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Deliverable D3.1

Report of functionalities and services of the Spanish demo

V1.0

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D3.1 - Report of functionalities and services of the Spanish demo

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Executive summary

This deliverable reports on CoordiNet task 3.1 “Characterization of the Spanish demo” which describes the main characteristics of the Spanish demo. The document presents the different demonstrator sites including the description of the resources, networks’ characteristics, more specific definition of the products considered, an updated description of the Business Use Cases, current system operations, platforms and the developments necessary to realize the Spanish demo.

Renewable generation units considered are connected at e-distribución, I-DE and REE at high, medium and low voltage levels. Demand-side resources considered are connected at low and medium voltages at e-distribución in Malaga and at i-DE in Alicante and Murcia. Cádiz and Albacete demo sites involve renewable sources, mainly wind power. In both locations, voltage control, common congestion management and balancing BUCs will be tested. For these resources, as most of the units currently participate in the markets, the specific developments required for the demos are not numerous. However, voltage control is a new service where the product and the market framework still need to be defined and agreed between the TSO and DSO. Figure 1 shows the locations, flexibility technologies, services, products and coordination schemes considered in the Spanish demo.

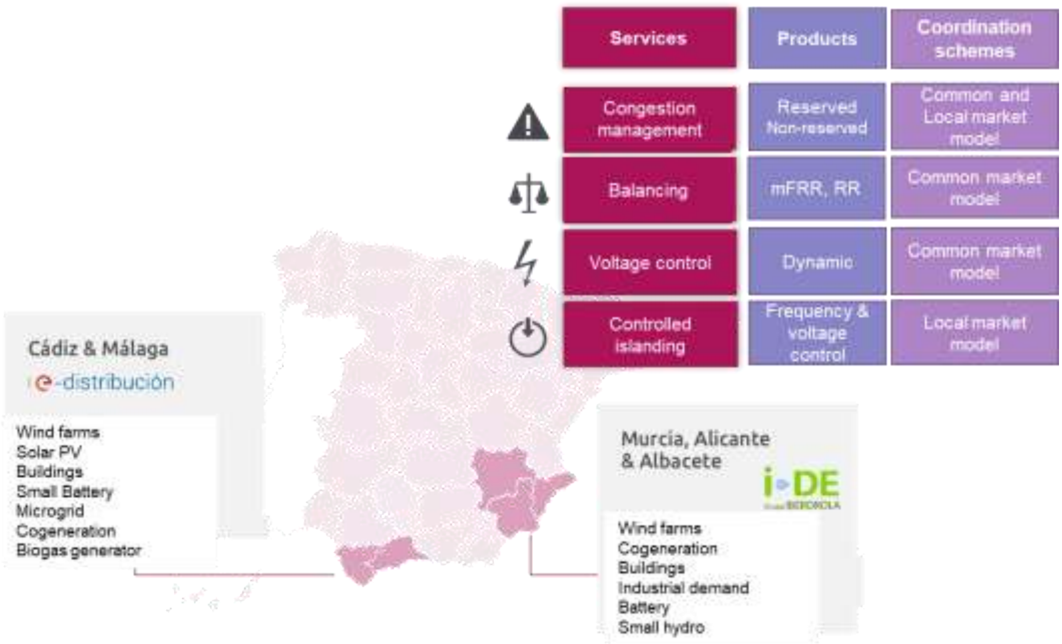

Figure 1: Spanish Demonstration Regions and Services

For each of the demo areas, the resources participating in the demonstration have been identified. This is the result of a collaborative work that lead to engaging a significant number of flexibility providers to participate in the project. The considered flexibility service providers have performed tests and analysis to determine their flexibility and identify their requirements (e.g. controllability, communication) to provide services to the TSO and DSOs in a coordinated manner either directly or through aggregators. This is an ongoing task which must be constantly updated based on changing circumstances and limitations of different nature which were not foreseen. Another important development was the description of the networks of the different demonstration locations, including the location of resources, topology, and electrical characteristics.

Systems and components will also play an important role in enabling the testing of CoordiNet solutions. Therefore, this deliverable has performed an assessment of the components that are presently in place and has identified the components that have yet to be deployed in the demo. In this regard, from the DSOs side, control systems will be developed and a hardware device will be implemented for the monitoring and control of flexibility providers that are connected to distribution networks. On the TSO side, adaptations on the existing market platforms will be done to incorporate the new type of resources (e.g. demand response), products, and processes being demonstrated. In addition, there is also a need for the development of the "CoordiNet Platform", as presented in CoordiNet deliverable D1.5. This platform will consist of two systems, one at the TSO side, the common platform, and the other at the distribution side, the local platform.

Products and services for the Spanish demonstration are also specified in this Deliverable D3.1. In Deliverable D1.3, a preliminary and theoretical assessment of possible products and services has been provided. For instance, the local congestion management has to be developed from scratch in the Spanish demonstration as this is not currently in place. All the different steps described for the Business Use Cases for each of the actors: TSO, DSO, and aggregators must also be developed. The local platform has to be established as well including the clearing algorithms and the interactions with the actors. This platform has to handle both local congestion management at e-distribución and i-DE as well as controlled islanding at i-DE. An initial proposal on the main components of this local platform is proposed in this deliverable D3.1. Additionally, the interactions between different actors are described.

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Notations, abbreviations and acronyms

Acronym	Definition
AC	Alternating Current
ALB	Albacete
ALI	Alicante
AUR	Additional Upward Reserve
PDBF	Day-Ahead Baseline Program, according to the Spanish acronym *Programa Diario Base de Funcionamiento*
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
BUC	Business Use Case
CAD	Cadiz
CECRE	Control Centre of Renewable Energies
CHP	Combined Heat and Power
CNMC	Comisión Nacional de Mercados y Competencia, Spanish National Regulatory Authority
DA	Day-Ahead
DC	Direct Current
DER	Distributed Energy Resource
DG	Distributed Generation
DR	Demand Response
DSO	Distribution System Operator
EBGL	Electricity Balancing Guideline
EB	Energy Box
ESS	Energy Storage System
EV	Electric Vehicle
FSP	Flexibility Service Providers
GCT	Gate Closure Time
GPRS	General Packet Radio Service
HV	High Voltage
HVAC	Heating, Ventilation, and Air Conditioning
ID	Intraday
ISP	Imbalance Settlement Period
LV	Low Voltage

MAL	Malaga
MARI	Manually Activated Reserves Initiative
mFRR	Manual Frequency Restoration Reserves
MUR	Murcia
MV	Medium Voltage
MV-BPL	Medium Voltage - Broadband over Power Line
NB-PLC	Narrowband - Power Line Communications
NRA	National Regulatory Authority
PF	Power Flow
PHU	Physical Unit
PRU	Programming Unit
PV	Photovoltaic
PICCASO	The Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PSSE	Power System Simulator for Engineering
REE	Red Eléctrica de España
RDL	Real Decreto Ley (Royal Decree Law)
RES	Renewable Energy Source
RESCC	Renewable Energy Control Centres
RR	Replacement Reserves
SCADA	Supervisory Control and Data Acquisition
sFSP	Small Flexibility Service Provider
SO GL	System Operation Guidelines
SS	Secondary Substation
SSL	Secure Sockets Layer
SUB	Substation
TBD	To Be Defined
TERRE	Trans European Replacement Reserves Exchange
TSO	Transmission System Operator
UMTS	Universal Mobile Telecommunications System
V2G	Vehicle-to-grid
WSDL	Web Services Description Language
XML	Extensible Markup Language

Table 1: Acronyms list

1. Introduction

1.1. The CoordiNet project

The CoordiNet project is a response to the call LC-SC3-ES-5-2018-2020, entitled "TSO – DSO – Consumer: Large-scale demonstrations of innovative grid services through demand response, storage and small-scale generation" of the Horizon 2020 programme. The project aims at demonstrating how Distribution System Operators (DSO) and Transmission System Operators (TSO) shall act in a coordinated manner to procure and activate grid services in the most reliable and efficient way through the implementation of three large-scale demonstrations. The CoordiNet project is centred on three key objectives:

1. To demonstrate to which extent coordination between TSO/DSO will lead to a cheaper, more reliable and more environmentally friendly electricity supply to the consumers through the implementation of three demonstrations at large scale, in cooperation with market participants.
2. To define and test a set of standardized products and the related key parameters for grid services, including the reservation and activation process for the use of the assets and finally the settlement process.
3. To specify and develop a TSO-DSO-Consumers cooperation platform starting with the necessary building blocks for the demonstration sites. These components will pave the way for the interoperable development of a pan-European market that will allow all market participants to provide energy services and opens up new revenue streams for consumers providing grid services.

In total, eight demo activities will be carried out in three different countries, namely Greece, Spain, and Sweden. In each demo activity, different products will be tested, in different time frames and relying on the provision of flexibility by different types of Distributed Energy Resources (DER). Figure 2 presents an approach to identify (standardized) products, grid services, and coordination schemes to incorporate them into the future CoordiNet platform for the realization of the planned demo activities[1].

[1] Considering that this Deliverable D3.1 is being published at an early stage of the project, these characteristics may change. Please refer to the latest CoordiNet deliverables for updated information.

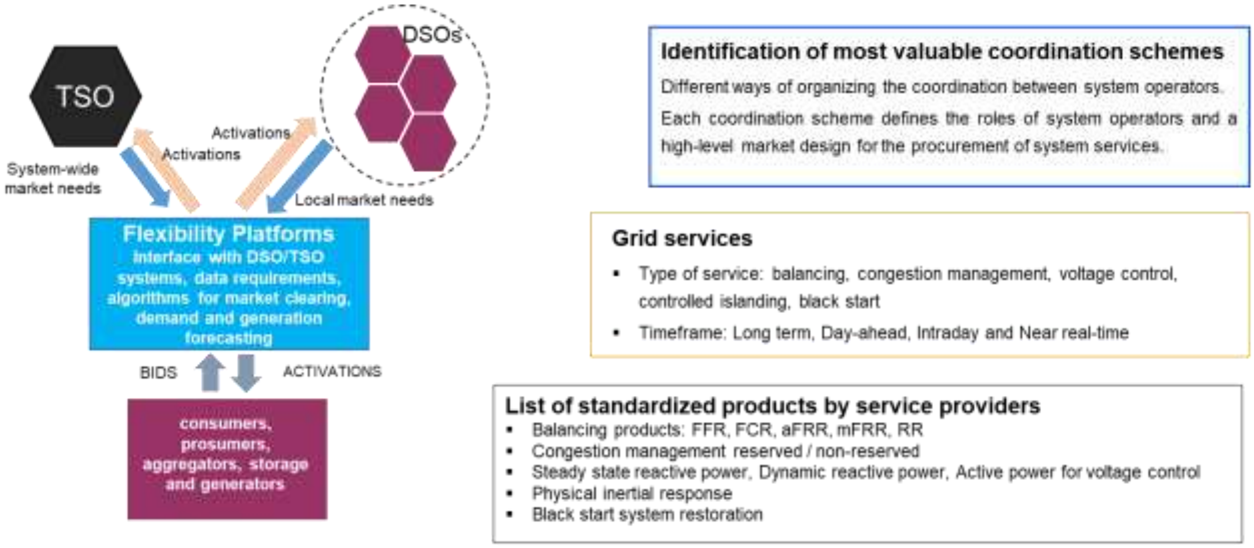

Figure 2 Overall CoordiNet approach

(FFR: Fast Frequency Response, FCR: Frequency Containment Reserves, aFRR: automatic Frequency Restoration Reserves, mFRR: manual Frequency Restoration Reserves, RR: Replacement Reserves)

1.2. Scope of the document

This deliverable reports on CoordiNet task 3.1 “Characterization of the Spanish demo” which describes the main characteristics of the Spanish demo is organized in the following five sections:

- A detailed description of the demo sites, both in terms of resources and networks characteristics for the different demo areas

The description of the resources includes the potential flexibility to be used in the Spanish demo. This identification is also extended to the identification of resources used in each BUC. As for the network characteristics, it is essential for deployment of each BUC to map the network at which the resources are connected, including details on the electrical configuration.

- Specification of the products considered for the Spanish demo

Although the general description of products has been presented in CoordiNet D1.3, the Spanish demo has defined more specific parameters. These additional definitions are also important for the identification of components, information and communication requirements.

- Updated description of the Business Use Cases and Key Performance Indicators

The BUCs methodology and initial description for the different CoordiNet demos has been defined in D1.5. In this deliverable, the Spanish Use Cases have been updated to represent the latest discussions and agreements within the Spanish demos. One of the most relevant updates is a new BUC which consists of a local platform for congestion management.

- Description of current TSO and DSO's activities and platforms

In order to demonstrate the provision of system services, a detailed knowledge of the current activities and platforms is required. This allows building upon the current state and identifying the needs to make possible the development of the BUCs in the Spanish demo.

- Required components and platform development to realize the Spanish demo at the different demo areas

The final section highlights the required components and platforms to realize the defined BUCs in the Spanish demo.

2. Demo site characteristics

This section describes the main characteristics of each of the demo sites, describing the resources considered, their flexibility potential and the network at which these resources are connected.

2.1. Cádiz

2.1.1. Resources characteristics

In Cadiz, the resources considered are renewable, specifically four wind farms and one solar photovoltaic installation as specified below. Initially, the total capacity considered was 160 MW. However, after considering the network topology and the potential flexibility, the installed capacity of resources participating in the demo was reduced to 103 MW.

The total installed capacity of wind farms considered is 91 MW, which are connected at 66 kV and 20 kV and divided between four different locations:

1. Wind CAD 1: connected in 20 kV in the substation SUB_CAD3. The total active power is 10,68 MW, and the Wind Farm has reactive capacity in the substation and in each machine.

   Each unit can reduce its active power through remote set points with the SCADA systems. Therefore, a step-wise flexibility can be performed. There is no possibility for remote changes on reactive power.

2. Wind CAD 2: connected in 20 kV in the substation SUB_CAD 4. The total active power is 32 MW and the reactive power depends on the PQ curve.

   As Wind CAD 2 has a doubly-fed induction generator (DFIG), the wind turbines have the possibility to change their active power output between 100% and 10% of the installed capacity for each turbine (2,070 MW). It also allows remote set point for reactive power.

3. Wind CAD 3: connected at 20 kV in the substation SUB_CAD 5. The total active power is 42 MW, and the reactive power depends on the PQ curve based on the technical capabilities of the wind farm.

   Similarly to Wind CAD 2, Wind CAD 3 has DFIG technology. Therefore, the wind turbines have the possibility to modify their active power between 100% and 10% of the installed capacity by turbine.

4. Wind CAD 4: composed of 12 NTK500/37 machines. The total active power is 6 MW, and the machines are connected at 66kV substation (SUB_CAD 6).

   Similarly to Wind CAD 1, it is not possible to change both active and reactive set points remotely. This would require additional investment.

In addition, a photovoltaic Solar CAD 1 will participate in the demo and is composed of 123 converters with a unit power of 100 kW, each adding a total active power of 12,3 MW and connected at 66kV.The possibility to control the active power output is following a step-wise mode disconnecting solar inverters. The control is possible using the SCADA system of each inverter. There is no possibility to modify reactive power.

All the units belong to Enel Green Power and participate in the day-ahead, intraday and congestion management market currently in place in Spain. Wind farms also participate in the provision of balancing services equivalent to mFRR and RR (currently known in Spain as tertiary reserves and imbalance management services).

2.1.2. Network characteristics

Figure 3 shows the representation of the Cadiz network where the resources are connected. As it can be seen, resources are connected to two different HV substations: SUB_CAD1 and SUB_CAD2.

At SUB_CAD2 substation, two windfarms are connected, Wind CAD 2 and Wind CAD 1, while at SUB_CAD1, two wind farms (Wind CAD 3 and Wind CAD 4) and one photovoltaic solar plant (Solar CAD 1) are connected.

These substations are generally operated without connection between them, but there is a line connecting substation Wind CAD 3 to substation SUB_CAD2. Under normal operational conditions, this line is usually in an open mode, but during the CoordiNet demo, it is going to be studied whether to close it. In this way, all resources can be available to provide flexibility services required at both substations but with different sensitivities or impacts on relieving constraints.

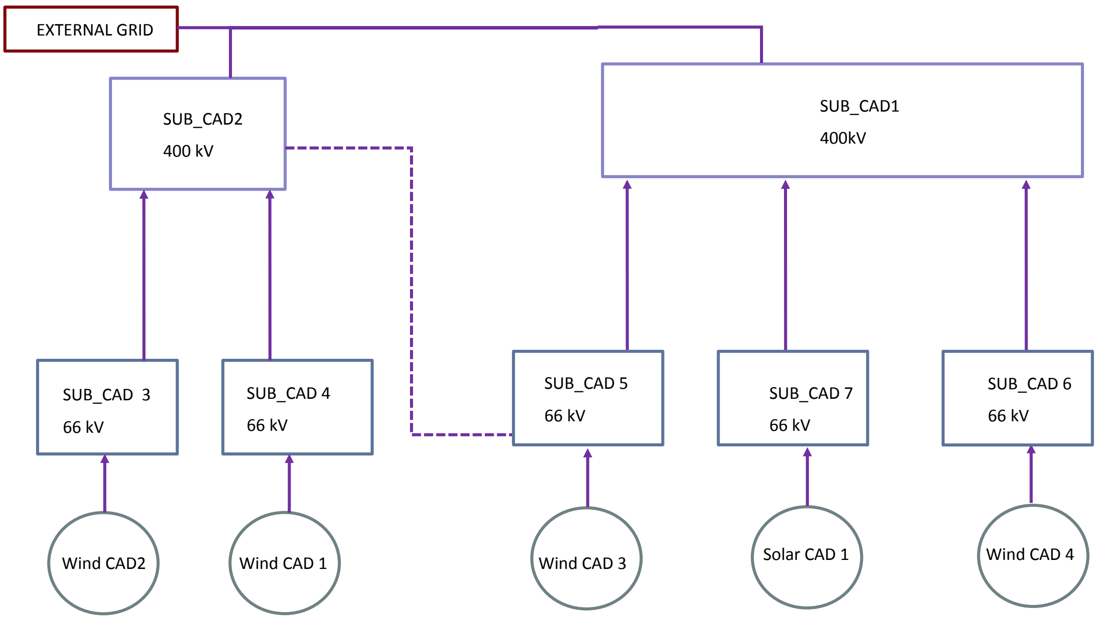

Figure 3 Cadiz network

2.2. Malaga

2.2.1. Resources characteristics

In Malaga, the resources considered are mainly demand-side resources, in which is associated with the generation processes (in the case of co-generation) or shiftable loads. The resources are located at 5 different locations, as described next.

- BIOGAS_MAL1

  The main facilities for the project are four thermal groups using the biogas generated from the landfill of an installed capacity of 1MW each. The flexibility capabilities result from moderating the generation power from the thermal groups.

- COGEN_MAL1: urban water treatment plant

  Similarly to for BIOGAS_MAL1, four thermal groups using biogas obtained from the waste water treatment have an installed capacity of 2,5 MW each. The flexibility capability is obtained from reducing or increasing generation power from these units.

  The water treatment facilities consume a significant amount of electricity, but due to the organic processes, this consumption is very inflexible. Due to the lack of water storage, mainly all water coming has to be treated immediately otherwise it would be spilled in the adjacent river.

- sFSP_MAL2

  sFSP_MAL2 constitutes a microgrid which includes several EV charging points, lead acid battery, and 15 kW PV units. As in the case of sFSP_MAL4, the flexibility results from modifying the operation set-point for the PV inverter and for the batteries charger.

- sFSP_MAL3

  The sFSP_MAL3 is a municipality building with different public offices, a museum and a start-up campus. As a service provider only loads from the start-up campus will be considered.

- sFSP_MAL4

  The sFSP_MAL4 considers a V2G charging point with a 12 kWh lithium- ion BESS and a 3,7 kW solar PV generator. The flexibility within sFSP_MAL4 originates from modifying the operation set-point for the V2G charging point, the batteries charger and the solar PV generation.

- sFSP_MAL5

  sFSP_MAL5 is a convention centre in which main facilities for the project are a 100 kW solar PV facility and lighting circuits. The flexibility capability originates from one lighting circuit. The possibility of obtaining flexibility from the solar PV facility is yet to be confirmed.

- sFSP_MAL1– urban microgrid

The promenade of the Malaga city has DERs including: a 10kW PV generator, a 1 kW mini-wind turbine, Vehicle-to-grid (V2G) charging points, public lighting, lead acid batteries and supercapacitors. The flexibility at this grid connection will be provided by inverters that modify the energy consumed from the grid and the energy injected, the charge/discharge of the batteries and the supercapacitors.

All of the resources considered in Malaga, listed above, do not currently provide any system services.

2.2.2. Network characteristics

The network considered in Malaga includes 40 transformer substations monitored from past projects, while 40 additional transformer substations are considered to be monitored as part of CoordiNet project.

The network covers industrial and residential areas (city centre and new neighbourhoods).

2.2.2.1. Network locations

The CoordiNet demo's scope in Malaga covers three main districts: City Centre, Industrial Park of Guadalhorce and Cádiz Road district, which are further described next.

2.2.2.1.1. City Centre

This area is the largest of the three districts considered within the scope of this demo, and it is spread over the centre of the city of Malaga. Figure 4 shows its extension.

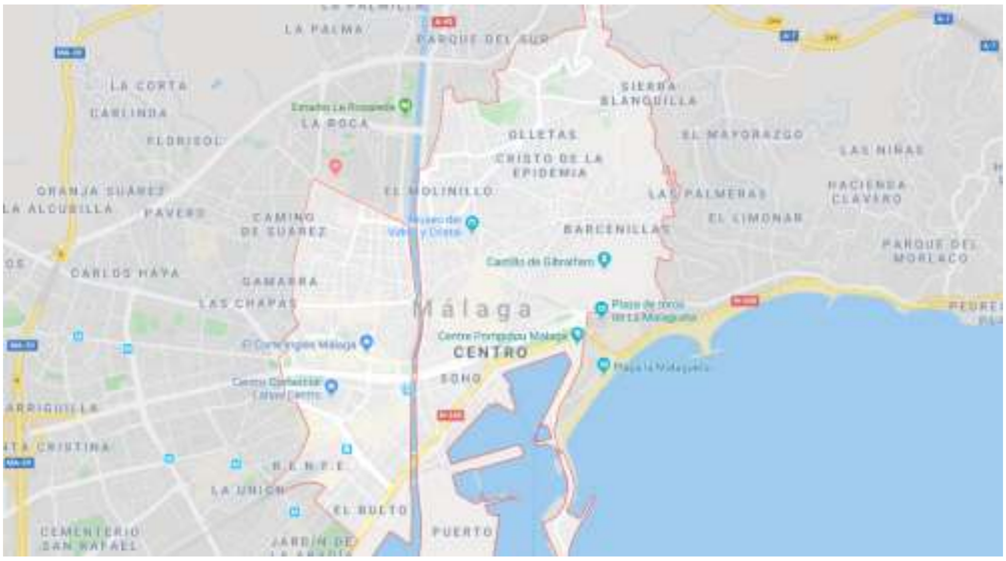

Figure 4 Aerial view of the Malaga centre district. Source: Google Maps

The considered distribution network consists of:

- 2 HV/MV substations
- 10 medium voltage lines
- 131 MV/LV secondary substations with the following characteristics:
    - a) **37** secondary substations for medium voltage clients
    - b) **11** transformers for medium voltage clients sharing a secondary substation with transformers for low voltage clients.

c) **96 secondary substations** consisting of **109 MV/LV transformers**, due to those double-transformer secondary substations, and **74.44 MVA of total rated power**.

2.2.2.1.2. Industrial Park of Guadalhorce

Figure 5 shows the location of the Guadalhorce industrial park.

Figure 5 Aerial view of the industrial park of Guadalhorce. Source: Google Maps

In the case of the Guadalhorce industrial park, the distribution network consists of the following elements:

- 2 HV/MV substations
- 6 medium voltage lines
- 120 MV/LV secondary substations: with the following characteristics:
  - a) 28 secondary substations for medium voltage clients
  - b) 3 transformers for medium voltage clients sharing a secondary substation with transformers for low voltage clients.
  - c) 91 secondary substations consisting of 89 MV/LV transformers, due to those double-transformer secondary substations, and 42.405 MVA of total rated power.

2.2.2.1.3. Cádiz Road District

Cadiz Road is located in the so-called "Smart city Malaga", an initiative of e-distribución. This part of Malaga is presently monitored due to several devices installed in many secondary substations throughout this area, as shown in Figure 6.

Figure 6 Aerial view of the Cádiz Road district. Source: Google Maps

The network monitored in Cádiz Road district consists of:

- 3 HV/MV substations
- 11 medium voltage lines
- 59 MV/LV secondary substations: with the following characteristics:
    a) **8** secondary substations for medium voltage clients
    b) **2** transformers for medium voltage clients sharing secondary substation with transformers for low voltage clients.
    c) **46 secondary substations** consisting of **62 MV/LV transformers**, due to those double-transformer secondary substations.

2.2.2.2. Distributed Generation and Flexibility Providers in Malaga

The different resources considering in the demo are: **BIOGAS_MAL1, COGEN_MAL1, sFSP_MAL1, sFSP_MAL2, sFSP_MAL3 and sFSP_MAL4.** The location information of these resources is summarized in Table 2.

DER name	Primary Substation	MV Line	Connection's Voltage Level	Type	DER Item	Power (kW) / Capacity (kW)
sFSP_MAL1	SUB_MAL5	Line MAL22	LV - 0.4kV	Generation	PV integrated in lighting posts	1,0
				Generation	PV sunshade	9,0
				Storage	Batteries GEL	38,0
				Generation	Mini wind generator	1,0
				Consumption	Public lighting	6,0
				Prosumer	V2G charger (to be confirmed)	TBC
sFSP_MAL2	SUB_MAL3	Line MAL 24	LV - 0.4kV	Generation	PV	15,0
				Storage	Batteries Pb-acid	72,0
				Prosumer	V2G charger (to be confirmed)	TBC
sFSP_MAL3	SUB_MAL3	Line MAL 24	LV - 0.4kV	Consumption	Museum 1	230,0
				Consumption	Museum 2	400,0
				Consumption	Building	
	SUB_MAL5	Line MAL22	LV - 0.4kV	Consumption	Module 1	495,0
					Module 2	
					Module 3	
					Module 4	
					Module 5	
					Module 6	
					Module 7	
sFSP_MAL4	SUB_MAL3	Line MAL 24	LV - 0.4kV	Prosumer	Smart Home PV Batteries V2H (sFSP_MAL4)	31,2
sFSP_MAL5	SUB_MAL3	Line MAL 28	MV - 20 kV	Generation	PV	100,0
BIOGAS_MAL1	SUB_MAL6	Line MAL 27	MV - 20 kV	Generation	Biogas Generation	2096,0
COGEN_MAL1	SUB_MAL3	Line MAL 11	MV - 20 kV	Generation	Natural Gas Cogeneration	10000,0

Table 2 Malaga FSP characteristics and network location

2.2.2.3. Network topological description

This section presents some representation about how the CoordiNet Malaga' network.

On the one hand, in order to clarify the way in which HV/MV are connected to each other through medium voltage lines and, also, to show where the flexibility providers are connected to the network, two diagrams are provided. In those diagrams, every box represents a HV/MV substations (SE), and every line represents a different medium voltage line. On the other hand, going deeper in details, every HV/MV secondary substation can be represented by its own particular diagram in which it is possible to see how MV/LV substations are connected in the MV lines that participate in Malaga's Demo. Figure 7 and Figure 8 present the overall network topology considering the different sbustations.

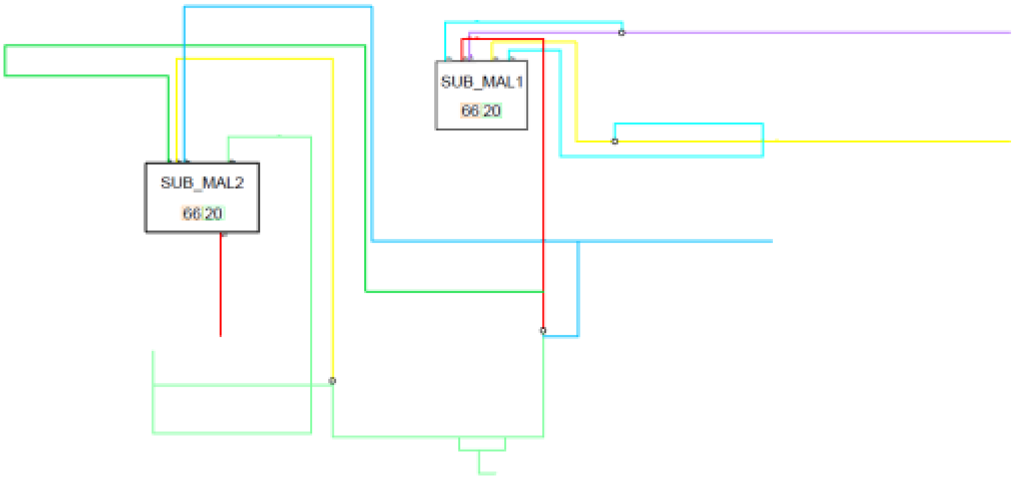

Figure 7 Malaga’s City Centre network diagram

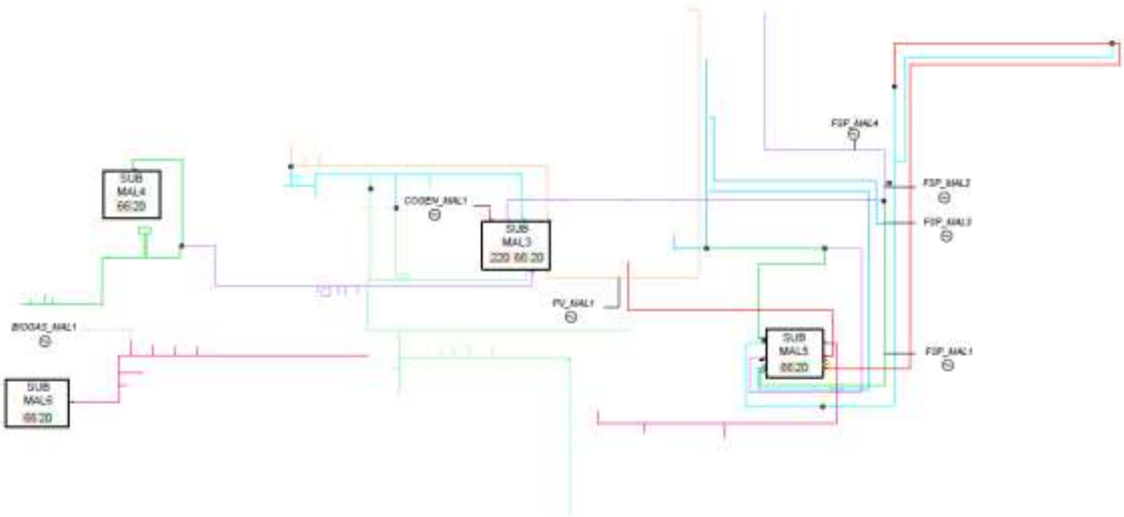

Figure 8 Industrial Park of Guadalhorce and Cádiz Road district single line diagram for Malaga’s demo

- Malaga SUB_MAL1

This HV/MV has 5 MV lines that take part in Malaga’s demo (Figure 9), which amount to 59 MV/LV secondary substations consisting of 57 transformers and 9 medium voltage clients. Also, 7 MV/LV secondary substations are remotely controlled, and 12 transformers have their low voltage side monitored.

