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Advanced Flexibility Support through DSO-Coordinated Participation of DER Aggregators in the Balancing Market

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Abstract: Future power systems with a high share of intermittent renewable energy sources (RES) in the energy portfolio will have an increasing need for active power balancing. The integration of controllable and more flexible distributed energy resources (DERs) at the distribution-grid level represents a new solution and a sustainable alternative to conventional generation units for providing balancing services to the transmission system operator (TSO). Considering that the extensive participation of DERs in ancillary services may lead to the violation of limits in the distribution network, the distribution system operator (DSO) needs to have a more active role in this process. In this paper, a framework is presented that allows the DSO, as the central coordinator of the aggregators, to participate in the balancing market (BM) as a balancing service provider (BSP). The developed mathematical model is based on the mixed-integer second-order cone programming (MISOCP) approach and allows for determination of the limits of active power flexibility at the point of the TSO–DSO connection, formation of the dependence of the price/quantity curve, and achievement of the optimal dispatch of each DER after clearing the balancing market. The simulation results are presented and verified on modified IEEE distribution networks.

Keywords: aggregators; distributed energy resources; balancing market; TSO–DSO coordination; balancing service provider; mixed-integer second-order cone programming

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1. Introduction

1.1. Motivation and Incitement

In order to maintain the sum of the active power exchange over the interconnection links and the frequency at the reference value, a balance between electricity generation and consumption must be achieved at all times. Any deviation from the scheduled generation or consumption and any disturbance caused by a power outage will result in a deviation from the system frequency. Future renewable-based power systems will have an increasing need for balancing reserves and a greater complexity of active power balancing as variable and non-dispatchable renewable generation units replace conventional generators [1]. Therefore, electricity generation will become less controllable and predictable, while the system's inertia will be reduced by integrating renewable energy sources (RESs) into the grid through power-electronic devices. In order to make the process of balancing electricity supply and demand more efficient and reliable, the balancing market (BM) is introduced [2]. The BM represents the entirety of institutional, commercial, and operational arrangements that establish the market-based management of balancing [3].

To ensure the secure and stable operation of the grid, the transmission system operator (TSO) provides balancing services in a two-stage process: first, by reserving capacity on the balancing capacity market, and then, in the case of an imbalance in the system, by activating the balancing energy purchased on the balancing energy market. Depending on the sign of the imbalance, the aforementioned markets can be divided into two independent entities: a positive market, where upward regulation is performed (generation up or consumption down), and a negative market, where downward regulation is performed (generation down or consumption up). The current practice in the European Union implies that the TSO clears balancing markets within its control area. The balancing market is organized in such a way that the capacity market is usually closed before the day-ahead electricity market, while the balancing energy market is closed before the time of delivery [2,4]. Balancing service providers (BSPs) are flexible market participants that can increase/decrease their generation/consumption relative to their established schedule. Prequalified BSPs are allowed to submit and/or update their bids for providing balancing services until gate closure time.

Power system balancing is traditionally performed at the transmission-grid level by activating large conventional generators. With the suppression of conventional production resources and the integration of RES, the need for balancing capacities is growing. One of the solutions is the integration of energy storage systems. Such balancing systems require the construction of new energy plants, which takes a certain amount of time. In addition, such solutions can have significant capital and operational costs, while losses in the storage cycle process are inevitable. One of the ways to efficiently and quickly provide new balancing capacities is to unlock the flexible potential within the distribution network. The increasing integration of distributed energy resources (DERs) at low and medium voltage levels, which have significant controllability and flexibility [5–8], offer the opportunity to support the balancing of the power system. The development of intelligent energy management systems, smart inverters, smart metering systems, and communication infrastructures [9] with a focus on cybersecurity [10] are the foundation for exploiting DERs' flexibility. In addition, it is necessary to introduce new regulations and policies to enable and facilitate the participation of DERs in the provision of ancillary services required by the TSO.

From the perspective of the power system, individual DERs do not represent a significant capacity, and TSO communication with each of them would be untenable and unprofitable. For this reason, they are combined and organized into a common entity by an aggregator [11]. This way, the aggregator can perform coordinated management of the resources and optimize their operation, while at the same time, making the resources more visible from the power system's point of view. Hence, the aggregators have the opportunity to exploit the flexibility of the resources and participate in the ancillary service markets, while on the other hand, the resources benefit from rewards or lower energy bills [12]. Among the many services that aggregators can provide to the distribution system operator (DSO), the emerging concept implies their support of the TSO by providing balancing services [13,14]. Introducing new BM participants can help increase competition, reduce system-balancing costs, and provide the flexibility needed to integrate new variable capacities based on RES technology.

The authors of [13,15] reviewed the requirements, criteria, and conditions for integrating BSPs into the BM and analyzed the positive features and potential barriers to aggregator involvement in this process. The most stringent conditions that aggregators must meet to access the BM are capacity provisioning, various technical requirements (activation speed and duration, ramp rate), the exact portfolio requirements in terms of the required technology mix, the minimum bid size, product symmetry, etc. A large amount of DER participation in providing ancillary services may lead to violating operational limits in the distribution network, such as voltage excursions, the congestion of network assets, excessive line losses [16,17], and increased DSO operation costs [18]. Therefore, the DSO needs to have a more active role in managing aggregators to provide system services and ensure the integrity of the distribution network. Further, the term DSO validation refers to the process performed by the DSO, in which aggregator bids are allowed completely or to a certain extent without jeopardizing the distribution network constraints. In the DSO validation process, a potential conflict of interest appears because the DSO can restrict the system's operating limits to preserve its assets and disable their close-to-the-limit operation. Innovative approaches are needed to address the above barriers and the potential conflicts that may arise from the participation of DER aggregators in the BM.

This paper focuses on the efficient inclusion of DERs in BM. The main idea presented here is a more active involvement of DSO in the balancing service bidding procedure. Under the new circumstances, consumption is being locally supplied due to extensive distributed production, and the DSO partially loses services that it had in the traditional system. In order to maintain its profit, DSO has to adapt to the new conditions and introduce new services to provide. This paper proposes a solution, in which the DSO becomes the central coordinator of the aggregators. This approach increases the level of aggregation since there is a possibility that not all aggregators will meet the strict BM requirements individually. DSO mediates between the aggregators and the TSO, while at the same time, it takes care of the security of its own network. In this paper, the focus is on active power flexibility since it is essential for power system balancing, while reactive power flexibility management is not considered.

1.2. Literature Review

The term flexibility of a distribution system in a DSO–TSO connection point refers to the extent to which a DSO can modify power flow from the transmission to the distribution network relative to the initial state. The determination of the flexibility limits of ADN is the subject of research in many papers. The authors of [19] evaluated the improvement of DG penetration in active distribution networks (ADNs) by integrating energy storage systems, whereby operational flexibility was quantified based on Monte Carlo simulations and the linearized DistFlow model. In [20], the PQ plane of operational flexibility at the TSO–DSO connection point was determined by exploiting controllable resources integrated into the ADN using the nonlinear AC optimal power flow (OPF) model. Reference [21] presents a hierarchical, multi-voltage-level, grid-control concept of TSO–DSO cooperation and sampling strategies for PQ-flexibility map determination at the TSO–DSO connection point. The mathematical tool used in [21] includes the application of different optimization methods, such as nonlinear programming, sequential quadratically constrained linear programming, and modified particle swarm optimization. Paper [22] establishes a methodology called Grid Structure Optimization to evaluate the feasibility/flexibility regions of slow and fast response systems at the TSO–DSO interconnection. The previous literature estimates flexibility potential at the TSO-DSO interface based on technical criteria, not including the financial aspect.

An extensive number of studies in the literature have proposed and exploited different operational frameworks that enable the participation of aggregators in the BM. These models can generally be classified into DSO-free and DSO-active models from the aspect of DSO involvement in the BM aggregator access process.

DSO-free models are purely economic, and the emphasis is placed on optimizing resources under the control of the aggregator, which aims to maximize its profit in the electricity market, including BM. These models do not include the OPF analysis carried out by DSO. That is, operational constraints are not considered, which may threaten the security of the distribution network in the case of extensive integration of DERs. Additionally, a potential conflict of interest may arise between DSO and TSO regarding DER flexibility, considering that the distribution network represents a link between TSO and DERs. Some works on DSO-free participation of aggregators on wholesale and different types of BM can be found in the literature [23–28].

DSO-active models treat DSO as an active participant in the process of using DERs' flexibility by TSOs, which prevents and solves distribution network problems caused by aggregators. A market-based coordination framework between TSO and DSO has been described in [29], whereby the DSO participates in the global BM as a balancing responsible party (BRP), based on the net result of the actions carried out for local ancillary services. The study in [30] introduced a new local market for residential prosumers, providing system-wide and local flexibility services. Prosumers sell their flexible capacity to the TSO and DSO, enabling system operators to follow their flexibility needs in real time. The model that enables the estimation and exploitation of DERs' potential flexibility at the transmission and distribution levels is also presented in [31]. The authors of [32] introduced the idea of a future flexibility market with a five-stage TSO–DSO cooperation procedure and presented a detailed mathematical model for the optimal management of both systems. By using flexible resources connected to both the transmission and distribution networks, the day-ahead operation plan was modified to reduce total operational costs. However, the financial settlement between the DSO and TSO was not fully addressed. Authors in [33] present the idea of a stochastic platform for coordinated energy and reserve scheduling for the TSO and DSOs. However, the problem of execution time may arise for balancing and near-real-time markets.

In [34], a generalized bidding function transferred between the TSO and the DSO was constructed, and a hierarchical coordination mechanism of TSO–DSO based on Benders decomposition was proposed. Reference [35] demonstrates how EV aggregators can maximize their profits by participating in the balancing market. The aggregators bid for regulating power, while the DSO examines if network limitations are violated. Until the network issues are resolved, aggregators adjust their schedules. Deterministic and stochastic approaches for network-constrained bidding strategy for aggregators' participation in multiple electricity markets are presented in [36,37]. The optimization problem is divided into aggregators and DSO sub-problems, where DSO evaluates the network feasibility of energy and reserve bids.

In short, papers [30–33] demonstrate the joint use of DERs' flexibility by DSO and TSO. These models require significant computational time and are questionable for real-time dispatch. At the same time, potential conflicts of interest in using DER flexibility and financial settlement between DSO and TSO can arise. On the other hand, some papers [34–37] include DSO in checking the network feasibility of aggregators' bids, which is most compatible with the current regulation and organization of the electricity market. However, the DSO's motives for ensuring the network's security to provide balancing support to the TSO still need to be fully addressed. Additionally, the existing analyses need to include the variations of active power losses due to the change in the network operation state. Additionally, in the previous literature, the aggregator's bids for providing balancing services are assumed to be single-price for the entire range of the achieved volume of service.

