

# TSO-DSO COORDINATION FOR ACQUIRING ANCILLARY SERVICES FROM DISTRIBUTION GRIDS

MAY 2019

**THE SMARTNET PROJECT FINAL RESULTS**

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691405





# Contents

Key Findings .....	4
Executive Summary .....	6
Introduction to Project Motivations and Consortium .....	9
Five TSO-DSO Coordination Patterns .....	12
Network and Market Models .....	17
ICT Requirements .....	22
Scenarios and CBA .....	26
Regulatory Analysis .....	31
Three Technological Pilots .....	34
Wrap-up and Way Forward .....	49
List of Project Deliverables .....	51

# 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:

**1. 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.

**2. 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 services 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).

**3. 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).

**4. 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.

5. **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).
6. **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.
7. **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 network 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 this coordination scheme is strongly dis-advised.
8. **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 network 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.
9. **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.
10. **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.
11. **ICT is nearly never an issue:** whatsoever TSO-DSO coordination scheme is implemented, 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.

# 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)<sup>1</sup>. 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 is to develop an *ad hoc* simulation platform which models all three layers (physical network, market and bidding), analysing three national cases (Italy, Denmark, Spain). Subsequently, this simulation platform will be scaled to a full replica lab, where the performance of real controller devices and ICT will be tested.

The consortium, under technical and administrative management by RSE<sup>2</sup>, 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 system 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 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

<sup>1</sup> 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.

<sup>2</sup> Ricerca sul Sistema Energetico: <http://www.rse-web.it>



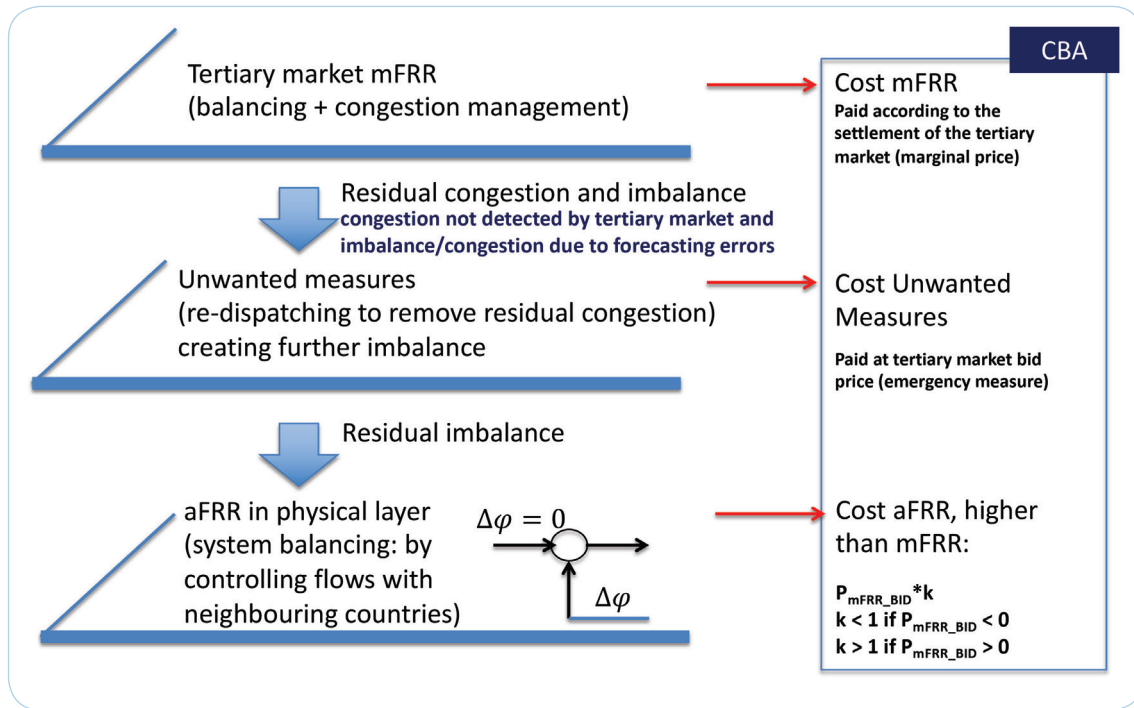


Figure 1 – The cost-benefit analysis approach of SmartNet

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).

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 costbenefit analysis with the following indicators (see figure 1) :

- 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” actions and supposed paid at mFRR market bid price.
- ICT deployment costs.

The last two indicators proved negligible wrt the first two. So, 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<sub>2</sub> emissions is an additional non-monetized monitored factor.

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.



# Introduction to Project Motivations and Consortium

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 retrieve 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.

Sets of bids aggregating availability coming from distributed generation, especially if integrated with local storage (VPPs), 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 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:

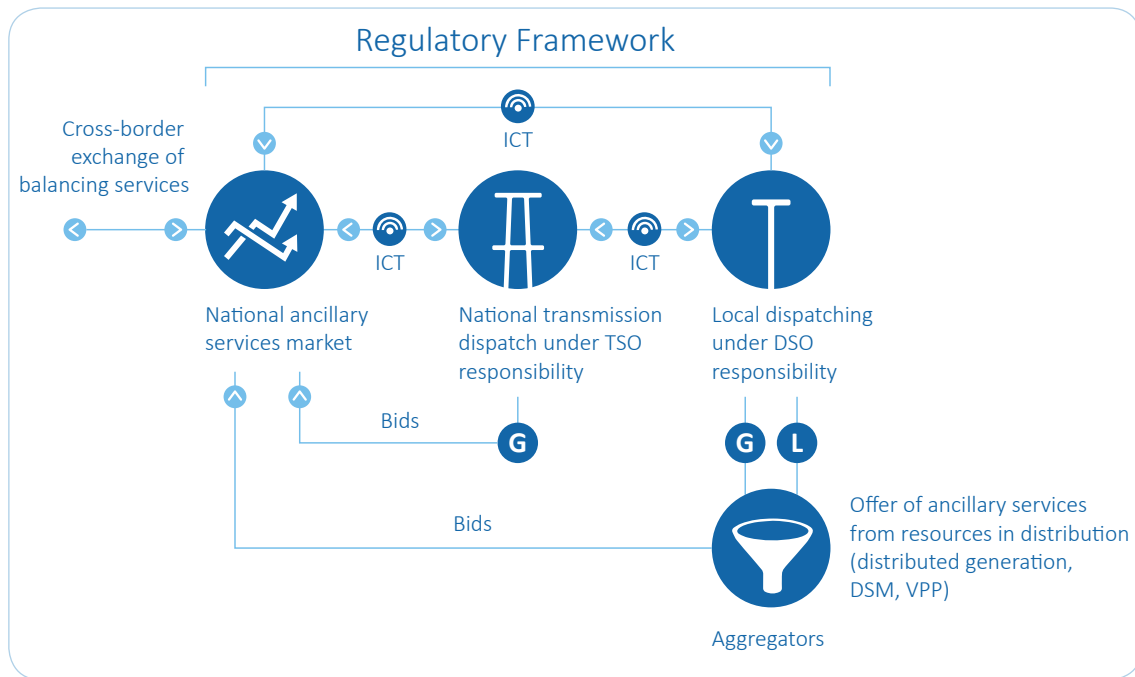


Figure 2 – Interaction for provision of ancillary services

- Which ancillary services could be provided from 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 nine 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, EDYNA

Manufacturers: SELTA, SIEMENS Italia

Software developers: Eurisco, N-SIDE

Telecom: VODAFONE

Trader: Danske Commodities and ONE

Vacation rental: NOVASOL



Figure 3 – Geographical spread of the SmartNet consortium

# Five TSO-DSO Coordination Patterns

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 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*