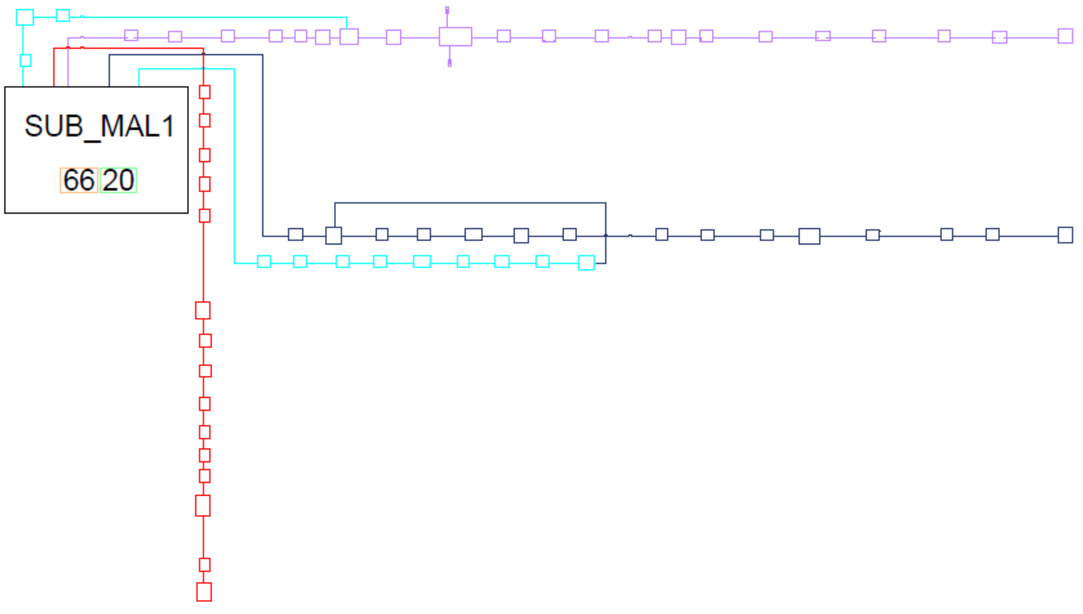

Figure 9 Malaga SUB_MAL1

- Malaga SUB_MAL2

This HV/MV has five MV lines that take part in Malaga's Demo (Figure 10), which amount to 67 MV/LV secondary substations consisting of 49 transformers and 32 medium voltage clients. Also, 10 MV/LV secondary substations are remotely controlled and 7 transformers have their low voltage side monitored.

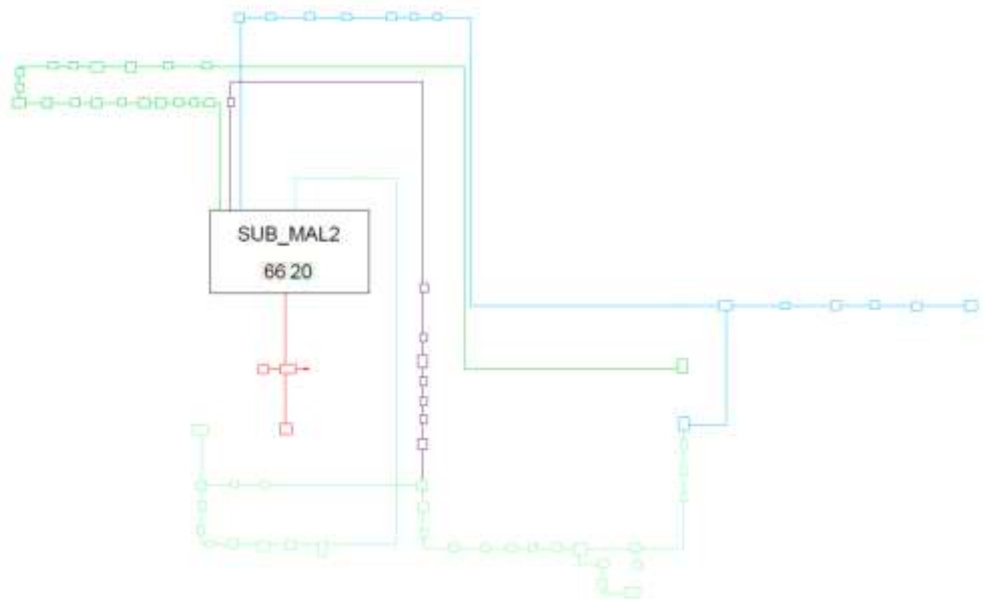

Figure 10 Malaga SUB_MAL2

- Malaga SUB_MAL4

This HV/MV has only one MV line that takes part in Malaga's Demo (Figure 11), which amounts to 9 MV/LV secondary substations consisting of 12 transformers. In addition, 1 MV/LV secondary substations is remotely controlled, and 1 transformer has its low voltage side monitored.

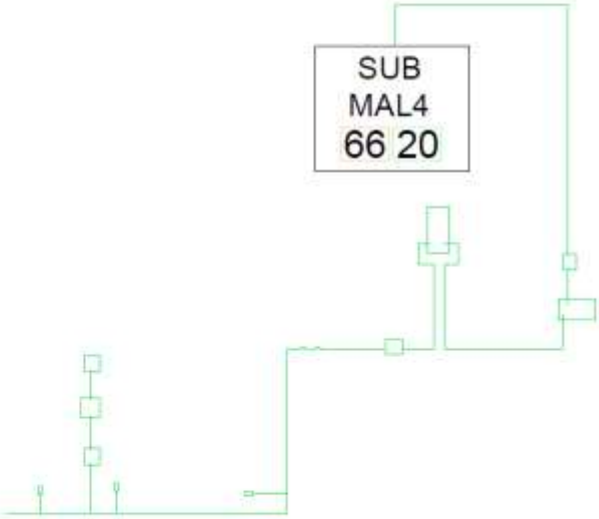

Figure 11 Malaga SUB_MAL4

- Malaga SUB_MAL3

This HV/MV has seven MV lines that take part in Malaga's Demo (Figure 12), which amount to 55 MV/LV secondary substations consisting of 54 transformers and 30 medium voltage clients. In addition, 6 MV/LV secondary substations are remotely controlled, and 4 transformers have their low voltage side monitored.

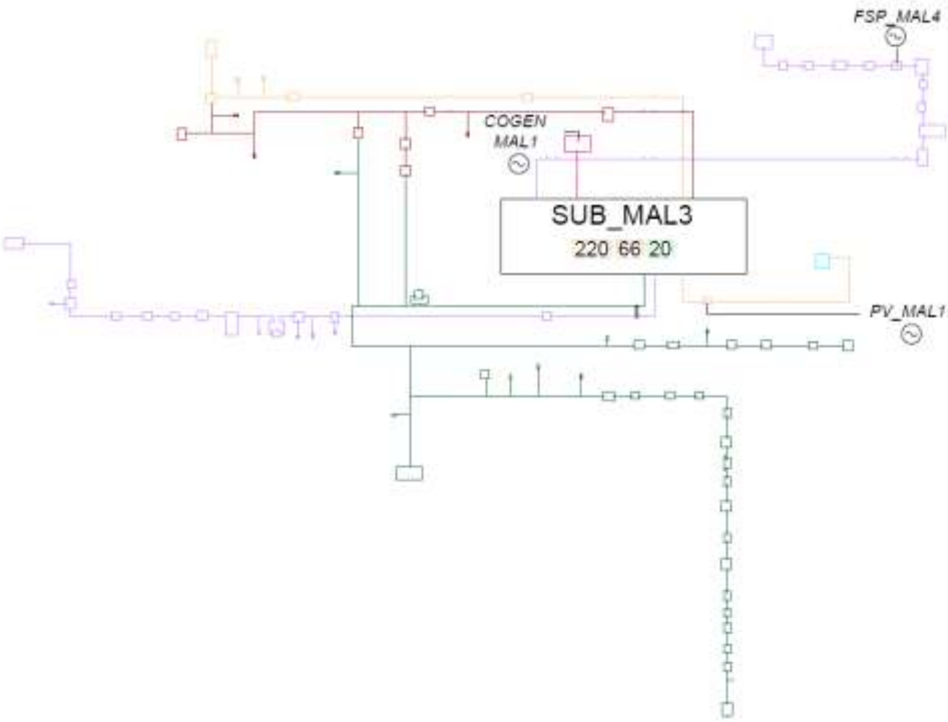

Figure 12 Malaga SUB_MAL3

In addition to this overview of the medium voltage lines and distribution secondary substations, supplementary information is available regarding the low voltage side of the network. This information is of particular interest as it describes the locations at which the low voltage flexibility providers are connected.

In the case of sFSP_MAL4, which is connected to the secondary substation, the distribution network is shown in Figure 15, where the purple line represents the low voltage lines.

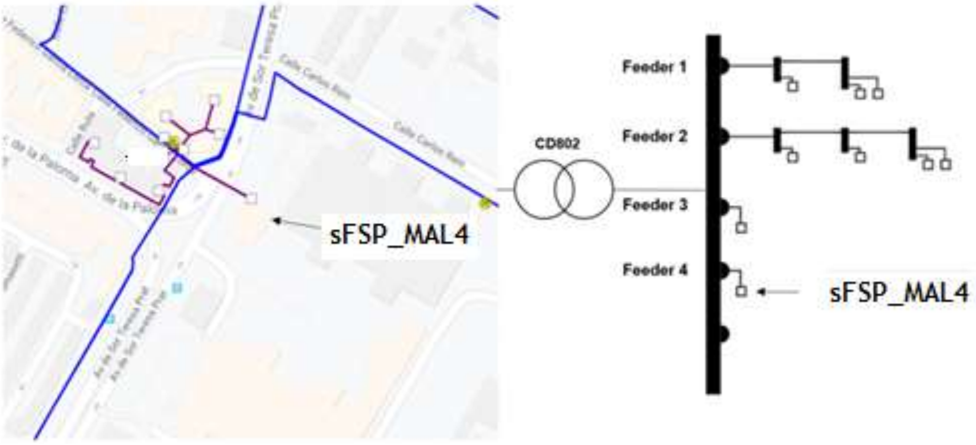

Figure 13 Malaga- sFSP_MAL4 LV feeders specification

- Malaga SUB_MAL5

This HV/MV has eight MV lines that take part in Malaga's Demo (Figure 14), which amount to 49 MV/LV secondary substations consisting of 54 transformers and 5 medium voltage clients. In addition, 14 MV/LV secondary substations are remotely controlled, 26 transformers have their medium and low voltage side monitored, 3 transformers only have their medium voltage side monitored, 7 only have their low voltage side monitored, and 10 MV/LV secondary substations have the input and output medium voltage lines monitored.

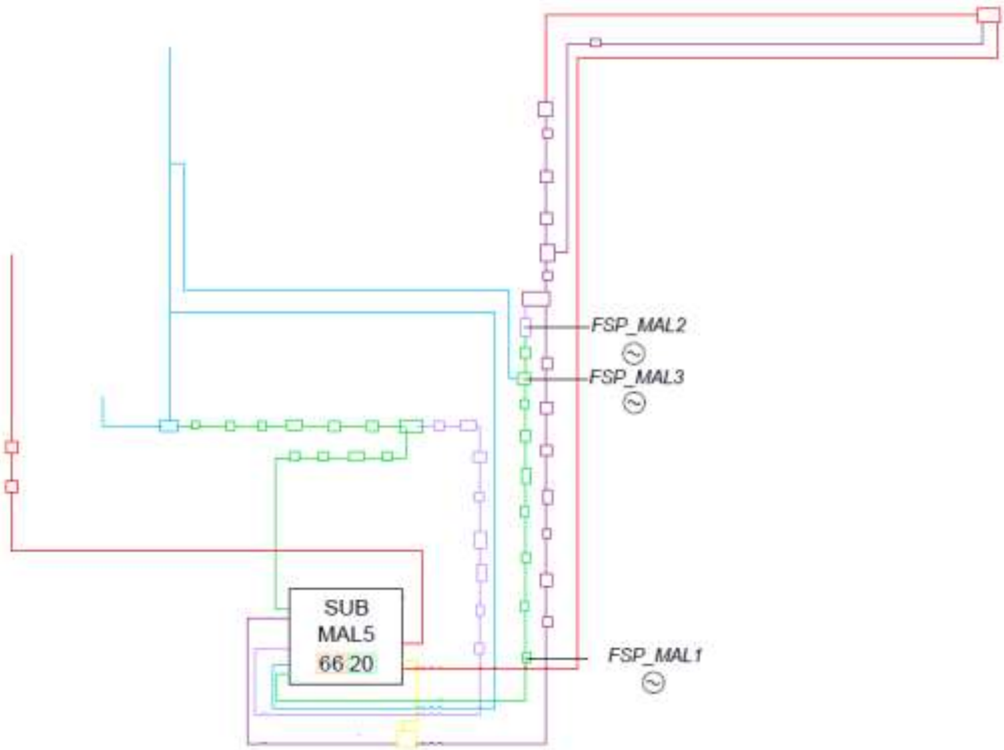

Figure 14 Malaga SUB_MAL5

There are several flexibility resources connected to the low voltage system downstream of SUB MAL5 substation (Figure 15). sFSP_MAL1 is connected to the secondary substation. The distribution network is shown in Figure 15, where purple lines represent the low voltage lines.

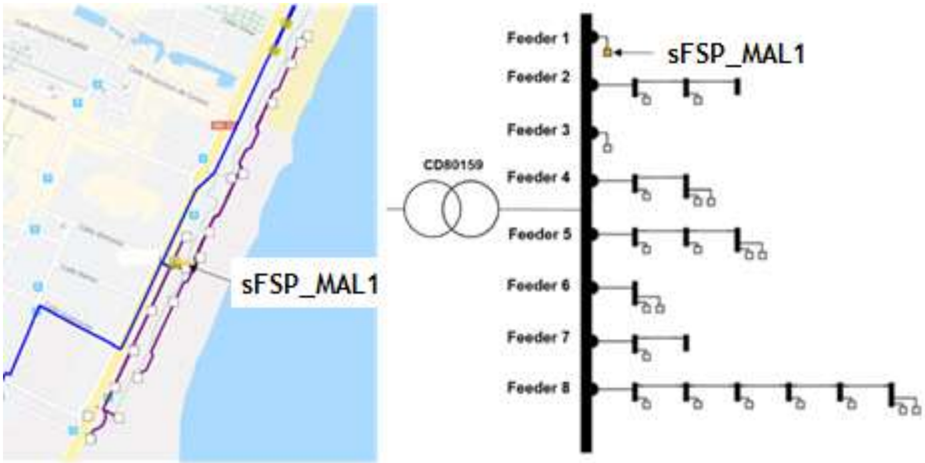

Figure 15 Malaga- sFSP_MAL1 specification

- SUB_MAL6

This HV/MV has only one MV line that takes part in Malaga's Demo (Figure 16), which amounts to 17 MV/LV secondary substations consisting of 11 transformers and 11 medium voltage clients. In addition, 5 MV/LV secondary substations are remotely controlled.

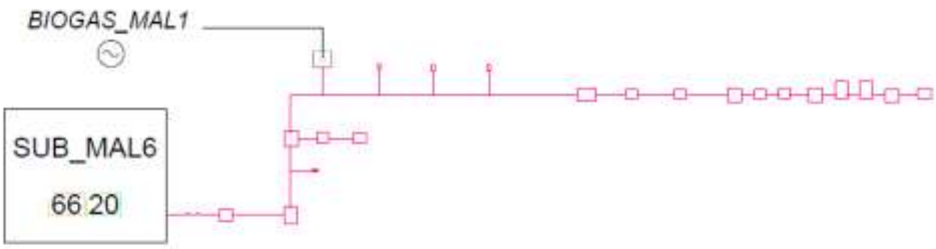

Figure 16 Malaga SUB_MAL6

2.3. Albacete

2.3.1. Resources characteristics

The tests planned for this demonstration involve the 400 kV SUB_ALB1 and SUB_ALB2. In the following sections a detailed description of these substations is presented.

2.3.1.1. Wind in TSO substation SUB_ALB1

Wind farms connected at SUB_ALB1 have significant flexibility for both real and reactive power as shown in Table 3.

Units involved	Type of resource	Total Capacity or contract capacity [MW]	Voltage level at which the unit is connected [kV]	Capability to provide flexibility up & down (MW)	Capability to provide flexibility up & down (MVAr)
Wind ALB 1	Wind	37,62	132	37,62	13,11
Wind ALB 2	Wind	49,5	132	49,50	17,25
Wind ALB 3	Wind	13,2	132	13,20	4,60
Wind ALB 4	Wind	36,96	66	36,96	12,88
Wind ALB 5	Wind	33,1	132	33,10	11,325
Wind ALB 6	Wind	24,42	132	24,42	8,51
Wind ALB 7	Wind	26,4	132	26,40	9,20
Wind ALB 8	Wind	23,1	132	23,10	8,05

Table 3 Wind units involved at TSO SUB_ABL1

2.3.1.2. Wind in TSO SUB_ALB2

Similarly to SUB_ALB1, wind farms connected at SUB_ALB2 have significant flexibility for both real and reactive power as shown in Table 4.

Units involved	Type of resource	Total Capacity or contract capacity [MW]	Voltage level at which the unit is connected [kV]	Capability to provide flexibility up & down (MW)	Capability to provide flexibility up & down (MVAr)
Wind ALB 9	Wind	20,4	132	20,40	6,72
Wind ALB 10	Wind	50	132	50,00	16,375
Wind ALB 11	Wind	42	132	42,00	13,755
Wind ALB 12	Wind	39,1	132	39,10	12,880
Wind Unit 13	Wind	29,75	132	29,75	9,80
Wind ALB 14	Wind	31,02	132	31,02	10,86
Wind ALB 15	WIN	48	132	48,00	
Wind ALB 16	Wind	49,5	132	49,50	17,25
Wind ALB 17	Wind	45,54	132	45,54	15,87
Wind ALB 18	Wind	22,95	132	22,95	7,56
Wind ALB 19	Wind	26,25	132	26,25	

Table 4 Wind units involved at TSO SUB _ALB 2

2.3.1.3. Units connected at SUB_ALB1, SUB_ALB3, SUB_ALB4 and SUB_ALB5

The units considered include small hydro (40,3 MW) and wind (48 MW), as shown in Table 5. The units are connected at 132KV, 66 KV and 20 kV. The maximum flexibility of the hydro units for active power are equal to their installed capacity and depends on the water inflows, except for Hydro ALB5 which, due to restrictions by the Water Management Authority, does not have flexibility. The flexibility of wind farms is to reduce power during high renewable generation and in case it is economically optimal from the system point of view. Table 5 shows the characteristics of each unit. All units can provide voltage control flexibility injection and consumption of reactive power. Currently, these units operate under the constraint of avoiding penalization related to deviations from power factor requirements.

Units involved	Location	Type of resource	Total Capacity or contract capacity [MW]	Voltage level at which the unit is connected [kV]	Capability to provide flexibility up & down (MW)	Capability to provide flexibility up & down (MVAr)
Hydro ALB 1	132kV from SUB ALB 1 to SUB_ALB 3	Small hydro	6,03	132	6,03 Run off river power plant without pondage. flexibility (just for down) assume wasted water	1,883
Hydro ALB 2	Line 132kV from SUB ALB 1 to SUB ALB 3	Small hydro	9,79	132	9,79 Run off river power plant without pondage. flexibility (just for down) assume wasted water	3,056
Hydro ALB 3	Line 132kV from SUB ALB 1 to SUB_ALB 3	Small hydro	13,68	132	13,68 Run off river power plant without pondage. flexibility (just for down) assume wasted water	4,271
Hydro ALB 4	Line 132kV from SUB ALB 1 to SUB ALB 3	Small hydro	4,8	66 SUB_ALB10	4,80 (for 5 minutes)	1,499
Hydro ALB 5	Line 132kV from SUB ALB 1 to SUB_ALB 3	Small hydro	8	20	No flexibility. Instant water flow is fixed by the Water Management Authority (Confederación Hidrográfica del Segura)	2,498
Wind ALB 20	Line 132kV from SUB ALB 1 to SUB ALB 3	Wind	48	132	48	15,720
Cogen ALB 1	Line 132kV SUB_ALB7 to SUB_ALB4	Cogeneration	24	132	18 (just down) 15 min respond	+16MVAr or -8MVA
Wind ALB 21	SUB_ALB5	Wind	24,42	66	24,42	8,51

Table 5 Units located in Albacete at 132 kV DSO SUB_ALB1, SUB_ALB3, SUB_ALB4 and SUB_ALB5

Table 6 shows the units connected at Albacete 66 kV DSO networks.

Units involved	Type of resource	Total Capacity or contract capacity [MW]	Voltage level at which is connected [kV]	Capability to provide flexibility up & down (kW)	Capability to provide flexibility up & down (kVAr)
Hydro ALB 6	Small hydro	8	66	8000 (for 30 minutes)	2498
Hydro ALB 7	Small hydro	3,84	66	3840 (for 30 minutes)	1199

2.3.2. Table 6 Units located in Albacete at DSO at “66 kV Albacete” Network characteristics

The transmission grid in the province of Albacete contains three 400 kV substations (SUB_ALB1, SUB_ALB2, and SUB_ALB6).

The substations 400 kV SUB_ALB1 and SUB_ALB2 are part of double circuits which cross the entire province connecting the provinces of Murcia and Cuenca. Additionally, substations 400 kV SUB_ALB2 and SUB_ALB6 connect Albacete with the province of Valencia. Figure 17 shows the transmission grid in Albacete.

The wind installed capacity in this region is higher than 2.000 MW, while the solar installed capacity is lower than 250 MW. Due to that, one of the main functions of the transmission grid is to allow the renewable generation feed into the grid. Additionally, through these substations, the city of Albacete and the two train substations (ADIF substations) are fed.

Figure 17 Transmission Grid in Albacete province

2.4. Alicante

2.4.1. Resources characteristics

In Alicante, one industrial customer is considered, its main characteristics are shown in

Table 7. With an installed capacity of 22 MW and possibility to increase or decrease active power up to 6 MW and flexibility of reactive power of 3 MVAr.

Units involved	Type of resource	Number of units	Total Capacity or contract capacity [MW]	Voltage level at which is connected [kV]	Capability to provide flexibility up & down (MW)	Capability to provide flexibility up & down (MVAr)
Customer ALI 1	Industrial demand	1	22,1	132	6	3

Table 7 Industrial customer located at 132kV Alicante South.

2.4.2. Network characteristics

The industrial customer is connected at the distribution HV network in a 132kV line between two transport substations connecting Murcia and Alicante.

2.5. Murcia

2.5.1. Resources characteristics

In Murcia, a cogeneration plant is considered which characteristics are shown in Table 8.

Units involved	Type of resource	Number of units	Total Capacity or contract capacity [MW]	Voltage level at which is connected [kV]	Capability to provide flexibility up & down (MW)	Capability to provide flexibility up & down (MVAr)
Cogen MUR 1	Cogeneration in the process of a plastics factory	1	90	132	6 (just down) 1 hour respond	23

Table 8 Characteristics of the cogeneration power plant located in Murcia

In addition, the municipality's buildings will be part of the demo. Table 9 and Table 10 show the flexibility of demand side resources for MV and LV networks respectively. These demand side resources could provide flexibility at different substations which may face voltage and congestion problems in the near future.

Installation	Localization	Cause of congestion	Total power (kW)	Flexible power (down) (kW)	Flexible power (up) (kVAr)
SUB _MUR 1	SUB _MUR 1	Overload	779	TBD	120
Line_MUR 1	SUB _MUR 2	Overload	312	191	36
Line_MUR 2	SUB _MUR 2	Overload	300	123	75

Table 9 Demand side resources location and flexibility at MV feeders in Murcia

Localization	Cause of congestion	Total power (kW)	Flexible power (down) (kW)	Flexible power (up) (kVAr)
Line_MUR 3 (SUB _MUR 1)	Overload	88 Kw	33	0
Line_MUR 4 (SUB _MUR 3)	Voltage Control	314 Kw	0	161
Line_MUR 5 (SUB _MUR 3)	Voltage Control	185 Kw	0	161

Table 10 Demand side resources location and flexibility at LV feeders in Murcia

As for the islanding operation, a battery will be used. Its characteristics are shown in Table 11. The battery capacity used for controlled islanding is limited to 1 MW.

Units involved	Type of resource	Number of units for each tech	Total Capacity or contract capacity [MW]	Voltage level at which is connected [kV]	Capability to provide flexibility up & down (MW)	**Flexible power (MW)**	Capability to provide flexibility up & down (MVAr)
Battery (simulated FSP)	Battery	1	1,25	20	1,25	1	n/a

Table 11 Battery characteristics for islanding operation

2.5.2. Network characteristics

The distribution network considered in Murcia is depicted in Figure 18, where the triangles are the transformers.

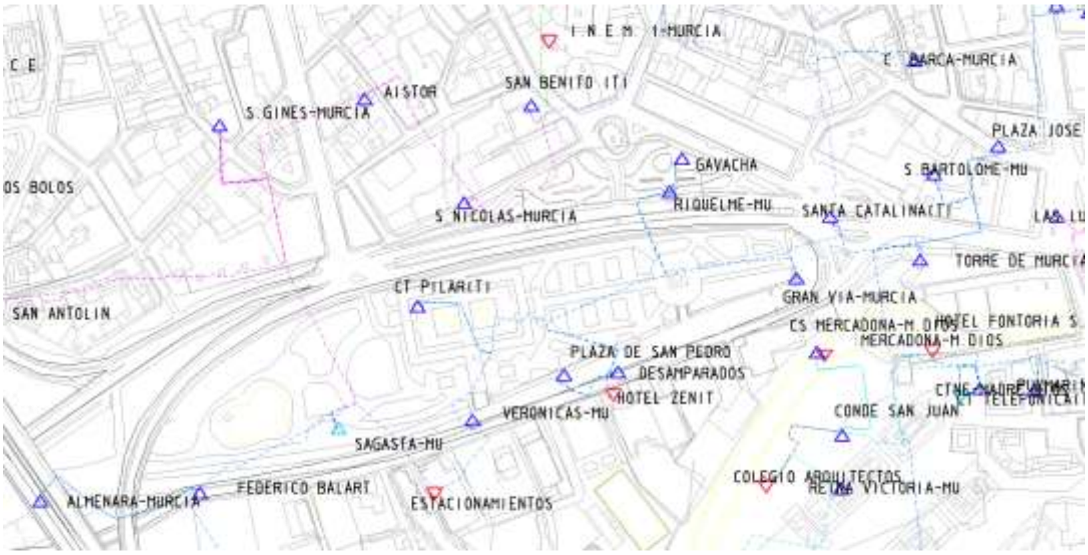

Figure 18 Distribution area involved in Murcia

The islanding service is provided by the simulated FSP. The location of these resources is in the rural region of the Murcia province shown in Figure 19.

The FSP consists of a battery installed in SUB _MUR 4 in a feeder of a rural substation. The battery is able of maintaining voltage and frequency during failures or maintenance.

Demand will be split into 4 different groups that can be added to the electrical island supervised by the DSO (See Figure 19). On the other hand, local PV generation can support the battery in supplying the islanding operation.

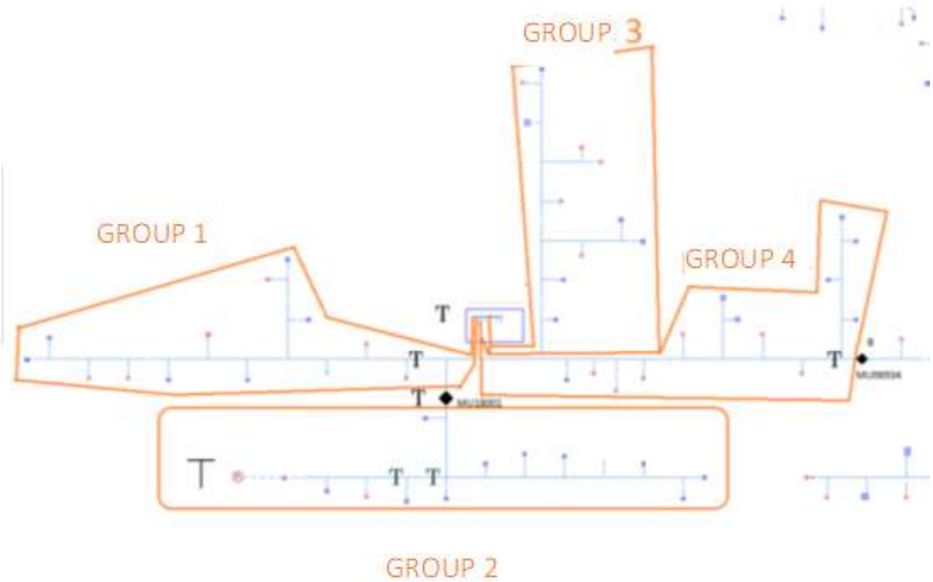

Figure 19 MV grid (20kV) and load groups in Murcia area for local islanding

3. Products definition for the Spanish demo

The definition of products has already been addressed in a general manner in CoordiNet's deliverable D1.3, defining general parameters and the definitions for the project. However, a detailed definition of such parameters is an essential step for defining the BUCs and the different requirements: information, communication and components. In the Spanish demo, those parameters have been defined in more detail as described in this section.

3.1. Balancing

Two balancing products will be tested in the Spanish demo, mFRR and RR. The products characteristics are presented in Table 12 and Table 13.

