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Innovation Action

INTERRFACE

TSO-DSO-Consumer INTERFACE aRchitecture to provide innovative Grid Services for an efficient power system

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D3.2 Definition of new/changing requirements for Market Designs

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List of Abbreviations

aFRR	automatic Frequency Restoration Reserve
AOF	Activation Optimisation Function
ASM	Active System Management Report by ENTSO-E
BEGCT	Balancing Energy Gate Closure Time
BMG	Brooklyn Microgrid
BRP	Balancing Responsible Parties
BSCCo	Balancing and Settlement Code companies
BSP	Balancing Service Providers
CACM GL	Capacity Allocation & Congestion Management Guideline
CFP	Common Flexibility Platform
CHP	Combined Heat and Power (Cogeneration)
CM	Congestion management
CMOL	Common Merit Order List
CRP	Conditional Reprofiling
DA	Day-Ahead Market
DACF	Day Ahead Congestion Forecast
DER	Distributed Energy Resources
DSO	Distribution System operator

DSP	Distribution System Platforms
EB GL	Electricity Balancing Guideline
EPAD	Electricity Price Area Differential
ERPS	Enhanced Reactive Power Service
ETPA	Electricity Trading Platform Amsterdam
EV	Electric Vehicle
FCA GL	Forward Capacity Allocation Guideline
FCR	Frequency Containment Reserves
FFR	Fast Frequency Reserves
FRT	Fault-ride Through
FSMO	Flexibility Services Market Operator
FSP	Flexibility Service Provider
GCT	Gate Closure Time
IACMS	Integrated Asset Condition Management System
ICT	Information and Communication Technology
ID	Intraday Market
IDCONS	Intraday Congestion Spread
IEGSA	Interoperable pan-European Grid Services Architecture

ISO	Independent System Operator
ISP	Imbalance Settlement Period
ISR	Imbalance Settlement Responsible
JAO	Joint Allocation Office
LEM	Local Energy Markets
LFC	Load Frequency Control
LFM	Local Flexibility Markets
MARI	Manually Activated Reserves Initiative
MCO	Market Coupling Operator
mFRR	manual Frequency Restoration Reserve
MOL	Merit Order List
NEMOs	Nominated Electricity Market Operators
NFS	Network Flex Study
NRA	National Regulation Authority
ORPS	Obligatory Reactive Power Service
P2P	Peer-to-Peer
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation

pp	powerpeers network
PQP	PreQualified Flexibility Power
PTDF	Power Transfer Distribution Factors
PV	Photovoltaics
PX	Power Exchange
RES	Renewable Energy Sources
REV	Reforming the Energy Vision
RR	Replacement Reserves
sC	sonnenCommunity
SO	System Operator
SO GL	Guideline on System Operation
SRP	Scheduled Reprofiling
TERRE	Trans-European Replacement Reserves Exchange
TNO	Transmission Network Owner
ToE	Transfer of Energy
TSO	Transmission System Operator
UKPN	UK Power Networks
VPP	Virtual Power Plant

Executive Summary

The interconnected European power system is confronted with numerous challenges within the next decade. The analysis of changes and developments within the energy landscape shows that these changes and developments can often be traced back to four main drivers, which are Decarbonisation, Decentralisation, Digitalisation and Democratization (the 4Ds). The transition towards a carbon-neutral economy is mainly based on the vast increase of renewable energy sources. This trend is accompanied by the decentralization of generation, an increased electrification of different sectors and the emerging digitalization. For the first time, digitalization empowers a large number of small customers to contribute to the challenges of the power system.

To address these trends and changes, the INTERRFACE project aims to design new services and markets in order to capture the effects of evolving energy markets and services and to ensure the participation of all service providers. Following D2.2 and D2.3 this report describes the results of the market design phase of potential new markets for services described in D3.1.

Taking into account these trends, the importance of markets for ancillary services and especially for congestion management markets is expected to rise. Furthermore, the rising interest of small consumers and producers to participate in the markets and to trade electricity locally while maintaining independence might lead to new local market concepts. Therefore, the analysis conducted in T3.2 of the INTERRFACE project focusses on these markets.

Taking into account the Active System Management Report by ENTSO-E, this report defines and describes different market options. The options are classified according to the level of integration between congestion management markets and other markets and the level of integration between TSOs and DSOs. Based on this classification, a detailed analysis of congestion management markets showed that depending on the markets' purpose a suitable market option needs to be chosen.

The analysis of congestion management markets which are separated from other markets shows that this approach is most likely the favourable approach for DSOs taking into account that it can be easily applied and it can be tailored to the needs of DSOs. In contrast to this, a combination of congestion management markets with balancing markets can increase the participation on those markets but at the same time, jeopardizes an easy and efficient procurement of balancing energy. Both concepts showed that splitting up congestion management markets into short-term and operational congestion management markets as described in D3.1 seems to be a reasonable approach to tackle the differences between both services. Differences occur in the exact set-up of those markets in terms of timing and product design.

Besides defining market designs for various markets a special focus of this document is set to the common processes like prequalification and settlement which will be facilitated by the introduction of a flexibility resource register which is expected to be one of the core functionalities of the Interoperable Pan-European Grid Services Architecture platform developed in the project.

The developed market designs act as the blueprint for the implementation of different markets in the demonstration projects, by which the developed market designs will be tested in reality. For this purpose, the results of this task will be utilized by the following task 3.3 and the following work package 4 for setting up the Interoperable Pan-European Grid Services Architecture platform ensuring a seamless operation of all demonstration projects and serving as a common platform for the future electricity system.

1 Introduction

1.1 Background

The interconnected European power system is confronted with numerous challenges within the next decade. The transition towards a carbon-neutral economy is mainly based on the vast increase of renewable energy sources. This trend is accompanied by the decentralization of generation, an increased electrification of different sectors, and the emerging digitalization. For the first time, digitalization empowers a large number of small customers to contribute to these challenges of the power system. As illustrated in D2.1 of the INTERRFACE project, an increased active participation of all grid users on the market is expected in the future. To facilitate the potential of small customers while maintaining the potential of all other customers, an easy access to various markets is especially important. Going along with this phenomenon the coordination between TSOs and DSOs becomes significantly more important due to the larger share of customers connected to DSOs but taking part on DSO and TSO markets. Besides the integration of decentralized energy resources into markets on TSO level, different markets on DSO level are expected to emerge in the future.

Direct consequences of these trends are also addressed within the Clean Energy Package of the European Union, which was formally adopted in May 2019. With this legislative package, the EU set the basis for a climate and energy framework for 2030 by, amongst others, amending the existing electricity directive and introducing a new electricity regulation.

To address these trends and changes, the INTERRFACE project aims to design new services and markets in order to capture the effects of evolving energy markets and services using state of the art and new digital technologies and to ensure the participation of all potential service providers. Following D2.2, that analysed existing tools and services, the INTERRFACE deliverable D3.1 aims to describe the evolvement of services within the power system. The deliverable D3.1, as INTERRFACE demonstrations core services, is the foundation for the following market design of potential new markets. The different implementations of the demonstration projects are taken into account while setting the focus of this task to services illustrated in the INTERRFACE project.

In this document the results of the market design phase are presented. Therefore, and based on the status quo of the European power market landscape presented in D2.3, the occurring challenges and their implications for markets will be presented. Taking into account the regulatory framework in the electricity sector which has been described in D2.4, potential new markets and their designs are evaluated. The market designs have to be aligned with the INTERRFACE strategic objectives of linking wholesale and retail markets to allow all electricity market players to trade and procure energy services in a transparent, non-discriminatory way. Furthermore, this deliverable D3.2 provides first insights into the definition of standardised products, key parameters and the prequalification and settlement process for energy services. Thereby, this definition always takes into consideration the market liquidity for all services. Based on this analysis, the succeeding work packages within the INTERRFACE project will be able to use the generalized market structures as a blueprint for implementation of the Interoperable pan-European Grid Services Architecture (IEGSA) platform which will be described in D3.3. Besides this aspect, other work packages will evaluate the necessary regulations to enable the proposed market structures. The demonstration projects in work packages 5 to 7 will be able to utilize these results while implementing their specific market concepts.

1.2 Report structure

In order to identify potential new markets and necessary adaptions of existing markets, several methodical steps are performed which are described in chapter 2. The second chapter focuses on the detailed description of steps that were followed to derive the results described in this deliverable D3.2 within the INTERRFACE project period.

To identify the need for new market based solutions, the upcoming challenges for the power system are anticipated in chapter 3.1. This high level description aims for a classification of different mega trends which are currently discussed within the field of power economics. This is followed by an analysis of the impacts of these changes on today's market structures within chapter 3.2. Subsequently, and based on the prior analysis and the findings within D3.1, necessary adaptions of existing markets and likely new markets are described within chapter 3.3.

Following the top-down identification of possible new markets chapter 4 provides an overview of the different demonstration projects and first approaches on the definition of markets that they want to show in their demonstrations. The results from this comparison have been taken into account to define the markets that will be analysed in detail in the following chapters.

The identified new and adapted market structures will be analysed in detail within chapter 5 and 0. The structure of both chapters will be explained in detail in chapter 2. The different markets taken into account here are analysed with respect to a general description of the market, the different actors on the markets as well as the structure of market processes. Another important topic that will be tackled is the TSO/DSO coordination scheme in the different markets.

Within the whole report references to the demonstration projects in the INTERRFACE project are provided, to ensure consistency within the whole consortium.

In the end, chapter 7 provides an overview of the most important results and conclusions of this report.

2 Methodological Overview

The development of possible new market structures and adaptions in the existing market structure in the INTERRFACE project followed a top-down and bottom-up process in order to facilitate a standardized way of describing necessary market designs while at the same time taking into account the needs of the demonstration projects.

These top-down and bottom-up processes are visible in the way of identifying the markets that were analysed in detail in the INTERRFACE project and within this deliverable. The top-down approach (compare chapter 3), shown in Figure 1, started with the identification of anticipated, upcoming challenges for the power system in chapter 3.1. This high level description aimed for a classification of different mega trends which are currently discussed within the field of power economics. This is followed by an analysis of the impacts of these changes on today's market structures within chapter 3.2. Subsequently, and based on the prior analysis and the findings within D3.1, necessary adaptions of existing markets and likely new markets are described within chapter 3.3.

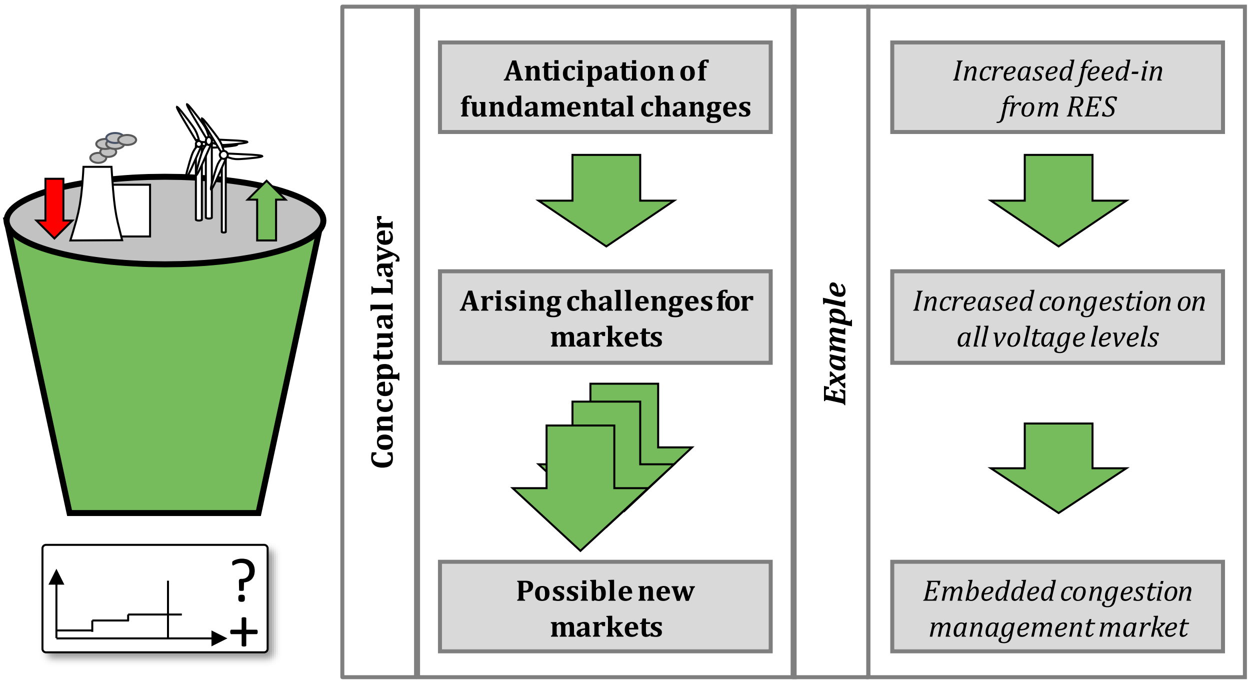

Figure 1: Top-down approach for analysing new market structures

Based on the results of this top-down process the question arose which of these markets should be investigated in detail. In order to answer this question, a questionnaire amongst the demonstration projects leaders was conducted to find the most relevant markets for the INTERRFACE project. Taking into account the demonstration projects preferences and the target period of the INTERRFACE project the most relevant markets were selected. To reflect these different markets, three WP3 visions (compare Figure 2) were created in order to reflect the different approaches. These visions were:

- *Vision 1 "Business-as-usual + flexibility market"*: In this vision wholesale and balancing markets as well as retail markets and markets for non-frequency ancillary [1]services are expected to remain similar to today, while additional markets for congestion management are introduced.
- *Vision 2 "Single Flexibility Market"*: In this vision derivatives, retail and non-frequency ancillary services market remain unchanged while balancing, intraday and congestion management markets are combined into one single market.
- *Vision 3 "Decentralized concept"*: This vision was supposed to reflect the increasing willingness of end-consumers to participate in the electrical supply by engaging into electricity markets. For this purpose local electricity markets are set up.

<table>
<tr><th></th><th colspan="3">WP3 visions</th></tr>
<tr><th></th><th>Business-as-usual + Flexibility Market (1)</th><th>Single Flexibility Market (2)</th><th>Decentralized concept (3)</th></tr>
<tr><td>Derivatives Market</td><td colspan="3">Out of Scope (Remain unchanged)</td></tr>
<tr><td>Day-Ahead Market</td><td colspan="2">General structure remains unchanged
Further Harmonization
Changes possible (Bidding zone configuration, Minimum bid size, Gate-closure-times,…)</td><td>Out of Scope</td></tr>
<tr><td>Intraday Market</td><td>Ongoing Harmonization
Minor adjustments expected</td><td rowspan="3">Integration of Balancing, Congestion-Management and Intraday Markets</td><td>Peer-to-Peer market for electricity exchange</td></tr>
<tr><td>Balancing</td><td>Ongoing Harmonization
Minor adjustments expected</td><td>Out of Scope</td></tr>
<tr><td>Congestion-Management</td><td>Additional market for Congestion-Management</td><td>Peer-to-Peer market for congestion-management on local level</td></tr>
<tr><td>Retail markets</td><td colspan="2">Out of scope</td><td>Peer-to-Peer market for electricity exchange</td></tr>
<tr><td>Non-frequency ancillary services</td><td colspan="3">Out of Scope (Remain unchanged)</td></tr>
</table>

Figure 2: Different WP3 visions

As visions 1 and 2 differ mostly in terms of integration of the markets a more detailed analysis of different levels of market integration in terms of TSO/DSO integration as well as market integration was conducted in the next steps.

[1] Non-frequency ancillary services as defined in Article 2 of Directive (EU) 2019/944

Taking into account WP3 visions focussing on ancillary services, it becomes clear, that vision 1 and 2 differ in terms of market integration for different ancillary services and the integration of TSOs and DSOs. Starting from CM-markets, these differences can be classified according to Table 1 into different market options. This concept was initially mentioned in the ASM-report by ENTSO-E and was further elaborated in the INTERRFACE project.

Table 1: Market Options

	CM separated from other markets	CM combined with other markets over subset or by overlapping MOLs	CM fully integrated in other markets
TSO	1A	1B	1C
DSO	1A	---	---
TSO & DSO Combined by subset or overlapping	2A	3A	3B
TSO & DSO fully integrated	2B	3C	3D

The market options can be classified according to the level of integration of different markets, which is illustrated by the different columns. Starting from separated markets, meaning that bids are only used on one of the markets, up to a fully integrated market with only one common Merit Order List, all different variations are possible. Nowadays, many pilot projects are working on a combination of CM- and other markets by sharing parts of the bids and adding them on two or more Merit Order Lists of different markets. The same classification can be carried out for the combination of TSOs and DSOs on these markets. Starting from completely separated markets, where the TSO/DSO coordination necessarily needs to take place outside of the market up to integrated markets where TSOs and DSOs can access the same bids on the same Merit Order List.

To align the top-down approach of selecting different markets for an in-depth analysis a survey of demonstration projects followed. This bottom-up process aimed to identify the markets that will be represented by the demonstration projects and to understand the fundamental basics that demonstration projects foresee. In order to be able to compare the different ideas of the demonstration projects, sequence diagrams were chosen as a valid format. A comparison of the sequence diagrams can be found in chapter 4, while all sequence diagrams are listed in the appendix. The analysis of these sequence diagrams showed, that the markets which are covered by most demonstration projects are consistent with the WP3 visions, focusing on congestion-management and balancing markets as well as local markets.

Following the decision which markets are supposed to be analysed in this project, a definition of a framework to describe these different market designs was required. The analysis of the markets this report is focussing on follows this framework and will be carried out in each of the following subchapters of chapters 5 and 6. The framework will be based on the aspects that are shown in Figure 3.

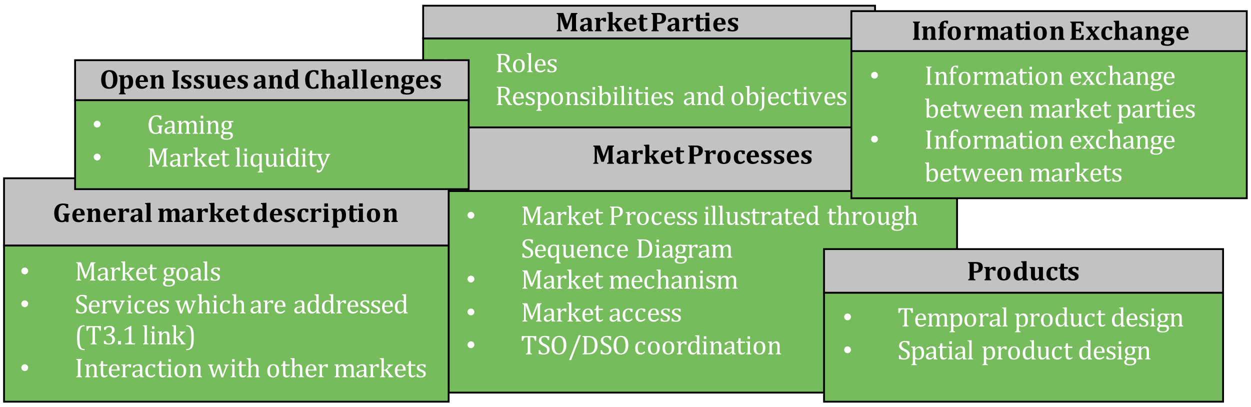

Figure 3: Market Design Framework

Each of the market design descriptions in the subchapters of chapter 5 and 0 starts with the description of the general working principle of a specific market to provide an overview of what this market is used for. This general description includes the market goals, illustrating the purpose and the idea of the market. Furthermore, this general description is supposed to identify the services that might be traded on the specific markets. With respect to the INTERRFACE project, these sections are supposed to provide a link to D3.1 which is a description of possible services. As an additional aspect of the general description of the market, the market setting was analysed. This involves information on how the described market is embedded within the existing sequence of markets and analyses possible interdependencies between markets, even though they are not directly linked. This should provide an overview whether the market is operated close to real-time, or it is a market where clearing takes place weeks before delivery.

After this general description of the market, a more detailed analysis will look at different market parties and ensures, that all market parties are well defined. Moreover, these sections will provide some insights on the individual aims of the different market parties being active on the market. Since the market parties will be very similar within different market concepts, these sections will be based on a thorough overview of possible market parties in Chapter 5.1.1. Therefore, the individual sections will highlight the differences compared to the general description only.

With clearly defined market parties, their market structure can be described in each section 3 of the different market descriptions. The market structure involves market processes as well as the market and clearing mechanism. A further aspect of the market structure is the market access, focusing on the provision of an easy access for all market parties including smaller consumers. Since many of these small market parties are connected to the distribution grid while many services are procured from TSO and DSO, a TSO/DSO coordination scheme is crucial for well-functioning markets and needs to be determined.

Central to a market and directly linked to the market mechanism and market processes is the spatial and temporal definition of products that can be traded on the described market and are further described in sections 4.

The issues and challenges associated with the market options are described in each section 5.

3 Analysis of challenges and implications

3.1 Challenges with respect to markets

The changes and development within the energy landscape are often characterized by four main drivers, which are Decarbonisation, Decentralisation, Digitalisation and Democratization (the 4Ds). The first trend is decarbonisation which generally describes efforts to reduce carbon emissions. Nowadays the most important approach is the greater usage of efficient or renewable technologies. Increasing the number of renewable energy plants is often associated with decentralisation, which foresees the paradigm shift towards are more decentralized generation stack. Especially for the installation of PV-units and onshore wind turbines this is important. The third trend digitalisation is an overarching enabler. This refers to new business models as well as being able to handle a new level of complexity. The trend of democratization leads to a higher participation of various, smaller consumer and the aligned increase of complexity.

These megatrends, which are of course not only applicable to the field of power economics, can be used to classify different developments within the power sector. Subsequently a classification of trends and developments, which raises no claim to completeness, as well the derivation of challenges will be performed for the most relevant trends.

The most prominent and most severe development is the increased diffusion with renewable energy plants which raises challenges related to the market integration as well as a successful grid integration. This trend is illustrated in Figure 4 by the development of the installed capacity of photovoltaic and wind power plants which are the two most important types of renewable energy plants.

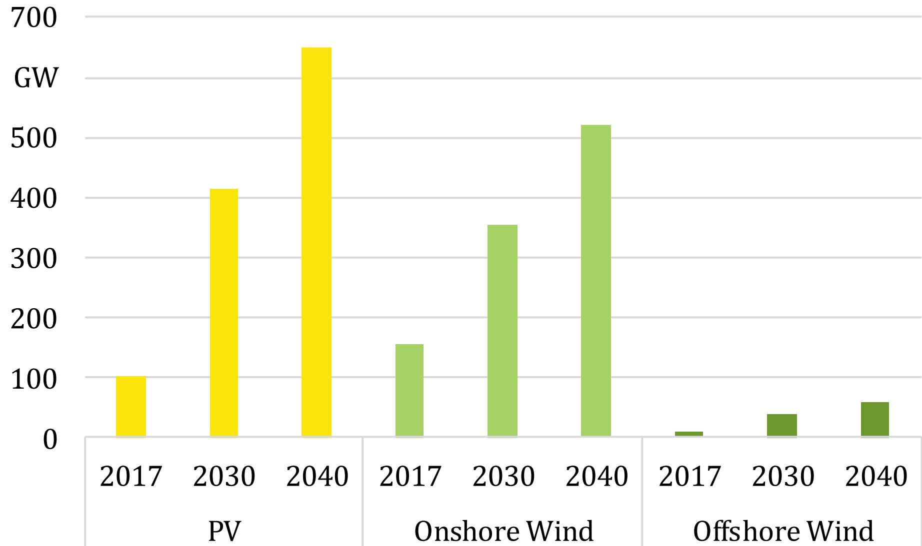

Figure 4: Development of installed onshore wind and PV capacity in Europe [2]

The generation of renewable energy plants is by nature characterized by a high dependency on the primary energy sources and in some cases for the volatile supply of these primary energy sources.

[2] Capacities from ENTSO-E factsheet for 2017 and Ten Year Network Development Plan 2020 for Scenario Distributed Energy

This immanent characteristic along with the limited predictability mark a significant paradigm shift in generation, which has been dominated by controllable power plants for centuries. This new volatility on the generation side causes an increased need for flexibility to balance the system in case of low generation from renewables. Therefore, a higher reserve need is expected. Along with a high volatility, also the occurring power ramps of wind power and PV plants increase the need of flexibility within the generation system.

Along with these technical challenges, some market-based issues arise. In times of high generation from renewables the residual load, which is defined as the delta between the load and the volatile renewable generation, can be small or even negative. This is equal to a low need of available generation capacity from conventional thermal power plants. Although, the market principle should generally be able to efficiently manage situations of scarcity (in this case a scarce demand), those situations are not easy to handle from a grid perspective since during those times high exports occur due to low prices. In addition, some conventional generation needs to remain in operation during situations of low residual loads due to stability reasons.

It should be noted, that the increasing capacity of renewable generation, has a significant impact on the grid infrastructure as well. The decentralized distribution of renewable generation confronts the existing distribution and transmission grids with challenges since they have been designed for a more centralized power supply. In order to guarantee a safe operation of the system, system operators are facing an increased need for remedial actions. The costs for these measures, which are illustrated for 2017in Figure 5, have been rising during the last years.

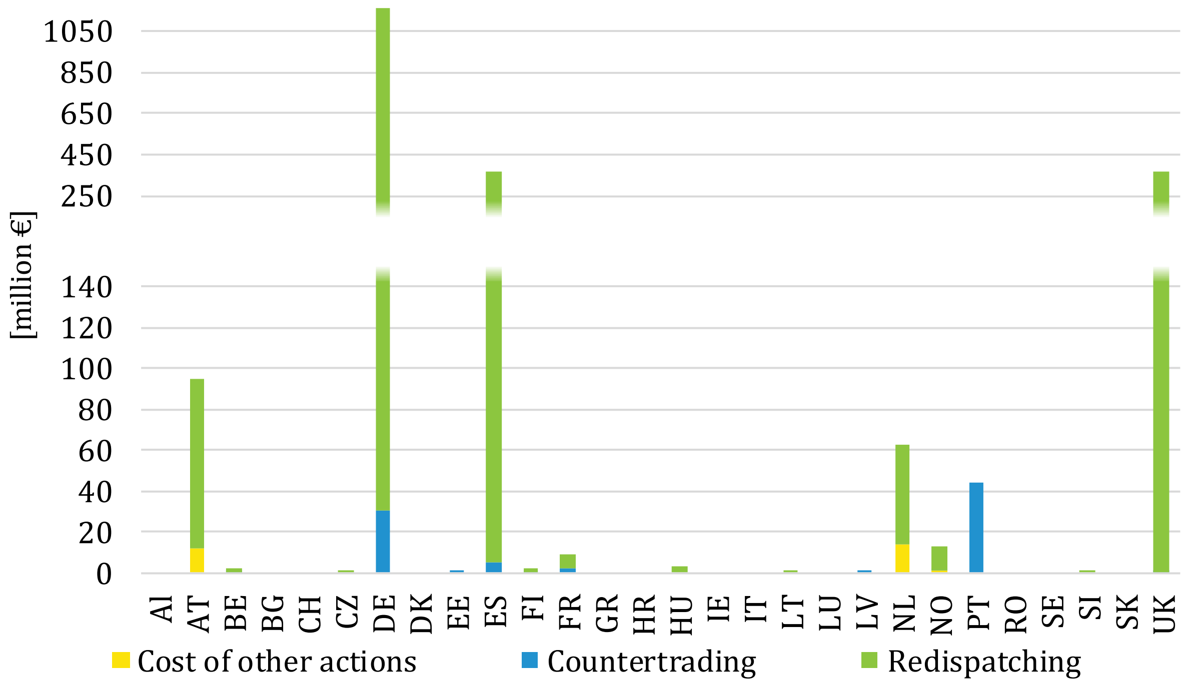

Figure 5: Costs for remedial actions in the European countries in 2017[3]

With an increased renewable generation, prices on a wholesale level are expected to decrease due to the low operational costs of renewable plants. These lowered prices lead to decreasing earnings for

[3] Source: Deliverable 2.3 or the INTERRFACE project

conventional plants. This is often referred to as the missing money problem, which means that the prices for energy within the wholesale market, doesn't reflect the value of investment in the resources which are needed to provide a reliable electricity system. The most prominent idea to overcome this issue is the idea to introduce any sort of capacity mechanism, which would also remunerate generation capacity instead of the sole delivery of energy.

This challenge is closely linked to the inverse trend of decreased thermal generation. Due to declining full load hours of thermal power plants, their business cases becomes more and more difficult. This leads to a lower secured capacity, which needs to be compensated in order to ensure security of supply. This is accompanied by the decreased availability of plants for ancillary services especially reserve power and the feed-in of reactive power. The technical challenges for renewable energies to provide ancillary services have mostly been solved. However, current legal efforts aim towards an increased integration of renewable energies also into the ancillary service market.

In addition to the comprehensive changes on the generation side, there are fundamental trends on the demand side as well. This encompasses the increasing electrification as well as sector coupling. Both approaches refer to the concept of replacing fossil fuels also in the sectors heat, industry and transport. In terms of practical appliances this refers especially to increasing numbers of electric vehicles and heat pumps which is illustrated in Figure 6.

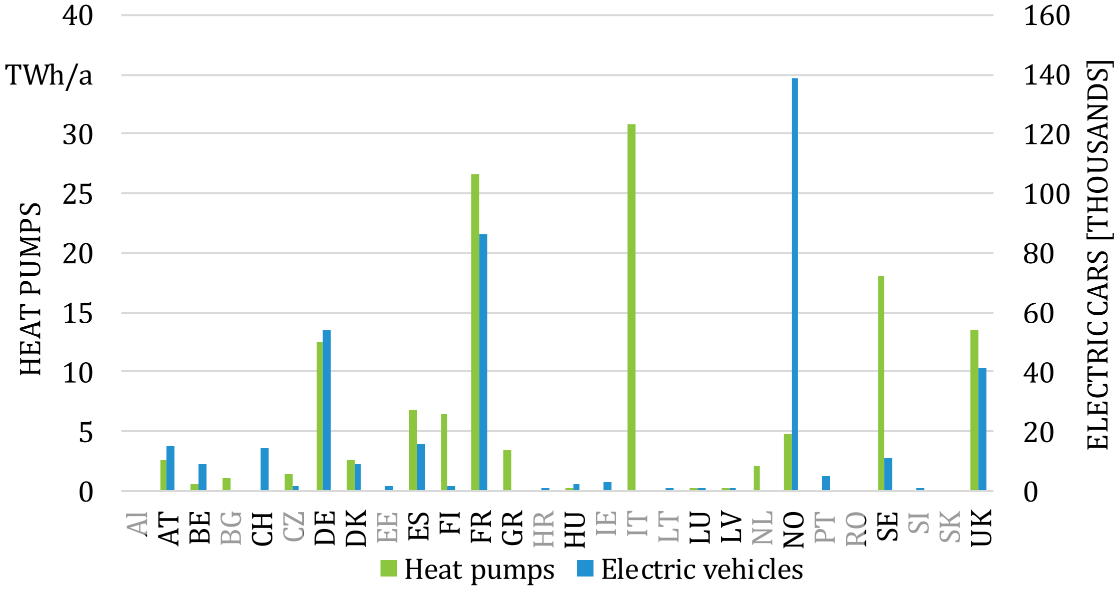

Figure 6: Number of installed electric vehicles and heat pumps in European countries in 2017[4]

From a market perspective this results in an increasing number of active consumers or prosumers which will be active on markets, which is empowered by the fourth trend of democratization. Additionally, there is a paradigm shift from static, appreciable towards new, more dynamic load patterns. Consequently, higher communication efforts with demand side appliances will be necessary in order to integrate prosumers into existing and new markets.

[4] Source: Deliverable 2.3 of the INTERRFACE project

The trend of democratization also adds a socio-economic dimension and describes the increasing participation of consumers as well as the rising public awareness within the field of power supply. From a market perspective those new players are not fully addressed by existing market structures, since those are still aligned to the needs of wholesale customers. In order to integrate small players into the market structures, removing entry barriers is a frequently discussed topic. There is a need for low-cost access solutions in order to enable new business models. This raises concerns regarding cyber security issues. In addition, the interoperability from a technical as well as a market perspective should be ensured. Therefore, a consistent market design framework is necessary to avoid inefficiencies.

3.2 Derived Implications for Markets

As described within chapter 3.1, the current market framework is confronted with fundamental trends and challenges on the road towards a carbon-free power supply. In order to meet those challenges, the existing market structures could be adapted or additional new markets might be suitable. Subsequently those two major approaches should be evaluated taking into consideration the identified challenges from chapter 3.1.

Group of Challenges: Increasing renewable energy plants and lower conventional generation

With a power supply mainly based on volatile primary energy sources, forecasting the generation is crucial in order to ensure a stable operation of the system. Since forecasts are naturally imperfect, there is an incentive to shift trading activities related to volatile renewable energy plants as close to real time as possible, in order to minimise deviations from the forecast. Within the current market framework, this is mainly done using the intraday market, which allows to balance the own position up to several minutes before real-time. A similar, even though less pronounced, trend could be identified for balancing markets (aFRR and mFRR) where gate closure times have been shifted closer to real time as well in order to allow different technologies to participate.

In addition to shorter lead-times also the structure of market based products on all markets might be subject to further changes in order to allow renewable energy plants and all other flexibility resources to participate and increase the liquidity on the markets by ensuring a sufficient number of active participants. This involves shorter product durations as well as lowered minimum bid sizes.

One regulatory instrument which has successfully been used to promote initial investments into renewable energies are feed-in tariffs. This relates to the issue that the majority of RES plants have been operated partly separated from the market with low or no motivation to be operated under consideration of market prices. In recent times the integration of feed-in tariffs that only compensate missing earnings from other markets (market premium model) become more relevant in order to guarantee that feed-in-tariffs do not create a parallel system for existing markets. With a limited duration of those feed-in tariffs, RES producers will be motivated to operate their plants in a market-oriented and efficient manner after the expiration of the governmental support. The operation of a power system with high shares of renewables which are not subsidised at all, remains a challenge and might lead to some unforeseen unwanted effects which require some adaptions of the existing market design. At the same time a higher share of unsubsidised resources can lead to a more effective balancing, since producers are incentivized to balance their portfolio due to higher price variations.

Supplemental to the adaption of the existing market design, diverse ideas regarding fundamental changes and new markets exist. In order to overcome the lack of secured capacity, different capacity mechanisms or markets are in place within Europe. These complement the existing energy-only markets.

Another field of discussion is the future procurement of frequency ancillary services. Due to the high efficiency of a market-based procurement, this will remain the best option to procure reserve power. Therefore, and as explained before, it is necessary to lower the hurdles for a market entry of renewable plants as well as refining the products of those markets to the needs of the future power system. This will ensure efficient market outcomes and a stable grid operation.

In terms of the provision of non-frequency ancillary services like feeding in reactive power, bilateral agreements with the grid operator or regulations based on the grid connection codes are in place, while in the future market-based procurement of non-frequency ancillary services might be conceivable.

A potential new market within the field of non-frequency ancillary services could be foreseen for the service of providing system inertia as Ireland has started. With a future majority of inverter-connected generation units which do not inherently provide rotational inertia, new solutions need to be found. Different technical solutions exist where flexibility resources that are connected via power electronics can be capable of providing synthetic or virtual inertia. To identify a combination of inertia providers which are associated with the lowest costs, a market similar to FCR could be used. Already today, specific products like FRR and grid restoration services are under development in different European countries.

Approaches which aim towards a more fundamental change of the existing market design are for example the ideas to implement nodal pricing. Benefits, compared to the existing zonal system, would be a more efficient dispatch while structural congestions are reflected within different market prices. However, the discussion of nodal pricing remains to be a theoretical one due to the extraordinary high costs which are related to changing the pricing scheme and the political unwillingness of changing the running system. An approach which aims for the incorporation of local price signals, which remains within the framework of zonal pricing, is the regular review and conclusively the adaption of bidding zones. Nevertheless, approaches towards fundamental changes of the existing market designs in order to take into account grid congestions into the dispatch might be possible in local energy and local flexibility markets.

A more concrete debate exists with respect to dedicated new markets for resolving congestion. This refers to setting up a new, additional or combined market place where market players can sell their operational flexibility. Possible demanders are grid operators which use the localized flexibility bids to resolve congestion. Currently, mFRR market is used for transmission congestion management inside a price zone in some European countries, and many different demonstration projects at distribution level exist which elaborate on different options to access the existing flexibility using market platforms.

Group of Challenges: Digitalization and Electrification

Also on the demand side, adapting market access rules is central to enable the participation of prosumers. This involves for example reducing the minimum bid size within different markets or the necessary effort to access them. Current minimum bid sizes for example on the day-ahead and intraday markets of EPEX-Spot are 0.1 MW, which is significantly more than small prosumers can deliver.

The market access should be embedded into a market framework, which ensures a safe operation of the grid by providing incentives for asset owners to operate their assets in a manner that is well-suited to the system. This should be an inherent characteristic of the market design. Possible approaches, which aim to ensure this compatibility, are for example time- and load-dependent grid fees. These dynamic grid tariffs can be used to incentivise a grid usage, which prevents congestion.

A potential new market, which could incorporate dynamic grid tariffs as well as addressing the rising interest in local energy supply, is a local energy market. This spatially limited market complements existing wholesale markets and allows bilateral peer-to-peer energy trading on a local level. The core concept is the consumer-centric and bottom-up perspective.

Besides local energy markets, local flexibility markets can provide flexibility for solving grid constraints or any other flexibility needs of the network- and system operator.

Another development, which is related to an increasing digitalization, is the setup of data exchange platforms or data hubs. These information platforms support market players by serving as a single point of information for e.g. meter data. Further ideas like a flexibility register with various possible designs are discussed nowadays. The most important aim of such a platform is to facilitate the integration of small customers on various markets. More information on this topic can be found in the Appendix Flexibility register concept proposal of INTERRFACE project. Integrating large numbers of prosumers into the electricity market may involve enormous communication efforts. In addition, information and cyber security are key challenges and need to be ensured in every process.

3.3 Possible Future Markets

Following the discussion of possible implications for markets within chapter 3.2 which were derived from the described challenges, the following subsection focuses on identifying potential new markets based on the service list as described in D3.1.

In general, services can be procured using different procurement schemes. The first scheme is the definition of requirements, which need to be met by assets, which are connected to the grid, within the network codes. These rules define the prerequisites for a new grid connection; this is the case for reactive power behaviour in some European countries. This type of procurement schemes is called "rule based" procurement. The second procurement scheme is a bilateral contract or connection agreement between the grid operator and the asset owner. If an asset is able to provide services (like providing black start capability) bilateral contracts between the asset owner and the grid operator define the modalities for the procurement of this service. Furthermore, grid tariffs are one possibility to incentivize specific services. In contrast to those schemes, fully market based schemes to procure services are conceivable, which are especially suitable for services that can be provided by a high number of assets (for example providing reserve power). Thereby, markets which are in place for services that need to be served locally, are confronted with a lower liquidity. In contrast to bilateral contracts, the market based approach normally consists of an organized market place which excludes the concept of bilateral contracts. A subgroup of the market based procurement schemes is the "administrative approach" which consist of restricted markets for service procurement. Within Table 2, the classification of system services from T3.1 with respect to possible procurement options is presented.

Table 2: Classification of system services according to D3.1

Market domain	Market sub-domain	Service	Procurement	Explanation	Locational Scope	User
Balancing markets	**EXISTING** **Frequency Response services**	**Frequency Containment Reserves (FCR)**	Market-based	A market-based procurement is standard due to the system-wide nature of the frequency. Therefore, no spatial restrictions regarding the provision of this service exist. In addition, a high number and variety of different assets are technically able to provide frequency response services.	Pan-EU	TSO
		automatic Frequency Restoration Reserve (aFRR)			Pan-EU with national specifics	
		manual Frequency Restoration Reserve (mFRR)			Pan-EU with national specifics	
		Replacement reserves (RR)			National level	
		Fast frequency reserves (FFR)			National level	
	NEW EMERGING	**Ramp control**	Market-based	A market-based procurement has been introduced by EirGrid.	National level	TSO

Market domain	Market sub-domain	Service	Procurement	Explanation	Locational Scope	User
	Frequency Response services	**Smoothed production**	Bilateral contract	Introduced by the TSO Statnett which pays a fixed administrative compensation as well as a variable tariff to participating assets.	National level	
Congestion management	**NEW EMERGING Intra-zonal**	**Operational**	Market-based	The efficiency of a market-based procurement of resources for congestion management is highly dependent on the nature of the congestion and the voltage level.	National level	TSO / DSO
		Short-term planning			National level	TSO / DSO
		Long term planning			National level	TSO / DSO
	Cross-border	**Redispatch**			Inter-zonal	TSO
		Countertrading			Inter-zonal	TSO
Non-frequency ancillary services	**NEW EMERGING Reactive Power and Voltage Control**	**Obligatory reactive power service (ORPS)**	Defined within Grid Code or bilateral contract	Voltage related services are usually defined within the grid codes due to the local nature of reactive power. In case of an additional provision, regulated prices are used.	National	TSO / DSO
		Enhanced reactive power service (ERPS)			National	
		Fault-ride through (FRT) capability	Defined within Grid Code	Specific to every generator	Pan-EU	
	NEW EMERGING System Restoration	**Black Start**	Bilateral Contract	Specific to the TSOs grid restauration plan. Usually selected plants receive a fixed remuneration for providing black start capabilities	National	TSO
		Islanding Operation	Defined within Grid Code	Specific to every generator	Local	TSO / DSO
	NEW EMERGING System Restoration	**Damping of power system oscillations**	Bilateral Contract	Dependent on the nature of the occurring oscillations. Usually eligible assets are contracted and remunerated with fixed tariffs.	Pan-EU	TSO
Adequacy	**NEW EMERGING Capacity Remuneration Mechanisms**	**Strategic reserve**	Market-based or bilateral contract	Currently different approaches exist within Europe which range from capacity markets to restricted capacity payments.	National	TSO

As it can be extracted from Table 2 only for some services a market-based procurement is reasonable. These services are especially within the field of frequency-ancillary services as well as congestion management. Within the procurement of frequency-ancillary services, market structures are well established whereas within the field of congestion management market-based approaches are still in the early stage. Therefore, one focus area of the following market analysis is within the field of markets for congestion management.

