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ISGAN
INTERNATIONAL SMART GRID ACTION NETWORK

Power Transmission & Distribution Systems

Ancillary services from distributed energy sources for a secure and affordable European system: main results from the SmartNet projects

Discussion paper

ISGAN Annex 6 Power T&D Systems

June 2019

iea Energy Technology Network

CLEAN ENERGY MINISTERIAL

About ISGAN Discussion Papers

ISGAN discussion papers are meant as input documents to the global discussion about smart grids. Each is a statement by the author(s) regarding a topic of international interest. They reflect works in progress in the development of smart grids in the different regions of the world. Their aim is not to communicate a final outcome or to advise decision-makers, but rather to lay the ground work for further research and analysis.

Disclaimer

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This discussion paper was prepared by Gianluigi Migliavacca (Ricerca sul Sistema Energetico), leader of Focus area "Expansion Planning and Market analysis" within ISGAN Annex 6, with contributing authors:

- G. Migliavacca, M. Rossi, D. Siface (RSE - Italy)
- H. Gerard, E. Rivero Puente, J. Vanschoenwinkel (VITO - Belgium)
- M. Dzamarija, H. Madsen, R. Ebrahimy, A. Ghasem Azar (DTU - Denmark)
- G. Leclercq (N-SIDE - Belgium)
- S. Horsmanheimo, L. Tuomimäki (VTT - Finland)
- C. Madina, R. Rodríguez-Sánchez, J. Merino (TECNALIA - Spain)
- L. Ortolano, M. Palleschi (TERNA - Italy)
- M. Pardo (ENDESA - Spain)
- I Kockar (University of Strathclyde - UK)
- A. Morch, H. Svendsen (SINTEF Energi - Norway)
- M. Marroquin, M. Herman (Our New Energy - Spain)
- F. Pröstl Andrén (AIT - Austria)
- C. Amtrup Andersen (EURISCO – Denmark)

The survey on ancillary services in selected world countries has been prepared with the contributions from:

- Barbara Herndler, Tara Esterl - AIT - Austria
- Maarten Noeninckx - Directorate General for Energy of the Belgian Federal Public Service for Economy - Belgium
- Jean Pompee, Jean-Yves Bourmaud and Frédéric Bienvenu - RTE - France
- Robert Eriksson – SVK - Hjalmar Pihl - RISE Sweden
- Steven Wong - NRCan/RNCan - Canada
- Nick Singh – ESKOM - South Africa

Executive summary

In Europe, there is a sharp increase in reserve needs for coping with the variability introduced by a steadily increasing RES share in the generation. The big challenge is to extend the possibility of providing Ancillary Services (AS) - frequency and voltage control, congestion management, etc.) to entities connected to the distribution network. The legislative package proposed by the European Commission in November 2016, nicknamed the Clean Energy Package, assigns a role to Distribution System Operators (DSOs) for local congestion management but not for balancing, whose management would remain in the hands of the Transmission System Operators (TSOs)[1]. However, such a sharp decoupling risks to lead to inefficient system operation.

All these issues are addressed by the SmartNet European research project (**http://smartnet-project.eu/**), which aims at comparing different TSO-DSO interaction schemes and different real-time market architectures with the goal of finding out which would deliver the best compromise between costs and benefits for the system. The objective of this three-and-a-half year project (2016-2019) is to develop an *ad hoc* simulation platform which models all three layers (physical network, market and ICT), analysing three national cases (Italy, Denmark, Spain).

The consortium, under technical and administrative management by RSE[2], consists of 22 partners from 9 European Countries, including TSOs (Energinet.dk, TERNA), DSO (ENDESA, Nyfors/SE/Evonet, Edyna), manufacturers (SELTA, SIEMENS), and telecommunication companies (VODAFONE).

SmartNet analyses five different coordination schemes between TSO and DSO and different architectures for the real-time ancillary services markets with reference to three countries: Italy, Denmark and Spain. For each country, the model needed to perform significant simulations encompasses nodal representation of the transmission network and of the distribution networks (some of them represented in detail till medium voltage, some others in a more synthetic way), detailed representation of the different resources providing bids for flexibility (both connected to transmission and distribution), detailed representation of the aggregation process and of the real-time ancillary services market.

SmartNet considers five TSO-DSO coordination schemes (CS) characterized by different roles and market architectures:

- **centralized AS market model (CS A):** TSO contracts services directly from DER. No congestion management is carried out for distribution grids;
- **local AS market model (CS B):** DSO manages a local congestion market. Unused resources are transferred to the AS market managed by TSO (procuring balancing and congestion management);
- **shared balancing Responsibility Model (CS C):** TSO transfers to DSO balancing responsibility for distribution grid. DSO manages a local congestion and balancing market using local DER;
- **common TSO-DSO AS Market Model (CS D):** TSO and DSO manage together a common market (balancing and congestion management) for the whole system;
- **integrated flexibility Market Model (CS E):** TSOs, DSOs and commercial market parties contract DER in a common flexibility market (raising regulatory problems: not implemented in simulation).

[1] EC (2016) Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on common rules for the internal market in electricity – Art.32.
[2] Ricerca sul Sistema Energetico: **http://www.rse-web.it**

In order to compare CS performance, SmartNet has developed a challenging simulation platform, modelling in detail T&D networks and ancillary services markets and implementing a very detailed dataset of generators and loads. Simulations are carried out on midterm scenarios (time horizon 2030) for Spain, Denmark and Italy to identify the best TSO-DSO coordination scheme for each country.
The same platform is also implemented in a laboratory in order to test real network equipment on the developed simulation scenarios (*hardware-in-the-loop*).
TSO-DSO coordination schemes are compared using a cost-benefit analysis with the following indicators (see figure below) :

- cost of mFRR (manual Frequency Restoration Reserve) purchased in AS market for balancing and congestion management;
- cost of aFRR (automatic Frequency Restoration Reserve) to cope with residual system imbalance not solved by mFRR because of simplified system representation, forecasting errors, network losses;
- unwanted measures (e.g. load shedding) activated in case of congestion still unsolved or unpredicted after AS market clearing. This creates further imbalance which is solved by aFRR. These measures are imagined as “emergency” measures and supposed paid at mFRR market bid price.
- ICT deployment costs.

The last two indicators proved much smaller than the first two. So, in most cases the comparison between the different coordination schemes can be carried out just by taking into account mFRR and aFRR costs.
Additionally, the total amount of CO_2 emissions is an additional non-monetized monitored factor.

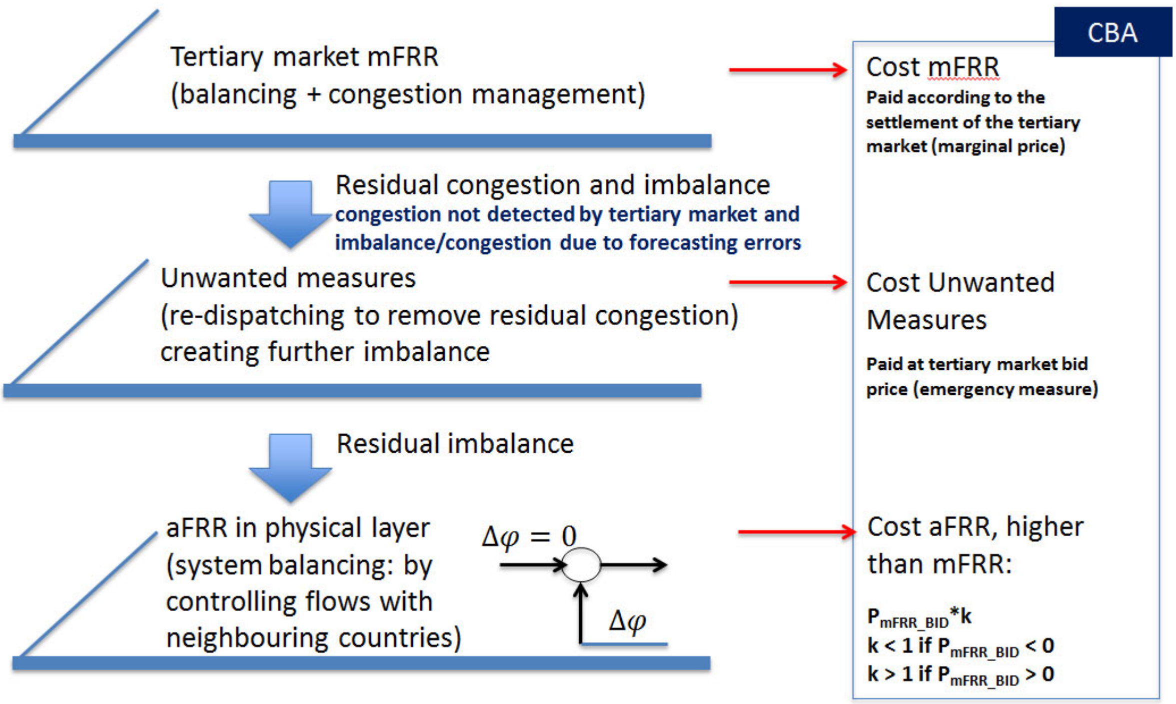

Figure 1 – The cost-benefit analysis approach of SmartNet

SmartNet also includes three physical pilots for testing specific technological solutions:

- technical feasibility of key communication processes (monitoring of generators in distribution networks while enabling them to participate to frequency and voltage regulation): Italian Pilot
- capability of flexible demand to provide ancillary services for the system:
    - thermal inertia of indoor swimming pools: Danish Pilot,
    - distributed storage of base stations for telecommunication: Spanish Pilot.

In addition to providing information on the main results obtained by the SmartNet project, the present report wants to include some information on the status quo of the procurement of ancillary services in selected countries.

A questionnaire was formulated and distributed among the members of ISGAN Annex VI. The questionnaire contained the following questions:

- What system services are provided in your country (voltage regulation, frequency regulation, inertia, support to power quality…)
- Who is providing them (generators and/or loads?)
- Modalities to collect ancillary services: via markets, contracts, compulsory non-paid services… Please describe in detail.
- Are generators and/or loads located in distribution admitted to provide system services? If yes, how is TSO-DSO interaction carried out (please describe in detail)
- Are there plans from the national regulator to activate demand side management or to collect inputs from generators connected to distribution for the future? Which timeframe? Are pilot projects already active?

Answers were received from the following Countries:

- Austria
- Belgium
- France
- Sweden
- Canada
- South Africa

Table of Content

1. Introduction

This report is prepared within the framework of ISGAN Annex 6 (http://www.iea-isgan.org/our-work/annex-6/). The work of Annex 6, on Power Transmission & Distribution Systems, promotes solutions that enable power grids to maintain and improve the security, reliability and quality of electric power supply. This report is the outcome of an activity within the focus area *Expansion Planning and Market analysis*. The main objective of this focus area is to study the functioning of electricity markets (day-ahead and real time) and to analyse the evolution of the transmission and distribution networks and their planning modalities. Figure 2 positions this work in the ISGAN context.

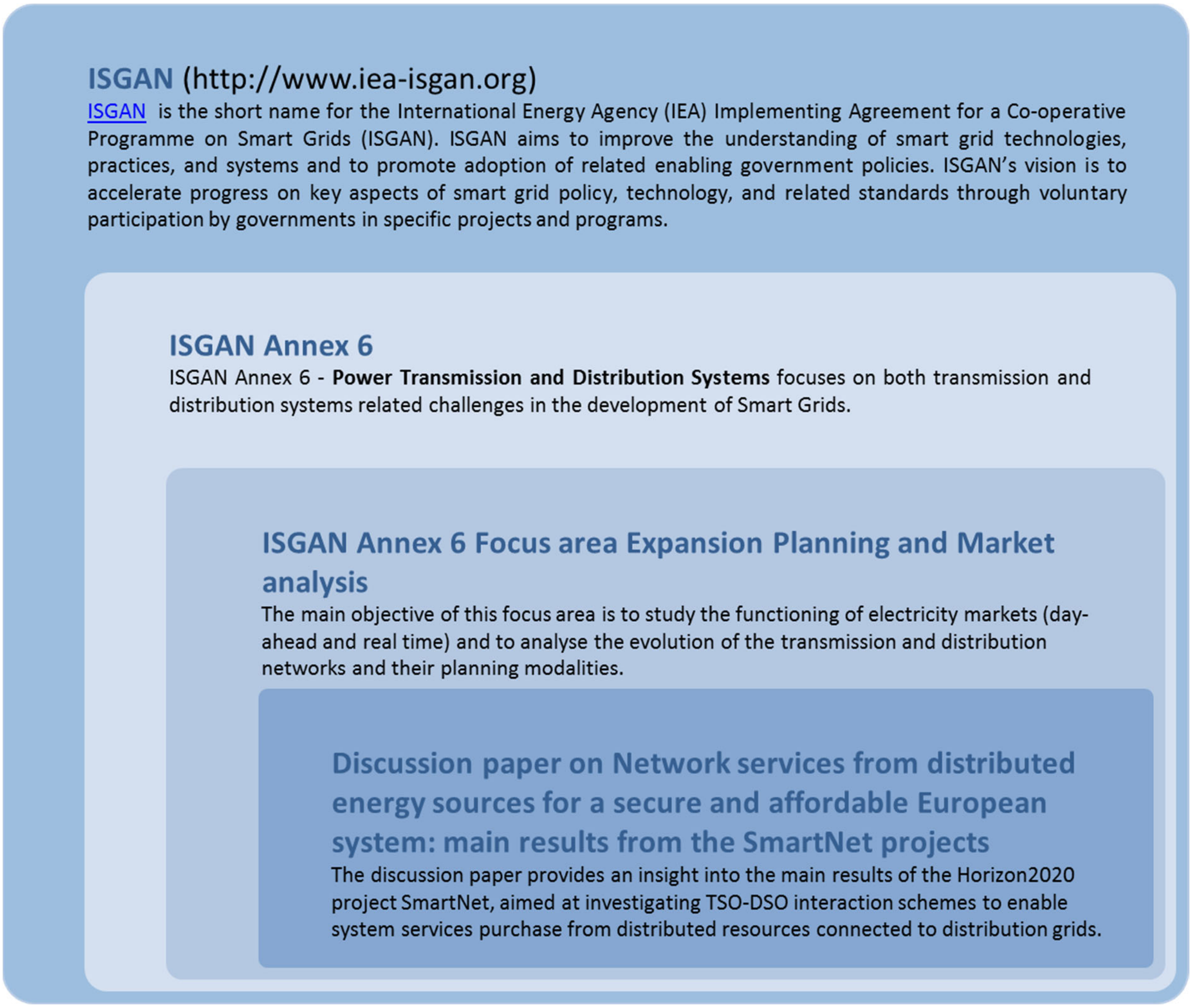

Figure 2 - Position of this report in ISGAN context

The present discussion paper provides an insight into the main results of the Horizon2020 project SmartNet, aimed at investigating TSO-DSO interaction schemes to enable system services purchase from distributed resources connected to distribution grids.

Section 1 provides an introduction to the project SmartNet and its consortium.

Section 2 provides the main motivations of the project.

Section 3 introduces the five reference coordination schemes.

Section 4 introduces the network and market models.

Section 5 deals with ICT requirements.

Section 6 copes with the results of the simulations and the cost-benefit analysis.

Section 7 focuses on the regulatory analysis and guidelines.

Section 8 provides details on the three technological pilots developed in SmartNet.

Section 9 provides some conclusions.

The appendix shows the results of a survey which was conducted in the ISGAN framework on the status quo of ancillary services in a few European and extra European Countries.

2. Motivation of the SmartNet project

The increasing amount of generation produced by Renewable Energy Sources (RES) is crucially challenging the pan-European electricity market. These resources have peculiar characteristics (in particular, the variability of their generation pattern) which push towards a reshaping of the traditional transmission system at all levels: local, national and even transnational. At the same time, big transformations are also affecting distribution and its interactions with the transmission system as an effect of the deployment of distributed generation, local storage and flexible loads. In the future, distribution networks will inject a growing amount of energy into the transmission system, and these electricity volumes could be linked to local storage and provide both local compensation and services for the entire system. Beyond local services for distribution grids (voltage regulation, congestion management), resource located in distribution could be helpful for providing reserve provision for the entire system through the connection points to the transmission grids.

This would bring a technological advancement of distribution system and the necessity to manage scattered bids coming from distributed generation and active loads. ICT should ensure a seamless integration of these bids within the trans-national ancillary services market and the control carried out by the DSOs of the dispatching in their relevant areas.

A delicate issue in this concern is the interface between TSOs and DSOs which is a crucial factor to ensure an overall efficiency target. On one side, the DSO network would have to procure resources for local services (e.g. voltage support, congestion management) and on the other, it should function as a collector of services for the whole system, in coordination with the adjoining TSO.

A strict real-time coordination will be needed between the different actors that are involved in the provision of ancillary services, particularly if connected to secondary and tertiary regulation.

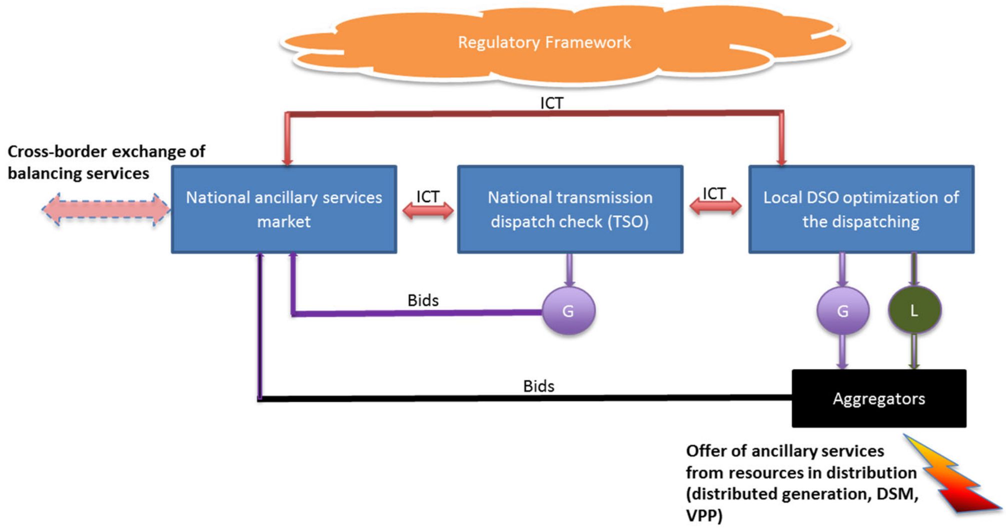

Figure 3 – Interaction for provision of ancillary services

Sets of bids aggregating availability coming from distributed generation, especially if integrated with local storage (concept of Virtual Power Plant), as well as from flexible load, could be presented to the trans-national Market Operator allowing a higher market liquidity and a better availability of dispatching solutions on the territory. ICT is going to be key also at this level in order to ensure a seamless integration of these bids coming from distribution within the trans-national ancillary services market and an integration with the control carried out by the DSOs of the dispatching in their relevant areas.

The current scenario opens several questions that the research should tackle in order to optimize the coordination between TSOs and DSOs in managing the exchange of information for monitoring and for the acquisition of ancillary services both at the domestic level and in the pan-European context.

The main aspects SmartNet is to investigate are the following:

- Which ancillary services could be provided for distribution to the whole system (via Transmission)?
- Which optimized modalities could be adopted for managing the network at the TSO-DSO interface and what monitoring and control signals could be exchanged to carry out a coordinated action?
- How the architectures of the real time markets (in particular the balancing markets) could be consequently revised?
- What information has to be exchanged and what role ICT plays in the coordination between distribution and transmission, to guarantee observability and control of distributed generation, flexible demand and storage systems?
- Which implications could the above issues have on the on-going market coupling process, that is going to be extended to real time markets over the next few years, according to the draft Network Code on Electricity Balancing by ENTSO-E?

Different TSO-DSO interaction modalities are compared on the basis of national key cases.

Physical pilots are defined for the same national cases (Italy, Denmark, and Spain) in order to analyze issues regarding the monitoring of distribution parameters from transmission and analyze modalities for the acquisition of ancillary services from specific resources located in distribution systems (indoor swimming pools and radio base stations of a telecommunication company).

The consortium, under technical and administrative management by RSE, is formed by a well equilibrated mix of partners from 9 European Countries:

- **R&D partners**
  - Research Organizations: RSE, AIT, SINTEF, Tecnalia, VITO, VTT
  - Universities: DTU, Uni-Strathclyde, KU Leuven
  - Other: EUI/FSR
- **Industrial partners**
  - TSO: Energinet.dk, TERNA
  - DSO: ENDESA, Nyfors/SE/Evonet, SELNET
  - Manufacturers: SELTA, SIEMENS Italia
  - Software developers: Eurisco, N-SIDE
  - Telecom: VODAFONE
  - Trader: Danske Commodities and ONE
  - Vacation rental: NOVASOL

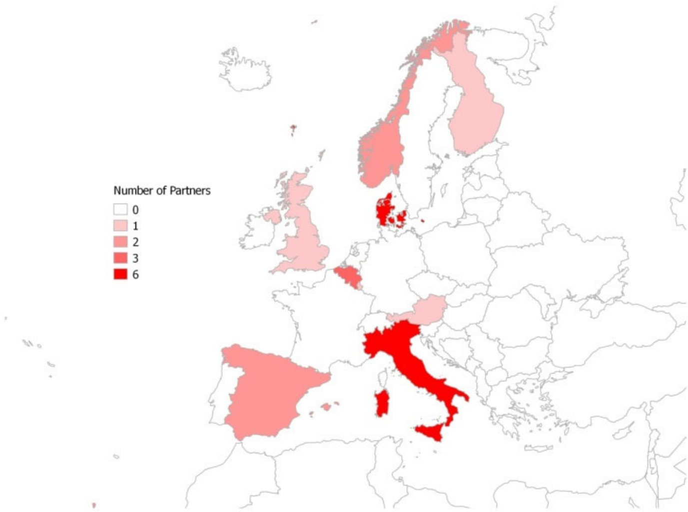

Figure 4 – Geographical spread of the SmartNet consortium

3. Five TSO-DSO coordination schemes

The energy market is undergoing important changes, driven by the realization of the European internal energy market on the one hand and the increase of distributed energy resources (DER) on the other hand. The significant amount of DER, mainly connected at the distribution grid, results in a higher need for flexibility services for system operators (TSOs and DSOs) and other commercial market parties (i.e. balance responsible parties (BRPs)). The increase of DER connected at the distribution grid provides an additional opportunity for system operators to use these resources for services such as frequency control, voltage control and congestion management, both at the distribution and transmission grid.

Today, resources from the distribution grid are starting to participate to the TSO ancillary services (AS) markets which enforces the need for increased cooperation between system operators. Within Smartnet, five coordination schemes are proposed that present different ways of organizing the coordination between system operators: the *Centralized AS market model*, the *Local AS market model*, the *Shared Balancing Responsibility model*, the *Common TSO-DSO AS market model* and the *Integrated Flexibility Market model*. Each coordination scheme is characterized by a specific set of roles, taken up by system operators, and a detailed market design. Each coordination scheme will determine the operational processes and information exchanges between system operators related to prequalification, procurement, activation and settlement of flexibility-based services that impact both transmission and distribution system level.

In the *Centralized AS market model*, the TSO operates a market for ancillary services for both resources connected at transmission and distribution level, without extensive involvement of the DSO. There is no separate local market. The TSO is responsible for the operation of its own market for ancillary services. The TSO does not take DSO constraints actively into account. A separate process (system prequalification) could be installed to guarantee that the activation of resources from the distribution grid by the TSO does not cause additional constraints at the DSO-grid (e.g. congestion). The DSO is not procuring local flexibilities in real-time or near to real-time. This scheme limits the involvement of the DSO to a possible role in the system prequalification process. To note that in exceptional cases, the DSO might want to include DSO grid constraints in the TSO market clearing process. Consequently, the DSO will need to provide the necessary data to the TSO or the TSO should have full observability of the DSO-grid.

