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A market-based framework for demand side flexibility scheduling and dispatching

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ABSTRACT

The massive integration of renewable energy resources increases the uncertainty with respect to real-time operation of the electrical systems. This transition introduces new challenges and opportunities for various entities that are involved in energy generation, transmission, distribution and consumption such as system operators and market participants in the wholesale electricity market. The concept of Decentralized Energy Management or Demand Response is emerging as one of the main approaches to resolve the violations of the network operation limits and to increase the flexibility of the system. This paper introduces an interaction framework for trading flexibility among proactive end-users in an economically efficient way. It proposes new market participants with their roles and functionalities, that will operate alongside the existing ones to ensure market efficiency and to enable secure operation of distribution grids. The proposed framework consists of a main mechanism called 'ahead-markets scheduling'. The ahead-markets scheduling includes two sub-mechanisms, day-ahead and intra-day, which are operated by a local flexibility market operator. The ahead-markets scheduling provides a trading platform that allows market participants to reflect their need(s) for flexibility and to monetize flexibility services in a fair and competitive manner. It enables flexibility trades which will eventually facilitate network management for the system operator.

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1. Introduction

1.1. Motivation and background

The massive deployment of renewable energy sources and high energy demanding appliances at household level (e.g., electric vehicles and heat pumps) are changing the landscape of energy systems by creating new possibilities to produce, use and store energy. These changes are challenging the operation of electrical power systems because of an increased uncertainty in the whole energy supply chain, in terms of network stability, security and efficiency, as well as system balancing. Therefore, it is becoming increasingly complex to control the power flows, and to guarantee stability and reliability of electricity networks [1,2].

To make the energy system sustainable and to keep it reliable and affordable, neither energy nor network management can be based on the traditional top-down approach. Instead, a bottom-up approach is required with a larger involvement of the regional distribution system operators and proactive end-users [3]. This can be achieved through different processes including Demand Response (DR) and Decentralized Energy Management (DEM) [4–7]. The concept of local energy markets is a key element to ensure the success of such concepts. It can enable an active system management and engage end-users in resolving network problems [8]. So far, little has been done on the development of market mechanisms at the distribution level. As a result, the existence of a market-based mechanism that enables energy trades while enhancing the operation of the network at the distribution level is not well understood yet. Therefore, there might be a need for developing a platform that coordinates the trades among various market parties that are involved in energy dispatch at distribution level [8].

Local energy markets have recently attracted interest in the literature as they have the potential to enable a more active contribution of the end-users in the energy systems [9,10,1,11,2]. However, there are different approaches for running a local energy market. One practice that increases market liquidity in the market and encourages larger involvement of the participants is to implement local market using an auction-based platform that allows energy trades in a local community [12–14]. The establishment of auction-based local energy trading platforms is shown to create a number of value streams for the participants. They contribute to energy and cost savings [15,16]. They also facilitate the integration of intermittent distributed generation into existing power systems by improving network stability and energy efficiency. Note that the higher energy efficiency is resulted by the reduction of losses as energy is consumed close to generation [17].

1.2. Literature review

Several auction-based energy platforms that are suitable for the distribution grid level have been investigated in literature [17,14,18–26]. In [17], Liu et al. develop an auction-based market for a local reserve energy market. They define the reserve energy as energy that has to be provided to a household in case of an unexpected high demand or unforeseen outage. The market is designed for a residential area and accommodates the needs of non-conventional energy producers such as private households. The proposed local market creates an opportunity for households to reduce cost and to realize local balancing. In [14], an energy management system is used to show that local energy markets can lead to energy cost savings for households in a specific micro-grid consisting of nine homes with varying battery and PV capacity. Marzband et al. in [18] propose a Virtual Energy District (VED) which is a co-operation model to exchange energy locally to handle network congestions. The work continues in [19] where the authors introduce a modified VED model to utilize a local energy storage system to manage congestions at distribution level. In [20,21], Brusco et al. propose a centralized demand response program that aggregates prosumers (i.e., consumers that can become active and perform as energy producers) in a coalition to minimize the reverse energy flows and to maximize net benefits in a day-ahead energy market. Nguyen et al. [22] propose the so-called demand response eXchange (DRX) which is a competitive market clearing platform that is used to trade demand response as a commodity. Buyers utilize demand response to improve the reliability of their systems. Note that sellers in this study are assumed to have the capacity to modify their electricity use upon request. The proposed platform is considered to operate synchronously with the existing Day-ahead and Intra-day markets.

A new arrangement for clearing the day-ahead distribution market is studied in [23] and extended in [24,25]. Antonio Papavasiliou investigates three decomposition approaches to formulate and understand the formation of distribution locational marginal prices in radial distribution networks in [26]. He shows that all approaches are able to derive the locational marginal prices within an acceptable computational time and numerical error for a relatively small example network.

Several auction-based frameworks have been developed and implemented in practice [4,27–30]. The EcoGrid project studies a real-time local market for enabling distributed resources to contain the over-all system imbalances [4,27]. Heerhugowaard project develops a USEF-based auction based framework which enables the Distribution System Operator (DSO) to solve the congestion problem and Balance Responsible Parties (BRPs) to resolve their imbalance problem using flexibility of households [28]. The REnnovates project presents an auction-based platform that enables the DSO to unlock the residential energy flexibility (e.g., PVs) for grid and system level services (e.g., congestion management in distribution grids). The proposed framework will be tested in three demo sites in the Netherlands, Poland and Spain [29]. A similar framework is utilized in the LOMBOK project to enable the DSO to coordinate electric vehicle charging to minimize curtailment of distributed energy resources (e.g., PVs) [30].

There are two key observations worth mentioning regarding the studies outlined above. Firstly a higher-level operator (i.e., the DSO) is considered to operate local auctions and to oversee the trades. Secondly, energy is considered as the commodity to trade in the local auction markets. However, running the local market by the DSO creates complications. For example, it can give advantages and therefore a superior position to the DSO over other market participants. That is, having the DSO operating the market and simultaneously competing with the other market participants (as a market party) over flexibility services creates an unfair advantage for the DSO. A solution to this problem is to prohibit the DSO from participating in the local flexibility market. However, this would imply that the DSO loses the opportunity to play a more active role in coordinating the production/consumption of controllable demand and supply devices in the local grid and benefit from their potential flexibility. For prosumers, this would mean that at least part of the flexibility that flexible consumers have available and that they could utilize for the purpose of resolving grid issues (and benefit from it) remains unallocated.

Regarding commodity or service to trade in the market, here we argue for flexibility (as opposed to energy) as the ideal service to be traded in the local markets. The first supporting argument is that, at the time of a network problem, the DSO is interested in the end-users' ability in adopting a change in their energy consumption (i.e., flexibility) and not in their absolute electricity consumption. Note that in such an occasion, the value of flexibility service for the DSO is not necessarily equivalent to the cost of energy being consumed. The second argument is that, considering energy as the main commodity would require the end-users to participate in a local or the wholesale energy market. Procuring energy directly from a local market exposes the end-users to uncertainties associated with energy markets (i.e., competition, need for accurate load and price forecast, balance responsibility) [31]. This is in contrast to current legal arrangements where, regardless of the outcome of the wholesale market, end-users are allowed to consume the amount of energy they need. Therefore, end-users are probably not willing to lose their current advantage, nor is it feasible for them to participate directly in an energy market. The third and last argument is that, trading flexibility as a service is intended to incentivize end-users to adopt their consumption patterns to the needs of the local market. This could mean that in certain occasions, a group of end-users would be asked to increase their energy consumption. In such a situation the end-user might end-up, in contrast to trading energy, being reimbursed for consuming more energy (flexibility service they have provided).

1.3. Contributions

To deal with the issues outlined above, this paper introduces a market-based framework including a local flexibility market that enables the mapping for both network security services [32] and electricity market participation to the distribution level of the grid. It provides a platform to monetize flexibility services independently from energy and that allows trading actions for flexibility in a specific location depending on the network condition or balancing needs. Such a local market-based environment provides a local decision making process with bilateral communication between the local system operators (DSOs) and the market participants (i.e., prosumers with flexibility). The intended framework aims to enable full use of the flexibility of households and improves economic and operation efficiency. The contributions of the paper are as follows:

1. Argues for a local market-based solution to enable larger involvement of end-users in the energy systems.
2. Introduces flexibility as the service to be traded in the local markets.
3. Introduces a market-based optimization framework to model the operation of the flexibility trading platform.

1.4. Outline of the paper

The remainder of this paper is organized as follows. Section 2 provides a basic overview of essential aspects of local flexibility markets. This helps the reader to understand the framework that is developed in Section 3. Section 4 describes the mathematical formulation of the market-clearing problem. Section 5 provides numerical simulation results to demonstrate the effectiveness of the proposed framework. Section 6 concludes the work and identifies some avenues for further research.

2. Overview of local flexibility markets

A general definition of market is "an environment that allows potential buyers, sellers, and retailers of a given economic product to engage in trade" [33]. A local market can be defined for a specific spatial region and so it can be thought of as a sub-market for a commodity that serves a specific purpose for that local community [34]. For the sake of our analysis, we consider the following four dimensions of a market mechanism:

1. Commodity or service to trade
2. Market participants
3. Market operator
4. Market clearing mechanism.

The remainder of this section deals with the first three aspects for our proposed local flexibility market. The market clearing procedure is discussed in detail in Section 3.