Attribute	Value
Preparation period	Defined in terms and conditions for BSPs[2].
Ramping period	Defined in terms and conditions for BSPs.
Full activation time	Current value: 15 minutes. Future value: 12,5 minutes (ENTSO-E, 2018).
Minimum quantity	1 MW (small units can participate under aggregation of this quantity).
Maximum quantity	9,9999 MW
Deactivation period	Defined in terms and conditions for BSPs.
Granularity	1 MW
Minimum duration of delivery period	5 min
Maximum duration of delivery period	5' for scheduled activation / 20' for longest direct activation.
Validity period	15 minutes (ENTSO-E, 2018) A scheduled activation can take place at the point of scheduled activation only. A direct activation can take place at any time during the 15 minutes after the point of scheduled activation.
Mode of activation	Manual.
Availability price	Mandatory bid.
Activation price	Yes
Divisibility	Divisible and indivisible bids are allowed. BSPs are allowed to submit divisible bids with an activation granularity of 1 MW. BSPs are allowed to submit indivisible bids (Maximum size of indivisible bids is defined according to national terms and conditions for BSPs).
Location	At least the smallest of LFC area or bidding zone (ENTSO-E, 2018); more detailed locational information is defined in the terms and conditions for BSPs.
Recovery period	Minimum duration between the end of deactivation and the following activation defined in the terms and conditions for BSPs.
Aggregation allowed	Yes
Product Symmetry	No symmetry required.

Table 12 Attributes of the mFRR product

[2] New terms and conditions for BRPs and BSPs have been approved on December 11th 2019, which permit the participation on balancing markets to demand and aggregators, as specified in https://www.boe.es/diario_boe/txt.php?id=BOE-A-2019-18423

Attribute	Value
Preparation period	Defined in terms and conditions for BSPs [3] (0-30 min).
Ramping period	Defined in the RR Implementation Framework (0-30 min).
Full activation time	30 minutes (ENTSO-E, 2018)
Minimum quantity	1 MW
Maximum quantity	No maximum quantity is requested, only technical limits (IT limits).
Deactivation period	In Spain, it will be determined by BSPs.
Granularity	Defined only in LIBRA as 1 MW for offers and 0.1 MW for results.
Minimum duration of delivery period	15 minutes (ENTSO-E, 2018) (one hour in Spain transitory).
Maximum duration of delivery period	Current value: 1h. In the future, it may be reduce to 15 min. Future value: 60 minutes[4] (ENTSO-E, 2018).
Validity period	Allowed in LIBRA between 15 and 60 minutes. In Spain it is 60 min transitory.
Mode of activation	Scheduled
Availability price	Not defined in common project. Not applicable for Spain as no reservation product is expected.
Activation price	Yes
Divisibility	Divisible and indivisible bids are allowed.
Location	At least the smallest of LFC area or bidding zone. In Spain, stakeholders should identify the location.
Recovery period	Not defined. Under BSPs responsibility through their offers.
Aggregation allowed	Yes
Symmetric / asymmetric product	No symmetry required upward and downward bids are separated.

Table 13 Attributes of the RR product

3.2. Congestion Management-Common

In Spain, non-reserved congestion management is defined. This is an energy-based product procured for congestion management services at an energy price (most likely to be procured closer to delivery given the fact that it is energy based). A summary of product attributes is shown in Table 14.

Attribute	Value
Preparation period	Not defined. The SO takes into account the flexibility of the different units.
Ramping period	Not defined. The SO takes into account the flexibility of the different units.
Full activation time	Not defined. Can vary from real time up to 31 hours.
Minimum quantity	0.1 MW
Maximum quantity	N.A.
Deactivation period	Not defined. Depends on the capability of the different units.
Granularity	0.1
Minimum duration of delivery period	NA

[3] The sum of the ramping period and preparation period cannot be greater than the full activation time.
[4] The maximum delivery period depends on the number of daily gates. The RR-Platform will start with 24 daily gates (one optimization which will cover 60 min balancing duration) and maximum delivery period of 60 min. For example, in case of moving the RR-Platform to 48 gates, the maximum delivery period will be 30 min (for 96 daily gates, maximum delivery period will be 15min).

Maximum duration of delivery period	NA
Mode of activation	Manual
Availability price	No. All the units must participate according to their schedules and maximum available power or production forecast.
Activation price	Yes. Bid price except for downwards energy in phase I of technical constraints process in D-1 (upwards energy in the case of pumping units), where the day-ahead market price is the clearing price.
Divisibility	Only divisible bids are allowed. Depending on the previous schedule of the unit, a complex bid could be used for thermal units (start-up costs, number of scheduled hours and energy price)
Location	NA
Recovery period	NA
Aggregation allowed	Yes
Symmetric / asymmetric product	No symmetry required

Table 14 Attributes of the congestion management non-reserved product

3.3. Congestion Management – Local

The local platform for congestion management considers the congestion management reserved. This is a capacity-based product procured for congestion management services at a certain availability price which is then activated when the service is needed by the relevant system operator. This product is defined to cope with structural constraints, the details of this product are shown in Table 15.

Attribute	Value
Preparation period	Day-ahead until hour ahead.
Ramping period	NA
Full activation time	Not defined can vary.
Minimum quantity	1kW
Maximum quantity	1MW (including aggregation). Additionally, the sum of installed capacity in the local market shall be less than 1MW.
Deactivation period	Defined in terms and conditions for sFSPs.
Granularity	1 KW
Minimum duration of delivery period	To be defined as a feature of the FSP in the prequalification and as a potential condition of the need.
Maximum duration of delivery period	To be defined as a feature of the FSP in the prequalification and as a potential condition of the need.
Mode of activation	Manual
Availability price	Yes
Activation price	Possible, dependent on the procurement process.
Divisibility	Divisible and indivisible bids are allowed.
Location	Included in the bid [5].
Recovery period	To be defined as a feature of the FSP in the prequalification and as a potential condition of the need.
Aggregation allowed	Yes, but depending on the grid congestion to be solved and whether the resource has an impact on the congestion.
Product symmetry	No symmetry required.

[5] At least the smallest granularity relevant from grid operation perspective.

Table 15 Attributes of local congestion management reserved product

3.4. Voltage Control

Steady state reactive product aims at providing means to control voltage under normal operation of the system. The product keeps the voltage profile within the safe range. Its provision takes place by injecting or absorbing reactive power according to a voltage set point (measured at the injection point) set by the system operator. Only units that are able to be controlled for the provision of reactive power in function of grid voltage will be able to participate.

In Spain, this service is mandatory for generators that should accomplish the UE 631/2016. In this regard, non-synchronous generators, might install static compensators and static VAR compensators among others to achieve capabilities required in the Spanish implementation of UE 631/2016, in particular in terms of voltage recovery.

A summary of Steady State Reactive Power product characteristics and values are shown in Table 16.

Attribute	Value
Preparation period	N/A
Ramping period	N/A
Full activation time	According to UE 631/2016, the FSP shall be capable of achieving 90 % of the change in reactive power output within a time t1 in the range of 1 to 5 seconds, and must settle at the value specified by the slope within a time t2 in the range of 5 to 60 seconds, with a steady-state reactive tolerance no greater than 5 % of the maximum reactive power
Minimum quantity	N/A
Maximum quantity	Within technical limits of the installation (incl. all available capacities capable of being coordinated at connection point) UE 631/2016[6].
Deactivation period	N/A (constant activation)
Minimum duration of delivery period	N/A (constant activation)
Maximum duration of delivery period	N/A (constant activation)
Validity period	Defined in terms and conditions for FSP
Mode of activation	Automatic (voltage set point)
Availability price	Yes
Activation price	Possible, dependent on the procurement process (€/MVArh)[7]
Divisibility	Not allowed
Location	POC (Point of connection)[8]
Recovery period	N/A (constant activation)
Aggregation allowed	Yes (at connection point level)

[6] Capacities are measured at the generator point of connection with the grid and not at the generator terminals.
[7] The price should in this case reflect, at the very least, incremental active energy losses due to the provision) (Elia, 2018)
[8] At connection point level (at transmission level and distribution level for the TSO and DSO, respectively)

Symmetric / asymmetric product	No symmetry required (injection or absorption of reactive power can be provided separately) (Elia, 2018)

Table 16 Attributes of the Steady State Reactive Power product

Dynamic Reactive Power aims at providing means to control voltage under system disturbance. The dynamic reactive power product consists of a punctual regulation of reactive power injection or absorption requested by the system operator. Participation is open to all technologies capable of following the request within specified time scales.

A summary of characteristics and values for the Dynamic Reactive Power product are shown in Figure 17.

Attribute	Value
Preparation period	N/A
Ramping period	N/A
Full activation time	30 ms for 90% response and 60 ms for 95% response. Or slower if requested by the Relevant Network Operator (in coordination with the SO), e.g. from 30 to 300 ms in 30 ms steps for 90% response and from 60 to 600 ms in 60 ms steps for 95% response.
Minimum quantity	0.1 MVAr
Maximum quantity	Within technical limits of the installation (incl. all available capacities capable of being coordinated at connection point)
Deactivation period	Until voltage enters the normal operation range (Vmin≤V≤Vmax) and after 5 ms from the event
Minimum duration of delivery period	Defined in terms and conditions for FSP
Maximum duration of delivery period	Defined in terms and conditions for FSP[9]
Validity period	Defined in terms and conditions for FSPs
Mode of activation	automatic
Availability price	Yes
Activation price	Possible, dependent on the procurement process (€/MVArh) [10]
Divisibility	Divisible and indivisible bids are allowed
Location	POC (Point of connection)[11]
Recovery period	N/A
Aggregation allowed	Yes (at connection point level)
Symmetric / asymmetric product	No symmetry required (injection or absorption of reactive power can be provided separately) (Elia, 2018)

Table 17 Attributes of the Dynamic Reactive Power product

[9] For instance, in Belgium the average activation period of the centralized voltage control (manual activation) is 10 hours (Elia, 2018)

[10] The price should in this case reflect, at the very least, incremental active energy losses due to the provision) (Elia, 2018)

[11] At connection point level (at transmission level and distribution level for the TSO and DSO, respectively) (Elia, 2018)

3.5. Controlled Islanding

Controlled islanding is often considered as the final stage of the power system defence plans. The difference between controlled islanding and traditional remedial action schemes is that it does not monitor the state of specific transmission lines and generating facilities, but looks at the system topology and the loads and generation in areas of the power system. Based on optimization procedures which take into account the known topology and the actual state of the grid, the size of the island and the isolation points are selected. The basis for islanding is not standard but rather depends upon the nature of the grid under consideration.

In some cases, this concept can be implemented at the transmission system level, while in other it can be done locally at the substation level, even all the way down to a distribution feeder.

In case of detection of events that may lead to a disturbance, signals are sent for the formation of the pre-selected islands in order to: 1) create a balance between the load and generation before the isolation from the system and 2) isolate the island from the system.

At this stage, specific products for this service will not be defined, as during the operation of the island, the services needed could be similar to the ones explained within the document. At the very least, balancing and voltage control would be needed. Similarly to the black start service, we assume that capacity would be procured long term ahead.

4. Use Cases tested in the Spanish demo

4.1. Domains definition used in the Spanish Use Cases

This section describes in detail the Use Cases that will be tested in the Spanish demonstration of CoordiNet. The first definition of BUCs is already provided in deliverable D1.5. Having that as a starting point, modification and inclusion are described here.

The BUC of the Spanish demo considered four differentiated domains: the Transmission System Operator, the Distribution System Operators, the CoordiNet platform and the Flexibility Service Providers.

4.1.1. TSO

The Spanish TSO, Red Eléctrica de España (REE), is the system and transmission network operator (TSO) and owner of the transmission grid. REE operates the system in mainland Spain as well as in the Balearic and Canary islands and in the isolated systems of Ceuta and Melilla.

REE, among other activities, is in charge of solving technical constraints in those systems and keeps electric system balance. In order to perform these tasks, REE runs different ancillary service markets, which include a congestion management market to solve the possible technical problems coming from the Day Ahead (DA) energy market. Currently, only generators and pump-storage units participate in this technical constraint management market. In this market, participants are remunerated following the pay-as-bid system.

Moreover, the TSO operates the balancing markets and contracts operation reserves. Subsequently the secondary - aFRR (reserve capacity: 14:45 – 16:30 of the previous day) is contracted.

After the intraday (ID) market sessions and the continuous intraday market trading, closing just 1 hour before real time, the following balancing markets take place. Firstly, the Replacement Reserves (RR) energy market, which is called deviation management market and is cleared according to marginal pricing at the minute 30 of h-1. Secondly, the tertiary reserves – mFRR –are first cleared in minute 45 of h-1 with possible subsequent clearings if needed until the end of hour h. The energy bid submission for the tertiary reserve market closes 25 min before real time.

In the case of mFRR, all the prequalified generators with available mFRR are obliged to provide their capacity in this last market without capacity market. For secondary reserve, both capacity (band) and the energy is remunerated. Secondary reserve capacity is cleared following the marginal pricing system, while the energy is remunerated at the substation price of tertiary reserves. For tertiary reserves and deviation management, only the energy activated is remunerated at the marginal price.

4.1.2. DSO

The distribution companies (DSO), own and operate the distribution network at voltages below or equal to 132 kV. Spain has six large distribution companies with more than 100.000 clients and 327 distribution companies with less than 100.000 clients[12]. The two largest distribution companies in Spain, e-distribución Redes Digitales S.L. and i-DE Redes Eléctricas Inteligentes, S.A.U., participate in the Spanish demo. e-distribución Redes Digitales S.L (from now on referred to as e-distribución) is present in 27 out of 52 Spanish provinces with 319.000 km of lines and, in 2018, supplied 116.879 GWh (44% of the total Spanish demand)[13]. I-DE Redes Eléctricas Inteligentes, S.A.U. (from now on referred to as i-DE) is present in 25 provinces with 268.570 km of lines and supplied 93.897 GWh in 2018 (35% of the demand)[14].

Currently, congestions at DSOs' networks are not frequent, as, traditionally before reaching technical limits according to planning criteria, the DSOs invest in grid assets to continue providing system security and quality of service to their customers as stablished in the current regulation. However, currently the DSO has limited possibility to use directly flexibility from resources connected to the distribution network (i.e. this activation is possible although it is done through the TSO). With the foreseen massive connection of renewable energy both at transmission and distribution levels, it is expected that congestions could also increase at the distribution level. The requirements of the Clean Energy Package as referred in CoordiNet D1.1 highlight the importance of a proper coordination between the TSO and the DSOs in order to be able to optimize the use of flexibility resources at the distribution level. This change would require necessarily new regulation and active participation of DSOs with the establishment of procedures to manage congestions at DSO networks.

4.1.3. Common and local CoordiNet platforms

The CoordiNet platforms are interfaces that are intended to manage different interactions between the TSO, DSOs and Flexibility Service Providers (FSP) to coordinate the different functions necessary to perform the BUCs. The ownership of the platform and the governance structure for the Spanish demo will not be addressed in the CoordiNet project.

The focus of CoordiNet is on defining the roles and functions that this platform may have. Some of the relevant functions to be performed by the platform include: gathering market bids, exchanging the sensibility of each potential FSP of resources that can solve technical constraints and flexibility needs from both TSO and DSO[15], performing market clearing functions, communicating the market results, submitting activation bids to service providers and grid operators, as well as the settlement process. All these functions will be described in detail for each of the BUCs. Operational functions –FSP activations- are out of the scope of this platform and are performed by the relevant grid operator.

The CoordiNet Platforms will be used to purchase flexibility through market solutions, but in cases where competition is not guaranteed, the use of flexibility can be alternatively used through other mechanisms such as non-firm connection charges which allow the DSOs or TSO to limit the generation output or consumption during a certain limited time.

For practical reasons, the platforms will be located in the Spanish demos on the TSO and DSO premises.

[12] https://sede.cnmc.gob.es/listado/censo/1
[13] https://www.endesadistribucion.es/es/conocenos/nuestro-negocio.html
[14] https://www.iberdroladistribucion.es/conozcanos/principales-magnitudes
[15] The sensitivity of each FSP to solve a grid constraints will depend on different factors, such as its location on the grid, the grid topology and the technological characteristics of the resource, among others. These sensitivities factors are needed when full network and FSP information is not fully available.

Two main platforms are considered: the common TSO-DSO platform used for balancing, common congestion management and voltage control. The local platform will manage local congestion management and islanding operation.

4.1.4. Flexibility Service Providers

Flexibility Service Providers (FSP) provide system services either directly or as an intermediary managing resources from grid users, based on which they are able to modify the energy injections or withdrawals from resources connected to the distribution or to the transmission grids. The intermediary can be an independent aggregator or a retailer that represents flexible resources and coordinate their response. Therefore, flexible resources can include both Distributed Energy Resources (DERs) and resources connected at transmission network. However, the main focus is on DERs and the need to aggregate these resources as there is less expertise in this developing this task, especially with regards to the aggregation of demand at the distribution level. Through interruptible contracts, many generation resources and industrial consumers connected at the distribution network are currently providing balancing and congestion management services.

As defined in the CoordiNet deliverable D1.1, DER is a concept used to encompass the multiple types of end-users connected to the distribution grid, capable of providing energy and/or services to the grid by mobilizing the flexibility they have available. Four different types of DER have been differentiated. The first type of DERs constitute generators connected to the distribution grid or to the consumer who must be supplied, which are termed Distributed Generation (DG) (Gharehpetian & Agah, 2017). The second type of DERs consists of the active/flexible demand, named Demand Response (DR). The third type of DERs is storage systems, named Energy Storage Systems (ESS). In this category, batteries are also included in addition to Electric Vehicles (EV), which act as a type of ESS with some specific features. Due to their potential importance and connection availability, EVs are considered separately from ESS. Finally, the fourth type of DERs is energy efficiency, which is considered to be a DER that allows the reduction of energy needs permanently.

An addition aspect of main importance is to consider the voltage level in the distribution grid at which the resources are connected. For example, a DG connected at the distribution high-voltage (HV)[16] level could be a wind farm of 10MW of installed capacity, while a DG connected at the low-voltage (LV) level can be a rooftop solar panel system with an installed capacity of 10kW or less. Therefore, these two DGs are clearly very different. The same can be said regarding DR provided by a residential consumer as compared to a large industrial consumer. Figure 20 summarizes the general definition of DER.

[16] In Europe, most DSOs also operate HV networks (Eurelectric, 2013). In general, distribution networks operate LV (<1kV), MV (typically 15, 20kV), HV (45, 66, up to 132kV), while TSOs operate Extra-High Voltage (EHV, typically 220, 275, 400kV). These boundaries, however, change from country to country. For additional details, please refer to (Eurelectric, 2013).

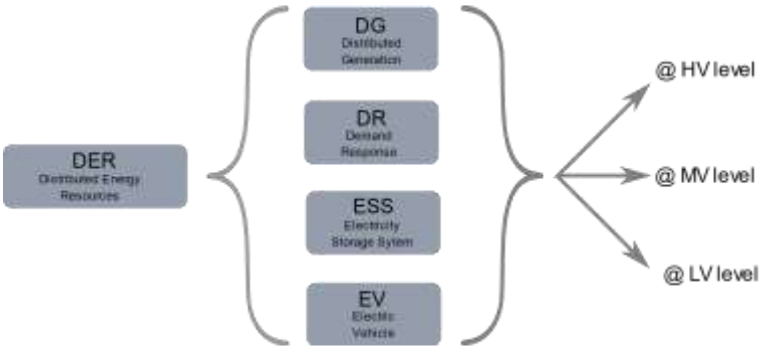

Figure 20: Classification of DER according to their nature and voltage level

4.2. Common congestion management

In the Spanish demo, grid congestions services can be provided to both the TSO and DSOs. This service can therefore solve the congestion problems that can occur either due to contingencies, programmed maintenance or more frequent or structural congestions due to limited transfer capacity at the TSO and DSOs networks. These structural congestions are currently common within the TSO networks. However, in the future, with increasing flexible operation of DSO networks, these structural congestions can be also expected at lower voltage levels. In order to alleviate congestions, within the focus of this BUC, modification in the levels of active power injections and withdrawals are required. Voltage control using induced changes to reactive power are addressed in a separate BUC.

4.2.1. Objectives

The main objective of this BUC is to procure flexibility from resources connected at both TSO and DSO networks in a coordinated manner to solve transitory congestions that can occur at both networks.

Currently in Spain, the TSO manages network congestions that occur both at transmission and distribution levels through a technical constraint management market by re-dispatching generation units connected at transmission, but also at all voltage levels (including LV and MV). If needed, the DSO has the possibility to request from the TSO to call the use of the interruptibility service or redispaching and curtailment of generation. The current price floor in the congestion management market is 0 €/MWh and, currently, there is no price cap applied apart from IT system limits. Moreover, the security planning and operating criteria (voltage bands, congestions thresholds, and n-1 criteria) that are necessary to identify transparently the technical constraints needs are contemplated at the TSO level in the current regulatory framework. The current regulation does not include this at the DSO level.

As highlighted in CoordiNet D1.1, in Spain, DSOs can use DER, more specifically DG, to solve congestions in the same way as the TSO does. This process, however, is done through the TSO in coordination with the DSO (i.e. after an outdated process based on an email or a similar process sent by the DSO to the TSO). Once congestions in the distribution grid are identified and DSO is not able to solve the problem operating the network, then the needs for change the dispatch are sent from the DSO to the TSO. This can be done if there are generation units that have an impact on the congestion. The TSO is the responsible to access the bids and calculates the necessary redispatch to solve the detected constraints[17]. In case a DG is redispatched, it will be remunerated according to the existing market rules (which are the same as the units re-dispatched due to congestions in the transmission grid). For planned curtailment, producers receive no financial compensation. In addition to congestion management, DSOs may also request to the TSO changes in the power factor instructions sent to generation units with installed capacity larger than 5 MW. In this case, the TSO is the responsible to order the relevant changes in the set points sent to the generators connected at the distribution grid. Nowadays, this mechanism applies only for generators and not for consumers.

Therefore, as of today, the DSO, through the TSO, can use DG for local congestion management and power factor control. In addition, consumers with contracted power above 5MW can participate in interruptible services. As the DSO and TSO send these requests, the TSO ultimately receives the congestion management bids that are able to solve the constraints, assigns them and instructs DERs.

Regarding the size (i.e. installed capacity limits) of DERs able to provide services for congestion management to the DSO, there are no limitations with respect to the voltage level to which providers are connected. Participation is currently only allowed for generation units and pumped hydro units.

As of today, in Spain, DSOs cannot sign interruptible contracts with DER. The only form of interruptible contract is between the TSO and industrial consumers. However, DSOs may use these interruptible contracts signed with the TSO to solve constraints in their distribution networks as well.

Starting in February 2016, all redispatch due to congestion management in the DSO or TSO networks, including generation from renewable sources, is done via market mechanisms (PO 3.2). In the real-time technical constraint management process, DG has to pay the downward bid price, which is generally very close to 0 €/MWh, enabling DG owners to keep almost 100% of the market marginal price (being the Day Ahead price of a specific hour) that they have received for selling their production in that hour. Thus, changes in the renewable generation production can happen due to market clearing from the congestion management or balancing market.

In any case, as a last resort, if still needed in real time, the TSO and DSO can curtail renewable generation for security reasons without a market based mechanism. However, since 2016, all congestion management situations have been solved through these market-based mechanisms.

4.2.2. Brief Overview

More active participation of resources including DER in the congestion management market, as well as more frequent procurement of flexibility by DSOs require a boost of the current congestion management market and operational procedures. Processes that are currently performed manually can be performed in a semi-automated manner and ensuring that the needed information is available to both the TSO and the affected DSOs. The product traded would be to increase or decrease energy to solve grid congestions, the possibility to have a capacity product would be explored in a second stage of the demo and it is not addressed in the following description.

[17] Process described in the *Procedimiento de Operación (Operation Procedure)* 3.2.

The main functions developed by each actor are represented in Figure 21.These functions are divided in four relevant timescales which are described in detail below: the long-term (from years until day-ahead), the day-ahead, balancing timeframe (from one hour to real-time) and after real-time. The numbering of the functions is described according to the sequential action, and the arrows represent the information flows among the different actors.

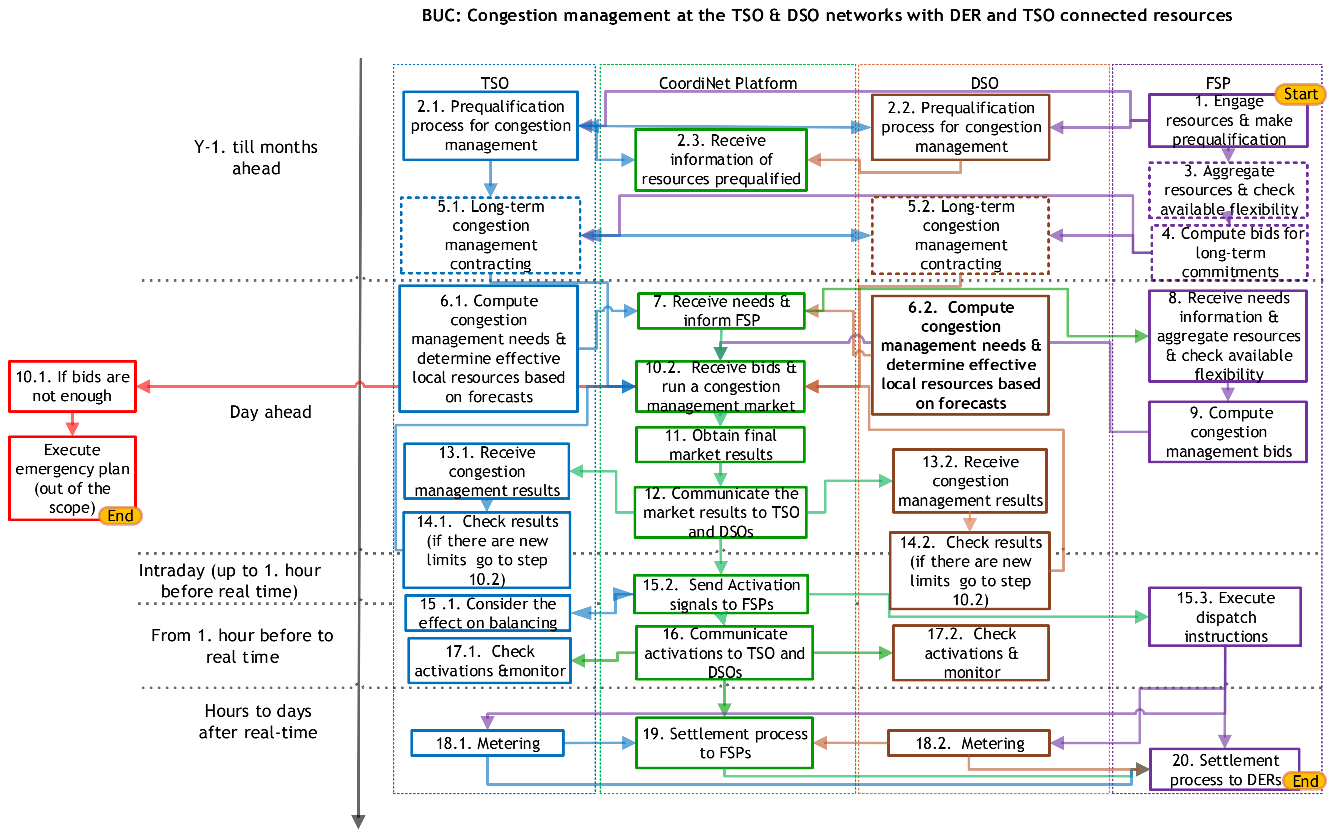

Figure 21 Flow diagram of main functions for common congestion management

4.2.2.1. Long-term

A prerequisite for the BUC is the product definition addressed in CoordiNet D1.3. Once the products are defined, the next step starts with the engagement of customers and the evaluation of their flexibility[18] (Step 1). Once the flexibility is known, FSP needs to successfully pass a prequalification process either with the TSO or both TSO and DSO in case the FSP is connected to the DSO network (step 2.1 and 2.2). This prequalification will be registered at the CoordiNet platform (step 2.3).

Long-term procurement of congestion management services may be necessary to include flexible resources in the planning process in a level playing field with traditional network investments “wires solutions”. Currently in Spain, the TSO contracts long-term flexibility only through interruptible contracts with large industrial consumers which is intended to be used for security reasons. Although the long-term procurement of flexibility for congestion management purposes from the TSO and DSO may be necessary, it requires a thorough evaluation which will not be addressed for the Spanish demo. Again, as both grid operators may procure flexibility through long-term contracts, a coordination is essential to guarantee that conditions from both grid operators are compatible. The possibility to include this long-term procurement is defined within steps 3 to 5 in the diagram.

[18] Customer engagement strategies are addressed in CoordiNet D1.2.

4.2.2.2. Day-ahead

At the day ahead timeframe, after the day-ahead energy market, the congestion management market takes place to account for possible network congestions. The process will start with computing the foreseen requirements from the TSO and DSOs and determining the effective local resources that can potentially solve the network constraints based on the power flows forecasts (steps 6.1 and 6.2). These effective local resources will be determined from those that have been prequalified while accounting for the impact on the identified congestion and considering also their offered bids. The TSO and DSO will inform the platform of the resources that have influence on the congestions (step 7).

In the meantime, the FSP have to aggregate DERs, determine the available flexibility (step 8) and compute congestion management bids for the relevant locations (step 9.1). Meanwhile, resources connected at the transmission network also compute their bids for the market (step 9.2).

The CoordiNet platform will receive the needs and the effective local resources identified from the TSO and DSOs, as well as the bids from the FSP (step 10.2). If bids are not enough to alleviate the foreseen congestions, then an emergency plan has to be activated (step 10.1), which is out of the scope of this document and the scope of the CoordiNet Spanish demo. A detailed procedure and the definition of the clearing algorithm have to be defined to handle situations where potential conflicts emerge. For example, the same resources may be used to solve congestions that affect two networks in the opposite direction. Therefore, the overall system approach has to be considered (step 10.2). For this BUC all bids are put together in one pool and then the market is cleared to alleviate the congestions at both network levels. This market scheme has been described as common market model as defined in CoordiNet D1.3. Once all the relevant constraints and available resources have been considered, the CoordiNet platform obtains the results (step 11) and communicates them to the TSO and DSOs (step 12). Both grid operators will receive the results (step 13.1 and 13.2) and check their feasibility (step 14.1 and 14.2). If there were any additional constraints, then the market could be run again (back to step 10.2), depending on the situation.

4.2.2.3. From 1 hour before to real time

From about one hour before real time, the TSO manages the balancing of the system. It can be the case that a resource used for balancing is will not be available anymore for congestion management or, by activating resources for congestion management, it can affect the balancing of the system. Therefore, the TSO has to establish a procedure to account for these circumstances (step 15.1). The final results are also sent to the concerned FSP (15.2). The CoordiNet platform will also inform the TSO of the flexibility activations, who will also inform the (European) balancing platform to correct the corresponding short and long balancing positions. This is necessary to ensure that the BRPs whose position has been affected are not penalized for this reason. The FSP has to perform the activation of resources manually or automatically (step 15.3). The platform communicates the different activations to the TSO and DSOs (step 16) who have to check the activation and monitor the system (step 17.1 and 17.2) to verify the fulfilment of the service (congestion management).