Besides possible new markets within the field of system services, additional new markets can be derived from the performed analysis. Thereby especially the concept of local energy markets (LEMs) will be addressed. These local market concepts empower consumers by enabling energy trading within the small scale. According to the Brooklyn Microgrid LEMs offer benefits to other stakeholders apart from customers[5]. For grid operators, LEMs could lower the need for grid expansion due to a more efficient allocation of consumption and generation. This would also decrease grid losses during daily operation. From a societal perspective, LEMs could provide better market transparency as well as a fairer allocation of systemic costs and benefits. Besides all these advantages LEMs have a couple of disadvantages at the same time. Market fragmentation reduces overall efficiency while at the same time issues about local market power can exist. Furthermore, transparency of local markets might be reduced in some cases, due to the fact that reporting for the public is not dictated. Individual prices based on the location in the grid in order to reduce needs for grid expansion might be politically unwanted, due to the fact of equality of all users.

To take into account the potential of LEMs to change the existing market structures, one concept of local energy markets will be included into the market analysis of this report. In addition, one demonstration project within the INTERRFACE project, focusses on the implementation of a local energy market.

Closely related to LEMs are local flexibility markets which are focussing on the provision of flexibility to the grid operator by enabling additional earnings for participants on those markets. These type of market needs to be clearly separated from LEMs.

[5] Brooklyn microgrid – Energy platform, https://www.brooklyn.energy/

4 Sequence Diagrams of Demonstration Projects

In order to understand the needs of the demonstration projects a thorough analysis of the different sequence diagrams has been conducted. Besides the information of the sequence diagrams even further information from prior questionnaires has been taken into account for this analysis. The sequence diagrams themselves always refer back to one market option that they are describing. A detailed explanation of those market options can be found at the very beginning of chapter 5. This section gives insights on the following issues gained during this analysis:

- Generic demonstration projects' characteristics
    - The services they implement,
    - Description of TSO-DSO coordination scheme,
    - Existence of flexibility register,
    - Actors
- Market Design
    - Market design options they follow (1A-3D),
    - Market product description,
    - Timeframe of the market,
    - Available bidding options,
    - Market clearing,
    - Market integration,
    - Communication to market participants

The following Tables provide a comparison of the demos, based on their sequence diagrams and business use cases with a focus on market design process. They provide an overview of the generic characteristics of the demonstration projects in Table 3, but the main focus is on the market design characteristics, which is shown in

Generic characteristics of the demonstration projects	
5.2	**5.3**
Congestion Management operational for TSO and DSO, mFRR for TSO, non-frequency	Congestion management operational, short-term, long-term at DSO and TSO TSO mFRR, aFRR, FCR at TSO
Coordination on CM	Coordination on CM and on Balancing as well as coordination on bid grid prequalification
Yes	Yes
TSO, DSO, Flexibility resource provider	Flexibility Service Provider, Aggregator, Balance Responsible Party, Balance Service Provider, Market Operator, Transmission System Operator, Distribution System Operator, Supplier, Billing Agent, Imbalance Settlement Responsible, Flexibility Register, TSO/DSO Coordination Platform

Generic characteristics of demonstration projects (Cont)					
7.1b	**7.2**		**5.1a**	**5.1b**	**5.1c**
Congestion management for DSO and TSO	Congestion management for DSO and TSO	**Services**	Congestion management operational for DSO	Power Quality for DSO	Congestion management operational for DSO
Coordination on CM and Balancing	Coordination on CM and ex-ante (proactive) rebalancing	**TSO-DSO coordination**	Limited Coordination	Limited Coordination	Limited Coordination
Yes	No, only some features like communication platform might be used	**Flexibility registry**	Yes	Yes	Yes
Balancing Service Provider, Transmission System Operator, Reserve Allocator, Flexibility Services Market Operator (FSMO)	Party Connected to the Grid, Balance Responsible Party, Resource Provider, Resource Aggregator, Scheduling Agent, Market Operator, TSO, DSO	**Actors**	Flexibility provider, TSO, Balancing Service Provider	DSO, Balancing Service Provider (acting also as demand aggregator), Flexibility Provider	DSO, Balancing Service Provider (acting also as demand and renewables aggregator)

	6.1	6.2	7.1a
Services	Congestion management short-term for DSO	Congestion management for TSO and DSO	FCR, mFRR, aFRR for TSO
TSO-DSO coordination	Limited Coordination	No coordination, but aggregated and remaining bids at DSO level are offered to	Limited Coordination
Flexibility registry	No, only some features like communication platform might be used	Yes	Yes
Actors	Party Connected to the Grid, Meter Data Responsible, Market Operator, DSO	Market Operator, Resource Aggregator, Resource Provider, DSO, TSO, Consumer	Balancing Service Provider, Transmission System Operator, Reserve Allocator, Flexibility Services Market Operator (FSMO)

Table 4 and Table 5. A more detailed comparison of demonstration projects is provided in INTERRFACE deliverable D3.1.

Table 3: General Characteristics of the demonstration projects

Generic characteristics of the demonstration projects					
	5.1a	**5.1b**	**5.1c**	**5.2**	**5.3**
Services	Congestion management operational for DSO	Power Quality for DSO	Congestion management operational for DSO	Congestion Management operational for TSO and DSO, mFRR for TSO, non-frequency	Congestion management operational, short-term, long-term at DSO and TSO TSO mFRR, aFRR, FCR at TSO
TSO-DSO coordination	Limited Coordination	Limited Coordination	Limited Coordination	Coordination on CM	Coordination on CM and on Balancing as well as coordination on bid grid prequalification
Flexibility registry	Yes	Yes	Yes	Yes	Yes
Actors	Flexibility provider, TSO, Balancing Service Provider	DSO, Balancing Service Provider (acting also as demand aggregator), Flexibility Provider	DSO, Balancing Service Provider (acting also as demand and renewables aggregator)	TSO, DSO, Flexibility resource provider	Flexibility Service Provider, Aggregator, Balance Responsible Party, Balance Service Provider, Market Operator, Transmission System Operator, Distribution System Operator, Supplier, Billing Agent, Imbalance Settlement Responsible, Flexibility Register, TSO/DSO Coordination Platform

Generic characteristics of demonstration projects (Cont)					
	6.1	**6.2**	**7.1a**	**7.1b**	**7.2**
Services	Congestion management short-term for DSO	Congestion management for TSO and DSO	FCR, mFRR, aFRR for TSO	Congestion management for DSO and TSO	Congestion management for DSO and TSO
TSO-DSO coordination	Limited Coordination	No coordination, but aggregated and remaining bids at DSO level are offered to	Limited Coordination	Coordination on CM and Balancing	Coordination on CM and ex-ante (proactive) rebalancing
Flexibility registry	No, only some features like communication platform might be used	Yes	Yes	Yes	No, only some features like communication platform might be used
Actors	Party Connected to the Grid, Meter Data Responsible, Market Operator, DSO	Market Operator, Resource Aggregator, Resource Provider, DSO, TSO, Consumer	Balancing Service Provider, Transmission System Operator, Reserve Allocator, Flexibility Services Market Operator (FSMO)	Balancing Service Provider, Transmission System Operator, Reserve Allocator, Flexibility Services Market Operator (FSMO)	Party Connected to the Grid, Balance Responsible Party, Resource Provider, Resource Aggregator, Scheduling Agent, Market Operator, TSO, DSO

Table 4: Market Designs of demonstration projects of WP5

Ma rke	Market design of demonstration projects of WP5					
5.3		**5.1a**	**5.1b**	**5.1c**	**5.2**	**5.3**
Con tinu ous mar ket clea ring	**Market design options**	1A for CM			1B and 1C, for CM and mFRR, 3A for non-frequency services	2A, 2B, 3A for CM
CM inte grat ed	**Market product**	Volume of generation capacity (from CHP)	Volume of demand capacity (from storage)	Volume of generation and demand capacity (from renewables, storage, CHP, EVs, flexible demand)	Volume of demand capacity and non-frequency services (from storage)	Standard mFRR product, (TSOs foresee using a linear ramp of 10 minutes for the cross-border exchange)
TSO and DS O defi ne thei r nee ds	**Timeframe of the market**	Day-ahead, Intra-day, Real-time (up to 15 minutes before activation)			Day-ahead, Intra-day	Long-term, Day-ahead, Intra-day Real-time
in a Sin gle Fle xibi lity mar	**Bidding options**	Non-priced capacity volume orders, as remuneration tariff is pre-agreed			Single priced capacity volume orders (stepwise or linear)	

	5.1a	**5.1b**	**5.1c**	**5.2**	
Market clearing	Pre-agreed tariff			Continuous market clearing at the zonal level of service request (TSO, DSO). Pre-agreed tariffs on non-frequency services.	
Market integration	CM discrete from balancing			CM discrete from balancing	
Communication to market participants	TSO or Balancing Service Provider informs the Flexibility provider for the needed service	DSO sends a signal to Flexibility service provider and to Flexibility provider to adjust their consumption	DSO requests from Flexibility service provider, acting also as demand and renewables aggregator, to adjust their consumption and/or generation, in case of high electricity production at DSO level	TSO and DSO define their service needs and Flexibility service provider (storage) provide order for meeting those needs	

Table 5: Market Designs of demonstration projects of WP6 and 7

Market design of demonstration projects of WP 6 and 7					
	6.1	**6.2**	**7.1a**	**7.1b**	**7.2**
Market design options	1A for CM short-term	1A for CM long-term	1A for CM	1A, 2A and 3A for CM	2B, 3A, 3B for CM
Market product	Volume of energy (from generation and demand grid users).	Volume of capacity (from generation and demand assets).	The minimum bid size is 1 MW from generating, demand and interconnections capacity. TSOs will allow divisible bids together with indivisible bids. Indivisible bids will have a maximum bid size of 25 MW.	The minimum bid size is 1 MW from generating, demand and interconnections capacity. TSOs will allow divisible bids together with indivisible bids. Indivisible bids will have a maximum bid size of 25 MW.	Volume of 15-min. energy from generation and demand assets and/or aggregated resources. Offers from both TSO and DSO.
Timeframe of the market	Intra-day	Intra-day Balancing	Day-ahead Day-ahead		Intra-day
Bidding options	Single priced capacity volume orders (stepwise or linear) (Note: all orders with locational information)	Single priced capacity volume orders (stepwise or linear)	Stepwise hourly orders. Block orders. Linked Block orders. Exclusive group of block orders. Flexible Hourly Orders. Complex orders (minimum income and load gradient)		Orders: - stepwise hourly - block / smart block - EUPHEMIA PUN orders (increased granularity of locational information)

Market design of demonstration projects of WP 6 and 7 (Cont)					
	6.1	**6.2**	**7.1a**	**7.1b**	**7.2**
Market clearing	Local P2P Market	P2P market at DSO level	Zonal prices		Zonal pricing (with TSO-DSO hierarchy), PUN-pricing
Market integration	CM discrete from balancing			CM integrated to balancing	CM discrete from balancing
Communication to market participants	DSO provides the grid topology information to the market platform. As a supplement to the local P2P marketplace, there will be an Integrated Asset Condition Management System (IACMS). IACMS will provide loadability limits for the P2P local market module.	DSO analyses the actual state of the distribution grid and forecast the flexibility needs, which are listed on marketplace. Marketplace communicates buyers' zones and size requirements ahead of tenders. Flexibility providers submit offers along with flexibility unit location to satisfy the corresponding services of DSO.	The TSO publishes the regional day-ahead reserve requirements (per type: FCR, aFRR, mFRR, considering individual TSO requirements and TSOs coordination). All the market participants assess their availability and create their flexibility services bids for the following day. The bids are sent to the regional Flexibility Services Market Operator (FSMO) before the gate closure date.	The regional TSO publishes the regional day-ahead reserve requirements (per type: CM, FCR, aFRR, mFRR, considering individual TSO requirements, DSO requirements and resources, TSOs and TSOS-DSOs coordination). All the market participants assess their availability and create their flexibility services (CM and balancing) bids for the following day. The CM and balancing bids are sent to the regional Flexibility Services Market Operator (FSMO)	The whole process is initiated by the market operator, with opening the order book for the bids. During the bidding process resource providers - traders, aggregators, producers and system operators – TSO, DSOs both submit their bids. System operators also provide information about available trans-mission capacity. After gate closure, the order matching begins, using a holistic mathe-matical formu-lation for optimal market outcomes, linking consumers – DSOs – TSOs.

5 Analysis of Markets for Ancillary Services

Combining the results of the top-down approach including the derivation of the three visions and the market options as well as the results of the bottom-up analysis of the sequence diagrams of the Demos the focus of the INTERRFACE project is set to congestion-management- (CM) and balancing markets as well as local energy markets. In this chapter possible markets for ancillary services, especially congestion-management and balancing markets, are described, while chapter 6 focusses on local energy markets.

Subchapter 5.1 is focussing on common actors and processes of the different market options. The further structure of this chapter follows the matrix structure of the described market options. Starting with CM-markets that are separated from other markets, subchapter 5.2 describes the possible combinations of TSO/DSO coordination within the different market options (1A, 2A and 2B). Afterwards subchapter 5.4 is focussing on combined congestion management and other markets, representing market options (1B, 3A, 3C). Market options for the full integration of congestion management markets into other markets (1C, 3B, 3D) are not taken into account in this report, because it is not expected that in the timeframe up to the next 10 years, which is the relevant timeframe from the INTERRFACE project perspective, a full integration of congestion management and other markets is going to be realized.

5.1 Common Actors and Processes

5.1.1 Market Parties

In the aforementioned markets various players are active, besides the buyers of flexibility and the parties providing flexibility various other roles exist. These roles have been described in detail in the harmonised electricity market role model of ENTSO-E, EFET, ebIX[6] (referred to as: harmonised role model) forming the basis for our discussion. The role description of the harmonised role model can be found in the Appendix of this deliverable. In the following subchapters focussing on individual markets, only deviations from these roles are described in further detail. For all other roles, the definitions according to the harmonised role model are valid. The definitions according to the harmonised role model can be found in the Appendix. One major question that comes up for all the different markets is the one about the role of the flexibility platform market operator.

Please refer to the Appendix that includes a detailed note on the Flexibility Platform Market Operator. The note consists of four sections and a wrap-up. First, a discussion of the different market operator tasks is described. Second, a description of the EU and US experience with market operator roles in different markets is provided. Third, a discussion of the pros and cons of having a network operator or a third party taking up the role of the market operator are compared. Fourth, an illustration of how the market operator role is filled in for four existing flexibility market projects in the EU and one in the US is analysed. In the following paragraphs, a short summary is provided.

First, the role of the flexibility platform market operator consists of multiple tasks that do not necessarily all have to be attributed to the same entity. Several tasks, for example collecting offers, clearing and settlement, could be more easily allocated to third parties. Other tasks, for example prequalification, validating offers and product design, could be the responsibility of network

[6] The Harmonised Electricity Market Role Model (v. 2019-01) by ENTSO-E, EFET, ebIX, available online: https://docstore.entsoe.eu/Documents/EDI/Library/HRM/Harmonised_Role_Model_2019-01.pdf

operators. For example, in some balancing markets in Europe (e.g. GB) the balancing market is operated by the TSO while the settlement of balancing energy and imbalances is done by a third party.

Second, in the EU, who takes up the role of the market operator depends on the specific market. For example, wholesale markets are operated by (third-party) power exchanges. Since the adoption of the CACM GL, power exchange organizing cross-zonal trade in the day-ahead and intraday market have been labelled Nominated Electricity Market Operators (NEMOs). The CACM GL lays out a governance framework of the market operator role in EU wholesale markets. Forward markets consist of two types of markets, namely futures markets organized by third party power exchanges and over-the-counter markets. Long-term cross-zonal capacity rights between different bidding zones are traded on the Joint Allocation Office (JAO), a service company jointly owned by multiple TSOs. Markets for ancillary services and redispatch markets, are operated directly by the TSOs in Europe. In some countries, the balancing energy and imbalance settlement task is outsourced to a third-party company. Recently, also European balancing platforms are being set up. In terms of the market operator, the Electricity Balancing Guideline (EB GL) allows two options, namely the operation 'by TSOs' and the operation 'by means of an entity created by the TSOs'. In the US and other parts of the world, the institutional setting is different. In liberalised systems in the US, forward markets are operated by competitive power exchanges or financial institutions. The Independent System Operator (ISO) is in charge of the operation of the integrated spot (day-ahead and real-time) and reserve market with nodal pricing. The ISO also auctions the financial transmission rights.

Third, three arguments in favour of having a third party as flexibility market operator are identified and one argument against. A first argument in favour is that in the case of DSOs as market operators, the know-how might not always be present in-house to build up market platforms from scratch. A second argument in favour is neutrality between buyers and sellers is ensured if the market operation function is taken up by a third party. A third argument in favour is that the platform will be monopolistic if it is operated by a network operator (DSO or TSO), while this is not necessarily the case if it is run by a third party. Note, however, that the market clearing itself will always be a monopolistic function. An argument against having a third party as a market operator is the cost of interface management between the grid operator and the market operator.

In this regard, it is important to note that the degree of integration of the flexibility market with other (existing) electricity markets has an impact on who can fulfil the market operator role. For example, in the case both DSOs and the TSO use the same platform to procure flexibility or the flexibility market is integrated in, for example, a local wholesale market, the neutrality among buyers is assured by having a third party as market operator. On the other hand and in the EU context, if the flexibility market is fully integrated with balancing, it is likely that the market operator would become the TSO as the balancing markets are operated by the TSO. If a DSO or multiple DSOs would take up the role of the flexibility market operator, this might require stronger unbundling requirements and/or an adjustment of the institutional framework.

Fourth, an analysis of different flexibility pilot projects (i.e. Piclo Flex, Enera, GOPACs and NODES) shows that different solutions currently compete for the market. Such competition is beneficial for innovation and the learning curves for the different solutions. Currently, all four platforms are operated by third parties and have a virtual monopoly position in the region they are active in. Moreover, the platforms are currently not strongly regulated. At this moment in time, it cannot be said with certainty whether competition between different flexibility platforms will be beneficial in the future. Certain is, however, that the monopolistic task of market clearing will in any case have to be carried out under cooperation. Otherwise, there is a risk that fragmentation of the market will lead

to less liquidity and reduced competition. In the US example (Reforming the Energy Vision in NY – see Appendix), six DSOs jointly operate the platform.

5.1.2 Prequalification

The prequalification process must be in place to ensure that a particular flexibility service provider is actually capable of delivering a particular product. This concerns the abilities related to both, the flexibility service provider and the flexibility resources contracted to it, on the one hand, and the grid where the resources are connected to, where the flexibility service is to be delivered to and any intermediate grid, on the other hand.

The former is ensured by product prequalification (sometimes also referred to as unit prequalification), whereby it is checked whether the flexibility service provider (FSP) fulfils the technical requirements for providing a product to a system operator. These requirements include the maximum timespan from sending the activation signal to a full activation, the accuracy of the activation (i.e., the activated amount must be within certain margins from the requested amount) and potentially other parameters depending on the particular service and its related product. The compliance of the flexibility service provider to the technical requirements can be established by performing a prequalification test, whereby an activation signal is sent to the flexibility service provider's assets during normal operating conditions.

In terms of flexibility service provision, it is important to note that in large part currently the most untapped potential of flexibility resources lies in small units which require aggregation to access markets. The prequalification test in such cases can conceivably be done in both ways – by testing the aggregated resources as a whole or each individually. The distinction between these two methods can clearly be seen in Figure 7[7].

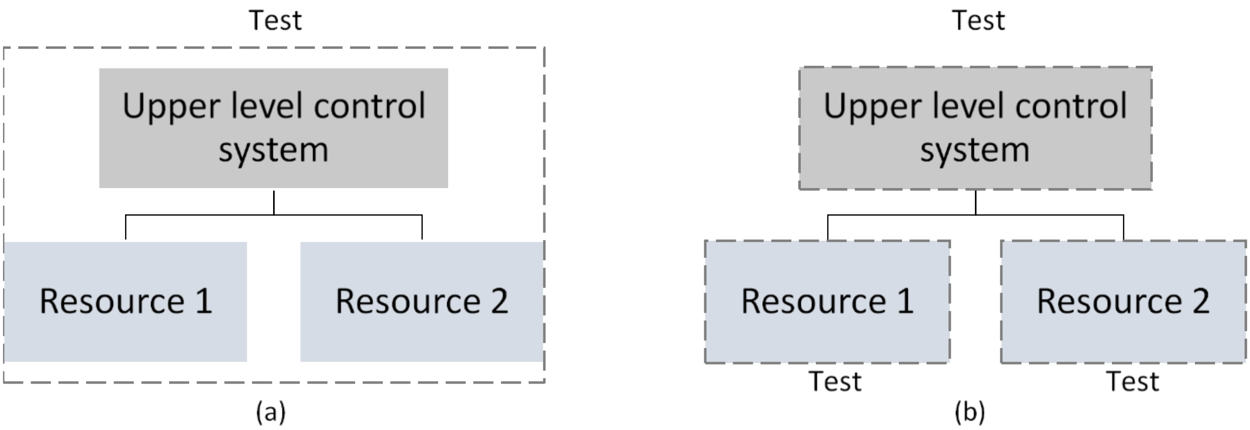

Figure 7: Testing of aggregated Reserve Unit (a) as a whole and (b) testing of individual resources

Testing the aggregated resources as a whole has some clear advantages over the testing of individual resources. Firstly, such an approach ensures that the testing process is less burdensome to the FSP, as a mandatory requirement to test every individual resource could be seen as an entry barrier, especially for FSPs which utilize a large number of small consumers (e.g., flexibilities on the residential scale). Secondly, the first option is simpler and more streamlined also from the system operator point

[7] Fingrid, The technical requirements and the prequalification process of Frequency Containment Reserves (FCR), https://www.fingrid.fi/globalassets/dokumentit/en/electricity-market/reserves/appendix3---technical-requirements-and-prequalification-process-of-fcr.pdf

of view. However, at the same time it is also generally a less reliable approach. Ultimately, the system operators intending to procure aggregated flexibility resources should have the discretion to apply a more thorough testing procedure if, for technical reasons, they deem it necessary.

The Guideline on System Operation (SO GL[8]) lays out principles for the prequalification process for specific reserves, namely, FCR (article 155), FFR (Article 159) and RR (Article 162). Additionally, this guideline sets out the minimum technical requirements for each type of reserves. SO GL does not deal with congestion management services, however, similar principles can be envisioned, whereby the system operator who intends to procure flexibility for congestion management services defines technical specifications and requirements the flexibility service provider needs to comply with to participate in the congestion management market. The testing procedure to be used also should be devised by the procuring system operator. However, if the same flexibility assets can be used and the flexibility service provider intends to use them to provide services to several system operators via the same product, coordination between the operators should be in place to avoid having to repeat the procedure multiple times. Nevertheless, the product prequalification must be repeated either periodically (the SO GL mandates at least within five years) or if notable changes to the technical capabilities of the flexibility service provider's flexibility assets have occurred.

The SO GL Article 182 more explicitly deals with prequalification for balancing resources connected to the distribution level as summarized in the EU Electricity Network Codes[9].

> "The SO GL specifies in Art. 182(3) that the prequalification process for balancing resources connected to the distribution level shall rely on rules concerning information exchanges and the delivery of active power reserves between the TSO, the reserve-connecting DSO and the intermediate DSOs. Each reserve-connecting DSO and each intermediate DSO, in cooperation with the TSO, shall have the right to set limits to or exclude the delivery of active power reserves located in the distribution system during the prequalification process. Reasons for limitations or exclusion should be technical, such as the geographical location of the reserve providing units and reserve providing groups (SO GL, Art. 182(4)).
>
> Further, each reserve-connecting DSO and each intermediate DSO can set temporary limits to the delivery of active power reserves before their activation. Procedures need to be agreed upon with the respective TSO (SO GL, Art. 182(5)). It is not decided yet to whom the costs of such an action should be allocated. In Art. 15(3) of the EB GL it is stated that each TSO may, together with the reserve-connecting DSOs within the TSO's control area, jointly elaborate a methodology for allocating costs resulting from the exclusion or curtailment of active reserves connected to the distribution level."

Grid prequalification indeed is crucial for the proper and effective functioning of any flexibility markets as well, because it is a process which ensures that the flexibility offered by a particular flexibility service provider can actually be delivered without causing an undesirable situation in either of the involved grids. In this regard, the Active System Management report[10] proposes two not mutually exclusive ways of enabling more flexibility service providers being qualified:

[8] Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32017R1485

[9] Schittekatte, T., Reif, V., Meeus, L., 2019. The EU Electricity Network Codes (2019ed.). FSR Tech. Rep. 2. doi:10.2870/188992

[10] TSO-DSO Report. An Integrated Approach to Active System Management, https://docstore.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/TSO-DSO_ASM_2019_190416.pdf

- Dynamic grid prequalification, where the possibility of grid access for flexibility resources is re-examined at regular intervals;
- Conditional grid prequalification, which grants improved grid access for flexibility resources based on clearly specified criteria determined in advance.

Furthermore, the ASM report additionally recommends that “the prequalification process should be user friendly striving to minimise the different steps and standardise them when possible”, and that “the prequalification could take place on an aggregated/portfolio level if technically acceptable”, similar to what is explained in Figure 7.

The prequalification processes described in this chapter are aligned with these recommendations and strive to expand on them. However, they are nevertheless described in a generally high-level so as to serve as a common basis for conceivably diverse implementations.

Taking into account the overall process, an initial screen and product pre-qualification will be necessary to verify the general performance of the FSP. Even though this process is called initial grid and product prequalification, the qualification can be repeated on a set regular basis and whenever the technical characteristics of the FSP notably change. However, the qualification also needs to be examined in case of possible activation. These qualification processes, in this report, are called prequalification processes for bids. If we refer to an overall sequence diagram encompassing all the steps of the balancing and/or congestion management interactions, e.g., Figure 37, we can see that the first step after agreement between flexibility resource owners and flexibility service providers, and the subsequent resource registration to the flexibility register is the initial grid prequalification. The sequence of this process is described in the following Figure 8.

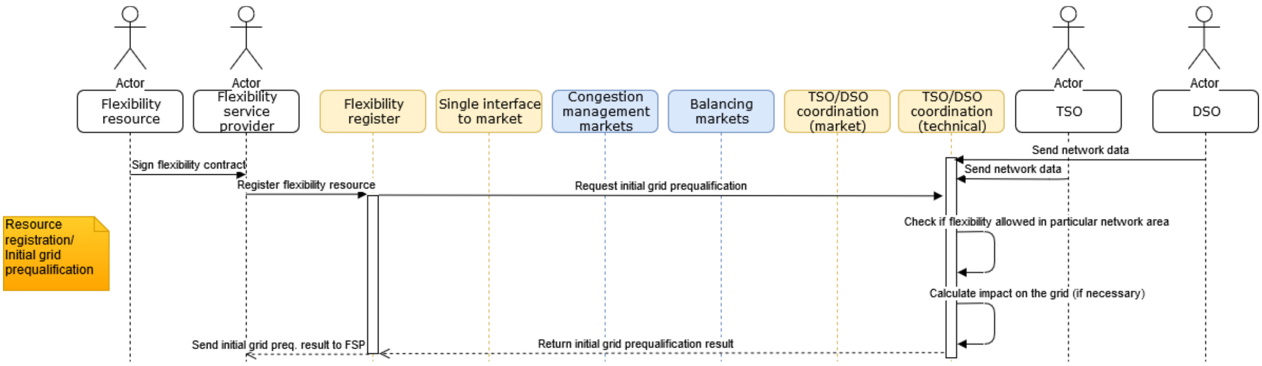

Figure 8: Initial grid prequalification process sequence diagram

It is envisioned that this process should benefit from the utilization of two new entities – a Flexibility Register and a TSO/DSO coordination platform (or more generally, an SO coordination platform). However, it is possible that the SO coordination function for prequalification purposes might also be performed by the Flexibility Register. Some consideration regarding this, as well as a thorough analysis of the possible functionalities and the full role of the Flexibility Register are elaborated in Annex Flexibility Resource Register. Nevertheless, the sequence diagrams in this chapter do presume these as separate entities to better illustrate the role of the coordination function.

Coordination between system operators in carrying out the prequalification process is beneficial, firstly, to avoid one system operator potentially causing issues to other operators, and, secondly, to also simplify and streamline the processes from the flexibility provider’s point of view. With more thorough coordination between operators, the prequalification processes should become more efficient also in terms of speed and accuracy, which is especially important for implementations of dynamic prequalification, e.g., to qualify bids.

In regards to the initial grid prequalification process, the implementation of it also can vary. Nevertheless, the most important steps in a common general description are as follows:

1. With certain periodicity (or whenever notable topology changes occur), the system operators send their network data to the TSO/DSO (technical) coordination platform. This data can either contain the full information on network topology, line parameters, congestion limits, forecasts from the operators (if the grid model calculations are to be performed within the coordination platform) or less information, such as power transfer distribution coefficient (PTDF) matrices, node capacities etc. The contents of the information exchange between the operators and the coordination platform (or any entity performing the coordination function) depend on the division of duties between them, e.g., where the grid models are calculated, what information the individual operators are willing to share etc.
2. After an FSP registers new flexibility resources to the Flexibility Register, the Register issues a request for initial grid prequalification to the TSO/DSO (technical) coordination platform. This request should utilize the following information stored in the Flexibility Register (or fetched from the data hub if applicable): Resource ID, Connection point ID, Voltage level, Locational information, connected SO ID, Type of resource (PV generation, CHP, heating load etc.), Resource nominal capacity, Flexibility direction (load/generation reduction/increase, both), Temporal availability, Maximum duration, Recovery time, Maximum downward and upward flexibility, Rebound effect characteristics (if applicable: temporal, maximum rebound, energy recovered, etc.)
3. In the simplest case, the need for exhaustive calculations for each new initial grid prequalification request can be avoided if the system operator has already determined in which areas flexibility (in a certain direction) cannot be allowed under all circumstances and in which areas it can always be allowed (i.e., akin to conditional grid prequalification wherein the condition is the expected congestion status of the grid area where the flexibility resources are connected in, this idea is also in line with the traffic light concept described in the note on the Flexibility Register in Annex Flexibility Resource Register). Thus, the initial grid prequalification result in such cases can be returned after a simple check of the flexibility resource grid location.
4. However, in the cases where the flexibility resource is not located in such a grid area where flexibility (in certain direction) can be accepted or denied without more detailed analysis, it is necessary to carry out an actual assessment of impact on the SOs grids. The methodology of this assessment depends on the information the SOs have shared with the TSO/DSO coordination platform.
5. The TSO/DSO coordination platform returns the prequalification result to the party issuing the request (i.e., the Flexibility Register).
6. The Register stores this result and notifies the concerned Flexibility Service Provider.

Once the flexibility resources have received the initial grid prequalification, the Flexibility Service Provider can issue product prequalification requests to the markets where it is interested in participating (conceivably, it can be done either directly or this can be delegated to the Single Interface to Market Platform, which would simplify the process for the FSPs). The main general steps of the product prequalification process are outlined in Figure 9. However, additionally to product technical prequalification for participation in a particular marketplace, the FSP also must have established contractual relations with the market operator, including posting collateral, if necessary. These procedures ought to be streamlined from the market operator's side to ensure easier FSP access, including but not limited to by minimizing the number of actions necessary to be taken from the FSP's side.

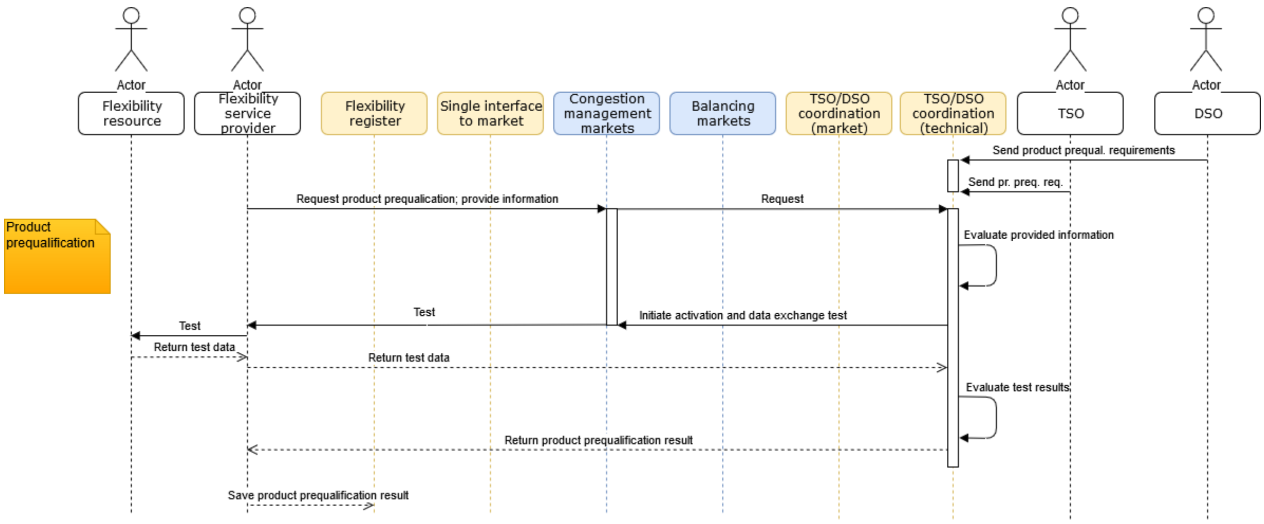

Figure 9: Product prequalification process sequence diagram

1. The System Operators (or, alternatively, market operators) define and publish the technical requirements for participation in a particular market for satisfying SO needs (including data exchange requirements, activation procedure, product specifications). These requirements should be available to the TSO/DSO (technical) coordination platform for more effective product prequalification, especially if an FSP wishes to prequalify for several markets at once.
2. On the other hand, the FSP (directly or via a Single Interface to Market[11]) notifies the operator coordination platform of their technical capabilities.
3. The Coordination platform evaluates the provided information. If it is insufficient for a decision it can issue a request for additional information. If the provided information is sufficient to establish that the FSP cannot provide the particular product, a denied product prequalification can already be issued.
4. Otherwise, a data exchange and activation test is to be organized to ensure that in case of need (and favourable market clearing) the flexibility resources can actually be activated and the relevant data exchanged in sufficient quality.
5. Depending on the outcome of the test, the prequalification results can be issued to the FSP and subsequently stored in the Flexibility Register. If the product prequalification process was initialized for participation in several differing markets, the returned result should contain prequalification decision for each of them.

The product prequalification tests can be repeated at regular intervals (e.g. at least each five years), when the technical characteristics of the flexibility assets utilized by the FSP notably change or when the technical requirements change. Additionally, if during normal market operation the FSP has failed to correctly deliver the activated volumes either a certain number of times or exceeding a specified margin of error, this can also be grounds to annul the issued product qualification to the FSP and require new tests to regain it.

[11] If a Single Interface to Market is implemented, it can notably simplify the product prequalification process for FSPs who are willing to participate in multiple distinct markets. In such case, this interface would issue product prequalification requests to each of the markets on behalf of the FSP. Furthermore, depending on the product requirements, a TSO/DSO coordination platform (or more generally an SO coordination platform or any entity performing such a function) can strive to minimize the prequalification tests that need to be carried out, for instance, when the FSP can be prequalified for several products at once.

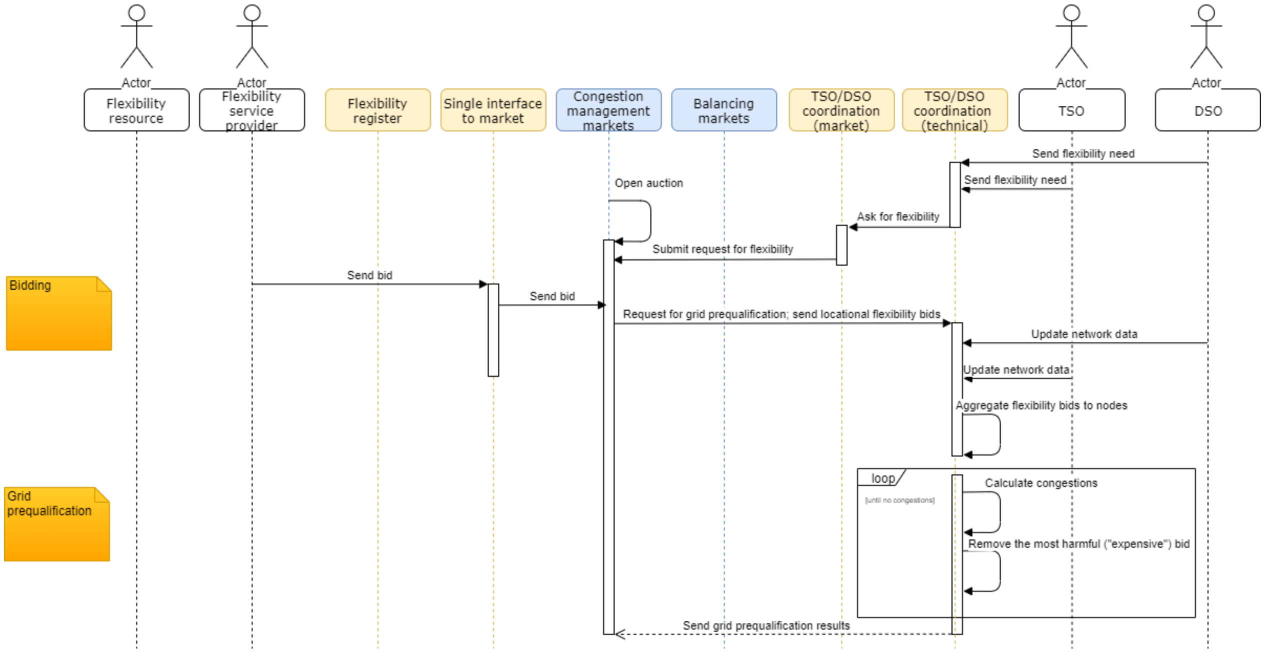

Figure 10: Grid prequalification process for bids sequence diagram

Finally, after product prequalification is obtained, the FSP can use its flexibility resources to bid in the markets it is qualified for. A dynamic grid prequalification process is envisioned in this report to be initiated on the TSO/DSO coordination platform after bid collection (for any single particular ancillary services market) for the purposes of increased liquidity[12] and more accurate avoidance of potentially negative effects caused by flexibility activations.

In Figure 10, the steps regarding this stage of grid prequalification are as follows:

1. The balancing or congestion management market (or more generally, a flexibility market) collects bids responding to needs issued by SOs.
2. Once the bids are collected, the market forwards their information to the TSO/DSO coordination platform.
3. The platform also requests/receives updated network information from the system operators. The full extent of this information depends on the division of duties and relevant data/network model sharing between the coordination platform and the individual SOs. However, compared to the initial grid prequalification phase, in this phase the permissible calculation times might be significantly smaller due to the nature of some of the types of ancillary services markets.
4. The Coordination platform aggregates the bids to their respective nodes.
5. An assessment is made on whether activation of all the aggregated bids could cause issues to the grid of the SO where the flexibility resources are located, or to other involved grids. Initially this process can be conditional, i.e., by knowing in advance where the grid is strong enough for bids in a certain direction to always be approved, or weak enough to always be denied. For the cases in-between, where the impact of bids on the grid can vary over time or based on a number of factors a more thorough analysis is required. The coordination platform

[12] The possibility to assess the impact of potential bids on the grid dynamically (e.g., before each market clearing) would increase overall liquidity by allowing the initial grid prequalification criteria to be laxer and thus less flexibility resources being outright rejected.

could calculate this with significant precision by estimating the post-activation state of the networks if it has data on the network topology, line parameters, load forecasts etc., however, there are two significant drawbacks to such an approach: (1) it is potentially too time consuming, (2) the SOs might be unwilling to share overly detailed network information.
Alternatively thus, the SOs could calculate the pre-activation operating states in-house prior to the closing of the concerned flexibility markets, obtain the related Jacobians, PTDF matrices, identify the available capacities in each node, forward this information to the TSO/DSO Coordination platform which would then only have to do simple comparisons to find if congestions could be caused by flexibility activations.
Nevertheless, a number of configurations between these two extremes is also possible. For instance, the SOs could share PTDF matrices, initial line flows, node voltages and congestion limits with the TSO/DSO coordination platform, which could then utilize the PTDF matrices to calculate network states in cases when all flexibility bids are activated. This approach does still have the issue of being an approximation (a linear model), but at the same time it is significantly less computationally expensive than full load flow analysis.
Ultimately, the grid prequalification process implementation can in either of these cases benefit from the TSO/DSO coordination platform (the processes as depicted in Figure 10 allow for any of these implementations). However, ultimately the separation of the functionalities between SOs and the coordination platform, and the exact methodology for bid impact analysis is a trade-off of the level of confidential information sharing, computational time and accuracy of the prequalification process.

