overload the lines.
The resulting optimization problem is:

$$\min_{\mathbf{x}} \sum_{t\in \mathcal{T}} \sum_{n\in \mathcal{N}} P^{\text{R+}}_{n,t} + P^{\text{R-}}_{n,t} \tag{4.39}$$

$$\text{s.t. Eq. (4.30)-(4.38)} \tag{4.40}$$

where $\mathbf{x} = \{P^{\text{R+}}, P^{\text{R-}}, P^{R}, u, P, Q\}$.
The objective of the DSO is to ensure that the operational network constraints are maintained with a given probability. The objective function (4.39) is formulated as a minimization of the upward and downward quantity of flexibility requests, such that those will only be generated to ensure feasibility of the real time dispatch.

##### 4.2.3.2 Reformulation

###### 4.2.3.2.1 Expression of Flexibility Activation

The activated flexibility due to the FlexRequests is expressed as an affine function of the total forecast error as in (4.41):

$$\tilde{P}^{\text{R}}_{n,t}(\xi) = P^{\text{R}}_{n,t} + \alpha_{n,t}\, \xi_{\text{tot},t}, \qquad \forall n \in \mathcal{N}, \forall\, t \in \mathcal{T} \tag{4.41}$$

###### 4.2.3.2.2 Balance Responsibility

When formulating such a problem, considering the uncertainty of injections in the distribution network, the question of who should be responsible to cover for the imbalance arises.
The FlexRequests can be thought of as a way of covering for the imbalance created following a forecast error. For example, if the load demand is higher than planned, upward flexibility will be activated to keep the balance. In order to make sure that the activation of the FlexRequests will cover for any value of the forecast error, and that the power balance will hold, we need to have the following requirement on the factors $\alpha$:

$$\sum_{n\in \mathcal{N}} \alpha_{n,t} = 1, \qquad \forall\, t \in \mathcal{T} \tag{4.42}$$

On the other hand, one could consider that the DSO is not responsible for the imbalances and assume that the energy necessary to cover them is generated in other parts of the network and received through the slack bus. In this case, FlexRequests are used to ensure that the distribution network will be able to handle the associated changes in terms of line flows and voltages. Since the activation of the FlexRequests does not modify the balance, the sum of $\alpha$ should be zero. The nodal balance at the slack bus should also be updated accordingly:

$$-\sum_{nk\in\mathcal{L}} P_{nk,t} = P_{n,t}^{\text{inj}} - \sum_{k\in\mathcal{N},k\neq\text{ref}} P_{k,t}^{\text{R}}\,, \qquad n = \text{ref}, \forall\, t \in \mathcal{T} \tag{4.43}$$

$$-\sum_{nk\in\mathcal{L}} Q_{nk,t} = Q_{n,t}^{\text{inj}} - \sum_{k\in\mathcal{N},k\neq\text{ref}} Q_{k,t}^{\text{R}}\,, \qquad n = \text{ref}, \forall\, t \in \mathcal{T} \tag{4.44}$$

$$\sum_{n\in\mathcal{N}} \alpha_{n,t} = 0\,, \qquad \forall\, t \in \mathcal{T} \tag{4.45}$$

where the slack bus is designed by the index “ref”.
In the case of a radial network, the balance is ensured for any realization of the uncertainty when including these constraints.
Depending on the regulatory framework, the corresponding equations should be added to the reformulation. In the case study, we follow the second approach, where the DSO is not balance responsible.

#### *4.2.3.2.3 Reformulation of the Chance-Constraints*

It is assumed that the forecast error follows a Gaussian probability distribution function with zero mean $\mu = 0$ and covariance $\Sigma$. Given a linear relation between the error and the variables, the chance-constraints (4.34) - (4.38) can be reformulated analytically to deterministic constraints. Chance constraints of the format $\mathbb{P}(x_i + b_i\xi \leq \overline{x}_i$ can be reformulated as $x_i + \Phi^{-1}(1-\epsilon_x)\sqrt{b_i^{\mathsf{T}}\Sigma b_i} \leq \overline{x}_i$, where $b$ is the matrix that linearly relates the uncertainty source with the variables. Hence, an *uncertainty margin* can be introduced, defined as: $\Omega_i = \Phi^{-1}(1-\epsilon_x)\sqrt{b_i^{\mathsf{T}}\Sigma b_i}$.
The power flow in the lines (4.46) - (4.47) and the nodal voltage (4.48) can be linearly related to the forecast error:

$$\tilde{P}_{ij,t}(\xi) = P_{ij,t} + \sum_{n\in\mathcal{N}} a_{ij,n}\big(\xi_{n,t} - \alpha_{n,t}\xi_{\text{tot},t}\big), \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.46}$$

$$\tilde{Q}_{ij,t}(\xi) = Q_{ij,t} + \sum_{n\in\mathcal{N}} K a_{ij,n}\big(\xi_{n,t} - \alpha_{n,t}\xi_{\text{tot},t}\big), \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.47}$$

$$\tilde{u}_{n,t}(\xi) = u_{n,t} - 2\sum_{ij\in\mathcal{L}} a_{ij,n} \sum_{m\in\mathcal{N}} a_{ij,m}\big(R_{ij} + KX_{ij}\big)(\,\xi_{m,t} - \alpha_{m,t}\xi_{\text{tot},t})\,, \qquad \forall\, n \in \mathcal{N}, \forall\; t \in \mathcal{T} \tag{4.48}$$

The matrices that relate the different to the source of uncertainty $\xi$ are described in (4.49) - (4.52):

$$b_t^F \;=\; \big[\alpha_{1,t}\,, \ldots, \alpha_{n,t}\,\big], \qquad \forall\, t \in \mathcal{T} \tag{4.49}$$

$$b_t^P \;=\; A(\Gamma\, - \alpha_{*,t}\, I^{\mathsf{T}}), \qquad \forall\, t \in \mathcal{T} \tag{4.50}$$

$$b_t^Q \;=\; KA(\Gamma\, - \alpha_{*,t}\, I^{\mathsf{T}}), \qquad \forall\, t \in \mathcal{T} \tag{4.51}$$

$$b_t^u = 2A^{\mathsf{T}}\big[A(R+KX)(\Gamma - \alpha_{*,t}I^{\mathsf{T}})\big], \qquad \forall\, t \in \mathcal{T} \tag{4.52}$$

Hence, the linear chance constraints (4.35) - (4.38) can be reformulated using uncertainty margins as in (4.53) - (4.56):

$$u_{n,t} \geq \underline{V}_n^2 + \Omega^u_{n,t}, \qquad \forall\, n \in \mathcal{N}, \forall\ t \in \mathcal{T} \tag{4.53}$$

$$u_{n,t} \leq \overline{V}_n^2 - \Omega^u_{n,t}, \qquad \forall\, n \in \mathcal{N}, \forall\ t \in \mathcal{T} \tag{4.54}$$

$$P^{\mathrm{R}}_{n,t} \geq\ -P^{\mathrm{R\text{-}}}_{n,t} + \Omega^F_{n,t}, \qquad \forall\, n \in \mathcal{N}, \forall\ t \in \mathcal{T} \tag{4.55}$$

$$P^{\mathrm{R}}_{n,t} \leq\ -P^{\mathrm{R+}}_{n,t} - \Omega^F_{n,t}, \qquad \forall\, n \in \mathcal{N}, \forall\ t \in \mathcal{T} \tag{4.56}$$

The quadratic chance constraint (4.36) can be reformulated following the method in [36] [37]. Two absolute value chance-constraints are introduced (4.57) - (4.58) as well as a quadratic constraint that connects the auxiliary variables with the rated apparent power in (4.59). The auxiliary variables $k^{\mathrm{P}}$and $k^{\mathrm{Q}}$ are defined with corresponding uncertainty margins in (4.60) - (4.61) respectively.

$$\mathbb{P}\left(\left|\tilde{P}_{ij,t}(\xi)\right| \leq k^{\mathrm{P}}_{ij,t}\right) \geq 1 - \beta\epsilon_S, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.57}$$

$$\mathbb{P}\left(\left|\tilde{Q}_{ij,t}(\xi)\right| \leq k^{\mathrm{Q}}_{ij,t}\right) \geq 1 - (1-\beta)\epsilon_S, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.58}$$

$$\left(k^{\mathrm{P}}_{ij,t}\right)^2 + \left(k^{\mathrm{Q}}_{ij,t}\right)^2 \leq \bar{S}^2_{ij,t}, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.59}$$

$$k^{\mathrm{P}}_{ij,t} \geq \Omega^{k^{\mathrm{P}}}_{ij,t}, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.60}$$

$$k^{\mathrm{Q}}_{ij,t} \geq \Omega^{k^{\mathrm{Q}}}_{ij,t}, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.61}$$

The absolute value constraints can be further reformulated as two-sided linear chance constraints (4.62) – (4.65).

$$P_{ij,t} \leq k^{\mathrm{P}}_{ij,t} - \Omega^P_{ij,t}, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.62}$$

$$P_{ij,t} \geq -k^{\mathrm{P}}_{ij,t} + \Omega^P_{ij,t}, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.63}$$

$$Q_{ij,t} \leq k^{\mathrm{Q}}_{ij,t} - \Omega^Q_{ij,t}, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.64}$$

$$Q_{ij,t} \geq -k^{\mathrm{Q}}_{ij,t} + \Omega^Q_{ij,t}, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.65}$$

The uncertainty margins for the active and reactive power and the auxiliary variables can be calculated as in (4.66) - (4.69). An additional factor of 1.25, is added for the reformulation of the two-sided linear constraints to achieve an inner approximation. If this factor is not used, the margins will provide an outer approximation and result in insufficiently conservative margins for the desired reliability level [36].

$$\Omega^P_{ij,t} = \Phi^{-1}\left(1 - \frac{\beta\epsilon_S}{1.25}\right)\sqrt{\left(b^P_{ij,t}\right)^T\ \Sigma b^P_{ij,t}}, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.66}$$

$$\Omega^Q_{ij,t} = \Phi^{-1}\left(1 - \frac{1-\beta\epsilon_S}{1.25}\right)\sqrt{\left(b^Q_{ij,t}\right)^T\ \Sigma b^Q_{ij,t}}, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.67}$$

$$\Omega^{k^{\mathrm{P}}}_{ij,t} = \Phi^{-1}\left(1 - \frac{\beta\epsilon_S}{2.5}\right)\sqrt{\left(b^P_{ij,t}\right)^T\ \Sigma b^P_{ij,t}}, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.68}$$

$$\Omega^{k^{\mathrm{Q}}}_{ij,t} = \Phi^{-1}\left(1 - \frac{1-\beta\epsilon_S}{2.5}\right)\sqrt{\left(b^Q_{ij,t}\right)^T\ \Sigma b^Q_{ij,t}}, \qquad \forall ij \in \mathcal{L}, \forall t \in \mathcal{T} \tag{4.69}$$

After reformulating all the chance-constraints, we obtain the following second-order cone (SOC) OPF:

The resulting optimization problem is:

$$\min_{\mathbf{x}} \sum_{t\in\mathcal{T}} \sum_{n\in\mathcal{N}} P_{n,t}^{\text{R+}} + P_{n,t}^{\text{R-}} \tag{4.70}$$

$$\text{s.t. Eq. (4.30)-(4.33), (4.49)-(4.56), (4.59)-(4.69)} \tag{4.71}$$

$$\text{Eq. (4.42) or (4.43)-(4.45)}$$

where $\mathbf{x} = \{P^{\text{R+}}, P^{\text{R-}}, P^{R}, u, P, Q, b, \Omega, k^{\text{P}}, k^{\text{Q}}\}$.

### 4.2.4 Deterministic Market Clearing

The FlexRequests can be submitted in any type of energy or reserve market. Here, we assume the simplest flexibility market architecture, similar to the ancillary services markets currently used on the transmission level. Such a market matches flexibility offers with flexibility requests neglecting all network constraints and not considering uncertainty (i.e., similar to an Economic Dispatch); the network constraints and the uncertainty have been already accounted for during the FlexRequests creation. In order to ensure that the resulting dispatch will be feasible, one option is to enforce that the offer should come from the same node as the request. In that case, all probable deviations of the power injections (which the FlexRequest has considered) would be balanced at each node and, thus, they would not result to line or voltage violations. This is, however, quite restrictive and could hinder market liquidity, i.e., the number of flexibility offers at the specific node could be very low or zero. In a less restrictive formulation, the DSO can have the opportunity to define and submit to the market operator zones that group several nodes, within which it is estimated that there could not be congestions. This is similar to the motivation behind the zonal market setup that is currently in operation in Europe.
This deterministic market clearing is formulated as follows:

$$\min_{p} \sum_{t\in\mathcal{T}} \left( \sum_{o\in\mathcal{O}_t} \lambda_o p_o - \sum_{r\in\mathcal{R}_t} \lambda_r p_r \right) \tag{4.72}$$

$$\text{s.t.} \sum_{o\in\mathcal{O}_{z,t}^{+}} p_o = \sum_{r\in\mathcal{R}_{z,t}^{+}} p_r, \qquad \forall z\in\mathcal{Z}, \forall t\in\mathcal{T} \tag{4.73}$$

$$\sum_{o\in\mathcal{O}_{z,t}^{-}} p_o = \sum_{r\in\mathcal{R}_{z,t}^{-}} p_r, \qquad \forall z\in\mathcal{Z}, \forall t\in\mathcal{T} \tag{4.74}$$

$$0 \le p_o \le \overline{P}_o, \qquad \forall o\in\mathcal{O} \tag{4.75}$$

$$0 \le p_r \le \overline{P}_r, \qquad \forall r\in\mathcal{R} \tag{4.76}$$

It is worth noting here that since the FlexRequest creation model is based on an optimization algorithm, the optimization solver by default would return only a single possible combination for the location of the requests; there could be, however, more than one solution. Having zones is one way to deal with this limitation.

### 4.2.5 Case study

In the following, we evaluate our method for the creation of FlexRequests. We compare it to having a stochastic market clearing, for which there is no need to formulate FlexRequests (there are implicit). The formulation of the stochastic market clearing model can be found in [38].

We apply our method to a radial 81 bus German distribution network, which was provided by the DSO bnNETZE. The 81 bus 0.4kV distribution system is connected to the substation through a 20kV line and has a total maximum loading of 3.5MW, and three wind farms with a total rated capacity of 500kW. We consider uncertainty from renewable production only, while the rest of the power injections are assumed to be certain for the purpose of this example. The covariance matrix is evaluated from a 1,000 wind forecast error scenarios with zero mean. These are taken from real measurements recorded in Denmark [39]. We consider one time period of one hour, and a power factor $\cos\phi = 0.95$.

Regarding the different prices, we make the following assumptions:

- Curtailment costs are set at 60€/MWh.
- Load shedding costs at 200€/MWh.
- Activation costs are assumed to be equal to 0, since we consider that the flexibility providers have no operational costs.
- FlexRequests have a price of 70€/MW for up- and 40€/MW for down-regulation.
- Offers are priced randomly between 25€/MW and 35€/MW.

For all the different chance-constraints, a violation of 5% is permitted.

The following are solved:

- FlexRequest creation with the chance-constrained model.
- Deterministic market clearing to match the created FlexRequests with FlexOffers that bid in the market.
- Stochastic market clearing as a benchmark to compare with the deterministic market clearing which considered the created FlexRequest.
- Out-of-sample Monte Carlo analysis to evaluate the violation of chance-constraints for both models.
- Real time dispatch (with LinDistFlow) to evaluate the real time costs after activation.

### 4.2.6 Results

The performance of the model for the creation of the FlexRequests is evaluated over two axes. The first is the definition of clearing zones by the DSO. The most extreme case is to have a clearing per node, which corresponds to either not having the possibility to define zones or to the DSO considering that all lines are likely to get congested such that any deviation shall be balanced through flexibility procurement at the same node it is created. This case will be identified as “Nodal Market”. On the other hand, we conducted a statistical study to identify which lines can get congested and defined zones accordingly. This will be further referred to as “4-Zones”. Finally, we define a test case that is between those two, with more zones, and it will be called “9-Zones”.

The second parameter is the overall liquidity of the market. The offers are designed following three levels of liquidity: high, medium and low. For the high liquidity scenario, all buses but for the reference bus are offering a high level of flexibility in both directions. It is then reduced to obtain the medium and low scenarios.

After running those, we compare the resulting social welfare. It is calculated as:

$$SW = (\lambda^{\mathrm{R+}} - \lambda^{\mathrm{O+}})\mathbf{p}^{\mathrm{f+}} + (\lambda^{\mathrm{R-}} - \lambda^{\mathrm{O-}})\mathbf{p}^{\mathrm{f-}} - \lambda^{\mathrm{NS}}\mathbf{p}^{\mathrm{NS}} - \lambda^{\mathrm{C}}\mathbf{p}^{\mathrm{C}} \tag{4.77}$$

The first part of the social welfare is linked to procurement and is calculated once. It is the difference between the price of accepted requests and offers multiplied by the procured quantity.
The second part corresponds to the costs resulting from real time dispatch, which are due to load shedding and curtailment. Those are calculated over 2,000 scenarios of wind realization, which are different from the ones used to evaluate the covariance matrix.

