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**Deliverable 6.1**

Optimal scheduling tools for day-ahead operation and intraday adjustment

**Part II: Commercial Aggregator concept**

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1 Introduction

This document covers Part 2 of 4 of IDE4L Deliverable D6.1 “Optimal scheduling tools for day ahead operation and intraday adjustment”. Its main objective is the definition of an optimal scheduling tool for day ahead operation and intraday adjustment for the Commercial Aggregator.

1.1 Motivation

European Energy Policy aims at promoting the integration of large amounts of renewable energy sources (RES) in the electricity sector. This growing share of variable generation in Europe is increasing the need for flexibility in the electricity system. Stochastic nature of the RES generation hinders system forecasting and scheduling procedures required for a normal and reliable operation. The move towards a liberalized electricity market with high penetration of RES requires an upgrade in the traditional architecture of the power system, including new approaches for system management and new players.

In this context, flexibility management offers the opportunity to exploit the flexibility potential of smaller customers connected to distribution networks, becoming a potential revenue source for them through incentives, and allowing Distribution System Operators (DSOs) to have a higher controllability of its networks. In accordance to [1]- [2], flexibility can be defined on an individual level as the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system. Within this document, flexibility is considered to be provided by both demand on a large scale, for example industrial and commercial consumers, and aggregated smaller sources, such as household load, distributed generation, and energy storage. The sole sources of flexibility comes from grid users in the form of industrial, commercial and domestic providers. As a general term, these grid users will be named as “prosumers” hereinafter, covering both “only-demand” consumers, and those consumers capable of producing their own energy.

The implementation of flexibility management would bring significant benefits to the electricity system, as it would allow for more efficient asset utilization, congestion management in distribution networks as well as environmental advantages. Many large and energy intensive industrial consumers already provide demand response services, and further services will develop over time.

Household electricity consumption and customer preferences differ significantly across Europe, hence the potential for demand response at household level will also differ. In countries such as Sweden and Finland for instance, the average yearly household consumption is three times higher than in Southern Europe (around 15,000 kWh compared to less than 5,000 kWh) [2].

According to the European Network of Transmission System Operators (ENTSO-E), Europe could lack up to 47 GW generation capacities by 2020. This significant figure reflects the tough economic conditions faced by power plant operators due to different factors. Authors in [3] estimate that demand response (DR) in EU28 could have a potential of 52.35 GW. The economic value associated to this potential could be substantial, especially when it is taken into account that the exploitation of this potential would avoid large investments in peak CO$_2$-emitting capacities, with large operational costs.
Two of the most promising approaches to flexibility management are examined within IDE4L project. The first approach (addressed within this deliverable) is the aggregation of flexibility sources (named as Commercial Aggregator approach (CA) onwards), where a mediator triggers the load re-profiling of prosumers by means of incentives. This approach (sometimes called “incentive-based”) would provide direct revenue to the businesses and homeowners, besides ensuring higher stability and efficiency in the grid. The second approach is the Dynamic Tariff (DT) (sometimes called “price-based”), where System Operators (SOs) affect the consumption in some problematic areas, where congestions occur, by means of an added tariff in the electricity price, applied locally to the consumers belonging in this area. This approach will be further developed in IDE4L Deliverable 5.4 (due in 2016), so it is out of the scope of this document.

Therefore, this document focuses on the so-called CA approach, as one of the main pieces of the network automation architecture proposed in the IDE4L project. Notwithstanding, both approaches (CA and DT) are compared in chapter 5, along with an assessment of a potential combination of both.

Flexibility management, besides its usage for distribution network management purposes (as it is the main objective within IDE4L project), can also be exploited for further purposes at the same time. Taking into consideration all potential uses of flexibility provided by prosumers connected to distribution networks, the following target markets are identified:

- **Capacity markets**: procurement of system capacity to ensure that electricity supply can match demand in the medium and long term, i.e. to support investment to fill the expected capacity gap and ensure security of supply.
- **System balancing**: procurement of balancing services (availability) and activation of balancing energy by the TSO to balance demand and supply through specific markets.
Constraints management for transmission and distribution grids: Network constraints resolution in all timescales, maintaining reliability and quality of service at TSO and DSO levels. Typical constraints refer to thermal ratings, voltage violations, fault levels and transient stability issues.

Portfolio optimization: used by market players to meet their energy obligations in the market at minimum costs by arbitrating between generation and demand response on all different time horizons.

1.2 Objectives

This document covers Part 2 of 4 of IDE4L Deliverable D6.1 “Optimal scheduling tools for day ahead operation and intraday adjustment”. Its main objective is the definition of an optimal scheduling tool for day ahead operation and intraday adjustment for the Commercial Aggregator. For doing so, optimal management tools for commercial aggregators are described and developed, aiming at modelling effects and potential benefits derived from flexibility participation on wholesale markets and specific ancillary services.

This document reflects the internal discussion among IDE4L partners involved in WP5 and WP6 about the Commercial Aggregator approach. This discussion along with the discussion of the Dynamic Tariff approach included in the internal document “IDE4L Market Setup”, is the key source for contents explained in this document.