1.3. Contributions

Inspired by the previously described research, the DSO-managed participation of aggregators as BSP in the BM framework is proposed in this paper. It was assumed that the aggregators, representing the interests of a group of DERs, submit bids to the DSO to provide balancing services, whereby the pay-as-bid pricing mechanism is adopted. It implies that the aggregators make their bids, containing at least one bidding block, based on the cost of using DER flexibility and potential profit. On the other hand, the DSO participates in the BM by disposing of resources offered by the aggregators. In order for the DSO to obtain a benefit from this process, i.e., to resolve potential conflicts between the TSO and the DSO in terms of using DER flexibility, the idea that the DSO makes a revenue proportional to the achieved volume of service was adopted. In this way, the DSO represents its interests and the interests of aggregators in the BM. The proposed framework ensures the integrity of the distribution network in the bid validation process, as it implies that the optimization problem is solved from the perspective of the DSO. As a result of the proposed optimization model, flexibility limits are obtained at the point of the TSO–DSO connection. In the process of bid aggregation, a price/quantity curve is derived, which should serve the DSO for strategy bidding in the BM. Moreover, the presented model solves the optimal dispatch of each DER to achieve the aggregated dispatch command sent by the TSO to the DSO after clearing the BM. The realization of such a coordination scheme requires a specific regulatory framework and market design modifications. More details on the proposed coordination scheme and the interpretation of the current regulatory framework will be discussed in Section 2.

The main contributions of this paper are as follows:

1. A proposed framework allows the DSO, as the central coordinator of the DER aggregators, to participate as a BSP in the BM. In this way, grouping aggregators is carried out, increasing the chance that they meet the strict requirements of BM. The proposed financial compensation of DSO is proportional to the actual volume of service delivered to TSO, which is a novelty compared with the other literature. Thus, DSO has an interest in making maximum use of its network assets. Additionally, the DSO keeps the integrity of the distribution network, considering its operational limits;
2. The developed mathematical formulation has practical applicability in the bidding balancing capacity as well as both bidding and real-time dispatching of balancing energy. All of the mentioned calculations are performed as ACOPF, based on the MISOCP approach, which is modified and adjusted for solving the group of problems of interest. The advantage of the proposed model is that it has a more comprehensive application because it covers all calculations required from the DSO point of view;
3. When determining the price/quantity curve, the cost of change in network active power losses is included. If the offer is activated after BM clearing, the cost of change in active power losses in the distribution network will be compensated by TSO. The other literature does not address who is responsible for settling these costs;
4. The model enables the aggregator to send an offer containing more than one service bidding block. In this way, the aggregators gain greater flexibility in bidding. This kind of problem formulation represents a more general and complex case compared with the other literature where unit prices of aggregators' services do not depend on the realized volume of service;
5. The TSO receives only the net of all planned actions at the distribution level. This way, the computational and modeling requirements of BM clearing are reduced compared with models where the aggregators and DERs individually interact with the TSO.

1.4. Paper Organization

The rest of the paper is organized as follows: Section 2 describes the framework for the participation of aggregators in the BM; Section 3 presents the optimization model for determining the active power flexibility limits of the ADN, and the DSO validation and aggregation of submitted bids; in Section 4, a case study of MV networks is presented along with the considered scenarios; and finally, the main conclusions are drawn in Section 5.

2. Aggregators' DSO-Managed Framework for Participation in Balancing Market

In [38], three general models for TSO–DSO coordination were presented, and it was recognized that the most promising one for the facilitation of DER services was the DSO-managed model. The proposed coordination scheme (Figure 1) implies that the TSO has no access to the resources connected at the distribution level, but only exchanges necessary information with the DSO. The total summary of scheduled actions at the distribution level is transferred to the TSO. The coordination procedure of the DSO-managed model can be described in the following steps:

1. Aggregators send their bids to the DSO;
2. The DSO validates bids, aggregates them, and submits a joint offer to the TSO;
3. The TSO collects submitted bids, clears the market, and dispatches commands to the DSO;
4. The DSO schedules the operation of the aggregators to match TSO requirements.

Based on the DSO-managed model, a mathematical definition that describes the participation of aggregators in the BM is developed in this paper.

At the lowest hierarchical level, multiple aggregators interact with the DERs, manage their power profiles, and estimate net flexibility potential. Aggregators link with DERs through resource energy management systems and exploit their flexibility by changing consumption/generation patterns. This is enabled through infrastructure that provides metering of the consumption/generation, enabling the two-direction exchange of information and controlling assets' set points. Contracts between aggregators and DERs should define the activation price for every flexibility asset. They can include additional constraints, such as permitted activation periods or the number of flexibility activations per day. As described in [39], these contracts define the flexibility reservation and activation prices, time constraints, and penalties for failures to meet contractual obligations. The contract reservation price stipulates the cost paid by the aggregator for periods during which the aggregator can manage flexibility devices. The activation price stipulates the fee when the aggregator activates the flexibility asset. These contracts can be renewed periodically. Negotiation between aggregators and DERs should consider DER's location in the distribution network and power loss cost if the aggregator activates DER's resources. While negotiating, the aggregator will offer and contract better prices to those DERs whose activation results in fewer losses. For each period of interest, the aggregators provide the DSO with information on the technical characteristics, the available capacities, locations of the resources, and the financial parameters of the balancing service (balancing energy or balancing capacity) that they offer. The data shared between the aggregators and the DSO represent the net flexibility features at each node and do not include sensitive customer data.

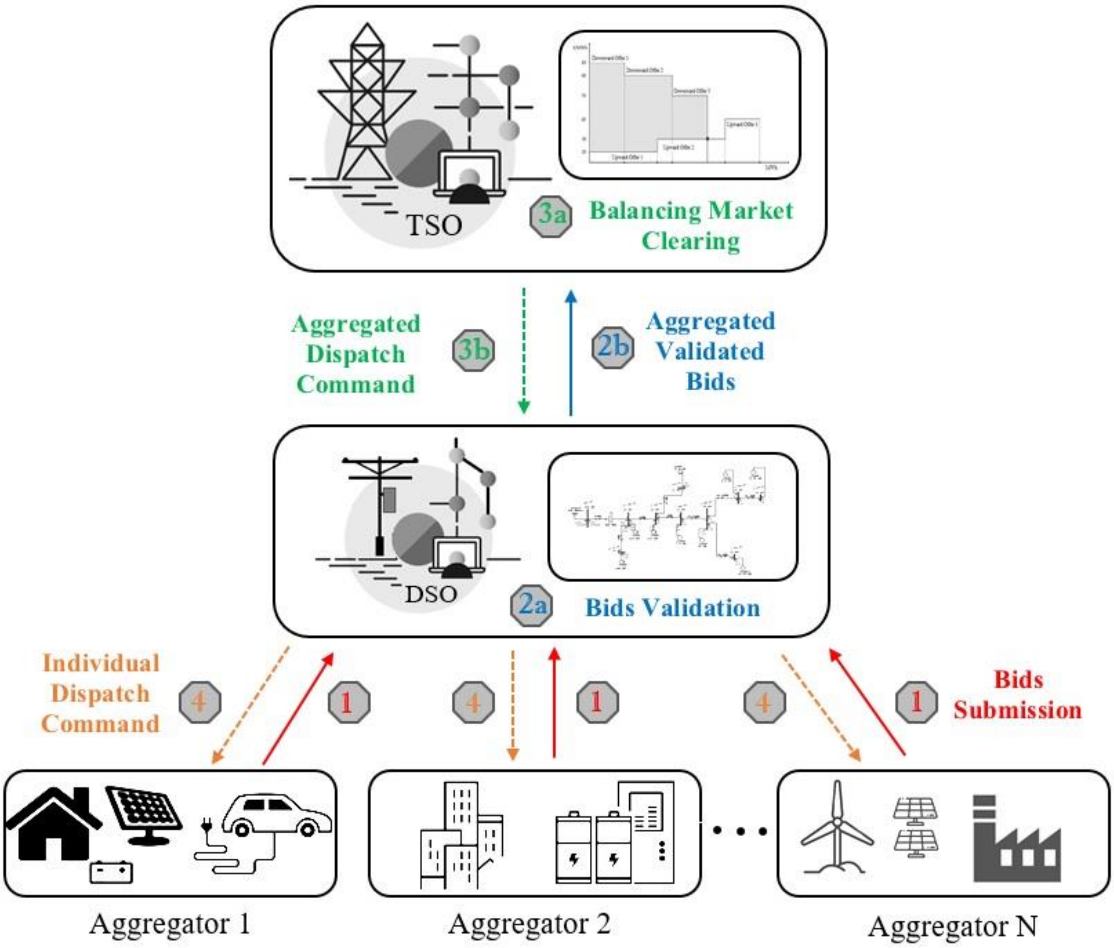


Figure 1. Aggregators' DSO-managed participation in balancing market (BM) framework.

On the other hand, the DSO organizes a local bid validation and delivers the aggregated offer to the BM organized by the TSO. The bid validation process refers to the pre-qualification action that ensures the network feasibility of aggregators' bids before they reach the BM. If the distribution system's security is jeopardized, some bids might be partially used. Before the gate closure time, all the above procedures must be performed for each market time unit (MTU). It should be noted that, in European energy markets, day-ahead electricity market closure happens before reserves trading, and the DSO contracted electricity transfer to end-consumers [40]. After clearing the BM, the DSO receives the cleared bidding quantity with the clearing price and takes responsibility for the delivery of the contracted service. During the time of delivery, the DSO sends commands to the aggregators to receive and follow dispatch instructions. In addition, the DSO performs measurements at the point of common coupling between each DER and the distribution system. These measurements are necessary for the DSO to determine the DER's response to the scheduled dispatch command and to make financial settlements with aggregators. In this way, balancing the system is additionally achieved by TSO–DSO coordination with the balancing energy measurement at the point of the TSO–DSO connection, whereby the DSO becomes the BSP as the central coordinator of the aggregators.

As discussed in [41], one of the well-hidden barriers to aggregators' participation in BM are the penalties for the non-delivery of the contracted balancing energy amount for which a reservation payment was earned. These penalties generally depend on the penalty scheme used on BM and can be a function of several parameters (total energy and a maximum power of unavailability, time of unavailability, etc.). For the proposed DSO-managed framework, DSO, as a central coordinator of aggregators on BM, is penalized in the case of the nonavailability of balancing energy. Based on measurements in the network, DSO should determine the difference between the total amounts of the activated and requested volumes of service to calculate and redistribute these penalties to aggregators. One of the roles of the aggregator is to manage all risks, such as energy deviations and technical failures. Aggregators can improve the reliability of their balancing services by leaving a certain margin between the maximum available capacity and the capacity it offers to DSO. This margin should cover unforeseen deviations between contracted and realized balancing services provided by end flexibility providers.

