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TSO-DSO-Customer coordination for purchasing flexibility system services: Challenges and lessons learned from a demonstration in Sweden

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Abstract—This paper presents a real-word implementation of a TSO-DSO-customer coordination framework for the use of flexibility to support system operation. First, we describe the general requirements for TSO-DSO-customer coordination, including potential coordination schemes, actors and roles and the required architecture. Then, we particularise those general requirements for a real-world demonstration in Sweden, aiming to avoid congestions in the grid during the high-demand winter season. In the light of current congestion management rules and existing markets in Sweden, we describe an integration path to newly defined flexibility markets in support of new tools that we developed for this application. The results show that the use of flexibility can reduce the congestion costs while enhancing the secure operation of the system. Additionally, we discuss challenges and lessons learned from the demonstration, including the importance of the engagement between stakeholders, the role of availability remuneration, and the paramount importance of defining appropriate technical requirements and market timings.

Index Terms — active distribution networks, balancing services, congestion management, flexibility markets, real-world demonstration, TSO-DSO coordination.

NOMENCLATURE

aFRR	automatic Frequency Restoration Reserves
API	Application Programming Interface
BSP	Balancing Service Provider
CET	Central European Time
DA	Day-ahead
DER	Distributed Energy Resource
DSO	Distribution System Operator
FCR	Frequency Containment Reserve
FSP	Flexibility Service Provider
GCT	Gate Closure Time
HEMRM	Harmonised Electricity Market Role Model
HVDC	High-Voltage Direct Current
ID	Intraday
mFRR	manual Frequency Restoration Reserves
P2P	Peer-to-Peer
RES	Renewable Energy Sources
SGU	Significant Grid User
TSO	Transmission System Operator

I. INTRODUCTION

HIGHER shares of renewable energy sources are challenging the capability of the system to both accommodate the massive connection of generation facilities to the distribution grid and to ensure the balance between generation and demand. In addition, the electrification of the transport, heating and industrial sectors, entails an increased electricity demand, which is putting a strain on both the transmission and distribution systems. Under this scenario, the coordination between Transmission System Operators (TSOs) and Distribution System Operators (DSOs) to purchase system services (e.g., balancing, congestion management and voltage control) becomes of paramount importance.

A pillar of the ongoing power system transformation is the use of the flexibility that resources connected to the distribution system may provide [1]. Variability and uncertainty related to growing shares of electricity generation from renewable energy sources (RES) jeopardise the traditional power system operation [2]–[4], which increases the need for flexibility in the transmission system, and complicate the distribution system operation due to bidirectional power flows that Distributed Energy Resources (DERs) fed by RES may create [5], [6]. The exploitation of the flexibility from DERs is considered to be an effective tool to support distribution system operation, along with the active network management, determining new responsibilities for the DSOs (e.g., market facilitator, enhanced

voltage control, congestion management) [1], [5], [7].

DERs' flexibility is relevant to the legislative framework. In particular, the European Clean Energy Packages recommend integrating DERs' flexibility in planning and operation, by resorting to market mechanisms [7]. Nevertheless, the exploitation of DERs' flexibility leads to a requirement for improved TSO-DSO coordination [1]: the exploitation of DERs by the TSO requires coordination with the DSO to avoid endangering the DSO network operation (e.g., exceeding thermal or voltage limits). Similarly, TSO-DSO coordination is also required to allow the DSO to exploit DERs' flexibility without undermining the power system operation (e.g., balancing issues or voltage problems).

The novelty of DERs' exploitation for distribution and transmission system operation triggered several initiatives to explore the topic and design the required TSO-DSO coordination mechanisms. Several conceptual frameworks and digital platforms have been proposed and developed to realise market-based coordination among TSOs, DSOs, flexibility service providers (FSPs), and other relevant stakeholders (e.g., aggregators, and energy communities) [8]–[10]. The topic of TSO-DSO coordination is a current focus area in several European research projects; in particular, the development of digital platforms for involving DERs in network congestion management, voltage control, and balancing (e.g. OneNet [11], INTERRFACE [12], EUniversal [13], along with CoordiNet [14]). The most relevant initiatives which propose digital market platforms to allow TSOs and DSOs to purchase system services from DERs as FSPs include [8] Cornwall Local Energy Market [15], ENERA (as a pilot) [16], GOPACS [17], NODES [18] and Piclo Flex [19]. However, the main objective of these platforms is to allow the FSPs to support solving local operation issues on the DSO network. Only a few of them (i.e., GOPACS and ENERA) also address the provision of system services to the TSO and TSO-DSO coordination.

In line with these initiatives, this paper proposes a new market framework in which both DSOs and TSOs can solve system needs with a large set of common resources. However, the coordination schemes proposed in this paper differ from the integrated and shared market frameworks recently discussed in the literature [20], [21], [22] in the sense that the buyers are active in separate markets.

This paper is part of the contributions of the CoordiNet project, which represents one of the key initiatives in the definition of the most effective way to coordinate the purchase of system services by TSOs and DSOs. For that purpose, the project has developed three real-world demonstrators in Spain, Sweden and Greece to evaluate the purchase of balancing, congestion management and voltage control services.

In Sweden, the energy transition is being confronted with the limited available capacity in the network. The load has a high temperature-dependence, with peak load experienced in winter months, because of a high degree of electrification for spatial heating (from heat pumps). As shown in Fig. 1, the Swedish operational responsibility for the power system is three-layered, so that regional DSOs operate their grid in between the TSO and local DSOs, normally in the range of 70 kV-130 kV.
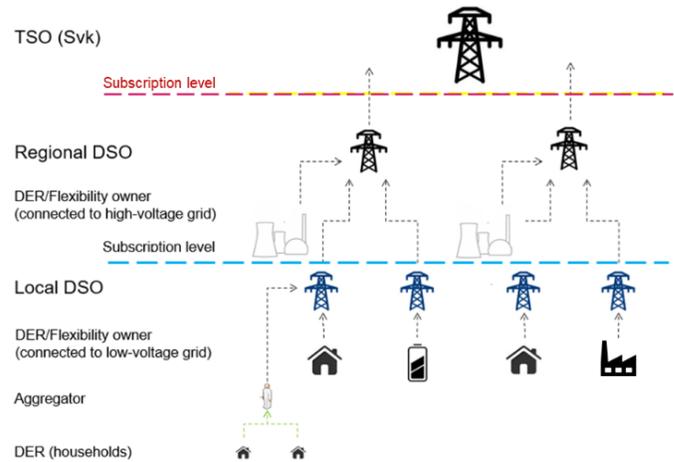

Fig. 1. DSO and TSO levels in the Swedish power system.

This implies that most DSOs do not have a connection directly to the transmission grid. Instead, regional DSOs contract capacity from the transmission grid, which is known as the *subscription level*. Since 2016, several regional DSOs were not permitted to raise their annual and temporal subscription levels, which resulted in both regional and local DSOs not being able to connect new customers. Hence, new flexibility markets, which are a joint effort from the DSOs and the TSO, can provide a solution to allow new customers' connections, while keeping the agreed subscription level even in the high-demand winter period.

