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Conceptual market organisations for the provision of innovative system services: role models, associated market designs and regulatory frameworks

D3.2

EU-SysFlex

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ABBREVIATIONS AND ACRONYMS

Acronym	Full name
ACER	The European Union Agency for the Cooperation of Energy Regulators
BRP	Balance Responsible Party
CBA	Cost-Benefit Analysis
CCR	Capacity Calculation Region
CEP	Clean Energy Package
CGM/IGM	Common Grid Model/Individual Grid Model
CM	Congestion Management
DACF	Day-Ahead Congestion Forecast
DER	Distributed Energy Resources
DRR	Dynamic Reactive Response
DSO	Distribution System Operator
DSR	Demand Side Response
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EU-SysFlex	Pan-European System with an efficient coordinated use of flexibilities for the integration of a large share of Renewable Energy Source
FAT	Full Activation Time
FCR	Frequency Containment Reserve
FFR	Fast Frequency Response
FRR/aFRR/mFRR	Frequency Restoration Reserve/Automatic FRR/Manual FRR
FSP	Flexibility Service Provider
GCT	Gate Closure Time
IDCF	Intra-Day Congestion Forecast
IEEE	Institute of Electrical and Electronics Engineers
LV/MV/HV/EHV	Low Voltage/Medium Voltage/High Voltage/Extremely High Voltage
MARI	Manually Activated Reserves Initiative
MO/NEMO	Market Operator/Nominated Electricity Market Operator
MOL	Merit Order List
MVA(r)	Mega Volt Ampere (Reactive)
MW/GW(h)	Mega Watt/Giga Watt (Hour)
N-1	The N-1 power system security principle
OO	Optimisation Operator
POR	Primary Operating Reserve
PV	Photovoltaics
RoCoF	Rate of Change of Frequency
RES	Renewable Energy Sources
RR/RRD/RRS	Replacement Reserve/ RR Desynchronised/RR Synchronized
SDAC	Single Day-Ahead Coupling
SIDC	Single Intra-Day Coupling
SIR	Synchronous Inertial Response
SO	System Operator

SOGL	System Operation Guideline
SOR	Secondary Operating Reserve
SSRP	Steady State Reactive Power
TOR	Tertiary Operating Reserve
TSO	Transmission System Operator
VDIFD	Voltage Dip-Induced Frequency Deviation
WP	Work Package

GLOSSARY

Schedules:

- ✓ Schedules refer to internal commercial trade schedule within the bidding zone, generation schedule, consumption schedule, external commercial trade schedules as relevant in given case.
- ✓ Generators and relevant individual grid users as defined in SOGL must send their generation/consumption schedules (nominations of previous obligation and expected obligations, for instance day-ahead market) in advance to the relevant system operators so that they can have enough time to perform the grid security analysis.
- ✓ Schedules are also sent to the market operator to use it as baseline for the proof of provision of the service and the following settlement process. Where such methodology has been agreed, schedules can also be calculated by another party.

BRP (balance responsible party) means a market participant or its chosen representative responsible for its imbalances

BRP perimeter is the portfolio of activities (injections and withdrawals) of the BRP that must be declared to TSO in order to calculate the BRP's imbalances. The BRP is financially responsible for the balancing of this portfolio. Balance perimeter imbalances due to SOs flexibility needs give rise to financial compensation between OOs and BRPs.

Bidding zone means the largest geographical area within which market participants are able to exchange energy without capacity allocation.

Grid constraints are technical requirements such as thermal limit of the network element and/or voltage limits and are part of operational security limits that need to be observed to meet security requirements defined in Article 18 of the System Operators Guideline (European Commission, 2017b).

Distributed Energy Resources (DERs) are electricity-producing resources or controllable loads that are connected to a local distribution system or connected to a host facility within the local distribution system. DERs can include solar panels, combined heat and power plants, electricity storage, small natural gas-fuelled generators, electric vehicles and controllable loads, such as HVAC systems and electric water heaters, as well as demand side response (DSR) providers.

Synchronous generator/consumer means an installation which can generate/consume electrical energy such that the frequency of the generated voltage, the generator/motor speed and the frequency of network voltage are in a constant ratio and thus in synchronism.
Other facilities are non-synchronous units.

Ancillary service means a service necessary for the operation of a transmission or distribution system, including balancing and non-frequency ancillary services, but not including congestion management;
Non-frequency ancillary service means a service used by a transmission system operator or distribution system operator for steady state voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, black start capability and island operation capability.

Flexibility service: in the context of this task means an ancillary service or a congestion management service
Energy product means energy (be it active or reactive) used by TSOs or DSOs to insure secure network operation and provided by a flexibility service provider.

Capacity product means a volume of reserve capacity (MW or MVAr) that a flexibility service provider has agreed to hold and in respect to which the flexibility service provider has agreed to submit bids for a corresponding volume of energy to the TSO/DSO for the duration of the contract.

Energy product means energy (be it active or reactive) used by TSOs or DSOs to insure secure network operation and provided by a flexibility service provider**.**

(**Maximum) Shifting time** describes the behaviour of FSPs with rebound effects, to compensate a flexibility provision at an earlier or later point of time (e.g. heat pumps provide downward flexibility at T0, and need to compensate this the latest 3 hours before or after the reduction). The maximum shifting time refers to the potential of FSPs to shift such compensation to a maximum point of time or any point of time in between – as selected by the buyer (e.g. the SO selects the shifting of the heat pump to 2 hours before the reduction).

MARI: Manually Activated Reserves Initiative (MARI) is the European implementation project for the creation of the European mFRR platform for cross-border procurement of mFRR energy.

EXECUTIVE SUMMARY

The energy transition is fundamentally re-shaping power systems[1]. Increased levels of weather-dependent and therefore variable renewable generation are expected to result in more and more technical and operational challenges. Moreover, an impact on the economic performance of different generation resources and flexibility providers is expected[2] .

In the context of the EU-SysFlex project, 'high' renewable penetration at a level that would result in over 50% of the total annual electricity demand in the whole European Power System originating from renewables generation are studied.

As well as being variable and non-synchronous, a large share of the renewable technologies is being connected to the distribution grid. The transition towards this 'new' mix and its locational distribution in the network will require the development of innovative flexibility services (as proposed in Task 3.1) in coordination between the System Operators to tackle the challenge of safe and reliable operation of the power systems (as highlighted in WP2).

Some products identified in Task 3.1 are not used in European Countries (or only in Islands where stability issues have already occurred). Several products already exist in many European countries. These are frequency control, congestion management, voltage control and inertia products, which will, in the future, have to be deployed on a larger scale as more variable, decentralized and multidirectional power flows will occur in the various grids creating instability and congestions to the SO to manage.

As a greater proportion of flexibilities will be connected to the distribution grid (whether renewable generation units or consumers' flexibility in consumption), new ways of procurement for these services will need to be explored. New market organisations might be required to reveal and tap into these new sources of flexibility

In this new setting, the role of the DSO becomes increasingly important, as does stronger cooperation and coordination between TSOs and DSOs across borders. Also, new ways of optimising the procurement (either centralised or decentralised) should be considered.

After introducing the task and the methodology, *the* different possibilities of procurement organisations have been described based on the role model framework established by Task 3.3 for a list of generic products based on work in Task 3.1 (frequency control products, voltage control products, congestion management products)[3].

Then, this report discusses the following aspects:

1) Feasibility of short- and long-term **market-based and regulated organisations** for the different flexibility products (Chapter 4)
2) **Processes for optimising the combination of flexibilities and grid measures (e.g. grid topology modifications) across transmission and distribution level** – regardless of the number of marketplaces, either performing the optimisation for transmission and distribution level in a **centralised or in a decentralised** (i.e. coordinated, but separate) **optimisation** (Chapter 5)

[1] The degree of already achieved transition is country-specific.
[2] See Deliverables D2.4 of Task 2.4 and D2.5 of Task 2.5 (EU-SysFlex Project, 2020, https://eu-sysflex.com/documents/)
[3] See Deliverables D3.1 of Task 3.1 and D3.3 of Task 3.3 (EU-SysFlex Project, 2019, https://eu-sysflex.com/documents/)

3) Options for **joint procurement of flexibilities**, specifically of one product to deliver several services, like congestion management and balancing, for meeting both DSOs and TSOs needs (Chapter 6)

The main results are presented below.

MARKET BASED VS REGULATED ARRANGEMENTS

Market-based organisation as preferred solution. Conditions for permitting regulated organisation

When it comes to the organisation of procurement, the general conclusions of Chapter 4 are that a **market-based** rather than a regulated **organisation should be the preferred solution**, if the necessary conditions are in place to allow for the introduction of a market. Such conditions include sufficient competition/liquidity, transparency and clear market rules, limited strategic behaviour such as increase/decrease gaming, regulatory oversight so that prices are determined by competition rather than being arbitrarily regulated. Nevertheless, a **regulated organisation could still be preferred in some cases**, provided it complies with the terms of the Clean Energy Package[4] (CEP), for instance:

- ✓ A market organisation has to be considered and implemented **unless** a regulated organisation is economically more efficient – in addition, regulatory requirements that apply to only a subset of resources should be introduced only as a last resort, as it would violate the principle of technology neutrality.
- ✓ In case of difficulty to price the service (no price or very low): mandatory capability can be stipulated by network codes (e.g. angular stability service).
- ✓ In case of liquidity problems and potential for strategic behaviour (e.g.: increase/decrease gaming[5]).
- ✓ In case of high transition[6]/operational costs and limited expected benefits.

In some cases, a mix of market-based and regulated organisations (options to choose firm and non-firm access, mandatory participation with or without compensation of opportunity costs, bilateral contracts …) can be used to minimise transition and system costs (e.g. due to limited liquidity, increase/decrease gaming or low benefits of market-based organisation).

What about the different products studied?

With regards to the procurement of the different products studied, the relative merits and suitability of regulated and market-based solutions can be summarised as follows:

- ✓ **Inertia**: While market-based procurement solutions are preferred, a regulated approach is allowed and appears to be the most appropriate in the first instance, as initially only synchronous inertial response is

[4] See articles 6 and 13 in the REGULATION (EU) 2019/943 on the internal market for electricity and articles 31.7 and 40.5 in the DIRECTIVE (EU) 2019/944 on common rules for the internal market for electricity

[5] Increase decrease game: a wholesale market neglects grid constraints inside zones, contrary to a following flexibility market. This creates a trading opportunity for producers located at export-constrained nodes: possibility to increase the revenue by increasing sales in the wholesale market and then buying back power at a lower price in the flexibility market. The same effect can also apply to loads.

[6] Transition from a regulated organisation to a market-based organisation

considered, which can only be procured from synchronous units and therefore the pool of providers is limited. In the future, this pool could be expanded by non-synchronous technologies with grid-forming control mechanisms Procurement of inertia should be aligned with future decommissioning plans for synchronous power plants.

- ✓ **Frequency control products**: the CEP imposes a market-based procurement in cases where the development of new capacity is required, market-based mechanisms (for example auctions) should be preferred over mandatory requirements for a limited number of specific resources.
- ✓ **Voltage control products**: there are mandatory requirements in the European network codes regarding voltage control capabilities, notwithstanding that lack of voltage control has been identified as a future technical scarcity. Where reactive power needs can be met by a large number of flexibilities, a market-based solution (for example long-term auctions) should be adopted. It is questionable, however, whether the benefits of short-term (e.g. day-ahead) auctions, especially given the limited monetary value of the service, outweigh the implementation effort. A more regulated approach could be envisaged if auctions are unsuccessful.
- ✓ **Congestion Management products**: market-based solutions should be preferred in all cases when market power and increase/decrease gaming can be limited sufficiently (e.g. via competition laws and/or regulatory oversight) – the solutions must ensure sufficient visibility and predictability for system operators and market players (auctions to procure new capacities with long-term agreements and/or market-based organisation for short-term allocation). However, if the liquidity is poor (even when demand side participation has been considered) and increase/decrease gaming cannot be limited sufficiently, voluntary non-firm connection agreements for loads and mandatory participation with cost-based remuneration for generation can be a potential option.

OPTIMISATION METHODOLOGIES AND GRID CONSTRAINT MANAGEMENT

Disclaimer

A distributed organisation of the market, without optimisation, has been described and evaluated at a high level. Two main conclusions emerged:

- ✓ Unlike procurement of energy products, for flexibility procurement (be it for active power or reactive power) a distributed organisation appears feasible (i.e. with sufficient interest for market actors) only in the form of a secondary market.
- ✓ Such organisation is not relevant for products where the replacement of one bid by another bid leads to different impacts on the grid in terms of solving scarcities or causing new scarcities. This especially accounts for localised products unless the peers offer flexibilities with the same sensitivity regarding the grid impact.

Therefore, this organisation was not considered further.

Optimisation methodologies

Besides the choice between regulated and market-based organisation, it is necessary to detail how the procurement optimisation will be performed**. Within a given procurement organisation, two main optimisation methods are possible: centralised or decentralised.**

To discuss the different possibilities of optimising bid selection a new role was introduced: **Optimisation Operator**. It is its responsibility to select bids (clear the market or choose in an order book) considering grid data and switching measures. We do not opine on which actor will play this role, be it each individual SO, a joint venture of SOs or a third party. However, in all cases, SOs provide grid-related information to the Optimisation Operator.

The two main possibilities for procurement optimisation are a centralised optimisation or a decentralised optimisation. In case of centralised optimisation, a single algorithm (run by a single Optimisation Operator) performs the optimisation for both transmission and distribution levels, considering all grid constraints. In case of a decentralised optimisation, several algorithms do the optimisation for different levels (run by the respective Optimisation Operator for each SO, thus at least one for transmission level, and one for distribution level) and require to be coordinated.

Grid constraint management: grid data sharing and coordination between optimisation levels

Several methods can be described to consider the different grid constraints in flexibility procurement.
When considering grid constraints in flexibility procurement, both centralised and decentralised optimisations can be applied for selecting flexibilities for a large set of products.

For both centralised and decentralised optimisations, **the amount and type of grid data shared between the SO and the Optimisation Operator roles may vary:**

- **comprehensive grid data**, describing the electrical properties of the grid to depict its dynamics, such that the optimisation algorithm is able to calculate diverse grid phenomena, select the most efficient combination of flexibilities and switching of topology
- **partial grid data**, using essentially the sensitivities of flexibilities towards critical U/I constraints and U/I margins in the grid, e.g. for one topology.
- **SO send solely bid limitations**, i.e. the SO reduces or rejects bids which, if accepted as submitted, would cause grid constraints to be violated. Two sub-options exist, depending on whether bid limitations are sent after a pre-selection step or before the selection led by the Optimisation Operator.

With a centralised optimisation all necessary data (bids, reserve needs, comprehensive or partial grid data or bid limitations where possible) are directed into a single algorithm to consider constraints at all voltage levels and select the most appropriate bids. In the case of comprehensive grid data, the algorithm also selects the optimal switching measures. Therefore, one optimisation for all system operators solves all their scarcities.

With a decentralised optimisation, there is one optimisation for each system operator to solve the respective scarcity. Then, a coordination is needed between the different optimisation levels. **Three coordination options are possible:**

- **bottom-up coordination**: optimisation at distribution level, followed by optimisation at transmission level
- **hybrid coordination**: optimisation at distribution level, followed by optimisation at transmission level, and again at distribution level
- **top-down coordination**: optimisation at transmission level, followed by optimisation at distribution level

In any case, to carry out each individual optimisation, each optimisation operator receives all necessary data from its allocated SO and (potentially in a consolidated way) from neighbouring optimisation operators (representing horizontally and vertically physically connected SOs) which results in a coordination between the different optimisation operators.

Regardless of centralized or decentralized optimisation, **sharing comprehensive grid data between the roles SO and Optimisation Operator appears to be the most promising solution**: The Optimisation Operator determines the most efficient solution by using flexibilities and switching of topology. Nevertheless, **a simplified process, such as placing limitations on the bids may be enough in certain instances, in particular for balancing products**. Bid limitations can be sent before the bid selection or, in case of grids where the probability of breaching constraints is low, after a pre-selection only in case of breaching grid constraints requiring an iterative process.

Comparison of centralised and decentralised optimisation

Some conclusions can be drawn when comparing the centralised and decentralised optimisation methods using qualitative analysis.

An important result is that **both centralised** (one optimisation across all voltage levels) **and decentralised optimisations** (at least 2 optimisations, one at transmission level and the other at distribution level) **might be applied for selecting flexibilities** (bid selection) **for each discussed product**. Both methods are feasible with one or several marketplaces and neither centralised nor decentralised optimisations reduce liquidity by design.

Conceptually, a **centralised optimisation** leads to an optimal **allocation of resources at system level.** Other advantages of a centralised optimisation lie in reduced coordination effort and lower interoperability challenges. However, there are challenges, among them the complexity of the algorithm.

In contrast, a **decentralised optimisation** requires coordination across the different levels. One solution could be a bottom-up coordination (i.e. optimisation at DSO level and then at TSO level) that leads to the optimal selection of bids where there is a separate optimisation of products and radial distribution grids. A hybrid approach (i.e. distribution level, transmission level and then distribution level again) can be more efficient where there is a joint optimisation of different products or meshed distribution grids with specific combinations of local grid structures, power flows and characteristics of flexibilities (such as location, voltage level and price). A top-down coordination only works for balancing products, if there is no need to limit the flexibility activation in the operational phase at distribution level (due to firm connection agreement or prequalification). **Therefore, decentralised optimisation appears more relevant for grids where DSOs need locational products to solve voltage and congestion problems.** Other advantages of a decentralised optimisation include the higher resilience, lower complexity of individual algorithms, the possibility to adapt individual optimisations to specific requirements (voltage level, region) and the better fit to the current regulatory framework including the subsidiarity principle.

The statements above have been examined for the different products studied. Although, as already stated, both centralised and decentralised optimisation allow TSO/DSO coordination and can be applied to all products**. There are some products for which a DSO can give its consent during the prequalification phase** (rather than during the procurement phase). The delivery duration of inertia, FFR or FCR[7]is in general at most several minutes, so that their activation has minimal impact on the grid. In these cases, firm grid prequalification is more useful and a decentralised optimisation including coordination between distribution and transmission level at daily or more frequent basis does not add any value. **Therefore, for inertia and FCR a centralised optimisation (without TSO/DSO coordination during the procurement phase) is more relevant.**

Allocation of optimisation operator role

The Optimisation Operator role could theoretically be allocated to any of the following actors: each SO, group of DSO/TSOs or commercial third parties.

Nevertheless, if the actor is different from the individual SO (being responsible for the safe operation of the power system under Electricity Directive articles 31 and 40), it would cause significant governance and regulation challenges, the implications of which have been partially addressed in this deliverable.

JOINT PROCUREMENT OF mFRR AND CONGESTION MANAGEMENT PRODUCTS

Different options for the joint procurement of energy for congestion management (CM) and mFRR are possible but may lead to a range of benefits and drawbacks.

In the context of EU-SysFlex, joint procurement is defined as the procurement of one (or more) products to deliver several services, for instance CM and balancing, to address the flexibility needs of TSOs and / or DSOs. Several options of implementation of joint procurement are possible.

The joint procurement of energy for CM and mFRR appeared to be the most relevant to be studied due to the similar characteristics of the needs. A joint product, which fulfils both of the requirements of CM and mFRR, was introduced and assumed as prerequisite for joint procurement[8]. **Possible cases of cost savings were identified,**

[7] For other products, an assessment of grid constraints is carried out during the procurement phase as detailed in Chapter 5.1. If the delivery duration of FFR and FCR exceeds several minutes, the assessment of grid constraints during the procurement phase might become necessary as well, leading also to the need for TSO/DSO coordination.
[8] In case of version 1 (see below) such prerequisite only exists if FSPs decide to submit one bid for both scarcities.

especially the joint optimisation of balancing and CM needs for which the maximum synergy potential compared to separate optimisation of both needs was evaluated for the German case. In contrast to a French case, with few congestions, but higher imbalances, mFRR bids might be used to solve congestions, avoiding separate CM processes.

Nevertheless, whilst complying with the rules imposed by SOGL and CEP (participation to MARI cross-border platform for the procurement of mFRR energy bids), the possible processes have very tight timeline constraints. Taking into account these timeline constraints, **three mFRR and CM joint procurement processes have been explored**:

- Version 1: coordinated optimisations via connected bidding phase,
- Version 2: coordinated optimisations via joint bidding phase,
- Version 3: joint bidding phase and a joint optimisation.

All versions reveal different effects increasing and decreasing costs, compared to separate procurement of mFRR and CM, which have been assessed in a qualitative manner[9]. The main results can be summarized as:

- **Reducing transaction costs and increasing liquidity** due to the possibility (version 1) and necessity[10] (version 2 and 3) to place bids combined for both scarcities.
- **Lower flexibility volume needed** due to the use of flexibility to solve both mFRR and CM (version 3)
- **Reducing liquidity** compared to separate procurement in the different versions, either **because the gate closure time** (GCT) for CM **is moved** forward (version 1), or because of the joint GCT for CM and mFRR (version 2 and 3), leading to the exclusion of certain FSPs.
- **Joint bidding** (version 2 and 3) could **decrease strategic behaviour**.
- As **in versions 2 and 3** the optimisation takes place after a joint gate closure compliant with MARI's timeline, **SOs cannot include certain grid flexibility potential** in the optimisation (shifting maintenance measures to allow topology switching), leading to a reduced efficiency of the optimisation

Challenges have been also identified among which:

- **The timeframe for CM optimisation, including the coordination of SOs,** is currently not sufficiently aligned for versions 2 and 3 (because of MARI constraints regarding the timeframe between FSPs bids gate closure time[11] and the clearing result for FSPs).
- **The joint algorithm and/or the coordination** between SOs is much **more complex**

To conclude, **joint procurement of mFRR and CM energy products is a relevant option.** However, **without quantitative analysis, it is difficult to do a final assessment** whether joint procurement, in any of the discussed versions, is more beneficial than separate procurement. An ex-post case study of Germany (year 2018), with a high potential of volume synergies, did not reveal convincing benefits of a joint optimisation. When considering the

[9] Therefore, it is not possible to judge, which effects outweigh.
[10] Such necessity can also increase transaction costs (of FSPs which would only offer mFRR in case of separate procurement), since there is the need to break-down the aggregated portfolio to locational bids and describe, where necessary, the rebound behaviour.
[11] Time limit for FSP's to submit bids

implementation of joint procurement, the **trade-off between potentially**[12] **decreased costs and increased complexity will depend on the national situation**, among others severity of grid congestions and mFRR needs, cost structures of CM and mFRR, existing processes.

Apart from the implementation of one of the different versions of joint procurement, combinations of separate and joint procurement or of different versions of joint procurement are possible. In countries with implemented replacement reserves (RR) processes, joint procurement of RR and CM could also be an option. However, their feasibility and consequences were out of scope for this task.

[12] The report revealed cost increasing and decreasing effects. It must be assessed which effects outweigh. In general, either higher or lower costs are possible.

1 INTRODUCTION TO TASK 3.2

1.1 CONTEXT

With the advent of very high levels of variable renewable generation, as well as a move to more decentralised and distributed power electronic interfaced technologies, there are likely to be significant challenges to ensure grid safety and power system stability. Deliverable 2.1 of the EU-SysFlex project (EU-SysFlex Project, 2018a) has identified a number of key technical scarcities associated with the integration of variable non-synchronous generation and the associated displacement of conventional synchronous generation frequency control capabilities across multiple timeframes. The deliverable also identified issues in relation to reactive power capabilities, congestion management issues, especially when renewable generation is situated far away from load centres, an increase in black start needs and a potential system adequacy issue. These scarcities, if not mitigated, may impact the security and stability of the power system of the future.

Deliverable 3.1 (EU-SysFlex Project, 2018b) outlined the need for new system services and new system service providers, in addition to already existing services and providers. Their role to address the identified scarcities was assessed, and a first analysis of relevant market arrangements was provided.
Task 3.2 aims to provide a more detailed analysis of the different market arrangements that could be implemented to procure these flexibilities. We assess the efficiency of the procurement and explore the need to employ new and innovative market designs.

The remainder of this report is organised as follows. First, we outline the objectives of WP3, more generally, and Task 3.2 specifically. Chapter 2 provides an overview of the approach that was followed in this task. Chapter 3 summarises the results of Task 3.1 (list of products and first analysis of market design options) and Task 3.3 (role list and framework to describe interactions between roles during the system service procurement) that have been used in Task 3.2. We highlight their adaptation to the context of Task 3.2. Chapter 4 details the process to acquire flexibilities under different selected market and optimisation options. It presents an analysis of the advantages and disadvantages of regulated or market-based procurement for different scarcities. Chapter 5 focuses on grid constraints considerations in the flexibility procurement process and the process itself to solve grid constraints. Chapter 6 examines the possibility to have joint procurement of different services, specifically frequency control products (mFRR) and congestion management (CM). We discuss the associated advantages. Finally, Chapter 7 concludes and identifies additional next steps necessary to enlarge upon the findings of the work presented here.

Disclaimer

For the discussion of the different implementation options, this report assumes flexibility procurement at a national level up to the level of coordination among system operators. Detailed challenges with respect to solving cross-border issues have not been addressed specifically.

1.2 WP3 OBJECTIVES

EU-SysFlex Work Package 3 is entitled "Analysis of market design and regulatory options for innovative system service". The main objectives of WP3 are the development of innovations for existing and new system services which goes hand in hand with the analysis of different options for market design. The assessment of product characteristics and corresponding market design will be supported by advanced modelling techniques. In addition, roles and interactions of both regulated and deregulated stakeholders will be examined in the context of the provision of system services. Within Work Package 3, generic functional specifications in terms of business use cases are provided for the services tested by the different demonstrators within EU-SysFlex.

1.3 OBJECTIVES OF TASK 3.2 AND RELATIONSHIP WITH OTHER TASKS

Task 3.2 objectives are as follows:

- ✓ To build upon the developed generic role models to describe the responsibilities and interactions between system operators (regulated players) and deregulated players (in particular flexibility service providers), for system service provision by both centralised and decentralised energy resources (demand response, storage, generation). This generic role model was also used in Task 3.3 to describe the project demos (EU-SysFlex Project, 2018c).
- ✓ To analyse relevant system service markets with specific attention to market harmonisation and the ENTSO-E network codes.
- ✓ To compare different proposed role models and market/regulatory organisations with existing market designs and regulation in EU countries.
- ✓ To provide a gap (elements lacking) and barrier (elements prohibiting) analysis of current market organisation/regulation, eventually to propose potential solutions.
- ✓ To identify key attention points in the market/regulation options for further investigation supported by advanced quantitative power system and market modelling (Task 3.4).

Outcomes will reveal market/regulation options to procure, activate/operate, measure and settle the defined innovative products for system services in a cost-efficient way. As such, the results will directly feed into the flexibility roadmap for a future pan-European power system charted in WP10 of this project.

TABLE 1-1: PROCESS FOR IDENTIFYING SYSTEM SERVICES THAT MAY BE NEEDED IN THE FUTURE AND THE RELEVANT MARKET ORGANISATIONS TO PROCURE THESE SERVICES

Steps in Process	Tasks in EU-SysFlex Undertaking this Work
1. Detailed technical studies and analysis to identify the technical scarcities and needs including an assessment of the capabilities of the portfolio of technologies	Task 2.1 (Literature Review), Task 2.2 (Scenario Development), Task 2.3 (Model Development), Task 2.4 (Technical Scarcity Studies)
2. Development of proposals for new services and alternative solutions to mitigate the scarcities and meet the needs identified	Task 3.1
3. Detailed market design assessment	**Task 3.2**
4. Quantitative analysis of the market design options including valuation of new services and solutions	Task 3.4 (Market Modelling), Task 2.5 (Financial impacts of a System with a large share of RES)

More generally, based on Task 3.1 and WP2 results, the discussion in Task 3.2 will interact with the work that will take place in Task 3.4, but will also inform the development of the roadmap in WP10. The relationship between Task 3.2 and other tasks in the EU-SysFlex project is graphically depicted in Figure 1-1.

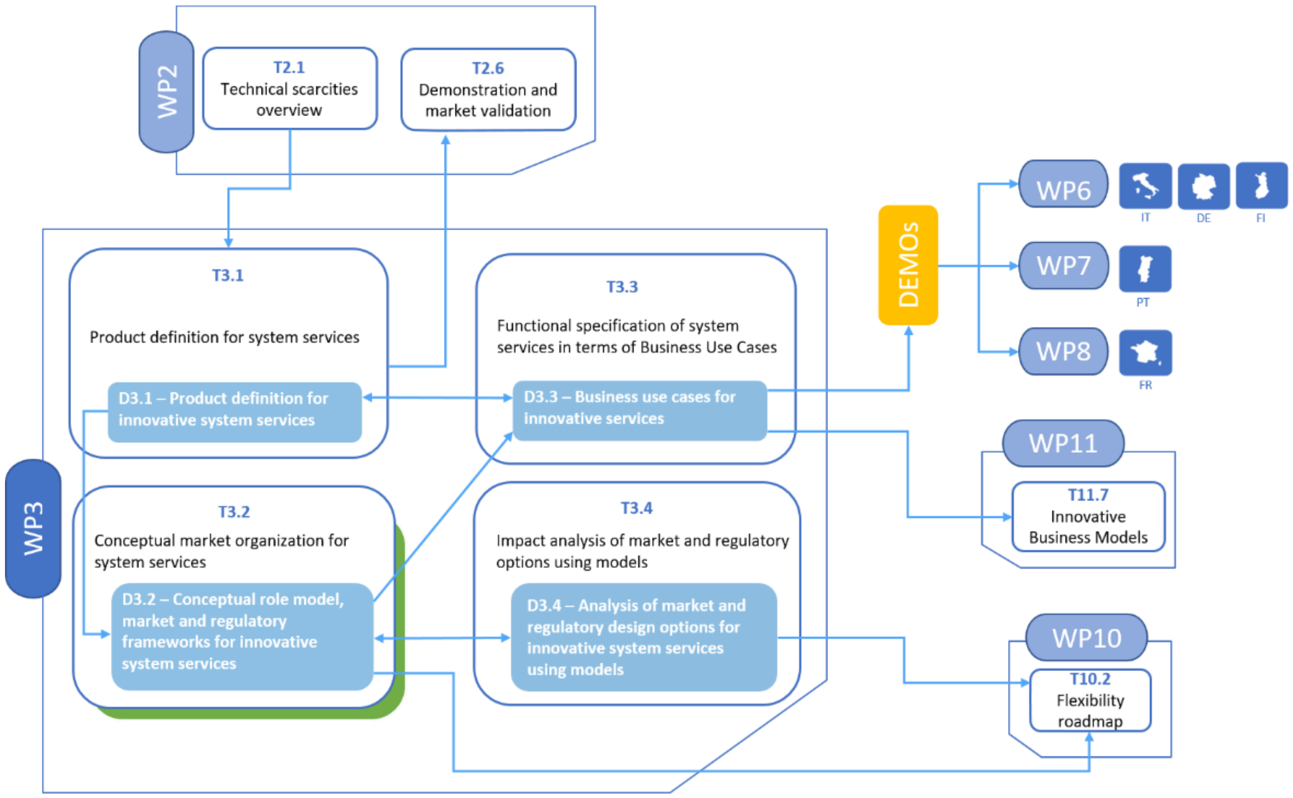

FIGURE 1-1: RELATIONSHIP BETWEEN WP3 TASKS AND OTHER WORKPACKAGES

In what follows, a **system service** is defined as the physical action, be it the provision of active or reactive power and/or energy, which is needed to mitigate a particular technical scarcity or scarcities. A **product**, on the other hand, is the "option" that is purchased and remunerated, where the service is what is actually delivered, and the service defines exactly what is needed once a particular option is called upon. For example, manual frequency restoration reserve (mFRR) is a product, while the covered system service is the provision of active power to restore the system frequency following a frequency deviation.

2 METHODOLOGY AND APPROACH

2.1 OVERVIEW

Firstly, it should be highlighted that the findings of Task 3.2 are the result of conceptual work on the options for organisation of markets for future system services. This has dictated and influenced the approach applied. The main facets of this task required information gathering, detailed discussions and challenging current practise. To achieve this, it was necessary to merge several different approaches including:

1. ***Out-of-the-box thinking through the use of a detailed questionnaire***, together with Task 3.1: A questionnaire was created in collaboration with Task 3.1, the aim of which was to collect a set of relevant ideas on potential characteristics of innovative system services and market architectures for further detailed discussion during the internal workshops. Details on the questionnaire can be found in Deliverable 3.1 (EU-SysFlex Project, 2018b).

2. ***Creation of a task force to work in-depth and propose concepts/principles*** to be discussed with all partners; EDF, EirGrid, Innogy, PSE and Vito were involved. Elering joined the task force in a second stage.

3. ***Detailed discussions during regular conference calls**, **but most predominantly during 3 internal physical Task 3.2 workshops** (see workshop description in ANNEX I)*
   a. on the 5th and 6th of December 2018 in Leuven, Belgium (together with Task 3.1 and 3.4), bringing together the perspectives of more than twenty consortium partners (research institutes, universities, consultants, TSOs, DSOs, etc)
   b. on the 21st and 22nd of May 2019 in Chatou, France (with Task 3.4)
   c. on the 10th and 11th of December 2019 in Heverlee, Belgium

Figure 2-1 visualises the approaches utilised in this task It shows the inputs that are used, and the outcomes that are obtained in the intermediate steps. The expertise and knowledge of each of the partners in this task was leveraged, not only in gathering information but also in fuelling the discussions that took place during the frequent interactions.

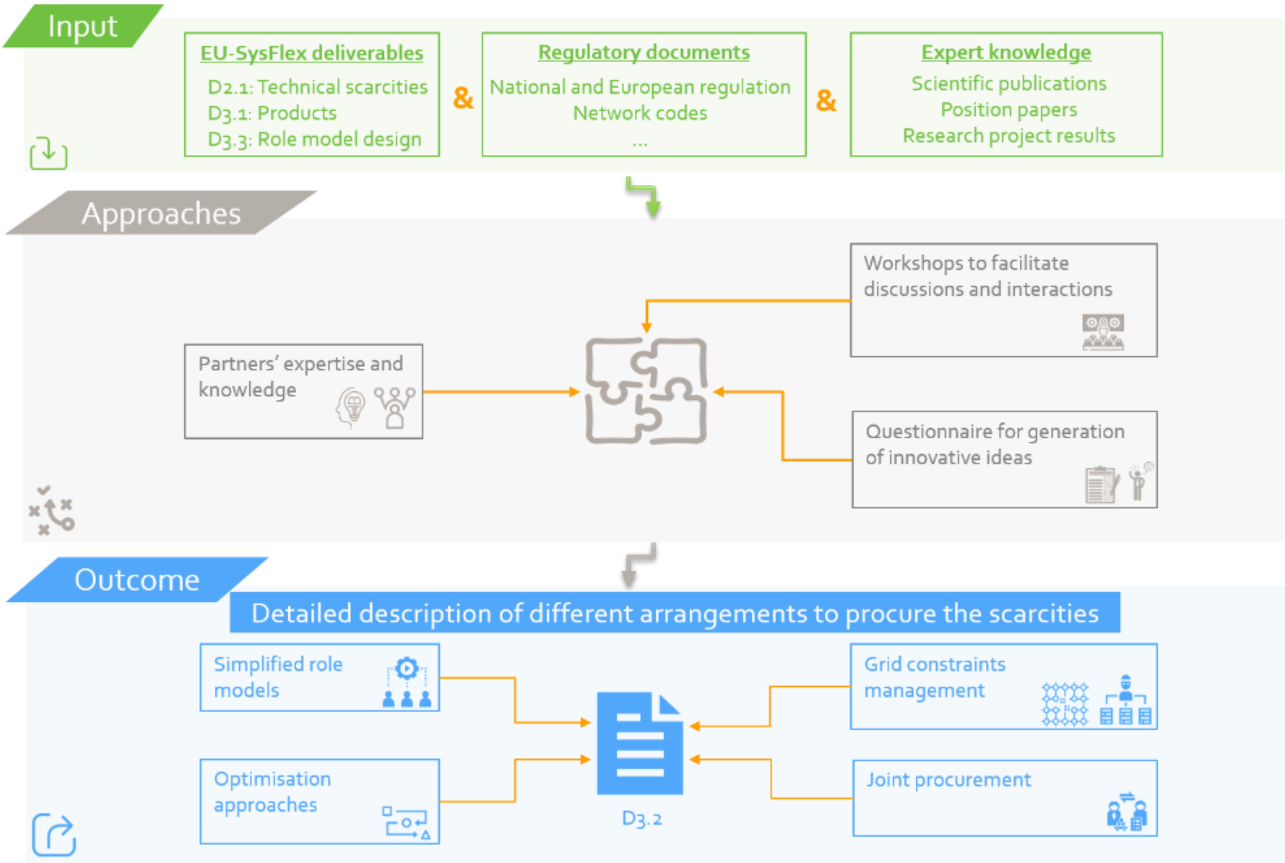

FIGURE 2-1: OVERVIEW OF THE APPROACHES UTLISED IN TASK 3.2 (ADAPTED FROM EU-SYSFLEX PROJECT, 2018B)

2.2 INTERACTIONS WITH TASK 3.4

As explained in Section 1.3, one of the main objectives of Task 3.4 was to complement the conceptual market designs of Task 3.2 through advanced power system and market modelling studies. Thus, it has been necessary to coordinate both tasks. Two common workshops have been organised to share and aligns the work in both tasks (see ANNEX I).

Task 3.2 identified different key attention points in the market/regulation options that have been addressed in Task 3.4. Among them, the following issues have been integrated into the Task 3.4 studies:

1) Which are the important parameters when designing products and markets characteristics?
2) What are the advantages and drawbacks of a regulated organisation versus market-based organisation?
3) How can grid constraints be considered in the organisation of flexibility procurement?
4) What coordination between TSOs and DSOs is required and beneficial?
5) Is a joint procurement of some flexibility services possible, in particular for frequency control products?

The results of the simulations have been taken into account in this deliverable, as far as applicable.

3 INPUTS FROM TASK 3.1 AND TASK 3.3

3.1 OVERVIEW OF THE ROLES TO BE USED IN TASK 3.2

To describe the different possibilities for organizing the procurement of flexibility services, a list of roles involved is necessary. The starting point is the list of roles established by D3.3 (see a summary in ANNEX II), which was extended and adapted to the needs of this task:

- In centralised/decentralised organisation, System Operators (SO) are the flexibility buyers. The market participants involved are Flexibility Service Providers (FSP). In the distributed organisation, or if a secondary market is organised (if some actors are obliged to provide flexibilities), several type of actors can buy services (consumers, traders, generators, etc.) thus the FSP role was modified to include this possibility.
  Moreover, to discuss the different possibilities of optimising bid selection considering grid constraints and (where relevant) grid switching possibilities[13] a new role was introduced: Optimisation Operator (OO). Consequently, the market operator (MO) role was modified: organize auctions, publish the results and carry out the settlement. Note that we do not presuppose which actor will take up the OO role, be it each individual SO, a joint venture of SOs or a third party (for instance a commercial market operator). In any case, the Distribution System Operator (DS_O) and Transmission System Operator (TS_O) provide grid related information to the OO.

An important remark is that roles describe different responsibilities in the electricity system. They can be carried out by different or, in some cases, by the same actors, as long as European and national laws and regulations are respected

[13] The benefits of a combined optimisation of bid selections and grid switching measures has been described in Chapter 3 of Deliverable 3.4 (EU-SysFlex Project, 2020).

3.2 DESCRIPTION OF THE DIFFERENT DESIGNS STUDIED

As Task 3.1 provided a selection of generic services, a first task was to describe the market characteristics applicable to them based on the Table 3-1. The results are provided in ANNEX III.

TABLE 3-1: LIST OF MARKET CHARACTERISTICS

Characteristics	Description / Options
Market pre-qualification	
Nature of the participants	Mandatory participation? Based on which characteristics (generator/DSR, location, flexibility size, …)?
Procurement	
Perimeter	The area the marketplace encompasses: Local (= DSO level), national or zonal (= one TSO level), cross-border (= cross TSO level).
Frequency	For instance, annual, daily, hourly, or even shorter
Nature of the buyer	Who is responsible for obtaining a specific product: is the TSO or the DSO the only buyer (monopsony, single buyer)? Or are SOs both buyers? Or even commercial market participants?
Product structure	Characteristics of the product One or several products procured on the same market: 1. one product, 2. several products co-optimised (for instance upward / downward / symmetric or capacity / energy)
Spatial resolution of the product (= location)	Which precision is required for the location of the product?
Temporal resolution	The length of the time period in which a specific product is defined
Delivery horizon	The length of the quantum of time in which a specific product shall be delivered
Activation	
Activation of the product	Procedure for the activation of a product: inherent, automatic, manual. Coordination between TSOs and/or DSOs, if required.
Settlement	
Verification	Rules for verification of actual delivery, including definition of the baseline.
Payment	- Regulated price? - Regulated bid price (for instance, market parties have to offer prices based on their variable costs)? - Existence of price caps/floors? - Pay as cleared or pay as bid
Penalties	In case of non-delivery or non-conform delivery

In addition, Task 3.1 identified four different possibilities for the organisation of procurement: centralised, decentralised, distributed and regulated. However, this classification should be reviewed since centralised and decentralised refers to optimisation principles (the coordination of the buyer's side (by SOs exclusively) to use flexibilities in a cost-efficient and secure way) be it in a regulated or in a market-based procurement organisation.

Since the terms "centralised" and "decentralised" refer to the optimisation principle, the link between the different organisations and the associated optimisation principles possible is depicted below in Figure 3-1. Figure 3-1 illustrates that both regulated and market-based organisations can be managed with centralised or decentralised optimisation principles. In addition, for market-based organisation, another possibility exists when there is no optimisation performed but a distributed market is put in place.