Concepts and models included on this document build upon state-of-the-art research, giving special attention to previous EC founded projects. Specifically, FP7 ADDRESS project, as the largest EC funded demand aggregation project and a key reference on current demand aggregation developments at European level, has been used as a starting point.

Specifically, this deliverable focuses on the following research contributions regarding the Commercial Aggregator topic:

- **Objective 1**: To adapt previously available commercial aggregator models to the latest regulatory framework as proposed by major European organizations (e.g. ENTSO-E, Eurelectric), and adapt it to the Advanced Distribution Network concept developed within IDE4L project.

- **Objective 2**: To extend commercial aggregator’s “Flexibility Forecast” and “Commercial Optimal Planning” tools, identified as key topics for further research in FP7 ADDRESS project:
  - Regarding the Flexibility Forecast, a sensitivity analysis procedure is included in order to investigate prosumer’s responses to the different price incentives, improving commercial aggregator’s portfolio optimization.
  - Concerning the Commercial Optimal Planning Tool, the prosumer model is extended taking into consideration further flexibility sources beyond pure demand response, meaning: electric vehicles, energy storage and on-site generation.

- **Objective 3**: To implement a Commercial Aggregator model taking into consideration Spanish electricity market regulatory framework, simulate its behaviour and evaluate its effects (D6.1 – Part 3). In addition, concepts and models developed within this document, will be used as an input for the lab emulations to be performed within the scope of IDE4L Task 6.4.
1.3 Role of this deliverable within IDE4L project

In the IDE4L project the market design plays an important role in different WPs, and some choices must be made. These choices should distort the least customers and grid managers behaviour, and rely as much as possible on current mainlines already accepted in most of the European countries.

The project is not centred on the detailed individual modelling of flexibility of the customers, since for properly doing this it would be necessary to carry out surveys and collect information, and this is out of the scope of the project. However, the aggregated use of this flexibility by means of the aggregator and its use with the purpose of maximizing the profits of this agent are modelled in detail, and new tools are proposed and tested to this end. The results of these increased profits would be translated into a lower price for the energy offered to the aggregators’ customers. To make this result more apparent, as discussed in further sections, commercial aggregators have also considered to take the role of a retailer in the IDE4L project (and in this way energy is bought in the market for their customers) and of balance responsible party, participating in the market in the name of the customers, and paying the imbalances between the traded energy and the actual consumption of their aggregated customers.

These and other assumptions have implications on the different WPs of the project as discussed below:

WP2 is aimed at planning and assessment of the benefits that the smart mechanism will have for the final user. These benefits are to be assessed under different scenarios of use of technologies (demand response, electric vehicles, heat pumps, PV panels, etc.). In WP2, the assumptions on the market design will be mostly aligned with the proposals included in this document. However, because uncertainty of future regulatory developments is very high, market design will be considered from a more generic perspective, avoiding some details described in this document. Nonetheless, the benefits of the smart mechanism can be at any rate quantified, irrespectively of how are they shared between the different agents in the market.

WP5, however, needs a more precise definition of the market mechanisms designed to manage the congestions presented in the grid. While this deliverable gives a more general view of the possibilities of solving efficiently these congestions, in WP5 a detailed design has been made, and an algorithm has been proposed for congestions management within this project (see section 4.2).

WP6 is centred on the side of the aggregator, and thus, advanced and realistic methods for the participation of the aggregator in the market will be devised and tested. The developed methods will be cantered on the current state of technology, even if this technology is not widely used (e.g. electric vehicle), and will also consider nowadays market architectures and regulations, with the minimum adjustments needed to consider these new technologies and management methods that are in the core of the IDE4L project.

1.4 Scope of the deliverable

The scope of this deliverable is to give a clear description of the Commercial Aggregator concept. In accordance with the committed objectives of this deliverable, the main focus of this document is on day-ahead and intra-day markets. For doing so, the general context of the commercial aggregator in Europe is discussed, and a Commercial Aggregator concept is proposed accordingly. The concept description covers
as well the required new roles that DSOs and TSOs should play in order to ensure an efficient and secure deployment of flexibility services.

Besides concept description, commercial aggregator algorithms are detailed along with its interaction with the rest of IDE4L architecture, including DSO control algorithms developed in IDE4L WP5. Finally, a potential combination of the two approaches for distribution network congestion management proposed in IDE4L project (i.e. Commercial Aggregator and Dynamic Tariff) is examined. The aim is to discuss the best way to make demand response a reality within the IDE4L project, in the most efficient way.

The document provides a condensed description of the most important results obtained. It comprises the following sections:

Section 2: The Commercial Aggregator approach is analytically described within this section. In the beginning, the concept of demand flexibility is presented along with the definitions of the basic flexibility products that are used throughout this deliverable. Then, there is an in depth presentation of the Commercial Aggregator and its main functions. Next subchapter contains a brief description of the list of new requirements for network operators needed for keeping the proper function of the system within the limits, after the implementation of the CA. Finally, target markets for flexibility are discussed along with a discussion about the market environment (i.e. market actors, marketplace, products, procedures, etc.) where flexibility products are going to be traded.

Section 3: Operational processes related to procurement and activation of flexibility products are described here. For doing so, the integration of CA processes into the general control framework of the power system is described. DSO functions developed in WP5 of IDE4L project are also considered in the description.