This paper describes a generic architecture and the allocation of responsibilities for TSO-DSO coordination, building on the coordination schemes proposed in the literature [9], and presents the real-world implementation in Sweden [23], which shows how DSOs and the TSO shall act in a coordinated manner to purchase system services in the most reliable and efficient way, through market-based and non-discriminatory mechanisms. The Swedish demonstration comprises several distinguishable TSO-DSO-customer field trials, which are further detailed in [24].

The major contributions of this paper are:
i. extension and customization of existing coordination schemes, which define the roles and responsibilities for a coordinated system operation,
ii. integration of newly defined flexibility markets within the scope and timeframe of existing markets,
iii. formulation of the generic platform architecture which facilitates the purchase of system services, and
iv. presentation of the results of the real-world demonstration in Sweden, together with the challenges and lessons learned on the described transition path towards integrated TSO-DSO coordination.

This paper, hence, aims to provide key lessons learned from a real-world implementation of innovative ways for the coordination of TSOs and DSOs to buy system services through pioneering market arrangements and platforms. The presented developments are part of a series of initiatives in Sweden related to the implementation of flexibility markets to improve grid data collection, time coordination between markets, product specifications and system architecture.

In Section II, we describe the overall requirements for real-world demonstrations of the coordinated purchase of system services by the TSO and DSOs. We particularise these requirements for the implementation in Sweden in Section III and present its results in Section IV. Section V shows the challenges and lessons learned through the application in Sweden and, finally, Section VI summarises the main conclusions.

II. General Requirements for TSO-DSO-Customer Coordination

A. Coordination schemes

To coordinate the purchase of flexibility among system operators, seven possible TSO-DSO coordination schemes have been identified. A coordination scheme has been defined in [9] as the relation between TSO and DSO, defining the roles and responsibilities of each system operator, when procuring and using system services provided by the distribution grid. This work builds further on the coordination schemes identified in [9], [25]. In addition, a review was done of other related work as presented in [26]. From this analysis, it became clear that there is not a one-size-fits-all solution. Local conditions, market maturities and regulatory conditions differ across countries and drive the decision on which scheme to choose [27], resulting in a multitude of proposed market structures with their own characteristics and nomenclature [28]. To cope with this complexity, we have proposed a classification of coordination schemes based on four main dimensions, which can be used to characterise and compare different potential coordination schemes:

i. the flexibility needs, with a distinction between local needs (e.g., by a DSO), central needs (e.g., by a TSO) and the combination of both needs in a market set-up,

ii. the flexibility buyer, specifying which stakeholder(s) buy(s) the flexibility to cover a certain need,

iii. the number of markets, specifying whether the TSO and DSOs purchase flexibility in a single market, or whether parallel/sequential markets are in place for procuring flexibility, and

iv. the level of access to flexibility resources, specifying whether, e.g., the TSO can directly buy system services outside its monitored area of control.

Since the proposed coordination schemes are service agnostic, they can be applied for the purchase of standardised products for different services or even a combination of services. Along these lines, the defined products—which have been used in the demonstration campaign—provide essential services to both DSOs and the TSO to maintain the operation of the grid and the entire system within safe operational limits.

The services investigated in this paper are balancing and congestion management. However, the coordination schemes have also been applied to the purchase of other services in CoordiNet, as described in [24]. Hence, for each service, standard products, i.e., products with commonly defined attributes, are defined. These products are delivered by third party FSPs and can cover different timeframes, considering reserves up to near real-time products.

Based on the four dimensions introduced above, we propose seven different coordination schemes. Two of them focus on a single flexibility need. In the *Local Market Model*, the DSO is the only buyer within a local flexibility market to cover its needs. Similarly, within the *Central Market Model*, the TSO buys flexibility to fulfil its needs in a central flexibility market.

Next, we propose two schemes which cover local and central needs in separate markets at central (for the TSO) and local level (for the DSOs). Within the *Multi-level Market Model,* the TSO has access to flexible resources connected to the distribution grid, while in the *Fragmented Market Model,* this is not the case. In the latter scheme, agreements between the TSO and DSOs have to be made on the exchanges between their respective networks, which translates into common constraints to be taken up by the market clearing formulation.

Two additional schemes are proposed which also address local and central needs, but this time in a single market setting. In the *Common Market Model,* the TSO and DSOs buy flexibility in a single market, to share resources automatically. In the *Integrated Market Model*, aside from the TSO and DSOs, also other parties (such as Balancing Responsible Parties) purchase flexibility within the same market.

Finally, we propose distributed market structures to solve grid-related issues, as these were not yet part of previous analyses. In a *Distributed Market Model,* peers are the sole buyers (and providers) in the market, to solve local and/or central needs by DSOs and/or the TSO.

The coordination scheme implemented in the Swedish demonstrator is the *Multi-level Market Model*, as we will further explain in Section III-B.

B. Roles

The coordinated purchase of system services by TSOs and DSOs requires a clear definition of the roles and activities to be performed by each of them. To enable a common understanding across Europe, relevant bodies representing European TSOs, DSOs, energy traders, suppliers and regulators worked together to devise the Harmonised Electricity Market Role Model (HEMRM) [29], which aims to establish the basis of common terminology for the prevalent roles in the European electricity market. Accordingly, each defined role represents a relatively autonomous function, mainly related to information exchange (further detailed in [30]). Recently, the BRIDGE initiative, promoted by the European Commission (EC) to foster the knowledge exchange amongst EC-funded projects, launched an action to review the definitions adopted by European H2020 projects, check the compliance with HEMRM and, when needed, propose definition updates [31]. This paper adopts the roles defined in [29], [31] for describing the relevant activities (i.e., market operation, system operation, system service provision, and aggregation).

For this paper, the actor responsible for market operation receives the flexibility requirements to be met, sets the order of the bids that can meet those requirements, matches those bids with the flexibility requirements, informs other market agents about market results, performs the settlement of the contracted and delivered flexibility, and invoices the affected parties.

Hence, based on the HEMRM definition [29], the actor responsible for market operation plays the roles of Market Operator, Billing Agent, Merit Order List Responsible, Reserve Allocator, and Market Information Aggregator.

In a similar fashion, within this paper, the actor in charge of system operation covers the roles of System Operator, Load Frequency Control Operator, Scheduling Area Responsible, Metered Data Collector, Metered Data Responsible and Metering Data Administrator. Also, we assume that the TSO performs the transmission system operation (including system balancing) and that DSOs operate the distribution system.

System service provision is the activity carried out by the role of the FSP, which is not defined in HEMRM and BRIDGE [29], [31]. In this paper (and in the CoordiNet project), the FSP is a party that handles the operation of resources connected to the grid at a single point of connection, and provides system services for the system operation [32]. Thus, this paper extends HEMRM definitions to include FSPs that provide all system services, and not only Balancing Service Providers (BSPs).

In this paper, the aggregator performs the role of Resource Aggregator, as defined in HEMRM [29].

C. Required architecture to exchange information to buy system services

In order to allow for an efficient coordination between TSOs and DSOs, both, and in particular DSOs, need to increase their monitoring capabilities and use decision-support tools showing information that is not available today. Likewise, the purchase of system services may require the establishment of new markets. Thus, the purchase of system services from FSPs, and, in particular, DERs requires that all the involved agents can exchange market-related information in an efficient and robust way. For that purpose, a well-designed platform with integrated architecture is essential. In the general case, this architecture for the exchange of market-related information comprises three main blocks: grid monitoring & operation, bidding & dispatching and market operation [33], as shown in Fig. 2.