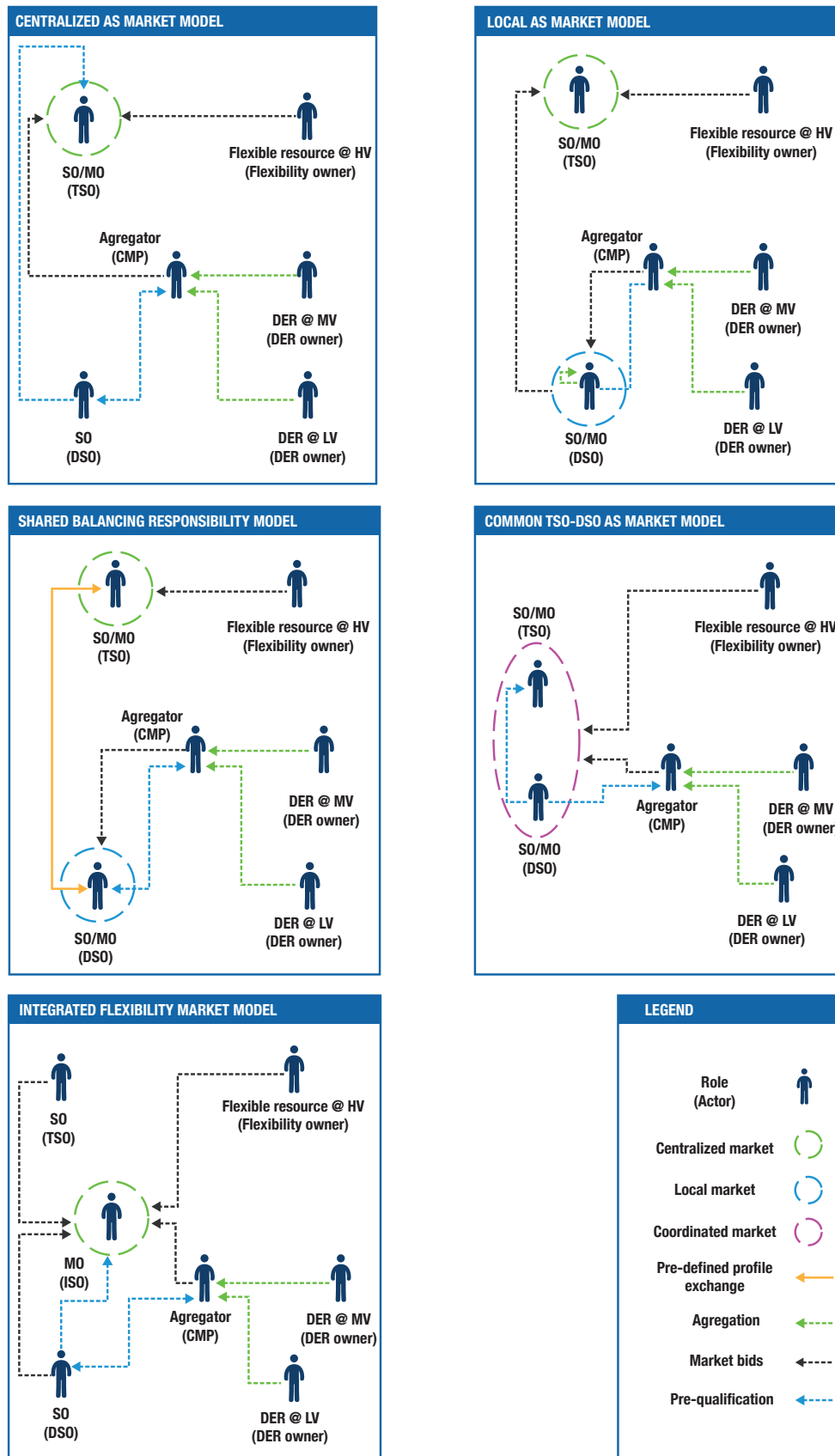


Figure 4 – Schematic overview of coordination schemes

*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 total 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.

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



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
<b>Centralized AS market model</b>	Limited to possible process of prequalification	Common market (TSO)	Priority for the TSO
<b>Local AS market model</b>	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
<b>Shared Balancing Responsibility model</b>	Organization of local market Buyer of flexibility for local congestion management and balancing	Central market (TSO) Local market (DSO)	Exclusive use for the DSO
<b>Common TSO-DSO AS market model</b>	Organization of flexibility market in cooperation with TSO Buyer of flexibility for local congestion management	Common market (TSO and DSO)	Minimization of total costs of TSO and DSO
		Central market (TSO) Local market (DSO)	
<b>Integrated Flexibility market model</b>	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.

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 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.



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 resources from the distribution grid by the TSO	High	Medium	Low	High	High
	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.

# 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.

## Market

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) approaches where the flexibilities from the DERs are leveraged via **local and/or global (common) markets** at the DSO and TSO levels.

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), as highlighted in Figure 5.

Market aims at activating services for balancing and congestion (both transmission and distribution) purposes

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

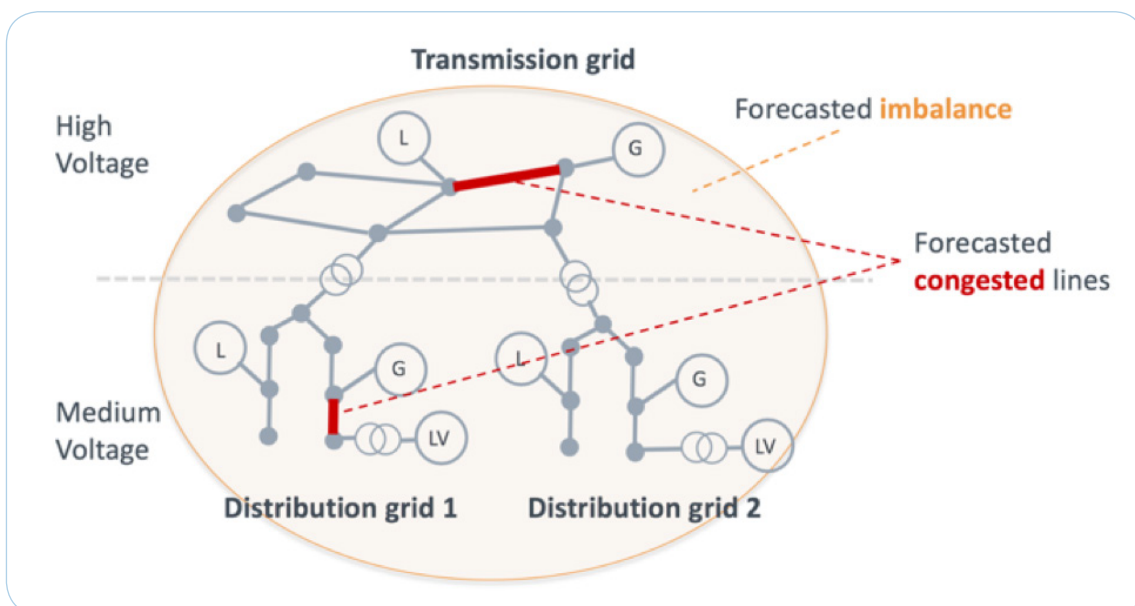


Figure 5 – Market aims at activating services for balancing and congestion (both transmission and distribution) purposes

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 (see Figure 6): 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 (see D2.2 for more details). 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.

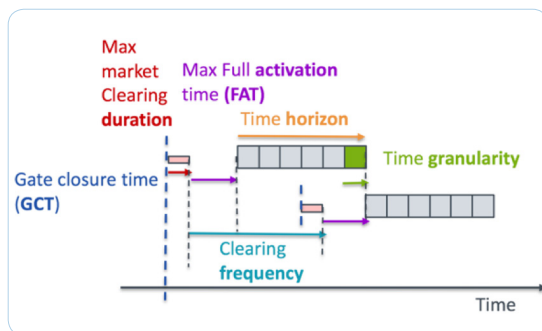


Figure 6 - Illustration of some key market design timing parameters

**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 below table):

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

**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. **Importantly**, the bids must be **location-specific: 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.

**4. Objective dimension:** the objective of market clearing optimization problem can be:

	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 DistFlow	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).

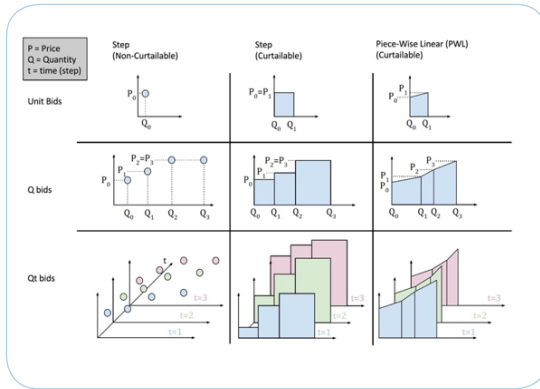


Figure 7 - Different types of standard bids (shown only for upward flexibility bids)

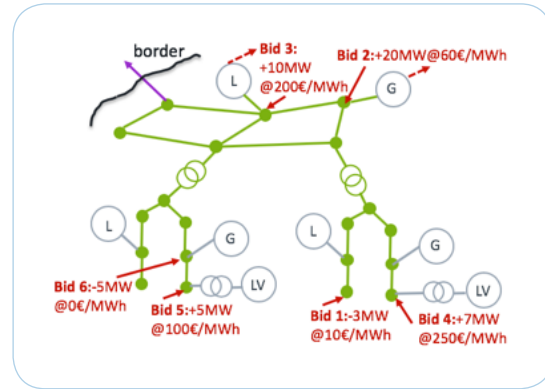


Figure 8 - Example of location-dependent upwards (+ quantity) and downwards (- quantity) flexibility bids

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 valorize the 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.