This paper discusses the steps of the coordination procedure related to the DSO and aggregators, i.e., steps (1), (2), and (4). Step (3) implies the activation of the optimization function based on the common merit order list (CMOL) initiated by the TSO [3]. This procedure is already established and well known in modern power systems markets. Advanced BM clearing technologies imply the simultaneous computation of AC OPF in the transmission network. All these procedures are beyond the scope of this paper. In step (1), it is assumed that each aggregator submits several blocks of upward and downward balancing capacity/energy along with their bidding prices. A pay-as-bid pricing mechanism was assumed for the financial settlement between the DSO and the aggregators. In step (2), a mathematical model was developed for the DSO to validate the aggregators' bids while determining the limits of active power flexibility at the TSO–DSO connection point. The presented method can also be used to obtain the price/volume curve, which the DSO can further use for strategy bidding at the BM. To resolve the potential conflict of interest, the DSO should see the benefit of providing balancing services. For this reason, the model assumes that the DSO's revenue is proportional to the realized volume of service. Therefore, the DSO is incentivized to use controllable assets and its own infrastructure to increase flexibility limits at the TSO–DSO connection point. The optimization problem includes the transmission cost of balancing energy, considering the distribution network's technical limits. In addition, the geographical dispersion of the aggregator's resources, i.e., the capacity provision limits for each network node, is incorporated into the problem definition. Finally, in step (4), the developed mathematical formulation is used to determine the distribution of the control signals sent by the DSO to the aggregators after clearing the BM to adjust the type and amount of power requested by the TSO.

The proposed formulation is restricted to the MV network being supplied from a single HV/MV substation. This means that the DSO should perform the described steps for each MV distribution network under its control, or, in other words, the DSO should deliver its offer to the global BM for each TSO–DSO connection point. An offer delivered by the DSO must fulfill every technical requirement of the BM. The developed formulation supports the presence of non-controllable DERs and end-customer loads that are not under contract with the aggregators.

It should be highlighted that the current European regulatory framework [42] supports that the DSO, for the sake of efficient, reliable, and secure distribution system operation following transparent, non-discriminatory, and market-based procedures, hires flexible services from all previously discussed DERs, including aggregators. According to [40], DSOs and TSOs should collaborate to establish the technical standards for entry into the retail, wholesale, and balancing markets, and to ensure the effective involvement of the market participants connected to their grids. However, the existing practice indicates that there are no accepted common regulations, rules, or frameworks by which DSO would be included in the BM. The conclusions of [43] state that it is reasonable to assume that the TSO will continue to be responsible for system balancing in the future. Therefore, the perspective markets for services should change to enable DSO's active role and allow new resources to participate.

Papers like [36,37] describe the framework where DSO has the role of a negotiator with DERs, which is not in accordance with current rules, requiring minor regulation changes. From the DSO point of view, its more active incorporation in BM is desirable because, with the high share of DERs, DSO partially loses services that it had in the traditional system. Thus, DSO must organizationally adapt to new conditions, and mediation between aggregators and TSO can be a new service. The model proposed in this paper is not discriminatory because it encourages competition among aggregators and favors those aggregators with the least total costs, including the impact on losses in the distribution network. Implementing such a regulatory framework can be especially suitable for countries with a single DSO, as has been the case in Serbia. The legal framework under which the participation of DSO in BM is possible can also be achieved by establishing a separate entity by DSO that could act as a participant in the BM.

3. Proposed Methodology

This section presents the mathematical formulation of the model used to determine the flexibility limit of the distribution network at the TSO–DSO connection point, as well as the validation and aggregation of bids submitted to the DSO by distribution-level BSPs for participation in the BM. In addition, the presented model can be applied to determine the optimal dispatch of BSPs after clearing the market. In this study, we adopt BSPs as aggregators of DERs and medium-sized distributed generation (DG) units that interact independently with the DSO. Moreover, we assume that aggregators submit bids containing at least one bidding block, while DGs submit bids containing just one bidding block. The proposed methodology is based on the MISOCP approach formulated for a single time step, and it can be extended to multiple time steps.

3.1. Objective Function

The objective function can be defined differently depending on the optimization problem to be solved. If the objective is to determine the flexibility limits of ADN at the TSO–DSO connection point, the objective function has the following form:

$$F_1 = \min P_{SUB} \tag{1}$$

$$F_2 = \max P_{SUB} \tag{2}$$

Minimizing the variable P_{SUB} (1) gives the largest reduction of active power flow from TSO to DSO. From TSO's perspective, it is equivalent to the additional production of active power (positive balancing reserve in an upward regulation problem). By maximizing the variable P_{SUB} (2), the greatest possible increase in the active power flow from TSO to DSO is achieved, which, from TSO's point of view, presents additional consumption (negative balancing reserve in a downward regulation problem). The extreme values of the objective function in Equations (1) and (2) are defined either by the active power flexibility limits of the aggregators/DGs or by the operating constraints in the distribution network. The absolute difference between variable F_1/F_2 and initial power flow from the transmission to the distribution network, P_{SUB}^{0}, defines the maximum volume of the reserve capacity that the DSO can provide in the case of an upward/downward regulation problem.

Another objective-function formulation defines the optimization of the cost price for a specific amount of balancing services that the DSO can deliver to the TSO. Solving this optimization problem from the DSO point of view yields an optimal dispatch for all controllable resources in the ADN.

The objective functions in the balancing energy market differ depending on whether the DSO considers bids for activating upward or downward balancing energy. In the first case, BSPs sell balancing energy in the BM, and the cost for delivering energy $\Delta P_{spec}^{up} \cdot \Delta t$ from the distribution system to the transmission system is minimized (it is adopted that ΔP_{spec}^{up} and ΔP_{spec}^{down} are constant during period Δt):

$$F_3 = \min\left\{\sum_{k\in\mathbb{A}} \Lambda_k + \sum_{r\in\mathbb{D}} \lambda_r \Delta P_r^{dg} \Delta t + p^{MWh}\left(P_\gamma - P_\gamma^0\right)\Delta t + p^{DSO}\Delta P_{spec}^{up}\Delta t\right\} \tag{3}$$

In Equation (3), the first term of the objective function refers to the cost of the activation of each aggregator's resources Λ_{k}. The second term refers to the cost of each DG selling balancing energy $\Delta P_r^{dg}\Delta t$ at unit price λ_r. The third term assigns monetary compensation for the additional active power losses $\left(P_\gamma - P_\gamma^0\right)$ in the ADN due to an operational state change (this quantity can be positive or negative). Finally, the fourth term in the objective function represents the compensation for the DSO, quantifying its role as a central coordinator. The DSO will receive income proportional to the upward balancing energy $\Delta P_{spec}^{up}\Delta t$ that it delivers to the TSO. The last term in Equation (3) does not influence the optimal solution finding since it is a multiplication of constant values.

The objective function representation defined by Equation (3) can be adapted to the balancing capacity market when the BSPs submit bids to sell upward or downward balancing capacity. In this case, removing the time term Δt in (3) and the third term of the objective function is necessary. The latter can be explained by the fact that the activation of the balancing capacity implies the volume of the reserve capacity that the BSP has agreed to hold, and therefore, it has no effect on losses in the ADN.

In the case where BSPs buy balancing energy in the BM, and then the offer for the delivery of balancing energy $\Delta P_{spec}^{down}\Delta t$ from the transmission to the distribution system is maximized, the following objective function is applied:

$$F_4 = \max\left\{\sum_{k\in\mathbb{A}} \Psi_k + \sum_{r\in\mathbb{D}} \psi_r \Delta P_r^{dg} \Delta t - p^{MWh}\left(P_\gamma - P_\gamma^0\right)\Delta t - p^{DSO}\Delta P_{spec}^{down}\Delta t\right\} \tag{4}$$

In Equation (4), the first term is the total fee collected from the purchase of balancing energy by each aggregator Ψ_k. The second term refers to the fee collected from each DG buying balancing energy $\Delta P_r^{dg}\Delta t$ at unit price ψ_r. The third term assigns monetary compensation for the additional active power losses in the ADN and the fourth term represents the compensation for the DSO. It should be noted that the signs for the third and fourth terms have been changed compared with Equation (3). This can be explained by the fact that the additional losses in the network and the remuneration for the DSO worsen the offer compared with the case where BSPs interact directly with the TSO.

3.2. Constraints Related to Bids Submitted by Aggregators

In this study, we assumed that the aggregators submit bids containing at least one bidding block, and the DGs submit bids containing just one bidding block. In this way, the aggregators gain a greater flexibility in bidding, i.e., they can adjust their bids to their variable costs and/or their prior experience. These costs can vary significantly depending on the volume of service, since the aggregator has many resources at their disposal. Considering a positive balancing energy market, aggregators submit bids for the sale of balancing energy (Figure 2a) in the form of a non-decreasing staircase function. In the case of a negative balancing energy market, aggregators submit bids for the purchase of balancing energy (Figure 2b) in the form of a non-increasing staircase function. The cheapest is used first among the upward-regulating bids, and correspondingly, among the downward-regulating bids, the most expensive is used first. In the balancing capacity market, aggregators submit their bids in the form of a non-decreasing staircase function, regardless of the direction of the reserve, since in both cases, they are offering their flexibility potential. In the considered example from Figure 2, the number of bidding blocks is assumed to be three, while in the general case, it is equal to ${N_k}^c$.