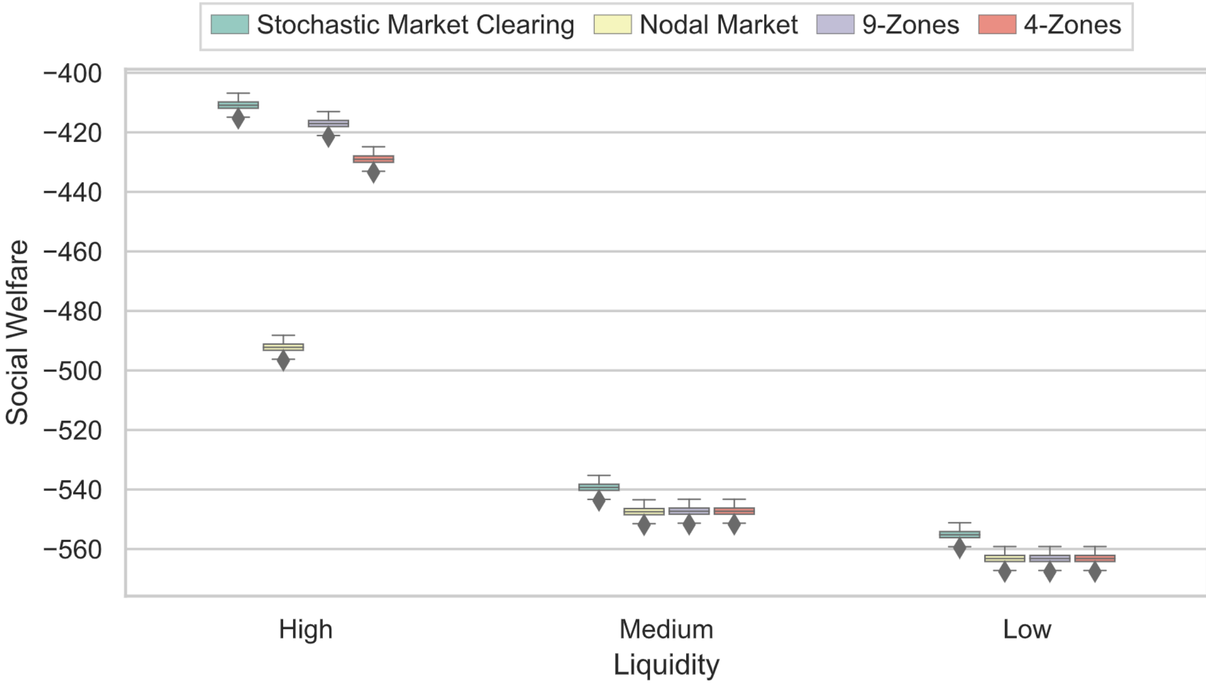


**Figure 28 Social welfare (€) for three levels of liquidity and comparing stochastic market clearing to deterministic market clearing with different ways to define clearing zones**

The social welfare for the different test cases is shown in Figure 28. The more offers are available, the higher the social welfare. This is due to both the social welfare gained from the matches and the reduction of real time re-dispatching costs. The deterministic market with no zones (i.e., nodal-based) can perform significantly worse than the others, as we see here in the high liquidity. It is consistent with the fact that it restricts the possibility of matches. Since less flexibility is procured, the real time costs, linked to load shedding in particular, are also higher. The performance of the deterministic market with zones is close to the one of the stochastic market in terms of social welfare. With less, larger clearing zones (4-Zones), more matches are allowed, so with similar redispatch costs, this can give an advantage to the deterministic market in terms of social welfare, but it means that some flexibility is not used. This happens when the zones are defined too large, which means that there exist congestions inside of the zone that prevent the activation of the procured flexibility.

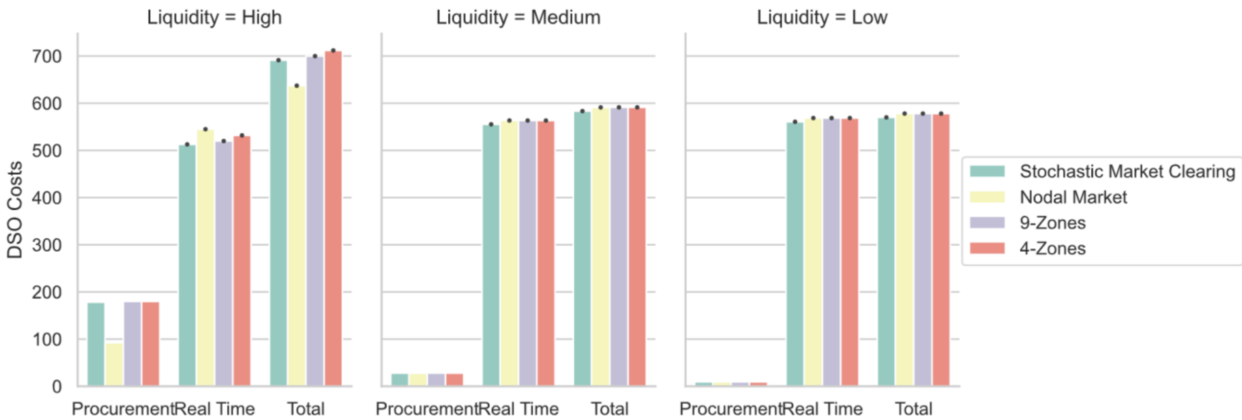


**Figure 29 DSO costs (€) for three levels of liquidity and comparing stochastic market clearing to deterministic market clearing with different ways to define clearing zones**

In Figure 29, the DSO costs in the different situations are compared. The procurement costs for the DSO depend on the payment scheme chosen in each market. To keep the market clearing models general on this regard, we considered here that the DSO had to pay what they bid, which would be a higher bound on the price paid.

With the nodal market, because of matching the bids per node, the quantity matched at each node can be reduced, which gives lower procurement costs. The level of liquidity plays a role on the allocation of the costs between procurement and real time.

Note that in this test case, the system is heavily loaded. The real-time costs are very high in all the scenarios tested, due to load shedding. The stochastic market clearing is performing better, as expected, but the zonal deterministic markets are comparatively close.

### 4.2.7 Conclusion

We hereby provide a framework for how DSOs can create a network aware FlexRequest as a tool that ensures compatibility with current legislation. We compared its efficacy against a stochastic benchmark, showing results for a real-world distribution network. FlexRequests can be generated with a chance-constrained approach and cleared in a very simple deterministic market, which includes the possibility to define zones. The definition of bidding zones by the DSO can become critical. With a clearing per bus, the costs for the DSO could increase significantly. With properly defined zones, the results obtained in terms of social welfare and costs for the DSO appear to be comparable to those obtained with stochastic market clearing.

A big advantage of our approach for the creation of the FlexRequests is that it avoids making assumptions on the flexibility providers. In particular, there is no need to evaluate their position in the network or their flexibility capabilities. In general, the DSO does not have access to such information, but if they did, they could be included as parameters in the model in order to create requests that consider what is actually available. Instead of using a random combination for the locations of the FlexRequests, this would help pointing at a solution that is in line with flexibility capabilities in the network.

The model introduced could be further improved by expanding the role of reactive power. Here, the influence of reactive power is included, but it is assumed to be linked to the active power by a constant factor, which would be determined by the DSO in the case of the creation of the FlexRequests. However, the DSO does not have access to such information in most cases. On the other hand, we do not consider here the possibility to have a flexibility market for reactive power too. The link between active and reactive power makes the DSO's problem for the creation of FlexRequests a lot more complex; it is probable that the DSO shall make some assumptions about how reactive power is consumed in order to have an algorithm that can efficiently determine the active power FlexRequests.

## 4.3 Conclusions and lessons learned

After communicating FLEXGRID scientific results on the FlexRequest price and volume creation of to both academic and industrial communities, we have come up with a short list of lessons learned that could be further investigated in future R&D initiatives. Table 23 summarizes research and business-related insights for each one of the lessons learned.

**Table 23 Lessons learned from the creation of FlexRequests**

| Lesson learned | Research & Business insights |
|---|---|
| The way FlexRequests are created depends on the level of information that is available, with respect to the network, forecasts for each bus or DSO area, etc. | In order to create efficient FlexRequests, DSOs should strive to obtain real-time data about the power balance at each node and have access to accurate forecasts. Furthermore, the link between active and reactive power makes the DSO's problem for the creation of FlexRequests a lot more complex; therefore the DSO might make some assumptions about how reactive power is consumed. |
| The way FlexRequests are created depends on the information exchange with the FMO and on which geographical resolution the FlexRequest are cleared. | FlexRequests can be generated with a chance-constrained approach and cleared in a very simple deterministic market, which includes the possibility to define zones. In order to clear the DLFM efficiently, the FMO would need access to the full network model, which the DSO may not be willing to share. An alternative is to clear the market on zonal level, which is inevitably suboptimal since it reduces the market efficiency. |
| The definition of bidding zones by the DSO (i.e. many small DN areas or a few large DN areas) can become a critical input parameter. | With a clearing per bus, the costs for the DSO could increase significantly. With properly defined zones, the results obtained in terms of social welfare and costs for the DSO appear to be comparable to those obtained with stochastic market clearing. |

# 5 Comparison of x-DLFM architectures with LinDistFlow model

This chapter deals with the research problem of how to possibly integrate DLFM in today's and future's EU electricity market architectures. More specifically, we propose the following x-DLFM architectures: i) Reactive (R-DLFM), ii) Proactive (P-DLFM), and iii) Interactive (I-DLFM). We also assume the current electricity market architecture called no-DLFM, in which there is no market for procuring flexibility at the distribution network level and the constraints of local distribution networks are not taken into consideration in the market clearing processes. Following up the advanced network-aware market clearing models and algorithms presented in the previous chapters, we adopt the LinDistFlow model, which achieves a good trade-off between accuracy and computational complexity.

## 5.1 Problem statement, related state-of-the-art and FLEXGRID research contributions

FLEXGRID introduces the novel concept of "Distribution Level Flexibility Market - DLFM", which is operated by an independent entity, referred to as Flexibility Market Operator (FMO). In FLEXGRID, a novel FMO market actor like NODES[2] operates the proposed DLFM. In this context, FLEXGRID focuses on the development of a digital Automated Trading Platform (ATP) that facilitates FMOs to: i) operate the DLFM and interact with existing energy/balancing markets operated by MO/TSO, ii) acquire flexibility requests from DSOs, and iii) interact with ESPs and FSPs by receiving flexibility offers.

The proposed FLEXGRID energy market architectures develop, combine, and bring to interaction the following six (existing or innovative) energy markets compiled in the table below. It should be noted that FLEXGRID follows the Nord Pool paradigm currently operating in the many European countries as EU's regulatory baseline.

**Table 24 Summary of markets assumed within FLEXGRID**

| **Market #1** | **Market Operator (MO) operates the day-ahead energy market at the Transmission Network (TN) level** |
|---|---|
| Input | MO receives bids from all market participants and basic power flow constraints at the TN level. Depending on FLEXGRID's various energy market architectures selected from the FLEXGRID's set of options (see below), the market clearing process of Market #1 either ignores the DN topology, or implicitly takes it into account (output of Market #3). |
| Output | Market clearing results (TN-aware price €/MWh per TN node and Day Ahead Dispatch (DAD) |
| **Market #2** | **TSO operates the day-ahead reserve market at the TN level** |

[2] https://nodesmarket.com/

| | |
|---|---|
| Input | Receives bids from all market participants at TN level, DAD, schedules from MO, RES/demand forecasts, maintenance-related info from assets and grid, TN model/topology and constraints<br>Depending on FLEXGRID's various energy market architectures (see below), the market clearing process of Market #2 either ignores the DN topology, or implicitly takes it into account (output of Market #4) |
| Output | Reserve market clearing results at TN level (price €/MW and reserve capacity commitment per accepted market participant) |
| **Market #3** | **Flexibility Market Operator (FMO) operates the day-ahead energy market at the Distribution Network (DN) level** |
| Input | Receives bids from all market participants at DN level, and DN topology constraints.<br>DAD schedule from MO at all TSO-DSO coupling points or respective day-ahead energy market price forecasts (depending on the selection of energy market architecture from the three FLEXGRID options below). |
| Output | Market clearing results (DN-aware price €/MWh and DAD per accepted market participant and DN node) |
| **Market #4** | **DSO operates the day-ahead reserve market at the DN level** |
| Input | Receives bids from all market participants at DN level, DAD schedules from FMO, local RES/demand forecasts, and maintenance-related info (if any) |
| Output | Reserve market clearing results at DN level (price €/MW per DN node and reserve capacity commitment per accepted market participant) |
| **Market #5** | **TSO operates the balancing energy market at the TN level** |
| Input | Receives bids from all market participants at TN level (incl. DER aggregators), updated RES/demand forecasts, updated data from SCADA/EMS.<br>Depending on the energy market architecture selected from the FLEXGRID's various options, the market clearing process of Market #5 either ignores the DN topology, or implicitly takes it into account through the output of Market #6. |
| Output | Balancing energy market clearing results at TN level (i.e. prices €/MWh per TN node, and Up/Down activation energy quantities per accepted market participant) |
| **Market #6** | **DSO operates the balancing energy market at the DN level (only when DSO has a balancing responsibility for its DN operation)** |
| Input | Receives bids from all market participants at DN level, updated local RES/demand forecasts, and updated data from DMS [8] |
| Output | Balancing energy market clearing results at DN level (i.e. prices €/MWh per DN node, and Up/Down activation energy quantities per accepted market participant) |

Through the design, modeling and performance evaluation of the three x-DLFM architectures, FLEXGRID puts emphasis on the trade-off between: i) social welfare maximization (or else market efficiency), ii) the level of compatibility of the proposed architecture with the existing markets' architecture (i.e., day ahead, balance), and iii) their efficiency for various energy sector stakeholders (e.g., ESPs, FSPs, market/system operators, etc.).

These three architectures are described in the system model subsection below. The first acts reactively to the existing energy markets and in this way sacrifices efficiency for compatibility. The second one (P-DLFM) acts proactively to the existing energy market. The third architecture is framed within existing markets (#1, #2, #5 according to the table above), but offers the maximum possible smart grid efficiency by allowing market participants to facilitate the transmission or the distribution network at the same time, independently of their location.

## 5.2 System Model

### 5.2.1 No-DLFM architecture – benchmark

As benchmark market architecture, we assume the no-DLFM system model, which is depicted in Figure 30. In the vertical axis, the temporal sequence of markets is illustrated. For example, in today's EU regulatory framework, where there exist no distribution-level markets, we assume 3 main markets, namely : i) Day-ahead energy market (cf. market #1), ii) day-ahead reserve market (cf. market #2), and iii) near-real-time balancing market (cf. market #5).

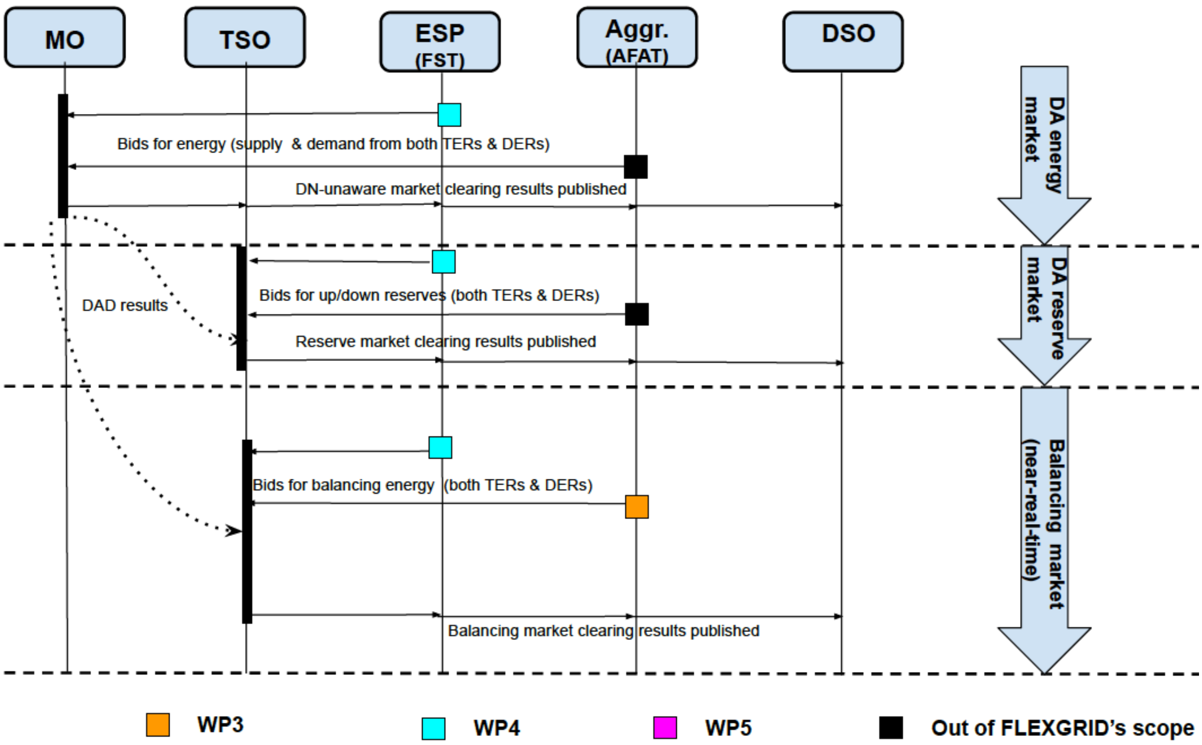


**Figure 30 No-DLFM architecture representing the today's EU regulatory framework**

### 5.2.2 Reactive DLFM architecture

The objective of the R-DLFM architecture is to be compatible and capable to interact with the existing TN-level markets (cf. #1, #2 and #5 in Table 24). In case that the R-DFLM operates right after day ahead energy market, it is capable to deal with the: i) congestion issues at DN level that the day-ahead dispatch (DAD) cannot capture, and ii) forecast inaccuracies in energy production and energy consumption of DN- and TN-level assets.

The drawback of this approach is the possibility of infeasibility, or the need for mandatory/forced load/RES curtailments, or financially unsustainable distribution of DAD due to costly flexibility assets at the DN level. All these may lead to discontented RES producers and end consumers. Furthermore, in cases in which DAD is modified, the spot market price (cf. market #5) at the transmission level has to be paid. Finally, the absence of joint optimization between transmission and distribution levels leads to market inefficiencies, which in turn deteriorates the economic viability of the participating market stakeholders.