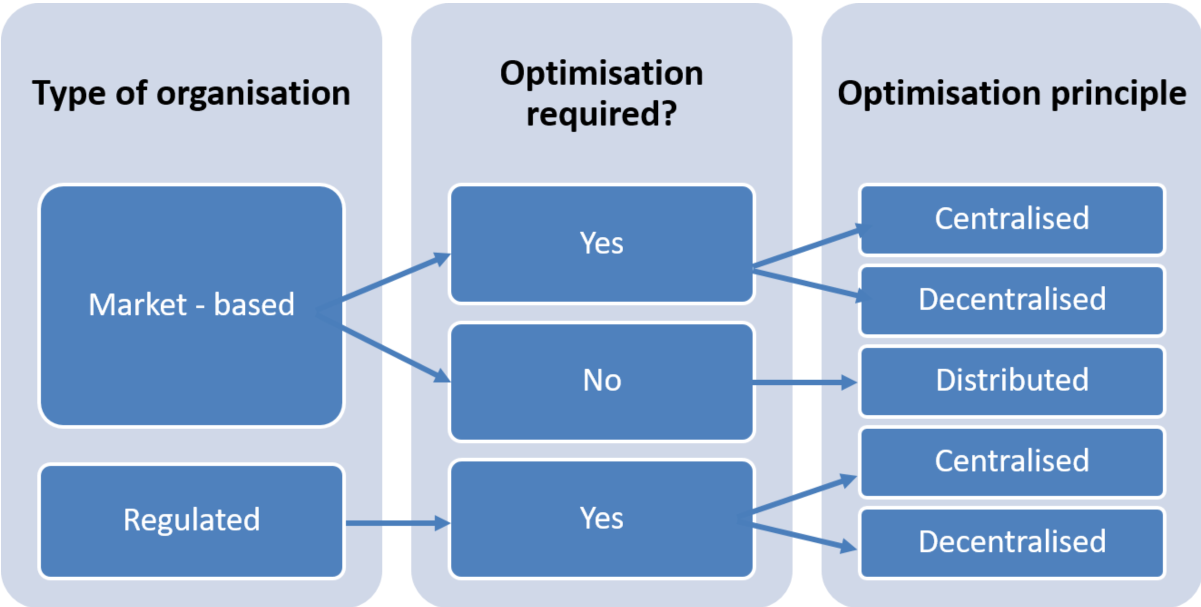

FIGURE 3-1: LINK BETWEEN PROCUREMENT ORGANISATIONS AND OPTIMISATION PRINCIPLES

Furthermore, for flexibility market design, it is necessary to distinguish organisation of marketplaces and optimisation principles. While organisation of marketplaces refers to the rules for buyers and sellers to place bids on specific marketplaces, the optimisation principle, as mentioned above, refers to the coordination of the buyer's side (by SOs exclusively) to use flexibilities in a cost-efficient and secure way. The choice of optimisation principle is independent from the choice of marketplace organisation[14].

In the task, priority has been given to the description and analysis of the different optimisation principles possible, centralised or decentralised. A discussion about regulated vs market-based organisation is also proposed (Section 4.2). The question of marketplace organisation is not addressed. It is assumed that independent of the choice for one or several marketplaces, an FSP submits its bids to a single platform only.

[14] One or several marketplaces can exist for gathering bids from FSP. Their selection can then be optimised by a unique centralised algorithm or several decentralised algorithms. The number of marketplaces does not preclude on the number of optimisation algorithms.

For the sake of clarity, the definitions used to describe the different organisations of procurement (left column in Figure 3-1) are the following:

Regulated organisation

In the regulated organisation, the provision of a certain quantity of service is mandatory for specific resources or the remuneration of the service is regulated. Thus, the procurement of flexibility does not need a market. In the regulated organisation the choice of flexibilities can still be optimised to minimise the system costs, in a centralised or decentralised way, depending on the regulatory framework.

It should be noted that mandatory participation of some resources can also be required in market-based procurement organisation. Moreover, hybrid organisations with some elements referring to a regulated organisation and some other referring to a market-based organisation exist: the different types of organisation cannot be described only with two extremities but would better be seen as a continuous spectrum.

Market-based organisations

Flexibility providers and flexibility buyers trade flexibilities on marketplace(s), with two different options depending on whether an optimisation is required or not:

I. Organisation with an optimisation of the allocation of flexibilities. Two sub-options exist depending on the optimisation principle that can be optimised in a centralised (I-A) or decentralised (I-B) way.
II. Distributed organisation without optimisation.

I-A: Centralised optimisation:

A centralised optimisation relies on one single algorithm selecting from all flexibility bids those that minimise costs and keep the system within its operational limits. The algorithm takes into account relevant grid data received from DS_Os and TS_Os. In the context of system services, this means that all resources from both the distribution grid and the transmission grid are jointly optimised to serve the needs of SOs (TS_O and DS_Os if relevant). To select bids efficiently, to leverage synergies between all system operators, and to avoid harmful bid selections, the centralised optimisation receives grid data from both DS_Os and TS_Os, such as topology, switching options, power flow forecasts, capacities of grid assets, sensitivities (for congestion management and voltage control) or bid limitations that reflect grid constraints. This optimisation can receive flexibility bids from a single marketplace or many different local marketplaces, which get coordinated by the centralised optimisation algorithm. The optimisation operator (OO) role could be carried out by a TSO, a DSO, a marketplace operator or a third party.

I-B: Decentralised optimisation

In a decentralised optimisation, separated optimisation algorithms exist at least for the distribution and transmission grid, so that at least 2 consecutive optimisation steps are required, executed by different optimisation operators: one at the distribution level (OO_D) and one at the transmission level (OO_T). These roles (OO_D and OO_T) can be carried out by respective DSOs and TSOs or third parties.

In a decentralised optimisation, each optimisation operator is responsible to fulfil the relevant TSO or DSO needs. However, both optimisation algorithms can coordinate. The coordination should prevent harmful bid selections in the distribution grid for TSO purposes and make use of synergies as much as possible. As for centralised optimisation, necessary grid data for each optimisation includes topology, switching options, power flow forecasts, capacities, sensitivities (for congestion management and voltage control) or bid limitations. OO_D and OO_T can receive flexibility bids from a single marketplace or many different (local or global) marketplaces, which get coordinated by the decentralised optimisation.

II: Distributed organisation (without optimisation):

A distributed market is characterized by a high number of potential buyers and providers of a service, often referred to as peers. A peer can be anyone owning or operating an asset or group of assets prequalified for the service. All peers cooperate with what they have available for trading services (Sousa et al., 2019). Each bilateral transaction involves the peer with the capability to provide the service and the peer with the need to buy the service/product.

In the case of flexibility provided to the system, the peer buyer of the service may only be a flexibility service provider with a regulatory obligation to provide the service (in a regulated organisation) or a flexibility service provider who has been awarded with a capacity or energy contract to provide the service in a market. The distributed market acts as a secondary market[15]. Within this organisation, there is no optimisation of transactions but one or several marketplaces can be defined to increase visibility to flexibility providers and buyers. Possibly, marketplaces can play the role of clearing houses for bilateral transactions among peers. In that case, a market price can be defined as an index of comparable bilateral transactions. The distributed market can cover a limited geographical perimeter or be system wide.

As stated above, in the following of the report priority has been given to the description of the two different optimisation principles, centralised and decentralised.

[15] Distributed energy sourcing is different since peers buy energy for their own needs, on a voluntary basis. In the case of flexibility, FSP don't have any needs (SOs have needs).

3.3 OVERVIEW OF THE INNOVATIVE SERVICES AND PRODUCTS IDENTIFIED BY TASK 3.1

The list of services and products provided by Task 3.1 (see ANNEX III) was used as a starting point to examine how the respective procurement organisations could be applied. A list of characteristics necessary to describe the products has been provided (see ANNEX IV). Some parameters are particularly important when describing procurement and activation phases. They are detailed in the following paragraphs:

Capacity and/or energy product

It is appropriate to differentiate capacity and energy products:

Capacity products:

1) Characteristics
   The flexibility buyer is provided with an obligation that an energy product corresponding to the capacity contracted will be provided when required
2) Procurement (two options)
   i) Procurement of a capacity product with capacity price and energy price[16] and no additional bidding phase for energy procurement: the FSP ensure a quantity for a certain period and receives a capacity payment. SO can request the activation of the contracted energy volume at the contracted energy price – only FSP with a capacity contract can be activated, no additional bidding for energy-only products is allowed.
   ii) or procurement of a capacity product with separate bidding phase for energy procurement: the FSP guaranties a quantity for a certain period and receive a capacity payment. Near the delivery time, SO procures energy via a separate bidding process (in fact, the SO procures an energy product). FSPs with a capacity contract are required to submit energy bids corresponding to the capacity procured. FSPs without a contract for capacity can also submit energy bids.
3) Justification
   Capacity products make sense if SO cannot be sure about solving scarcities by procuring flexibilities close to delivery, or if the SO wants to reduce the risk of high costs close to delivery. The option ii) (with separate energy procurement process) maintains the same level of risk as option i), but the additional bids can lead to reduced costs in the end as additional flexibility providers can participate to the energy procurement process.
   Moreover, in case of very fast products which would be activated with very short notice for a very short time (say few seconds), capacity procurement is justified since it is easier to price capacity rather than energy.

[16] Note that these kind of contract is not allowed for balancing product : CEP Electricity Regulation art 4 : *The price of balancing energy shall not be pre-determined in contracts for balancing capacity*

Energy products:

1) Characteristics
The flexibility buyer is provided with an energy to be delivered at the agreed delivery time for a predefined period.
2) Procurement
As explained above, if a separate procurement of capacity has been done, FSP awarded with a contract for capacity are required to submit corresponding energy bids; in addition, or as an alternative market arrangement, "free" bids (meaning without a capacity contract) can be allowed. The selection of energy bids to answer the needs of the buyer shall be based, whenever possible, on the merit order (if necessary including the location).
3) Justification
Participation without guaranteeing prior capacity/availability enables different types of assets with lower availability to provide flexibility and thus enabling more liquidity.

Activation principle:

The Guideline on Electricity Balancing (European Commission, 2017a), defines two modes of activation: manual and automatic. The automatic activation is defined as activation performed in closed-loop manner, while the manual activation is done manually by an operator. While this distinction is sufficient for balancing products, it is not sufficient for other system services. The automatic activation is split onto three sub-modes: (i) automatic following an inherent activation, (ii) automatic following internal control loop, and (iii) automatic following signal sent by SO. The definition of (iv) manual activation is kept.

(i) The first automatic activation mode is inherent activation: For some products (e.g. inertia), specific types of machines provide response following the laws of physics, without explicit control system. The activation is based on local conditions. It might be possible for other technologies to design a control system that emulates a similar inherent activation.

(ii) In case of automatic activation following internal control loop, the activation is based only on local measurements, the SO does not have the possibility to directly influence the actual activation in the given moment. The SO may only decide on parameters concerning the control loop in advance. Therefore, in such cases there is no natural way to set up a market for an energy product.

(iii) In case of automatic activation following a signal sent by the SO (e.g. aFRR), the SO directly sets the level of activation, therefore there is a possibility to design a market for energy products.

(iv) In case of manual activation, SO sends the activation signal to FSP, however it is not done in the closed loop feedback scheme, it could be based on decision of dispatcher (human decision), simple rule-based decision, and solution of some optimisation problem. The consequence for FSP is that in this mode of activation the changes of activation signal are much less frequent - in case of automatic control activation signal changes continuously, in case of manual activation periods between changes of activation signal are usually longer than FAT.

Summarized, we identified four possible activation principles:

(i) Inherent
(ii) Automatic (following an internal control loop –(il))
(iii) Automatic (following a signal sent by SO to an internal control loop- (S))
(iv) Manual

Locational products

Some products, like congestion management or voltage control products can be provided only by assets located in a certain geographical area.

There are more characteristics defining a product. Examples are full activation time, minimum bid size, minimum/maximum duration are also important parameters. They might also have an impact on the participation of technologies, or even form barriers for new technologies or combinations thereof that plan to offer flexibility.

The list of generic services established by Task 3.1 was not detailed enough on product characteristics, in particular, the type of product (energy or capacity), as well as, the time line for procurement (long-term, short-term). Before considering the appropriate market arrangement for procurement of the products, it was necessary to precise these elements. Choices made for characterising the products are the following[17], they do not refer to any specific national context but consider the existing European regulation requirements:

[17] Note that the choices made here are only dedicated to run the analysis on procurement solutions within T3.2 and do not prejudge of a technical analysis on efficiency and relevance to solve scarcities.

TABLE 3-2: SYNTHESIS OF THE PRODUCTS ANALYSED IN THE FOLLOWING CHAPTERS

Service	Product	Capacity/Energy	Locational	Activation
Inertial Response	Inertia	Long-term capacity	no	Inherent
Frequency control	Fast Frequency Response	Capacity	no	Automatic (il)
	Frequency Containment Reserve	Capacity Energy	no	Automatic (il)
	Automatic Frequency Restoration Reserve	Capacity Energy	no	Automatic (S)
	Manual Frequency Restoration Reserve/Replacement Reserve	Capacity Energy	no	- Manual
Voltage Control	Dynamic voltage control	Capacity	yes	Automatic (il)
	Steady state reactive power	Capacity Energy	yes	Manual
	Continuous dynamic reactive power	Capacity Energy	yes	Automatic (S)
	Long-term capacity	Capacity	yes	-
Congestion Management	Short-term (day ahead / intraday) capacity or energy procured to manage congestions that occurs unpredictably due to weather and availability uncertainties.	Capacity Energy	yes	Manual
	Long-term / medium-term capacity (and energy) to manage congestions that occurs predictably due to high-levels of RES or high level of consumption or grid maintenance	Capacity Energy	yes	Manual
	Manage congestions as an alternative to network investment exists	Long-term Capacity (with energy price) Energy	yes	Manual

4 ROLE MODELS AND INTERACTIONS FOR THE RELEVANT GENERIC PRODUCTS IN THE SELECTED MARKET ORGANISATIONS

In this chapter, the generic process for procuring and delivering flexibility to address the SOs' needs is described. Diagrams are provided to explain the different interactions between the roles. The procurement process is described for each of the relevant products mentioned in Section 3.1. As explained in Section 3.2 centralised or decentralised optimisation can be used in a regulated or a market-based organisation. Thus, the diagrams describe the procurement for each optimisation method (centralised optimisation, decentralised optimisation, and distributed organisation) presented in Section 3.2, regardless the regulated/market-based organisation option. Qualitative advantages and disadvantages of market-based versus regulated organisation conclude the discussion. Finally, conditions required to foster flexibility service providers' participation in a market, in case of a market-based approach are listed.

In what follows, each service (and product) is assumed to be procured individually, joint procurement of different services is covered in Chapter 6. Note that the scope of this work covers flexibility services for DSO and TSO needs – commodities such as energy for commercial sourcing is not discussed.

4.1 GENERIC DESCRIPTION OF PHASES (PREQUALIFICATION, PROCUREMENT, ACTIVATION, SETTLEMENT) & SPECIFICTIES

In this section, general assumptions (that apply to all products) and generic schemes that can be used for the different optimisation principles are provided. These assumptions are based on proposed market designs in the Clean Energy Package.

General assumptions

- When applicable, short-term auctioning or running an order book is facilitated by a marketplace[18]
- Nature of the participants: technology neutrality is assumed, therefore all the flexibilities that can demonstrate capability can participate in markets
- Aggregation: aggregation of flexibilities by FSP is allowed if the resulting virtual unit is compliant with the technical requirements of a given service and if control (potentially by SO) is possible according to control and settlement rules. Moreover, technical reality of the grid shall be considered: for instance, aggregation is limited by possible congestions (e.g. only FSP connected in a defined area can be aggregated) or by flexibilities' sensitivities towards congestions.
- Buyer: SOs are the buyers of services, except for distributed organisation.
- Procurement: Transmission Network Flexibility Provider (TN_FSP) bids can only be used for TSO needs; Distribution Network Flexibility Provider (DN_FSP) bids may be used for TSO or DSO needs.

[18] This assumption on short term auctioning was validated in Task 3.4 for mFRR, where it is shown show that significant efficiency gains materialize by changing from monthly only to daily procurement of mFRR, while an intermediary weekly procurement is hardly better than a monthly one.

- SO (DS_O or TS_O) do not have direct control over commercial flexibility units in the described market phases. SO only have direct control over network assets.

Generic descriptions:

The description is based on Task 3.3 work, which divided the process of acquiring each product into four main phases that can be found in each selected organisation:

1) **Prequalification**: The prequalification phase deals with the certification and registration of all assets applying to provide the flexibility service
2) **Procurement of capacity and energy products:** Interactions between the roles covering the acquisition of flexibility capacity (when relevant) and energy, i.e., bidding of flexibility offers and the clearing of the market (or selection of resource if there is no market).
3) **Activation of flexibility:** Interactions between roles covering the activation of flexibility when required.
4) **Settlement:** Measurements and data exchanges for verification and financial flows for the settlement.

A generic description of each phase that can be applied to all products is described in Sections 4.1.1 - 4.1.4 using the roles listed in ANNEX II. If necessary, specificities for products are mentioned.

It is important to highlight that in this chapter the organisations are described between roles, instead of actors. Each role is defined by replicable responsibilities, independent on the country-specific context; the roles aim to be neutral regarding the technical implementation of a product. Each role is delegated to only one actor, where one actor can fulfil several roles. Advantages and disadvantages of different role allocation options are discussed in Chapter 5.

In what follows, for an Optimisation Operator (OO) (see ANNEX II), optimisation refers to **optimisation and selection of bids** (market clearing in case of auctions or selection of individual bids in the order book organised by the MO) **taking into account grid data** (constraints and sensitivities/topology if needed) provided by DS_O and / or TS_O.

4.1.1 PREQUALIFICATION PHASE

The aim of the prequalification phase is to assess if an individual resource of flexibility is compliant with the rules defined for the market for which it is applying. This mainly concerns the compliance with the technical product requirements, as well as the financial and communication requirements necessary to participate in the market. In some cases, the prequalification phase also includes a system prequalification step. This is to verify that the flexibility is not causing congestion (see Chapter 5).
The prequalification phase starts with a request **for market prequalification** from the FSP. The FSP, as a whole, applies to the market operator to qualify as a flexibility resource for a given flexibility market. The market operator checks if the FSP complies with financial requirements, including credit rating (or any other market requirements set by the market operator) and has the necessary communication tools to connect to the market platform. If these

conditions are met, the MO provides the FSP with all required authorisations and data. The prequalification of the FSP is valid for its whole flexibility portfolio.

Once the FSP is qualified at market level, it submits **a product prequalification** application, based on an agreed general framework, for each flexibility providing unit. To this end, the FSP sends to the responsible party (e.g. SO) all technical information required to run predefined tests[19]. Prequalification could be checked per unit or per aggregated unit. In case of the latter, the FSP would be responsible to define the aggregation and to submit the necessary information for its characterisation.

During this product prequalification, the connecting SO checks whether the flexibility unit[20] can deliver the product it wants to sell/deliver (incl. balancing and congestion management products). This sub-process tests the technical capability and validates technical requirements (response) of an (aggregated) unit (Gerard et al., 2018). The SO assesses the quality of the response (considering technical characteristics of the unit (e.g., nominal capacity, energy limitations). Note that specific tests or criteria may be developed and applied to specific units (for instance, a unit with limited energy reservoir). Results from analysis of the tests are communicated to the FSP: if the response complies with the specificities of the product, the unit is allowed to offer flexibility for this product. If response is negative, i.e. the unit failed in passing the test, modifications at the FSP side are required. Once these modifications are made, the unit could re-apply for the technical qualification.

For some products (e.g. inertia, FCR, aFRR) a **grid prequalification** can be run at this stage. The goal is to check that the flexibility does not cause congestion and avoids constraint-related checks later during the procurement phase. However, this is only the case for specific products. In other cases, a grid constraint analysis is preferable during the procurement, as detailed in Section 5.1.

The outcome of the prequalification process is a qualified volume per product per unit or aggregated unit. This volume is the maximum volume allowed to be offered to the auction (taking place at the marketplace organised by the MO). Participation is accepted after successfully completing the technical and market validations (FSP <-> TS_O/DS_O/MO).

The DS_O is involved in the definition of the product qualification criteria if the product is procured for both TS_O and DS_O needs. For DN_FSP, testing and methodology are agreed and coordinated between DS_O and TS_O, even if the DS_O is not a buyer of the product (to assure that there will not be any negative impact on the safety of the distribution grid). However, it is also possible that some products in some locations of the distribution grid technically can only significantly contribute to DS_O needs (e.g. voltage control in low voltage grids), so that the TS_O is not involved.

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[19] In general, the FSP shares with the responsible party (e.g., SO) all technical characteristics of the flexibility unit (e.g., voltage level and connection point, maximum capacity and rate of change, type of product to be deliver). The responsible party, in contrast, has no obligation to provide the FP with detailed characteristics of the surrounding grid. This data is not considered as commercial data and thus, it remains only available to the party responsible for the qualification sub-process.

[20] A flexibility unit can be either a single site unit or an aggregated unit. An aggregated unit needs to be prequalified in the same way that a single site unit does. It needs to meet the financial and technical requirements necessary to bid and it needs to be able to be settled. In the following, the term flexibility unit refers to a single unit or an aggregated unit.

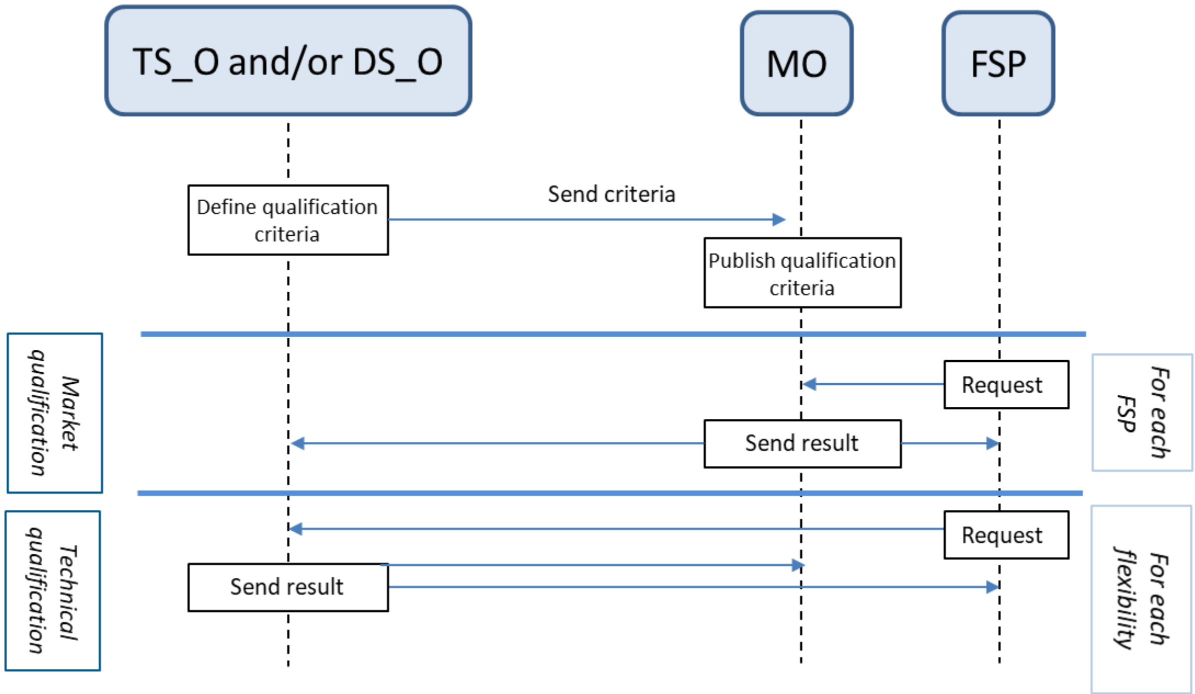

FIGURE 4-1: PREQUALIFICATION PHASE

The prequalification takes place in advance of the auction. As mentioned above, the prequalification consists of a market and product prequalification[21]. Units only need to be prequalified once (before they can offer any flexibility) unless product requirements change. For new assets, it should be possible to include the tests in the connection procedure. Significant changes to units already prequalified may also require a new technical qualification.

Specificities related to products/services:

Inertia:

The technical parameters relevant to service provision capability (base MVA, inertial constant) etc. will be confirmed either via compliance testing (which for inertial response will involve the verification of previous system data) or may require model submission.

Only synchronous units can provide synchronous inertial response. A synchronous unit may adjust its minimum load level to offer a higher volume of inertial response, if agreed by the SO. In the future, non-synchronous technologies with grid-forming control mechanisms may be able to offer a type of pseudo-inertial control. In such a case, compliance testing would have to be adapted to account for this.

Frequency control product (FCR, FFR, mFRR, RR):

The technical prequalification process for frequency control products is defined in the Guideline on Electricity Transmission System Operation. It verifies the compliance of a unit or an aggregated unit for reserve products (FCR, FRR, mFRR or RR) with the requirements set by the relevant TS_O according to principles stipulated in the guideline. For this process, TS_O and DS_O (connecting and intermediate, if any) exchange information such as

[21] Note that a third prequalification – grid prequalification – is optional and can be carried out for some products. This is discussed in Chapter 5

(i) voltage levels and connection points of providing units or groups, (ii) type of product provided, (iii) maximum reserve capacity per connection point; and (iv) maximum rate of change (active power) per unit or aggregated unit.

For congestion management:

The definition of prequalification criteria is done by DS_O and/or TS_O. Both could have very different needs (duration of the delivery, full activation time (FAT)) depending on the grid state. On the other hand, FSPs, especially when integrating the demand side, could also have very individual constraints and technical capabilities. That is why, in future, few standardized products are likely to be necessary, although there should be an accepted set of parameters to describe the product. But standardised tests valid across the complete set of parameters should be implemented, to avoid having to detail individual sets of tests increasing the cost of prequalification.

The prequalification phase will require grid connected tests: the unit (or aggregated units) should change its set-point (increase or decrease injection/consumption), with the required full activation time, for a minimum delivery duration. The test will identify the maximum quantity (in MW) that the FSP can offer on the markets. If the assets can only deliver for a limited time, the energy constraints must be checked as well.

One important aspect of congestion management is the rebound effect. Rebound effects occur when loads are shifted from one point in time to another, for instance, a decrease in power demand (response) will be followed or preceded by an increase (rebound) or vice versa. This shift can alleviate one congestion and create another one. Such events are crucial as the consequences of activating flexibility services on day-ahead and intraday operations must be considered (Esmat et al., 2018; Hermann et al., 2019). If the rebound behaviour is static, e.g. an FSP always shifts its demand to the next period, such behaviour can be described during the prequalification phase. If the rebound behaviour is dynamic (e.g. shifting to the second period at one point of time and to the third at another point of time) or if the buyer can decide the point of time for shifting (e.g. to the second period although at maximum a shifting to the fourth period is possible), such forward/backward (maximum) shifting times need to be part of the bid characteristics during the procurement phase. Another aspect is the recovery period, i.e. the time when a flexibility can be selected again. However, this parameter does not necessarily describe the rebound effect so that by default it is independent from it.

4.1.2 PROCUREMENT PHASE

The procurement phase of a certain product deals with the bidding of flexibility and the clearing of the market, resulting in the selection of flexibility resources.

For this selection, as described in Section 3.2, there can be a (i) centralised or a (ii) decentralised optimisation, or a (iii) selection without optimisation (e.g. mandatory participation, distributed organisation/optimisation). The procurement phase will be described for these three options.

As explained in Section 3.2 centralised and decentralised optimisation can be used in regulated or market-based procurement processes). In the following, we consider a market-based procurement. The comparison between regulated and market-based procurement processes will be done in Section 4.2.

Several assumptions are valid throughout the discussion:

- Clearing results will always respect distribution and transmission grid constraints.
- System operators receive relevant and timely data about (wholesale and/or single generation / load / storage) schedules and activations requests. This data is used for an up-to-date security assessment.
- All available capacity from technically capable units may be offered by FSPs to the marketplace(s).

Specificities related to the products/services:

Voltage control (long-term capacity product):

Voltage control capacity products are procured in medium or long-term because (i) highly localised needs limit the possibility of substituting one provider with other, and (ii) alternatives to procurement of these products are investments in the grid[22], which takes a longer time. Therefore, a SO may be compelled to proceed to a long-term procurement, since they need a guarantee that necessary resources are consistently available in relevant locations over a longer time range, which is not guaranteed in case of short-time procurement.

Inertia:

For the synchronous inertial response product, as only synchronous machines are capable of its provision, the procurement should be organised way in advance of real-time, on an annual or multi-annual basis. This is to ensure that sufficient units remain online. Where a capacity market exists in the market arrangements, the possibilities to co-optimise procurement may be considered. The SOs' determination of inertia requirements will determine the volume to be procured (allowing for seasonal and unforced outages of units).

Frequency control products:

Procurement for frequency-related services is typically short-term (i.e., from a day to an hour ahead), as required in the Clean Energy Package[23]. To comply with the short FAT, products that tackle frequency fluctuations require units to be online and response must be automatic. Markets are cleared at TS_O level as frequency control is a system issue.

Congestion management:

For a centralised or a decentralised optimisation, DN_FSP and TN_FSPs can submit capacity bids to the (or their) MO. They must be accompanied with the description of their capabilities (active and reactive power, ramping, minimum activation duration, (maximum) shifting time, technical limits). Since congestion management is a substitute for grid expansion, which takes long time to implement, system operators need to have a long-term guarantee that necessary resources are available in relevant locations. Such guarantees can be designed either in

[22] Grid investments refers to investments in grid components, not necessarily transmission/distribution lines.

[23] Regulation on the internal market for electricity article 6.9 « Contracts for balancing capacity shall not be concluded more than one day before the provision of the balancing capacity and the contracting period shall be no longer than one day, unless and to the extent that the regulatory authority has approved the earlier contracting or longer contracting periods to ensure the security of supply or to improve economic efficiency »

form of market-based long-term capacity products or regulated mandatory participation (possibly with opportunity cost compensation). Short-term procurement allows the cost-efficient optimisation of the flexibility selection.
DS_O and TS_O provide the (or their) optimisation operators with all necessary grid data required to support an efficient bid selection process as well as the needs[24], in particular the area concerned by congestion, the time interval for the required bid selection and the capacity required for each time interval.

CENTRALISED OPTIMISATION

The buyer(s) of the product, TS_O and/or DS_O, submit its/their requirements to one central optimisation operator (OO). Prequalified flexibility service providers submit their bids to one or several market operators, which are entitled to validate bids (checking validity of the qualification and technical aspects of bids) and forward them to the central optimisation operator.
Based on the flexibilities available and the technical grid constraints, the optimisation operator matches requirements from SOs and offers from FSPs. The results are sent to system operators and market operator(s).

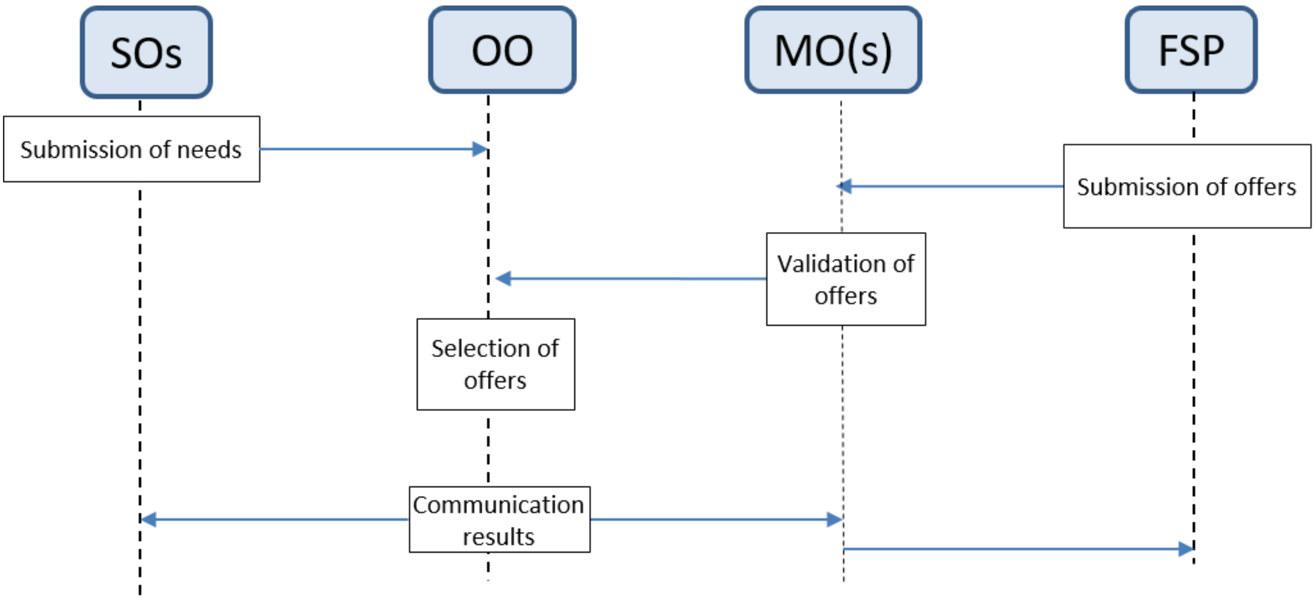

FIGURE 4-2: PROCUREMENT PHASE – CENTRALISED OPTIMISATION

Obviously, grid constraints shall be considered for the selection of offers. Several options can be studied to deal with grid constraints, they are discussed in Chapter 5 on grid constraints management.

Specificities related to the products/services:

<u>Voltage control / congestion management (long-term products)</u>
Reminder: these products will be used to avoid or defer grid investments and are procured long-term (annual or multiannual)

[24] Chapter 5 is dealing with several options for transmission of grid data from system operators to optimisation operators.

In the first step, SOs provide OO with grid data. Provision of grid data is necessary to assess the impact of a given FSP bid on the scarcity (voltage stability/congestion). The FSP provides its flexibility bids to the MO. The MO receives and validates bids from the FSP, and afterwards send them to the OO. Upon collecting all data, the OO assesses the need for additional sources of reactive power and selects the optimal solution.
When a solution is found, the OO communicates the results to the SO and MO. MO de-anonymizes results and communicate them to SO. SO accepts the selected bids only if they are cheaper than grid investment's solutions[25].

DECENTRALISED OPTIMISATION

In a decentralised optimisation, the procurement of flexibilities is done in separate steps to satisfy both DS_O and TS_O requirements. DS_O and TS_O submit their requirements respectively to the OO at DN level (OO_D) and TN level (OO_T). FSPs send their bids to one or several market operators that validate the bids (checking the validity of the qualification and technical aspects of bids) and forward them to the optimisation operators at distribution and transmission level.
The selection of bids is made successively by each OO. The OOs coordinate to ensure that bid selection does not create additional grid constraints at either transmission or distribution level and that flexibilities are scheduled only once. Each optimisation operator is responsible to cover the requirements of its allocated network.
Finally, Optimisation Operators communicate the results of bid selection to MO (s) that clears the demand with the selected bids and informs the respective FSP. Any potential bid clustering and declustering is done between OO_D and OO_T[26]. Both OO_D and OO_T can be carried out by the respective DSOs and TSOs or third parties, as discussed in Chapter 5. However, if the OO role were to be carried out by an actor other than the SOs, significant changes in EU regulations concerning the role of the SOs in maintaining system security is required. As explained for a centralised market arrangement, several options can be studied to deal with grid constraints (see Chapter 5).

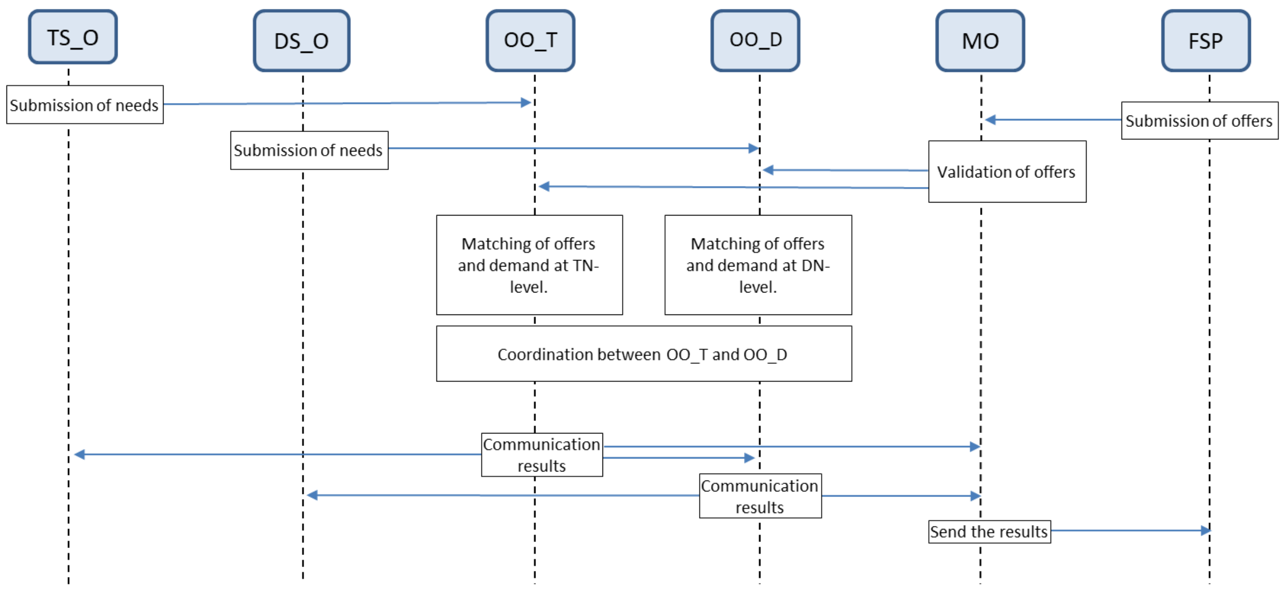

FIGURE 4-3: PROCUREMENT PHASE – DECENTRALISED OPTIMISATION

[25] This trade-off between the use of flexibility and grid investment will involve regulators and can be a complex process
[26] See Chapter 5.2.2 for detailed explanation

SELECTION WITHOUT OPTIMISATION: DISTRIBUTED

As outlined in Chapter 3, we assume that for system services procurement, a distributed market acts as a secondary market: the peer buyer of the service may be a flexibility provider with a regulatory obligation to provide the service (in a regulated organisation) or a flexibility provider which has been awarded a capacity contract to provide the service

One or several marketplaces can be defined to increase the visibility to flexibility providers and buyers. If in place, the MO's role is limited to validate the compliance of bids from FSP (sellers) and display all bids and offers. Since it is a distributed organisation, there is no entity optimising and selecting pairs of bids and offers. Instead, FSPs, buyers and sellers, match bids and offers independently on the marketplace. In case of conflict, the MO might intervene ("first come first served" rule for instance). Moreover, the MO can act as a clearing house for the settlement.

Once the transaction is agreed between seller and buyer, the FSP buyer sends a notification to its connecting SO to notify the "transfer of service". If the SO refuses the transfer (grid constraints), there is an iterative process. In the end, if no transfer is acceptable for the SO, the initially obliged peer(s) must provide the SO requirement itself (or face the legal consequences for non-delivery).

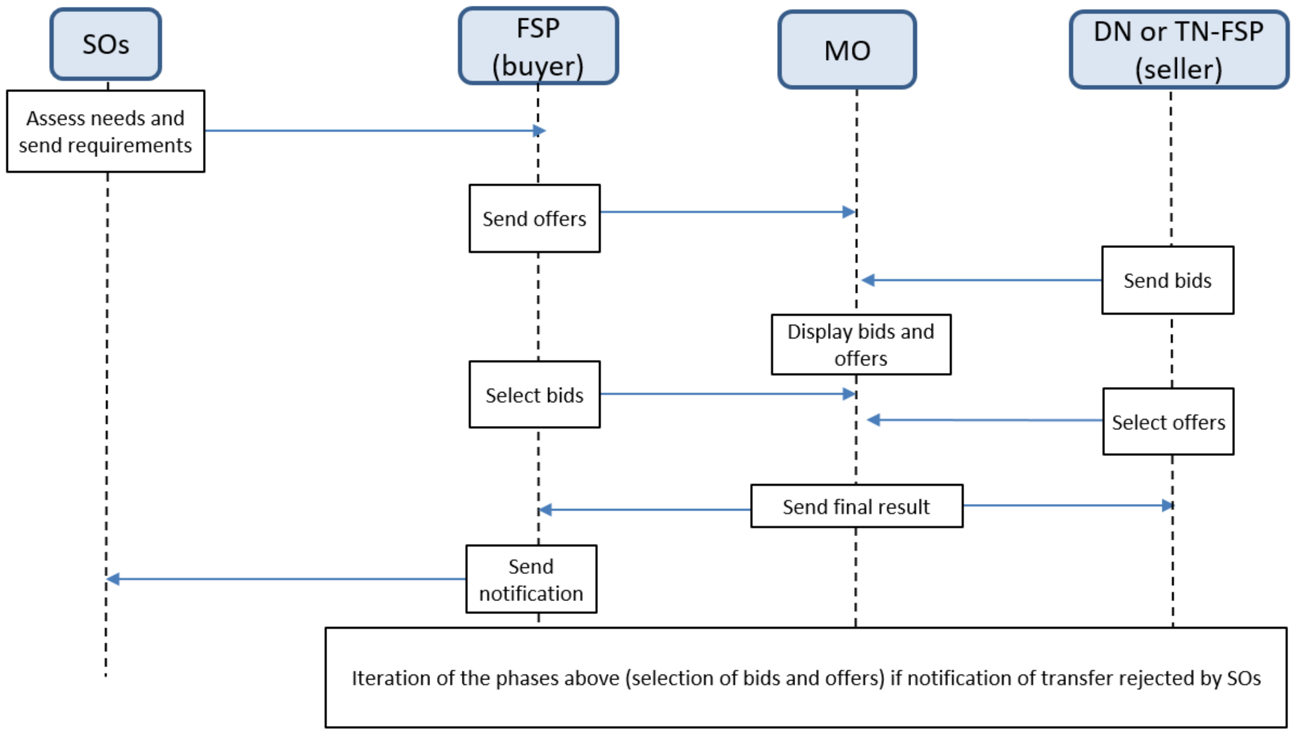

FIGURE 4-4: PROCUREMENT PHASE – DISTRIBUTED

Specificities relevant to products/services

<u>Congestion management and voltage control procurement:</u>

The applicability of a distributed organisation to the procurement of congestion management or voltage control products is not self-evident since there is a locational requirement associated with these products: if there is an SO requirement for some flexibility providers to deliver a product for congestion management or voltage control, the transfer of this obligation to another flexibility provider would not always have the same impact on the grid and thus will not be relevant. Therefore, for these products, a distributed market is only possible at a local level where all flexibilities have the same impact towards the needs of the system operator. This possibility depends on the grid structure, the location of the needs and the location of the established distributed market.