This general architecture is adaptable to the specific needs of the DSO and/or TSO that purchases certain services. In this sense, it is important to mention that the functionalities included in the grid monitoring & operation block correspond to a regulated activity. In the market operation block, both a regulated agent (the DSO, or the TSO) or a commercial agent (an independent market operator) can be active. The functionalities of the bidding & dispatching block are performed by FSPs subject to competition and, hence, they will affect the coordination between TSOs and DSOs in terms of market aspects, but will not be part of the platforms to be developed by TSO or DSOs.

The grid monitoring & operation block (depicted in black in Fig. 2) falls under the responsibility of the relevant system operator (TSO or DSO), who identifies the amount of flexibility required to obtain the services needed. To that end, DSOs and the TSO use several tools to perform activities such as load and/or RES forecasting, or monitoring of the state of system assets, Significant Grid Users (SGUs) and potential FSPs, to evaluate the state of the system (through e.g., state estimation, power flow analysis or the use of impact factors as explained in

Section IIIB). They also use the production plans of SGUs and other relevant information (subscription levels, state of energy flows with other TSOs or DSOs, etc.) in the evaluation of the system state. After identifying purchase needs, the buyers (DSOs and TSOs) send those needs to the market operator.

In parallel to all these activities, FSPs (either individual providers or aggregators) make use of the functionalities included in the bidding & dispatching block (depicted in pink in Fig. 2) to provide and operate the flexibility required by the system. Different tools are used to monitor the state of the DERs, estimate the flexibility in each of them, forecast the expected RES generation and load (among others), predict the likely prices in different markets, etc. All this information provided by the different tools in this block allows the FSPs to optimise their market bids, which are then sent to the market.

In the third block in the presented architecture, i.e., the market operation block (depicted in blue in Fig. 2), the market operator uses the most cost-efficient bids created in the bidding & dispatching block to satisfy the system needs identified by DSOs and the TSO through the functionalities in the grid monitoring & operation block. The market operator must be able to receive information from the other two blocks, to perform the clearing of the market—according to the defined objective function and constraints—and to communicate market results to the other blocks, so that both the buyers (TSO and DSOs) and the sellers (FSPs) are aware of market results. Depending on the coordination scheme, this block may include local, central or common markets, whose interrelation in terms of bidding times, market horizon, clearing frequency, etc. needs to be clearly defined in advance.
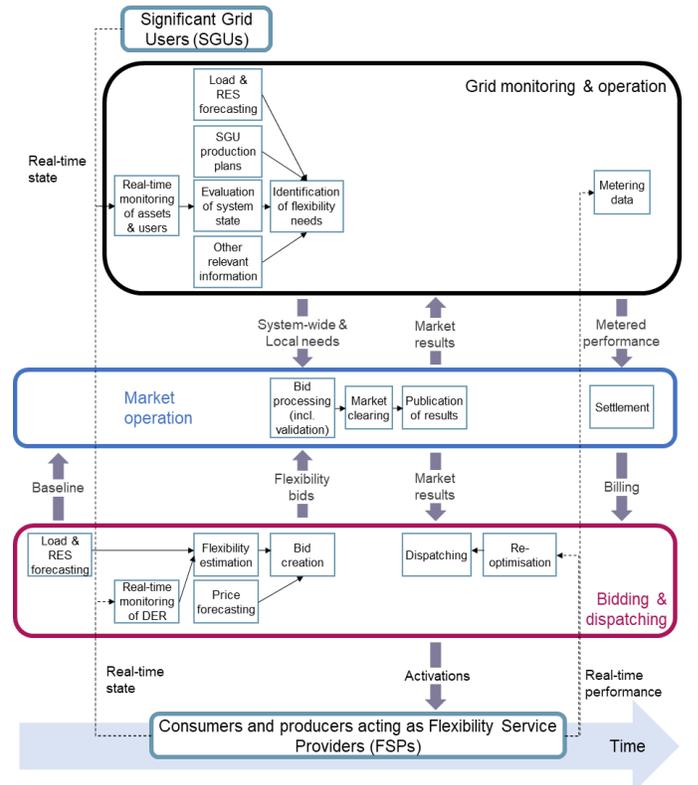

Fig. 2. Generic architecture for flexibility trading, with main blocks, activities and information exchanges.

After receiving market results, the functionalities included in the bidding & dispatching block allow aggregators and FSPs to dispatch the most suitable units, based on the amount of energy cleared in the market, the cost function of their units, their real-time state, etc. To ensure that the flexibility is provided, the FSPs monitor the flexibility provision of the different assets and, if needed, update the setpoints allocated to each unit.

Likewise, and based on these market results, both TSO and DSOs monitor, through the grid monitoring & operation functionalities, the status of FSPs, to check that they indeed provide the committed flexibility and to identify additional flexibility requirements for the upcoming time horizons, considering also the performance of the other system users.

Finally, the market operation block receives information about real-time performance of FSPs, to perform the settlement.

As a result, any real-world implementation of such a market platform will be strongly influenced by pre-existing systems and structures, and by the specific need the new flexibility markets aim to solve.

III. IMPLEMENTATION THROUGH THE SWEDISH DEMONSTRATION ACTIVITY

The aim of the Swedish demonstration is to relieve the existing and growing large-scale network constraints in the regional DSO grid and on DSO/TSO interfaces, which are hindering the integration of RES, urbanisation and industrialisation. In this demonstration, the DSO utilises flexibility services to lower peak demand in the grid during winter (November to March).

In addition, there is an increasing need for flexibility for the TSO, as forecasted by the Nordic TSOs [23], including the Swedish TSO, Svenska kraftnät [34]. The DSOs have local urgent needs for flexibility, which may be provided by customers, aggregators and DERs, to alleviate network congestions during the winter peak load. This urgency is the background and reasoning for conducting the demonstration at three different sites, Skåne, Uppland and the island of Gotland. Since there are different conditions locally, each of the three sites requires a separate solution.

A. Current congestion management rules and existing markets

Like most EU countries, Sweden has various established short-term wholesale and balancing markets with different timeframes: day-ahead (DA), intraday (ID) and near real-time. The Swedish DA and ID markets are divided into four price areas. The price areas are based on the structural congestions within the transmission network (i.e., generation units are mainly in the North, while consumption centres are in the South). Both DA and ID markets consider the congestions between these areas, but currently, there is no means to consider grid congestion within one price area. In defining local congestion markets, existing market closure times must be taken into account. The Gate Closure Time (GCT) of the DA market is at 12:00 Central European Time (CET), and the market clearing follows the pan-European market coupling process through the Euphemia algorithm. The ID continuous

market takes place until one hour before delivery and prices are set based on a first-come, first-served principle, but following the European Single Intraday Coupling regulations [35].

The Nordic TSOs are integrating their balancing market in a single Nordic Balancing Model among the four TSOs: Svenska kraftnät, Energinet, Fingrid and Statnett [36]. This program aims to harmonise and share among the Nordic countries the acquisition, activation and pricing of balancing services: manual frequency restoration reserves (mFRR) and automatic frequency restoration reserves (aFRR). These services are used to keep the system balance and the frequency within safety margins. In addition, mFRR can also solve congestions in the TSO grid [37], and the TSO can limit the participation of bids in the mFRR markets during congestions. The manual balancing markets are coordinated in time with the DA and ID wholesale markets. The GCT for the mFRR market is 45 minutes before the hour of delivery.