4.2.2.4. After real-time

Once the services are delivered, the electricity generated or consumed has to be metered. In Spain, the entity that performs the metering activity depends on the consumption, generation and the grid level of the connection point[19]. For consumers, metering activity is only performed by the DSO regardless of the grid level (transmission or distribution) to which they are connected. Metering for generators with capacity below 450kW is performed by the DSO, while all the rest is done by the TSO regardless of the grid level (transmission or distribution) to which they are connected (step 18). The CoordiNet platform will then use the metering data to perform the settlement process of congestion management services with the FSP (Step 19). Then, the FSP will perform the individual settlement with the resources, which may include other services or even the energy sold in the day-ahead market or other contractual agreements (step 20). In other words, it is the FSP's responsibility to settle with individual units all the different services provided.

4.2.3. Key performance indicators for congestion management

Table 18 presents the list of KPIs which will be used for congestion management in the Spanish demo. The numbering, definition of the KPIs, and the classification are presented in CoordiNet D1.6.

KPI ID	KPI Name	KPI Category
KPI_1	Cost of counteractions needed based on the activated flexibility	Economic
KPI_3	Cost of R&I solution vs. grid alternative solution	Economic
KPI_4	OPEX - OPerational EXpenditures	Economic
KPI_5	OPEX for service procurement	Economic
KPI_6	Average cost per service for the examined period	Economic
KPI_7	Increase RES and DER hosting capacity	Technical
KPI_8	Reduction in RES curtailment	Environmental
KPI_9	Share of fossil-based activated energy	Environmental
KPI_10	Accuracy of the RES production forecast calculated 1 hour in advance	Technical
KPI_11	Accuracy of the RES production forecast calculated 24 hours in advance	Technical
KPI_13	Criticalities Reduction Index	Technical
KPI_16	Potential Offered flexibility	Technical
KPI_17	Increase in the amount of load capacity participating in DR	Social
KPI_18	Volume of transactions	Economic
KPI_19	Number of transactions	Economic
KPI_20	ICT cost	Economic
KPI_22	Requested flexibility	Technical
KPI_25	Accuracy of load forecast calculated 24 hours in advance	Technical
KPI_30	Peak load demand reduction	Technical
KPI_31	Total activation time of a product	Technical
KPI_34	Percentage of tested products per demo	Technical
KPI_36	Participant recruitment	Social

[19] See Article 3 in Royal Decree 1110/2007, *por el que se aprueba el Reglamento unificado de puntos de medida del sistema eléctrico*.

KPI_37	Active participation	Social
KPI_38	Type of flexibility providers per demo	Technical
KPI_39	Total Computational Runtime	Technical

Table 18: KPIs for congestion management

4.2.4. Common congestion management in Cadiz

Congestion management in Cadiz will consider all the resources available for this demo. As described before, two different substations are considered where specifically two transformers are connected:

- 220/66 kV transformer in SUB_CAD1 substation
- 220/66 kV transformer in SUB_CAD2 substation

These substations are, in principle, not connected, and therefore congestion management should be tested in two separate areas. Nevertheless, there is a possibility to close a line, therefore connecting substations SUB_CAD1 to SUB_CAD2 and all resources will then be in a single demo are for congestion management purposes.

4.2.5. Common congestion management in Malaga

Flexibility resources connected to the distribution MV networks will manage congestions of the HV/MV substation transformer to which the resource is connected.

There are two flexibility scenarios that can be studied: one related to sFSP_MAL5 and COGEN_MAL1, and the other related to BIOGAS_MAL1.

sFSP_MAL5 and COGEN_MAL1 are connected to substation SUB_MAL3. This substation is constituted by three HV/MV transformers.

- sFSP_MAL5 is connected downstream transformer. This transformer has a rated power of 30 MVA and a rated voltage of 66/20 kV. sFSP_MAL5 resource has the capability of managing consumption in order to provide flexibility. Concretely, the flexibility proposal is to reduce air conditioning consumption, which would allow to reduce transformer load percentage.
- COGEN_MAL1 is connected downstream transformer. This transformer has a rated power of 30 MVA and a rated voltage of 66/20 kV. COGEN_MAL1 resource has the capability of reducing or increasing generation power from thermal groups with a rated power of 10 MW.

BIOGAS_MAL1 is connected to substation SUB_MAL6. This substation is constituted by 2 HV/MV transformers.

- BIOGAS_MAL1 is connected downstream transformer. This transformer has a rated power of 20 MVA and a rated voltage of 66/20 kV. BIOGAS_MAL1 resource has the capability of reducing generation power from thermal groups with a rated power of 4.4 MW.

4.2.6. Common congestion management in Albacete

Four different substations are considered for congestion management in Albacete:

- Congestions in 132kV from SUB_ALB1 to SUB_ALB3

The BUC for congestion management will be tested considering different limits for the line capacity to relieve such congestions. Possible faults of connections (i.e. SUB_ALB1 to SUB_ALB3) will be also simulated.

- Congestions in 132kV from SUB_ALB7 to SUB_ALB4

In this case, we will simulate the limit for the line capacity and consider alternatives to relieve such situation that may be caused by an excess of generation. Possible faults of connections (i.e. near SUB_ALB7 and SUB_ALB4) will be also simulated.

- Congestions in transformation capacity from SUB_ALB7 or SUB_ALB8

A problem to feed SUB_ALB9 will be studied by a simulated lack of power coming from 132kV to 66kV, which would be similar to the case of a transformer fault. Also the lack of connection to substation Albacete will be studied. In this latter case, the limit for the transformer capacity will be simulated, and various options will be considered to relieve this situation.

- Congestions in lines coming from SUB_ALB10 and SUB_ALB11

A problem to feed SUB_ALB4 will be studied by a simulated lack of power coming from both connections. Wind farms are considered to contribute to relieving congestions by reducing the power injected at time of high generation. The lack of the power coming from two neighbouring substations will also be studied.

4.2.7. Common congestion management in Alicante

Demand response could help in case of lack of capacity to feed Elche, which is the main city supplied by this 132kV line. For this test case, a simulated limit to demand capacity will be tested, as well as simulated failures of connections, near the locations of Rocamora and San Vicente.

4.2.8. Common congestion management in Murcia

In Murcia different locations are considered for congestion management:

- Congestions in 132kV from SUB _MUR 5 to SUB _MUR 1.

Because of the large power flows coming from the south of Murcia to the north, the 132kV lines going from SUB _MUR 5 to SUB _MUR 1, SUB _MUR 2 and SUB _MUR 3 could in a near term be congested. Reducing generation may relieve expected congestions.

- MV congestions in Murcia City

In Murcia city, only demand response to avoid congestions will be considered. The list of units involved are still to be determined as their flexibility is being tested.

4.3. Local congestion management

4.3.1. Objectives

The main objective of this BUC is to procure flexibility from resources connected at the DSO LV networks to solve transitory congestions that can occur at the DSO LV networks. This BUC is of main importance due to:

- The local nature of the congestions in the network where the DSO may not have full observability and monitoring capabilities.
- Small flexibility service providers (sFSP) may face an entry barrier to particiapte in the common congestion management platform.
- The proposed product is less complex, has low response time and longer activation in case of structural congestions, maintenance and outages on local networks.

4.3.2. Brief Overview

The main functions developed by each actor for the local congestion platform are represented in Table 22. Similarly to the case of the common congestion management platform, these functions are divided in four relevant timescales which are described in detail below: the long-term (from years until day-ahead ahead), the day-ahead, the balancing timeframe (from one hour to real-time) and after real-time. The numbering of the functions is described according to the sequential actions, and the arrows represent the information flows among the different actors.

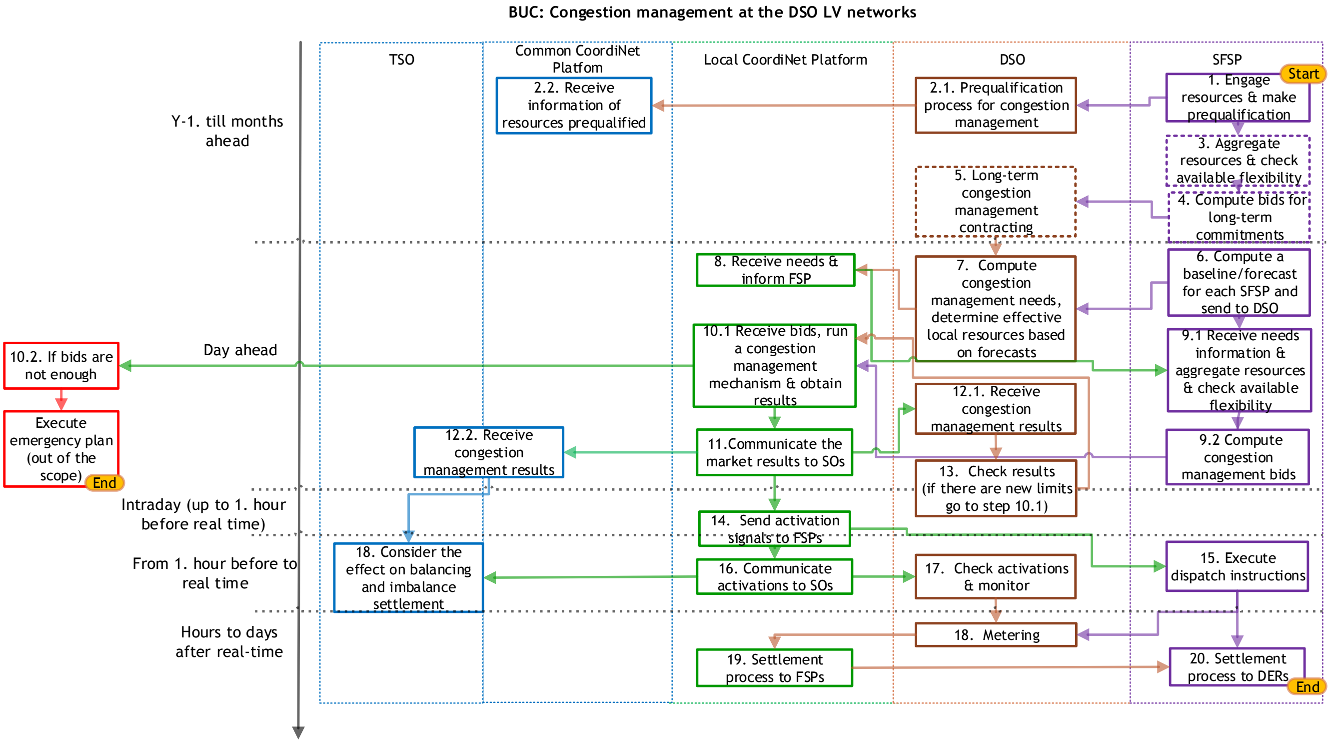

Figure 22 Flow diagram of main functions for local congestion management

4.3.2.1. Long-term

Once the flexibility is known, a prequalification process will be carried out between the sFSP and the DSO or both[20] (step 2.1 and 2.2). The outcome of this prequalification process will then be registered in the CoordiNet common platform (step 2.2).

In similar a way similar to the common congestion management, long-term procurement of congestion management services may be necessary to include flexible resources in the planning process in a level playing field with traditional network investments or "wires solutions". The possibility to include this long-term procurement is defined within steps 3 to 5 in the diagram.

4.3.2.1. Day-ahead

At the day ahead timeframe, after the day-ahead energy market takes place, the congestion management market takes place to account for possible network congestions. The process will start with the FSP computing the individual baseline (i.e. reference power profile from which flexibility will be accounted) for the flexible resources and sending it to the DSO (step 6) who would compute the foreseen requirements and determine the effective local resources that can potentially solve the network constraints based on the power flows forecasts (step 7). These effective local resources will be determined from those that have been prequalified while accounting for the impact on the identified congestion, and considering also the offered bids. The DSO will inform the local platform of the resources that have influence on the congestions, and the platform will inform the FSP (step 8).

In the meantime, the sFSP must aggregate DERs, determine the available flexibility (step 9.1) and compute congestion management bids for the relevant locations (step 9.2).

The CoordiNet local platform will receive the bids from the sFSP (step 10.1). If the received bids are not enough to alleviate the foreseen congestions, then an emergency plan has to be activated (step 10.2), which is out of the scope of this document and of the CoordiNet Spanish demo. Once all the relevant constraints and available resources have been considered, the CoordiNet local platform obtains the results (step 10.1) and communicates them to the TSO and DSO (step 11). Both grid operators will receive the results (step 12.1 and 12.2), at which time the DSO checks their feasibility (step 13). If any additional constraints persist, then the local platform could be run again (back to step 10.1), depending on the situation.

4.3.2.1. From 1 hour before to real time

Once the final solution is obtained at the local platform, the activation signal is sent from the local platform to the sFSP (step 14) who execute the dispatch (step 15). The local platform informs the TSO and DSOs of the activations (step 16). The DSO controls and monitors the activation (step 17), while the TSO considers the effect on balancing and the economic deviations (step18).

[20] The prequalification process can be limited to the DSO, but can also be extended to the sFSP, as an aggregator. In this case, the sFSP may want to carry an internal prequalification with the aggregated resources.

4.3.2.2. After real-time

Once the sFSP delivers the service, the electricity generated or consumed has to be metered by the DSO, as the resources considered for local congestion management are connected to LV level (step 18). The CoordiNet local platform will then use the metering data to perform the settlement process for local congestion management services with the sFSP (Step 19), and then the sFSP will perform the individual settlement with the resources which may include other services of even the energy sold in the day-ahead market or other contractual agreements (step 20). In other words, it is the sFSP's responsibility to settle with individual units all the different services provided.

4.3.3. Key performance indicators for congestion management

Table 19 presents the list of KPIs which will be used for local congestion management in the Spanish demo. The numbering, definition of the KPIs, and the classification are presented in CoordiNet D1.6.

KPI ID	KPI Name	KPI Category
KPI_1	Cost of counteractions needed based on the activated flexibility	Economic
KPI_3	Cost of R&I solution vs. grid alternative solution	Economic
KPI_4	OPEX - OPerational EXpenditures	Economic
KPI_5	OPEX for service procurement	Economic
KPI_6	Average cost per service for the examined period	Economic
KPI_7	Increase RES and DER hosting capacity	Technical
KPI_8	Reduction in RES curtailment	Environmental
KPI_9	Share of fossil-based activated energy	Environmental
KPI_10	Accuracy of the RES production forecast calculated 1 hour in advance	Technical
KPI_11	Accuracy of the RES production forecast calculated 24 hours in advance	Technical
KPI_13	Criticalities Reduction Index	Technical
KPI_16	Potential Offered flexibility	Technical
KPI_17	Increase in the amount of load capacity participating in DR	Social
KPI_18	Volume of transactions	Economic
KPI_19	Number of transactions	Economic
KPI_20	ICT cost	Economic
KPI_22	Requested flexibility	Technical
KPI_25	Accuracy of load forecast calculated 24 hours in advance	Technical
KPI_30	Peak load demand reduction	Technical
KPI_31	Total activation time of a product	Technical
KPI_34	Percentage of tested products per demo	Technical
KPI_36	Participant recruitment	Social
KPI_37	Active participation	Social
KPI_38	Type of flexibility providers per demo	Technical
KPI_39	Total Computational Runtime	Technical

Table 19: KPIs for local congestion management

4.3.4. Local congestion management in Malaga

In Malaga, a local platform model will be tested. The resources participating in this BUC are all the resources described in section 2.2. The detailed characteristics of this platform is described in section 6.1.2.

Flexibility resources connected to the LV system will manage congestions of the MV/LV transformer of the secondary substation to which the resource is connected.

There are four flexibility scenarios that can be studied: one related to sFSP_MAL1, other related to sFSP_MAL2, other scenario involving sFSP_MAL3 and the last with sFSP_MAL4.

- sFSP_MAL1 is connected to a secondary substation SS_MAL1. This SS is constituted by one transformer with a rated power of 630 kVA and a rated voltage of 20/0.4 kV. sFSP_MAL1 is a microgrid constitud by diferent agents that can provide flexibility: management of PV generation by inverters with a rated power of 10 kW and management of storage systems (batteries, EV charging points and supercapacitors). The aforementioned microgrid agents can be used to reduce or increase load percentage of SS transformer.
- sFSP_MAL2 is connected to secondary substation SS_MAL2. This SS is constituted by three transformers. sFSP_MAL2 is connected downstream transformer, with a rated power of 230 kW. sFSP_MAL1 is a microgrid formed by diferent agents that can provide flexibility: management of PV generation by inverters with a rated power of 15 kW and management of batteries with a maximun charge/discharge power of 6 kW. The aforementioned microgrid agents can be used to reduce or increase load percentage of SS transformer.
- sFSP_MAL3 is connected to secondary substation SS_MAL2. This resource is connected downstream customer transformer 2, with a rated power of 400 kW. This resource is a campus with the capability of managing consumption.
- sFSP_MAL4 is connected to secondary substation SS_MAL4, formed by one transformer with a rated power of 400 kW and a rated voltage of 20/0.4 kV. This resource is constitued by EV charging points with the capability of recharging or discharging their batteries, with a maximum charge/discharge power of 22 kW. The storage capability of this resource can be used to reduce or increase load percentage of SS transformer.

In order to control the loads in Malaga, the monitoring and control system is done through an Energy Box (EB). The EB is a solution for micro-grid management developed by CIRCE. It is a multi-purpose concentrator for the operation in various scenarios of advanced electrical networks and Smart Grids. In addition to its versatile communication capabilities, it contains an embedded computer that provides computing and processing capacity to implement distributed computing: collection and storage of information, execution of algorithms and control of the installation among others.

The modular architecture of the Energy Box has been completely designed, developed and tested by CIRCE with different physical communication interfaces: Ethernet, serial connectors, ZigBee and Wi-Fi. The central processor is based on Raspberry Pi technology for industrial environments, which guarantees continued interoperability, support and supply. The software is also an integral creation of CIRCE. Its architecture is divided into two blocks: communication and management.

The management block is responsible for gathering all system information for further processing, in addition to performing real-time management of the system. For this management, local algorithms can be implemented using ADA as programming language, which is specific for critical systems with very strict temporal requirements.

The Energy Box has been used successfully in many R&D projects such as FLEXICIENCY and EV-OPTIMANAGER, among others. In these projects, the EB has been used to monitor and manage microgrids, public and residential ones, and electric vehicle charging facilities. An important example of the versatility of the

Energy Box is that, in these projects, it has been used to control CIRCE developments (EV charging points, batteries and super capacitors storage systems and solar PV inverters) and commercial ones such as: EV charging points (MAGNUMCAP), solar PV converters and batteries charge regulators (SMA and SCHNEIDER).

In the flexibility providers' premises, the EB will have two main objectives:

- Directly connected to devices or to local SCADAs, the EB will monitor operating state of the flexibility providers and send this data to the agreggator.
- Receive operation set points from the aggregator and apply it to the flexibility providers.

The energy box main technical specifications are shown in Table 20.

Energy Box hardware specifications	
EnergyBox CPU	Raspberry Pi CM3 Lite: • Quad-core BCM2837 @ 1,2 GHz (x10 RPi1) processor • 1 GB RAM • Shape factor DDR2 SODIMM (67.6mm x 31mm)
External connectors	• RS485 • Ethernet • 5 V DC supply voltage
Wireless communications	• WiFi • Zigbee
Local data storage	**micro SD** slot to store local data and loading the Raspberry Pi 3 Lite operative system
External envelope	• Material: Polystyrene (PS) • Size: 100x150x30 mm • Material width: 3 mm
Back-up energy source	3V battery that powers the real time (RTC) DS1307 clock that takes control of the internal time of the EB. This battery allows controlling the time even when the primary power supply is not available.
External LEDs	4 external LEDs indicating: • WiFi connection state • Zigbee connection state • RS485 connection state • Voltage supply state
External buttons	3 external buttons to reset: • WiFi connection • Zigbee connection • The Raspberry, and to reset predefined values

Table 20 Energy Box hardware specifications

Figure 23 shows the main components of the EB, which will be used for the Malaga demo.

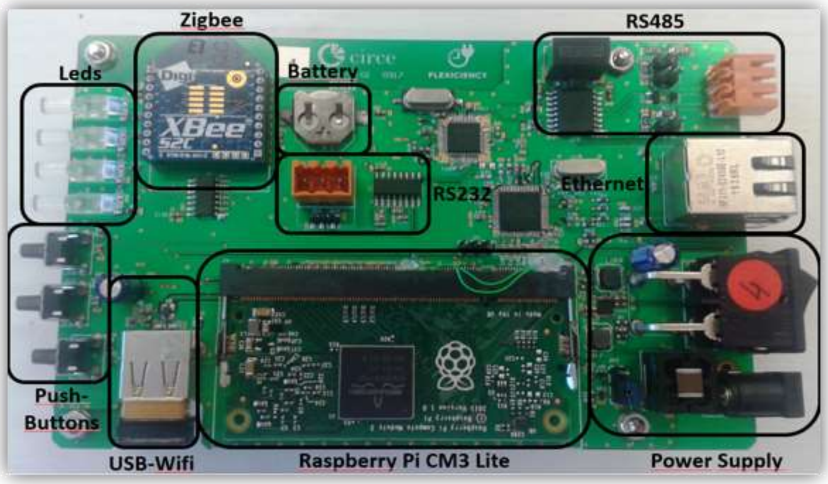

Figure 23 Components of the Energy Box

The operating system used is Linux, as it is open source, safe and it supports many, almost all, programming languages. Local algorithms will be programmed in Ada / GNOGA programming languages:

- GNOGA - GUI applications based on Ada language where security is essential.
- Ada is ideal for compact and efficient embedded applications due to its multitasking capabilities and orientation to critical system security.

In addition to the communication between the DSO and the sFSP, there are communications between the DSO and the TSO through the local and common market platforms, further details on these interactions among the platforms are detailed in section 6.1.2.

4.3.5. Local congestion management in Murcia

Resources belonging to Murcia city hall are considered to solve overloads at LV. These resources are presented in Table 10. The detailed characteristics of this platform and the main differences with respect to the Malaga platform are described in section 6.1.2.

The considered congestions are at LV feeders and transformers in Murcia city.

4.4. Procure and manage balancing services (FRR & RR) to reduce balancing costs

The system balancing is a function performed exclusively by the TSO. Therefore, the primary actor in this BUC is the TSO.

This BUC evaluates how to improve the coordination between the TSO and DSOs when the activation of energy resources including DER providing balancing services to the TSO increases. This might result in constraints in the DSO network. The process description would apply for both manual Frequency Restauration Reserves (mFRR) and Replacement Reserves (RR).

4.4.1. Objectives

Reducing balancing cost (TSO perspective), while avoiding unforeseen congestion problems at the distribution level.

4.4.2. Brief Overview

Currently, generation resources connected at distribution networks can provide balancing services, but not demand-side resources.

Figure 24 presents the main functions developed by each of the actors that interact in the BUC. In a similar manner to congestion management, the functions are divided in four relevant timescales which are described in detail below: the long-term (from years until day-ahead), the day-ahead, from one hour to real-time and post-real-time. The numbering of the functions are described according to the sequential actions, and the arrows represent the flows of information among the different actors.

Two main products relevant for balancing are: the balancing capacity and the balancing energy. According to the EBGL, the balancing capacity is defined as: “a volume of reserve capacity that a balancing service provider has agreed to hold and in respect to which the balancing service provider has agreed to submit bids for a corresponding volume of balancing energy to the TSO for the duration of the contract” and the balancing energy: “means energy used by TSOs to perform balancing and provided by a balancing service provider” (European Commission, 2017). The flow diagram specifies the functions necessary to deliver both services.

In this use case, the FSP perform the function of Balance Service Provider (BSPs), which, according to the EBGL, means a market participant with reserve-providing units or reserve-providing groups able to provide balancing services to TSOs.

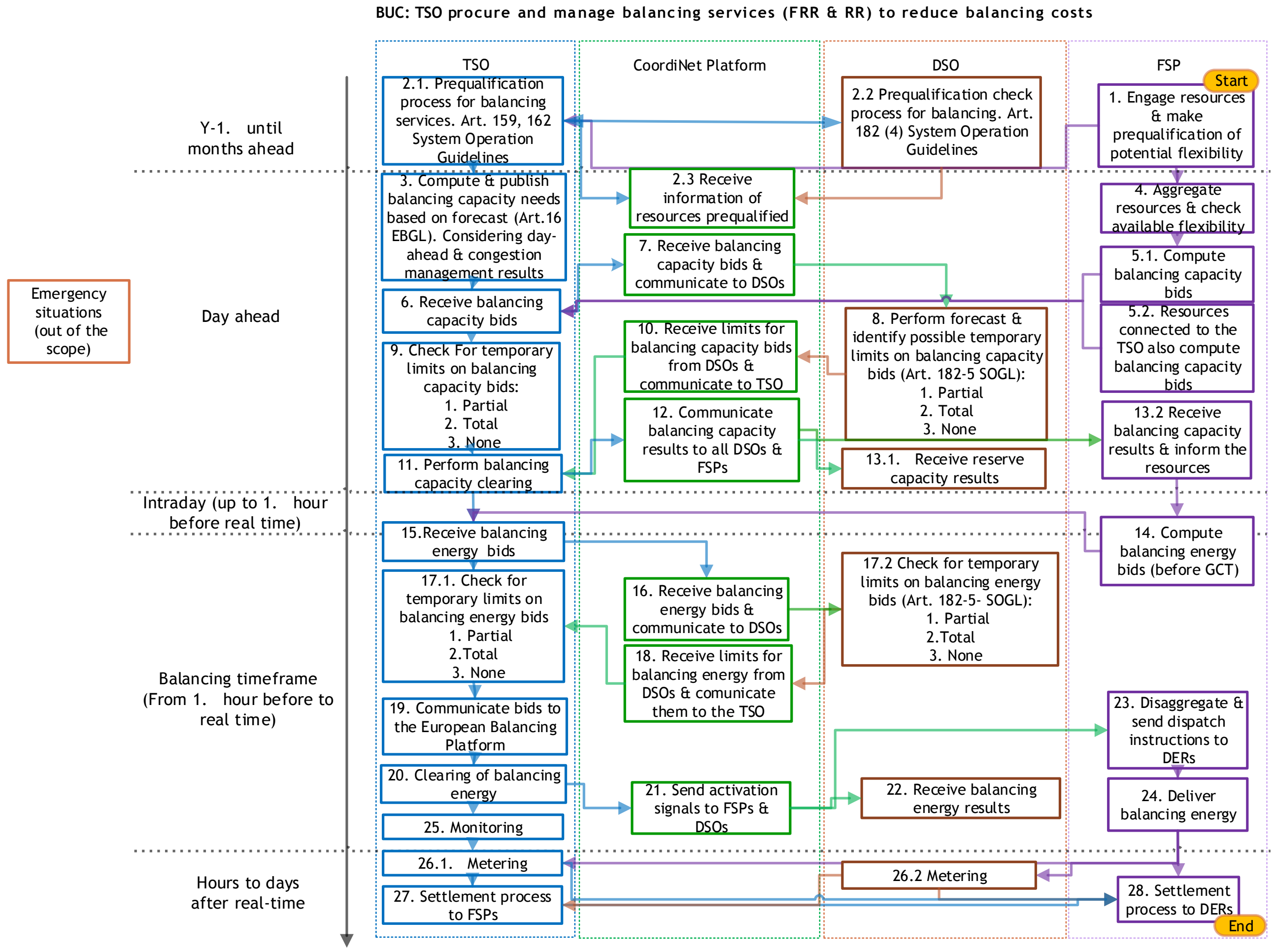

Figure 24 Flow diagram of main functions for balancing service

4.4.2.1. Long-term

The balancing products are being defined in the European Balancing Platforms (see CoordiNet D1.1). They have been specifically harmonized in the TERRE and MARI platform for both RR and mFRR. In a manner similar to congestion management, the first steps will be to engage resources and understand their flexibility (step 1). Once the flexibility is known, the TSO performs a prequalification process for the FSP that are interested in providing balancing (step 2). As resources are connected to the DSO, the TSO performs the prequalification with information exchange with the DSO (Art. 182 of SOGL) and informs the CoordiNet platform.

4.4.2.2. Day-ahead

In Spain, the balancing process starts after the day-ahead and congestion management markets. The TSO computes the balancing capacity needed based on the energy market results and its own forecasts (Step 3). The FSP estimate their available flexibility (step 4) and compute the balancing capacity bids (step 5.1) in a similar manner as resources that are connected to the TSO (step 5.2). The TSO receives the capacity balancing bids[21] (step 6) and communicates them to the CoordiNet platform, which sends them to the relevant DSOs (Step 7). The DSOs forecast and identify transitory limits in their networks (step 8). These limits can completely or partially restrict the bids from FSP in the balancing markets. In a similar manner, the TSO may identify limits on certain bids (step 9). The limits from DSOs are communicated to the platform (step 10), and then to the TSO which runs the balancing capacity market and obtains results (step 11). These results are then communicated to the platform which sends them to the DSOs and the FSP (step 12). The DSOs consider this information in their systems (step 13.1) and the FSP inform the affected resources (step 13.2).

4.4.2.3. From 1 hour before to real time

Based on the balancing capacity and additional available information, the FSP submit balancing energy bids to the TSO before the gate-closure time of the balancing energy markets (step 14). Resources that have not provided balancing capacity can, in any case, also provide balancing energy (voluntary bids).

The TSO receives the balancing energy bids until the gate-closure time of each balancing service (step 15). Then, the TSO communicates these bids to the platform, which are sent to the DSOs (step 16). Both the TSO and DSOs check again if new limits on their networks are foreseen which may restrict the delivery of balancing energy (step 17.1 and 17.2). Any additional limit is communicated to the platform, which informs the TSO (step 18). Considering this information, the TSO communicates the available energy balancing bids and its balancing needs to the European Balancing Platforms (step 19). The Balancing platforms (MARI, TERRE, PICASSO) perform the energy balancing market clearing while considering all of the relevant information and bids available from neighbouring systems (step 20) and submit the results to the platform

[21] A separation can be made for FRR and RR capacity products and different markets can be established but they would follow similar procedure.

(step 21). The CoordiNet platform then submits the results to the DSOs[22] (step 22) and the FSP, which have to allocate the response to the controlled resources (step 23) and deliver balancing energy (step 24). Meanwhile, the TSO has to monitor the system and guarantee adequate energy balancing of the system (step 25).

4.4.2.4. After real-time

The TSO and DSOs read the delivered and consumed energy for balancing (step 26). Then, the TSO performs the balancing settlement with the FSP based on the energy delivered as well as on the corresponding penalties for non-delivery (step 27). The FSP will then perform their own settlements for the individual units with the final provision of services (step 28), similar to the previous BUCs.

4.4.3. Key performance indicators for balancing

Table 21 presents the list of KPIs which will be used for balancing in the Spanish demo. The numbering, definition of the KPIs and the classification are presented in CoordiNet D1.6.