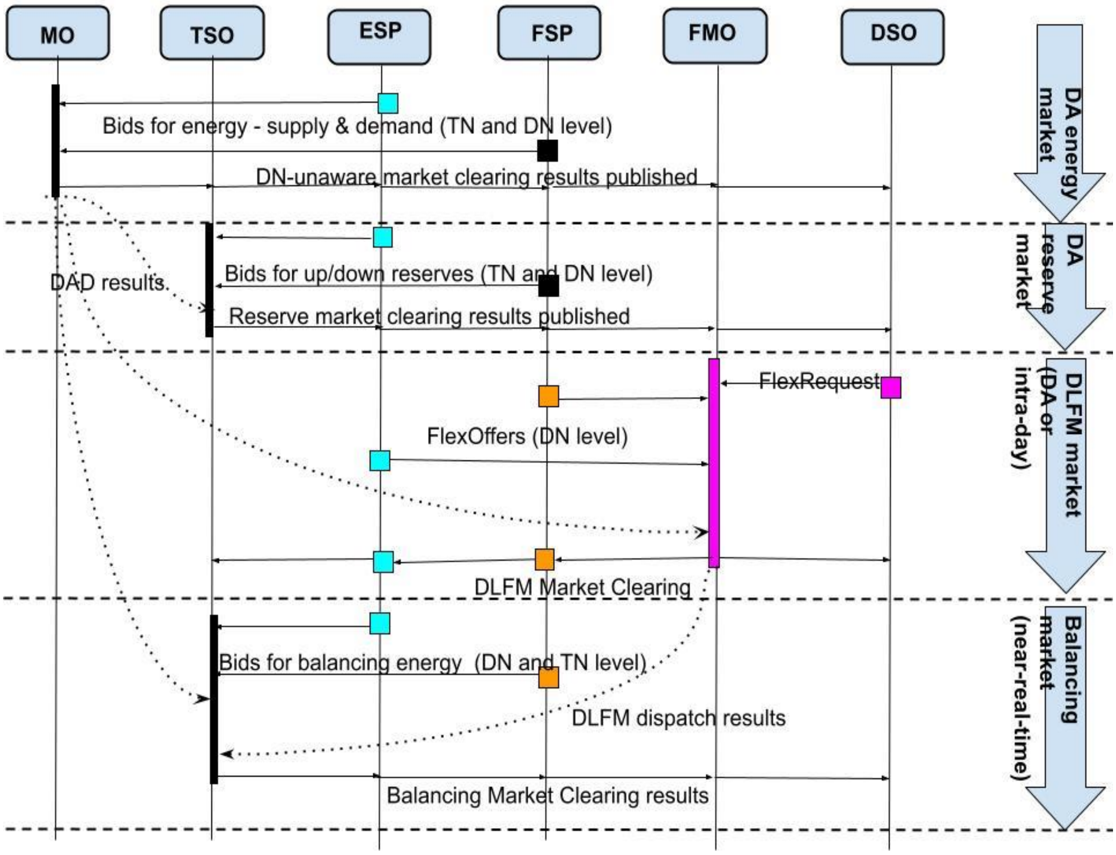


**Figure 31 Reactive DLFM architecture (compatible with today EU regulatory framework)**

The sequence and timing of the markets in the R-DLFM energy market architecture is described in Figure 31 above. Initially, the operation of the Day Ahead (#1) and the Reserve Market (#2) take place. Then, FMO takes the output of these two markets and clears the R-DLFM (#3) according to: i) DSO's network topology and constraints (which generate FlexRequests) and ii) FSP and ESP bids (FlexOffers). A reserve market at DN level could optionally take place in this phase through the same procedure (#4). In the next phase, the outputs of DAD and R-DLFM are given as input to the Balancing Market (#5). In the optional case that DSO wants to handle voltage limits due to RES in DN a balancing energy/capacity market at the DN level (#6) may also take place right after clearing the TN-level balancing energy market.

Table 25 illustrates the steps of the R-DLFM market clearing process:

**Table 25 Steps of the R-DLFM market clearing process**

| | |
|---|---|
| **Step 1** | The FMO takes as input the DAD that is composed from the power flows in the coupling point with the TSO and the dispatch that concerns producers and consumers in its distribution network. |
| **Step 2** | The DSO sends its DN data to the FMO. |
| **Step 3** | The FSPs and ESPs connected to the DSO send their flexibility bids to FMO (FlexOffers). |
| **Step 4** | The FMO generates Distribution Network Dispatch - DND (execution of a DND algorithm - DNDA). |
| **Step 5** | Flexibility assets are compensated for their operation according to a Distribution Network Payment Algorithm (DNPA) that the FMO executes. |

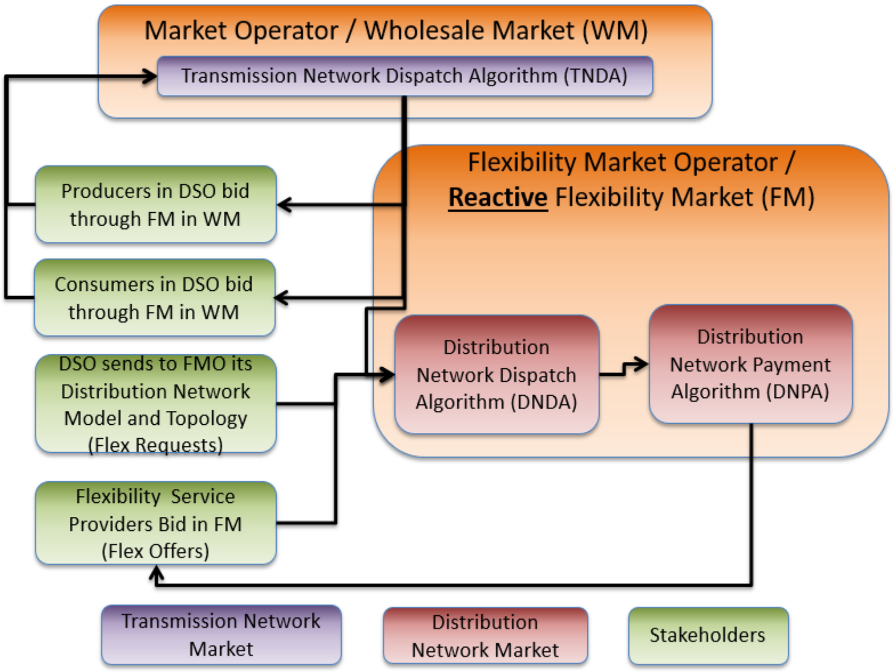


**Figure 32 Steps in the R-DLFM process**

| |
|---|
| **In this market setup, we assume that two flexibility products are traded in the R-DLFM, namely: i) active power reserves (cf. UCS 1.2) to solve local congestion issues, and ii) reactive power reserves (cf. UCS 1.3) to solve voltage control issues. We also assume the auction-based market clearing algorithm and the LinDistFlow model described in chapter 3 above.** |

### 5.2.3 Proactive DLFM architecture

In order to mitigate the drawback of the R-DLFM architecture (i.e., the difficulty to manage an infeasible (DN-level) or expensive (TN-level) market clearing) a proactive clearing of bids in the DN level by the FMO before the MO clearing is proposed. In this way, it ensures an a-priori feasible dispatch of the DN-level DERs.

In order to allow the FMO to operate proactively, an accurate estimation of the TN-level market clearing prices (Markets #1, #2 and #5) at the TSO-DSO coupling point is required. An over- or under-estimation in TLMPs may result in economically inefficient dispatch for both DSO and TSO.

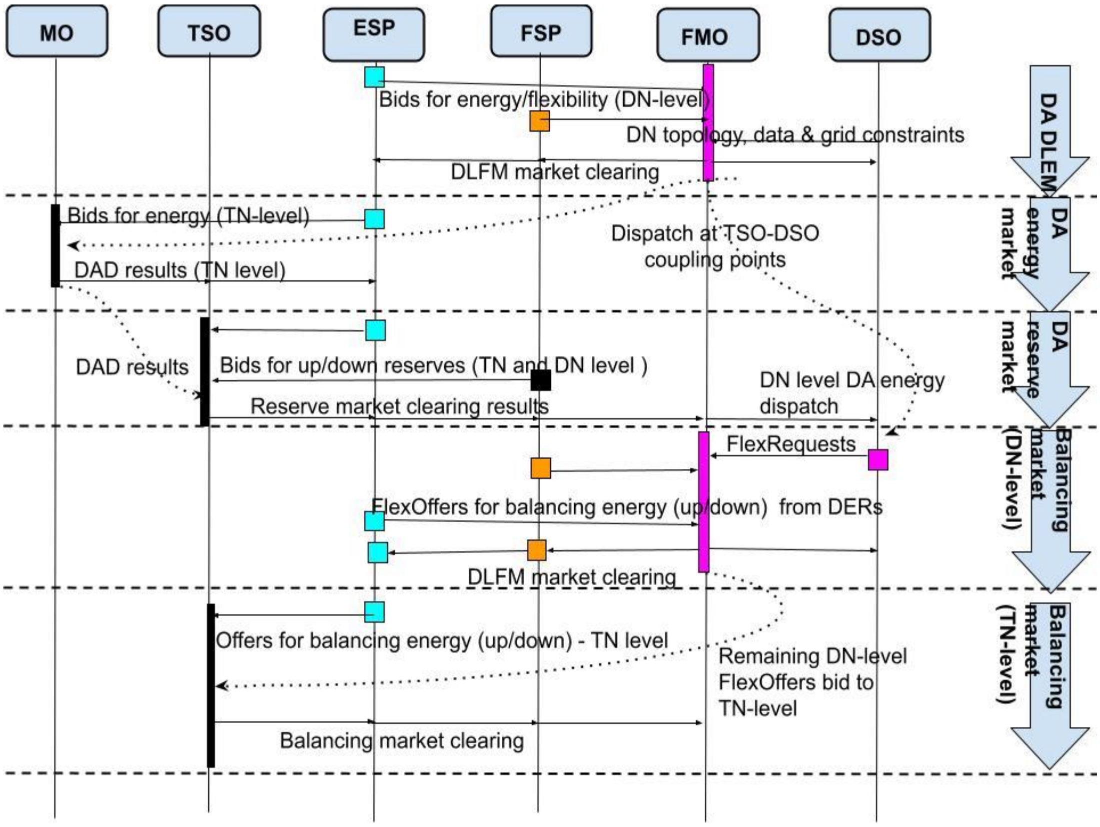


**Figure 33 Proactive DLFM architecture (DN feasibility check and optimal DN-level bidding in wholesale market)**

As shown in Figure 33 above, the sequence of markets starts with Market #3 operated by the FMO. In this phase, the P-DLMP is a day-ahead energy market at the DN level (ESPs and FSPs in DN level bid in this market). Right afterwards, in the next phase, the Day-Ahead Market (#1) and the Day-Ahead Reserve Market (#2) at TN level close. The output of Day-Ahead P-DLFM acts as input to the Day-Ahead market at TN level. Finally, for near-real-time balancing markets, the DSO could run a proactive balancing market (Market #6) right before the established balancing capacity market operated by the TSO (Market #5). Thus, the local congestion and voltage problems at the DN level can be directly solved by the DSO locally, at the DN level, while the “remaining bids” of “Balancing P-DLFM” (Market #6) can be used as input to the Balancing Market (Market #5). The Balancing P-DLFM acts as a balancing market at DN level and takes as input ESP and FSP bids at that level. It additionally propagates its clearing prices (output) into the TN-level balancing market, which may facilitate balancing at DN level in case of inadequate balancing resources.

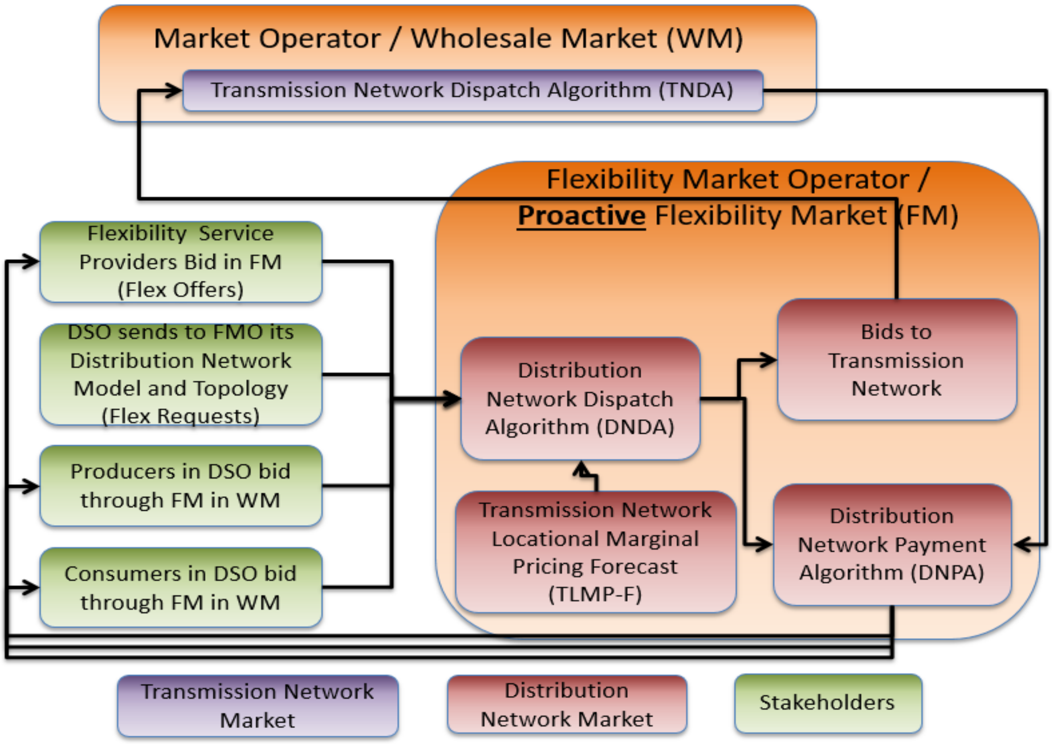


**Figure 34 Steps in the P-DLFM process**

Figure 34 shows the steps of the P-DLFM market clearing process and its interaction with TN-level markets:

| | |
|---|---|
| **Step 1** | The DSO sends to the FMO information that suffices to model its distribution network. |
| **Step 2** | The producers and retailers (ESPs) connected to the DSO send their production and consumption (i.e., energy) bids to the FMO. |
| **Step 3** | The FMO (or any other 3$^{rd}$ party) generates a forecast for the TLMPs for the coupling point at which the DSO is connected. |
| **Step 4** | The FMO generates the DND through the execution of an algorithm noted as DNDA (may reduce the quantity in the initial bids, but it does not reduce the bidding prices). |
| **Step 5** | The TLD uses DNDA results as input bids. |
| **Step 6** | After the TLD, the DNPA uses as input: i) bidding prices of flexibility providers, producers and consumers, ii) TLD, and iii) DLD in order to derive the compensations for all the stakeholders that bid in Steps 2-4. |

**In this market setup, we assume a Distribution Level Energy Market (DLEM), in which the energy product is traded (cf. UCS 1.1). We also assume the auction-based market clearing algorithm and the LinDistFlow model described in chapter 3 above.**

### 5.2.4 Interactive DLFM architecture

Novel smart grid architectures which are able to maximize social welfare (through efficient markets) lead to: i) energy with lower cost for consumers, ii) more revenue streams for Energy and Flexibility Service Providers (ESPs/FSPs), and iii) lower operation/management costs for network operators (i.e., TSO and DSOs). In a smart grid with high and distributed RES and high flexibility exploitation in which the distribution network faces congestion and voltage issues, an evolved energy market architecture through an advanced interaction between MO (TSO) and FMO (DSO) is needed. In this perspective, a market architecture that evolves Markets #1, #2 and #4 and is not constrained to be compatible with their existing versions can theoretically maximize social welfare.

In the proposed Interactive DLEM (I-DLEM) model, FLEXGRID considers an iterative process that takes place between the MO and FMO until they converge to an optimal dispatch schedule at both the TN and DN levels.