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** 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.

## Aggregation and Disaggregation

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 ancillary

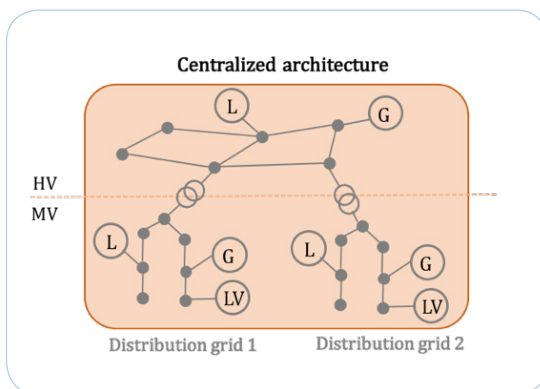


Figure 9 - Diagrams showing centralized and decentralized market architectures.

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

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

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.

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 10). 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.

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

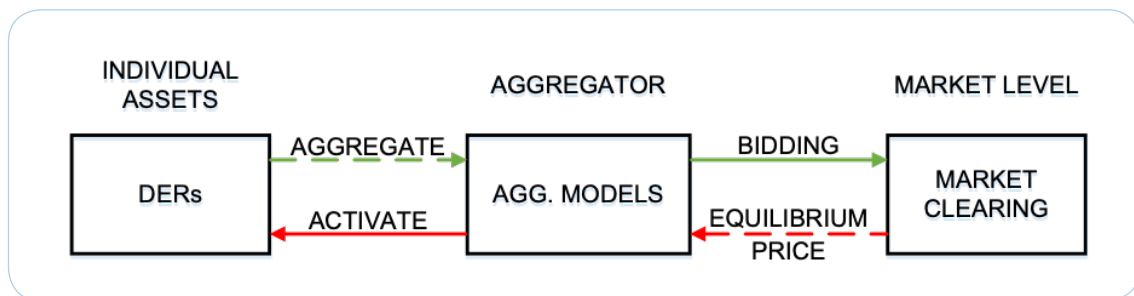


Figure 10 - Illustration of aggregation, bidding, market clearing and disaggregation processes

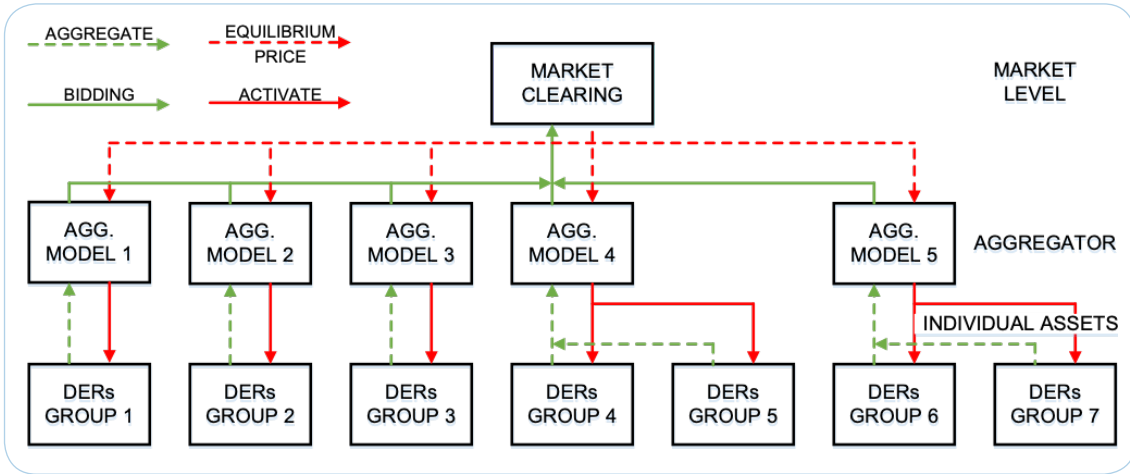


Figure 11 - Illustration of SmartNet aggregation models

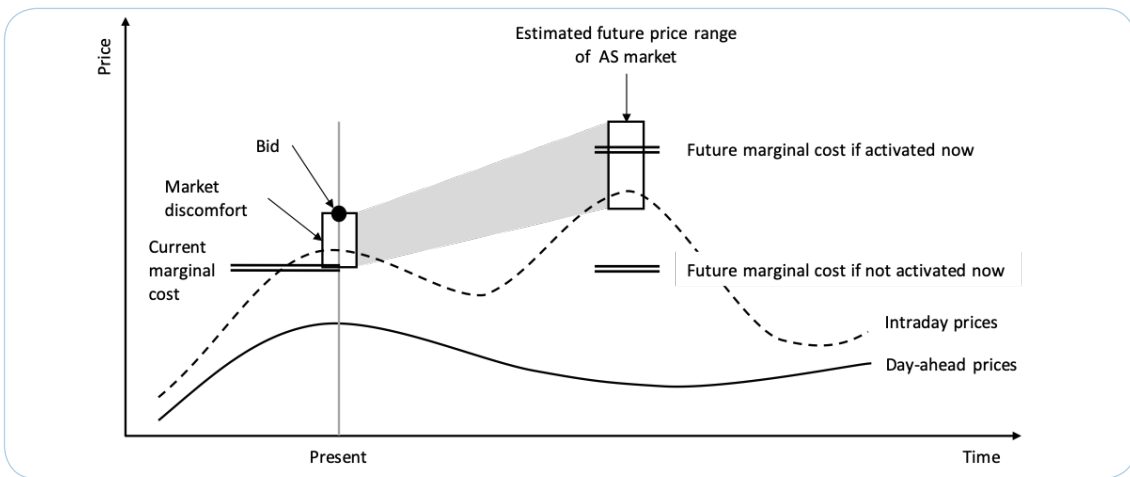


Figure 12 - Representation of the Market Discomfort Cost

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<sup>3</sup>, that makes the aggregator indifferent between an immediate activation and the one in the future at a potentially better profit.

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



# 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.

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





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.

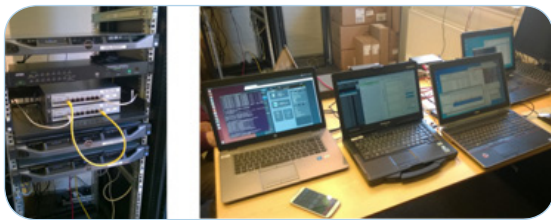


Figure 14 - A wireless QoS measurement setup

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 16 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).

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 15.

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.



Figure 15 - SmartEST Laboratory at AIT used for emulated communications tests

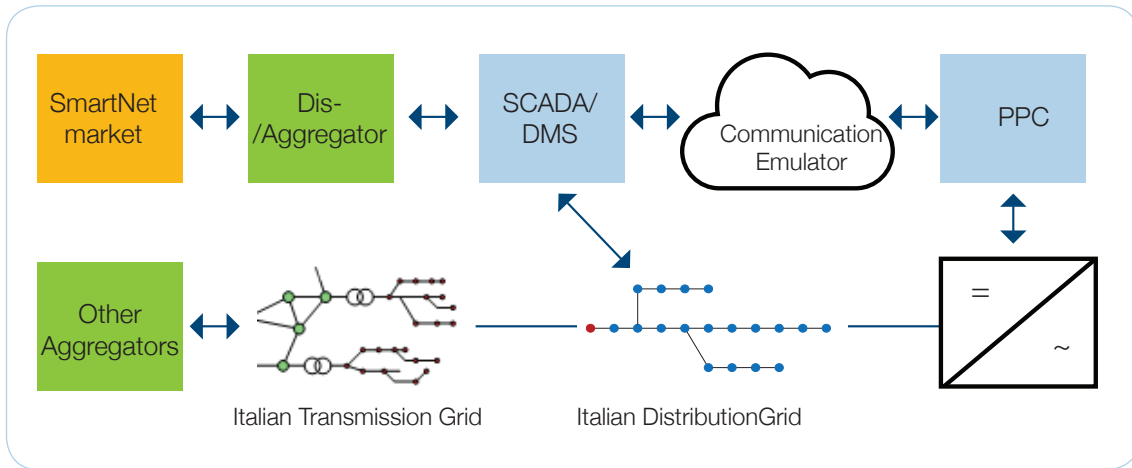


Figure 16 - Communication Network Effects on the Interactions of the SCADA/DMS and the PPC