Table 21: KPIs for balancing services

KPI ID	KPI Name	KPI Category
KPI_3	Cost of R&I solution vs. grid alternative solution	Economic
KPI_4	OPEX - OPerational EXpenditures	Economic
KPI_5	OPEX for service procurement	Economic
KPI_6	Average cost per service for the examined period	Economic
KPI_9	Share of fossil-based activated energy	Environmental
KPI_10	Accuracy of the RES production forecast calculated 1 hour in advance	Technical
KPI_11	Accuracy of the RES production forecast calculated 24 hours in advance	Technical
KPI_16	Potential Offered flexibility	Technical
KPI_17	Increase in the amount of load capacity participating in DR	Social
KPI_18	Volume of transactions	Economic
KPI_19	Number of transactions	Economic
KPI_20	ICT cost	Economic
KPI_21	Deviation between accepted and actual activated mFRR	Technical
KPI_22	Requested flexibility	Technical
KPI_25	Accuracy of load forecast calculated 24 hours in advance	Technical
KPI_31	Total activation time of a product	Technical
KPI_34	Percentage of tested products per demo	Technical
KPI_36	Participant recruitment	Social
KPI_37	Active participation	Social
KPI_38	Type of flexibility providers per demo	Technical
KPI_39	Total Computational Runtime	Technical

[22] In this BUC, the balancing market is cleared within the TSO's premises, so no need to communicate the TSO.

4.4.4. Balancing in Cadiz

All the wind farms units considered in Cadiz are prequalified to provide balancing services. Therefore, the interaction between balancing participation and other BUCs will be considered for all the wind farms.

4.4.5. Balancing in Malaga

In Malaga, the resources considered are not prequalified to provide balancing services. As most are demand-side resources, the prequalification process is not in place yet in Spain. In CoordiNet, the possibility to test the provision of these resources in the demo will be considered.

4.4.6. Balancing in Albacete

All wind farms considered in Albacete are prequalified to participate in the balancing markets (tertiary reserves and imbalance management). In addition, three small hydro plants are also prequalified: Hydro ALB4, Hydro ALB6 and Hydro ALB7.

4.4.7. Balancing in Alicante

As described earlier, there is not a procedure in place to enable demand-side resources to provide balancing services. During CoordiNet, this possibility will be studied after determining which resources are suitable for assessment.

4.4.8. Balancing in Murcia

In Murcia, only demand-side resources are considered. As described previously for Malaga, the possibility to provide balancing services is not determined yet but will be explored in the project.

4.5. Voltage control

This service can be tested to solve voltage problems that occur at the TSO and DSOs' networks.

4.5.1. Objectives

The increasing penetration of intermittent generation connected at distribution networks might create unwanted voltage variations. Moreover, the replacement of traditional synchronous generators by wind and solar plants -some of whose voltage control capacity may be more limited- results in voltage control scarcity in some areas of the network. However, the latest technological improvements in inverters allow RES to support voltage control[23]. In this context, the existing voltage control mechanism based on a unique power factor set point by generation plant[24] can be improved by voltage set points at the connection point. In fact,

[23] For further details, see Generators Connection Grid Code (UE/2016/631 or RfG), or the Spanish TSO and DSO national implementation proposal and sent to the Spanish Regulatory Authority.
[24] See Royal Decree 413/2014 or Procedimiento de Operacion 7.4.

plants could inject -or consume- reactive power to manage the voltage at their connection point with the grid. Reactive power consumption is a means to reduce overvoltages in the grid, while reactive power injection is used to increase voltages. Although overvoltages tend to be more common at off-peak hours, this depends on the grid operation and the specific plants that are producing at each time.

Currently, there is no service established for voltage control for DG, and, for consumers, an obligation to follow cos(fi) is established with some exemptions. For units under the scope of the (European Commission 2016a, 2016b), additional requirements are applied to both DG and DER.

The TSO traditionally invests in reactors (currently in order to increase the flexibility of the Transmission Network new devices are considered, such as STATCONs and other kind of FACTs) to consume reactive power. Moreover, DSO used to install condensators to compensate reactive power. However, this could be supplemented with inverters' capabilities in a more cost-effective manner.

4.5.2. Brief Overview

Currently, in Spain, there is no voltage control services market, only power factor controls. In order to efficiently use all the capabilities from DG and DER, a suitable mechanism has to be designed from scratch.

At the transmission level, voltage can be controlled by the injection or consumption of reactive power. At the distribution level, both active and reactive power have to be used. However, in the case that active power is used for solving voltage problems, the congestion management BUC would be used. At distribution level, reactive power is not as useful as at transmission level, due to its higher R/X ratio compared to transmission. Therefore, this service will be mostly provided by FSP connected at the highest voltage of the distribution network, i.e. from 132kV to 25kV, where meshed networks are commonly operated.

Figure 25 represents the main functions developed by each of the actors that interact in the BUC. In a similar manner to congestion management and balancing, the functions are divided in four relevant timescales which are described in detail below: the long-term (from years until day-ahead), the day-ahead, from one hour to real-time and post-real-time. The numbering of the functions are described according to the sequential actions, and the arrows represent the flows of information among the different actors.

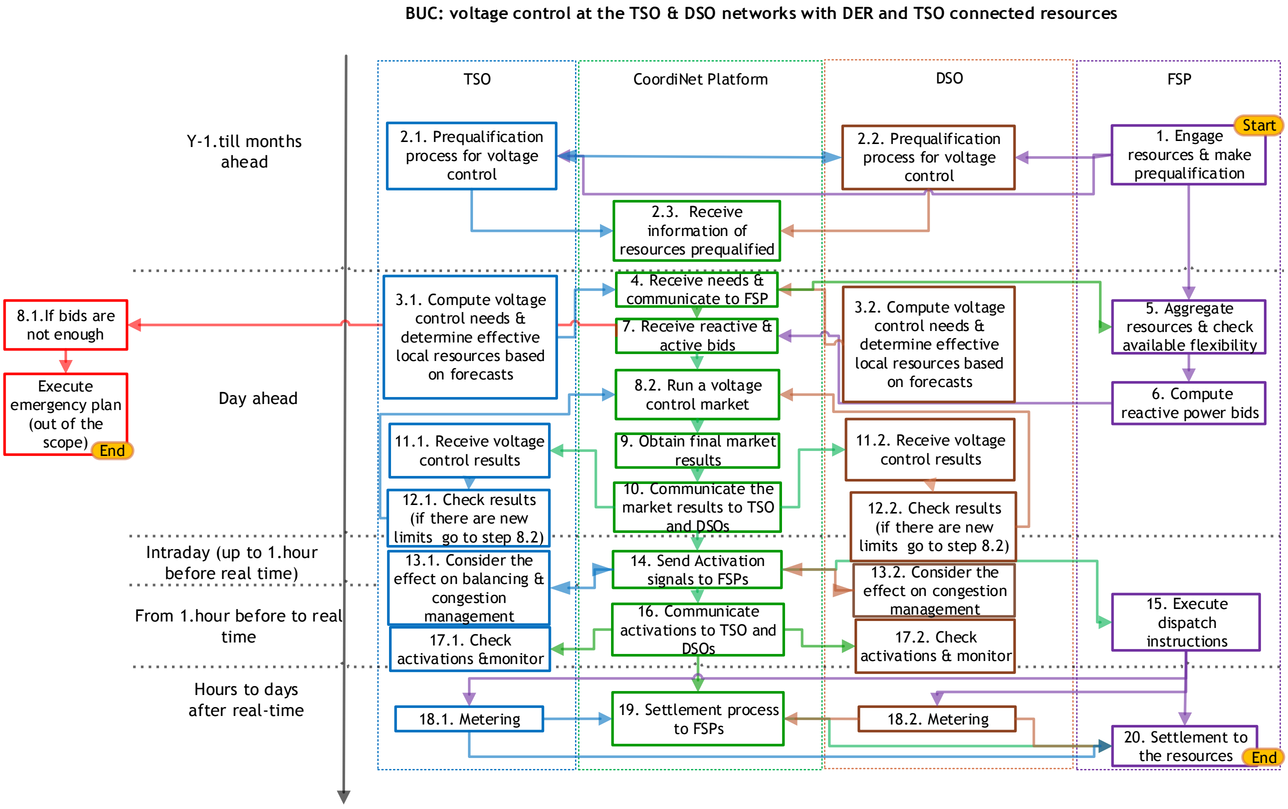

Figure 25 Flow diagram of main functions for voltage control

4.5.2.1. Long-term

A prerequisite for the Use Case is the product definition, which is addressed in CoordiNet in D1.3. Once the products are defined, the next step starts with the engagement of customers and the evaluation of their potential reactive power provision (Step 1). After the potential is known, a prequalification process will be carried out for the FSP by the TSO, the DSO or both (step 2.1 and 2.2). The prequalification results will then be registered in the CoordiNet platform (step 2.3). As resources can provide reactive power for voltage control to both TSO and DSO, the prequalification has to be coordinated among the TSO and DSO[25].

For voltage control, long-term procurement may not be relevant for the Spanish case, as existing resources in the demo areas are expected to provide voltage support.

[25] It is important to note that DG and DER can be prequalified for reactive power capabilities beyond the national implementation of UE/2016/631. This issue is important in the voltage market design since the non-mandatory capabilities will be the only resources bids by them. Mandatory capabilities should be provided without compensation by them.

4.5.2.2. Day-ahead

The process will start with computing the foreseen requirements from the TSO and DSOs and determining the effective local resources that can potentially solve the voltage power problems, it is important to note, that in the calculation of this voltage resources, there is a mandatory provision for every generator before the market base product can be used, based on the power flows forecasts (steps 3.1 and 3.2). These effective local resources will be determined from those that have been prequalified and accounting for the impact on the identified locations. It may be the case that voltage problems are not frequent and, thus, the TSO and DSO can inform the platform when and where voltage problems emerge (step 4). It is important to note that voltage needs can require consumption or generation of reactive power.

In the meantime, the FSP must aggregate DERs, determine the available flexibility (step 5) and compute reactive power bids for the relevant locations (step 6.1). Meanwhile, resources connected at the transmission network also compute their bids for the market (step 6.2).

The CoordiNet platform will receive the needs and the effective local resources identified from the TSO and DSOs, as well as the bids from the FSP (step 7). If bids are not enough to resolve the foreseen voltage needs, an emergency plan may need to be activated (step 8.1), which is out of the scope of this document and of the CoordiNet Spanish demo. A detailed procedure and the definition of the clearing algorithm have to be defined to handle situations where potential conflicts emerge. For example, the same resources may be used to solve voltage problems that affect two networks in the opposite direction. Therefore, the overall system approach has to be considered (step 8.2). Once all the relevant constraints and available resources have been considered, the CoordiNet platform obtains the results (step 9) and communicates them to the TSO and DSO (step 10). Both grid operators will receive the results (step 11.1 and 11.2) and check their feasibility (step 12.1 and 12.2). If any additional voltage control problems persist, then the market has to be run again (back to step 8.2).

4.5.2.3. From 1 hour before to real time

From about one hour before real time, if changes in reactive power are needed for voltage control, there may be consequences on congestion management or even on system balancing. Therefore, the DSOs and TSO have to establish a procedure to account for these effects (step 13) and then send the relevant information to the CoordiNet platform before sending the activation signals to FSP (step 14). The FSP must perform the activation of resources manually or automatically (step 15). The platform communicates the activation to the TSO and DSOs (step 16), who must check the activation and monitor the system (step 17.1 and 17.2).

4.5.2.4. After real-time

Once the services are delivered, consumption and generation of reactive power is metered. As mentioned before, in Spain, the entity that performs the metering activity depends on the consumption, generation and the grid level of the connection point[26]. For consumers, metering activity is only performed by the DSO, regardless of the grid level (transmission or distribution) to which they are connected. Metering for generators with capacity below 450kW is performed by the DSO, while all the rest is done by the TSO

[26] See Article 3 in Royal Decree 1110/2007, *por el que se aprueba el Reglamento unificado de puntos de medida del sistema eléctrico*

regardless of the grid level (transmission or distribution) to which the generators are connected (step 18). The CoordiNet platform will then use the metering data to perform the settlement process for reactive power delivered from FSP (Step 19) and then the FSP perform the individual settlement with the resources which may include other services (step 20).

4.5.3. Key performance indicators for voltage control

Table 22 presents the list of KPIs which will be used for voltage control in the Spanish demo. The numbering, definition of the KPIs and the classification are presented in CoordiNet D1.6.

KPI ID	KPI Name	KPI Category
KPI_2	Estimation of the increment of reactive power flexibility for the network operators (TSO and DSO)	Technical
KPI_3	Cost of R&I solution vs. grid alternative solution	Economic
KPI_4	OPEX - OPerational EXpenditures	Economic
KPI_5	OPEX for service procurement	Economic
KPI_6	Average cost per service for the examined period	Economic
KPI_12	Voltage variation	Technical
KPI_18	Volume of transactions	Economic
KPI_19	Number of transactions	Economic
KPI_20	ICT cost	Economic
KPI_29	Capacity increase with reactive management	Technical
KPI_31	Total activation time of a product	Technical
KPI_34	Percentage of tested products per demo	Technical
KPI_36	Participant recruitment	Social
KPI_37	Active participation	Social
KPI_38	Type of flexibility providers per demo	Technical
KPI_39	Total Computational Runtime	Technical

Table 22: KPIs for voltage control

4.5.4. Voltage control in Cadiz

Voltage control will be tested in both substations: at 220 kV level in SUB_CAD2 substation and at 66 kV level in SUB_CAD1 substation. In the case both substations are connected, a single test will be carried out.

The voltage control will be tested at both transmission and distribution nodes, and the SOs would provide set-points based on voltage values, power factor or reactive power.

To determine the capability of the resources to provide voltage control, different tests have been performed in the different units or values from the technical specification of the technologies installed are obtained.

For wind farm Wind CAD 2, the reactive power available depends on the PQ curve obtained through the tests. In Wind CAD 1 wind farm, the reactive power available is split in two groups. One group is installed in each turbine generator and the other group in the substation Wind CAD 2. For Wind CAD 4, the reactive power available is installed in each turbine generator. Finally, for Wind CAD 3, the reactive power available depends on the PQ curve obtained through the documentation of Wind CAD 3.

For photovoltaic solar panel Solar CAD 1, the reactive power available depends on the PQ curve.

In SUB_CAD2 substation, the reactive capacity of the generation associated to the SUB_CAD2 substation in the 220 kV voltage level can be modified by 2,2 kV in the case of undervoltage and by 1 kV in the case of overvoltage.

In SUB_CAD1 substation, the reactive capacity of the generation associated to the SUB_CAD2 substation can be modified by 1,85 kV, in the 66 kV voltage level, in the case of undervoltage and by 2,25 kV in the case of overvoltage.

4.5.5. Voltage control in Albacete

In Albacete, voltage problems (mainly high voltages) will be simulated and a testing of the real capacity of FPS to solve those problems in different locations will be performed. The substations being considered in the Albacete area are:

- 132kV line from SUB_ALB1 a SUB_ALB3
- 132kV line from SUB_ALB7 to SUB_ALB4
- 132kV line from SUB_ALB1 to SUB_ALB3.
- Transformer SUB_ALB5.

4.5.6. Voltage control in Alicante

Customer ALI 1 can also contribute to solve congestions by disconnecting some capacitive assets to maintain voltage levels within secured ranges.

4.5.7. Voltage control in Murcia

In case of voltage issues (overvoltage or undervoltage) in the secondary substation, a flexibility resource available connected at LV from municipality buildings with a capacity around 161 kVAr lines could provide voltage control.

4.6. Controlled Islanding

4.6.1. Scope

The resources included in this demonstration activity will only be connected to I-DE's networks in a rural area of Murcia, where energy storage and PV units located in medium and low voltage grids can be used. The battery capacity power is 1 250 kW for injecting and withdrawing, whereas the energy capacity is 2 772 kWh. The connected consumption is around 400kW.

The primary actor is the DSO.

4.6.2. Objectives

The objective of this BUC is to operate part of the distribution network in an islanding mode during outages or programmed maintenance services.

4.6.3. Brief Overview

During outages or programmed maintenance services, a part of the grid may be disconnected from the system, remaining electrically islanded. In this situation, the DSO activates DG to supply the consumers within the island during the outage or the maintenance period. The DSO has to be able to maintain within required limits technical parameters such as voltage and frequency in the electrical island. The DSO has to determine the size of the island which, in turn, may affect the TSO.

Figure 26 represents the main functions developed by each of the actors that interact in the BUC. In a similar manner to previous BUCs, the functions are divided in four relevant timescales which are described in detail below: the long-term (from years until day-ahead), the day-ahead, from one hour to real-time and post-real-time. The numbering of the functions is described according to the sequential actions, and the arrows represent the flows of information among the different actors.

BUC: Controlled islanding in the DSO network

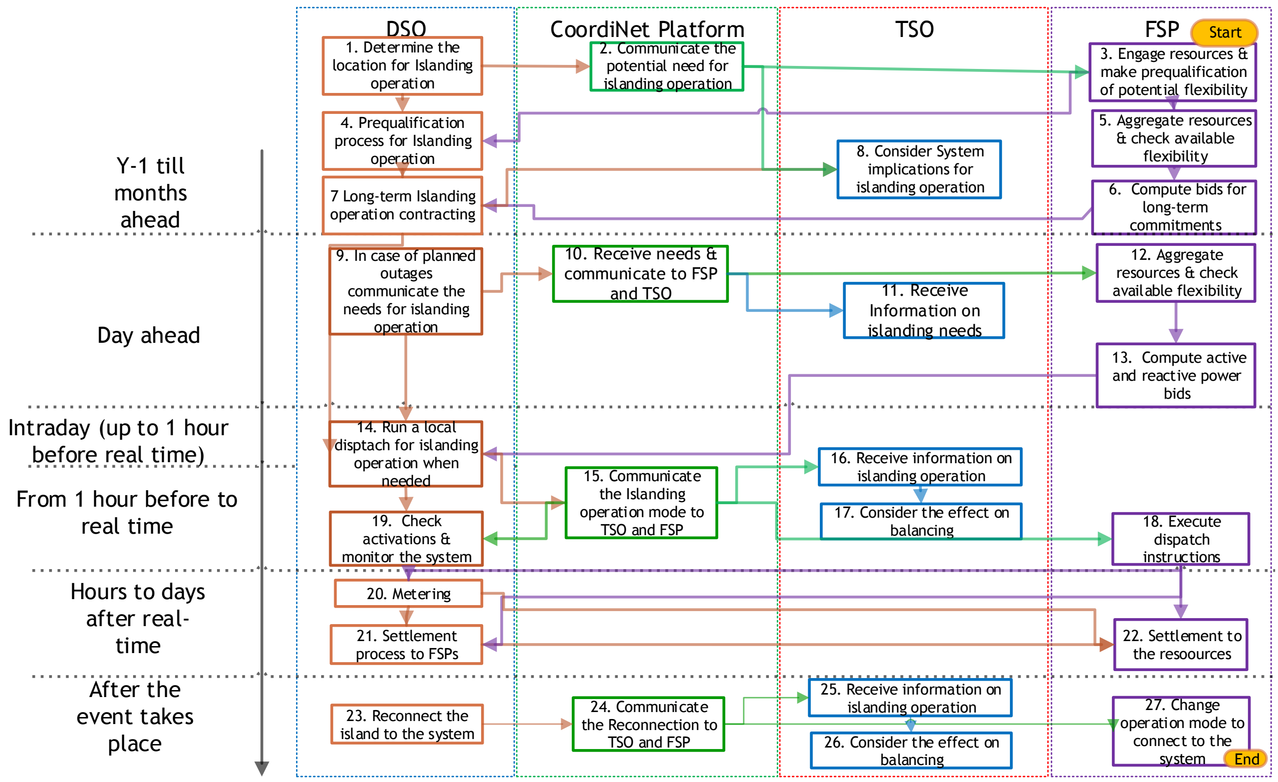

Figure 26 Flow diagram of main functions for controlled islanding

4.6.3.1. Long-term

A prerequisite for the Use Case is the product definition, which is addressed in CoordiNet in D1.3. Once the products are defined, the next step starts with the evaluation by the DSO of the islanding needs (step 1). Once the needs and location are identified, they are communicated to the platform (step 2), so that the platform makes this information available to FSP in order to engage customers and evaluate their flexibility (Step 3). Once the flexibility is known, a prequalification process will be carried out between the FSP and DSO (step 4). For this service, it is essential to guarantee a long-term commitment. Hence, a long-term contract is necessary between the DSO and the FSP (steps 5 to 7). On the other hand, the TSO has to be aware of the possible islanding operation, to take it into account for the system balancing and security (step 8).

4.6.3.2. Day-ahead

In case of planned outages, the DSO communicates the FSP the needs for islanding operation for the following day (step 9). The usage of this service may not be frequent. The DSO will inform the platform when this service is required (step 10). The platform will inform the TSO (step 11) and the FSP when islanding operation is needed, then the FSP aggregate DERs, determine the available flexibility (step 12), and compute active and reactive power bids (step 13).

4.6.3.3. From 1 hour before to real time

The DSO performs the islanding operation when needed and dispatch resources according to the price-quantity bids for both active and reactive power in order to maintain frequency and voltage in security limits in the electrical island (step 14). The DSO registers the islanding operation in the CoordiNet platform, which informs the TSO and FSP (step 15). The TSO receives the information of islanding operation (step 16) and accounts for the net effect on the balancing from temporarily disconnection from the rest of the network (step 17). In the meantime, the FSP execute the instructions from the DSO (step 18).

4.6.3.4. After real-time

After the islanding operation, the DSOs meter the energy delivered[27] and all the energy withdrawn from consumers during the islanding operation mode (step 20) and performs the settlement (step 21). Finally, the FSP perform the individual settlement with the resources which may include other services (step 22).

4.6.3.5. After the event takes place

The electrical island has to be reconnected with the rest of the system (step 23). This action has to be communicated to the CoordiNet platform which informs the TSO and the FSP (step 24). The TSO receives the information of islanding operation (step 25) and, if needed, compensates the impact on balancing from the temporarily isolation of the island from the rest of the system (step 26). In the meantime, the FSP execute the instructions to reconnect from the DSO (step 27).

4.6.4. Key performance indicators for controlled islanding

Table 23 presents the list of KPIs which will be used for control islanding in the Spanish demo. The numbering, definition of the KPIs and the classification are presented in CoordiNet D1.6.

KPI ID	KPI Name	KPI Category
KPI_3	Cost of R&I solution vs grid alternative solution	Economic
KPI_4	OPEX - OPerational EXpenditures	Economic
KPI_5	OPEX for service procurement	Economic

[27] If the islanding is performed by generation units larger than 450 kW, the TSO performs the meter reading.

KPI_6	Average cost per service for the examined period	Economic
KPI_8	Reduction in RES curtailment	Environmental
KPI_14	Islanding duration	Technical
KPI_15	TIEPI - Equivalent interruption time related to the installed capacity	Technical
KPI_18	Volume of transactions	Economic
KPI_19	Number of transactions	Economic
KPI_20	ICT cost	Economic
KPI_31	Total activation time of a product	Technical
KPI_32	Delivered energy in controlled island	Technical
KPI_33	Maximum power (non-transient) in controlled island	Technical
KPI_34	Percentage of tested products per demo	Technical
KPI_36	Participant recruitment	Social
KPI_37	Active participation	Social
KPI_38	Type of flexibility providers per demo	Technical
KPI_39	Total Computational Runtime	Technical

Table 23: KPIs for controlled islanding

5. Current TSO and DSOs' management activities and platforms

This section will describe the different management systems used by the DSOs to procured services from DERs. This section provides the specifications of platforms including the existing specifications and those that must be created and adapted in relation to the definitions provided in CoordiNet T2.2.

The specifications of software and hardware will be also described as well as the control and communication requirements.

5.1. TSO's management systems and platforms

The purpose of this section is to get a detailed description of current platforms used for congestion management and balancing in electricity systems.

5.1.1. Balancing

In Spain, different products serve as RR, mFRR and aFRR. These services are in the process to be adapted to the harmonized services being defined in Europe. This section describes the current services and if possible describe how they would evolve to adapt to the European Balancing Network Code. Demand-side and batteries are not currently participating in these markets but there are initial proposals to allow their participation. Prequalification tests (and terms and conditions related to balancing, as well as Regulation in the future) are being updated in order to include demand and storage. However, right now, they are in a very preliminary phase.

Tertiary reserves energy bids are received from 16:00 D-1 up until 250 min before real time. As all the prequalified generators with available tertiary reserve are obliged to provide their capacity in this last market, there is only energy contracted in this market. For secondary reserve, capacity (band) and the energy is remunerated. For tertiary reserves, only the energy activated is remunerated.

The TSO might find it appropriate to contract additional reserves. From November 12th 2019, this additional reserve is provided by starting up thermal units in real time.

Between ID sessions, an additional balancing market is performed, in an hourly basis (RR energy market called deviation management market with marginal pricing clearing). This market is used in cases where imbalances higher than 300 MW are expected.

5.1.1.1. Prequalification

Before becoming a BSP, it is necessary to successfully pass a prequalification process and have a minimum capability of 10 MW. The prequalification process is done at the physical unit level or several physical units together not exceeding 1000 MW in total. These physical units, once prequalified, enter as a BSP. At the time of bidding, the minimum bid size is currently 0.1 MW for all balancing services. The only exception is in the market for aFRR capacity, for which there is also a minimum bid size of 0.1 MW, but there is a minimum matched bid size of 1 MW. That is that in order to be matched, a provider needs to have at least bids for 1 MW sent at a price equal or lower than the marginal price for that hour. In order to adapt to EBGL, the balancing products offered in the future to the balancing platforms will have a minimum bid size of 1 MW. Demand and storage (which are not BSP as of today), will be able to become BSPs when the Terms and Conditions related to Balancing are approved in Spain.

The responsible is the unit or the control centre which the unit belongs to. The prequalification process is done by the TSO. According to the SO GL (Art 182(4) and 182(5)), currently under implementation phase, if during the prequalification process of a unit connected to the distribution grid or for real time activation of the service, a DSO considered a need for limitation due to the security in their network, the DSO would indicate this limitation to the TSO in order to take it into account in the prequalification process/real time activation. Up to now, no request for limiting or banning the participation of a DER in balancing mechanisms due to distribution congestions have been received by the TSO.

The prequalification process lasts between one week and one month (highly dependent on primary generation energy resource).

The technical process consists on the following tests

a. Ramping test
b. Start-up test: only for thermal units
c. Set point test during 72 hours.

The actual prequalification process will be modified in order to include demand and storage units. However, the entire process shall not include any differences between a generation unit and demand/storage units.

5.1.1.2. Forecasting of balancing needs

In the D-1, the TSO checks the total volume of reserves in the system, taking into account demand and renewable generation uncertainties, and procures reserves. Without prejudice of the previous, the TSO checks the reserves capacity in real time and after every intraday market.

If congestions are detected by the TSO on its network, all units that can be used to solve the congestion are grouped into a bundle and a total limitation, that assures N-1 security, is calculated for this bundle.

The rules for sharing the limitation of the bundle among the units guarantee that the least cost option is chosen to solve the congestion. In order to calculate the cost of the limitation, the following bids will be used:

- Tertiary regulation downward reserve bid: if the unit belongs to a portfolio that participates in the tertiary regulation market.
- Congestion management downward bids for Day-Ahead Market: if the unit belongs to a portfolio that does not participate in the tertiary regulation market. Congestion management downward bids for Day-Ahead Market are compulsory for all generation units.
- In case the congestion is detected by a DSO on its network, the DSO identifies the units that are able to solve this congestion notifying the TSO which units form the bundle and the maximum possible production of the bundle. The TSO, via the CECRE, solves the congestion by limiting and, if necessary, redispatching the units included in the bundle in the same way as if the congestion were located in the transmission network.

Balancing market bids are managed through eSIOS (details on the eSIOS platform is provided in section 5.2.1.3), a system information developed by REE to perform the tasks of information and processes management specifically related to the electricity market. eSIOS allows REE, among other functions, to communicate with market actors who participate at the Spanish electricity market with bids to buy or sell energy, to notify the acceptance or rejection of such bids in a transparent and confidential manner and to publish the results of the different markets and schedules. The clearing process considers all the bids sent by the BSPs, sorts them from the cheapest to the most expensive one, and selects cheapest bids which fulfil the requirement.

5.1.1.3. Bidding

The participation in the deviation management market is not mandatory for qualified generation and pumping units. Bids are sent until 55 minutes before Real Time.

In tertiary regulation market, participation is mandatory for qualified generation and pumping units. They have to offer their available reserve power. Bids are sent before 23:00 of D-1 and can be updated every hour, until 25 minutes before Real Time.

Balancing needs are evaluated for the hour ahead considering renewable forecast errors, demand forecast errors and unavailabilities of conventional generation. Additionally, balancing needs balancing needs for mFRR are continuously checked.

Regarding deviation management and tertiary reserve[28], prices are set by marginal hourly price of the selected bids, see Figure 27.

[28] As a result of the implementation of the TERRE platform in January 2020, the deviation management service is replaced by RR, which maintain, at least temporarily, some of the characteristics of deviation management service and associated market framework. The corresponding changes are specified in the updated version of P.O. 14.4 is available at: https://www.ree.es/sites/default/files/01_ACTIVIDADES/Documentos/ProcedimientosOperacion/BOE-A-2019-18741_Comision_Nacional_Mercados_y_Competencia.pdf

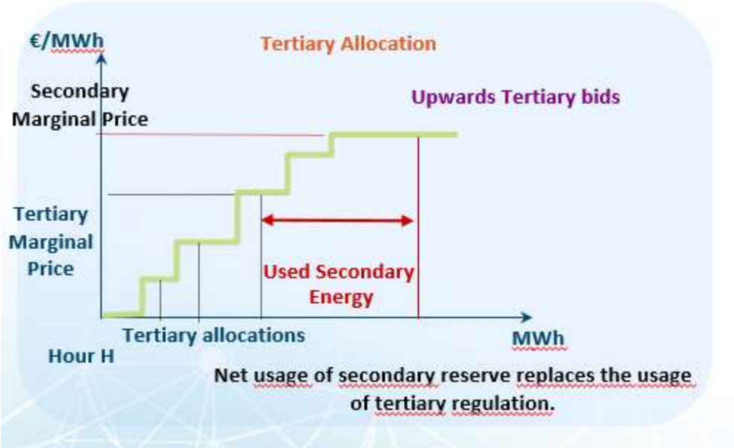

Figure 27 Market clearing representation of the deviation management and tertiary reserve markets

Clearing markets results are published via eSIOS, 15 minutes before real time for mFRR, and 30 minutes before real time for RR.

5.1.1.4. Settlement

REE performs the settlement process in a similar manner for all markets.

Penalties for non-compliance are applied for tertiary reserves and deviation management which is to the net energy allocation in tertiary and deviation management services (verified by Regulation Area, or by BRP if the unit do not belong to any regulation zone).