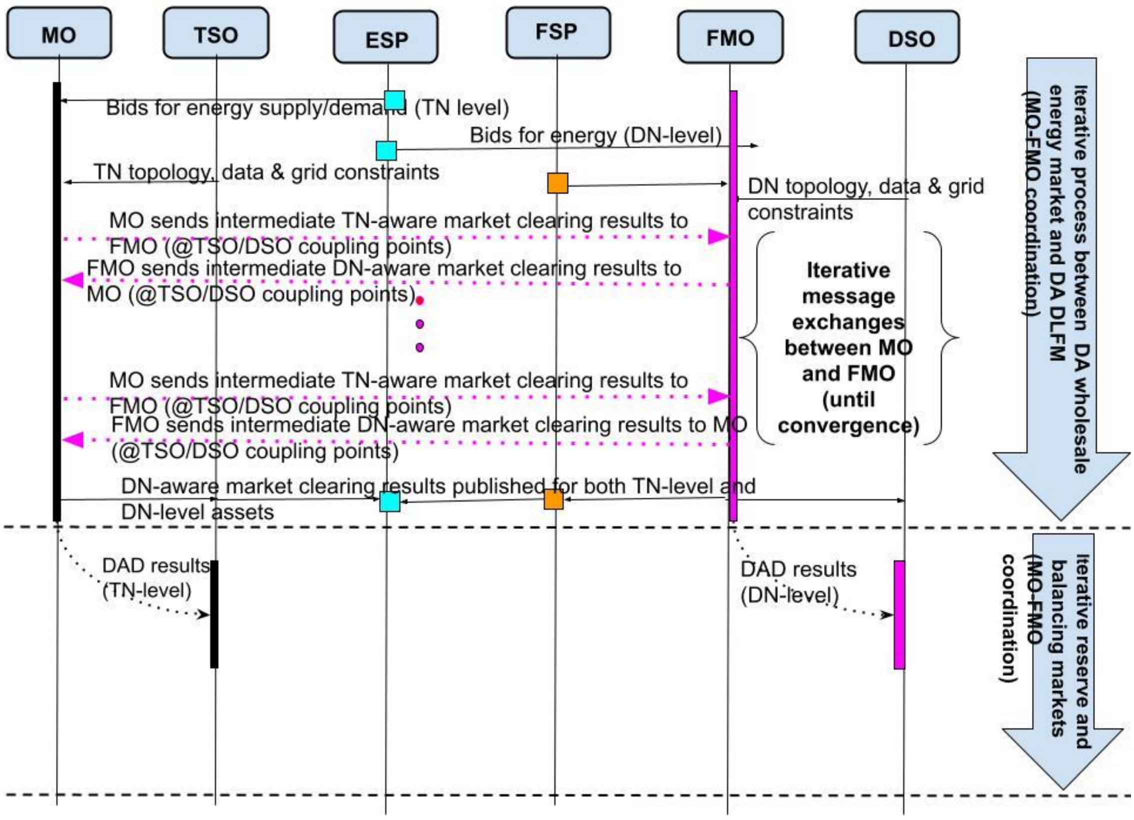


**Figure 35 FLEXGRID's I-DLEM architecture**

In the day-ahead energy market context, the MO initially runs an instance of its market clearing problem at the TN level and sends the results (in the form of Lagrange multipliers - LMPs) to the FMO. Then, the FMO takes the MO's results as input and runs its own market clearing problem at the DN level. The respective dispatch results are sent back to the MO, who runs another round of the TN-level market clearing. Of course, the dispatch schedules that are decided in each round of the algorithm's execution are virtual and are not actuated in reality. After several algorithmic iterations (i.e., several message exchanges between MO and FMO), the process converges (through the use of optimization theory) to an overall dispatch schedule (i.e., at both TN and DN levels) that maximizes social welfare. A similar iterative process may take place for day-ahead reserve markets and near-real-time balancing markets (cf. TSO-DSO collaboration).

Figure 36 below presents the aforementioned interactive market clearing process of a unified energy market, in which stakeholders in the DN (i.e., ESPs) and the TN (ESPs) are able to trade energy. Briefly, **the core of the proposed market architecture is a unified market clearing based on an iterative process (cf. yellow arrows) between the MO managing the TN and the FMO managing the DN**.

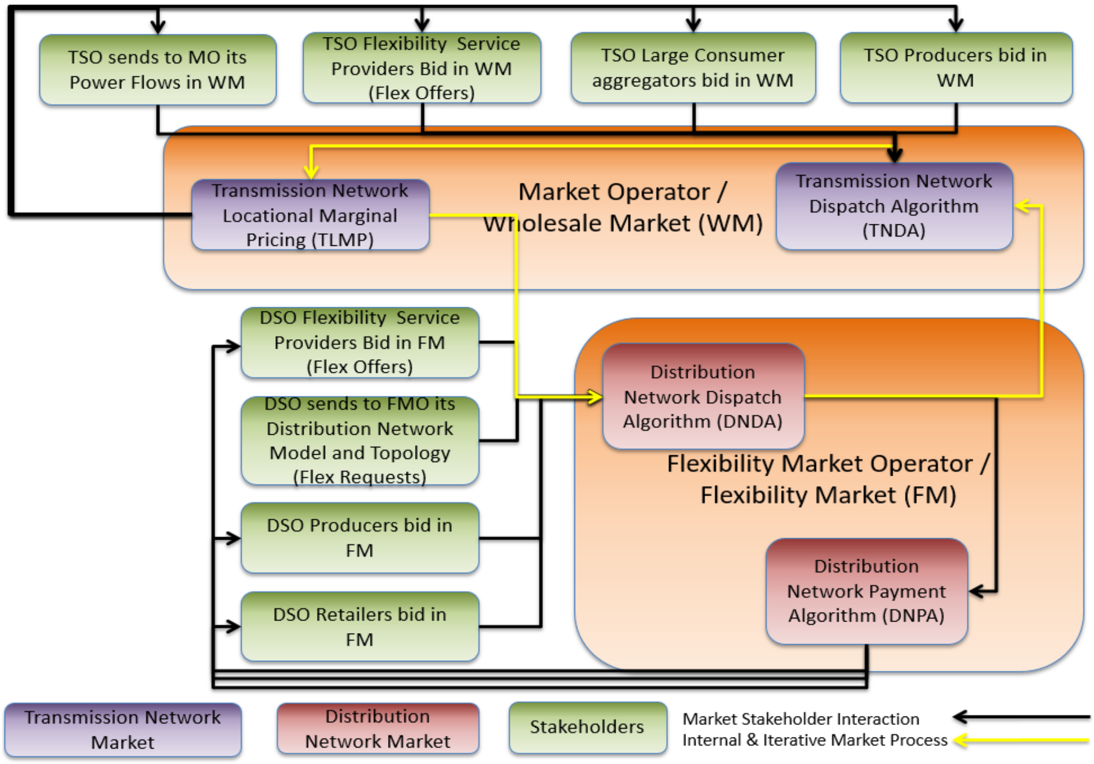

**Figure 36 Steps in the I-DLEM process**

At each iteration of this process, and according to the bids of the TN-level market stakeholders, the MO derives a time series (according to the scheduling horizon) of prices, noted as Transmission Network Locational Marginal Prices (TLMPs) for each node in the TN. These nodes include the interface nodes through which each DN exchanges power with the TN. An FMO operating in a certain DSO area takes as input: i) TLMPs that the MO derived, and ii) the bids of the DN-level market participants. In a second step, the FMO derives a time series of power flows (Distribution Network Dispatch – DND) in each node of the DN and updates the coupling point (DN-TN connection nodes) power flow time series. The termination condition of this iterative process is an identical dispatch in TN and DN in two consecutive iterations (with respect with an accuracy threshold).

According to the final dispatch, the pricing in the TN is coherent with the existing pricing policy in today's smart grids (TLMPs) and the pricing in the DN is conducted through a clearing algorithm that the FMO executes. The necessary steps for the operation of the proposed Interactive Market Clearing Algorithm (IMCA) are:

| | |
|---|---|
| **Step 1** | The DSO sends its distribution network data to the FMO. |

| | |
|---|---|
| **Step 2** | The FSPs, connected to the DSO, send their flexibility asset (e.g., ESS, DSM) bids (i.e., FlexOffers) to the FMO. Each FlexOffer includes the cost/utility function of the FSP and its operating constraints. |
| **Step 3** | The Producers (ESPs) connected to distribution network (e.g., RES, prosumers) send their bids to the FMO. |
| **Step 4** | The Consumers (ESPs) connected to the distribution network (i.e., demand aggregators) send their bids to the FMO. |
| **Step 5** | The MO generates a set of the TLMPs for the first iteration of the IMCA. |
| **Step 6** | In each iteration k of MCA: |
| **Step 6a** | Taking the $TLMP_k$ (TLMPs in $k^{th}$ iteration of IMCA) at the coupling point, the FMO generates a Distribution Network Dispatch denoted by $DND_k$ ($k^{th}$ iteration of IMCA) for each specific DSO area through the execution of the DND Algorithm (DNDA). |
| **Step 6b** | The DLEM stakeholders are compensated for their operation according to a Distribution Network Payment Algorithm (DNPA). |
| **Step 6c** | The TN stakeholders (i.e., generators, demand aggregators, etc) decide their dispatch based on the corresponding $TLMP_k$. The TSO calculates its power flows based on the zonal $TLMP_k$, which along with the TN-level stakeholders and the FMOs' decisions formulate the TN Dispatch (TND). |
| **Step 6d** | If the DND and the TND remain the same between two consecutive iterations of IMCA, then IMCA terminates. Otherwise, $TLMP_k$ are calculated by a TLMP Update Algorithm (TLMP-UA) based on the previously computed dispatches and $TLMP_k$). |
| **Step 7** | The last calculation of TLMPs and the last calculation of DNPA determine the payments of participants in the TN and DN, respectively. The last TND and DND solutions/schedules determine the dispatch in the two networks. |

**In this market setup, we assume that a Distribution Level Energy Market (DLEM), in which the energy product is traded (cf. UCS 1.1). We also assume the auction-based market clearing algorithm and the LinDistFlow model described in chapter 3 above. As this market is incompatible with the existing energy market architectures, FLEXGRID implemented this market in simulations in order to realize its advantages and quantify the disadvantages (through comparisons) over the other x-DLFM setups. The proposed algorithmic solution is based on the Dantzig-Wolfe decomposition method that is analyzed in subsection 5.3.2.1.**

## 5.3 Problem formulation and algorithmic solution

In this section, the models of the various market participants and the market clearing processes of the x-DLFMs are presented. We will start describing the market players connected at the transmission network and the description of DN-level assets (subsection 5.3.1). Then, the optimization problems representing the market clearing processes of each x-DLFM will be discussed (subsection 5.3.2).

### 5.3.1 Modeling TN- and DN-level assets

#### 5.3.1.1 Large Generators (supply side at TN level)

The technical constraints of large Generation Companies (GenCos) follow.

$\forall i \in G$

$$P_{i,b}^{g,min} \leq P_{i,t,b}^{g} \leq P_{i,b}^{g,max} \quad \forall t \in H, b \in B \tag{5.1}$$

$$-RD_i \leq \sum_{b\in B} P_{i,t,b}^{g} - \sum_{b\in B} P_{i,t-1,b}^{g} \leq RU_i, \quad \forall\, t > 1 \tag{5.2}$$

$$-RD_i \leq \sum_{b\in B} P_{i,t_0,b}^{g} - \sum_{b\in B} P_{i,t_0,b}^{g} \leq RU_i, \quad t = 1 \tag{5.3}$$

The set of TN-level GenCos is denoted by $G$. We assume that each GenCo $\forall i \in G$ owns $b$ number of generating units (the set of generating units per GenCo is denoted by $B$). Equation (5.1) represents the minimum and maximum limits on production, while ramping constraints are taken into consideration in Eqs. (5.2) and (5.3). The set of timeslots, into which the time horizon is divided, is denoted by $H$.

#### 5.3.1.2 Large Consumers (demand side at TN level)

Below, the technical characteristics of a Load Service Entity (LSE) are presented.

$\forall i \in D$

$$P_{i,b}^{d,min} \leq P_{i,t,b}^{d} \leq P_{i,b}^{d,max} \quad \forall\, t \in H, b \in B \tag{5.4}$$

$$-R_i^{dn} \leq \sum_{b\in B} P_{i,t,b}^{d} - \sum_{b\in B} P_{i,t-1,b}^{d} \leq R_i^{up}, \quad \forall\, t > 1 \tag{5.5}$$

$$-R_i^{dn} \leq \sum_{b\in B} P_{i,t_0,b}^{d} - \sum_{b\in B} P_{i,t_0,b}^{d} \leq R_i^{up}, \quad t = 1 \tag{5.6}$$

$$\sum_{t\in H} \sum_{b\in B} P_{i,t,b}^{d} \geq E_i^{d} \tag{5.7}$$

The set of consumers is denoted by $D$, and it is assumed that each one owns $b$ loads (with $B$ being the set of loads per LSE). We consider minimum and maximum limits on consumption as shown in eq. (5.4), ramp up and down bounds (Eqs. (5.5)-(5.6)) and a minimum energy demand that has to be always satisfied in eq. (5.7).

#### 5.3.1.3 Storage Units connected at the transmission network

In this subsection, the storage unit model is described.

$\forall i \in S$

$$0 \leq ch_{i,t} \leq \overline{ch_i} \quad \forall t \in H \tag{5.8}$$

$$0 \leq dis_{i,t} \leq \overline{dis_{\iota}} \;\; \forall t \in H \tag{5.9}$$

$$E_{i,t} = E_{i,t-1} + \Delta\left(ch_{i,t}\eta^{ch} - dis_{i,t}/\,\eta^{dis}\right), \qquad \forall t > 1 \tag{5.10}$$

$$E_{i,t} = E_{i,o} + \Delta\left(ch_{i,t}\eta^{ch} - dis_{i,t}/\,\eta^{dis}\right), \qquad t = 1 \tag{5.11}$$

$$E_i^{min} \leq E_{i,t} \leq E_i^{max} \;\; \forall t \in H \tag{5.12}$$

$$E_{i,T} = \gamma_i E_{i,o} \tag{5.13}$$

Equations (5.8) and (5.9) limit the charging and discharging power respectively of every storage unit $i \in S$ (with $S$ denoting the set of TN-level storage units), while Eqs. (5.10) and (5.11) state the State of Charge (SOC) dynamic equations. Eq. (5.12) sets the lower and upper bounds of the storage unit's SOC at each timeslot. Last but not least, eq. (5.13) enforces that the SOC at the last time instant (T) will be a fraction of the initial SOC, so a minimum level of energy will be available at the beginning of the next scheduling horizon (i.e., next day). In other words, this is a restoration SOC constraint.

#### *5.3.1.4 Transmission System Operator*

We consider a Transmission Network with a set of buses $N$ and a set of transmission lines $L$. We use the DC power flow model in order to represent the TN constraints, which are presented below:

$$-T_{i,j}^{max} \leq \left(\theta_{i,t} - \theta_{j,t}\right) y_{i,j} \leq T_{i,j}^{max} \;\; \forall (i,j) \in L, t \in H \tag{5.14}$$

$$-\pi \leq \theta_{i,t} \leq \pi \quad \forall i \in N, t \in H \tag{5.15}$$

In Eq. (5.14), $y_{i,j}$ is the admittance of the transmission line $(i,j)$ and the product $(\theta_{i,t} - \theta_{j,t})y_{i,j}$ is the power flow at line $(i,j) \in L$. Thus, Eq. (5.15) sets the lines' capacity limits, while via eq. (5.16), the nodal voltage angle is bounded.

#### *5.3.1.5 Distributed Generators – DGs (supply side at DN level)*

The limits of the distributed generators on active and reactive power are set based on equations (5.16) and (5.17). These bounds are related with physical constraints of DGs and weather conditions.

$$p_{i,t}^{DG,min} \leq p_{i,t}^{DG} \leq p_{i,t}^{DG,max} \; \forall i \in G^D, t \in H \tag{5.16}$$

$$\frac{p_{i,t}^{DG}}{\sqrt{\left(p_{i,t}^{DG}\right)^2 + \left(q_{i,t}^{DG}\right)^2}} \geq PF_{i,min} \; \forall i \in G^D, t \in H \tag{5.17}$$

Eq. (5.17) can be transformed into a linear one as follows:

$$-\frac{p_{i,t}^{DG} * \sqrt{1-\left(PF_{i,min}\right)^2}}{PF_{i,min}} \leq q_{i,t}^{DG} \leq \frac{p_{i,t}^{DG} * \sqrt{1-\left(PF_{i,min}\right)^2}}{PF_{i,min}} \quad \forall i \in G^D, t \in H \tag{5.18}$$

since a minimum Power Factor (PF) could be assumed and considering that $p_{i,t}^{DG}$ and $PF_{i,min}$ are non-negative.

#### 5.3.1.6 Distributed Energy Storage Systems (DESSs)

Equations (5.19) and (5.20) set the power limits of the charging and discharging mode of the distributed energy storage units (DESSs). In eq. (5.21), the SOC of each battery is shown, which depends on the SOC at the previous timeslot and of course on the charging and discharging power at the specific timeslot. The Greek letter $\eta$ indicates the efficiency of charging and discharging modes. In Eq. (5.22), SOC limits are considered, while Eq. (5.23) ensures the restoration of SOC at the end of the day. The apparent power capacity of inverters is represented in Eq. (5.24). A positive value of $q_{i,t}^{DS}$ means the DESS generates reactive power. The equation (5.24) is replaced by a linear set of constraints using the inner polygon approximation, as in eq. (5.25):

$$0 \leq p_{i,t}^{DS,dis} \leq p_i^{DS,dis,max} \ \forall i \in S^D, t \in H \tag{5.19}$$

$$0 \leq p_{i,t}^{DS,ch} \leq p_i^{DS,ch,max} \ \forall i \in S^D, t \in H \tag{5.20}$$

$$E_{i,t}^{DS} = E_{i,t-1}^{DS} + \eta_i^{DS,ch} * p_{i,t}^{DS,ch} - \left( 1 \middle/ \eta_i^{DS,dis} \right) * p_{i,t}^{DS,dis} \ \forall i \in S^D, t \in H \tag{5.21}$$

$$E_i^{DS,min} \leq E_{i,t}^{DS} \leq E_i^{DS,max} \ \forall i \in S^D, t \in H \tag{5.22}$$

$$E_{i,T}^{DS} \geq E_{i,0}^{DS} \ \forall i \in S^D \tag{5.23}$$

$$\left(p_{i,t}^{DS,ch} - p_{i,t}^{DS,dis}\right)^2 + \left(q_{i,t}^{DS}\right)^2 \leq \left(S_i^{DS,max}\right)^2 \ \forall i \in S^D, t \in H \tag{5.24}$$

$$A_i \cdot \left(p_{i,t}^{DS,ch} - p_{i,t}^{DS,dis}\right) + B_i \cdot q_{i,t}^{DS} \leq \Gamma_i \ \forall i \in S^D, t \in H \tag{5.25}$$

where,

$$A_i = \begin{bmatrix} \sin\theta_0 - \sin\theta_1 \\ \sin\theta_1 - \sin\theta_2 \\ \vdots \\ \sin\theta_{M-2} - \sin\theta_{M-1} \end{bmatrix}$$

$$B_i = \begin{bmatrix} \cos\theta_1 - \cos\theta_0 \\ \cos\theta_2 - \cos\theta_1 \\ \vdots \\ \cos\theta_{M-1} - \cos\theta_{M-2} \end{bmatrix}$$

$$\Gamma_i = \overline{S_i^s} \cdot \begin{bmatrix} \cos\theta_1 \cdot \sin\theta_0 - \sin\theta_1 \cdot \cos\theta_0 \\ \cos\theta_2 \cdot \sin\theta_1 - \sin\theta_2 \cdot \cos\theta_1 \\ \vdots \\ \cos\theta_{M-1} \cdot \sin\theta_{M-2} - \sin\theta_{M-1} \cdot \cos\theta_{M-2} \end{bmatrix}$$

$$\theta = \frac{2\pi}{M}, \quad \theta_\kappa = k \cdot \theta, \quad k = 0, 1, \dots, M-1$$

with M indicating polygon's vertices number[3].