6. Regardless of the approach selected for the congestion analysis, if it concludes with identified congestion issues caused by the flexibility bids, the most harmful ("expensive") bid should be removed from the aggregated bid list. At this point, stages 5-6 can be repeated (if necessary), removing bids one-by-one until the remaining bids no longer cause issues to the grid. If technically feasible and allowed by the FSP and market operator, an FSP portfolio of aggregated resources can be qualified/disqualified also partially.
7. Once the condition for the iterative process to end is met (no more congestions), the prequalification results are sent to the market, which can disqualify the bids which were denied during the iterative prequalification process, and combine the remaining bids into a Merit Order List (or forward them to a party which forms a common MOL) for market clearing.

It should also be pointed out that even if the flexibility bids do not cause any negative issues to the grids during the activation time, it is possible that due to the characteristics of the rebound effect of particular resources, congestions in the grids could be expected once the activation time is over. There are generally three solutions to this issue: (1) permitted rebound characteristics could be part of the product specification for congestion management, thereby allowing the SOs to limit participation by resources with excessive rebound effect, however, this approach would harm the overall market liquidity; (2) the rebound effect could also be taken into account during the grid prequalification of the collected bids, thereby disqualifying those bids which at those particular times could cause congestions; (3) alternatively, the rebound effect can be taken into account in the congestion forecast, thereby enabling the affected SO to purchase congestion management services as necessary in the respective time to alleviate the rebound. However, the latter would obviously not be an effective way to conduct congestion management from the SO point of view. Thereby the best option seems to be to consider potential issues caused by the rebound effect during the grid prequalification of the collected bids. Either way, this signifies the necessity for the flexibility register, as if it were to store information about the flexibility resources, including their rebound characteristics, this would allow for increased market liquidity by not outright disqualifying rebounding assets, instead utilizing this information to evaluate their permissibility on a case by case basis after bid collection.

5.1.3 Settlement

If the product and initial grid prequalification take place in the beginning of the overall balancing and/or congestion management process, activities related to settlement conclude it. Indeed, according to the ASM report, the various phases in the overall process are as follows:

Figure 11: Phases of the overall congestion management process

As can be seen from Figure 11, the settlement function is closely connected to the measurement and control of activation (i.e., validation) functions. Furthermore, when discussing settlement, in practice there are at least two interlinked yet sufficiently distinct processes: Imbalance settlement and Financial settlement of trades. Sequence diagrams containing the most important steps of these processes are summarized in Figure 12.

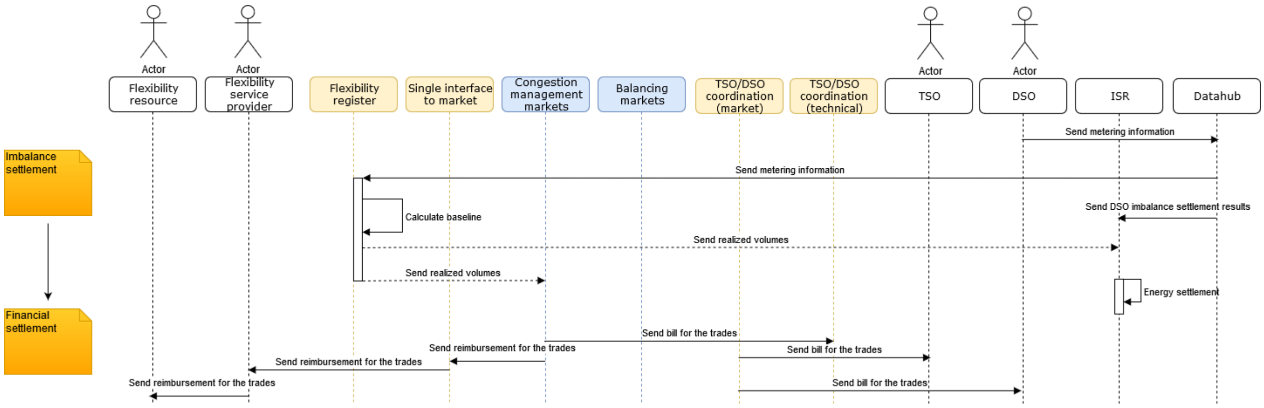

Figure 12: Sequence diagrams of the Imbalance settlement and Financial settlement processes

It should be noted that, within the example provided in the diagrams of Figure 12, those are trades from the Congestion Management market, which need to be settled, however, the corresponding sequence of sub processes is detailed in such a way as to be sufficiently generalizable and common for various types of ancillary services market setups. Furthermore, the necessary precondition of settlement is that the market has been cleared and the market operators have sent the trading results to the trading parties (FSPs, SOs), either directly or via intermediaries like a single market interface, flexibility register and/or TSO/DSO coordination platform.

The Imbalance settlement process starts sometime after the corresponding bid activations and the further sequence of events follows this structure:

1. Metered Data Collector, which is a party responsible for meter reading and quality control of the reading, sends metering information to a Metered Data Responsible, which is a party responsible for the history of the metered data for a Metering Point. In practice, this most often means that a system operator (e.g., the DSO for distribution connected resources, as in Figure 12) forwards the metered data to a data hub for long-term storage and sharing with other authorized parties as necessary.
2. Afterwards, the data hub forwards the metering data to a Flexibility Register. It is envisioned that the Flexibility Register should already hold detailed information regarding the Flexibility Service Provider and the Flexibility Resources it utilizes, from the prequalification processes,

and information about cleared trades involving the particular FSP, received from the respective Market Operators or Interfaces to markets.

3. Utilizing the historical metering information, metering data from the particular Imbalance Settlement Period (ISP) and a commonly agreed baseline methodology, the Flexibility Register may calculate a baseline and use it to establish the amount of flexibility (e.g. energy) delivered as a consequence of the activation signal.
Alternatively, in case the schedule of the Flexibility Resources is known in advance, baseline calculations are not necessary and the amount of delivered flexibility can be verified by comparing the scheduled and metered profile of the resources.
Nevertheless, definition of a trustworthy baseline methodology is an issue of most significance in terms of flexibility market development and facilitation of flexibility resources for system services provision. The Baltic TSOs[13] in their proposal on a harmonized independent aggregation model pointed out that the baseline methodology should have four most important characteristics: accuracy, simplicity, integrity and alignment.
4. Once the amount of flexibility activated (i.e., realized volume) has been determined, this information should be sent to the Imbalance Settlement Responsible (ISR) party.
In general, the role of the ISR is often assumed by the respective TSO, however, there is also the possibility that this role can be performed by another party. For instance, in the Nordic countries a third party (jointly owned by the Swedish, Finnish and Norwegian TSOs), eSett Oy, handles the role of the ISR[14]. Although it should be noted that national regulations nevertheless still ultimately stipulate that each national TSO holds the ultimate responsibility for balancing operations and imbalance settlement.
5. Depending on the specifics of the particular system service and rules surrounding independent aggregator implementation (if applicable), the ISR performs imbalance position adjustment to the involved Balancing Responsible Parties (BRPs). In the case of independent aggregation, the ISR must have methodology in place to correctly and fairly discern the imbalances for which the BRP of the Supplier of the respective flexibility resource holds responsibility and those for which the BRP of the Flexibility Service Provider should be responsible (due to, e.g., non-delivery of all activated flexibility). Furthermore, depending on the national implementation of the new Directive on Electricity Markets[15], a Transfer of Energy (ToE) process[16] (not portrayed in Figure 12) might need to be envisioned to ensure fair compensation between the Independent Aggregators and Suppliers. Preferably, this function should be delegated to a third party, e.g., a TSO or the same entity holding the ISR role. Moreover, the disaggregated flexibility data supplied should not be exposed to suppliers (or their BRPs) to ensure confidentiality of the FSPs portfolio.

[13] Elering AS, Augstsprieguma tīkls AS, Litgrid AB. Demand response through aggregation - a harmonized approach in Baltic region. Concept proposal.
https://elering.ee/sites/default/files/public/Elektriturg/Demand%20Response%20through%20Aggregation%20%20a%20Harmonized%20Approach%20in%20the%20Baltic....pdf

[14] Nordic Imbalance Settlement Handbook. Instructions and Rules for Market Participants.
https://www.esett.com/wp-content/uploads/2019/05/NBS-Handbook-v2.3.1.pdf

[15] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32019L0944

[16] USEF: Workstream on Aggregator Implementation Models.
https://www.usef.energy/app/uploads/2017/09/Recommended-practices-for-DR-market-design-2.pdf

In regards to the Financial settlement process, the steps 1–3 of the Imbalance settlement process also hold true. The difference is in step 4, whereby for Financial settlement purposes information on realized volumes is instead transmitted to the respective Market Operator (Figure 12).

Depending on the rules employed by the respective Market Operator for each product, failure to deliver volume of flexibility in accordance to the accepted bid can incur direct penalties to the FSP. If not, the FSP (or rather its BRP) is indirectly penalized through the Imbalance settlement.

However, in either case, the Market Operator must invoice the parties procuring services (i.e., the system operators) and reimburse the parties selling the services in its market. In the sequence diagram portrayed in Figure 12, the bills to the system operators are distributed via the TSO/DSO market coordination platform. This is particularly relevant for such market setups, where the usage of the same flexibility bid can be utilized in meeting the needs of more than one system operator.

On the other hand, the FSPs in Figure 12 are reimbursed via the Single interface to markets platform. Although, of course, if such an interface is not being used, the market operator can reimburse the FSPs directly. Finally, the last process in the sequence diagram is the FSP (i.e., Resource Aggregator) reimbursing its utilized flexibility assets (i.e., Resources). However, the existence and the type, and extent of this reimbursement entirely depends on the contractual agreement between the particular asset owners and aggregators/FSPs. In some cases, some minimum level of compensation might also be stipulated in national legislation.

In summary, both the prequalification and settlement process play very important roles in the successful functioning of any ancillary services markets, but even more so if these markets strive to also utilize distributed flexibility resources. While these processes are somewhat sufficiently defined for the existing, mature balancing markets, the emerging congestion management markets are more diverse in their implementation, particularly in regards to their approach to baseline definition. The deliverable D2.4[17] of the INTERRFACE project contained extensive Q&A with four pioneering flexibility markets: Piclo Flex, Enera, GOPACS and NODES, which was later further expanded. The results of that also contained comparison of the prequalification and baseline definition (for settlement) approaches employed by these markets.

All projects have a pre-qualification procedure. In almost all cases, the pre-qualification is done by the connecting SO, i.e. the system operator to which the flexible asset is connected. The pre-qualification procedure is in most cases similar to the procedure in place to obtain access to balancing markets.

Over all the four projects, there is no harmonized approach in calculating the baseline. UKPN[18] describes the use of a baseline methodology based on representative historical data when activating flexibility. GOPACS currently makes use of the transport prognoses (T-prognosis), i.e. flexibility providers have to communicate day-ahead schedules that serve as baselines. The applied baseline method in Enera and NODES depends on the connecting SO and technology. For example, there can be a different baseline method for renewable generation than for demand response. Setting an adequate baseline is a difficult task, more discussion can be found in Rossetto[19].

[17] Schittekatte, T., Reif, V., Nouicer, A., Meeus, L., 2019. INTERRFACE project: review of D2.4 regulatory framework

[18] UKPN (2018), 'Flexibility Services Invitation to Tender - 2018/19'

[19] Rossetto, N. (2018), 'Measuring the intangible : an overview of the methodologies for calculating customer baseline load in PJM', FSR Policy Brief 2018/05

A comparison of the pioneering markets regarding these issues is presented in the table below.

Table 6: Overview of a selection of design choices beyond flexibility markets

	Piclo Flex	Enera	GOPACS	NODES
Data	**1st auction (cleared 15/05/2019), flexibility procured by UKPN**	**Status in September 2019 based on interview**	**Status in September 2019 based on interview**	**Status Norway pilot in September 2019 based on interview.**
Pre-qualification	Yes, done by the connecting DSO	Yes, done by the connecting SO	Yes, done by the connecting SO	Yes, collaboration between NODES and the connecting SO
Baseline	Default baseline is based on representative historical data	Depending on the connecting SO and technology	T-prognose (schedule communicated D-1 by flex provider)	Depending on the connecting SO and technology

5.2 Separated Congestion Management and Balancing Markets

5.2.1 General Description of the market

The congestion management market separated from the balancing market can be implemented in three different ways including options 1A, 2A, and 2B as shown in the following Figure 13. The aim is to analyse the mentioned market structures for CM of DSOs and TSO. A market structure based on option 1A includes three different market processes meaning that three Merit Order Lists (MOLs) are formed for DSOs' CM, TSO's CM, and balancing separately. A market design according to option 2B contains two market processes, including a market for fully-integrated DSO & TSO CM and a separate market for balancing. The market option 2A is similar to 2B with the difference that in 2A, the MOL for DSOs' and TSO's CM is not fully-integrated[20] but overlapping[21]. It is assumed that DSOs and TSO's coordination to build a market platform will most probably be of fully-integrated kind if they wish to make a single CM market useful for both of them. Therefore market option 2A is excluded from further analysis and market options 1A and 2B will be scrutinized and compared in the following sections.

	CM separated from other markets	CM combined with other markets over subset or by overlapping MOLs	CM fully integrated in other markets
TSO	1A	1B	1C
DSO	1A	---	---
TSO & DSO Combined by subset or overlapping	2A	3A	3B
TSO & DSO fully integrated	2B	3C	3D

Figure 13: Market Options in Separated Markets

Since CM and balancing markets are completely separated in both market options (1A and 2B), some preventive mechanisms should be put in place to avoid adverse interactions of markets. One possible option is to utilize time-sequential integration where the opening and closing of markets are coordinated mostly based on the needs of market participants especially flexibility buyers. Here are

[20] One MOL is formed for DSO and TSO CM

[21] Two MOLs exist for DSO and TSO CM but bids from one MOL can be procured by another system operator (interchangeable bids).

listed some alternatives for the sequences of the markets from short-term CM viewpoint. The diagram 14 demonstrates various implementation ways of short-term CM market including market option 1A and 2B stressing that market option 1A can be implemented in three different ways including 1A-(1), 1A-(2) and 1A-(3). Market option 1A with three different implementation ways and market option 2B will be discussed in the following:

Market option 1A

The idea of having short-term CM markets parallel with the intraday market is that the market participants are aware of their position (based on day-ahead market results) when the intraday market is open. For instance, grid operators by employing their grid tools, with a relatively high degree of confidence, can predict their networks' state for the day ahead with respect to the traded volumes in the day-ahead market. Now it depends on how short-term CM management market is constructed for DSOs and TSO which is the topic of discussion in the following.

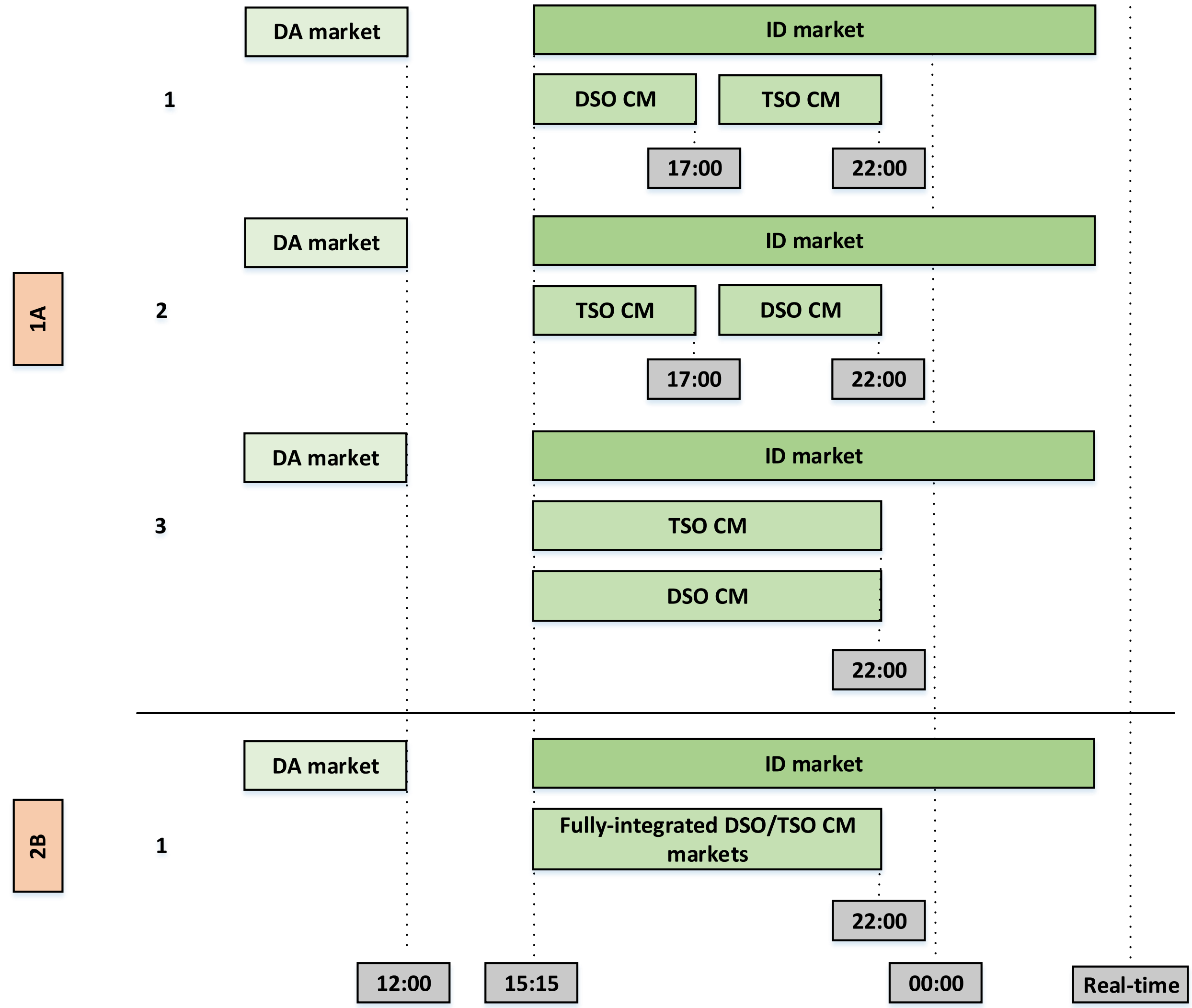

Figure 14: Sequential integration of CM markets into existing markets

The market structure, according to 1A-(1) defines that the short-term CM market starts with DSO and later followed by TSO in a time-sequential manner. In other words, DSOs' CM is prioritized to TSO CM

in terms of opening and closing time frames. The opening of the DSOs' CM and Intraday market are proposed to be simultaneous at 15:15. Once the DSO CM market is open, based on the day ahead market results, weather forecast etc DSO's grid tools (if they have it) can foresee upcoming congestion throughout the network. The predicted congestions in the form of flexibility need requests are forwarded to the DSO CM market to inform flexibility providers about the current needs. After receiving flexibility offers and filtering the bids through the grid prequalification, a MOL for the use of DSO is created. The DSO selects the cheapest bid and informs the CM market about that at 17 o clock. In the market structure 1A-(1) shortly after DSO CM closure, the TSO CM market is opened. A similar process happens in the TSO CM market. As shown in the diagram above, it is proposed that the TSO CM market is closed at 22 when the flexibility buyers are informed about the market clearing results by the market operator. The CM market based on market option 1A-(2) prioritizes the TSO CM unlike market option 1A-(1). Since cross-border coordination is needed in TSO level and the timing of the market option 1A-(2) does not genuinely comply to that, the market option 1A-(2) is not a viable option, however, theoretically, it is possible to have a market structure according to 1A-(2). Regarding the market option 1A-(3), both DSOs and TSO CM markets operate parallel providing an equal chance for grid operators to access their desired flexibility. In below, the pros and cons of three implementation ways of market option 1A will be presented.

Whenever the CM market of DSO and TSO are separated, the product design becomes more flexible, reflecting the exact needs of DSOs and TSO in contrast to the "one size fits all" approach in a fully-integrated CM market. Since the product design becomes more localized (in DSO level), then low entry barriers for small local market parties (aggregators) are expected. Besides, if a product requires some amendments, it can be done without mutual interactions because of separated governance over the CM markets. From a TSO's perspective, the CM and balancing costs are distinguishable which gives a more precise indication for future investments of transmission systems.

One of the downsides of having separated CM markets for DSOs and TSO is that CM of one grid operator can cause congestion for an involved grid operator. Such a scenario usually happens for a grid operator that its CM market is closed ahead of other grid operator's CM market (e.g., DSO in market option 1A-(1) and TSO in 1A-(2)). Therefore coordination is vital between local CM markets and TSO CM market. Another noticeable point is that a grid operator may feel uncertain about the adverse effects of the upcoming CM market trades for its network. Therefore, a grid operator with an earlier gate closure time may procure extra flexibilities to have a larger margin of operation, which may lead to unused flexibility and higher CM costs. For instance, DSOs in market option 1A-(1) may procure extra flexibilities for the sake of compensating possible adverse impacts of TSO's actions in its CM market. The mentioned problem is less probable in market option 1A-(2) as the traded volumes for DSO CM are often less than the amount that can cause congestion for TSO. As another disadvantage of having separated CM markets, due to having different bidding systems, extra interfaces are needed which is not favorable from IT and communication perspective.

Apart from the general advantages and disadvantages which are expected from the market structures where DSO and TSO CM are separated, there are some aspects specialized to each implementation of market option 1A, which will be discussed in the following paragraph.

In market option 1A-(1), since the DSO CM is served first, it seems that DSO CM receives more flexibility compared to TSO CM in contrast to 1A-(2) where TSO is served first. In other words, DSOs in the market option 1A-(1) receive the most local flexibilities leading to higher liquidity for DSO CM markets. From TSO perspective, since each TSO of member states, require to coordinate with all the nearby TSOs regarding the cross-border capacities and congestions, the idea of market option 1A-(1)

better supports the cross-border coordination needs compared to 1A-(2) because closure time of TSO CM in market option 1A-(1) is at 22 providing enough time for TSOs' cross-border coordination.

Regarding market option 1A-(3), it receives the mentioned benefits of separating CM markets for DSOs and TSOs. Regarding the deficiencies, adverse impacts of the flexibility trade of one CM market on the previous CM market still exists in a similar way in 1A-(3) because CM markets of DSOs and TSO function at the same time and the grid operators are not fully aware of the traded flexibilities in a parallel CM market especially if proper coordination is not in place. In addition, from aggregators' standpoint, bid optimization and coordination of flexibilities are more difficult when there are two open markets for CM that can be a reason for conservative bidding in the CM markets to stay on the safe side and therefore finally leading to less liquid CM markets. Besides, if proper coordination is not in place, grid operators may end up competing with each other for procuring flexibility of a resource leading to high CM costs. Also, competition in CM markets in its negative sense (without coordination) may lead flexibility buyers to sign long-term flexibility contracts with aggregators meaning that flexibility is locked and not used dynamically where it creates the most benefit.

Having said the argument above, if DSOs and TSO decide to separate their short-term CM markets, the market design based on option 1A-(1) serves their needs better compared to 1A-(2) and 1A-(3).

Market option 2B

A market design based on market option 2B includes one market process and MOL for both DSOs and TSO CM. Flexibility procurement is dependent on how the coordination and agreement between different buyers are made. The situation falls into two categories depending on the direction (upward/downward) of flexibility need at a certain congestion area. If both DSO and TSO have flexibility needs in the same direction (whether upward or downward), then coordination is much easier compared to the situation that their flexibility needs are in the opposite direction. In the latter case, the coordination can be such that TSO may choose a flexibility resource in another location where there is no local flexibility need, given that another location can have the same positive effect on the congestion. The price difference then should be agreed to be shared between the DSO and TSO. As there is one market process, if proper coordination is in place, concerns of grid operators regarding adverse impacts of trades in upcoming (1A(1), 1A(2))/parallel (1A(3)) CM markets are eliminated. Besides, due to having one market place, coordination between DSOs and TSO is easier in this market structure. Another positive aspect of the CM market according to market option 2B is that one gate is introduced for CM, which facilitates the market participants bidding and most probably increases the liquidity. Also, from information technology (IT) and communication viewpoint, it is easier to have one platform compared to market option 1A where there are two CM market platforms.

One downside of market structure 2B is about product design. It should be agreed between DSOs and TSO, which is not easy because their needs are not on the same scale (i.e., MW, kW etc). In fact, product design is a compromise that just takes into account the most critical needs of grid operators and skips the insignificant ones. Besides, as the needs of grid operators change over time, the agreement on the product parameters should be repeated periodically, which is time and energy-consuming because, as mentioned before making an agreement on product design that suits everyone best is not easy.

The above argument has clarified the various aspects of both market options 1A and 2B so far. Since DSO/TSO coordination is highly necessary irrespective of the chosen market model, it seems that all the efforts in constructing the coordination pay off better when the effort is made once to construct the fully-integrated CM market (market option 2B) compared to the situation that coordination between market platforms to avoid interaction is done before buying each bid separately (market option 1A). Besides, market option 2B facilitates participation of FSPs in flexibility provision and has

higher liquidity because of providing a single entry gate for CM. Therefore, from now on in section 5.2, the focus will be on short-term CM market design of the option 2B. Figure 14 demonstrates the proposed market design for fully-integrated DSO/TSO CM markets including short-term and operational CM markets.

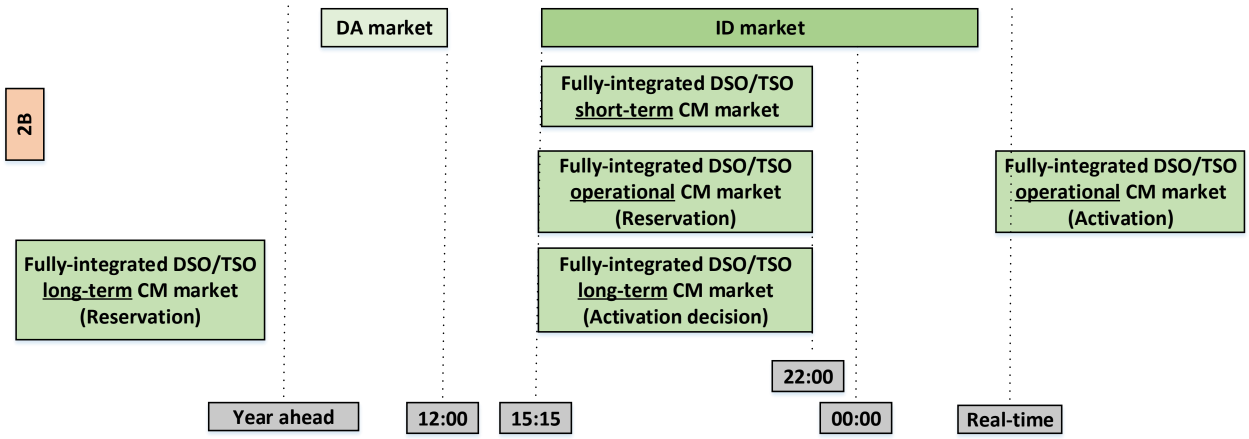

Figure 15: Sequential integration of CM

5.2.1.1 Market goals

The initial goal of CM markets is to ensure the secure operation of the network within technical boundaries (e.g., voltage, current, etc) in both TSO and DSO levels and moving toward flexibility utilization for optimization of the network's operation. The goal is to manage day-ahead situations of the grid to avoid occasional congestion and optimize the operation of the grid. If congestion is predicted to occur repetitively, then grid reinforcement or long-term congestion management is needed instead. Secondly, the markets target to utilize the utmost capacity of the existing networks which is essential from a socioeconomic perspective. This can be realized by increasing the hosting capacity of grids for renewable energy sources, demand response, new loads like electric vehicles, heat pumps, etc.

Unlocking and utilizing the flexibility for the benefit of customers, flexibility providers, BRPs, and network operators is counted as another goal of CM markets. Markets of short-term and operational congestion management should take care of unlocking flexibility from distribution grids to all possible markets where flexibility may be traded, ensuring the business case of stakeholders especially flexibility providers and BRPs.

Earning the trust of all stakeholders is a general goal of CM markets by providing a transparent flexibility validation, trading, verification, and settlement along with having an easy to use market platform where flexibility providers and buyers can readily meet their needs. For instance, when it comes to a situation that a grid operator is evaluating the available and viable options for congestion management, a liquid and reliable CM market may be preferred to other existing congestion management alternatives (i.e., technical solutions).

5.2.1.2 Services

CM markets include the short-term, operational and long-term services. Regarding the short-term service, once the grid operators are aware of positions of energy market actors (e.g., BRPs) in the day-ahead market, with the utilization of their grid tools, they can predict upcoming congestion for the day ahead. Consequently, the short-term CM market is the marketplace where flexibility needs match scheduled reprofiling (SRP) bids of FSPs. SRP is described as the obligation of the flexibility to modify the demand or generation at a given time for the benefit of flexibility buyers. Therefore, flexibility buyer should be sure enough to participate in the short-term CM market as procurement of SRP product entails activation of it.

Operational service can be used whenever a grid operator is not completely sure about upcoming congestion. In this situation, a conditional reprofiling (CRP) product is used. CRP is used as when the flexibility seller must have a capacity to satisfy the traded flexibility with a specified demand or generation profile modification at a given period; however, the delivery is called upon by the buyer's request in real-time.

For the flexibility needs which can be foreseen a year ahead, the long-term CM market is used. The grid operators assess the outlook of the flexibility needs basing on the scheduled maintenance/construction plans, the seasonal hosting capacity (HC) changes of the grid, expected load/production changes etc. The long-term service is similar to what is explained for operational CM with differences that the capacity reservation is done once a year, and the activation decision should be made a day ahead of the real-time operation. The three services above enable flexibility buyers to participate in CM markets according to their needs and level of certainty.

5.2.2 Market Parties

The following parties involved in CM markets are well described in the harmonised role model available in the appendix of this document.

- Balance Responsible Party
- Balance Supplier
- Balancing Service Provider
- Merit Order List Responsible
- Producer / Consumer
- Resource Aggregator
- Resource Provider
- System Operator
- Market Operator

Depending on how the proposed market structure (market option 2B) is implemented in practice, the following market parties can be understood as a role or functionality. The aim to explain them here is to facilitate understanding of the market process in section 5.2.3.1.

Flexibility register

The information related to characteristics of a flexibility resource (e.g., amount of flexibility (kW), locational info (e.g., postal code or locational information with better resolution), up/down regulation capability, etc), initial grid prequalification results, product prequalification results, metering data of previous flexibility activations exist in the flexibility register system. In addition, baseline calculation is proposed to take place in the flexibility register. More information about the flexibility register available in the appendix.

Fully-integrated CM market for DSO and TSO

A market place as a result of a synergy between DSOs and TSO for CM aims to form one MOL for CM in both distribution and transmission levels according to market option 2B. The market receives bids from flexibility providers and matches them with the needs of grid operators. The market operator publishes the clearing results to involved stakeholders and all market participants for transparency reasons. Based on the realized volumes of flexibility activation, in the settlement process, the market operator forwards the bill and reimbursement voucher to flexibility's buyer and seller, respectively.

TSO/DSO coordination (technical)

The TSO/DSO coordination (technical) is responsible for initial grid prequalification, product prequalification, harmonizing, and stacking the flexibility needs of grid operators and grid prequalification.

The technical platform adds network data to the data that the FSP has already provided to the flexibility register in the initial grid prequalification phase. In other words, the network data which is absent in the flexibility register are added by the technical platform in the initial grid prequalification phase in order to clarify where the resource has been located in DSO and TSO network in order to use these data later in the market process. For product prequalification, the technical platform is used to test the flexibility product of flexibility provider to make sure that the flexibility provider can deliver its offered product in a real scenario.

Different approaches can be used for grid prequalification in the market process in order to assure that flexibility activation of a bid does not cause a problem for another grid operator. Using the sensitivity matrix is an accurate and dynamic method of grid prequalification; however, due to the cumbersome features of sensitivity analyses especially for large and meshed networks, static methods such as node-wise capacity can be used for grid prequalification.

Another responsibility of the technical platform is harmonization and stacking of the flexibility needs of grid operators in such a way that the final flexibility needs along with its technical parameters can be forwarded to the TSO/DSO coordination (market). For instance, it might be so that the flexibility need of a DSO at a particular location coincides with the need for TSO. Therefore, both needs can be merged. In contrast, the opposite needs of a DSO and TSO can be addressed if TSO chooses another location belonging to a nearby DSO for flexibility procurement because the flexibility need of TSO is less location-dependent than a DSO.

TSO/DSO coordination (market)

The grid operators need to participate in the CM market as a flexibility buyer. Therefore their flexibility needs available in the technical platform should be translated to be usable in the CM market. According to the predefined products (SRP, CRP), flexibility needs are transformed into the format required in the CM market so that the CM market can publish the needs to FSPs.

5.2.3 Market structure

5.2.3.1 Market Processes

The whole operational CM process based on the market structure 2B has been proposed in the following figure.

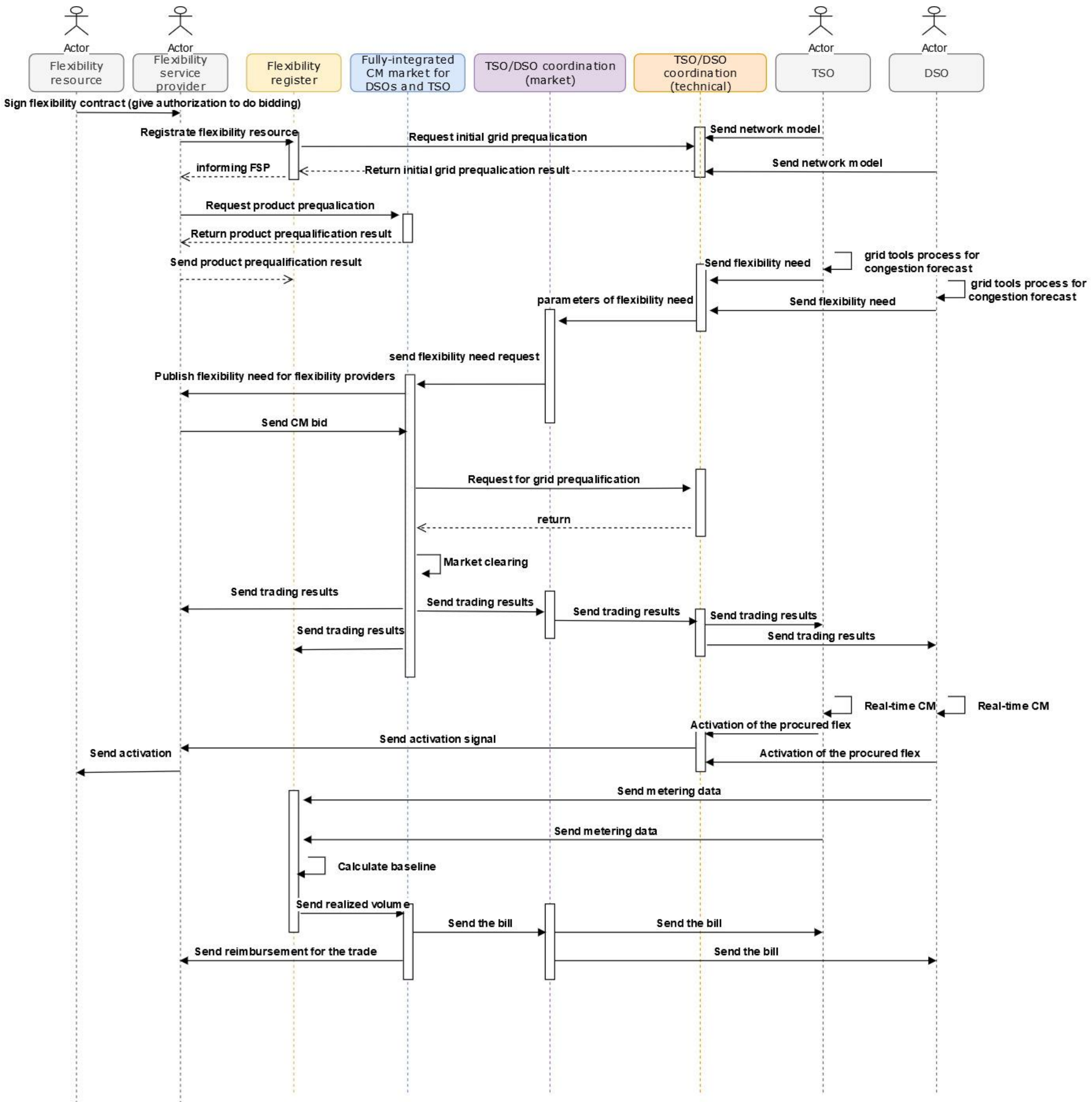

Figure 16: Proposed sequence diagram of operational CM market for DSO/TSO

Regarding the above diagram, it can also be applied for short-term CM if the activation part is omitted. The figure involves different stages including flexibility aggregation and registration, initial grid prequalification, product prequalification, CM of DSOs and TSO, grid prequalification, CM market clearing process, flexibility activation, monitoring and validation, baseline calculation, and settlement. Each of the stages above will be shortly explained in the following paragraphs:

Once the flexibility aims to participate in the CM markets, it needs to be registered in the flexibility register system. The flexibility register sends a request to TSO/DSO coordination (technical). The technical platform then informs the flexibility register about the results of initial grid prequalification. A similar process needs to be accomplished for product prequalification. To do so, the FSP sends a product prequalification request to the operational CM market. Once the flexibility resource is tested,

the market operator informs the flexibility provider about the results of product prequalification. For more details about initial grid prequalification and product prequalification refer to section 5.1.2

The fully-integrated CM market starts a day ahead of operation time (parallel with intra-day as shown in the proposed market structure). The grid operators need to forecast their flexibility need and inform the TSO/DSO coordination (technical) about their flexibility request. The technical platform forwards the technical specifications of the flexibility need to the TSO/DSO coordination platform (market) to create the flexibility needs request compatible with CM market products (SRP CRP). The TSO/DSO coordination platform (market) sends flexibility needs to either short-term or operational CM market and then the relevant market operator forwards the flexibility needs to all FSPs. Based on the released market information, FSPs send their bids to a CM market. All the bids are filtered by TSO/DSO coordination (technical) in the grid prequalification phase to prevent possible conflicts of grid operators due to a bid activation. The final bids form a MOL for both TSO and DSOs which is an input for a CM market. The grid operators optimize their networks separately, based on the bids of the MOL and inform the market operator about their desired bid. Coordination between grid operators is significant here in order to prioritize a buyer who needs the flexibility most if two grid operators aim to buy a single bid (i.e., DSOs usually have less freedom compared to TSO. Synergy is needed). The CM market operator then publishes the market-clearing results to the involved stakeholders by forwarding it to the TSO/DSO coordination platform (market), flexibility register and FSPs.

In real-time operation, in case of CRP product, whenever the previously bought flexibility is needed, the buyer (grid operator) sends the activation of the procured flexibility to the TSO/DSO coordination platform (technical). The TSO/DSO coordination (technical) forwards the activation signal to the FSP. Once the flexibility is realized, the DSO forwards the metering data (with 15 min resolution for instance) to the flexibility register to be compared with baseline calculations. The flexibility register sends the realized volume to the CM market for monetary calculations (bill for buyer and reimbursement for the provider). Regarding the SRP product, the activation signal is not needed as the activation is entailed in the product specification.

5.2.3.2 Market Access

Facilitating the access of parties (especially ones with smaller sizes) with interest in CM including flexibility buyers and providers is the initial goal of CM markets. Since CM markets are separated in the market option 2B, CM market can be specifically designed for CM unlike market option 3 (3A, 3B, 3C and 3D), where CM market require to somehow adapt to the existing balancing market. Therefore, from a market access perspective, unlocking the local flexibilities (i.e., located in lower voltage levels) to participate in CM markets without any need to follow TSO level requirements of the balancing market are more feasible in market option 2B.

5.2.3.3 TSO/DSO coordination schemes

Coordination is imperative for the integrated CM market to prevent any conflict in flexibility trade between grid operators and to utilize the existing flexibility in an optimum possible way. In the proposed market structure, the coordination is mainly done in the TSO/DSO coordination (technical) as well as the TSO/DSO coordination (market). In the coordination agreement between SOs, various possible scenarios should be foreseen to clarify the actions of SOs in the technical and also market coordination platforms. We propose that DSOs are prioritized to TSO in flexibility procurement due to having a small area of the network compared to a TSO. For instance, the overloading of a

transmission line leading to a primary substation can be eliminated by procuring upregulation flexibilities located downstream of the substation irrespective of its location. Meanwhile, due to a weak network in some parts of a DSO area and extra penetration of RESs, downregulation is needed. In this situation, the technical platform will make two separate flexibility needs, including one downregulation for the congested DSO area and one upregulation everywhere below the primary substation except the congested DSO area. The mentioned example explains why coordination is essential and how it can be addressed in the proposed market structure.