In Sweden, all agents (including DSOs) connected to Svenska kraftnät's transmission grid must pay network charges to cover the TSO's costs of building, operating and maintaining the transmission network and the energy losses due to the energy transport. The network charges comprise four elements:

i. The usage fee (SEK/kWh), which covers the energy losses costs.

ii. The regular capacity charge (SEK/kW), which is a monthly fee, based on the subscribed kW for an annual duration.

iii. The temporary capacity charge (SEK/kW), which is a weekly fee paid, based on a temporary subscription for a week and which must be requested at least one hour before the subscription period starts. This temporary increase of the subscription level must be granted by Svenska kraftnät, subject to available network capacity. The granted temporary subscriptions can be revoked if, according to Svenska kraftnät's assessment, it may lead to congestions in the transmission system. Therefore, both the regular and the temporary subscription levels are important for the operational safety of the transmission grid.

iv. The temporary subscription usage fee (SEK/kWh), which accounts for the energy consumed above the regular capacity, but within the increased temporary capacity granted by Svenska kraftnät. This is normally the highest part of the payment.

When temporary subscriptions are granted, the usage fee ranges between 220 and 250 SEK/MWh, depending on the TSO substation. When not granted, the agent (e.g., DSO) exceeding the subscription level pays a penalty. The penalties in force during 2021 were 560 SEK/MWh and 1,400 SEK/MWh for the first and second hours of overrun within a day, and 2,800 SEK/MWh for the rest of the hours with limit violations [38].

Both local DSOs and regional DSOs buy annual capacity subscriptions that allow the power consumption up to the agreed capacity with the TSO. Since 2016, several regional DSOs in Sweden have been denied raising the annual subscription level. Additionally, the TSO has also denied temporary subscription levels. As a consequence, connecting

new customers to DSO networks became impossible. Hence, new flexibility markets, which are a joint effort from the DSOs and the TSO, can provide a solution to allow new customers' connections while respecting the agreed subscription level.

B. Integration of new schemes in existing markets

With newly designed market frameworks, both DSOs and TSOs should be able to solve system needs with a large set of common resources. The Swedish demonstrator implemented a multi-level market model, with separate and sequential markets, so that, first, the distribution level (for the regional and local DSOs) is solved and, then, the central level (for the TSO). All flexibility markets are designed to fit into the schedules of the existing energy markets, as described in Section III-A. The proposed multi-level market scheme can be achieved by using successive market GCTs, as summarised in Fig. 3. The central balancing market is active in a last stage before and during service delivery. The depicted timeline refers to the latest realization of the CoordiNet market scheme, demonstrated in the campaigns of the winters 2019/20 and 2020/21.

After the closure of the DA flexibility market, hourly load forecasts are updated regularly. If there is any remaining congestion forecast, the DSOs place their buy orders on the ID flexibility market. The ID flexibility market opens after the TSO frequency containment reserve (FCR) market closes, i.e., at 15:00 CET, and is available until two hours before the delivery time. After the closure of the national DA wholesale market and within one hour before delivery time, trades on the ID spot market can continue up to 15 minutes before delivery time, when the mFRR market opens.

Thanks to this integration in existing markets, unused bids from the DA flexibility market can be forwarded to the ID flexibility market for congestion management. This option only exists for pre-qualified products. If not dispatched in the regional DSO ID flexibility market, qualified unused bids can be further forwarded to the mFRR market to support the balancing needs of the TSO.
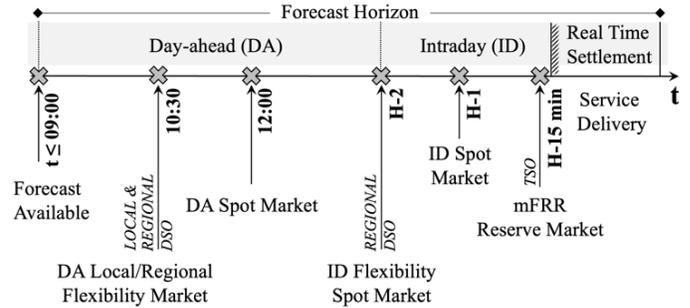

Fig. 3. Short-term local flexibility market embedded in existing common market structure. The indicated separation of markets and GCTs represents the latest state of the trial which may be subject to change.

C. Description of the necessary tools to implement the demonstrators

The tools developed for implementing the flexibility markets can be divided into a tool to identify the flexibility needs and monitor both FSPs and SGUs, called the "*FlexTool*", (corresponding to the monitoring & operation block in Section II-B) and a market tool (corresponding to the market operation block in Section II-B). Fig. 4 summarizes the tools used in the market platform, including some well-established existing tools of the TSO, such as the mFRR market and subscription purchase tools [39], which are not further described here.

The flexibility need of the buyer is determined by comparing the load forecast at the substation level (part of the FlexTool) and the current substation subscription level. Moreover, the FlexTool is used to monitor and evaluate the delivery of flexibility according to the market results to ensure a secure operation, as well as for the settlement process.

The market tool matches the sell orders with the DSO flexibility needs, according to the mathematical formulation presented in Section III-C.1. The market tool also communicates with the TSO mFRR market to implement the multi-level market model.
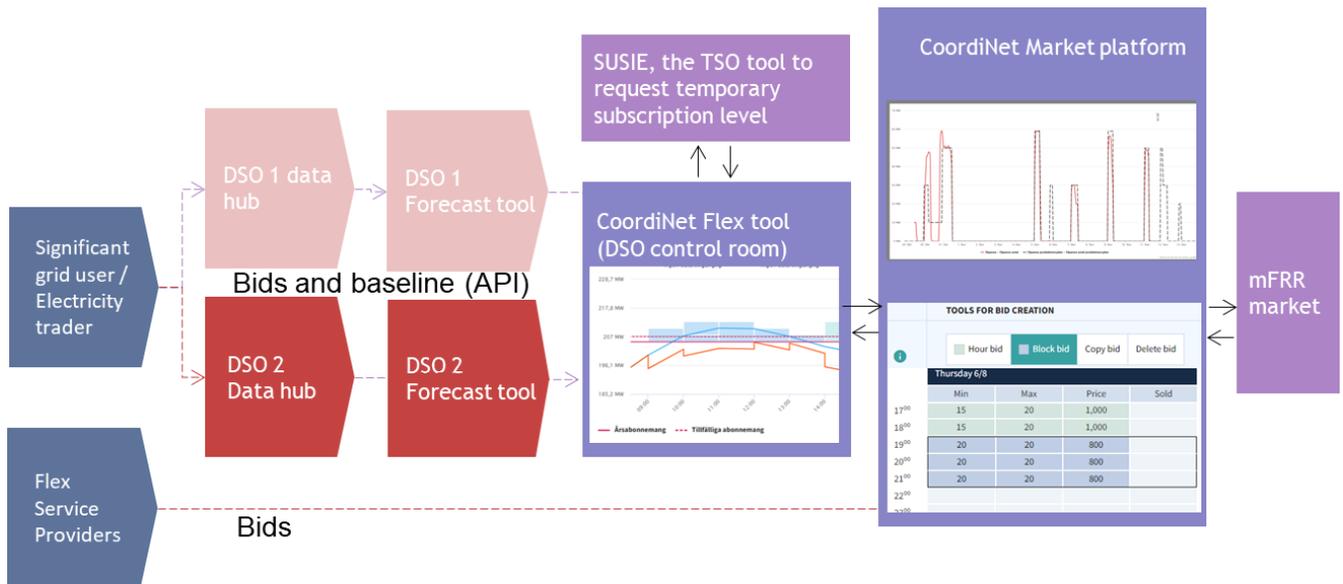

Fig. 4. Components of the CoordiNet market platform.