#### *5.3.1.7 Demand Aggregators – DA (demand side at DN level)*

The DAs can schedule their flexible demand consumers, and they are capable of accomplishing Demand Response. In eq. (5.26) and (5.27), limits on the active/reactive power of the loads are imposed:

$$p_{i,t}^{DA,min} \leq p_{i,t}^{DA} \leq p_{i,t}^{DA,max} \quad \forall i \in D^{DA}, t \in H \tag{5.26}$$

$$0 \leq q_{i,t}^{DA} \leq p_{i,t}^{DA} * tan\big(acos(PF_i)\big) \ \forall i \in D^{DA}, t \in H \tag{5.27}$$

Both the active and reactive power related to the DA portfolio incur cost to the DA. Hence, the goal of the DAs is to achieve the lowest cost possible by trading their active and reactive power.

#### *5.3.1.8 Static Var Compensators (SVCs)*

The SVCs are reactive power elements that can either supply or absorb reactive power aiding to the voltage stability of the distribution network. Assuming that the SVCs operate in a continuous way, they are represented with eq. (5.28). If $q_{i,t}^{SVC}$ is positive, then the SVC offers reactive power to the grid.

$$q_i^{SVC,min} \leq q_{i,t}^{SVC} \leq q_i^{SVC,max} \ \forall i \in D^{SVC}, t \in H \tag{5.28}$$

#### *5.3.1.9 Distribution Network Model*

The distribution network participates in the market as an aggregator of multiple and various distributed energy resources (DERs) that reside at the distribution grid, whose various models have been formulated above. Moreover, the topology and the constraints are included to represent more accurately the conditions that would hold at the grid based on the mathematical formulation below.

The distribution network model includes voltage bounds, lines' capacity limits, while the location of the various assets that reside within the network are integrated. The linearized DistFlow equations are used as follows:

$$\sum_{k \in \Omega_p(n)} f_{nk,t}^p - \sum_{j \in \Omega_d(n)} f_{jn,t}^p = p_{i,t}^{DS,ch} + p_{i,t}^{DA} - p_{i,t}^{DG} - p_{i,t}^{DS,dis} \ \forall n \in N^D, t \in H \tag{5.29}$$

[3] It should be noted that a proper size of M should be selected in order to achieve a desired trade-off between efficiency and accuracy.

$$\sum_{k\in\Omega_p(n)} f_{nk,t}^{q} - \sum_{j\in\Omega_d(n)} f_{jn,t}^{q} = q_{i,t}^{DA} - q_{i,t}^{DS} - q_{i,t}^{DG} - q_{i,t}^{SVC} \;\; \forall n \in N^D, t \in H \tag{5.30}$$

$$U_{n,t} = U_{j,t} - 2 \cdot \left(r_{jn} \cdot f_{jn,t}^{p} + x_{jn} \cdot f_{jn,t}^{q}\right) \qquad \forall n \in N^D, j \in \Omega_p(n), t \in H \tag{5.31}$$

$$U_n^{min} \leq U_{n,t} \leq U_n^{max} \;\; \forall n \in N^D, t \in H \tag{5.32}$$

$$\left(f_{nk,t}^{p}\right)^2 + \left(f_{nk,t}^{q}\right)^2 \leq \left(S_{nk}^{f,max}\right)^2 \qquad \forall nk \in B, t \in H \tag{5.33}$$

$$p_t^{sub} = \sum_{0k} f_{0k,t}^{p} \qquad \forall t \in H \tag{5.34}$$

$$q_t^{sub} = \sum_{0k} f_{0k,t}^{q} \qquad \forall t \in H \tag{5.35}$$

Eq. (5.29) indicates the active power balance, while Eq. (5.30) the reactive one. On the left side of the equations (5.29) – (5.30), there are the power flows, while on the right side the distributed production and consumption are included. The voltage drop on each DN bus is modeled via eq. (5.31) and the respective voltage limits that have to be satisfied are expressed in eq. (5.32). The non-linear equation (5.33) imposes the limits on the capacity of the lines. As mentioned earlier, in the case of DESSs, eq. (5.33) can be replaced by a linear one using the inner polygon approximation. The active and reactive power balance at the coupling point between the DSO and the TSO (substation) are imposed on Eqs. (5.34) and (5.35) respectively.

### 5.3.2 Description of x-DLFM clearing processes

#### *5.3.2.1 I-DLFM Clearing Process*

In each iteration of the Dantzig-Wolfe decomposition algorithm, which is used to clear I-DLFM, the MO declares a set of nodal TLMPs (or else zonal TLMPs if we consider today's EU market), denoted by $\{\lambda_{i,t} |\ i \in N, t \in H\}$. Given these prices, the TSO optimizes its portfolio (TN-level GenCos, LSEs, storage units and transmission lines):

$$\begin{aligned} \min_{X^{TN}} \sum_{i\in G}\sum_{t\in H}\sum_{b\in B}\left\{\left(c_{i,t,b} - \lambda_{i,t}\right) \cdot P_{i,t,b}^{g}\right\} + \sum_{i\in D}\sum_{t\in H}\sum_{b\in B}\left\{\left(\lambda_{i,t} - U_{i,t,b}^{d}\right) \cdot P_{i,t,b}^{d}\right\} \\ + \sum_{i\in S}\sum_{t\in H}\left\{\lambda_{i,t} \cdot \left(ch_{i,t} - dis_{i,t}\right) + MC_i^{ch} \cdot ch_{i,t} + MC_i^{dis} \cdot dis_{i,t}\right\} \\ + \sum_{t\in H}\left\{\sum_{l\in L}\left(\lambda_{i,t} - \lambda_{j,t}\right) \cdot \left(\theta_{i,t} - \theta_{j,t}\right) \cdot y_{i,j}\right\} \end{aligned} \tag{5.36}$$

Subject to: (5.1) – (5.15).

Where $X^{TN} = \{P_{i,t,b}^{g}, P_{i,t,b}^{d}, E_{i,t}, ch_{i,t}, dis_{i,t}, \theta_{i,t}\}$. The objective of the TSO is to maximize the summation of the individual profit functions of TN-level assets. The first term of the objective function (5.36) represents the difference between the production marginal cost $c_{i,t,b}$ and the price $\lambda_{i,t}$, for each quantity of energy traded. The second term refers to the consumers' welfare, which equals to the difference between their electricity buying cost ($\lambda_{i,t} \cdot P_{i,t,b}^{d}$) and the utility ($U_{i,t,b}^{d} \cdot P_{i,t,b}^{d}$) they gain from the electricity consumption. The third term in Eq. (5.36) represents the storage owners' net profit. A storage unit can act either as generator or load. In generation mode (i.e. discharging), the storage units are paid at the relative TLMPs ($\lambda_{i,t} \cdot dis_{i,t}$), whereas in load mode (i.e. charging), these units have to pay at the same TLMPs to the Market Operator for the amount of power they draw ($\lambda_{i,t} \cdot ch_{i,t}$). We also take into consideration the operating cost of the storage units every time they charge or discharge power ( $MC_i^{ch} \cdot ch_{i,t}, MC_i^{dis} \cdot dis_{i,t}$ ). Finally, the last term in Eq. (5.36) reflects the transmission cost for delivering energy from one geographical region (TN node) to another.

On the other hand, the LMO takes as input the hourly price signals[4] ($\lambda_{i,t}$) set by the MO and its goal is to minimize the operational cost of the distribution network, meaning that is aiming at minimizing the cost of purchasing energy from the wholesale market and the costs related with the operation of DERs. A difference between the DLEM and the wholesale market is the presence of reactive power. It has to be noted that even if the DERs absorb or offer reactive power, a cost is incurred. Thus, the objective function should include this particularity. A simple way to do so is by using the absolute values of $q_{i,t}^{DS}, q_{i,t}^{DG}, q_{i,t}^{SVC}$. The corresponding optimization problem of LMO is formulated as follows:

$$\min_{X^D} \sum_{\forall t \in H} \Bigg( \lambda_t^{TSO,k} \cdot p_t^{sub} + \sum_{\forall i \in G^D} \left( c_{i,t}^{P,DG} \cdot p_{i,t}^{DG} + c_{i,t}^{Q,DG} \cdot \left| q_{i,t}^{DG} \right| \right)$$
$$+ \sum_{\forall i \in S^D} \left( c_{i,t}^{P,DS,dis} \cdot p_{i,t}^{DS,dis} + c_{i,t}^{P,DS,ch} \cdot p_{i,t}^{DS,ch} + c_{i,t}^{Q,DS} \cdot \left| q_{i,t}^{DS} \right| \right)$$
$$+ \sum_{\forall i \in D^{DA}} \left( u_{i,t}^{P,DA} \cdot p_{i,t}^{DA} \right) + \sum_{\forall i \in D^{SVC}} \left( c_{i,t}^{Q,SVC} \cdot \left| q_{i,t}^{SVC} \right| \right) + \sum_{\forall i \in G^R} \left( VoRS \cdot \left( p_{i,t}^{DG,max} - p_{i,t}^{DG} \right) \right) \Bigg) \tag{5.37}$$

Subject to: (5.16), (5.18)-(5.23), (5.25)-(5.35)

Where $X^D = \{p_t^{sub}, q_t^{sub}, p_{i,t}^{DG}, q_{i,t}^{DG}, p_{i,t}^{DS,dis}, p_{i,t}^{DS,ch}, q_{i,t}^{DS}, p_{i,t}^{DA}, q_{i,t}^{DA}, q_{i,t}^{SVC}, f_{nk,t}^{p}, f_{nk,t}^{q}, U_{n,t}\}$. The objective function (5.37) takes into account all the costs related with the operation of the distribution network. The term $\lambda_t^{TSO,k} \cdot p_t^{sub}$ indicates the cost of purchasing from or selling active power to the TN. The parameters $c_{i,t}^{P,DG}$ indicate production cost of active power from the DGs and $c_{i,t}^{Q,DG}$ is the cost related to the compensation of DGs for supplying or absorbing reactive power. In the DESSs case, there is a cost of active power for both charging and discharging (i.e. ($c_{i,t}^{P,DS,dis} \cdot p_{i,t}^{DS,dis} + c_{i,t}^{P,DS,ch} \cdot p_{i,t}^{DS,ch}$) and a cost related to reactive power (consumed or offered), $c_{i,t}^{Q,DS} \cdot \left| q_{i,t}^{DS} \right|$. The price bid of the DA for active power is denoted by

[4] A vector of 24 hourly timeslots for the day-ahead energy market is assumed. We may also consider 15-minute time units (if real-life data will be available) in order to study whether there will be any difference in the need for flexibility.

$u_{i,t}^{P,DA}$ and is related with the respective quantity $p_{i,t}^{DA}$. The compensation of SVCs for supplying or absorbing reactive power is presented with the term $c_{i,t}^{Q,SVC} \cdot |q_{i,t}^{SVC}|$. Finally, the last term of (5.37) corresponds to the cost of distributed renewable energy spillage ($VoRS$). The set of distributed renewable energy generators is denoted by $G^R$, which is a subset of the set of distributed generators (i.e. $G^R \subseteq G^D$).

In order to linearize the absolute values, we add some auxiliary continuous variables $w_{i,t}$ and the following constraints:

$$w_{i,t}^{DG} \geq q_{i,t}^{DG} \qquad \forall i \in G^D, t \in H \tag{5.38}$$

$$w_{i,t}^{DG} \geq -q_{i,t}^{DG} \qquad \forall i \in G^D, t \in H \tag{5.39}$$

$$w_{i,t}^{DS} \geq q_{i,t}^{DS} \qquad \forall i \in S^D, t \in H \tag{5.40}$$

$$w_{i,t}^{DS} \geq -q_{i,t}^{DS} \qquad \forall i \in S^D, t \in H \tag{5.41}$$

$$w_{i,t}^{SVC} \geq q_{i,t}^{SVC} \qquad \forall i \in D^{SVC}, t \in H \tag{5.42}$$

$$w_{i,t}^{SVC} \geq -q_{i,t}^{SVC} \qquad \forall i \in D^{SVC}, t \in H \tag{5.43}$$

resulting to the following problem:

$$\begin{aligned}\min_{X^D} \sum_{\forall t \in H} \Bigg( & \lambda_t^{TSO,k} \cdot p_t^{sub} + \sum_{\forall i \in G^D} \left( c_{i,t}^{P,DG} \cdot p_{i,t}^{DG} + c_{i,t}^{Q,DG} \cdot w_{i,t}^{DG} \right) \\ & + \sum_{\forall i \in S^D} \left( c_{i,t}^{P,DS,dis} \cdot p_{i,t}^{DS,dis} + c_{i,t}^{P,DS,ch} \cdot p_{i,t}^{DS,ch} + c_{i,t}^{Q,DS} \cdot w_{i,t}^{DS} \right) \\ & + \sum_{\forall i \in D^{DA}} \left( u_{i,t}^{P,DA} \cdot p_{i,t}^{DA} \right) + \sum_{\forall i \in D^{SVC}} \left( c_{i,t}^{Q,SVC} \cdot w_{i,t}^{SVC} \right) + \sum_{\forall i \in G^R} \left( VoRS \cdot \left( p_{i,t}^{DG,max} - p_{i,t}^{DG} \right) \right) \Bigg)\end{aligned} \tag{5.44}$$

subject to: (5.16), (5.18)-(5.23), (5.25)-(5.35) and (5.38)-(5.43).

After the TSO and the DSO having optimally decided on the dispatch of their assets, solving optimization problems (5.36) and (5.44) respectively, the MO updates the nodal TLMPs. This iterative process terminates when after two successive iterations, the nodal TLMPs remain unchanged. For more details on the Dantzig-Wolfe decomposition algorithm implemented to clear the proposed I-DLFM, the interested reader can refer to FLEXGRID D5.2 section 5.5[5].

[5] https://flexgrid-project.eu/assets/deliverables/FLEXGRID_D5.2_final_26032021.pdf

### 5.3.2.2 P-DLFM Clearing Process

In the P-DLFM architecture, the clearing process of the DLFM precedes the one of the TN-level energy market. The FMO operates the DN-level market using a forecast of the price at the substation, which is the coupling point between the distribution and the transmission networks. Thus, the FMO solves the following optimization problem:

$$\min_{X^D} C_{DSO} = \sum_{\forall t \in H} \Bigg( \widetilde{\lambda_t^{TSO,k}} \cdot p_t^{sub} + \sum_{\forall i \in G^D} \left( c_{i,t}^{P,DG} \cdot p_{i,t}^{DG} + c_{i,t}^{Q,DG} \cdot w_{i,t}^{DG} \right)$$
$$+ \sum_{\forall i \in S^D} \left( c_{i,t}^{P,DS,dis} \cdot p_{i,t}^{DS,dis} + c_{i,t}^{P,DS,ch} \cdot p_{i,t}^{DS,ch} + c_{i,t}^{Q,DS} \cdot w_{i,t}^{DS} \right) - \sum_{\forall i \in D^{DA}} \left( u_{i,t}^{P,DA} \cdot p_{i,t}^{DA} \right)$$
$$+ \sum_{\forall i \in D^{SVC}} \left( c_{i,t}^{Q,SVC} \cdot w_{i,t}^{SVC} \right) + \sum_{\forall i \in G^R} \left( VoRS \cdot (p_{i,t}^{DG,max} - p_{i,t}^{DG}) \right) \Bigg) \tag{5.45}$$

subject to: (5.16), (5.18)-(5.23), (5.25)-(5.35) and (5.38)-(5.43).

Solving optimization problem (5.45), the FMO calculates the dispatch of the DN-level assets and ultimately the power traded between the TSO and the DSO at the substation ($p_t^{sub}$). Note that $p_t^{sub} > 0$, when the DSO absorbs power from the TN, while $p_t^{sub} < 0$, when the DSO supplies power the main grid. Next, the MO clears the TN-level energy market, solving the following optimization problem, while taking as input the FMO's decisions.

$$\min_{X^{TN}} \sum_{i \in G} \sum_{t \in H} \sum_{b \in B} \{ c_{i,t,b} \cdot P_{i,t,b}^{g} \} - \sum_{i \in D} \sum_{t \in H} \sum_{b \in B} \{ U_{i,t,b}^{d} \cdot P_{i,t,b}^{d} \}$$
$$+ \sum_{i \in S} \sum_{t \in H} (MC_i^{ch} ch_{i,t} + MC_i^{dis} dis_{i,t}) \tag{5.46}$$

Subject to:

Eqs. (5.1) – (5.15)

$$P_{i,t,b}^{g} - P_{i,t,b}^{d} + dis_{i,t} - ch_{i,t} - \overline{p_t^{sub}} = 0; \quad (\lambda_{i,t}) \quad \forall i \in N, t \in H$$
(5.47)

In the objective function (5.46), the MO maximizes the Social Welfare, or in other words minimizes the system's Social Cost, calculating the optimal TN-level assets' dispatch. In Eq. (5.47), the nodal power balance is imposed, and its corresponding dual variables are the nodal TLMPs. The parameter $\overline{p_t^{sub}}$ denotes the power flow through the TSO-DSO coupling point, decided by the FMO.