5.2.4 Products

Once the day-ahead market is cleared, grid operators perform day ahead congestion forecast (DACF). The results of DACF determine the flexibility need of grid operators, which is then forwarded to the TSO/DSO coordination (technical). The flexibility products in the short-term and operational CM markets are SRP and CRP respectively. The specifications of SRP and CRP are rather similar except the activation and settlement part. As mentioned before, separate activation is not needed in real-time for SRP product unlike CRP. Also, in the settlement process, payment of CRP has two stages including reservation and activation which means initially flexibility buyer pays reservation fee followed by activation fee in the real-time operation if the flexibility is activated. If the CRP is not activated, just reservation fee must be paid by flexibility buyer. In other words, the idea of CRP is similar to the power reserve products at the transmission level. The attributes of SRP are min and maximum bid size, temporal measurement resolution, up/down regulation, activation time, duration, location, rebound condition (payback time and percentage), partial or “all or none” bids, ramping up period, min full activation period, mode of activation (manual, automatic). It should be stressed that the product design for CM is more national level depending on the local needs of DSOs as well as TSO. Therefore, in the following, the proposed product’s attributes are examples that can be changed to other values based on the needs.

Regarding the min and maximum bid size, there is a conflict of interest between DSOs and TSO because the scale of the needs of grid operators does not match perfectly. In general, DSOs tend to receive bids with smaller sizes (100 kW), whereas TSO prefers larger amounts (1MW). It is proposed that the DSOs needs are more taken into account to define the min bid size, whereas for the maximum bid size, the TSO needs are more considered.

The temporal measurement resolution is dependent on some factors such as smart metering coverage, the level of aggregation, communication infrastructures etc. If the smart meter's coverage is close to 100 percent, then regardless of the aggregation level, the measurement can be realized whether once in 5 min, 15 min or one hour. Otherwise, metering is not possible for small customers and flexibility in the aggregated level can only be measured. In the latter case, the temporal measurement resolution can be reduced because, in the aggregated level, the fluctuations of the individual customers are not visible and not interesting for the flexibility buyer. Therefore, measurement with lower resolution is recommended. As grid operators can cope with short time over and under-delivery of demand response (for instance, 5 min), then lower measurement resolution (15 min) is proposed in the product’s attribute because from FSPs’ perspective it is easier to realize flexibility with 15 min resolution than 5 min. Lowering the measurement resolution also increases

the FSPs' confidence to provide more flexibility to the CM market compared to satisfying a product with higher measurement resolutions[22].

The direction of the flexibility is either upregulation or downregulation that should be specified in the flexibility request in addition to the activation time, its duration and location. Remuneration can be based on the realized capacity rather than energy because energy is a global variable, and therefore, FSPs' behavior is unified by the energy price. For instance, the times when the energy price is cheap, upregulation flexibility gets expensive[23] leading to an expensive congestion management cost for a buyer. In addition, the technical methods of CM such as curtailment, are capacity terms than energy. For grid operators, it is easier to deal with capacity than energy to express the real need of their network in the CM market.

The rebound condition should be determined in a flexibility need and product. Once the flexibility deliver is accomplished, the rebound time specifies the time when the resource can get its energy back (i.e., upregulation of production flexibility (battery)). Due to special grid situations, the payback time can be some hours that are usually during the off peaks. It should be clear the time when the resource can receive what it offered in the past. If the payback percentage is low, it might be so that the flexibility buyer does not mind about rebound time. Therefore, rebound time and percentage should be included in the SRP product.

The bids that can be split are "partial" whereas "all or none" refers to bids with no splitting option. If the flexibility need of a buyer is less than the offered flexibility in the CM market, assuming that the bid is "partial", then the buyer is allowed to buy what is required and pay for the procured amount. Otherwise, the buyer may buy the whole flexibility if it is "all or none" without needing the entire amount. Bid splitting is advantageous from flexibility buyers' point of view, and it makes the flexibility to be utilized at the right volume. In contrast, from the FSPs' viewpoint, bid management is more difficult when bids are divisible.

[22] Based on "Ecogrid 2, main results and findings" online available here: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=2ahUKEwi5pdPop7rmAhWv0KYKHUOZCVsQFjAAegQIAxAJ&url=https%3A%2F%2Fwww.danskenergi.dk%2Fsites%2Fdanskenergi.dk%2Ffiles%2Fmedia%2Fdokumenter%2F2019-09%2FEcoGrid_MainResults_and_Findings.pdf&usg=AOvVaw3QN7zA-YnGLPG2Zu1NNZCo

[23] Upregulation flexibility is understood as production rise or consumption reduction. When the energy price is high, production units tend to produce less electricity whereas consumers tend to use more electricity. Therefore, upregulation flexibility becomes expensive if it is needed for CM.

5.3 Balancing Markets

5.3.1 General Description of the market

The balancing market separated from congestion management market can be implemented in three different ways including options 1A, 2A, and 2B as described in Table 1. The purpose of this chapter is to describe the harmonised European balancing energy markets since these markets will set some boundaries on how the possible integration of congestion management markets (options 1B, 1C, 3A-3D) could be organised.

5.3.1.1 Market goals

The general purpose of the balancing market is to keep electricity consumption and production at the same level and thus keep the system frequency at 50 Hz. This is the responsibility of the load frequency control (LFC) Operator which is a role that has been defined within the harmonised role model and is usually performed by a transmission system operator. Even though producers and consumers have forecasts on their expected behaviour, the actual behaviour during the operating hour will differentiate and cause imbalance to the system. In order to balance the system operation, the transmission system operators need reserves. Reserve resources are consumption and production units that are able to change the behaviour based on the system needs.

TSOs have different type of reserves. Therefore, in this chapter the balancing products and their market places are described. The chapter is focusing on the automatic and manual Frequency Restoration Reserves (aFRR and mFRR). The main purpose of the aFRR and mFRR balancing markets is to restore the faster reserves (FCR, frequency containment reserves) in order to be able to use it for the next frequency deviations since these FCR reserves are able to react faster than the aFRR and mFRR balancing reserves. System balancing needs are transformed into various types of balancing market products, based on the energy or capacity and with different characteristics, these vary at the moment nationally and traditionally balancing market has been operated in national level.

As a part of Commission regulation (EU) 2017/2195 establishing a guideline on electricity balancing[24], guidelines for the European platform for the exchange of balancing energy from frequency restoration reserves with manual activation (Article 20) and from frequency restoration reserves with automatic activation (Article 21) were published. Based on those the implementation projects were created.

In the future, by the year 2022, national balancing markets will be replaced by European balancing market places, MARI for mFRR (manual frequency restoration reserve) and PICASSO for aFRR (automatic frequency restoration reserve). MARI stands for The Manually Activated Reserves Initiative. PICASSO stands for The Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation.

The European balancing market places are for balancing energy only. For balancing capacity, there are currently no plans for European common market places.

[24] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing. Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2017.312.01.0006.01.ENG&toc=OJ:L:2017:312:TOC

Aim of these European markets is to integrate the national markets for balancing and thus enhance the operational security and efficiency. The cross-borders balancing market should secure economically efficient purchase and in-time activation of the regulating energy, ensuring the financial neutrality of the TSOs. [25]

The main targets of the PICASSO project are:[26]

- Design, implement and operate an aFRR-Platform compliant with the approved versions of the EB GL, SO GL and CACM, as well as other regulations.
- Enhancing economic and technical efficiency within the limits of system security.
- Integrating the European aFRR markets while respecting the TSO-TSO model.

5.3.1.2 Services

This section of balancing market addresses only the automatic Frequency Restoration Reserve (aFRR) and manual Frequency Restoration Reserve (mFRR) from the balancing market services. All the balancing market services are shortly described in Table 2 and more detailed in the INTERRFACE deliverable D3.1 “Services design based on customers’, grids’, market players’ perspective”.

5.3.1.3 Integration between market levels

Balancing markets are currently not integrated in any other markets. From the balance service providers’ perspective, the forthcoming European balancing markets are not that visible since the interface will be organised by the national TSO and the national TSO is going to organise the activation requests also in the future.

Balancing markets are within the regulated domain and thus associated with lower competition between the balancing market places, i.e. establishment of balancing market in not a competitive domain. From the market participants’ and balancing service suppliers’ perspective, depending on their resources and their capabilities, they might have multiple possibilities on providing the flexibility to different market places and thus there is some competition. Balancing energy markets is only one of the possibilities. Between the different balancing market products, in aFRR and mFRR the technical requirements for the bidding and providing the service are not that demanding as in the FCR, so in that sense there is also competition inside the balancing market domain.

Considering the product requirements of mFRR and aFRR, there could be some potential on integrating these products also to congestion management services. This integration will be further discussed in chapter 5.4.

5.3.2 Market Parties

Since the balancing market is an existing and well-established market place, it doesn’t cause changes to the general harmonised role model.

The actual market participants in the balancing energy markets are balance service providers (BSP) and LFC operators. A LFC operator is responsible for the load frequency control of its LFC area. Typically, a Transmission System Operator (TSO) performs this role.

[25] Entso-e. Manually Activated Reserves Iniative. Available at https://www.entsoe.eu/network_codes/eb/mari/

[26] Entso-e. PICASSO. Available at https://www.entsoe.eu/network_codes/eb/picasso/

A Balancing Service Provider (BSP) is an actor which is providing the balancing service to the LFC operator, meaning that this actor has reserve-providing units or reserve-providing groups. The units or groups are parties connected to the grid, like producers and consumers.

Considering the settlement of the balancing energy markets, Balancing Supplier and Balance Responsible Party - BRP (subtypes Trade responsible party, Production Responsible Party) are involved too. The role description of the harmonised role model can be found in the Appendix of this deliverable.

5.3.3 Market structure

5.3.3.1 Market Processes

Balancing service providers (BSPs) will trade with their national TSOs through TSO-BSP interfaces. BSPs will operate through national TSO-BSP interfaces also when the new European balancing energy platforms are in place. The temporal diagram of the gate closure times for balancing energy platforms is presented in Figure 16 below.

The balancing energy gate closure time (BEGCT) means the time after when submission or update balancing energy bids is not more permitted for a specific validity period. For MARI and PICASSO this is T-25 min. TSOs have their own energy bid submission gate closure time (TSO GCT) to submit the local merit order lists (in PICASSO, T 10-20 min) or the bids (in MARI, T-12 min). TERRE (Trans-European Replacement Reserves Exchange) is included in the figure to illustrate all the initiatives for European platforms, but the details of TERRE won't be covered in this report.

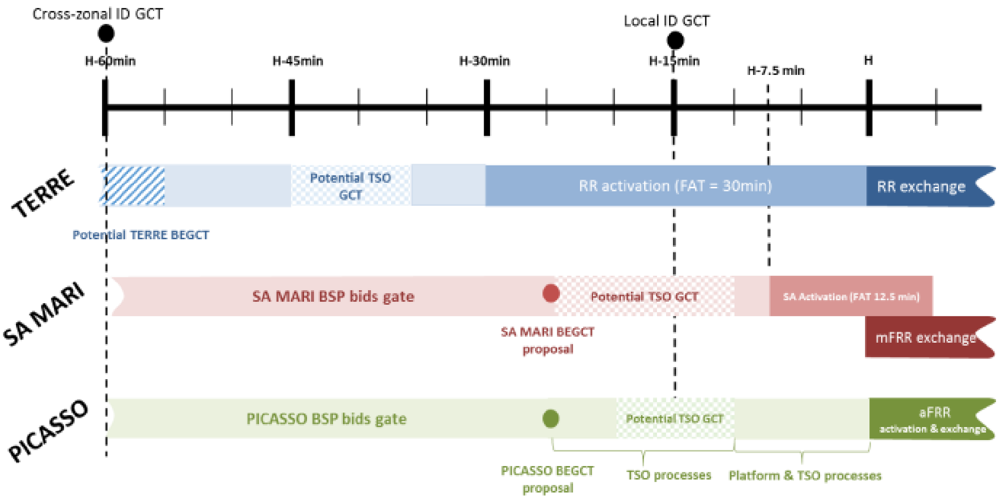

Figure 16: Gate closure time of the balancing energy platforms[27]

[27] ENTSO-E. Explanatory Document to All TSOs' proposal for the implementation framework for a European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation in accordance with Article 21 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing. Available https://consultations.entsoe.eu/markets/afrr_implementation_framework/supporting_documents/20180426_aFRRIF_Explanatory_document.pdf

The market process for the MARI platform is described as a sequence diagram in Figure 17[28]:

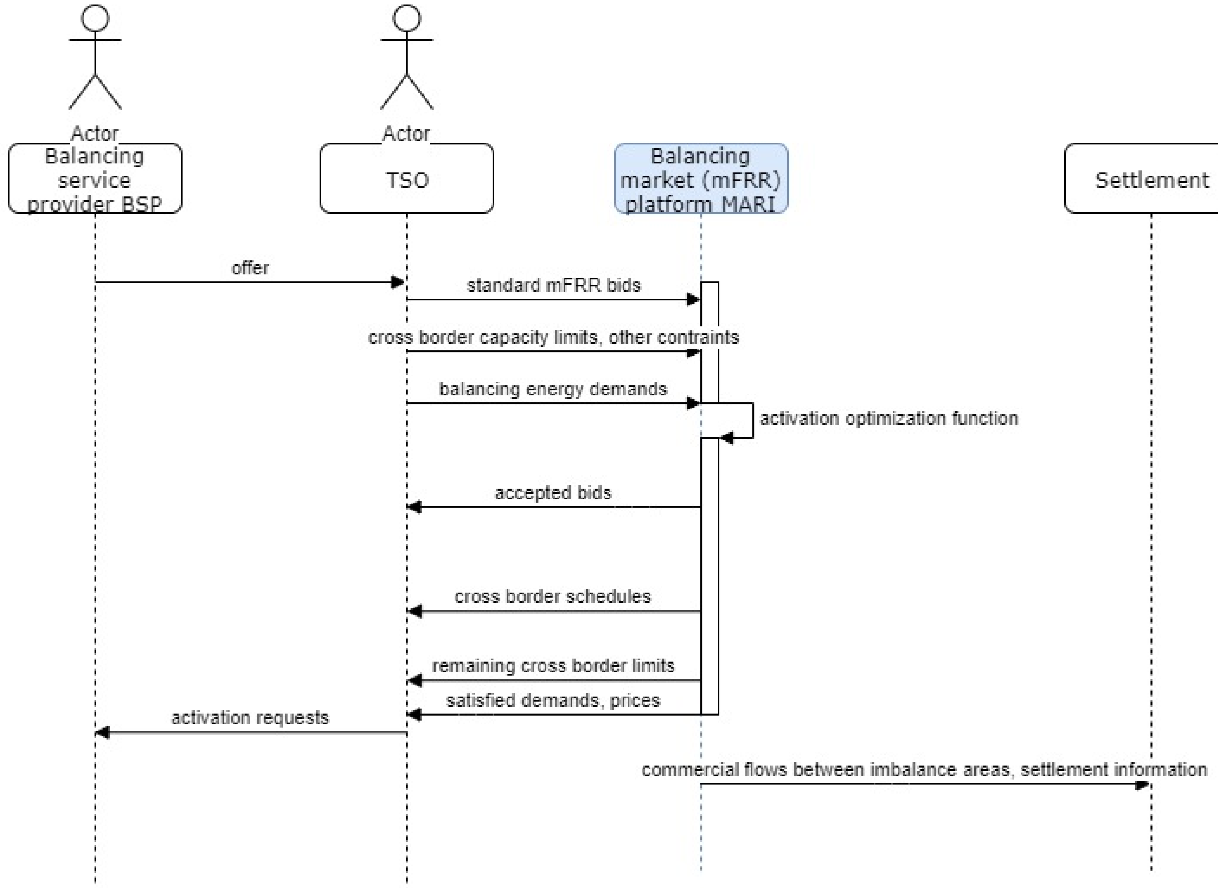

Figure 17: Market process for MARI

The market process for PICASSO described as a sequence diagram is described in Figure 18 [29].

[28] ENTSO-E. Explanatory document to all TSOs' proposal for the implementation framework for a European platform for the exchange of balancing energy from frequency restoration reserves with manual activation in accordance with Article 20 of Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing. https://docstore.entsoe.eu/Documents/nc-tasks/EBGL/EBGL_A20_181218_ALL%20TSOs%20proposal_mFRRIF_explanatory_document_for%20submission.pdf?Web=0

[29] ENTSO-E. Explanatory Document to All TSOs' proposal for the implementation framework for a European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation in accordance with Article 21 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing. Available https://consultations.entsoe.eu/markets/afrr_implementation_framework/supporting_documents/20180426_aFRRIF_Explanatory_document.pdf

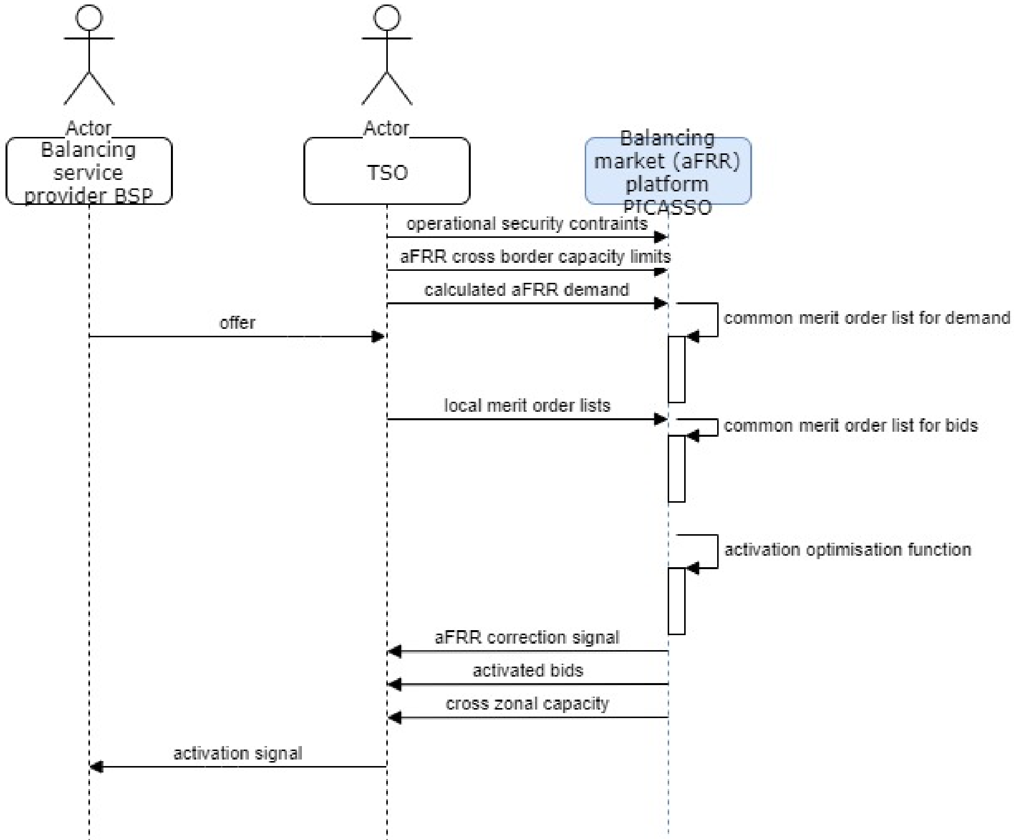

Figure 18: Market process for PICASSO

Merit orders lists, both local and common, are made for the both direction of activation. For the aFRR bids, a TSO is able to update the availability status of the bid in the PICASSO platform also after the TSO gate closure time. TSO is not able to do any other updates to the bid. MARI and PICASSO processes don't consider TSO/DSO coordination.

5.3.3.2 Market mechanism

mFRR and aFRR markets operate by auctions where balance service providers place bids and LFC operators/transmission system operators send their demand.

In aFRR, local TSO forms a local merit order list which is send to PICASSO platform where the common merit order list is formed. This common merit order list takes into account the needs and constraints of all TSOs.

Cross-platform communication hasn't yet been investigated, since this would increase the complexity of the implementation. In the collaboration of the platforms (PICASSO, MARI, TERRE), the best possible sequence of gate closure times has been taken into consideration between the balancing processes. This sequence is chosen so that it will consider different bidding approaches (unit based or portfolio bidding), providing one or different balancing services at the same time, possibilities of

BSPs to submit flexibility on the different balancing platforms (local conditional bids) and the possibility to release bids for the local intraday market as much as possible.[30]

5.3.3.3 Market Access

Balance service providers participate the MARI and PICASSO platforms via local TSO-BSP interfaces and TSOs specify the requirements for market participation. MARI and PICASSO platforms themselves don't set any market access requirements. Also prequalification requirements to participate within mFRR and aFRR markets are set by the national TSOs. Platforms have common requirements for bids which will improve the liquidity in the balancing energy market platforms. This will, in the long run, increase possibilities for market access because of the harmonisation of the products.

In order to reduce the barrier for new market entries, the minimum bid size for both MARI and PICASSO is 1 MW. This is at the moment higher in many, but not all, European balancing markets as has been analysed within D2.3. For PICASSO platform the minimum bid size affects the number of bids in the common merit order list (CMOL) (impact on IT and administration) and the complexity of the activation optimisation function (AOF) and that is why the minimum bid size might be reconsidered later.

5.3.3.4 TSO/DSO coordination schemes

So far for balancing services there isn't a TSO/DSO coordination scheme in place. For the flexibility resources connected to the distribution grid and participating the balancing markets, there will be need for the coordination of the balancing activation between TSO and DSO in the future.

Considering the system operator responsibility of the security of the system and system stability, any harmful interference should be avoided. At the moment there is no need for such a coordination scheme. Also from the market processes perspective the needs and demands of both DSO and TSO have to be coordinated.

If a mFRR product is going to be used for other services in the future as well, and possibly for DSO, such coordination mechanisms have to be in place. One of the key requirements is more detailed information about the resource location. At the moment the information about location in balancing energy bids is at a very high level to be used for the distribution network. The TSO/DSO balancing market and congestion management market integration and coordination will be elaborated in next chapter.

5.3.4 Products

MARI and PICASSO use common product definitions that have been agreed when proposing the implementation framework for a European platform for the exchange of balancing energy from

[30] ENTSO-E. Explanatory Document to All TSOs' proposal for the implementation framework for a European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation in accordance with Article 21 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing. Available https://consultations.entsoe.eu/markets/afrr_implementation_framework/supporting_documents/20180426_aFRRIF_Explanatory_document.pdf

frequency restoration reserves with manual and automatic activation. As stated, the product definitions are for balancing energy, not for capacity.

The following Table 7 will present the main specifications of the mFRR and aFRR products that are exchanged between the TSOs through mFRR and aFRR platforms. There are still local differences on what are the bid characteristics that are accepted locally. These are not described in this report.

Table 7: Bid characteristics for mFRR and aFRR products[31,32]

Bid characteristic	**mFRR**	**aFRR (foreseen harmonization)**
Mode of activation	manual	automatic
Activation type	scheduled only (SA), direct (DA)	
Full activation time	maximum 12,5 minutes	7,5 minutes (2025 5 minutes)
Minimum/maximum quantity	1 MW / 9999 MW	1 MW / 9999 MW
Bid granularity	1 MW	1 MW
Minimum delivery period	5 minutes	no minimum
Validity period	for DA: T-7,5min until T+7,5min	15 minutes
Price and price resolution	€/MWh, with 0,01 €/MWh resolution	
Location	Per LFC Area, per bidding zone	LFC area
Bid divisibility	Yes, activation granularity 1 MW. Non-divisible bid possible.	Yes. Non-divisible bid impossible.

[31] ENTSO-E. Explanatory document to all TSOs' proposal for the implementation framework for a European platform for the exchange of balancing energy from frequency restoration reserves with manual activation in accordance with Article 20 of Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing. https://docstore.entsoe.eu/Documents/nc-tasks/EBGL/EBGL_A20_181218_ALL%20TSOs%20proposal_mFRRIF_explanatory_document_for%20submission.pdf?Web=0

[32] ENTSOE-E. Explanatory Document to All TSOs' proposal for the implementation framework for a European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation in accordance with Article 21 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing. Available https://consultations.entsoe.eu/markets/afrr_implementation_framework/supporting_documents/20180426_aFRRIF_Explanatory_document.pdf

For mFRR, the specifications determine also the common bid characteristics that are defined in the terms and conditions for BSPs. These include location, preparation period, ramping period, deactivation period and maximum duration of the delivery period. In the bid characteristics there also technical and economic links of the bids.

For the mFRR platform, TSO to submit a balancing energy demand to the platform following characteristics are required: quantity [MW], direction, TSO demand price [€/MWh, with 0,01€/MWh price resolution] and location of demand.

5.3.5 Open Issues and Challenges

Harmonisation of the MARI and PICASSO platforms leaves still some room for national differences in the product design and implementation, but the common product definition will reduce the differences. Most, not all, of the European TSOs are members in the MARI and PICASSO projects[33], some TSOs are observers, so the coverage of these platforms is very wide.

Since the platforms are pan-European, it's difficult and time consuming to make changes in the common product structures or the trading mechanism if such needs would appear. This can be seen also as an advantage because it presents stability for the flexibility service providers.

It has been identified that especially mFRR product could be used for other services as well besides balancing market, like congestion management. Details on how this integration would be possible on the practical level, considering the main function and the operation of MARI platform, is still to be defined.

[33] Entso-e. MARI and PICASSO projects. https://www.entsoe.eu/network_codes/eb/mari/, https://www.entsoe.eu/network_codes/eb/picasso/

5.4 Combined Congestion Management and Balancing Markets

5.4.1 General Description of the market

5.4.1.1 Market goals

This market aims for an efficient provision of flexibility for all grid operators within multiple markets, a congestion management market, which is used to procure short-term and operational flexibility, as well as the balancing market. The fundamental idea within that approach is the increased liquidity if flexibility resources are accessible within multiple markets.

In order to optimally respond to the occurring congestion risks within grid operation, the presented market approach consists of two timeframes. Within a short-term timeframe, anticipated congestion is addressed using a localised energy market. Subsequently, congestions, which result from deviations within an operational timeframe, are resolved using flexibility capacities which have been reserved within the day ahead timeframe.

Since the timeframe and the operational requirements of operational congestion management are similar to the mFRR market, the integration of those markets offers some liquidity potential. This could be achieved by combining the merit order lists of both markets.

With respect to congestion management, different market layouts taking into account the relationship of DSOs and TSOs are possible. Possible designs reach from completely separated congestion management markets to a fully integrated TSO/DSO congestion management market.

5.4.1.2 Services

Within the addressed markets, the balancing as well as the congestion management market, system or ancillary services are procured by grid operators. With the aim to achieve efficiency gains by an integration of markets, it is also necessary to cover the demand of flexibility for both purposes.

Within the proposed market structure, congestion management is elaborated within two different time horizons. On the one hand, congestion management within an operational timeframe will be addressed. This relates, according to D3.1 within the INTERRFACE project, to the usage of flexibility bids by TSO/DSOs enriched with locational information for internal congestions. Thereby the activation decision will be done in real-time. On the other hand, the procured flexibility is used for the same purpose within the service of short-term congestion management. But notwithstanding, the activation decision is done with a longer lead-time, within the D-1 timeframe.

With respect to the different existing balancing markets, the focus of this combined market is within the product of manual Frequency Restoration Reserve (mFRR) since the need for flexibility of the respective congestion management is in the same timeframe. In addition, similar product requirements exist which will be further elaborated within chapter 5.4.4 covering the product design.

5.4.1.3 Integration between market levels

The analysed market structure is by default designed to integrate different markets. According to the systematisation, which is presented in Figure 19, the congestion management markets from TSOs and DSOs could be combined up to on fully integrated market where both grid operators are active. With respect to the second dimension, which describes the degree of integration with other markets, the congestion management market is combined with the balancing market.

	CM separated from other markets	CM combined with other markets over subset or by overlapping MOLs	CM fully integrated in other markets
TSO	1A	1B	1C
DSO	1A	---	---
TSO & DSO Combined by subset or overlapping	2A	3A	3B
TSO & DSO fully integrated	2B	3C	3D

Figure 19: Systematisation of market options and scope of the presented market framework

It is important to note that, within this analysis, only a partial integration (by combining or overlapping MOL) of the balancing market is considered. Therefore, only the outlined market options (1B, 3A, 3C) are possible configurations.

From a temporal perspective, the market processes are embedded within the market sequence which is presented within Figure 20.

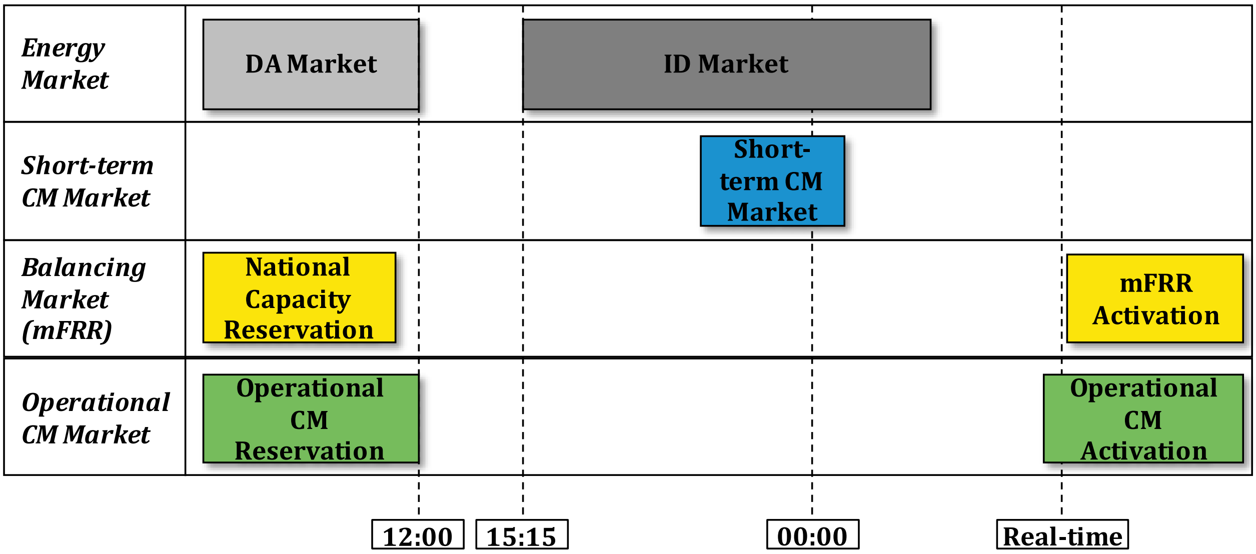

Figure 20: Integration of the described markets within the market sequence

For the anticipation of occurring congestion within grid operation, uncertainty exists. This uncertainty consists of market influenced factors (how generation and load units operate based on the price) as well as operational uncertainties (due to outages or forecast deviations). The firstly mentioned type of uncertainty is significantly reduced after the clearing of the day-ahead auction. The resulting unit schedules, which are aggregated by balance responsible parties, enable the grid operators to carry out a first estimate of the future load flows within their grid. Therefore, a realistic estimate of the expected congestion on the next day is only possible after closing the day ahead market. Therefore, within the analysed market structure a congestion management market is proposed which opens after the closing of the day ahead market.

The remaining uncertainties within an operational background are based on outages of units or deviations due to intraday trading. While the firstly mentioned could lead to a system-wide imbalance (which would be resolved by using balancing energy), the latter could cause local grid congestion (which is a use case for congestion management markets). In either case, activated flexibilities have almost no lead time, since in that timeframe, counter-measures are reactive instead of preventive. The reduced lead time (from activation signal to physical fulfilment) limits the bandwidth of eligible units. This might be due to technical reasons like start-up times of thermal power plants or a commitment within other markets. Therefore, in order to guarantee that a sufficient amount of flexibility is available, a mechanism to reserve an adequate amount of capacity seems reasonable.

It is also important to note that both markets, the operational CM market and the balancing market, tackle a similar problem which suggests a (partly) integration of the markets. Within the balancing market, the location of the bid is almost negligible, since the flexibility is used to restore the system-wide frequency. For an efficient congestion management, which is by definition a local issue, precise local information is necessary. For that reason, the integration of the two markets needs a harmonisation of product requirements.

5.4.2 Market Parties

With respect to the different market parties, all parties, which operate in the individual markets, could also be active within a combined CM and balancing market. Therefore, the involved market parties

are active in either one or both of the markets. Specifically, for the balancing markets this contains the following market parties:

- Balance Responsible Party
- Balance Supplier
- Balancing Service Provider
- LFC Operator
- Merit Order List Responsible

The definitions of these market parties are equal to the definitions within the harmonised role model which is included in the Appendix of this report.

The units, which provide flexibility used for CM and balancing, are operated and marketed by the following market parties:

- Party Connected to the Grid (Producer and Consumer)
- Resource Aggregator
- Resource Provider

While aggregators are already able to participate in balancing markets, small consumers or producers are not able to sell their flexibility on the existing markets due to minimum product requirements. One aim of the INTERRFACE project is to enable the participation of small end users as customers and prosumers, therefore their influence on balancing and CM market is taken into account.

The flexibility procured via CM and balancing markets is used by the DSOs and TSOs and therefore system operators are one major further market party:

- System Operator

The markets for CM and balancing energy need to be operated, therefore the following market parties are necessary:

- Market Operator
- Trader

Indeed, the detailed discussion of different concepts of market operators in the Appendix showed that there can either be an independent market operator or the TSO can become the market operator since in Europe TSOs are responsible for the operation of the balancing markets today. This would lower the entry barriers, since the TSOs only need to widen up the market and market platforms are already existing. On the other hand, DSOs might be willing to participate more actively in markets with independent market operators, since this concept ensures the equality of all market parties.

5.4.3 Market structure

5.4.3.1 Market Processes

As shown within Figure 21, the proposed market framework is not only embedded into the existing market sequence, but also into the existing planning processes of the grid operators.

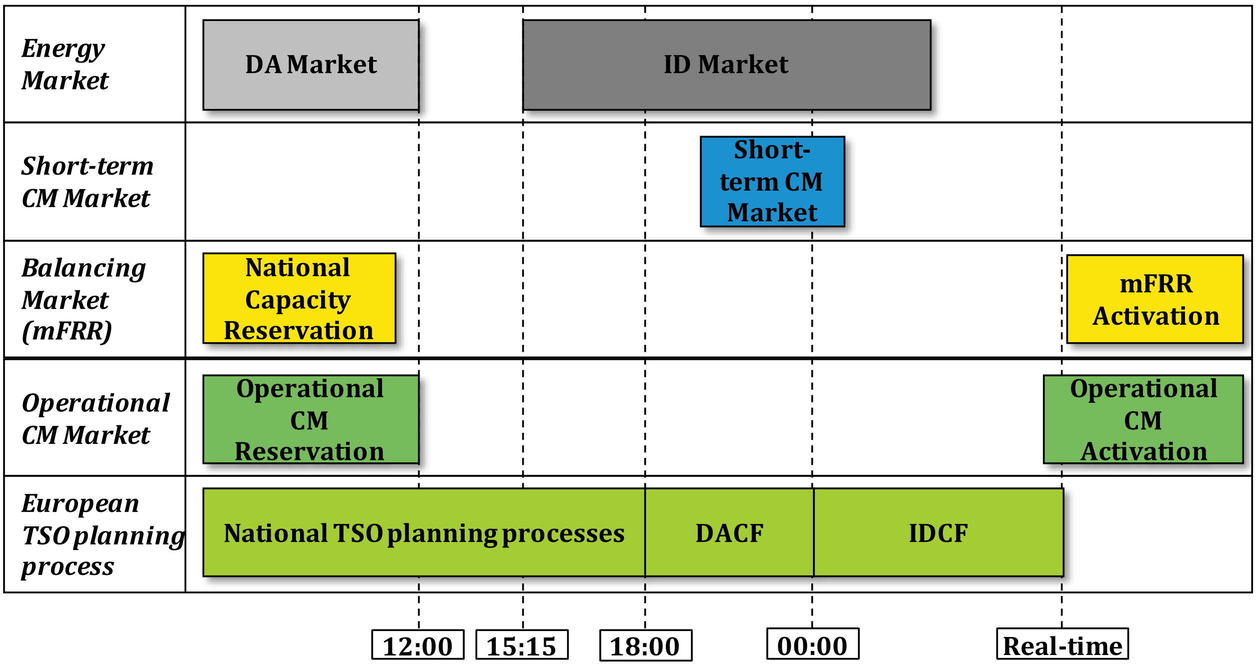

Figure 21: Integration of the market processes into the existing TSO planning processes

These planning processes, which are illustrated by means of the TSO planning process, follow a rolling principle, incorporating new information, regarding changing schedules of grid users, whenever possible. Within the highly interconnected European power grid, day-ahead planning is also done on a European level using the day-ahead congestion forecast (DACF). This process allows grid operators to identify possible congestion taking into account neighbouring control areas. Based on the market results and the resulting schedules of grid customers, load flow calculations using a harmonized grid model are carried out. This results in the anticipation of occurring congestion on the next day. Using mathematical optimization models, the minimum necessary flexibility volume for the next day can be determined.

Due to the galvanic isolation of distribution grids, no common pan-European planning process between DSOs similar to the DACF exist. However, DSOs use a regular, internal planning process to detect occurring congestion and plan necessary counteractions. It should also be noted that a high heterogeneity of DSOs exists within Europe. The variety of voltage levels and grid structures implies different processes as well as the need for specific market-based solutions. For that reason, in the following descriptions, the market structures have strong reference to the TSO processes while simultaneously being valid for DSOs.

Combined short-term CM Market

Since large shares of the occurring congestion, can be anticipated within the DACF, it seems reasonable to procure the determined, necessary flexibility subsequently to this process. This ensures that an adequate volume of flexibility is procured as early as possible. Otherwise, if flexibility resources are contracted prior to the market clearing, high costs for preventive flexibility can be expected.

Following the DACF, grid operators are able to determine localised needs of flexibility. Therefore, the market for short-term congestion management is opened subsequently. Due to the high forecasting accuracy, no capacity reservation mechanism is necessary. Instead, an energy trading mechanism with localised bids is used. Prospectively, this could be subject to a further integration with the existing energy markets namely the intraday market. This would require market participants to extend their bids by locational information. Moreover, additional analyses are necessary to investigate how efficient a continuous market mechanism is for resolving occurring congestion.

Procuring flexibility with a certain lead time to real-time always involves a trade-off. With longer lead times, uncertainties are rising. Reducing the lead times by moving the market process close to real-time, reduces uncertainties. However, market liquidity decreases as well since thermal power plants have to take the decision on a potential start-up at least one day in advance and will not be able to participate if the lead time is too short. Therefore, opening up the market for short-term congestion management after the DACF can be seen as a compromise. It should be noted that in reality, the DACF process might take longer and can even reach into the intraday time horizon. Combined with congestion which appears within the first hours of the following day, the lead time of the market is reduced significantly. This is considered an exceptional case which could be addressed by an increased reserved capacity within the operational congestion management market. In addition, it seems likely that with a further harmonization of the European power markets and their gate closure times, the DACF process could be preponed.

Combined Balancing and Operational CM market

The market processes within the combined mFRR and operational CM market are similar to the ones within the balancing market. Since, apart from forwarding mFRR balancing energy bids to a common European platform (MARI), the procurement of mFRR is still specific to the different countries, one possible two-stage market process is explained subsequently. A detailed analysis of the existing reserve and balancing markets in Europe can be found in chapter 4.3 within the INTERRFACE deliverable D2.3. The pan-European analysis shows that apart from the standardization of the different reserve products, heterogeneity regarding the procurement process exists. This includes, but is not limited to settlement rules, lead-times and activation mechanisms.

To ensure that a sufficient amount of capacity is withheld and not marketed within the energy markets, a capacity reservation mechanism is used within the combined market. In order to procure the necessary amount of capacity, a market-based approach is used. Thereby, a daily auction as well as a high product resolution increase liquidity within the market. The participating grid operators determine their need of flexibility a priori, based on their experience and statistical analyses which is then published on the respective bidding platform. Bids of participating units, consist of a price for the offered capacity as well as for the delivered energy. Since this process resembles the procurement of capacity for mFRR, an integration within that stage (e.g. by using a common procurement platform) could unlock additional synergy potentials. It should be however noted that the reservation of capacity is subject to national specifics and therefore will not be considered within the proposed market framework. In order to be activated for congestion management purposes, bids need to be extended by some locational information. The spatial resolution of that information depends on the grid as well as the nature of the occurring congestion.

Bidding within that first stage is possible until the gate closure time of 12 p.m. which is synchronised with the closing of the day-ahead market in order to minimize the inference of both markets.

Subsequently, bids are selected based on their capacity price using a pay-as-bid mechanism which is described further within chapter 5.4.3.2. Apart from the price, the location of the potential bid is highly relevant for the grid operator if it is intended to be used for congestion management. Possible approaches of the bid selection considering locational information are also covered within the subsequent chapter. As a result of the first stage of the combined balancing and operational congestion management market, an adequate[34] amount of capacity for balancing and CM purposes is procured and withheld for the next day.

Within the second stage and within the operational timeframe, congestion management bids are activated preventively before real-time, if congestion occurs. Balancing bids are activated reactively after the occurrence of an outage. The derived merit order within the individual markets consists of the submitted energy prices of the bidders which have been successful within the former capacity reservation, but could also be extended by some free bids. These free bids could consist of unsuccessful bids from the capacity reservation mechanism or flexibility which is marketed within the short-term horizon and can’t be reserved. Accepting free bids would also require a rolling mechanism where bidders regularly submit their bids.