In the *Local AS market model*, the DSO organizes a separate local market for resources connected at the DSO-grid. The DSO is the operator of a local market for flexibility, clears the market and selects the necessary bids for local use. The DSO has priority to use the flexible resources from the local grid. The DSO aggregates and transfers the remaining bids to the TSO-market, after all local constraints are solved, while ensuring that only bids respecting the DSO grid constraints can take part in the AS market. The TSO is responsible for the operation of its own market for ancillary services, where both resources from the transmission grid and resources from the distribution grid (after aggregation by the DSO) can take part. The Local AS market model deviates from the Centralized AS market model by promoting a local market. The implementation of such a market shifts priorities towards the DSO. All flexibility not needed/procured at the local market (where the DSO is the market operator) is sent to the central market (where the TSO acts as the market operator) in an aggregated form, taking into account that the distribution network constraints are respected (e.g. some local market bids could possibly not be transferred to the TSO if that would jeopardize the distribution grid operation).

In the *Shared balancing responsibility model*, balancing responsibilities are divided between TSO and DSO according to a predefined schedule. The TSO transfers the “balancing” responsibility for the (local) distribution grid to the DSO. The TSO remains responsible for the balancing of the transmission grid. The DSO organizes a local market to respect the schedule agreed with the TSO. DSO constraints are integrated in the market clearing process of the local market. There is a separate AS market for resources connected at the TSO-grid, managed by the TSO. Resources from the DSO grid cannot be offered to the TSO-grid. This *Shared balancing responsibility model* is the only coordination scheme where the TSO has no access to resources connected at the distribution grid. Flexibility from the distribution grid is reserved exclusively for the DSO, in order to fulfill its responsibilities with respect to local grid constraints and local grid balancing.

In the *Common TSO-DSO AS market model*, the TSO and the DSO have a common objective to decrease costs to satisfy both the need for resources by the TSO and the DSO. This common objective could be realized by the joint operation of a common market (centralized variant) or the dynamic integration of a local market, operated by the DSO, and a central market, operated by the TSO (decentralized variant). Both resources connected at transmission level and resources connected at distribution level participate to the same market place. DSO constraints are integrated in the market clearing process. There is no priority a priori for the TSO or DSO. The choice of which resources to be used by the DSO to solve local constraints will depend on the combined optimization of both needs for flexibility at distribution level and needs for flexibility at transmission level. The resources are allocated based on minimisation of toal system costs, leading to increased social welfare.

In the *Integrated flexibility market model*, the market is open for both regulated (TSOs, DSOs) and non-regulated market parties (Balance Responsible Parties, Commercial Market Participants). The common market for flexibilities is organized according to a number of discrete auctions and is operated by an independent/neutral market operator. There is no priority for any party. Resources are allocated to the party with the highest willingness to pay. There is no separate local market. DSO constraints could be integrated in the market clearing process, which requires the introduction of an independent market operator to guarantee neutrality. In addition, TSOs and DSOs can sell previously contracted DER to the other market participants. The *Integrated flexibility market model* proposes a market mechanism where available flexibility can be procured by system operators and commercial market parties under the same conditions. There is no distinction between regulated and liberalized actors. Market forces dictate how flexibility will be allocated.

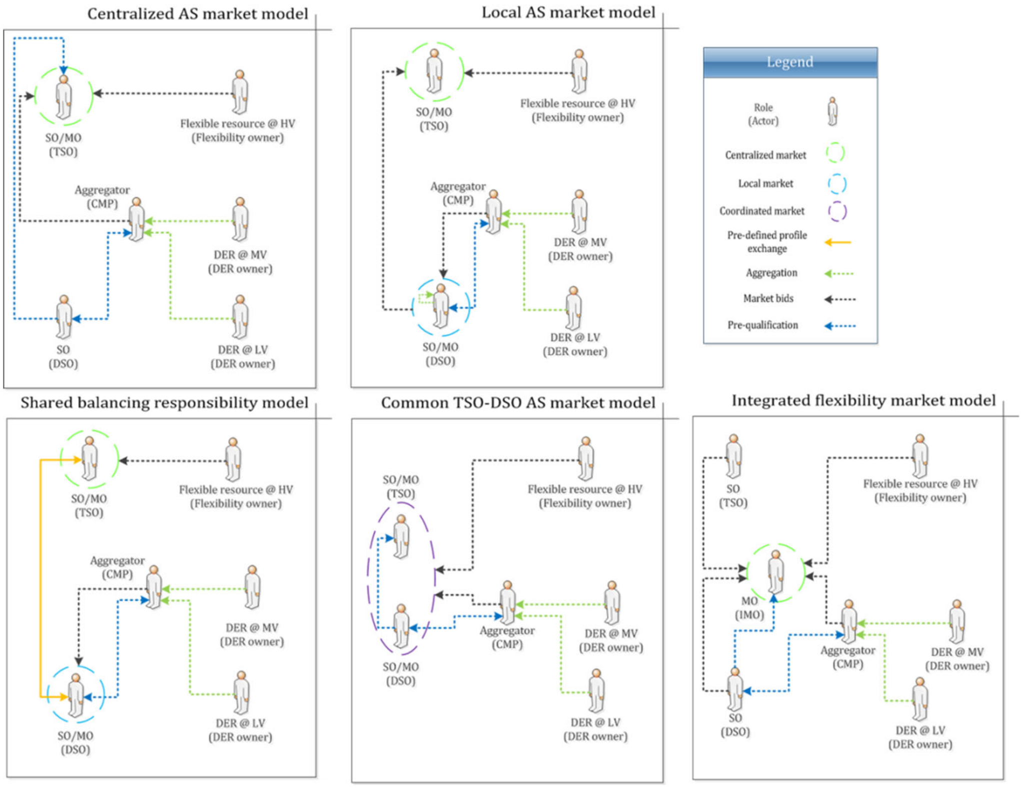

Figure 5 - Schematic overview of coordination schemes

The table below compares the key elements of the five coordination schemes.

Coordination scheme	Role of the DSO	Market organization (market operator)	Allocation principle of flexibility from the distribution grid
Centralized AS market model	Limited to possible process of prequalification	Common market (TSO)	Priority for the TSO
Local AS market model	• Organization of local market • Buyer of flexibility for local congestion management • Aggregation of resources to central market	Central market (TSO) Local market (DSO)	Priority for the DSO
Shared Balancing Responsibility model	• Organization of local market • Buyer of flexibility for local congestion management and balancing	Central market (TSO) Local market (DSO)	Exclusive use for the DSO

Common TSO-DSO AS market model	• Organization of flexibility market in cooperation with TSO • Buyer of flexibility for local congestion management	Common market (TSO and DSO) Central market (TSO) Local market (DSO)	Minimization of total costs of TSO and DSO
Integrated Flexibility market model	• Buyer of flexibility for local congestion management	Common market (independent market operator)	Highest willingness to pay

Source: Gerard, H., Rivero Puente, E.I., Six, D., 2018. *Coordination between transmission and distribution system operators in the electricity sector: A conceptual framework.* Utilities Policy 50, 40–48.

The different coordination schemes all have specific benefits and attention points related to the TSO grid operation, the DSO grid operation, other market participants involved and the market operation in general. The choice of the appropriate coordination scheme is dependent on multiple factors such as the type of ancillary service, normal operation versus emergency situations, the state of the grid, the amount of RES installed, the current market design and the regulatory framework. Moreover, the choice for a specific coordination scheme does not imply that this scheme could never be adapted. Across coordination schemes, there is a gradual increase of the role and responsibilities of the DSO. Dependent on the national evolution, a country can evolve from one coordination scheme to another. In particular, the Centralized AS market model, the Common TSO-DSO AS market model (centralized variant) and the Integrated flexibility market model share a common market architecture in terms of market platform and ICT requirements. A shift between these coordination schemes is mainly a question of a change in roles and responsibilities. The Shared balancing responsibility model could be seen as a duplication of the same market architecture as well. Also the Local AS market model and the Common TSO-DSO AS market model (decentralized variant) share a common market architecture.

The table below summarizes the main benefits and attention points for each scheme for the different stakeholders.

Domain	**Performance Criteria**	**Coordination scheme**				
		Centralized AS market model	**Local AS market model**	**Shared Balancing Responsibility model**	**Common TSO-DSO AS market model**	**Integrated Flexibility market model**
Interaction between system operators	Adequacy of existing communication channels, including the use of common data	High	Medium	Medium	Low	Medium
Grid operation	Respecting distribution grid constraints	Low	High	High	High	High
	Use of	High	Medium	Low	High	High

	resources from the distribution grid by the TSO					
	Recognition of the evolving role of the DSO	Low	High	High	High	High
Market operation	Possibility to lower market operation costs	High	Low	Low	Medium	Medium
	Liquidity of the market	Medium	Low	Low	Medium	High
	Economies of scale	Medium	Low	Low	High	High

Source: Gerard, H., Rivero Puente, E.I., Six, D., 2018. *Coordination between transmission and distribution system operators in the electricity sector: A conceptual framework*. Utilities Policy 50, 40–48.

The feasibility of the implementation of each coordination scheme is very dependent upon the regulatory framework. The Centralized AS market model is the most in line with current regulations. The other coordination schemes would require considerable changes with respect to roles and responsibilities of TSOs and DSOs. The implementation of a coordination scheme is also influenced by the national organization of TSOs and DSOs, e.g. the number of system operators (both TSOs and DSOs) and the way they currently interact. In addition, the implementation of certain coordination schemes will have an impact on other markets, such as the Intraday markets. Dependent on the services offered in the AS market, and compared to the Intraday markets (IDM), these markets might be able to co-exist or alternatively, may need to be integrated. Although TSO-DSO coordination could be organized on a country level, it is important to integrate national TSO-DSO coordination set-ups within the process of EU harmonization and integration.

4. Network and market models

As highlighted in previous sections, DER have the potential to provide local services to the DSOs and/or ancillary services (AS) to the TSOs. The provision of such flexibility services by resources connected to the distribution grid requires the coordination between TSO and DSOs. To this end, several TSO-DSO coordination schemes have been designed, described and analyzed in the SmartNet project. They rely on **centralized** or **decentralized** (see Table below) approaches where the flexibilities from the DERs are leveraged via **local and/or global (common) markets** at the DSO and TSO levels.

Centralized architecture	Decentralized market architecture
Centralized AS market	Local AS market
Common TSO-DSO AS market (centralized)	Common TSO-DSO AS market (decentralized)
Integrated flexibility market	Shared balancing responsibility model

Table showing the different TSO-DSO coordination schemes according to their centralized/decentralized nature

In the framework of the Simulator implemented in SmartNet, a real-time energy market has been designed for each TSO-DSO coordination scheme, for the purpose of **activating balancing** and **congestion** management services (for the latter, both for transmission and distribution levels).

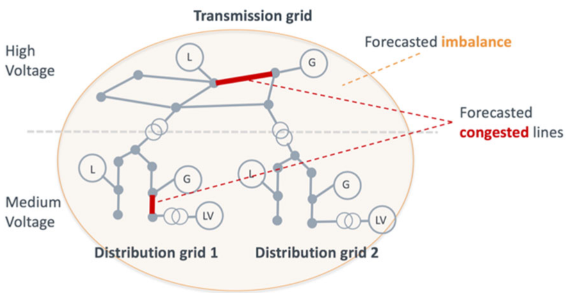

Fig. 6 – The market aims at activating services for balancing and congestion

Different **key market design ingredients** have been considered, for each TSO-DSO coordination scheme:

1. **Timing** dimension: In a discrete auction, a few key timing dimensions have an important impact on the potential results and efficiency of the market. Among them: Gate Closure Time (GCT), Market Time Horizon, Time granularity, Clearing frequency, Full activation time (FAT). In practice, the algorithms developed work for a whole combination of these parameters. For simulations, GCT of 15 min before real-time was used, a time horizon of 1 hour with four 15-min time steps and with a market clearing frequency of every hour.

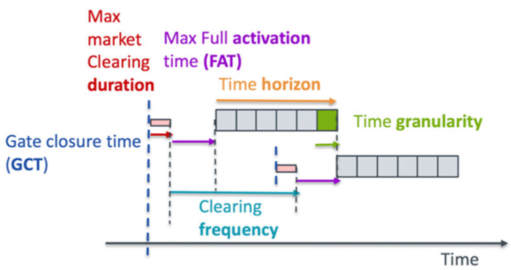

Fig. 7 - Illustration of some key market design timing parameters

2. **Network** dimension: Transmission and Distribution network models are used in the **market clearing algorithm** in order
    1. to make sure that their constraints are not violated when clearing the market (e.g. for balancing purpose)
    2. to solve congestions or other local problems (e.g. over- or under voltages)

There is a **trade-off** regarding the complexity of the network model to be included in the constraints of market clearing algorithm: it cannot be very simplified (otherwise it creates a big demand for countertrading because the physical constraints of network will not be taken into account in the market clearing algorithm) but it cannot be too complex (in order to maintain the algorithm computationally tractable). Therefore, a proper network model is chosen based on the type, topology, and size of the power network. The selected model is the classical direct current (DC) model for the transmission network, while for distribution networks, 3 models have been tested and implemented (see characteristics in table below):

- a second-order cone programming model (SOCP) model
- a linearized version (Ben-Tal relaxation)
- a linear model (simplified distflow)

	Complexity	nature	penalty	losses	under-voltage	over-voltage	over-current	dual var.	quality	tractability	optimality	algorithm
Classic AC	Nonconvex	exact	No	exact	medium	medium	medium	hard	high*	low	local	IP
DistFlow	SOCP	exact relax	Yes	exact	easy	hard	hard	hard	high	high	global	IP
DistFlow Ben-Tal	LP											IP, simplex
Simplified DisfFlow	LP	approx..	No	neglected	hard	easy	easy	easy	medium	high		IP, simplex
Linearized 'DC'	LP	approx..	No	neglected	hard	hard	hard	easy	low	high		IP, simplex

Properties of proposed formulations for radial grids (* Nonlinear solvers usually have good tractability for power system optimization with only continuous variables, but tractability is low for problems including integer variables).

3. **Bidding** dimension: The market products (or bids) list defines the types of bids which can be submitted to the market. The market allows both simple bids (specified by quantities and prices) and complex bids (specified by quantities, prices but also further constraints on the quantities, such as ramping constraints or exclusive bids). Complex products aim at capturing the dynamics of different flexibility resources while expressing the constraints of assets, aggregators, and system operators. The result is a catalog of products which can be optionally integrated in the market, according to the desire of system operators and regional regulations. Bids must be **location-specific** (right panel in figure below): **bids must be detailed per node of the modelled transmission/distribution grid.** So only in Centralized AS market (CS A) may the flexibility from DER be aggregated across whole distribution areas.

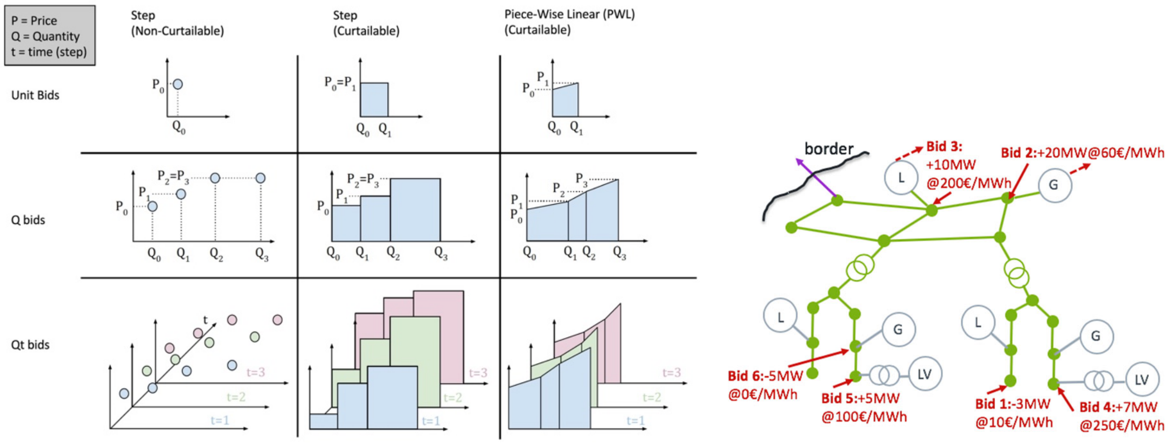

Fig.8 - Left: Different types of standard bids (shown only for upward flexibility bids). Right: Example of location-dependent upwards and downwards flexibility bids

4. **Objective** dimension: the objective of market clearing optimization problem can be: 1) maximize welfare, or 2) minimize activation costs. For all CS but one (Integrated flexibility market), the objective is to minimize activation costs (i.e. maximizing welfare but avoiding unnecessary activations, i.e. trades between non-regulated market parties)
5. **Pricing** dimension: because distribution and transmission network constraints are explicitly taken into account, *nodal pricing* is used, allowing to value flexibility at its true value to solve local problems like congestions. Also, pay-as-clear was chosen over pay-as-bid to incentivize flexibility providers to bid at their marginal cost.

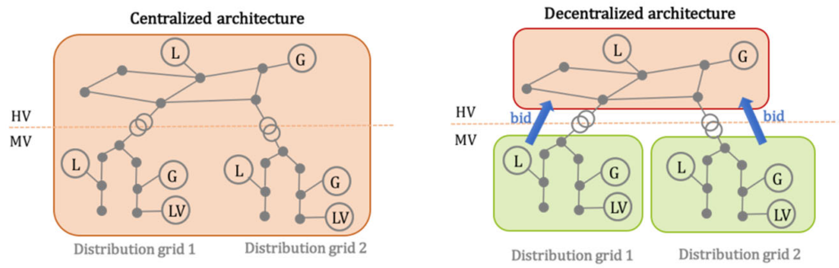

Fig. 9 - Diagrams showing centralized and decentralized market architectures

For decentralized TSO-DSO architectures, the interaction between local and TSO markets could take several forms: 1) a schedule at each TSO-DSO interconnection point (i.e. transformer) was agreed in advance between DSO and TSO (**Shared balancing responsibility model),** or 2) DSO uses local market to solve local issues and then **smartly aggregates**[3] remaining flexibility to the TSO market, i.e. aggregating bids provided at DSO level while taking into account the distribution grid constraints (**Local AS market** and **Common TSO-DSO market (decentralized)).**

In terms of computational complexity, the following table shows the computational tractability for each TSO-DSO coordination scheme[4].

[3] see Deliverable D2.2
[4] more details in D2.2.

Qualitative assessment of the computational complexity of each TSO-DSO coordination scheme

Centralized AS market	Common TSO-DSO AS market (centralized)	Integrated flexibility market	Local AS market	Common TSO-DSO AS market (decentralized)	Shared balancing responsibility model
The **easiest** since only transmission grid	The **most difficult** since full transmission AND distribution grids in a single problem		Optimizations in parallel BUT with smart aggregation using some complexity		Many optimizations in parallel

The majority of distributed energy resources (DERs) cannot compete individually in the electricity markets since the power offered to the market must be above a certain threshold, and a high number of market participants may have a negative impact on the performance of the market clearing process. Thus, an aggregator is needed in order to gather the small sources of flexibility, into a single market entity and obtain access to the ancilliary services (AS) market, while reducing the amount of the passed-on data. An aggregator is also in charge of the disaggregation process, leading to the resources activation, after the market clearing has taken place. Figure 10 shows the aggregator's input and output, i.e. the information flow between the aggregator, individual DERs and the market.

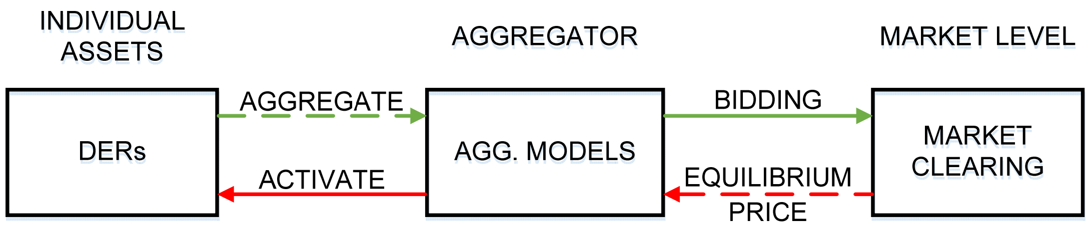

Figure 10 – Illustration of aggregation, bidding, market clearing and disaggregation processes

Different aggregation approaches can be used for bidding in the electricity market, each of them having certain advantages. When considering near real-time AS markets, complex aggregation and disaggregation processes must be avoided since they tend to add latency to both the bidding to the market and to the response to the market clearing. Hence, the aggregator in SmartNet, uses several technology specific aggregation models, aimed at separate DER categories, in order to take into account the physical constraints of the devices being aggregated, while enabling a fast, straightforward, aggregation/disaggregation procedure (illustrated in the figure below). Due to this reason only the DERs that are reasonably similar in terms of their specific core features are grouped together in the same aggregation model.

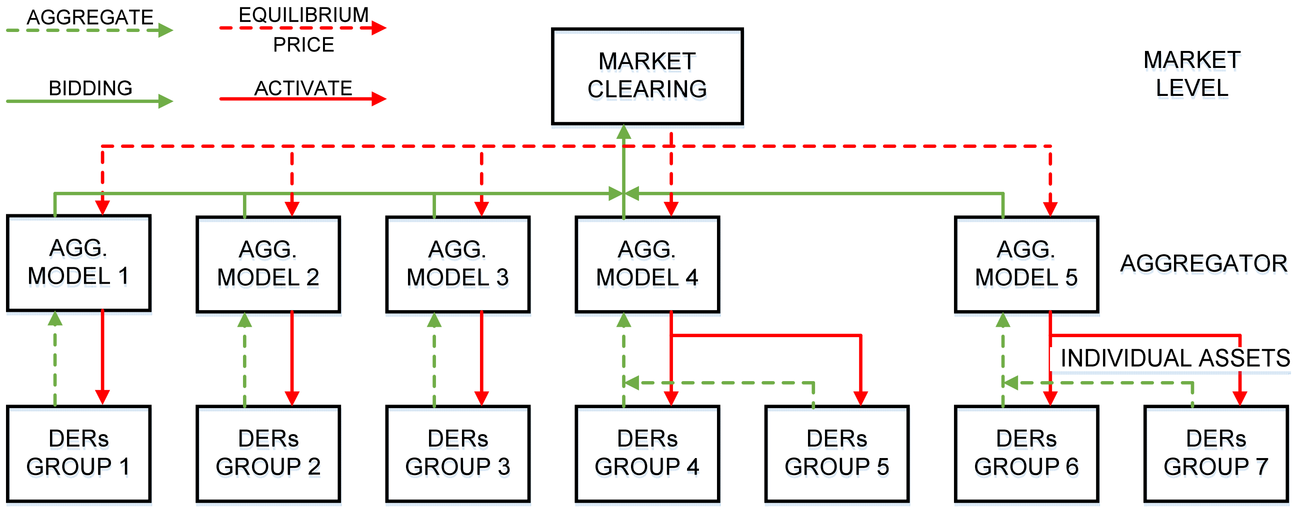

Figure 11 – Illustration of SmartNet aggregation models

The grouping of DERs categories, done according to the individual models' constraints similarities, simplifies the bidding system. As the market clearing mechanism is able to cope with multiple bid types, belonging to different aggregation models and originating from the same aggregator, the simplest approach is for the aggregator to allow all five aggregation-type-specific categories (see Figure 11), to generate bids for their own aggregated devices. That is to say, a single aggregator can use several aggregation models for providing its bids. By doing so, every bid that is accepted by the market can then be assigned to the corresponding device-type-specific disaggregation algorithm, which is best equipped for optimally distributing the allocated flexibility over its individual devices. The reason behind this approach is the fact that it would not be convenient to build an overarching aggregation model, as it would inevitably make the disaggregation complex. Despite the aforementioned advantages of the aggregation approach taken here, its drawback is the higher number of bids going to the market, since five relatively simpler aggregation models are used.