# 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 and Cost Benefit Analysis.

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 (Figure 17):

- **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

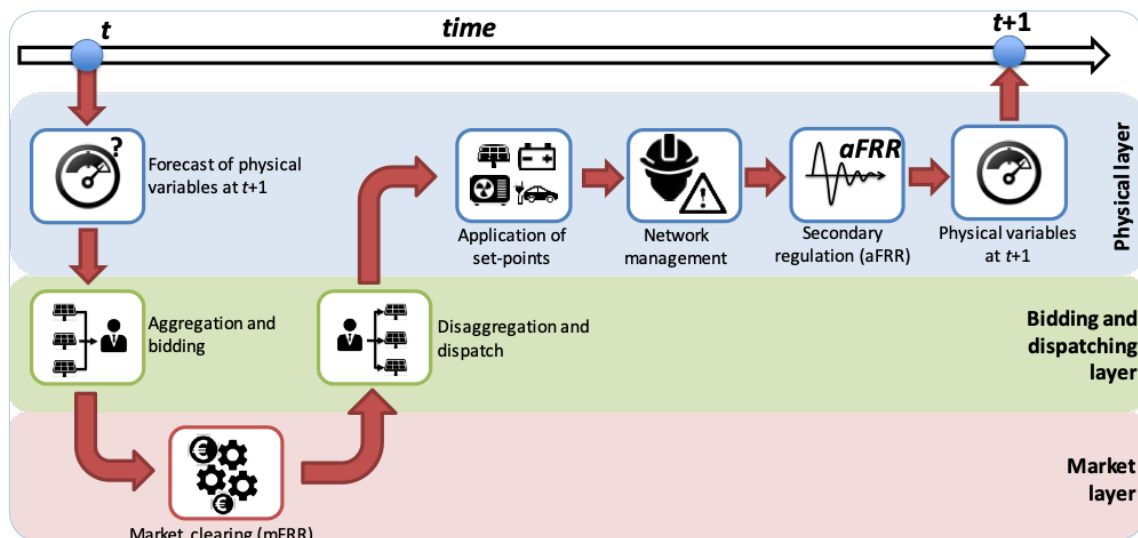


Figure 17 – High level structure of the SmartNet simulator

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.).

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 and further analyses have been conducted in order

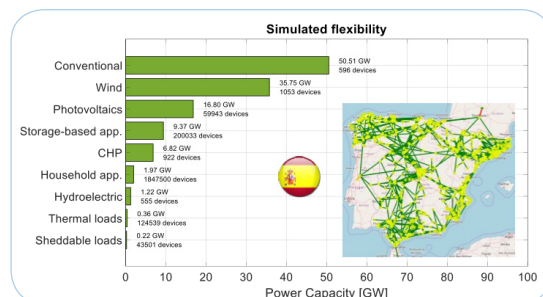
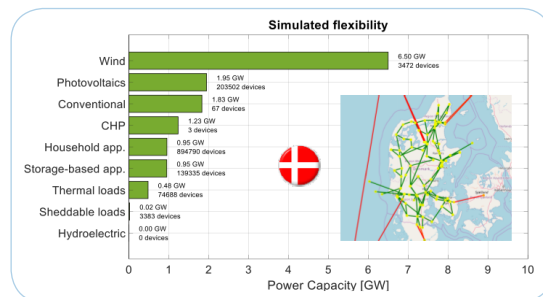
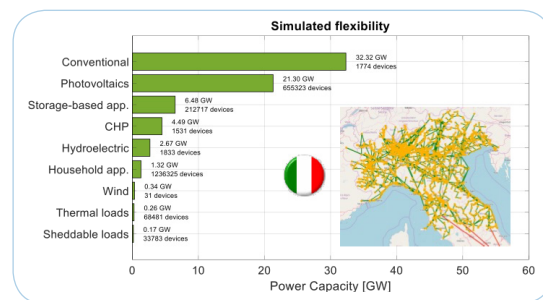


Figure 18 - Scenario characteristics of the three simulated regions



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 (Figure 18).

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. 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 19, the differences among coordination schemes can provide information such as:

- the costs implication related to the inclusion of distribution network

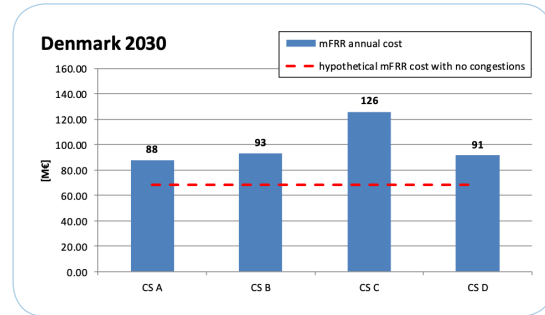


Figure 19 - Illustrative mFRR costs comparison among TSO-DSO coordination schemes

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.

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

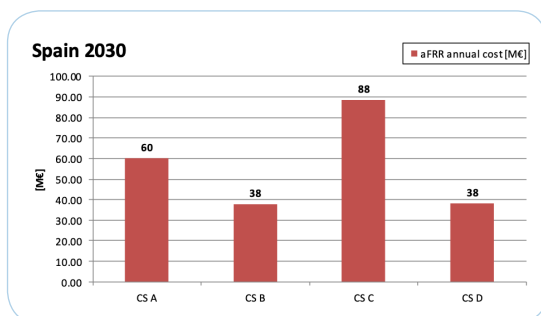


Figure 20 - Illustrative aFRR costs comparison among TSO DSO coordination schemes

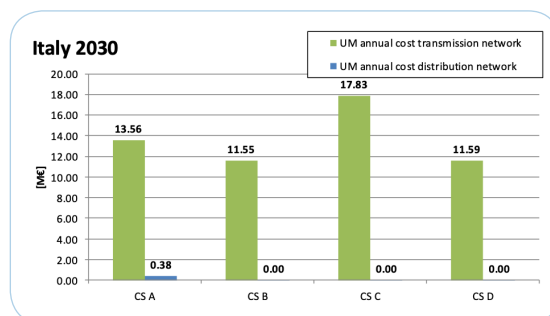


Figure 21 - Illustrative UM costs comparison among TSO DSO coordination schemes

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.
- **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 21, 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).

- **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 reports the results of this analysis.

### 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.

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)

ICT costs comparison among TSO DSO coordination schemes and country



In Italy (Figure 21), 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.

Denmark (Figure 23), 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).

Finally, Spain (Figure 24) 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.

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

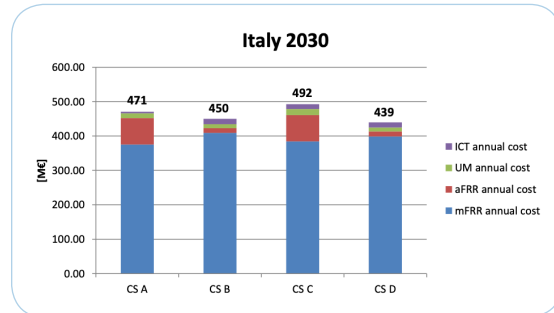


Figure 22 – Final simulation and CBA results for Italy 2030

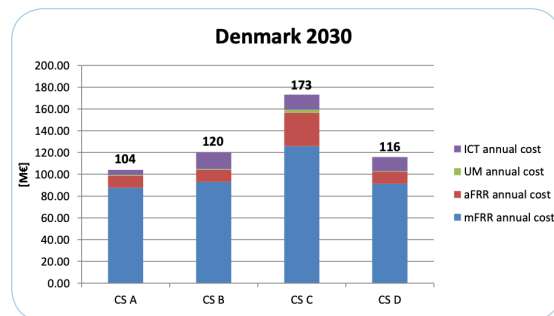


Figure 23 – Final simulation and CBA results for Italy 2030

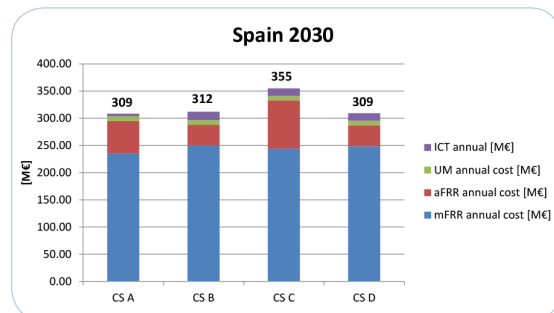


Figure 24 – Final simulation and CBA results for Italy 2030

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.