1) FlexTool

One key functionality of the FlexTool is monitoring, which provides the DSOs with a visual representation of subscription levels and local generation that are necessary to operate the system properly. DSOs can monitor the consumption and production of all FSPs participating in their markets. A bi-directional meter is installed at all FSPs to collect the relevant data every 5 minutes and send it to the DSOs' SCADA system. This data is used in combination with market results to perform the settlement. Measurement data is compared with FSPs' baseline to validate whether they provide the flexibility according to the market results. The FSPs update the baseline every hour, based on the method that has been approved by the DSO in the prequalification process.

In extension to the monitoring functionality, the FlexTool incorporates forecasting functionalities which are central to the operation of the flexibility market for congestion management. This functionality supports the decision-making concerning *if* and *when* to purchase flexibility within the embedded market framework described in Section III-B. Based on the forecasted load, an alarm functionality indicates potential expected violations of substation subscription levels. In that case, the required amount of active flow reduction in the substation is calculated and sent to the market tool.

The targeted residual load forecast considers large industrial loads and planned generation forecast (central and local). Small- and medium-sized loads, subject to a larger uncertainty, are predicted and, then, added to the already scheduled generation plans. The residual load forecast that is not supplied by the planned and intermittent local production may not exceed the subscription limit. Both in Gotland and Skåne, High-Voltage Direct Current (HVDC) connections to the mainland of Sweden and Germany, respectively, have a large impact on the grid connection points between the Swedish TSO and the regional DSOs. Thus, prior capacity agreements are integrated into the operational planning. Any forecasted violation of the subscription limit triggers processes in the market tool.

The Swedish demonstration primarily relies on supervised learning forecasting models within the area, which apply regression algorithms and neural network models [40]. The explored electricity consumption and generation patterns are in parts highly variable. Accurate forecasting requires both short- and long-term factors. In the short-term, the main influencing factors are the weather conditions, daily and weekly periodic cycles, and unusual behaviour during special calendar days. Long-term factors, such as increased electrification, economic growth and expansion of urban areas, slowly shift the overall consumption and generation and influence the forecasting with a trend component.

Both the areas of Skåne and Uppland are urban areas, facing rapid growth, entailing an increased electricity demand. At the same time, further RES capacity is being installed, while controllable generation plants are decommissioned. Together, the higher demand and generation from RES reduce operational margins, which increase the need for flexibility and necessitate short-term forecasting. Yet, long-term factors are also crucial to identify whether historic data can represent the future grid state.

The most relevant period in the historic measurements is determined during the pre-processing of the data. This pre-processing results in a set of selected features that are relevant to create an accurate short-term load forecasting model.

Given the manifold grid particularities at the demonstration sites, different forecasting methods have been implemented to match the target load profiles. For the forecasting models, time series characteristics, such as the autoregressive dependence on observations for the same hour in previous timesteps, calendar information (hour, weekday, season), holidays temperature, and other meteorological factors are of particular interest.

2) Market tool

The market tool connects to the mFRR market tool to forward unused bids. The forwarding happens from the congestion management market to the TSO mFRR market. The market tool then receives information about the activated bids. Based on the information received from the TSO mFRR market, clearing signals are automatically sent to the FSPs connected to the networks of the local and regional DSOs through Application Programming Interface (API), email, or message. Prior to the development of the market tool, the communication of TSO mFRR market-clearing results or DSO bilateral agreements with FSPs were made via telephone calls.

The tool receives the flexibility needs identified by the DSOs, as well as the bids submitted by the FSPs, e.g., through an API, and performs a market clearing process based on the optimisation problem described below. Once the market clearing process is executed, the unpurchased bids in the DA and ID flexibility markets of the DSOs are forwarded to the TSO mFRR market, if those bids have been pre-qualified and meet all requirements for the TSO mFRR market participation.

The mathematical formulation of the DA market algorithm of the regional and local DSOs is provided below.

$$\min_{p,u,z} \sum_{t \in \mathcal{T}} \sum_{i \in \mathcal{J}} c_{i,t} p_{i,t} + \sum_{t \in \mathcal{T}} \sum_{l \in \mathcal{L}} h_{l,t} A_{l,t} \tag{1}$$

$$u_{i,t} p_{i,t}^{Smin} \leq p_{i,t} \leq u_{i,t} p_{i,t}^{Smax}, \qquad \forall i \in \mathcal{J}_s, t \in \mathcal{T} \tag{2}$$

$$z_i p_i^{bmin} \leq p_{i,t} \leq z_i p_i^{bmax}, \tag{3}$$
$$\forall i \in \mathcal{J}_b, t \in [t_{start}, t_{end}]$$

$$p_{i,t} = p_{i,t+1}, \quad \forall i \in \mathcal{J}_b, t \in [t_{start}, t_{end} - 1] \tag{4}$$

$$\sum_{i \in \mathcal{J}} a_{i,l} p_{i,t} + A_{l,t} \geq P_{l,t}, \quad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{5}$$

$$A_{l,t} \geq 0, \qquad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{6}$$

The objective function (1) aims to minimise the cost of the activated flexibility and the cost for surpassing subscription level in the most cost-efficient way during the examined horizon. Hourly steps are considered. $c_{i,t}$ and $p_{i,t}$ represent, respectively, the unit price and the cleared amount of active power of the ith bid submitted at time interval t. $h_{l,t}$ and $A_{l,t}$ represent, respectively, the unit fee for surpassing the subscription level and the excess of active power above the subscription level of the lth substation at time interval t. $\mathcal{T}$, $\mathcal{L}$, $\mathcal{J}_s$ and $\mathcal{J}_b$ are, respectively, the sets of time intervals, substations under consideration, as well as single and block bids ($\mathcal{J}_s \cup \mathcal{J}_b = \mathcal{J}$). When the problem is solved for the local DSO,

$\mathcal{J}$ and $\mathcal{L}$ contain, respectively, the bids submitted by the FSPs connected to the network of the local DSO and the substations under consideration between the local and regional DSOs. When the problem is solved for the regional DSO, $\mathcal{J}$ would contain the bids submitted by the FSPs connected to the network of the regional DSO, as well as the network of all local DSOs with a connection to the regional DSO network, while $\mathcal{L}$ would contain the substations under consideration between the regional DSO and the TSO. To reduce the active power flow at the substation level, the bids submitted constitute either an increase in generation or a decrease in demand downward of the substation. In both cases, $p_{i,t}$ is non-negative. It is noted that the availability price, which is not a marginal cost, is not considered to determine the market-clearing. By considering the cost for buying flexibility and the cost for surpassing the subscription level, the market will not activate a bid if its activation cost is higher than the reduction in the cost for surpassing the subscription level brought about by the activation of that bid.