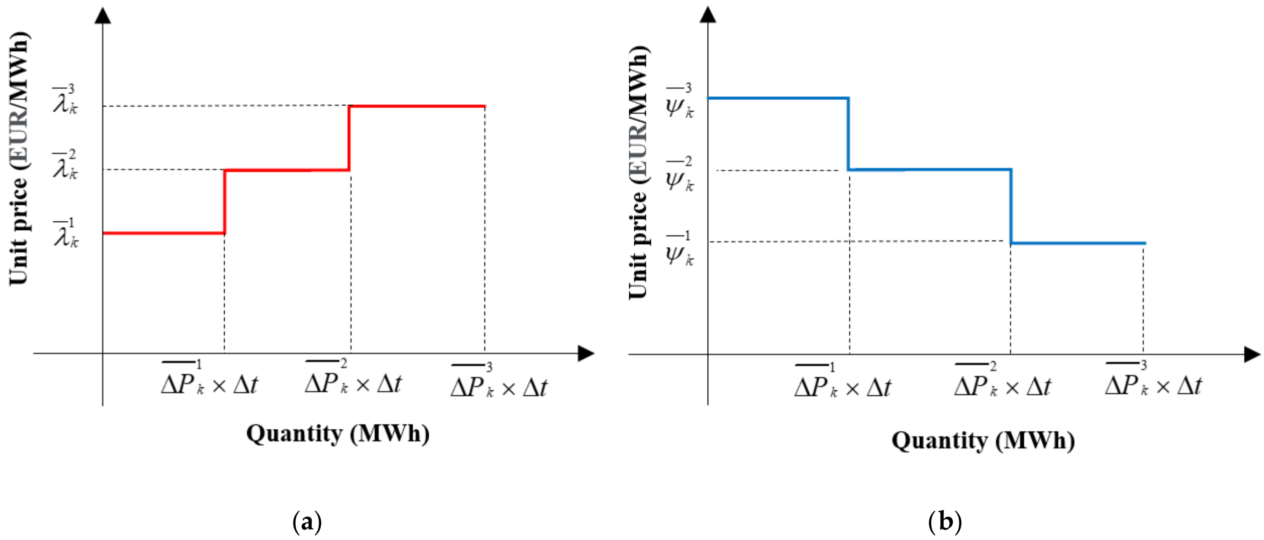


Figure 2. (**a**) Upward and (**b**) downward bids submitted by aggregator to DSO for corresponding time interval.

In the presented framework, aggregators do not participate directly in the BM, but they are represented by the DSO in charge. In this case, there is a two-stage bidding process. In the first stage, there is competition between aggregators within the considered distribution network, while in the second stage, DSO, as the central coordinator of aggregators, competes with other BSPs in the global BM. Each aggregator strives to make an optimal bidding strategy that will allow him to sell flexibility and maximize profit. Due to the uncertainties and dynamics of the electricity market, this task is a complex optimization problem and is the subject of research in many papers [24–28]. Generally, the aggregator should form his bidding curve based on influential factors, such as:

- Costs of engaging flexible resources;
- The volume of service at its disposal;
- Estimation of market clearing price;
- Estimation of the bidding behavior of the rival participants;
- Allocation of resources in the network.

The strategy of the aggregators' bid creation is beyond the scope of this research, and it is considered that these functions are known inputs for the proposed optimization model.

The variables Λ_k/Ψ_k represent the total fee that is collected from the sale/purchase of the kth aggregator's balancing energy. These depend on the aggregator's total absolute active power change ${\Delta P_k}^{agg}$, which is the decision variable of the optimization problem. This can be expressed as follows, noting that the "pay-as-bid" pricing mechanism is applied:

$$\Lambda_k = \sum_{n=1}^{N_k^c} \lambda_k^n \, ind_{k,n} \, \Delta P_k^{agg} \, \Delta t, \; k \in \mathbb{A} \tag{5}$$

$$\Psi_k = \sum_{n=1}^{N_k^c} \psi_k^n \, ind_{k,n} \, \Delta P_k^{agg} \, \Delta t, \; k \in \mathbb{A} \tag{6}$$

In Equation (5), $ind_{k,n}$ represents a binary variable that is equal to 1 if $\Delta P_k{}^{agg}$ is within the range $(\overline{\Delta P}_k^{n-1}, \overline{\Delta P}_k^{n})$; otherwise, it takes a value of 0.

The variables $\Delta P_k{}^{agg}$ can only belong to one bidding block, which is defined by the following equation:

$$\sum_{n=1}^{N_k^c} ind_{k,n} = 1\,,\ k \in \mathbb{A} \tag{7}$$

Furthermore, it is necessary to add an inequality constraint that connects the variables $\Delta P_k{}^{agg}$ and $ind_{k,n}$ to the limits of the blocks $\overline{\Delta P}_k^{n}$:

$$ind_{k,n}\, \Delta P_k^{agg} \le \overline{\Delta P}_k^{n},\ k \in \mathbb{A} \tag{8}$$

The proposed model can be explained using the example from Figure 2. Let us assume that $\Delta P_k{}^{agg} \cdot \Delta t$ belongs to the second block. According to (8), $ind_{k,1}$ must be equal to 0, while the variables $ind_{k,2}$ and $ind_{k,3}$ can still be equal to 1. In each objective function where the variable Λ_k figures, there is a tendency to minimize it, which is achieved when $ind_{k,2}$ = 1 and $ind_{k,3}$ = 0, because $\lambda_k^2 \le \lambda_k^3$.

In each objective function where the variable Ψ_k figures, there is a tendency to maximize it, which is achieved again if $ind_{k,2}$ = 1 and $ind_{k,3}$ = 0, because $\psi_k^2 \ge \psi_k^3$. It should be noted that Equation (7) makes it impossible for both binary variables $ind_{k,2}$ and $ind_{k,3}$ to take the value of 1.

In Equations (5), (6), and (8), the products of the binary $ind_{k,n}$ and the non-negative continuous variables $\Delta P_k{}^{agg}$ bounded from above appear. Each of the products can be linearized by introducing a new continuous variable $Z_{k,n}^{agg}$ with an additional four inequality constraints:

$$Z_{k,n}^{agg} = ind_{k,n}\, \Delta P_k^{agg},\ k \in \mathbb{A},\ n = 1, \ldots, N_k^c \tag{9}$$

$$Z_{k,n}^{agg} \ge 0,\ k \in \mathbb{A}, n = 1, \ldots, N_k^c \tag{10}$$

$$Z_{k,n}^{agg} \le ind_{k,n}\, M,\ k \in \mathbb{A}, n = 1, \ldots, N_k^c \tag{11}$$

$$Z_{k,n}^{agg} \ge \Delta P_k^{agg} - M(1 - ind_{k,n}),\ k \in \mathbb{A}, n = 1, \ldots, N_k^c \tag{12}$$

$$Z_{k,n}^{agg} \le \Delta P_k^{agg},\ k \in \mathbb{A}, n = 1, \ldots, N_k^c \tag{13}$$

where M is a big positive number.

Equation (9) defines $Z_{k,n}^{agg}$ as the product of $ind_{k,n}$ and $\Delta P_k{}^{agg}$, while constraints (10)–(13) determine $Z_{k,n}^{agg}$ more precisely. Namely, if $ind_{k,n}$ is equal to 0, then $Z_{k,n}^{agg}$ must be 0 due to (10) and (11). On the other hand, if $ind_{k,n}$ is 1, then $Z_{k,n}^{agg}$ must be equal to $\Delta P_k{}^{agg}$ due to (12) and (13).

3.3. Power Flow Constraints in the Distribution Network

The radial distribution load flow using the conic programming presented in [44,45] was adapted to formulate the problem so that the aggregators and DGs offer their flexibility in terms of active power, while reactive power management is not considered. A set of active and reactive power injection equations is defined for all nodes of the distribution network, except for the slack node:

$$P_{I,i} = \sum_{j \in \alpha(i)} g_{ij} V_i^2 - V_i V_j (g_{ij} \cos\theta_{ij} + b_{ij} \sin\theta_{ij}) = P_{G,i} - P_{D,i} \pm \sum_{k \in \beta(i)} \Delta P_{k,i}^{agg} \pm \sum_{r \in \delta(i)} \Delta P_r^{dg},\ i = 2, \ldots, N_B \tag{14}$$

$$Q_{I,i} = \sum_{j \in \alpha(i)} -(b_{ij} + b_{shij}/2) V_i^2 + V_i V_j (b_{ij} \cos\theta_{ij} - g_{ij} \sin\theta_{ij}) = Q_{G,i} - Q_{D,i},\ i = 2, \ldots, N_B \tag{15}$$

In (14) and (15), the sign + should be adopted if the optimization problem is solved when the BSPs provide upward flexibility, and the sign − should be adopted when the BSPs provide downward flexibility. In the case that there are no manageable resources at the same node, the last two terms in (14) are equal to zero. Equations (14) and (15) have a nonlinear form, but it is possible to linearize them by introducing new state variables associated with voltage magnitudes and phase angles:

$$u_i = V_i^2/\sqrt{2}, i = 1, \ldots, N_B \tag{16}$$

$$R_{ij} = V_i V_j \cos\theta_{ij}, ij \equiv l = 1, \ldots, N_L \quad (17)$$

$$T_{ij} = V_i V_j \sin\theta_{ij}, ij \equiv l = 1, \ldots, N_L \quad (18)$$

The injection equations defined by (14) and (15) become:

$$P_{I,i} = \sum_{j\in\alpha(i)} \sqrt{2} g_{ij} u_i - g_{ij} R_{ij} - b_{ij} T_{ij} = P_{G,i} - P_{D,i} \pm \sum_{k\in\beta(i)} \Delta P_{k,i}^{agg} \pm \sum_{r\in\delta(i)} \Delta P_r^{dg}, i = 2, \ldots, N_B \quad (19)$$

$$Q_{I,i} = \sum_{j\in\alpha(i)} -\sqrt{2}(b_{ij} + b_{shij}/2)\, u_i + b_{ij} R_{ij} - g_{ij} T_{ij} = Q_{G,i} - Q_{D,i}, i = 2, \ldots, N_B \quad (20)$$

The relationship between the variables u_i, R_{ij}, and T_{ij} can be expressed using second-order rotated cone constraints:

$$2u_i u_j \geq R_{ij}{}^2 + T_{ij}{}^2, u_i \geq 0,\ u_j \geq 0,\ R_{ij} \geq 0 \text{ for } ij \equiv l = 1, \ldots, N_L \quad (21)$$

The sign $\geq$ in Equation (21) indicates the relaxation of the constraints. Equations (19)–(21) represent the final mathematical model for the OPF calculation of the radial distribution network.

Since all terms are linear, the objective functions of the above optimization problems become convex by introducing the variables u_i, R_{ij}, and T_{ij}. However, the overall problem will be nonconvex if the equal sign is used in Equation (21). Therefore, the equalities in the original OPF problem are reduced to inequalities. The convex relaxation closes the nonconvex space into a feasible convex space for power flow equations. By using SOCP relaxation for OPF, a feasible and exact solution can be obtained, and the solution is the global optimum, as shown in [46,47]. That is, these inequalities will be tight in the optimal solution. This means that the physical connections between voltage phasors and flows of active and reactive power transmitted between two adjacent nodes will be met with high accuracy. Authors in [48] show that binding voltage limitations can lead to infeasible solutions in SOCP formulations. This can happen in the proposed mathematical formulation if, solving the objective Equations (3) and (4), a reference for total balancing support (ΔP_{spec}^{up} or ΔP_{spec}^{down}) is not physically feasible. In that case, deviations occur in Equation (21), which does not satisfy the physics of power flows in the network. However, this outcome is not possible, considering that the actual flexibility limit was determined in validating the aggregator's offers. For the stated reasons, in results section, the discrepancy that appears in Equation (21) is included as an indicator of the results' reliability.