Supply and demand are satisfied in a series of consecutive markets. The sequence of markets, comprised of the day-ahead, the intraday and the AS market, represents a string of opportunities, for the aggregator, to valorize DERs' flexibility. The aggregator in SmartNet forms a vision of the expected clearing price for flexibility in the future, enabling it to set the price for the limited number of activations available. Hence, the aggregator takes into consideration the possible future market related variables, as well as its own forecast error. The market discomfort cost (MDC) represents a possible additional profit of a future activation (see Figure 12). This is to say that the MDC makes the aggregator refrain from offering its flexibility, in the present market, at a purely technical cost, when there is an opportunity to earn more in the near future. If a bid that considers MDC is accepted, the additional revenue from MDC should compensate for the opportunity cost received from activation in the nearby future. In other words, MDC represents an artificial cost, incorporated in the existing flexibility cost[5], that makes the aggregator indifferent between an immediate activation and the one in the future at a potentially better profit.

[5] A comprehensive explanation, with equations, can be found in deliverables D2.1 and D2.2.

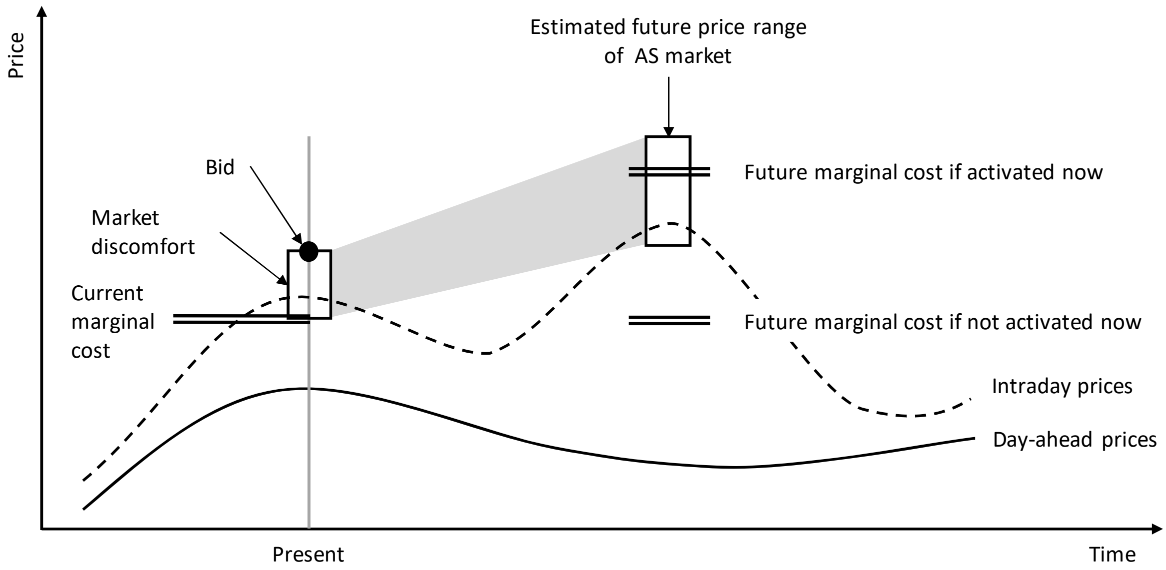

Figure 12 – Representation of the Market Discomfort Cost

5. ICT requirements

The trend is towards more intelligent distributed energy systems exploiting ICT for flexibility. New market models and smartness of the energy system require a tighter coupling between energy and ICT communication system components. The challenge is to adequately define and identify ICT requirements for the future energy systems and include them in the parallel development of communication and grid system components. This requires increased dialogue between energy and communication system developers and providers.

Another trend is towards more realistic lab simulations where SW simulators and HW components are interconnected (Hardware-in-the-Loop (HIL) simulation). As larger parts of the grid are included in the simulations, the modelling of communication links becomes more important. The process of converting field measurements into QoS profiles is compelling for both lab environments and simulation tools. It would give new opportunities to test communications and smart energy components already in the prototype stage, which helps to reduce components and services' time-to-market, time-to-revenue, and deployment costs.

Process for capturing ICT requirements

As a starting point, the Smart Grid Architecture Model (SGAM) has been a good tool in energy domain, since it offers a framework for the validation of smart grid use cases and their support by standards. However, handling of ICT requirements and market designs is not included in the SGAM model, which may result in inadequate system designs. Therefore, there was an evident need for an enhanced SGAM model that also includes communication requirements to help interaction between energy and communications domains to detect and resolve potential bottlenecks in the future energy systems.

SmartNet's ICT requirements capturing process is an extension to the SGAM approach. The developed analysis process enhances the SGAM approach by embedding communication and security requirements in each SGAM layer. As a result, ICT requirements are specified in business, function, information, communications, and component layers. To make the process well adoptable, IEC 62559's design template and ELECTRA project's use case design methodologies were utilised. They provided structured guidelines for preparing use case descriptions as well as mapping business and system functionalities into SGAM layers. The developed process is incremental to enforce close interaction between energy and communications system providers and developers. Requirements for communications tend to change, so a parametrised architecture model was implemented in SmartNet using Architect Enterprise with SGAM toolbox that offers a practical tool to validate architecture design and assess effects of changing ICT requirements in cases of centralised, local, shared, common TSO-DSO, and integrated market models. To support the process, a conceptual model depicted in Figure 13 was used for the dialogue between ICT and energy personnel to capture the main data exchange operations and their requirements in different TSO-DSO coordination schemes.

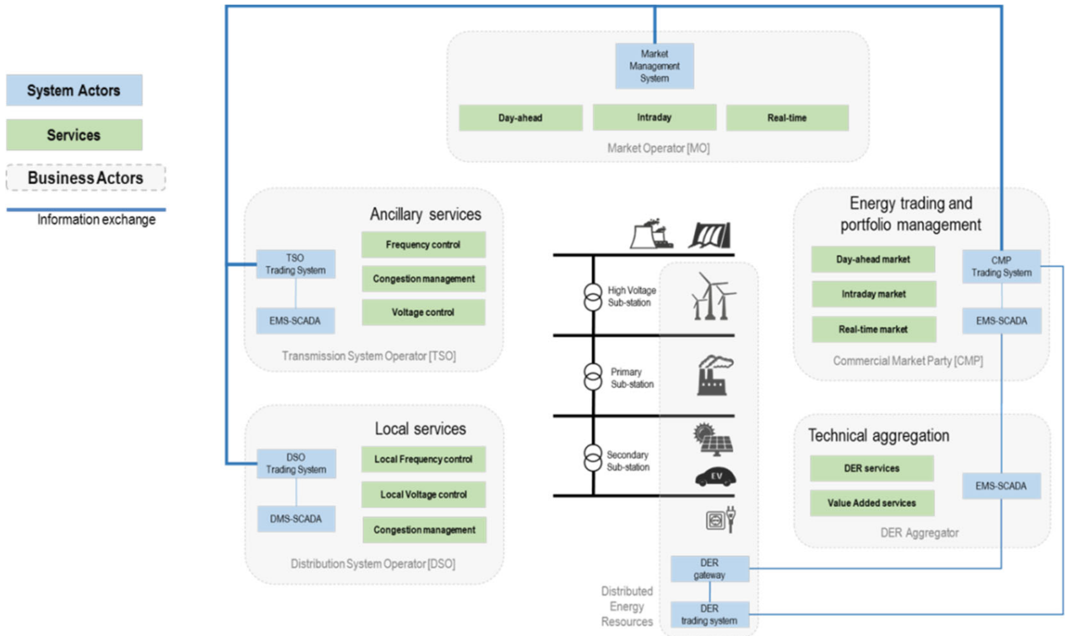

Figure 13 - A concept model for identifying communication links and their requirements.

The model presents actors, system components, and services. In the figure, grey rounded boxes present core business actors/roles in different coordination schemes. The stakeholders can play multiple business actor roles. For example, an aggregator can do both technical aggregation and energy trading. The Market Operator (MO) role can be played by various stakeholders depending on the market scenario: central TSO (market), DSO (local), TSO-DSO (shared), or IMO (independent).

Blue boxes represent the main system components a.k.a. system actors or entities used by business actors. Trading system (TS) is devoted to exchange information with the market management system, e.g. schedules for prequalification, procurement, or activation of ancillary services. DMS/EMS-SCADA is considered here as the system used for network monitoring and control operations. Respectively, Market management system (MMS) is dedicated for running market processes (by the TSO, DSO, or IMO) and to establish a link between the market operator and stakeholders. Connecting blue lines represent external data exchange links between system components. Thinner lines in the figure are presenting internal communication links. The model was used for analysing the system operations from an energy market point of view, but it can be extended to remote control and protection. Green boxes represent core ancillary services including e.g. frequency and voltage control, and congestion management. The pictures in the middle represent the grid infrastructure and distributed energy resources, from high-voltage down to low-voltage grid, which help mapping the energy market events to the physical grid entities.

For exploiting SmartNet results, the ICT requirements capturing process and the respective specification templates are promoted to industrial parties operating in energy and telecom domains to strengthen their collaboration already in the design phase. The process has already been exploited in national pilot projects in Finland, so it has proven its applicability also to support the design of smaller systems and system parts targeted to e.g. remote monitoring, control, or protection in medium voltage networks.

Communication QoS profiles for combined lab and simulation environment

The exploitation of new wireless technologies e.g. 5G is anticipated as the smart remote monitoring and control are extended to distant entities in the power grid. 5G cellular technology is making a significant advance in the combination of latency reduction and reliability enhancement. This makes 5G an alternative to replace fixed cable connections. Electricity distribution has been one of the major use cases for ultra-reliable low-latency communications (URLLC). Until now, mobile devices have offered connectivity for people, but 5G is aiming to make a big difference in offering better connectivity for machines.

SmartNet's way to generate QoS (Quality of Service) profiles from field measurements is a new approach to include the effects of wireless communication in lab simulations. This process offers a chance to imitate real-life or statistical latency profiles in e.g. commercial 3G/4G/5G mobile networks and to analyse the effects of different communication network parameters on the interaction of the distributed energy system components. For the process, a wireless QoS measurement setup depicted in Figure 14 and a dedicated communication emulator were implemented. The former gives an opportunity to create profile data that can be used directly on an emulator or used for generating synthetic QoS profiles for lab systems and simulators. The QoS profile mimics the effects of wireless network by changing e.g. delays, packet losses, and corrupted packet rates. The communication emulator can also be used to experiment different communication technologies, such as fixed, GPRS, 3G, 4G, Wi-Fi, etc.

Figure 14 - A wireless QoS measurement setup

This allows device and system manufacturers to test their equipment or simulator components in the same lab environment using data from different parts of Europe without the need of performing full field tests in different locations.

Figure 15 illustrates the connections between SmartNet Simulator, Laboratory equipment, and Communication Emulator. In this example, the emulator allows to test the communication link between SCADA/DMS and PPC with different communication technologies and in different radio propagation conditions. In the SmartNet trial, the emulator was placed between Supervisory Control and Data Acquisition / Distribution Management System (SCADA/DMS) and the Power Plant Controller (PPC).

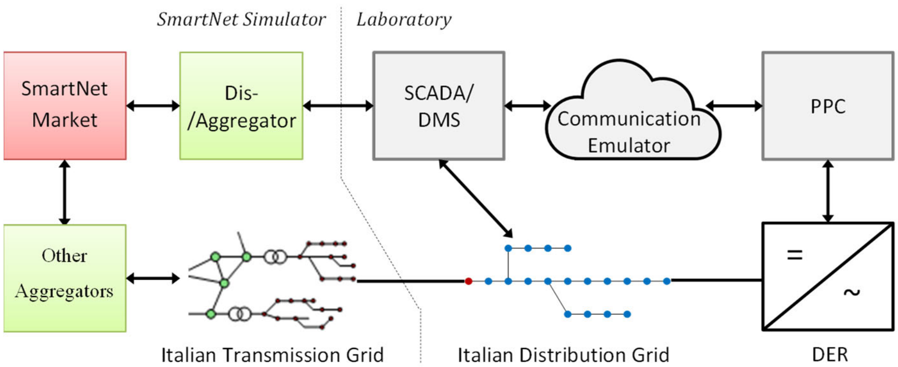

Figure 15 - Communication Network Effects on the Interactions of SCADA/DMS and PPC

This setup can be exploited by TSO and DSO companies to test or evaluate new communication technologies between new energy system components or to retrofit new technologies to existing ones. It also gives an opportunity to test communication and smart energy components already in the prototype stage. This helps to reduce components and services' time-to-market, time-to-revenue, and deployment costs. By linking measurements from real operational environment with the lab platform, larger scenarios can be created to support also regulation and standardisation activities. Additionally, full testing including real devices and a "lab" environment mimicking the real energy system components paves the way for a faster transition of the SmartNet simulator platform from a demo setup to a fully operational system. SmartEST Laboratory at AIT in Austria used in trials is shown in Figure 16.

Figure 16 - SmartEST Laboratory at AIT used for emulated communications tests

According to "*Europe 5G Readiness Index: Assessing Europe's readiness to deploy 5G*", Denmark, Finland, Iceland, Norway, and Sweden are ranked among the top 10 countries, and three of them are in the top 5. The Nordic countries have traditionally been at the forefront of communication technology development, whereas Central and Southern Europe are leading the way in smart energy systems. Combining communication measurements from the Nordic countries with a lab environment modelling Southern European energy systems opens new business and R&D opportunities for a variety of European companies.

6. Scenarios and CBA

In order to validate the proposed TSO-DSO coordination schemes and to compare their performance, SmartNet has developed a dedicated simulation platform. This software environment is fed by the scenario data which have been designed in order to evaluate the different TSO-DSO interactions in hypothesized 2030 scenario for Italy, Denmark and Spain. Finally, the results returned by the simulator are processed by means of an ad-hoc Cost Benefit Analysis (CBA), aimed at determining the coordination schemes with the highest performances and highlighting the peculiarities of each scenario.

The SmartNet simulator

In order to exhaustively evaluate the impact of each TSO-DSO coordination scheme, the simulation platform needs to precisely cover all the aspects in which network operators and market players are involved. In addition, the effects of TSO-DSO interactions on the management of the physical grid, as well as the control of aggregators on devices flexibility, play an important role and need to be represented within the simulation environment. According to this, a three-layer structure has been implemented[6] (**Figure**):

- **The market layer**. It integrates the market clearing routines which process the flexibility bids submitted by the aggregators in order to return the optimal activations aimed at restoring the system balancing and solving/avoiding network congestions in real time. Depending on the coordination between the network operators, the outputs provided by this layer are the outcome of a combination of separated market clearing algorithms (e.g. one local market for each distribution network and one central market for the entire system).
- **The bidding and dispatching layer**. It simulates the behaviour of market players which process the available flexibility from large number of physical devices into market bids and translates market clearing results into activations. In addition to the traditional energy traders and retailers, it models the action of the aggregators, who optimally combine flexibilities of several small energy resources (located at distribution level) into few representative bids. After market clearing, aggregators also decompose the market layer results into the individual power set points to be sent to all the aggregated units.
- **The physical layer**. It simulates the effects of the activations on transmission and distribution networks, including the physics of each (flexible and non-flexible) power device connected to them. This layer also includes the algorithms which model the automatic and low-level operations (carried out by TSOs and DSOs) which are not directly triggered by market results but may have an impact on them (state estimation/forecasting, automatic frequency control, intervention of protections, etc.).

[6] Reference: project deliverable D4.1

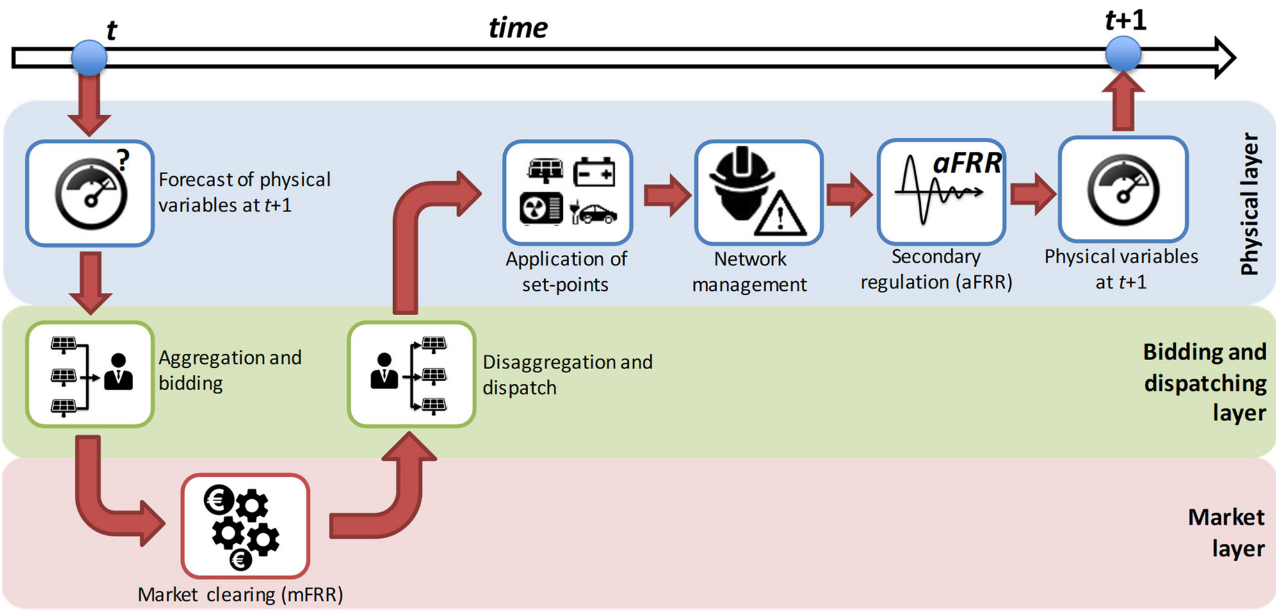

Figure 17 - High level structure of the SmartNet simulator

Depending on the expected evolution of the current market architecture for the three considered countries, the three layers mentioned above may show different interaction times. For this reason, the SmartNet simulation platform has been designed considering an arbitrary selection of market clearing frequency (how often the market is cleared) and latency (how long the market takes to process bids and carry out the clearing procedure). This option allows investigating different market dynamics (also faster than the current ones), without neglecting the network evolution occurring during the clearing process, which can result in deviations between actual and forecasted network status.

These timing concepts also apply to bidding and dispatching layer routines, which are called according to input requests and availability of results from the market clearing algorithms. For simulation purposes, the physical layer (which is continuous in the real world) has been subjected to time discretization as well, opportunely selected to be in line with the dynamics of the other layers.

The considered scenarios

The SmartNet project takes into account a hypothetical 2030 energy scenario for each of the following three European regions: Northern Italy, Continental Denmark and Spain. In particular, looking at the energy mixes reported below, it can be noticed that:

- Italy and Spain are expected to face a significant increase of photovoltaic and wind generation, which will be comparable to the total power capacity of conventional power plants. In addition, this renewable generation will be located mostly at distribution level.
- Thanks to the spread of electric vehicles, storage-based technology is expected to have a significant potential in all the considered regions, even where large storage power plants (pumped hydro) cannot be hosted.
- Flexible thermal loads will shyly increase in all the scenarios, except for Denmark where they represent a significant portion of the available flexibility (in 2030 it is assumed that controllable heat pumps will replace large CHP units).

The main information related to these scenarios have been investigated during the first activities of the project[7] and further analyses have been conducted in order to precisely locate every single source of flexibility on the considered territories. Later, thanks to the reconstructed electrical maps of the transmission and distribution power systems, devices and flexibility providers have been assigned to the grid nodes[8].

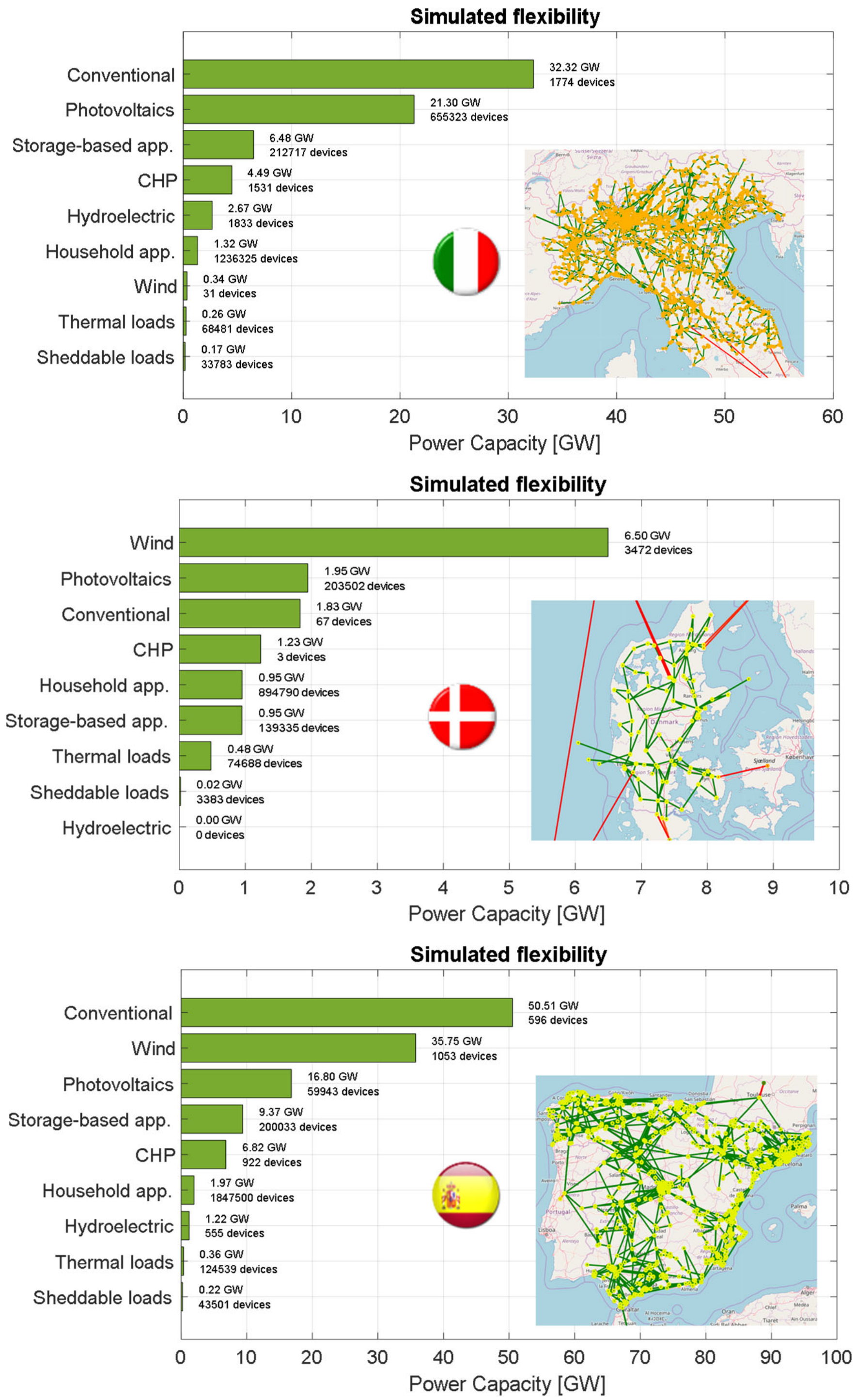

Figure 18 - Scenario characteristics of the three simulated regions

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[7] Reference: project deliverables D1.1 and D1.2
[8] Reference: project deliverable D4.2

The main goal of the simulation activity consisted of returning representative data of ancillary services market operation. Specifically, balancing and congestion management services (operated by mFRR) have been investigated, for each country, on a few reference days. Each of them has been opportunely selected in order to choose the most heterogeneous network/energy mixes and to cover the highest number of possible situations. Having considered the complexity of the simulated scenario and the computational burden, the selection of three characteristic days has represented a reasonable compromise between accuracy and simulation time.

Simulation results and Cost Benefit Analysis

The performance of the four simulated TSO-DSO coordination schemes have been evaluated by means of a dedicated CBA process[9]. Having considered that SmartNet is focused on the collaboration among network operators for the management of the balancing and congestion management reserve, the cost of reserves activation has been considered a promising performance indication. The most immediate simulation results are represented by the manual Frequency Restoration Reserve:

- **Total mFRR cost**. This indicator includes the total balancing costs resulting from the mFRR activated by the ancillary services market in order to solve the imbalance and congestions predicted for the next time steps. The cost is calculated by assuming a pay-as-clear approach of mFRR activations (according to a nodal price structure).

  mFRR cost can provide significant contribution in terms of scenario analysis. In particular, as depicted in **Figure** , the differences among coordination schemes can provide information such as:
  - the costs implication related to the inclusion of distribution network constraints in centralized market (CS A vs. CS D);
  - the impact of local markets on the overall mFRR activation (CS B vs. CS D);
  - the effects of a physical separation between transmission and distribution for the management of balancing services (CS C vs. CS D).