### 5.3.2.3 R-DLFM Clearing Process

Initially in the R-DLFM architecture, the MO clears the TN-level energy market, in which the DN-level producers and consumers participate, without taking into account the DN physical constraints. Thus, the MO solves the following optimization problem:

$$\min_{X^{RTN}} \sum_{i\in G}\sum_{t\in H}\sum_{b\in B}\{c_{i,t,b}\cdot P^{g}_{i,t,b}\} - \sum_{i\in D}\sum_{t\in H}\sum_{b\in B}\{U^{d}_{i,t,b}\cdot P^{d}_{i,t,b}\} + \sum_{i\in S}\sum_{t\in H}\left(MC^{ch}_{i} ch_{i,t} + MC^{dis}_{i} dis_{i,t}\right) + \sum_{\forall i\in G^{D}}\left(c^{P,DG}_{i,t}\cdot p^{DG}_{i,t}\right) - \sum_{\forall i\in D^{DA}}\left(u^{P,DA}_{i,t}\cdot p^{DA}_{i,t}\right) + \sum_{\forall i\in G^{R}}\left(VoRS\cdot (p^{DG,max}_{i,t} - p^{DG}_{i,t})\right) \tag{5.48}$$

Subject to:

Eqs. (5.1) – (5.16), (5.18), (5.26)-(5.27)

$P^{g}_{i,t,b} - P^{d}_{i,t,b} + dis_{i,t} - ch_{i,t} - p^{sub}_{t} = 0; \quad (\lambda_{i,t}) \ \ \forall i\in N, t\in H$
(5.49)
$p^{sub}_{t} = \sum_{\forall i\in D^{DA}}\left(p^{DA}_{i,t}\right) - \sum_{\forall i\in G^{D}}\left(p^{DG}_{i,t}\right); \qquad \forall t\in H$
(5.50)

Where $X^{RTN} = \{P^{g}_{i,t,b}, P^{d}_{i,t,b}, E_{i,t}, ch_{i,t}, dis_{i,t}, \theta_{i,t}, p^{DG}_{i,t}, p^{DA}_{i,t}, p^{sub}_{t}\}$. The MO minimizes the system's Social Cost, which comparing to P-DLFM, it also includes the cost of distributed generators, the utility of DN-level loads and the cost of distributed renewable energy spillage. Equations (5.49) and (5.50) represent the nodal and the DSO-TSO coupling point power balance constraints. The optimal decisions on the distributed generation and demand are denoted by $\overline{p^{DG}_{i,t}}$ and $\overline{p^{DA}_{i,t}}$ respectively.

Since, the MO's optimal dispatch is DN-unaware, the FMO, following the TN-level energy market clearing process, runs the DLFM in order to ensure the reliable operation of the distribution network. Thus, the FMO solves the following optimization problem in order to procure the necessary flexibility so as to alleviate any potential contingencies.

$$\min_{X^{RDN}} \sum_{\forall t\in H}\left(\sum_{\forall i\in G^{D}}\left(c^{P,DG}_{i,t}\cdot (p^{DG,fl,up}_{i,t} + p^{DG,fl,dn}_{i,t}) + c^{Q,DG}_{i,t}\cdot \left|q^{DG}_{i,t}\right|\right) + \sum_{\forall i\in S^{D}}\left(c^{P,DS,dis}_{i,t}\cdot p^{DS,dis}_{i,t} + c^{P,DS,ch}_{i,t}\cdot p^{DS,ch}_{i,t} + c^{Q,DS}_{i,t}\cdot \left|q^{DS}_{i,t}\right|\right) + \sum_{\forall i\in D^{DA}}\left(u^{P,DA}_{i,t}\cdot (p^{DA,fl,up}_{i,t} + p^{DA,fl,dn}_{i,t})\right) + \sum_{\forall i\in D^{SVC}}\left(c^{Q,SVC}_{i,t}\cdot \left|q^{SVC}_{i,t}\right|\right) + \sum_{\forall i\in G^{R}}\left(VoRS\cdot p^{DG,fl,dn}_{i,t}\right)\right) \tag{5.50}$$

Subject to :

Eqs. (5.19)-(5.23), (5.25), (5.28), (5.31)-(5.35), (5.38)-(5.43)

$p^{DG,min}_{i,t} \le \overline{p^{DG}_{i,t}} + p^{DG,fl,up}_{i,t} - p^{DG,fl,dn}_{i,t} \le p^{DG,max}_{i,t} \ \forall i\in G^{D}, t\in H$
(5.51)

$$-\frac{\left(\overline{p_{i,t}^{DG}}+p_{i,t}^{DG,fl,up}-p_{i,t}^{DG,fl,dn}\right)\cdot\sqrt{1-\left(PF_{i,min}\right)^2}}{PF_{i,min}} \le q_{i,t}^{DG} \le \frac{\left(\overline{p_{i,t}^{DG}}+p_{i,t}^{DG,fl,up}-p_{i,t}^{DG,fl,dn}\right)\cdot\sqrt{1-\left(PF_{i,min}\right)^2}}{PF_{i,min}} \quad \forall i \in G^D, t \in H \quad (5.52)$$

$$p_{i,t}^{DA,min} \le \overline{p_{i,t}^{DA}} + p_{i,t}^{DA,fl,up} - p_{i,t}^{DA,fl,dn} \le p_{i,t}^{DA,max} \quad \forall i \in D^{DA}, t \in H \quad (5.53)$$

$$q_{i,t}^{DA} = \left(\overline{p_{i,t}^{DA}} + p_{i,t}^{DA,fl,up} - p_{i,t}^{DA,fl,dn}\right) \cdot tan\left(acos(PF_i)\right) \ \forall i \in D^{DA}, t \in H \quad (5.54)$$

$$\sum_{k\in\Omega_p(n)} f_{nk,t}^{p} - \sum_{j\in\Omega_d(n)} f_{jn,t}^{p} = p_{i,t}^{DS,ch} + \left(\overline{p_{i,t}^{DA}} + p_{i,t}^{DA,fl,up} - p_{i,t}^{DA,fl,dn}\right) - \left(\overline{p_{i,t}^{DG}} + p_{i,t}^{DG,fl,up} - p_{i,t}^{DG,fl,dn}\right) - p_{i,t}^{DS,dis}; \quad (\lambda_{n,t}^{P}) \ \forall n \in N^D, t \in H \quad (5.55)$$

$$\sum_{k\in\Omega_p(n)} f_{nk,t}^{q} - \sum_{j\in\Omega_d(n)} f_{jn,t}^{q} = q_{i,t}^{DA} - q_{i,t}^{DS} - q_{i,t}^{DG} - q_{i,t}^{SVC}; \ (\lambda_{n,t}^{Q}) \, \forall n \in N^D, t \in H \quad (5.56)$$

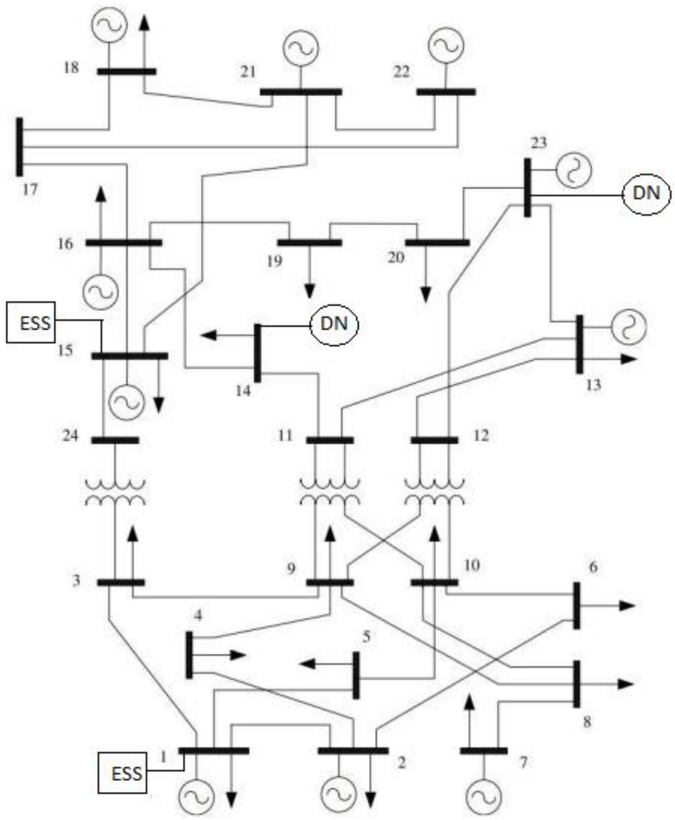


**Figure 37 The IEEE One-Area Reliability Test System**

In the objective function (5.50), the FMO minimizes the flexibility procurement cost. The distributed generators and loads can deviate from the TN-level energy market positions ($\overline{p_{i,t}^{DG}}, \overline{p_{i,t}^{DA}}$), providing either upward flexibility ($p_{i,t}^{DG,fl,up}, p_{i,t}^{DA,fl,up}$), or downward flexibility ($p_{i,t}^{DG,fl,dn}, p_{i,t}^{DA,fl,dn}$) to the DSO. Equations (5.51)-(5.52) and (5.53)-(5.54) represent the distributed generators and loads constraints respectively, taking into account the final dispatches of these assets. Equations (5.55) and (5.56) represent the active and reactive nodal power balance constraints and their corresponding dual variables are the DLFM active and reactive flexibility prices ($\lambda_{n,t}^{P}, \lambda_{n,t}^{Q}$). When the DSO needs upward flexibility, these prices take positive values, while when the DSO needs downward flexibility the DLFM prices take negative values. The optimization variables of the above optimization problem is $X^{RDN} = \{p_t^{sub}, q_t^{sub}, p_{i,t}^{DG,fl,up}, p_{i,t}^{DG,fl,dn}, q_{i,t}^{DG}, p_{i,t}^{DS,dis}, p_{i,t}^{DS,ch}, q_{i,t}^{DS}, p_{i,t}^{DA,fl,up}, p_{i,t}^{DA,fl,dn}, q_{i,t}^{DA}, q_{i,t}^{SVC}, f_{nk,t}^{p}, f_{nk,t}^{q}, U_{n,t}\}$.

## 5.4 Simulation setup and performance evaluation results

### 5.4.1 Simulation setup

The proposed x-DLFM architectures are tested on the IEEE one-area Reliability Test System[6], which is illustrated in Fig. 37. A daily (24-h) time horizon is considered. The transmission network lines characteristics are given in table 26. Two storage units are located in transmission buses 1 and 15. Technical characteristics of the transmission-level generators, storage units and loads are given in Tables 27, 28 and 29. We assume that the TN-level loads follow the same electricity consumption curve that is depicted in Figure 38. Finally, the power base is 100MVA.

**Table 26 Transmission Network Lines Technical Characteristics**

| Line (#) | From Bus (#) | To Bus (#) | $y$ (p.u.) | $T^{max}$ (MW) |
|---|---|---|---|---|
| 1 | 1 | 2 | 68.49 | 175 |
| 2 | 1 | 3 | 4.44 | 175 |
| 3 | 1 | 5 | 11.03 | 350 |
| 4 | 2 | 4 | 7.37 | 175 |
| 5 | 2 | 6 | 4.88 | 175 |
| 6 | 3 | 9 | 7.87 | 175 |
| 7 | 3 | 24 | 11.90 | 400 |
| 8 | 4 | 9 | 9.01 | 175 |
| 9 | 5 | 10 | 10.64 | 350 |
| 10 | 6 | 10 | 15.58 | 175 |
| 11 | 7 | 8 | 15.34 | 350 |
| 12 | 8 | 9 | 5.68 | 175 |
| 13 | 8 | 10 | 5.68 | 175 |
| 14 | 9 | 11 | 11.90 | 400 |
| 15 | 9 | 12 | 11.90 | 400 |
| 16 | 10 | 11 | 11.90 | 400 |
| 17 | 10 | 12 | 11.90 | 400 |
| 18 | 11 | 13 | 20.49 | 500 |
| 19 | 11 | 14 | 23.47 | 500 |
| 20 | 12 | 13 | 20.49 | 500 |
| 21 | 12 | 23 | 10.15 | 500 |

[6] C. Ordoudis, P. Pinson, J. Morales, and M. Zugno, "An updated version of the ieee rts 24-bus system for electricity market and power system operation studies", 2016. [online]. Available: "https://orbit.dtu.dk/en/publications/an-updated-version-of-the-ieee-rts-24-bus-system-for-electricity-".

| | | | | |
|---|---|---|---|---|
| 22 | 13 | 23 | 11.31 | 200 |
| 23 | 14 | 16 | 16.84 | 250 |
| 24 | 15 | 16 | 58.14 | 500 |
| 25 | 15 | 21 | 40.16 | 400 |
| 26 | 15 | 24 | 18.90 | 500 |
| 27 | 16 | 17 | 38.02 | 500 |
| 28 | 16 | 19 | 42.74 | 500 |
| 29 | 17 | 18 | 69.93 | 500 |
| 30 | 17 | 22 | 9.35 | 500 |
| 31 | 18 | 21 | 75.76 | 1000 |
| 32 | 19 | 20 | 49.26 | 1000 |
| 33 | 20 | 23 | 89.29 | 1000 |
| 34 | 21 | 22 | 14.45 | 500 |

**Table 27 TN-level Generating Units Technical Characteristics**

| Bus (#) | $P^{g,max}$ (MW) | $P^{g,min}$ (MW) | $RU$ (MW/h) | $RD$ (MW/h) | $P^{g}_{t=0}$ (MW) | $c$ (€/MW) |
|---|---|---|---|---|---|---|
| 1 | 152 | 30.4 | 120 | 120 | 76 | 48.32 |
| 2 | 152 | 30.4 | 120 | 120 | 76 | 48.32 |
| 7 | 350 | 75 | 350 | 350 | 0 | 57.7 |
| 13 | 591 | 206.85 | 240 | 240 | 0 | 78.93 |
| 15 | 60 | 12 | 60 | 60 | 0 | 60.11 |
| 15 | 155 | 54.25 | 155 | 155 | 0 | 10.52 |
| 16 | 155 | 54.25 | 155 | 155 | 124 | 10.52 |
| 18 | 400 | 100 | 280 | 280 | 240 | 5.47 |
| 21 | 400 | 100 | 280 | 280 | 240 | 5.47 |
| 22 | 300 | 300 | 300 | 300 | 240 | 1 |
| 23 | 310 | 108.5 | 180 | 180 | 248 | 10.52 |
| 23 | 350 | 140 | 240 | 240 | 280 | 29.89 |

**Table 28 TN-level Storage Units Technical Characteristics**

| Bus (#) | $\overline{ch}$ (MW) | $\overline{dis}$ (MW) | $E^{max}$ (MWh) | $E^{min}$ (MWh) | $E_{t=0}$ (MWh) | $\eta^{ch}$ (%) | $\eta^{dis}$ (%) | $\Delta$ (h) | $\gamma$ | $MC^{ch}$ (€/MW) | $MC^{dis}$ (€/MW) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 15 | 20 | 50 | 0 | 50 | 100 | 100 | 1 | 0.5 | 0.5 | 1 |
| 15 | 15 | 20 | 50 | 0 | 50 | 100 | 100 | 1 | 0.5 | 0.5 | 1 |

**Table 29 TN-level loads Technical Characteristics**

| Bus (#) | $P^{d,max}$ (MW) | $P^{d,min}$ (MW) | $R^{up}$ (MW/h) | $R^{dn}$ (MW/h) | $P^{d}_{t=0}$ (MW) | $E^{d}$ (MWh) | $U^{d}$ (€/MW) |
|---|---|---|---|---|---|---|---|
| 1 | 100.72 | 0 | 25 | 25 | 63.45 | 300 | 100 |
| 2 | 90.12 | 0 | 25 | 25 | 56.77 | 300 | 100 |
| 3 | 166.98 | 0 | 25 | 25 | 105.20 | 300 | 100 |
| 4 | 68.91 | 0 | 25 | 25 | 43.42 | 300 | 100 |
| 5 | 66.26 | 0 | 25 | 25 | 41.75 | 300 | 100 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 6 | 127.22 | 0 | 25 | 25 | 80.15 | 300 | 100 |
| 7 | 116.62 | 0 | 25 | 25 | 73.47 | 300 | 100 |
| 8 | 159.03 | 0 | 25 | 25 | 100.19 | 300 | 100 |
| 9 | 161.68 | 0 | 25 | 25 | 101.86 | 300 | 100 |
| 10 | 180.23 | 0 | 25 | 25 | 113.55 | 300 | 100 |
| 13 | 246.50 | 0 | 25 | 25 | 155.29 | 300 | 100 |
| 14 | 180.23 | 0 | 25 | 25 | 113.55 | 300 | 100 |
| 15 | 294.21 | 0 | 25 | 25 | 185.35 | 300 | 100 |
| 16 | 92.77 | 0 | 25 | 25 | 58.44 | 300 | 100 |
| 18 | 310.11 | 0 | 25 | 25 | 195.37 | 300 | 100 |
| 19 | 169.63 | 0 | 25 | 25 | 106.87 | 300 | 100 |
| 20 | 119.27 | 0 | 25 | 25 | 75.14 | 300 | 100 |

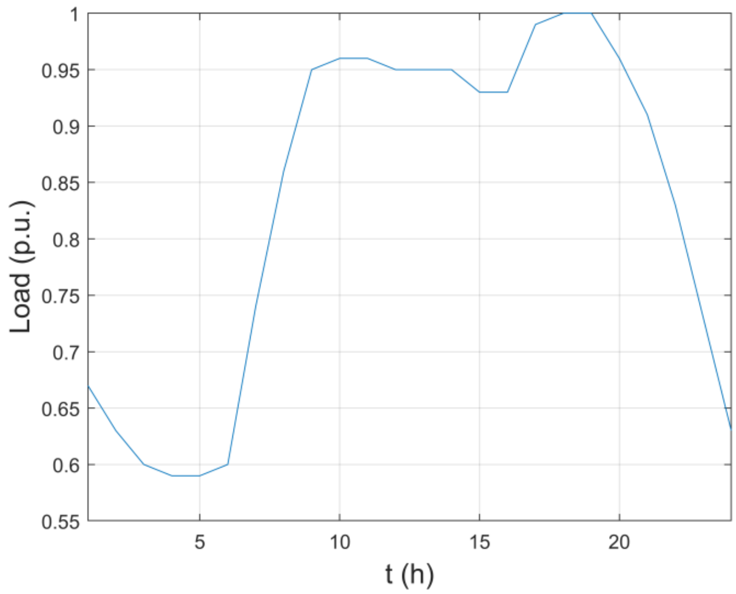


**Figure 38 Energy Consumption Curve of TN-level loads**

Regarding the distribution systems, without loss of generality, we consider two identical 15-bus radial distribution networks[7], depicted in Figure 39. The total demand varies between 5MW and 6.9MW. Renewable energy generation (RG) units are placed on nodes 2, 5, 8, 10, 11 and 13 and three diesel generators of capacity 10 MW are placed on distribution nodes 1, 2 and 5. The price offers of the diesel generators are assumed to be $c_{i,t}^{P,DG} = 50$€/MW and $c_{i,t}^{Q,DG} = 50$€/MVAr. The distribution network technical characteristics are presented in Tables 30 and 31. We consider that the DN-level loads follow a similar consumption curve that is illustrated in Figure 40. The root buses of the distribution systems (substations) are connected to the transmission network at transmission buses 14 and 23 (see Figure 37). The nodal voltage lower and upper limits are set to 0.95 and 1.05 p.u. respectively. The voltage base is 11kV.