3.4. Limitation of Operating Variables in the Distribution Network

In addition to the power flow constraints, the operating variables must be within the permissible limits. The apparent power at the TSO–DSO connection point should be less than the substation transformer rated power:

$$\overline{S}_{SUB} \geq \sqrt{P_{SUB}^2 + Q_{SUB}^2} \quad (22)$$

where:

$$P_{SUB} = P_{I,1} = \sum_{j\in\alpha(1)} \sqrt{2} g_{1j}\, u_1 - g_{1j} R_{1j} - b_{1j} T_{1j} \quad (23)$$

$$Q_{SUB} = Q_{I,1} = \sum_{j\in\alpha(1)} -\sqrt{2}(b_{1j} + b_{sh1j}/2)\, u_1 + b_{1j} R_{1j} - g_{1j} T_{1j} \quad (24)$$

Equation (22) represents the second-order cone constraint, while (23) and (24) indicate the equality of variables P_{SUB} and Q_{SUB} with the active and reactive power injections at the root node of the distribution network.

The boundaries of the voltage magnitude can be expressed in the following form:

$$\underline{V} \leq V_i \leq \overline{V}, i = 2, \ldots, N_B \quad (25)$$

Taking into account the previously defined new variables in (16)–(18), (25) can be rewritten:

$$\frac{\underline{V}^2}{\sqrt{2}} \leq u_i \leq \frac{\overline{V}^2}{\sqrt{2}}, i = 2, \ldots, N_B \tag{26}$$

Moreover, the operating line current must be less than the line's current carrying capacity:

$$I_l{}^2 = A_{ij}V_i{}^2 + B_{ij}V_j{}^2 - 2V_iV_j\left(C_{ij}\cos\theta_{ij} - D_{ij}\sin\theta_{ij}\right) \leq \bar{I}_l{}^2, ij \equiv l = 1, \ldots, N_L \tag{27}$$

where A_{ij}, B_{ij}, C_{ij}, and D_{ij} depend on network parameters as follows:

$$A_{ij} = g_{ij}^2 + \left(b_{ij} + b_{shij}/2\right)^2 \tag{28}$$

$$B_{ij} = g_{ij}^2 + b_{ij}^2 \tag{29}$$

$$C_{ij} = g_{ij}^2 + b_{ij}\left(b_{ij} + b_{shij}/2\right) \tag{30}$$

$$D_{ij} = g_{ij}b_{shij}/2 \tag{31}$$

Considering the introduced substitution in (26), Equation (27) becomes:

$$I_l{}^2 = \sqrt{2}A_{ij}u_i + B_{ij}u_j - 2C_{ij}R_{ij} + 2D_{ij}T_{ij} \leq \bar{I}_l{}^2, ij \equiv l = 1, \ldots, N_L \tag{32}$$

The total active power losses can be represented as the sum of the active power injections in all the nodes of the distribution network:

$$P_\gamma = \sum_{i=1}^{N_B} P_{I,i} \tag{33}$$

The total balancing support provided by the TSO is reflected in the active power injection change at the root of the distribution network. In the case of the upward regulation problem, it can be written as:

$$\Delta P_{spec}^{up} = P_{SUB}^0 - P_{SUB} \tag{34}$$

On the contrary, in the case of a downward regulation problem, we have:

$$\Delta P_{spec}^{down} = P_{SUB} - P_{SUB}^0 \tag{35}$$

In Equations (34) and (35), superscript 0 denotes the initial operating state of the distribution network.

3.5. Additional Constraints Related to Aggregators and DG Units

In the problem description, it has been assumed that system-balancing support can be provided by aggregators of the DER and DG units that are not under the jurisdiction of aggregators and interact independently with the DSO. It should be noted that aggregators may offer their services at multiple nodes of the distribution network, and more than one aggregator/DG may be connected to the same node. Each of these resources provide a limited capacity for upward and downward flexibility, which can be expressed by:

$$0 \leq \Delta P_{k,i}^{agg} \leq \overline{\Delta P}_{k,i}^{agg,up},\ k \in \beta(i),\ i = 2, \ldots, N_B \tag{36}$$

$$0 \leq \Delta P_{k,i}^{agg} \leq \overline{\Delta P}_{k,i}^{agg,down},\ k \in \beta(i),\ i = 2, \ldots, N_B \tag{37}$$

$$0 \leq \Delta P_r^{dg} \leq \overline{\Delta P}_r^{dg,up},\ r \in \mathbb{D} \tag{38}$$

$$0 \leq \Delta P_r^{dg} \leq \overline{\Delta P}_r^{dg,down},\ r \in \mathbb{D} \tag{39}$$

Equations (36) and (38) are used when the upward regulation problem is solved, while Equations (37) and (39) are used in the case of a downward regulation problem. When dispatchable DG units are considered (e.g., CHP, RESs with internal storage, diesel generators), it is generally possible to achieve an active power change in both directions. Non-dispatchable DG units (e.g., PV power plants, wind turbines) usually operate at the maximum available active power and cannot increase their output.

The total change in active power required by the kth aggregator is distributed among the nodes where this aggregator offers its services. Mathematically, this can be expressed as follows:

$$\Delta P_k^{agg} = \sum_{i \in \gamma(k)} \Delta P_{k,i}^{agg}, k \in \mathbb{A} \quad (40)$$

3.6. Summary

The proposed mathematical model can be used to solve a wide range of optimization problems. The solution of (1)/(2) with the constraints (19)–(21), (22)–(24), (26), (28)–(32), (36)/(37), (38)/(39), and (40) determine the limits of upward/downward active power flexibility at the point of the TSO–DSO connection. Once the limits are determined for both problems, each interval from zero to the absolute difference between variable F_1/F_2 and parameter P_{SUB}^{O} can be divided into evenly spaced breakpoints. One point determines the specified power $\Delta P_{spec}^{up}/\Delta P_{spec}^{down}$, for which the optimization problem (3)/(4) with the constraints (5)/(6), (7)–(8), (10)–(13), (19)–(21), (22)–(24), (26), (28)–(33), (34)/(35), (36)/(37), (38)/(39), and (40) is solved and the F_3/F_4 value is obtained. When the described procedure is repeated for the entire set of previously defined operating points, a cost curve for providing the upward/downward balancing service is obtained. It should serve the DSO for strategy bidding in the BM. In addition, if the DSO receives a request from the TSO to activate the balancing energy $\Delta P_{spec}^{up}\Delta t/\Delta P_{spec}^{down}\Delta t$ by solving problems (3)/(4) with the constraints (5)/(6), (7)–(8), (10)–(13), (19)–(21), (22)–(24), (26), (28)–(33), (34)/(35), (36)/(37), (38)/(39), and (40), an optimal re-dispatching of the distribution network is performed. The reformulated problems used the MISOCP approach and were solved using Matlab 2020b with the MOSEK optimization package installed [49].

4. Case Study

The proposed methodology was demonstrated on a modified IEEE 15-bus radial network, whose single-line diagram is shown in Figure 3. Line and load data were taken from [50]. Since testing the proposed methodology requires a significant amount and dispersiveness of different types of flexible resources, the modification of the network was performed as follows:

- The active power consumption at node 12 was increased by 400 kW due to the presence of an electric-vehicle charging station with V2G technology;
- There were three aggregators of DERs. The dashed lines in Figure 3 show the areas covered by each aggregator. In addition to the dispatchable resistive load that was part of the base consumption, aggregator 1 coordinated the charging station at node 12, aggregator 2 had a battery storage with a rated power of 600 kW at node 7, and aggregator 3 had two battery storage units at nodes 14 and 15 with a rated power of 300 kW and 400 kW, respectively. Data for the aggregators are shown in Table 1;
- DG units consisting of a photovoltaic power plant, a wind turbine, and a CHP unit were added at nodes 5, 10, and 11, respectively. All DGs were assumed to operate on a unity power factor, whereby only the CHP unit submitted bids to the DSO to provide balancing services. The parameters of the DGs are listed in Table 2.

In Figure 3, the serial number of each branch is marked, and the values of the current carrying capacity of the lines in amperes are given in brackets. The power transformer had a rated apparent power of 5 MVA. It was assumed that the voltage module at the root of the distribution network was equal to 1 p.u. The upper and lower voltage limits at all nodes were set to 1.05 p.u. and 0.93 p.u., respectively.

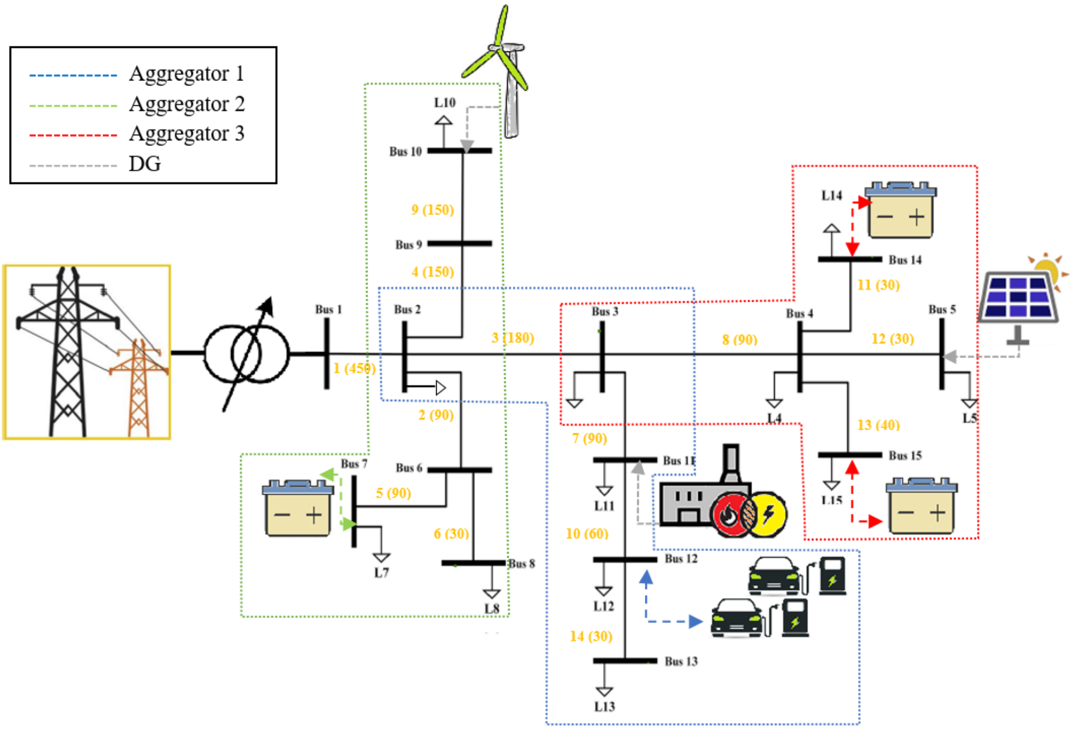


Figure 3. Modified IEEE 15-bus distribution network.