  In addition, by running an additional simulation (in which network physical constraints are removed), indications on the impact of congestion management on mFRR costs can be deduced as well.

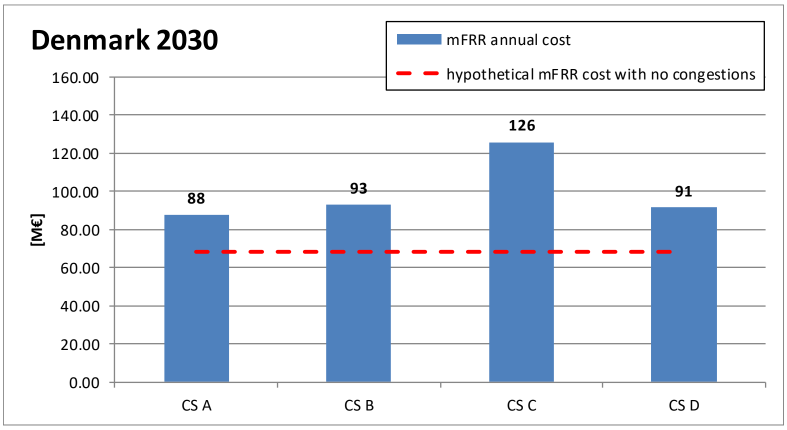

Figure 19 - Illustrative mFRR costs comparison among TSO-DSO coordination schemes

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[9] Reference: project deliverable D4.3

After the first market layer interaction, the aggregators send the setpoints to the individual resources. The physical layer reacts to these activations and network operators activate reserves for the compensation of residual imbalance and unpredicted congestions.

- **Total aFRR cost**. This indicator corresponds to the cost related to the re-balancing of the system after the application of mFRR. In addition to the residual imbalance due to the forecasting error, TSO-DSO coordination schemes can have a significant impact on the aFRR activations. For instance (Figure 20):
  - CS A is based on mFRR activations regardless of potential distribution network limitations. This situation leads the DSO to block some flexibility margins provided by distribution resources with a consequent imbalance caused by missed activations.
  - CS B and CS D activate the same amount of aFRR. Since the markets implemented for these coordination schemes include distribution network models, the activations are addressed more precisely, making mFRR more effective in terms of residual imbalance.
  - mFRR flexibility is not uniformly distributed on the simulated territory and some distribution networks do not host enough reserve to be rebalanced by themselves. Sharing the balancing responsibility between TSO and DSO (CS C) often drives to situations in which the market does not find a feasible solution and large volumes of aFRR are needed in order to face the high amount of residual imbalance.

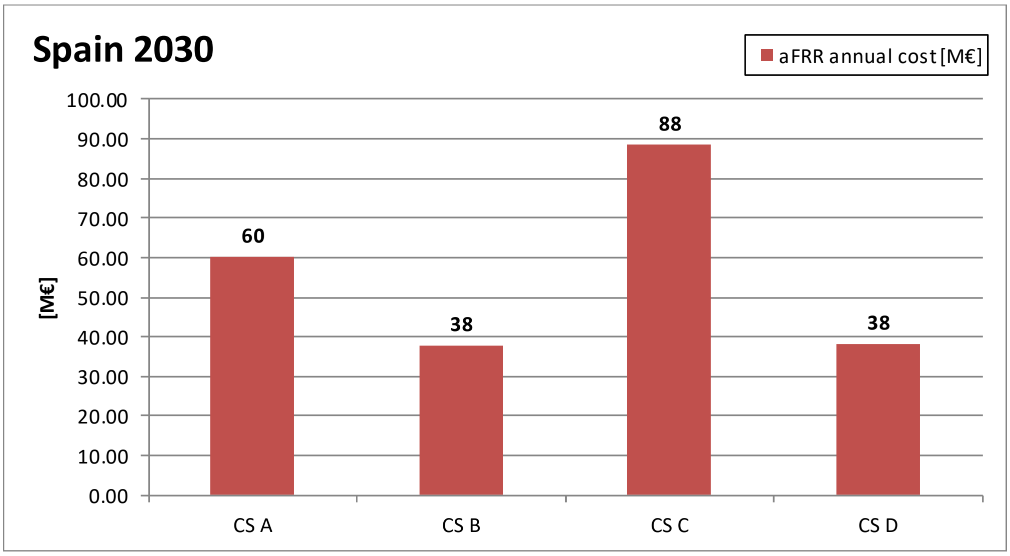

Figure 20 - Illustrative aFRR costs comparison among TSO-DSO coordination schemes

- **Cost of Unwanted Measures (UM)**. This indicator represents the cost of emergency actions taken by network operators in order to promptly eliminate network congestions and failures (which have not been predicted by the market clearing algorithm). In this case, when flexible resources are involved, network operators are supposed to pay their services according to the bid price. Looking at the graphs reported in **Figure** , it is evident how including the distribution network constraints has a positive impact in reducing the emergency situations, not only at distribution level, but also on the transmission side (thanks to the more predictable behaviour of distribution networks).

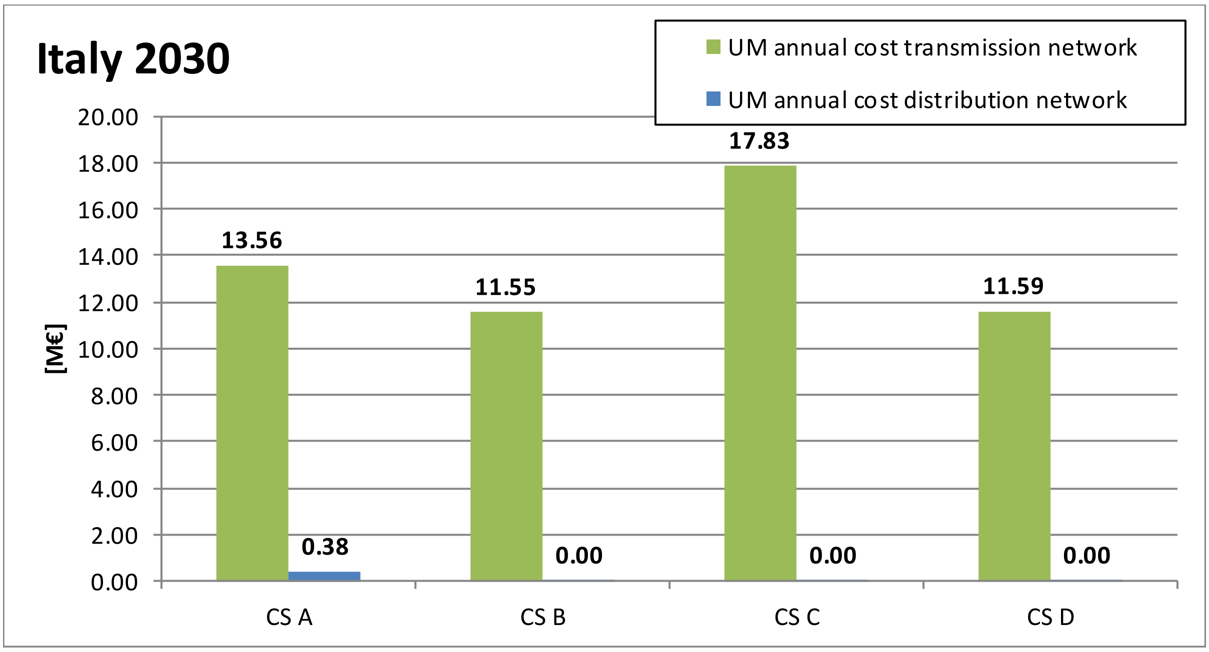

Figure 21 - Illustrative UM costs comparison among TSO-DSO coordination schemes

- **ICT costs**. This indicator includes the costs related to communication and information technologies involved within the TSO-DSO coordination schemes, with particular attention to the necessary resources for the aggregation of distribution resources and advanced market clearing processes.

This indicator has been defined in terms of ICT system cost in the event of upgrading from a centralized AS market model (CS A) to alternative coordination schemes. This is stated under the assumption that CS A is the natural evolution of current systems to 2030. The following table (

Figure 22 reports the results of this analysis.

Equivalent Annual Cost (M€) **10-year investment with 5% interest rate**			
Current situation → CS A	**CS A → CS B**	**CS A → CS C**	**CS A → CS D**
4.59 ± 1.31	10.95 ± 2.40	9.17 ± 1.62	10.01 ± 0.61 (Italy) 8.36 ± 0.64 (Denmark) 9.30 ± 0.62 (Spain)

Figure 22 - ICT costs comparison among TSO-DSO coordination schemes and country

The final SmartNet simulation results and CBA

Thanks to these indicators the considered TSO-DSO coordination schemes can be exhaustively analysed and compared in terms of cost-effectiveness by looking, in addition to the overall costs, also to the repartition between aFRR and mFRR, the impact of UM and ICT, etc.

In Italy (Figure 23), the highest performance of CS B and D is evident, and this is happening thanks to the large amount of distribution flexibility that is constantly procured for local congestion management. It is also noticeable how an optimized management of low power resources (the ones located at distribution level) significantly decreases the amount of aFRR needed with respect to CS A, making the mFRR market more efficient.

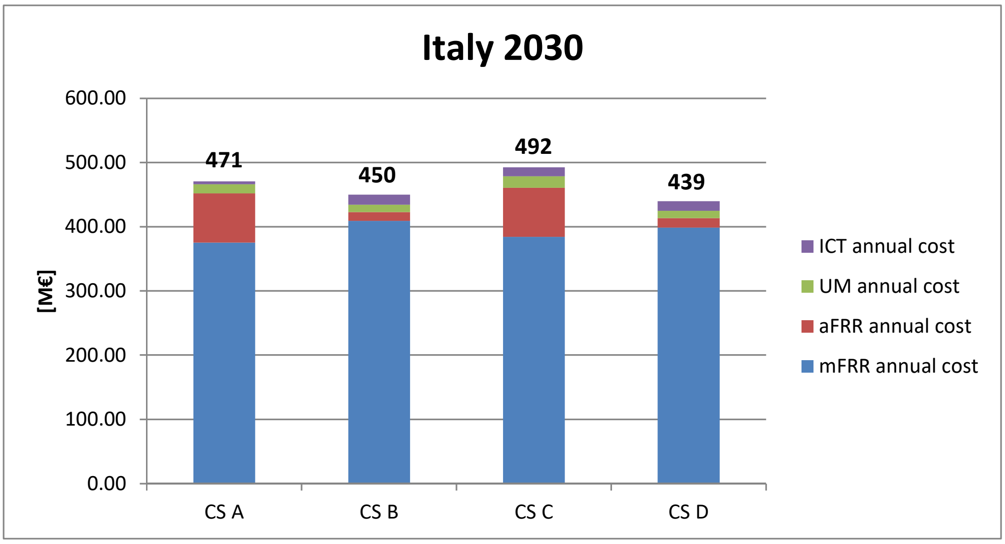

Figure 23 - Final simulation and CBA results for Italy 2030

Denmark (Figure 24), instead, shows a counterintuitive behaviour. In fact, TSO-DSO coordination schemes that are supposed to be more optimal than CS A, demonstrates a lower performance. This can be simply explained by noticing that the distribution network of the considered Danish scenario has a congestion probability comparable with the uncertainty introduced by the forecasting error (in fact wind generation, one of the major sources of uncertainty, is mostly located at transmission level). This means that there is a concrete risk that the market overestimates the limitations of the distribution systems, increasing the cost of activated mFRR (with no benefits in terms of residual imbalance – aFRR does not change).

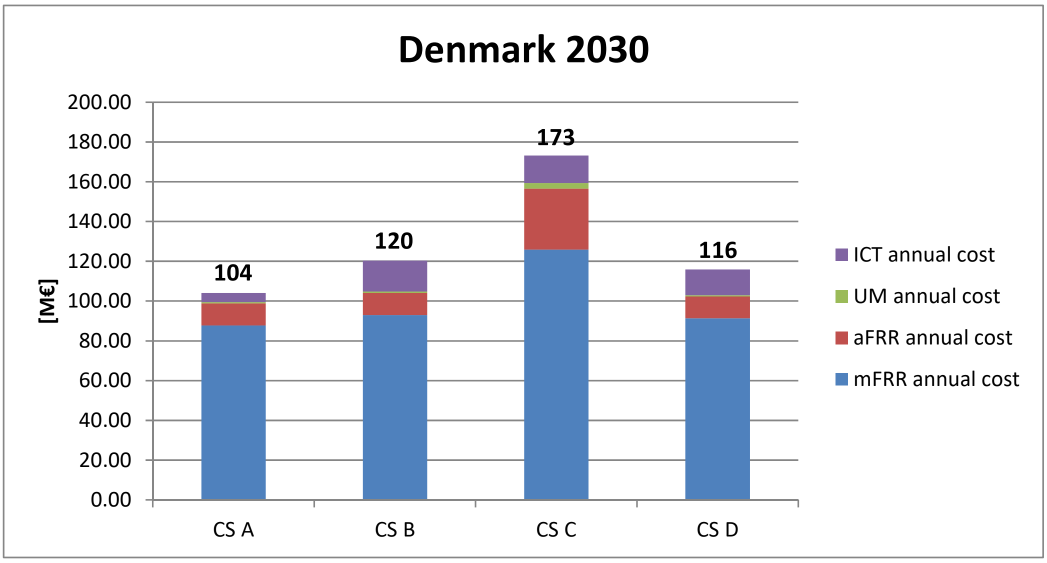

Figure 24 - Final simulation and CBA results for Denmark 2030

Finally, Spain (Figure 25) represents a middle ground between the Italian and Danish scenarios. In this case, the adoption of market architectures which include distribution constraints has its advantages. Nevertheless, these benefits are cancelled by the higher ICT costs (led by the increased system complexity). This phenomenon is not making evident the added value of adopting a complex coordination scheme rather than the centralized CS A. This conclusion is applicable to all the situations in which reserves activations lead to similar costs among coordination schemes: in addition to ICT, however the cost impact is marginal, also scenario uncertainties can change the merit order of coordination schemes.

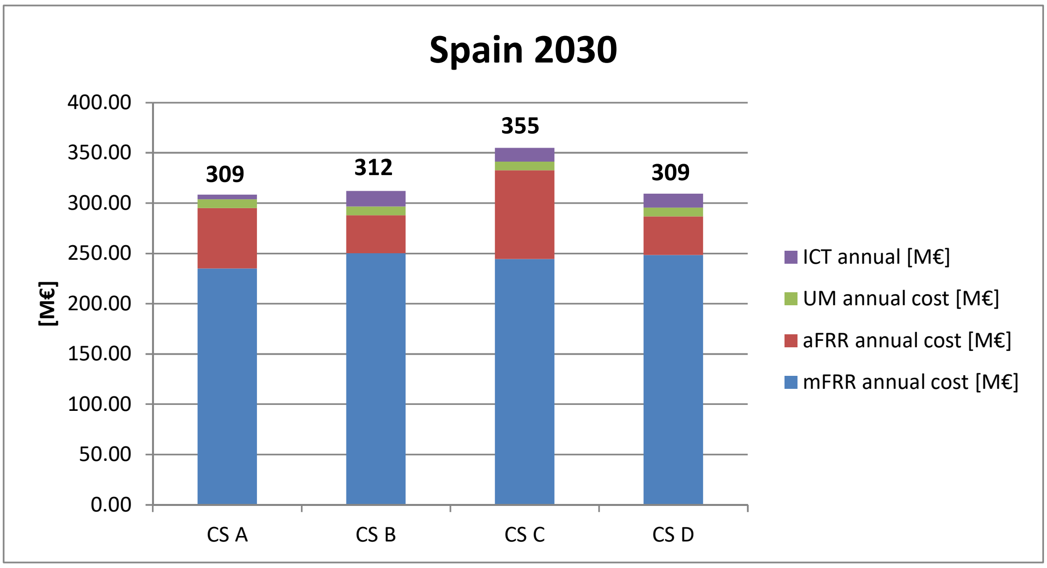

Figure 25 - Final simulation and CBA results for Spain 2030

In all these scenarios, CS C is definitively the coordination scheme with the lowest performance. As anticipated above, the flexibility margins available at distribution level are not often capable of guaranteeing an effective balancing service. Depending on the country (and on the distribution network structure), the behaviour of CS C can be explained as:

- Spain and Italy perform low costs of mFRR activations, particularly due to the fact that the local market is not capable of solving imbalance situations (poor availability of non-constrained resources). This can be also noticed by the high amount of aFRR, which is requested for the system rebalancing.
- Denmark, instead, features high costs for mFRR too. This demonstrates the availability of expensive flexible resources at distribution level which are activated in order to solve the system imbalance. However, their availability is not enough to effectively re-balance the system, since aFRR is still pretty high when compared to other coordination schemes.

7. Regulatory analysis

All the schemes of TSO-DSO coordination that have been assessed within the SmartNet project imagine that levels of DSO's involvement in the System Operation and so of DSO's responsibility will be far larger than what happens today. This will require significant investments in monitoring and control systems, as well as higher level of expertise on DSO side (which can especially concern smaller DSO). Additionally, the so called "fit-and-forget" reinforcement policy (oversizing of networks in order not to have to deal with network "problems", mainly congestions) which is, currently, often the basis of Distribution Network (DN) "operation" must be overtaken. These policies, in fact, may lead some DSOs to develop a resistance to consider flexibility as a value. Also, some DSOs may underestimate the needs to invest in implementing monitoring and control system, mainly during the first years, in which the DN monitoring systems have to be deployed, as costs would probably overcome benefits;

Long term planning should also be extended to cover the whole DN as it already happens for Transmission Network (TN). This implies that, apart from all the technological improvement needed, DSOs should also be able to extend their expertise. The effort needed to achieve this is considerable, even in the case of the sharing of the market operation responsibilities with TSOs.

If local congestion management markets are implemented, it will require a good level of coordination between TSOs and DSOs. Any level of separation between Transmission and Distribution that may be introduced at the market level with, in the extreme case, balancing responsibilities also given to the DSOs, could potentially decrease the overall economic efficiency, since the knowledge of the global system operation and condition may not be available to some extent (for instance: counteraction in TN to activation in DN; rebalancing in DN subsequent to congestion management that increases global imbalance). This issue should be tackled at a regulatory level, e.g. by introducing a mechanism of revocation of the bids accepted locally.

Furthermore, the local and global markets could be implemented with different clearing frequencies, with the possibility that a bid which is offered both at local and at transmission level is accepted twice. To avoid such situation it is recommended that the setup of the two markets, in particular the setup of the bidding procedure, should be carefully coordinated by TSO and DSOs, e.g. by means of a common shared database of resources without time correlation.

Local markets could also be affected by scarcity of liquidity, with the following two major problems:

- if only a small number of resources are reliable or at the DSO disposal, those resources could have potential to exercise market power;
- the DSO may not be able to solve congestion in the DN by means of the market and thus be forced to activate unwanted measures, thus increasing the costs for the System.

The very high prices that may occur as result of illiquidity in the AS market is expected to encourage investments in new resources in the local networks, but the consequent boom-and-bust price cycles could not be tolerable for the society, bringing the necessity for the regulator to intervene and filter (part of the) price signals.

Introduction of the local market may raise the important questions of their operation, including operation of network areas with multiple DSOs, which vary in size and resources availability. Small DSOs may avoid scarcity of liquidity by grouping together in a single and sufficiently large local market, which may also increase economic efficiency, since many small local markets have higher ICT implementation costs than a local market with a reasonable size.

It is also important to recognize that different countries have different "DSO landscape" as in some countries there are relatively few DSOs, where other countries have a very high number of small DSOs. Thus, one of the important issues to recognize when discussing and deciding on the existence, structure and operation of the local markets also includes questions on what are the options for small DSOs to procure distribution services, and also how DSOs can anticipate the reaction/behaviour of the TSOs, which is relevant for a number of proposed coordination schemes. Small DSOs should be allowed to define and implement a procurement mechanism for their own needs that is cost efficient. They can either organize/run their own market or, if more efficient, sub-contract it (e.g., from a larger DSO).

A local market should be established where it makes more sense. As with unbundling requirements, small DSOs (e.g., with 100k consumers or less) should not be forced to implement measures impacting their cost structure without sound reason to do so. Small DSOs should be given the option to decide if they need a local market and who the operator of such a market should be.

Nevertheless, there are some rare cases in which the separation between Transmission and Distribution could bring the positive side effect that high prices in one area are prevented to spread in the others.

All this considered, the experience of SmartNet project suggests that DSOs should be responsible for local (voltage) regulation and, at most, only for the congestion management of their local networks, but at the expense of the overall market clearing efficiency. Balancing should always remain a "global issue" under the responsibility of TSO.

On the other hand, if a sharing of the Market Operation responsibility between TSOs and DSOs is implemented (so that distribution constraints are managed together with transmission constraints), issues related to data and information sharing may arise, with the need of investments in ICT. However, these may prove not to be consistent when compared with the baseline expected in 2030 (the Centralized Ancillary Services Market model). Furthermore, although this is not a topic investigated in the SmartNet project, we highlight that it will become necessary to tackle problems related to data ownership and access.

Given that it is expected that in 2030, and beyond, resources at distribution level will likely be mainly composed by RES generation, forecast error could heavily affect market efficiency, mainly when a Common TSO-DSO Ancillary Services Market is implemented. Improvements in reliability of forecast, even if it is not under regulators' control, and, even if it affects some generation technologies more (e.g. PV) than others (e.g. mini-hydro), should be encouraged. Since forecasting techniques can have better performances if applied to shorter time forecast horizons, another option could be to move the gate closure time of AS Market as close as possible to real time, keeping in mind that there still has to be left sufficient time between these two events (i.e. gate closure and real time) to carry out market clearing and enable response of devices that need to respect their technological limits, e.g. the activation and ramping-up/down of the resources.

Moreover, although there is a widespread agreement that Intraday Markets should bring gate closure as close as possible to real time (this would allow RES to recalculate their actual generation taking into account the most updated forecasts so to reduce imbalances), there is a need to allow time in-between to allow sufficient time to TSO and DSOs to evaluate the status of the System, calculate the needed reserve and arrange the Ancillary Services market and, as mentioned above, provide activation signals sufficiently ahead of actual activation to allow all technologies that are called to provide their services. Implementation of an Integrated Flexibility Market scheme, the result of the mix of Intraday and Ancillary

Services Markets, where flexibility resources would be available not only to System Operators but also to private operators to solve their own flexibility problems, could also be useful to overcome some of the mentioned issues. However, time periods in which the commercial parties are allowed to change their own positions should be well distinguished from those in which DSO and TSO select resources in order to procure system, services: otherwise there would be high risk for TSOs and DSOs to assess system needs on the basis of a non-firm situation. In any case, further investigation on this subject is recommended.

In addition, from 1st January 2025, the imbalance settlement period should be 15 minutes in all control areas, as defined by EU Commission Regulation. Since Market Operators (MOs) on the Day-ahead Market (DAM) and IntraDay Market (IDM) shall provide the opportunity to trade energy in time intervals which are at least as short as the imbalance settlement, energy will be traded in at least 15min period from 2025.

To ensure level playing field in the participation of distributed energy resources, including industrial loads, to the tertiary market, our analysis showed that it may become necessary to introduce new bidding products, tailored to the technical and physical constraints of particular resources of the different technologies. These bids can use a state-space representation and simulate the internal physics of different energy devices, such as batteries and thermostatically-controlled loads, while others have used discrete models. While simple bids can be used, their implementation may require more complex market clearing algorithms to model these constraints, and/or put additional burden on participants to account for constrains such as ramping or energy shifting. In any case, inclusion of technical constraints of different technology may impact computational time of the market clearing procedure, but is necessary in order find technically sound solutions. Thus, a trade-off between computational time and accuracy of the solutions needs to be carefully evaluated.