For both reserves, the penalty is calculated using the following formula (see P.O. 14.4):

OPEINCLEBALSz,s = EINCLEBALSz,s x PBALz,s x 0,2

where:

EINCLEBALSz,s is the noncompliance balancing energy (per regulation zone z or market participant s) and

PBALz,s is the average hourly price for tertiary and deviation management (per regulation zone z or market participant s)

5.1.2. Congestion management

Currently in Spain, the TSO manages network congestions that occur both at transmission and distribution levels through a technical constraint management market by re-dispatching generation units connected at transmission, but also at distribution levels after the day-ahead market. There are basically two time horizons in which congestion management (technical constraints management) is performed. One right after the day-ahead market clearing from 13 to 16 h of day D-1 to ensure that the results of the market are physically feasible. After this horizon, in real-time, congestion management is performed again if still needed. All providers are expected to be able to attend the redispatches performed in day D-1 for all programming periods of day D by activating the technical constraints bids from generator units. In real time, providers are asked to activate their downward bids within 15 minutes. There is not a clear activation time for upward bids except for those units that provide upward mFRR for which the time is the same as mFRR and is, thus, 15 min.

If needed, the DSO has the possibility to request from the TSO to call the use of the interruptibility service or redispaching and curtailment of generation. The current price floor in the congestion management market is 0 €/MWh and, currently, there is no price cap applied apart from IT system limits. The cleared prices follow the pay-as-bid scheme.

As highlighted in CoordiNet D1.1, in Spain, DSOs can use DER, more specifically DG, to solve congestions in the same way as the TSO does. This process, however, is done through the TSO in coordination with the DSO (i.e. after an outdated process based on e-mail interactions, or similar processes, sent by the DSO to the TSO). Once congestions in the distribution grid are identified and the DSO is not able to solve the problem, if there are generation units that have an impact on the congestion, the needs for changing the dispatch are sent from the DSO to the TSO. The TSO accesses the bids and calculates the necessary redispatch to solve the detected constraints. In case a DG is redispatched, it will be remunerated according to the existing market rules (which are the same as the units re-dispatched due to congestions in the transmission grid). For planned curtailment in case of maintenance, producers receive no financial compensation. In addition to congestion management, DSOs may also request from the TSO a change in the power factor range instructions sent to generation units with an installed capacity larger than 5 MW. Currently, this mechanism applies only for generators and not for consumers.

Therefore, as of today, the DSO, through the TSO, can use DG for local congestion management and power factor control while consumers with contracted power above 5MW can participate in interruptible services. In this context, although both DSOs and the TSO may need to solve congestions, is only the TSO that receives the congestion management bids that are able to solve the constraints, assigns them and instructs the DER, even for units connected at the distribution grid.

Regarding the size of DER able to provide services for congestion management to the DSO, there are no limitations with respect to the voltage level to which providers are connected. Participation is currently only allowed for generation units and pumped hydro units (the same conditions for units connected to both distribution and transmission grids).

As of today, in Spain, DSOs cannot sign interruptible contracts with DER. The only form of interruptible contract is between the TSO and industrial consumers. However, DSOs may use these interruptible contracts signed with the TSO to solve constraints in their networks as well.

Starting in February 2016, generation from renewable sources can participate in balancing markets and congestion management processes. Thus, redispatch due to congestion management in the DSO or TSO network including generation from renewable sources is done via market mechanisms (PO 3.2). In the real-time technical constraint management process, DG has to pay the upward/downward bid price, while in the day-ahead process, downward redispatches are determined by the sensibility in the congestion and cleared at the day-ahead market hourly marginal price. Thus, renewable generation reductions can happen because of market outcome in the congestion management or balancing markets.

In any case, as a last resort, if still needed in real time, the TSO and DSO can curtail renewable generation for security reasons, other than congestion management. In this case, a market-based mechanism is not needed. Nevertheless, since 2016 all congestion management situations have been solved through market-based mechanisms.

5.1.2.1. Day- Ahead Technical Constraints Process

Congestion management currently has two different processes: day-ahead and real-time. In addition, day-ahead process has two phases:

- Phase 1: In Phase 1 the TSO limits or redispatches the generation units to guarantee the system security (voltage control, congestion management, etc…). Participation is mandatory for all units.
- Phase 2: the TSO balances the net amount of energy redispatched in Phase 1. Participation is mandatory to:
- Units with availability ratio (with respect to its installed capacity) ≥ 50%.
- Units with availability ratio < 50% if they pass the deviation management & tertiary regulation prequalification tests (no obligation to participate in these services).

5.1.2.2. Real-Time Technical Constraints Process: as Phase I in the day-ahead process

The prequalification process is done by the TSO. According to the SO GL (Art 182(4) and 182(5)), currently under implementation phase, if during the prequalification process of a unit connected to the distribution grid or for real time activation of the service a DSO considers a need for limitation due to the security in their network, the DSO would indicate this limitation to the TSO in order to take it into account for the prequalification process/real time activation. Up to now, no request for limiting or banning the participation of a DER in balancing mechanisms due to distribution congestions have been received by the TSO.

Technical checks similar to the checks described in the balancing prequalification process for mFRR and RR.

Congestion management bids are managed through eSIOS. The protocol used to communicate with eSIOS is via Web Services IEC- 62325-504 over the internet. This is a standard of utilization of web services for electronic data interchanges on the European energy market for electricity[29]. This standard is part of the documents that have been approved by ENTSO-E for the harmonisation and implementation of standardised electronic data interchanges.

5.1.2.3. Bidding

The congestion management market is divided the two phases, as described above.

Bids can be sent from 12:00 to 15 minutes after the functional day-ahead base program (referred to as PDBF) has been published. Additionally, bids can be updated in real time until 15 minutes before the hour.

Bidding is mandatory for all units as per the following requirements:

- Upwards energy: limits are the maximum available capacity for thermal units and best forecast to renewable production. The minimum price is set to 0 €/MWh and there is no limit to the maximum price (this could change when/if negative prices are allowed).
- Downwards energy: from schedule to 0 MWh. The limit to the price is 0 €/MWh (this could change when/if negative prices are allowed).

[29] https://webstore.iec.ch/publication/22465

At Phase 1 of the Day-Ahead process, changes to the day-ahead schedules are set at the day-ahead price. In real time, the bid price is used, usually being inferior to the energy market price. For phase 2, specific bids are sent by the participants in the process. These bids can be updated in real time. There are not specific measures to avoid market power in the process itself. However, market power issues can be investigated by the CNMC (national regulatory authority). Phase 2 is used to correct the imbalance produced in Phase 1, thus units are not activated for congestion management purposes. The redispatches associated to Phase 2 modifies the previous schedule of the units and the unit does not face any kind of imbalance cost.

For units that have been cleared in the congestion management market, the participation in the balancing markets is restricted only if they are not compatible. It means that, if a unit is limited downwards due to congestions, this unit can only offer the available upward reserve for balancing.

5.1.2.4. Market clearing and activation

The market pricing is based on pay as bid, except for downward energy redispatches in Phase I, where the clearing price is the day-ahead market marginal price.

- Phase 1: bids selected are the ones that solve the congestion at minimum price.
- Phase 2: cheapest sale/purchase bids (merit order).

The gate closure time is 15 minutes after PDBF publication for the day-ahead process. Figure 28 provides the timeline sequence of the current Spanish markets.

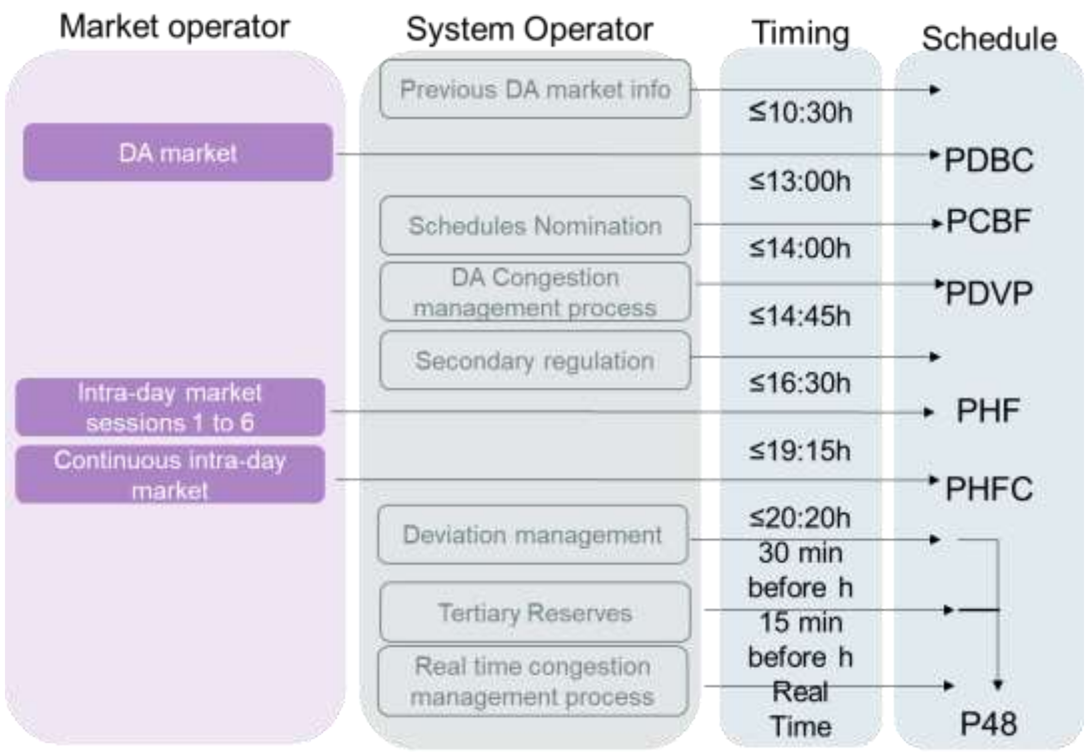

Figure 28 Current Spanish markets timeline sequence

In the D-1 market, results must be published before 14:45. In the real time market, limits are published every hour or when required, while redispatches for the hour are published when generated, after the publication of the last continuous intraday market round before the hour.

There are not specific times for participation in the congestion management market. However, technical times are taken into account when choosing the solution.

The results are published to the participants via .xml files, and can be visualized in the eSIOS private web.

5.1.2.5. Settlement

REE performs the settlement process. The settlement is performed 15 days after. However, several resettlements take place (1/3/8 months).

There are penalties associated with noncompliance with the net energy allocation in tertiary reserve and deviation management services (verified by Regulation Area[30] or by BRP if the unit do not belong to any of such Regulation Areas).

5.2. TSO platforms

5.2.1.1. Control Centre of Renewable Energies (CECRE)

The CECRE, is the control centre devoted to renewable generation. It was commissioned in June 2006 as wind generation started to become a relevant technology in the Spanish electrical system. It is composed of an operational desk where an operator continuously supervises renewable energy production and CHP (see Figure 29).

Figure 29 Control Centre of Renewable Energies

As required by the current regulation, all single production facilities or clusters sharing the same connection point, with a total installed power greater than 1 MW, send every 12 seconds real-time telemetry of the active power produced. Plants or clusters with a total installed capacity greater than 5 MW send additional tele-measurements of the reactive power and voltage at the connection point. Additionally, each of the

[30] Regulation Area refers to a balancing portfolio which provides balancing service, usually these Regulation Areas are formed by generation companies' holdings.

wind or solar photovoltaic renewable energy plants or clusters, larger than 5 MW, receives from the CECRE an active power set point to which they must comply within 15 minutes.

This real-time information is collected from the plants by the Renewable Energy Control Centres (RESCC), and it is channelled via the ICCP links connecting these control centres to the CECRE (see Figure 30). To minimize the number of points of contact dealing with the TSO, the RESCC acts as the only real-time speaker with the TSO. The RESCC also manage the limitations established by the set-points and are responsible for assuring than the non-manageable plants comply with them.

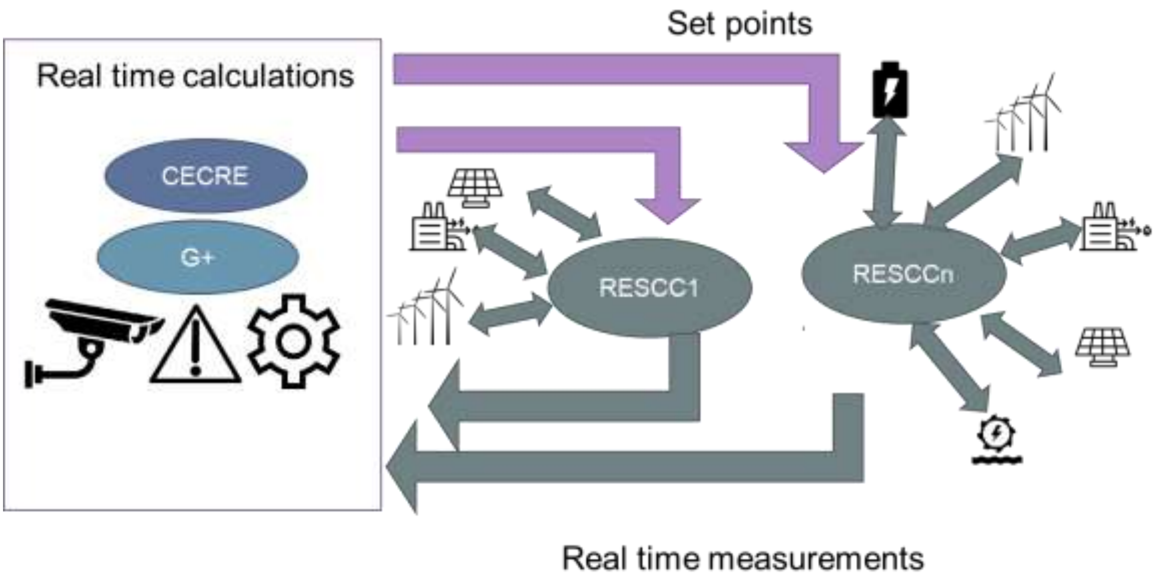

Figure 30 Renewable Energy Control Centres interactions with the TSO system

Such scheme assures that the system is continuously under the TSO control to overcome within 15 minutes unexpected events related to congestion management or balancing, for example by returning the system to a N-1 secure state after the trip of an element. Thus, it allows a large penetration of dispersed renewable facilities and reaches the European objectives while maintaining the same high standards of security of supply.

This control and supervision scheme leads to improved security and effectiveness in system operation and allows the substitution of permanent or long-lasting production hypothesis and preventive criteria for real time production control, thus allowing higher energy productions for the same installed capacity and a more efficient real-time operation of the plants.

5.2.1.2. G+

The main tool used by the CECRE's operator to carry out these tasks is named G+. G+ accesses the real-time information received in CECRE and uses it to determine whether the present generation scenario is admissible for the system due to each of the following criteria:

- Fault ride through capabilities of generation connected to the network through power electronics will not cause an inadmissible simultaneous disconnection of generation.
- Congestions which must be solved by reducing RES generation considering security margins such as N-1 criterion.
- System balance can be achieved while maintaining an appropriate level of downward reserves.

G+ has been designed taking into account that the operator must be able to create, manage and activate plants rapidly as some situation may arise in which it may be necessary to return the system to a balanced, N-1 secure state as soon as possible. It must be observed that there are more than 800 wind farms installed in the Spanish peninsular system, so their management must be done by means that are as automatic as possible. The reliability of the tool is a crucial issue as the failure to be able to deliver limitations to the RESCCs could result in a significant decrease in the security of supply.

The architecture of G+ from a high level point of view is depicted in Figure 31.

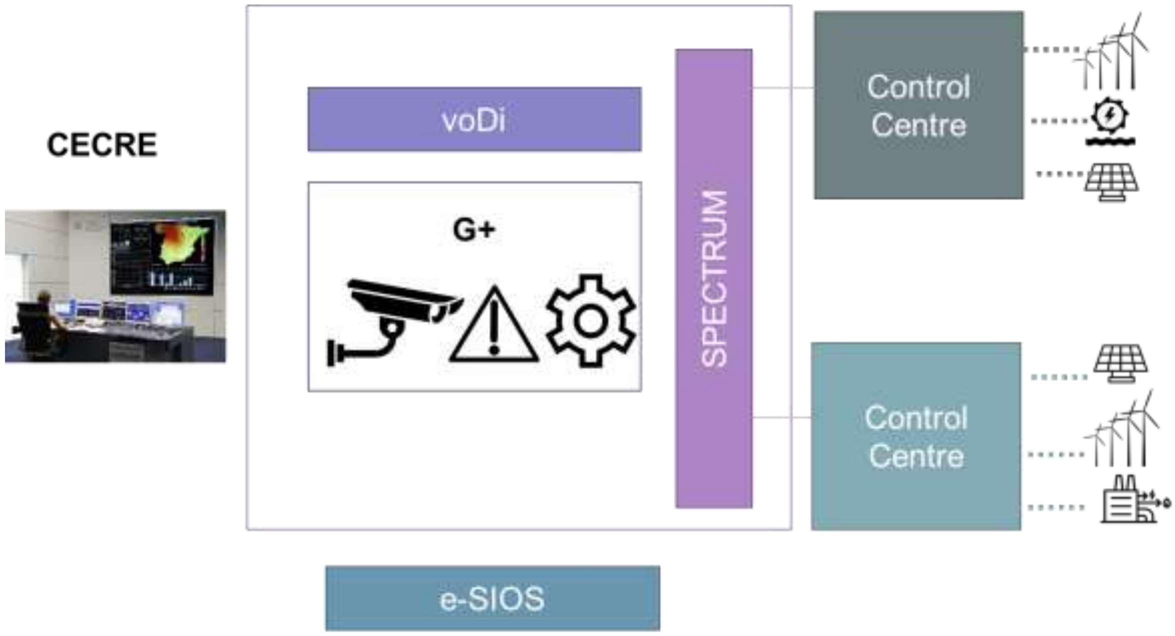

Figure 31 G+ Structure

G+ receives the following inputs automatically:

Spectrum: telemetries are updated every 12s (2900 generation points, and 1600 of these are controllable) sent by the RESCC.

- eSIOS: programs, congestion bids and limitations (updated at least every hour, but this update can be shorter).
- VoDi (Voltage Dip assessment): this tool assesses the loss of wind generation taking into account the Fault Ride-Though capabilities of the wind farms. This module simulates several three phase short-circuits in different buses of the Spanish electrical system while taking into account the real time wind generation, technical characteristic of each wind farm, and the saturation of the interconnection with France.
- PSSE cases from the state estimator.
- Structural information from all generators (update once a week).

Based on the national grid code P.O. 3.7., there exists several reasons for active power reduction:

- Local congestions
- Stability
- Surplus of generation not admissible in the system
- Others

G+ calculates the amount of power reduction, minimizing the overall cost for the system. In a first stage, applying a pure economic criteria, and secondly -only if necessary, in case of generation causing the congestions has the same cost for the system- by using a technical criteria. Set-points are calculated at least once an hour.

Regarding the horizons for the calculation, if the local congestion can be identified in the day-ahead, the technical restrictions are set in the day-ahead market. On the other hand, i.e. local congestions identified in real time, technical restrictions are set by using:

- Installed capacity, technical minimum, programming unit, technology.
- Real time production, congestions downward bids.

As a result, G+ generates a file with the set-points and reason for each generator. This information is sent to the RESCC and eSIOS.

5.2.1.3. eSIOS Platform

Balancing markets bids are managed through eSIOS, a system information developed by REE to perform the tasks of information and processes management specifically related to the electricity market.

eSIOS allows REE, among other functions, to communicate with market participants, who participate in the Spanish electricity market using bids to buy or sell energy, to notify them of the acceptance or rejection of the bids in a transparent and confidential manner and to publish the results of the different markets and schedules.

The participation of all generators and pumping units in balancing services is organized through the so called programming units (PRU) which may consist of a large conventional generator or pumping unit (>100 MW) or a group of one or several smaller generators with the same primary source (hydro, wind, solar etc.) each of which creates a physical unit (PHU). A PRU may include PHUs connected to different nodes and areas of the network and also units connected to the TSO network or the DSO network indistinctively. A generator belongs to only one PRU for all balancing services. Each BSP uses one or several PRUs to participate in balancing services. BSPs submit balancing bids for their PRUs in the markets for which they have been prequalified and are allowed to participate, and the TSO acts as a single buyer in these markets activating the submitted bids when necessary.

After each notification for activation and before the physical activation of the reserves, BSPs must nominate how the new PRUs schedules are broken down between the PHUs that compose that schedule. This means that, before activation, the TSO has locational information on the schedule of each PHU at any time. This locational information can be then used to perform real-time security analysis to check if the activation of the bids may cause congestions. PRUs may be formed by PHUs that connect both to the transmission and the distribution network.

If congestions are detected by the TSO on its network, all PHUs that can be used to solve the congestion are grouped into a bundle and a total limitation, that assures N-1 security, is calculated for this bundle. The bundle may include units that participate in balancing services and units that don't or units located in the transmission or distribution network. The G+ calculates then the needed limitation for each PHU of the bundle according to the rules of sharing the burden of the limitation that are established by the operational procedures in place. If the limitation is lower than the PHU schedule, the PRU is redispatched by an amount equal to the difference between the original PHU schedule and the limitation imposed. The limitations are issued via the SCADA to the control centre of the PHU and via eSIOS to the BSP.

The rules for sharing the limitation of the bundle within the PHUs that compose it guarantee that the least cost option is chosen to solve the congestion. In order to calculate the cost of the limitation, the following bids will be used:

- Tertiary regulation downward reserve bid: if the PHU belongs to a PRU that participates in the tertiary regulation market.
- Congestion management downward bids for the day-ahead market: if the PHU belongs to a PRU that does not participate in the tertiary regulation market. Congestion management downward bids for the day-ahead market are compulsory for all generation units.

In case the congestion is detected by a DSO on its network, the DSO identifies the PHUs that are able to solve this congestion notifying the TSO which units form the bundle and the maximum possible production of the bundle. The TSO via the CECRE solves the congestion by limiting and, if necessary, redispatching the PHUs included in the bundle in the same way as if the congestion was located in the transmission network. This process is presented in Figure 32.

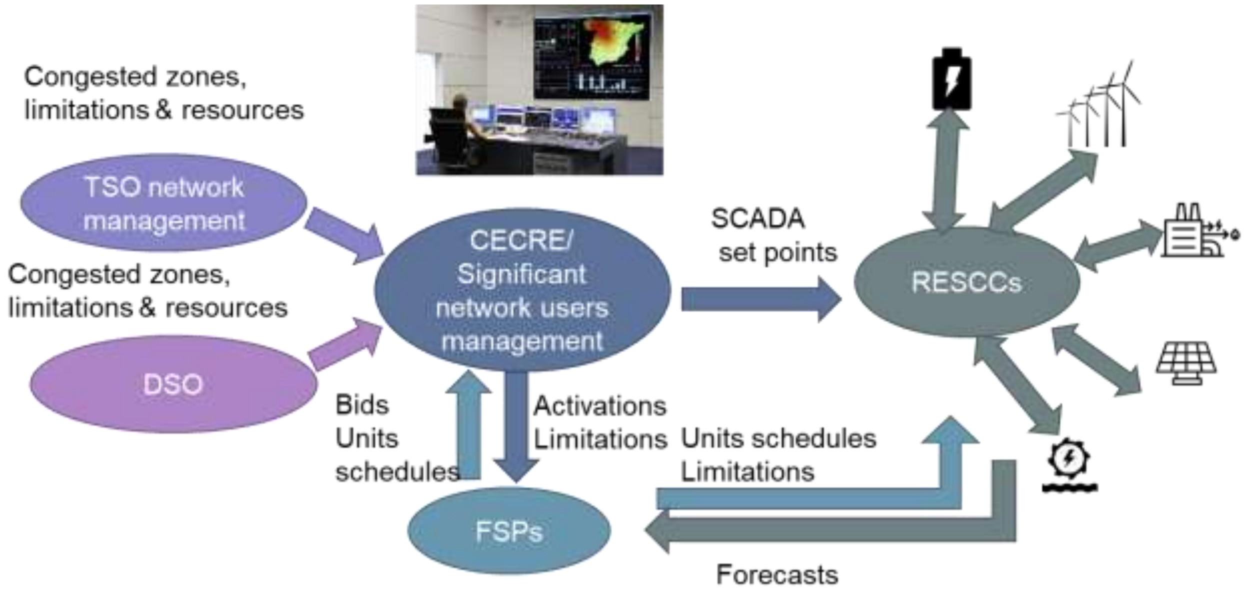

Figure 32 Activation process of renewable generation

This structure of programming units and physical units allows the possibility for aggregators to participate in the TSO balancing markets while still making it possible for TSOs and DSOs to use DER to solve congestions in the real-time.

The eSIOS platform is secured based on Digital Certificates for transport, authentication and signature:

- Confidentiality: SSL (https) for transport layer.
- Authentication / Authorization: User certificate.
- Non-repudiation: XML Digital signature.
- Reliable: Synchronous communication. Critical in case of deadlines.
- Based on W3C standards: http, xml, wsdl, soap, schema, xml-signature, etc.

As mentioned for congestion management, the protocol used to communicate with eSIOS is via Web Services IEC- 62325-504 over the internet. This is a standard of utilization of web services for electronic data interchanges on the European energy market for electricity[31].

REE has developed a public client tool to communicate with this kind of interface. More info of this tool can be found in https://bitbucket.org/smree/eemws-core/downloads/.

[31] https://webstore.iec.ch/publication/2246

5.3. DSO management systems and platforms

This section describes the main roles that the DSOs currently perform in Spain and can potentially be modified in the future to utilize more flexible resources.

5.3.1. Network connection management process

In Spain, for generation units, a deep connection scheme (direct grid connection costs and possible upstream reinforcement costs) is used to settle new connections, in accordance to the existing regulatory framework. Indeed, when a DSO evaluates the necessary grid adaptations or reinforcements, they use some security criteria[32] (Royal Decree 413/2014). If the applicant decides to proceed with the process, all the costs would be borne by this applicant. However, the previous criteria are too cautious and might result in excessive network investments.

Depending on the connection area, some obligations are given to the DSO or to the applicant. For small power demands in urban areas, customers only have to apply for connection and the DSO provides the correspondent connection. For bigger generation units or non-urban locations, costs would be borne by the applicant in accordance to the technical and economic conditions given by the DSO (Royal Decree 1955/2000). These adaptations or reinforcements to the grid are required to provide grid connection given that the conditions requested must meet the technical normative (Royal Decree 842/2002, Royal Decree 223/2008, Royal Decree 337/2014 and other technical regulations).

In the case of small generators connection requirements, the scenario is highly similar. According to RD 1699/2011, reinforcements needed for small generators connection are provided by the DSO, and bigger generators must be connected following the conditions given by the DSO. Moreover, every generator connection request must abide by Royal Decree 413/2014.

Real time communications requirements with generation devices are defined in P.9.0 and RD 413/2014. Generators whose capacity is higher than 5MW must communicate with the System Operator using a Generation Dispatching Centre. Generators from 1MW to 5MW must send real time information directly to the TSO or DSO, unless they provide balancing services. In this case, they have the same requirements than 5MW generators.

All of the above regulatory framework is under review due to the national implementation of the Art 40.5 and 40.6 of the System Operation Guideline.

[32] Security criteria are not specified in the current Spanish regulatory framework.

5.3.2. Management of foreseen events (scheduled maintenance)

The DSO does have the possibility to use flexibility as a service from resources connected to the distribution network, by requesting to the TSO to modify schedules from generation units connected at distribution grid under well-justified cases.

Foreseen events are necessary to make scheduled maintenance activities or to connect new grid assets. They are planned and requested days in advance by the DSO field-technicians. In this process, DSO Dispatching Centre evaluates its technical feasibility and potential impacts on the grid operation. In contrast with the new connection processes, security criteria considered in foreseen events[33] might be slightly more permissive.

If these events may have an impact on the TSO, there is a coordination mechanism defined in P.O. 3.5 which determines that the DSO should communicate preventive/predictive maintenance to the TSO in case it impacts the transmission network.

In both E-Di and i-DE, there is a process for every intervention on the distribution grid. Foreseen events are managed under a safety procedure which requires supervision and authorizations that influence the whole process more than the mere grid management. Specific profiles are needed to participate in each part of the process. Petitioners need to pass an exam, workers need specific licenses, etc. Every actor must be prequalified for its role.

Requests for intervention on the grid are managed in a different way depending on the service impact and also on the timing. If power cut is needed, this should be informed two weeks before, and no later than one week before the event. It is not possible to program foreseen events out of these terms.

5.3.3. Operational planning and corrective actions

The DSO routinely simulates multiple contingence scenarios to identify possible bottlenecks or grid investments. From them, DSO propose investment plans to the regional government and National Regulatory Authority. When the plans are approved by the authorities, the DSO makes the corresponding investments.

Currently, a regulatory framework related to the investment plan approval is being discussed, and Spanish NRA has presented a new regulatory draft for public consultation [34]. The DSO constantly evaluates Network configurations as means to: reduce electricity losses, improve quality of supply to consumers, balance congestions, reduce voltage drops, etc. As flexibility is not recognized in the current regulatory framework, this is not considered in the current Network reconfigurations made by the DSO.

Forecasts are obtained every week, after every intervention is authorized. Possible critical situations are considered in the process of authorization. On the day of the execution, all the operations needed and

[34] For further details, see https://www.boe.es/diario_boe/txt.php?id=BOE-A-2019-16639.

planned are done. If any anticipation on the reconfiguration is needed, it must be planned in order to manage all the resources.

Both the DSO and TSO have real-time communication to control electrical parameters in their grids. For further details, see P.O.9.0-Red Observable [35]. This is currently being discussed in the national implementation of the System Operation Guideline.

5.3.3.1. Power factor requirements for generation and loads

Voltage limits are used for planning, connection criteria and operational criterion used by the DSO. A description of how voltage limits are used is provided below, according to the different situations.

For loads:

The Spanish regulatory framework RD 1164/2001 defines specific incentives and penalties for the reactive power consumption/injection related to consumers. In general, the consumption of reactive power by a consumer is penalized but not to small consumers/generators (for tariffs 3.X and 6.X PO7.4 with contracted power >=30MW and later changed in RD413/2014: contracted power >=5MW).

However, this is being deeply discussed by TSO and DSO in the national implementation of the System Operation Guideline (SO GL UE/2017/1485) because the previous incentives seem to be outdated and not fulfil the current necessities of the Spanish electricity system where there is a surplus of reactive power, especially in the transmission grids.

In the Spanish regulatory framework, the voltage at the point of connection of end consumers must be within ±7% of the rated voltage, regardless of the voltage level. This limit is stricter than the one in the IEC50160.