# 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 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 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 differed “DSO landscape” as in some countries there are relatively fewer DSOs, with 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 AS 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 constraints 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 to 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.

# 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.

	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

Complementarity of technological pilots



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 is 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.

## 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 23.

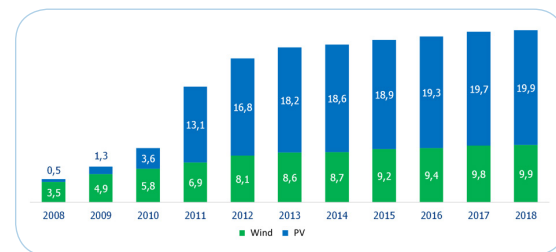


Figure 25 - Wind and photovoltaic capacity installed in Italy (GW), 2008-2018

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 24).



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

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

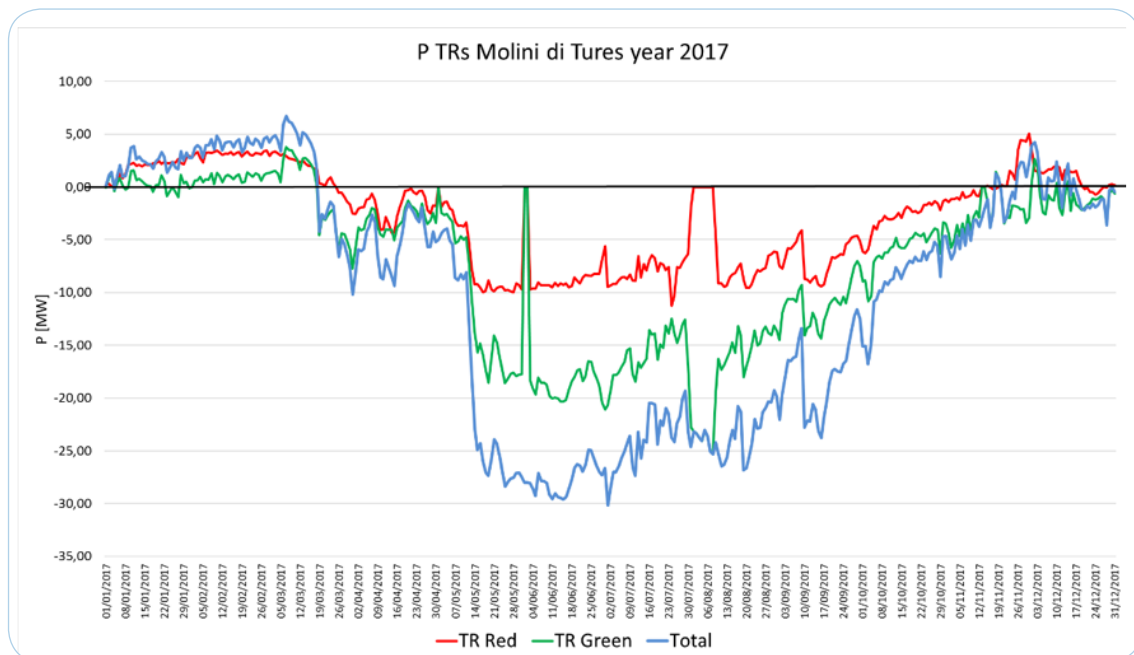


Figure 26 - Trend of the active power at the HV/MV primary substation during 2017

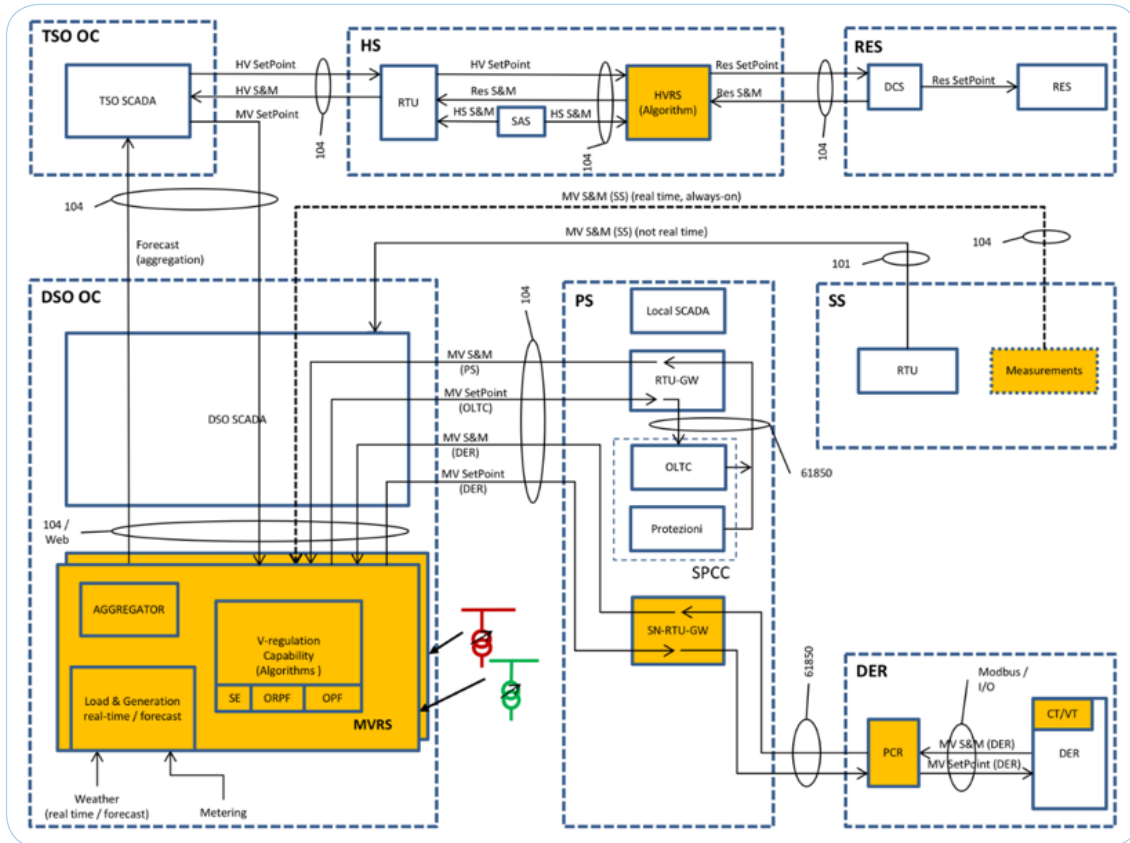


Figure 27 - Architecture of the system implemented in the Italian Pilot of SmartNet: at the top is represented the HVRS system and at the bottom is represented the MVRS system

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 26). The aggregation is updated every 20 seconds.
- **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

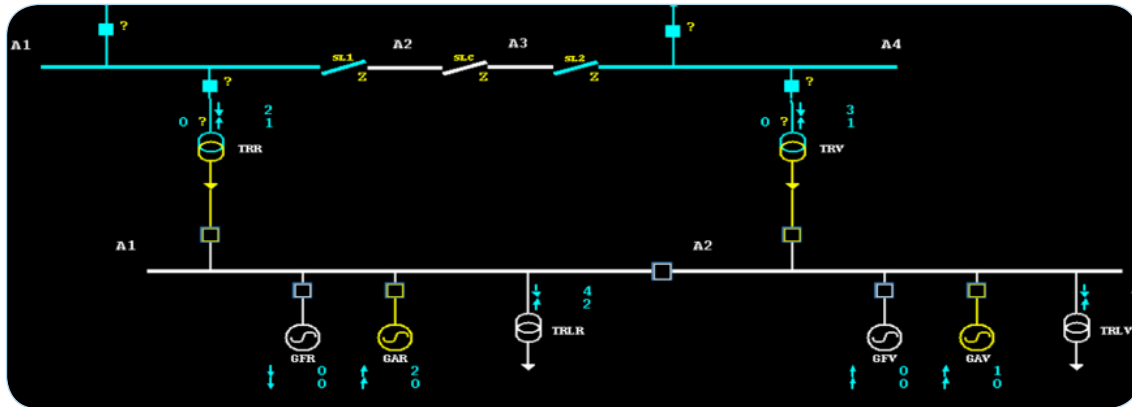


Figure 28 - Representation of MV grid aggregations in Terna SCADA HMI

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 and 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 27, 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.

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 28 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.