In addition, minimum size of the bid needs to be carefully determined so not to significantly increase computational burden for the market clearing, while still allowing smaller market participant to offer their services, thus helping achieve liquidity in local markets. Furthermore, smaller bid sizes can be used to reduce complexity of bids, since finer granularity can help some technologies better model their complex technical constraints.

Finally, solutions proposed in the SmartNet project will help realise European Commission goal to deliver “clean energy for all Europeans”, and addressed some of the issues that are key to “enable Short-term electricity markets which allow trading RES-E across borders are key for successful integration of RES-E into the market”. In particular, SmartNet solutions will help better understand technical, economic and regulatory issues that need to be addressed when creating market designs that will allow provision of flexibility at a short notice, before the actual delivery. This will enable better integration of renewable resources while providing new business opportunities for participants that are willing to offer flexibility to better match variability of these resources.

8. Three technological pilots

There are few real-life experiences in the application of the concepts developed within SmartNet, in particular, regarding the different coordination schemes and the market models developed. Therefore, the deployment of technological pilots is of paramount importance for testing and demonstrating the technical feasibility of those concepts.

Additionally, the results of the simulations and the CBA described earlier focus on the economic aspects of the mid-term scenarios created within the project. However, there may be some implementation difficulties which cannot be anticipated by the scenario analysis and the CBA, but which can be identified by implementing real-life technological pilots.

The three technological pilots have been deployed within SmartNet, with a holistic view, so that they complement each other. First of all, each of them focuses on different parts of the TSO-DSO coordination value chain, so that one of them looks at the communication requirements between the TSO and the DSO, another one investigates the issues arising from the broadcasting of unidirectional price signals from the aggregator to the DER and the third one studies the capability of the DSO to run a local flexibility market. Furthermore, different potential TSO-DSO coordination schemes have been demonstrated, so that issues arising from each of them can be identified. Moreover, different types of DER have been considered, so that their flexibilities can be better assessed and the advantages and disadvantages for real-life implementation can be properly identified and addressed.

Finally, they are also complementary in terms of geographical implementations. The first pilot has been implemented in Italy, in an area with high penetration of RES, especially run-of-river hydro, and to provide an answer to the growing challenge of reverse power flow, i.e. to power going from distribution up to transmission. The main focus in on the DSO aggregating the information for load and generation, so that real-time information can be obtained, but also to better forecast grid conditions in upcoming periods. This way, the TSO can anticipate (and avoid) problems in the transmission network, but it can also estimate the flexibility that DER could provide for controlling the voltage or to helping balance the system.

The second pilot has been deployed in Denmark, with the aim of demonstrating the potential of using price signals to exploit the flexibility of heat water pumps for indoor swimming pools. The owners of swimming pools will react to different levels of prices by consuming more or less energy and, thus, an aggregator can estimate such response and broadcast the required price signals to obtain the required flexibility level. Based on that price-flexibility function, the aggregator can bid the flexibility available in those DER units into the markets for ancillary services. In this case, the market for ancillary services takes a new market setup, where both the TSO and the DSO post their balancing and congestion management needs.

The third pilot has been installed in Spain, with the objective of demonstrating the technical feasibility of creating a new, local market for congestion management and managed by the DSO. In order to be even more ambitious, the pilot also considered a coordination scheme in which the balancing responsibility is shared between the TSO and the DSO, so that both must ensure the fulfilment of a scheduled program (agree among the two parties) in each TSO-DSO interconnection point. As a result, the DSO organizes a local flexibility market, where aggregators bid the flexibility of different types of DER to solve congestions in distribution networks and to meet the requirements of the scheduled program. In this case, flexibility is obtained from radio base stations, leveraging on the availability of back-up batteries, which were installed for maintaining the mobile communication service in case of a blackout, but which are almost never used.

The table below summarises such complementarity.

	Pilot A	Pilot B	Pilot C
Country	Italy	Denmark	Spain
Coordination scheme	Centralised Ancillary Services market	Common TSO-DSO Ancillary Services market	Shared balancing responsibility
Services to be gathered by TSO/DSO	- Aggregation of information for TSO - Voltage control for TSO - Frequency control for TSO	- DSO Congestion management - Frequency control for TSO	- DSO Congestion management - Frequency control for DSO
DER providing flexibility	Run-of-river hydro power plants	Impulsion pumps for heat water for indoor swimming pools in rental houses	Back-up batteries for radio base stations used in mobile phone communications
Main focus of the pilot	- TSO-DSO communication - TSO control - Assessment of DER capability to participate in markets	- Price-signals from aggregators to obtain DER flexibility - Communication chain from market to DER through aggregators	- Monitoring of distribution network - Creation and operation of local flexibility markets - Assessment of base station capability to provide services for grid support

Pilot A: Centralised TSO control in high-DER area

In Italy, the adoption of a policy that aims to encourage the development of new and renewable forms of energy and the fossil fuel replacement has resulted in a strong growth of the renewable penetration: since 2008, about 6.6 GW of wind power capacity and about 19.6 GW of solar power capacity have been installed, as shown in Figure 26.

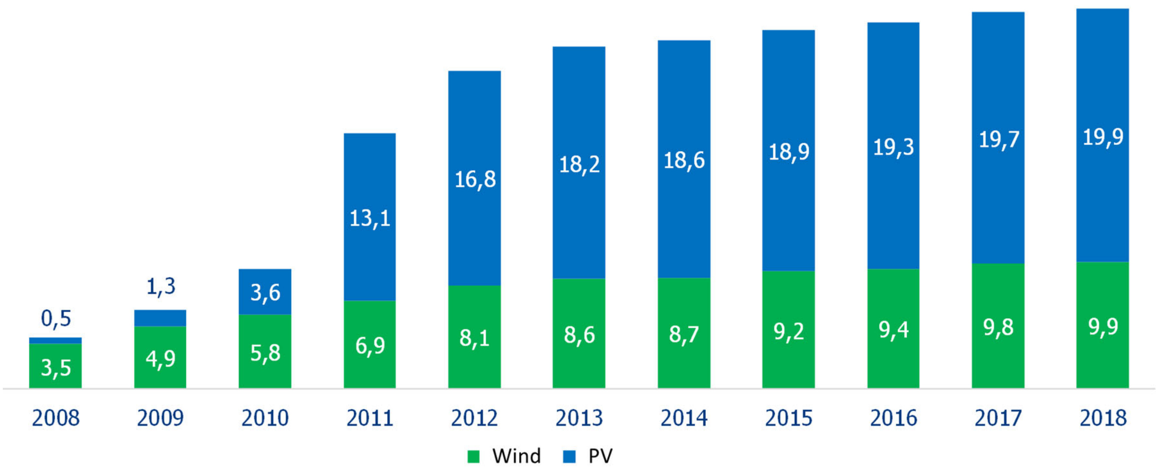

Figure 26 - Wind and photovoltaic capacity installed in Italy (GW), 2008-2018

The consequence is that the energy framework is moving from a power generation mainly characterized by few big traditional plants connected to HV transmission grid and directly controlled by the TSO to a park composed by numerous unpredictable power plants connected to MV and LV grids. It may affect the management of the electrical system and the increase in the share of generation from renewable sources and the consequent reduction in the number of traditional units in service will lead to the need to propose new approaches to ensure the availability of ancillary services essential for the management of the grid which, at the moment, are provided by programmable traditional power plants.

Within this context, the Italian pilot represents a technological application within SmartNet project and it aims to implement new tools to promote the integration of renewable energy in smart grid systems. The pilot is located in South-Tyrol, at the border with Austria, characterized by a wide exploitation of hydro power plants of different sizes connected to different voltage levels. The installation of many small-sized power plant at MV and LV levels results in power reverse flow at the interconnection point (primary substation) between the TSO (Terna) and the DSO (Edyna), with a peak higher than 30 MW in summer (Figure 27).

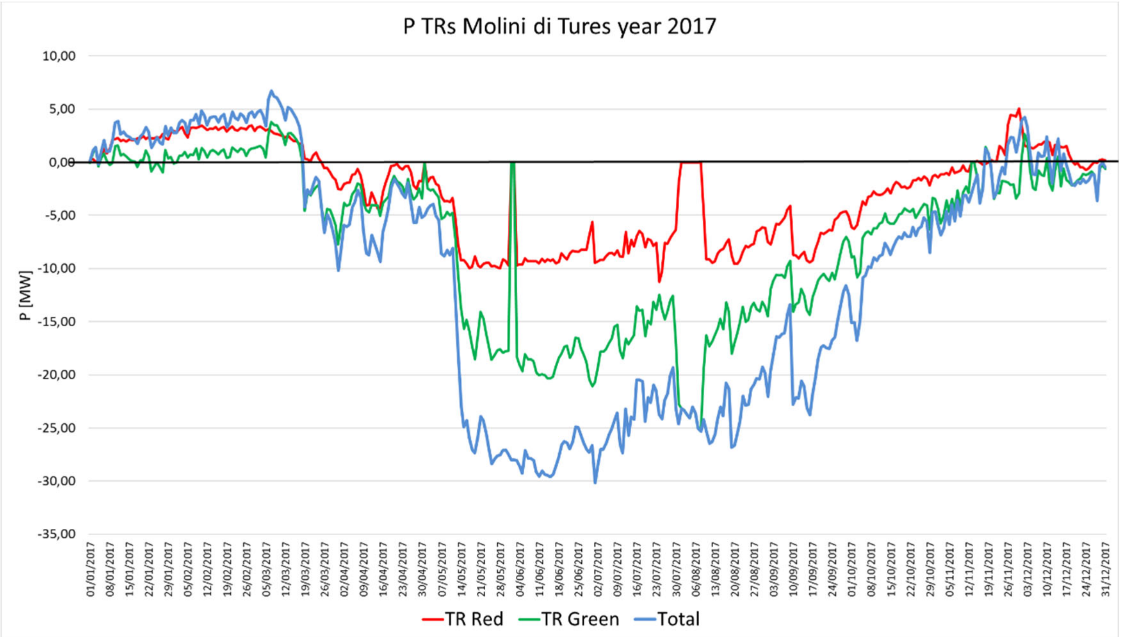

Figure 27 - Trend of the active power at the HV/MV primary substation during 2017

The project aimed to develop and implement in field two devices developed by the technological partners of the consortium (Siemens and Selta) to monitor in real time the sources connected to the distribution grid and to use these plants to provide both the voltage and the power/frequency regulation, controlled in a centralized scheme by TSO. The two devices realized are:

1. The High Voltage Regulation System (HVRS), installed in the HV substation (HS) to control the reactive power of the two hydro power plants (RES) directly connected at the sub-transmission grid (132kV) that currently do not participate in the hierarchical voltage regulation.
2. The Medium Voltage Regulation Systems (MVRS), installed in the DSO's Operation Centre (DSO OC) to allow the TSO to monitor and control the distributed generation (DER) connected to the HV/MV transformers of the Primary Substation (PS). This application allows for monitoring a MV grid, composed by 23 plants and 5 interconnection points with subtended DSOs, through Plant Central Regulators (PCRs, devices that interface the power generation module control system to the MVRS), and to control 7 of the biggest hydroelectric plants of about 22 MW total.

Figure shows the system architecture implemented in field and the data flow among the devices involves in the project.

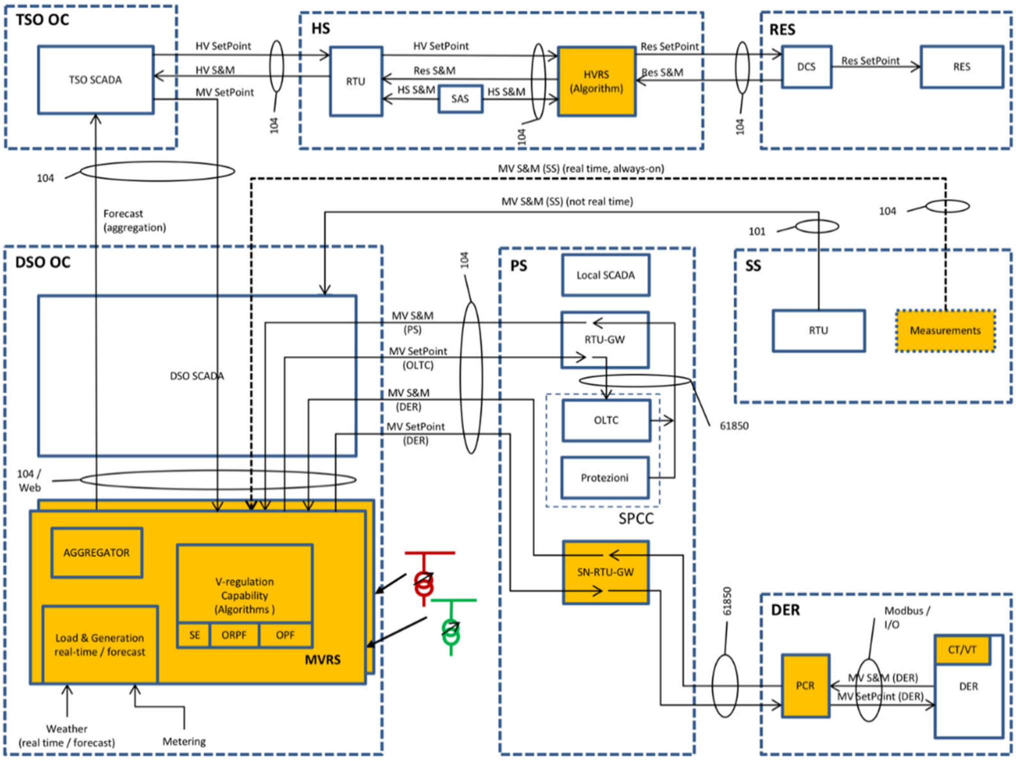

Figure 28 - Architecture of the system implemented in the Italian Pilot of SmartNet: at the top is represented the HVRS system and at the bottom is represented the MVRS system

The task of HVRS is to allow the TSO to control the reactive power of the plants in a coordinated way, sending a reactive power setpoint or a voltage setpoint referred to the HV busbar of the substation. In the SmartNet application, it aims to smooth the voltage fluctuations measured in the 132kV substation, by controlling the reactive power exchanged by the four synchronous generators (absorption or injection), so that they satisfy the TSO commands sent from the TSO's Control Room.

The TSO can control the reactive power sending a reactive power setpoint or a voltage setpoint. In the first case, the setpoint is a percentage value of the capability calculated in current operating conditions, while in the second case the setpoint is a voltage value expressed in kV. The TSO requests the optimal voltage value at the HV busbar and the HVRS converts the setpoint in a reactive power command on the basis of the voltage error, defined as the difference between the voltage setpoint and voltage measurement.

With both types of control, the HVRS shares the desired Q level (received or converted) among the four synchronous generators, in order to require the same contribution to each power plant's DCS, expressed as the percentage of the generator capability, and sends the setpoint.

The tests carried out to evaluate the coordinated voltage regulation showed the technical feasibility of controlling the reactive power exchange of power plants, despite the effect on the voltage of the transmission grid and the performance of the power plants controller are not the same of the service provided by big-size programmable power plants connected at transmission grid. In any case, the system allows the TSO to coordinate the reactive exchange of these power plants with the area needs, in order to avoid the reactive loop that can be established between the groups and, thus, wasting reactive resources. The potential of the HVRS is the opportunity to control different power plants and parks of different technology in a coordinated way, by sending a unique setpoint.

Regarding the MV part of the project, the main functionalities of the MVRS, developed by Siemens and Selta adopting different approaches and algorithms, are:

- The **aggregation function**, which allows for exchanging real-time data of the active and reactive power at the distribution level with the TSO's SCADA. The MV level is represented as equivalent aggregations, differentiated by type of source (solar resources, hydro resources and load), connected at the HV/MV substation (Figure 29). The aggregation is updated every 20 seconds.

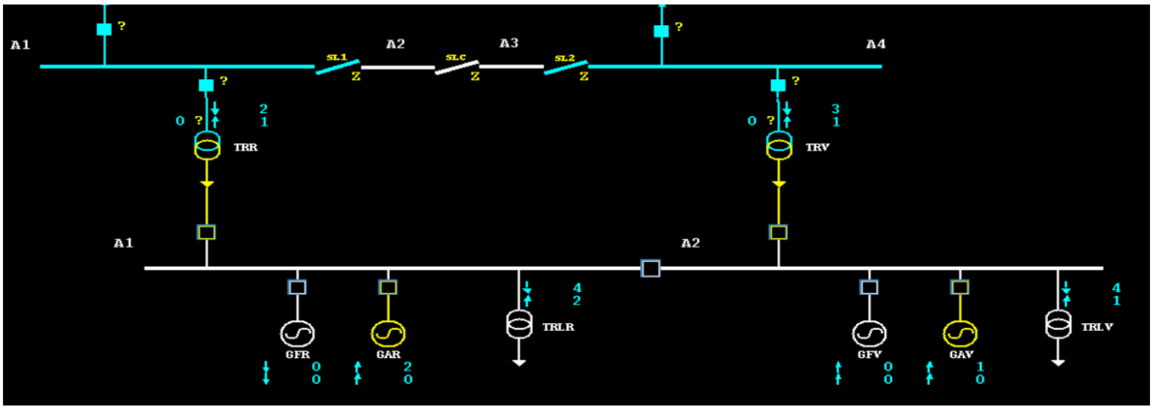

Figure 29: Representation of MV grid aggregations in Terna SCADA HMI

- The **estimation module**, to estimate the active power of unmonitored plants through algorithms that elaborate and combine available data (e.g. weather data, neighbouring plants' measurements, "near real-time" data registered by smart energy meters, historical profiles, etc.). This functionality has been tested offline in order to evaluate the accuracy of the algorithm developed and, in this application, almost all the power plants' production and the net power exchange at the interconnection points with subtended DSOs have been measured to guarantee the required accuracy in network monitoring, so as to be able to test ancillary services. The offline analysis provided the comparison between the estimation and the measurement ant it highlighted the dependence on the type of source: on the one hand, it is necessary to measure the 60 % of the installed hydro power and to choose the right power plants to monitor, as well as to have access to historical data, to have a good accuracy of the estimation, while, on the other, the estimation of solar production based on weather data can achieve quite accurate results.
- The calculation of the **capability of the virtual power plant** composed by the embedded generation in order to allow the TSO to know the available active and reactive power margin on DSO network considering the capability of each power plant and the operational limits of the distribution grid.
- The **voltage regulation of HV** busbar of the Primary Substation through the embedded generation connected at the transformers of the substation. As shown in Figure , through the computation of the virtual capability, the MVRS provides to the TSO an instrument to know the reactive availability in the distribution grid, considering the availability of each generator and taking into account the DSO's grid constraints. The TSO can control the reactive power of the embedded generators to regulate the HV busbar voltage considering them as a unique power plant: the MVRS receives a unique setpoint and provides a smart splitting of reactive power command among the controlled plants according to single DERs capability.
  In case of constraints violation in the distribution grid the priority of the device is to solve the violation, making the generators unavailable for the voltage regulation.

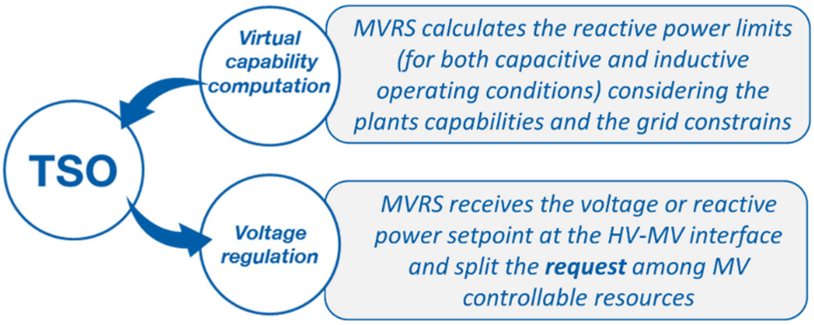

Figure 30 - Diagram of operation of voltage regulation functionality of MVRS

The tests showed that activation of reactive sources at the distribution grid leads to the control of the voltage rise effect along the feeders of the DSO grid, usually subjected to overvoltages, in order to maintain the voltage within required limits. From the point of view of the management of the transmission grid, the field tests carried out have shown the technical feasibility of controlling the reactive power exchange of the power plants, although the behaviour of power plants connected at transmission grid is more prevalent than the contribution of distributed generation. Figure shows the trend of the voltage at the HV busbar during the tests: voltage reacts to the setpoints in the two feeders (red and green), although other elements of the grid may also affect the voltage, as happened at 15:55, when a decreasing of voltage was independent of any MV regulation.

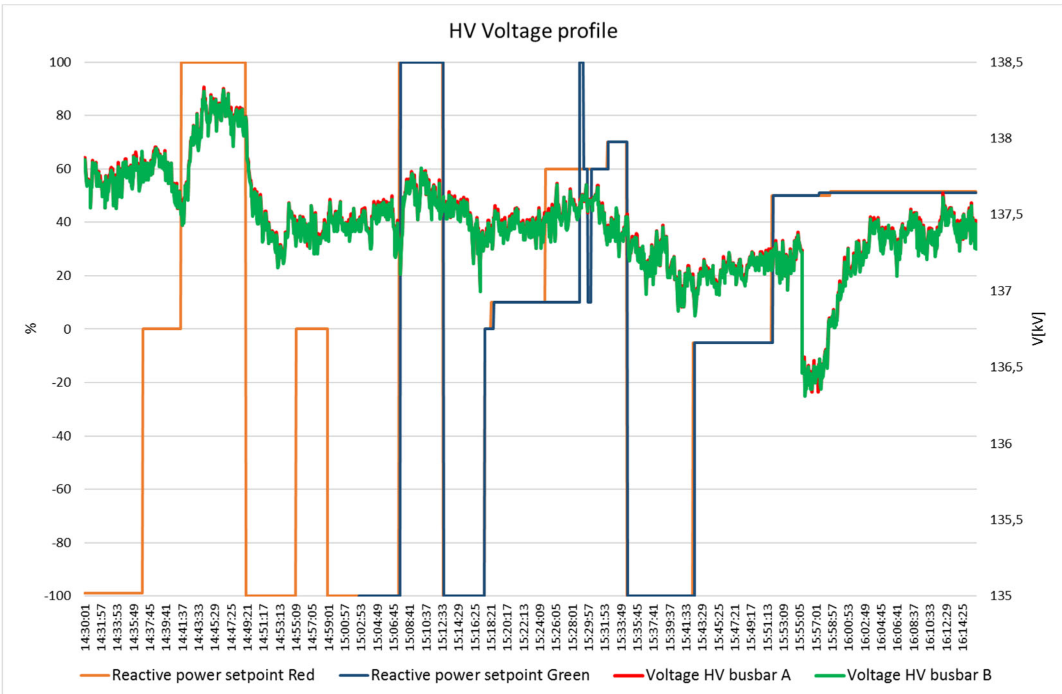

Figure 31 - Trend of the voltage at the HV side of the PS during tests

At the moment, the involvement of embedded generation in this service does not provide evident advantages in the management of the HV grid because the voltage trend follows the performance of the HV power plants. Nevertheless, the coordination of the reactive power exchange of these power plants can contribute to avoid wasting of sources that provide reactive power regulation. Moreover, it is very likely to have a big importance in the future as the contribution of renewables increases.

- The **frequency/power regulation** (aFRR), through the generators connected at the MV side of the transformers of the substation and involved in the pilot. It consists of providing a modulation of the active power of the embedded generation according to a signal level sent by Terna to the control system every 4 seconds. The MVRS calculates and sends to the TSO the program value and the half-band available for the regulation, considering all the power plants available for the service. The tests were performed by sending a level signal with a ramp profile, composed by a ramp-down to reach the minimum production made available and a ramp-up to return to the initial program value (Figure 32).