Section 4: This section includes the detailed description of the commercial aggregator algorithms developed within this project. In addition, a high level description of the main control algorithms interfacing CAs with DSOs is provided. Finally, the full interaction between CA and DSO algorithms within the IDE4L control architecture is described.

Section 5: An evaluation of CA and DT approaches and its potential combination is included here. It looks at the roles of each actor in the two methods and investigates how to integrate the two approaches.

Section 6: In this section, future challenges for DSOs from a regulatory prospective are identified taking into consideration the Commercial Aggregator concept as well as the IDE4L Active Distribution Network concept.

Section 7: A summary of the main conclusions derived from previous sections is included.
2 Commercial Aggregator concept

2.1 General framework

Potential services to be provided by means of flexibility products within the power system are traded in electricity markets. Given that most consumers and prosumers do not have neither the means nor the size to trade directly into wholesale electricity markets, they require the services of a CA to access them [4]. Main role of the CA will be therefore to gather flexibility products from its prosumers portfolio and to optimize its trading in electricity markets aiming to maximize its profits.

The Commercial Aggregator concept considered within the IDE4L Project is following the architecture proposed in ADDRESS FP7 Project, where all the players of the electricity system are considered, with a major emphasis on the Aggregator, the Consumers and the DSO [5].

“The Aggregator is a central concept: he is the key mediator between the consumers on one side and the markets and the other electricity system participants on the other side. The Aggregators gather the flexibilities and the contributions provided by the former to build AD-based products relevant and interesting for the latter. “Flexibilities” and contributions of consumers are provided in the form of modifications of their consumption: an Aggregator sells a deviation from the forecasted level of demand, and not a specific level of demand.

At the consumer level, the EBox is the interface between the consumer and an Aggregator. It carries out the optimisation and the control of the loads and local distributed energy resources at the consumer’s premises. It represents the consumer from an Aggregator’s perspective.

The DSOs also play an important role because AD (as developed in the project) concerns consumers connected to distribution networks. With the development of AD, DSOs will have to continue to ensure the secure and efficient operation of the grid; they will do so mainly through interactions with the other power system participants and, in particular, with Aggregators via markets. They will also maintain direct interactions with TSOs for this purpose.”

This Commercial Aggregator framework has been used as a basis for further developing the concept of demand aggregation in Europe during the last years. Therefore, the use of ADDRESS FP7 project is motivated not only from a technical side, but also for ensuring the coherence with the latest market and regulatory trends.

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1 ADDRESS (2008-2012) was an EC founded 16 M€ project with 25 partners, including EDF, ENEL, IBERDROLA & VATTENFALL. It included an in-depth review of the state of the art, including previous results from FP5&FP6 projects such as FENIX, MICROGRIDS & MORE-MICROGRIDS. ADDRESS market definition has been used as a reference by relevant actors such as Eurelectric.

2 Within IDE4L Project the term “Commercial Aggregator” is used for making a clear differentiation between technical and commercial (market) activities.

3 Active Demand (AD). Within IDE4L project the term “flexibility” is used instead, in order to make a clear reference not only to pure demand consumers, but also to those customers equipped with generation and/or storage assets.

4 Energy Box (EBox), referred as Energy Management System (EMS) within IDE4L Project.
For those readers not familiar with current electricity market functioning and renewable energy integration into the power system, an overview of market actors and regulation is provided in Annex 1 together with a description of current trends on flexibility requirements from DERs (Annex 2).

2.2 Commercial aggregator specification and functions

In order to ensure a transparent and equitable market design for flexibility aggregation, the role of CA towards other market parties (i.e. customers, Balance Responsible Parties (BRPs)/suppliers and TSOs/DSOs) should be clarified. Commercial aggregators are entering several European electricity markets, some of them acting as third parties, contacting directly with customers for flexibility services and selling them in an aggregated manner on wholesale electricity markets. In this context, it should be ensured that BRPs/suppliers are compensated for the energy they inject and that is re-routed by these CAs acting as third parties – as it is already done in Switzerland, where clear rules on imbalances management have been recently settled [4]. An alternative scheme where BRP/suppliers act as CAs is also possible, making the chain of balance responsibility remain intact and delivering simple arrangements such as one main contact point for the customer [6].

Both approaches present advantages and disadvantages (see summary in Table 2-1). For the sake of simplicity, within this project it has been decided to follow the approach where BRP/suppliers act as commercial aggregators. Nevertheless, it is still an open question which approach will prevail, being also possible to end up with hybrid solutions or different solutions co-existing across Europe.

Table 2-1 Pros and Cons of considering BRP/suppliers to act as CAs.