2.1. Service to trade: flexibility

2.1.1. Definition of flexibility

In the context of this work, we consider flexibility as the service to be traded in local flexibility markets in response to a market need. In particular, energy Aggregator/Supplier (AggSups) (see 2.2.1) are sellers and BRPs (see 2.2.2) and the DSO (see 2.2.3) are buyers of such a market. We adopt the same definition as in [35] e.g. "the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or direct activation) in order to provide 'system balancing' and 'constraints management' services within the system".

2.1.2. Flexibility direction

Prosumers can act as either a source or a sink of energy, dependent on the service required. We define the direction of flexibility from the prosumers' point of view as follows:

1. **positive**, when prosumers act as energy sink. In this case, they are required to increase their energy consumption (e.g., by charging storage devices) or decrease their local energy production.
2. **negative**, when prosumers act as energy source. In this case, they are required to decrease their energy consumption or increase their local production (e.g., by discharging storage devices).

Analogous to this definition, the flexibility requested by the DSO (or BRPs) could be positive or negative. For example, when the DSO encounters a network problem that requires the local consumers to decrease their energy consumption, the DSO sends requests for negative flexibility.

2.2. Market participants

We assume that a Local Flexibility Market (LFM) consists of a number of AggSups, one DSO and a number of BRPs, all of which aim to exploit flexibility that is available at the demand side. The demand side constitutes of prosumers and their Controllable Devices (CDs) (including smart appliances, generation sources and storage devices such as electric vehicles) that provide flexibility. The new roles (i.e., AggSups, LFM operator (see 2.3)) will operate alongside the existing ones such as BRPs. Most of these roles are adopted from the Universal Smart Energy Framework (USEF) [36] and are discussed in our previous work [37]. In what follows, we briefly discuss the roles and functionalities of the three main participants of the proposed LFM: AggSups, BRPs and the DSO.

In this paper, we assume that the goal of the DSO is to securely operate the distribution grid at minimum costs, whereas the goal of BRPs is to minimize the costs of imbalances in their profiles between their day-ahead energy programs and real-time. The goal of AggSups is to maximize their profit. Note that, although prosumers do not participate in the market directly, they are assumed to pursue total energy cost minimization. The objective of a prosumer is assumed to be accounted for in the financial terms of the contract a prosumer engages in with an AggSup.

2.2.1. Aggregator/supplier (AggSup)

The AggSup agrees with prosumers it manages, on commercial terms for the supply and procurement of energy and flexibility. We assume that the role aggregator and supplier should be carried by a same market entity. The reason is, energy suppliers adjust their energy program to participate in the wholesale electricity market on behalf of the consumers. If the flexibility of a household would be traded by an aggregator that would be a different market entity than the energy supplier, the energy suppliers would have ended-up paying large imbalances penalties due to imbalances that would have been created in their day-ahead energy program, as a result of flexibility trades that would be concluded in flexibility market by the aggregator. To avoid such an undesired outcome, we assume that the role of aggregator and the role of energy supplier are performed by a same market entity.

Therefore, an AggSup performs two roles: aggregator role and supplier role. As an aggregator, it collects flexibility offers from prosumers, forms aggregated flexibility offer profiles, and presents them (as flexibility provider) to the LFM. It can also engage in bilateral agreements with BRPs, the DSO or (other) third parties. However, for the sake of simplicity, such bilateral agreements are neglected in the scope of this work. As a supplier, the AggSup purchases the energy from the wholesale electricity market and provides it to its prosumers. To do so, the AggSup first forms the so-called base-energy profile by analyzing the information (i.e., measurements, historical data and forecasting) it receives from its prosumers. The AggSup then takes a position in the wholesale electricity market on behalf of its prosumers considering the flexibility obligations it has due to (flexibility) trades from preceding hours in the LFM and/or bilateral agreements with other third parties.

AggSups hold energy balance responsibility in production and /or consumption of electricity. Likewise, we assume AggSups hold flexibility balance responsibility for providing flexibility in the LFM. This implies that AggSups are financially accountable for deviations from the flexibility cleared in the market.

2.2.2. Balance responsibility parties

The BRPs are entities that are responsible for keeping the supply and demand balance for a portfolio of producers and consumers (net sum of their injections and withdrawals) over a given time frame — the imbalance settlement period. (the remaining short and long energy positions in real-time are described as the BRPs' negative and positive imbalances respectively [38]) BRPs can benefit from participating in a LFM by optimizing their portfolios and reducing imbalance volumes and from there, lowering their imbalance charges. A key assumption we make here is that BRPs have no obligations before the closure of the DA wholesale energy market. Therefore, BRPs no imbalance penalty can be calculated. As a result, BRPs have no incentive to participate in the day-ahead scheduling of the LFM although they are allowed to do so if they would wish to do so.

In general an AggSup can also perform as a BRP however, in the context of this work, we assume that an AggSup can perform only one role in our proposed LFM platform: the AggSup role. So an AggSup that intends to perform the BRP role is considered as a BRP in our proposed LFM.

2.2.3. Distribution System Operator (DSO)

The DSO is responsible to transport energy to the consumers in an efficient, sustainable and cost-effective way. The DSO maintains the security of the network and ensures the long-term quality of energy delivery services in the distribution network.

2.3. Market operator

In the operation of the LFM we assume that the LFM market operator is an independent entity that provides a bidding platform and clears the market. Market clearing is the process that includes collecting supply offers and demand requests and determining a market equilibrium (i.e., trade volume and equilibrium price) as further discussed in Section 3. A LFM serves many purposes/applications such as balancing, congestion relief, over/under voltage, current phase imbalance mitigation, network loss minimization, component life extension, postponement of network reinforcements or a combination of the above objectives [37,39]. In this work we focus on congestion problem of medium to low voltage transformer or congestion problem of radial connections in the low voltage grid.

2.4. Bid profiles

Market participants announce their flexibility offers and requests to the market operator in the form of (quantity and price) bid pairs. We consider two bid-types:

1. bid pairs per Programmable Time Unit (PTU) [40], in this case the operator clears the market for every PTU independently from the other PTUs, meaning that when the market clears, every bid is either accepted or rejected independently of the outcomes of other PTUs for the same market party;
2. bid profiles for a whole market horizon [41,42]. In this case buyers and sellers participate in the market with quantity/price profiles for the whole market horizon. When the market clears, a profile is either wholly accepted or is completely rejected.

The first approach (i.e., bid pairs per PTU) is more convenient for the DSO and BRPs as it allows them to acquire the exact amount of flexibility they require for every PTU, independently from other PTUs. However, this approach is less desirable for AggSups, as it exposes the AggSups to the possibility of unplanned consumption profiles. The reason is that the majority of flexibility that an AggSups provides is derived from applying load shifting. That is, the AggSups provides flexibility by steering the daily load of CDs (including storage units) from PTUs where flexibility is required to less heavily-loaded PTUs. Note that, load-shifting as such may eventually modify the total energy consumption of CDs and at the same time, it creates an inter-temporal dependency between different PTUs of a flexibility bid that an AggSups offers to the LFM. As an example, for a specific household, a load decrease offered by the AggSups during peak PTUs, should be compensated by a load increase during the off-peak PTUs. The problem is, when the markets for the different PTUs are cleared independently, there is always a risk for one AggSup to have its load-decrease bids accepted during peak PTUs, while the load-increase bids during the off-peak hours (i.e., the complementary pair) are rejected. This makes it impossible for the AggSup to complete the load shift.

Therefore, the ‘bid profiles for a whole market horizon’ approach is more convenient for AggSups, as for a profile that is cleared in the market, both the load increase and load decrease actions are accepted simultaneously. This would enable the AggSup to plan for the necessary actions to take for any combination of profiles to be accepted prior to market clearing.

3. Local flexibility market clearing mechanism

3.1. Overview

The main objective of the proposed framework is to provide a basis for the market participants to procure and then utilize flexibility that is available from the prosumers and their CDs, to address the needs of the DSO as well as the other market participants. As outlined above, AggSups offer flexibility to the LFM on behalf of the prosumers. The flexibility is demanded by the DSO as well as other participants including BRPs. In the context of this work, we assume that only BRPs compete with the DSO over the flexibility offer of AggSups. The proposed framework also discussed in our previous work [37] includes two main mechanisms that enable harnessing the prosumers’ flexibility in an economically-efficient way:

1. Ahead market-based scheduling
2. Direct control-based demand-side management (DSM).

The ahead market-based scheduling includes two LFM platforms which are discussed in the remainder of this paper. The second mechanism, DSM constitutes, a set of all control actions that are determined and implemented by the DSO to resolve a network issue close to real-time, should the ahead-markets scheduling mechanisms fail to resolve them. For DSM the main objective is to maintain the security of the network at minimum costs. As direct control-based DSM has been widely discussed in the literature see e.g., [43–47] and it does not fall within the scope of this paper.

3.2. Ahead-markets scheduling

The local ahead-markets scheduling mechanism consists of two sub-mechanisms:

1. Day-ahead scheduling (DA)
2. Intra-day scheduling (ID).

The difference between the two mechanisms lies in the market participants, the time horizon and the ‘gate closure time’ (i.e., time elapsed between the closure of the decision-making process and the actual energy delivery).