4.1.3 ACTIVATION PHASE

The description of the activation phase depends on the activation mode (see Section 3.2. If a market design incorporates the procurement of energy bids, the selection of energy bids determines the activation by the respective FSPs.

AUTOMATIC ACTIVATION

Two cases can be described depending on the trigger for activation:

1) Self-activation triggered by network state (inherent activation or activation via an internal control loop)
2) Automatic signal sent by SO to an internal control loop

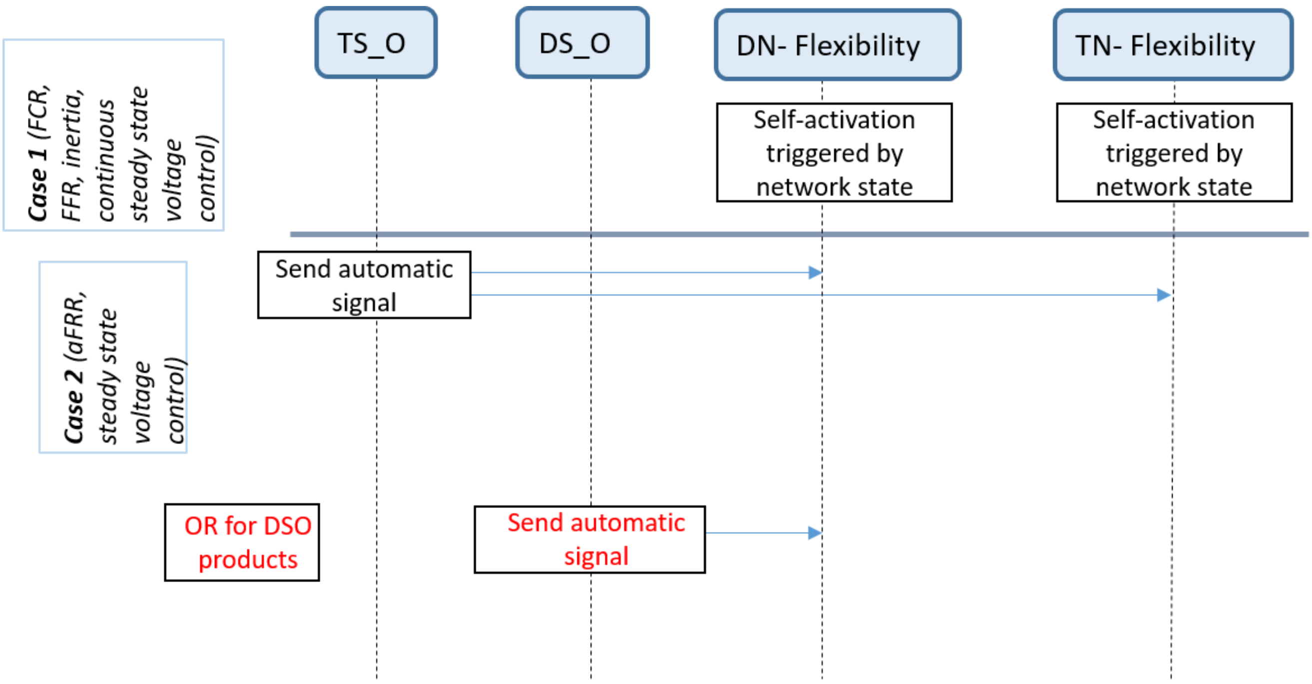

FIGURE 4-5: ACTIVATION PHASE - AUTOMATIC

MANUAL ACTIVATION

Manual activation assumes that an activation order (modification of schedule) is sent either by the system operator (SO) or the market operator (MO) and executed by the flexibility provider. The activation signal can include additional information like the time when the activation shall take place (e.g. in case the activation is planned such as for congestion management).

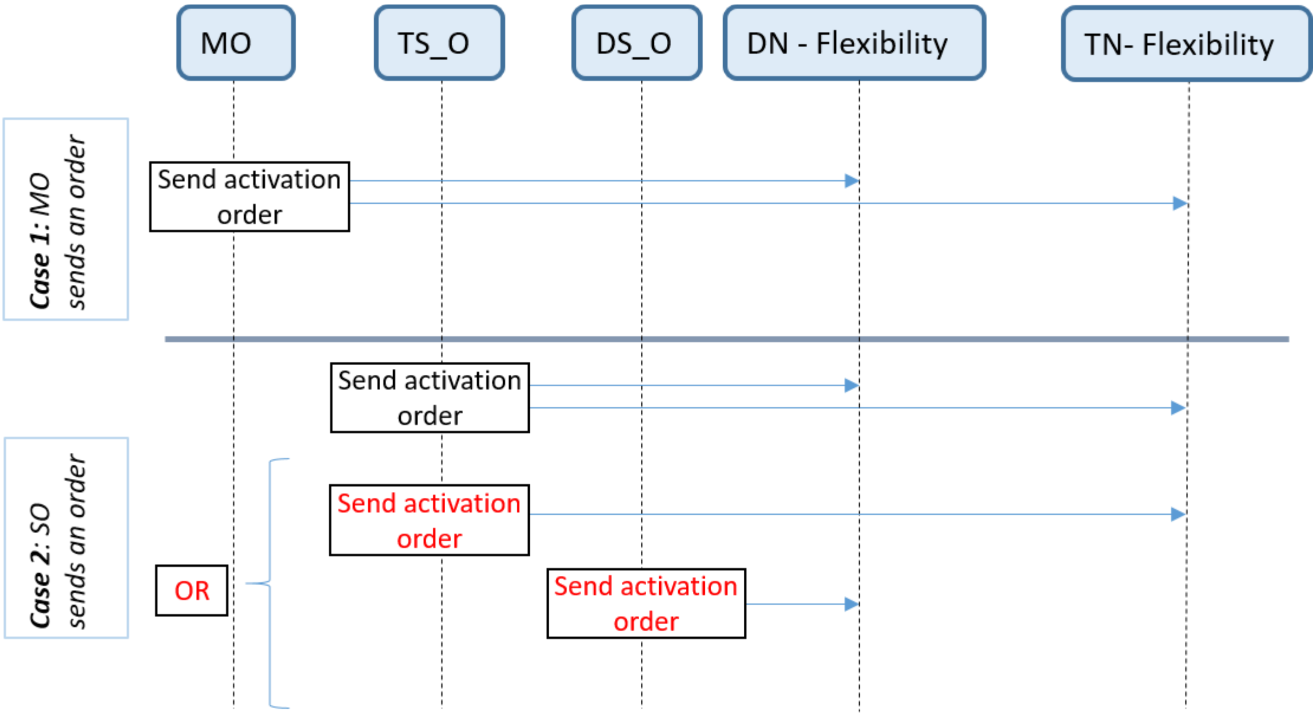

FIGURE 4-6: ACTIVATION PHASE - MANUAL

Specificities related to products/services:

Inertia

Inertia is an inherent response of synchronous machines, proportional to the rate of change of frequency and the stored rotational kinetic energy of the machine. Its activation is automatic, triggered by a sudden fall in frequency. The system operator has no role in its activation. Non-synchronous machines coupled with grid-forming electronics would need to have a controller tuned to provide an analogous response, i.e. automatic activation of synthetic inertia.

Frequency control products

For FFR and FCR, contracted capacity should be activated following a frequency deviation (based on local measurements). The activation does not require any signal from the SO, i.e., activation is automatic[27]. This means that the activation is controlled by a close-loop in which the trigger is a frequency deviation caused by a sudden power imbalance. Activated capacity should remain activated for as long as required by the system[28] within the

[27] With full activation time (FAT) below 2 seconds.
[28] This product helps increase the time to reach the frequency nadir and mitigate the rate of change of frequency (RoCoF).

agreed delivery period. Moreover, units or groups providing FFR are expected to continuously supply this product[29]. For aFRR, contracted capacity should be activated in response to an explicit signal sent by the TS_O to the FSP. For mFRR, activation is manual, based on activation orders issued from a merit order list which usually results in a new schedule for the rewarded unit(s).

For congestion management products, manual activation is sufficient as needs are the result of an assessment taken in advance of delivery.

For voltage control products, the activation is manual for steady state reactive product and automatic for continuous reactive product.

4.1.4 SETTLEMENT PHASE

As for the prequalification and activation phases, this phase description does not depend on the optimisation and market options described in Section 3.2

- Measurement of the amount of the actual active or reactive power delivered by the flexibility
- Comparison with the amount expected following the activation order
- If necessary, adjustments for balancing perimeter of the flexibility provider's BRP[30].

Taking into account the data exchange, the financial settlement between the buyer and seller of the service is conducted. The settlement process develops as follows: first, readings are sent via the metering equipment of the FSP (DN_FSP/TN_FSP) to the MO[31]. After having received the validation of the collected data from the SOs (and if necessary correction of BRP perimeter), the MO calculates the payments and penalties (financial settlement) based on the baseline[32] for participating FSP[33]. Updated perimeters are then used in the calculation of the imbalance settlement by the responsible authority[34]. Note that steps involved in the imbalance settlement are out of the scope of this report.

[29] Unless otherwise specified. For instance, technologies with limited energy reservoirs may have to comply with a different criterion.

[30] If a BRP's perimeter's balance is modified due to activation of a flexibility required by a SO, it can result in an imbalance adjustment so that the BRP is not penalized. This is not applicable for all products but mainly for frequency control products.

[31] Note that the exchange of information requires both real-time and on-line communication between the relevant parties.

[32] The baselining method is agreed ex-ante between the product supplier and the entity in charge of the settlement: a consistent set of rules that apply to all FSPs is established ex-ante but one can imagine several methods applicable depending on flexibility nature (generation, demand, …).

[33] Payments and penalties are based on measurements. These measurements should show whether volumes were activated and delivered according to requirements and agreed baseline.

[34] For instance, following the full or partial activation of capacities impacting BRPs' perimeter (e.g., provision of mFRR power), the TSO includes the corresponding quantity of power that a BSP has to provide in the calculation of the BSP's quarter-hour imbalance. Note that changes in provided energy are measured every 15 min.

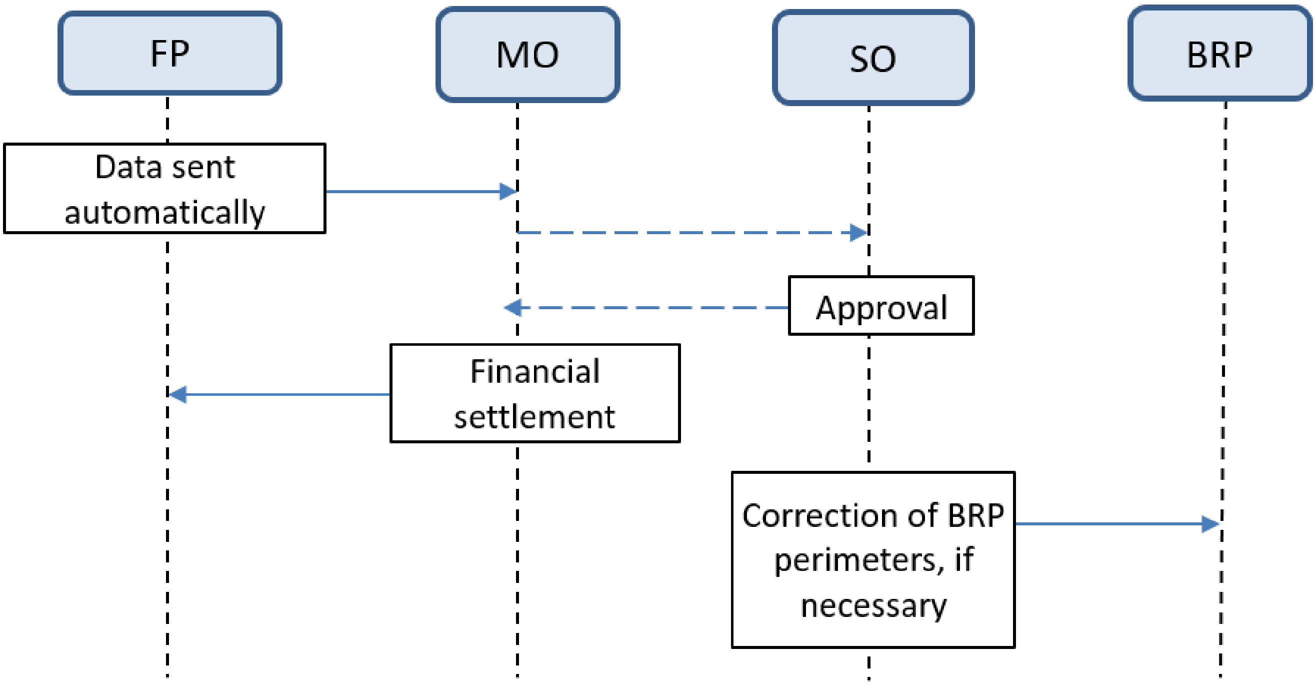

FIGURE 4-7: SETTLEMENT PHASE

Specificities related to products/services:

Inertia:

As the capable volume from a unit providing the product in a given trading period will depend on (i) its status (synchronised and online) and (ii) its minimum stable operating point, both parameters will be considered during settlement.

The FSP will make a declaration of its minimum generation to the SO. The status of the unit (online or not, on maintenance, …) will be communicated by the SO to MO. For a given trading period, it can be determined whether the unit was synchronised and thus capable of inertia provision. If so, its minimum generation is used to calculate its available volume.

For non-synchronous machines, if in the future they can provide an equivalent service through grid forming control mechanisms, settlement data would depend on the way the unit could provide the service.

Frequency control:

The SO corrects BRP perimeters based on the metering. Updated perimeters are then used in the calculation of the imbalance settlement by the responsible authority[35]. Note that steps involved in the imbalance settlement are out of the scope of this report.

[35] For instance, following the full or partial activation of capacities impacting BRPs' perimeter (e.g., provision of mFRR power), the TSO includes the corresponding quantity of power that a BSP has to provide in the calculation of the BSP's quarter-hour imbalance. Note that changes in provided energy are measured every 15 min.

Congestion management:
The settlement of congestion management products corresponds to both the settlement of the capacity, for instance the contracted availability of a unit or its limitation on power injection; but also, to the settlement of the energy finally delivered. For that reason, the MO responsible for the procurement of capacity first checks the compliance of the flexibility in delivery time with its commitments and secondly provides the precise energy delivered to answer requirements if any. Data is sent automatically from a communicating metering equipment at the FSP's asset to the MO and is consequently approved by the relevant SO before proceeding to the financial settlement. If required, the DS_O or TS_O may have to correct BRP perimeters.

4.2 COMPARISON OF MARKET-BASED VERSUS REGULATED PROCUREMENT FOR THE DIFFERENT PRODUCTS

In Section 4.1, we have provided simplified descriptions based on role models of prequalification, procurement, activation and settlement phases for acquiring flexibility services. We have seen that the main differences lie in the procurement phase, depending on the optimisation options (centralised or decentralised, no optimisation for the distributed organisation).

Concerning the distributed organisation, as explained in Section 3.2 implementation of a distributed market for flexibility services for SO is only considered in the form of a secondary market. The interest of implementing a distributed market for the procurement of flexibility services seems very limited and not comparable to the one that can exist for energy sourcing (e.g. including preferences for local sourcing). In addition, the complexity is not negligible. A deeper investigation on distributed markets would be necessary to assess properly its potential relevance for the procurement of system services. However, this was out of scope of Task 3.2[36]. An idea could be to envisage a distributed market at a system wide perimeter (for instance on bidding zone level), including the sourcing of energy as well as the procurement of system services.

Furthermore, it has already been stated that both centralised and decentralised optimisation approaches are compatible with either a market-based solution or a regulated solution. Thus, **in the following section, the focus will be a comparison between market-based organisations (with centralised or decentralised optimisation) versus a regulated organisation (with centralised or decentralised optimisation) for each product.** Note that the discussion about centralised and decentralised optimisation options will be provided in Chapter 5.

The Clean Energy Package states that flexibilities should be procured by System Operators via market-based processes, but some exceptions are nevertheless allowed. In the following section, cases where a regulated approach could be more efficient than a market based one considering the nature of the service, the forecasted market depth, the bidding behaviour and the transition costs are examined.

[36] The definition of a distributed algorithm is an algorithm where each agent communicates with its neighbours, but there is not a centralised controller (Molzahn et al., 2017). (Molzahn et al., 2017) define following advantages of distributed optimisation as compared to centralised optimisation: (i) improve cybersecurity and reduce expense of necessary communication infrastructure (computing agents only have to share limited amounts of information with a subset of the other agents), (ii) more robust (with respect to failure of individual agents), (iii) higher solution speeds and maximum problem size (due to the ability to perform parallel computations), and (iv) respect privacy of data, measurements, cost functions, and constraints. Finally, (Olivella-Rosell et al., 2018) state that the need for a central entity can be avoided. Conversely, (Olivella-Rosell et al., 2018) state that this avoidance of a central entity could result in low negotiation power when selling flexibility services to bigger stakeholders, such as BRPs, DSOs or TSOs and that individual market players like prosumers would not have access to wholesale markets depending on their size and national regulations.

A qualitative assessment is carried out based on a list of criteria: compliance with EU rules, liquidity, strategic gaming and market power issues, efficiency for short term allocation of resources, efficiency to procure the relevant investments, simplicity and transition costs. The assessment will be conducted for each product selected in Chapter 3.

4.2.1 FREQUENCY CONTROL PRODUCTS

The **Balancing Guideline and the Clean Energy Package require a market-based procurement**: indeed, in most European countries, the procurement is already market-based, but does not necessarily encompass all products (FCR, FRR, RR). Transition to the target model is in progress everywhere: the target model for these products is a procurement of capacity in a short timeframe (day-ahead or some hours ahead) and a close to real-time procurement for energy (when relevant). There is a minimum mandatory capability for generators with a power capacity above a given threshold, as defined in the European Network Conde on Requirements for Generators (European Union, 2016). This threshold can be modified by the TSOs at a national level if necessary (based on security analysis).

At the moment, there is sufficient capacity in Europe, but the services are for a large share still delivered by conventional plants (except for FCR where batteries are increasingly entering the market): indeed, the fact that some actors are obliged by national connection network codes to offer their capacities could prevent new entrants to develop capacities. This situation could lead to suboptimal market outcomes if SOs require costly participation of small generators while more efficient solutions could be provided by other actors.

If new needs arise[37], the question could be asked if market signals to develop new capacities (with the required technical capabilities) are sufficient: to facilitate the transition. Complementary auctions to procure new capabilities with a long-term contract could be introduced.

Since frequency management is a service provided to the TSO, a centralised optimisation of a market-based procurement is relevant, at least when considering only the procurement of frequency control products and not joint procurement.

> **Market-based organisation is the only possible option for frequency control products**. Mandatory capacity or participation could be required by European or National grid codes, but market-based procurement should be preferred if new capacities are needed.

[37] Studies from Task 2.4 show that the insertion of high shares of RES would lead to a significant rise in the amount of aFRR size as well as in its distribution, which means the difference between the minimum and the maximum requirement for both EU-SysFlex scenario (Energy Transition and Renewable Ambition)

4.2.2 INERTIA

As previously explained, inertia is an inherent capability of synchronous machines. As a number of synchronous power plants will be decommissioned in the coming years, two issues must be addressed in parallel to ensure that there will be always sufficient inertia in the system:

- Management of the decommissioning phase
- Procurement of new capacities

As other technical solutions for inertia provision, for example synchronous condensers, already exist, it will be possible to align the process for procuring new capacities, from either existing or new assets, with the decommissioning of synchronous machines which are currently providing this capability.

As for other services, a market-based procurement would be preferable, where possible. Independent of the approach, new-built service providers will need a stable investment climate. This includes a comprehensive analysis of all potential revenues coming from additional system services, capacity and/or energy.
The overall solution is likely to involve a combination of (i) incentivising existing synchronous units which are not decommissioned to further improve their capabilities and (ii) to ensure investment in new solutions for inertia provision, which may include synchronous condensers and non-synchronous units with grid forming solutions.

Compliance with EU legislation: From a regulated framework point of view, inertia is not a frequency control product, therefore while market-based solutions are preferred, a regulated approach is nevertheless possible.

> To ensure system stability, procurement of inertia should be aligned with future decommissioning plans for synchronous power plants. **While market-based procurement solutions are preferred, a regulated approach is allowed and could be used, if necessary, to ease the transition phase (decommissioning of synchronous generators).**

4.2.3 VOLTAGE CONTROL PRODUCTS

Preamble
There are some specificities to consider in the choice between regulated and market-based organisation:
First, the needs are difficult to evaluate: there are different types of needs and capabilities (dynamic, continuous response or steps, etc.). To keep the voltage in the relevant ranges, local actions are needed and SOs can use both network assets [38]and market actors' assets to provide reactive power, depending on the localisation and on the type of the scarcity.

Secondly, for the generators, it is difficult to evaluate properly certain costs incurred by voltage control. While some costs are easily evaluated (like losses, opportunity costs when it is necessary to decrease the active power in order to provide the requested reactive power (rare)), other costs cannot be properly allocated between active power

[38] Before liberalization generation and transmission lines belong all to the same entity.

and reactive power supply: investment costs for components used for both purposes and part of operating costs (maintenance costs, part of the losses).

Voltage control is a very local service in case the voltage problem is caused by an individual grid user. Thus, the liquidity of a market could be poor, as explained below and more completely in Section 5.1.

Probably due to all these reasons, in Europe and in the USA, mandatory capabilities for generators and mandatory behaviour of consumers are required in the connection grid codes and currently this service is generally not remunerated directly or only invoiced via regulated tariffs – in some cases, there is a remuneration only above (or beyond) a reactive power threshold. In addition, the system needs are not clearly defined (quantity, dynamic, localisation of the needs).

Assessment of the different criteria:

Compliance with EU target model: as mentioned, market-based solutions are preferred but for non-frequency services, deviations can be granted

Liquidity and power market: voltage control is a very local product thus liquidity can be very poor and the risk of market power abuse is high unless taking into account larger area

Long-term efficiency: Long-term procurement options allow the increase of voltage control capacity, whereas SOs can choose whether to use flexibilities or to invest in the grid instead. The price can be determined via regulation (i.e. that it can also be zero) or in market-based procedures, whereas all options can, depending on the circumstances, be appropriate. If the price of long-term voltage control capacity products is cost-reflective, the SOs choice leads to the lowest societal costs.
Furthermore, in many countries, SOs revenues depend on the actual capex[39] and thus they are more incentivized to invest than to pay flexibility providers.

Different solutions could be proposed: there could be incentives to provide more capability than legally required in the connection agreement in some deficit areas[40] (rather than increasing mandatory requirements for everybody in the network codes) or market-based procurement (e.g. long-term auctions) could be used. However, demanding different ratios of reactive to active power in different areas would also widen the range of technical requirements for grid users, leading to less standardisation on the flexibility side.

Short-term efficiency: Market based daily procurement can theoretically give the best allocation of resources[41]
However, there are some relevant issues to take into account:

- How to fix the price if the marginal cost is very low (or not easy to evaluate).

[39] there can be incentives to minimize /reduce the CAPEX in some countries

[40] Or solution as Non-firm access (price regulated), could be proposed during the connection procedure – FSP volunteers to decrease injection/withdrawal for an agreed duration in the year or according to another criterion. In return they get a rebate in connection or grid use fees and potentially can be connected faster.

[41] In WP7, demonstrators will address this question – see Deliverable 3.3 to get the description of these BUC.

- How to value the service (as sensitivities of FSPs will differ depending on their location and technical characteristics and since the market would still be very small).
- How to trade-off between the use of FSPs capacities and grid assets capacities

The current organisation in most countries, i.e. mandatory participation of some categories of capacities (be it on generation or demand) with no price, is problematic too: it gives no incentive to improve (or maintain) the capability – and no incentive for new entrants (to prepare a possible decommissioning or an increase in SO needs). The FSP should at least be compensated for the costs incurred when providing the services beyond their connection agreement.

Simplicity: the current system (mandatory participation of generators / consumers) is very simple. The organisation of market-based procurement, and particularly a near to real time market, would complicate the process.

Transition costs: low for long-term market-based procurement; and probably high for short-term procurement with respect to expected benefits.

> There are strong mandatory requirements in the European network codes regarding voltage control capabilities. It is questionable, however, whether the benefits of short-term (e.g. day-ahead) auctions, especially given the value of the service, outweigh the implementation effort. **A distinction must be made according to the nature of the voltage problem**:
>
> - **Voltage problems due to too high feed-in/consumption should be regulated** (mandatory participation, part of connection agreements), because this problem can only be solved by the source causing the problem or neighbours close by.
> - **Voltage problems (reactive power need) due to power flows in long-distance transmission/distribution lines** far away from their foreseen operating range: sources of reactive power provision can be more widespread. **A market for daily procurement could be considered** if reactive potential from connection agreement is not sufficient
>
> **If lack of reactive power occurs in the future in some local areas, there could be a regulated remuneration** to improve the capacities in this area (for example during the connection agreement discussions). **In case of reactive power needs which can be fulfilled by a large set of flexibilities, a market-based solution** (e.g. long-term auctions) should be preferred. A general increase of mandatory requirement could be used if the market-based solution fails and, in this case, FSPs should be compensated.

4.2.4 CONGESTION MANAGEMENT PRODUCTS

As for voltage control, congestion management is a locational need. Consequently, the procurement design must consider the market power risk as well as the risk for increase/decrease gaming. The solutions could also differ according to the type of product: long-/ medium-term capacity product for structural congestions or maintenance periods (for which procurement options could be market-based or regulated with mandatory participation and compensation of opportunity costs) or short-term capacity and energy products (day-ahead, and intra-day) to optimise in the short-term against the long-term options.

Regulated approach can include:

- Non-firm access (price regulated), proposed during the connection procedure – FSP volunteers to decrease injection/withdrawal for an agreed duration in the year or according to another criterion. In return they get a rebate in connection or grid use fees and potentially can be connected faster.
- Mandatory participation and cost-based remuneration

Assessment of the different criteria:

- Compliance with EU target model: market-based solutions are preferred but for non-frequency services, as congestion management products, derogations can be granted (in case of lack of liquidity or risk of strategic gaming).
- Liquidity/market power: as mentioned above, congestion is a localised issue and, in many cases, very few assets can mitigate the congestion: there is a risk of lack of liquidity and market power.
- Strategic gaming: even without market power, flexibilities can bid at the wholesale market in a way which causes congestions in order to get selected at the congestion management market ("increase/decrease gaming" for generators or "decrease/increase gaming" for loads)
- Long-term efficiency: for long term capacity product (trade-off between grid investment and flexibility): market-based organisation is more efficient (auctions), if there is sufficient liquidity and no potential for strategic behaviour during the day-ahead/intraday timeframe[42]. In case very few FSP participate to the auction, a regulated price can be used.
    - Duration of the contract should be sufficient to allow SOs to bridge the time gap between a following auction and the potentially needed time for a grid reinforcement at the one hand and to (at least partially) cover the fixed costs for the FSP at the other hand
    - The contract should include a mandatory participation to short term procurement process of the corresponding energy bid or the obligation to be available/decrease/increase power injection/ withdrawal to ensure that SOs can use the flexibility when needed. A price cap could be used based on opportunity cost where they can be derived.
    - In some cases, particularly in case of congestion in LV/MV due to demand (electric vehicles, heat pumps[43], etc.) non-firm connection agreement could be proposed (no mandatory participation). The price of such connection agreements might be regulated.
- Efficiency for short-term allocation: market-based solutions are more efficient if there are sufficient liquidity and no market-power.
    - To limit the consequences of market power, a price cap can be used (based on opportunity costs) and/or mandatory participation for certain actors (hybrid model of market-based and regulated procurement).
    - FSP should be indifferent to bid in energy market or in congestion management market: this would limit the strategic gaming risk.

[42] Even with long-term products, flexibilities could be incentivized for strategic gaming in order to cause the demand for LT capacity products.
[43] Transportation and heating/cooling electrification will strongly increase to insure energy transition. This evolution will increase risks of congestions in LV/MV

- Transition cost: in both market-based and regulated regimes, SO coordination and interfaces to FSPs at different voltage levels need to be built up. In case of market-based procurement, such processes must be connected to marketplaces. The use of common marketplaces with locational order books/auctions or the replicability of such platforms enables also smaller DSOs to introduce market-based procurement, if this is considered as more efficient.

> **Market-based solutions should be preferred in all cases when market power and increase/decrease gaming can be limited sufficiently** – the solutions must insure sufficient visibility and predictability for SOs and market players: auctions to procure new capacities with long term agreements, market-based organisation for short term allocation. If the liquidity is very poor and increase/decrease gaming cannot be limited sufficiently, voluntary non-firm connection agreements for loads and mandatory participation with cost-based remuneration for generation can be feasible options.

EU-SysFlex

4.3 GENERAL CONSIDERATIONS TO FACILITATE PARTICIPATION OF FLEXIBILITY SERVICE PROVIDER

To minimize the barriers and to facilitate the participation of flexibility providers in flexibility markets, the following elements should be considered when designing processes to procure flexibility services. These "pre-requisites" are common to all types of optimisation options (centralised, decentralised). These elements have been broadly discussed in the academic literature (f.i., Borne et al., 2018; Codani et al., 2014; Eid et al., 2016; Knezovic et al., 2015; Villar et al., 2018). A selection of barriers and possibilities to foster flexibilities are quantitatively studied in Task 3.4. The findings are described in Deliverable D3.4 (EU-SysFlex Project, 2020).

<u>Product characteristics:</u>

At unit level, some principles regarding product characteristics avoid hindering DER (intermittent generation or demand side response) participation:

- Delivery duration, frequency of procurement: shorter time periods facilitate DER participation and can lead to more efficient matching of offers and technical needs, but operational constraints for MO/SO/OO must be considered as well. Therefore, choices must ensure operational feasibility and minimisation of transaction costs. Task 3.4 studied the impacts of these parameters. The results are presented below:
    - Investigation of temporal granularity: Reducing the reserve procurement contract duration and procuring reserve capacity more frequently yielded cost savings and facilitated the integration of intermittent renewables in reserve markets.
    - Investigation of increasing technology neutrality: The results indicate that, from a system's perspective, large cost savings can only be achieved by reducing the procurement cycle to daily auctions; changing from monthly to weekly auctions only reduces the cost in a limited way. When it comes to the technologies perspective, the results show a very strong increase of offered capacities from wind and solar towards the daily procurement
- Asymmetric procurement for active power products to the extent that it is possible.
- Minimum bid size must be the result of a trade-off between smaller bid sizes for FSP and larger bid size for SOs and MOs to limit transaction costs. For some products, also smaller bid size is beneficial for SOs to solve local problems.

<u>Rules regarding aggregation:</u>

- Allow aggregation when technically feasible to maximize the participation of DER:
    - Avoid geographical or other barriers – allow cross DSOs and TSOs aggregation
    - For locational products, rules can be defined (aggregation by network nodes or at TSO/DSO interface substation level for instance) where aggregation is possible
- Allow portfolio bidding: the FSP sends a price/volume curve to the marketplace and optimises itself the allocation of resources in its portfolio (choice of physical assets).
    - Even if delivery is checked by unit during the settlement phase
    - In the case of locational products, all the assets aggregated in the bid must be located in the relevant geographical area

Revenues for FSP:

- The FSPs should be able to value their flexibility in the most efficient way and to stack up revenues from different markets if technically feasible.
- The market design should ensure sufficient certainty about revenues streams to support FSPs, while also considering the cost-efficiency.

This question is addressed in Chapter 10 of Deliverable 3.4 (EU-SysFlex Project, 2020). In this study, new technical needs, such as FFR and ramping, are taken into account in the investment model. The results demonstrate how the inclusion of new (needed and valued) system services alter the generation mix, and how new system services markets can send long-term signals to investors. Moreover, the conclusions of the simulations are that for future (high renewables) systems, it is essential that adequate investment in flexible technologies are incentivised through strong investment signals via stable markets for the new system services. Marginal prices for both energy and system services are dependent on many factors, including fuel prices, interconnection capacity, installed capacity and capacity factors of variable renewables, and, indeed, competing sources of flexibility, all of which are associated with a high degree of uncertainty. While a fast product such as fast frequency reserve is of high value, the quantities required are small (compared to the energy market) and market saturation is a risk. Markets for such services require careful design and relying on marginal cost pricing may not provide sufficient certainty for investors.

Data exchanges:

To minimize transaction costs, to facilitate the participation of FSPs (allow cross-DSOs aggregation for instance) and data exchange between the different actors (FSPs, OOs, MOs, TSOs, DSOs), the market design should rely on interoperability at different layers (business, function, information, communication) of SGAM (Smart Grid Architecture Model).

- Alignment of markets rules and product characteristics (standardisation when relevant), at national and even European level if relevant and after considering national/regional or even voltage-level specifics;
- In a consecutive stage, for each FSP and each bidding zone, standardisation of some elements of interfaces to send bids, at least by product and ideally for several or all products should be promoted:
    - Necessary for FSPs with country/zonal-wide portfolio for practical reasons
    - Cross-country/cross-zonal data exchange to enable European level market
    - Facilitate data exchange between FSPs and MOs
- In case of competitive market operators (for individual scarcities/needs), FSPs should have access to any marketplace at which matching with needs of the SOs as buyers is possible. At the same time information exchange should be ensured so that SOs (or respectively their OOs) can compare offers across the marketplaces to ensure single market outcomes.

Price mechanisms:

- As put forward by the Clean Energy Package as default choice for balancing products[44], pay-as-cleared should the favoured pricing mechanism

[44]REGULATION (EU) 2019/943 on the internal market for electricity – article 6.4

- Pay-as-bid will theoretically give the same results assuming perfect information, but this condition is generally not met.
- Easiness of bidding for the small FSPs
- Pay-as-bid mechanism can be used in case of low liquidity or market power issues (or even regulated prices)

5 CONSIDERATION OF GRID CONSTRAINTS IN THE FLEXIBILITY PROCUREMENT PROCESS

In their conclusion paper on the future role of DSOs, the Council of European Energy Regulators states that the relationship between DSO and TSO is a ''key area for change in many European countries''. For this new type of relationship, the following principles are identified: (i) a whole system approach, in order to avoid inefficiencies; (ii) greater coordination between DSO and TSO with respect to procurement of system services and network planning; (iii) data exchange and cyber-security; (iv) use of flexibility; and (v) fairer cost sharing (Council of European Energy Regulators, 2015).

Also, the TSO/DSO report on an integrated approach to active system management (CEDEC et al., 2019) states that there is an enhanced need for DSOs and TSOs to coordinate closely for grid and system needs. "Effective coordination between DSOs and TSOs as well as resilient, efficient and effective 'signalling' (information sharing) become increasingly important to ensure cost-efficient, sustainable and reliable system and grid operation as well as facilitating markets throughout Europe".

Moreover, active system management refers to the actions taken by TSOs and DSOs to monitor and to ensure that the grid operational parameters are within satisfactory ranges. It encompasses the operational planning processes, the required observability and controllability of the grid, the necessary data exchanges and the interaction with market parties delivering those services (CEDEC et al., 2019).

Such TSO/DSO coordination becomes especially necessary, when power flows in distribution grids reach the capacity limits of the grids and when TSOs make use of flexibilities located in the distribution grid. This will occur even more often due to the phase out of conventional generation connected to the transmission grids. In addition, grid constraints will be more frequently breached due to the increasing feed-in of RES and the concurrently increasing consumption. Both phenomena directly affect distribution grids. In conclusion, congestion management also becomes increasingly important for DSOs.

Therefore, this chapter deals with the consideration of grid constraints in the flexibility procurement process. Section 5.1introduces security limits and grid assessment. Section 5.2 proposes different solutions for considering grid constraints when procuring flexibilities for other needs, as well as solutions for optimally solving existing grid constraints. Section 5.3 discusses the advantages and disadvantages of such solutions, whereas Section 5.4 gives insights regarding the allocation of the optimisation role to different actors.

Additionally, if not stated otherwise, the following sections deal with the independent optimisation of the procurement of all possible products.

EU-SysFlex

5.1 GRID CONSTRAINTS ASSESSMENT

The procurement and activation of flexibility must not create security violations in the grid (both transmission and distribution grids). The reasons are twofold: Firstly, grid constraints violation could endanger security of supply and quality of power. Secondly, in such a situation there is a risk of reducing (or even cancel out) the effects of flexibility activation[45] Therefore, every process for selecting flexibilities must respect the grid constraints of all affected system operators.
Grid constraints are technical requirements as thermal or voltage limits and part of security constraints that need to be observed to meet security requirements defined in Article 18 of the System Operators Guideline (European Commission, 2017b). Other security constraints are system constraints due to, e.g., balancing reserves requirement, stability requirements, etc.

Grid constraints basically can be identified by calculating power flows. They may arise due to thermal limits that are linked with maximal current or due to voltage requirements. In many cases thermal constraints can be exceeded for short time periods (several minutes) but loading of elements needs to be brought back into normal operational limits after this time. Regarding voltage limitations, there are maximal and minimal acceptable voltage limits. In case the limits are exceeded, the result is under- or overvoltage. Under- and overvoltage occurrences must be resolved within seconds. The voltage issues are strongly linked to reactive power, however active power also impacts voltage. When we consider the impact of active power on voltage, there is a difference in voltage scarcities[46] caused by either long-distance energy transmission or local injection (withdrawal) of active power. In the case of a local scarcity, the number of potential grid users capable of resolving the scarcity is very limited (causer and potentially neighbours in close proximity) which is why local grid users are required by grid codes to provide necessary voltage support (e.g. compensation of reactive power). In case of voltage problems due to power flows in long-distance transmission/distribution lines outside their rated operating ranges, the problem depends on more grid users than for a local voltage problem. In those cases, there could be a wider range of flexibilities which can solve the problem.

The case of meshed distribution and transmission grids, the check for grid constraints are typically considered for "N" and "N-1" states. The "N" state is the state where all grid elements operate properly, in other words all grid elements are available (except for planned outages, e.g. due to maintenance). The "N-1" state is a hypothetical state, when a single unplanned outage is considered which still shall not lead to exceeding operational security limits at any grid elements. Therefore, the "N-1" states need to be considered in the grid assessment to avoid cascading disconnections, which would lead to a brownout or even blackout.

To describe the handling of grid constraints the term *sensitivity* needs to be explained. The sensitivity measures how a change of injection (withdrawal) of active/reactive power in a given node affects selected grid constraints.

[45] E.g. additional injection of active power due to the activation of mFRR could lead to violation of thermal constraints, which causes a counteraction in the form of a decrease of other generation connected to such grid, therefore the net effect of activation would be reduced or even zero.
[46] Voltage scarcity can refer to undervoltage or overvoltage

In the case of a meshed grid, the active power can flow over different paths as presented in Figure 5-1 (left). Consequently, injection of X MWs of active power at the FSP connection induces a variation of flow on multiple lines. As the result, the sensitivity of active power injection (withdrawal) to active power flow is within a range from -1 to 1 in meshed grids, if we neglect Joule losses. It can be described for each pair of connection point and line. In the case of a radial grid, as presented in Figure 5-1 (right), sensitivity of active power injection (withdrawal) to active power flow takes one of three values:

- -1: power flow on specific line is increased by volume of activated power, i.e. constraint is aggravated,
- 0: additional injection of active power flow does not affect specific line, as shown in Figure 5-1 (right),
- 1: power flow on specific line is decreased by volume of activated power, i.e. constraint is relieved.

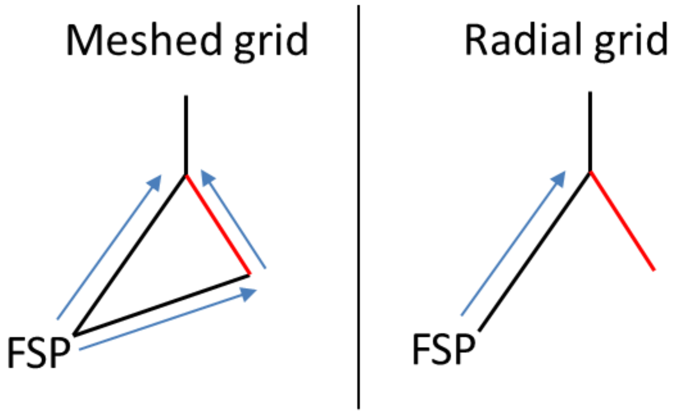

FIGURE 5-1 EXPLANATION OF SENSITIVITIES FOR MESHED AND RADIAL GRIDS WITH VIOLATED CONSTRAINT ON SPECIFIC LINE (RED)

Bids refer to flexibility offers of one or several units behind a grid connection point or an aggregation of units across several grid connection points. The first option is always feasible. The latter option is feasible if the individual units do not or are allowed to breach constraints, and in case of locational products, the sensitivities of the individual units are the same. The allowance of breaching constraints can be ensured via firm connection agreements (e.g. part of the prequalification process), so that the SO needs to find other measures than limiting this unit. In case of non-firm connection agreements, conditional prequalification can allow the aggregator to know when certain units must be limited resulting in offers of this specific amount. Otherwise, the limitation is carried out during the procurement phase by the OO(s).

There are four stages within the procurement process when there is potential to check for grid constraints:

1) Prequalification
2) Procurement
3) Monitoring before activation
4) Activation

Table 5-1 gives an overview of the relevant phases of assessing grid constraints for the different products.