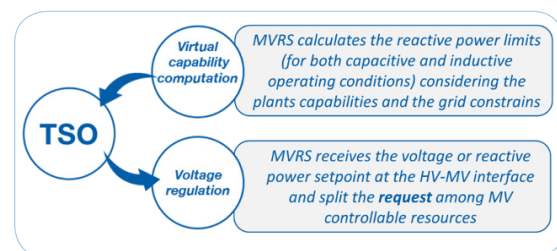


Figure 29 - Diagram of operation of voltage regulation functionality of MVRS

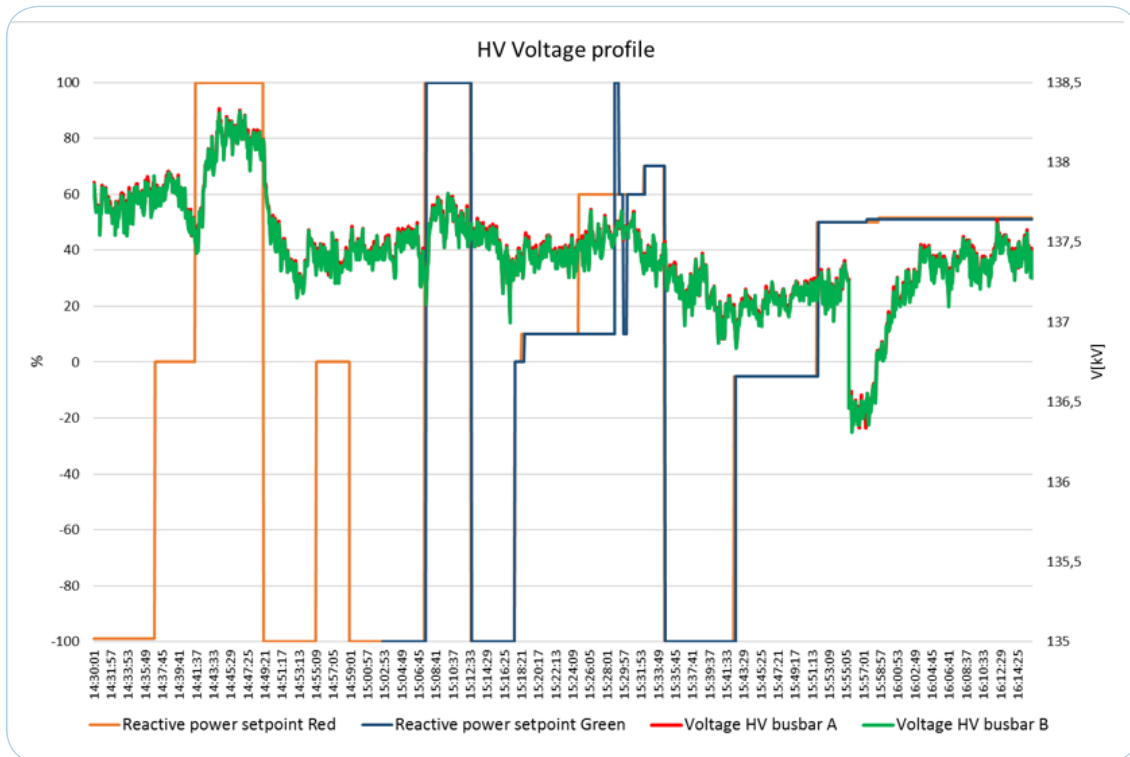


Figure 30 - Trend of the voltage at the HV side of the PS during tests

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 29).

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 30, where the blue line

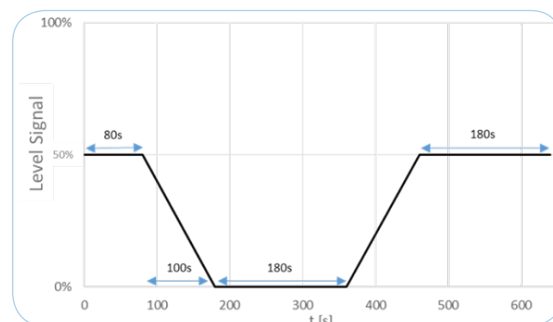


Figure 31 - Ramp of the level signal used for the f/p regulation tests

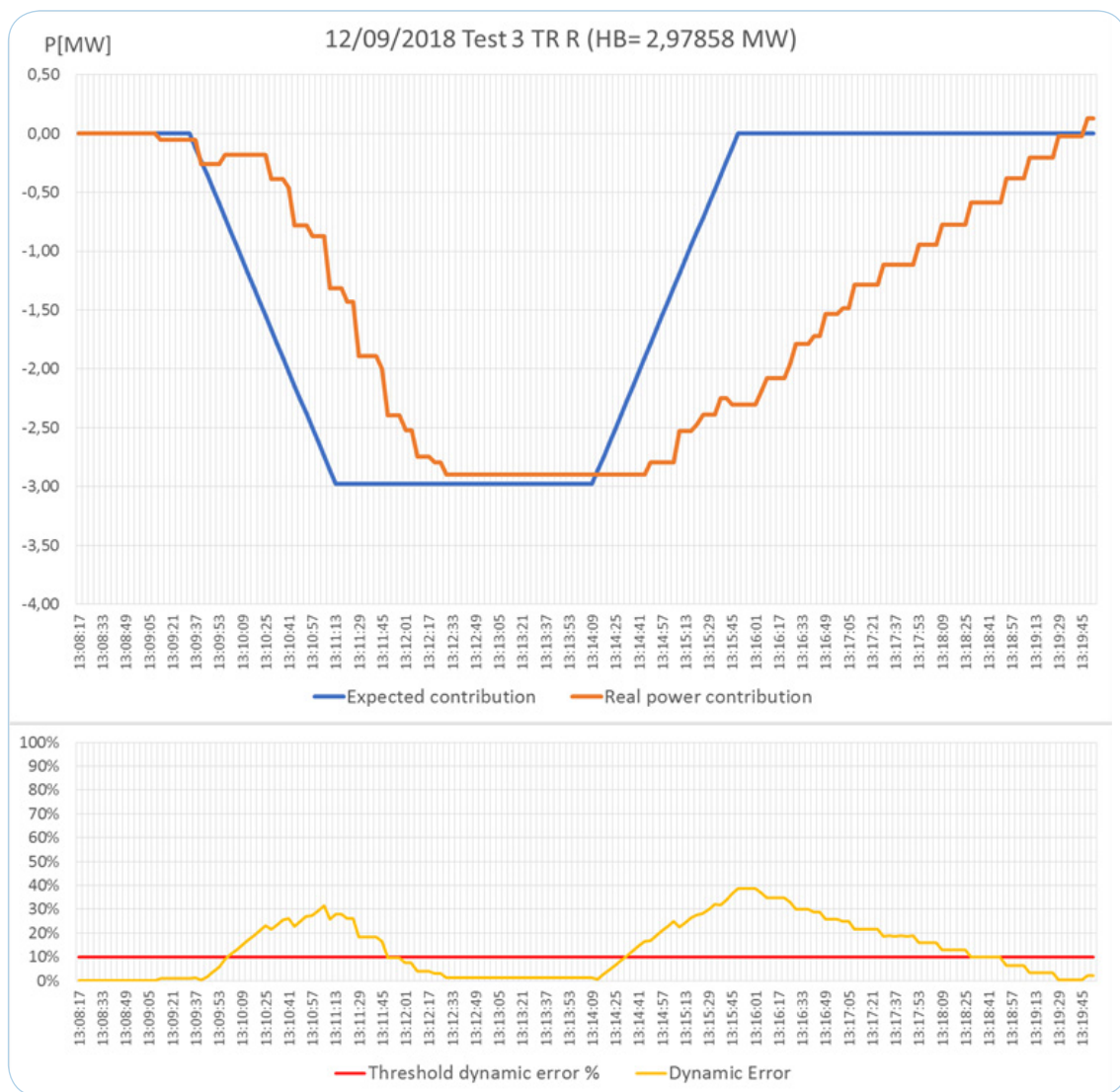


Figure 32 - Example of trend and analysis of the HV contribution of the virtual power plant connected at the transformer

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.

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 31 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.