Table 1. Aggregator data.

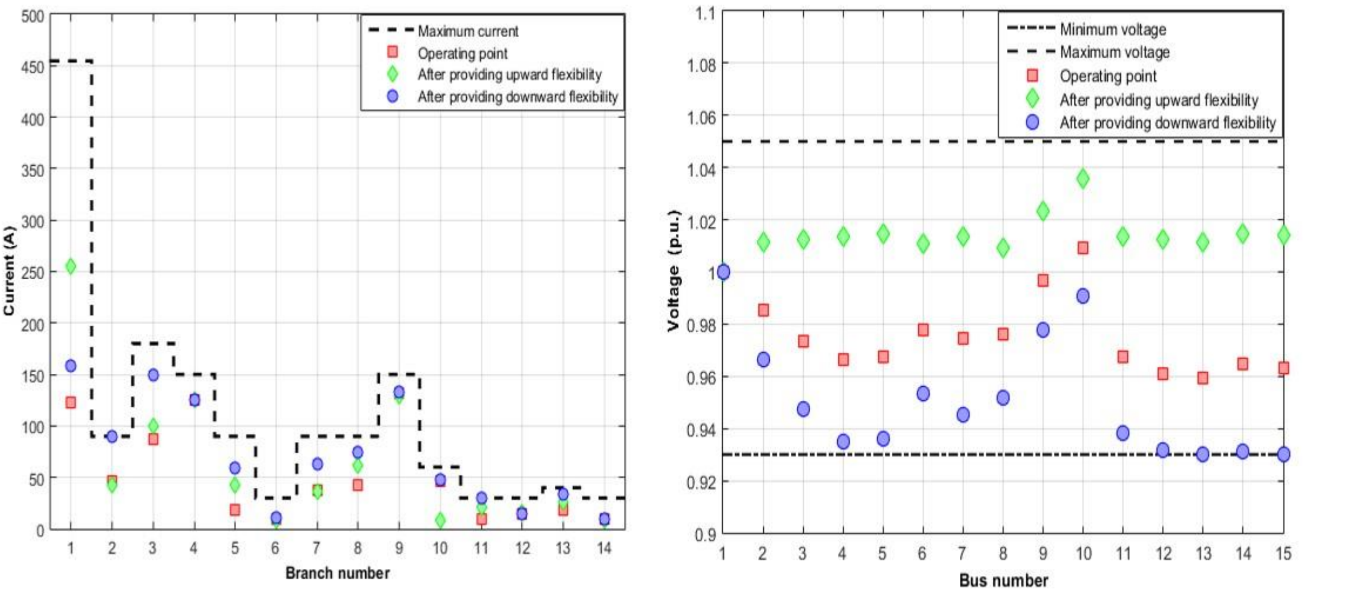
Aggregator 1			Aggregator 2			Aggregator 3		
Node i	$\overline{\Delta P}_{k,i}^{agg,up}$ **(kW)**	$\overline{\Delta P}_{k,i}^{agg,down}$ **(kW)**	**Node i**	$\overline{\Delta P}_{k,i}^{agg,up}$ **(kW)**	$\overline{\Delta P}_{k,i}^{agg,down}$ **(kW)**	**Node i**	$\overline{\Delta P}_{k,i}^{agg,up}$ **(kW)**	$\overline{\Delta P}_{k,i}^{agg,down}$ **(kW)**
2	13.23	11.025	2	21	17.5	3	21	17.5
3	21	17.5	6	42	35	4	42	35
11	42	35	7	600	600	5	13.23	11.025
12	500	50	8	21	17.5	14	300	300
13	21	17.5	9	21	17.5	15	400	400
			10	13.23	11.025			

Table 2. DG unit data.

Node i	DG Type	$P_{G,i}$ (kW)	$\overline{\Delta P}_r^{dg,up}$ (kW)	$\overline{\Delta P}_r^{dg,down}$ (kW)
5	PV	200	0	0
10	WT	1500	0	0
11	CHP	300	100	300

4.1. Determining the Flexibility Limits of the Distribution Network at the TSO–DSO Connection Point

In order to aggregate the bids sent by the aggregators and DGs to the DSO, it was necessary to determine the flexibility limits of the distribution network first, i.e., the maximum capacities for the additional injection/absorption of active power at the TSO–DSO connection point. The voltage and current magnitudes before and after activation of the maximum flexibility are shown in Figure 4a,b.



(**a**) (**b**)

Figure 4. (**a**) Branch currents and (**b**) node voltages for the initial operating point and after providing maximum flexibility.

The DSO capability for providing upward flexibility was 2.1109 MW, which was less than the net upward active power flexibility limit of all BSPs (2.1917 MW). In addition, the total active power losses increased by 0.0808 MW compared with the initial operating state. It should be emphasized that the operating constraints in the network were not violated, and the total upward flexibility capacity of the BSPs was activated.

The DSO capability for providing downward flexibility was 1.3952 MW, which was lower than the net downward active power flexibility limit of all BSPs (1.8931 MW). In this case, the network's operational constraints reached the limits: the voltages at nodes 13 and 15 equaled the lower limit, while the current carrying capacity over branches 2 and 11 was reached. The optimal solution implies that aggregator 1 did not change injections at nodes 12 and 13 and increased its consumption at node 11 by 0.0173 MW; aggregator 2 increased its consumption at node 7 by 0.4648 MW; and aggregator 3 increased its consumption at nodes 14 and 15 by 0.2289 MW and 0.1807 MW, respectively. Moreover, the DGs at nodes 5 and 10 did not change their operation mode, while the CHP unit reduced its production by 0.2619 MW. Finally, the BSPs changed their power at all other nodes as much as possible. The increase in active power losses compared with the initial state was 0.051 MW.

4.2. Validation and Aggregation of Bids Submitted by BSPs to DSO

The validation and aggregation of bids submitted by the BSPs to the DSO were studied in the case of the balancing energy market, since this represents a more general and complex case. The duration of the unit time step was 15 min, corresponding to a realistic BM [3,51]. The aggregators' bids for upward and downward balancing energy could contain more than one bidding block. Note that, in the first case, the unit price increased with the serial number of the block (Table 3), while in the second case, it decreased (Table 4). The CHP unit submitted a single price offer to the DSO, which was 200 EUR/MWh when selling balancing energy and 50 EUR/MWh when buying balancing energy. The cost of the electrical losses was 120 EUR/MWh and the financial compensation for the DSO was 6 EUR/MWh.

Table 3. Upward balancing energy bids submitted by aggregators.

Aggregator 1			Aggregator 2			Aggregator 3		
Block n	λ_k^n (EUR/MWh)	$\overline{\Delta P_k^n} \cdot \Delta t$ (kWh)	Block n	λ_k^n (EUR/MWh)	$\overline{\Delta P_k^n} \cdot \Delta t$ (kWh)	Block n	λ_k^n (EUR/MWh)	$\overline{\Delta P_k^n} \cdot \Delta t$ (kWh)
1	140	74.65	1	150	89.8	1	160	194.05
2	170	149.3	2	170	179.5	2	-	-

Table 4. Downward balancing energy bids submitted by aggregators.

Aggregator 1			Aggregator 2			Aggregator 3		
Block n	ψ_k^n (EUR/MWh)	$\overline{\Delta P_k^n} \cdot \Delta t$ (kWh)	Block n	ψ_k^n (EUR/MWh)	$\overline{\Delta P_k^n} \cdot \Delta t$ (kWh)	Block n	ψ_k^n (EUR/MWh)	$\overline{\Delta P_k^n} \cdot \Delta t$ (kWh)
1	96	32.75	1	100	87.3	1	104	95.45
2	-	-	2	90	174.6	2	88	190.9

The flexibility limits regarding the additional injection/absorption of active power obtained in Section 4.1 determined the set of all possible operating states at the TSO–DSO connection point. Each flexibility interval was divided into 16 uniformly distributed operating points, so one breakpoint determined the specified power $\Delta P_{spec}^{up}/\Delta P_{spec}^{down}$ for which the objective function (3)/(4) was solved. When the optimization procedure was repeated for the whole set of operating points, the dependence of the aggregated price/quantity curve was obtained for both upward (Figure 5) and downward (Figure 6) regulation problems. The resulting cost function was the basis for creating a joint bid that the DSO would submit to the global BM. If the DSO has the option of bidding in blocks, the breakpoints and unit prices for each block should be chosen so that the resulting cost function deviates as little as possible from the curves shown in Figures 5 and 6.

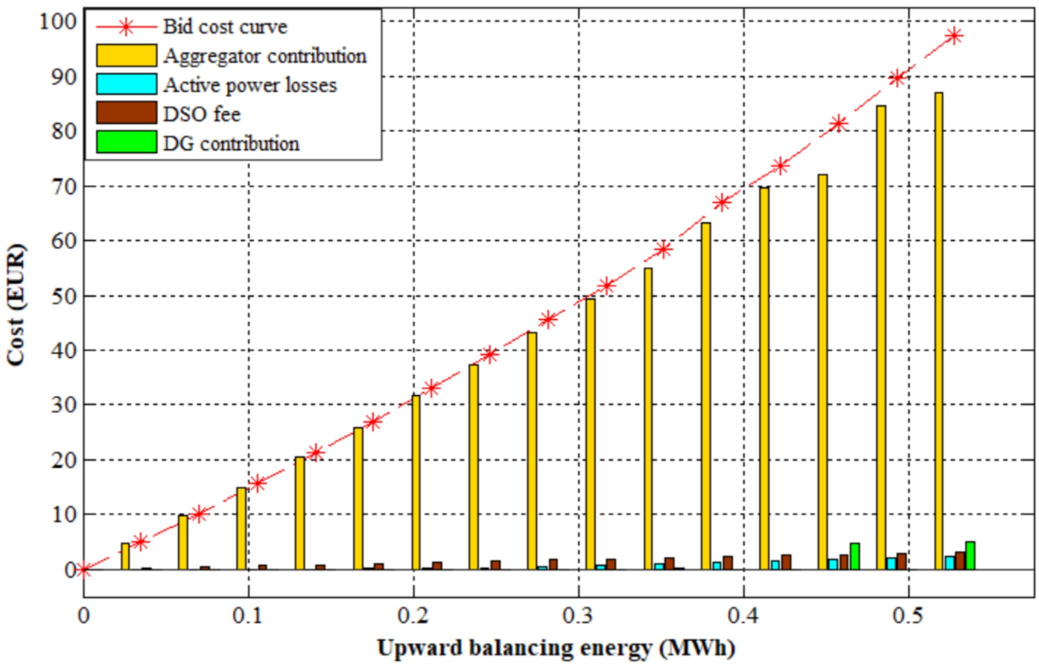


Figure 5. Aggregated price/quantity curve as a function of upward balancing energy.