Constraint (2) specifies the minimum ($p_{i,t}^{s_{min}}$) and maximum ($p_{i,t}^{s_{max}}$) amount of power that the ith single bid is willing to sell. The binary variable $u_{i,t}$ becomes 1 when the ith single bid is selected at time interval t. Single bids can be long-term bids with pre-defined activation prices or free activation bid prices. Constraint (3) sets the minimum ($p_i^{b_{min}}$) and maximum ($p_i^{b_{max}}$) amount of power that the ith block bid is willing to sell every hour within the period $[t_{start}, t_{end}]$. The binary variable z_i becomes 1 when the block bid is selected. This binary variable does not depend on time and, therefore, the bid is fully accepted or fully rejected. Constraint (4) guarantees that the amount of activated power is the same in every time interval within the period $[t_{start}, t_{end}]$. This is a requirement for the block bids that are accepted by the market presented in this paper. Equation (5) is used to determine the cleared bids so that the cleared amount of active power satisfies the flexibility need $P_{l,t}$ for substation l at time interval t. The flexibility need is equal to the difference between the forecasted active power flow at the substation level and the substation subscription level, when the former is higher than the substation subscription level. If the submitted bids do not suffice or it is not cost-effective to purchase bids to remove subscription level violation (due to the high unit price of the bids), the excess of active power above the subscription level, $A_{l,t}$, is calculated. $a_{i,l}$ is the impact factor of the ith bid to the active power flow of the lth substation and indicates the incremental change in real power flow of the lth substation due to the activation of 1 MW flexibility of the ith bid. Impact factors take values between 0 and 1, and their value depends on the connection point of the FSP submitting the bid. The factors used in the demonstration campaign have been calculated in the planning phase and are static, i.e., they are not adapted to the current system state, but they do depend in reality. The dynamic calculation of impact factors would require third parties' access to system parameters that are classified information in Sweden due to security reasons. To ensure that the static impact factors are relevant for the problem to be solved, they have been calculated based on the winter peak load scenario when the subscription level violations are expected to occur.

By adding the excess of active power above the subscription level, the feasibility of the optimization problem is guaranteed. If there are not enough bids to meet the required flexibility, the problem would not be infeasible, as the excess of active power above the subscription level is allowed. Constraint (6) guarantees that $A_{l,t}$ obtains values equal or higher than zero.

Network constraints, such as line capacity and voltage limits are not considered in the market algorithm. Although, in theory, congestions and voltage limit violations can occur with the activation of the flexibility, this is not the case of the Swedish implementation presented in this paper. In the market planning stage, network analysis was used to prove that the activation of flexibility would not lead to violations of network constraints, as there is adequate network capacity, and, thus, the relevant constraints have not been added to the optimization problem. Their inclusion would have resulted in a problem of greater complexity [41] without adding any value to the demonstration.

To include line congestion constraints (over all, or over a subset of lines) in the formulation, the relevant impact factors indicating the effects of activation of any flexibility in the system–not only on the flow over the interconnection points but also on the flow over every line within the grid–would have been used. These constraints should have been determined through a network analysis during the market planning stage for that market, to determine the required constraints which should be included in the market clearing algorithm.

The presented market is intended for solving congestions, particularly focusing on alleviating violations of subscription at the interconnecting substations' levels. The subscription level is violated when, in order to meet the demand connected to the distribution system, the power transferred through the substations between the transmission and distribution systems is higher than the subscription level of each substation. Therefore, the problem is solved when the power transferred from the transmission to the distribution system is reduced. This is achieved by either increasing the generation or decreasing the demand in the distribution system. If the generation in the distribution system increases or the demand decreases with the activation of the flexibility, the generation in the transmission system can then be reduced to maintain the power balance in the power system if needed, i.e., if this imbalance is not netted by other imbalances occurring at the same time.

The mathematical formulation of the ID market is similar to that of the DA market, but, in the ID market, $P_{l,t}$ is updated based on the forecasting executed within the day and on the impact that the bids already bought in the DA market have on the active power flows at the different substations.

This optimization problem results in the optimal (cost-minimizing) set of bids, which should be purchased by the DSO (local or regional) to resolve its congestions, i.e., to prevent or limit the surpassing of the subscription levels at the substations connecting that DSO to the overlaying grid. Once the optimization problem is solved, the DSOs can decide whether to follow the optimization result, or to partially activate the bids within the suggested solution. Additionally, the tool allows the DSOs to add further constraints to the problem, such as the maximum unit price of the bids. Furthermore, the DSOs can

change the parameters of the problem. For instance, the DSOs can change the value of the parameter $P_{l,t}$, if they consider that, at a certain time instant, the values provided by the forecasting tool may not provide an adequate representation.

The flexibility markets follow a first-come first-served principle, to prioritise the access of the DSOs to the submitted bids. In other words, in case both DSOs (regional and local) aim to purchase flexibility to eliminate potential subscription level violations, and a bid is present in both solutions provided by the market algorithm, the DSO who has earlier declared its intention to buy that bid would be the one purchasing first. This means that if one DSO purchases a bid, this bid is no longer available for the other DSO. Nonetheless, a bid purchased by one DSO can benefit the need of another DSO, providing value stacking for the purchased bids. For example, a local DSO, by purchasing bids that end up reducing its aggregated load, can also result in the decrease of the load of a regional DSO. This will also result in a decrease in the flows over this regional DSO's connection points with the TSO. We note here that, even under this value stacking principle, the DSO who purchases a bid would be fully accountable for the costs of that bid.

IV. CASE RESULTS

As described in Section III-B, the field demonstrations for TSO-DSO-Customer coordination in CoordiNet developed from an initial design of flexibility products, services, and market schemes (see Section II) to a productive environment. The markets are active from November to March when electricity consumption is the highest in the grid due to an increased need for electrically powered heating. While the markets are open to generation (controllable and non-controllable with storage) units too, almost all flexibility comes from consumers, as there is only a small amount of generation in the congested grid areas.

TABLE I
DETAILED OVERVIEW OF COORDINET SWEDISH DEMONSTRATIONS DURING THE WINTER 2020-2021

FLEXIBILITY MARKET	SKÅNE	GOTLAND	UPPLAND
Period	Nov '20 - Mar '21	Dec'20 - Mar '21	Nov '20 - Mar '21
Local markets	DA/ID	DA/P2P	DA/ID
Flexibility providers	9	4	11
Resources	11	4	18 +340 houses (aggregator)
Contracted flexibility [MW]	120	24	243
Hours with accepted bids	35	39	412
Days with accepted bids	16	12	41
Average price [SEK/MWh]	1,503	1,610	235
Volume cleared [MWh]	122	82	6,596

The modular design allows to further adapt the initial scheme with new findings from the demo runs during the different project phases and activities beyond the project scope. The case results of the second demo run emerge from an intensive customer engagement effort, adaptation of remuneration concepts and particular easing of pre-qualification processes over two demonstration periods (in the winter 2019/2020 and the winter 2020/2021) to allow a fast

uptake and utilization of the flexibility market, both from the FSP and the DSO point of view. Based on these efforts, in total 3 local flexibility markets with in total 24 FSPs and 6,800 MWh of cleared flexibility bids in the regions Skåne, Uppland (Uppsala) and Gotland (see Table I) were part of the demonstration run in the period from November 2020 to March 2021. The regional DSOs in Skåne and Uppland region could trade both in an ID and a DA market. The local DSO in Gotland could request for bids via the DA market. In parallel, in Gotland, a local peer-to-peer (P2P) market was established to allow active grid customers to offer peers in the same grid section flexibility options during times in which the local grid experiences congestion. Since the P2P market operation was a small-scale demonstration only, including a preliminary demonstration and testing of the blockchain technology, this work focuses on the DA and ID flexibility market activities, which are in a more mature state.