1) **Prequalification.** The prequalification process may include a check of the impact on grid constraints of activating the flexibility. In the general case, there is too much uncertainty to conclude that activation of a given flexibility will always be secure (it depends on injections, withdrawals and topology). However, in some special cases it may be possible, to validate provision of some products, e.g. products with a short delivery period duration - FFR, FCR, against grid constraints.
2) **Procurement** In the general case, grid constraints need to be checked during the procurement phase in order to prevent procurement of flexibilities that would be unavailable due to grid constraints. Procurement of such unavailable flexibilities would provide a false sense of security and would unnecessarily burden ratepayers. Before selecting a flexibility, assessment of grid constraints is needed to identify potential violated constraints and possible remedial actions to solve these violations. The selection process of such remedial actions, i.e. solving local problems, must include the sensitivities of such flexibilities towards the violated constraints and in more sophisticated cases, it can also include the optimisation of other possible remedial actions, e.g. changing taps of transformers to solve voltage issues or changing the topology.
   The check, whether a flexibility can breach new constraints, can be abandoned (especially for fast balancing products) if it was determined at system prequalification that the flexibility can be safely activated. Compared to the prequalification phase, at procurement phase there is much less uncertainty, in particular if this phase takes place in the day-ahead timeframe or later. But there is still some uncertainty concerning the needs, e.g. changes due to intraday trading may change the overloads in the grid. It is possible to efficiently perform procurement if such uncertainties are properly addressed, e.g. via reliability margins. Alternatively, the procurement phase could take place from the day-ahead timeframe until closer to real-time if resources providing the given service are still available. Restrictions on procurement timelines exist due to coordination times between system operators and preparation times of flexibility providers.
3) **Monitoring** After the procurement there is a need for continuous monitoring to ensure that the flexibility is still available – both due to resource availability and due to grid constraints, to deliver the required response after activation. In case of the unavailability of the flexibility, relevant system operators need to take appropriate action, e.g. procure additional flexibility. The detailed description of how SOs can handle situations of unexpected unavailability of flexibility is out of scope of the EU-SysFlex project.
4) **Activation** In the case of the activation of slow products – i.e. products with manual activation, activation is the last stage where it is possible to check grid constraints. In normal operation, flexibilities to be activated have been chosen in the procurement phase; thus, checking grid constraints before activation should be needed only in an emergency situation (or in cases where the procurement is done long before activation). In the case of faster products, during activation generally there is not enough time to check against grid constraints – the activation process needs to rely on the monitoring process, to ensure that previously selected flexibilities can be safely activated.

TABLE 5-1: RELEVANT PHASES OF CHECKING GRID CONSTRAINTS FOR THE DIFFERENT PRODUCTS

Product	Energy[47]/Capacity	Phase during which grid constraints are checked
Inertia	Capacity	Prequalification
FFR	Capacity	Prequalification
FCR	Capacity	Prequalification
aFRR	Capacity	Procurement, monitoring
	Energy	Free bids[48] – grid constraint before procurement Bids due to awarded capacity – no additional check[49]
mFRR	Capacity	Procurement, monitoring
	Energy	Procurement
RR	Capacity	Procurement, monitoring
	Energy	Procurement
Steady-State Voltage Control	Capacity	Procurement, monitoring
Congestion Management	Capacity	Procurement, monitoring
	Energy	Procurement

See in ANNEX VI for instance: the timeline of the operational phase (general features for all the organisations).

Situations for which it is not possible to observe all security constraints are out of scope of the EU-SysFlex project. In such situations relevant system operators need to prioritize security requirements considering consequences of violating them, assess out-of-market intervention and possibly even involuntary load shedding. A description of handling of such situations is out of scope.

5.2 OPTIONS FOR CONSIDERATION OF GRID CONSTRAINTS DURING THE TECHNICAL BID SELECTION PROCESS (OPTIMISATION) AND DISCUSSION OF PRIORITY TO LOCAL NEEDS

The OO[50] is responsible for the optimisation of bid selection and switching measures[51] to solve grid constraints and satisfy reserve needs. This section describes options for the consideration of grid constraints during the bid selection process (procurement phase). The options mainly depend on the choice between centralised and decentralised optimisation, as seen in Section 3.2 and on the grid data the SO makes available to the OO.

[47] It needs to be noted that for energy products activation is performed immediately after bid selection.
[48] Free bids are bids submitted by FSP, which didn't receive capacity in procurement of balancing capacity. For self-dispatch TSO such grid constraints check would be performed as bid limitation, for central-dispatch TSOs grid constraint check is inherent part of bid conversion (art. 27 of EB GL (European Commission, 2017)).
[49] However, the grid constraint check is performed as part of monitoring of capacity product.
[50] Optimisation Operator: optimises and selects the bids, taking into account the grid data. The OO role can theoretically be allocated to different actors – see Chapter 5.4.1
[51] See also Chapter 3 of Deliverable 3.4 (EU-SysFlex Project, 2020), which indicates that a combination of bid selection and switching measures reduces overall system costs.

Grid data can be sent in a comprehensive or partial way, but it is also possible to send solely bid limitations. However, the latter option only works for balancing needs and few cases of congestion management and voltage control. Where not otherwise stated, the following optimisation options are feasible for all possible products and refer to the independent optimisation of the procurement of these products.
As described in Section 5.1, all grid constraints (i.e. local needs) must be respected when selecting flexibility bids. Therefore, both centralised and decentralised optimisation must take these requirements into account.

5.2.1 CENTRALISED OPTIMISATION

In centralised optimisation, one algorithm considers all voltage levels, thus including transmission and distribution. An important choice is the kind of grid data sent by the SO to the OO to take the grid constraints into account.

5.2.1.1 WITH COMPREHENSIVE GRID DATA

In this option, the OO is able to calculate diverse grid phenomena, including non-linearities of current and voltage as a consequence of the injected and withdrawn power, the situations of N-1 and the diverse solutions to solve the grid constraints, including switching of topology. The grid data is comprehensive in the way that it describes the electrical properties of the grid to reflect its dynamics. The OO sends the selected flexibility bids to the MO and the SOs, and the necessary switching measures to the SOs.

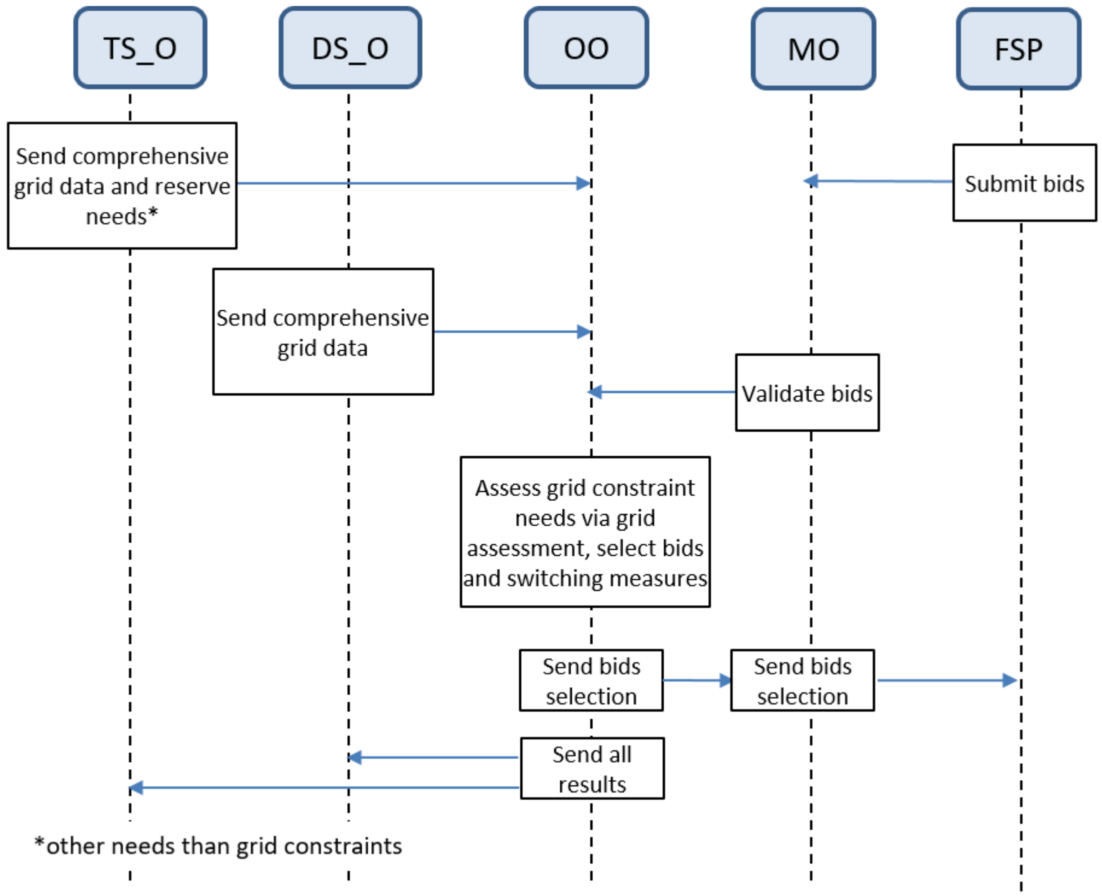

FIGURE 5-2: CENTRALISED OPTIMISATION WITH COMPREHENSIVE GRID DATA

5.2.1.2 WITH PARTIAL GRID DATA

The organisation depends on the many options in relation to the grid data sent to the OO. In one option, the partial grid data are the sensitivities of flexibilities towards critical U/I constraints, i.e. constraints that risk being violated, and the margins for these constraints. For a given constraint, the margin is the difference between the actual U/I and the limit. The value of the margin indicates if the constraint is active; otherwise it is potential, i.e. might become active if the margin shifts.
These data do not allow to consider changes to the grid topology via switching measures.

In this case, the SOs have more information on the grid than the OO. They could observe the variation of sensitivities of U/I or the emergence of new critical constraints. Thus, it is useful that the TS_O and the DS_O check that the selection of bids by the OO solves or respects all constraints. If constraints are remaining, SO calculates and sends, for the already known and the new critical constraints, the actual sensitivities together with the margins, such that the OO calculates a new outcome. Such an iterative process continues until no constraints remain.

In this option, thanks to the sensitivities, the OO is still able to recognize the relieving effect that a given flexibility has on some constraint. This includes the interactions of multiple flexibility bids, e.g. active power flexibility from FSP 1 leads to overvoltage while there is reactive power flexibility from FSP 2 that compensates this problem. OO can recognize that FSP 1 can be safely activated, in conjunction with FSP 2 to alleviate the initial constraint.

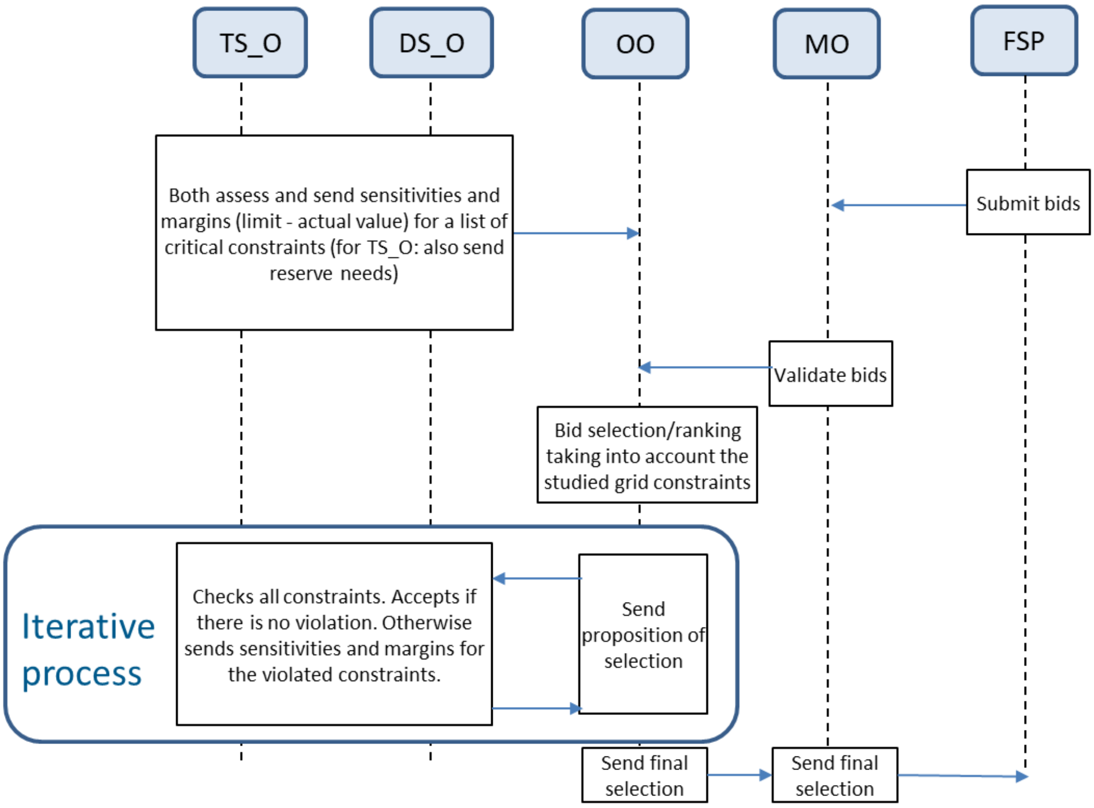

FIGURE 5-3: CENTRALISED OPTIMISATION IN AN OPTION OF PARTIAL GRID DATA: SENSITIVITIES TOWARDS A LIST OF CONSTRAINTS IN THE CASE OF ONE GIVEN TOPOLOGY

If there are many critical constraints to consider, the quantity of sensitivities/margins to send is not necessarily lower than a full description of the grid in the selected topology, close to the option “comprehensive grid data”.

If switching is an option for the SO, the OO result on the initial topology will not necessarily give the most efficient solution. A possible variant is that OO receives different data sets for the reasonable and interesting topologies and research the best solution (topology, bids selection). In this variant, the grid description would be close to the option “comprehensive grid data”.

5.2.1.3 WITHOUT GRID DATA, BY BID LIMITATIONS

In this approach, the OO does not receive any grid data such as electric characteristics of grid elements or sensitivities. However, the SOs may provide information that some bids need to be rejected or reduced to a defined value in active or reactive power or energy. Since no sensitivities are sent to the OO, the optimisation cannot ensure the relieving effect of the flexibilities on local scarcities such as congestions or voltage problems. Nevertheless, the approach might work in specific cases, e.g. for local needs at or upstream of certain grid coupling points where the flexibilities are located below the grid coupling points in radial grids.

Since the OO only needs to consider diverse bid limitations and not a set of grid data, the discussed approach is simpler. Two sub options exist, depending on whether bid limitations are sent (i) after pre-selection of the OO or (ii) before.

In the first option (see Figure 5-4), the bid limitations are sent to the OO only for the bids which were pre-selected. OO is still responsible for the selection of flexibility, but cannot ensure that grid constraints are observed. Thus, for each proposition of selection by OO, SO will assess the grid constraints, and perhaps define new bid limitations for OO. An iterative process is established until the OO sends a bid selection for which SO does not find constraints violations. This option is more viable in systems where the probability of constraints is low, so that there is a low likelihood that flexibility selection cause new constraints. To reduce the number of iterations, it is possible that the OO sends the SO a larger number of pre-selected bids than necessary for solving the scarcity, whereas the DS_O and TS_O limit only such bids by anticipating their selection based on criteria such as price.

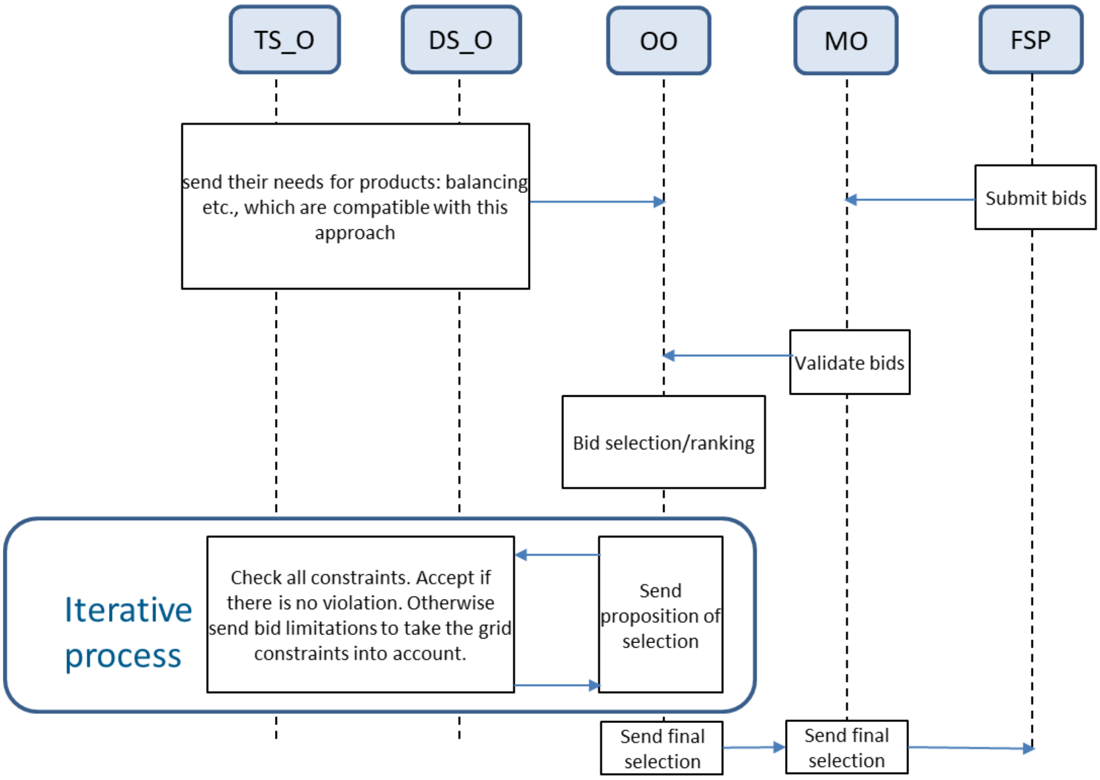

FIGURE 5-4: CENTRALISED OPTIMISATION WITH BID LIMITATIONS SENT AFTER THE OO PRE-SELECTION

In the second option (see Figure 5-5), the DS_O and TS_O receive the available bids to calculate their limitations. This is only possible, where they can anticipate the bid selection in their grid according to a pre-defined ranking principle. For global needs, such as balancing, this is solely the price for each product. For local needs, such as congestion management, price and location must be considered. The latter approach can especially be applied for creating merit order lists for flexibilities below a certain grid coupling point in a radial grid to solve grid violations at the coupling point or in the upstream grid.

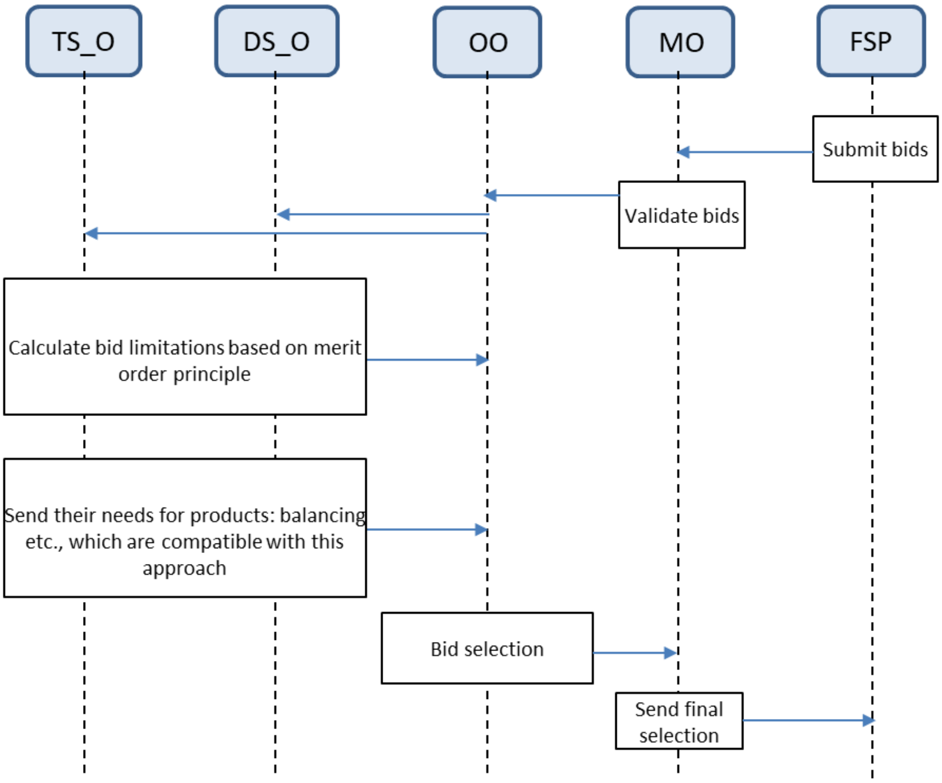

FIGURE 5-5: CENTRALISED OPTIMISATION WITH BID LIMITATIONS SENT BEFORE THE OO SELECTION

5.2.2 DECENTRALISED OPTIMISATION

In decentralised optimisation, each system operator has – in the perspective of roles – an allocated optimisation operator. Consequently, there is at least one OO_T for transmission and one OO_D for distribution grids. The separate OOs receive grid data from their SO. The OOs coordinate to avoid bid selections causing new grid constraints and create synergies to the maximum extent possible ("one system approach"). Decentralised optimisation can apply to the independent procurement of congestion management, voltage control and some frequency control products (for instance mFRR). In any case, decentralised optimisation aims at providing the service for DS_Os or TS_Os, considering all grid constraints. For all products, it is checked whether the selection of such products leads to new congestions or voltage constraints, so that the selection of bids is limited. For congestion management and voltage control, products are procured to solve these scarcities; note that the procurement of products is independent from each other, but the constraints to study are both in current and in voltage. Ideally the OO_D and OO_T should use both flexibility resources and switching options to solve scarcities. The use of switching can also lead to an increase of flexibility potential, e.g. for the OO_T for balancing.

As in centralised optimisation, different levels of grid data provision from the SOs to the OOs are possible. To avoid repetition, only the case of provision of comprehensive grid data is described for decentralised optimisation.

The coordination between the voltage levels can take place in the same way, as in centralised optimisation, with the difference that such coordination takes place between two algorithms and not within one. After the coordination, the resulting bid selections are communicated to the SOs and the MO, which carries out the transaction and informs the FSPs. The described process is depicted in Figure 5-6.

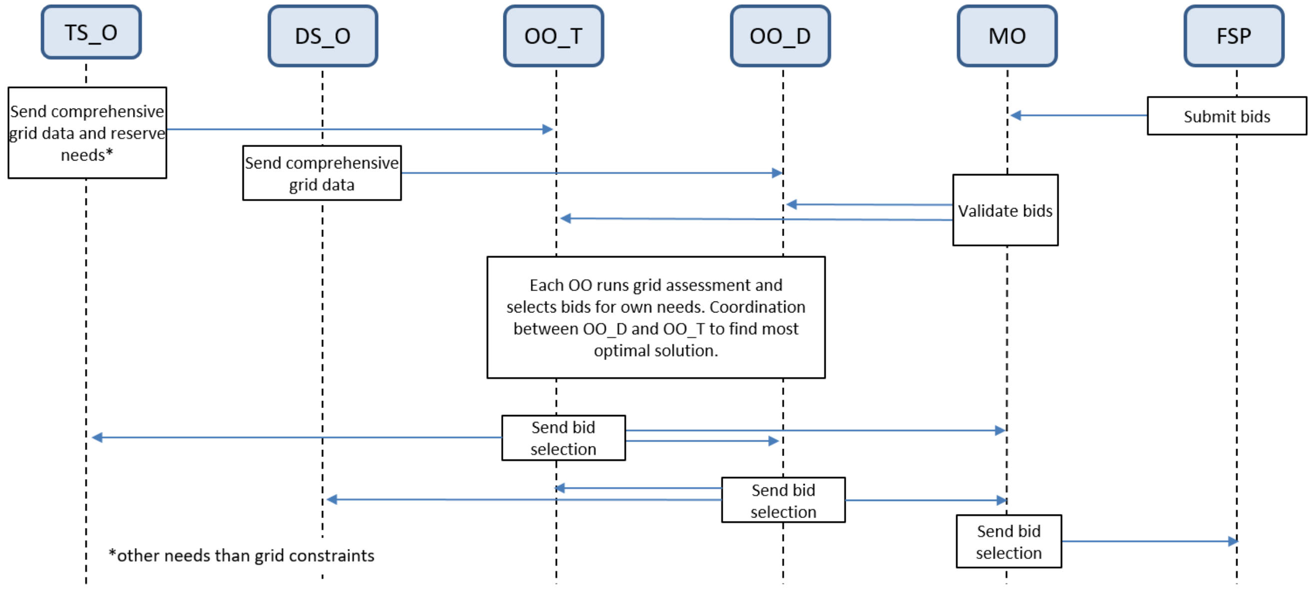

FIGURE 5-6: DECENTRALISED OPTIMISATION WITH COMPREHENSIVE GRID DATA

Introduction of coordination options between OO_D and OO_T

The coordination of both OO roles can work in a bottom-up, top-down or hybrid approach (see Figure 5-7).

In the **bottom-up approach**[52] (see Figure 5-7, left), the OO_D selects first flexibilities for the product needed in distribution (congestion management or voltage control) taking into account the distribution grid constraints, and afterwards calculates for the OO_T per DSO/TSO coupling point in a Merit Order List (MOL) the residual available flexibility potential including bid limitations and sensitivities. Such selection by the OO_D is not applicable for pure balancing products. In that case, the OO_D only sends bid limitations to the OO_T but does not select bids for own purposes. The OO_T receives information on the residual potential, but also on the selected bids, so that it can calculate the remaining needs via its grid assessment. It then selects the appropriate bids in its own or the connected distribution grids. The advantage of this approach is the knowledge of the OO_T of the flexibility

[52] Chapter 3 of Deliverable 3.4 (EU-SysFlex Project, 2020) carried out a simulation comparing the bottom-up decentralised optimisation with a centralised optimisation.

potential and prices in the underlying distribution grids. As a disadvantage, situations might exist, where the knowledge of the OO_T's needs by the OO_D could lead to better synergies (details see following sections).

In the **top-down approach**[53], the OO_T would demand the required flexibilities to the OO_D without being able to consider grid limitations or sensitivities in the distribution grid. Therefore, it is not possible for the OO_T to evaluate the flexibility potential in the distribution grid for such products, which shall solve transmission congestions or could cause congestions in the distribution grid. That is why it is necessary that the OO_D provides such information before the OO_T's selection – as it is done in the bottom-up approach. The pure top-down approach is only possible for non-locational products which do not cause congestions in the distribution grid, either because the distribution grid is generally congestion-free or because such products do not cause additional congestions, e.g. due to their short-term duration (such as FCR, aFRR). A grid prequalification carried out by the DS_O could ensure that the OO_T could directly access such flexibilities, making OO_D/OO_T coordination during the procurement phase redundant.

In some grid situations which are explained in the following sections, **hybrid approaches** (see Figure 5-7, right) might be useful to combine advantages of both approaches.

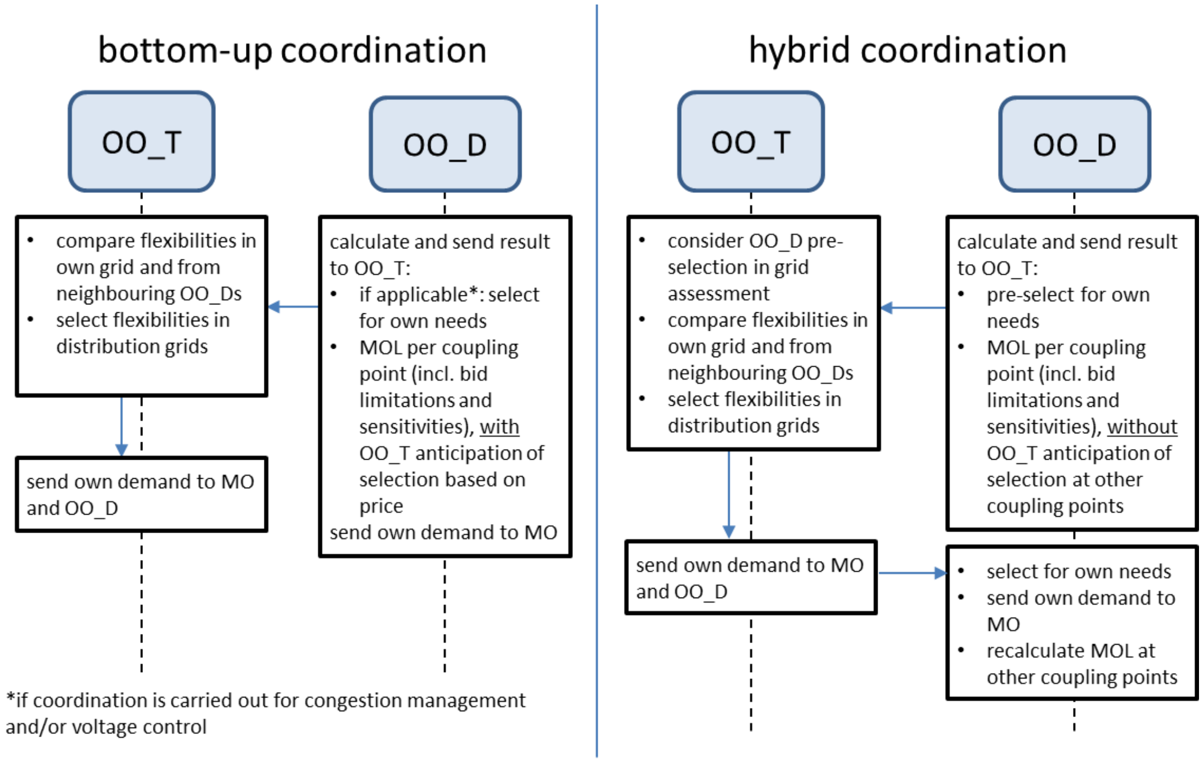

FIGURE 5-7: COORDINATION OF OO_D AND OO_T IN A BOTTOM-UP (LEFT) AND HYBRID (RIGHT) APPROACH

[53] In current power systems, this approach is mostly used to curtail RES or to do load shedding (in emergency situations). In the first case, the TSO forecast the RES infeed on its own and therefore knows the RES curtailment potential. However, sensitivities and costs are not considered.

Coordination in case of radial DSO grids

In case of solely radial DSO grids, i.e., mostly where the TSOs operates HV and EHV (see Figure 5-8, left), the separate procurement of products (different types of scarcities) by considering in the first step the local constraints leads to the optimal result. For congestion management and voltage control, the OO_D selects the bids for its own needs, and forwards its selected bids and the residual flexibility potential including flexibility limitations to the OO_T. In case of balancing, the OO_D does not select for its own needs, but also forwards the possible flexibility potential incl. bid limitations to the OO_T. The possible flexibility potential including the bid limitations is computed by anticipating the order of selection based on the price of bids (MOL principle). In this way, constraints are respected, and synergies are created. Note that this detailed data exchange works when OOs receive comprehensive grid data.

Example for congestion management:

- Synergies leveraged: Both OO_D and OO_T need to decrease RES infeed (or increase of consumption). The OO_D selects the most efficient bids to solve its own congestions. These bids also relieve the congestion in the transmission grid. The OO_T only selects further bids, if necessary.
- Counteractions avoided: If the OO_T wants to increase consumption in the distribution grid to solve a congestion, a counteraction of the OO_D (selecting a flexibility to decrease consumption or increase generation) would reduce or even fully eliminate the effect for the OO_T at the coupling point. Therefore, the bid limitations support the OO_T in selecting only those bids, which can be safely activated, solve the transmission grid needs and do not cause counteractions by the OO_D.

Example for balancing:

A balancing bid can cause congestions, so that its activation could be cancelled by the affected SO in the activation phase, if no bid limitation was sent to the OO_T. Another option could be the use of at least two congestion management bids (one inside, one outside the congested area) to allow the balancing bid to be activated. The latter increases the volume of flexibility needed and could be part of joint procurement approaches (see Chapter 6).

Only when different scarcities are optimised jointly, theoretical cases of more economical results are possible when the first optimisation is not done for local constraints. One case, as shown in Figure 5-8, is that the OO_T need for active power (e.g. for congestion management), resulting in a selection of the cheapest flexibility, solves the OO_D need for voltage control at another location, whereas the OO_D would have selected active power closer to its problem. Assumptions are: there is not sufficient reactive power available, the competing flexibilities are in very close proximity and the OO_Ts selection of larger demand and lower price have more weight than the worse sensitivity (lower positive impact towards the voltage problem in the distribution grid) compared to the OO_D selection.

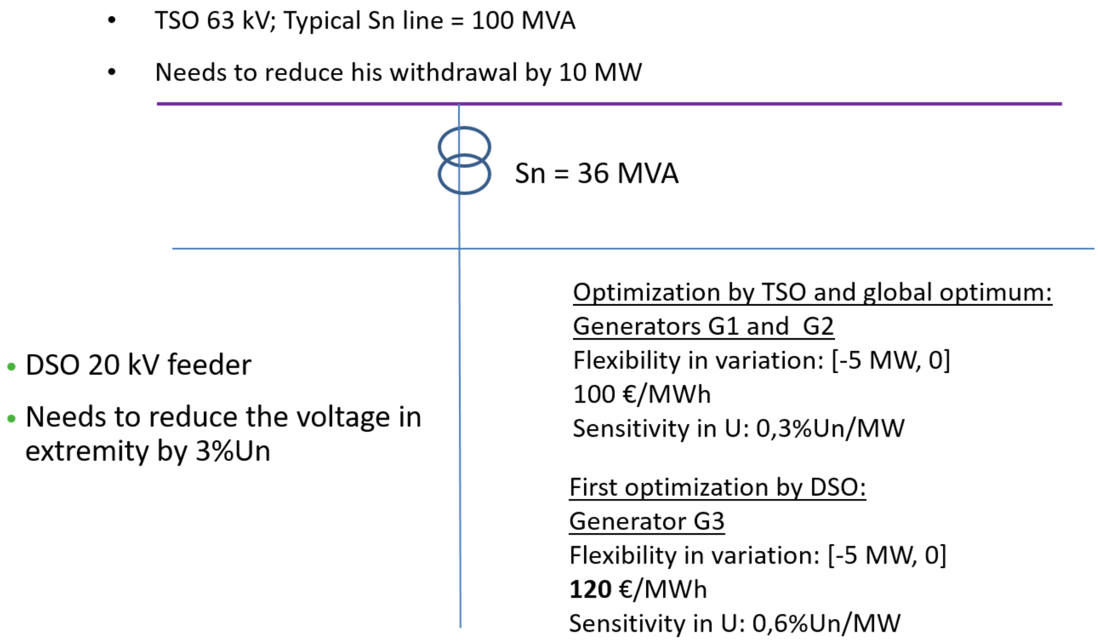

FIGURE 5-8: CASE OF RADIAL GRID IN DISTRIBUTION, A CURRENT CONSTRAINT IN TSO GRID AND AN OVERVOLTAGE CONSTRAINT IN DSO GRID

Another case would be similar to the depicted, but the OO_D would need active power for congestion management and the OO_T would need active power for balancing. In this case, an even higher likelihood exists that the OO_T's favourable resource can solve the OO_D scarcity at the same time, since the pool of resources for balancing is even higher, and the activation request must fit into the same time as the congestion need[54].

Therefore, in radial grids, the bottom-up approach mostly leads to the optimal result. In consequence, the hybrid approach is only advantageous in very rare cases.

Coordination in case of meshed[55] DSO grids

The coordination approach of radial grids (see Figure 5-7, left) can be applied to meshed distribution grids, i.e. mostly where the TSO operates solely EHV (see Figure 5-7, right), as well. However, two examples exist where a pure bottom-up approach, especially for congestion management and to a smaller degree for voltage control, leads to results lower than the theoretical optimum[56]:

- The OO_T demand at one coupling point A solves the OO_D demand close to another coupling point B and replaces a potential OO_D selection. The assumption here is, that the higher OO_T demand and the lower price of the selected flexibility have more weight than the lower sensitivity towards the OO_D scarcity.

[54] Congestion needs start at roughly 15 min and can last several hours, whereas balancing needs start at ms and last maximum one hour.
[55] With loops
[56] For balancing, the OO_D can anticipate the OO_T selection (purely based on price) and therefore can optimise the merit order lists (MOL) at the coupling points.

- The selection of flexibilities by the OO_T at coupling point A further limits the flexibilities at other coupling points. In few cases, also sensitivities could change. Therefore, the bottom-up approach without knowledge of the OO_T needs cannot lead to the most efficient calculation of MOLs at the coupling points.

Such cases are specific to local grid (location and volume of congestions, topology, and impedances) and flexibility characteristics (location of connection, price, volume). Under these specific circumstances, cases for congestion management and voltage control can exist, where a combined bottom-up/top-down approach can increase synergies and reduce flexibility limitations. Such hybrid approach could be designed in a way that the OO_D runs a pre-selection for the meshed grid and calculates a MOL per coupling point without knowledge of the OO_T demand. Afterwards, the OO_T compares the available flexibilities in its own grid and the connected distribution grids, sending the demand first for the coupling point with the most economical bids. The OO_D recalculates the MOL (in case of changes of its selection), confirms the flexibility selection to the OO_T and recalculates the other MOLs at the other coupling points (in case of high interdependency). The process for one coupling point is described in Figure 5-7 (right).

It must be noted that this iterative process would increase the efficiency of the solution only in the specific grid cases. The benefits of the iterative process can vary as well. In addition, such iterative process would also be part of a centralised optimisation.

Clustering of bids

In a decentralised optimisation scheme, OO_D and OO_T can agree on a clustering of bids by the OO_D based on certain criteria such as an agreed span of prices in combination with the sensitivity of the bid to the coupling point. In this process, the OO_D would cluster the bids and the OO_T could only select such a clustered bid (or a part of it). After informing the OO_D, the OO_D declusters and chooses[57] the bids[58] most efficient for the OO_D based on updated grid information. Such efficiency can relate to e.g. avoiding new congestions or creating synergies. The sum of the chosen individual bids by the OO_D must fulfil the needs of the OO_T. Such clustering can be designed in a way distinct from commercial aggregation, since it is a process to improve the coordination between OO_D and OO_T[59].

There are two different purposes of such clustering: The first relates to reducing the limitation of bids, the second relates to reducing the data exchange between OO_D and OO_T. The first purpose addresses the need of the OO_T, that the information of the flexibility potential from the distribution grid to the transmission grid needs to be available to the OO_T earlier (current European TSO-TSO coordination for congestion management takes place day-ahead) than potentially flexibility providers must be informed about the selection. Consequently, the OO_D has room for manoeuvre to react on changes in its grid (e.g., changed weather or demand forecasts), before the final individual bid selection must take place. It is possible, that the OO_D only informs the OO_T about the final possible

[57] Such choice can mean that the OO_D procures the individual bids on the market on behalf of the OO_T and forwards the costs to the OO_T later on or that the OO_D informs the OO_T of the possible selection of individual bids inside the cluster so that the OO_T can procure the individual bids itself on the market.
[58] If bids are dividable in volume, the OO_D might also choose parts of these bids.
[59] With regard to prequalification the single bids are not treated differently compared to a scheme without clustering.

bid selection, so that the OO_T carries out the procurement on the marketplace itself. However, the OO_D might also procure such bids on behalf of the OO_T and forwards the associated costs to the OO_T. The latter is a prerequisite for the second purpose, addressing the possibility to reduce data exchange volumes between OO_Ds and OO_Ts.

5.2.3 CONCLUSION

Both centralised and decentralised optimisation can be applied for selecting flexibilities to solve congestions, voltage or balancing problems. Where centralised optimisation concentrates all necessary data (bids, reserve needs, comprehensive or partial grid data, or bid limitations where possible) in one algorithm to consider constraints in all voltage levels, decentralised optimisation focuses on the allocated voltage levels but still allows the “one system approach” by coordinating across the voltage levels. Such coordination can lead to the optimal selection of bids or get at least very close to the optimum of a perfectly designed centralised optimisation.

The selection of the coordination approach depends on the addressed scarcities as well as the grid structures and flexibility characteristics (e.g. location, volume and prices) between the different optimisation operators. Coupled meshed grids can lead to higher coordination needs and are more likely to make hybrid approaches more efficient than pure bottom-up approaches. The coordination approach could also vary for different grid areas. The advantages of both optimisation models are discussed in Section 5.3.

The amount and type of grid data shared between the roles SO and OO may also vary. The analysis shows that comprehensive grid data sharing including changing of topologies is the most promising solution for the operation of more congested grids in the future. Exceptions of simpler solutions might exist depending on the grid structure or on the product. In particular, for balancing products, simplified process such as bid limitations could be used. These bid limitations can be sent before bid selection, or in case of weakly constrained grids, after a pre-selection initiating an iterative process.

5.3 DISCUSSION OF OPTIMISATION MODELS

Table 5-2 discusses the advantages of both centralised and decentralised optimisation[60]. We assume the exchange of comprehensive grid data to compare the two solutions which can get the closest to the theoretical optimum. Advantages of one optimisation results in the disadvantage of the other. The discussion does not include the perspective of flexibility service providers, since their interface is independent of the decision of optimisation. From an FSP's point of view, the different models do not affect their processes. However, for an FSP it is easier to have at least standardised and interoperable interfaces to market platforms. One option is a single market platform gathering all bids, meaning that an FSP with a large portfolio dispersed on several geographic areas has only one interface to connect and place its bids. An alternative is a data exchange platform ensuring the interoperability and the single interface. All options can be possible in centralised or decentralised optimisation.

Moreover, decentralised optimisation does not reduce liquidity by design: it can be used for each scarcity/product independently or even work for joint procurement approaches (with a joint or coordinated optimisation of the procurement of products). All flexibility bids can also be gathered in one marketplace, independent of the optimisation model. Decentralised and centralised optimisation both use local flexibility to respect the operational security limits.