<table>
<thead>
<tr>
<th>BRP/Suppliers acting as commercial aggregators</th>
<th>Markets – Prosumers</th>
<th>Operative Decisions</th>
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<tbody>
<tr>
<td>Pros</td>
<td>More efficient solution</td>
<td>Gaming behaviour of the Commercial Aggregator is avoided. Clear framework for imbalances management</td>
</tr>
<tr>
<td></td>
<td>• Consumers deal with only one agent instead of two</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Less contracts and less connections</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Contracts easier to handle → billing is easier</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Already known load profiles → easier to forecast the consumption and the flexibility⁵</td>
<td></td>
</tr>
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</table>

⁵ in many countries this will require to install smart meters – where not present – or to install a new generation of smart meters – where already present
<table>
<thead>
<tr>
<th>BRP/Suppliers acting as commercial aggregators</th>
</tr>
</thead>
<tbody>
<tr>
<td>Markets – Prosumers</td>
</tr>
<tr>
<td>Flexibility products will easily be integrated in all markets in which retailers are already participating nowadays.</td>
</tr>
<tr>
<td>Duplicities are avoided:</td>
</tr>
<tr>
<td>- No double remuneration by the flexibility service consumer (by both the Commercial Aggregator and the retailer)</td>
</tr>
<tr>
<td>- A single combined player will forecast loads and flexibility avoiding duplicities between 2 players</td>
</tr>
<tr>
<td>Baseline issue is avoided</td>
</tr>
<tr>
<td>- No need to distinguish where the deviation of the consumption came from</td>
</tr>
<tr>
<td>Cons</td>
</tr>
<tr>
<td>The CA entity is restricted to exploit only its contracted clients’ flexibility (not flexibility from clients owned by other retailers)</td>
</tr>
<tr>
<td>Regulatory developments required at the beginning. More difficult from the regulatory perspective in early stages</td>
</tr>
<tr>
<td>Higher market entrance barriers: it could be more difficult for a start-up company willing to play the role of CA to compete with the already established BRPs/suppliers</td>
</tr>
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In order to be capable of carrying out with its duties, the Commercial Aggregator Architecture consists of the following functions:

- **Consumption Forecasting:** This tool is used to forecast the consumption of the prosumers. This information will rely on historical consumption data as well as demand models based on weather information. Consumption forecast will be used for estimating the consumption baseline that will be used afterwards for flexibility services quantification. Baselines should balance accuracy, simplicity and integrity. They should be designed to produce statistically valid and consistent results, unbiased in either over-predicting or underpredicting actual performance. A number of reliable methodologies and ICT solutions capable of establishing reliable baseline values are currently in use throughout the world. A baseline is important to calculate the effective service provided by the aggregation service provider and to avoid strategic users from being incentivized to emphasize their individual benefits without real gain for the system [2].

- **Consumer Segmentation (Clustering):** The objective of this function is to classify prosumers belonging Commercial Aggregator’s portfolio into several groups, defined as clusters. Every cluster comprises a group of prosumers sharing some key characteristics for flexibility provision such as a similar consumption pattern, kind of contract, kind of appliances included, or existence (or not) of Energy Storage Systems (ESS). The clusters are a commercial segmentation, and are used by the CA in order to better handle its portfolio of prosumers and to simplify the calculations. Since every cluster consists of prosumers having a similar behaviour, an average one per cluster may be assumed. Then, incentive policies and their results may be simplified by simulating the average consumer of every cluster.

- **Flexibility Forecast Tool:** This tool is simulating the behaviour of the consumers under different price and volume signals. The algorithm is run for an average consumer from every cluster. Thus,
after forecasting the response of this average consumer, the aggregated response for the whole cluster can be obtained. Improvements on the Flexibility Forecast tool will be on the focus of this research.

- **Market forecasting:** This function forecasts the market price of the sold and purchased electricity. These methodologies rely on statistical and financial analyses of the markets where CAs participate.

- **The Commercial Optimal Planning Tool:** Given the flexibility forecast, as well as the market price forecast, the Commercial Aggregator can schedule the optimal bidding policy, by using the Commercial Optimal Planning Tool. This tool calculates the optimal incentive and bidding policy, in order to maximize the profits of the Commercial Aggregator when participating in wholesale markets, mainly daily markets. For doing so, prosumer’s behaviour is simulated. Within this project, the Commercial Optimal Planning scope is extended including not only demand flexibility, but also local generation and energy storage sources.

An illustration of the modules comprising the Commercial Aggregator is shown in the following figure:

![Figure 2-1 The different modules of the Commercial Aggregators](image)

Within the scope of this document, as discussed above, two out of the CA’s tools are further described. These tools are the Flexibility Forecast Tool and the Commercial Optimal Planning Tool, further described in section 4.1.

### 2.3 Flexibility Services

As defined in [1], flexibility can be described as the modification of consumption patterns and/or generation injection in reaction to an external signal (price signal or activation request) in order to provide a service within the energy system. The sole source of flexibility are consumers and prosumers – meaning consumers capable of producing their own energy – in the form of industrial, commercial and domestic providers [2].

It is important to note that within the scope of this project flexibility corresponds to both:

- Modification of consumption (Consumers, Storage Systems)
- Modification of production (DG, Storage Systems)
Different electricity market players require different services, thus in order to trade the services in the market, it is necessary to define standardized flexibility products that can be used to formulate those services. Flexibility products considered for this study are the ones defined within the ADDRESS project. The basic flexibility products are the following:

- **SRP** (Scheduled Re-Profiling) *Obligation for a specified generation/demand modification* (increase or decrease) at a given time
- **CRP** (Conditional Re-Profiling) *Capacity for a specified generation/demand modification* (increase and/or decrease) at a given time. The modification is activated by a control signal from the buyer

Originally in ADDRESS project, CRP products were distinguished for directional and bi-directional flexibility provision. For the sake of simplicity, commercial aggregator models within IDE4L project have been adapted in such a way that a single CRP definition (bi-directional) can be considered, keeping system performance unaffected.