Both scheduling mechanisms in the ahead-markets scheduling provide platforms for trading flexibility and are operated by a local flexibility market operator. The local day-ahead and intraday scheduling can be utilized as long as the two corresponding auctions in the wholesale energy markets are open and accepting bids from the participants. Such a coordination between the wholesale energy market and local energy markets would serve the wholesale market participants in two ways; firstly, it would allow the wholesale market participants to maximize their profit from the wholesale energy market by inducing new production/consumption patterns in the energy program of prosumers and secondly, it would allow them to minimize their deviations from the original energy program that have been cleared in the DA and ID wholesale energy markets and the associated imbalance costs. In what follows, the two sub-mechanisms within the ahead markets scheduling are discussed in details.

3.2.1. Day-ahead scheduling

In the following, the steps that should be taken in DA and ID scheduling mechanisms in accordance with time are given (for an overview of the steps and there relations, see Fig. 1). The steps are explained in a sequential order for the DA scheduling:

Step 1: The AggSups collects the DA base energy profiles and DA flexibility profile offered by prosumers (**Step 1.a**). Based on the base energy profiles, the AggSups create a preliminary aggregated DA energy profile (i.e., energy program) and provides it to the DSO (**Step 1.b**).

Step 2: The DSO runs a risk analysis (including load flow analysis) to investigate whether this profile would lead to a problem at any point in the network and at any moment in time in the future. DSOs can use their own models as well as the AggSups DA energy profiles to investigate the possibility of a violation of operational limits.

Step 3: If the DSO predicts such a risk, it sends a request for a certain amount of flexibility in a specific direction, for specific PTUs, to the LFM. That is, the DSO nominates a flexibility request with a positive, negative or zero value for every PTU (**Step 3.a**). In parallel, the DSO also provides technical information about the network (including the system state, the location where flexibility is needed and type of the problem) to the AggSups and the LFM (**Step 3.b**) [47]. Note that in case of ID scheduling, BRPs also provide their flexibility request profiles to the LFM at this stage. The flexibility request profile of a BRP contains the amount and direction of the flexibility the BRP wishes to procure at every PTU over the ID scheduling horizon.

Step 4: Based on the technical information received from the DSO, the location of the network problem and the location of the

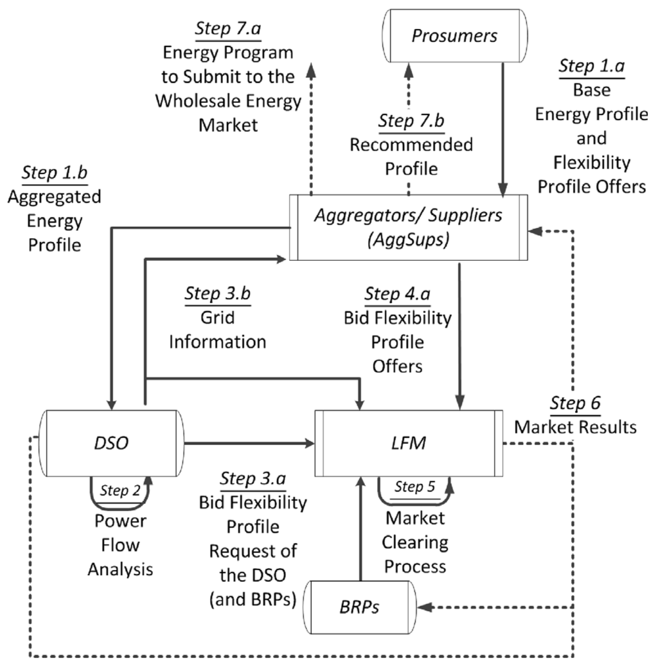

Fig. 1. Schematic diagram of interactions between different market participants in the proposed DA and ID scheduling. The solid and dashed lines represent the direction of information transfer before and after market clearing, respectively.

households providing flexibility, AggSups accumulate the flexibility offers from their prosumers to offer DA bids to the LFM in the form of flexibility profiles. The offered flexibility profile contains the amount and direction of the flexibility an AggSup can offer to the market at every PTU (i.e., 15 min or 1 h) over the 24-hour DA scheduling (or ID scheduling) horizon. Note that the direction of the flexibility offered by AggSups has to be aligned with the request of the DSO in every PTU.

Step 5: The LFM operator clears the market (see Section 4 for a possible way to realize this). Note that BRPs are not participating in the DA scheduling of the LFM, as they can adjust their position in the wholesale DA market. Thus, the DSO is the sole buyer of the flexibility in the DA scheduling sub-mechanism.

Step 6: Once the market is cleared, the result is announced and the necessary information is made available to AggSups and the DSO.

Step 7: AggSups adjust their aggregated DA energy profile accordingly to determine the so-called DA schedule (**Step 7.a**). In addition, based on the initial DA base energy profile and the outcome of the DA LFM, AggSups determine new energy profiles for every household (i.e., recommended profile in **Step 7.b** in Fig. 1). This process is done by adopting the planned profile for the CDs, respecting the operating boundaries defined by the prosumers and technical restrictions.

To encourage prosumers to stick to the DA recommended profile, prosumers to some extend are held responsible for their total energy consumption for every PTU. This means that a prosumer will gain benefit from the flexibility trades only if its energy consumption in real-time is as projected in the DA recommended energy profile. Furthermore, the AggSups also have balance responsibility for the energy profile transactions concluded in the wholesale energy market as well as the flexibility transactions concluded in the LFM(s).

3.2.2. Intra-day scheduling

Due to the uncertain nature of the market, the DSO might not be able to acquire all the flexibility it needs from the DA market. In addition, due to forecast inaccuracies and uncertainty in scheduling production and consumption, a significant amount of errors remains in the DA energy programs submitted to the wholesale energy market. Thus, the DSO, in addition to BRPs, might have a need for flexibility (e.g., DSO encounters an unforeseen network problem or BRPs encounter an imbalance in their portfolio in the current delivery day) after the closure of the DA wholesale market. Therefore, after the closure of the DA flexibility scheduling, the flexibility trade continues in the Intra-Day (ID) scheduling sub-mechanism. Similar to the DA scheduling, the ID scheduling runs in parallel with the ID wholesale energy market.

The steps that are explained in DA scheduling are valid also for ID. However, the ID scheduling mechanism is slightly different from the DA scheduling. The reason is, here, BRPs are also participating in the market and competing with the DSO for the flexibility of the AggSups. Therefore, in contrast to the DA scheduling, where the flexibility request of the DSO determines the flexibility direction in which the market should be cleared (single buyer auction), in the ID scheduling both BRPs and the DSO can influence the flexibility direction in which the market will be cleared. In fact, there are interdependencies between the amount and direction of flexibility that is cleared in each direction and the price of bid profiles that have to be accounted for. Note that having the flexibility traded in both directions, can create gaming opportunities as is discussed below. Therefore, regulation and monitoring is required to limit such opportunistic activities as discussed below.

One important key issue here is that the DSO and BRPs are seeking flexibility for different purposes. A BRP seeks flexibility to balance an imbalances in its portfolio. BRPs are only interested in the amount of offered flexibility, regardless of the location of the prosumers providing the service and the impact it might have on the network. By purchasing a certain amount of flexibility, BRPs are transferring balance responsibility to AggSups providing the flexibility service. By contrast, the DSO requires flexibility to solve a problem in the network. Therefore, the needs of the DSO and BRPs are independent but overlapping. There are two situations possible here. First a flexibility offer from an AggSup can serve BRP(s) and the DSO at a same time. This means that the flexibility service that is executed to resolve a BRP's imbalance, affects the network condition in a positive way and from there, the severity of problem(s) the DSO is dealing with gets reduced. In an extreme case the flexibilities that are cleared to BRP(s) may even completely solve the DSO's problem as well. Second, also the opposite may happen when the flexibilities that are cleared for BRP(s) result in worsening the problem of the DSO. Which of the two situation happens depends on the direction of the requests of the BRP(s). One key finding here is that BRPs and the DSO are not competing directly over flexibility, although their activities affect the position of the other in the market. Instead, the position a (group of) BRP(s) would take, affects the situation the DSO is dealing with and vice versa.

In what follows, we propose an ID clearing mechanism that determines/selects a set of profiles, whereby profiles may clear in both directions, and where by the flexibility quantities for all PTUs requested by the BRP's and the DSO and the flexibility quantities and prices of the profiles offered by the AggSups are taken into account. The mechanism ensures that the aggregated flexibility traded satisfies the flexibility needs of the DSO. More details on how to determine the amount of flexibility that the DSO requires per PTU is formulated and investigated e.g., in [26,47], in this research we assume that this flexibility is given.

The schematic diagram in Fig. 2 shows the proposed clearing process in the ID scheduling. All bids from BRPs that are in opposite direction of the DSO are cleared in the first clearing platform (block B2) and all requests in similar direction to that of the DSO are cleared in the second clearing platform (block B3). Block B4 determines the residual flexibility requests of the DSO. The residual flexibility request is defined as the sum of the original flexibility request of the DSO and the flexibility offers of AggSups to be nominated in B2 (in opposite direction, which tend to increase the needs of the DSO) and in B3 (in similar direction which leads to decrease in the need of the DSO). In a lucky case, the aggregated offers of B2 and B3 have already covered the flexibility needs of the DSO. If this is not the case (i.e., the DSO's problem is not entirely resolved) in block B5 the DSO procures the flexibility in the desired direction that it requires to fill-in the remaining flexibility gap. Note that the amount of flexibility the DSO requires is affected by the bids and offers that are assigned in B1–B3 (referred to as residual flexibility) and is calculated in B4 and, if needed, cleared in block B5.