TABLE 5-2: DISCUSSION OF ADVANTAGES OF CENTRALISED AND DECENTRALISED OPTIMISATION (FOR COMPREHENSIVE GRID DATA)

Advantages of centralised optimisation	Advantages of decentralised optimisation

• Less coordination effort between roles needed (by definition of centralised optimisation with comprehensive grid data, there is no iteration in the operational timeline):
  ○ Save time of coordination
• Can achieve theoretical possibility of (fully) optimal solution:
  ○ More likely to achieve solution of lowest flexibility costs for all scarcities
• Economy of scale (one vs multiple places for the optimisation algorithm)
  ○ Less investment in buildings and less hardware maintenance costs
• interoperability concentrates on interface to one OO:
  ○ One set of rules[61] will be established (process organisation, IT requirements…)
	• Stepwise optimisation implementation along the voltage levels is possible, considering specific voltage level and regional requirements.
	• Easier to match localised solutions to scarcities, since no new optimisation of the whole system is necessary
	• Simpler individual algorithm, less data processed:
	  ○ Lower development cost for each algorithm
	  ○ Each algorithm will compute an optimum faster
	• Fit to current SOs responsibility framework and regulation framework:
	  ○ Each SO has its own allocated OO: SO can select its own OO, responsibilities are clearly allocated for keeping each system secure
	  ○ No adaptation of incentive regulation needed
	• Higher resilience:
	  ○ in case of one OO's failure due to distribution of data processing
	  ○ in case of missing data (only causes calculation interruption in local (and not whole) optimisation, thus lower risk for the whole system)

[60] Reminder: centralised or decentralised optimisation can be used in regulated or market-based procurement process
[61] Such single set of rules can also be developed in the decentralised optimisation.

	○ in case of failures, decentralised fall-back procedures must be established anyway (no need for additional IT and telecommunication systems if SO is OO)

This qualitative assessment does not allow to make a choice between these two optimisation types.

Quantitative studies are needed to evaluate in concrete cases (with actual structure of TSO/DSO, regulatory framework, …) and depending on the scarcity to be solved:

- Efficiency gains (Chapter 3 of Deliverable 3.4 (EU-SysFlex Project, 2020) provides detailed results (see below)
- Investment and operational costs of both solutions
- Temporal feasibility: Can a complex centralised algorithm provides results fast enough? Can the coordination between OOs be done fast enough in the decentralised optimisation?
- Communication costs: communication channels between OO_T and all other roles in centralised optimisation versus communication channels between OO_T and OO_D and between OO_Ds/OO_Ts for decentralised optimisation.

Chapter 3 of Deliverable 3.4 (EU-SysFlex Project, 2020) carried out a simulated comparison of a centralised with a decentralised bottom-up optimisation. They came to the following conclusions:

- The performance differences between the centralised and the decentralised optimisation can be minimised if the allocation of distributed resources can be corrected to consider both transmission and distribution requirements during real-time. This can be facilitated if the optimisation is quite close to real-time and the distribution network operation is quite flexible.
- The centralised optimisation is ideal from the optimality point of view, but very challenging in terms of computation and control. It requires a central entity to optimise the whole system. Therefore, it may not be compatible with the current structure.

In addition, it should be noted that in case of a centralised optimisation, cybersecurity and resiliency issues should be addressed extensively. The regulatory framework should be adapted (responsibility issues) depending on which actor is the OO.

On the contrary, in case of decentralised optimisation, harmonisation/standardisation rules should be established to help decrease interoperability costs and facilitate the coordination between SOs. Finally, the question of small DSOs should be examined: a CBA to set-up a local optimisation could be executed, or the possibility to group neighbouring DSOs to a reach critical size could be assessed.

5.4 ALLOCATION OF ROLES TO ACTORS

The OO and MO (for flexibility market) roles can theoretically be carried out by different actors[62]. However, the selection of such actors must be compliant with EU Regulations and has various implications which include regulation, governance, responsibilities, transition and operational costs and data exchange needs.

5.4.1 ALLOCATION OF THE OO ROLE TO ACTORS

The OO role was introduced in order to examine whether bid selections based on grid data could theoretically be carried out by any actors or entities other than system operators (TSO, DSO), for whom the bid solves a scarcity. Other actors or entities would be joint ventures of system operators, commercial or non-commercial third parties (like marketplace operators). Independent of the choice, the ultimate responsibility for system security rests with the SOs. In order to compare the different OO role allocation options, the following prerequisites (both technical and regulatory) were defined which would need to be met by an actor performing this role (in the hypothesis of comprehensive grid data is sent to the OO):

- select flexibility bids in a non-discriminatory way
- be incentivized to minimize the costs of flexibility use
- be incentivized to continuously improve the resilience of the algorithm for which it is responsible (e.g. improve "state estimation")
- for congestion management and voltage control: high grid operation skills, such as finding the most efficient solution among switching measures and flexibility use
- responsibility for timely provision of optimisation result or in case of failure of such notification
- able to transfer and process very high amount of data in real-time
- very high resilient and blackout-safe IT and communication systems

Additional aspects shall be considered, where the OO and SO roles are carried out by different actors:

- According to Article 31 and 40 of the Electricity Directive 2019/944 (European Parliament and Council of the European Union, 2019), distribution and transmission system operators shall be responsible for ensuring a secure, reliable and efficient electricity system and, in that context, for ensuring the availability of all necessary ancillary services and for procuring ancillary services to ensure operational security. This role remains regardless of the market organisation chosen. Therefore, even in case of the allocation of the OO role to other actors, SOs have the final responsible (in accordance with current European rules). For that reason, system operators must always be able to undertake at least rule-based emergency measures to allow a secure grid which also implies own IT systems for grid assessment and direct communication channels to significant grid users.
- Since system operators are also responsible for economic efficiency of their systems, they will pay for the costs of flexibility services. If DSOs and TSOs have to defend the costs towards the regulator - assumedly also reflecting the trade-off with grid investments - and the OO is allocated to another actor, contractual

[62] Reminder: each role is defined by replicable responsibilities, independent on the country specific context; the roles aim to be neutral about the technical implementation of a product. Each role is delegated to only one actor, where one actor can fulfil several roles

rules might be in place that costs for non-efficient or non-feasible results are covered by the OO actor. For this reason, system operators will need possibilities to retrace the optimal solutions which the OO actor has not found. Different solutions exist which give DSOs/TSOs more or less insight into the efficiency of the OO results. As a basis, the optimisation algorithm should be completely transparent to SOs. Besides, the SO could build up its own optimisation system to compare results or softer solutions could be chosen, such as comparing the OO result with its previous results or other OO's results.

TABLE 5-3: COMPARISON OF ADVANTAGES AND DISADVANTAGES OF THE ALLOCATION OF THE OO ROLE TO DIFFERENT ACTORS IN CASE OF CENTRALISED OPTIMISATION

	Allocation of the role "Optimisation Operator" in case of centralised optimisation		
	TSO[63]	**TSOs/DSOs JOINT VENTURE**	**Commercial third party (e.g. marketplace operators)**
(+)	• main focus on grid safety and efficiency • easier governance (no new actor) • existing high transmission grid operation skills	• existing high grid operation skills • main focus on grid safety and efficiency • interest in improving optimisation easier to implement: SO actors pay the flexibility • could be neutral towards DSOs/TSOs	• in case of existing market operators in the function of market coupling operators: existing skills in optimisation [64](partial grid data) • neutral towards DSOs/TSOs
(-)	• difficulty for DSO to take over system responsibility • regulatory framework to adapt to introduce a new responsibility (optimisation of DSO systems) to the TSO • challenge to incentivize cost-efficient selection and improvement of algorithm for DSO needs (discrepancy: actor selecting and paying)	• Would need to be consistent with SOs' role wrt. procuring ancillary services under EU Regulations • regulatory framework to adapt, where needed[65], to modify responsibilities and coordination • difficulty for DSO/TSO to take over system responsibility • governance issues	• Would need to be consistent with SOs' role wrt. procuring ancillary services under EU Regulations[66] • regulatory framework to adapt, where needed, to introduce new responsibilities for such actor • Chinese walls between commercial activities and optimisation role must be ensured • challenge to incentivize cost-efficient selection and improvement of algorithm (discrepancy: actor selecting and paying) • difficulty for DSO/TSO to take over system responsibility

[63] Only feasible in countries with one TSO, otherwise it is a joint venture of system operators
[64] MO in their function as MCO currently receive partial grid data for market coupling
[65] National cases of TSO/DSO Joint Venture already exist for certain scarcities
[66] See DIRECTIVE (EU) 2019/944 on common rules for the internal market for electricity article 31 and 40

TABLE 5-4: COMPARISON OF ADVANTAGES (+) AND DISADVANTAGES (-) OF THE ALLOCATION OF THE OO ROLE TO DIFFERENT ACTORS IN CASE OF DECENTRALISED OPTIMISATION

	Allocation of the role "Optimisation Operator" in case of decentralised optimisation		
	Each DSO and TSO	**TSOs/DSOs JOINT VENTURE**	**Commercial third party (e.g. marketplace operators)**
(+)	• main focus on grid safety and efficiency • very low governance challenges due to implementation according existing DSO/TSO structure, fits to system responsibility • in many countries: fits to current regulatory framework • lower external data exchange needs • Switching actions, flexibility selection and determination of flexibility potential for other SOs at one actor: ▪ less external coordination needed ▪ lower reaction times • SO can defend flexibility costs more easily towards regulator, also simplifying regulatory trade-off with grid investment • no double IT equipment needed • existing high grid operation skills	Not applicable	• in case of commercial party being existing market operators in the function of market coupling operators: existing skills in optimisation [67](partial grid data) • neutral towards DSOs/TSOs
(-)	• small DSO might see optimisation as challenge, if no voluntary delegation possible	Not applicable	• regulatory framework to adapt, where needed, to introduce new responsibilities for such actor • Chinese walls between commercial activities and optimisation role must be ensured • challenge to incentivize cost-efficient selection and improvement of algorithm (discrepancy: actor selecting and paying) • additional IT systems will be built up (DSO/TSO & third party) • difficulty for DSO/TSO to take over system responsibility • additional interface between DSOs/TSOs and third party

Apart from the compared allocation solutions, mixed solutions might also be possible, e.g. where some DSOs/TSOs decide to delegate the optimisation to other actors.

[67] MO in their function as MCO currently receive partial grid data for market coupling

5.4.2 ALLOCATION OF THE MO ROLE TO ACTORS

The MO role could theoretically be allocated to different actors, such as existing marketplace operators or system operators. The question also depends on the number of marketplaces and whether there shall be a competition of marketplaces or not (see CEDEC et al., 2019). Moreover, the decision for centralised or decentralised optimisation and the allocation of this optimisation responsibility to actors influences the allocation of the MO role to actors.

5.4.3 CONCLUSION

All solutions are feasible and, to properly allocate the roles of OO and MO, it's necessary to conduct a cost-benefit analysis, considering all chances and risks, but specifically also addressing national specificities (regulation, number of DSOs and TSOs within a bidding zone, existing processes of optimisation, historical organisation, etc.) and choice for centralised or decentralised optimisation.

Regardless of the national situation, it can be concluded that an allocation of the optimisation to an actor other than each individual system operator, being responsible for the safety of their systems under Articles 31 and 40 of the Electricity Directive (European Parliament and Council of the European Union, 2019), leads to significant governance and regulation challenges. This report only reveals first implications and further research is needed in this direction.

6 JOINT PROCUREMENT OF mFRR AND CONGESTION MANAGEMENT

Chapter 5 described options for TSO/DSO coordination (or its delegation to other actors) in the sense that such coordination leads to the procurement of one product for each scarcity be it for TSO need, DSO need or for both TSO and DSO need. In the latter case, we have a form of joint procurement of the product, as both SOs procure the same product in a common process. This chapter of the deliverable will focus on the joint procurement of one product for two scarcities: a joint product, aligned to mFRR and congestion management (CM) products, shall solve imbalances and congestions. For that purpose, it is investigated more closely what is meant by 'joint procurement', going from a very broad generic definition to a very concrete definition in the framework of EU-SysFlex. Based on existing literature and discussions within EU-SysFlex, advantages and challenges related to joint procurement of mFRR and CM are described, potential products and processes identified.

6.1 GENERAL INTRODUCTION INTO JOINT PROCUREMENT

In the scientific literature, definitions and studies of joint procurement are provided, mainly focused on energy and reserve procurement.

González et al. (2014) distinguish two different market designs that are commonly used to organize energy and reserve markets: joint optimisation and sequential optimisation. In joint market optimisation, energy and reserves are optimised simultaneously (co-optimisation) (f.i., US markets such as CAISO, ERCOT, etc.), implicitly accounting for interdependencies, while in sequential market optimisation, two separate markets are optimised sequentially, without implicitly accounting for interdependencies (f.i., the European Integrated Energy Market) (Van Den Bergh and Delarue, 2019).

According to Soleymani et al. (2007), joint markets result in higher social welfare compared to sequential markets as joint markets better account for the various couplings between energy and reserve markets. This topic has been addressed through detailed modelling in Task 3.4.

The interdependence of energy and reserve markets is also quantified in Task 3.4 of the EU-SysFlex project (EU-SysFlex Project, 2020) The performance of a sequential and a joint energy-reserve market design is analysed for a realistic and large-scale case study of the Central Western European electricity system and for scenarios with different levels of intermittent renewables. The study demonstrates that joint procurement leads to a better efficiency (lower total operational system costs). The cost difference increases with increasing levels of wind and solar PV, up to 2.0-2.5% of total operational system cost at 30-35% wind and solar PV. The cost difference also increases in absolute terms, from €58M at 7% share wind and solar PV (on a total operational system cost of €47.5B) to €535M at 33% share wind and solar PV (on a total operational system cost of €23.0B). However, this cost difference between a joint and sequential design can be significantly reduced with decreasing reserve costs or increasing participation of flexible load and renewables.

Also, Task 3.4 quantifies the benefits of coordinating regional markets for balancing capacity (EU-SysFlex Project, 2020). The case study compares different variants of joint procurement of energy and reserves. The investigated variants included: a) an option where cross-zonal capacity is allocated only for energy exchange, b) an option where exchange of balancing capacity is considered in addition to energy exchange and c) an option where balancing capacity is shared. For each option, joint optimisation of energy and reserves is applied. In the case studies, the benefits of exchanging balancing capacity ranged between 0.49-6.73% of operating costs or 98-1146 M€/year for the CWE system for variable renewable shares ranging between 27.2-41.3%, respectively. The benefits of sharing balancing capacity were even greater, ranging between 1.40-17.1% of operating costs or 280-2904 M€/year for the CWE system for variable renewable shares ranging between 27.2-43.3%, respectively.

Similar to energy and reserve markets, different flexibility services are linked through the technical constraints of the service providers. In other words, the use of capacity for one type of flexibility service may constrain the use of that same capacity for another type of service (Liu and Tomsovic, 2014; Morales-Espana et al., 2014). In the remainder of Chapter 6, joint procurement of different flexibility services will be studied.

Where separate procurement leads to the procurement of one product by one buyer to solve only its own scarcity without any coordination of procurement activities with other buyers, the major characteristic of joint procurement is that FSP may provide only one bid for solving one or several scarcities of one or several system operators. Therefore, the necessity for them to choose between several separated markets is limited or completely avoided, causing higher liquidity[68] on the combined market. Joint procurement can also lead to lower volumes of flexibilities needed, where one bid can solve different problems. This includes solving different problems of the same scarcity (e.g. congestions at DSO and TSO level) or even different scarcities (e.g. imbalance and congestion). Therefore, "joint" can relate to:

- the buyers, i.e. the coordination of DSOs and TSOs
- the scarcities and products, i.e. that one product can be used to solve several scarcities or vice versa
- the optimisation across scarcities, i.e. that scarcities can be solved in a joint process (based on centralised or decentralised optimisation).

Table 6-1 describes the different forms of joint procurement in more detail.

The first form of joint procurement is the **coordinated procurement by TSOs and DSOs** of a certain type of products (e.g. congestion management), to solve one specific type of scarcities (e.g. congestions). Such coordinated action can take place in a centralised (single optimisation process for both transmission and distribution) or decentralised optimisation (two (or more) sequential coordinated optimisation processes at DSO and TSO level) and is described in Chapter 5. The optimisation of scarcities takes place separately, meaning that the buying process is independent from each other, but TSOs and DSOs coordinate to jointly procure the flexibilities for each scarcity.

[68] Liquidity decreasing effects also exist and will be explained in Chapter 6.3.1

Another form of joint procurement is the use of **one product to solve more than one scarcity**, either by one or more buyers. The first case is e.g. the TSO's use of mFRR bids for balancing and CM or the DSO's use of CM bids for voltage control and CM. The second case is the one which is investigated in the following sections: The DSO's and TSO's use of one product (in this case: mFRR type of product) for balancing and CM. The optimisation process across the scarcities can be joint or coordinated (2-step). The wording "joint optimisation" refers to "co-optimised" or also called "simultaneous" optimisation of two or more different, yet related, products (for the allocated scarcities) within one optimisation formulation (Liu et al., 2015; Olatujoye et al., 2017)

The last form of joint procurement is the **procurement of two or more products** by one or more buyers to solve one or more scarcities. One example is the use of active (e.g. mFRR or CM) and reactive power bids to solve voltage problems and/or congestions. It is possible, that several products can solve both scarcities, and that DSOs and TSOs coordinate in that matter.
<u>Independent of the format of optimisation across scarcities,</u> a pre-requisite used in Chapter 4 and 5 is that procurement of one product shall not breach grid constraints, in current or voltage, for TSO and DSO. Therefore, this principle shall not be considered as a form of joint procurement but a pre-requisite.

TABLE 6-1: OPTIONS FOR JOINT AND SEPARATE PROCUREMENT

Number of products	Number of scarcities	Number of buyers	Centralised/ Decentralised optimisation	Joint Procurement	Optimisation across scarcities	Example
1	1	1	No (missing coordination across SOs)	No	No (separate optimisation of scarcities)	Separate procurement of mFRR and CM by TSOs; procurement of CM by DSOs
1	1	2	Yes	Yes	No (separate optimisation of scarcities)	Coordinated procurement of CM by TSOs and DSOs (see Chapter 5)
1	2	1	Yes	Yes	Yes (joint or coordinated)	Procurement of mFRR type of product for CM and imbalances by TSOs; Procurement of CM product for CM and voltage control by DSOs
1	2	2	Yes	Yes	Yes (joint or coordinated)	Procurement of mFRR type of product for CM and imbalances by DSOs and TSOs
2	1	1	Yes	Yes	No (separate optimisation of scarcities)	Procurement of reactive power and active power for voltage control by TSOs or DSOs
2	2	1	Yes	Yes	Yes (joint or coordinated)	Procurement of reactive power and active power for CM and voltage control by TSOs or DSOs
2	2	2	Yes	Yes	Yes (joint or coordinated)	Procurement of reactive power and active power for CM and voltage control by DSOs and TSOs

6.2 MOTIVATION FOR JOINT PROCUREMENT OF MFRR AND CM

The different concepts of joint procurement were discussed in detail during an EU-SysFlex internal workshop (EU-SysFlex Project Task 3.2 Consortium, 2019) It was decided to focus on the joint procurement of the frequency-related mFRR and CM products for both the TSO and the DSO. The aim is to design one product and a related process for the joint procurement of mFRR and CM for several reasons:

First, mFRR and CM products have some similarities that could allow to design a common product with possible synergy: in both cases, the product deals with active power increase/decrease with manual activation, with FAT greater or equal to 15 minutes and with duration greater or equal to 15 minutes. A combined product could allow FSPs to bid once to apply for solving both imbalance- and congestion-related scarcities. Additionally, if both scarcities were optimised jointly, in total less flexibility could be used. Secondly, the joint procurement of these two products is being looked at specifically by different stakeholders, most prominently in the TSO/DSO report on active system management (CEDEC et al., 2019).

Other reasons include that mFRR and CM joint procurement already exists in some countries. One example is the Great-Britain Balancing Mechanism, or the French Balancing mechanism.

Focus on Great-Britain Balancing (and Congestion Management) Mechanism:
The TSO, National Grid, co-procures all services and makes (manual) adjustments to set an energy imbalance price which (to some degree) excludes the effect of non-energy actions (i.e. TSO's actions to solve constraints as congestion, margin, …) on the energy imbalance price. FSPs make unit-specific bids and offers for incremental and decremental delivery of MW, relative to a Final Physical Notification (FPN), which is a minute-by-minute declaration of intended production. Offers and bids are accompanied by technical offer data, e.g., ramp rates, soak times, dwell times, notice to sync, minimum on and off times, minimum stable generation, etc. National Grid accepts these offers and bids (balancing offer acceptances – **BOAs**) to meet its needs, i.e., any combination of energy, congestion, positioning plants for response/reserve, etc. There is no distinction between the offer price for energy or some other service, it is up to the FSP to calculate the value of its service to National Grid. Settlement of the BOAs is pay-as-bid. Therefore, a generator behind a constraint may end up with a price that reflects the value of energy at its location.

The following case studies of Germany and France show different situations of balance and congestion management needs.

Germany

In Germany, in 2018, 114 GW of RES were installed, the majority being wind and solar power, leading to a high number of congestions in the transmission and distribution grid.

Figure 6-1 shows the sorted duration of single flexibility activations to solve these congestions.

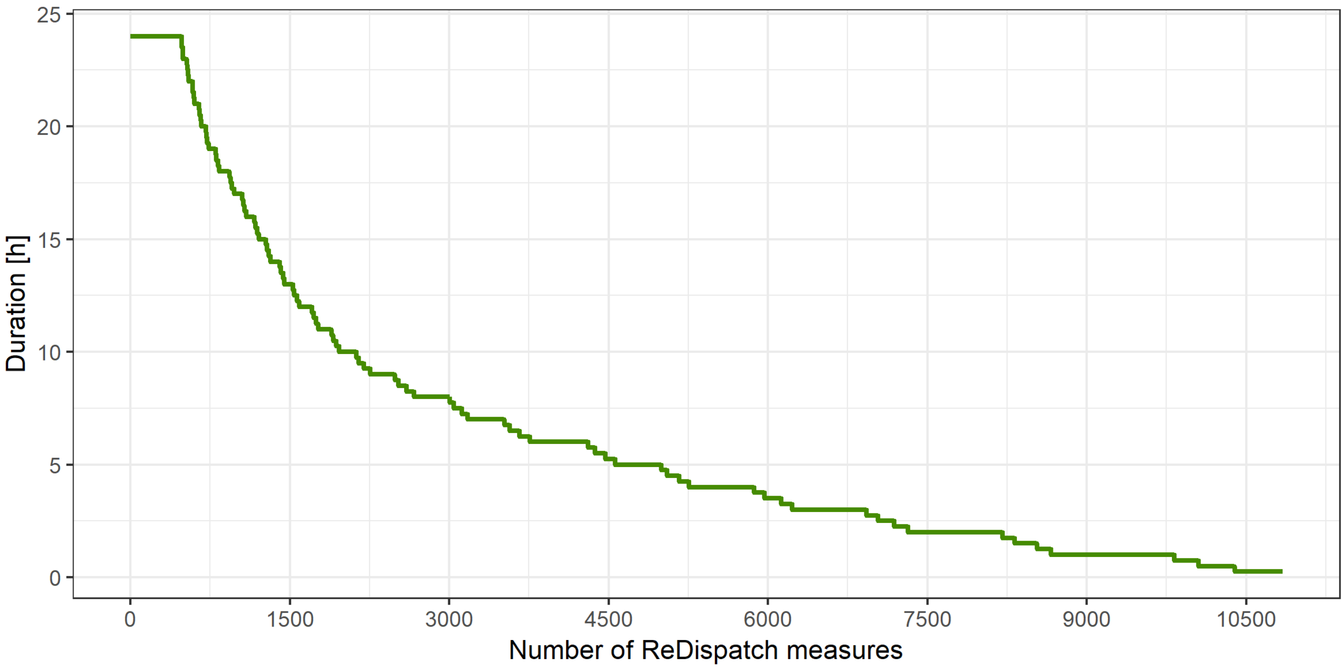

FIGURE 6-1: SORTED DURATION OF REDISPATCH MEASURES IN GERMANY IN 2018 AND 2019 (SOURCE: NETZTRANSPARENZ.DE)

The graph shows that 1500 redispatch measures have been observed that took 12.5 hours or longer. In total, more than 10500 individual redispatch measures have been observed.

Figure 6-2 depicts the maximum and average power of these single flexibility activations.

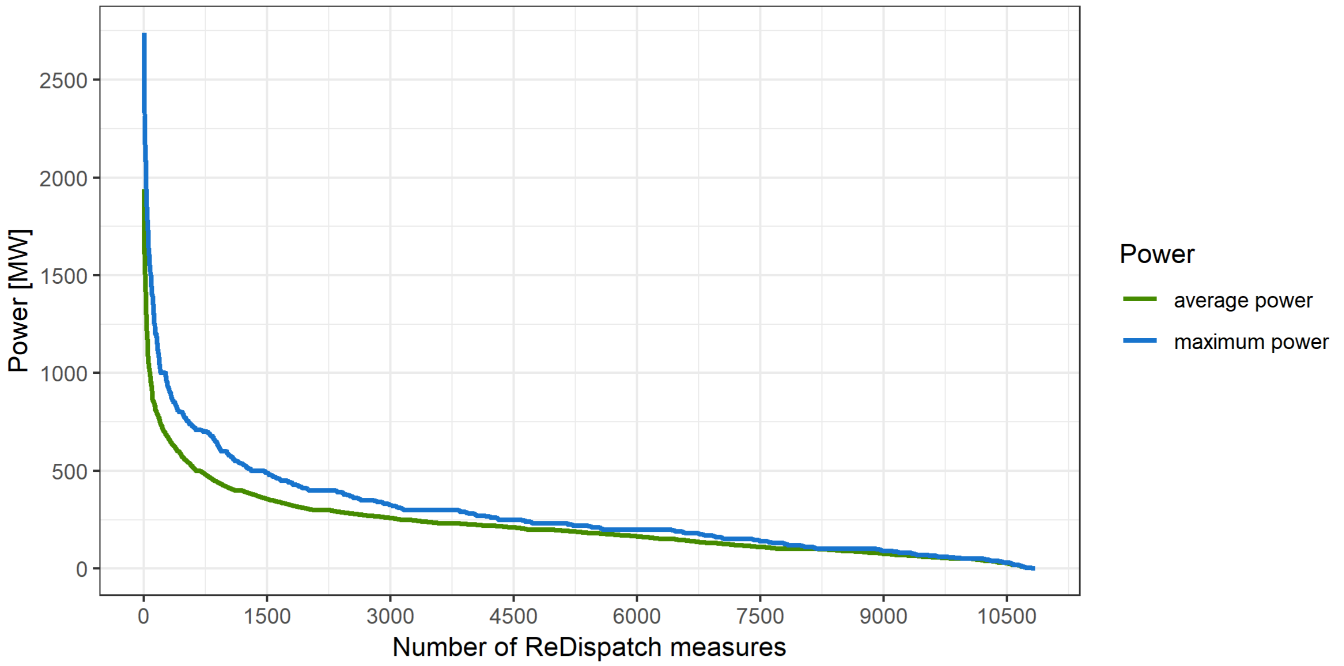

FIGURE 6-2: SORTED MAXIMUM AND AVERAGE POWER OF REDISPATCH MEASURES IN GERMANY IN 2018 AND 2019 (SOURCE: NETZTRANSPARENZ.DE (SOURCE: SMARD.DE)

Figure 6-3 presents a histogram of the duration and size of mFRR activations for Germany for the years 2018 and 2019. The left-handed side of the figure shows the results for mFRR up while the right-handed side shows the results for mFRR down.

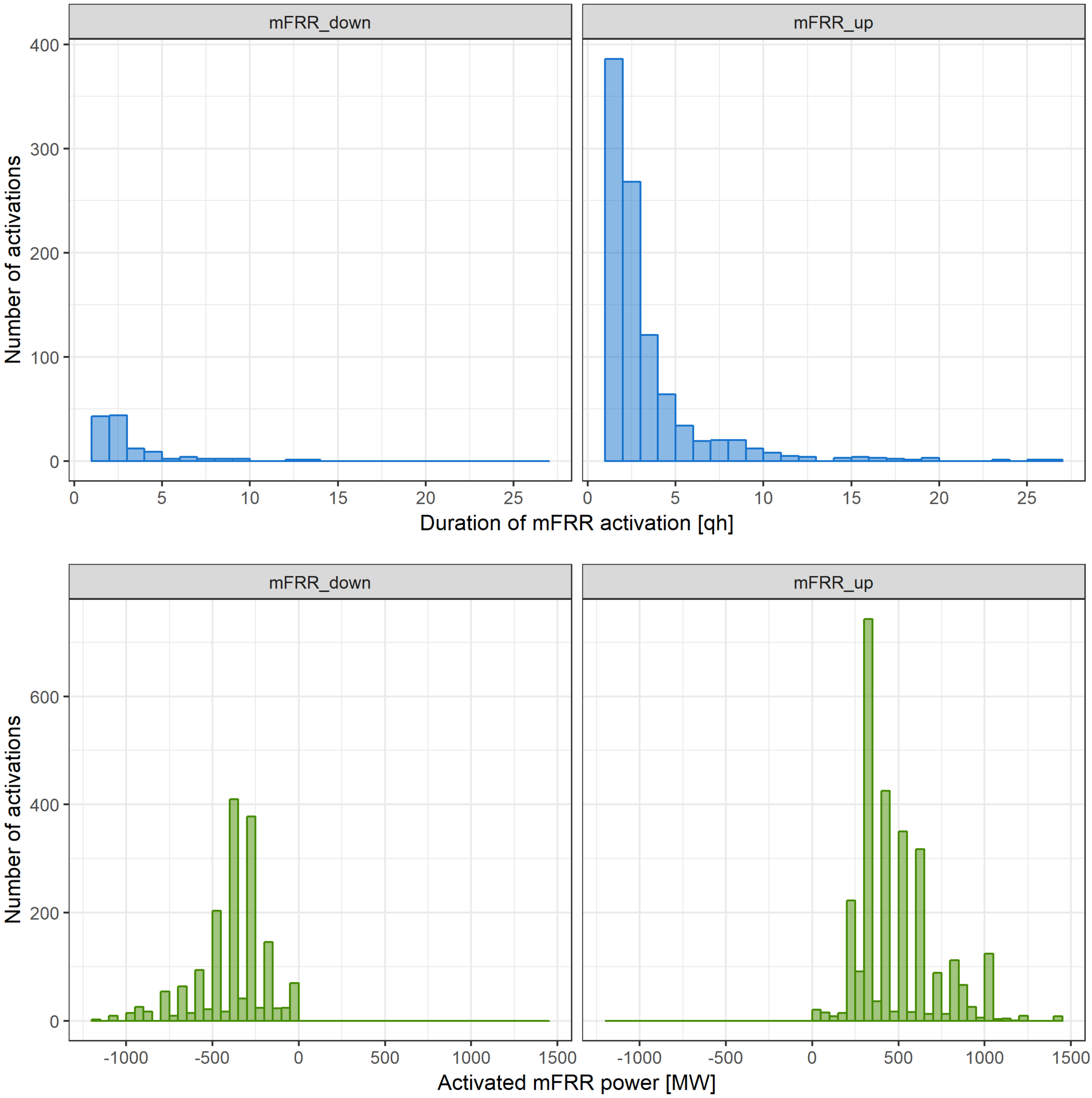

FIGURE 6-3: HISTOGRAM OF THE DURATION OF mFRR ACTIVATION (UPPER FIGURE, IN QUARTER-HOURS) AND ACTIVATED mFRR VOLUME (LOWER FIGURE) IN GERMANY FOR THE YEARS 2018 AND 2019 (SOURCE: BUNDESNETZAGENTUR'S ELECTRICITY MARKET INFORMATION PLATFORM, WWW.SMARD.DE)

The figure clearly shows that, in 2018 and 2019, mFRR up was activated more frequently than mFRR down and that most activations took place over a period of one quarter-hour to one hour.

If we compare this activation duration with the duration of congestion management (
Figure 6-1), we see that congestion management is activated for periods beyond one quarter hour in 96% of the cases and beyond one hour in 80% of the cases. The duration of activation for both products hence differs

significantly in this particular case. Additionally, the size of activated volumes differs in most times: Where the maximum mFRR activations of all resources within a single time interval did not exceed 355 MW (average: 110 MW), single redispatch FSP activations did not exceed 2.740 MW (average: 216 MW). The aggregation of redispatch measures for each time interval would lead to even higher differences. It is also important to note that the activation of CM and balancing must fall in the same timeslot and at the same location to be able to create synergies.

France

Besides the product differences between CM and mFRR, differences for a same product between countries exist as well. For instance, we could compare the German case with the French one. First of all, with regard to CM, France is currently facing very few congestion issues so there is no data available. Secondly, with regard to mFRR, **Error! Reference source not found.** shows the same histogram for mFRR duration and activated volume but this time applied to France.

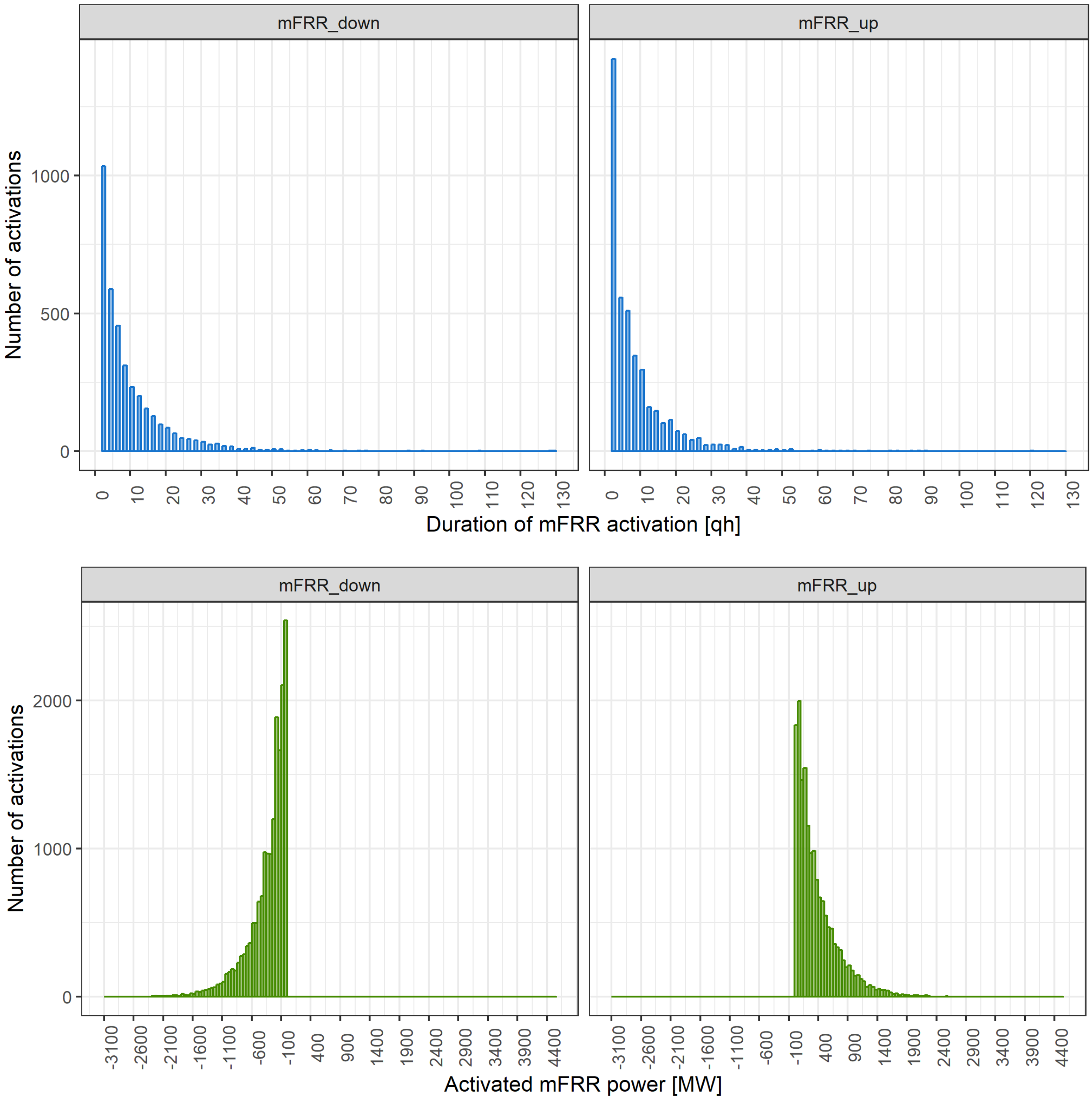

FIGURE 6-4: HISTOGRAM OF THE DURATION OF mFRR ACTIVATION (UPPER FIGURE, IN QUARTER-HOURS) AND ACTIVATED mFRR VOLUME (LOWER FIGURE) IN FRANCE FOR THE YEARS 2018 AND 2019 (SOURCE: ENTSO-E TRANSPARENCY PLATFORM, HTTPS://TRANSPARENCY.ENTSOE.EU/)

Comparison

Compared[69] to German mFRR data, in France the number of activations is much higher. Moreover, while the bulk of activated volumes is situated within the same range, i.e., between 0 and 250 MWh, the range of activations is larger for France, i.e., up to 2270 MWh for mFRR up and -1537 MWh for mFRR down, as compared to Germany, i.e., up to 355 MWh for mFRR up and -300 MWh for mFRR down.

It must be noted that, in France, mFRR is activated for a period of 30 minutes (settlement period) instead of 15 minutes as in Germany. Additionally, intraday trading closes in France 30 minutes before delivery, whereas in Germany trading across the four TSO control zones is possible up to 15 minutes before delivery and trading within one control zone is possible until real time. However, also other factors can influence the balancing needs, such as the reliability of generators or the forecasting error of generation and demand and the operational practices of the TSOs.

The country cases of Germany and France reveal different motivations of joint procurement. In Germany, the motivation could lie in the creation of synergies between the use of balancing energy and congestion management based on joint optimisation (see also Section 6.4). In France, joint procurement allows the use of mFRR bids for the few cases where congestions exist.

6.3 PRODUCT DESIGN

In this section, we first analyse which kind of mFRR and CM products could be aligned and what is the purpose of such alignment. Afterwards, the characteristics and attributes of a joint energy product are described. Capacity and energy products

Task 3.1 of the EU-SysFlex identified three potential CM products (EU-SysFlex Project, 2018b, p. 55):

- Long-term product: A capacity and energy product with a long lead time for dealing with regular or permanent congestion. It is used to mitigate structural congestion, relied upon as part of the planning process, or used as an alternative to network upgrades caused by changes in demand levels, increased RES penetration.
- Slow product: A capacity and/or energy product for dealing with predictable congestion. It is used to deal with congestions caused by high-levels of variable renewable generation output, to minimise curtailment.
- Fast product: A capacity and/or energy CM product. It is used to mitigate congestions that are caused by faults and associated remedial actions.

These three generic products have been proposed for congestion management; in addition, the Electricity Balancing Guideline and the Clean Energy Package enforce characteristics for mFRR products. Table 6-2 shows how the three potential CM products can be aligned with mFRR products and highlights potential synergies.

[69] To allow for comparison with German data, half-hours were converted into quarter-hours. Moreover, the discrepancy between number of activations in function of the duration and number of activations in function of the activated volume can be explained by the fact that activations can last for more than half an hour but also can have different volumes for each of those half hours. Therefore, every change in activated volume is counted as a separate instance while the total duration of the overall activation is counted as only one instance.

TABLE 6-2: DIMENSIONS OF mFRR AND CM

CM products	mFRR products
Capacity procured in the long term (annual or more)	
Capacity procured in the medium term (monthly, weekly)	
Capacity and/or energy procured in D-1	Capacity procured in D-1 ➔ *No standard defined in network codes nor CEP*
Energy procured near real time ➔ *Product delivery of 15 min to several hours*	Energy procured T-15 min before real time ➔ *Product definition and timeframe for procurement defined by all TSO for implementation of platform MARI.*[70]

The Clean Energy Package imposes the procurement of frequency capacity products in the day-ahead timeframe. Consequently, there cannot be a common procurement for products procured in a longer timeframe.

Energy procured near real time:

Table 6-2 indicates that energy product procured near real-time to manage congestions, even if delivery duration is not standard and could even last for several hours, could match with the energy product for mFRR, which is precisely defined by ENTSO-E for the implementation of the MARI platform. Synergies can be found as the activation of a flexibility can solve a congestion and meet the balancing need. It must be noted that the procurement of a mFRR energy product means the detection of a necessity for balancing action and thus energy activation to solve the issue.

Capacity product procured in day-ahead timeframe:

For congestion management, D-1 capacity products are used by SOs to ensure congestions could be solved if they appear. In the case of mFRR, D-1 capacity products are used by TSOs to ensure that they will always have sufficient bids to balance the system. Since synergies can be found in the joint optimisation of energy products for CM and mFRR, joint procurement of capacity products makes sense for the expected volume where synergies in energy can be leveraged. This joint procurement will translate into reduction of total amount of capacity procured for the two scarcities, congestions and imbalances. In the following, solely the joint procurement of the energy product will be considered, as being the basis for potential further synergies for the procurement of capacity products.

[70] The platform MARI is currently defined by all participating TSO (following System Operation Guideline requirements) to allow a cross-border optimisation of mFRR energy bids following the Electricity Balancing Guideline requirements.

Characteristics of the energy product

First, it can be noted that the mFRR energy product characteristics are precisely defined in the MARI[71] implementation framework (ACER, 2020), whereas the product characteristics for congestion management are defined on national level.

The mFRR energy standard product is detailed in Figure 6-5. Basically, the product is a block of 15 min energy delivery, but the preferred delivery shape is a trapezium beginning 5 min before T0 and ending 5 min after real time. In the following, the mFRR energy product will be simplified as a rectangular-shaped bloc of 15 min delivery.