As DSO must fulfil the previous thresholds, these voltage limits are used as a criteria in the analysis of future grid connection consumers and generators, as well as an operational criterion used by the DSO.

Voltages are monitored by the DSO at the substations and main nodes in the grid. Using that information and the short-circuit rate at each node, the DSO can accurately simulate potential voltage dips related to the connection/disconnection of generators and voltage for all consumers connected in their grids.

For generation:

Distributed generation units have to keep their power factor within a range of 0.98 lagging to 0.98 leading (see RD 413/2014). Otherwise they have to pay a penalty of 3% of the value defined in the regulation (set at 8.2954 c€/kWh in RD 1565/2010). Moreover, if DG units maintain their power factors above 0.995 (either leading or lagging) they receive an incentive equal to 4% of 8.2954 c€/kWh.

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[35] https://www.ree.es/sites/default/files/01_ACTIVIDADES/Documentos/ProcedimientosOperacion/BOE-A-2019-18275_ministerio_para_la_transicion_ecologica.pdf

In principle, the mandatory range may be different across regions, although this provision has not been used.

Units larger than 10MW may be requested by the system operator to alter the mandatory power factor range or even follow voltage set points at specific transmission grid busses. When generators comply with the latter set-points sent by the SO, they receive the same compensation mentioned above (see P.O. 7.4).

This is expected to change with the implementation of Requirements for Generators Grid Code (RfG or UE/2016/631). In there, generators must be able to control voltage by means of a power factor set-point, voltage set-point or reactive power set-point. Therefore, the future grid voltage control currently discussed by TSO and DSOs seems to change from a power factor to a voltage set-point. The latter is more efficient and allows the generator to inject or consume as much reactive power as is necessary depending on the grid voltage at each time.

For further details, see RD 413/2014 and P.O.-7.4. In i-DE grids, minimum power factor for loads is 0,6 in order to avoid disturbances[36].

5.3.3.2. Management of emergency situations/unforeseen events

By default, emergencies and unforeseen events in the distribution grid are solved by the DSO itself (without generation support). However, when these situations have an impact on the TSO (they are close to a border point or the amount of generation production is relevant), coordination mechanisms between the TSO and DSO exist (see P.O. 1.1.).

In the future, Emergency and Restoration Grid Code (ER or UE/2017/2196) will improve the existing TSO-DSO coordination. At this time, the TSO and DSO are discussing its national implementation.

5.3.4. Metering, monitoring and control of DSO networks

As stated before, in Spain, for consumers, metering activity is only performed by DSO regardless the grid level (transmission or distribution) where they are connected to. However, metering for generators with capacity below 450kW is performed by DSO, while all the rest is done by TSO regardless the grid level (transmission or distribution) where they are connected to. The DSOs are responsible for providing the metering data of all consumers’ meters to the retailers for billing, forecasts, offers, to the NRA to supervision, to the TSO for settlement and finally to the customers in a non-discriminatory way.

It is important to highlight that the customers are the owners of their meter data according to the European and national regulation. For this reason, if a third party requests access to the customer's data, a client’s consent is mandatory. The Commission Regulation (EU) 2017/2195 of 23 November 2017 established a guideline on electricity balancing where it was defined a harmonised duration for the imbalance settlement period (ISP) for EU countries to 15 minutes. This implementation is going to change the requirements of meters that actually register the consumption data hourly and apparently will take effect from 2025.

[36] Further Specifications required by i-DE can be downloaded from https://www.i-de.es/disdoct/iberdrola.

Also other European regulations, specifically, the European Directive "Common rules for the internal market in electricity", where the minimal functionalities required by the meters are defined, are introducing a new concept of "near-real time data". This means that the DSO must facilitate the validated historical consumption to final customers. It also introduces that, non-validated near real-time consumption data shall also be made easily and securely available to final customers at no additional cost, through a standardized interface or through remote access, in order to support automated energy efficiency programs, demand response and other services.

In addition, Spanish regulation is introducing in the RDL 15/2018 new terms and conditions of access to consumption data for retailers, still pending to be enforced, in order to offer services to demand management and energy efficiency measures, either directly or through energy services providers, while always considering the General Data Protection Regulation.

DSOs are not responsible for billing customers the electricity costs. However, they are responsible for collecting regulated charges of the electricity bills either from suppliers or big (direct) customers.

The DSO system monitoring depends on the level of observability and controllability of the networks, which significantly change at the voltage level. This section provides an overview of the status of DSO networks level of measurement and observability, especially in the networks considered for the CoordiNet demo sites.

a. Frequency of metering

According to the regulation, the frequency of metering registration from generators/consumers depends on the type of the measurement point.

The metering points type 5[37], which are points located at generators/consumers whose power is equal to or less than 15 kVA, register the load curve hourly.

The metering points type 4, that are points located at generators/consumers whose power is equal to or less than 50 kVA and up to 15kVA, register the consumption according to the tariff periods but must have the capacity to parameterize hourly by 2022.

The metering points type 1,2 and 3, that are points located at generators (only type 3)/consumers whose power is equal to or less than 450 kVA and up to 50kVA, register the load curve hourly and quarter-hourly simultaneously.

In addition, the Spanish guideline for balancing requires that once the 15 minutes ISP is established in the Spanish electricity system, all BSPs should have real metering (without profiling) every 15 minutes (expected by 2025).

b. Measurement, monitoring and control at different voltage levels

[37] For further details, see RD 1110/2007.

DSO monitors voltages in all the sub-transmission grid and their corresponding substations, considering on-load tap-changer transformers as well.

Capacity banks[38] are only useful in the highest voltage grid because the R/X ratio is the lowest. However, the installation of these devices may not be always the most cost-effective solution and the DSOs advocate for an updating of the voltage regulatory incentives for consumers and generators. If incentives for third-parties are not enough to solve voltage problems, the installation of capacity banks or reactive devices might be a solution.

In the future, higher shares of distributed generation might produce relevant overvoltages and under voltages depending on their flows. As a solution in these cases, the DSO is working on the replacement of specific existing MV/LV transformers by on-load tap-changer MV/LV transformers.

DSOs have grid architecture criteria to define the necessity of monitoring and control points. In the case of i-DE, generators in >1kV grid are requested to be monitored in real time with remote switches. For demand connected at medium voltage will depend on the installed power and/or line length. Demand connected at high voltage must be monitored in real time with remote switches.

c. Communication protocols and information standards

The communication protocols between the DSO and the generation/consumers points depends on the capacity. According to RD1110/2007, the communications protocols will preferably be public. However, these protocols can be exceptionally specific, of a private nature, and forming part of a global remote management solution.

Specifically, in Spain, a hierarchical communication architecture is used to remotely manage this type of points of measurements. This communication architecture uses a data concentrator, typically located at the secondary substations, to aggregate the data coming from the smart meters, as well as to forward the commands coming from the information systems / MDMS (Meter Data Management Systems) to them.

For the so-called last-mile communication segment (i.e., between the smart meters and the data concentrators), NB-PLC (Narrowband – Power Line Communications) is used. In particular, in the case of e-distribución, the NB-PLC technology Meters&More (promoted by the ENEL group and later standardized in CLC TS 50568-4) is used; whereas in the case of i-DE, the NB-PLC technology PRIME (promoted by Iberdrola group and later standardized in ITU-T G.9904) is used. On top of any of these NB-PLC technologies, at the application layer, the information between smart meters and data concentrators is exchanged using DLMS as application protocol and COSEM as data model (both standardized in the set of standards IEC 62056 for metering data exchange).

For the backhaul communication segment (i.e., between the data concentrator and the information systems / MDMS), different communication technologies can be used. Cellular communications (e.g., GPRS; UMTS) is probably the most widely used option. Nevertheless, i-DE combines this option with MV-BPL (Medium Voltage – Broadband over Power Line), making the most out of their medium voltage infrastructure as communication medium up to a substation equipped with broadband access which works as gateway to the

[38] *Reactive devices (STATCOM) use to be installed in the transmission grid.*

information systems. In this communication segment, at the application layer, web services based protocols are used (in the case of i-DE, STG-DC, Sistema de Telecontrol – Data Concentrator).The metering points type 4 and 3 could communicate through an open protocol based on IEC 870-5-102[39], as well as remote management solution.

The metering of connection points type 1 and 2 communicate through an open protocol based on IEC 870-5-102.

Regarding to operational devices protocols, at the moment, DSOs are not allowed to (directly) send orders to network users. This is a TSO role and the corresponding protocols and specificities are defined in P.O. 9.0.

5.3.5. Flexibility activation

Activation of flexibility at DSO networks is limited as stated before and generally managed for congestion management by the TSO. This function clearly needs to be developed in the project to establish the role of market facilitator as required by EU regulation.

As stated in the congestion management BUC description, in case of technical constraints, in distribution networks, the DSO can ask the TSO for the interrumpibility service activation (this is rarely used until now).

Therefore, as of today, the DSO, through the TSO, can use DG for local congestion management and power factor control, and consumers with contracted power above 5MW can participate in interruptible services. As the DSO and TSO send these requests, the TSO receives the congestion management bids that are able to solve the constraints, assigns them and instructs the DER.

As of today, in Spain, DSOs cannot sign interruptible contracts with DER. The only form of interruptible contract is between the TSO and industrial consumers. However, DSOs may use these interruptible contracts signed with the TSO to solve constraints in their networks as well.

Starting in February 2016, all redispatch due to congestion management in the DSO or TSO networks including generation from renewable sources is done via market mechanisms (PO 3.2).In case of emergency situations, the DSO directly curtails demand and/or generation. In addition, in case of emergency, it is possible to take actions if demanded by the TSO using manual activation.

[39]https://www.ree.es/sites/default/files/01_ACTIVIDADES/Documentos/Documentacion-Simel/protoc_RMCM10042002.pdf

6. Components and platforms required for the development of the Spanish demo

This section presents the components and platforms required for the development of the Spanish demo. The section is divided in three subsections: platforms and management procedures to be developed, the definition of aggregation activities, components specifications and information and communication required.

6.1. Platforms developments and management procedures for CoordiNet

6.1.1. TSO platform

The Spanish TSO REE will develop and host the common platform within the CoordiNet Platform concept. The common platform is not one single system, but composed by the adaptation of the already existing systems by REE, and the development of the necessary functionalities and interface for the deployment of the different BUCs that make use of the common platform.

- **CoordiNet Platform Interface**: consists of a new platform that allows DSOs to call markets for different needs, based on the structural information already in place in the G+ system. Therefore, the DSO will be able to call for congestion management markets for different locations, including specifiying the units connected to those locations with the sensitivities to relieve congestions. A common markets will be run in a coordinated manner with the TSO.
- **G+:** Several adaptions to the already existing G+ will be made so the TSO can run the congestion management market created by the DSO in the CoordiNet Platform Interface. This application will use similar market structure and algorithms already used by the TSO.
- **CECRE:** In principle, no considerable modifications are foreseen due to the implementation of the common platform. The CECRE will be the gateway between the generation units and the TSO, both for reception of monitoring data and for sending set-points.
- **E-SIOS:** The current system E-SIOS will be slightly modified to accommodate the new markets called by the DSO through the CoordiNet Platform. E-SIOS will also be the interface between the common platform and the markets agents (FSP and sFSP).

New developments in existing platforms (G+ and SIOS) are required to test voltage control. Some of the key aspects for these developments are:

- Making possible the grouping of resources at certain nodes of the network (pilot nodes)
- Developing an interface to provide setpoints
- The platform must allow the TSO and DSO to:
- Create and modify the group of units that can potentially support voltage control.
- Modify setpoints in their own networks.
- Send setpoints to the users that participate in the service provision.
- Define limits to possible voltage control setpoints.

Figure 33 summarizes the different systems considered for the common platform and their interaction regarding the congestion management processes.

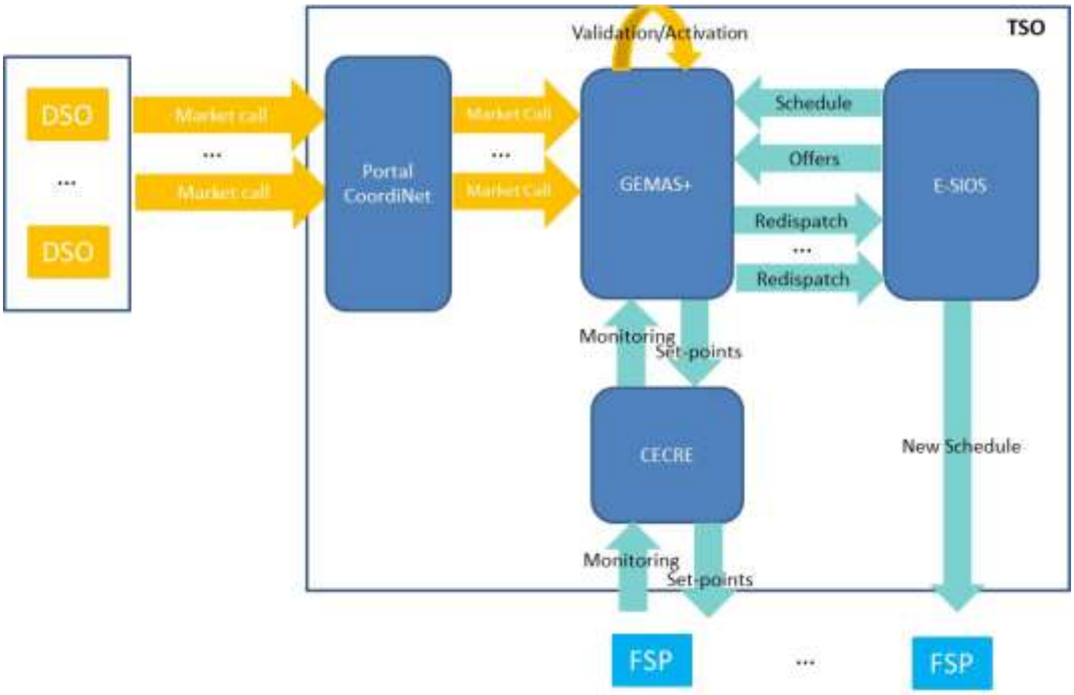

Figure 33: common platform Architecture

Figure 34 shows the process of calling a market and the different information exchange between systems is detailed regarding the congestion management processes.

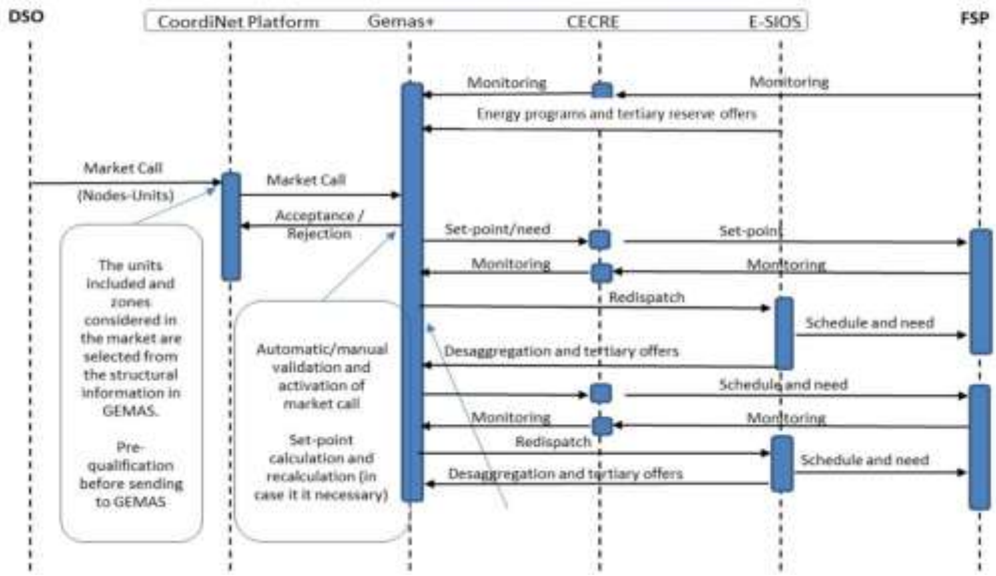

Figure 34: Process Diagram - common platform

6.1.2. DSO platform

E-di and i-DE are building a DSO platform which has five main modules (see Figure 35): Day ahead DSO, CoordiNet local platform, intraday operation DSO, observability and communications. Each of these modules is in charge of a range of functionalities that are described in the following subsections.

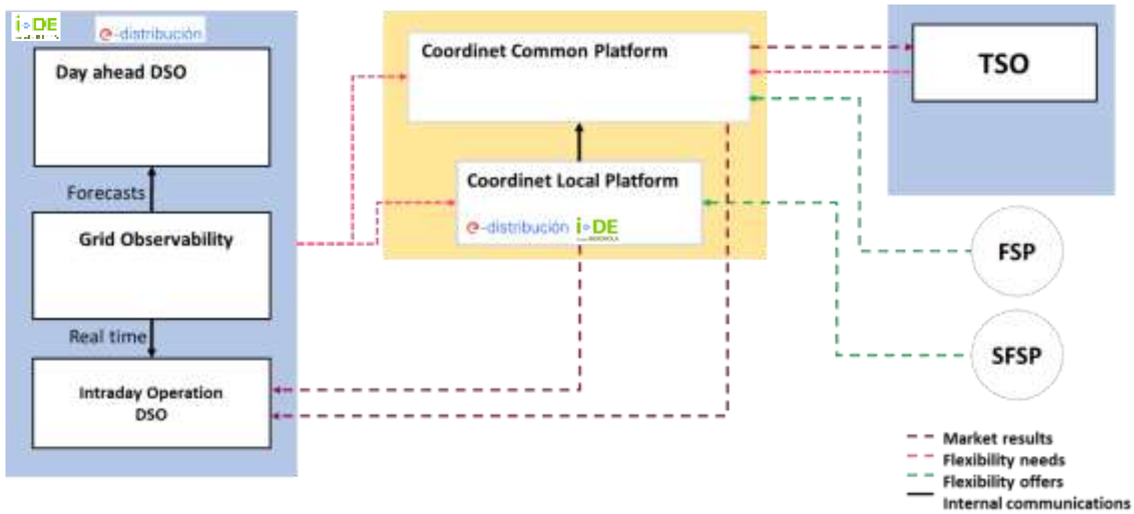

Figure 35: DSO Platform structure

6.1.2.1. Day ahead DSO

This module is in charge of sending the needs of distribution networks to different platforms. The platform also allows registering manual requirements or inputs from other platforms of the DSO different from the observability module.

6.1.2.1.1. Local congestion management

This module is responsible for estimating the expected congestions on the distribution network in order to send the requirements to both the CoordiNet local platform and CoordiNet common platform. The module operates at day ahead timeframe.

More precisely, the module takes into account the generation and consumption forecasts, which profiles are computed in the observability module. Based on these profiles, the solution of the AC Power Flow (PF) equations determines whether there will be any line congested. For this to be possible, in the PF model, it is necessary to establish the security level per line at which the line will be considered to be congested (for example at 70% of its capacity).

Once the requirements are computed, the local congestion management module sends them to the Common and Local Congestion Markets (Market module) together with the technical constraints related to the defined security limits.

6.1.2.1.2. Local voltage control

This module is in charge of controlling the voltage in the local network. It operates at the day ahead timeframe.

As in the previous case, the expected voltage in the grid is computed and analysed by solving the PF equations, taking into account the forecast profiles performed in the observability module. The security limit of node voltages must be established according to current regulations. More restrictive limits could also be used. This security limit must be added to this PF model developed.

The voltage control needs that are computed using the PF model are sent to the CoordiNet common platform.

6.1.2.1.3. Security check for balancing

This module is in charge of identifying the possible limits in the distribution network related to the TSO capacity balancing bids.

In this case, a PF algorithm analyses whether the activation of any balancing bid can affect the operation of the distribution network. In this analysis, the expected generation and consumption's forecasts provided by the observability module will be used. The TSO capacity balancing bids will be also used as inputs to the PF algorithm.

If there are congestions on the DSO networks, the DSO may set limits to sFSP to provide balancing services and will communicate these limits to CoordiNet common platform.

6.1.2.2. CoordiNet local market platform

The local platform receives bids from Small FSP (sFSP). Then, the market clearing algorithm is executed, and the matched offers and corresponding activations are sent to the sFSP. In addition, the market results are also sent to the common platform and to the intraday operation submodule.

An electricity market block can, on a high level, be seen as indicated in Figure 36. This framework will be implemented for the local congestion management BUC.

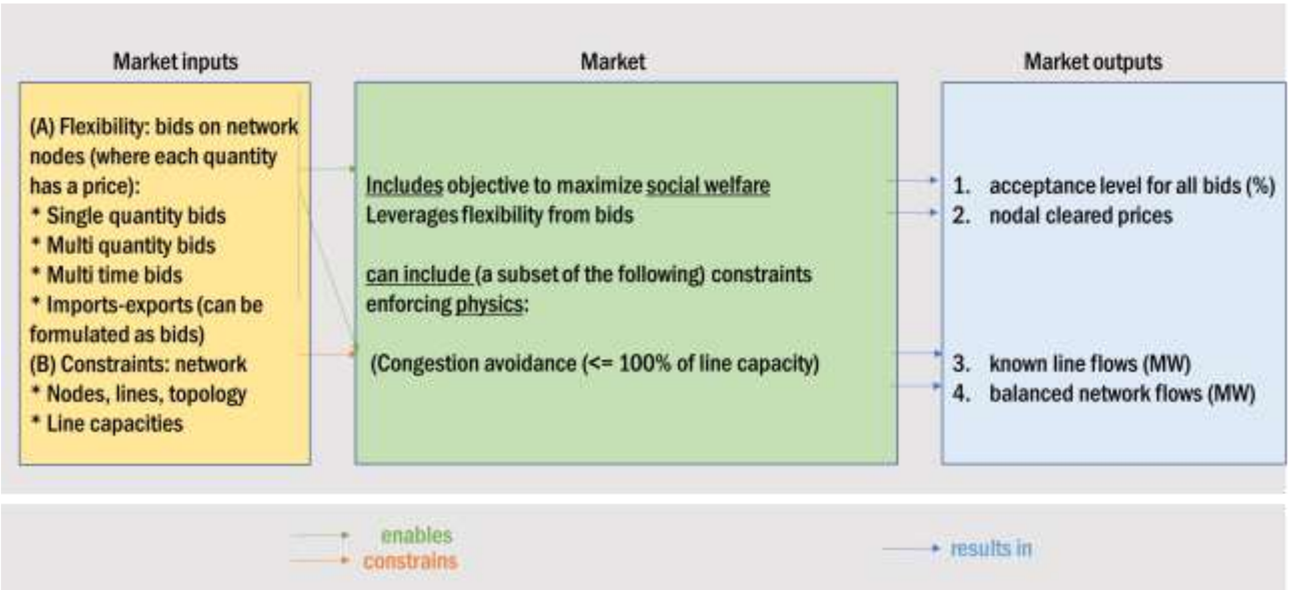

Figure 36 Typical Electricity Market Block

For a given market design, the needed inputs and resulting output will depend on the detailed definition of the BUC. Different inputs may be required depending on flexibility constraints from sFSP and the network specification. The objective function is to ensure the global maximization of social welfare. It is ensured that the total acceptance of injection and offtake bids in different locations does not lead to any violations of specified network limits. The generated outputs will include: the acceptance bids and resulting prices, line flows and balanced network flows.

Based on the requirements for Spanish demo needs, this is the high-level market design description proposed. Further information and description of the different possible market designs will be included in CoordiNet D2.1.

- **Maximize the welfare**. The objective that the market clearing algorithm will optimize is the welfare. The market solution will be a feasible solution that maximizes the welfare, defined as the sum of the buyer surplus, the seller surplus and the congestion rent.
- **Portfolio based trading**. The proposed design relies on a portfolio based trading. This means the market relies on market products such as "single bids" or "block bids",… which are matched and cleared by the market. Behind a single market product, a sFSP can have one or multiple physical assets. In order words, the sFSP will not bid the technical and physical characteristics of its assets into the market (such as "minimum up and down time", "start-up costs"…) but will express it via market products. Portfolio based trading is by far the most used model in European electricity markets.
- **Closed-gate auction**. The market will clear based on an auction mechanism: the market participants have a period during which they can bid into the market for a given market horizon. Then the market closes, clears and provides the prices and dispatch instructions.
- **Automatic market clearing**. It is assumed both the supply side (the flexibility service providers) and the demand side (the grid needs from the DSO) will bid into the market which will clear automatically with a clearing algorithm.
- **Bids**. As the market is assumed to be of the portfolio-based trading kind, the market participants will need to express their needs and offers with some market products which are the "bids". Ramping constraints will likely be modelled, both for supply ('generator inertia') and demand ('consumer inertia'). In addition, more complex constraints (involving non-continuous, integer or Boolean decision variables) like enforcing a minimum or maximum activation duration or accepting a bid conditionally on the acceptance of other bids (implication constraint, exclusive constraints, etc.) could be also required.
- **Network model**. It is assumed the network will be modeled explicitly in the market. The network model will depend on the use case considered.
- **Pricing**. When the market clears, it provides the dispatch instructions to the sFSP which need to come with some kind of settlement refering on how are the sFSP activations paid for. It has to be further specified if the pricing algorithm follows a pay-as-bid or uniform marginal pricing rule. A uniform price per node can mean that side-payments are required if block bids are allowed in the market; or alternativly some further rules could be put in place to avoid side payments. The choice will depend on the network model and the bids that are allowed in the market.

6.1.2.2.1. Integration of market clearing block in the local platform

From Figure 35, the components that fall into the local platform and deduce a sequence diagram including the interactions with other platforms. Figure 37 presents the different platforms and agents' interactions with the local market platform.

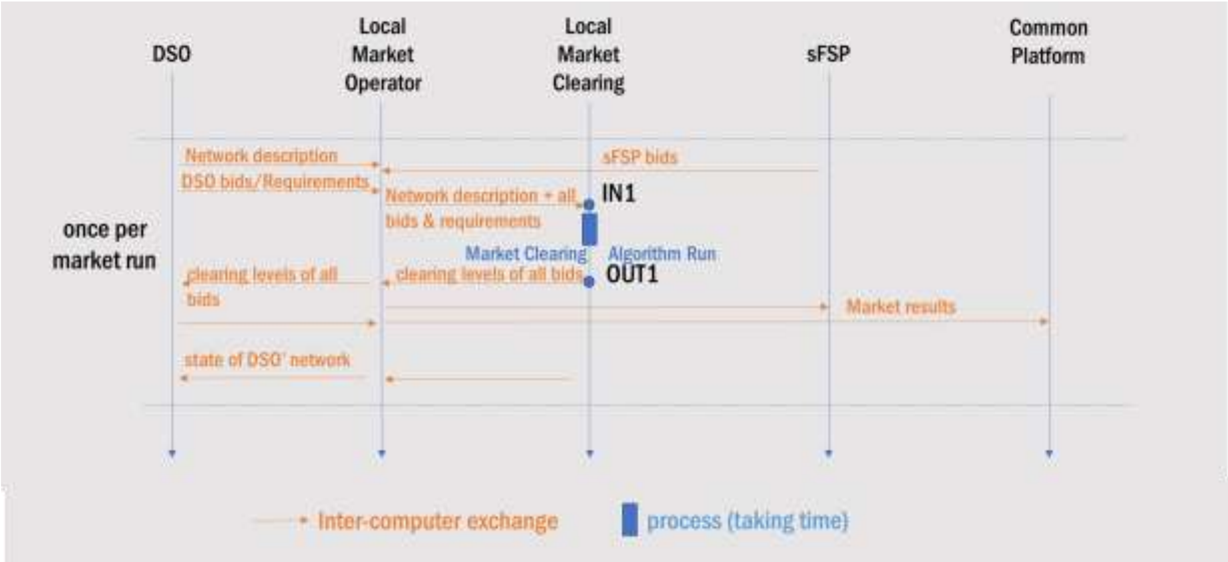

Figure 37 Local platform interactions

In Figure 37, the sequence of messages exchanged is as follows for one market run. The DSO sends its bids to the market operator together with the DSO network description. These sFSP also send their bids. The order of these two messages is irrelevant. The market operator only accepts these bids until gate closure. When the gate is closed, the market operator sends ('forwards') all bids and the network description to the market clearing engine. The market clearing engine immediately starts to clear the market, and derives acceptance levels of all submitted bids and calculates the corresponding power flows. These acceptance levels, active power flows (and if modelled, also reactive power flows, reactive power injections/offtakes per bid and voltage level) are sent back to the market operator (OUT1). The market operator then sends ('forwards') answers to the relevant parties (acceptance bids to sFSP, acceptance levels of DSO bids or cleared requirements to DSO and network variables (energy flows, voltages) to the DSO).

In Figure 37, note that all communication of bids going towards the local market as well as the acceptance answers for these bids originating from the local market, pass via the 'neutral' market operator. The market operator just delegates the clearing function to the market clearing. Given the assumptions presented in the previous section, a simple architecture for the local market clearing is proposed and is shown in Figure 38.

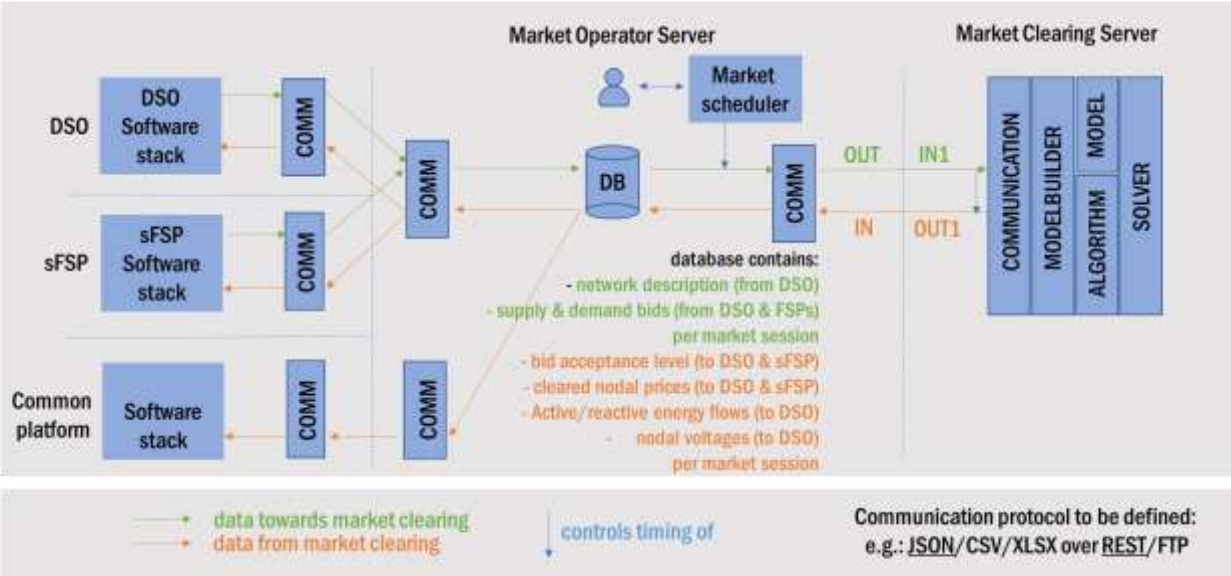

Figure 38 Proposed system architecture between DSO, sFSP with local market operator and market clearing

The local market operator runs a scheduler that knows when gates for auctions close. This means it collects the bids from the market supply (sFSPs) and demand (DSO) sides during some time before that gate time (see left side of the picture). The DSO also sends its network description to the local market operator, possibly only when it changed since the last market run. Directly after the gate closure time (GCT), this collection of bids, together with the most recent DSO network description is sent to the local market clearing block. Hence, the market clearing block receives this data collection (indicated in green in Figure 38) and immediately builds the optimization model and solves it with an in house algorithm and a commercial performant solver. The result of the optimization (in orange in Figure 38) including bid acceptance levels for all bids, energy flows for all lines, voltage levels per node and cleared nodal prices, are sent back to the local market operator server. The market operator stores these results for further use/recording and also forwards the right information to the right parties. Bid clearing levels and nodal prices go to the respective bidding parties (DSO and sFSPs). In addition, the network related information, energy flows per network line, possibly voltages are forwarded to the DSO.