[7] A. Gopi, P. Ajay-D.-Vimal Raj, "Distributed generation for line loss reduction in radial distribution system", in Proc. 2012 International Conference on Emerging Trends in Electrical Engineering and Energy Management (ICETEEM), Chennai, India, 2012, pp. 29-32.

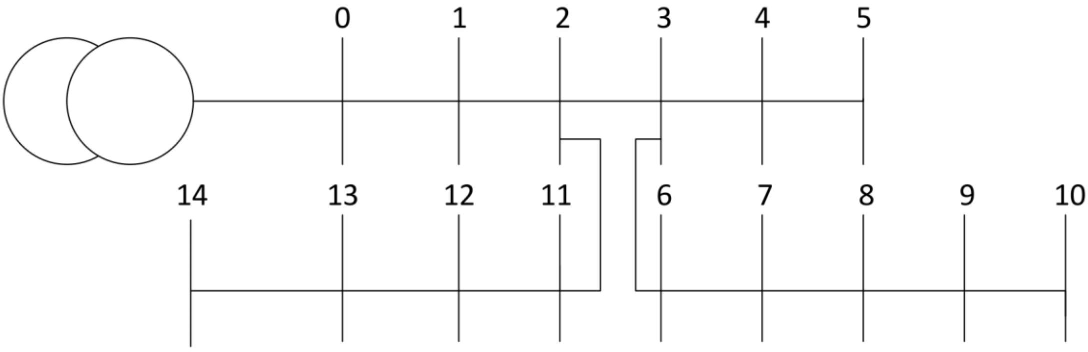


**Figure 39: A 15-Node Radial Distribution Network**

**Table 30 Distribution Network Lines Technical Characteristics**

| Line (#) | From Bus (#) | To Bus (#) | $r$ (Ohm) | $x$ (Ohm) | $S^{f,max}$ (MVA) |
|---|---|---|---|---|---|
| 1 | 0 | 1 | 0.012705 | 0.303334 | 20 |
| 2 | 1 | 2 | 0.001331 | 0.007457 | 7 |
| 3 | 2 | 3 | 0.026902 | 0.124258 | 7 |
| 4 | 3 | 4 | 0.023353 | 0.060294 | 7 |
| 5 | 4 | 5 | 0.057031 | 0.147414 | 7 |
| 6 | 3 | 6 | 0.032266 | 0.149076 | 7 |
| 7 | 6 | 7 | 0.036300 | 0.167685 | 7 |
| 8 | 7 | 8 | 0.028233 | 0.130462 | 7 |
| 9 | 8 | 9 | 0.014802 | 0.068324 | 7 |
| 10 | 9 | 10 | 0.036300 | 0.167687 | 7 |
| 11 | 2 | 11 | 0.110916 | 0.512406 | 7 |
| 12 | 11 | 12 | 0.127050 | 0.328333 | 7 |
| 13 | 12 | 13 | 0.159921 | 0.415368 | 7 |
| 14 | 13 | 14 | 0.042793 | 0.016750 | 7 |

**Table 31 DN-level loads Technical Characteristics**

| Bus (#) | $p^{DA,max}$ (MW) | $p^{DA,min}$ (MW) | $PF$ (p.u.) | $u_{i,t}^{P,DA}$ (€/MW) |
|---|---|---|---|---|
| 1 | 0.44 | 0 | 0.8 | 1000 |
| 2 | 1.04 | 0 | 0.8 | 1000 |
| 3 | 2.02 | 0 | 0.8 | 1000 |
| 4 | 0.89 | 0 | 0.8 | 1000 |
| 6 | 1.34 | 0 | 0.8 | 1000 |
| 7 | 0.68 | 0 | 0.8 | 1000 |
| 10 | 0.15 | 0 | 0.8 | 1000 |
| 11 | 0.28 | 0 | 0.8 | 1000 |
| 12 | 0.06 | 0 | 0.8 | 1000 |

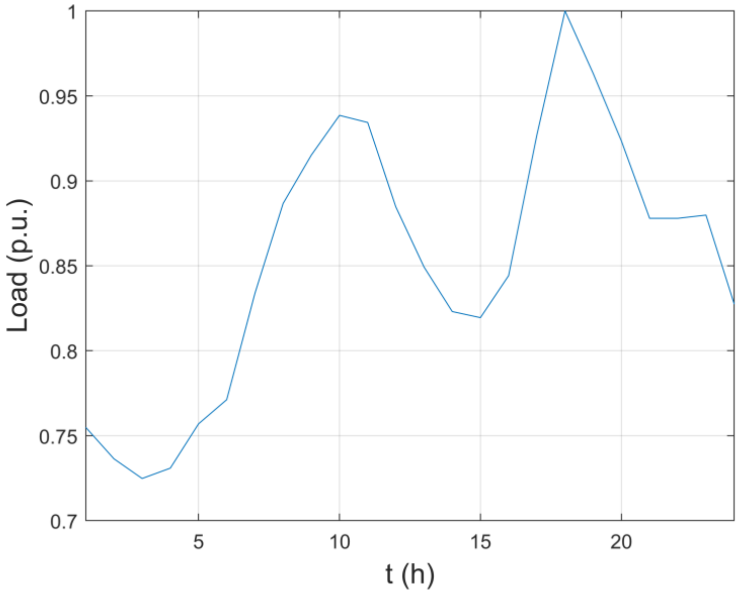


**Figure 40 Energy Consumption Curves of DN-level loads**

Furthermore, in order to study the impact of the available DN-level flexibility capacity on the performance of the x-DLFM architectures, we consider several flexibility liquidity scenarios which are demonstrated in Table 32. Seven identical storage units are placed at the distribution nodes 1, 2, 5, 8, 10, 11 and 13. Their price offers for active power vary from 3.5 to 10 €/MW, with the average price offers being demonstrated in Table 5.8. Finally, two SVCs with the same characteristics are located at nodes 1 and 2.

**Table 32 Flexibility Assets Technical Characteristics in different Flexibility liquidity scenarios**

| **Flex Liquidity Scenario (#)** | **DESS Units** | | | | | | | | | | **SVCs** | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $\overline{p^{ch,max}}$ (MW) | $\overline{p^{dis,max}}$ (MW) | $E^{DS,max}$ (MWh) | $E^{DS,min}$ (MWh) | $E^{DS}_{t=0}$ (MWh) | $\eta^{DS,ch}$ (%) | $\eta^{DS,dis}$ (%) | $c^{P,DS,ch}$ (€/MW) | $c^{P,DS,dis}$ (€/MW) | $c^{Q,DS}$ (€/MVAr) | $q^{SVC,max}$ (MVAr) | $q^{SVC,min}$ (MVAr) | $c^{Q,SVC}$ (€/MVAr) |
| Low | 1 | 1 | 6 | 0 | 3 | 0.9 | 0.9 | 5.45 | 5.55 | 0.5 | -0.2 | 0.6 | 3 |
| Medium | 1.5 | 1.5 | 9 | 0 | 4.5 | 0.9 | 0.9 | 5.45 | 5.55 | 0.5 | -0.3 | 0.9 | 3 |
| High | 2 | 2 | 12 | 0 | 6 | 0.9 | 0.9 | 5.45 | 5.55 | 0.5 | -0.4 | 1.2 | 3 |

### 5.4.2 Performance evaluation results

#### *5.4.2.1 No-DLFM Case*

At first, we highlight the need for the establishment of a DN-level Flexibility Market. To this end, we examine the NO-DLFM case, which is the current approach that the DSOs adopt in order to secure the reliable operation of their networks. In case of a contingency (thermal congestion or over-/under-voltage issue), not having any other flexibility asset, the DSOs are compelled to curtail load or renewable energy generation. Figure 41 shows the flexibility cost that the DSO has to pay in order to maintain the secure functioning of the distribution grid. Studying this figure, we can see that with zero renewable generation, the DSO needs to curtail load to avoid local congestion and under-voltage issues, and thus pay a high cost of lost load (i.e. the value of lost load is assumed to be 1000 euros/MWh). The incremental increase in distributed RES capacity eliminates the DSO's flexibility cost, since the local net demand/generation is relatively small and the DN functions within its operating limits. However, in scenarios with 150% and above RES penetration, the flexibility cost increases significantly, since the DN constraints force renewable energy curtailment, and the RES producers need to be compensated accordingly (i.e. the value of curtailed renewable energy is assumed to be 133 euros/MWh).

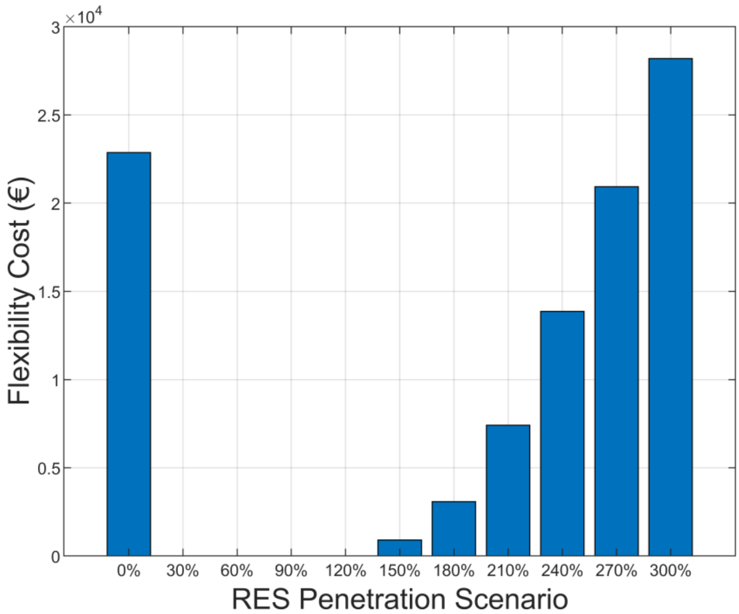


**Figure 41: DSO's Flexibility Cost in various RES penetration scenarios – No DLFM Case**

It should be noted that for demonstration purposes, no-DLFM case assumes that all DERs are non-dispatchable or else there are no controllable thermal units in the DN level. Conclusively, we can observe that no-DLFM does not seem to experience DN-level problems when the ratio of distributed RES capacity to local peak load (i.e. depicted RES penetration) lies between 30 and 120%. These levels of RES penetration are quite common case in today's EU distribution grids, so DNs do not really need a DLFM (or else today's DN-levels costs are acceptable). However, in the short-term future, it is expected that the DN-level flexibility costs will increase exponentially as a function of the continuously increasing distributed RES penetration levels.

#### *5.4.2.2 R-DLFM Case*

In the R-DLFM architecture, comparing to the No-DLFM case (current regulatory framework), we consider that the FMO runs a distribution-level Flexibility Market in order to procure the necessary flexibility so as to tackle the potential contingencies rising from the TN-level market dispatch. The FMO can minimize the flexibility cost making use of the flexibility assets that participate in the DLFM. Thus, curtailing load or generation is not the only option for the FMO for securing the DN operation as it is the case in the No-DLFM. In the figure below, we compare the flexibility costs in No-DLFM and in R-DLFM for various RES penetration and flexibility liquidity scenarios. We can see that the R-DLFM manages lower Flexibility costs than the No-DLFM case. In the 50% RES penetration scenario, for example, the R-DLFM achieves 31% to 61% flexibility cost reduction depending on the flexibility liquidity scenario. In the 200% RES penetration scenario, the R-DLFM decreases the flexibility cost by 23% in the low flexibility case, by 33% in the medium flexibility case and by 40% in case of high flexibility liquidity.

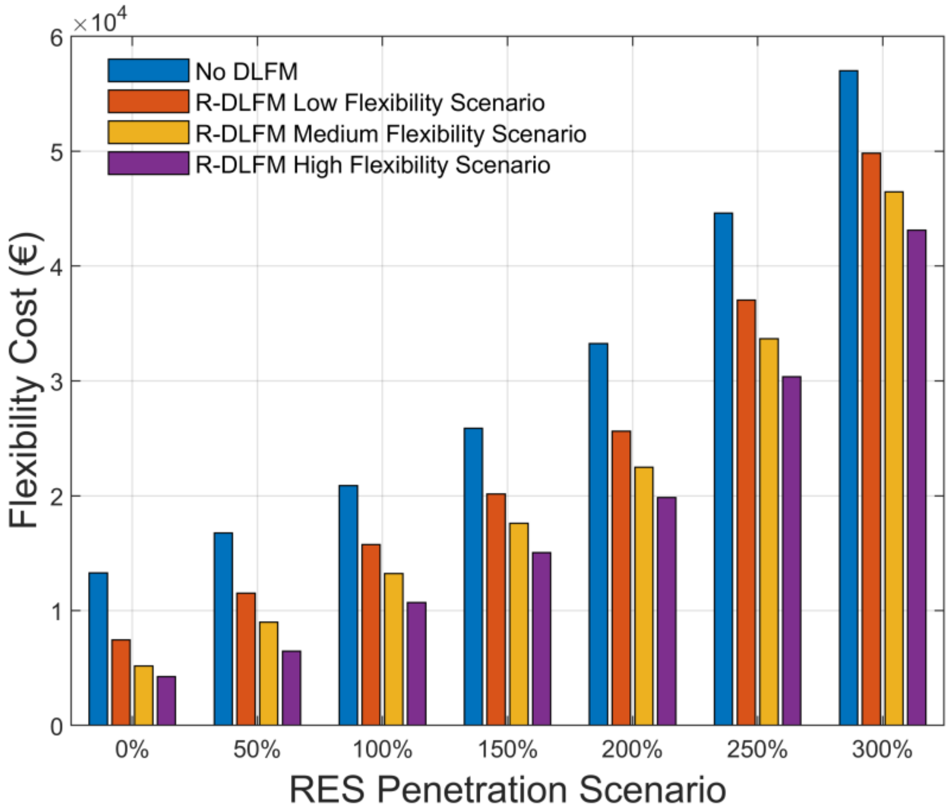


**Figure 42: Flexibility Cost in No-DLFM and R-DLFM**

#### *5.4.2.3 P-DLFM Case*

In order to evaluate the P-DLFM architecture, we compare it to the I-DLFM, which gives globally optimum results (see more results about I-DLFM algorithm's convergence in previous D5.2, section 5.6). In case the energy market price forecast ($\widehat{\lambda_t^{TSO,k}}$) is completely accurate, then the P-DLFM results in the same dispatch schedules with the I-DLFM and ultimately achieves global optimality. However, in the most common case, the price forecast error is not zero, with the FMO over- or under-estimating the TN-level day-ahead energy market prices. The sub-optimal results of P-DLFM with respect to price forecast error are evident in Figure 43. In this figure, the P-DLFM is compared to the I-DLFM, in terms of DN-level assets' profits, for various price forecast errors. In Figure 43, we have assumed 0% distributed RES penetration. Negative price forecast errors indicate underestimations of the TLMPs, while positive price forecast errors indicate over-estimations of the TLMPs. As one can observe, in the P-DLFM, the under-estimation of the TLMPs by the FMO has a huge impact in the energy market profits of the DN-level assets. This is due to the fact that, under-estimating the TLMPs, the FMO does not dispatch units with marginal costs higher than the forecasted prices. These units are dispatched in the I-DLFM (the actual TLMPs are higher than their marginal costs) and make significant profits. On the other hand, by over-estimating the TLMPs, the FMO chooses not to supply power to flexible loads, whose price bids (marginal utility) are lower than the forecasted TLMPs.