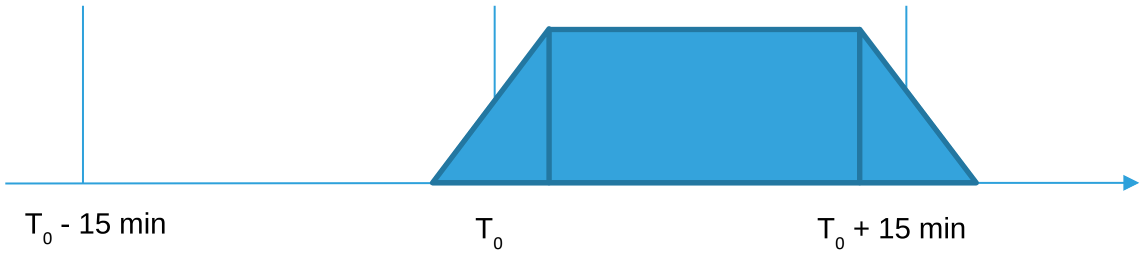

FIGURE 6-5: mFRR ENERGY STANDARD PRODUCT DEFINED BY ENTSOE

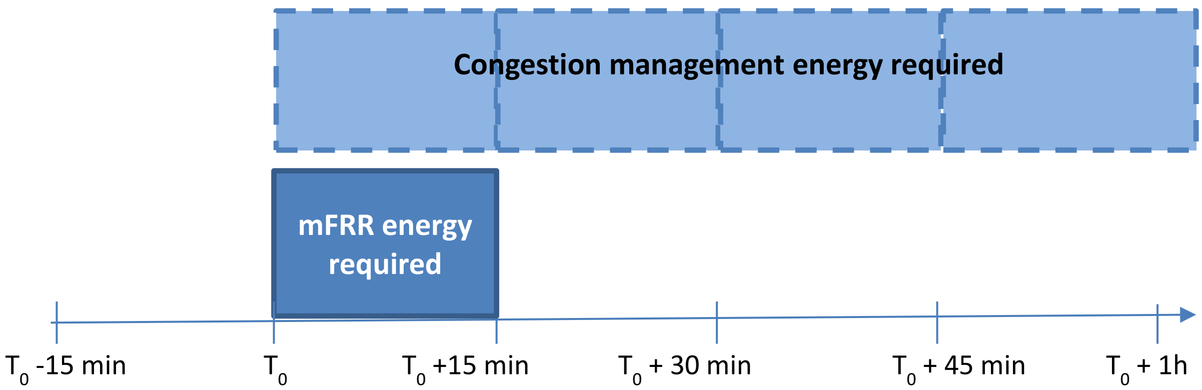

FIGURE 6-6: ENERGY REQUIRED FOR CONGESTION MANAGEMENT AS A COMBINATION OF mFRR ENERGY STANDARD PRODUCT

Therefore, mFRR energy product procured every 15 min for a 15 min delivery duration could be combined with the procurement of energy for congestion management.

mFRR energy product procurement has also been precisely defined by ENTSO-E in order to put in place the platform MARI where all TSOs participating could place bids from their FSPs and require activation to suit their needs. This standard process is described in Figure 6-8, where the word **clearing** is used to depict the result of the precedent optimisation as shown in Figure 6-7.

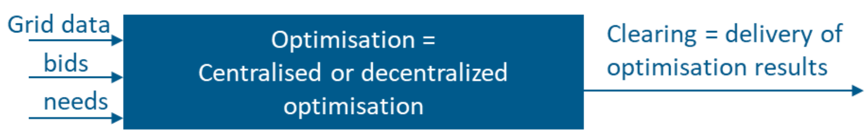

FIGURE 6-7: DEFINITION OF OPTIMISATION AND CLEARING

[71] Defined in the glossary

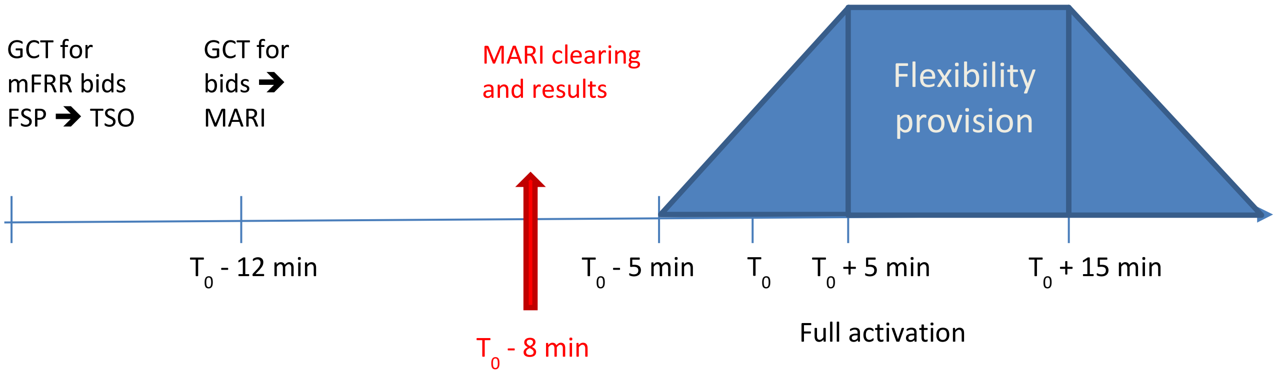

FIGURE 6-8: mFRR ENERGY PRODUCT PROCUREMENT PROCESS DEFINED BY ENTSO-E FOR MARI PLATFORM

One consequence of this process is that the FAT is equal to 12.5 minutes (see Figure 6-8 – maximum delivery must be reached at TO + 5 min), excluding all assets with long preparation time or longer FAT. Regarding congestion management, there are no predefined products on European level. However, from a technical point of view, differences exist:

- The longer duration of the scarcity (see Section 6.2) and its locational character make it necessary to include rebound effects in the product design. Such rebound effects occur if flexibilities shift their behaviour in time. If the shifting occurs within the congestion timeframe, the problem is shifted to another point of time, which has to be considered by the buyers.
- Since most congestions[72] are more predictable than imbalances, the flexibilities can be selected earlier[73] so that flexibilities with longer activation and preparation times can be used that would fail to meet mFRR requirements otherwise.

Taking into account these differences, an alignment means that the most severe characteristics must be chosen to comply with both needs and rules:

Consequently:

- Flexibilities with long preparation times would be excluded.
- Flexibilities with long FAT would be excluded or their participation will be limited.

Therefore, the alignment of product characteristics will imply a decrease of liquidity and consequently of the efficiency. However, alignment is a prerequisite for joint optimisation and therefore for creating synergies in the sense that less flexibilities are needed. For congestion management purposes, the following attributes must be added to the mFRR product attributes (either in the prequalification phase – if static – or the procurement phase):

- Location
- Maximum forward/backward shifting time to take into account the rebound effect in the optimisation process (see Section 4.1.1).

[72] E.g. there is a scheduled Day-Ahead Congestion Forecast (DACF), on which basis many measures are planned.

6.4 PROCESS DESIGN

The focus of this section is the description and analysis of possible processes of joint procurement of mFRR and CM. Therefore, timeframe considerations are explained before the different versions of creating synergies are introduced. Afterwards, for the most integrated version of joint procurement, joint optimisation, the process and conditions of creating synergies is explained in more detail. For a country case, the maximum economic potential is derived. The influence on the different phases (prequalification, procurement, activation and settlement) is analysed. The section closes with the comparison of the different versions of joint procurement compared to separate procurement.

6.4.1 TIMEFRAME CONSIDERATIONS

The following temporal constraints must be considered when designing the joint procurement process:

- EU rules:
  As explained, in Section **Characteristics of the energy product**, CEP and Balancing guidelines will impose harmonised rules for energy procurement[74].
- TSO/DSO coordination constraints:
  When defining the timeframe for joint procurement, it should be checked whether the envisioned timeframe fits with existing operational processes at the level of coordination and with European mFRR procurement rules.
  If procurement processes move close to real-time, the coordination should be able to follow. The EU-SysFlex partners from SO-entities believe that at least 30 min are necessary to coordinate among and between TSOs and DSOs to run grid assessments and select the most efficient measures[75].
- FSPs constraints:
  Another aspect to consider, apart from the time needed for coordination between the different SOs and between SOs and FSPs, is the time needed for technologies to be able to participate in the joint market. When designing product and their respective timeframes for procurement, the choice should consider different sources of flexibility have different preparation times and, hence, might not be able to participate in all markets. For instance, if the GCT for CM approaches real-time, some generators will not be able to participate in the market anymore due to their start-up times. Load or storage flexibilities with rebound effects could also need preparation time, e.g. to charge or discharge their (electrical/heat/ product) storages. On the contrary, some FSPs can only participate if the GCT is close to real-time, since otherwise they cannot forecast their behaviour and flexibility potential.

[74] Electricity Regulation (2019), Article 6: "Market participants shall be allowed to bid as close to real time as possible, and balancing energy gate closure times shall not be before the intraday cross-zonal gate closure time."
Electricity Balancing Guideline (2017/2195): articles 20 (implementation of a cross border platform), 24 (Balancing Energy gate closure time rules) and 25 (requirements for standard products)
[75] Drivers for a longer duration could be existing secondary DSOs in some countries and congestions in LV and MV due to electrification of transport and heat, which would make more coordination across voltage levels necessary. In case of centralised optimisation, this coordination is integrated in the algorithm. No assessment has been possible which optimisation approach is faster.

- SO operational constraints:
  Apart from using flexibilities, system operators can also undertake switching measures to solve congestions. Both options must be considered in one optimisation (see Section 5.1). If switching measures lead to topology changes affecting planned maintenance measures, such changes must be planned e.g. day-ahead to efficiently deploy maintenance staff for other maintenance activities. Therefore, shifting the optimisation closer to real-time leads to the exclusion of such switching measures in the optimisation (i.e. efficient selection of combination of energy bids and switching measures) and therefore has a reducing effect on its efficiency.

6.4.2 PROCESS DESCRIPTION FOR DIFFERENT LEVELS OF SYNERGIES

As mentioned in introduction of Section 6.4, several levels of synergies for joint procurement to solve imbalances and congestions can be described, from basic one with coordinated optimisation of the scarcities to a more integrated with a joint optimisation. All processes are designed to be compliant with MARI platform rules.

The first basic level of joint procurement process would be to have a procurement of a single product for both DSO's and TSO's CM needs, and then procurement of the same type of products for mFRR needs by and for the TSO taking into account the energy activated by TSO and DSO for congestion management purpose. A more integrated version of joint procurement would be to have joint optimisation of energy for managing congestions for both TSO and DSO, as well as to serve TSO mFRR needs, based on the same pool of bids.

The different versions are described below (with associated timelines)

<u>Version 1: coordinated optimisations via connected bidding</u>

The timeline for the basic level of joint procurement will be called Version 1 (coordinated optimisations via connected bidding), can be defined as follows:

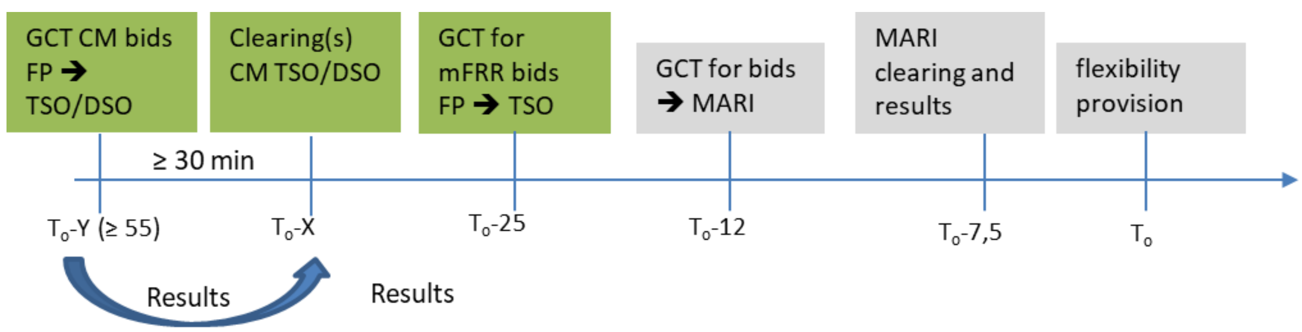

FIGURE 6-9: TIMELINE FOR JOINT PROCUREMENT OF CM AND mFRR ENERGY PRODUCTS – VERSION 1 (COORDINATED OPTIMISATION VIA CONNECTED BIDDING)

As described in the Figure 6-9 above, for an activation of mFRR and CM energy at T0 for a 15 min period, the standard process for procurement of mFRR energy through platform MARI imposes a Gate Closure Time (GCT) for FSPs to provide their bids to their connecting TSO about 25 minutes before T0. This deadline imposes that FSPs have received the results of clearing(s) for DSO and TSO procurement for congestion management energy bids so that they can consider the remaining flexibility available for mFRR energy bids.

In version 1 of joint procurement, the procurement of mFRR and CM energy products is based on a coordinated optimisation, since results of clearing(s) for CM activation can be used by FSPs to update their bids for mFRR as well as by the TSOs to send their mFRR needs. If wished by the FSP, it might also be possible to automatically transfer the remaining bids from the CM clearing to the mFRR balancing bidding process.

Based on the current knowledge of time requirements for SO coordination, the GCT for congestion management, must be at least 55 minutes before delivery to be able to transfer the remaining bids to the mFRR balancing bidding process.

If new congestion appears that must be solved before the delivery timeframe of the next CM clearing, one option could be that SOs use mFRR bids for that purpose. Nevertheless, it is likely that this situation would fall within the scope of emergency under which specific remedial actions could apply.

Note that in this version and in version 2 (below), the bid selection for balancing purpose is carried out by MARI platform (with the assumption that mFRR and CM markets only deal with a standard product, compliant with MARI rules, to simplify the process description.

<u>Version 2: coordinated optimisation via joint bidding</u>

An intermediate version of joint procurement, called version 2, would be that there is only one GCT for mFRR and CM bids for FSPs but still the procurement of mFRR energy product by TSOs would take into account the energy activated by TSOs and DSOs for CM in the precedent CM optimisation process.

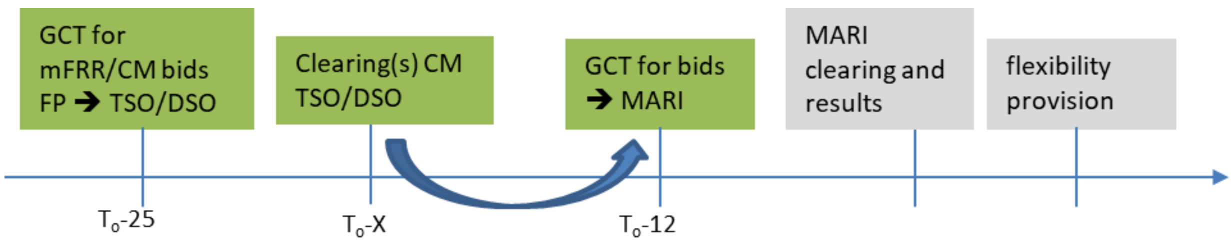

FIGURE 6-10: TIMELINE FOR JOINT PROCUREMENT OF CM AND mFRR ENERGY PRODUCTS – VERSION 2 (COORDINATED OPTIMISATION VIA JOINT BIDDING)

As described in Figure 6-10 above, results of clearing(s) for CM products procurement by TSO and DSO shall be published before T0-12 minutes to be taken into account by all TSO when forwarding their mFRR energy needs to the platform MARI.

Since the SO congestion management optimisation and coordination takes about 30 minutes, the timeframe of 13 minutes between the GCT for FSPs and the MARI GCT for TSO (send bids to MARI) is currently not sufficient.

Version 3: joint bidding and joint optimisation

Last, a more integrated version of joint procurement would be to have a simultaneous procurement of CM and mFRR energy products, based on the same pool of bids, as defined in Figure 6-11 below.
There are 2 options to carry out this optimisation:

- The MARI algorithm is modified to solve mFRR and CM constraints in a cross-border optimisation
- As it seems difficult to change MARI's perimeter within the next years and because this task did not study cross-border procurement, the other solution is to have a first optimisation at national level, followed by the MARI process: The national optimisation will select bids for congestion management under consideration of the imbalance needs (creating synergies) and calculate the remaining mFRR needs, which are sent together with the remaining bids to MARI.

For this reason, it was decided to describe the second option.

As for Version 2, there is only one GCT for FSP to provide bids to TSO and DSO for both mFRR and CM products at T0-25 minutes (as imposed by MARI platform process) but there is also one optimisation to allocate bids for TSO CM energy needs, DSO CM energy needs and TSO mFRR energy needs. Such optimisation must take place in the timeframe between the GCT for FSP to provide bids and GCT to send remaining bids and needs to MARI. Therefore, as for version 2, the time restrictions, from a current perspective, do not allow sufficient time for SO coordination and optimisation.

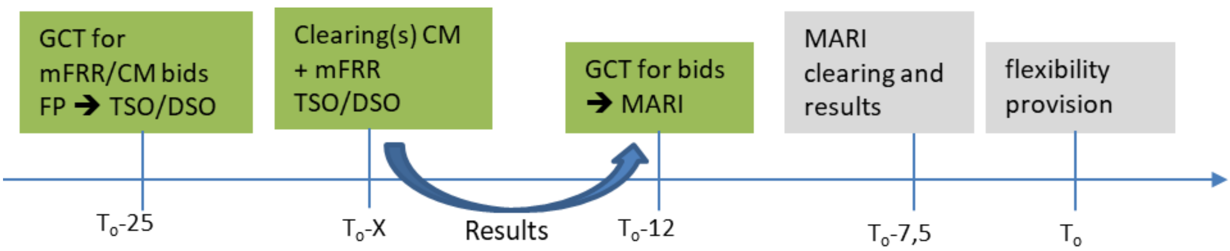

FIGURE 6-11: TIMELINE FOR JOINT PROCUREMENT OF CM AND mFRR ENERGY PRODUCTS – VERSION 3 (JOINT BIDDING AND JOINT OPTIMISATION)

6.4.3 METHODOLOGY FOR CREATING SYNERGIES DURING JOINT OPTIMISATION

The joint optimisation of energy bids for mFRR and congestion management (see Version 3) can lead to synergies compared to the separate procurement, which is explained above.

In Figure 6-12, the separate procurement of mFRR and congestion management as base case is depicted: due to a congestion between an importing zone with high demand ("load pocket") and an exporting zone flexible generation[76] must be reduced in the exporting zone and increased in the load pocket. Therefore, those FSPs with the lowest costs inside and outside the load pocket, which are prequalified for congestion management, get selected. This selection is done in a separate process from the mFRR bid selection process and can be carried out day-ahead or as close to real time as possible under the consideration of the preparation and activation times of the FSPs and the coordination time of the system operators. Therefore, in this case, FSP 1 and FSP 3 are selected to deliver 1 GW of downward/upward congestion management flexibility. Due to an additional sudden demand reduction by 1 GW an imbalance is created in the system which can be solved with FSPs being prequalified for mFRR. FSP 1, which already reduces its generation by 1 GW for congestion management, is the cheapest mFRR bid and its selection would not cause new congestions. Therefore, it reduces its generation by another 1 GW to solve the imbalance.

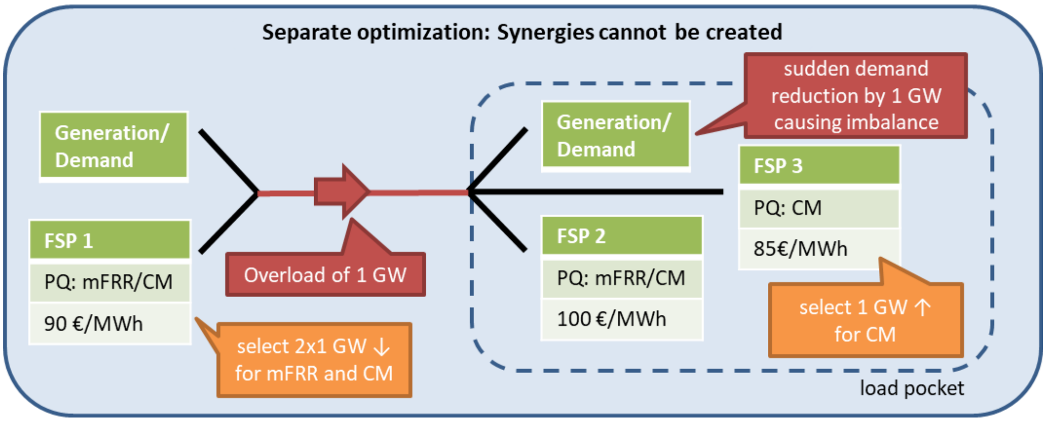

FIGURE 6-12: SEPARATE OPTIMISATION OF mFRR AND CONGESTION MANAGEMENT

Figure 6-13 shows the synergy potential in case of joint optimisation of mFRR and congestion management for the same appearing volume of scarcities. In this case, FSPs can only be selected which are fast enough to solve both the imbalance and congestion problem. For this reason, only FSP 1 and FSP 2 can be selected. Due to the sudden demand reduction inside the load pocket by 1 GW and the congestion also of 1 GW, FSP 1 – being located outside the load pocket and being the cheapest FSP for mFRR – can solve both problems at once by reducing its generation by 1 GW. The ramping up of FSP 2 is not needed, because the demand reduction takes place inside the load pocket.

[76] For simplicity reasons, only generation flexibility is used in this example. The example can be fully transferred to demand flexibility as well, which would not change the results.

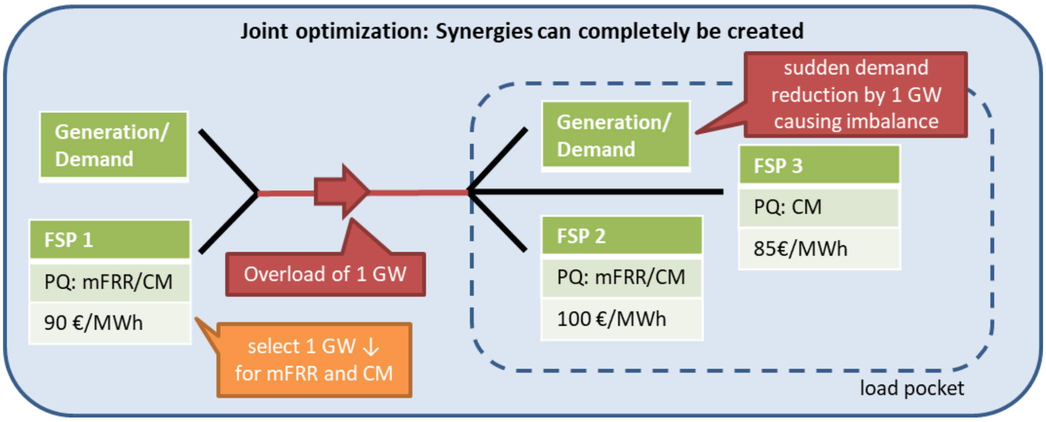

FIGURE 6-13: JOINT OPTIMISATION OF mFRR AND CONGESTION MANAGEMENT WITH LEVERAGING OF ALL SYNERGIES

Figure 6-14 illustrates a case when the synergies cannot be created despite the joint optimisation, so that in the end the flexibilities are used in the same way as done in case of separate optimisation. The prerequisite for this case is that the sudden demand reduction causing an imbalance is now situated outside the load pocket. Since the joint optimisation takes place in a timeframe, where FSP 3 cannot provide flexibility anymore in sufficient time, only FSP 2 can be ramped up. In addition, FSP 1 needs to be ramped down by 1 GW for congestion management and another 1 GW for solving the imbalance. If there were a cheaper FSP inside the load pocket for mFRR, it could not be used, because otherwise it would aggravate the congestion. The assumption is that joint optimisation would lead to the omission of margins for mFRR, since no congestion management process is needed ahead of the balancing process to allow the delivery of mFRR. Instead, the joint optimisation takes into account the constraints of the grids and all bids are in line with mFRR characteristics so that no earlier selection is necessary.

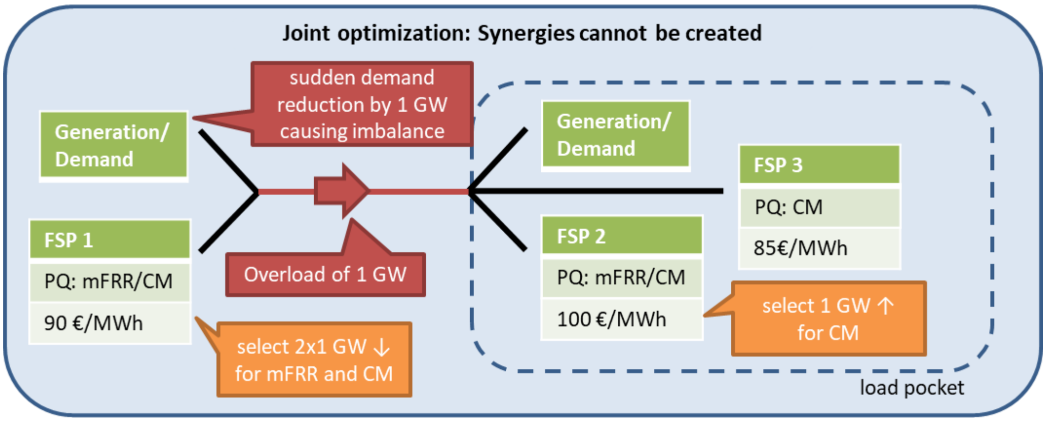

FIGURE 6-14: JOINT OPTIMISATION OF mFRR AND CONGESTION MANAGEMENT WITHOUT LEVERAGING OF SYNERGIES

Table 6-3 summarizes the theoretical cost differences of the described examples in the figures above. Note that prices for the bids are only examples and do not relate to any statistical figures. However, the German case study shows an example of maximum cost savings under the assumption of perfect foresight, being an upper boundary for the economic synergy potential of joint optimisation.

TABLE 6-3: THEORETICAL EXAMPLE OF COST REDUCTION DUE TO JOINT OPTIMISATION OF mFRR AND CONGESTION MANAGEMENT IN CASE OF FULL CREATION OF SYNERGIES

	Separate optimisation / joint optimisation: no synergies created	Joint optimisation: synergies created
FSP 1	Congestion Management: 1 GW x 90 €/MWh = 90,000 € Balancing: 1 GW x 90 €/MWh = 90,000 €	1 GW x 90 €/MWh = 90,000 €
FSP 2	--	--
FSP 3	Congestion Management: 1 GW x 85 €/MWh = 85,000 €	--
Total	265,000 €	90,000 €
Saving: 175,000 €		

Figure 6-15 depicts a case, where synergies can partly be created, since now the congestion and imbalance volumes differ. The overload accounts 5 GW, whereas the imbalance caused by a sudden demand reduction inside the load pocket still accounts 1 GW. Therefore, the load pocket needs an increase in generation by 4 GW from FSP 2. Outside the load pocket, FSP 1 delivers 5 GW downward flexibility. Therefore, in total 9 GW flexibility are used instead of 11 GW in case of separate optimisation.

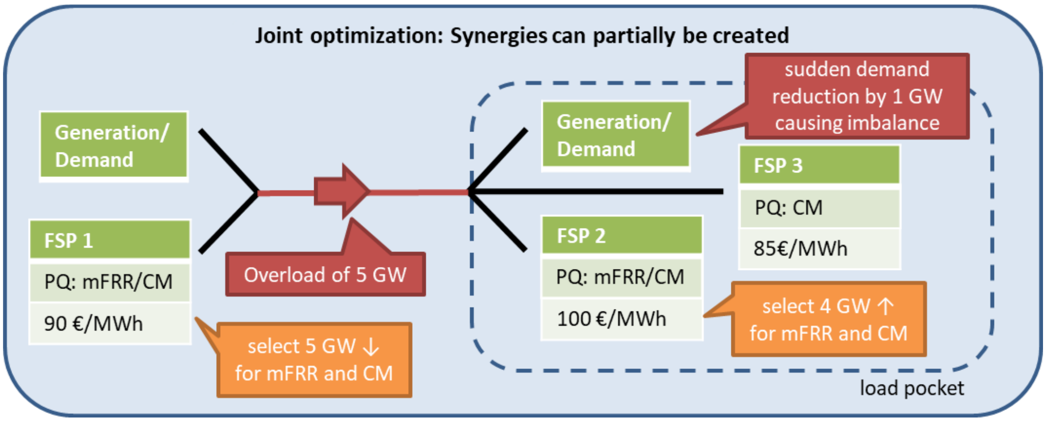

FIGURE 6-15: JOINT OPTIMISATION OF mFRR AND CONGESTION MANAGEMENT WITH PARTIAL LEVERAGING OF SYNERGIES

Table 6-4 summarizes the cost savings for the example of partial creation of synergies. In this case, the cost savings are lower than the cost savings where the full synergy potential can be reached, although the saved volume of selected flexibilities stays the same (2 GW). The reason for the decrease in savings lies in the need to use FSP 2 instead of FSP 3 for congestion management. Since joint optimisation needs to be carried out in the mFRR timeframe, FSP 3 – although it is cheaper - cannot be chosen. The assumption that FSP 3 is cheaper relies on the idea, that as a tendency bids become more expensive if further requirements, here the mFRR requirements, are imposed.

TABLE 6-4: THEORETICAL EXAMPLE OF COST REDUCTION DUE TO JOINT OPTIMISATION OF mFRR AND CONGESTION MANAGEMENT IN CASE OF PARTIAL CREATION OF SYNERGIES

	Separate optimisation	Joint optimisation – synergies partially created
FSP 1	Congestion Management: 5 GW x 90 €/MWh = 450,000 € Balancing: 1 GW x 90 €/MWh = 90,000 €	5 GW x 90 €/MWh = 450,000 €
FSP 2	--	4 GW x 100 €/MWh = 400,000 €
FSP 3	Congestion Management: 5 GW x 85 €/MWh = 425,000 €	
Total	965,000 €	850,000 €
Saving: 115,000 €		

6.4.4 COUNTRY CASE STUDIES FOR ESTIMATING THE MONETIZED BENEFIT OF JOINT OPTIMISATION

In order to estimate the potential of synergies between mFRR and congestion management for grids with a high share of volatile RES, figures of the selection of mFRR and congestion management in Germany in the year 2018 are used as an example (see Table 6-5).

TABLE 6-5: FIGURES OF THE USE OF mFRR AND CONGESTION MANAGEMENT IN GERMANY (SOURCES: NETZTRANSPARENZ.DE, SMARD.DE, GERMAN NRA MONITORING REPORT 2013 AND 2019)

mFRR in 2018		congestion management in 2018	
positive energy	127 GWh	increase generation (energy)	7,610 GWh
negative energy	64 GWh	decrease generation	7,919 GWh
		curtailment RES+CHP	5,403 GWh
Total energy	**191 GWh**	**Total energy**	**15,529 GWh**
capacity costs	6.2 mn €	costs redispatch	387.5 mn €
energy costs	27.9 mn €	costs curtailment RES+CHP	635.4 mn €
Total costs	**34.1 mn €**	**Total costs**	**1,022.9 mn €**
Specific costs energy	**146 €/MWh**	**Specific costs redispatch**	**25 €/MWh**
Specific total costs	**179 €/MWh**	**Specific costs curtailment RES+CHP**	**118 €/MWh**
Change of max. capacity volume procured 2012-2018	**-50%**	**Change of redispatch volume 2012-2018**	**+505%**

The numbers show, that due to the high differences in volume the likelihood is high, that the selection of mFRR flexibilities could be reduced by leveraging synergies between mFRR and congestion management. However, the total amount of energy flexibility volume saved in the reference year would be at maximum 2%, saving the energy for mFRR twice due to the avoidance of mFRR energy bid selection and the equivalent reduction of congestion management bids.

The maximum cost savings (best case) would therefore result in saving the energy costs of the balancing bids and the congestion management bids equally for the volume of the mFRR energy activations (see also example of Figure 6-15) under the strong hypothetical assumptions, that

- there is always an overlapping in time of mFRR and CM needs,
- CM needs (considering only down- or upward) are equal or higher to the mFRR needs,
- there is a combined approach of separate and joint optimisation, allowing to perfectly forecast the synergy potential when selecting the slower CM FSPs at an earlier point of time,

- the reduction of flexibility volume does not breach constraints.

Under these assumptions, the savings would range from 32.7 mn € (saving redispatch and mFRR energy costs) to 50.4 mn € (saving curtailment mFRR energy costs) for the year 2018. Therefore, the costs for mFRR/congestion flexibility use would be reduced at maximum by 3% to 5%. If the reduced selection of slower congestion management bids does not fit to the imbalance to leverage the synergies fully (due to missing perfect foresight in reality), additional mFRR bids will have to be used closer to real-time in order to solve remaining congestions. Since the use of such bids closer-to-real-time imposes further requirements on flexibilities causing a cost increasing effect, the cost saving effects will be reduced and can potentially also lead to higher system costs compared to separate procurement. The cost decreasing effect is also reduced, if the other assumptions cannot be fulfilled.

Despite the increase of renewable capacity from 2012 to 2018 by 50% (Source: bundesnetzagentur.de), the maximum procured capacity for mFRR in the same timeframe was reduced by -50%. In the same time, congestion management increased by 505%. Therefore, in Germany, an increasing need for leveraging synergies between mFRR and congestion management for high shares of renewable energies (2018: 36% of total net generation; Source: German NRA Monitoring Report 2019) cannot be identified based on historical data.

6.4.5 DESCRIPTION OF INTERACTION PHASES

As described in Section 4.1, the interactions between the different roles can be divided into the four phases prequalification, procurement, activation and settlement. These phases have been made more concrete in Chapter 5 in order to describe different possibilities to consider grid constraints in the bid selection process or to solve grid constraints via flexibility bids. These processes were described for the separate procurement of scarcities and independently of the product to be procured. The following section analyses how these different phases must be adapted to jointly procure an mFRR and CM energy product.

Prequalification

Joint procurement of mFRR and CM does not modify the description of prequalification phase provided in Chapter 4. However, dependant on the versions of joint procurement, prequalification criteria could be the same by design or could allow differences: allowing two GCT for mFRR and congestion management and separate optimisation steps (version 1) leads to the possibility for FSPs to offer one product for both scarcities, so that the remaining bid can be transferred from the congestion market to the balancing market. However, FSPs may also decide to place different products for congestion management and mFRR. Also, FSPs with longer preparation times may submit bids for congestion management but may not be capable of providing mFRR. The closer the alignment of mFRR and congestion management processes, the more aligned the products must be which also influences the product pre-qualification phase.

Procurement

As the MARI platform imposes strong temporal constraints, the interactions with MARI have been added to the procurement schemes. The description is provided for version 1 and version 3 described in Section 6.4.2 and for centralised and decentralised optimisation, making the procurement of an aligned energy product possible. Grid constraint assessment and coordination between SOs are included to give the comprehensive overview of all interactions to be done in the limited time. Only interactions in the case of optimisation with comprehensive grid data are presented (reducing the number of interactions and being the most efficient solution). The different diagrams are placed in the ANNEX VIII, based on the generic diagrams presented in Sections 4.1 and 5.2, adding additional information such as the timeline and interactions with the MARI platform.

The diagrams show that both centralised and decentralised optimisation can be designed to cope with all versions of joint procurement. This statement is inconclusive because of potential time restrictions of centralised and decentralised optimisation, since no analysis could have been undertaken on the computational performance of both optimisations, reflecting the complexity of the algorithm and the coordination needs.

Activation and settlement

There is no specificity regarding activation: both products are manually activated. Diagrams provided in Chapter 4 apply. The settlement processes differ for Version 3 (joint optimisation) since the costs of flexibility selection must be allocated to congestion management and balancing, leading to an additional step.

6.4.6 COMPARISON OF THE VERSIONS OF JOINT PROCUREMENT WITH SEPARATE PROCUREMENT

In order to evaluate the different versions of joint procurement, they shall be compared with the base case, which is the separate procurement of mFRR and congestion management.

Separate procurement means different products for mFRR and CM and independent procurement processes of mFRR and CM. Such parallel processes constitute of

- separate bidding processes,
- potentially the same GCT,
- CM procurement could be carried out in a single auction or, as it is mostly today, in a continuous trading scheme starting day-ahead with a GCT similar to mFRR (close to real-time, e.g. 30 minutes before delivery).

The analysis is divided into a qualitative assessment of the marginal cost effects on the one side and other effects (e.g. transition costs, regulatory challenges, etc.) on the other side.

Table 6-6provides an overview of the increasing and decreasing marginal cost effects of the different versions. A common decreasing cost effect is based on the possibility for FSPs to place their bids only once both for CM and balancing purposes. Therefore, there is an effort reducing effect for FSPs, and those FSPs which can provide both services are available to solve both scarcities so that this leads to a liquidity increasing effect which can also reduce costs. In case of connected bidding phases (version 1), the latter is based on the will of FSPs to bid already in the first bidding phase. In case of joint optimisation (version 3), the creation of synergies also decreases costs.

Another aspect in case of forced joint bidding (version 2 and 3) is that there is a reduced likelihood that, agents know beforehand how offers will be allocated between the two scarcities so that there will be fewer possibilities for strategic behaviour (Roos, 2017).

Two cost increasing effects refers to the exclusion of FSPs due to stricter bidding requirements. In version 2 and version 3 the joint GCT and consequently the following selection of bids closer to real-time leads to the exclusion of those FSPs, which are not capable of providing the flexibility that quickly. On the other hand, version 1 causes the need for a GCT for CM purposes approximately 55 min before delivery, which – compared to separate procurement – leads to stronger requirements and therefore could also exclude FSPs which can only place bids 25 to 55 min before delivery due to forecasting reasons. For the same reason, aggregators might, if aggregation is allowed, set an increased risk margin upon their price.

Another cost increasing effect in versions 2 and 3 is the exclusion of those grid switching measures from optimisation (resulting in efficient combination of selection of bids and switching measures), which make the shifting of maintenance plans necessary. In addition, in version 2 and 3, aggregators normally bidding with their portfolio for balancing needs, have to break-down their portfolio to the locational needs of CM and also need to provide shifting times, if single units show relevant rebound effects. This leads to increased imposed efforts for such FSPs.

TABLE 6-6: MARGINAL COST EFFECTS OF THE DIFFERENT VERSIONS OF JOINT PROCUREMENT COMPARED TO SEPARATE PROCUREMENT OF CM AND MFRR

Marginal costs of joint procurement based on a joint product compared to separate procurement of CM and mFRR		Version 1: coordinated optimisation via connected bidding	Version 2: coordinated optimisation via joint bidding	Version 3: joint bidding and optimisation
Cost decreasing effects	Offering energy flexibilities both for mFRR and CM (one product): Liquidity increasing effect for the buyers and effort decreasing effect for FSPs	X (on voluntary basis)	X	X
	Lower flexibility volume needed due to the use of flexibility to solve both mFRR and CM			X
	Limited exposure to the risk of strategic bidding between the scarcities		X	X
Cost increasing effects	Break-down of aggregated portfolio to locational bids and – in case of rebound effects – delivery of max. shifting times lead to an increased risk margin and increased efforts for aggregators normally bidding only for mFRR		X	X
	For CM: Liquidity decreasing effect due to exclusion of FSP with preparation times non-capable for mFRR		X	X
	Exclusion of some grid flexibility potential (shifting grid maintenance measures to allow topology switching) in the optimisation of CM measures		X	X
	For CM: Exclusion of FSPs which can only place bids in the timeframe of 25-55 min before delivery or increased risk margin in case of (allowed) aggregation	X		

The impact of the cost increasing and decreasing effects, especially with regard to liquidity effects, highly depends on the national situation (costs of mFRR and CM, regulated or market-based CM, volumes needed). Therefore, it is possible that in countries with high volumes of CM compared to mFRR the application of a joint bidding phase could exclude many slower FSPs so that CM measures (which can be predicted) must be solved with the fast mFRR-like bids. This effect can also increase system costs.

The following Table 6-7 identifies other challenges of the versions compared to separate procurement. Such challenges are described based on current knowledge.

TABLE 6-7: FURTHER CHALLENGES OF THE DIFFERENT VERSIONS OF JOINT PROCUREMENT COMPARED TO SEPARATE PROCUREMENT OF CM AND BALANCING

Challenges[77] of joint procurement compared to separate procurement of CM and balancing	Version 1: coordinated optimisation via connected bidding	Version 2: coordinated optimisation via joint bidding	Version 3: joint bidding and optimisation
Timeframe currently not sufficient for CM optimisation, incl. TSO/TSO - DSO/DSO coordination		X	X
No possibility to allow congestion-specific solutions (with regard to local marketplace design, product design, bidding and optimisation across several time intervals, etc.)		X	X
Higher complexity of the algorithm(s) and/or coordination between SOs			X
Cost allocation to SOs for CM and BRPs for balancing (see Electricity Regulation, Art. 13)			X
Transition costs	Depends on already implemented national solution		

As described in Section 6.4.1, the current time needs of system operators to find the most effective and efficient CM measures and coordinate among each other (cross-border and across voltage levels), takes at least 30 min, so that the versions which require an optimisation after mFRR GCT are not feasible from a current perspective. These versions also do not allow the possibility to design congestion-specific solutions (e.g. different product or marketplace design, bidding and optimisation across different time intervals) to cope with the heterogeneous grid situations (congestions at different voltage levels for different durations and with different levels of flexibility liquidity and flexibility characteristics) and the time-coupling constraints in case of rebound effects. For instance, a bidding across several time intervals of 15 min could allow an optimisation to select the efficient combination of flexibilities with short and long shifting times as well as no rebound effects.

[77] In this report, we analysed a joint optimisation of mFRR and CM on national basis – as mentioned in Section 6.4.2, there could be also a cross-border process (like for mFRR). In that case, transition costs to adapt MARI platform should be added to the table.

In case of joint optimisation of the scarcities, two aspects are important:

(i) The requirements towards a centralised optimisation or decentralised optimisations are a lot higher to enable the joint optimisation of scarcities compared to separate or coordinated optimisation of such scarcities. The short timeframe of approx. 10 minutes for the computation of such a detailed optimisation poses significant challenges.

(ii) The use of flexibilities to jointly solve imbalances and congestions poses a challenge regarding the requirement of Article 13 of the Electricity Regulation, which defines that balancing energy bids used for redispatching shall not set the balancing energy price. Thus, it is necessary to design a process of calculating imbalance prices which exclude the effect for congestion management purposes (including redispatching). Ideally, this process should be automatic (algorithm) to avoid any subjective selection.

Furthermore, there are various transition costs at national and European level for adapting regulation and developing as well as implementing the new processes. The extent of the national transition costs depends on the solutions which are already implemented in the different countries. At European level, an adaptation of MARI processes might be necessary as well as of European law and network codes.

Overall, our discussion shows that the more integrated joint procurement becomes, the more challenges arise in order to reach the mentioned cost decreasing effects.