However, note that the decisions regarding acceptance or rejection of flexibility request/offer profiles in blocks B2–B5 are made simultaneously, considering inter-dependencies that exists among the three clearing blocks (i.e., B2, B3 and B5). One key observation here is that, in addition to the flexibility quantity that is requested/offered in either direction per PTU, the price of every requested and offered profile can substantially affect the results of the ID scheduling. For example, a low profile price from the DSO, if accepted, induces little increase in total social welfare (as is defined in Section 4) [48,49]. Therefore, assuming a low price profile from the DSO, the market tends to accept the DSO's request only if the trading flexibility requests of BRPs fails to suffice the flexibility needs of the DSO. Alternatively, a high price profile from the DSO would induce a significant increase in social welfare if accepted.

The market clearance process visualized by blocks B1–6 in Fig. 2 is executed as explained in Steps 1 to 7 in Fig. 1 for both DA and ID scheduling. The only difference is that in the case of DA scheduling, BRPs do not participate in the LFM and therefore, blocks B2–B4 are not required to be implemented in DA scheduling. As a result, in the DA scheduling, the AggSups would only sell their flexibility services to the DSO in the process visualized by block B5.

Finally, the clearing mechanism outlined above allows the opportunity for AggSups to take advantage of the market by providing two identical flexibility profiles in the opposite directions, e.g., first one in B3 to the BRP and later the opposite to the DSO in B5. One possible outcome would be that both profiles are accepted, and the AggSup would benefit from participating in the market without delivering any service. To avoid fostering such a strategic behavior and gaming opportunities, we assume that in a given scheduling mechanism and platform, an AggSup can sell its flexibility service only in one direction. That is, if "one profile" of an AggSup is nominated in B2, that AggSup becomes ineligible to participate in B3 and B5 and vice versa.

4. Mathematical formulation of ahead-markets scheduling

4.1. Assumptions

DSOs are facing a number of network problems such as over /under voltages, reverse flows, congestions, protection sensitivity and power quality. The amount of flexibility the DSO requires for a problem at a certain location, depends largely on the type of the problem and the location of the prosumer which offers the flexibility [36,47]. In this paper, we only focus on the thermal overloading problem of a medium-to-low voltage transformer or radial connections in distribution grids. The reason is that, for this specific case, the DSO is only interested in the absolute power consumption and we can neglect the locational dependencies of the problem that are discussed in [50,47]. We assume that the DA and the ID scheduling platforms are cleared with hourly resolution. To avoid gaming, we allow each AggSup to sell only profiles in one direction, meaning that, if one profile of an AggSup is nominated in one direction, the AggSup loses the chance to offer flexibility in the opposite direction. To guarantee that flexibility trades between BRPs and AggSups do not lead to an emergence of new problems in the direction opposite to the direction of the initial flexibility request of the DSO, we assume that the size of the request of the DSO is adequately larger than the request of an individual BRP or AggSup.

4.2. Day ahead scheduling

This section presents the mathematical formulation of market clearing in the DA and ID scheduling platforms. We define Ω_t as a set of indexes of all PTUs included in the scheduling horizon. We use the operator $n()$ to specify the number of elements of a set and we use index t to refer to the tth PTU. Now consider a DSO procuring flexibility from a set Ω_A of AggSups $a \in \Omega_A$. We use index a to refer to the AggSups. We assume every AggSup provides a set of flexibility profiles Ω_a^P to the LFM operator. We define $q_{a,da}^{p_a,t}$ as the amount (quantity) of flexibility that the ath AggSup offers in its p_ath profile during tth PTU to the LFM operator. And we use $\rho_{a,da}^{p_a}$ to denote the price of that offered profile. Likewise, we use $q_{d,da}^{t}$ and $\rho_{d,da}$ respectively as the amount of flexibility the DSO requests from the LFM at every PTU in its single request profile and the associated price. Finally, we define β_d as the binary variable associated with the DSO's request getting accepted or rejected and $\beta_a^{p_a}$ as a binary variable associated with the profile $p_a \in \Omega_a^P$ of AggSup $a \in \Omega_A$ being accepted or rejected.

The market clearing mechanism is modeled as a social welfare maximization problem over the DA scheduling horizon and can be formulated as follows:

$$\max_{(\beta_d,\beta_a^{p_a})} \mathcal{S}_{da} = \sum_{t\in\Omega_t} \left[\mathcal{B}_{da}^t - \mathcal{G}_{da}^t\right] \tag{1a}$$

subject to

$$\mathcal{B}_{da}^t = \beta_d \cdot \left|\rho_{d,da} \times q_{d,da}^t\right|, \ \forall t \in \Omega_t \tag{1b}$$

$$\mathcal{G}_{da}^t = \sum_{a\in\Omega_A} \sum_{p_a\in\Omega_a^P} \beta_a^{p_a} \cdot \left|\rho_{a,da}^{p_a} \times q_{a,da}^{p_a,t}\right|, \ \forall t \in \Omega_t \tag{1c}$$

$$\left|q_{d,da}^t\right| \le \sum_{a\in\Omega_A} \sum_{p_a\in\Omega_a^P} \left|\beta_a^{p_a} \times q_{a,da}^{p_a,t}\right|, \ \forall t \in \Omega_t \tag{1d}$$

$$\beta_d \in \{0, 1\}\,; \beta_a^{p_a} \{0, 1\}\,, \ \forall a \in \Omega_a, p_a \in \Omega_a^P. \tag{1e}$$

The term $\mathcal{S}_{da}$ in the objective function represents the aggregated social welfare over the scheduling horizon (e.g., 24 h) of the DA scheduling. It is defined as the benefit of consumption $\left(\mathcal{B}_{da}^t\right)$ minus the costs of providing flexibility $\left(\mathcal{G}_{da}^t\right)$ that are defined in Eqs. (1b) and (1c).

Correspondingly, $\rho_{d,da} \times q_{d,da}^t$ is the cost of buying $q_{d,da}^t$ flexibility in PUT t by the DSO at the price $\rho_{d,da}$. The multiplication product denotes the total budget the DSO is willing to spend to select a set of flexibility offers from AggSups to solve its problem. Note that the optimization problem is formed such that, if the budget of the DSO is not enough, then β_d, $\beta_a^{p_a}$ will be zero and the market will not clear. Likewise, $\rho_{a,da}^{p_a} \times q_{a,da}^{p_a,t}$ is the benefit of selling $q_{a,da}^{p_a,t}$ units of flexibility in PTU t provided by AggSup a in its profile p_a during PTU t, at price $\rho_{a,da}^{p_a}$. Constraint (1d) enforces the net flexibility procured from the AggSups to be larger than or equal to the flexibility requested by the DSO for every PTU.

The optimization objective (1a) is to determine a combination of all flexibility profiles provided by AggSups such that it maximizes the social welfare over the scheduling horizon. Note that $\beta_a^{p_a}$ is not a function of time. This implies that the profile of each AggSup contains a flexibility offer for per PTU and that a decision $\beta_a^{p_a}$ is made for the complete profile by solving the social welfare maximization problem over all PTUs together.

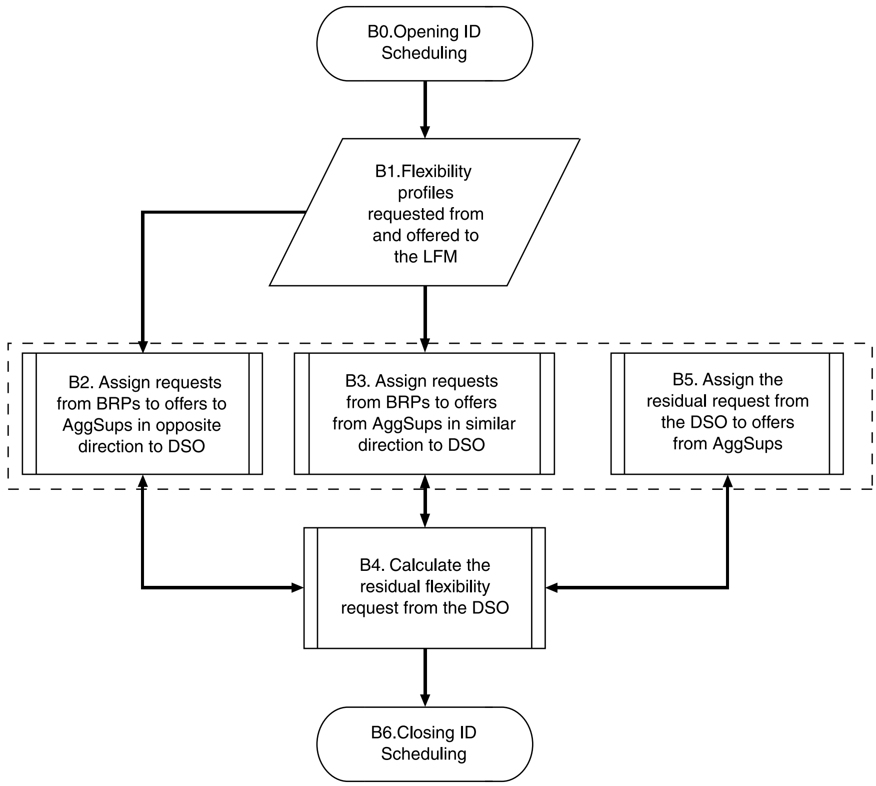

Fig. 2. Schematic diagram of proposed ID scheduling process.