In particular, the developed regional and local flexibility market offers options for adhering to the subscription limit in high demand situations, i.e., as described earlier, in the case of Sweden, extreme winter days. Thus, a comparison between the encountered cost for the flexibility solution and the actual subscription cost in the winter periods is of particular interest.

The demonstration area with the highest activity in terms of cleared flexibility volume is Uppland. The flexibility purchased for one day when the subscription level was not surpassed is shown in Fig. 5 (left) and for another day when the subscription level was surpassed due to insufficient volumes of flexibility bids (right). The full realised market activity is presented in Table II (both the first and second winter) and in Fig. 6 (for the first demo run). The numbers underline that, within one year, more FSPs and higher volumes of flexibility were achieved.

TABLE II
THE DEVELOPMENT OF THE FLEXIBILITY MARKET IN UPPLAND FROM THE FIRST TRIAL IN 2019 TO THE SECOND WINTER IN 2020

DESCRIPTION	UNIT	Demo '19-'20	Demo '20-'21
Number of FSPs bidding		5	11
Number of resources (aggregators summed to one resource)		9	19
Number of transactions		196	538
Hours of purchased flex	Hours	172	412
Duration of congestion <u>without</u> flexibility coordination	Hours	97	270
Summed duration of congestion <u>after</u> flexibility coordination	Hours	29	179
Summed necessary temporary capacity	MWh	1,470	4,060
Cost* <u>without</u> flexibility coordination	kSEK	12,880	15,229
Total cost for flexibility purchase	kSEK	717	1,558
Average flexibility cost	SEK/ MWh	220	235
Contracted flexibility	MW	96	243
Volume of cleared transactions	MWh	3,260	6,596
Hours with transaction (some hours have multiple FSP providing flex)	Hours	172	412
Days with transaction (out of 130 days market open)	Days	16	41

*The cost incurred upon subscription violation, if temporary option is denied by the TSO. This cost is not the important business case. The TSO can deny the DSO to go over the subscription level.
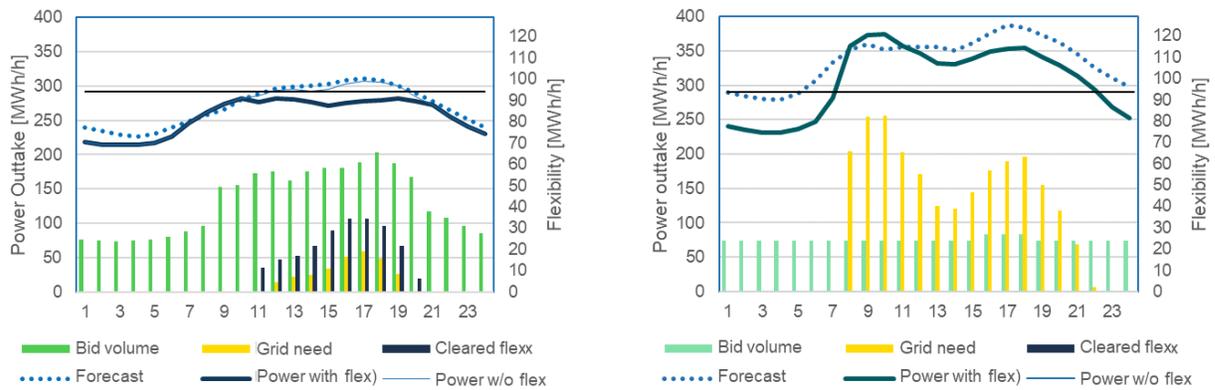
Fig. 5. Example of two market days in Uppsala. Left a day with good forecast and sufficient bids on the market. Right a day with less accurate forecast and insufficient volume of bids available on the market (these bids were not cleared on this day due to high price that surpassed TSO cost for subscription violation).
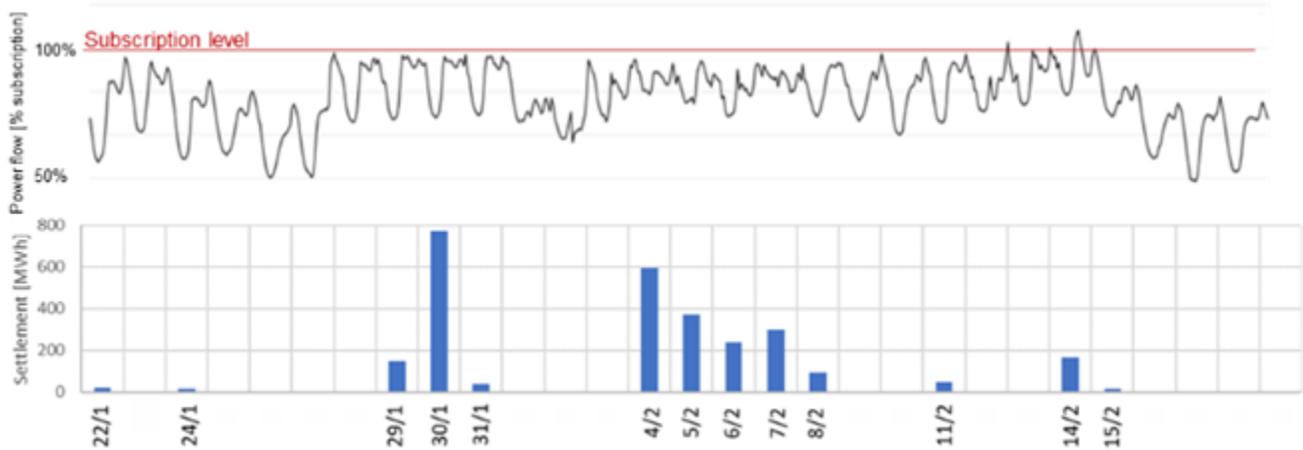

Fig. 6. Measured sum of power flow at the two regional DSO and TSO connection points (top) and cleared volume of flexibility in Uppland (bottom graph) for the period from 22nd January to 19th of February 2020. (Flexibility amounts to 1/5 of subscription level).

The characteristics of the Uppland market framework are further detailed in the following to clarify how to interpret these numbers. Two substations together amount to a subscription level, i.e., maximum residual load, of 292 MW for the region. Each substation has its own agreed annual subscription limit, whose values are 205 MW and 87 MW. Flexible resources connected to the underlying grid impact the two substations differently, depending on their geographical location and electrical connection (as described in Section III-C). Upon forecasted congestion in one or both substations, bids are collected for congestion management services. The activated bids are determined according to the optimization problem presented in Section III-C.2. As described in Section III-A, the fixed subscription cost varies depending on the location of the substations in the distribution grid and the temporary subscription cost depends on the duration of the congestion.