6.5 CONCLUSION

This chapter dealt with different facets of joint procurement and focused in depth on the different possibilities for the joint procurement of one aligned product to solve two scarcities: imbalances to the extent of requiring mFRR flexibility, and congestion management. The analysis of the joint procurement appeared relevant due to the similar characteristics of both needs and ongoing discussions under the framework of so called “active system management” and “TSO/DSO cooperation”.

Country studies for France and Germany revealed different situations of mFRR and CM needs. In countries with few congestions but higher imbalances, mFRR bids might be used to solve congestions, avoiding separate CM processes. Where congestion volumes are a lot higher, there is a certain likelihood that in total less flexibility might be needed if both needs are optimised jointly. For both use cases, a joint energy product[78] might be developed, whose characteristics and attributes must be able to solve both needs. The joint energy product must comply with the required maximum preparation and activation times of mFRR bids. For CM, it must contain as much locational information as needed and describe its rebound behaviour.
Following the product design, also three different versions of CM and mFRR processes were developed, with different levels of integration:

[78] The development of a capacity product would base on such joint energy product. This was not in the scope of this chapter.

The first version describes a coordinated optimisation via connected bidding phases, where the CM processes ends before the mFRR process starts. Results of the CM are transferred to the mFRR process and FSPs can decide to let their bids of the first phase be automatically transferred to the second phase. An intermediate second version includes a joint bidding phase, but also a coordinated, stepwise optimisation starting with CM first. The third version incorporates a joint bidding phase and a joint optimisation, resulting in the possibility to create synergies across the two scarcities leading to a reduced volume of needed flexibilities. This effect is only possible to the extent of overlapping volume and differing direction of balancing and one-sided (e.g. up- or downward) congestion needs and only if such reduction still solves the congestion.

All versions reveal different cost increasing and decreasing effects, which have been assessed in a qualitative manner. One common benefit for FSPs is the possibility to place bids only once for mFRR and CM, leading to reduced transaction costs and an increasing liquidity for both scarcities, leading also to reduced costs. However, liquidity can also decrease in the different versions compared to separate procurement, either because the GCT for CM is moved forward (version 1), or because of the joint GCT for CM and mFRR (version 2 and 3), leading to the exclusion of FSPs with longer preparation and activation times in contrast to the case of separate procurement. However, such joint bidding could decrease strategic behaviour.

Since in the versions 2 and 3 the optimisation must take place after the joint gate closure, SOs cannot include certain grid flexibility potential in the optimisation (shifting maintenance measures to allow topology switching), leading to a reduced efficiency of the optimisation. Another effect of the joint gate closure time is the break-down of the portfolio of mFRR aggregators to the locational granularity and the inclusion of the description of potential rebound behaviour, both needed for CM and leading to an increased risk margin and higher efforts.

Challenges also arise in case of a joint bidding phase: First, the timeframe for SO coordination, especially to find the most efficient CM measures and to check the feasibility of flexibility activations, is currently too short. In case of joint optimisation, timing is even stricter. Secondly, these versions do not allow local congestion-specific solutions to cope with the heterogeneous grid situations.

Joint optimisation reveals further challenges. The algorithm and/or the coordination between SOs is much more complex. Since FSPs are selected to solve both balancing and congestion problems, it is difficult to define an imbalance price independent of the CM measures, which is necessary according to Electricity Regulation, Art. 13. Additionally, the transition costs of the MARI platform and of national processes must be considered.

To conclude, mFRR and CM joint procurement of energy product is a relevant option but without quantitative analysis, it is not possible to determine whether joint procurement and which specific version is superior to separate procurement. A country-case study of Germany (year 2018) with a high potential of volume synergies has not revealed a clear net advantage of joint procurement. When considering the implementation of joint procurement, the right balance between synergies, increasing cost effects and the increase of complexity will depend on the national situation (volume of grid congestions and mFRR needs, cost structures of CM and mFRR, existing processes). If a fully integrated joint procurement of energy product is chosen, it would become relevant to implement also a joint procurement of a capacity product for the anticipated volume of synergies.

Apart from the solely unique implementation of the different versions of joint procurement, also combinations of separate and joint procurement or of different versions of joint procurement could be possible. In countries with implemented RR processes, the joint procurement of RR and CM could also be an option. However, their feasibility and consequences require further research.

7 NEXT STEPS

As demonstrated by WP2, a future generation mix with a high share of renewable energy sources will require a large-scale deployment of flexibilities. The power system will face increasing technical scarcities, a number of which already exist today. Task 3.1 highlighted several products related to generic services that would have to be largely deployed to help the power system to cope with these scarcities, namely frequency control products, congestion management products, voltage control products and inertia. If the highlighted scarcities and corresponding products to address them are to a large extent already known, and some procurement arrangements are already in place, a re-examination of the most efficient market design for the procurement of flexibility services is necessary.

Therefore, **different procurement arrangements of generic flexibility services** have been studied by Task 3.2 and **feasibility, advantages and drawbacks of different options** have been assessed:

- regulated organisation compared to a market-based organisation
- methodologies to consider grid constraints in the flexibility procurement and different possibilities of coordination between TSO and DSO
- centralised optimisation of flexibilities compared to a decentralised optimisation
- allocation of the optimisation operator (OO) role to each individual system operator or other actors
- joint procurement of services, in particular for mFRR and congestion management

But to adequately detail a market design, some additional studies would be required extending on the work of the deliverable of this task.

Quantitative studies are needed to evaluate the proposed solutions in real situations (with actual structure of TSO/DSO, regulatory framework, existing processes of optimisation …) and depending on the scarcity to be solved. The **following elements would require a more detailed quantitative assessment**:

- Efficiency gains[79]
- Investment or transition costs for the implementation of the new market design as well as operational costs for running the optimisation and the marketplace
- Temporal and computational feasibility: Can a complex centralised algorithm provide results fast enough for all voltage levels and possibly several products in case of joint procurement? Can the coordination between OOs be done fast enough in decentralised optimisation options?
- Communication costs: The number of communications channels and data exchange requirements between different actors vary depending on the choice of optimisation (centralised versus decentralised optimisation). The allocation of the OO role to system operators or other actors and the type and amount of grid data to be exchanged between actors[80].
- The question of small DSOs should be examined: small DSOs could carry out a CBA to assess whether an independent optimisation or a grouping with neighbouring DSOs (to reach a critical size) is more advantageous.

[79] EU-SysFlex Deliverable 3.4 (EU-SysFlex Project, 2020) provides quantitative results
[80] Only the communication between FSPs and market operators is independent of the described choices.

In addition, the question arises if **FSP revenues would be sufficient to ensure an appropriate deployment of flexibilities**. The following elements should be basis for a detailed CBA from the FSP's perspective:

- WP2 of the EU-SysFlex project, and in particular Task 2.1, has shown that although developing RES has a small impact on the need for conventional capacity in terms of generation adequacy, with a growing share of renewables in the system, the need for flexibility and capability to deliver specific system services increases.
- In addition, Task 2.5 on financial implications of high levels of Renewables on the European power system has demonstrated that an energy only market will not provide sufficient revenue in a high variable renewables future to cover investment costs and to ensure that there is sufficient flexibility available in the power system. As the marginal cost of energy decreases in the future, with increasing levels of renewables in the market, there will need to be a holistic view of energy market, capacity market and flexibility services revenues to ensure that the various revenue streams are aligned and that overall, appropriate investment signals are created for both new entrants offering flexible services and existing service providers which can improve their flexible behaviour.
- Task 3.4 reaches similar conclusion, when they analyse long-term investment signals provided by new ancillary services markets: the simulations demonstrate the necessity of incentivising new investments in flexible technologies through strong investment signals via stable markets for the new system services. The risks of market saturation for certain services (as FFR) are highlighted. The study concludes that relying only on marginal cost pricing may not provide sufficient certainty for investors.

The present report describes some market design solutions, e.g. the proposed long-term capacity product that can foster investment in new flexibilities if short-term markets are not able to provide these signals. **It is of great importance to properly quantify revenue streams available for all sources of flexibility** (be they conventional or renewable providers, storages or consumers), **in order to adapt market design proposals adequately.**

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ANNEX I. DESCRIPTION OF THE WORKSHOPS

FIRST WORKSHOP: 5th AND 6th OF DECEMBER 2018 IN LEUVEN

The questionnaire, available in Deliverable 3.1 (EU-SysFlex Project, 2018b), provided the basis for discussion topics and content for the WP3 workshop, which took place in Leuven in December 2018. The workshop was organised with Task 3.1 and Task 3.4, as well as WP4 for a specific session, and had the following objectives:

- Generate innovative product ideas related to system services, in link with Task 3.1 objective,
- Initiate discussions on market design options for different ancillary service products, in link with Task 3.2 objectives,
- Challenge the product and market design ideas in the context of the EU-SysFlex project,
- Discuss the interactions between Tasks 3.2 and 3.4,
- Discuss the interaction between WPs 3 and 4.

The workshop approach was built upon the concept of the 'discovery café'.

The methodology and the different working sessions are described in Deliverable 3.1 (EU-SysFlex Project, 2018b).

SECOND WORKSHOP: 21st AND 22nd OF MAY 2019 IN CHATOU

This second Workshop was organised with Task 3.4.

Based on the work done since the meeting in Leuven, the purposes of this second seminar were to:

- Discuss and validate the generic role models proposed by the Task Force
- Discuss the issues identified (see below) by the Task Force
- Define criteria to benchmark the different market organisation options
- Ensure the alignment between T3.2 and T3.4

Four working sessions took place during this seminar:

1. Validation of market and product characteristics and of the generic role models proposed for the procurement of 4 services (Inertia, mFRR/FFR, voltage control, congestion management) in the 4 selected market organisations.
2. Generic issues: coordination TSO/DSO, bid selection (SO vs MO), responsibility for flexibility's activation).
3. Criteria to assess pros and cons of the different market organisations
4. Common session with Task 3.4

During most of the working sessions, partners were divided into 4 mixed groups (DSO, TSO, academics, utilities). The first working session was prepared before the seminar: the intention was that each mixed group would review the generic role models for one of the four selected services and prepare answers to the generic issues.

THIRD WORKSHOP: 10th AND 11th OF DECEMBER 2019 IN HEVERLEE

This workshop was organised to validate the first chapters of the Deliverable 3.2 (Chapters 3 and 4) and to conclude on the approach about grid constraints management. The second day of the meeting was dedicated to joint procurement issues.

Four working sessions were organised:

1. Discussions on Chapters 3 and 4 proposals
2. Validation of the content proposed for Chapter 5 “Consideration of grid constraints for the flexibility procurement process”
3. Joint procurement: definition – principles – when does joint procurement make sense?
4. Joint procurement of congestion management and balancing services

ANNEX II. LIST OF ROLES ESTABLISHED BY TASK 3.3, WITH NEW ROLES CREATED FOR TASK 3.2

TABLE II-1: LIST OF ROLES

Roles ID	Roles name	Responsibilities
DN_FSP	Distribution Network Flexibility Provider	Provide flexibility by assets connected to the distribution network or buy flexibility in the case of distributed organisation
TN_FSP	Transmission Network Flexibility Provider	Provide flexibility by assets connected to the transmission network or buy flexibility in the case of distributed organisation
A	Aggregator	Aggregate and maximise value of portfolio(s) of resources
DS_O	Distribution System Operator	Elaborate network development plan (including defining system needs for distribution) Ensure a transparent and non-discriminatory access to the distribution network for each user Operate the distribution grid over a specific region in a secure, reliable and efficient way Optimise system operation distribution grid from planning to real-time, using available levers (grid expansion, flexibility activation,...) Assess network status of the distribution grid and broadcast selected information of the network status to eligible actors (e.g. aggregators, other system operators) Support the Transmission System Operator in carrying out its responsibilities (including load shedding) and coordinate measures if necessary
TS_O	Transmission System Operator	Elaborate network development plan (including defining system needs for transmission) Ensure a transparent and non-discriminatory access to the transmission network for each user Operate the transmission grid over a specific region in a secure, reliable and efficient way Secure and manage in real time the physical generation-consumption balance on a geographical perimeter, including ensuring the frequency control service Optimise transmission system operation from planning to real-time, using available levers (grid expansion, flexibility activation,...) Assess network status of the transmission grid and broadcast selected information of the network status to eligible actors (e.g. aggregators,

		other system operators) Provide data to the interconnection capacity market operator for the management of cross border transactions In critical situations, implement dedicated actions and deliver alerts during stress events If necessary, implement emergency measures (e.g. system defence plan) including load shedding
MO	Market Operator	Organize auctions (continuous auction, discrete auctions, call for tenders) or run order books between buyers and sellers of electricity-related products in the markets, and more generally publish the corresponding prices, for assets connected to its area, manage/operate the platform for trading (where bids and offers are collected), communicate results to the FSP and organize settlement
MO_D	Market Operator in Distribution	Organize auctions (continuous auction, discrete auctions, call for tenders) or run order books between buyers and sellers of electricity-related products in the markets, and more generally publish the corresponding prices, for assets connected to distribution grid, manage/operate the platform for trading (where bids and offers are collected), communicate results to the DN_FSP, organize settlement.
MO_T	Market Operator in Transmission	Organize auctions (continuous auction, discrete auctions, call for tenders) or run order books between buyers and sellers of electricity-related products in the markets, and more generally publish the corresponding prices, for assets connected to transmission grid, manage/operate the platform for trading (where bids and offers are collected), communicate results to the FSP, organize settlement.
OO	Optimisation Operator	Optimise and select the bids, where relevant in combination with switching measures; clear the market for auctions or select individual bids in the order book organised by the MO taking into account the grid data (constraints and sensitivities/topology if needed) provided by DS_O and TS_O; communicate results (rewarded offers and prices) to the MO. The OO role can be carried out by a system operator, market operator or a third party.
OO_T	Optimisation Operator in Transmission	Optimise and select the bids, where relevant in combination with switching measures; clear the market for auctions or select individual bids in the order book organised by the MO_T taking into account the grid data (constraints and sensitivities/topology if needed) provided by SOs; communicate results (rewarded offers and prices) to the MO_T.

		The OO_T role can be carried out by the transmission system operator, market operator or a third party.
OO_D	Optimisation Operator in Distribution	Optimise and select the bids, where relevant in combination with switching measures; clear the market for auctions or select individual bids in the order book organised by the MO_D taking into account the grid data (constraints and sensitivities/topology if needed) provided by DS_O; communicate results (rewarded offers and prices) to the MO_D. The OO_D role can be carried out by a distribution system operator, market operator or a third party.
BRP	Balance Responsible Party	Manage Operational planning of imbalances within its perimeter Ensure financial liability for imbalance between realized energy injection/withdrawal

ANNEX III. GENERIC SYSTEM SERVICES IDENTIFIED BY TASK 3.1

TABLE III-2: BREAKDOWN OF THE BASKET OF GENERIC SYSTEM SERVICES

System Service	Aim	FAT
Inertial Response	Minimise RoCoF	Immediate
Fast Response	Slow time to reach nadir/zenith	<2 secs
	To manage voltage dip induced frequency deviations	<250 ms
Frequency Containment Reserve (FCR)	Contain the frequency	< 5 secs
		5 to 10 secs
		10 to 15 seconds
		15 to 30 seconds
Frequency Restoration Reserve (FRR and mFRR)	Return frequency to nominal	30 to 90 secs
		90 to 120 secs
		120 to 180 secs
		180 to 300 secs
		300 to 450 secs
		450 to 900 secs
Replacement Reserve (RR)	Replace reserves utilised to provide faster products	<900 secs
		900 to 1200 secs
		1200 to 1800 secs
		>5400 secs
Ramping	Oppose unforeseen sustained divergences, such as unpredicted wind or solar production changes	1 hour
		3 hours
		8 hours
Voltage Control - Steady-State	Voltage control during normal system operation	Long or short timeframe for activation
Dynamic Reactive Power	Voltage control during a system disturbance and mitigation of rotor angle instability	<40ms
Congestion Management	Manage congestion that occurs unpredictably as a result of a fault	Could be similar aFRR
	Manage congestion that occurs predictably due to high-levels of RES	Could be similar to mFRR
	Manage congestion as an alternative to network investment	Could be similar to mFRR or RR

ANNEX IV. LIST OF PRODUCT PARAMETERS AND MARKET CHARACTERISTICS

TABLE IV-3: LIST OF PRODUCT PARAMETERS AND MARKET CHARACTERISTICS

Characteristics	Inertia	FFR	FCR	aFRR	mFRR/RR
Type of event	under-frequency & over-frequency	under-frequency & over-frequency	under-frequency & over-frequency	under-frequency & over frequency ACE deviation	under-frequency & over frequency ACE deviation followed by need to restore FCR/FRR
Product structure	Kinetic Energy	MW upward	MW upward and downward	MW upward and downward separately	mFRR MW upward and downward separately RR MW upward
Activation Principle	inherent response for synchronous machine/automatic	automatic	automatic (internal control loop)	automatic (TSO send a signal to an internal control loop)	manual
Full Activation Time	ms	2 sec standardisation possible at synchronous area level	< 30s	< 300s standardisation at synchronous area level	< 15 min mFRR <30 min RR standardisation at EU level
Maximum Delivery Time	NA	10 seconds unlimited number of activations in the future	15/30 min	some hours	8 hours (per day)? To be aligned with GLBAL unlimited number of activations
Required duration	NA	8 seconds Standardisation at Synchronous			15 minutes (minimum)
Locational product	No	No	No	No	No
Symmetry	Yes	No	yes	No	No

Minimum size		1 MW or less? Trade-off between complexity for TSOs and limitation of barriers for new entrants (DER)	1 MW or less? Trade-off between complexity for TSOs and limitation of barriers for new entrants (DER)	1 MW or less? Trade-off between complexity for TSOs and limitation of barriers for new entrants (DER)	1 MW or less? Trade-off between complexity for TSOs and limitation of barriers for new entrants (DER)
Mechanisms for demonstrating capability	Inherent capability for synchronous machine - measurement possible but challenging,	(DS3) Qualification trial process (QTP) in place of non-proven technologies Unit testing process in place for proven technologies	tests at unit level or delivery point level	tests at unit level or delivery point level	tests at unit level or delivery point level
Proof of Provision		Performance monitoring process	Performance monitoring process	Performance monitoring process	availability: comparison metered data/schedule
Aggregation		Yes, but maybe technically challenging	Yes	Yes	Yes

Characteristics	Long Term Capacity Congestion Management Product (defer grid investment)	Long Term/Medium Term Congestion Management Product	Short term Congestion Management
Type of event	**Long term prevision**: planned flexibility needs to mitigate a structural congestion ==> allow to defer or avoid reinforcement of the grid.	Long Term / Medium Term capacity and/or energy to manage congestions that occurs predictably due to high-levels of RES or high level of consumption or grid maintenance	**Short term prevision:** unplanned flexibility needs to mitigate an occasional congestion
Product structure	Availability of the FP during a certain period to procure a certain flexibility (limit MW injection/withdrawal or adjust schedule) Localisation parameter	Availability of the FP during a certain period to procure a certain flexibility (limit MW injection/withdrawal or adjust schedule) Localisation parameter	MW upward or downward with a FAT = a few seconds (very fast product) or FAT < 15 min (fast product) or > 15 min (slow product) Localisation parameter
Activation Principle	No activation. The product is only a capacity product: guarantee availability (for injection or withdrawal) for a given period.	2 cases: 1: No activation. The product is only a capacity product: guarantee availability (for injection or withdrawal) for a given period. 2: Activation: for an energy product: manual	Manual
Full Activation Time	no standardisation	no standardisation	It would be interesting to have a CM product with characteristics compatible with mFRR ones, to have a common optimisation of mFRR and CM needs when possible <=> FAT < 15 min. Other products with the least standardisation possible would be useful to deal with individual congestion issues.
Maximum Delivery Time	no standardisation	no standardisation	no standardisation
Required duration	no standardisation	no standardisation	no standardisation, at least 15-30 min.

Locational product	Yes	Yes	Yes
Symmetry and Direction	No	No	No
Minimum size	no standardisation	no standardisation	no standardisation
Mechanisms for demonstrating capability	tests at unit level or delivery point level	tests at unit level or delivery point level	tests at unit level or delivery point level
Proof of Provision	availability: comparison metered data/schedule	availability: comparison metered data/schedule	comparison metered data/schedule
Aggregation	Yes, but with localisation criteria	Yes, but with localisation criteria	Yes, but with localisation criteria

Characteristics	Voltage control -Long term capacity product	Voltage control - steady state reactive power	Voltage control - continuous dynamic reactive power	Voltage control - dynamic product
Type of event	Long-term prevision: structural need of MVAr	Short term: regular calculation of MVAr needs	regular (closed to real time) calculation of MVAr needs	Sudden voltage drop
Product structure	Availability of the FP during a certain period to procure MVAr (downward and/or upward) Localisation parameter	MVAr upward and downward separately	MVAr upward and downward separately	the FP should provide voltage control or reactive current
Activation Principle	No activation - capacity product - guarantee availability	Manual (FP receive a schedule)	automatic set points continuously provided by SO to voltage control loop	automatic (the FP should detect the voltage drop)
Full Activation Time	depending on the need no standardisation	no standardisation	few minutes depending on the SO requirements / no standardisation at the moment - dynamic criteria to be fulfilled	very fast (<1s ?)
Maximum Delivery Time	no standardisation/no limit	no standardisation/no limit	no limit	no standardisation
Required duration	no standardisation/no limit	no standardisation/no limit	signal to be followed no limit	profile to be followed
Locational product?	yes	yes	yes	yes
Symmetry and Direction	no standardisation	no standardisation	no standardisation	no standardisation
Minimum size	no standardisation	no standardisation	no standardisation	no standardisation
Mechanisms for demonstrating capability	tests at unit level or delivery point level	tests at unit level or delivery point level	tests at unit level or delivery point level	simulations or check after an event
Proof of Provision	comparison metered data/schedule	comparison metered data/schedule	performance monitoring (comparison metered data and received setpoint	performance monitoring
Aggregation	yes, but with localisation criteria	yes, but with localisation criteria	yes, but with localisation criteria	challenging

Characteristics	Market Characteristics				
	Inertia	FFR	FCR	aFRR	mFRR/RR
Pre-qualification					
Nature of the participants	Inherent capacity for synchronous machine. Only units that have the inertial characteristics equivalent to those of synchronous machines qualified. In the future, grid forming technology could be used on a voluntary or mandatory basis	Voluntary participation; mandatory participation may be imposed to RES (specially wind) in case of insufficient inertia/FFR to assure the system safety All type of FSPs	Mandatory technical capability for some categories of generators (European NC) Mandatory participation for dispatchable generators in many countries Voluntary participation for other assets. All type of FSPs	Mandatory technical capability for some categories of generators (European NC) Mandatory participation for dispatchable generators in many countries Voluntary participation for other assets. All type of FSPs	Mandatory participation for dispatchable generators in many countries Voluntary participation for other assets. All type of FSPs
Procurement					
Perimeter	System-level (synchronous area), since inertia is a system level phenomenon and a lack of inertia is a system-level technical scarcity.	National (1 TSO level) Synchronous area in the future?	National and evolution towards synchronous area	National and evolution towards synchronous area	National and evolution towards synchronous area

Frequency of procurement	Annual or for multiple years – TSOs need certainty in relation to amount of inertial response that is available. The operational policy related to the use of the service will determine the frequency with which it must be procured. For example, if a number of synchronous units reduce their minimum generation, the minimum operational requirements for the number of synchronous units synchronised during a given Trading Period may reduce.	Monthly; However, new design should aim for a smaller lead time. Therefore, we suggest aiming for a daily procurement for capacity. Capacity may be procured at day-ahead timeframe	FCR cooperation target: daily	CEP target: daily procurement (or even more frequent)	CEP target: daily procurement (or even more frequent) for capacity 15 minutes for mFRR energy product, 30 min for RR ENERGY PRODUCT
Nature of the buyer	TSO is the only buyer	TSO is the only buyer Distributed Market: obliged peers are the buyers	TSO is the only buyer Distributed Market: obliged peers are the buyers	TSO is the only buyer Distributed Market: obliged peers are the buyers	TSO is the only buyer Distributed Market: obliged peers are the buyers
Who benefits from the product?	TSO	TSO	TSO	TSO	TSO
Spatial resolution of the product (= location)	Transmission or distribution (if relevant in the future) connected generator.	Sourced from Transmission or distribution grid.	Sourced from Transmission or distribution grid.	Sourced from Transmission or distribution grid.	Sourced from Transmission or distribution grid.
Temporal resolution	15 seconds to 45 seconds (SIR product in EirGrid and SONI)	Capacity: hourly blocks, however, smaller blocks may be envisioned	4hours blocks	few second for Energy	Energy: quarter hour for mFRR, half hour for RR Capacity: base/peak/long off-peak => different products differentiated by time scope

Settlement					
Payment	Auction clearing price to determine the price to be paid for the service. May be advantageous to increase payment for the service at times of increased system need through the scaling of payments with a temporal scarcity scalar.	target: clearing price	CEP/GL BAL target: clearing price	CEP/GL BAL target: clearing price	CEP/GL BAL target: clearing price
Penalties	There should be no non-delivery as the response is inherent and does not need to be performance monitored	for (partial or total) undeclared unavailability	for (partial or total) undeclared unavailability	for (partial or total) undeclared unavailability	for (partial or total) undeclared unavailability

Characteristics	Market Characteristics			
	Voltage control - Long term capacity product	Voltage control - steady state reactive power	Voltage control - continuous dynamic reactive power	Voltage control - dynamic product
Pre-qualification				
Nature of the participants	Voluntary participation All type of flexibility providers	Mandatory capacity and participation for most generators (code Rfg and GL SO) Voluntary participation for other FSPs All type of flexibility provider	Mandatory participation for some types of generators in some countries Voluntary participation for other FSP All type of Flexibility providers	Mandatory capacity for generators in many countries (possibility provided by Rfg network code) All type of flexibility provider
Procurement				
Perimeter	Centralised market: Zonal Decentralised market: zonal for TSO - local for DSO markets - remaining bids are sent to the higher markets	Centralised market: Zonal Decentralised market: zonal for TSO - local for DSO markets - remaining bids are sent to the higher markets Distributed: only the peers - depends on the perimeter of the platform	Centralised market: Zonal Decentralised market: zonal for TSO - local for DSO markets - remaining bids are sent to the higher markets Distributed: only the peers - depends on the perimeter of the platform	Centralised market: Zonal Decentralised market: zonal for TSO - local for DSO markets - remaining bids are sent to the higher markets Distributed: only the peers - depends on the perimeter of the platform
Frequency of procurement	Yearly	capacity: yearly energy: 15 min	capacity: yearly	during connection contract negotiations, yearly or less depending on the needs (if additional needs)
Nature of the buyer	TSO + DSOs (buy offers according to alternative cost) Distributed: obliged peers are the buyers	TSO + DSOs (buy offers according to alternative cost)	centralised: TSO and DSO Decentralised: DSO for local market, TSO for zonal market Distributed: obliged peers	centralised: TSO and DSO Decentralised: DSO for local market, TSO for zonal market Distributed: obliged peers
Who benefits from the product?	TSO and DSO	TSO and DSO	TSO and DSO	TSO and DSO
Spatial resolution of the product (= location)	Node of DN (probably some aggregation possible)	Node of DN for DSO needs and node of TN for TSO needs,	Node of DN for DSO needs and node of TN for TSO needs,	Node of DN for DSO needs and node of TN for TSO needs,

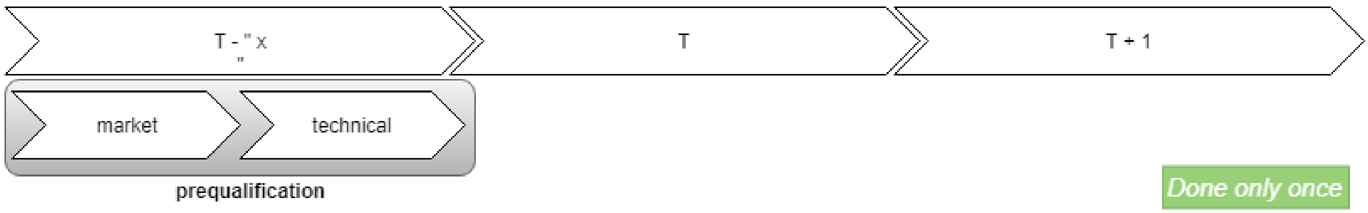
Temporal resolution	Year or more if necessary (missing information of horizon – this could be 1.5 years)	Capacity: Yearly or monthly daily Energy: 15 min	Capacity: Yearly or monthly or daily Energy: few seconds	one or several years
Settlement				
Payment	Mandatory requirement in many countries - no payment. If market-based procurement, clearing price or bid price	Mandatory requirement in many countries - no payment If market-based procurement, clearing price or bidding price	Mandatory requirement in many countries - no payment. If market-based procurement, clearing price or bidding price	Mandatory requirement in many countries - no payment.
Penalties	for (partial or total) unavailability	for (partial or total) undeclared unavailability	for (partial or total) undeclared unavailability	for (partial or total) undeclared unavailability

Characteristics	Market Characteristics		
	Long Term capacity product for Congestion Management (investments)	LT/MT Congestion Management Products	Short Term Congestion management products
Pre-qualification			
Nature of the participants	All types of Flexibility Provider localized in the congestion area (connected at DN or TN level) Existing or new voluntary participation	All types of Flexibility Provider localized in the congestion area (connected at DN or TN level) Voluntary participation Mandatory participation of some FSP could be needed (if lack of liquidity)	All types of Flexibility Provider localized in the congestion area (connected at DN or TN level) Voluntary participation Mandatory participation of some FSP could be needed (if lack of liquidity)
Procurement			
Perimeter	Centralised-decentralised: Zonal or cross-border (for congestion near the border?) Distributed: only the peers - depends on the perimeter of the platform	Centralised-decentralised: Zonal or cross-border (for congestion near the border?) Distributed: only the peers - depends on the perimeter of the platform	Centralised-decentralised: Zonal or cross-border (for congestion near the border?) Distributed: only the peers - depends on the perimeter of the platform
Frequency of procurement	Annual or less, depending on the needs	Annual/ seasonally (maintenance)/weekly/d-2/ d-1/ possibility to update regularly (for example monthly for an annual procurement).	Daily for capacity product 1H to 15 min for energy product
Nature of the buyer	TSO and DSOs (buy offers according to alternative cost)	Centralised: TSO and DSO Decentralised: DSO for local market, TSO for zonal market Distributed: obliged peers	Centralised: TSO and DSO Decentralised: DSO for local market, TSO for zonal market Distributed: obliged peers
Who benefits from the product?	TSO and DSO	TSO and DSO	TSO and DSO
Spatial resolution of the product (= location)	TSO needs: Connecting node in the grid for TN-FP or TSO/DSO substation (or group of substations) for DN-FP. DSO need: connecting node in the grid	TSO needs: Connecting node in the grid for TN-FP or TSO/DSO substation (or group of substations) for DN-FP. DSO needs: connecting node in the grid	TSO needs: Connecting node in the grid for TN-FP or TSO/DSO substation (or group of substations) for DN-FP. DSO needs: connecting node in the grid

Temporal resolution	Case dependant – windows of availability defined for each contract (hour/day/months ranges) / length of the contracts depending of each case but probably longer than 1 year as SOs need time to apply alternative solutions and FSPs need visibility in case of new investment	Case dependant – windows of availability defined for each contract (hour/day/months ranges) / length of the contracts depending of each case	Capacity: Daily or some hours Energy: quarter hour
Settlement			
Payment	Depends on the procurement: clearing price or cost-based payment	Depends on the procurement: clearing price or cost-based payment	Depends on the procurement: clearing price or cost-based payment
Penalties	for (partial or total) unavailability	for (partial or total) undeclared unavailability	e.g. for changes of schedules

ANNEX V. TIMELINES FOR MARKET ORGANISATION PHASES

For prequalification:



For centralised procurement:

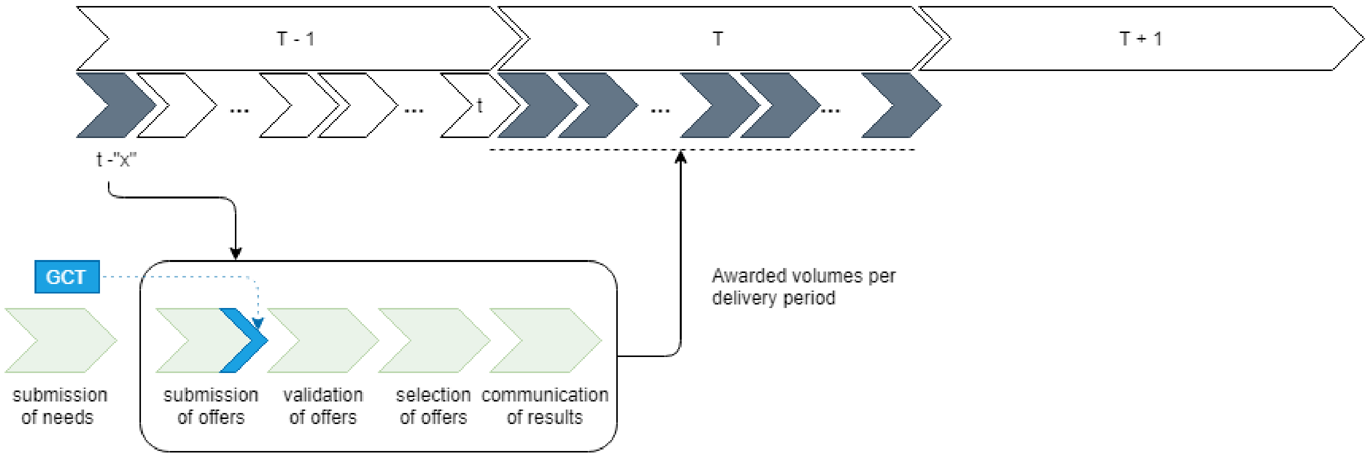


FIGURE V-1: TIMELINE FOR CENTRALISED PROCUREMENT

Figure V-1 presents the timeline for centralised procurement with time divided into periods T. Depending on the product, this period can refer to days, weeks or even months. Every period T can be subdivided into smaller periods t. For instance, a week T can be subdivided into seven days t, or a day T can be subdivided into twenty-four hours t. The submission of offers take place before gate closure time (GCT) at a certain time t- “x” in time period T-1. If the time period T under consideration is weeks, then t – “x” refers to a certain hour on a specific day t in that specific week T. The awarded volumes are meant to be used in a specific period T, which is situated after period T-1 on the timeline. Settlement will take place in T+1.

For decentralised procurement:

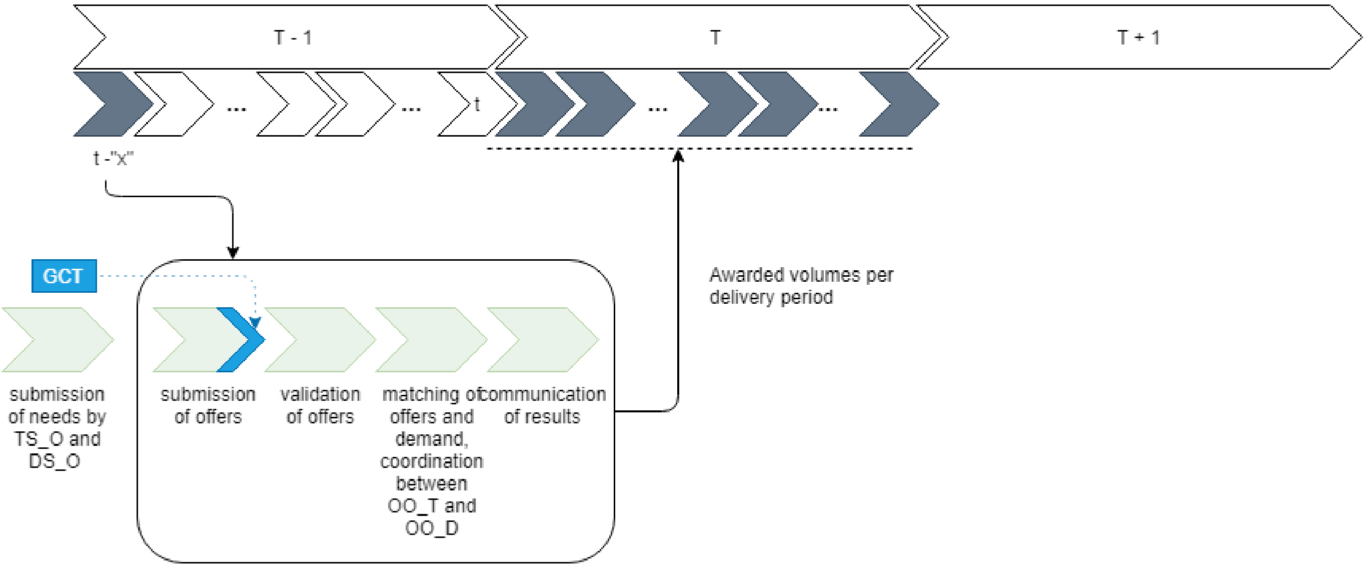


FIGURE V-2: TIMELINE FOR PROCUREMENT PHASE - DECENTRALISED

Figure V-2 presents the timeline for decentralised procurement with time divided into periods T. The timeline is identical to the timeline for centralised procurement, with the difference that TS_O as well as DS_O both submit their needs and that there needs to be coordination between the OO_T and OO_D during the procurement process.

For distributed procurement:

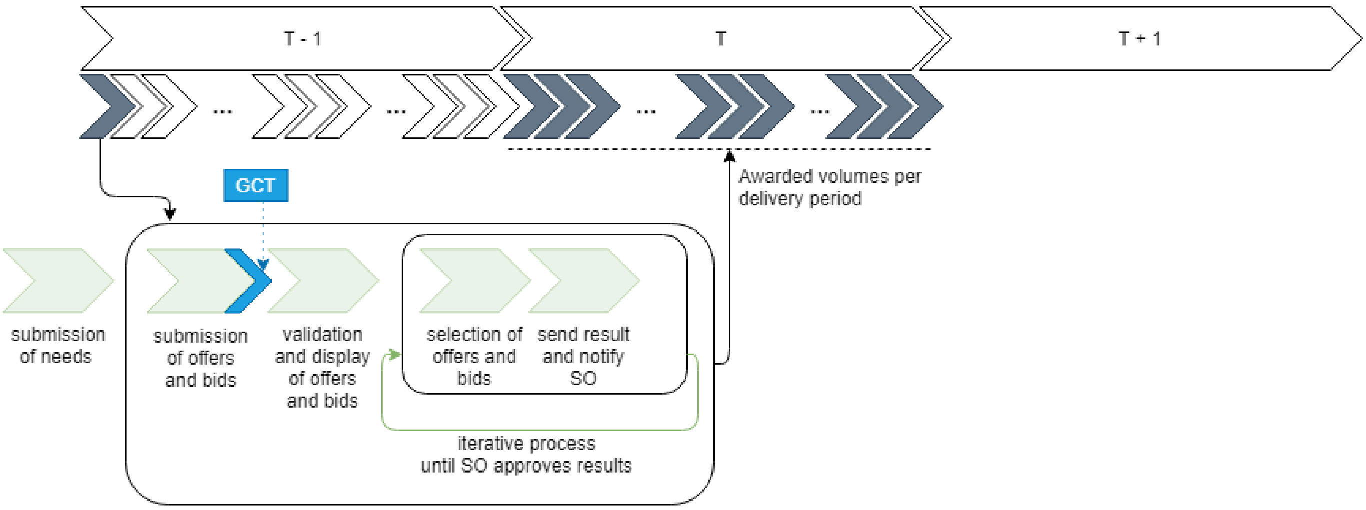


FIGURE V-3: TIMELINE FOR DISTRIBUTED PROCUREMENT

Figure V-3 presents the timeline for a distributed procurement with time divided into periods T. As shown in the sequence diagram, there is an iterative process of bid and offer selection pending the SO's approval of the results.

For activation phase:

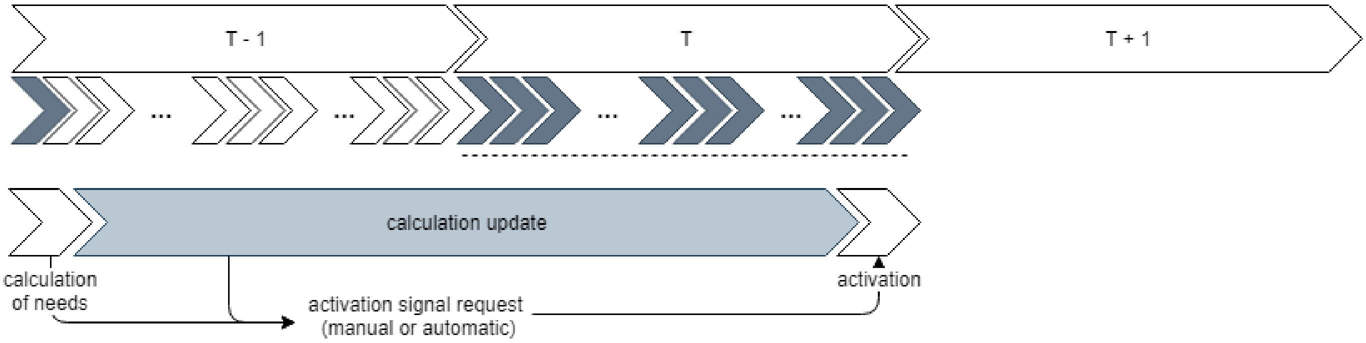


FIGURE V-4: TIMELINE FOR ACTIVATION PHASE

Figure V-4 presents the timeline for product activation. In most cases, the time period T refers to days where needs are calculated day-ahead (D-1) to be activated on day D. The needs calculation is constantly updated and adapted until real-time. An activation request is sent manually or automatically if and when a specific product is needed.