Within the operational timeframe, the partial integration of both merit order lists could boost liquidity and reduce activation costs. This is illustrated in Figure 22 for the exemplary activation of flexibility resources for congestion management. It is also important to note that a purely cost-based evaluation of the bids assumes that every bid has a similar sensitivity on the congestion. In this stylized example, the additional bids are able to reduce the activation costs, since the weighted average price within the combined market is lower. The same mechanism applies for the balancing use case, where localized congestion management bids are integrated into the balancing MOL and even higher efficiency gains are expected since theoretically, not just a subset, but all congestion management bids can be used for balancing purposes. It should be noted, however, that the activation of flexibility resources for CM and balancing is always associated with mutual backslashes, which need to be taken into consideration during grid operation.

[34] For balancing this relates to the well-established dimensioning methodologies. With respect to the necessary procured capacity within a congestion management market, the operational experience of grid operators will be key.

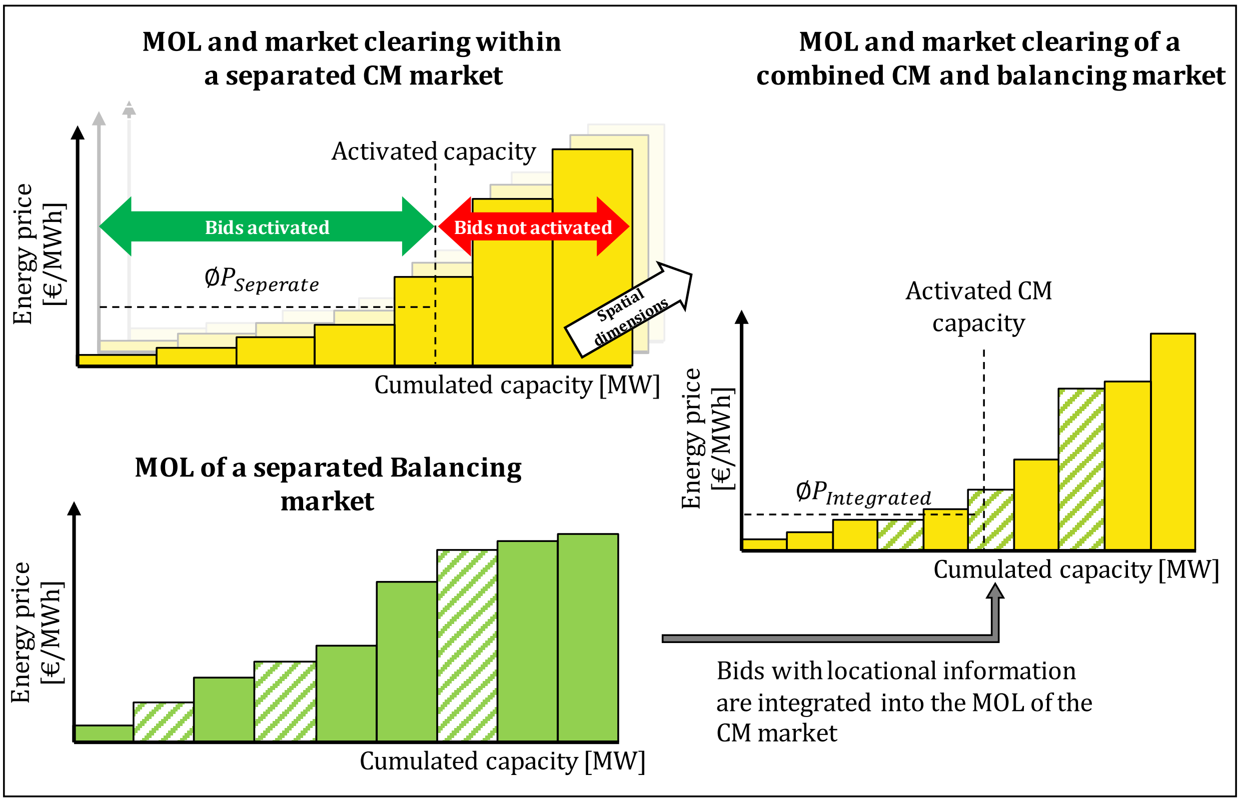

Figure 22: Economical benefits of a combined MOL for CM and balancing energy

The market processes, which were described, referred mainly to TSO processes while being applicable for DSOs as well. Within a market, where only a TSO is active and the DSO is not part of the described market (option 1B within Figure 19), a simple coordination scheme between the TSO and DSO is necessary since the TSO can directly access certain units within the distribution grid and therefore informs the respective DSO.

However, also a partly (3A) or full integration (3C) of the underlain DSO is possible and could be beneficial in case of an efficient market design. The integration of a DSO involves including the additional flexibility demand into the market as well as enabling market access of assets which are located in lower voltage levels. Essential for an efficient market operation of such a market, is a well-designed TSO-DSO coordination scheme which will also be discussed within chapter 5.4.3.4. Subsequently only the major challenges with respect to the market processes are described.

With respect to the presented market processes, DSO can be integrated with low efforts. Due to the galvanic isolation of distribution grids, no common pan-European planning process between DSOs similar to the DACF exist. Instead and in addition to the internal planning of the DSO, the coordination process with the TSO also encompasses the planning phase. Due to the high heterogeneity of DSOs this process can hardly be generalised.

Following the idea of an integration of DSOs, the demand for flexibility within the short-term as well as the operational congestion management market is extended by integrating the needs of the DSO. Therefore, a higher spatial resolution of the bids is needed to efficiently resolve occurring congestion. Including additional and lower voltage levels also implies a decreasing liquidity of the market since the number of units which have an effect on the occurring congestion decreases likewise. With respect

to balancing, a participation of units within the low(er) voltage grid is still associated with numerous challenges e.g. the required level of reliability. In addition, the radial grid structures which occur within lower voltage levels, limit the number of flexibility units which have a sensitivity on the occurring congestion limiting the liquidity of a CM market by design. The additional benefit of the integration of low(er) grid levels is also highly dependent on the development of the costs for the information and communication components and the resulting business case for aggregators. Therefore, only congestions which occur in the highest voltage level of the DSO (predominantly associated with a meshed grid structure), is considered within the proposed market design[35]. A possible market design for dealing with congestion in lower voltage levels could be based on local flexibility markets (LFM) or local energy markets (LEMs) (compare chapter 6). The latter are introduced in chapter 6 of this deliverable. Furthermore, the separated congestion management market, described in subchapter 5.2, offers advantages in terms of adaptability to the DSOs needs and might be better suited for dealing with congestions in low-voltage networks. On the supply side, the integration of the DSOs and units, which are connected to the distribution grids, significantly increases the flexibility potential and therefore the liquidity within the described markets.

5.4.3.2 Market mechanism

Within the proposed combined CM and balancing market, different market mechanisms are used for clearing. Therefore, the main differences and major challenges will be explained subsequently.

Combined short-term CM Market

The presented short-term CM market is conceptually linked to the energy markets and uses an auction-based market mechanism. Using an auction has an operational advantage with respect to timing. In order to ensure a sufficient lead time before physical delivery, the trading time is limited and doesn't allow a continuous mechanism where trading unfolds over a longer period of time. Furthermore, for an efficient estimation of the flexibility demand of the grid operator, it is necessary to have the collected bids for all hours of the next day at once. This allows the grid operator to perform a time-coupled optimisation of its flexibility demand while being able to see all bids (degrees of freedom within the optimisation problem) for the next day. Having a continuous trading mechanism would end up in a more complex sequential optimisation.

Combined Balancing and Operational CM market

Within the combined CM and balancing market a two-stage bidding model is in place which is illustrated in Figure 23. For the initial capacity reservation, which takes place separately for CM and mFRR, an auction based mechanism is used. Successful bids receive a capacity payment and appear within the merit order for activation. These bids could be complemented by free bids which did not participate within the capacity tendering or have not been successful. In that case, additional information regarding those bids, consisting of price and volume (and location in case of the CM market), is needed to ensure that the respective merit order list is extended. Subsequently, during the activation, bids are activated in ascending price order until the demand is met.

[35] Congestion occurring for example in the low voltage grid would not be resolved using the proposed congestion management market. Nevertheless, flexibility units on all voltage levels are able to participate in CM markets within higher voltage levels.

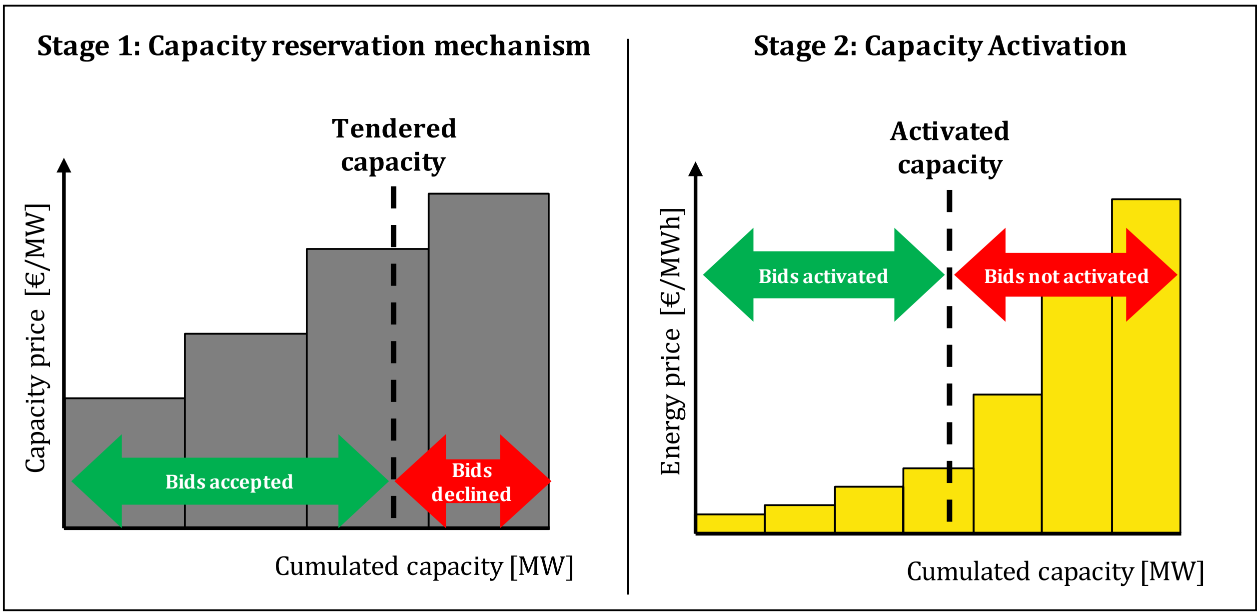

Figure 23: Two stage bidding model for the combined CM and balancing market

In case of an activation for balancing purposes, bid selection follows the well-established economic principle. If bids are activated for congestion management purposes, bids cannot be chosen based on their price tag only, since the sensitivity on the occurring congestion might differ. The spatial evaluation of bids could follow two different general principles: a nodal approach or an introduction of specific market areas.

Using a nodal approach in that sense refers to the degree of detail and the resolution of the local information which could be found within the CM market. This is illustrated in Figure 24 where the sensitivity of all nodes within the grid is also reflected within the market.

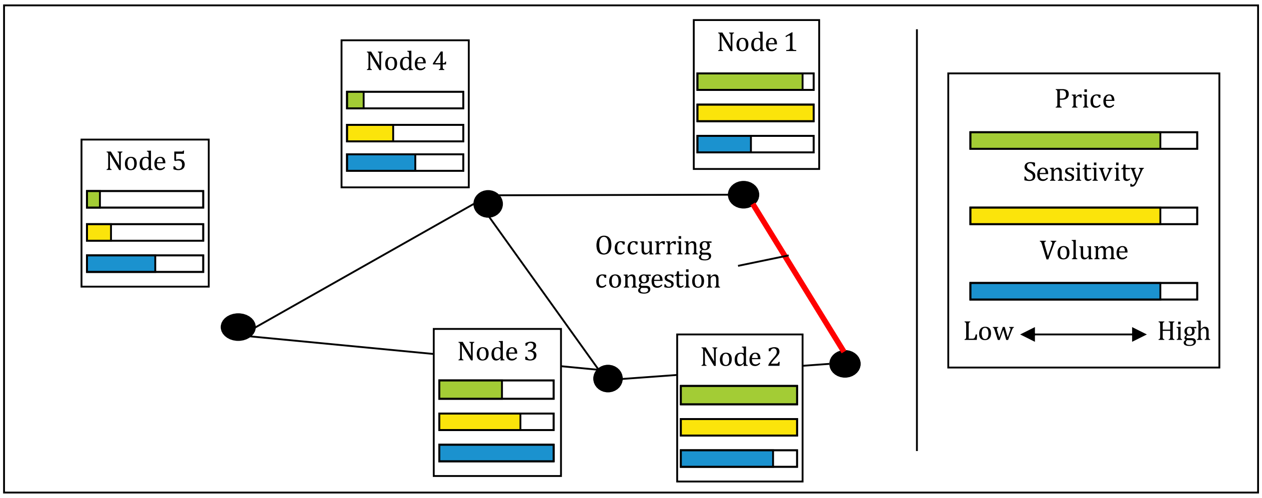

Figure 24: Nodal resolution of the local information within a CM market

Thereby, every node not necessarily needs to be reflected by a single aggregated price, but could have a specific merit order list with the bids of the individual units which are aggregated to that node. The optimal selection of bids is an optimisation problem, which is solved by the grid operator after closing

the market. The advantage of using such a detailed approach is the higher efficiency compared to an approach with market areas since the precise effects of an activation of the flexibility resources can be anticipated. It is however questionable whether this level of detail and complexity is necessary within the market.

In order to reduce complexity within the CM market and harmonise the products, locational characteristics of CM bids could be represented by market areas. These market areas, which are illustrated in Figure 25, are defined as a certain number of nodes where an activation of flexibility resources has a similar effect on an occurring congestion. This aggregation simplifies the structure of the products by tolerating a certain degree of inaccuracies.

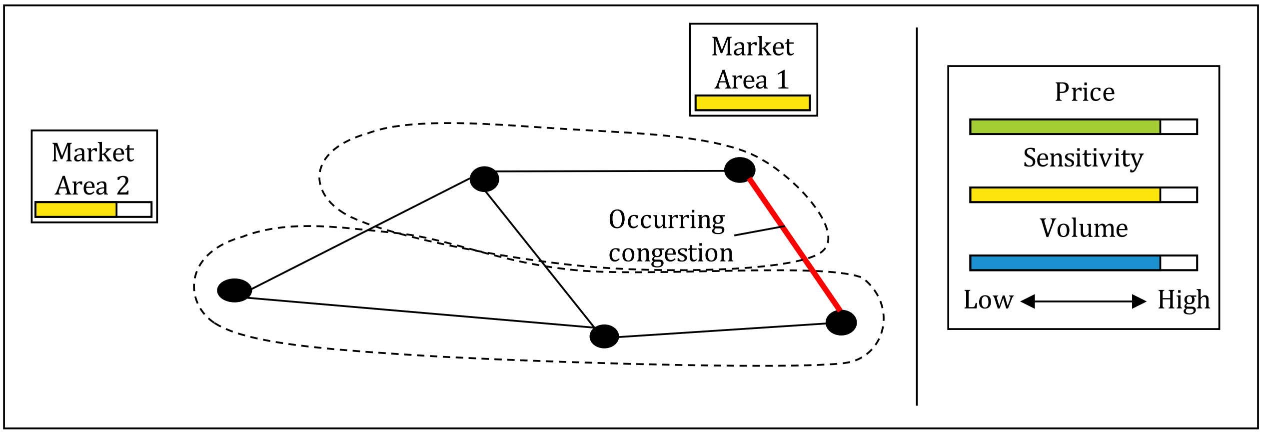

Figure 25: Zonal resolution of the local information within a CM market

However, the determination of these areas is a challenging task, since their setup is linked with the grid condition. In addition, relieving congestion within a market area becomes impracticable, since for CM, as explained within the product requirements, the adjustment of power in both (positive and negative) directions is necessary. With intra-area congestion, it could happen that, positive and negative flexibility potentials are practically activated at the same node. For that reason, the dimensioning of these market areas is a difficult process and should also incorporate operational expertise. The selection of a suitable local resolution is also dependent on the grid structure. Within radial systems the additional value and the applicability of a nodal representation is low due to the high number of nodes. Within meshed networks, where the number of nodes is lower, a nodal approach seems more suitable.

5.4.3.3 Market Access

Enabling access to the market for a high number of potential market participants raises liquidity and the efficiency of the market. Therefore, within the proposed combined CM and balancing market, as low as possible market entry barriers exist while still ensuring that the high product requirements within the balancing market are met.

Apart from larger flexibility units within the grid of the TSO and the higher voltage levels of the DSO, also small consumers should be able to access the market via aggregators. A certain threshold with respect to the size of the market participants limits the complexity during the market clearing process. First of all gathering all necessary information for a high number of participants increases complexity in terms of data handling and calculation times, while especially the more complex introduction of the spatial dimensions make a high number of units more complicated. For the balancing markets, as explained in chapter 5.3.3.3, market access rules are defined by the TSOs.

5.4.3.4 TSO/DSO coordination schemes

With the proposal of a market where transmission and distribution grid operators could be simultaneously active, there is the need for a well-functioning coordination scheme between the different grid operators. Therefore, within the following subchapter the major challenges associated with TSO/DSO coordination and approaches towards a solution are described.

Most importantly, an effective TSO/DSO coordination scheme prevents the activation of flexibility resources that could endanger grid security and cause additional congestion in the over- or underlying grid. Additionally, a holistic concept where TSOs and DSOs are considered together could gain efficiency by unlocking synergy potentials.

The required need for coordination is highly dependent on the level of TSO/DSO integration which is related to the introduced market options within Figure 19. In case of a combined market which is limited to TSOs (option 1B), the necessary coordination needs are comparably low. Flexibility resources located within the lower grid levels are able to participate on the market (within the short-term CM as well as the combined operational CM and balancing market). If they are accessed by the TSO after the market clearing, it needs to be ensured that the DSOs are not able to use the resource for similar purposes. Thus, DSOs need to consider the measures TSO have been taken within their planning process. A possible technical solution in practice could be a flag within the flexibility resource register which is activated if the resource is used by the TSO.

In a market setup where DSOs are integrated and also procure flexibility for CM purposes using the combined market (3A and 3C), coordination becomes more complex. This also includes a high synergy potential for the procurement of flexibility which is also illustrated within Figure 26. Thereby, a TSO uses a high volume of flexibility in order to resolve occurring congestion within his own grid regardless of any congestion within the DSO grid. This could result in an inefficient flexibility usage, since both congestions could be resolved by a flexibility resource located in the underlying grid as depicted on the right. Therefore, the holistic approach could unlock synergy potentials.

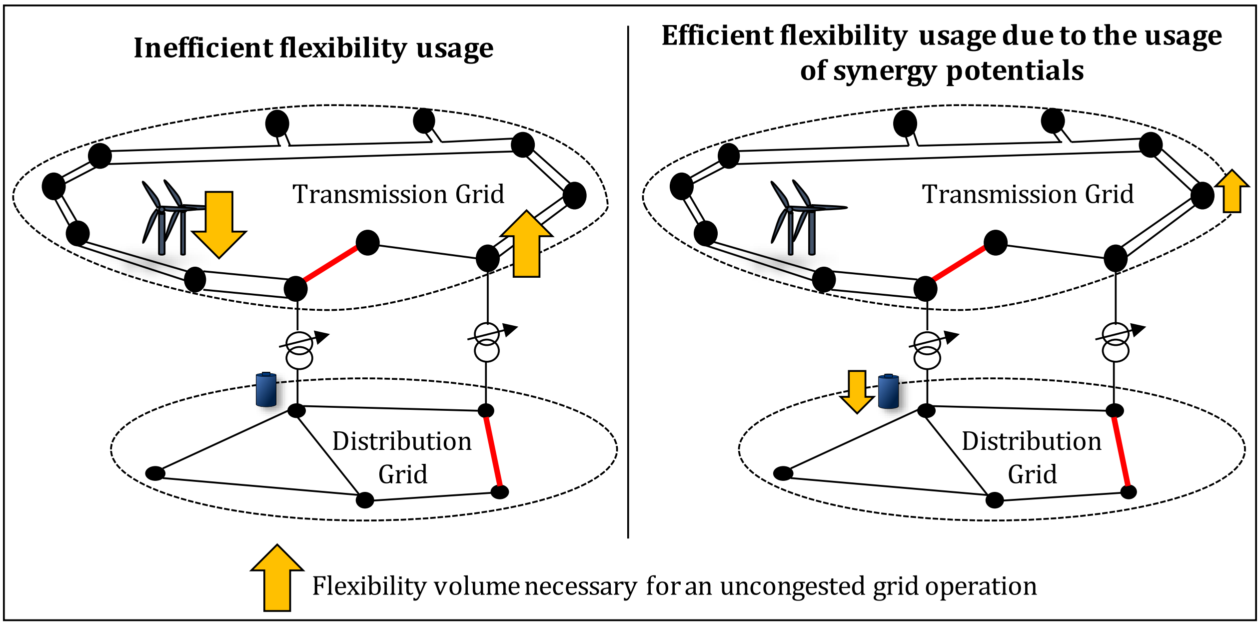

Figure 26: Possible efficiency gains due to a holistic TSO-DSO approach

Designing an efficient coordination mechanism is strongly influenced by the boundary conditions for grid operators during grid operation which are defined within the Operation Handbook[36] and illustrated in Figure 27. Firstly, grid operators are responsible for guaranteeing a safe operation of assets within their own responsibility area. Beyond this, neighbouring assets with significant influence on the own grid are monitored in real-time to ensure the operational security. Especially important for grid operation is the set of assets and units, which can be directly controlled and accessed and is defined as the control area. This given set of assets is the operational "toolbox" for grid operators to guarantee a safe operation of the grid. At the same time, the aim of an efficient grid operation is an operation with least costs (due to loss compensation or congestion management measures).

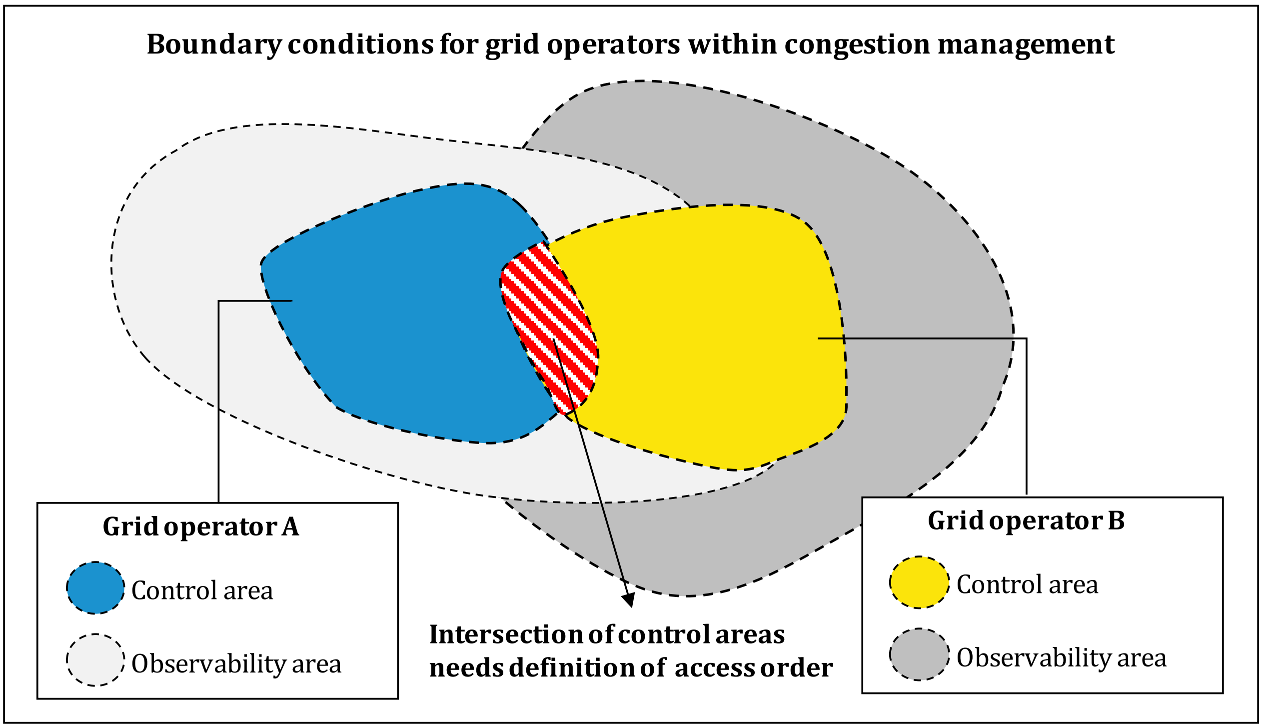

Figure 27: Boundary conditions for grid operators within congestion management

Within practical grid operation, the set of assets is often overlapping between TSOs and DSOs and therefore requires the definition of a certain order of access. This refers to the sensitive question which grid operator has priority access to these assets. Since this aspect is highly influenced by numerous regulatory and legal factors, subsequently only the conceptual idea of a solution is presented which is abstracted from a practical implementation. The basic concepts regarding a TSO/DSO coordination are namely:

- Prioritisation of one of the Grid Operators
- Central Coordination

Prioritisation concept

[36] UCTE OH – Appendix 3: Operational Security. ENTSO-E. Online available: https://www.entsoe.eu/fileadmin/user_upload/_library/publications/entsoe/Operation_Handbook/Policy_3_Appendix_final.pdf.

Using the approach of a prioritisation, the flexibility demand of the grid operators is procured sequentially. In doing so the grid operators run separate optimisations considering only their responsibility area when determining the flexibility demand which is then procured separately on the market. Thus, either the TSO or the DSO has priority access to the flexibility bids which are degrees of freedom within the optimisation problem. The subsequent grid operator is therefore only able to access a reduced (available) number of flexibility resources.

Central coordination

Conceptually different is the central coordination approach where a single flexibility demand is derived based on co-optimization. Therefore, one single optimisation problem is solved ensuring a secure operation of both grids while being able to access all flexibility potentials that are available within the market. This approach enables to unlock synergy potentials while being non-discriminatory in terms of flexibility access. It however requires a regular, complex exchange of grid and operational data.

5.4.4 Products

The detailed definition of products for the proposed short-term CM and combined operational CM and balancing market is highly relevant for flexibility providers as well as grid operators which procure flexibility. The following product features which have been identified during the analysis are valid for both CM markets. In addition, it is necessary to distinguish and take into account the different presented market options with respect to the level of integration between the grid operators.

Due to the local character of occurring congestion within the grid, the products within the CM markets need to be extended by a local component. Therefore, it is necessary to define the spatial resolution of the local component. As described within chapter 5.4.3.2, the spatial component could be represented generally by market areas or individual grid nodes.

In a CM market according to market option 1B, where only TSOs participate in the market, the spatial resolution of the local information can be lower compared to markets with DSO participation. Practically, the TSO needs to know the location of the participating flexibility units on the basis of transmission grid nodes. This means that all participating resources within the lower distribution grid levels need to be assigned to single transmission grid nodes according to their sensitivity. In doing so, it is important to take into account the impact on the surrounding transmission nodes, which depends on the grid structure.

In an integrated market similar to market options 3A or 3C, where TSOs and DSOs participate in the market, the level of detail necessarily needs to be higher since DSOs are using the market to relieve occurring congestion in their own grid. Therefore, the spatial resolution of the product within such a combined market could be on the basis of distribution grid nodes.

Defining an adequate spatial resolution includes balancing practicability in terms of market clearing and the level of detail, which is necessary for a correct estimation of congestions and their countermeasures. The definition of highly granular products also effects market liquidity negatively and suggests a higher level of aggregation.

The products for congestion management and manual Frequency Restoration Reserves (mFRR) differ in the way the flexibility providers deliver their products. Products for mFRR are always defined as either positive or negative in order to compensate for example a power plant outage. In that sense balancing products affect the system balance. In comparison, congestion management needs to be done in a balance-neutral manner, meaning that a positive and a negative product need to be activated

simultaneously. In order to relieve congestion a decrease and increase close to the congested grid element is necessary.

For defining the products for both markets more detailed, the product features of the ASM report of ENTSO-E[37] are used. The most important features identified are the number of products per trading period, the minimum/maximum bid size, the decision between 'partial' or 'all or none' bids, the product delivering duration, the product availability and the ramping duration. On the following pages these features are discussed for short-term and operational CM markets starting with short-term markets.

Short-term CM market

Considering the day-ahead frame, it is possible to identify potential products for the short-term CM market on the day-ahead market, since similar products are needed for congestion management.

'Partial' or 'all or none' bids

It should be predefined, if products/bids can be partially obtained. On the one hand, obtaining bids partially gives the grid operators more flexibility but on the other hand, there is also an operational CM market where participants can trade energy to compensate deviations from their congestion forecasts. In order to provide the most flexibility for the grid operators a valid approach is to define the products in the short-term market as partially obtainable.

Number of products per trading period

By setting a number of products per trading period, it is necessary to consider different time gradations. On wholesale markets as operated by EPEX-Spot and NordPool hourly and quarter-hourly products are mostly used. Especially, on day-ahead markets products are most often traded hourly. A higher resolution of quarterly products would lead to a significantly higher complexity for flexibility providers on the one side, but for market operators or flexibility buyers on the other side as well. On contrast, the higher resolution would allow a better coverage of the estimated congestions, but due to the fact that the day-ahead estimations do face some uncertainties this higher resolution doesn't seem to be reasonable. In order to be consistent with the resolution of the Day-Ahead market and allow an integration of both markets in the future, a reasonable approach seems to be the definition of products within the short-term CM-market with the same resolution.

Minimum/Maximum bid size

It is necessary to set a minimum and maximum bid size. On day-ahead markets operated by EPEX-Spot and NordPool the minimum bid size is around 0.1 MW and the maximum bid size is defined as 600 MW without block products[38]. The minimum and maximum bid size on short-term CM-markets depend on the market design. If only TSOs participate in the short-term CM market (market option 1B) the minimum bid size can be equal to the existing size of 0.1 MW because not every flexibility provider needs to have access to this market. On the other hand, if TSOs and DSOs share the same short-term CM-market the minimum bid size should be lower than 0.1 MW to enable more flexibility-providers to have access to the short-term CM-market. Nevertheless, the minimum bid size should

[37] TSO – DSO REPORT. AN INTEGRATED APPROACH TO ACTIVE SYSTEM MANAGEMENT. ENTSO-E. Online available: https://docstore.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/TSO-DSO_ASM_2019_190416.pdf

[38] Trading Products. Day-Ahead trading. by EPEX Spot. Online available: https://www.epexspot.com/en/tradingproducts#local-flex-trading

not be too low otherwise the number of participants and thereby the complexity of the market would become too high.

As the minimum bid size, the maximum bid size depends on the market participants as well. In order to work well with existing market, the adaption of existing sizes on day-ahead market seems to be a plausible approach. If only TSOs participate on the short-term CM market, a maximum bid size of 600 MW seems to be reasonable, taking into account that 600 MW are enough to solve a huge share of congestions. Furthermore, the availability of more than 600 MW of capacity at the same location seems to be comparatively small in comparison to the day-ahead markets, where the location is not relevant. If TSOs and DSOs participate in the markets the maximum bid size can be lower than 600 MW since the capacities to solve congestions are significantly smaller in many cases. Furthermore this reduction of the maximum bid size, makes the bids more comparable.

Availability of products

Generally speaking, an availability of 100% is the availability that network operators would like to have in order to solve their congestions. Obviously, it is very hard for flexibility providers to guarantee such a high level of availability. Taking into account, that most network operators do have further congestion management measures and that an increased number of production unit is based on forecasts, the restrictions from the balancing markets seem to be the binding ones. Taking into account the balancing products of the FRR markets, a 95 % availability of the products is required.

Mode of activation

Another feature is the mode of activation of the products, which can be manually or automatically. On short-term CM-markets there is no explicit activation as on existing wholesale markets today. Going along with the market clearing the flexibility provider knows whether his bid was accepted or not. If a bid is accepted, the flexibility provider knows at what specific time the flexibility needs to be provided.

Ramping period

The ramping time for the automatic Frequency Restoration Reserves (aFRR) is set to 5 minutes to react as fast as possible on frequency oscillations. Since congestions can be predicted more accurate, it is not necessary to define a ramping period. The flexibility providers only need to ensure that their products are available as contractually agreed.

Remuneration mechanism

In order to be consistent with the simultaneously operated Intraday energy market, it seems reasonable to introduce an energy-based product within the short-term CM market. This allows a prospective integration of the two markets.

Operational CM market

Products for the operational CM market have slightly different features as products for the short-term CM market. The trading takes place at the same time as the capacity auctions for balancing products and the trading products have now two components according to the aFRR. Within the first auction the reservation of available capacity is determined, while in the activation the actual activation of flexibility units is determined.

'partial' or 'all or none' bids

Since the aim of the combined CM and balancing market is the integration of both, the product definitions should be as coherent as possible. Considering the FRR markets the products in the

operational CM market should be partially obtainable. By allowing partially obtaining flexibility, the grid operators become more flexible and can fix the congestion with higher precision.

Number of products per trading period

The temporal resolution of the bids should be similar to the respective resolution of FRR products. These resolutions vary between the different European countries, between hours and days. In order to adapt to upcoming congestions more accurately the most suitable product would have a hourly resolution.

Minimum/Maximum bid size

The minimum bid size is similar to the short-term market and depends if TSOs and DSOs participate or only DSOs. However, the maximum bid size is 100 MW since the operational CM market is only used for smoothing of deviations in real time. In the context of congestion real time this means the products need to be available until 15 minutes before delivery.

Availability of products

Congestions management, similar to FRR can occur at any moment. Therefore, the products have to be available in the contractually agreed quarter-hours and with a 95 % reliability.

Mode of activation

The products in the aFRR markets are automatically activated to reduce the frequency oscillations as fast as possible. On the other hand, the products on the manual Frequency Restoration Reserves (mFRR) are manually activated because the energy deliverer has more time to react. Nevertheless, the products in the operational CM market should be automatically activated to ensure the fastest way to fix the congestions.

Ramping period

Due to the better short-term congestion forecast, the ramping period is longer for products on the operational CM market than on the short-term market. Following the recommendations of the MARI project for mFRR the ramping period should be 12.5 minutes[39]. Nevertheless, the products in the operational CM market are automatically activated and the providers only need to ensure the availability in the contractual agreed time.

Remuneration mechanism

Within the operational timeframe, a power-based product is suggested. This is consistent with the balancing market. Having a power-based product also minimises deviations of the delivered power over time, which need to be tolerated having an energy-based product.

5.4.5 Open Issues and Challenges

Despite a comprehensive theoretical analysis of the possible market design of CM markets, numerous challenges exists, which are associated with their practical implementation. These will be addressed in the following paragraphs.

[39] MARI – First Consultation. Call For Input. Online available: https://consultations.entsoe.eu/markets/mari-first-consultation-call-for-input/supporting_documents/20171121_%20MARI%20First%20Consultation_Final.pdf

Gaming

Combining the zonal market design of the European wholesale markets with a CM where the spatial resolution is on the basis of single nodes, the risk of Increase-Decrease gaming exists which is comprehensively covered within the literature[40]. Inc-Dec gaming refers to a strategy of market participants (flexibility resources) which anticipate the outcome on a subsequent CM market. If participants are able to predict the outcome of the market, they take into account its profit potentials and adapt their strategy within the wholesale market such that market participants in oversupply, low price market areas underbid their variable costs while market participants in undersupply, high price market areas withhold their capacity. On a system level, this leads to aggravated congestion and higher CM volumes and costs. In addition, and as a long-term consequence, Inc-Dec gaming creates disincentives regarding the location of additional generation capacity. It is important to note that the occurrence of Inc-Dec gaming is not a consequence of market power, but rather an issue of the combination of a zonal and a nodal market design. Proposed solutions are a consistent market design using either regulated congestion management or locational marginal pricing. However, within the practical implementation of innovative CM markets, Inc-Dec gaming has shown minor practical relevance yet.

Market Power

Within lower voltage levels, grid structures are characterized by radial structures which – compared to the highly meshed grids within the high voltage and ultra-high voltage level - limit the number of assets which have an effect on occurring congestions. Additionally, a significant number of individual flexibility resources are assigned to individual nodes within the transmission network whereas e.g. in the low voltage grid single flexibility resources are assigned to each node. Both effects have a crucial impact on market power so that the market power within a CM market operating in lower voltage levels tends to deal with higher market power of the participants. This leads to a decreasing efficiency of the market.

Liquidity & Participation willingness

Closely linked to the issue of market power, poor liquidity within newly build CM markets also decreases their efficiency. Therefore, the market entry barriers should be as low as possible to allow a high number of flexibility units to participate while guaranteeing practicability. This is highly dependent on the resulting prices within the market and the willingness of flexibility units to participate. This willingness however is significantly influenced by the resulting trading opportunities which appear within other markets. If revenue potentials within the CM markets exist, market participants will shift their flexibility potentials marketed within other markets (e.g. balancing market) to the CM market. Therefore, the analysis of the efficiency of CM markets require an integrated approach to consider these substitution effects. Apart from potential revenues, arising costs market participants are confronted with highly influence their participation willingness. Therefore, the development of costs for information and communication technology indirectly also affects liquidity and therefore market efficiency.

TSO/DSO cooperation

It has been shown that within the market design of CM markets, the interaction of TSOs and DSOs plays a crucial role and needs to be considered on multiple levels (access of flexibility assets as well

[40] Hirth & Schlecht (2019): Redispatch Markets in Zonal Electricity Markets: Inc-Dec Gaming as a Consequence of Inconsistent Power Market Design (not Market Power). Online available: https://www.econstor.eu/bitstream/10419/194292/1/Market-Based-Redispatch-in-Zonal-Electricity-Markets.pdf

as the location of the occurring congestion). The presented coordination schemes serve an indicative purpose but need to be adapted for the practical usage since the relationship between TSOs and DSOs can vary heavily depending on national specifics and the grid structure. Therefore, no standardized solution exists.

Especially within the lower grid voltage levels, possible benefits of the introduction of a CM market within those levels should be compared with the resulting effort and costs since issues of liquidity and market power tend to occur there. In addition, at the current technical state the observability and controllability of the grid within the lower grid levels is very limited compared to the high voltage and ultra-high voltage grid. This will improve with the progressing digitalisation, allowing a more dynamic grid operation also within lower grid levels. Therefore, currently a market-based solution should be carefully considered since it is not the only option to resolve congestion.

When combining CM markets with the existing balancing market, the high requirements of the TSO/DSO coordination are notably. This relates especially to the major differences with respect to the products. Products within the balancing market are clearly defined and require a high degree of availability due to the crucial role of frequency control within the whole system. The requirements within a potential low-voltage CM market are fundamentally different due to the local character of occurring congestion. Harmonizing the product requirements of both markets is a major challenge and will require further analyses.

6 Local energy exchange markets

The peer-to-peer (p2p) local market has been designed to open a new market for the distribution grid consumers. Therefore, it would exist parallel to the wholesale intraday market. The market is going to cover low and medium voltage consumers. Low voltage consumers are possibly not participating at the existing wholesale electricity markets today, but rather purchase their electricity from a supplier. Nevertheless, already today medium voltage customers might be active at the balancing market of the transmission system operator.

Nowadays, various local market concepts exist all over the world. Examples are amongst others the Brooklyn Microgrid (BMG)[41], the powerpeers network (pp) in the Netherlands[42] and the sonnenCommunity (sC) in Germany[43]. Most of these existing market concepts are only virtual as powerpeers and the sonnenCommunity and most of them do not consider the underlying grid (BMG, pp, sC).

The BMG is a local p2p market in Brooklyn, New York, USA. Through its' so called Exergy platform, it realizes a local energy market that helps to connect RES producers with the local grid consumers and thereby increasing the integration of RES in the network. Additionally, the BMG provides flexibility services for the DSO, that can be activated by the DSO upon need. In contrast to the BMG, the INTERRFACE T6.1 local p2p market concept is not foreseen to provide explicit flexibility services for the DSO. Instead, DSOs' preferences and grid-properties are considered by the algorithm which is based on load-flow-like calculations. The BMG applies Blockchain-technology as a facilitator of small consumers in the INTERRFACE T6.2 concept. Another similarity between the BMG and the INTERRFACE T6.1 demonstration project, apart from being a p2p local market, is the fact that the conventional electricity delivery via a supplier can exist in parallel to the local market. Furthermore, and according to European legislation, market participants can choose their suppliers.

The sC is a virtual community, where prosumers with PV-units and battery-systems connected to a “sonnenBatterie” energy management system and a “sonnenFlat-box” communication interface are connected. The sC provides balancing services for the TSO (TenneT) by acting as a VPP. At the same time, sC acts as an energy supplier for the members of the community.

Powerpeers is a p2p energy retailer that brings together renewable energy producers and customers. It provides a platform where each customer can set up a specific preference list of suppliers. Powerpeers matches the customers' consumption with one of the five preferred suppliers chosen by the consumers. Thereby, a very simplified market is modelled, while the preferences are not only based on prices but further than that on social or ecological benefits. If the consumers cannot be supplied from the preferred supplier, pp, as their official retailer, supplies them from large green energy suppliers. In contrast to the INTERRFACE T6.1 concept no grid components are taken into account in this market.

The comparison of the introduced local markets can be seen in the table below (Table 8).