6.1.2.3. Intraday Operation DSO

The intraday operation module is in charge of checking the results computed in the market clearing, where the flexibility services can be traded. This module is shared by four functionalities: “local congestion management”, “local voltage control”, “controlled islanding” and “security check balancing”.

This module will receive the results of the different services from the common market platform. In case there are LV congestions, their results will be received from local congestion market module, otherwise, their results will be also sent by CoordiNet common platform. In case of long-term contracts with services previously matched, such as controlled islanding services, they will also be considered.

The bids presented in the different markets should contain, at least, the following information for every offer and for each interval of the market’s timeframe:

- matched quantity of flexibility [kWh, kVArh];
- direction of deviation [up/down];
- matched price [€/kWh, €/kVArh];
- consumption’s baseline [vector kWh, kVArh];

- consumption's baseline taking into account the rebound effect for each offer [vectors kWh, kVArh].
- location [node ID];

If the product is a portfolio bidding offered by an aggregator, all the locations and matched quantities of the involved physical providers must be specified as well as all the rebound effect for each one, although the bid will be activated completely.

Close to real time, it is performed a power flow algorithm in order to ensure that there are not congestions nor voltage problems, if required, in the distribution network. In a similar manner, the local platform receives balancing energy bids and check limits on the distribution network. This includes new limits taking into account the matched flexibility bids received. In case new limits exist for any of services considered, they are sent to the local and common platforms.

Any additional limits are communicated to the common platform, which informs the TSO.

6.1.2.3.1. Observability

This module is related to the grid's operation. It includes the forecasting, metering and checking of activation functionalities, which are essential for the correct operation of the market module as depicted in Figure 39.

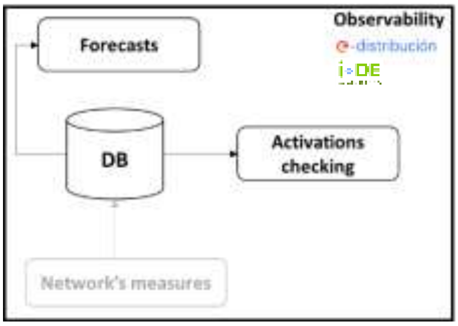

Figure 39: Observability Module Structure

In order to obtain the expected grid's operation and know the necessities of activation of flexibilities resources, it is necessary to develop two forecast models: one related to the generation, and other related to the consumption. This functionality is in charge of develop and execute all forecasting models.

The consumption of the participants in the local and common platforms have not to be forecasted when they present their consumption's baselines when presenting a bid. These consumption's baselines are received from common platform with the markets results, as explained in the previous module. However, the total consumption of the grid includes the consumption of clients which do not participate in the local and common platforms or do not send valid forecasts, so their consumption must be forecasted.

In Malaga, a network state estimator tool will provide information about all grid nodes near real time. This information will be stored in a database and it will be accessed to collect past information to perform the forecasting models based on machine learning techniques. In Cádiz, the network's measures will be provided by e-distribución. In Albacete, Murcia and Alicante the network's measures will also be provided by i-DE.

The forecasting operates at the day ahead timeframe, before executing the power flows algorithms of the local congestion management, local voltage control and the security check balancing modules.

In the i-DE platform, the forecast will be done by the existing operation platforms, different from the observability module. In this case, data will be provided by this platform.

The activation checking depends on the measurement of the activated flexibility. The amount of flexibility delivered is determined by evaluating the measurements at the connection point and compared with a schedule. When a service given by a flexibility provider is not delivered or does not respect the agreed parameters, a penalty is possible.

For e-distribución, the measurements of the network will be provided by the network state estimator in real time in Malaga and by e-distribución in Cádiz. These quantities will be compared with the baselines provided by the common CoordiNet platform to check if the activation of flexibility is performing correctly.

The activation checking also allows controlling whether any new problems arise in the grid's operation and secure that the status of the grid is within the operational requirements. When a flexibility service is delivered, it is needed to check the performance and whether the problem is solved. This module operates once the services are delivered, after real-time.

In the case of i-DE, real time monitoring will be done through the SCADA platform allowing the DSO platform to send the temporary limits for alarm configuration. Delivery checking will be done by the DSO platform for the settlement.

6.1.2.3.2. Communications

This module is responsible for establishing all communications between the local platform, common platform, DSO platform, and sFSP. Since different corporate networks are to be connected, in principle, these communications will take place over the Internet, being appropriately secured (using end-to-end encryption, e.g., using TLS/SSL). At the application layer, the communication protocols must be clearly specified and agreed with all participating agents. In addition, data models and formats must also be specified and agreed. In both cases, standard options should be preferred, avoiding proprietary solutions. Furthermore, if it were not possible to use the same data format for the communications between all the actors and the market operator server, the use of a middleware that translates to a common format to be stored in the database should be considered. Access permission and privacy concerns should be also considered at the server database.

Table 24 shows the information that must be interchanged among the different modules and platforms.

Message	From	To
Expected grid's operation	DSO operation system	Observability -> Day ahead DSO
Forecasts	Observability	Day ahead DSO
Baselines	Common platform	Observability
Local voltage needs	Local voltage control	Common platform
Local congestion needs	Local congestion management	Local platform
Voltage market results	Common platform	Intraday operation
Flexibility bids	sFSP	Local Congestion Platform
Local congestion market results	Local platform	Common platform
Local congestion market results	Local platform	Intraday operation
Expected grid's operation	Observability	Intraday operation
New voltage needs	Intraday operation	Common platform
New congestion needs	Intraday operation	Local platform
Flexibility activations	Intraday operation	Observability

Table 24 Messages between DSO platform modules and other platforms

6.2. Aggregation activities

6.2.1. e-distribución demos

6.2.2. Cádiz

Endesa energy management unit (the market unit inside the Endesa holding) will develop the task as aggregator in this demo, with support from ONE and Tecnalia.

In order to perform the BUC, the generation forecast will be obtained for each unit. The forecasts will be obtained the day-ahead but updated every hour. Currently, the forecasts are obtained on an hourly basis, but in CoordiNet the possibility to compute 15 minutes forecasts will be explored.

Currently, the participation in the markets is done at the aggregated level per technology. However, for local congestion and voltage control, each unit will be considered separately.

The participation of the unit in the provision of balancing services is manage by regulation zones, meaning by company level. Wind farms are part of Endesa regulation zone and imbalances can be compensated with other units inside the Endesa regulation zone. The solar farm considered is not part of the Endesa regulation zone.

As the units are renewable generation, they generally would be providing at full available capacity. Reducing the generation from that maximum available capacity would represent an opportunity cost for the power unit. This opportunity cost would be considered for the flexibility bids on providing the different products.

How the information will be received has to be defined for each of the flexibility needs from the TSO and the DSO, either accessible through a webpage or through other mean. It is relevant to use the same identification for the units both for the system operators as well as the market manager and the aggregator.

Once bids from renewable generation unit is cleared in any of the markets, the activation is done from a generation control centre (GCC). Currently the renewable control centre from REE sends the set-points to the GCCs.

One relevant aspect is to determine the level of disaggregation for common congestion management, as currently the set points for congestions at transmission levels are established aggregated for transmission nodes and not which much detail at distribution networks.

6.2.3. Malaga

In Malaga, the aggregation activity will be performed by ONE and Tecnalia with technical support for the development of Energy Box (EB) from Circe which will perform the function of monitoring and controlling local flexibility providers' facilities. The EB will be upgraded and adapted to be installed in industrial facilities, as COGEN_MAL1 and BIOGAS_MAL1 ones, to monitor and control devices that can provide flexibility to the system.

Within the CoordiNet Project, the Energy Box is being improved to be used in the facilities of the local flexibility providers. As some of these providers are industrial ones, the EB will be ruggedized to support hard operating conditions and adapted to different industrial communication protocols. The main improvements, among others, will be:

- Metallic envelope
- 110-230V AC / 125V DC energy source
- Second secured digital slot
- Second ethernet connector
- Data encryption

6.2.4. I-DE demo

For the i-DE demo, the aggregation role will be developed by different actors as shown in Table 25. For renewable generation units, this role will be developed by Iberdrola holding group as owners of the units. The decision to participate in the different markets considered in CoordiNet depends on the participation in the energy market and the decisions are taken for the aggregated portfolio that the company has. On the other hand, the cogeneration units belong to Energyworks company which will take the aggregation decisions. For the industrial customer ALI 1, its owner will directly interact in the different markets. The buildings that belong to the Murcia city hall will provide their flexibility by directly managing their flexibility internally. Finally, for the controlled islanding BUC, i-DE will directly control and manage the battery used.

Unit	Technology	Aggregation role
Multiple units	Wind and hydro units	Iberdrola
Cogen ALB 1	Cogeneration in the process of a cheese factory	Energyworks
Cogen MUR 1	Cogeneration in the process of a plastics factory	Energyworks
Battery	Battery / Storage	i-DE
Customer ALI 1	Industrial demand	Customer ALI 1
Secondary substations & LV resources in Murcia City	Demand	Ayuntamiento Murcia

Table 25 Aggregation role in i-DE demo

6.3. Components specifications

Several components are being adapted or developed, while communication protocols and information exchange needs are being defined. Although this is a work in progress, in this subsection we highlight what could be the most critical missing elements for the implementation of the Spanish demonstration, and that should be defined at the early months of the second year of the project.

We divide this analysis into two blocks. Firstly, we comment on the most critical components (devices and applications) and their definitions. Secondly, in the next subsection, we address the key communication and information exchange aspects that have to be defined. Components are here understood as devices and applications necessary for the implementation of the demonstration and associated BUCs.

At the centre of the demonstration is the concept of the CoordiNet Platform. In the case of the Spanish demo, the CoordiNet platform can be divided into the common platform and the local platform. The development and deployment of these platforms is the basis for all BUCs implementations.

The common platform will be used in all BUCs, with the exception of the islanding operation BUC. To this date, this platform is set to be developed and hosted by REE. It will consist of adaptations on the already existing systems G+ and eSIOS, in order to include the functionalities foreseen in the BUCs, and be accessible to the participants of the demonstration. It is yet to be defined how exactly these applications will be developed and hosted. They can be part of the actual existing systems, or an external platform replicating the existing systems and adding the new functionalities.

On the DSO side, platforms are also being developed. The “DSO Platform”, as described in section 5.3, the necessary tools for DSOs to operate and interact with other actors, devices and applications. Additionally, to the internal tools for the DSOs, another key component in the Spanish demo is the “local platform” concept. This application will be necessary for the BUCs testing local service procurement, such as congestion management and islanding operation.

It is important to notice that two DSOs are participating in the demonstration activities in Spain, and therefore, they will have their own platforms developed separately. Nevertheless, the functionalities and specifications are being planned jointly, so that the solutions can be comparable and replicable. In addition, the communication interfaces (i.e., application protocol and data model and format) between both DSO platforms and the CoordiNet platforms (both Common and Local) must be as similar as possible, in order to ease the incorporation of any other DSO platform to the TSO-DSO coordination solution developed in CoordiNet.

Finally, on the DER side, two main components are critical for the deployment of the demonstration activity. On one hand, the EB hardware and software are being upgraded for the use in CoordiNet. This device is key for the different DER types to be able to receive set-points, execute them and provide sufficient monitoring for the different products and services being demonstrated. It is important to notice though that not all FSP will have an EB. Resources connected at the transmission grid will probably use the existing metering and control infrastructure. In this case, it must be assured that the platforms market and dispatch platforms developed are interoperable to be able to work with these additional control devices as well.

On the other hand, the aggregation applications are also critical, especially for the participation of sFSPs. The aggregation components will be the interface between the DERs and the market platforms envisioned in CoordiNet (both Local and Common platforms). It should be able to aggregate and disaggregate resources for biding and dispatching, respectively.

Specific components required to develop the BUCs are described next for each of the DSOs.

6.3.1. e-distribución

6.3.1.1. Malaga

As for December 2019, the following elements have been identified for each of the demo sites in Malaga:

1. COGEN_MAL1: 1 EB connected to the COGEN_MAL1 SCADA. The EB has to be connected with the COGEN_MAL1 SCADA control system to activate the available flexibility of the CHP unit.
2. BIOGAS_MAL1: 1 EB connected to the ADAM monitoring systems. ADAM is the communication system used in BIOGAS_MAL1 which is used for communication with e-distribución and REE.
3. sFSP_MAL1: 1 EB to be connected to the current control system.
4. sFSP_MAL3:
   - 1 EB + grid analyser, to monitor the demand of the building
   - 1 EB, to monitor and control the HVAC system
   - 2 if the control is made per floor level
5. sFSP_MAL5:
   - 1 EB, to monitor the solar PV inverter
   - 1 EB + grid analyser (commercial one, 3-phase device from CIRCUTOR), to monitor the demand of the building.

6.3.1.2. Cadiz

In Cádiz, new metering systems must be included to monitor real and reactive power at the e-distribución network. In addition, new software to allow automatic remote control on the units is being considered.

6.3.2. I-DE

The following elements have been identified for the demo site in Murcia-Alicante:

a. Customer ALI 1: This customer can be monitored with the current grid information, but it will be necessary to monitor and control the unit.
b. Buildings in Murcia will be monitored from the customer-aggregator side, but the components in the LV grid that are going to be tested in the business use cases must be supervised (4 LV lines and 4 transformers).

There is no need for installation of additional components for the Albacete demo.

6.4. Missing Communication and Information Exchange

To realize the BUCs and exchange the required information between the different components, communication protocols need to be defined. The definition of such protocols and exchanges depends on both the development of the missing components mentioned above, and the final specifications of products and services being tested in the Spanish demonstration (e.g., in terms of reliability, availability, latency, jitter or cardinality). The following paragraphs highlight what could be the most critical communication protocols and information exchange to be defined early in the second year of the project.

Firstly, both local and common platforms will have to interact with multiple stakeholders at multiple time-steps. As shown in deliverable D1.5, these platforms (under the concept of the CoordiNet platform) will receive bids from market participants, communicate market results to them, as well as system operators, receive restriction from SOs, send set-points to services providers, and finally send financial settlements to agents. However, as highlighted above, some of these functions will be done by different already existing systems in the TSO, in the case of the common platform. Therefore, it is key to define which already existing systems will be part of the CoordiNet platforms and which functional modules need to be developed, as well as to define the interfaces (i.e., application protocols, data models and data formats, end-to-end security mechanisms) between all the actors and the CoordiNet platforms. Standard solutions should be preferred, avoiding proprietary ones which hamper interoperability. In the case that already existing systems were integrated, if they use standard protocols, data models and formats, they should be preferred in order to favor backwards compatibility. If different data models and formats are used in the different communication interfaces, the use of a middleware which translates to a common data model and format should be consider to ease the handling, management and exploitation of the data to be stored in the platform. Furthermore, permission access must be also considered when storing and sharing the information among the actors involved.

Along this line, it will be important to define, within the project, how many points of contact there will be between FSP and the CoordiNet platforms, and how they will behave. For instance, it will be yet decided if EB will be directly connected to the CoordiNet platform and receive set-points from the common/local platform or through to the aggregator's platform.

Similarly, the communication protocol will have to be defined. As of today, for TSO's markets, units with an installed capacity greater than 5MW receive online set-points directly from the CECRE control center, while units below that threshold receive the dispatch orders through the eSIOS webpage. It is yet to be confirmed if this rule will remain or if different dispatch processes will be tested.

Another important definition is which system operator sends the dispatch instruction to each FSP. Each platform (Local or Common) can independently send the dispatch order to the required FSP, or the dispatch order can be sent to the connecting SO, and then to the FSP. As of today, this aspect is also being discussed by the TSO and DSOs for the implementation of the System Operations Guideline.

Regarding the information to be exchanged, it is necessary to define precisely the time-steps involved in each product and service being tested. Considering this information, the necessary information exchange can be defined, taking into account also the scalability and replicability of these solutions.

Further description of the missing communication and information exchange is presented in the Annex of this document.

7. Conclusions

This deliverable characterizes the demonstrator in Spain. The document presents the different demonstrator sites including the description of the resources, networks' characteristics, more specific definition of the products considered, an updated description of the Business Use Cases, current system operations, platforms and the developments necessary to realize the Spanish demo. Renewable generation units considered are connected at e-distribución, I-DE and REE at high, medium and low voltage levels. Demand-side resources considered are connected at low and medium voltages at e-distribución in Malaga and at i-DE in Alicante and Murcia.

Cádiz and Albacete demo sites involve renewable sources, mainly wind power. In both locations, voltage control, common congestion management and balancing BUCs will be tested. For these resources, as most of the units currently participate in the markets, the specific developments required for the demos are not many. However, voltage control is a new service where the product and the market framework still need to be defined and agreed between the TSO and DSO.

A very innovative part of the Spanish demo is to consider demand side resources whose participation in the market is currently limited. However, to make this participation possible in balancing and congestion management markets, technical prequalification requirements has to be established. This is an ongoing task in the Spanish demo. Demand-side resources are expected to participate in balancing and congestion management (both within common and local platforms). Control systems such as energy boxes must be installed on demand resources to provide system services. In addition, aggregation and disaggregation algorithms and communication channels to coordinate the provision of balancing and congestion management need to be defined to allow flexibility activation.

REE performs the system balancing and congestion management activities, for which established markets and operation systems including the Control Centre of Renewable Energies have been functioning for a long time. As previously mentioned, new developments and adaptations are required to include demand-side resources, interactions with aggregators and new voltage control services.

DSOs must increase the observability of their network, especially at low voltages, which is envisioned to be a relevant part in the Spanish demo. Furthermore, new roles as active participation on the procurement of services are new functions that need to be defined, to realize these functions it is required to perform different activities such as: network forecasting and state estimation, handling data and communication with resources, aggregation, short-term network operation, data handling and stronger communication with network users and the TSO.

The local congestion management function must be developed from scratch as this is not currently in place. All the different steps described for the Business Use Cases for each of the actors: TSO, DSO and aggregators need to be developed. The local platform has to be also established including the clearing algorithms and the interactions with the actors. This platform must handle both local congestion management at e-distribución and i-DE plus controlled islanding at i-DE. An initial proposal on the main components of this local platform is proposed as well as the interactions with the different actors.

The considered flexible service providers have performed tests and analysis to determine their flexibility, identify requirements (e.g. controllability, communication) to provide services to the TSO and DSOs in a coordinated manner either directly or through aggregators. This is an ongoing task which need to be constantly updated based on changing circumstances and limitations of different nature which were not foreseen.

8. References

8.1. Project Documents

CoordiNet Deliverable 1.1. Market and regulatory analysis: Analysis of current market and regulatory framework in the involved areas. https://coordinet-project.eu/publications/deliverables

CoordiNet Deliverable 1.3. Scenarios and products: Definition of scenarios and products for the demonstration campaigns. https://coordinet-project.eu/publications/deliverables

CoordiNet Deliverable 1.5. Business use case: Business use case definition. https://coordinet-project.eu/publications/deliverables

CoordiNet Deliverable 1.6. List of KPIs: KPI and process of measures. https://coordinet-project.eu/publications/deliverables

8.2. External Documents

ENTSO-E, 2018. Explanatory document to all TSOs' proposal for the implementation framework for a European platform for the exchange of balancing energy from frequency restoration reserves with manual activation in accordance with Article 20 of Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing.

Eurelectric. (2013). Power Distribution in Europe. 1–26. Retrieved from http://www.eurelectric.org/media/113155/dso_report-web_final-2013-030-0764-01-e.pdf

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Annex

This Annex presents a preliminary version of the Spanish demo architecture. This is a work in progress document that will be part of WP2.

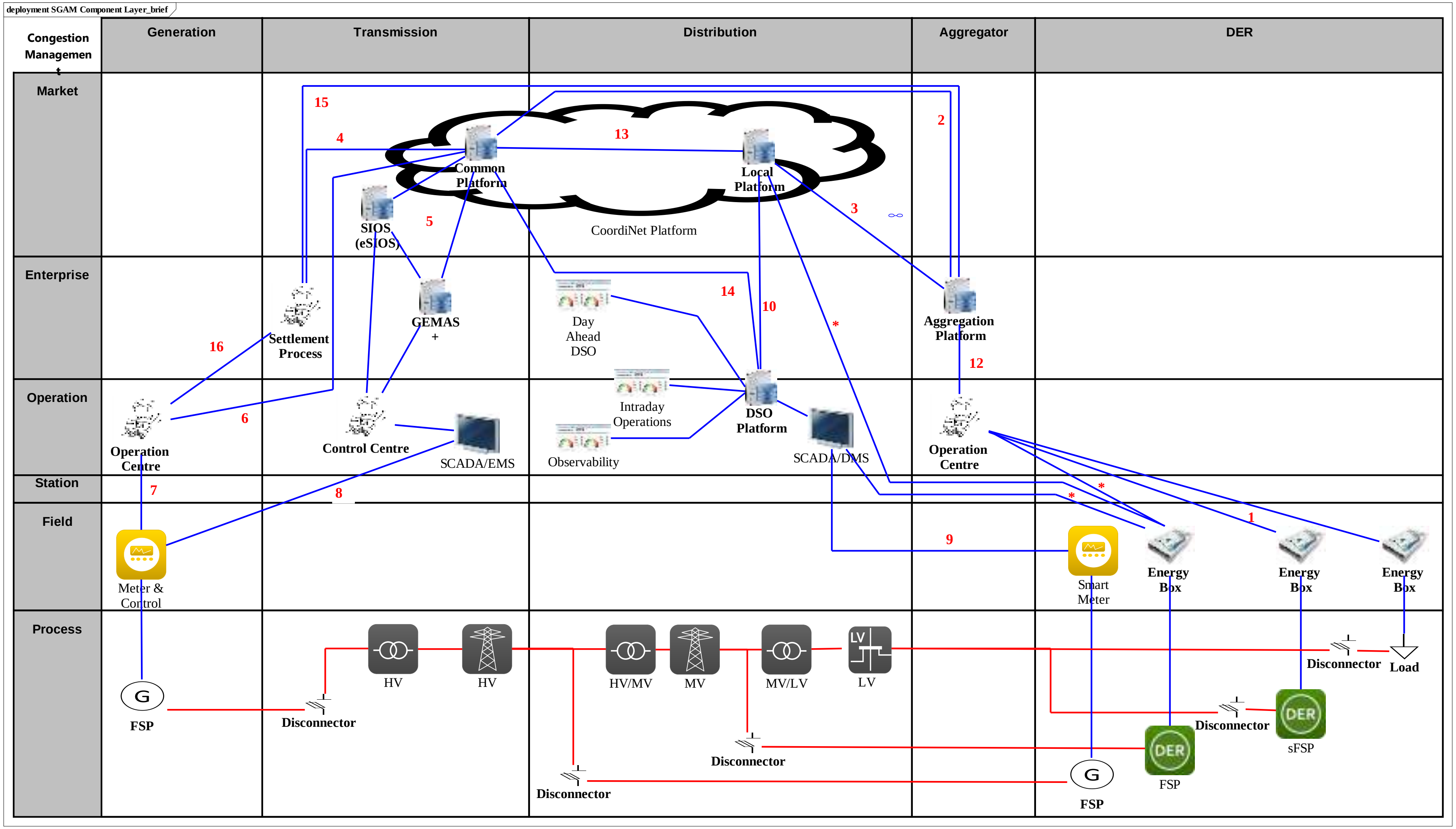
Acronym	BUC Description
ES-1a	Congestion Management – Central Platform
ES-1b	Congestion Management – Local
ES-2	Balancing services for the TSO
ES-3	Voltage Control
ES-4	Controlled Islanding

Description of Components

Component	Type	Company	Function/Description
G+	Processing and database Application	REE	TSO system responsible for market clearing and operation. It is part of the "CECRE/G+/SIOS" system, usually used together with the publishing platform eSIOS
SIOS	Processing and database Application	REE	TSO system responsible for publishing and receiving market information (e.g. bids, markets results). Used together with the G+ (or GEMAS)
Central Platform	Processing and database Application	REE (TBD)	The "Central CoordiNet Platform". This platform has yet to be defined. Nevertheless, as of today, it is expected to be at the TSO's premises, and to be based in the already existing systems such as GEMAS and eSIOS.
Control Centre	Human Machine Interface	REE	REE's control center
State Estimator	Software-based Application	e-distribución	SE of Endesa. Already operational for HV, and under development for MV and LV
Spectrum	Processing and database Application	i-DE	Iberdrola's control center system. Includes SCADA and DMS

EnergyBox	Field/Station Device	e-distribución	Smart Meter developed under the "Flexiciency" project that will be also used in CoordiNet. It can be used to connect the DER to an aggregator or directly to SO control center
Aggregation Platform	Processing and database Application	Tecnalia/ONE	Platform being developed to aggregate resources
Meter	Field/Station Device	DSOs/TSO	Generic Smart Meter
DSO Platform	Processing and database Application	e-distribución (similar to i-DE)	Platform being developed by IREC, composed of 5 modules: Day ahead DSO, CoordiNet local platform, Intraday Operation DSO, Observability and Communications
Settlement process	Processing and database Application	REE	For the sake of simplicity, this "component" represents the settlement process done by REE.

Preliminary Diagram of the Architecture for the Spanish Demo



Communication view

Defines the communication protocols for each connection between components.

In CEN-CENELEC-ETSI Smart Grid Coordination Group (2012), the following definition is provided, regarding the communication view:

> “The emphasis of the communication layer is to describe protocols and mechanisms for the interoperable exchange of information between components in the context of the underlying use case, function or service and related information objects or data models.”

In the light of CoordiNet’s initial stage and considering that some protocols are yet dependent on the to-be-implemented hardware components and systems, most connections presented in previous section do not have a communication protocol identified yet. The following table presents the communication protocol to be implemented in the Spanish demo.

Connection ID	Protocol	BUCs Affected	Comments
1	MQTT	All	
2	Will be identified in a later stage	All	In call with aggregators, it was mentioned that from their side it is ok to be connected to FTP, and have a process to read files as they are uploaded.
3	Will be identified in a later stage	ES-1b	
4	Will be identified in a later stage	All	
5	Will be identified in a later stage	All	
6	Will be identified in a later stage	All	
7	Will be identified in a later stage	All	
8	Will be identified in a later stage	All	
9	Will be identified in a later stage	All	
10	Will be identified in a later stage	ES-1b	

11	Will be identified in a later stage	All	
12	Will be identified in a later stage	All	
13	Will be identified in a later stage	ES-1b	
14	Will be identified in a later stage	All	
15	Will be identified in a later stage	All	
16	Will be identified in a later stage	All	

In the diagram, a direct connection is shown between the common and local platforms to the EB or whether this communication will be through the aggregator.

Information view

Defines the information exchanged between components in the different BUCs.

In (CEN-CENELEC-ETSI Smart Grid Coordination Group, 2012), the following definition is provided, regarding the information view: "The information layer describes the information that is being used and exchanged between functions, services and components."

The following table presents the information to be exchanged between components within the Spanish demo. Similar to the communication layer, several information exchanges are to be defined (TBD) in a later stage.

BUC	Sender	Receiver	ID	Information Content	Timing/Frequency	Format
ES-1a	EnergyBox	Aggregation Platform	1	State of the Unit	Every 5min (if market frequency is every 15mintues	SAREF
ES-1a	EnergyBox	Aggregation Platform	1	Monitoring of activation	Every 1min	SAREF
All	Aggregation Platform	Central Platform	2	Bids	TBD	TBD
All	Central Platform	Aggregation Platform	2	Market results	TBD	TBD
All	Central Platform	Aggregation Platform	2	Dispatch instructions	TBD	TBD
All	Aggregation Platform	Operation Centre	12	Disaggregated Dispatch Instruction	TBD	TBD
All	Central Platform	DSO Platform	14	Market Results	TBD	TBD
All	DSO Platform	Central Platform	14	Restrictions, DSO needs	TBD	TBD
All	GEMAS/SIOS	Central Platform	5	Congestion Management Needs, Balancing Needs	TBD	TBD
All	Central Platform	GEMAS/SIOS	5	Market results	TBD	TBD
ES-1a, ES-2, ES-3	Central Platform	Settlement Process	4	Metered Information	TBD	TBD
All	Operation Centre	Central Platform	6	Bids	TBD	TBD

All	Operation Centre	Meter and control	7	Set points	TBD	TBD
All	Meter and Control	SCADA/EMS	8	Measurements (V, A, P, Q, PF)	TBD	TBD
All	Smart Meter	SCADA/DMS	9	Measurements		
ES-1a, ES-2, ES-3	Settlement Process	Aggregation platform	15	Settlement information	TBD	TBD
ES-1a, ES-2, ES-3	Settlement Process	Operation Centre	16	Settlement information	TBD	TBD
ES-1b, ES-4	Local platform	Common platform	13	Market results	TBD	TBD
ES-1b	DSO Platform	Local platform	10	Congestion management needs	TBD	TBD
ES-1b	Local platform	Aggregation Platform	3	Congestion Management Needs, Market Results	TBD	TBD
ES-1b	Aggregation Platform	Local platform	3	Bids	TBD	TBD
ES-4	DSO Platform	Local platform	10	Islanding need	TBD	TBD
ES-4	Local platform	Aggregation Platform	3	Islanding need Market Results	TBD	TBD
ES-4	Aggregation Platform	Local platform	3	Bids	TBD	TBD
ES-4	SCADA/DMS	EnergyBox	9/*	Setpoints	immediate	IEC104
ES-4	Energy Box	SCADA/DMS	9/*	Measurements	TBC sensitivity to changes	IEC104