4.3. Intra-day scheduling

The ID scheduling is different from the DA scheduling as in the ID scheduling the profiles may clear in both directions. Consequently, we define $\Omega_{A^o_{id}}$ and $\Omega_{A^s_{id}}$ respectively as the set of AggSups with flexibility offers in the opposite and similar direction of the DSO and $\Omega_{A_{id}} = \Omega_{A^o_{id}} \cup \Omega_{A^s_{id}}$.

As BRPs can also participate in the ID scheduling, we use $\Omega_{B_{id}}$ to define the set of indexes of all BRPs that participate in the market and split the set up in $\Omega_{B_{id}} = \Omega_{B^o_{id}} \cup \Omega_{B^s_{id}}$ where subsets $\Omega_{B^o_{id}}$ and $\Omega_{B^s_{id}}$ respectively define the set of indexes of BRPs with flexibility requests in the opposite and similar direction of the DSO.

Similar to previous subsection, we use index d to refer to the flexibility request of the DSO, index a_r to refer to AggSups and index b_r to refer to BRPs that have flexibility offers and requests in direction $r \in \{o, s\}$ where o and s denote respectively opposite and similar directions to the DSO. Note that the direction of flexibility requests and offers from BRPs and AggSups are defined in relation to the flexibility requests of the DSO. In addition, we define $\left\{\Omega^P_{k_r} | k \in \{a, b\}, r \in \{o, s\}\right\}$ as the set of indexes of all profiles offered by AggSups and BRPs, in the direction r and $r \in [o, s]$ is defined by the DSO. Note that index $q^{p_{k_r},t}_{k_r}$ denotes the amount of flexibility offered/requested in the pth profile of market participant k in direction r and index $\rho^{p_{k_r}}_{k_r}$ denotes the price of the pth profile and $k \in \{a, b\}, r \in \{o, s\}$. Note that the DSO has only one request profile ($n(\Omega^P_{d_s}) = 1$).

We use $\beta^{p_k}_k$ as a binary variable associated with the p_kth profile of market participants k being accepted or rejected where $k \in \{a_r, b_r, d\}$ and $r \in \{o, s\}$.

The ID-Scheduling problem is formulated as follows:

$$\max_{(\beta^{p_{b_o}}_{b_o}, \beta^{p_{a_o}}_{a_o}, \beta^{p_{b_s}}_{b_s}, \beta^{p_{a_s}}_{a_s}, \beta_{d,s})} \mathcal{S}_{id} = \mathcal{S}_{id,o} + \mathcal{S}_{id,s} \tag{2a}$$

subject to

$$\mathcal{S}_{id,o} = \sum_{t \in \Omega_t} \left[\mathcal{B}^t_{id,o} - \mathcal{G}^t_{id,o}\right] \tag{2b}$$

$$\mathcal{S}_{id,s} = \sum_{t \in \Omega_t} \left[\mathcal{B}^t_{id,s} - \mathcal{G}^t_{id,s}\right] \tag{2c}$$

$$\mathcal{B}^t_{id,o} = \sum_{\substack{b_o \in \Omega_{B^o_{id}} \\ p_{b_o} \in \Omega^P_{b_o}}} \beta^{p_{b_o}}_{b_o} \cdot \left|C^{p_{b_o},t}_{b_o}\right|, \ \forall t \in \Omega_t, r \in \{o, s\} \tag{2d}$$

$$\mathcal{B}^t_{id,s} = \sum_{\substack{b_s \in \Omega_{B^s_{id}} \\ p_{b_s} \in \Omega^P_{b_s}}} \beta^{p_{b_s}}_{b_s} \cdot \left|C^{p_{b_s},t}_{b_s}\right| + \beta_{d,s} \cdot \left|C^t_{d,id}\right|, \forall t \in \Omega_t \tag{2e}$$

$$\mathcal{G}^t_{id,o} = \sum_{\substack{a_o \in \Omega_{A^o_{id}} \\ p_{a_o} \in \Omega^P_{a_o}}} \beta^{p_{a_o}}_{a_o} \cdot \left|C^{p_{a_o},t}_{a_o}\right|, \ \forall t \in \Omega_t \tag{2f}$$

$$\mathcal{G}^t_{id,s} = \sum_{\substack{a_s \in \Omega_{A^s_{id}} \\ p_{a_s} \in \Omega^P_{a_s}}} \beta^{p_{a_s}}_{a_s} \cdot \left|C^{p_{a_s},t}_{a_s}\right|, \ \forall t \in \Omega_t \tag{2g}$$

$$C^{p_{k_r},t}_{k_r} = \rho^{p_{k_r}}_{k_r} \times q^{p_{k_r},t}_{k_r}, \ \forall t \in \Omega_t, r \in \{o, s\}, k \in \{a, b, d\} \tag{2h}$$

$$\sum_{\substack{b_r \in \Omega_{B^r_{id}} \\ p_{b_r} \in \Omega^P_{b_r}}} \beta^{p_{b_r}}_{b_r} \cdot \left|q^{p_{b_r},t}_{b_r}\right| \leq \sum_{\substack{a_r \in \Omega_{A^r_{id}} \\ p_{a_r} \in \Omega^P_{a_r}}} \beta^{p_{a_r}}_{a_r} \cdot \left|q^{p_{a_r},t}_{a_r}\right|, \quad \forall t \in \Omega_t, r \in \{o, s\} \tag{2i}$$

$$\left|q^t_{d,id}\right| + \sum_{\substack{a_o \in \Omega_{A^o_{id}} \\ p_{a_o} \in \Omega^P_{a_o}}} \beta^{p_{a_o}}_{a_o} \cdot \left|q^{p_{a_o},t}_{a_o}\right| \leq \sum_{\substack{a_s \in \Omega_{A^s_{id}} \\ p_{a_s} \in \Omega^P_{a_s}}} \beta^{p_{a_s}}_{a_s} \cdot \left|q^{p_{a_s},t}_{a_s}\right|, \ \forall t \in \Omega_t \tag{2j}$$

$$\beta_{d,s} \in \{0, 1\}; \beta^{p_{k_r}}_{k_r} \ \{0, 1\}, \ \forall k \in \{a, b\}, r \in \{o, s\}. \tag{2k}$$

The term $\mathcal{S}_{id,r}$ in Eqs. (2a)–(2c) defines the social welfare as the sum of benefit of consumption $\mathcal{B}^t_{id,r}$ (defined in (2d) and (2e)) minus the cost of providing flexibility $\mathcal{G}^t_{id,r}$ (defined in (2f) and (2g)) over the scheduling horizon Ω_t.

Subsequently, $\mathcal{B}^t_{id,o}$ is defined as the cost of buying flexibility requests of BRPs in the opposite direction o. Likewise, the term $\mathcal{B}^t_{id,s}$ is the cost of buying $q^{p_{d_s},t}_{d_s}$ amount of flexibility of DSO at price of $\rho^{p_{d_s}}_{d_s}$ and the cost of buying $q^{p_{b_s},t}_{b_s}$ amount of flexibility requested in the p_{b_s}th profile of BRP $\left\{b_s | b_s \in \Omega_{B^s_{id}}\right\}$ at price of $\rho^{p_{b_s}}_{b_s}$ in the similar direction to the DSO. Eqs. (2f) and (2g) define the benefit of providing flexibility $\mathcal{G}^t_{id,r}, r \in \{o, s\}$ as the sum of the cost of providing flexibility in either direction. Eq. (2k) defines $C^{p_{k_r},t}_{k_r}$ as the per-PTU cost of buying or selling $q^{p_{k_r}}_{k_r}$ amount of flexibility at price $\rho^{p_{k_r}}_{k_r}, r \in \{o, s\}, k \in \{a_r, b_r, d\}$. Constraint (2i) states that, if there is any request or offer (from BRPs or AggSups, respectively) being accepted in the opposite direction, then the total flexibility amount procured from the AggSups has to be larger than or equal to the total flexibility requested by BRPs. The immediate impact of clearing the market in the opposite direction is that the AggSups offers that are cleared (and executed) in the market (i.e., in block B2 in Fig. 2) would further aggravate the problem of the DSO. To ensure that the need of the DSO for flexibility is satisfied, constraint (2j) enforces that the flexibility procured from the AggSups in the positive direction should be equal to or larger than the flexibility the DSO initially requested plus the extra flexibility that is needed to compensate the excessive amount that is superimposed from the trades in the opposite direction.

The optimization objective is to determine a combination of all flexibility profiles offered by AggSups (flexibility profiles requested by BRPs and the DSO) that maximizes the social welfare over the scheduling horizon.