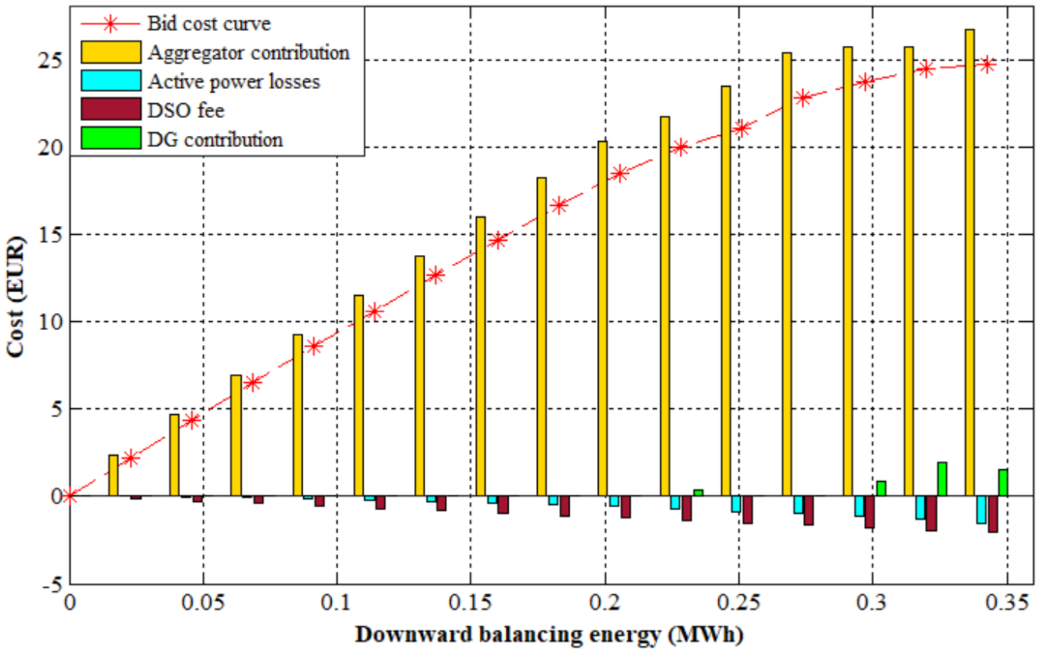


Figure 6. Aggregated price/quantity curve as a function of downward balancing energy.

4.3. Optimal Dispatch of BSPs in the Distribution Network after Clearing the Global BM

When the nature of the imbalance is determined on the global BM, i.e., after the financial settlement is made, the DSO receives a request from the TSO to inject/absorb the appropriate amount of balancing energy at the TSO–DSO connection point. Thus, for the time interval under consideration, the quantity $\Delta P_{spec}^{up}/\Delta P_{spec}^{down}$ is known. By solving the optimization problem (3)/(4), a new optimal operating state of the network is determined to fulfill the TSO's requirements. Based on the received information, the DSO sends commands to the aggregators and DGs to change their generation/consumption power. In addition, the aggregators are provided with a reference for power redistribution by the network nodes. This process will be demonstrated in two cases:

- Case 1: activation of 375 kWh of upward balancing energy (ΔP_{spec}^{up} = 1.5 MW).
- Case 2: activation of 300 kWh of downward balancing energy (ΔP_{spec}^{down} = 1.2 MW).

Table 5 shows references that DSO sends to aggregators for each node flexibility activation, clearing power, and service unit price for each aggregator, while the new operational state of the network after balancing energy activation is shown in Table 6.

In Case 1, the optimal solution involved increasing the active power injection into the distribution network by 298.6 kW from aggregator 1463.7 kW from aggregator 2776.2 kW from aggregator 3, and 0 kW from the CHP unit. It should be noted that the entire capacity of the first block was selected for all three aggregators (at a lower unit price, (see Table 3)), while the remaining capacity required to meet the injection requirement of 1.5 MW was distributed only to aggregator 2 (the second block of aggregator 2's bid was activated). Even though aggregators 1 and 2 offered the same unit prices for the second block of their bids, the remaining capacity was allocated only to aggregator 2. For the considered scenario, aggregator 2 was favored over aggregator 1 due to its better position in the network, as its additional balancing energy activation led to lower power losses compared with aggregator 1 and a lower total cost value. The sum of all aggregators' power changes are slightly higher than the reference balancing energy due to an increase in consequential losses in the distribution network.

Table 5. References that the DSO sent to the aggregators.

Aggregator 1			Aggregator 2			Aggregator 3		
Node i	$\Delta P_{k,i}^{agg}$ (kW) for Case 1	$\Delta P_{k,i}^{agg}$ (kW) for Case 2	Node i	$\Delta P_{k,i}^{agg}$ (kW) for Case 1	$\Delta P_{k,i}^{agg}$ (kW) for Case 2	Node i	$\Delta P_{k,i}^{agg}$ (kW) for Case 1	$\Delta P_{k,i}^{agg}$ (kW) for Case 2
2	13.2	11.0	2	21	17.5	3	21	17.5
3	0	17.5	6	42	35	4	42	35
11	0	35	7	379.7	467.7	5	13.2	11.0
12	264.4	50	8	21	17.5	14	300	194.5
13	21	17.5	9	0	17.5	15	400	123.7
			10	0	11.0			
clearing power (kW)	298.6	131	clearing power (kW)	463.7	566.2	clearing power (kW)	776.2	381.7
clearing unit price (EUR/MWh)	140	96	clearing unit price (EUR/MWh)	170	90	clearing unit price (EUR/MWh)	160	104

Table 6. Voltage magnitude and branch loadability after upward/downward balancing energy activation.

Voltage Magnitude (p.u.)			Branch Loadability (p.u.)		
Node i	**Case 1**	**Case 2**	**Branch j**	**Case 1**	**Case 2**
1	1.0000	1.0000	1	0.4591	0.3254
2	1.0041	0.9691	2	0.3729	1.0000
3	1.0018	0.9517	3	0.4286	0.7367
4	1.0026	0.9406	4	0.8202	0.8313
5	1.0038	0.9416	5	0.2813	0.6650
6	1.0011	0.9560	6	0.2625	0.3586
7	1.0018	0.9481	7	0.2351	0.6030
8	0.9998	0.9543	8	0.6954	0.7423
9	1.0156	0.9807	9	0.8588	0.8820
10	1.0280	0.9933	10	0.3293	0.9032
11	0.9990	0.9439	11	0.7271	0.8858
12	0.9958	0.9365	12	0.5283	0.4882
13	0.9944	0.9346	13	0.6720	0.7282
14	1.0038	0.9371	14	0.2639	0.3662
15	1.0031	0.9361			

In Case 2, the reference sent by DSO was to increase the absorbed power by aggregator 1 for 131 kW, aggregator 2 for 566.2 kW, aggregator 3 for 381.6 kW, and to decrease generation of the CHP unit for 80.6 kW. In this example, the entire capacity of the first block of all three aggregators was used (see Table 4), while aggregator 2 provided the rest of the power needed, since its unit price of the second block was higher than the second-block unit price of aggregator 3. It should be noted that the total power change in nodes 6, 7, and 8 of aggregator 2 was limited by the congestion over branch 2 (566.2 kW < 698.5 kW). Therefore, it was additionally necessary to reduce the production of the CHP unit by 80.6 kW. This additional power change was neither assigned to aggregator 1, since its capacities were fully utilized, nor to aggregator 3, since its entire offer would pass with the unit price of its second block, which was a less economical solution. The sum of all aggregators' power changes is smaller than the reference power because, in a downward regulation problem, an increase in network power losses helps to reach the reference.

Existing models for aggregators' participation in the BM assume an uncoordinated engagement of their resources. Therefore, the DSO only performs security analyses of the distribution network operation based on the bids submitted by the aggregators. An uncoordinated approach can lead to excessive losses and nonoptimal utilization of distribution network assets, reducing the maximum balancing capacity that the TSO can exploit in the TSO–DSO connection point. To verify these claims, two cases were analyzed for the reference power of 0.5 MW in the downward regulation problem. At first, it was assumed that aggregators participate individually in the BM without DSO coordination (DSO only performs security analysis) and that the aggregator 3 offer was solely activated. In the second case, DSO's coordination of aggregator offers was applied according to the methodology proposed in this paper, assuming that all aggregators offer the service at the same price. The optimal engagement of resources for the mentioned example is equivalent to the minimization of active power losses. Active power losses in the first case are 93.2 kW and 84.5 kW in the second case. As seen from the analysis, the proposed model can ensure the reduction of losses, which consequently causes lower balancing costs. In addition, with DSO-coordinated aggregators' participation, loads of the distribution system assets are more even, extending the assets' lifetime.

4.4. Scalability of the Proposed Methodology

In order to explore the effectiveness of the developed methodology in larger networks, it was applied in several MV test systems of higher node numbers. The scenarios were formulated as follows:

- At each node, 20% of the active load is manageable in both positive and negative directions;
- Each battery storage unit has a rated power of 800 kW, and it does not exchange active power with the network in the initial state;
- Each DG has a non-controllable production of 1000 kW with the unity power factor, there are three aggregators of DERs, and each covers one-third of the nodes (aggregator 1 covers the first third of the nodes, aggregator 2 covers the second third, and aggregator 3 covers the last third of the nodes);
- The offers that the aggregators deliver to the DSO are the same as in Section 2 (same number of blocks, same unit price per block, and same ratio between breakpoints and maximal volume of service);
- The voltage at the root node equals 1 p.u.