A flexibility model developed by DTU predicts the electricity demand as a function of prices and reacts to price signals. The CMP sends

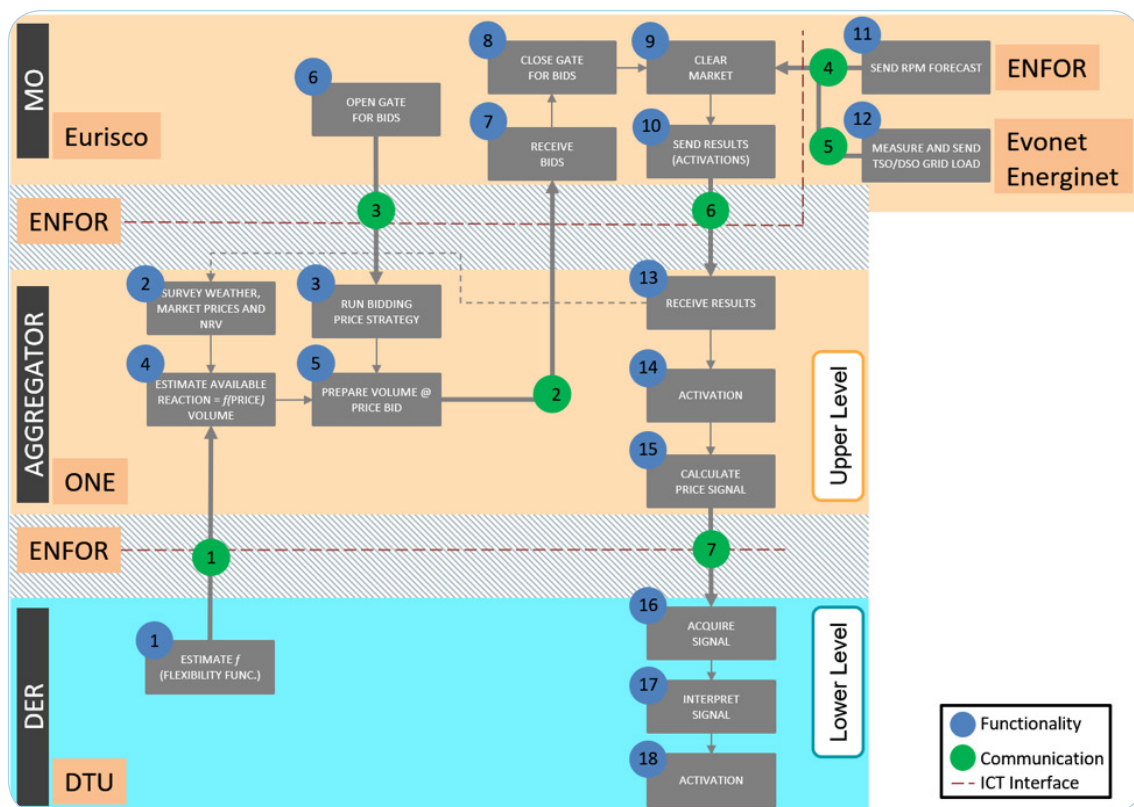


Figure 33 - Communication and ICT interfaces in the Danish Pilot



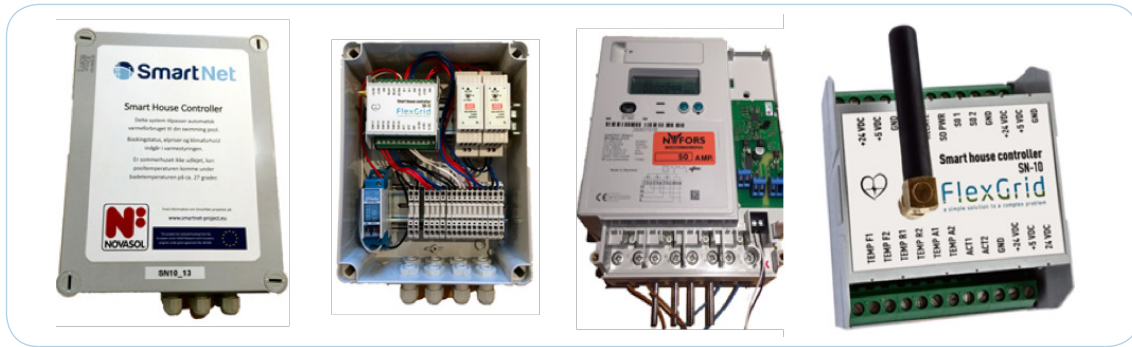


Figure 34 - SN-10 Communication gateway and local controller

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 32, 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.

The actuators, labeled as ACT1 and ACT2 in Figure 33, 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

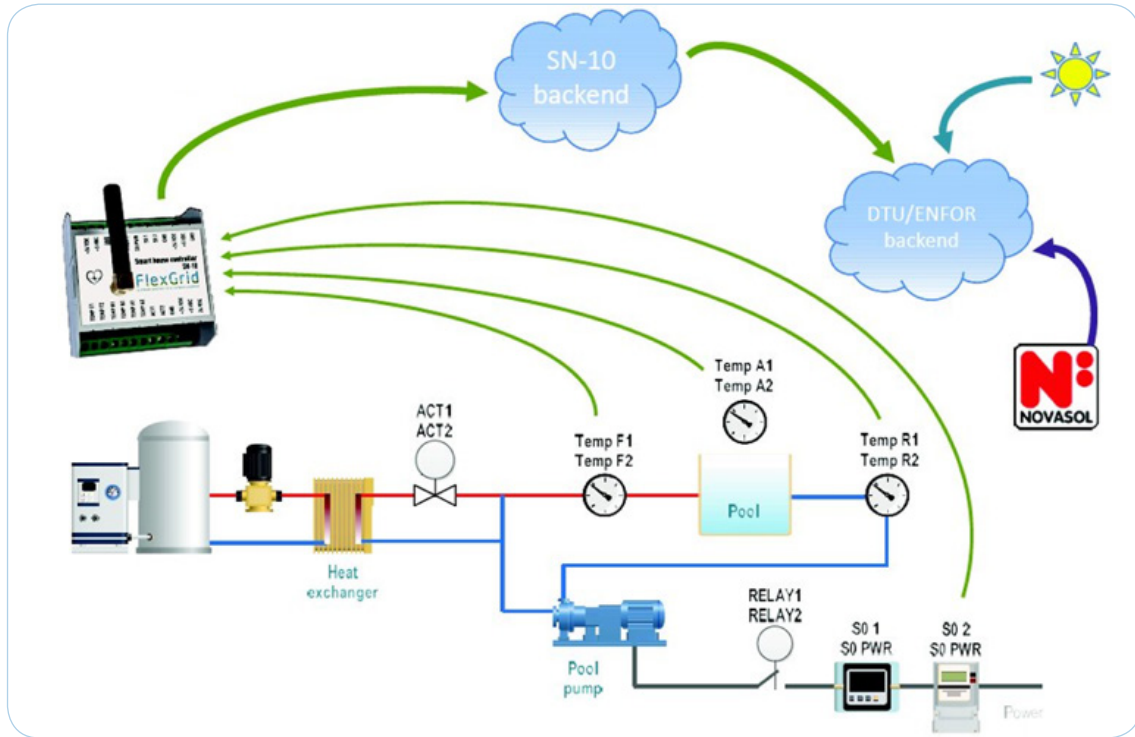


Figure 35 - Data measurement and information gathering by SN-10

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.

An estimated flexibility function can be seen in Figure 34. 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<sub>2</sub>-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 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.

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

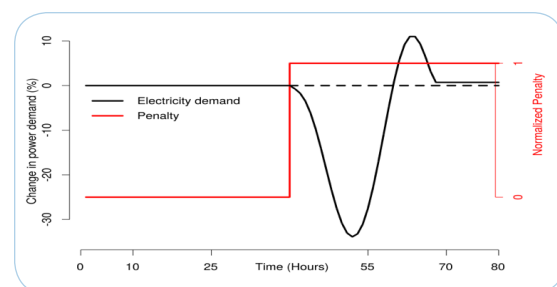


Figure 36 - Estimated step-response, based on data from October 2017, where the penalty was based on CO<sub>2</sub>-intensity.