[41] Brooklyn Microgrid, available online: https://www.brooklyn.energy/

[42] Powerpeers, available online: https://www.powerpeers.nl/about

[43] SonnenCommunity, available online: https://sonnen.de/sonnencommunity/

Table 8: Comparison of the local market concepts

	Virtual	Considering the grid	Provide explicit flexibility (reserve) services
Brooklyn Microgrid	no	no	for the DSO
sonnenCommunity	yes	no	for the TSO
powerpeers	yes	no	no
INTERRFACE 6.1 local market	no	yes	no

6.1 General Description of the market

6.1.1 Market goals

The local energy market aims to create a marketplace where small customers, who are not capable of participating at existing (wholesale) electricity markets because of the minimum size limits and the relatively high entrance costs, can participate in. The consumers should be enabled to cover their electricity demand via this local energy market. The local market trading facilitates the local useage of locally generated electricity from distributed generation units (especially units based on renewable energy sources), thus reducing reverse flows to higher voltage levels and keeping losses on manageable levels. Therefore, the local p2p market is supposed to support the integration of energy from renewable energy sources.

At such local markets consumers have the choice to buy directly from their neighbours, from specified generation units based on social or ecological reasons, or simply based on economic reasons. Trading at the local market is expected to imply a community feeling and a certain independency. The consumer has the choice to choose their preferred energy mix, choosing directly the different sources at any given time. Because it involves trading with neighbours, participants have a higher involvement in fulfilling their energy needs, which transforms in either higher participation, word-to-mouth expansion of the market, it is up to the consumer to decide how much they are willing to pay for energy, depending on their use. This market can integrate different distributed energy sources efficiently and at a low cost.

In the meantime, this local market also supports DSO operation for which some proposals are going to be tested and to be selected (excluding those being not feasible in a real market environment). For this purpose, the market algorithm will consider the asset limits in the grid due to effects of trades and can block trades that would cause congestions. For this purpose, an asset condition management system is going to be integrated that would provide the loadability limits of line sections, transformers and switchgears based on the condition of the assets and not simply on their nominal values. Dynamic grid usage tariff will be applied favouring trades (with price incentives) that reduce DSO loss, diminish overloading and thus faster ageing of grid assets, reduce asymmetry, voltage problems and overall reducing negative effects of increasing intermittent renewable generation in the grids.

Local market participation is only optional and incentivized by expectedly lower energy amounts procurement and higher selling prices for locally generated electricity as well as the above mentioned

soft effects like the community feeling, green supply from neighbours and reduced environmental effects.

6.1.2 Services

In the INTERRFACE project several services that need to be addressed in the future have been defined in INTERRFACE deliverable D3.1. How markets for these services might look like is one of the major outcomes of this report.

Short-term congestion management service gathered in D3.1 can be linked to the local market concept of T6.1 that implicitly solves congestions as the market algorithm considers the grid effect of the trades and can prevent congestions by not permitting trades leading to them. Therefore, in this specific case, congestion management is not based on a direct activation by a system operator. Instead, CM is realized firstly by line section limitations considered in the load-flow like algorithm and secondly by penalizing through dynamic network usage tariff elements. While taking into account that section limitations through the load-flow like algorithm are part of the demonstration of T6.1, the dynamic network usage tariffs might be implemented additionally. The short-term CM is focused on the distribution grid where the local market takes place.

Another service defined in INTERRFACE deliverable D3.1 is voltage regulation, which can be procured via the proposed local p2p market concept as well. Similar to CM this service is implicitly covered in the market algorithm. This application of the local p2p market will be tested during the demonstration period of T6.1 as well.

While the provision of voltage regulations seems to be especially interesting for DSOs at low voltage levels the coordination of CM seems to be more relevant on medium voltage levels. Subsequently, depending on the market location and scope, the specific services might be more relevant.

The concept of the local market in T6.1 also provides a dynamic grid usage pricing (dynamic network usage tariff) for the DSO giving a solution for market-based grid cost distribution and procurement of energy for covering losses.

6.1.3 Integration between market levels

The decentralized local p2p market is separated from the existing wholesale and balancing markets. However, supplier and retail markets can still exist parallel to the concept of the local p2p market. The participation on the local market is not compulsory and the demand of a customer can be also traded partly from the local p2p market and from the currently operational supplier/retail market. For passive consumers, the supply does not change.

6.2 Market Parties

Distribution grid users (Defined as “Parties connected to the Grid”[44]) would trade actively on the local p2p market – they would be sellers and buyers of energy traded in the intra-day timeframe. Market participation is only a right of local grid consumers, not an obligation. If a trade intervenes, the peers (the seller and the buyer) are obliged to fulfil their contracts.

The local p2p market needs to be operated by a local market operator, which could either be an independent market operator or the DSO. While normally an independent market operator is

[44] Harmonised Role Model Version 2019-01

considered, the necessary interactions between DSO and market operator might make a solution where the DSO is the market operator more suitable. Although the authors do not recommend the latter case as the legislative framework (i.e. Clean energy for all Europeans Package[45]) does not support it. Other studies support the thesis that the DSO is expected to procure reserve-like services on a separate single buyer market (monopsony) similar to the TSOs' reserve market or at an integrated reserve market shared with the DSO (like the concept in the TSO-DSO Report[46]).

Another market party is the DSO who needs to co-operate with the local market operator in order to provide grid asset data for the market algorithm. The DSO would also need to provide metering data for the settlement related to the local market in lack of independent metering operator. The DSO might also request for extra cost parameters in the dynamic grid usage fee (e.g. increasing it when congestion or voltage problem is expected). Furthermore, DSOs need to provide information to the market regarding the expected CM needs and activities in advance. This can be achieved for example through a heat-map of congestion. This short-term information will help flexibility providers to offer and allocate their resources efficiently, allowing for optimal efficiency of the market.

The TSO does not play a main role in the local market but remains as a user of flexibility for system management. TSOs can acquire flexibility directly from the market through aggregators or groupings of prosumers or energy communities that take on the roles of suppliers or aggregators themselves. Further investigation is planned to be made on the possibility of the TSO to make bids on the local market or offering unpaired bids from the local market for TSO balancing and congestion management.

The NEMO has no direct role in the local p2p market concept. It might operate the local market, but as more local markets are expected related to real grid parts, maybe the NEMO is not the right entity to operate a local and not country-wide wholesale market.

Traditional suppliers have no special role at the local p2p market. The local market is originally designed for the trade of distribution grid users and not suppliers. As the proposed local p2p market would not be compulsory for all grid users, supplier contracts would exist parallel to the local market. First of all, those customers who would not participate at the local market, get energy from their supplier as currently. Secondly, the energy not traded on the local market would be supplied by the contracted supplier or trader.

The local market is not primarily designed for aggregators. Its aim is to enable the trading of small consumers directly at a local level and not aggregating them for wholesale or balancing market.

BRPs have no special role in the local p2p market concept. The local grid (and possible market) users of course belong to a balancing group. Local market participants might need to correct their schedules towards their supplier/trader depending on their local market trading.

[45] CEP https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/clean-energy-all-europeans

[46] TSO-DSO Report, An Integrated Approach to Active System Management - https://docstore.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/TSO-DSO_ASM_2019_190416.pdf

6.3 Market structure

6.3.1 Market Processes

The market processes of such a local p2p market is illustrated in Figure 28. The local p2p market algorithm needs to be initialized by a provision of grid information through the DSO. The grid information includes the grid layout and the location of grid users as well as the asset parameters (such as line section length, impedance, transformer type, nominal value, age…). This initialisation can happen once and following the initial initialisation it is necessary to update these information every time the grid layout, the asset parameters or the location of grid users changes. Furthermore, an Integrated Asset Condition Management System (IACMS) ensures that the actual asset conditions are monitored. The IACMS would be able to process information of on-site sensors as for example voltage sensors, in order to make those available to the local market module. Those sensors can be used by the DSO to receive updated information on specific grid assets for the smart asset condition management module in supplement to the grid asset information which can be updated by site visits only. Due to the higher importance in terms of security of supply of high and medium voltage levels, sensors could be used at high and medium voltage level first. The IACMS calculates loadability limits for the assets and sends that information to the local market module. These limits can be updated at any time.

Metering data history is necessary for the local p2p market as well, in order to estimate base case power flows on the distribution grid.

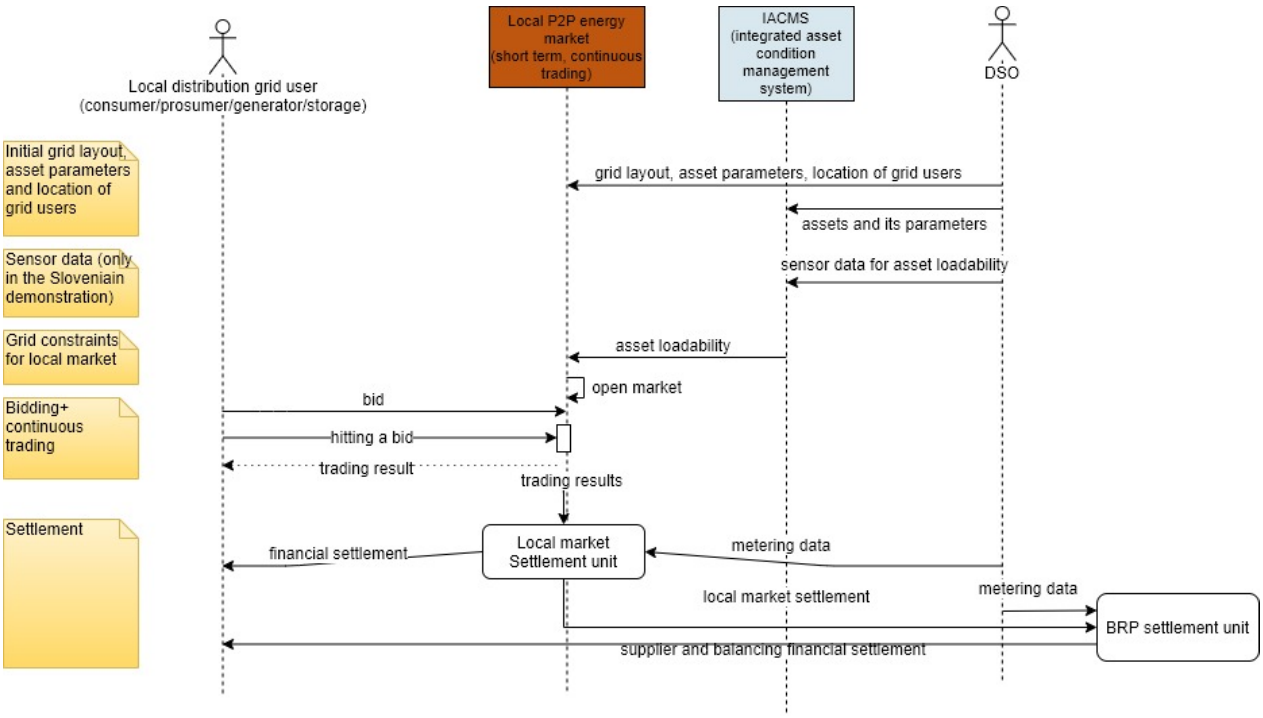

Figure 28: Sequence Diagram of Local P2P markets

Before the gate opening of the local market, a base case power flow is calculated by the local market algorithm. Possible trades will be compared to this. It models that consumption is considered as usual without any local market trade.

Then the local market can be opened for trading on D-1. Market opening is advised similar to the wholesale intraday continuous market timing – opening after the day-ahead processes are closed (this means around 5PM (depending on the country) after day-ahead market closing when the day-ahead operational schedules are available). The gate closure time is not important from the market concept's point of view, nevertheless it is advised to shift the gate closure time as close to real time as possible.

The grid users can submit orders to the order book of the local market or accept (hit) any offers in the order book. Order hitting is necessary as there won't be an automatic order matching to preserve the p2p characteristics. The order book looks different for all users by means of pricing. Order makers need to specify energy limit price for their offered quantities. The local market model calculates and adds grid usage fee to each placed orders and the other participants see the original order price modified by the grid usage fee. The fee can be different for all users depending on the possible flow caused by the given order. After each trade, the estimated load flow is recalculated that modifies the prices of the personal views.

Finally metering data and local market trading summary is needed to be compared for settlement that is done ex-post. The settlement of the local market trades is expedient to be processed by a special local market module similar to the current intraday market settlement.

BRPs will not only receive the metering data but also the local market settlement in order to be able to bill the supplied energy from the retailer/supplier and if necessary and having schedule-based contract, to settle the balancing. This settlement is like the current trader-BRP settlement with the additional information of the local market trades.

6.3.2 Market mechanism

The local p2p market mechanism is going to follow the continuous trading concept featuring quarter hourly products without automatic order matching. Automatic order matching should not be used, because the market aims to realize a p2p concept and therefore, the matching should be done by individual market participants. Hence the route of the flow is important and is dependent on the party who would accept an existing offer in the order book. For this reason, the concept of an aggressor has been proposed who needs to hit an offer and defines the power flow with this.

There is a risk of low liquidity as the market size is limited. Nevertheless, continuous trading has been chosen instead of an auction-scheme to better handle this.

6.3.3 Market Access

All customers connected to the given local distribution grid should be able to participate on the market. They can be consumers, prosumers or generators having either low or medium voltage connection to the respective distribution grid. Market access is ensured by small minimum bid sizes and low registration fees. The technical minimum requirement for participation on the proposed local p2p market is quarter hourly metering – either realized by smart meters or older industrial meters their quarter hourly profiles can also be read remotely once per day. The only further requirement for the customers is a contract with the local market operator.

There is no prequalification needed (defined in chapter 4.1.2) as it is not like the balancing market where the reserve providers need to pass the accreditation of the TSO checking their response capabilities.

6.3.4 TSO/DSO coordination schemes

As the TSO is not significantly affected by the local market concept, no special TSO-DSO coordination is necessary. It is nor assumed that all grid users trade exclusively at the local market as local market participation is only optional and not compulsory for the grid users. Moreover, local market participants can trade also at other markets (e.g. wholesale day-ahead or intraday), if they meet their requirements which is also possible for a minority of participants. They are simply responsible to satisfy all their contracts. This means that the supplement need of a consumer can be procured partly from the local market and partly from the supplier, trader or directly from the wholesale market. It is also the responsibility of the consumer to inform its trader or BRP in case of schedule modification. The local p2p market is going to have its own interface to the participants, similar to the wholesale intraday market.

6.4 Products

Since the aim of the local p2p market is to cover the electricity demand of consumers by bringing together consumers and producers, the product is energy based. Especially for small generation units or consumers a power product would be very hard to realize, since a constant demand is not a realistic scenario of end consumers. Instead, those smaller consumers or producers can only estimate their energy demand and therefore energy products are used in this market. Furthermore, this choice makes the market more similar to existing day-ahead and intraday markets and therefore reduces the entry barriers.

In most European countries, the metering and settlement intervals are expected to be 15 minutes. Looking at the existing European day-ahead and intraday markets the product resolution are 15 minutes to an hour. Since the energy demand of small consumers is subject to fluctuations, it is proposed to set the product resolution to 15 minutes in order to give consumers greater flexibility. The lead-time is set based on the settings at the different demonstration locations. Naturally, shorter lead-time is recommended to leave more opportunity for trading.

Local markets face the problem of liquidity. Therefore, it is not recommended to exclude potential market participants by setting a too high minimum bid size. The exact amount will be defined based on the analysis of metering data. The tick size of the products is not defined yet. With regard to the algorithm, it has to be examined how much a tick size would increase the complexity and the time required for the algorithm.

Since the power flow information are important for congestion management the products traded on the local markets are provided with a local component. All products are collected in one order book but every participant will see different prices. The difference is because of the different dynamic grid usage tariff added to the submitted energy orders that would be different at different locations of the grid. When one bid is submitted to the local market with an energy sale/purchase price and quantity, the algorithm calculates a full fee (energy + dynamic network usage fee) for all other grid users considering if any of them would accept the bid. The dynamic network usage fee can contain different components such as grid loss or congestion, and reflect the grid effect of the possible trade between any two peers.

The cost to be paid by the buyers is going to be proportional to the energy traded on the local market and verified by the meter reading of the given grid user.

6.5 Information Exchange and Data Management

6.5.1 Information Exchange between market actors

Distribution system operators must share the network topology of the local market area with the local market and the grid, transformer and switchgear asset parameters with the IACMS to calculate the load limit. The IACMS will provide the utilization limits of the grid facilities to the local market algorithm. The grid users will be able to submit or accept bids through a web interface to the local market. The DSOs might have the opportunity to indicate expected congestions or close to overloading events to the market algorithm.

The local market will send the financial settlement to the local market users after validating the trades with the metering data provided by Meter Data Responsibles (DSOs or third-parties). Meter data from the smart meters are usually read out only once per day during the night. Therefore, the financial settlement of the local market can be done earliest on D+1.

The local market will share the traded volumes with the adequate BRPs to acknowledge how much energy has been traded at the local market by the given grid user that its meter data includes. The local market traded volumes can be sent after the financial settlement of the local market on D+1 after comparing the traded volumes to the metered data. The BRP needs to make its settlement based on the metered data minus the local market trade of the given grid user both regarding energy supply/purchase and if justifiable also for balancing energy. Balancing cost billing might be adequate however once per month between the grid users and BRPs.

The information exchange will be done automatically during the demonstration of T6.1. The data channel will be dependent on the different DSOs during the demonstrations. Data sharing can be expected through servers. Metering and grid data formats are expected to be received in Excel, xml, txt format while grid topology maybe also specified in AutoCAD files.

6.5.2 Information exchange across markets

No direct information exchange is expected with other existing markets. Only the balancing energy market is touched consequentially but the settlement is only between the BRP and the grid users and the base for the settlement is the metered consumption (generation) minus the local market trade that can be compared to a schedule if having schedule based contract.

6.6 Open Issues and Challenges

Most of the challenges associated with this market design stem from the local scope of this market design. Typical congested areas could appear on a local grid that might put certain grid users to special position. This will be monitored during the demonstration project 6.1. However, this special role would simply mean that flexibility is more substantial at a certain grid part.

One open issue is the compensation that must be paid for the BRP, either through the supplier or trader of the grid user after the local market trading. Generally, there are no schedule-based users at low voltage (profiled consumers) but also not at medium-voltage (bigger consumers). Most grid users simply have full supply based contract where they do not need to give schedule for their trader/supplier or inform them about any changes in consumption. However local market trading

might cause higher fluctuation in procurement from the BRP. But in this case the BRP will have the right to force schedule-based contracts with its consumers which clearly defines balancing costs comparable to the schedule. Some medium voltage generators need to provide schedule for their BRPs but in this case they will have the obligation and motivation to change their schedules upon local market trading.

It is not clearly defined yet which options will be included in the dynamic network usage tariff – e.g. voltage regulation based network usage tariff element, loss based grid usage tariff element, extra tariff element in case of predicted congestion, asymmetry tariff element or time-of-use based network usage tariff element. It will depend on what data will be available at the DSOs at the different demonstration sites, what are their interests. Furthermore, several combinations are planned to be tested during the demonstration and the suggestion will be given based on the experience.

7 Summary and Conclusions

The interconnected European power system is confronted with numerous challenges within the next decade. The transition towards a carbon-neutral economy is mainly based on the vast increase of renewable energy sources. This trend is accompanied by the decentralization of generation, an increased electrification of different sectors and the emerging digitalization. For the first time, digitalization empowers a large number of small customers to contribute to these challenges of the power system. To facilitate the potential of small customers while maintaining the potential of all other customers, an easy access to various markets is especially important. Going along with this phenomenon the coordination between TSOs and DSOs becomes significantly more important due to the larger share of customers connected to DSOs but taking part on DSO and TSO markets. Besides the integration of decentralized energy resources into markets on TSO level, different markets on DSO level are expected to emerge in the future.

To address these trends and changes, the INTERRFACE project aims to design new services and markets in order to capture the effects of evolving energy markets and services using digital and science technologies and to ensure the participation of all service providers. Following D2.2 and D2.3 this report describes the results of the market design phase of potential new markets for services described in D3.1.

The analysis of changes and developments within the energy landscape showed that these changes and developments can often be traced back to four main drivers, which are Decarbonisation, Decentralisation, Digitalisation and Democratization (the 4Ds). Taking into account these trends, the importance of markets for ancillary services and especially for congestion management markets is expected to rise. Furthermore, the rising interest of small consumers and producers to participate on markets and to trade electricity locally while maintaining independence might lead to new local markets concepts. Therefore, the analysis conducted in T3.2 of the INTERRFACE project and described in this report focusses on these markets.

Taking into account the Active System Management Report by ENTSO-E different market options has been developed for this D3.1 report. The market concepts can be classified according to the integration between different congestion management markets and other markets and the integration of TSO and DSO levels. Following this classification, a detailed analysis of congestion management markets which are separated from other markets and congestion management markets which are combined with other markets was conducted.

The analysis for separated markets showed that this market design could be the target model for DSO congestion management markets because of its easy applicability and the fact that it can easily be tailored to the DSOs needs. The proposed market design is split up in a market for short-term congestion management and operational congestion management with procurement of short-term congestion management products and reservation of capacity for operational congestion management taking place in parallel.

The analysis for a combination of CM markets with further markets showed that in contrast to the separated markets, this market design is more favourable for TSOs and parts of the DSO grid with meshed structures. The market design is proposed to be split up into one market for short-term congestion management which is similar to the wholesale day-ahead trading in an auction based approach and a capacity reservation mechanism and activation for operational congestion management. While the processes of operational congestion management are similar to existing balancing markets, the short-term markets are more related to wholesale markets. The combination with further markets is therefore foreseen as a combination of operational-congestion management

markets with balancing markets and probably a combination of wholesale markets with short-term congestion management markets. Especially the combination of operational congestion management markets with balancing markets leads to high requirements for market participation, as for todays balancing markets, and makes the market therefore more suitable for TSO needs. At the same time using shared MOL increases liquidity and complexity. These shared MOL can be completed by locational information on a nodal or zonal basis to enable congestion management measures. The TSO/DSO coordination on those markets can happen either via prioritization or co-optimization for asset access.

Independent of the integration of markets specific processes like prequalification and settlement processes needs to be ensured. The design of this processes in future markets was analysed in greater detail. The analysis showed that both processes can benefit from a flexibility resource register where all necessary information are available. Therefore, this flexibility resource register was further analysed in a side note of this report (see Appendix).

Besides these markets for ancillary services, local energy exchange markets have been intensively discussed and a market design for those markets was proposed. The discussion concluded that local p2p markets can be a possibility to increase consumer participation on markets. Furthermore, these markets can incorporate additional decision criteria like regional, or ecological parameters.

The comparison of all market designs showed that all approaches have different advantages and disadvantages compared to other market designs. Furthermore, all market designs proposed in this document are subject to specific challenges and open questions that might be answered in the next steps of the INTERRFACE project.

The obtained results have been forwarded to the demonstration projects to test the proposed market structures in a realistic environment. Furthermore, the following tasks T3.3 uses the results for the definition of a system architecture for a common platform connecting all market participants and the different markets. Thereby, this deliverable together with D3.1 form the basis for the incorporation of the IEGSA platform.

APPENDIX

Market Operators

Flexibility platform market operator

Flexibility markets are not precisely defined in the existing academic literature and can take many forms. In this note, as a convention, flexibility markets are defined as market platforms that enable system operators, and possibly also balancing responsible parties (BRPs), increased access to flexibility services being it congestion management, system balancing and/or portfolio balancing. Both current and new market players (e.g. aggregated small- and large-scale demand, storage, generation) can participate. In this note, we focus on the question around the flexibility platform market operation function. Plausible options for the market operator are a network operator, being the DSO and/or TSO, a group of network operators or a third party.

The note is split up into five sections. First, we discuss in more depth the different market operator tasks. Second, we describe the EU and US experience with market operator roles in different markets. Third, we discuss the pro and cons of having a network operator or a third party taking up the role of the market operator. Forth, we illustrate how the market operator role is filled in for four existing flexibility market projects in the EU and one in the US. Fifth, we end this note with a wrap-up.

The market operator tasks

First, it is important to emphasize that this question around who should be the market operator is not black and white. Namely, there are several market platform tasks that do not necessarily all have to be attributed to the same entity. As an illustration, Ofgem (2019), the GB regulator, describes six flexibility platform tasks: coordination, flexibility procurement, dispatch and control, platform transaction settlement, platforms market settlement, and analytics and feedback. Figure 29 gives more details around these tasks.

Coordination	Coordinating platform tasks Facilitating data flows Harmonisation of standards and principles Alignment with external platforms and markets Conflict avoidance
Flexibility Procurement	Attracting flexibility providers and purchasers to the market Communicating requirements and availability Matching providers and purchasers
Dispatch and Control	Sending signals to dispatch assets Notification of asset dispatch Verification of asset dispatch
Platform Transaction Settlement	Verification of service against transaction Settlement of transactions
Platforms Market Services	Credit checking Asset pre-qualification
Analytics and Feedback	Network analytics, response times etc. Counterparty scoring and review Identification of market faults

Figure 29: Six identified flexibility platform tasks (Ofgem 2019)

In this note, we consider the market operator's core tasks are flexibility procurement and platform transaction settlement. In what follows, we will focus on these two tasks when discussing the market operator role. Coordination in the broader sense (i.e. not just between TSO and DSO, but also including market operators, flexibility providers, etc.) is also important but can be a joint task of the platform operator and other parties, e.g. if a third party is the platform operator, defining market products can be a task carried out in cooperation with the network operators and might require regulatory approval. Analytics and feedback is a task which is important to improve the functioning of the market place but not fundamental for setting up the platform. Platform market services can be a task of the market platform operator, depending on the exact service. For example, asset pre-qualification will most likely be done by TSO and/or DSO though as main 'end users' of flexibility services, while it is less obvious who would be in charge of credit checking. Dispatch and control is rather a task of the network operator.

The experience in other established electricity markets

Looking at the existing electricity markets in the EU, it can be seen that the market operator role depends on the specific market.

For example, wholesale markets are operated by (third-party) power exchanges. Important to add is according to the Congestion Allocation Management Guideline (CACM GL), power exchanges can be designated as monopolies within a Member State or as a merchant. Examples of monopoly power exchanges are OMIE in Spain and GME in Italy. Examples of merchant power exchanges are EPEX Spot and NordPool active in a multitude of countries such as France, Germany, Belgium, the Netherlands and others. Since the adoption of the CACM GL, power exchange organizing cross-zonal trade in the day-ahead and intraday market have been labelled Nominated Electricity Market Operators (NEMOs). An overview of the current NEMO landscape can be found in Schittekatte et al. (2019a). Besides collecting orders and settling contracts, a very important task for NEMOs is collectively establishing and operating the market coupling operator (MCO) function. The market coupling operator (MCO) function is defined as the task of matching orders from the day-ahead and intraday markets for different bidding zones and simultaneously allocating cross-zonal capacities. This task is done jointly by all NEMOs as it is by nature monopolistic. Figure 30 summarizes the CACM GL governance framework of the market operator role in EU wholesale markets.

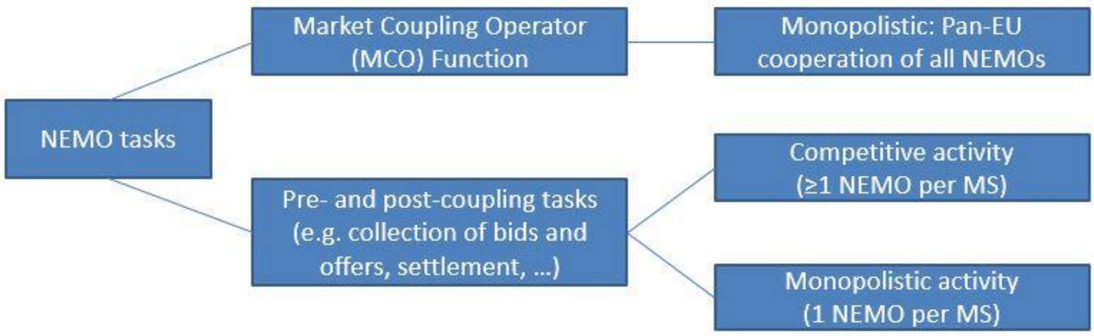

Figure 30: Summary of the CACM GL governance framework of the market operator role in EU wholesale markets

Forward markets (>1 day before delivery), consist of two types of markets. Futures markets are long-term markets organised by third party power exchanges where standardised products are traded. Over-the-counter markets are long-term markets where unstandardized products are traded. Long-term cross-zonal capacity rights between different bidding zones are traded on the Joint Allocation

Office (JAO). JAO was designated the single allocation platform according to the Forward Capacity Allocation Guideline (FCA GL). JAO is a service company owned by twenty-five Transmission System Operators (TSOs) from 22 countries.

Markets for ancillary services and redispatch markets, are operated directly by the TSOs in Europe.[47] Thus, the market platform is a monopoly with TSOs being both the market operator and the single buyer. On the other hand, recently, EPEX SPOT and National Grid joined forces to develop and operate a platform which will host a brand-new firm frequency response auction trial in Great Britain in 2019 (EPEX SPOT 2018). In some countries, the balancing energy and imbalance settlement task is outsourced to a third-party company. These are so-called Balancing and Settlement Code companies (BSCCo). An example is Elexon in GB. Recently, also European balancing platforms are being set up. In terms of the market operator, the Electricity Balancing Guideline (EB GL) allows two options, namely the operation 'by TSOs' and the operation 'by means of an entity created by the TSOs'. All NRAs are of the opinion that if all TSOs want to propose that the platform is operated by an entity created by the TSOs, this entity needs to be legally distinct from the TSOs and enjoy full legal capacity (All NRAs 2019).

The institutional setting is different in the US and other parts of the world. For example, in liberalised systems in the US (e.g. PJM, MISO, ERCOT) there is one Independent System Operator (ISO) active who is in charge of the operation of the integrated spot (day-ahead and real-time) and reserve market with nodal pricing. The ISO also auctions the financial transmission rights. Futures markets are organised by competitive power exchanges or financial institutions. There is no need for redispatch at transmission-level as the transmission constraints are optimised in the clearing function of wholesale prices. The transmission assets are owned and maintained by Transmission (Network asset) Owners (T(N)Os). Table 9 summarizes the market operator role in the EU and the US for different markets.

Table 9: Overview of the market operator role in the EU and the US for different markets

<table>
<tr><th>Which market?</th><th>Market operator EU</th><th>Market operator US – e.g PJM</th></tr>
<tr><td>Forward energy</td><td>Competitive PXs</td><td>Competitive PXs</td></tr>
<tr><td>Forward transmission capacity</td><td>Monopolistic service company owned by TSOs , with exception[48]</td><td rowspan="3">Monopolistic RTO/ISO
(no need for redispatch due to nodal pricing)</td></tr>
<tr><td>Spot markets</td><td>Competitive or monopolistic PXs</td></tr>
<tr><td>Congestion management</td><td>Monopolistic TSO</td></tr>
</table>

[47] Currently redispatch is mostly done in a cost-based manner. It is also jointly done with balancing in several Member States. The CEP requires market-based redispatch, i.e. the abolishment of regulated or cost-based prices for redispatch, except under certain conditions. Such conditions include, among others, the unavailability of market-based alternatives as well as situations whereby regular and predictable congestion gives way to regular strategic bidding which would increase the level of internal congestion. Currently, for example, TenneT NL, the TSO in the Netherlands, does market-based procurement for redispatch (TenneT 2019).

[48] With the exception of the organisation of the Electricity Price Area Differentials (EPADs) in the Nordics done by Nasdaq.

(National) Balancing	Monopolistic TSO (possibly third-party settlement company)	
EU platforms for balancing	Monopolistic TSOs or monopolistic entity created by TSOs	/

The arguments for the different options for the market operator entity

Multiple academic papers, e.g. Burger et al. (2019a), Stanley et al. (2019), Ramos et al. (2016), emphasize that to ensure transparency and prevent foreclosure the market operator must maintain complete independence from market activities and seem to suggest a third party taking up this role. ENTSO-E et al. (2019) stress that network operators should act as neutral market facilitators.[49]

More general, Schittekatte and Meeus (2019) list three arguments in favour of having a third party as flexibility market operator and one argument against.

First, in the case of DSOs, the know-how might not always be present in-house to build up market platforms from scratch. Stanley et al. (2019) point out an engagement with a specialized third party can allow for a faster development of the procurement mechanisms of new services.

Second, an argument often brought up by power exchanges is that by letting the market operation function over to a third party, neutrality between buyers and sellers is ensured. Relevant in this regard is that Gerard et al. (2018) and USEF (2018) note that the party being the market operator will be a function of whether the flexibility market is separated or integrated with other markets. For example, in the case both DSOs and the TSO use the same platform to procure flexibility or the flexibility market is integrated in, for example, a local wholesale market, the neutrality among buyers is assured by having a third party as market operator.[50] Burger et al. (2019a) emphasize that neutrality is even more important if the network operator would own distributed energy resources itself (e.g. a battery). Reversing this argument, if a network operator or multiple network operators would become the flexibility market operator, stronger unbundling requirements would need to be enforced and the institutional framework might need to be adjusted. This point is mainly relevant for DSOs in Europe as even in the scenarios where CEP allows storage ownership by TSO, this is for integrated network components that cannot be used for balancing and congestion management. This argument is detailed in Buchmann (2019).

Third, if network operators (DSO or TSO) operate the market platform for flexibility procurement, the platform will be monopolistic by nature. However, if a third party operates the platform, this is not necessarily the case. The question of whether market operation is a monopolistic activity or whether it can be a competitive activity is discussed in depth in Meeus (2011) for wholesale markets. In that paper, it is argued that due to network effects it is hard to have well-functioning competition between

[49] We understand under a neutral market facilitator a party that guarantees equal market access for all market parties but not necessarily a party that takes up the role of market operator.

[50] On the other hand, if the flexibility market is fully integrated with balancing (an option considered in ENTSO-E et al. (2019)), it would be obvious in the current EU context that the market operator would become the TSO as the balancing markets are operated by the TSO. Currently redispatch at transmission-level and balancing are already fully integrated in several countries, e.g. GB and the Nordics (ENTSO-E 2018).

market platforms but that allowing competition has several advantages, for example, stronger incentives for innovation. However, the market clearing itself will always be a monopolistic function.

An argument against having a third party as a market operator is the cost of interface management between the grid operator and the market operator.[51] In general, there is always a cost to manage interfaces between different parties when formerly integrated activities are unbundled. A typical example of the trade-off between removing conflicts of interest and the costs of interface management beyond flexibility market design is the historical debate about the unbundling of TSOs in network asset owners (TNO) and a system operator (ISO) as documented by Pollitt (2012) . More recently, this debate has been revived for DSOs, see e.g. Burger et al. (2019b).[52]

Models chosen in existing flexibility markets

In Schittekatte and Meeus (2019) four flexibility pilot projects are analysed: Piclo Flex, Enera, GOPACs and NODES. In all four cases, a third party operates the market platform.

First, Piclo Flex is developed and operated by a new entrant in the energy business, Piclo (previously known as Open Utility). Piclo is an independent software company that has been active in the energy industry since 2013. Piclo Flex was piloted in June 2018 with funding from UK Government Department of Business, Energy & Industrial Strategy (BEIS) and subsequently launched as a commercial offering from March 2019 (Stanley et al. 2019). All six DSOs in Great Britain participated in the BEIS trials. Subsequently, Piclo has signed commercial agreements with three DSOs to support their ongoing flexibility procurement activities: UK Power Networks (UKPN), Scottish and Southern Electricity Networks and Western Power Distribution. Piclo builds the platform on which the tenders take place, announces auctions, matches flexibility providers with demand, deals with the settlement and provides feedback and analytics. DSOs forward their flexible demand to Piclo and deal with the dispatch. Products depend on the particular need of a DSO for a particular location. More precisely, the tenders are organised per constraint area, i.e. all flexible resources connected within a predefined geographical area can compete in the tender. For one constraint area multiple tenders can be held, e.g. for a different service (reinforcement deferral, maintenance, etc.) and different contract periods.

Second, in the case of Enera, EPEX SPOT built up the platform, one of the two largest power exchanges in Europe. Enera is a joint project between the power exchange EPEX SPOT, the energy group EWE AG, one of the German TSOs TenneT DE and the German DSOs Avacon Netz and EWE NETZ. A scalable pilot is built up in a showcase region, in this case in the windy Northwest of Germany. In Enera, network operators can buy flexibility in the intraday time frame to proactively alleviate congestion. As congestions are specific to certain locations in the grid, local order books are set up in Enera. Similarily as with Piclo Flex, besides building up the platform, Enera also matches flexibility offers with demand, deals with the settlement and provides feedback and analytics. Products are designed by Enera but set up in collaboration with the network operators. Flexibility providers should adjust their dispatch depending on their cleared offered on Enera.

Third, similarly, for NODES, Nord Pool, the other large European power exchange is backing up the development. NODES is a joint venture between the Norwegian utility Agder Energi and the European

[51] Please note that this argument only applies for platforms operated and used by one network operator. In case a platform is operated by one network operator but used by multiple network operators, there will also be a cost of interface management.

[52] Please note that with a third party market operator and a DSO, there is an interface between the market on one side and the grid assets and operation on the other side. With an IDSO as market operator and a DNO, an interface would be created between the market and operation on one side and the grid assets on the other side.

power exchange Nord Pool. Agder Energi holds both distribution network assets and generation assets. In the white paper of NODES (2018), it is stated that if NODES is in full operation, it will need to be an independent party. As such, Agder Energi will not be a major owner of the marketplace. NODES was established in early 2018. Currently, NODES is active in three pilots. One installation is in place in Norway with the DSO Agder Energi Nett. The other two installations are situated in Germany. One is in use by the German DSO Mitnetz Strom and the other by the German DSO WEMAG Netz (Engelbrecht et al. 2019). Both DSOs are situated in the TSO area of 50Hertz. On the NODES platform, balance responsible market parties (BRPs) and network operators can procure local flexibility in the intraday timeframe. The offered flexibility, which is not needed locally, will be forwarded to other existing market platforms, i.e. the intraday and balancing market. Currently, the interfaces between NODES and the existing markets are not in place yet. In NODES, flexibility providers tag their offers with a grid location (GL). One or multiple GLs constitute a local (dynamic) pricing zone. Again, similarly as with the other already covered projects, besides building up the platform, NODES also matches flexibility offers with demand, deals with the settlement and provides feedback and analytics. There are no predefined products on NODES, instead flexibility providers have the option to characterize their offers through a set of parameters. NODES also allows network operators to create a template with the parameters they would like to see specified. Flexibility providers should adjust their dispatch depending on their cleared offer on Enera.

Fourth, in the case of GOPACS, currently, the platform provider is the Electricity Trading Platform Amsterdam (ETPA) which is a new independent power exchange active in the intraday timeframe in the Netherlands. Again, similarly as with the other already covered projects, besides building up the platform, ETPA also matches flexibility offers with demand, deals with the settlement and provides feedback and analytics. GOPACS is an intermediary between the network operators and the market platform which coordinates the flexibility needs of network operators. GOPACS stands for Grid Operators Platform for Congestion Solutions and was launched in January 2019. GOPACS is owned and operated by the Dutch TSO and four DSOs (Stedin, Liander, Enexis Groep and Westland Infra). Besides ETPA, GOPACS intends to be connected to more market platforms at a later stage. Offers from flexibility providers active on ETPA can be procured by GOPACS if they add a locational tag. There are no static geographical zones defined in ETPA. Instead, GOPACS identifies through its algorithm which assets offer the cheapest solution to solve a congestion.[53] GOPACS always clears two bids. This product is called an Intraday Congestion Spread (IDCONS) (GOPACS 2019). The buy and sell orders have the same format as intraday wholesale orders (simple bids of 15 minutes or 1 hour), and orders match in starting time, volume and duration but are located in a different area. For example, imagine a congestion in one part of the network due to high load. One energy sell order will be procured by GOPACS in that part of the grid. At the same time, in a non-congested area, an energy buy order will be activated. As such, an energy imbalance is avoided. The price of the energy sell order will be higher than the price of the energy buy order. The network operator who requests the flexibility pays the price difference (or spread) between the orders. At the time of writing, only flexible assets connected to the transmission grid are active on GOPACS. In the near future, also DSO connected assets at lower voltages are expected to participate.

Also, flexibility market places are being developed in the US. In the US context, these are referred to as Distribution System Platforms (DSPs). In parallel, there are also ideas to extend nodal pricing to the distribution-level in the longer run. Such approach is called distribution locational marginal

[53] Finding the cheapest solution to solve a congestion is a function of the price of the offer from the flexibility provider and of the location of the flexible asset. Some flexible assets can have a higher offer price but be more effective due to their location relative to the congestion issue.

pricing (DLMP) and would be the first best as grid congestions are included in energy prices and as such markets and grids can be better aligned. An implementation is discussed in Caramanis et al. (2016). However, in the meantime, DSPs are seen as immediate solution to allow for a market-based way to deal with congestion in the distribution network. An example of a DSP project which is part of the Reforming the Energy Vision (REV) proceedings of the New York State Public Service Commission (TCR 2016). The core idea is to create distribution level market for energy and related electric products from DER. According to the original approved plans, six investor-owned utilities would own and operate the DSP (RevConnect 2015; State of New York Public State Commission 2015).[54] But, the utility-as-DSP model is being disputed (Trivedi 2015).

Wrap-up and other thoughts

Four points summarize this note.

First, it is important to emphasize that the market operator role consists of multiple tasks of which several (e.g. collecting offers, clearing and settlement) could be more easily allocated to third parties while others could be the responsibility of network operators (e.g. prequalification, validating offers and product design). For example, in some balancing markets in Europe (e.g. GB) the balancing market is operated by the TSO while the settlement of balancing energy and imbalances is done by a third party.