For settlement phase:

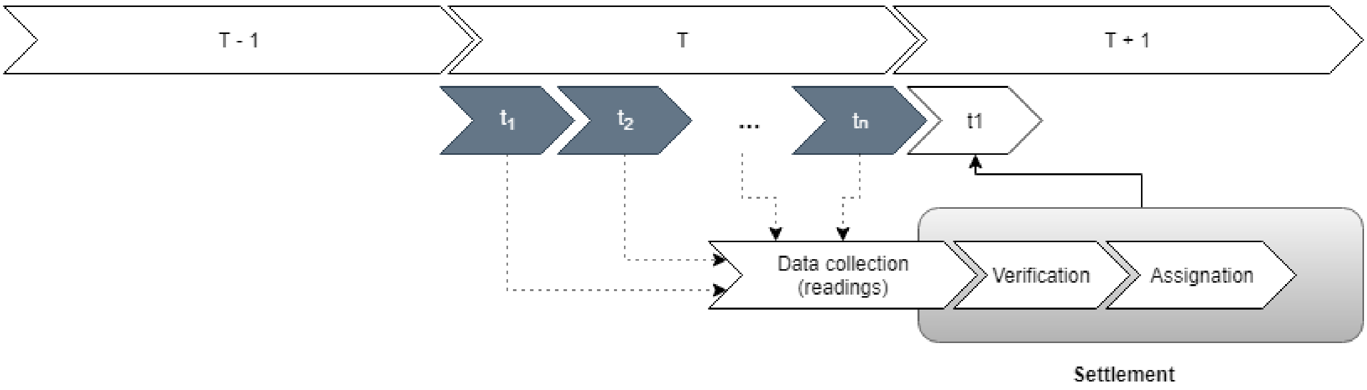


FIGURE V-5: TIMELINE FOR SETTLEMENT PHASE

ANNEX VI. INTER-TSO PROCESSES INVOLVED IN COORDINATED REDISPATCHING

Figure VI-6 depicts simplified inter-TSO processes for coordinated cross-border remedial actions based on current processes in Core CCR. The remedial actions include actions done using TSOs' assets: topology changes, Phase Shifting Transformers and redispatching of market participants' assets. As there are different processes, where remedial actions are considered and some processes run in parallel, this set up is more complex than individual schemes described in chapter 4. In general, these processes start two days before the day of delivery (D). On the day D-2, TSO gather relevant data (GLDPM[81]) from relevant entities. Using these data and data about its own grid each TSO creates IGM (Individual Grid Model), all IGMs are combined into CGM (Common Grid Model). This CGM is the basis that will be used for the Capacity Calculation Process. In the Capacity Calculation Process remedial actions are considered.

Calculated cross-zonal capacity is provided into SDAC (Single Day Ahead Coupling). The process that is run by NEMOs (Nominated Electricity market Operator), where market participants may trade energy. In parallel it is possible for market participants to trade energy bilaterally. After performing SDAC the market participants receive SDAC results, which are portfolio-based, and establish preliminary work schedules of their units. These schedules are provided to the TSOs, who once again create IGMs and CGM, which this time include market results. The resulting CGM is used in two following processes: DACF (Day Ahead Congestion Forecast) and Capacity Calculation Process.

In the DACF process TSOs jointly identify forecasted violations of grid constraints and remedial actions that would solve these violations. Currently there are no explicit bids from market participants in this process – this procurement is done in a regulated approach with mandatory participation of certain classes of generators (different in different Member States). Typically, redispatching is not activated in the DACF process, however it will be activated if it has to be, e.g., due to long lead time.

The cross-border trading via SIDC (Single Intra-Day Coupling) continues until Cross-Zonal Gate Closure Time, which is generally until one hour before start of the delivery period. Bilateral trading within given bidding zones can continue until internal gate closure, which depends on national arrangements. During the time trading is allowed, market participants may update working schedules of their units.

After DACF, within IDCF (Intraday Congestion Forecast), TSOs repeatedly update their IGMs, create CGM and assess whether prepared remedial actions are still sufficient and necessary. In case prepared remedial actions are identified as insufficient – due to new or more severe overloads than forecasted, TSOs prepare additional remedial actions. In case overloads are less severe TSOs will forego activating not needed remedial actions. The IDCF process is used for monitoring, additional (regulated) procurement and activation of remedial actions.

[81] GLDPM It is a set of data necessary for calculation of cross-zonal capacity. It is established based on art. 16 of CACM GL.

It contains at least:
(a) information related to their technical characteristics;
(b) information related to the availability of generation units and loads;
(c) information related to the schedules of generation units;
(d) Relevant available information relating to how generation units will be dispatched.
Current cope of this data is defined in Generation and Load Data provision methodology approved in 2016 (https://www.entsoe.eu/2017/01/11/gldm-cgm-amendments/)

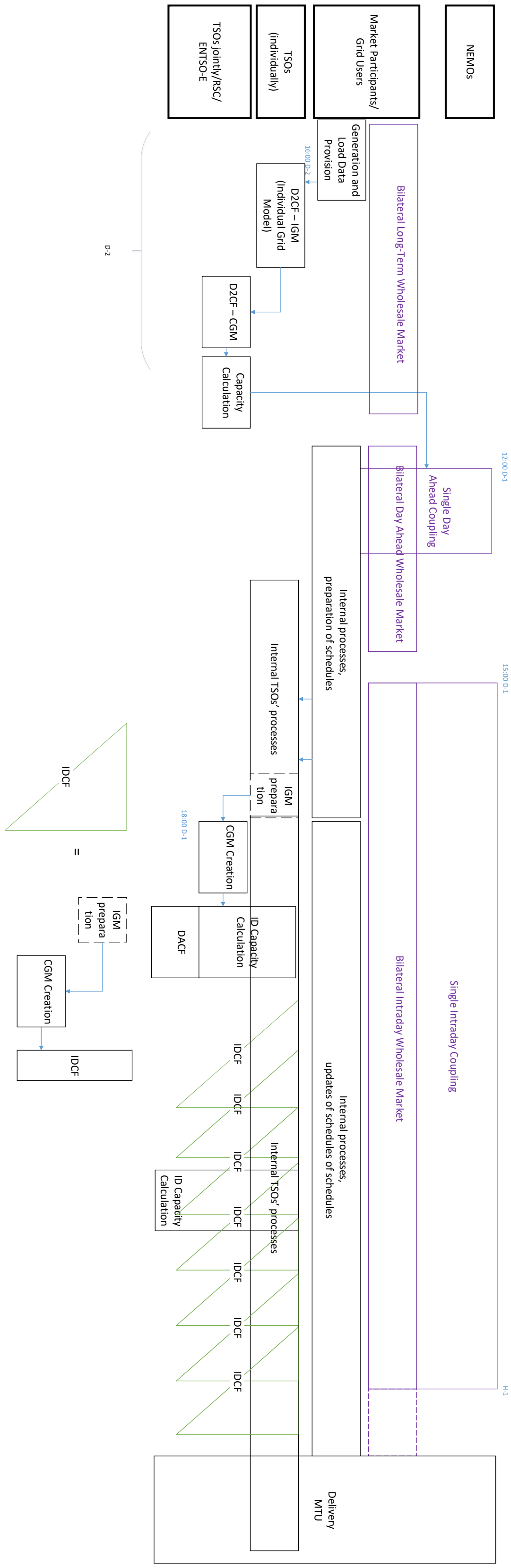


FIGURE VI-6: INTER-TSO REMEDIAL ACTIONS COORDINATION SCHEME

ANNEX VII. ATTACHMENTS OF DECENTRALISED OPTIMISATION

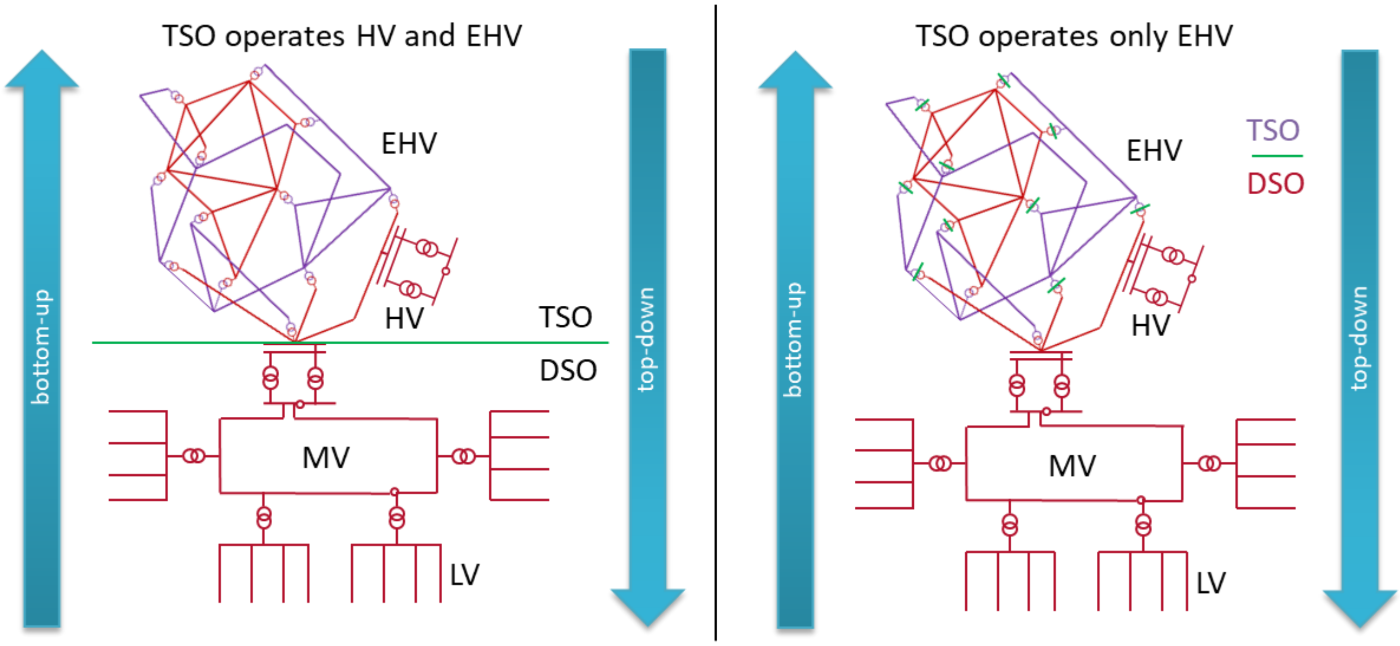


FIGURE VII-7: DIFFERENCE OF TOP-DOWN AND BOTTOM-UP COORDINATION AND GRID STRUCTURES DEPENDING ON VOLTAGE ALLOCATION TO DSO AND TSO

ANNEX VIII. DESCRIPTION OF PROCUREMENT PHASE FOR MFRR AND CM JOINT PROCUREMENT

As MARI platform imposes strong temporal constraints, the interactions with MARI have been added to the procurement schemes. The description is provided for version 1 and version 3 described in Section 6.4.1 and for centralised and decentralised optimisation, for energy product.

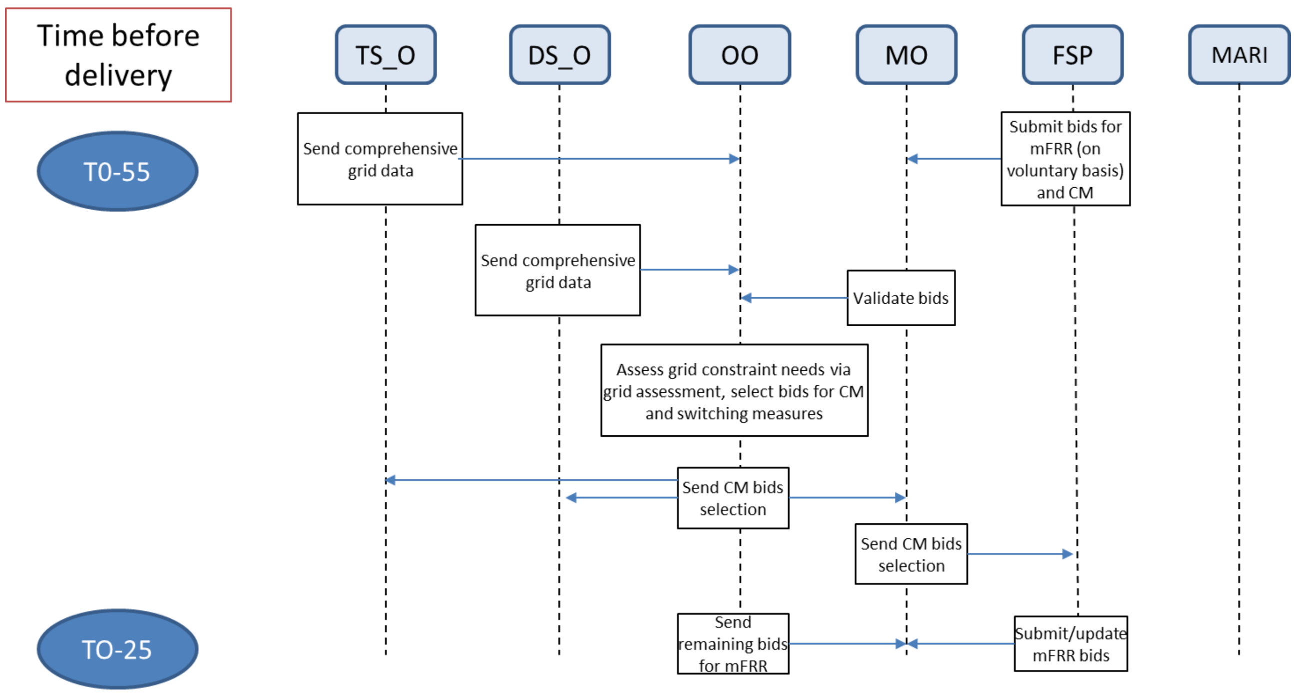
Grid constraint assessment and coordination between SOs are included to give the comprehensive overview of all interactions to be done in the limited time. Only interactions in the case of optimisation with comprehensive grid ta are presented (the easiest case because the less interactions)

Note: MARI provide 2 results: first a list of bids that will be activated directly after the clearing (SA) and second a Merit Order List that can be used by SOs for new needs that should be solved before next clearing (DA)

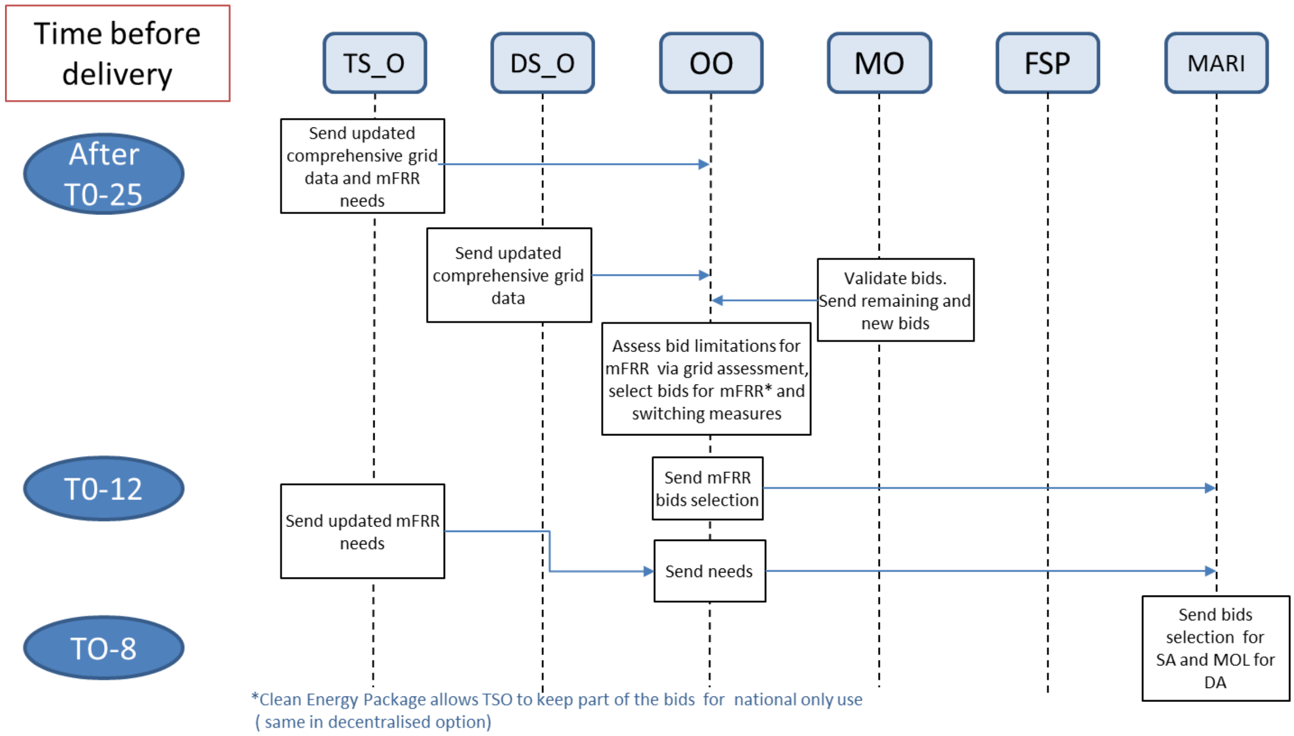
<u>Centralised optimisation</u>

Version 1: coordinated optimisations via connected bidding

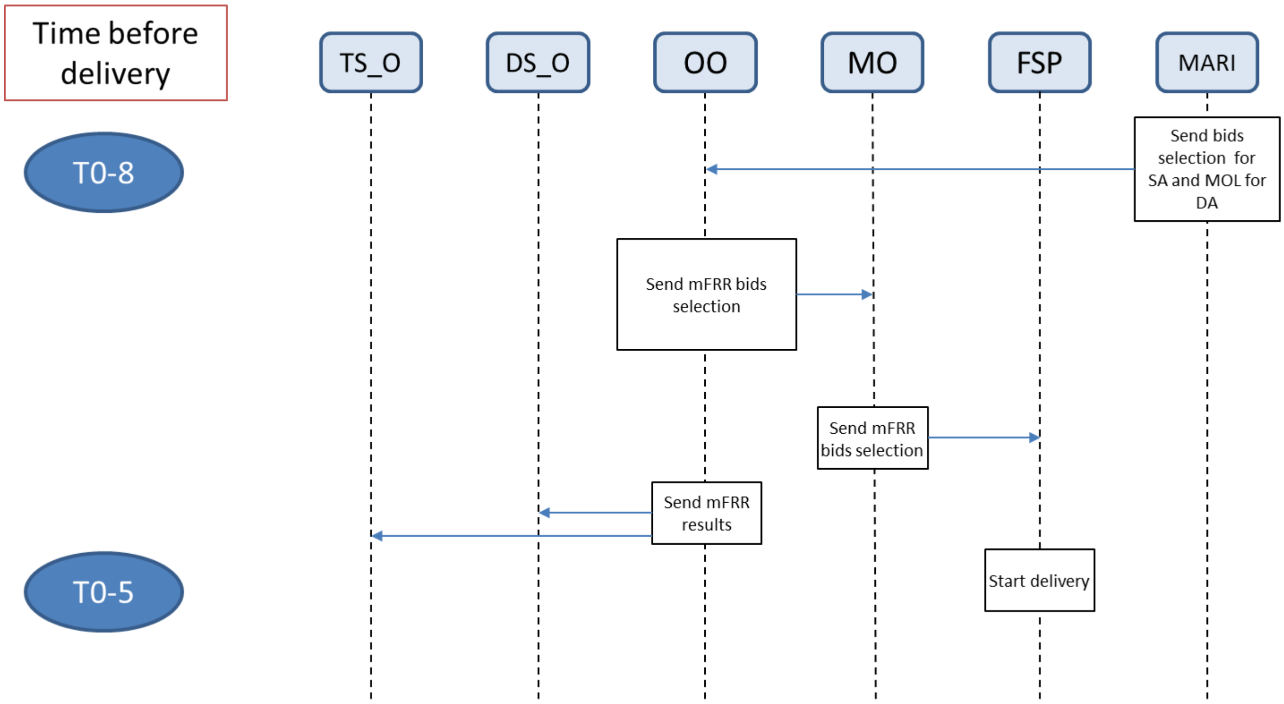
In this version, we have two sequential optimisations: first, a centralised optimisation for congestion management and then a centralised optimisation for mFRR.



<u>Step 1:</u> CM procurement as described in Section 5.2.1 The CM procurement process must be achieved 25 minutes before mFRR delivery to respect MARI timeframe. Thus, the process must start 55 minutes (or before) delivering time to have enough coordination time. Remaining bids must be transferred to mFRR platform before T0-25 min. FSP can send new bids to MO (mFRR only bids).



Step 2: mFRR procurement: bids and needs gathering
OO must select bids to be transferred to MARI (some bids can be kept by the OO (not standardized or necessary due to safety reasons)) and make the coordination with SOs in 13 min and send to MARI TSO's mFRR needs in 15 min.
MARI gives the results (allocation of bids to the different TSOs) 8 min before delivery.



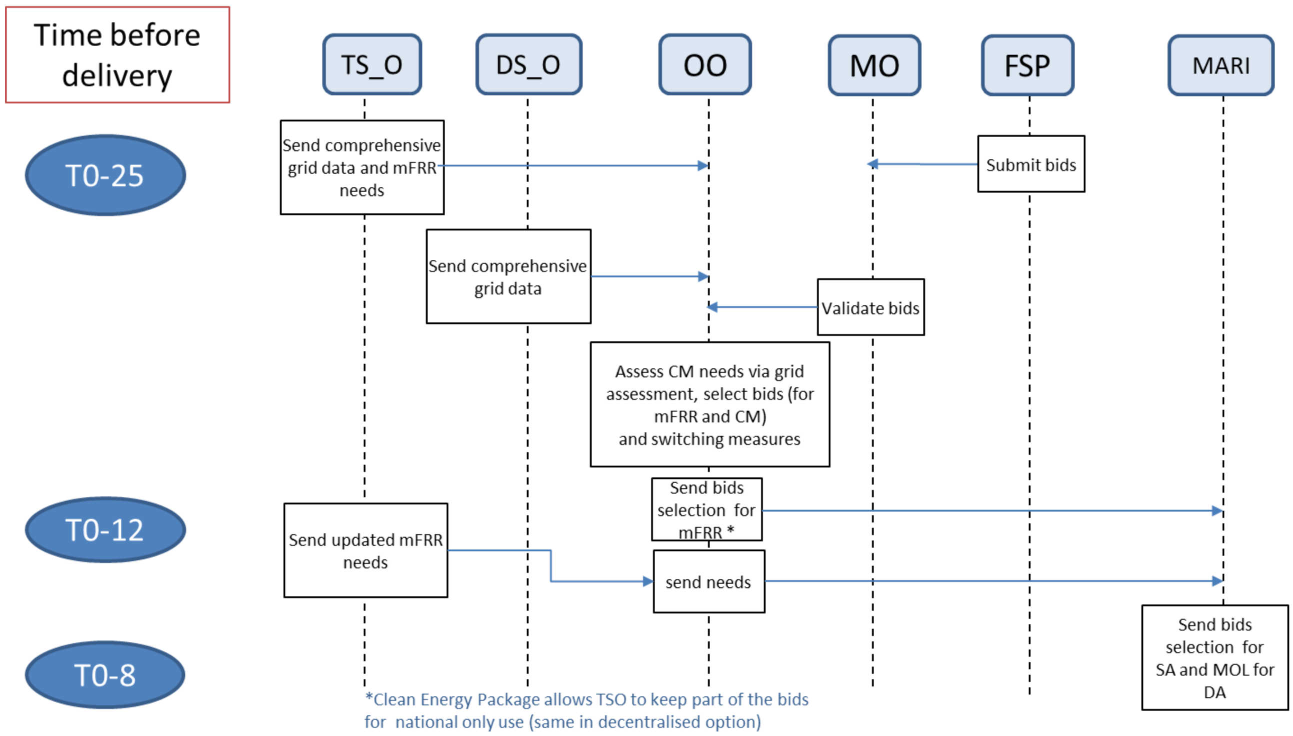
Step 3: mFRR procurement clearing
OO receives from MARI bid allocation for next delivery period and MOL for Direct Activation between 2 periods.
SOs and FSPs receive the result of MARI platform and selection of specific bids by OO.

Rewarded FSPs begin delivery 3 min after MARI clearing.

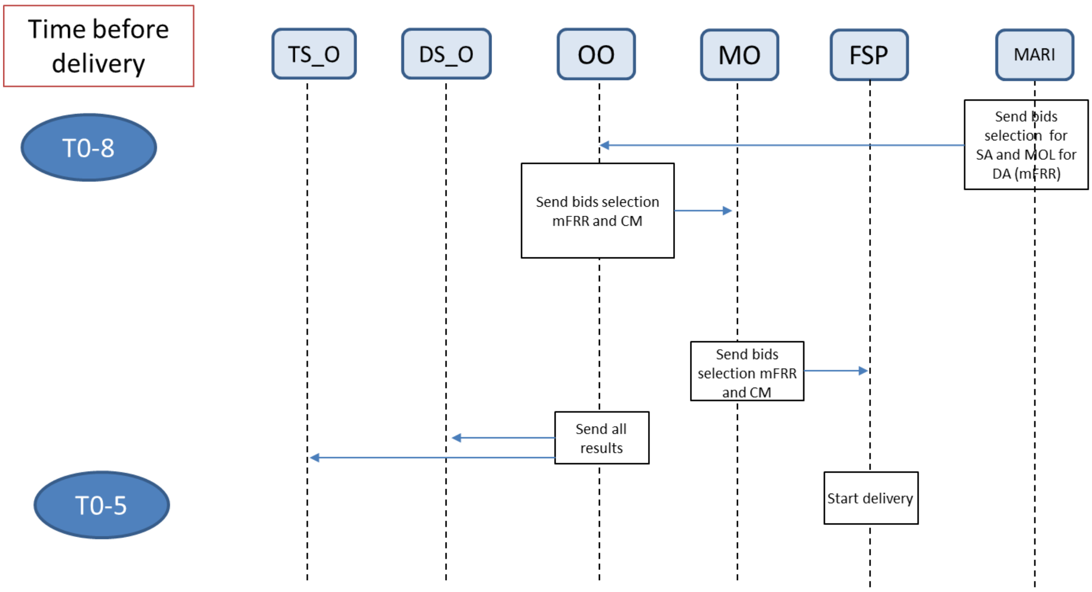
Version 3: joint bidding phase and joint optimisation

In this version, there is a joint optimisation to allocate flexibility for both needs (mFRR and CM).

The timeframe must comply with MARI rules.



Step 1: joint optimisation of mFRR and CM OO receive bids for mFRR and CM from FSP and needs from SOs. OO must select bids for CM, considering synergies across balancing and CM, and select bids to be transferred to MARI. This process must be achieved in 13 min

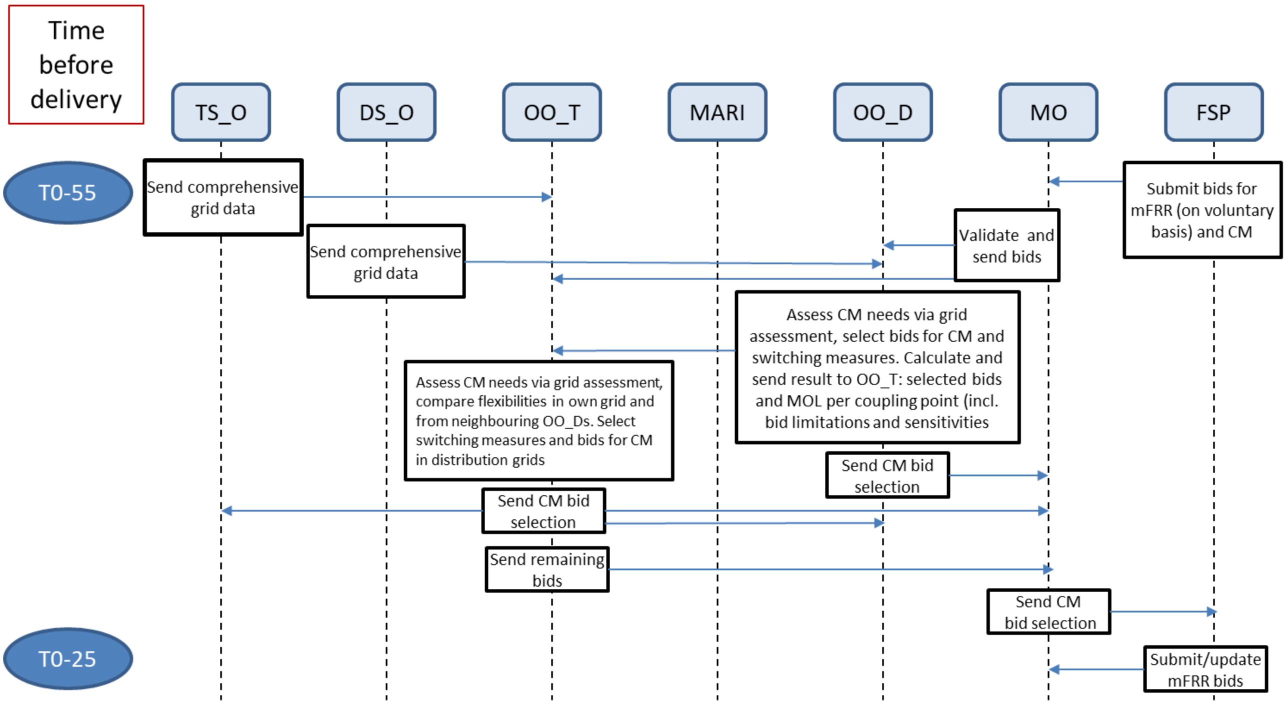


Step 2: mFRR procurement: Same as for option 1

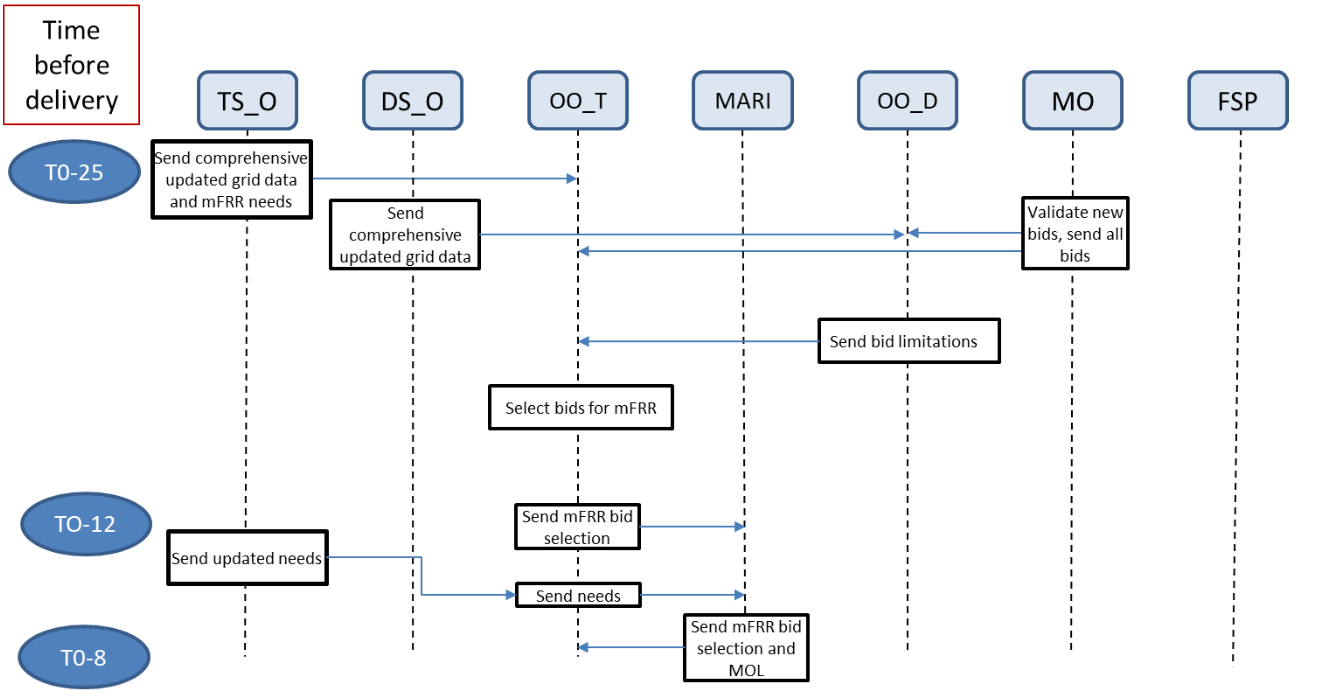
Decentralised optimisation:

Version 1: coordinated optimisation via joint bidding

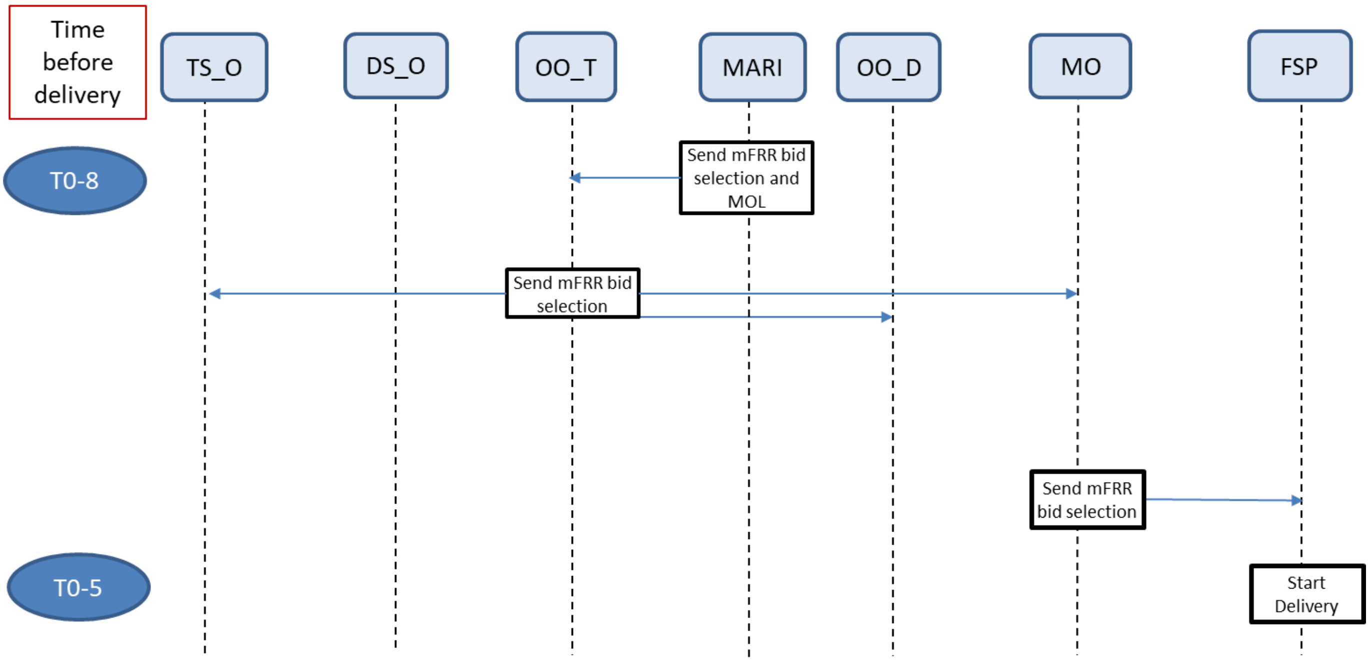
Only one option of decentralised optimisation defined in Chapter 5.2.2 is described (pure bottom-up).



Step 1: CM procurement as described in Section 5.2.2 with 2 procurement levels The CM procurement process must be achieved 25 minutes before mFRR delivery to respect MARI timeframe and thus must start 55 minutes (or before) delivering time to have enough coordination time. Remaining bids must be transferred to mFRR platform before T0-25 min. FSP can send new bids to MO (mFRR only bids).

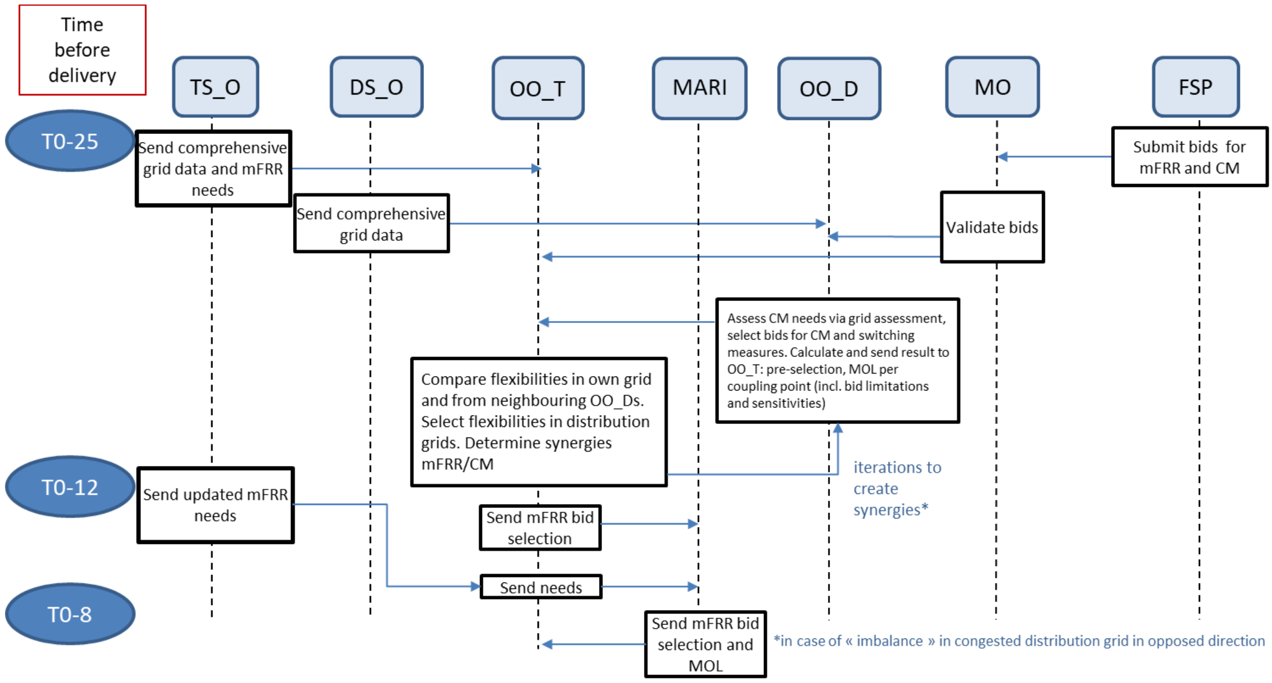


Step 2: mFRR procurement (TSO need only)
Same as described in Chapter 5 but in a very short timeframe. At the end of the step, OO-T send selected bids to MARI (and keeps non-standardised bids and bids necessary for safety)

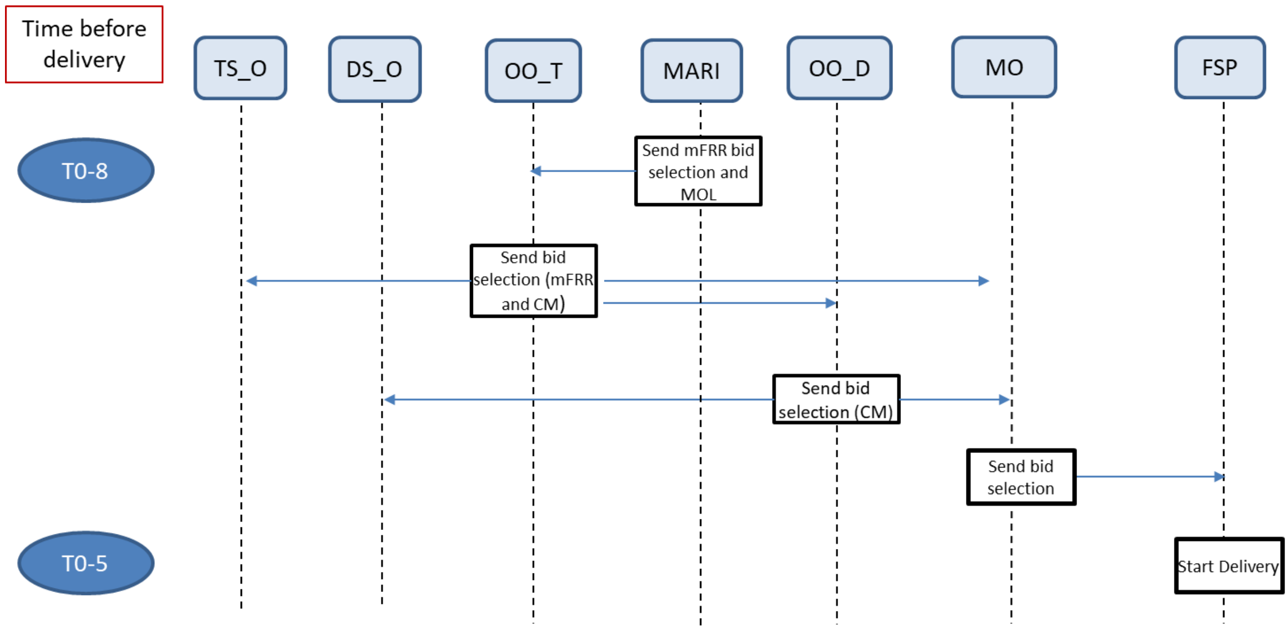


Step 3: End of mFRR procurement process
OO_Ts receive from MARI bid allocation for next delivery period and MOL for Direct Activation between 2 periods.
SOs and FSPs receives the result of MARI platform and selection of specific bids by OOs.
Rewarded FSPs begin delivery 3 min after MARI clearing.

Version 3: joint bidding and joint optimisation



Step 1: CM and mFRR procurement with 2 procurement levels
OO_D pre-selects bids from distribution connected FSP for CM and, if necessary, iterates with OO_T to create synergies between balancing and CM.
OO_T must select bids to be transferred to MARI.
OO_Ds and OO_Ts selection of bids, bids to be transferred to MARI and coordination between OOs must be achieved in 13 min.



Step 2:
Based on MARI results and previous optimisations for CM (by OO_D/OO_T) and consideration of synergies across CM and mFRR, both OO_D and OO_T send bid selections for own scarcities to the MO to start the activation process.