In order to define the flexibility products and plan their bids, CAs need to model individual response from its prosumers together with their aggregated response and their associated cost. Then, CAs can submit their bids in the electricity market. Figure 2-2 shows a generic description of a flexibility product.

![Figure 2-2 Flexibility product power delivery template](image)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Re-profiling Volume</td>
<td>The flexibility product volume (i.e. energy) or volume range. It may be positive or negative. Instead of a volume, a range may also be specified to provide upper and lower bounds on the product delivery</td>
</tr>
<tr>
<td>Energy Payback</td>
<td>Energy payback is a tolerance specifying an admissible energy payback effect that may occur after the delivery of the flexibility product. We note that the energy payback tolerance could be an extension of the service delivery envelope. Moreover, if energy payback is explicitly considered in the product delivery, it may happen prior to the “main” product delivery (e.g. by charging thermal or chemical storage) as well as partly before and partly after</td>
</tr>
<tr>
<td>Re-profiling duration</td>
<td>The deployment duration associated with the product power shape</td>
</tr>
</tbody>
</table>
### Re-profiling availability interval ($T_{ser}$)

The re-profiling availability interval (for CRP only) is the time interval over which the conditional power delivery associated with the product may be called upon by the buyer.

### Re-profiling activation time ($T_{act}$)

The re-profiling activation time (for CRP only) is the time between activation call by the buyer and the effective start of the power delivery by the Commercial Aggregator.

Regarding its activation, as described above, the Commercial Aggregator is defined as the player who sells energy and controllable power (flexibility) in the electricity markets or via other forms of trading (bilateral contracts, call for tenders, etc.), by modifying the consumption patterns of their prosumers.

This modification is achieved by sending different incentives to the prosumers or by “directly” controlling their consumption via active power set points. On the one hand, the SRPs are formed by means of price incentives, triggering the load re-profiling of the prosumers. On the other hand, CRPs demand a more immediate and direct control, so their activation is performed by means of direct control signals (power set-points). In response to the signals, the prosumers change their consumption/generation level at specific time intervals. Therefore the Commercial Aggregator sells a deviation from the forecasted level of demand, and not a specific level of demand.

The CA will communicate with the prosumers thanks to a communication device, which becomes the gateway between prosumers and Commercial Aggregator. This device acts as an Energy Management System (EMS), which is in charge of the coordination of load, generation and storage at consumer premises. Triggered by signals received by the CA, the EMS will reschedule the consumption profile of the system, running a specific optimization algorithm.

### 2.4 New requirements for network operators

To ensure safe, secure and cost-efficient distribution and transmission network operation and development, CAs will have to coordinate themselves with DSOs and TSOs. At their turn, DSOs and TSOs must also coordinate with each other and have access to flexibility services and all technical relevant data needed to perform their activities both at pre-qualification and operation stages.

From DSO perspective, distribution network connected flexibility should be integrated as part of their control systems where new functionalities should be integrated aiming to realize the new roles to be played by the DSO:

- Flexibility procurer to feed its Distribution Management System (DMS) and its functions to hinder network congestion; and
- Becoming responsible for technical validation of distribution network located flexibility products coming from day-ahead and intra-day markets and technical validation before its activation when requested by third parties (TSOs, BRPs, etc.).

Therefore, flexibility products are procured by both DSOs and TSOs to deal with various constraints of the system. However, the activation of a flexibility product must not cause new violations of constraints, in terms of voltage, congestions or imbalances. This is the reason why they must be checked and validated.
before their activation. The feasibility of flexibility products and the good function of the Power System are ensured by the DSO, in collaboration with the TSO.

For this reason, new tools have to be included in the DSO scope/working area:

- **The “Off-Line” Validation (OLV) tool:** this tool is used for flexibility product acquisition and validation after the gate closure assuming some possible configuration and forecasting the operating conditions of the distribution system.

- **The Real-Time Validation (RTV) tool:** this tool is used by DSO for deciding on the activation of already procured CRPs, and for giving its consent to the close to real-time activation of a flexibility product by the TSO or other deregulated players, and therefore which refers to the actual configuration and operating conditions of the distribution system.

Previously, for controllability and observability purposes, the concept of Load Areas (LAs) should be introduced.

### 2.4.1 Load Areas (LAs)

The Aggregator architecture is based on the concept of Load Areas (LA) and Macro Load Areas (MLA), for the sake of simplicity. Instead of calculating the loads and the voltages to every bus of the network, the buses are grouped in LAs, in a way that they provide the observability and the information required for all the functions of the DSO.

The definition of the load areas is made in such a way that the consumers are grouped in terms of:

- Load (generation/consumption) pattern
- The impedance value
- The connectivity of consumers
- Etc.

So the consumers of each LA present a similar impact on the network operating constraints.