Second, the degree of integration of the flexibility market with other (existing) electricity markets has an impact on who can fulfil the market operator role. Both design controversies are hard to decouple. For example, in the case both DSOs and the TSO use the same platform to procure flexibility or the flexibility market is integrated in a local wholesale market, the neutrality among buyers is assured by having a third party as market operator. On the other hand, if the flexibility market is fully integrated with balancing (an option considered in ENTSO-E et al. (2019)), it is hard to imagine in the EU context that the market operator would not become the TSO as the balancing markets are operated by the TSO. If a DSO or multiple DSOs would take up the role of the flexibility market operator, stronger unbundling requirements would need to be enforced and/or the institutional framework might need to be adjusted as also argued by Buchmann (2019). Currently DSOs are required to be legally unbundled in the EU (CEER 2019). This means that they can still be integrated with the market parties that offer their flexibility on the flexibility market.[55]

Third, currently we see different solutions compete for the market. This is beneficial for innovation as they all try to implement their own solutions and as such we can learn by doing. Currently, these third party platforms have a virtual monopoly position in the region where they are active and are not strongly regulated. It is unclear whether in the future it would be beneficial to see different flexibility platforms compete in the same region. Anyhow, the monopolistic task of market clearing would in any case have to be carried out under cooperation, if not fragmentation of the market should will lead to less liquidity and reduction of competition.

Fourth, Buchmann (2019) argues that even though discrimination between buyers and sellers and among flexibility providers can be avoided with a third party as a market operator, as long as DSOs remain only legally unbundled, there can be risks for other forms of discrimination, namely

[54] Utilities in the US context are companies owning distribution assets and possibly a retail business and generation assets.

[55] The Netherlands remains the only Member State where national law requires full ownership unbundling.

discrimination related to strategic network investment withholding and information sharing. The former discrimination evolves from the fact that network operators can decide on the need and potential for flexibility through their network investment.[56] The latter discrimination concerns the possibility that integrated network operators may discriminately share information on future network bottlenecks. These two concerns evolve independently of the DSO's active involvement in either ownership or operation of the flexibility market. Rather, these discrimination concerns are related to the DSO's role as potential single buyer (or one of the few buyers (TSOs and DSOs)) in a flexibility market. These discriminations could be addressed by requiring full ownership unbundling of DSOs or requiring an Independent Distribution Operator, i.e. the network operator is still owned by an integrated company but it is an independent division with its own corporate identity, resources and management. Another, maybe more pragmatic solution proposed by Buchmann (2019) would be to have a Common Flexibility Platform (CFP), a concept inspired from collaborative governance. The CFP is a cooperative, not-for-profit organization constituted by the relevant stakeholders of local flexibility markets (flexibility providers and network operators) that takes over solely responsibility for the governance of the local congestion market. The CFP could either perform the role of market operator or could delegate the market operator role to a third party. It is argued that such setup would still be compatible with the current setting, legally unbundled DSOs, while mitigating the different discrimination concerns.

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Flexibility Resource Register

Introduction and ASM report perspective

The TSO–DSO Report on An Integrated Approach to Active System Management (further – ASM report) [1] recommends the usage of a Flexibility Resources Register (further - Flexibility Register) for a coordinated, efficient and secure Active System Management (further – ASM) process. The objective of the Flexibility Register is to gather and share relevant information on potential sources of flexibility.

This would allow transmission and distribution system operators (further – TSOs and DSOs respectively) to have visibility on which flexibility resources are connected to their own grid and to their connected grids, so they know what resources are available to them at all voltage levels when solving grid constraints. This would improve the competition and utilization of flexibility resources.

The Flexibility Register should support the ASM process of each Member State. The role of the Flexibility Register for solving grid constraints, be it congestion management, system balancing, or other issues (e.g. power quality and voltage control) in each step is listed below.

Preparation phase

Information on flexibility resources that are pre-qualified or are seeking participation in congestion management and balancing should be shared and available for both TSOs and DSOs, through a flexibility Register. Due to this reason, the qualified connections would be registered in the Flexibility Register by the connecting transmission or distribution system operator.

It would, as a minimum, contain data as agreed and evaluated in the pre-qualification process. This would include technical information on the flexibility resource, such as location, approved capacity limits, duration, ramp rates, mode of activation, flexibility provider, baseline information. Additionally, this information could be further complemented with data on contractual arrangements with transmission or distribution system operator(s) and schedule data so as to prevent double or contradictory activation. The attributes depend on the type of service required by the transmission or/and distribution system operators. A flexibility resource can deliver multiple flexibility services to transmission or/and distribution system operators (e.g. congestion management, balancing, etc.). Once a resource is qualified to provide a service, its connection point is flagged as a potential provider of a specific flexibility service in the register.

The responsibility for entering and maintaining the data of the register should be decided at national level. However, the transmission or distribution system operator to whose grid the unit is connected stays responsible for the correct representation of the connection data. One flexibility service provider would not be able to see the data from another flexibility service provider.

Forecasting phase

Transmission and distribution system operators need to exchange relevant data to perform accurate forecast for congestion management and signal these congestions to each other and market parties (traffic light). Following ASM report, it is noted, that the flexibility register could support the exchange of information between TSO and DSO about their respective grids such as planning of grid reinforcements (year and months ahead), outage planning (months, weeks and day-ahead) and even

grid utilisation forecast (from month ahead up to intraday). Some of this data can be updated up until close to real time (e.g. weather forecasts data).

However, from the INTERRFACE project perspective, the TSO-DSO level Operational Planning Data exchange is more reasonable to arrange on separate platform – at the moment called "grid coordination" platform, which should be developed on national level in cooperation between TSO and DSOs. The functionalities and main approach of grid coordination platform could follow the Common Grid Model and Operational Planning Data environment (further - OPDE) concepts, which are now done for TSO-TSO level Operational Planning Data exchange.

Once the TSO-DSO Operational Planning Data is shared, the transmission and distribution system operators can define congestion areas. This enables to run common TSO-DSO grid calculation for each flexibility resource in the area using a list of metering points (using standardized identifiers[57] GS1, EIC, etc.) of pre-qualified connections with support of the aforementioned national Grid coordination platform. The results of such calculations should be sent to the Flexibility Register and inform eligible FSPs in this area[58] as it is defined in ASM report.

Market phase

When evaluating and before activating bids connected to other grids, the system status and system needs in neighbouring electricity grids must be considered. Information from the Flexibility Register could be helpful in this step, notably by evaluating bids from FSPs. For transmission and distribution system operators to solve congestion, the location of the units providing the flexibility services must be provided. Once a bid has been accepted or rejected, the Flexibility Service Provider (further - FSP) is informed.

Monitoring and activation

The ASM report states that, in the monitoring and activation phase, the Flexibility Register could be used to assess the impact of activating the resource in relation to the current status of the grid. This assessment by TSOs and DSOs needs to continue up until activation in order to adapt to unexpected events that may arise.

However, from the perspective of the INTERRFACE project, this assessment of the flexibility resource's impact on the grid will be performed by a separate tool, most likely the grid coordination platform. Given that that the present grid coordination platform concept is still being developed the separation of roles between these two tools (or usage of single platform) will rather be one of design choices addressed at the national level.

Measurement & Control of activation & Settlement

The Flexibility Register can also bring added value to in the settlement phase. The information in the Flexibility Register could be used to verify if and how much energy is delivered when comparing the measurements of the meter to the baseline of the unit; this could also be performed for aggregated bids.

[57] More information: ebIX. Recommended identification schemes for the European energy industry (link):

[58] This last action could be done by the market operator

The possibility of aggregation is essential for providers and requesters of flexibility services; in this view, the Flexibility Register could be developed to support information exchange on aggregated bids. However, deciding how this process should work in a meshed and congested grid is a challenge and must be undertaken in a co-ordinated way between DSOs, TSOs and FSPs. From the INTERRFACE project's perspective, it is also noted that such a process requires high coordination not only between TSOs-DSOs, but also market platforms. Hence, the involvement of Flexibility Register, Grid coordination platform and Market coordination platform would be needed for efficient information exchange for aggregated bids.

Other considerations

In addition to the functionalities already mentioned, the Flexibility Register can be developed into an important source of information for market platforms. For example, it can support the use of balancing bids for congestion management if the locational information is available. It can also combine different data sources (e.g. connection register, GIS data) and create different views for different transmission and distribution system operators and other users.

Therefore, there are more possible use-cases for the Flexibility register and those should be considered at the national level. Already existing tools should be considered when assessing and developing a Flexibility Register. As result, the overview of national initiatives is provided in the following chapter.

Summary

The design of the Flexibility Register may vary depending on the aims and capabilities of the relevant parties. For instance, the type of data collected and stored may differ based on the transmission and distribution system operators' view as to what constitutes sufficient visibility on their observability areas and how much coordination is needed for various functionalities. Design features can also ensure that the use of flexibility does not jeopardise system stability or does not create local challenges through the implementation of a traffic light concept. Finally, the Flexibility Register could also help meet other aims with regards to transparency (e.g. aggregated or/and anonymized information flexibility market information could be shared with ENTSO-E Transparency Platform throughout established link between Flexibility Register to increase the market transparency activation) and coordination not only between transmission and distribution system operators, but also with BRPs, e.g. ensuring that relevant BRPs are well informed about the activations in their portfolio and the contra actions, which could take place to ensure balance in the portfolio by BRP, are avoided.

Case Studies

Belgium

Synergrid Initiative

Having identified a rising need for flexibility by both the TSO and DSOs and the ensuing coordination requirements, Elia BE and several Belgian DSOs (among which Fluvius) have launched the Synergrid initiative in 2017, which aims at developing a joint T/DSO Flexibility Data Hub (Flex Data Hub). The Flex Data Hub not only contains basic registration data (location, maximum capacity, etc.) but also

supports the active management of service delivery points by FSP, the activation of the FSP by the TSO, and the settlement of the delivered services.

Currently, the Flex Data Hub covers mFRR products and is soon expected to expand to aFRR products. It incorporates three core modules:

- The **Flex Register**, which defines the FSP-EAN[59]-BRP relation and provides locational information supporting the prequalification process;
- The **Flex Data Register** which contains the relevant metering data for each delivery point;
- The **Activation Register**, which measures the time of activation, duration, energy delivered, etc.

Furthermore, these core modules are complemented by a calculation module for determining the baseline calculations, thus supporting Elia in performing activation control, availability control, and imbalance adjustment. Finally, a publication module provides aggregated information to market parties to support the transfer of energy (ToE)[60].

It is furthermore expected that several more functionalities be added, such as the inclusion of the outage and scheduling agent role and a traffic light or congestion risk indicator which allows to block bids if they are expected to cause additional grid constraints.

Blockchain-based solution for residential scale resources

In December 2019, Elia announced a partnership with several Belgian DSOs for the development and testing of a blockchain-supported flexibility register (based on EWF's Energy Web Flex solution) for the integration of residential-scale distributed energy resources [5].

The blockchain technology will notably enable the implementation of a decentralised flexibility registry and hub for managing asset registration, while also supporting activation and settlement. This decentralised approach is meant to strengthen transparency and trust between the interacting parties without disclosing information about the users. Similarly, it is expected to guarantee the security of the data and the resiliency of the platform as a whole.

Some of the functionalities supported by this newly announced project include:

- On-boarding DERs: Grid operators are able to pre-qualify types of DERs (e.g., a specific model produced by a specific manufacturer), and then a qualified installer verifies that the customer's asset is of that type and located behind that customer's meter.
- Participating in flexibility markets: TSOs and DSOs submit their requests and constraints into the system, DERs submit their offers (themselves or via third-party providers of intelligence), and the system determines the lowest-cost way to meet the requests.
- Activation: TSOs and DSOs can activate the reserved DERs when needed and within required response time limits.
- Settlement: When DERs deliver flexibility in response to activation, clear records are produced, and settlement can be conducted at appropriate frequencies and very low cost.

While the project has only just recently been announced at the time of writing, it seems that the basic flexibility hub platform that will be tested will not cover grid safety analysis while prequalification

[59] EAN code is a unique number that identifies a connection to the electricity or natural gas network.

[60] See section 4.1 for further explanations of the Transfer of Energy concept.

will only be performed for new/first-time registration of assets, rather than being dynamic, (i.e. whereby the pre-qualification can change over time).

Great Britain

In February 2019, National Grid, UK Power Networks (DSO), SP Energy Networks (Scottish TSO/DSO) and Electron (Software company) launched a project named recorDER (formerly DER asset register) aiming to develop a TSO-DSO shared register of assets focusing on blockchain technology for the hosting platform. The platform will notably host data on generation and flexibility assets equal or larger than 1MW in capacity across several regions as well as transmission generation assets.

The RecorDER platform proposes linking asset IDs to multiple data sets as well as multiple markets and services controlled by different parties. It will serve as a single reference point for all energy asset data on top of which protocols for modular markets and services can be deployed, while asset IDs are used to coordinate participation across multiple markets. While recorDER does not seem to support dynamic prequalification, it nonetheless enables SOs to have much greater visibility and forecasting ability over distributed flexibility resources at more frequent intervals than is currently the case.

Expected benefits of this flexibility asset register are first to significantly reduce in the short-term the time and resources currently dedicated the gathering, cleansing and processing data. Secondly, it will support more accurate long-term planning as well as short-term forecasting of wind, solar, and demand. Further down the road, the platform could enable greater market liquidity, lower transaction costs for small-scale market participants, and more dynamic portfolio management by flexibility providers and aggregators.

Portugal

The H2020 EU-Sysflex project aims to develop and test a DSO Flexibility Hub in its Portuguese demonstration project [6], applied to the provision of flexibility to the TSO in terms of both active and reactive power in a local setting. The platform, developed jointly by EDP and INESCTEC, is expected to be demonstrated at the distribution grid connected to Frades primary substation, providing service to about 8000 grid connection points. It will notably support 3 main objectives:

- the creation of a new local market for the provision of reactive power from DERs
- the creation of a new market for providing active power from both transmission and distribution connected resources, somewhat altering the design of the current restoration reserve market
- the introduction of an equivalent dynamic model, enabling the TSO to assess the network's transient stability, which is relevant for both frequency and voltage disturbances.

The flexibility hub architecture nonetheless remains to be further defined. In a high level description provided in June 2019, it is said that it will "use the updated grid configuration and the real and forecasted active and reactive power flows from DSO information systems, and the bids from the market agents, to provide the flexibility services described" [8]. While this concept seems more fit for a DSO's own purposes, it could nonetheless provide relevant insights for the development of a general flexibility resource register supporting TSO-DSO coordination.

Flexibility register concept proposal of INTERRFACE project

Flexibility register concept and modules description

Specific design choices of the flexibility register and how it interacts with existing platforms and tools should be developed in cooperation between TSO(s) and DSOs at national level at least, while common principles on the fundamental features of the flexibility register concept should be developed at the European level so as to ensure interoperability. This allows the participation of all grid users who opt to offer flexibility and bring together all data needed to economically assess and coordinate the flexibility used between different market places, regions, TSOs and DSOs. Following the best practices of the EU countries and recommendations of ASM report, the Flexibility register concept proposal is represented in Figure 31.

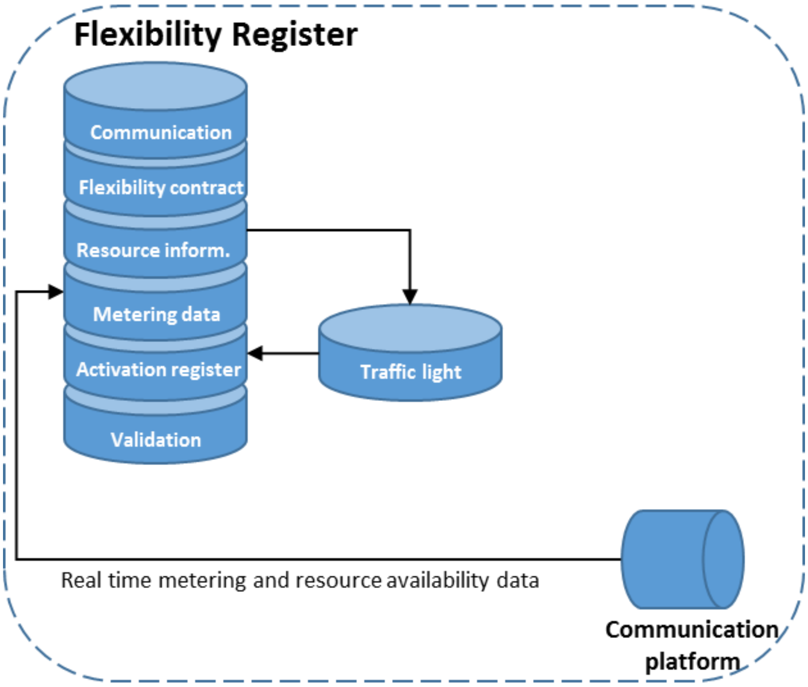

Figure 31: Flexibility register concept proposal

One of the key functions of the Flexibility Register is to provide the bases for the management of flexibility resource data and support the settlement process mainly by the calculation the quantity of capacity reserve ensured or/and energy 'not consumed' or 'generated' in a given period following the specific product requirements. This means the Flexibility Register is an essential data tool in ensuring the smooth operation of the market processes involved in flexibility and the functionalities has to be adapted case-by-case for each market product (e.g. FCR, aFRR, mFRR, Congestion Management (CM) etc). This Flexibility Register should also provide an information to the energy suppliers, when the FSP activates their customers' flexibility. This sharing of information will make it possible to correctly produce a detailed account of all market players [2]. To fulfil the different functionalities, the Flexibility register can be divided in several different modules, which are described in more details below:

- **Data governance module**. The Data governance module ensures the effective execution of application of collection processes, roles, policies, standards, and metrics that ensure the effective and efficient use of information in enabling a Flexibility Register to fulfill the requirements. It ensures the quality and security of the data used across all internal modules and external communication. This module ensures the security and granted data access only to authorized parties to protect the confidentiality of the aggregator's, suppliers, BRPs and other market parties' portfolios.
- **Flexibility contract module**. This module collects and stores the contract information, which connects a flexibility resource with flexibility owner and other market parties (e.g. Supplier, Aggregator, trading platforms etc.). The main reasoning of this module to keep up to date relation between FSP-metering point[61]-BRP. Without clear contractual relation setup, the FSP cannot report a trade to a resource.
- **Resource information module**. Module collects and stores the technical (static) data per delivery point (standardized identifier of metering point like GS1, EIC etc., installation ID, Supplier, BRP, FSP, local measurement device validation etc.) locational info, prequalification information. The module can also accommodate the results of prequalification process e.g. obtained during the grid impact results for the FSP contract points.
- **Metering data module**. This module stores (or links) the information collected from metering points (including local devices for close to real-time metering and resource availability data). Metering data granularity depends on the specific needs of the market products, which Flexibility register is supporting. In general, the module should contain close to real time or/and daily non-validated metering data and monthly (validated) metering data per delivery point. In addition to the raw metering data, the module contains the Validation module calculation results for realized flexibility volumes per delivery point as well as aggregated volumes on the FSP level.
- **Activation register module**. Module stores and distributes the activation data (time of activation, duration, activated delivery points per bid per product, baseline per delivery point, energy delivered per delivery point etc.). In case of capacity products, additional information (e.g. reserved capacity durations and windows) per delivery point level can be collected. Main reasoning of such information collection is to be able monitor and validate if the reserved capacities were available and not used for other products at the same time.
- **Validation module**. Module performs the validation of the fulfilment of the reserved capacity or/and delivered energy for each product and market timeframe.

  In case of energy products or delivery (e.g. capacity bid is activated), the module is used for calculation of delivered energy per delivery point using the baseline method and validated metering values which are collected from metering points at connection point level or even at local device level if the measurements of such device are trusted, validated and accepted by system operators.

  A commonly agreed baseline method, which should be approved on national level, is used to calculate a reference value for the imbalance settlement periods. In addition, aggregators should be able to aggregate flexibility within the perimeter of suppliers. This creates a need to transfer volumes between the energy balances of balance responsible parties (BRPs). As result, the Validation module should be capable to provide data aggregation following the information available in the Flexibility contract module.

  In case of capacity products, the module performs the capacity availability assessment based on direct measurements of unit availability (if such information is available) and/or

[61] using standardized identifiers GS1, EIC, etc.

contractual information, records of resource usage in other markets at the same timing and prequalification results cross-check. Same as for baseline methodology, common methodology to access the delivery of reserved capacities should be approved on national level.

- **Traffic light module**. Traffic light module is needed to avoid congestion while performing balancing activations or/and flexibility trading on local markets. This requires near real time grid analysis based on scheduling data to generate the grid constraints. For this reason, transmission and distribution system operators should be able to screen bids against any grid constraints and avoid any overload or/and voltage limits violation. The traffic light module can also be used to avoid double activation or reservation of the same flexibility resource, by cross-checking the usage of flexibility resource in different markets.
- **Communication platform.** A real-time communication platform is put in place for the collection of data from the local measurement devices (or smart meters with increased data granularity) for the flexibility services, which requires higher granularity or close to real-time data for execution (e.g. aFRR).
  A private device should be allowed to be used to minimize entry barriers for participation to the flexibility service. A gateway needs to be put in place to connect the physical asset in a digital way with the real-time communication platform. A minimum storage of individual data will be required and is to be foreseen locally by the BSP.

To ensure the data quality, a Flexibility Data Manager, in cooperation with the transmission and distribution system operators, should have the right at any time to perform an on-site audit and/or to perform ad-hoc quality checks on the data and communication infrastructure that has been put in place for the delivery of the flexibility service. For delivery points connected to the DSO-grid, a sealing of the physical link between the private device and the gateway should be responsibility of the DSO's, e.g. specifications of the device (accuracy, precision etc.), modalities to guarantee availability of the real time communication etc.

- During the implementation of the Flexibility Register, special attention should be given to cyber security, data privacy and even the physical security of private devices. Connection with the communication platform should ensure the possibility to exchange and install updates automatically.

Flexibility register integration into power system concept

Specific details of the process, data exchange and communication between different parties might differ for different products (e.g. DA/ID, mFRR, aFRR, FCR, other). The description below outlines the main functionalities of the flexibility register and proposes a first draft for a harmonized approach which will inform general discussions and possibly further standardization between all INTERRFACE demonstration areas. Figure 1 presents a general view of the Flexibility register as an integrated part of the overall energy system. The main ideas are taken from the Belgian example [3, 4], where FSP processes and the Flexibility register have a high technology readiness level and are already applicable in the actual market.

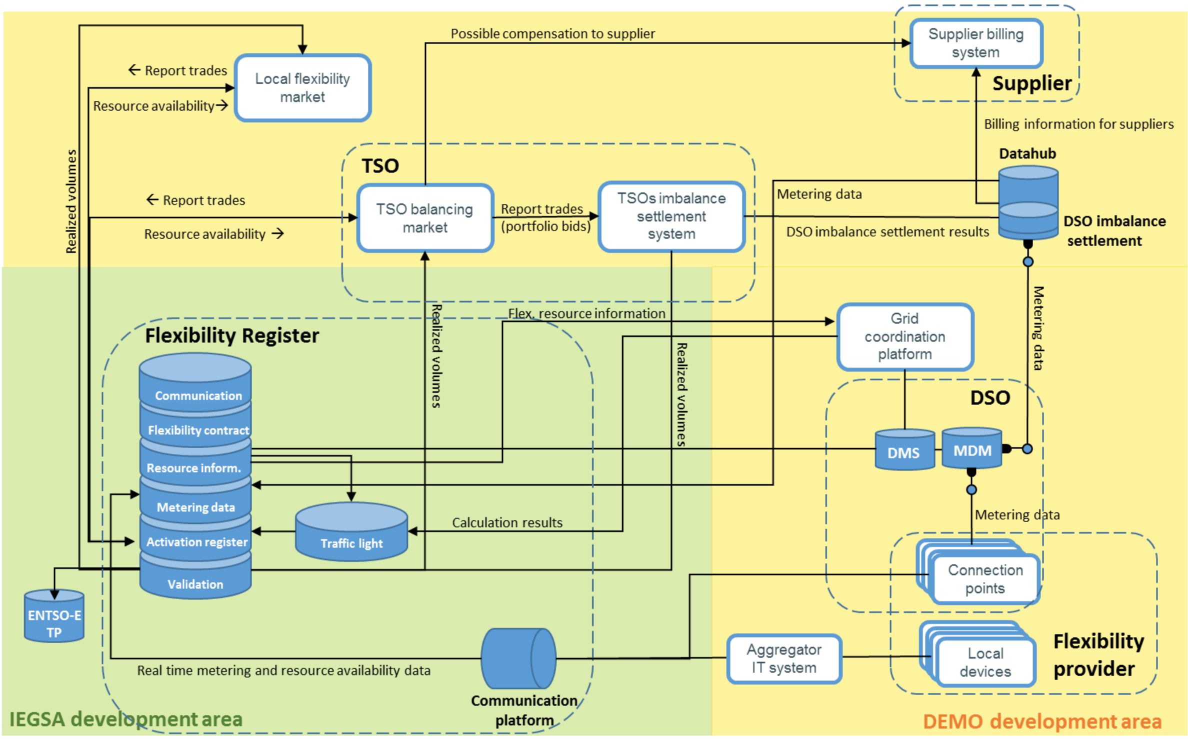

Figure 32: Flexibility register concept proposal

Registration and Prequalification

In order to be allowed to provide flexibility exchanged on the markets (ID/DA, CM or balancing) all FSPs should[62] pass the registration and prequalification process. This process consists of an application, a contract signature, BRP designation, a pool registration and communication tests:

- **Step 1. Application and contract signature**. A FSP submits an application form to Flexibility Data Manager. If a candidate FSP is eligible, he gets invited to sign a Flexibility Data Manager-FSP agreement which stipulates the terms and conditions between Flexibility Data Manager and the FSP. To do so the candidate FSP needs to fulfil all the formalities concerning contract completion, which includes, but not limited to:
    - Selection of the baseline methodology per Delivery Point and per product.
    - Estimation and provision of valid bank or other type required warranty.
    - Provision of valid network connection agreements
    - Provision of local Device (sub-meter) Technical Checklist (and successfully complete a Local Device commissioning test performed by connecting DSO), if applicable.
    - Provision of the FSP and Supplier(s) bilateral agreement(s) for the compensation price, if applicable.

  Information provided must always be kept up-to-date to ensure proper performance of the related market processes. The Flexibility Register and related information sources (e.g. integration with Data hubs to receive contract information from this system if available)

[62] Only for independent aggregators in case of DA/ID energy trading.

should be set-up to reduce the burden of the highest quality of information with as little burden to FSP as much as possible.

- **Step 2. BRP Designation**. The FSP has to designate a BRP (in the context of the flexibility service markets referred to as BRP_{FSP}) with a valid contract in order to be able to trade with other BRPs on the dedicated market. The candidate FSP has to provide Flexibility Data Manager with a proof of this designation.
- **Step 3. Pool registration**. The FSP has to provide Flexibility Data Manager with the list of Delivery Points to be added in his pool and with the following information for each of them:
  - Delivery Point name;
  - Type (TSO, Submetering, CDS, DSO);
  - Standardized metering point identifiers, like GS1, EIC, etc.;
  - Grid User;
  - Maximum upwards and/or downwards flexibility. For Delivery Points located in distribution grid, its absolute value must be ≤ than the absolute value of the Prequalified flexibility Power (also called "PQP") delivered by the DSO for the associated Access Point and for the corresponding direction[63].
  - A copy of a signed TSO/FSP if the Delivery Point is connected to the TSO or DSO/FSP contract[64] if the Delivery Point is connected to the DSO grid respectively (and the qualification by a grid study providing among others the PQP, for the Delivery Point);
  - The Local Device (sub-meter) Technical Checklist (and successfully complete a Local Device commissioning test performed by connecting DSO or other trusted party), if applicable.
  - In case the FSP and the concerned Supplier(s) has the bilateral agreement(s) for the compensation price, FSP provides a proof of an agreement(s). Otherwise, the regulated compensation price should be applied.

  The specific list of required information must be set case-by-case, depending on the product supported by Flexibility Register. Flexibility Data Manager check provided information and register it to the Flexibility Register.
- **Step 4. Communication tests**. The FSP performs an IT communication test before the delivery of the service. The purpose of this test is to verify that the FSP is able to receive, interpret and send the signals regarding real-time exchange of information (i.e. notifications).

Market, monitoring and activation phase

In case the FSP is participating in ID/DA, CM or balancing markets, an appropriate communication method should be established between BRP_{FSP} and the Flexibility Register. The Flexibility Data Manager should have access and appropriate methods established in order to keep contractual and technical information updated and error-free for each delivery point.

[63] Follow here for more information: Transfer of Energy in DA and ID markets – Elia. Link.

[64] The details of the contract have to be agreed on national level and harmonized among all grid operators. In general contract may contain terms and conditions with regard to data transfer, procedure for qualification & pool changes, liability & confidentiality, pool lists as annexes of the contract (master data). The contract is required to prove to Flexibility Data Manager that the DSO/TSO has verified compliancy and capacity reservation of the concerned delivery points (identified by GS1, EIC codes) and will include the concerned access points in data handling for settlement of flexibility.

In addition, the Flexibility Register should be able to collect and track the "Flexibility nomination" in all relevant markets, which refers to flexibility volumes that will be activated by the associated FSP during an activation period, for which the BRP_{FSP} is responsible. In the case of Belgium, two subtypes of Flexibility nomination are possible: DA Flex nomination and ID Flex nomination. However, in the case of INTERRFACE, additional frameworks could be introduced to acknowledge the existence of local Flexibility markets and needed coordination with it.

This information is meant to be used by TSOs next to the existing types of nominations, which usually BRP submits, today to TSO. TSO will use the last update of the information on Flexibility nominations or respective market together with all other nominations of the BRP_{FSP} to verify if his portfolio is balanced in day-ahead or intraday. TSO use all nominations in combination to calculate the total flexibility volume supposed to be activated by the corresponding FSP for imbalance period of the day D.

In case of Belgium, the Flexibility nomination information is collected using Notifications of the FSP. In case of mFRR product, FSP send the 'FSP-Notification 0' to TSO several minutes (5-15 min) before the delivery time. The notification contains information like total activated flexibility volume, activation period, identifier of the BRP_{FSP}, the list of the Delivery Points which will contribute to the delivery, so that TSO is able to take into account this information during operational planning. In addition, TSO forward aggregated information to the respective BRPs to avoid counter balancing.

In the case of Belgium, for the observability reason, the FSP is obliged to send an additional 'FSP-Notification 1' (immediately after the start of activation) and 'FSP-Notification 2' (immediately after the end of activation) with the information of activated energy, which further are excluded by TSO for the settlement calculations. The aggregated information is also forwarded to respective BRPs. The total activated volume, activation period, list of Delivery Points and identifier of the BRP_{FSP} must match with 'FSP-Notification 0'.

All this information is also forwarded to Flexibility Data Manager in order to be able to include it in the Flexibility Register baseline calculation and volume determination for the correction of the BRP_{FSP} and the BRPs[65] as well as the calculation of the aggregated delivered volumes to be communicated to the Supplier and the FSP for their financial settlement.

Measurement and settlement phase

During the settlement phase, the Flexibility register plays a key role for calculating the baseline, which is used for the calculation of the delivered volume of flexibility on a Delivery Point. The baseline calculation methodology should be approved by NRA and can be different for different market frameworks and products.

In case of several baseline methodologies, the FSP should have possibility to choose the baseline methodology per Delivery Point and per product during the contracting and registration phase. In case of Belgium, it is preferred that each product (aFRR, mFRR, DA/ID) uses the product-specific baseline if no combined activations take place.

In case of combined activation, the calculation of the total delivered volume per delivery point has to be done based on one and unique reference baseline; therefore one single master-baseline should be adopted. Such a master-baseline serves to calculate one overall delivered energy of a Delivery Point

[65] The Balance Responsible Party who has in his portfolio the Access Point of the Grid User providing flexibility with a Delivery Point.

participating to a combined activation, that afterwards is split amongst the different products (aFRR, mFRR and DA/ID).

After baseline is determined, the Flexibility register is able to estimate the delivered energy for a given activation period. Calculation is performed for each Delivery Point that has been communicated by the FSP notifications. The energy volume is determined as a difference between the baseline and the validated metering during the delivery period.

The delivered volume of flexibility on a Delivery Point is always validated and limited to the maximum upward or downward flexibility, which were set during the prequalification phase. In addition, special measures (like reduction of the aggregated delivered volume down to the requested volume pro-rata for each delivery point in the portfolio) should be set in place if the calculated delivered volume of flexibility exceeds the sum of all the flexibility nominations submitted by the FSP for the activation period.

The delivered energy volumes are sent to TSOs to be used to amend the imbalance of the BRPs. To guarantee the confidentiality of the different market parties, TSO should correct the balancing perimeter of BRPs per imbalance period and on the level of the portfolio. In addition, TSO can publish the aggregated (upward and downwards) delivered volumes on a quarter-hourly basis and per metering direction to be used for the financial compensation between FSP and Supplier.

Analysis of Potential Regulatory and Market barriers and challenges

This section is divided in two parts: first, based on the Belgian experience of the Flex Data Hub outlined in 2.1, the first sub-section looks more specifically at the regulatory environment and challenges in which this platform was developed. Secondly, subsection 4.2 addresses wider concerns that are relevant for the general implementation of a Flexibility Register.

Understanding the market and regulatory context in Belgium

Belgian **market rules** are innovative, since they allow for aggregators as independent balance responsible parties to aggregate flexibility from within the balance perimeter of other BRPs. This prompts for the need to transfer volumes between the energy balances of balance responsible parties (BRPs), which is now regulated in the electricity law and codes. The Flexibility Data Manager plays a key role in the organisation, calculation and settlement of flexibility and is entrusted with the role to settle the energy balances with aggregators and suppliers, whilst protecting the confidentiality of the aggregator's portfolio [4].

Law changes: The Transfer of Energy was introduced by the Law of 13 July 2017, amending the federal Electricity Law of 29 April 1999, in order to improve the participation of demand side flexibility. Transfer of Energy[66] (ToE) implies is used for the wholesale electricity transaction (financial adjustment mechanism) between the Supplier and the Aggregator, triggered by a flexibility activation by the Aggregator on the retail side, restoring the energy balance of both the Aggregator and the Supplier (and their BRPs) [8]. In this system, the transmission or distribution system operator is entrusted with the mission of flexibility data management with a series of tasks to be fulfilled and that are specified in Art.19 of the Electricity Law.

[66]Definition taken from: European Smart Grids Task Force Expert Group 3. Final Report: Demand Side Flexibility Perceived barriers and proposed recommendations. 2019. Link.

The **confidentiality requirement** means that the Flexibility Data Manager must calculate volumes to be transferred between balances while suppliers cannot see the underlying data. It is therefore essential that suppliers can trust the implementation at Flexibility Data Manager of these processes.

The Flexibility Data Manager's role is delicate for a number of reasons:

- Flexibility Data Manager determines the impact of aggregators on the balance of the balance responsible party (BRP) but cannot provide the underlying details for reasons of confidentiality. This means that trust rather than verification is the basis for acceptance of these numbers by BRPs;
- Flexibility Data Manager itself is acting as single buyer of the same volumes of flexibility that it determines. Transparency is needed to demonstrate the impartiality of the calculations and their settlement;
- Markets for aggregated flexibility are recent developments and they are evolving. There is no standard set of rules nor are there long-standing practices that can be applied. This means rules and practices as foreseen need to be evaluated thoroughly to ensure the market works efficiently and properly.

A specific condition for the task of flexibility data management is that the client portfolio of the FSP, who has invested in acquiring clients and setting up the conditions for demand response activations, remains confidential, i.e. is not shared with Suppliers. Parties will have to rely on volumes provided by **Flexibility Data Manager** to execute financial settlement on their transfer of energy without further detailed information regarding volumes per delivery point and without the possibility to validate those data.

The control of the mission of the flexibility data management activity is to independently verify that Transfer of Energy volumes can be trusted, since mostly aggregated volumes are to be transmitted by the flexibility data manager to different parties (BSPs, BRPs and Suppliers) due to confidentiality reasons.

In order to ensure the fulfilment of the task of **gaming monitoring** of flexibility activated volumes, the Flexibility Data Manager should apply the following **controls**:

1. **Baseline methodology choose**: in case the FSP has the possibility to choose between several baseline methodologies, the Flexibility Data Manager should have the right in a motivated way to refuse the methodology of the Baseline chosen by the FSP.

2. **High prices vs offered volume check**: In periods of high prices, there is likelihood that grid users' offtake is artificially increased during the hours/days of a potential activation in order to artificially increase his baseline and therefore the calculated delivered volume in case he is activated. The baseline design aims at mitigating that risk, but Flexibility Data Manager will still verify in case of activation if there is an abnormal increase of the offered volume and/or the baseline.

The special information exchange routine must be established between Flexibility Data Manager and NRA for monitoring purposes and comments on suspected manipulation.

General challenges and open questions

Based on the observation of the Belgian case, it has been noted, that Introduction of the Flexibility Registers has some open questions, which must be analysed before the introduction to the market:

- What minimum sets of rights and obligations should be given to the FSP (access to register, trading solvency, obligation to notify if change of contract, obligation to update other parameters)
- How to ensure no discrimination based on contract type and baselining methodology.
- Confidentiality issues (especially with the inclusion of residential customers): there is a general belief that as much data as possible should be made accessible to third parties (with customer consent) to foster data exchange and new services.
- More generally: what functions of the Flexibility Register should remain in the regulated domain, what could be part of the commercial domain.
- Roll out of up-to-date ICT: many customers/vendors do not have incentives to offer up-to-date ICT when already available technology suffices to be competitive.

Currently, many potential flexibility providers have little incentive to adopt the latest up-to-date ICT when already available technology suffices to be competitive and the cost of newer smart meters and SCADA systems can be dissuasive. Therefore, there is a strong need for the flexibility register to be ready to use, especially in terms of GDPR and cybersecurity. As such, its development should consider the inclusion of an integrated cybersecurity certification, thus ensuring that no additional measures need to be taken by the IT department of current and new users to comply with cybersecurity standards.

One option for ensuring the security and reliability of communication would be to rely on the functionalities provided by ENTSO-E Communication & Connectivity Service Platform (ECCo SP) - especially its Energy Communication Platform (ECP) component, which provides several benefits in terms of cybersecurity. First, it provides a public communication API to business applications, ensuring the secure transport of messages to receiver endpoints using message encryption and signing. In data networking, FSR writes, "*a signal is passed between communicating devices to signify receipt of the message ('technical acknowledgement') or reject a previously received message or indicate some kind of error ('negative acknowledgement'). The signal informs the sender of the receiver's state so that the sender can adjust its own state accordingly*" [8]. Technical acknowledgement in ECCo SP is done automatically via connection by a data provider to its ECP Endpoint (or user interface). Once the content of the message has been received, the receiver sends a "functional acknowledgment", thus stating whether the document is then accepted or rejected according to the business rules. Additionally, ECCo SP's portability means it can be installed on most widely-used operation systems and can be integrated with a wide variety of technologies, without additional measures having to be taken to ensure a company's conformity with cybersecurity standards. Finally, the EDX component of ECCo SP would allow for large volumes of information to be exchanged (>30 Mo) and supports a publish/subscribe function, whereby a message is sent to multiple receivers [7, 8].

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[3] Elia. Transfer of Energy in DA and ID markets Market Development. 17/06/2019

[4] IBM, Flexibility Data Manager Audit on the Transfer of Energy process and systems. Link.

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[6] Villar, Aguiar, Retorta et al. (2019). Flexibility Hub – Multi Service framework for coordination of

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[7] ENTSO-e, Energy Communication Platform (ECP): High Level Concept

[8] Schittekatte, T., Reif, V., & Meeus, L. (2020). The EU electricity network codes. FSR Technical report. February 2020. (in press)

[9] European Smart Grids Task Force Expert Group 3. Final Report: Demand Side Flexibility Perceived barriers and proposed recommendations. 2019. Link.

Role Description of Harmonised Role Model

Source: Harmonised Role Model Version 2019-01[67]

Type	Role name	Description
Role	Balance Responsible Party	A party that has a contract proving financial security and identifying balance responsibility with the Imbalance Settlement Responsible of the Scheduling Area entitling the party to operate in the market. This is the only role allowing a party to nominate energy on a wholesale level. Additional information: The meaning of the word “balance” in this context signifies that the quantity contracted to provide or to consume must be equal to the quantity really provided or consumed
Role	Balance Supplier	A party that markets the difference between actual metered energy consumption and the energy bought with firm energy contracts by the Party Connected to the Grid. In addition, the Balance Supplier markets any difference with the firm energy contract (of the Party Connected to the Grid) and the metered production. Additional information: There is only one Balance Supplier for each Accounting Point.
Role	Balancing Service Provider	A party with reserve-providing units or reserve-providing groups able to provide balancing services to one or more LFC Operators. Based on Electricity Balancing -Art.2 Definitions.
Role	Billing Agent	The party responsible for invoicing a concerned party.
Role	Capacity Trader	A party that has a contract to participate in the Capacity Market to acquire capacity through a Transmission Capacity Allocator. Note: The capacity may be acquired on behalf of an Interconnection Trade Responsible or for sale on secondary capacity markets.
Role	Consumer	A party that consumes electricity.