5. Numerical results

5.1. Input data and assumptions

The aim of this section is to demonstrate how the proposed framework work under different aspects and situation that might occur in the LFM. We consider eight AggSups ($n(\Omega_A) = 8$), four BRPs ($n(\Omega_B) = 4$) and one DSO participating in the LFM. We assume all profiles are with 24-ahead horizon and hourly resolution. To increase the liquidity of the market we assume that each AggSup provides three different flexibility profiles ($n(\Omega^P_a) = 3$) and each BRP provides one flexibility profile request ($n(\Omega^P_b) = 1$) to the LFM. Thus in total, we consider 24 flexibility profiles offered by AggSups and 4 flexibility profiles requested by BRPs. To investigate the influence of knowing the direction of the flexibility request of the DSO on the performance of the market, we investigate two case studies. In case 1, we assume that the DSO announces the direction of flexibility it requires at every PTU to the AggSups and BRPs. Therefore, next to the profile prices, AggSups and BRPs have to specify the magnitude of their flexibility offers and request in the similar direction. In case 2, the direction of the flexibility request of the DSO is kept hidden from the other market parties and therefore, AggSups and BRPs have to predict the direction of flexibility request of the DSO. This would in turn put AggSups and BRPs at a higher risk associated with forecast errors. To capture this uncertainty, also to reflect different situations that might occur within the LFM, the flexibility profiles of AggSups and BRPs are generated manually. In addition, to simplify the case, we assume that offered AggSups profiles and requested BRPs profiles that are in the opposite direction are the negative counterpart of those profiles offered and requested in similar direction. Finally, to exhibit the difference between DA and ID scheduling, we assume that the set of request(s) from the DSO (and BRPs' in ID) and offers from AggSups provided to the DA and ID market platforms are similar. In addition, to signify the importance of the role of BRPs in the market and to demonstrate the impact of offers and requests in opposite direction to the DSO request on the performance of the ID scheduling, we investigate three scenarios:

- Scenario 1: DA scheduling with no AggSup offer in the opposite direction to the DSO request,
- Scenario 2: ID scheduling with no AggSup offer or BRP request in the opposite direction to the DSO request and,
- Scenario 3: ID scheduling with AggSup offers and BRP requests in both directions.

Note that under case 2, BRP request and AggSup offer profiles can get negative values as the direction of flexibility request from the DSO is kept unknown to BRPs and AggSups. Therefore, BRPs and AggSups are at risk of predicting flexibility request of the DSO incorrectly and therefore might, make a request/offer that is in the opposite flexibility direction of the DSO.

5.2. Results analysis

This section presents the numerical results concerning the DA and ID scheduling. To better capture the uncertainty associated with forecasting the direction of flexibility request of the DSO in case 2, the market clearing problem is solved three times for different input sets, for every scenario under each case study. In the following only the results of the input set that returns the highest social welfare is presented.

5.2.1. Case 1

Fig. 3 presents the aggregated flexibility profiles that are cleared to the DSO in the DA LFM. The dashed blue line with up-ward triangles shows the aggregated AggSup offers. The solid black line presents the flexibility request of the DSO. One can observe that the flexibility requested of the DSO is completely covered by the aggregated flexibility offered by AggSups.

Figs. 4 and 5 subsequently present the aggregated flexibility requests and offers in the ID scheduling in case 1, under scenario 2 and scenario 3 respectively. In Fig. 4, the dashed red line with upward-pointing triangle presents the aggregated BRP request and the dashed blue line with upward-pointing triangle presents the aggregated AggSup offers in similar direction. The solid black line presents the flexibility request of the DSO that are cleared in B5. Similar to scenario 1, one can see that the aggregated flexibility offered by the AggSups surpasses as the aggregated flexibility requested by the BRPs and the DSO.

Fig. 5 presents the aggregated flexibility requests of BRPs (dashed magenta line with downward-pointing triangle) and offers of AggSups (dashed green line with downward-pointing triangle) that are cleared in the opposite direction (block B2 in Fig. 2). Fig. 5 also shows that the aggregated request of BRPs (dashed red line with upward-pointing triangle) and offers of AggSup (dashed blue line with upward-pointing triangle) that are cleared in B3 in the similar direction. Finally, the solid black line presents the residual flexibility (flexibility amount initially requested by the DSO plus the aggregated AggSup flexibility offers that are cleared in the opposite direction in B2). One can see that the proposed market framework determines $\beta^{p_{b_o}}_{b_o}$, $\beta^{p_{a_o}}_{a_o}$, $\beta^{p_{b_s}}_{b_s}$, $\beta^{p_{a_s}}_{a_s}$, $\beta_{d,s}$ such that, the flexibility offered by AggSups in every hour (i.e., PTU) covers the flexibility requested by BRPs and the DSO in each direction.

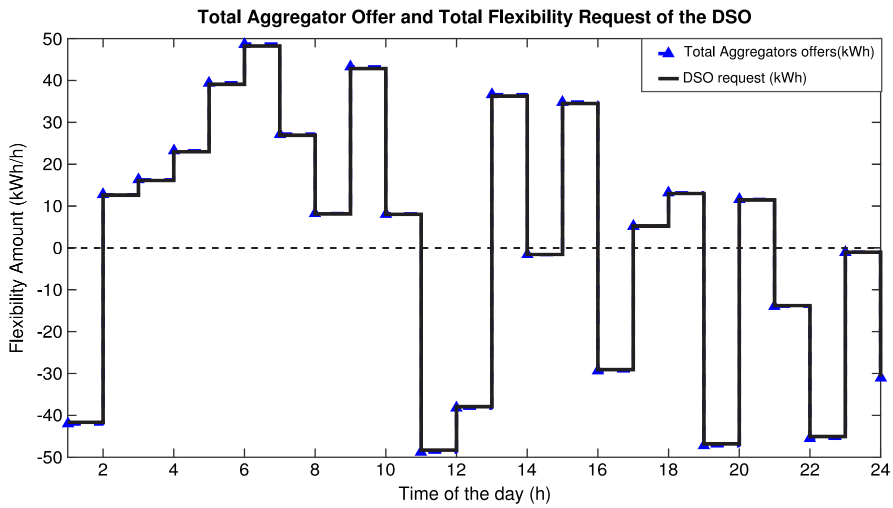

Fig. 3. Flexibility profiles cleared in the DA scheduling under case 1-scenario 1.

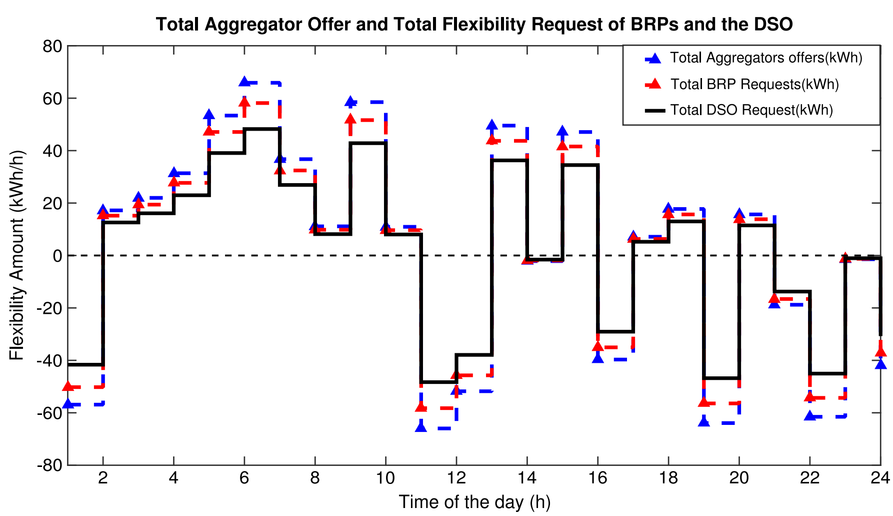

Fig. 4. Flexibility profiles cleared in the similar direction in ID scheduling under case 1-scenario 2.

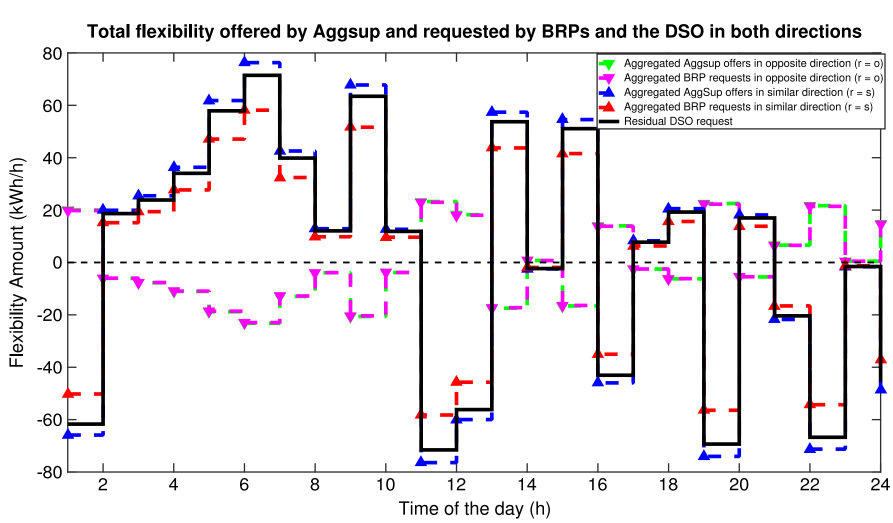

Fig. 5. Flexibility profiles cleared in the similar and the opposite directions in ID scheduling under case 1-scenario 3. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

5.2.2. Case 2

Figs. 6–8 present the aggregated flexibility requests and offers respectively in the DA and the ID scheduling determined in the three scenarios under case 2. One can see that in all scenarios there are several hours (i.e., PTUs) in which the flexibility offered by AggSups falls short of the flexibility requested by the DSO and if involved, BRPs. This implies that the model fails to converge to a feasible solution as constraints (2i)–(2j) are not satisfied.