The Macro Load Area is defined in the exact same way, but for a larger area. The DSOs group the Load Areas into Macro Load Areas, tailored according to TSOs point of view (e.g. a HV/MV substation as a whole). They must be communicated to the TSO and updated on every change. In principle, a LA might be a part of a LV feeder, an entire LV feeder, or even a MV/LV substation as a whole.

LAs definition should:

- Avoid determining LAs that are too small and generating too many LAs;
- Define LAs that are observable, in the sense that enough measurements are available at the boundaries of the LA to determine its operating status.

An example of how the loads can be grouped in LAs and MLAs, presented in [9], is shown in Figure 2-3.
Every consumer can be identified within any LA or MLA by means of a unique key, called consumer’s ID. This key is composed by 3 terms: the Macro Load Area code, the Load Area code and the consumers ID. Thus DSOs and TSOs can place the consumers geographically in the network when dealing with network technical validation and flexibility products acquisition/activation.

2.4.2 Off-Line Validation (OLV)

The aim of Off-Line Validation is twofold: to validate day-ahead and intra-day base operating schedules; to procure SRPs from flexibility markets to hinder network congestion.

All energy bids submitted by the different Commercial Aggregators (including consumer’s ID) and other market agents should be validated. Together with these energy bids, when dealing with day-ahead and intra-day validation, DSOs/TSOs should also consider CRPs that to some extent will probably be activated for technical reasons from other actors (e.g. BRPs) or themselves. In order to take into account the probability of being activated, a specific weighting factor is used for each one of these CRPs. This prioritizes the CRPs that are more probable to be activated. The use of this weighting factor reduces the network capacity that is reserved for products that may not be activated, thus releasing capacity for other flexibility products. The weighting factor is calculated and improved after some experience and learning.

It should be noticed, however, that CRPs validation is not included in the scope of the OLV implemented within IDE4L project for the sake of simplicity, but it is described here as a relevant topic to be considered when describing OLV from a generic viewpoint.

With regards to time frame, OLV is applied right after the Base Operating Schedule is available (i.e. after market clearing and inclusion of bi-lateral contracts). The validation algorithm is normally run for timeslots of 1 hour. This means that the validation is not executed for the whole day-ahead period, but for every 1 hour time slot independently.
The OLV should be performed by both the DSO and the TSO, in coordination. The followed procedure is:

1. First, the daily Base Operating Schedule is drawn up by each TSO/DSO where the result of the daily market matching is accompanied by the notifications of the executions of the bilateral contracts (if any). CAs bids are accompanied by its consumer ID, indicating the LA and MLA where they belong to.

2. The DSO aggregates the bids per Load Area together with its own load forecasts, and validates them. If grid congestions are identified, first the DSO will try to solve them by means of its own controllable assets including potential network configuration. If needed, SRP based flexibility products are purchased from the Flexibility Market. Also, a curtailment factor can be applied to CA energy bids if they were the less costly solution (e.g. in case of excess of PV generation, consumption reduction bids may be limited instead of PV curtailment).

3. The flexibility products are aggregated per Macro Load Area (MLA) and sent to the TSO.

4. The validation procedure is repeated by the TSO.

5. An SRP procurement or curtailment factor is applied, by combining the response of both the DSO and the TSO.

6. As a combination of responses from DSOs and TSOs, the Base Operating Schedule is modified. The modifications to the Base Operating Schedule are the Provisional Viable Schedule, which after the inclusion of the Ancillary Service markets results, will become the Viable Daily Schedule.

The scope of the TSO’s participation in the validation procedure is to check the feasibility of the traded flexibility globally, i.e. at the transmission system level. The reason for this is that every DSO only validates the flexibility within its distribution network. Further details on the role of the OLV and the developed algorithms within IDE4L project can be found in sections 3.1 and 4.2, and [7].

2.4.3 Real-Time Validation (RTV)
 Analogously to the OLV, RTV tool is used for two purposes: first, solving potential grid constraints arising in the short term by means of activating/curtailing already procured CRPs; second, giving consensus to the activation request of a CRP product by the TSO or other deregulated players. It is the equivalent of the OLV, but it is based on a different time framework. This function runs on demand, every time there is a request from DSOs centralized control systems, or a CRP activation request is received from an external actor.

The core procedure is almost the same as in the OLV tool. Due to the close to real-time use of this Tool (i.e. 15 minutes before the deployment), the real-time measurements and description of the system are used (topology, load, generation etc.). Figure 2-4 illustrates the sequence of the RTV, presenting an example of a CRP request for activation from the TSO, where the DSO should approve/curtail its activation taking into consideration the grid conditions.
The TSO sends an order to CA stating the quantity (+/- kW) of the CRP

The CA sends a status request to the prosumer
- On/Off
- Temperature
- Power Consumption
- etc.

The prosumer returns the operational status to the CA

The CA asks the DSO for validation of the CRP

The DSO runs a power flow calculation and approves or curtails the request

The CA sends a volume signal for CRP activation

The CA confirms the CRP activation to the TSO

Table 2-2 Example of the steps followed for a CRP activation

The RTV should be performed both by the DSO and the TSO, in coordination. The procedure differs depending on which is the condition for which the RTV is requested upon:

- **Option A**: from the DSO control system if a network constraint is identified; or
- **Option B**: from a CA having received a CRP activation request from a third party (TSO, BRP...) concerning a CRP connected to its distribution network.