[67] The Harmonised Electricity Market Role Model (v. 2019-01) by ENTSO-E, EFET, ebIX, available online: https://docstore.entsoe.eu/Documents/EDI/Library/HRM/Harmonised_Role_Model_2019-01.pdf

		Additional information: This is a Type of Party Connected to the Grid.
Role	Consumption Responsible Party	A party who can be brought to rights, legally and financially, for any imbalance between energy nominated and consumed for all associated Accounting Points. Additional information: This is a type of Balance Responsible Party.
Role	Consent Administrator	A party responsible for keeping a register of consents for a domain. The Consent Administrator makes this information available on request for entitled parties in the sector.
Role	Coordinated Capacity Calculator	Coordinated Capacity Calculator is the entity or entities with the task of calculating transmission capacity, at regional level or above. Source: Commission Regulation (EU) 2015/1222 (CACM).
Role	Coordination Centre Operator	A party responsible for the coordination of its Coordination Centre Zone in respect of scheduling, load frequency control, time deviation and compensation of unintentional deviation.
Role	Data Provider	A party that has a mandate to provide information to other parties in the energy market. Note: For example, due to Article 2 of the European Commission Regulation 543/2013 of the 14th of June 2013, a data provider may be a Transmission System Operator or a third party agreed by a TSO
Role	Energy Service Company (ESCO)	A party offering energy-related services to the Party Connected to Grid, but not directly active in the energy value chain or the physical infrastructure itself. The ESCO may provideinsight services as well as energy management services.
Role	Grid Access Provider	A party responsible for providing access to the grid through a Metering Point for energy consumption or production to the Party Connected to the Grid. The party is also responsible for creating and terminating Metering Points.
Role	Imbalance Settlement Responsible	A party that is responsible for settlement of the difference between the contracted quantities and the realised quantities of energy products for the Balance Responsible Parties in a Scheduling Area.

		Note: The Imbalance Settlement Responsible may delegate the invoicing responsibility to a more generic role such as Billing Agent.
Role	Interconnection trade Responsible	Is a Balance Responsible Party or depends on one. He is recognised by the Nomination Validator for the nomination of already allocated capacity. Additional information: This is a type of Balance Responsible Party.
Role	LFC Operator	Responsible for the load frequency control for its LFC Area or LFC Block. Additional information: This role is typically performed by a TSO.
Role	Market Information Aggregator	A party that provides market related information that has been compiled from the figures supplied by different actors in the market. This information may also be published or distributed for general use. Note: The Market Information Aggregator may receive information from any market participant that is relevant for publication or distribution.
Role	Market Operator	A market operator is a party that provides a service whereby the offers to sell electricity are matched with bids to buy electricity. Additional Information: This usually is an energy/power exchange or platform
Role	Merit Order List Responsible	Responsible for the management of the available tenders for all Acquiring LFC Operators to establish the order of the reserve capacity that can be activated.
Role	Meter Administrator	A party responsible for keeping a database of meters.
Role	Meter Operator	A party responsible for installing, maintaining, testing, certifying and decommissioning physical meters.
Role	Metered Data Aggregator	A party responsible for the establishment and qualification of metered data from the Metered Data Responsible. This data is aggregated according to a defined set of market rules.

Role	Metered Data Collector	A party responsible for meter reading and quality control of the reading.
Role	Metered Data Responsible	A party responsible for the establishment and validation of metered data based on the collected data received from the Metered Data Collector. The party is responsible for the history of metered data for a Metering Point.
Role	Metering Point Administrator	A party responsible for registering the parties linked to the metering points in a Metering Grid Area. The party is also responsible for registering and making available the Metering Point characteristics.
Role	Nominated Electricity Market Operator	An entity designated by the competent authority to perform tasks related to single day-ahead or single intraday coupling. Source: Commission Regulation (EU) 2015/1222 (CACM). Additional Information: A NEMO performs MCO functions. (Market Coupling Operator) A NEMO runs a power exchange related to day-ahead or intraday market. A NEMO is a type of Market Operator.
Role	Nomination Validator	Has the responsibility of ensuring that all capacity nominated is within the allowed limits and confirming all valid nominations to all involved parties. He informs the Interconnection Trade Responsible of the maximum nominated capacity allowed. Depending on market rules for a given interconnection the corresponding System Operators may appoint one Nomination Validator.
Role	Party Connected to the Grid	A party that contracts for the right to consume or produce electricity at an AccountingPoint.
Role	Producer	A party that produces electricity. Additional information: This is a type of Party Connected to the Grid.
Role	Production Responsible Party	A party who can be brought to rights, legally and financially, for any imbalance between energy nominated and produced for all associated Accounting Points. Additional information:

		This is a type of Balance Responsible Party.
Role	Reconciliation Accountable	A party that is financially accountable for the reconciled volume of energy products for a profiled Accounting Point.
Role	Reconciliation Responsible	A party that is responsible for reconciling, within a Metering Grid Area, the volumes used in the imbalance settlement process for profiled Accounting Points and the actual metered quantities. Note: The Reconciliation Responsible may delegate the invoicing responsibility to a more generic role such as a Billing Agent.
Role	Reserve Allocator	Informs the market of reserve requirements, receives tenders against the requirements and in compliance with the prequalification criteria, determines what tenders meet requirements and assigns tenders.
Role	Resource Aggregator	A party that aggregates resources for usage by a service provider for energy market services.
Role	Resource Provider	A role that manages a resource and provides production/consumption schedules for it, if required.
Role	Scheduling Agent	The entity or entities with the task of providing schedules. Source: System Operation Guideline, Commission Regulation (EU) 2017/1485. Additional information: A party that is responsible for the schedule information and its exchange on behalf of a Balance Responsible Party.
Role	Scheduling Area Responsible	A party responsible for the coordination of nominated volumes within a scheduling area. Additional information: This role is typically performed by a TSO.

Sequence Diagrams of demonstration projects

Demonstration Project 5.1

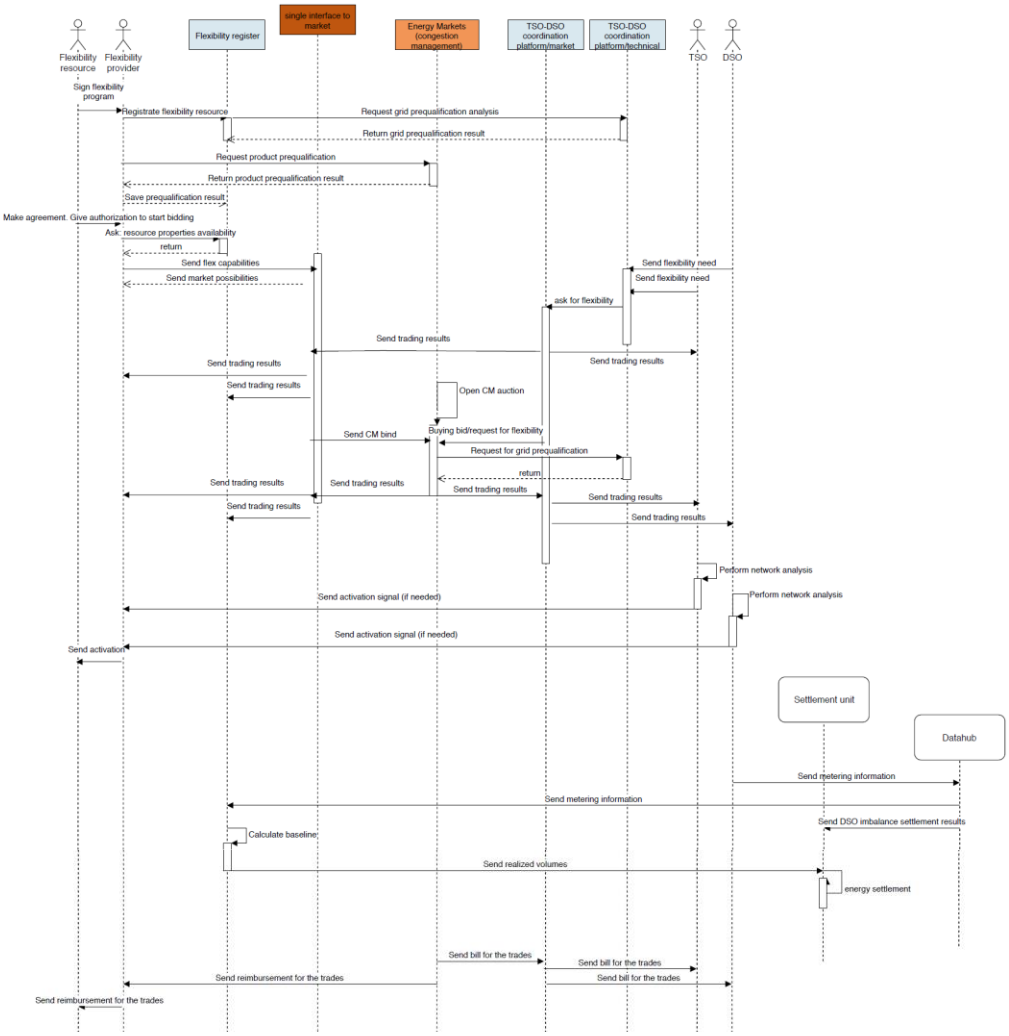

Figure 33: Sequence diagram of demonstration project 5.1 for "Congestion Management - TSO supplier"

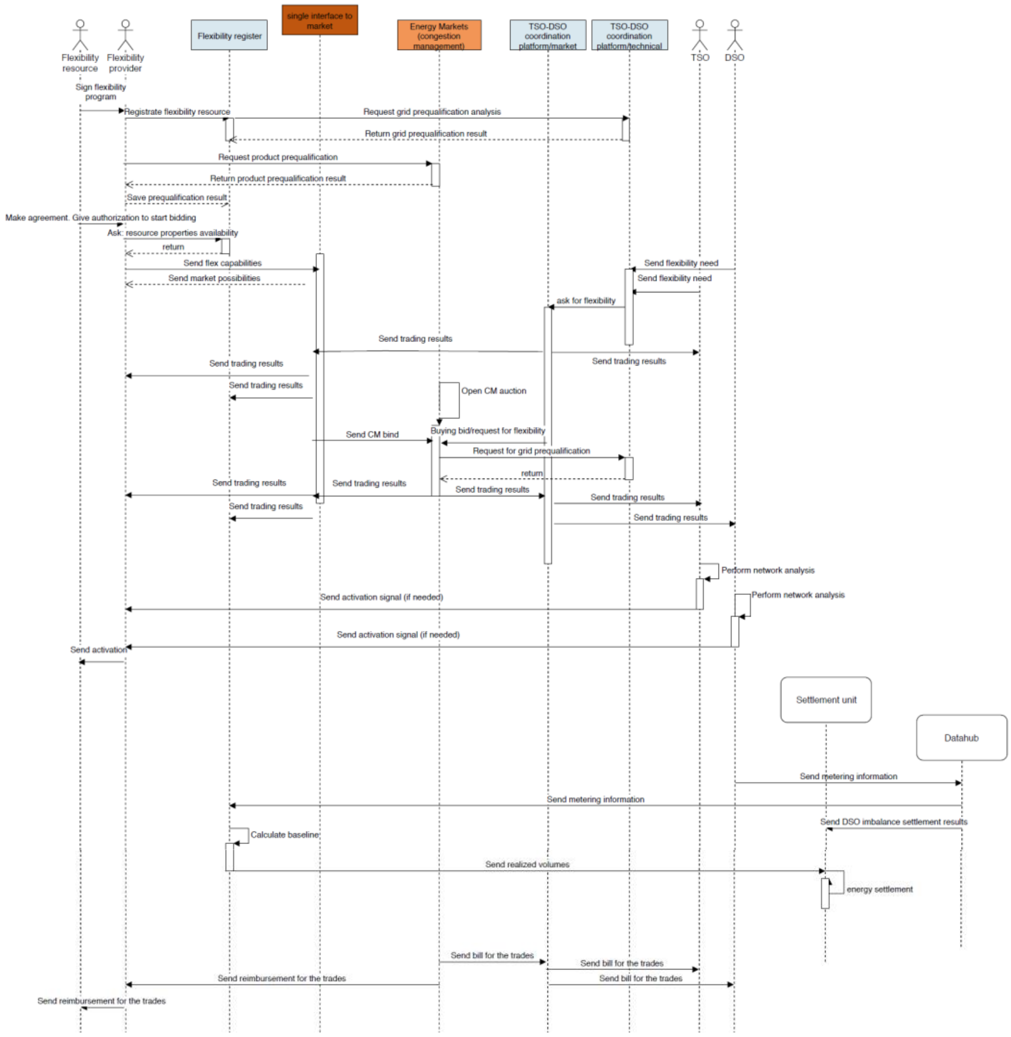

Figure 34: Sequence diagram of demonstration project 5.1 for "Congestion Management - LV regulation Power quality"

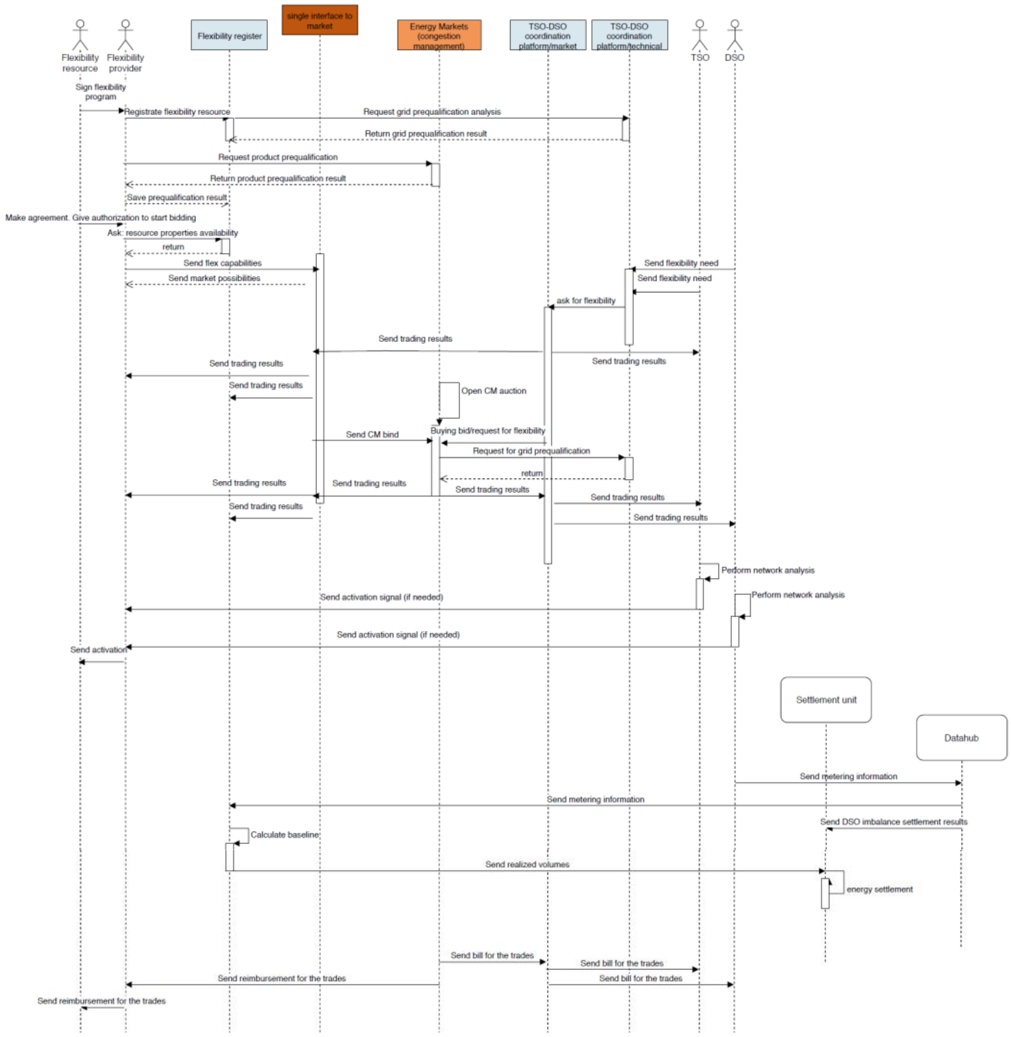

Figure 35: Sequence diagram of demonstration project 5.1 for "Local Energy Community"

Demonstration Project 5.2

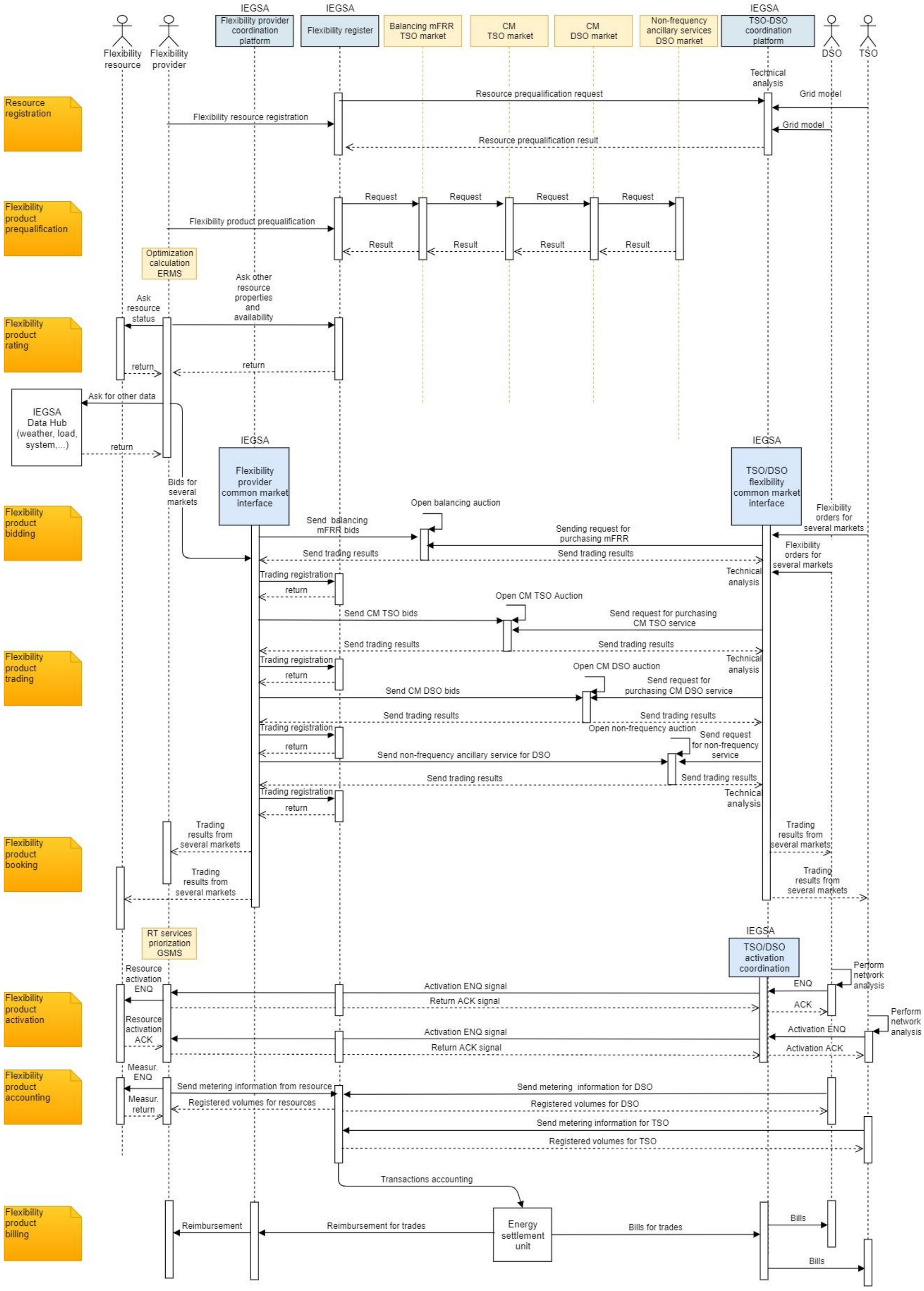

Figure 36: Sequence diagram of demonstration project 5.2 for "Aggregated CM service to the TSO/DSO": "Fast balancing reserve to the TSO" and "Non-frequency ancillary services to the TSO/DSO Local Energy Community"

Demonstration Project 5.3

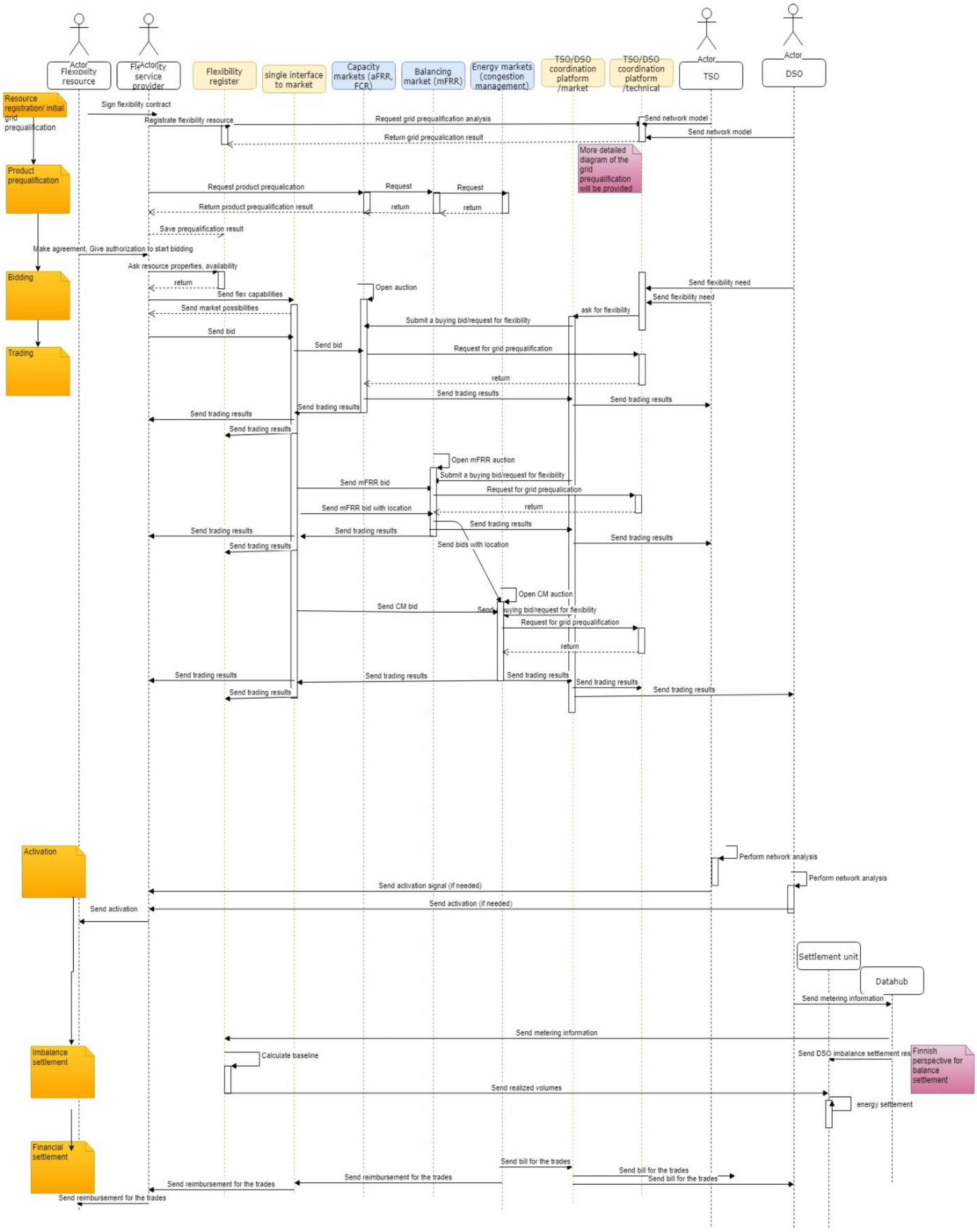

Figure 37: Sequence diagram of demonstration project 5.3 for" Congestion management operational, short-term long-term (TSO / DSO) and mFRR, aFRR, FCR services (TSO) within a Single Flexibility Platform"

Demonstration Project 6.1

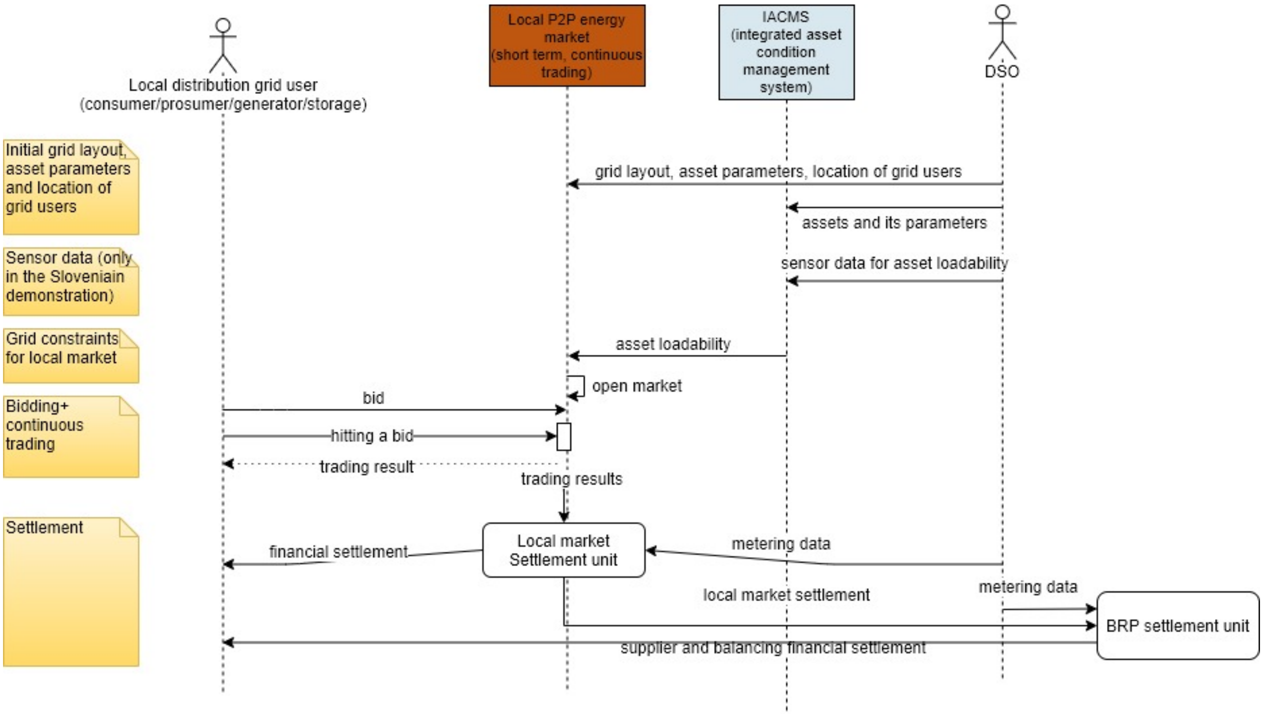

Figure 38: Sequence diagram of demonstration project 6.1 for "Distribution grid users participating in P2P local market"

Demonstration Project 6.2

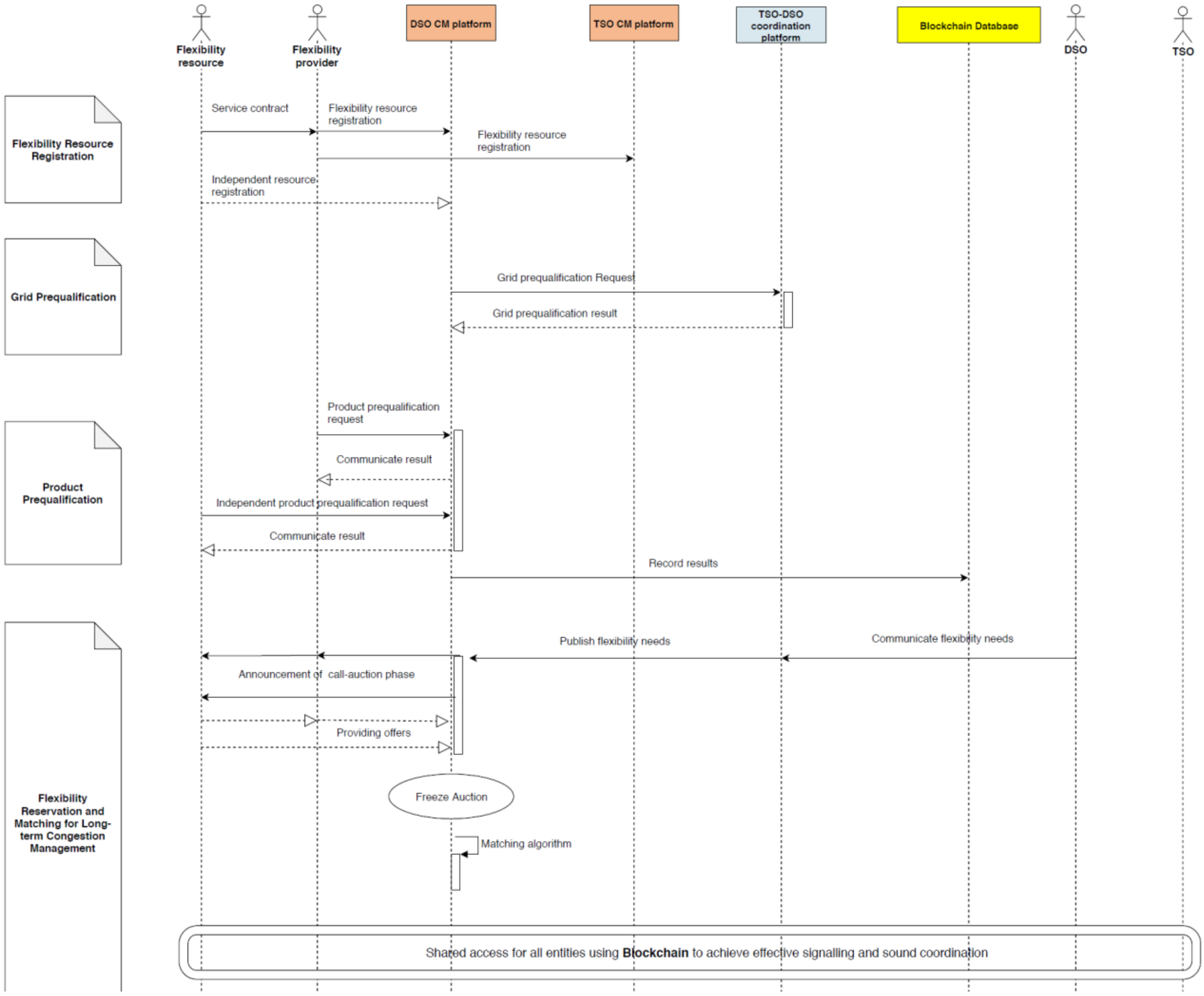

Figure 39: Sequence diagram of demonstration project 6.2 for "Flexibility services for DSO congestion management and allowing more renewable connection without unreasonable DSO network investments"

Demonstration Project 7.1

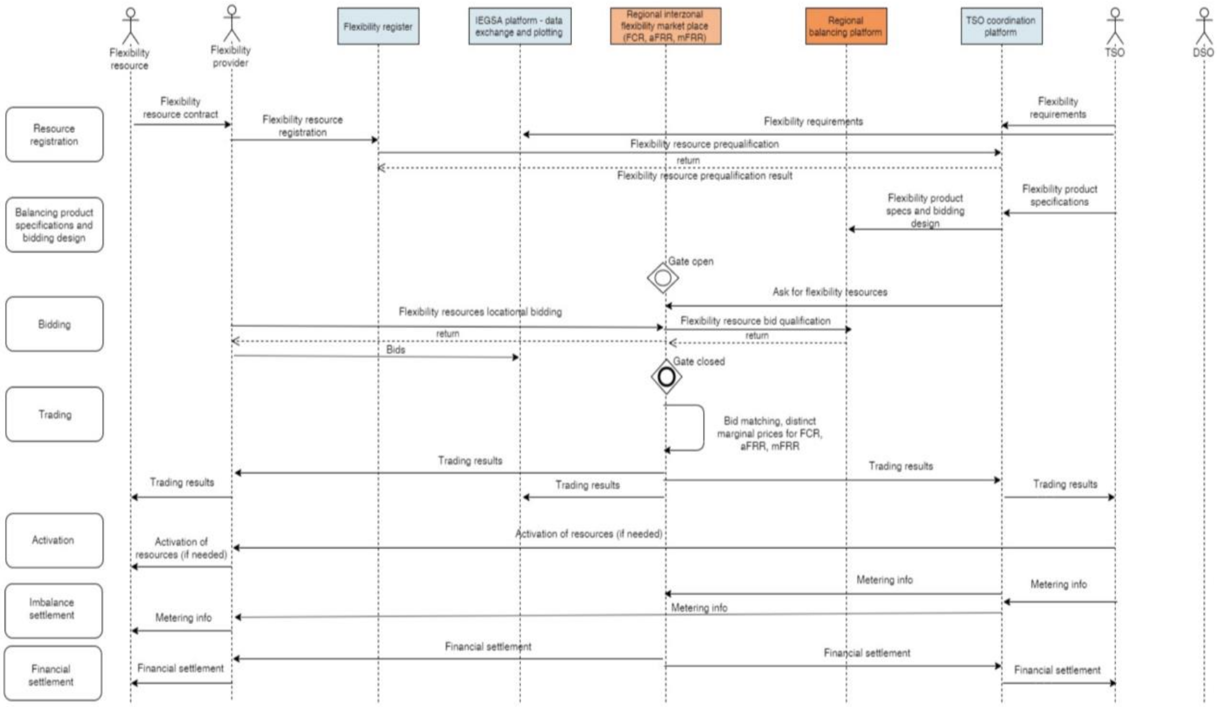

Figure 40: Sequence diagram of demonstration project 7.1 for "Regional inter-zonal provision of FCR, aFRR, mFRR services in South East Europe"

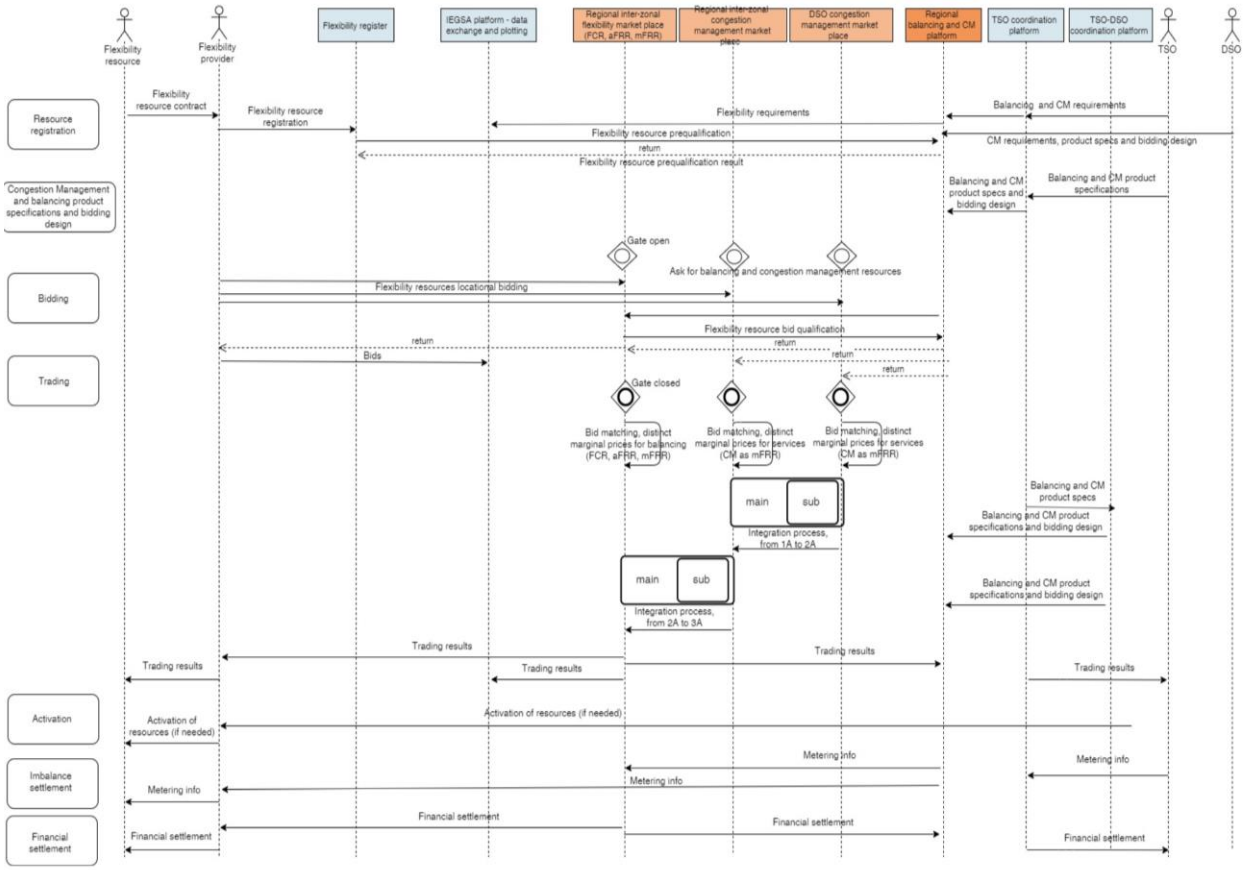

Figure 41: Sequence diagram of demonstration project 7.1 for "Regional inter-zonal provision of Congestion management services in South East Europe"

Demonstration Project 7.2

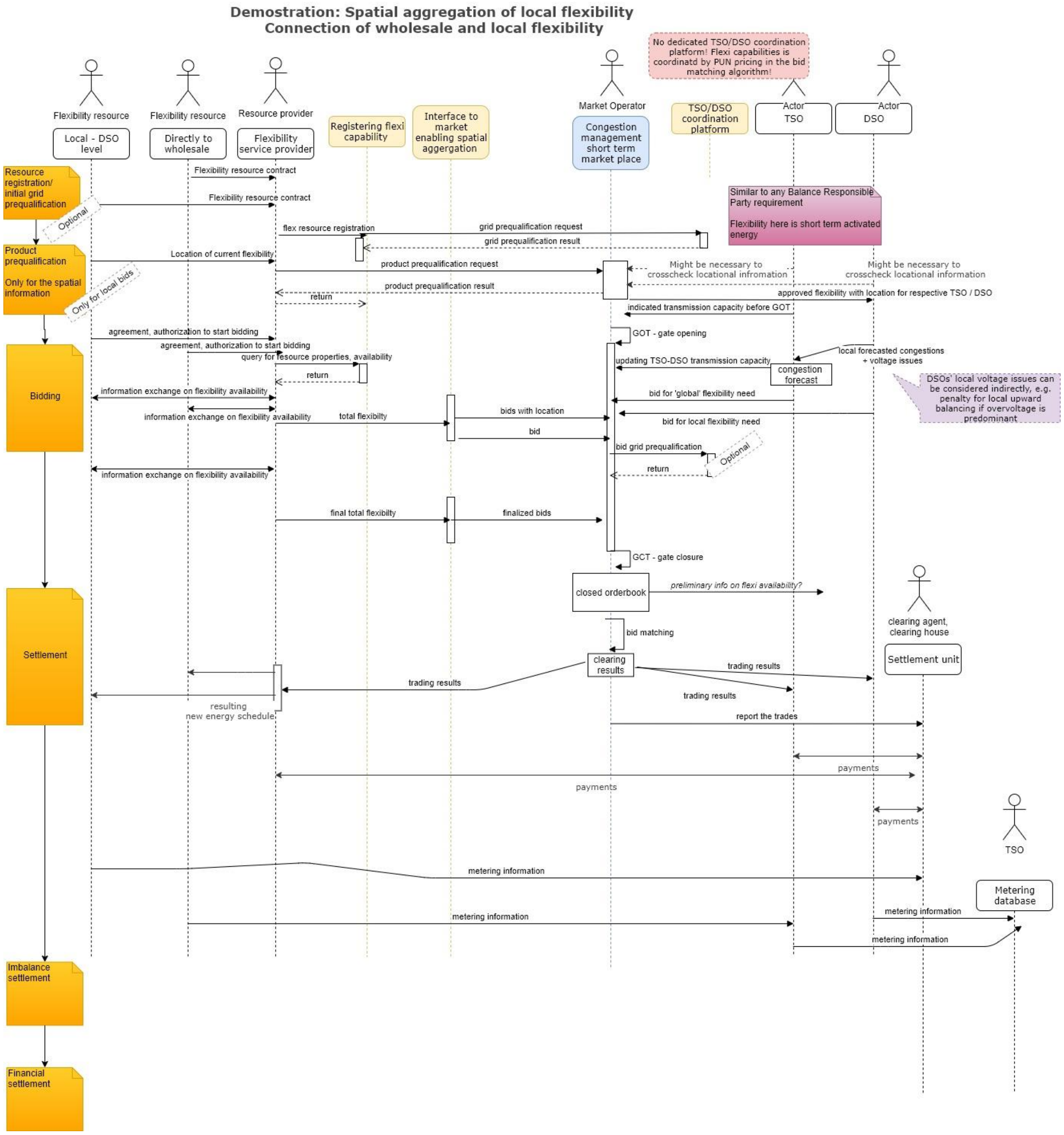

Figure 42: Sequence diagram of demonstration project 7.2 for "Spatial aggregation of local flexibility connection of wholesale and local flexibility"