Due to discrete nature of the problem, also to further investigate this issue, we examined several different initial points but failed to find a feasible solution where all constraints are satisfied. As a result, the uncertainty associated with AggSups and BRPs not knowing the direction of the flexibility request of the DSO resulting in an intangible market equilibrium. In the context of this work, our assumptions force us to reject the market clearing as determined under case 2. In practice, this would imply that as a result of a forecast error, the flexibility buyers seem unable to source the flexibility they require at certain PTUs. Whether or not such a condition is to be allowed depends on the applicable regulatory regime. Comparing the results of case 1 and 2, one can observe that lack of communication between the DSO and the market participants results in market inefficiency in the sense that not all potential of flexibility markets is utilized.

5.2.3. Comparison

Table 1 presents the social welfare, the number of AggSup offer profiles and the DSO (and BRPs' where applicable) requests that are nominated under every scenario of case 1. Note that the results of case 2 are not presented here as no feasible equilibrium was found in the numerical simulation discussed above.

Comparing results of DA with ID scheduling shows that, under current assumptions, the DSO's request for flexibility accounts for a large share of the total social welfare. In addition, it can be seen that the social welfare increases as the number of trades (requests and offers) increases. Trading flexibility in the opposite direction increases the number of trades and therefore the liquidity of the LFM market. This effect can be observed in the number of profiles that are accepted in each market and direction, as is shown in the last two columns of Table 1. Let us begin with the number of BRP requests that are accepted in each clearing platform. No BRP participates in the DA scheduling under scenario 1. Four BRP profiles (out of four) are accepted in the ID scheduling in scenario 2. Eventually, there is one BRP profile (out of the two requested) accepted in the opposite direction, and four (out of four requested) in the similar direction in ID scheduling in scenario 3.

Now looking into the AggSup offer profiles, after the closure of the DA scheduling under scenario 1, four AggSup offer profiles are cleared to the DSO. Moving from DA to ID in scenario 2 (with $r = \{s\}$) and scenario 3 (with $r = \{s, o\}$), the number of AggSups that are accepted increases; there are six profiles (out of 24 offered) accepted under scenario 2 to match the four requests from the BRPs. In scenario 3, there are three AggSup offers (out of 24) that are nominated to clear the request form BRPs in the opposite direction. In this example, flexibility offers belong to three different AggSups. As AggSups are restricted to sell their profiles only in one direction, the three AggSups are banned from and are therefore not considered in the continuation of clearing process in the similar direction $r = \{s\}$ under scenario 3. This leaves 15 (=24 − 9) profiles to process in the similar direction. Eventually, under scenario 3, there are six offers (out of 15) cleared in the similar direction to match the four flexibility requests of BRPs in the similar direction plus the residual flexibility request of the DSO. The results of Table 1 show that, allowing trades in the opposite direction increases the number of trades in the market and consequently results in a higher social welfare.

The last column of Table 1 presents the computation time. All simulations were implemented in MATLAB/Simulink R2015b. The computer used ran Windows 10 64-bit with an Intel Core i7 quad-core processors clocking at 2.93 GHz and 6-GB memory. A computing time of 430 s was needed to solve Scenario 1 where as the figure is 521.8 s for Scenario 2 and 735.2 s for Scenario 3. The computation times refer to a 24 horizon, with hourly resolution. We observed that the computational time for clearing the market increases as the number of profiles increases from Scenario 1 to Scenario 2 and as the problem becomes more complex by considering flexibility profiles in both directions in Scenario 3.

6. Conclusion

In this paper, we introduce a market-based framework that defines new roles and functionalities for new types of market parties to trade flexibility in the distribution grids (e.g., aggregators) and provides a platform that enables prosumers to participate in this process. The proposed framework includes a set of economic and control mechanisms that allows the system operator to maintain reliable and affordable operation of the distribution grid. The market clearing procedure presented in this manuscript is a complete (and more advanced) version of the work presented in [37]. In practice, the position that the DSO takes in the DA and ID platform can be based on (probabilistic) predictions or actual measurements of operation limit violations. One way to conduct such calculation can be by using the method presented in [47]. Thus [47] can be considered as the continuation of the work presented in this manuscript.

A key observation for the design of our proposed framework is that, while BRPs are competing with the DSO, they are seeking flexibility for different purposes. As a result, the DSO and BRPs have a complementary position with respect to flexibility offers of aggregators (AggSups). This implies that the flexibility service offered by an AggSup might serve both a BRP and the DSO at the same time. It may also serve only one of them or even deteriorate the situation of the other. As a result, BRPs and the DSO are not competing directly over flexibility, although their activities affect the position of the other in the market as in the end, they are seeking to buy the same product.

Our analysis showed that having the DSO announcing the direction of its flexibility request is a key element that strongly affects the success of the market in reaching an equilibrium. One can see that the DSO's success in determining the correct flexibility amounts that it needs to utilize per time unit is strongly affected by the accuracy of load and DERs production forecasts. The problem is, such forecasts are difficult to determine at the desired accuracy [47,18]. One solution to this problem is to aggregate a number of flexibility profiles. The reason is that, in contrast to an individual profile, the forecast error in one profile would cancel out the error in another one. Therefore, the forecast error of the aggregated flexibility profile is more accurate than that of individual profiles. Therefore, in the context of this work we assume the DSO makes its decision regarding the amount of flexibility it requires based on the aggregated flexibility profiles it receives from AggSups and not based on each individual profile.

Once the direction of the flexibility request of the DSO is known, it allows AggSups and BRPs to coordinate their position in the similar and opposite directions such that it results in a higher trade volume and therefore a higher economic efficiency. Our numerical analysis shows that lack of such communications between the DSO and market participants may easily lead into not finding a reaching a possible equilibrium at all.

The numerical results presented are based on assumptions that are reflecting only a quite specific possibility for market conditions. Only the congestion problem (of a medium to low voltage transformer or a radial connection in the low voltage grid) is investigated. Nevertheless, the proposed market mechanism and

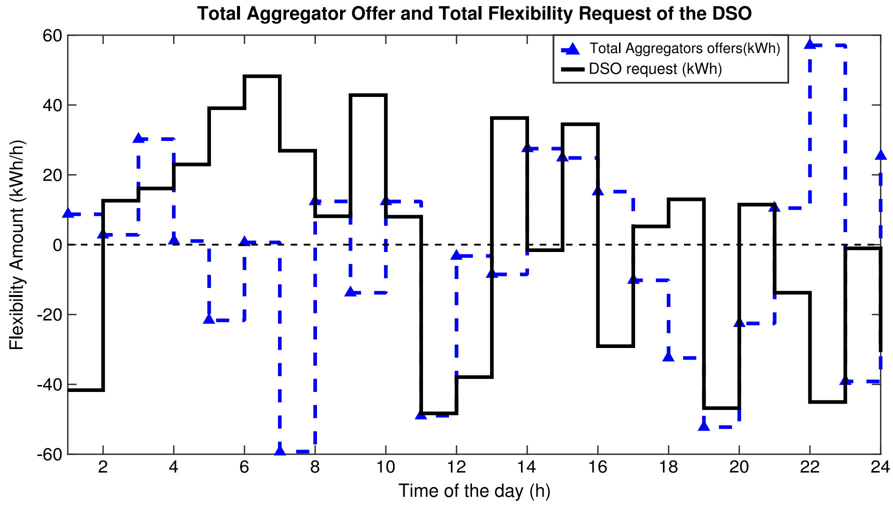

Fig. 6. Flexibility profiles cleared in the DA scheduling under case 2-scenario 1.

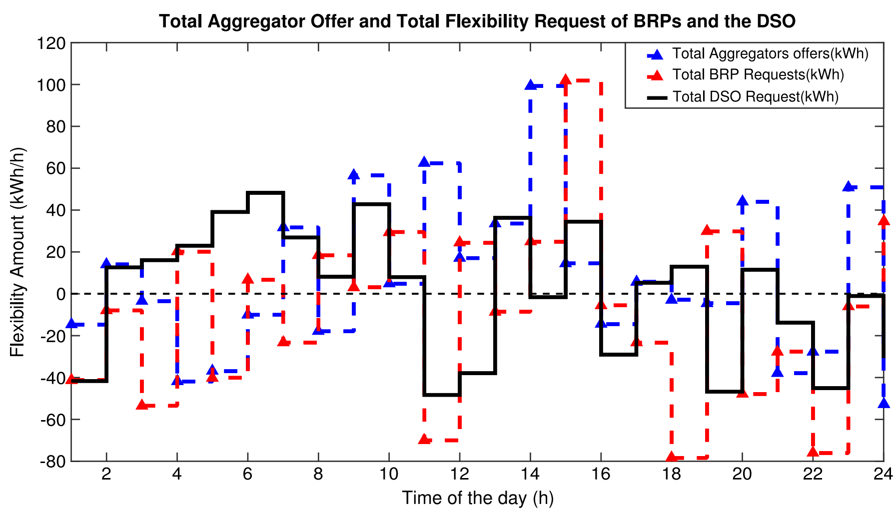

Fig. 7. Flexibility profiles cleared in the similar direction in ID scheduling under case 2-scenario 2.