**RTV sequence for Option A:**

1. If grid congestions are identified, first the DSO will try to solve them by means of its own controllable assets including potential network configuration.
2. If needed, previously procured CRP products will be activated following a cost-minimization criteria. If necessary, a curtailment factor can be applied to already activated CRPs and SRPs if it was the less costly solution (e.g. in case of excess of PV generation, consumption reduction products may be curtailed instead of PV generation).
3. In case of the conditions at the DSO/TSO point of common coupling are above/below a reference value previously agreed between the DSO and the TSO, the CRP should be validated by the TSO.

4. TSO acceptance/rejection received by the DSO.

RTV sequence for Option B:

1. First, the Commercial Aggregator submits the bids to be validated by the DSO. In this case, the requested CRPs should be accompanied by its consumer ID, indicating the LA and MLA where they belong to.
2. The DSO aggregates the bids per Load Area and validates them. If needed, a curtailment factor is applied.
3. If the requester is different to the TSO, flexibility products are aggregated per MLA and sent to the TSO for validation.
4. The validation procedure is repeated by the TSO.
5. A final validation or curtailment factor is applied, by combining the response of both the DSO and the TSO.
6. The combined responses of the DSO and the TSO, i.e. the acceptance reply or the curtailment factor per load area, are sent to the Commercial Aggregators involved.

2.4.4 Notes on the IDE4L implementation approach

Regarding the sequence of events for both OLV and RTV, first the DSO is assumed to check the feasibility of the distribution network and then it passes the results to the TSO, who is performing a second check. This is the same approach reported in [10]. However, if the country regulation requires a change in the time sequence, then the TSO check can guide the following check which will be done by the DSO. In IDE4L implementation, only the validation made by the DSO is assumed, not the one made by the TSO that is considered out of the scope of the project.

Regarding the case when the OLV or the RTV dictates a curtailment of the flexibility products, there are 2 options:

1. Application of the same curtailment factor to all the flexibility products that are traded within the problematic load area. This approach, though, does not compensate the CAs for their losses, occurring by the weakness of the grid. For the sake of simplicity, this has been the approach followed within IDE4L project.
2. Re-dispatching the flexibility that has to be curtailed to another Load Area. The alternative flexibility source may belong to the same or another CA. The extra cost for this re-dispatching are charged to the DSO. This is an incentive for the DSO to invest in reinforcing its grid in case of occasional need for flexibility curtailment, instead of paying for the costs of re-dispatching.

2.5 Target markets for flexibility products

As discussed in previous sections, new methodologies need to be applied regarding the energy management of the system and there, the CA as a new player to be introduced in the electricity markets is a key ingredient.

Flexibility management is a very ambitious way of dealing with the stochastic nature of the RES generation. In general, energy industry foresees a large potential benefit in flexibility services from a commercial and technical perspective. Flexibility services would provide direct revenue to the businesses and homeowners participating in those programs. Moreover, significant benefits to the electricity system would arise, as the
more efficient assets utilization, congestion management in distribution networks as well as environmental advantages.

The efficiency of the Smart Grid would considerably improve. Some flexibility markets are being developed in countries around the world. In the US, for example, 28.5 GW of demand side management (DSM) was already available to market participants in 2013 [8]. The situation in Europe is promising, but yet in an early stage of development. Energy Efficiency Directive 2012/27/EC is the main legal basis for promoting flexibility markets at European level, enforcing in its Art 15.8 that “Member States shall ensure that national energy regulatory authorities encourage demand side resources, such as demand response, to participate alongside supply in wholesale and retail markets”. Countries like Belgium, Great Britain, Finland, France, Ireland and Switzerland are already in a level of commercial DR product offerings. The rest of Europe states are still bounded to national regulations, which makes flexibility services infeasible so far (see Figure 2-5).

Based on their own calculations, authors in [3] identify, at European level (EU28), a total consumption of about 800 TWh of electricity in 2012 for processes with DR potential. This represents 29 % of the total electricity consumption. After having consecutively determined the installed capacity per process, the capacity guaranteed at peak per process and the reduction potential per process, authors in [3] estimate that total DR potential in Europe amounts 52,35 GW. This value equals and even surpasses the 47 GW that, according to ENTSO-E Europe will lack of by 2020 due to the tough economic conditions faced by power plant operators.

![Figure 2-5 Demand response activity in Europe](image-url)
Flexibility programs are often classified by their incentive structure, i.e., capacity payments vs. energy payments. While this distinction is important, it is more instructive to examine flexibility programs by the purpose they are designed to serve [9]. For example, Emergency and long-term capacity programs are both typically capacity-based (i.e. a single payment per MW-year or MW-hour available) and receive similarly structured incentives, but each one is used for a different purpose and, consequently, has unique program parameters. In an energy-only program or market (e.g. day-ahead or intra-day wholesale markets), all electricity produced (or demand reduced) is compensated based on the price for that MWh of electricity. Conversely, in a capacity-based program (such as secondary regulation), participants receive a capacity payment for being willing to curtail consumption when required, and usually an energy payment for actual load reductions as well.