In the Uppland flexibility market, which was in operation for 130 days, 6,596 MWh of flexibility was cleared on 41 days and 412 hours. In total, 538 bids were accepted at an average price of 235 SEK/MWh. The reduction to 179 hours for the two substations was realised with flexibility options through the regional DA and ID flexibility market, plus the bilateral contracted flexibilities of SGUs. If high price flexibility services had been purchased, potentially all but 25 hours of subscription violations (see Fig. 7) might have been avoided.
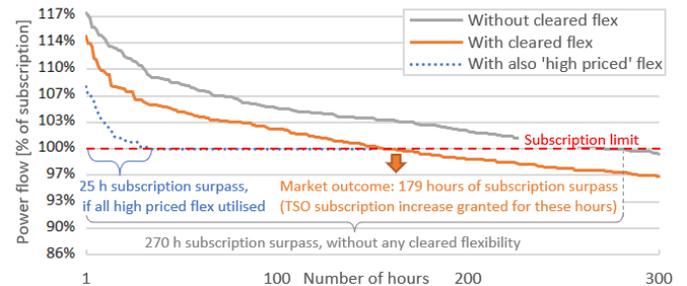

Fig. 7. Duration curve showing potential congestion relief, using all bided and potential flexibility (seconds trial run, winter 2021/2022).

The reason for not using all available bids was that the cost for some flexibility resources (referred to as 'high priced' flex) was higher than the temporary subscription (see Section III-A).

In the presented demonstration, the days of transactions and the contracted flexibility are limited to the grid needs dependent on the severity of local meteorological conditions. With fewer local energy production and higher electric demand in severe, cold winters, the probability of being denied temporary subscriptions increases. Based on the uncertainty in planning these occurrences, the expected revenues for FSPs remain uncertain as well. Thus, remuneration of dispatch (=energy only) might not be sufficient to compensate the cost to participate to the flexibility market. Through discussions with regulatory bodies, FSPs and municipalities within the

CoordiNet forum and bilateral customer engagement meetings, the DSOs developed a careful design for the remuneration concept of flexibility availability. The resulting design includes not only energy-only products but also mixed forms with capacity remuneration, on a seasonal contracting horizon or shorter-term weekly contracting horizon.

Weekly bidding processes are designed in which FSPs should guarantee availability during peak-load hours determined by the DSO for the following week only. The intention behind this is to give FSPs more flexibility in the planning, not only in their product schedules but also in their requested price.

When combining local flexibility markets for congestion management and mFRR ancillary services, i.e., the multi-level market mechanism, FSPs can benefit not only from the flexibility market compensation but also from trades in the balancing market. The clearing price, the FSP's operational expenditures, as well as the FSP's bidding strategy can differ from provider to provider and from time to time. In consequence, potential revenues will vary significantly. However, a concluding quantification of potential revenues from a hybrid capacity and energy remuneration goes beyond the presented study. While future work could elaborate further on this question, we refer the reader to a first brief numerical study with two different bidding strategies based on the Nord Pool market data from 2020 to 2021 [42].

Without a guarantee that this business will be maintained beyond the demonstration, many FSPs are discouraged from investing and committing in the flexibility market.

The results indicate that more flexibility could be utilised for system services, e.g., congestion management purposes, if the flexibility bid costs were lower, or the regulated subscription costs were higher. Another option could be to incentivise an early reaction of the DSOs to purchase flexibilities in advance to mitigate any congestion risks, as the TSO can always reject a request for temporary subscription.

V. LESSONS LEARNED

The Swedish demonstrator has implemented a large-scale, real-world implementation of a flexibility market, by inviting FSPs to prequalify for providing flexibility in each of the winter seasons. Seven large-scale events with stakeholders were organised and a continuous dialogue with FSPs is set up by means of surveys. Together with the main contributions of this paper, i.e., extending and customizing the dedicated coordination schemes, re-defining roles and responsibilities, seamlessly integrating new products in an existing market framework and developing necessary tools in this context, we obtained several lessons learned, as described below.

Engagement between stakeholders is a key factor for the success of flexibility markets. The dialogue between DSOs and the TSO created new values in understanding and developing tools and processes for better coordination and efficient grid usage. This dialogue has involved FSPs, including aggregators and assets owners, to understand their needs, motivations and barriers, and to co-create solutions.

The flexibility needs in the DSOs markets vary heavily from year to year, due to factors such as weather and new investments in the grid.

Availability remuneration is a mitigation measure to guarantee enough flexibility volume on the market. The availability payments contribute to providing certainty to FSPs that they will recover both the costs on investments in new process development and necessary infrastructure, and the continuous cost for placing bids and dispatching. A market with only activation bids, at the early stage of market development, is insufficient for many customers and aggregators to invest and become FSPs. Availability remuneration could provide DSOs certainty that the flexibility will be accessible when most required. A key challenge of this market is finding a balance between availability and activation remuneration.

It is important to set technical requirements in such a way that they do not pose a barrier for customer participation. During prequalification, the legal treatment of metering data, baseline agreements and locational information of aggregated resources requires a significant effort by DSOs and FSPs, creating a barrier to participation for aggregators. Determining an extremely accurate baseline and measurement can entail a high cost and financial risk for FSPs. The monitoring of the grid status, reliable energy schedules and metering data from SGUs are critical to achieve high accuracy forecasting and to make the right decision about flexibility needs. For monitoring purposes, it is important to have real-time data and production plans, but the accuracy of that data is less critical. From the demonstrator experience and stakeholder dialogue, there is no consensus on the metering data source, either from DSOs or from FSPs. In addition, stricter prequalification criteria for the mFRR market compared with the prequalification criteria for the local flexibility market was a barrier to participate in both. Therefore, we suggest a balance which ensures a secured operation of the system without forcing excessive entry barriers.

The timing of the market is key. A close consideration of proper GCT coordination with other markets could allow using flexibility wherever it creates more value (e.g., local or regional) and to forward bids to the mFRR market. Timing is also particularly critical for FSPs, as some can only take part on a DA basis, e.g., industries and district heating. Other flexibility providers prefer to provide flexibility closer to delivery hours, e.g., aggregators or other FSPs using technologies such as energy storage systems. Therefore, to unlock the flexibility potential, both a DA and an ID market are indispensable.

Finally, CoordiNet has contributed with a series of initiatives in Sweden related to flexibility market implementation related to grid data collection, time coordination between markets, product specifications and system architecture, such as the flexibility market in the greater Stockholm region: sthlmflex [18], a Common Information Model [43], and a Swedish flexibility product catalogue launched in 2021 [44]. Despite the specific characteristics of the Sweden power system regarding the subscription level, these lessons learned can be easily applied to other EU Member States when considering the use of flexibility to support system operation.

VI. Conclusion

The Swedish CoordiNet demonstration revealed a more dynamic and digitalised way for DSOs to leverage flexibility for the operation of the network. It has been proven that using flexibility can successfully alleviate network congestions, if market liquidity is high enough. The project developed abilities and tools needed for the newly developed flexibility markets. These involve demand forecasting, product and prequalification criteria, baseline methodologies, business models, and time coordination with other markets. The results of the implemented demonstration show that the use of flexibility can reduce system costs while keeping a secure operation.

The dialogue between DSOs, customers and FSPs (including aggregators) has been active, resulting in mutual understanding on how to utilise flexibility in local and regional markets. TSO-DSO coordination has been a catalyser for new cooperation and innovation, resulting in several activities and contributing to enhance the Swedish market structure for flexibility services.

VII. Acknowledgment

VIII. References

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