The DER positions and operational network limits are presented in Table 7.

The numerical experiments were carried out with MOSEK running on a 3.8 GHz PC with 8 GB of RAM. Table 7 shows a summary of the results. In each case, the flexibility limit of the distribution network at the TSO–DSO connection point was calculated, and the network operational limit reached is also given in Table 7. The termination criteria were set to their default values [49]. The average, minimum, and maximum execution times in Table 7 refer to the durations of one simulation in the bid-aggregation process. The longest computation time was 2.07 s, fast enough for real-time dispatch. The computation time could be further reduced by using a computer with better performance or by reducing the number of flexible resources in the network. In this analysis, the power flow accuracy of the applied model was tested by comparing the bus voltage and branch current results with the model presented in [52]. Moreover, by calculating the maximum absolute error from (21), it was concluded that the relaxation of the equality constraints by introducing second-order rotated cones was justified. The presented results demonstrate the effectiveness and accuracy of the presented mathematical formulation and point out its practical implementation.

Table 7. Summary of the results.

	Test System 1	**Test System 2**	**Test System 3**	**Test System 4**
Number of nodes	**15**	**33**	**69**	**85**
System data reference	[50]	[53]	[53]	[54]
Nodes of DG connection	Section 4	14, 20, 22, 30	6, 23, 48	23, 39, 44, 66, 82
Nodes of battery storage connection	Section 4	6, 14, 30	10, 42, 50	20, 46, 66, 80
Voltage limits (p.u.)	(0.93–1.05)	(0.93–1.05)	(0.9–1.05)	(0.9–1.1)

Table 7. *Cont.*

	Test System 1	Test System 2	Test System 3	Test System 4
Current carrying capacity (A)	Figure 3	lines 1–5: 500 A lines 6–23: 150 A other lines: 100 A	lines 1–9: 500 A lines 41–49: 180 A other lines: 150 A	lines 1–4: 800 A lines 41–49: 500 A other lines: 200 A
Maximum upward flexibility power provided by the DSO (total upward active power flexibility of all BSPs) (MW)	2.111 (2.192)	2.874 (3.329)	3.056 (3.161)	2.865 (3.714)
Network limits reached for upward problem	not achieved	current of line 29	not achieved	max. voltage at node 46
Maximum downward flexibility power provided by the DSO (total downward active power flexibility of all BSPs) (MW)	1.395 (1.893)	2.432 (3.329)	2.311 (3.161)	3.647 (3.714)
Network limits reached for downward problem	min. voltage at nodes 13 and 15; current limit of lines 2 and 11	min. voltage at nodes 18 and 33	current limit of line 41	not achieved
Average execution time (s)	0.23	0.48	1.17	1.09
Minimum execution time (s)	0.14	0.19	0.39	0.32
Maximum execution time (s)	0.38	0.84	1.72	2.07
Maximum absolute error in (21)—case of 1 MW of specified upward power (kV^2)	6.42×10^{-5}	2.517×10^{-4}	1.548×10^{-4}	2.332×10^{-5}
Maximum current/voltage percentage error—case of 1 MW of specified upward power (%)	0.036	0.075	0.161	0.0838

4.5. Discussion

It should be noted that MISOCP is an NP-hard problem [55]. In the case of convex optimization problems, there are exact methods for solving them that guarantee finding an optimal solution or proving that such a solution does not exist [56]. On the other hand, it is computationally challenging to obtain an optimal global solution for MISOCP in case of a big problem dimensionality. Suppose that problem arises in the case of an extensive distribution network. In that case, it could be divided individually or into a group of feeders, which is easy considering that the distribution networks are mostly radial or weakly interconnected. The proposed algorithm can be independently applied to individual regions (feeders), reducing the problem's dimensionality so that problems can be solved in polynomial time. Another approach combines heuristic techniques to find integer variables and solve the SOCP, enabling suboptimal solution finding [57].

Considering the large dimensionality of distribution networks and the wide dispersiveness of DERs, the possibility of a large information flow during real-time operation arises. The recommendation is to maintain the optimal operating state in the distribution network after clearing the BM during the entire market time unit, i.e., the DSO sends constant signal references to the DER. The proposed framework enables the DSO to support the balancing mechanism, but the conventional large-scale control resources are still expected to cover fast and unpredicted imbalances. In other words, the proposed formulation completely matches the needs of manual Frequency Restoration Reserves (mFFR) provision. Its application for automatic Frequency Restoration Reserves (aFRR) is questionable due to its frequent and fast activations and the need for DERs to be equipped with additional control and telecommunication infrastructure. aFRRs can be performed as described in this paper in small-scale distribution networks with significant balancing resources.

5. Conclusions

Future power systems with a high share of RES impose the need for an increasing volume of balancing services procured by TSO. For this reason, new flexibility providers and procedures that enable sufficient flexibility should be ensured. Therefore, this work presented a framework that enables active power flexibility to be achieved at the TSO–DSO connection point.

The presented framework enables DSO's active role in aggregators' participation in the BM. DSO, as the central coordinator of the aggregators, validates and aggregates the offers submitted by aggregators, representing their interests in the global BM. Upon request of the TSO, the DSO activates the service by engaging resources according to market criteria, considering their influence in active power loss changes as well as the security of the distribution network. On the lower hierarchical level, aggregators enter into contracts with DER, considering their position in the distribution network regarding effects on losses and network operational limits when activating their service. This way, a potential conflict of interest between TSO and DSO in using DER flexibility is avoided. DSO ensures the integrity of the distribution network and can realize an extra profit for BM. At the same time, aggregators have more opportunities to respond to strict requirements and conditions for participation in the BM by joining together.

The mathematical optimization problem definition for each process stage is presented, including flexibility limits' determination at the point of TSO-DSO connection, the bids validation and aggregation process, and the optimal dispatch of ADN after BM clearing. Numerical results from the test distribution networks prove the proposed methodology's high accuracy and efficiency, indicating its practical implementation potential.

The main result of the proposed framework is the cost minimization of providing balancing services that will benefit all participants in the electricity market. As shown in the paper, the proposed mathematical optimization model will increase the total flexibility potential and the efficiency of distribution networks compared with models where aggregators directly participate in BM.

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Nomenclature

List of Acronyms

RES	renewable energy source
DER	distributed energy resource
DG	distributed generation
TSO	transmission system operator
DSO	distribution system operator
AND	active distribution network
BM	balancing market
BSP	balancing service provider
BRP	balancing responsible party
MTU	market time unit
CMOL	common merit order list

MISOCP	mixed-integer second-order cone programming
OPF	optimal power flow
Sets	
$\mathbb{A}$	set of aggregators in distribution network
$\mathbb{D}$	set of DGs in distribution network
$\alpha(i)$	set of nodes adjacent to node i
$\gamma(k)$	set of nodes at which the aggregator k offers its services
$\beta(i)$	subset of aggregators from set $\mathbb{A}$ offering services at node i
$\delta(i)$	subset of DGs from set $\mathbb{D}$ offering services at node i
Parameters	
g_{ij}	series cond0uctance in the π-model of line between nodes i and j in Ω
b_{ij},b_{shij}	series and shunt susceptance in the π-model of the line between nodes i and j in Ω
Δt	duration of one time step in h
N_B	number of nodes in distribution network
N_L	number of lines in distribution network
N_k^c	number of bidding blocks (stairs) within the bid submitted by aggregator k
λ_k^n, ψ_k^n	unit price of upward/downward balancing energy within the nth block of the bid submitted by aggregator k in EUR/MWh
$\overline{\Delta P}_k^n$	upper limit of active power within the nth block of the bid submitted by aggregator k in MW
λ_r, ψ_r	unit price for upward/downward balancing energy bid submitted by the rth DG in EUR/MWh
p^{MWh}	day-ahead price of electricity for the considered time interval in EUR/MWh
p^{DSO}	unit price of DSO compensation for providing balancing services in EUR/MWh
$\overline{\Delta P}_{k,i}^{agg,up}$	upward active power flexibility limit of the kth aggregator at node i in MW
$\overline{\Delta P}_{k,i}^{agg,down}$	downward active power flexibility limit of the kth aggregator at node i in MW
$\overline{\Delta P}_r^{dg,up}$	upward active power flexibility limit of the rth DG in MW
$\overline{\Delta P}_r^{dg,down}$	downward active power flexibility limit of the rth DG in MW
P_γ^0	active power losses in distribution network in the initial state in MW
P_{SUB}^0	active power flow from transmission to distribution network in the initial state in MW
ΔP_{spec}^{up}	scheduled additional active power exported to the TSO at the TSO–DSO connection point in MW
ΔP_{spec}^{down}	scheduled additional active power imported from the TSO at the TSO–DSO connection point in MW
$P_{G,i}$,$Q_{G,i}$	active and reactive power generation at node i in MW and Mvar, respectively
$P_{D,i}$,$Q_{D,i}$	active and reactive load power at node i in MW and Mvar, respectively
$\underline{V}$, $\overline{V}$,	upper and lower limit of node voltage in kV
$\overline{I}_l$	lth line current carrying capacity in kA
$\overline{S}_{SUB}$	apparent power rating of substation transformer in MVA
Variables	
ΔP_k^{agg}	scheduled active power absolute variation in the kth aggregator in MW
$\Delta P_{k,i}^{agg}$	scheduled active power absolute variation in the kth aggregator at node i in MW
ΔP_r^{dg}	scheduled active power absolute variation in the rth DG in MW
$ind_{k,n}$	a binary variable equal to 1 if ΔP_k^{agg} is within the range $\left(\overline{\Delta P}_k^{n-1}, \overline{\Delta P}_k^n\right)$; otherwise, it is 0
$Z_{k,n}^{agg}$	an auxiliary variable used to linearize the product $ind_{k,n}\,\Delta P_k^{agg}$ in MW
$P_{I,i}$,$Q_{I,i}$	active and reactive power injection at node i in MW and Mvar, respectively
P_{SUB},Q_{SUB}	active and reactive power flow from the TSO to the DSO in MW and Mvar, respectively
V_i	voltage magnitude at node i in kV
θ_i	voltage phase at node i in rad

θ_{ij}	voltage phase difference between nodes i and j in rad
P_{γ}	active power losses in distribution network in MW
u_i	variable in the load flow model associated with node i in kV^2
R_{ij}	variable in the power flow model representing the product of $V_i V_j \cos\theta_{ij}$ in kV^2
T_{ij}	variable in the power flow model representing the product of $V_i V_j \sin\theta_{ij}$ in kV^2
I_l	current magnitude over the lth line in kA

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