The impact of the distributed RES penetration on the efficiency of the P-DLFM is shown in Figure 44, where a price forecast error of -10% is assumed. The ratio between the DN-level assets' profits in the P-DLFM and the I-DLFM is presented for increasing distributed renewable energy capacity. We can infer that, in low RES penetration levels, the DN-Level Profits are much lower in P-DLFM than in I-DLFM, since, as explained above, dispatchable units with marginal costs higher than the under-estimated TLMPs and lower than the actual TLMPs, are not dispatched in P-DLFM. Increasing the distributed RES capacity, this gap is closing since the zero marginal cost renewable energy generators are far cheaper than the thermal units, the majority of which are dispatched neither in the P-DLFM nor in the R-DLFM. In high RES penetration scenarios, where the flexibility units provide flexibility in order for the FMO to achieve the minimum RES spillage, the difference between the P-DLFM and the I-DLFM DN-level assets' profits increases again. In these cases, flexibility units are not utilized by the FMO, since their operation is not considered financially advantageous by the FMO, which has under-estimated the TLMPs. Finally, in this figure, we observe that with increasing levels of flexibility liquidity, the impact of price forecast error reduces and the P-DLFM achieves better results.

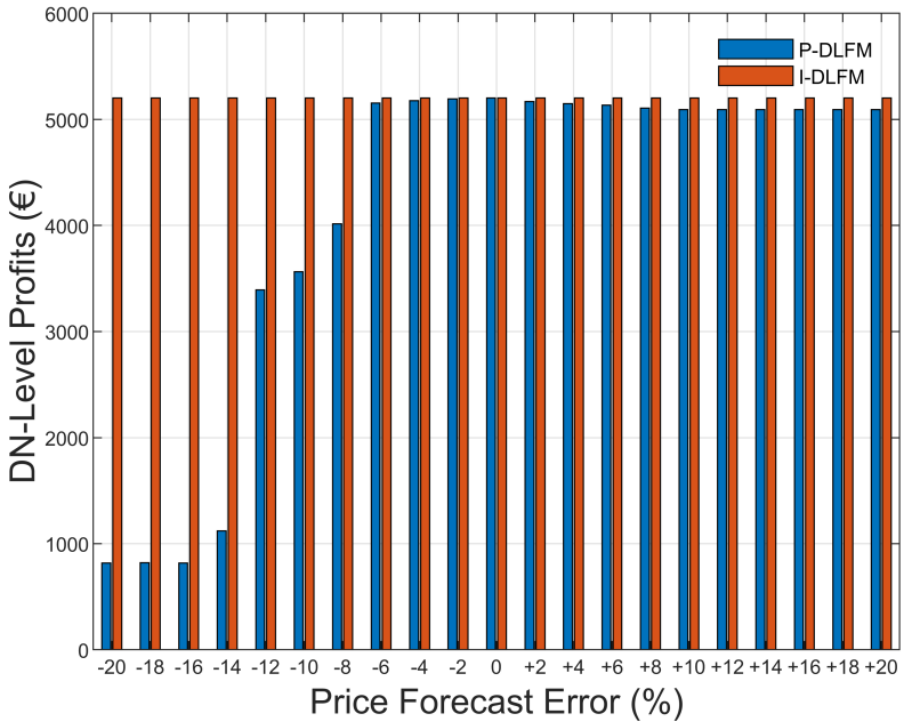


**Figure 43: P-/I-DLFM Comparison in terms of DN-Level Profits for various Price Forecast Errors**

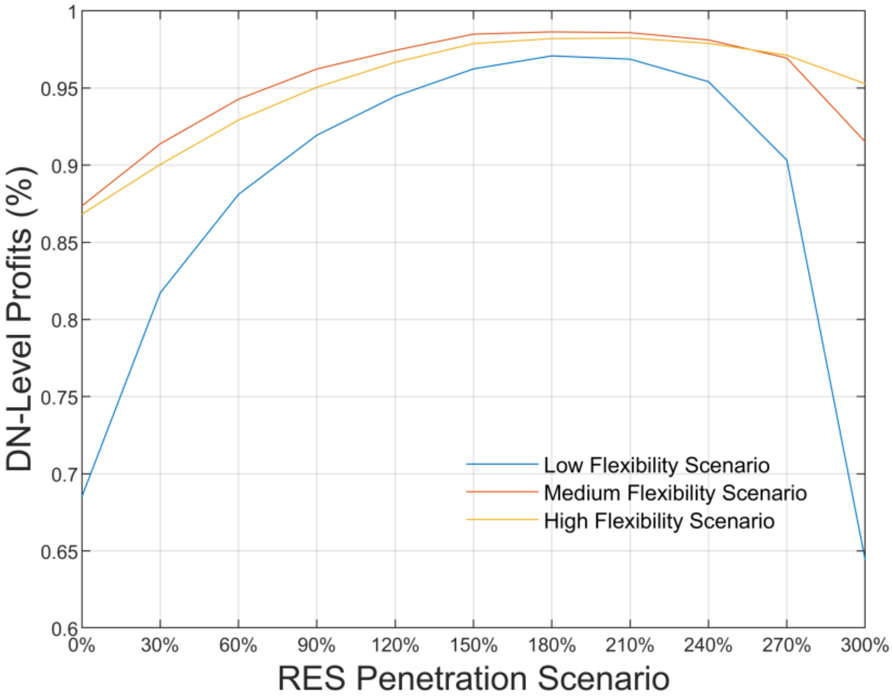


**Figure 44: Ratio between DN-level profits in P-DLFM and in I-DLFM**

*5.4.2.4 Comparison between the x-DLFMs*

In this subsection, we make a comparison of the x-DLFM architectures in different RES penetration scenarios for the medium flexibility liquidity scenario simulated above. In Figure 45, we can see that the TN-level Welfare is higher in R-DLFM. This is due to the fact that low-cost DN-level generators can be used by the TSO in order to reduce the generation cost and overall increase the TN-level Welfare. The opposite holds for P-DLFM case, in which the priority of DN-level assets is given to DSO. However, since the R-DLFM can change the TN-level energy market positions of these assets, the TSO's balancing cost is higher in R-DLFM.

Regarding the DN-level Welfare, since in the P-DLFM, DSO has priority on the usage of the DN-level assets, it can achieve DN-level welfare close enough to the I-DLFM (optimal) case (see figure below). On the contrary, in the R-DLFM architecture, the low-cost DN-level assets participating with their entire capacity in the TSO market, decrease the TLMPs at the TSO-DSO coupling points. In addition, the DSO has to pay higher flexibility costs comparing to the P- and I-DLFM.

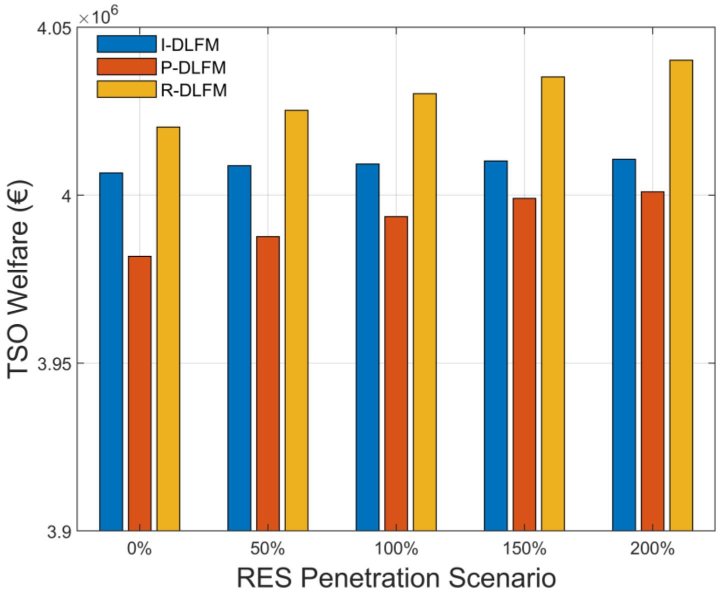


**Figure 45: Comparison of x-DLFMs in TN-level Welfare**

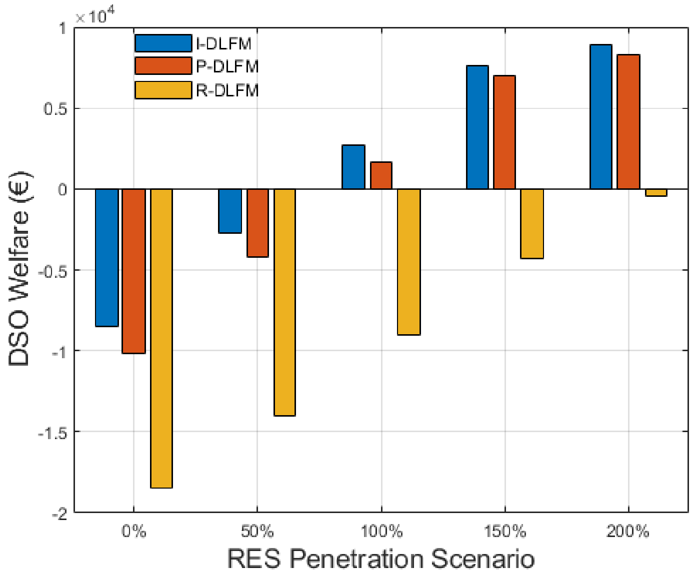


**Figure 46: Comparison of x-DLFMs in DN-level Welfare**

## 5.4 Conclusions and lessons learnt

In this section, we provide a summary of lessons learned that could be further investigated in future R&I initiatives. It should be noted that these WP5 results (i.e. at TRL 3) are just initial ones and will be elaborated within WP7 context by AIT (with help from ICCS and DTU) at TRL 4. The table below summarizes research and business-related insights for each one of the lessons learned.

**Table 33: Lessons learned from the comparison of x-DLFM architectures**

| Lesson learned | Research & business insights |
|---|---|
| Contingency issues at DN-level will continuously grow and become | Maybe, the first step would be for the DSO to start procuring active/reactive power reserves in a market- |

| | |
|---|---|
| more as the distributed RES penetration levels are growing. The existing no-DLFM architecture will soon not be able to deal with high RES penetration and low levels of available flexibility at DN-level, because of the high Value of Lost Load (VoLL) and high value of curtailed renewable energy. | based manner and at the same time define the communication requirements for a loose-coupled collaboration with the upstream TSO. Specific DSO areas that tend to have more contingencies in the short-term future should be prioritized. |
| R-DLFM performs best in high flexibility liquidity scenarios or more generally in scenarios, where RES penetration increase rate in the future is expected to be lower than the available flexibility increase rate in the future. TSO has a leading role, so it is relatively easier to be adopted by today's EU regulatory framework. | New regulatory schemes such as redispatch 3.0 should be introduced. The DSO should be able to receive a TN-level re-dispatch order and decide about an efficient allocation of dispatch commands to all available local FlexAssets. If FlexAssets' market participation is voluntary, then relatively low liquidity is expected. On the other hand, if market participation is obligatory, then truthfulness property of FlexOffers should be guaranteed in order to avoid market manipulation phenomena by FSPs. |
| P-DLFM performs best in high RES penetration scenarios or more generally in cases where the distributed RES production is much higher than the peak load in a local DSO (or else microgrid) area. P-DLFM's performance highly depends on the mean absolute percentage error (MAPE) of market price forecast and should be not higher than 5%. | P-DLFM can be applied in rather small, remote and islanded distribution grids in order to take full advantage of the fact that the TSO can procure the maximum levels of clean and distributed RES. However, the local DSO (or microgrid operator) should be able to run an OPF algorithm to decide the optimal dispatch schedules for all local DERs, which requires full monitor & control capabilities on the latter. If all the required data is not available, then P-DLFM results would be worse than the ones assumed in this case study. |
| I-DLFM has the best performance among all proposed x-DLFM architectures. The largest gains of I-DLFM (compared to the other ones) are observed in high RES penetration and high flexibility liquidity scenarios. On the other hand, in rather short-term future scenarios, I-DLFM gains may not be large enough to justify vast investments on sophisticated ICT infrastructure that enables efficient TSO-DSO collaboration. | Much research should take place in order for an iterative data exchange framework to take place in real-life conditions between a TSO and DSO. Moreover, substations at TSO-DSO coupling points should not only have monitor & control capabilities, but also computational capacity and algorithmic intelligence, which will be rather difficult to realize within the next decade. Efficient and real-time communication should also take place between the various substations in the future, so that the I-DLFM architecture could be instantiated in near-real-time balancing markets, too (apart from day-ahead energy market that is assumed in this case study). |
| Differences in the DN-level welfare are significantly higher (in terms of % improvement) than in TN-level welfare, which is normal | More targeted case studies and "what-if" simulation scenarios are required on a DSO area basis in order to define an efficient ratio between the available options for increasing system flexibility, such as DN upgrades |

| | |
|---|---|
| because TN-level production capacity is much higher than that in DN-level. | and more profit-based flexibility and DER investments. FSPs generally want to guaranteed RoI for their new RES and FlexAsset investments, while DSO wants to minimize its flexibility procurement cost and TSO wants to include as much as possible clean RES in the energy mix. These business objectives seem to be conflicting, so efficient FSP-DSO-TSO coordination schemes are needed in order to maximize the social welfare (i.e. sum of gains for all involved market actors) of future flexibility investments. |

# 6 Conclusions and lessons learned

In this deliverable, several algorithms have been presented that can be used by the FMO and DSO. First, chapter 2 presents DLFM clearing algorithms for an FMO to *continuously* clear a distribution level energy (UCS 1.1), active power reserve (UCS 1.2) and reactive power reserve market (UCS 1.3) in a *network aware* fashion. Second, chapter 3 presents DLFM clearing algorithms for an FMO to clear *auctions* in a distribution level energy (UCS 1.1), active power reserve (UCS 1.2) and reactive power reserve market (UCS 1.3) using different types of *network aware OPF* algorithms. The market clearing algorithms include multi-period clearing capability and allow FlexSuppliers and FlexBuyers to submit block bids. Chapter 4 presents methods for the DSO to compute viable prices and necessary volumes in order to *create efficient FlexRequests* to the DLFM. Finally, chapter 5 compares various x-DLFM architectures with the existing no-DLFM architecture with respect to various KPIs.

To the best of our knowledge, we propose for the first time a design of a *continuous* local flexibility market (DLFM) that explicitly considers network constraints. We discuss the general architecture of such a market, the structure of the FlexRequests and FlexOffers, and elaborate on a number of design options for the inclusion of network constraints in the market clearing process. In the early stages of local flexibility markets, where insufficient liquidity may hinder market development, continuous markets are expected to be the most suitable option. At the same time, in increasingly loaded distribution systems, including the network constraints in the market clearing ensures that every matched pair of bids will not violate operational limits, and would not require additional actions from the distribution system operators that result in additional costs.

Table 34 summarizes the main lessons learned, as well as the research and business insights that were derived.

**Table 34 Lessons learned in WP5 on from a high-level perspective**

| Lesson learned | Research & Business insights |
|---|---|
| The benefits of continuous vs. auction-based clearing are not generalizable. Advantages exist depending on the geographical context, surrounding market frameworks, regulation, market participants etc.<br>The only general conclusion is that continuous clearing is preferred on short-term markets, whereas auctions are preferred in long-term markets. | Real-time markets are likely to use continuous clearing. The longer the market lead time, the better the argument for an auction-based market. |
| Some countries (e.g., Germany) are headed down a policy path that involves heavy regulation and requirements from local flexibility assets. This may prevent the formation of local flexibility markets since flexibility is implicitly traded via regulatory | The business case depends on the specific geographical context and may vary with the regulation that is in place. |

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| frameworks rather than voluntary market transactions. | |
| In the underlying distribution network, reactive power reserves are predominantly needed with low RES penetration, while active power reserves become more important the higher the RES penetration. | It is not generalizable whether active or reactive power are more significant. The answer may depend on the specific network and RES penetration. |
| The social welfare is only maximized with the use of auction based OPF algorithms. Continuous markets are not guaranteed to achieve social welfare maximization and will, in most practical cases, not achieve the optimal social welfare. | The strengths of continuous markets are found in increased liquidity and stakeholder engagement, not necessarily in social welfare maximization. |
| Locational Marginal prices (LMPs) can send transparent price signals and investment incentives but can be complex to compute. The difficulty arises from, e.g., inclusion of block bids in auctions, or from the use of continuous clearing. | If LMPs are not available, alternative means of investment signals should be established that can transparently communicate the need for local FlexAssets at a given network node or DSO area. |
| Ideally, the DLEM/DLFM would be integrated into transmission network level markets. | The advantage of such integration is reduced balancing cost from a system perspective. The disadvantage is that it requires increased data exchange and computational power. |
| The way FlexRequests are created depends on the level of information that is available, with respect to the network, forecasts for each bus or DSO area, etc. | In order to create efficient FlexRequests, DSOs should strive to obtain real-time data about the power balance at each node and have access to accurate forecasts. Furthermore, the link between active and reactive power makes the DSO's problem for the creation of FlexRequests a lot more complex; therefore the DSO might make some assumptions about how reactive power is consumed. |
| The way FlexRequests are created depends on the information exchange with the FMO and on which geographical resolution the FlexRequest are cleared. | FlexRequests can be generated with a chance-constrained approach and cleared in a very simple deterministic market, which includes the possibility to define zones. In order to clear the DLFM efficiently, the FMO would need access to the full network model, which the DSO may not be willing to share. An alternative is to clear the market on zonal level, which is inevitably suboptimal since it reduces the market efficiency. |

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| The definition of bidding zones by the DSO can become critical. | With a clearing per bus, the costs for the DSO could increase significantly. With properly defined zones, the results obtained in terms of social welfare and costs for the DSO appear to be comparable to those obtained with stochastic market clearing. |

In the following months, the FLEXGRID consortium will integrate the final version of WP5 algorithms in the FLEXGRID ATP within the scope of WP6. The algorithms developed in this deliverable D5.3 will also be tested and validated in the test environment of WP7 (i.e. at TRL 4 by utilizing AIT's Large Research Infrastructure).

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