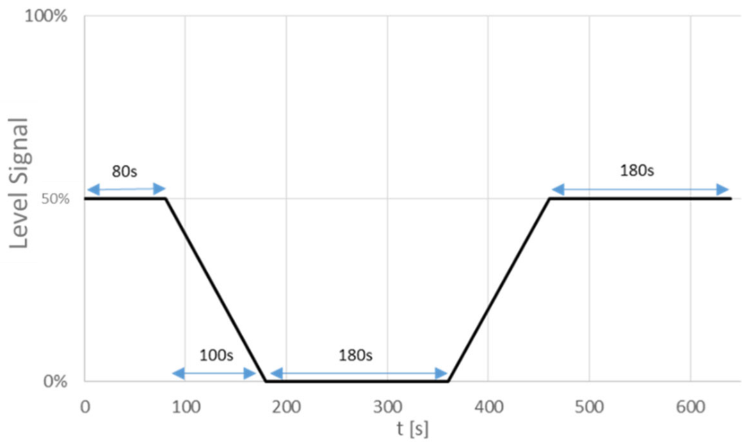

Figure 32 - Ramp of the level signal used for the f/P regulation tests

The tests provided promising results, with the activation of 7 power plants and a variation of the production of more than 6 MW. Regarding the quality of the regulation, the dynamic response did not comply with the technical requirements of the service, due to delays in the communication and the inaccurate regulation of power plant controller. Moreover, the tests showed that the reliability and the quality of the regulation of the virtual power plant at the interconnection point does not depend solely on the single power plant performance, but the trend is influenced by other elements of the grid, uncontrolled and unforeseeable. An example is reported in Figure 33, where the blue line is the expected contribution calculated from the percentage setpoint sent by Terna and the red line is the real contribution of embedded generation calculated by subtracting an offset value to better appreciate the trend. In the lower part of the graph, the trend of the dynamic error has been reported in comparison with the limit value used for acceptance to the secondary frequency control service (10%). The error increases with increasing response inaccuracy and delay.

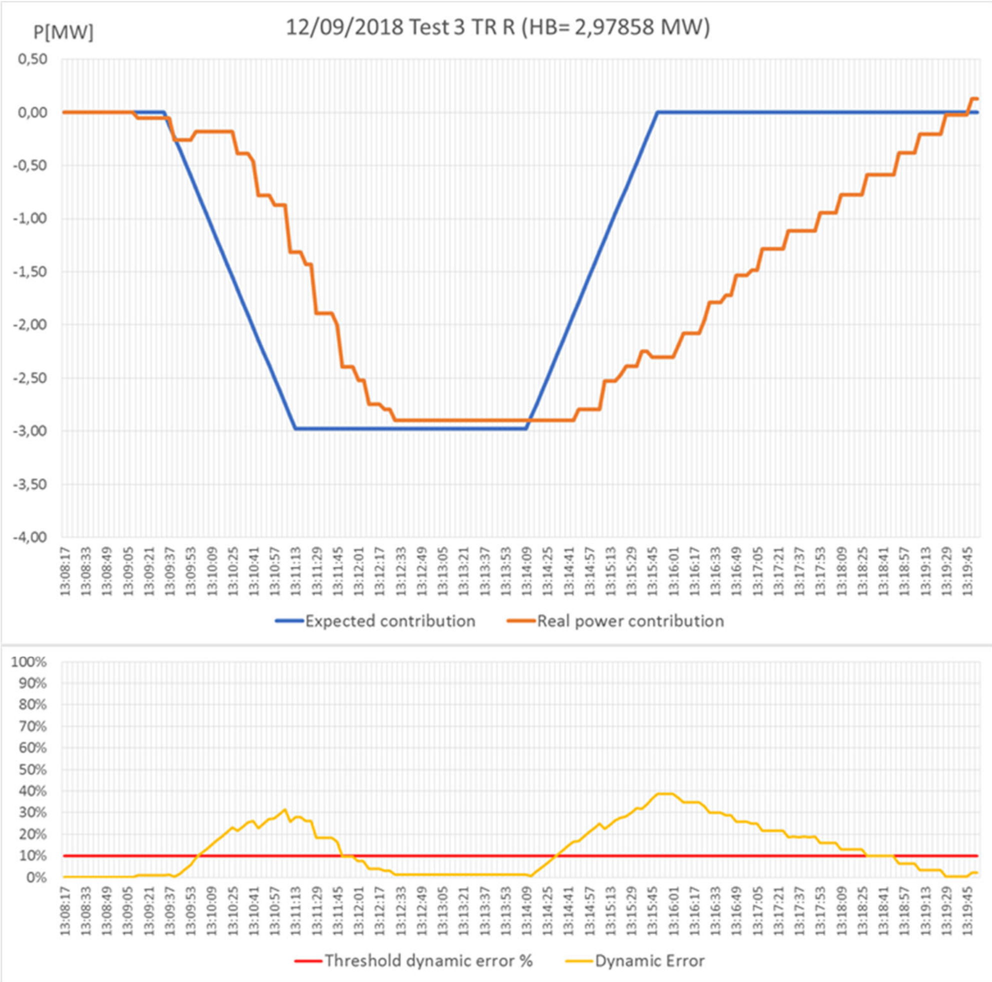

Figure 33 - Example of trend and analysis of the HV contribution of the virtual power plant connected at the transformer

In general, an important value of the pilot is the results of tests and the detection of the aspects to be improved in order to integrate the renewable energy sources in the electrical grid. It is clear the need of further experimentations, some of which are already in place, in order to improve the performance and the reliability of the behavior of renewable energy sources. Moreover, the tests highlighted the importance of a continuous monitoring of the sources and of the actuation of the services so as to guarantee the efficiency, the safety, the adequacy and the quality of the dispatching.

Pilot B: Common TSO-DSO market with pool flexibility

Summer houses with indoor swimming pools consume substantial amounts of electricity for heating water and humidity control. The electricity demand from summer houses is particularly flexible. For example, swimming pools have a large thermal capacity and, thus, the load to heat pool water can be disconnected or shifted with little consequences on the comfort of the occupants within given intervals that depend on the size of the heated environment and other factors. The Danish Pilot is aimed at assessing and demonstrating to which extent flexibility of summer houses could be exploited to provide both transmission and distribution grid operators with ancillary services.

NOVASOL is a rental company that operates about 900 summer houses with an indoor swimming pool in Denmark, holding an average annual power consumption of about 30 000 kWh per house. Although the summer houses are not occupied permanently, they have a year-round base load, e.g., to guarantee that the pool water temperature does not fall below a certain threshold, should a customer wish to rent the house with short notice. The location of the houses, coupled with their thermal inertia, make their load a suitable candidate for the provision of grid services. Indeed, many are in coastal areas of northern Jutland (in the DK1 control area of NordPool), where the distribution grid is weak. 30 summer houses were selected, based on their location, size and characteristics for field-testing and as a proof-of-concept to demonstrate the feasibility of the proposed aim. For this pilot, the selected properties have been equipped with a dedicated communication gateway, temperature sensors and a smart controller that reacts to price signal from the market operators.

This pilot benefited from deploying software solutions including cloud, server technologies and big data to ease the interaction among industry and research partners and to provide an agile environment where pilot partners could test various models, physical components and technologies in parallel.

Figure 34 illustrates the functionalities, communications, and ICT interfaces in the Danish Pilot, which is divided into lower- and upper-levels, and the role of various partners in the pilot. The Pilot, which focuses on balancing and voltage regulation, is characterized by a bidding and clearing procedure operated by the market operator. It receives grid status from the TSO and the DSO and interacts with Commercial Market Party (CMP) to gather the required flexibility.

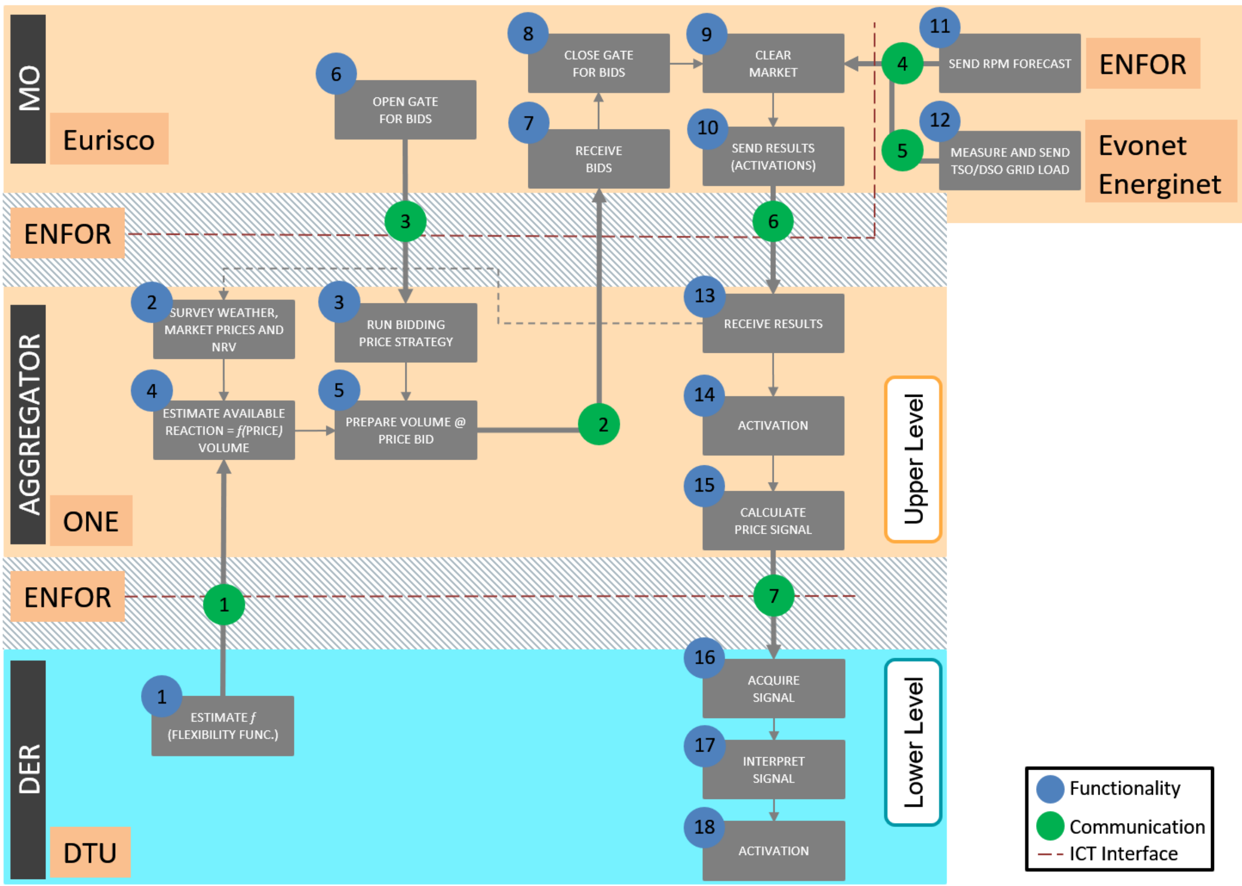

Figure 34 - Communication and ICT interfaces in the Danish Pilot

A flexibility model developed by DTU predicts the electricity demand as a function of prices and reacts to price signals. The CMP sends out both prices and price forecasts. Such communication intends to create a balanced situation for the relevant market operator (MO) for the next hours. The technical aggregator then receives two rates; one is the forecasted price, and the other is the actual price. In addition, it also collects weather forecasts and booking information, to calculate the optimal set points for the thermostats of all the summer houses. Measurements from the summer houses are then collected and used to feed price-responsiveness information in the flexibility model.

The implementation of the Pilot has been made in a step-wise manner. The laboratory tests, the first demonstrative implementations which were completed in late 2016, were carried out by using a water tank as a small representation of a swimming pool installed in Eurisco's lab. The tank had sensors and actuators connected to it and was connected to ENFOR's platform for the remote-control purposes. Upon completing the lab experiments, a full field-test was conducted on selected summer houses during 2017 and 2018. The selection has been based on the summer house characteristics, the stability of their communication network and their booking status.

ICT deployment and digital communication have been pivotal in this pilot to ensure reliability of the service and for models and the controller to provide accurate output. To achieve a reliable communication, an SN-10 controller has been designed for this pilot and installed in the selected summer houses. These controllers were used as data communication interfaces from the Technical Aggregator to the summer houses. This device was made specially for the SmartNet project, because no existing commercial products could meet the requirement specification. As can be seen in Figure , the SN-10 is a hardware component inside the system installed at the summer houses. The system also includes a 5V/12V DC power supply, a 230V switch and sensors for temperature measurements. The SN-10 also has an interface and access to the electricity meter in the summer house to provide the total amount of electricity consumption in the property to the controller and forecast model.

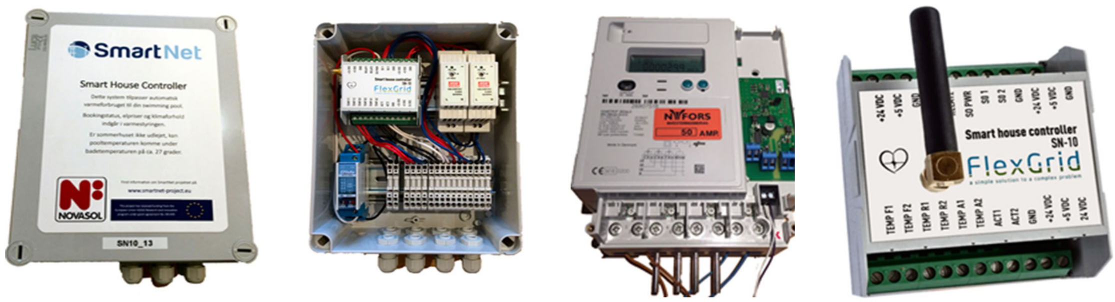

Figure 35 - SN-10 Communication gateway and local controller

The actuators, labeled as ACT1 and ACT2 in Figure , are controllable thermostats, which open or close depending on a Pulse Modulated Signal (24VDC) from the SN-10 controller. Water temperature is measured for the pool water going in and out of the pool and the air temperature sensor measures the heat from the pool room. The pool pump can be switched off during high-energy periods, but only for a limited time due to constraints in the water cleaning process. The power consumption is measured with an internal electricity meter (sub-meter) and with the household revenue meter.

The SN-10 controller is an internet-of-things (IoT) unit, which is connected to the internet and can collect the measurements and send the controlling signals received from the smart controller. The main part in the controller is a "Particle Electron" (http://www.particle.io), which is connected to the internet via a 2G/3G communication. Every 5 minutes, the SN-10 sends data to a cloud server, and then relays to the data management system (DMS). Control signals are calculated and sent to the SN-10 unit on a 5-minute basis. The control signal is a temperature set-point, with which the SN-10 controller will regulate the water temperature. If the SN-10 is installed with an electrical boiler, it will activate the relay when heating is needed and deactivate it when the set-point is reached. In order to prevent fast switches, a 1-degree Celsius hysteresis is used. If the SN-10 is installed in a house with a central heating system, a thermal actuator is used instead of the relay.

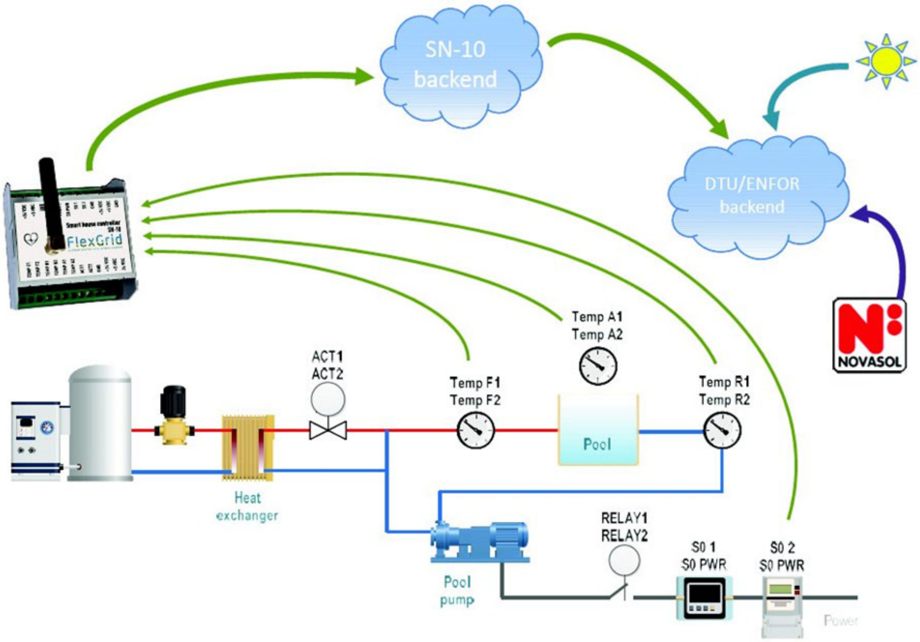

Figure 36 - Data measurement and information gathering by SN-10

An estimated flexibility function can be seen in Figure 37 - Estimated step-response, based on data from October 2017, where the penalty was based on CO2-intensity.. This flexibility function is estimated during the trial of the pilot when the swimming pools were operating according to a penalty signal based on CO_2-intensity in the electricity mix. It is seen that the response to an increase in penalty is slow, with the full effect taking approximately 10 hours to be reached. This extremely slow response is due to two things. Firstly, the heat pumps used to heat the swimming pools are not designed to be turned on and off frequently, and thus a Model Predictive Control (MPC) has been designed to limit how of often this happens, to prevent damaging them. This meant that the MPC often chose not to react immediately to changes in penalties. Secondly, technical issues with the hardware meant that the SN-10 was occasionally unresponsive to MPC due to some communication barriers. However, if the concepts developed within the pilot are widespread used, the hardware will be updated to be able to react as quickly as required.

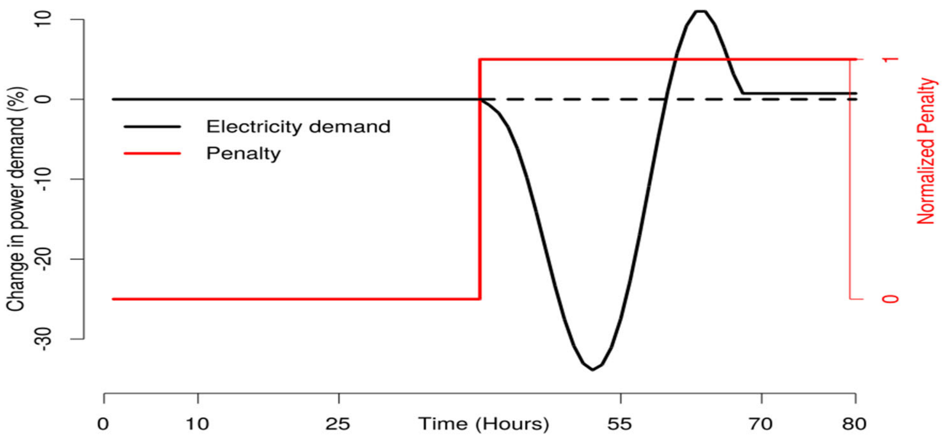

Figure 37 - Estimated step-response, based on data from October 2017, where the penalty was based on CO2-intensity.

The architecture of the Danish Pilot has been based on the current situation in Denmark (in terms of DER penetration and uniform taxation scheme). The Pilot assessed to what extent flexible summer houses could provide ancillary services as balancing services and voltage regulation. The control models and algorithms of the pilot were drawn from the models devised in various contributions in the SmartNet project. Danish Pilot benefited from utilising Smart-Energy Operating System (SE-OS) concept, which is a framework for implementing energy flexible solutions consisting of top-down, one-way communication from aggregators to DERs using price-based control method. A similar idea for the Danish pilot has been implemented in the cloud with a dedicated DMS. It promotes a common flexibility market for system operators.

As described above, the Danish Pilot was split into upper and lower levels. The former, included market clearing at the MO and the interactions among the MO, the economic aggregator, the DSO, and the TSO, while the focus of the lower level was to compute optimal heating schedules and to activate those computed heating schedules in the swimming pools. To validate the technologies developed and incorporated, the Danish Pilot did a laboratory test, a hardware-in-the-loop (HIL) simulation, and real field test. Throughout these validation phases, both the results obtained and the advanced technologies developed in the Danish Pilot attracted the attention from all around the world. Results and analysis derived from the output of the experiments and test performed in the pilot show that using these new methods could reduce the CO_2 emissions by at least 10%. Besides, the Danish pilot has provided indirect benefits that were not anticipated at the initial stages of the projects, such as remote control of the heating system and the status of property occupancy by the house renters.

The Danish Pilot paves the way for new developments and the creation of new technologies that help in providing extra flexibility to the energy sector. In addition, at the consumer level, they can gain additional benefits from such methodologies and set-up from some of the challenges this pilot has faced during the execution phase. In general, the Danish pilot has achieved its objectives, in how to apply new control algorithms, defining new technologies for such systems and for more substantial scale scenarios it will help reduce the CO_2 emissions and provides cost savings to the energy consumers.

Pilot C: Shared balancing responsibility with base station flexibility

The coordination scheme used in the Spanish pilot is called “Shared balancing responsibility model”. In this model, there are joint balancing responsibilities between the TSO and the DSO, according to a predefined schedule in the common border. The DSO organizes a local market to respect the schedule agreed with the TSO. A new regulated function located at the control centre of the DSO, called Local Market Operator (LMO), the aim to this function is to facilitate that Commercial Market Parties (CMPs) become flexibility providers of aggregated DER. This new function is designed to allocate flexibility among the different CMPs in a competitive manner.

The Spanish pilot aims to demonstrate the technical feasibility of using radio base stations to provide ancillary services for the DSO through demand flexibility. In particular, the radio base stations are equipped with back-up batteries, which ensure the continuity of communications service in the (rare) event of a blackout in the distribution grid. By using the back-up batteries, radio base stations can be disconnected from the grid on purpose when requested by the CMP.

The main goals of the pilot are the following ones:

- Proof of concept of the “Shared balancing responsibility model” in a real demonstration environment by a real DSO.
- Proof of concept of participation of back-up batteries to solve DSO issues, which provides useful hints to the DSO.
- Proof of concept of DER aggregation in a real demonstration environment, which is of particular interest for the aggregator because it offers the opportunity to participate in a new markets and test in a real world.

- Proof of concept of usage of back-up in base stations for DSM. The value for DER owners is to understand, both in real time and under real usage conditions. To ensure the technology used is enough and the usage doesn't impact to the radio station consumers.

Fundamentally, the pilot aims to implement balancing and congestion management services for the distribution network through direct bidirectional signals to the aggregator. This is pushed further downstream to the activation of back-up capacities to reduce the consumption in selected grid regions.

The pilot C involves 5 primary substations and 18 radio base stations in the city of Barcelona, as shown in Figure 38. Moreover, the scenario considered in the pilot is looking into a future situation, with a more electrified energy system, which may result in congestion problems at distribution level. For this reason, part of the network is virtual, in order to generate such a new scenario, with an effort made to provide characteristics, which could reasonably adapt to the current grid topology.