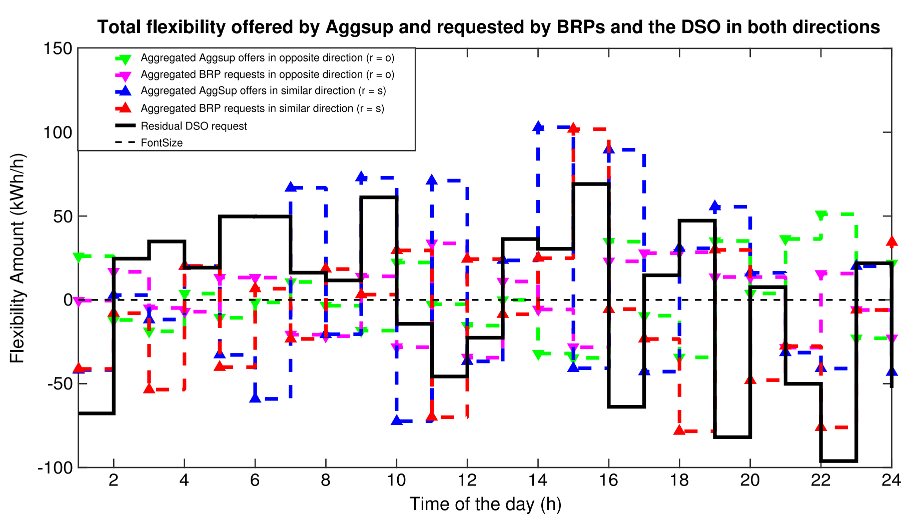

Fig. 8. Flexibility profiles cleared in the opposite and the similar directions in ID scheduling under case 2-scenario 3.

results of the paper can support regulators and DSOs as it provides an economic insight over the operation of a local flexibility market. They can also be useful to different market participants as they allow them to evaluate their participation strategy in such a market.

Table 1
Social welfare ($\mathcal{S}$) after the closure of the DA and ID scheduling. $n\left(\beta_{d,s}=1\right)$, $n\left(\beta_{a_r}^{p_{a_r}}=1\right)$ and $n\left(\beta_{b_r}^{p_{b_r}}=1\right)$ denote the number of DSO request, AggSup offer and BRP request profiles nominated in each platform under case 1, respectively. The last column presents the computing time in seconds.

		$\mathcal{S}^{(€)}$	$n\left(\beta_{d,s}=1\right)$	$n\left(\beta_{a_r}^{p_{a_r}}=1\right)$	$n\left(\beta_{b_r}^{p_{b_r}}=1\right)$	t (s)
Scenario 1 (**DA**)		**18.33**	**1/1**	**4/24**	**–**	438.1
Scenario 2 (**ID** $r=\{s\}$)	**Total**	**44.28**	**1/1**	**6/24**	**4/4**	521.8
Scenario 3	$r=o$	20.46	–	3/24	1/2	–
(**ID** $r=\{o,s\}$)	$r=s$	46.83	1/1	6/15	4/4	–
	Total	**67.29**	**1/1**	**3/24 + 6/15**	**1/2 + 4/4**	735.2

One area for future research would be to investigate other problems for the DSO including over/under voltages and 3-phase voltage imbalances which are location dependent and would explicitly require a network model. In addition, given the early state of the research, additional theoretical and experimental investigations for real-world applications are required to gain better understanding on how local flexibility markets perform in different technologic, economic and regulatory contexts. For example, further research is demanded to investigate the execution of the accepted profiles and reduction of the uncertainty associated with (un)intended deviations that can occur after the closure of a LFM trading platform. Finally, it is important to conduct an extensive analysis on the computation cost of the market clearing problem, especially when a large number of flexibility offer and request profiles are submitted to the LFM.

7. Glossary

7.1. List of abbreviations

- AggSup: Aggregator Supplier
- BRP: Balance Responsible Party
- DSO: Distribution System Operator
- LFM: Local Flexibility Market
- PTU: Programmable Time Unit.

7.2. List of definitions

- Prosumer: an energy consumer that can become active and performs as an energy producer.
- Base energy profiles: the original energy consumption profile that an AggSup initially determines based on measurements, historical data and forecasting it receives from its prosumers.
- Flexibility: the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or direct activation) in order to provide 'system balancing' and 'constraints management' services within the system [35].
- Flexibility profile: a flexibility profile contains the amount and direction of the flexibility a flexibility provider (e.g., an AggSup) offers to or a flexibility consumer (e.g., a BRP offers or the DSO) requests from the market at every PTU of the scheduling horizon in DA or ID scheduling of the LFM.
- Flexibility direction: prosumers can act as a source or a sink of energy dependent on the requests from DSO and/or BRPs. The direction of flexibility is defined from the prosumers point of view:
  - Positive: prosumers act as energy sink. They are required to increase their energy consumption.
  - Negative: prosumers act as energy source. They are required to decrease their energy consumption.
- Flexibility profile direction: in the ID scheduling, we consider the direction of the flexibility request of the DSO as the conventional flexibility direction in which the market clears. Based on this direction, two are two situation possible:
  - AggSup flexibility offer in the similar direction: the flexibility offered at every PTU of the flexibility offer profile (of an AggSup) is in the similar direction of the DSO.
  - BRP flexibility offer in the similar direction: the flexibility requested at every PTU of the flexibility request profile (of a BRP) is aligned with of the DSO.
  - AggSup flexibility offer in the opposite direction: the flexibility offered at every PTU of the flexibility offer profile (of an AggSup) is in the opposite direction of the DSO.
  - BRP flexibility offer in the opposite direction: the flexibility requested at every PTU of the flexibility request profile (of a BRP) is aligned with of the DSO.

7.3. List of symbols and notations

7.3.1. Sets: DA

- Ω_t set of indexes of all PTUs included in the scheduling horizon
- Ω_A set of indexes of all AggSups
- Ω_a^P set of indexes of all flexibility offer profiles of the ath AggSup.

7.3.2. Sets: ID

- $\Omega_{A_{id}^o}$ set of AggSups with flexibility offers in the opposite direction of the DSO
- $\Omega_{A_{id}^s}$ set of AggSups with flexibility offers in the similar direction of the DSO
- $\Omega_{A_{id}}$ set of AggSups with flexibility offers in the similar and opposite direction
- $\Omega_{B_{id}}$ set of indexes of all BRPs that participate in the LFM
- $\Omega_{B_{id}^o}$ set of indexes of BRPs with flexibility requests in the opposite direction of the DSO
- $\Omega_{B_{id}^s}$ set of indexes of BRPs with flexibility requests in the similar direction of the DSO
- $\Omega_{B_{id}}$ set of indexes of BRPs with flexibility requests in the similar and opposite direction
- $\left\{\Omega_{k_r}^P \,|k\in\{a,b\}, r\in\{o,s\}\right\}$ as the set of indexes of all profiles offered by AggSups and BRPs, in the direction r and $r\in[o,s]$ is defined by the DSO.

7.3.3. Variables: DA

- β_d binary variable associated with the DSO's request getting accepted or rejected
- $\beta_a^{p_a}$ binary variable associated with the profile $p_a\in\Omega_a^P$ of AggSup $a\in\Omega_A$ being accepted or rejected.

7.3.4. Variables: ID

$\beta_k^{p_k}$ binary variable associated with the p_kth profile of market participants k being accepted or rejected where $k \in \{a_r, b_r, d\}$ and $r \in \{o, s\}$.

7.3.5. Indices: DA

- d index to refer to the DSO
- p_a index to refer to the pth profile of the ath AggSup
- $q_{a,da}^{p_a,t}$ amount (quantity) of flexibility that the ath AggSup offers in its p_ath profile during tth PTU
- $\rho_{a,da}^{p_a}$ price of the p_ath flexibility offer profile of the ath AggSup
- $q_{d,da}^{t}$ amount of flexibility the DSO requests from the LFM at every PTU in its single request profile
- $\rho_{a,da}$ price of the flexibility request profile of the DSO
- $\mathcal{S}_{da}$ the aggregated social welfare in DA scheduling
- $\mathcal{B}_{da}^{t}$ the cost of buying flexibility requests of the DSO per PTU
- $\mathcal{G}_{da}^{t}$ benefit of providing flexibility offers of AggSups per PTU.

7.3.6. Indices: ID

- d index to refer to the DSO
- o index that denotes the direction of the flexibility profile is in the opposite directions to the DSO
- s index that denotes the direction of the flexibility profile is in the similar directions to the DSO
- r index that denotes the direction of flexibility profile with regards to the direction of the flexibility request profile of the DSO
- k index that denotes the profile under study belongs to an AggSup, a BRP or the DSO
- a_r index to refer to AggSups that have flexibility offers and requests in direction $r \in \{o, s\}$
- b_r index to refer to BRPs that have flexibility offers and requests in direction $r \in \{o, s\}$
- $q_{k_r}^{p_{k_r},t}$ the amount of flexibility offered/requested in the pth profile of market participant k in direction r
- $\rho_{k_r}^{p_{k_r}}$ the price of the pth profile and $k \in \{a, b\}$, $r \in \{o, s\}$
- $\mathcal{S}_{id,r}$ the aggregated social welfare in ID scheduling
- $\mathcal{B}_{id,o}^{t}$ the cost of buying flexibility requests of BRPs in the opposite direction o per PTU
- $\mathcal{B}_{id,s}^{t}$ the cost of buying $q_{d_s}^{p_{d_s},t}$ amount of flexibility of DSO and of BRPs in the similar direction per PTU
- $\mathcal{G}_{id,o}^{t}$ benefit of providing flexibility offers of AggSups in the opposite direction o per PTU
- $\mathcal{G}_{id,s}^{t}$ benefit of providing flexibility offers of AggSups in the similar direction o per PTU.

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