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<sub>2</sub> 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<sub>2</sub> 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 of 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

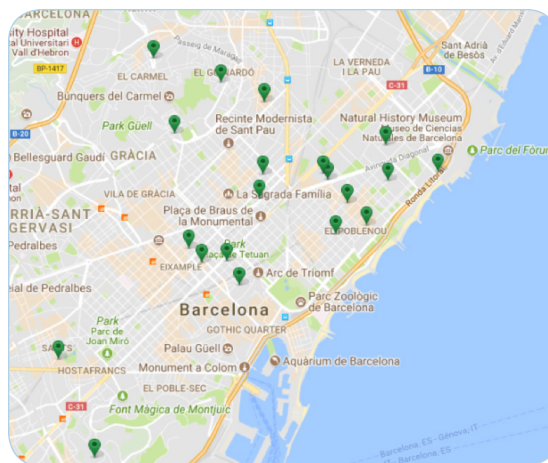
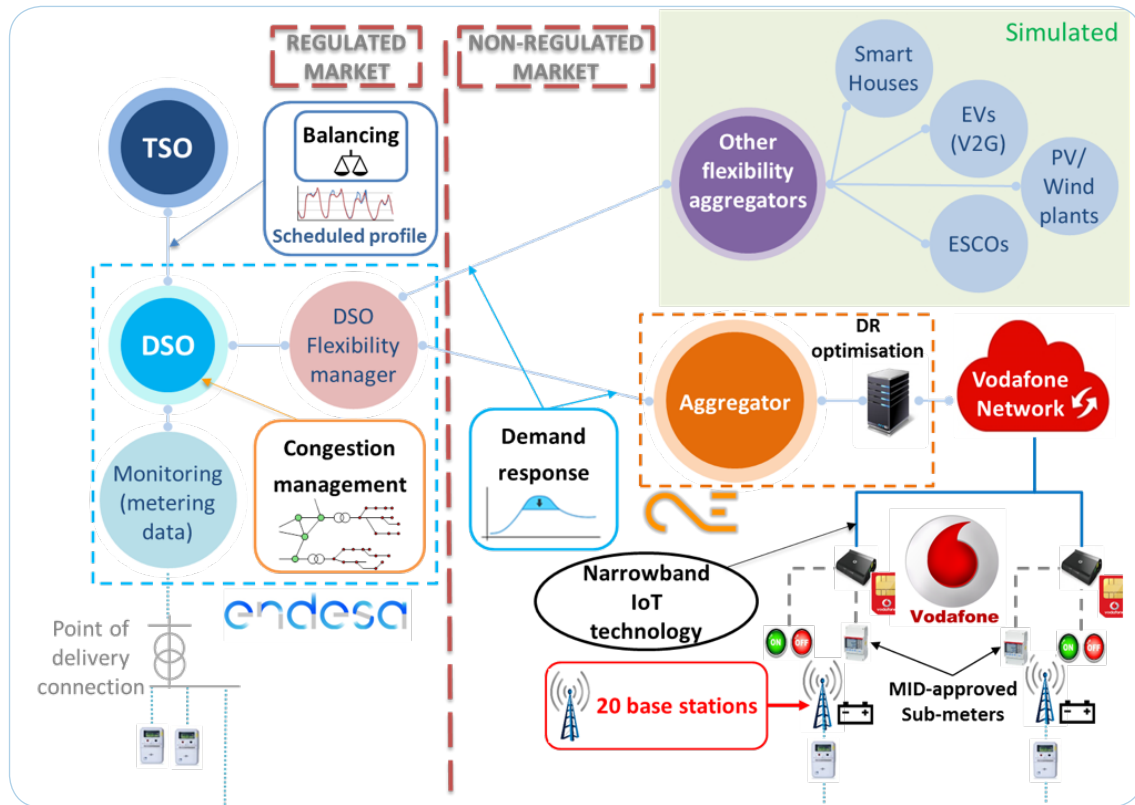


Figure 37 - Location of the base stations in Barcelona



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 35. 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.

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 constraints. 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 established. 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.

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 and 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

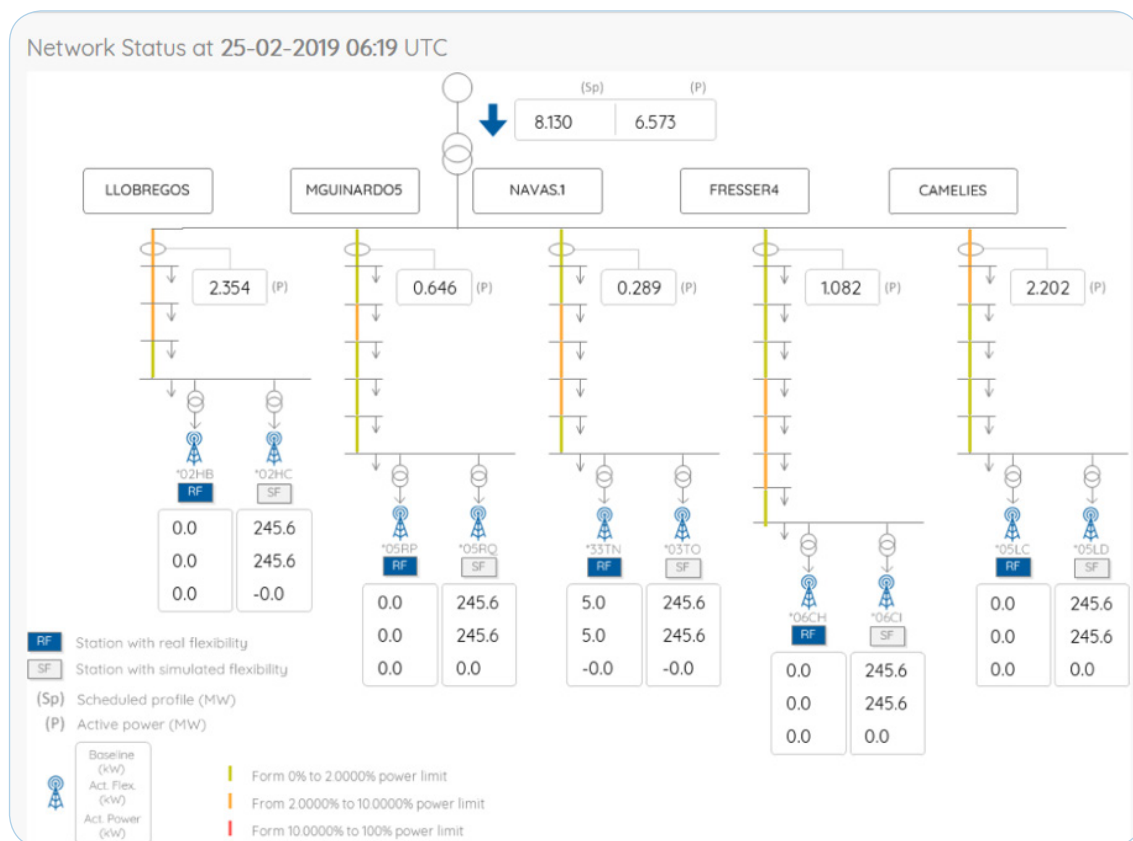


Figure 39 - Screenshot of the grid monitoring tool developed for the pilot

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.

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.





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

# Wrap-up and Way Forward

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”.

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.

Also after the end of the project, the SmartNet platform could still be available in order to enable testing of new technically optimized and cost-effective modalities to employ local resources for the support of balancing and congestion management. **The SmartNet simulation platform could be put available, behind commercial agreement, to all those actors, most notably the DSOs and the TSOs and/or possible subjects deputed to manage**

**future ancillary services markets both at local and at system level, that will be interested to a further exploitation.** TSOs, DSOs and other actors (like Regulators for impact assessment of new regulations) could be interested in an application for analysing the operation in their own markets.

On the other side, it is assumed that the up-scaling of the reduced environment simulated by the demo tests will not constitute a big problem. The up-scaling of the project results should presumably not be hindered by any technological barrier but just be seen as a natural evolution of the proposed platform in the sense of a commercial application to be applied to real systems in their full complexity. As an example, the Italian regulator ARERA has already proved particular interest in the results achieved by the Italian pilot of SmartNet, which could result in an enlarged future national demo project to be experimented over the entire national territory.

# List of Project Deliverables

Here in the following, a list of the most important deliverable of the SmartNet project. They can all be downloaded from the project web site: <http://smartnet-project.eu/publications>.

In the same section of the web site, scientific papers (published in open access modality) and presentations can be downloaded as well.

**D 1.1** Ancillary service provision by RES and DSM connected at distribution level in the future power system

**D 1.2** Characterisation of flexibility resources and distribution networks

**D 1.3** Basic models for TSO-DSO coordination

**D 2.1** Aggregation models

**D 2.2** Network and market models

**D 3.1** ICT requirements specification

**D 3.2** ICT architecture design specification

**D 4.2** Scenario set up and simulations results

**D 4.3** Cost-benefit analysis of the selected national cases

**D 4.4** Lab-environment set-up and simulations

**D 5.1** Results of pilot A (Italy)

**D 5.2** Results of pilot B (Denmark)

**D 5.3** Results of pilot C (Spain)

**D 5.4** Evaluation report for SmartNet pilots

**D 6.1** Summary of lessons learned from the SmartNet activities

**D 6.2** Survey of regulation and stakeholders' positions on TSO-DSO coordination for ancillary services acquisition from distributed resources

**D 6.3** Policy recommendations to implement and/or overcome barriers and enable TSO-ISO integration



**SmartNet**

[smartnet-project.eu](http://smartnet-project.eu)