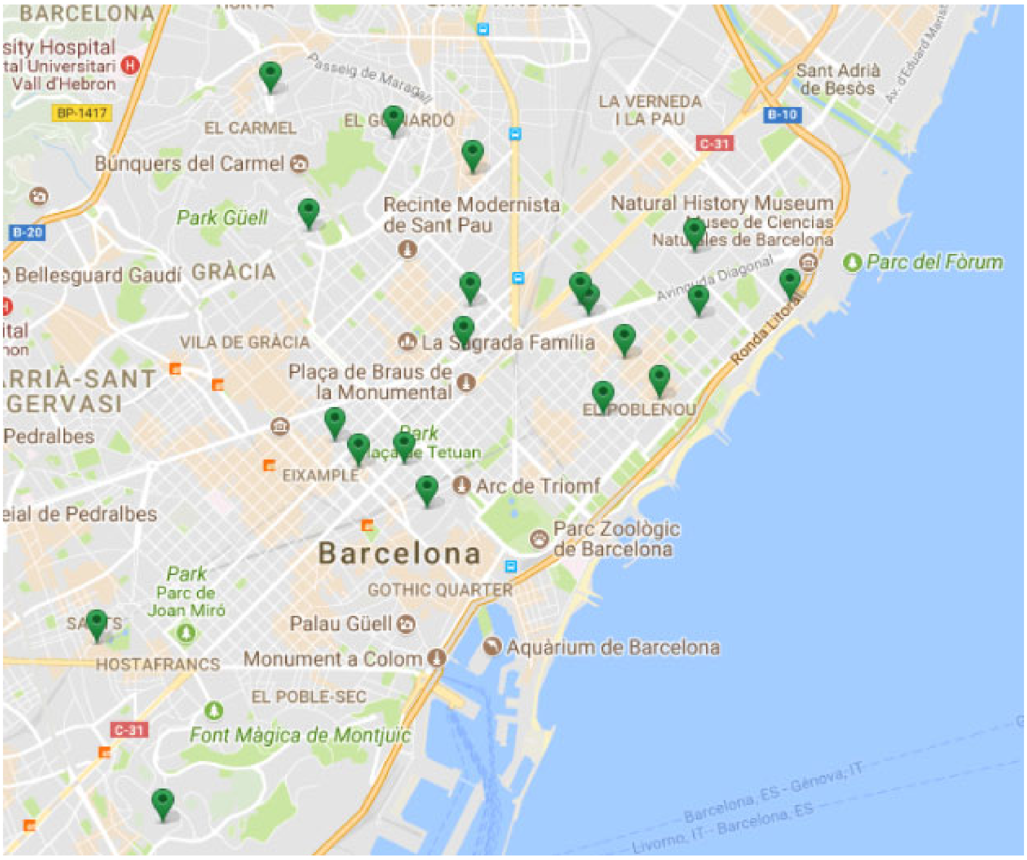

Figure 38 - Location of the base stations in Barcelona

The pilot has been deployed according to the architecture below:

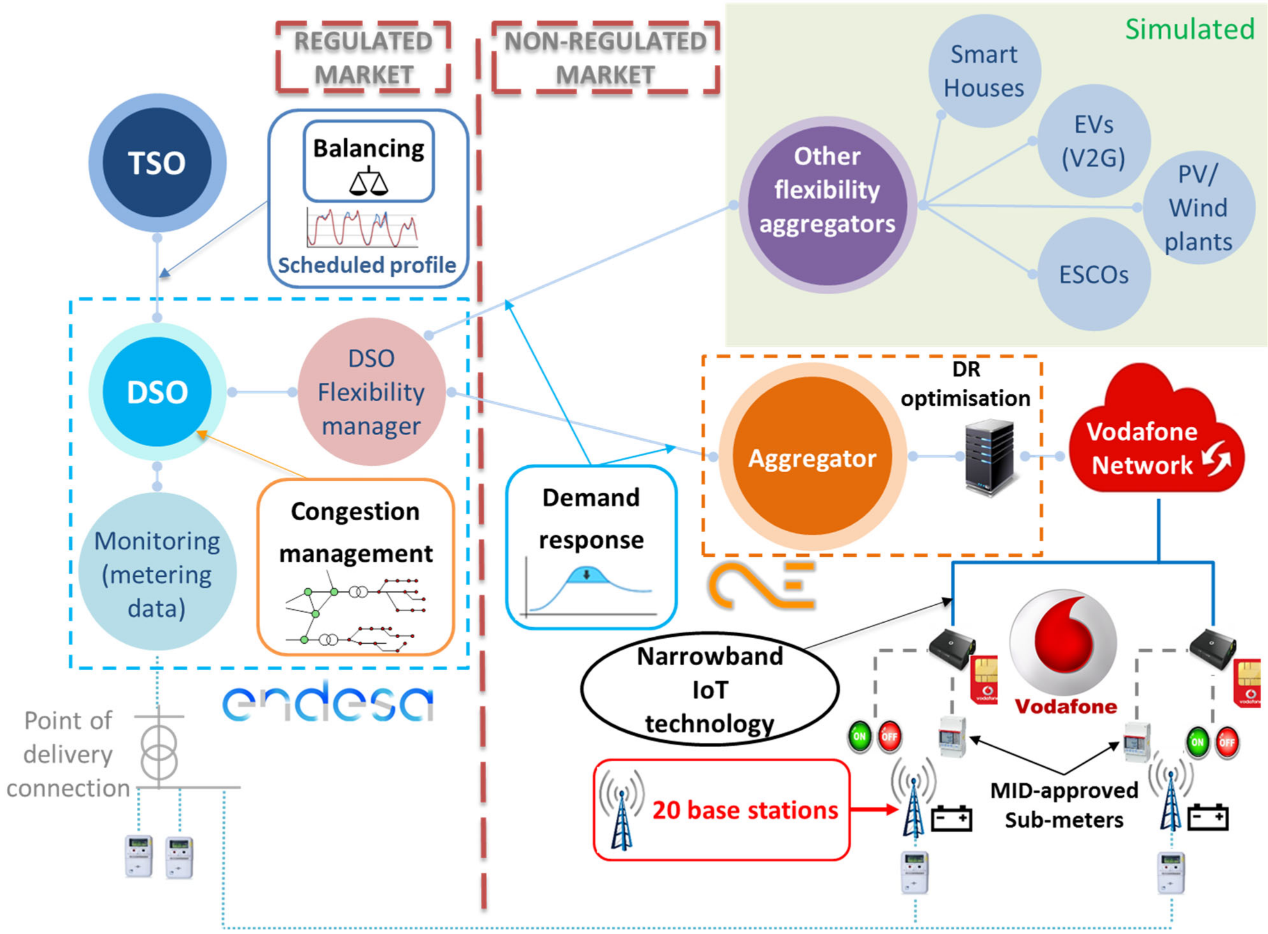

Figure 39 - General architecture of the Spanish pilot

The TSO and the DSO agree on a scheduled profile at the TSO-DSO interconnection. For the purpose of the pilot, such profile is based on historical consumption data for each of the 5 primary substations involved in the pilot. In order to ensure the fulfilment of such profile, the DSO monitors in real-time the exchanged power in each substation. In parallel, the DSO monitors the status of the distribution grid and identifies potential constraints that may arise if demand flexibility is not used. Based on the requirements arising from both the monitoring of the power exchange in the TSO-DSO interconnection and the potential constraints in the network, the DSO requests the LMO to open the local market. The LMO receives flexibility bids from CMPs, clears the market, while avoiding the creation of additional constraints in the grid and informs both the DSO and CMPs about market results. Finally, CMPs dispatch the flexibility and the DSO checks the actual delivery of the flexibility required.

The four participants in this pilot assumed different responsibilities and perform different roles:

- VODAFONE has performed the role of DER owner. A party that produces electricity via a flexible resource. The flexible resource is a unit connected to the grid that provides flexibility for one or more purposes. VODAFONE is the owner of the radio base stations.
- ONE has performed the role of CMP, aggregating local DER resources. Hence, they are responsible for selling the flexibility of the DER in their portfolio on the local market.
- ENDESA has led the pilot and has performed different roles; the first role is the TSO, this role simulates the creation of the TSO-DSO interconnection scheduled profile. Second role is the DSO, operates the distribution network in the pilot and monitors

the status of the grid, by means of the metered data management system. The third role is CMP, manages some virtual nodes emulating other CMPs participating in the local market. Finally, the last role is the LMO, plays the local market operator role at the local (distribution) level.
- TECNALIA has provided technological consultancy to Endesa when designing and implementing the overall pilot architecture. It also contributed to ensuring the consistency of the pilot with the rest of the developments in the SmartNet project and the complementarity with the other two technological pilots. Last, Tecnalia assisted ONE to develop new aggregation models for the pilot.

The LMO implements local market clearing activities and is in charge of gathering and delivering information of local market rules. The flexible resources are grouped in LAs along the distribution network. CMPs consider all these resources to offer bids. The LMO, is a modified OPF optimization model to include the market constrains. The objective is to determine the optimal activation of bid blocks among all CMPs and the clearing price is set as the most expensive matched bid (Pay-as-clear).

The objective function of the model is the minimization of the total flexibility activation cost, that is, the sum of all matched positive power bid prices for all nodes. Three main assumptions have been made:

- For each node, the model includes an active and reactive power balance constraint.
- For each line, active and reactive line power flow constraints have been stablished. Constraints have also been included to set operating limits both in voltages and flows in lines (i.e. line security limits).
- For each generator, the optimization model includes constraints on generation limits.

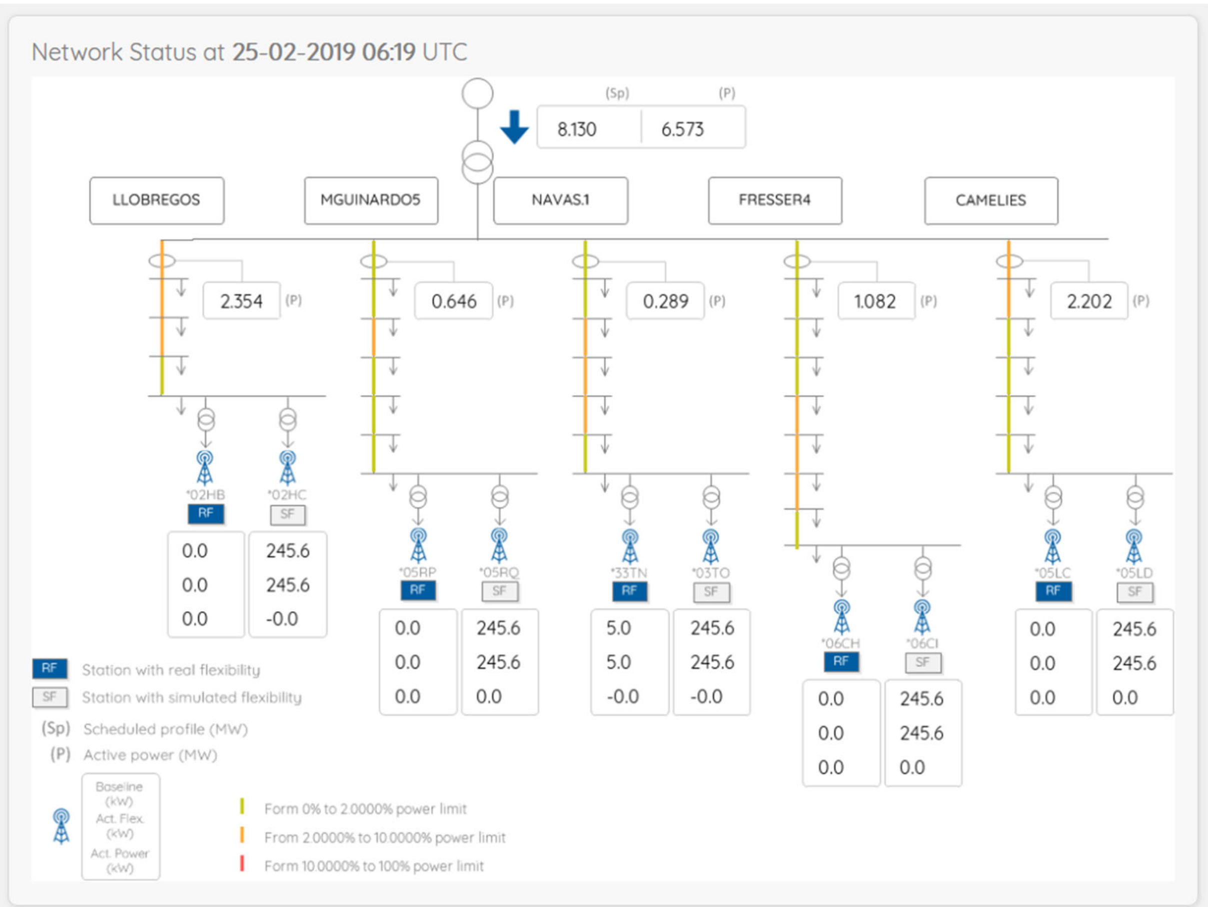

Figure 40 - Screenshot of the grid monitoring tool developed for the pilot

The market performed in the pilot has two major innovations: the time execution and the use of an OPF to clear the market. The time execution is set in 5 minutes, which is close to a real-time operation and, thus, it may provide more accuracy to balancing and to control activations. Using an OPF to clear the market allows the LMO to evaluate the technical restrictions and, at the same time, dispatch the flexibility to achieve the balancing objectives.

In addition to the innovation on the DSO-LMO side, there is an important innovation in the CMP's role to perform the monitoring, bidding and activation of a portfolio of homogenous (from the flexibility point of view) batteries in radio base-stations.

In order to fulfil these duties, the CMP needs to communicate with the rest of the parties. In particular, communications are required with the LMO for bidding and clearing, with DER for managing and activating flexibility, and (indirectly) with the DSO for real-time information of the actual load per asset to guarantee the effective provision of the traded flexibility.

Given the nature of the DERs in this pilot, a number of parameters and real-time information exchange is required between DERs and the CMP, which is performed by means of a communication between Vodafone's energy data management (EDM) system and ONE's asset gate. Furthermore, none of the aggregation model developed in the project are completely applicable to the pilot (neither the one for atomic loads because batteries will need to be recharged again after service provision, nor the battery model because it will only be used for providing upward balancing).

In order to implement the aggregation algorithm, the Aggregator has to obtain the state of charge of the battery ant the load in real time, also the CMP need other parameters like the minimum allowed state of charge and the nominal charging power. The algorithm developed for this task allows the CMP to manage the different data and communication interactions, as well as to model the potential behaviour of the different assets.

Figure 41 - Screenshot of DER monitoring tool developed for the pilot

The pilot also offered ONE the opportunity to test Vodafone's machine-to-machine technology, which aggregates a number of operational parameters from the assets in one single platform. This solution allows the CMP to communicate with an array of assets through one single communication channel, which simplifies the process significantly, as most routines and processes are already designed. Furthermore, it is worth underlying that the communication protocol and activation have led to real activations in the physical assets, thereby seriously decreasing the implementation problems and resulting in a significantly high technology readiness level (TRL) exercise.

Conclusions

Being in the forefront of technology implementation, these pilots uncovered a number of issues, ranging from regulatory (such as impeding DER to participate in the markets for ancillary services organized the TSO or having different metering requirements depending on the contracted consumption power) to technical (such as low mobile phone connectivity in remote rural areas or faulty back-up batteries, which, fortunately, never had to provide back-up power until the pilot started the testing phase) and even practical barriers (e.g. radio base stations are located in the roofs of residential buildings, so replacing their cabinets requires obtaining permission from landlords but also from municipalities, as they must be uploaded by huge cranes located in the streets).

However, the three pilots were successfully completed and resulted in a number of very important lessons learnt for the next step to be taken to deploy the concepts developed in SmartNet, which is the replication of these pilots in other regulatory environments, with different flexibility providers and at a larger scale.

9. Conclusions

It is expected that the theme of TSO-DSO coordination for acquisition of ancillary services from distributed resources, for which SmartNet has provided a pioneering work, is one of the “hot” themes of the present regulation: the first paragraph of Art. 32 in the Directive on common rules for the internal market in electricity (recast) – part of the Clean Energy for All Europeans Package, - states: “*Member States shall provide the necessary regulatory framework to allow and incentivise distribution system operators to procure flexibility services, including congestion management in their service area, in order to improve efficiencies in the operation and development of the distribution system*”.

Here some important achievements of the SmartNet project which stand as a milestone for further reflections:

- The new simulation platform developed by SmartNet, endowed by an unprecedented level of details on the three layers (mFRR market layer, physical and aFRR layer and bidding/aggregation layer)
- Comprehensive benchmark scenario at 2030 for three countries (Italy, Denmark and Spain) to allow and comparison of different TSO-DSO coordination schemes
- A cost-benefit analysis methodology to compare different TSO-DSO coordination schemes, which could be re-used in the future on other scenarios and countries
- Three physical national pilots showing concrete modalities to acquire ancillary services from distributed generation (run-of-the-river hydro power stations in the Italian pilot, thermostatically controlled loads in the Danish pilot, local storage located in radio base stations of the mobile phones networks).
- An in-depth analysis of the simulation results, which brought to the formulation of a set of regulatory guidelines.

Key findings:

The main aim of the SmartNet project is to compare different TSO-DSO coordination schemes for acquiring ancillary services from distributed resources: five coordination schemes were analysed in depth corresponding to different typologies (centralized, decentralized) and roles of the network operators (TSO and DSO), four of them were implemented in simulation and compared in their technical and economic performance on the basis of three national scenarios referred to the target year 2030 for: Italy, Denmark and Spain. Moreover, three technological pilots have investigated the main problems in implementing typical TSO-DSO coordination schemes for acquiring services from specific typologies of distributed resources (hydro power stations for the Italian pilot, thermostatically controlled loads for the Danish pilot, storage units located in radio base stations of mobile networks for the Spanish pilot).

Main findings can be summarized in the following eleven points:

- **Traditional TSO-centric schemes could stay optimal if distribution networks don’t show significant congestion** not unlikely in near-future scenarios, since distribution grid planning was (and still is) affected by the fit-and-forget reinforcements policy. In a first period, costs to implement monitoring and control systems within distribution networks could result higher than the effect of over-investments inefficiencies due to the old fit and forget philosophy. This could engender resistance in some DSOs to consider flexibility as a value. This could also call for a revision of present remuneration schemes for DSOs’ investments, so that they can claim OPEX and not only CAPEX.

- **More advanced centralized schemes incorporating distribution constraints show higher economic performances but their performance could be undermined by big forecasting errors**, which could bring them to take wrong decisions. As distributed generation, constituting a good share of the possible service providers in distribution, is mainly composed by RES generation (e.g. PV power plants, mini-hydro…) it is important that the gate closure is shifted as much as possible toward real time and forecasting techniques are improved. Such techniques can be better for some generation technologies (PV) but much worse for others which are strongly influenced by local factors (mini-hydro).

- **Technical reasons and high ICT costs dis-advise to give balancing responsibility to DSOs.** Nonetheless, the sheer economic performance of such shared responsibility schemes is not always bad (sometimes separating transmission and distribution markets could prevent high prices in one area to be spread to the other).

- **Decentralized schemes are usually less efficient than centralized ones** because the two-step process introduces undue rigidities. Scarcity of liquidity and potential impact of local market power, along with extra constraints introduced to avoid counteracting actions between local congestion market and balancing market (e.g. increasing system imbalance while solving local congestion) furthermore negatively affect economic efficiency of decentralized schemes.

- **Decentralized schemes request to put in place further coordination actions between TSO and DSO:** resources which are bid in both sequenced markets should not be selected twice (a **"common marketplace"** mechanism should be implemented).

- **Local congestion markets should have a "reasonable" size and guarantee a sufficient number of actors are in competition** in order to prevent scarcity of liquidity and exercise of local market power. For that, **small DSOs should pool-up** in order to create a common congestion management market: too many small local markets would increase ICT costs and reduce competition, with detrimental effects.

- **Intraday markets should bring gate closure as close as possible to real time. However, it is not feasible to overlap a real-time session of intra-day market with a services market**: this solution would create uncertainty in the operators (TSO and DSO) in charge of purchasing ancillary services because they would be no longer sure of how many resources are needed (i.e. the real amount of congestion and imbalance). For this reason the fifth coordination scheme ("*Integrated flexibility market model*") is strongly dis-advised.

- **Balancing and congestion markets should have as target not to optimize system social welfare (that is, by contrast, the goal of energy markets) but just to buy the minimum amount of resources to get the needed ancillary services while perturbing the least possible the results of the energy markets.** This advises against allowing the award of sets of balanced upward and downward bids just to reduce total costs (**"market arbitrage"**) even whenever this could reduce total system costs.

- **Ensuring level playing field in the participation of distributed resources (especially industrial loads) to the tertiary market means to be able to incorporate into the market products some peculiarities of such resources** (loads or generators) without which it is nearly impossible for them to participate. This could imply to enable complex bids or other sophisticated products.

- **Reaction to commands coming from TSO or DSO in real time of the control loops which were initially planned for real time services provision can be too slow.** So, a testing is needed to ensure compatibility with requested reaction times.

- **ICT costs are nearly never an issue**: independent of the implemented TSO-DSO coordination scheme, the economic performance depends by wide and large on operational costs. For all coordination schemes, ICT costs stay one order of magnitude lower than operational costs.

10. Appendix – Ancillary services in selected Countries

In addition to providing information on the main results obtained by the SmartNet project, the present report wants to include some information on the status quo of the procurement of ancillary services in selected countries. On this, some details referred to a few EU Countries are provided in the report D1.1 of the SmartNet project, which can be downloaded from: http://smartnet-project.eu/wp-content/uploads/2016/12/D1-1_20161220_V1.0.pdf

However, with the ides of extending the enquiry to several extra-EU Countries and to compare all responses on the same basis, a questionnaire was formulated and distributed among the members of ISGAN Annex VI. The questionnaire contained the following questions:

- **What system services are provided in your country (voltage regulation, frequency regulation, inertia, support to power quality…)**
- **Who is providing them (generators and/or loads?)**
- **Modalities to collect ancillary services: via markets, contracts, compulsory non-paid services… Please describe in detail.**
- **Are generators and/or loads located in distribution admitted to provide system services? If yes, how is TSO-DSO interaction carried out (please describe in detail)**
- **Are there plans from the national regulator to activate demand side management or to collect inputs from generators connected to distribution for the future? Which timeframe? Are pilot projects already active?**

Answers were received from the following Countries:

- Austria
- Belgium
- France
- Sweden
- Canada
- South Africa

The following tables synthetize the received responses.

10.1. Austria

System services	Voltage	Frequency	Inertia
Description	The transmission grid is typically seen to be highly stable and thus the influence of distribution connected generation is minimal. The network contains inherent voltage regulation available for the regulation of generation synchronous generators. Furthermore, when reactive power flows exceed the defined limits, the DSO is requested to take the necessary measures. The changing of transformer tap position of the transmission-distribution transformer is often seen as common practice. This is achieved by coordination between the two control rooms (TSO and DSO) by manual operation. An automated process is possible; however, it is currently not widely implemented.	The TSO uses flexibility for system balancing purposes: frequency containment reserve (FCR), automatic frequency restoration reserve (aFRR) and manual frequency restoration reserve (mFRR).	Since the Austrian network is connected to the Continental Europe power system, significant inertia concerns are not identified. However, as the EU foresees a decrease in the future network condition, there is an initiative to explore FCR via inverters and other new products that may appear in the market
Who is providing them (generators and/or loads?)	Selected loads & Generators	Generators Loads can participate	Generators
Modalities to collect ancillary services	This is defined in the network connection codes (ENTSOE's network code on requirements for grid connection of generators and Network Code on Demand Connection and is integrated in the national regulatory framework.	The policy and regulatory processes is based on a technical prequalification process performed by the TSO. The framework conditions are defined by the national TSO APG Austrian Power	The process follows an approach similar to the one for the prequalification methodology for balancing energy, however it is currently in the process of being fully defined.

		Grid in line with the *ENTSO-E Operation Handbook, Policy 1*. Once the Framework Agreement has been concluded, the tendering process follows.	
Are generators and/or loads located in distribution admitted to provide system services? If yes, how is TSO-DSO interaction carried out (please describe in detail)	Transformer tap changers Batteries (during emergency conditions) Electric-cars (during emergency conditions) Customers connected in close proximity to substations No direct DSO-TSO interaction	Loads are allowed to participate and no size limits apply. Therefore, no technical barriers exist that hinder the participation of aggregators. The DSO is involved in the prequalification process by the aggregator of flexibility who need a contract with the DSO. During this process the DSOs can intervene should they fear that it impacts them negatively.	Still to be discussed
Are there plans from the national regulator to activate demand side management or to collect inputs from generators connected to distribution for the future? Which timeframe? Are pilot projects already active?	**DSO voltage regulation projects:** **Project:** Leafs (in progress**)** **Project:** DGDemoNET (completed)	**Project:** Flex+ (ongoing) **Project:** Hybrid-VPP4DSO (completed) **Project:** InteGrid Demo in Portugal and Slovenia (in progress) **Project**: Leafs (in progress)	**Project:** ABS4TSO (in progress)

10.2. Belgium

System services	Voltage	Frequency	Black Start
Description	Under the Federal Grid Code, generators with units exceeding 25 MVA have to contribute to the generation and absorption of reactive power to maintain the voltage level within the required range (automatic control). To increase flexibility, The TSO contracts from generators a positive and negative control band for each unit (centralized control). If the system has a high load, the TSO asks for extra MVArs to be generated, whereas when the load is low, it resorts to the absorption of MVArs. Since reactive power cannot be transmitted over long distances, the TSO bases its choice of the units participating in this service on their location. The Belgian TSO Elia contracts some 6300 MVAr of generation capacity and 3200 MVAr	<u>Primary frequency control (0-30 sec) – Frequency Containment Reserve (FCR, ex-R1)</u> The objective of primary frequency control is to maintain the balance between generation and consumption within the high-voltage European interconnected system. A deviation of this balance will lead to a deviation in the frequency which will automatically trigger the contracted primary reserves to be activated. The volume of the primary reserve is set by the European Network of Transmission System Operators for Electricity (ENTSO-E). The global reaction of primary reserves set forth by the ENTSO-E regulations must be a symmetrical and linear activation with a total activation at a frequency deviation of +-200mHz. However in order to allow different types of flexibility (generation, load) to participate in primary reserves, the TSO sources different service types who react at different frequency deviations. Together these service types will deliver the product required by ENTSO-E: • FCR symmetrical 200mHz: this product is activated between -200mHz and + 200mHz, whereas the total contracted volume must be activated at the most extreme bands of the frequency interval. • FCR symmetrical 100mHz: this product is activated between -100mHz and +100mHz, whereas the total contracted volume must be activated at the most extreme bands of the	In line with its obligations, The Belgian TSO Elia makes sure it can restore its grid in the event of a blackout. It does this by using generation units that can start up without an external electricity supply.

	of absorption capacity. The contracts have a period of one year.	frequency interval. This maximum contracted volume must however also remain activated for frequency deviations between [-200mHz,-100mHz] and [100mHz, 200mHz]. • FCR upwards: this product is activated between [-200mHz, -100mHz], whereas the total contracted volume must be activated at -200mHz. • FCR downwards: this product is activated between [100mHz, 200mHz], whereas the total contracted volume must be activated at 200mHz. <u>Secondary control (30 sec - 15 min) – R2</u> The TSO also has a symmetric secondary reserve it can activate to balance its own grid, which is procured from Belgian generators located on the transmission grid. These reserves are activated based on a set point that is sent continuously to the supplier. <u>Tertiary control with reserved volumes (15 min) – (R3 Std/R3 Flex)</u> The TSO also procures tertiary reserves from Belgian generators as well as load connected to the TSO and DSO grid. Tertiary control reserves (as materialized in different products) are activated manually upon reception of a signal by the TSO. Activations of the tertiary reserve vary through the year, depending on incidents and congestion on the grid. These services are activated within 15 minutes from reception of the signal by the TSO. <u>Tertiary control with non-reserved volumes – (R3 Non-Reserved)</u> As of July 2017, non-CIPU generation (type of contract,	

		see later for explanation) and load can offer non-reserved power volumes to the TSO. The offered volumes are submitted through the BMAP (Balancing Market Platform) web platform. Suppliers are activated by the TSO in case of need and are only remunerated for the provided energy (and not for their availability). When activated by the TSO, the Supplier should activate the offered volume as soon as possible within a margin of 15 minutes.	
Who is providing them (generators and/or loads?)	Voltage control and black start services are exclusively for generators due to its technical nature.	The balancing services are delivered by generators and loads. The loads deliver only upward reserves, besides the classic ICH (Imputed Curtailment Hour) systems, aggregators are providing more flexibility within these services and can so deliver also primary, secondary and tertiary reserves.	
Modalities to collect ancillary services Ancillary services have to be offered in blocks of 1MW for the primary, secondary or tertiary reserves. The TSO has a special type of contract called CIPU (Coordination of the Injection of the Production Units)	The contract for the service MVAR gives two price rates: a fixed rate to remunerate one-time expenses (IT implementation, technical adaptations to the unit to expand the technical band) and an activation price remunerating the produced and absorbed reactive energy providing	<u>Primary frequency control (0-30 sec) – Frequency Containment Reserve (FCR, ex-R1)</u> All of these service types can be offered from CIPU & non-CIPU generation or load resources. All FCR symmetric & asymmetric products are offered in a weekly tendering. The TSO also procures part of its FCR volume (only the 200mHz symmetric service type) from a regional platform common with TSO's from Germany, Austria, the Netherlands, Switzerland, France and Denmark. Volumes for a certain delivery period are procured in	Black-start contracts are signed for a number of years with Belgian generators that have such facilities. The supplier receives a fixed payment for supplying this service, regardless of whether it is activated or not. The participating units have to meet certain technical criteria regarding e.g. power (at least 100 to 200 MW depending on

contract. CIPU is a type of contract which ensures that the TSO always has the necessary generating facilities at its disposal. The CIPU contract provides a framework for activating capacity not used by generators (and complements R1-R2-R3 reserves). It is also the basic agreement for providing and activating ancillary services (primary, secondary, tertiary reserves, voltage control and black start). Production units that have a nominal capacity of over 25 MW and/or are directly connected to the transmission grid must sign a CIPU contract with the TSO. This is a statutory obligation. Production units not directly connected to the transmission grid but which are liable to seriously affect it (congestion, voltage,	a minimum level of MW injection by the concerned unit. Penalties are applied in case the automatic or centralized control are not well executed.	two stages: first, an auction held in the local platform held in W-2 before start of the delivery period and afterwards in an auction of the regional platform in W-1 before delivery period. The volume procured on the regional auction is variable and decided each week as a result of the financial optimization of the local auction. In the local platform auction the FCR symmetric products can be offered in a combined way with the asymmetric R2-products. The TSO remunerates the supplier for making the capacity 100% of the time available. <u>Secondary control (30 sec - 15 min) – R2</u> Although the TSO is looking for the same amount of upwards as downwards secondary reserves, the TSO foresees the possibility to offer separately upwards and downwards volumes. All R2-symmetric & asymmetric products can be offered via a weekly tendering as of August 2016. R2-asymmetric-products can be offered in a combined way with the symmetric R1-product. <u>Tertiary control with reserved volumes (15 min) – (R3 Std/R3 Flex)</u> The TSO procures the R3 Standard and R3 Flex who are offered by CIPU and non-CIPU demand or generation technical units alike. Both TSO- as DSO-connected non-CIPU generation or load are able to participate in the month-ahead tendering.	the case) and grid restoration time. The units are selected on the basis of cost (total cost and relative cost vis-à-vis power) and their location. They must also be able to operate smoothly at any time, and therefore regular tests are carried out. They are paid for and penalties are imposed if they are not passed.

short-circuit power, etc.) may also be required to sign this type of contract in accordance with the Grid Code.			
Are generators and/or loads located in distribution admitted to provide system services? If yes, how is TSO-DSO interaction carried out (please describe in detail)	Yes, any user connected to the distribution grid can offer ancillary services to the DSO or the TSO. The DSO drafts the technical requirements for the ancillary services and has to submit them to the regional regulatory authority for approval. (Note: In Belgium the grids at a voltage above 70kV are subject to national legislation and the NRA, the grids at a voltage level of 70kV or below are subject to regional legislation and the regional regulatory authority). The services offered are also subject to the requirements determined for the transmission grid. The DSO can only refuse the delivery of ancillary services for reasons of operational security. Such a refusal has to be motivated by the DSO. The basic technical requirements of a connection between DSO and TSO are described in legislation on regional and national level. Other requirements and more details are described in the collaboration agreement between TSO and DSO. The TSO needs to collaborate with the DSO's when elaborating the procedures for the ancillary services provided by users of the distribution grid.		
Are there plans from the national regulator to activate demand side management or to collect inputs from generators connected to distribution for the future? Which timeframe? Are pilot projects already active?	Demand side management can deliver already some services to the tertiary reserve (mFRR). As these services are more related to the distribution grid, regional regulatory authorities have to regulate this. The TSO has already drafted a new structure in line with the European network codes, which define a list of requirements to have the market ready for new products like these. This whole system has to be enabled the coming years. The Belgian TSO, Elia, is proposing new products and adjusting existing balancing products to incorporate DSM in the balancing services.		

10.3. France

<table>
<tr><th>System services</th><th>Voltage</th><th>Frequency</th><th>Inertia</th></tr>
<tr><td>Description</td><td><u>Primary voltage control</u>
The rapid and random voltage variations are compensated by local primary and automatic actions. For conventional generators, the ancillary service relies on the generators AVRs.

There are conditions for renewables as well:
For VRES connected to the HV distribution grid[10] before 2016, a reactive power or a tan(phi) = Q/P is required.
For VRES connected to the HV distribution grid[10] after 2016, or to the transmission grid the reactive power control loop is set up to feed reactive power into the network proportionally to the voltage difference at the connection point.
It is a "compulsory non-paid service", legally imposed on</td><td><u>Primary frequency control (FCR)</u>
The share of FCR to be supplied by the French system amounts to about 540 MW. All power plants over 120 MW must legally be able to technically provide FCR, but units participate is on a voluntary basis.

This service may legally be provided by all technologies meeting the prescribed technical requirements (including VRES). In practice, most of it comes from conventional generation units, although some industrials are active.

Since 2016, the FCR market has been opened to asymmetric up/down frequency control providers, in order to foster demand side participation. Base units, which might benefit from this new feature as well (to avoid opportunity costs), have not made the switch yet, apparently for technical historical reasons.</td><td>As of now, inertia is not considered in France as an ancillary service, whose supply would entitle market players to receive a remuneration.</td></tr>
</table>

[10] The French HV distribution grids are usually operated at 20 kV.

	generation units, be they renewable or conventional, under penalty of a fine. Secondary voltage control The slow voltage variations are regulated by the secondary (or regional) level. A local voltage index is calculated on a relevant point of the network, and then sent to units connected to the transmission grid[11] and belonging to an electrically consistent area: • Depending on this voltage index, conventional participating units are requested to feed in more or less reactive power (adjustment of rotor excitation current). • As for VRES participating units, their voltage set point is altered. It is a "compulsory non-paid service", legally imposed on generation units, be they renewable or conventional, under penalty of a fine.	Since January 2017, the FCR has been procured via a weekly call for tenders, run jointly by RTE and its German, Austrian, Belgian, Dutch and Swiss counterparts. On that market, the offered capacity is paid-as-cleared. The provider's revenue is complemented ex post by a (low) energy remuneration. Secondary frequency control (aFRR) RTE is in charge of determining, on an hourly basis, the French aFRR requirement (which remains in practice between 500 and 1180 MW). All power plants over 120 MW must legally be able to technically provide aFRR, but the total requirement is parted among portfolios proportionally to the installed capacity. This service may legally be provided by all technologies meeting the prescribed technical requirements (including VRES). In practice, most of it comes from conventional generation units. Since 2016, the aFRR market has been opened to asymmetric	

[11] The TSO is responsible for the VHV grid starting from the 63 kV level.

		up/down secondary frequency control providers, although market players do not seem to use this new opportunity yet. The remuneration rate is fixed, although there exists a small energy remuneration.	
Who is providing them (generators and/or loads?)	See above.		
Modalities to collect ancillary services			
Are generators and/or loads located in distribution admitted to provide system	For historical reasons, the French system encompasses a major DSO (ENEDIS) and a large number of small local distribution companies. <u>Focus on ENEDIS</u> 387.6 TWh were feed into the distribution grid of ENEDIS in 2016[12] in order to supply:		

[12] Figures given in this section come from the following sources:

- ENEDIS Opendata http://www.enedis.fr/open-data
- Bilan ENEDIS http://www.enedis.fr/sites/default/files/Enedis_Chiffres_cles_2016.pdf

services? If yes, how is TSO-DSO interaction carried out (please describe in detail)	• 35 million residential and small office customers[13] (LV, power ≤ 36 kVA): • around 473 000 industrial and business customers (MV, power ≥ 36 kVA): The distribution grid operated by Enedis encompassed 1.34 million km of lines in 2017: • MV overhead lines 326 712 km • MV grounded lines 312 580 km • LV overhead lines 393 960 km • LV grounded lines 323 130 km 2 260 substations were interfacing the distribution and transmission grids. At lower voltage level, 783 262 MV/LV substations were in place. LV and MV grid are operated unmeshed (one single electric circuit in operation at a time), but many branches (especially is urban areas) are equipped with switches at each of its ends, so that the branch might be switched from one feeder to the other in case off fault (after opening of the necessary circuit breakers to isolate the faulty line section). The average power outages duration was 64 minutes per customer (not including load shedding related to the transmission grid). <u>Focus on Local Distribution Companies (LDCs)</u> The number of LDCs amounts to more than 150. 23.2 TWh were feed into the distribution grid of the LDCs in 2012, in order to supply 1.8 million industrial, business, small office and residential customers[13]. The distribution grid operated by the LDCs encompassed 75 000 km of lines in 2012: • HV lines 1 200 km • MV overhead lines 19 764 km • MV grounded lines 16 836 km • LV overhead lines 19 396 km • LV grounded lines 17 904 km

[13] 1 customer = 1 connection contract = 1 meter.

	The LDCs operate more than 41 000 substations. <u>Ancillary services provided by generators and/or loads connected to the distribution grid</u> Generators and/or loads located in distribution admitted to provide system services. As of now, the activation for balancing purposes of flexibility sources connected to the distribution grid does not seem to create major additional constraints for the DSOs. Activation for balancing purposes is currently handled by the DSO as an additional uncertainty in the network planning stage. The increasing share of decentralized VRES is likely to alter this picture in the future.
Are there plans from the national regulator to activate demand side management or to collect inputs from generators connected to distribution for the future? Which timeframe? Are pilot projects already active?	<u>Generation and storage unit register</u> Generation and storage units connected to the distribution grid are listed in a national register completed by the DSOs, and communicated to the TSO: • Every month for DSOs with more than 100 000 customers. • Every semester otherwise. RTE is responsible for publishing regularly these data in an aggregated and anonymized form. <u>Certified capacity register</u> In order to set up the national register for certified capacity (capacity mechanism), DSOs are responsible for collecting and sharing with the TSO data enabling the certification by the TSO of the generation units connected to the distribution grids: • Power levels which can be activated • Load curves

The table below sums up the main data exchanged (or that probably will be in the future) between the TSO and DSOs and their purpose.

Data	Purpose	Issuer <-> Recipient	Currently (c)/Likely (l)
Available power, historical load curves: - Aggregated for production capacities of less than 100 MW.	Certification Register for capacity mechanism	DSOs -> TSO	C

- Individual for production capacities of more than 100 MW.			
Capacities (Power) to be certified are sent to the relevant grid operator	Capacity mechanism	Operator -> DSO/TSO	C
Real capacities available on the distribution grid Data needed to compute the real capacity available	Capacity mechanism	DSOs -> TSO TSO -> DSOs	C
Suppliers obligations for the capacity mechanism	Capacity mechanism	DSOs -> TSO	C
Storage and production capacities: - Monthly for DSOs with more than 100,000 clients - Biannually for others	Energy policy implementation monitoring	DSOs -> TSO	C
Historical production and storage curves if available for each unit	Adequacy forecast	DSOs -> TSO	C
Monthly load aggregated by department and industrial sector	Adequacy forecast	DSOs -> TSO	C
Electricity flows by city and by injection substation, or influence factors	Adequacy forecast	DSOs -> TSO	C
Day ahead Call Schedule of distribution grid units if participating to the balancing market with implicit orders	Grid operation	Unit -> TSO	C
Day ahead Call Schedule of distribution grid units if participating to the balancing market with standard orders	Grid operation	Unit -> TSO	L

Day ahead Aggregated (granularity to be defined) Call Schedule of distribution grid units not participating to the balancing market	Grid operation	1st level DSOs -> TSO	L
Intraday aggregated (granularity to be defined) Call Schedule changes or forecasts of distribution grid units[14]	Grid operation (take into account renewable energy sources variations)	1st level DSOs -> TSO	L
Monthly estimations of the influence on the transmission grid of offer activations from the distribution grid	Grid operation	DSOs -> TSO	C
Injection limitations stated by the TSO on distribution grids	Grid operation	TSO -> DSOs -> units or TSO -> units	L
Offer activations by the TSO with an impact on the distribution grid or vice-versa	Gird operation	TSO <-> DSOs	L

[14] In a centralised case, the first level DSO sums the call schedules and forecasts from units directly connected to its grid and from lower level DSOs (cascading principle) on the day ahead. Updates are then also summed and sent before each intraday gate closure time.

If data is not automatically centralised by the top level DSOs, it is different to consider that producers keep a unique deadline to transmit their programs to whatever grid operators (TSO or DSOs) or to have only a deadline for the TSO submission meaning that programs must be provided beforehand to the DSO.

10.4. Sweden

System services	Voltage	Frequency	Inertia
Description	Provided by generators (compulsory unpaid service) and reactive power equipment (owned by the TSO Svenska kraftnät, SVK)	Frequency regulation: provided by any unit fulfilling requirements (via market and through contracts - Details: https://www.svk.se/en/stakeholder-portal/Electricity-market/information-about-reserves/ Frequency Containment Reserve SVK procures two FCR services: FCR-N (Frequency Containment Reserve – Normal) and FCR-D (Frequency Containment Reserve – Disturbance). FCR-N responds to frequency deviations within 49.9-50.1 Hz, and FCR-D to deviations below 49.9 Hz. Both are procured through bid-based markets, with pay-as-bid remuneration. Frequency Restoration Reserve SVK procures two FRR services: aFRR (automatic Frequency Restoration Reserve) and mFRR	Unpaid service from synchronous generators. There is no explicit market for inertia.

		(manual Frequency Restoration Reserve). aFRR is activated automatically through a central control signal, and mFRR is activated manually. aFRR capacity is procured through a weekly market and remunerated with pay-as-bid. mFRR is based on marginal pricing for activated reserves.	
Who is providing them (generators and/or loads?)	Both generators and loads can provide frequency regulation services. In practice, most services are provided by hydroelectric generators.		
Modalities to collect ancillary services	See comments above		
Are generators and/or loads located in distribution admitted to provide system services? If yes, how is TSO-DSO interaction carried out (please describe in detail)	Separate connection agreements, often with zero reactive power exchange + demanded to be able to regulate within certain interval	Yes, resources at the distribution level can participate in reserve markets, provided that they meet the requirements. Smaller resources can be aggregated into groups and submit bids for the group as a whole.	

Are there plans from the national regulator to activate demand side management or to collect inputs from generators connected to distribution for the future? Which timeframe? Are pilot projects already active?	• **Demand response pilot with Fortum:** https://www.svk.se/siteassets/om-oss/rapporter/2018/final-report-pilot-project-in-demand-response-and-energy-storage.pdf • **Part of the newly started H2020 project: CoordiNET -** https://www.svk.se/om-oss/press/Nytt-samarbete-for-smartare-anvandande-av-elnatet---3243407/ The Swedish NRA Energimarknadsinspektionen has conducted a comprehensive review of potential measures for increased demand flexibility in the Swedish electricity system. The report (in Swedish) is available here: https://www.ei.se/Documents/Publikationer/rapporter_och_pm/Rapporter%202016/Ei_R2016_15.pdf This report outlines a set of perceived obstacles for activation of demand side flexibility, and a suggested action plan for how to overcome such obstacles. Examples of obstacles discussed in the report are the lack of interest and/or knowledge among end-users, the limited services available for end-users who wish to be flexible, as well as regulatory considerations.

10.5. Canada

Description	System services (bulk system) are generally composed of frequency response, regulation, spinning reserve, non-spinning reserve, replacement reserve, reactive support, black start. Of Canada's ten provinces, two have deregulated electricity markets (Alberta and Ontario); the rest are predominantly composed of vertically integrated utilities. In the deregulated markets, energy is traded on the real-time market (with day ahead considerations) and in Ontario, both supply and demand can participate (via double-sided auction). Additionally, in these markets some ancillary services (mainly reserves) are also acquired through the market while others are contracted. Regarding balancing and congestion management, Ontario's market uses system-wide pricing and settles assuming no congestion; following, generators may be curtailed (but still paid) and others dispatched to manage any congestion; new solutions, including locational pricing, are being considered. In Alberta, a different solution, composed of transmission must run and dispatch down mechanisms, is used.
Who is providing them (generators and/or loads?)	Generally, generators. However, some system operators (particularly in the deregulated markets of Alberta and Ontario) are exploring the use of non-generation resources (e.g., storage and load) to provide services such as regulation or reserve.
Modalities to collect ancillary services	In deregulated markets, collection can be by sub-hourly, daily or annual bid, RFPs (request for proposals), contract, or compulsory, depending on the system, service, and provider. In vertically integrated (non-market) systems, explicit costs for these services may be just seen as part of 'running the system'; referring to provincial open access transmission tariffs may provide some additional insight.
Are generators and/or loads located in distribution admitted to provide system services? If yes, how is TSO-DSO interaction carried out (please describe in detail)	Generally speaking, no, distributed resources do not provide bulk grid services. However, this possibility is a topic of conversation with some utilities and operators (but mechanism would differ on type, i.e., market or vertically-integrated). Canada does not at the moment have any DSO's as common in Europe; here, local distribution companies both own and operate their assets/territory.
Are there plans from the national	Canada's national regulator (NEB) does not have jurisdiction over intra-provincial electricity matters. Generally speaking, there is an awareness that distributed energy resources will likely play a greater role on future electric grids, and pilot

regulator to activate demand side management or to collect inputs from generators connected to distribution for the future? Which timeframe? Are pilot projects already active?	projects and explorations looking at such are already in progress. See, for example, PowerShift Atlantic (http://www.powershiftatlantic.com/) , Summerside (https://ieeexplore.ieee.org/document/8064615/), IESO ETNO (http://www.ieso.ca/en/Learn/Ontario-Power-System/etno/etno-Meetings).

10.6. South Africa

Description	South Africa implements voltage regulation (VR), frequency regulation (FR) and quality of supply via a combination of mechanisms. These include a recent rollout of a wide area measurement system (WAMS) based on phasor measurement units (PMUs) and automated generation control (AGC) at Generation Plant (Gx) including Hydro Storage and Peaking Plant such as Gas Turbines. There are also tap changers and capacitor banks at Transmission Plant (Tx). The system Operator is dependant on a load forecasting team. In depth research is being conducted in collaboration with WITS University on inertia based on the PMU data collected thus far.
Who is providing them (generators and/or loads?)	Besides the internal service quality of supply (QoS) mechanisms on both generation and load side: Independent Power Producers can supply extra generation when needed (<2GW) and load can be managed via demand management agreements between the utility and agricultural, commercial and industrial customers. For instance Large Power Users (LPU) such as smelters contribute to system balancing. At this stage large scale load control via smart meters is inhibited by the low footprint of smart meters in South Africa.
Modalities to collect ancillary services	South Africa lacks the heavily interconnected situation evident in Europe such as Sweden with dedicated frequency reserve markets and several Transmission System Operators (TSOs) and Distribution System Operators) DSOs competing for market share since there is currently only one major vertically integrated utility in South Africa. Thus, most of the services provided in South Africa are enforced by regulations, e.g. Eskom Standards, Grid Code and the National Energy Regulator of South Africa (NERSA). This should enforce safety and QoS and similar services (thus unpaid). The cost of implementation is embedded in standard revenue streams. These revenue streams include pre-paid and post-paid billing and tax-based budget allocation, but there exist local government issues such as municipalities with severe non-payment issues reaching figures to the value of $1.5 Billion in debt. There are cross-border tie-lines but agreements are not such that there had developed the large scale markets such as those in play in Europe.
Are generators and/or loads located in distribution admitted to provide system services? If yes, how is TSO-DSO interaction carried out (please describe in detail)	There are no heavily competing TSO-DSO players in play as of yet and both the Transmission Line Division (Tx) and Distribution Line Division (Dx) of Eskom still forms part of an integrated business model and in combination contribute to provided services. Distributed Generation will be a part of our future business. It has started with internally owned and operated Renewable Plants (e.g. Hydro storage and generation, Sere Wind

	Farm), Microgrids and Residential PV systems and the external Independent Power Producers.
Are there plans from the national regulator to activate demand side management or to collect inputs from generators connected to distribution for the future? Which timeframe? Are pilot projects already active?	The Utility (Eskom) has always driven demand side management (DSM) and notified maximum demand (NMD) to curtail the peak demand and manage the system with initiatives per MWh saved or deferred.