That said, it is important to recognize the basic incentive structures of the different types of flexibility programs, but for an exhaustive classification of them, the purpose they are fulfilling should be the characteristic to be considered. Bearing that in mind, the following classification of potential markets for flexibility is proposed:

- **Capacity markets**: procurement of system capacity to ensure that electricity supply can match demand in the medium and long term, i.e. to support investment to fill the expected capacity gap and ensure security of supply.
- **System balancing**: procurement of balancing services (availability) and activation of balancing energy by the TSO to balance demand and supply through balancing markets.
- **Constraints management for transmission and distribution grids**: Network constraints resolution in all timescales, maintaining reliability and quality of service at TSO and DSO levels. Typical constraints refer to thermal ratings, voltage violations, fault levels and transient stability issues.
- **Portfolio optimization**: used by market players to meet their energy obligations in the market at minimum costs by arbitrating between generation and demand response on all different time horizons.

In the following sections, each market category is further explained. Finally, a comprehensive summary chart including the flexibility product better fulfilling the purpose of each market application is presented.

### 2.5.1 Capacity markets

An increasing number of countries are taking actions to secure their electricity supplies and prevent potential black-outs by introducing capacity mechanisms. Capacity mechanisms are measures taken by these countries to ensure that electricity supply can match demand in the medium and long term. Capacity mechanisms are designed to support investment to fill the expected capacity gap and ensure security of supply. Typically, capacity mechanisms offer additional rewards to capacity providers, on top of income obtained by selling electricity on the market, in return for maintaining existing capacity or investing in new capacity needed to guarantee security of electricity supplies [10].

While in US flexibility services mainly traded through long-established capacity markets, Europe has just started to create the structures that allow flexibility side resources to participate. Belgium was the first country in Europe allowing flexibility participation in capacity auctions in 2014. Also in later 2014 the U.K.
held its first capacity auction for which CAs where qualified. In 2016, in France, an over-the-counter market for capacity purposes will be set up, in which demand response is expected to be qualified for participation.

2.5.2 Flexibility for balancing services and reserves

TSOs are responsible for maintaining system balance and hence for adjusting the system user actions. In order to achieve this, TSOs use a portfolio of reserves which can be activated when encountering disturbances or imbalances. The activation of these reserves would result in generation facilities, energy storage devices or flexibility side reducing or increasing their energy output or intake [2].

An option for CAs to trade its flexibility products for balancing purposes could be by using the existing market organized by the TSO. The limiting factor though is that it is very difficult for a CA to get access to these markets, due to the high technical requirements. Some of the cases where a CA shall not access to the markets are:

- The Commercial Aggregator is not able to provide the minimum tradable volume
- The costs to access the market are too high for the Commercial Aggregator’s business
- The TSO or the regulation judges that flexibility is not reliable enough to offer balancing products

Access to balancing markets is developing at different speeds across European countries. In 2013, REstore⁶ was the first European company to network and control building loads for primary reserves markets run by Belgian TSO Elia⁷. Since then, similar programs have been set up in other countries like the Firm Frequency Response program started by U.K. grid operator National Grid in 2015, which opened up around 1.000 MW for qualified participants. In France, at the time this document is being written, it is expected to allow flexibility services to compete for a share of nearly 600 MW of fast-acting grid reserves [11].

Finally, most TSO across Europe also have some sort of emergency or reliability programs in which resources are only called during an emergency condition. Emergency or reliability programs primarily differs from previous balancing services in the sense that response is not voluntary. Generally, participants in these programs receive a payment for being available, known as a capacity payment (€/kW), and are typically compensated for their demand reductions during events through an energy payment (€/kWh). Emergency programs are called infrequently and typically dispatched once a defined "trigger" has been met. These triggers are usually system characteristics that correspond with reliability issues, such as actual or forecasted capacity shortages or the achievement of a specific system condition.

As a summary, the following flexibility opportunities are identified for balancing purposes:

- Frequency containment reserves (FCR)
- Frequency restoration reserves (FRR)
- Replacement reserves (RR)
- Emergency reserves

⁶ www.restore.eu
⁷ www.elia.be
Further details on the nature and features of these ancillary services are provided in Annex 3.

2.5.3 Flexibility for voltage regulation, power flow and congestion control

Considering the challenges faced by power system and networks in the coming years (higher penetration of distributed electricity resources, including renewables and other flexibility resources, development of smart grids, implementation of capacity markets), the role of DSOs/TSOs should be redefined to make sure they can exploit flexibility services to solve their grid constraints (to solve voltage issues or manage local congestions) and reduce their grid losses (distributed flexibility resources could reduce the amount of energy lost transmission and distribution because the electricity is generated nearer to where it is used). These processes will take place in the long term, where network security will be assessed against future generation and demand scenarios. In the short/medium term, where TSO/DSO will have the opportunity to make use of flexibility services for day-ahead and intra-day market validation purposes. And in the short term, where flexibility services will be used for solving unexpected congestions.

Flexibility providers, DSOs and TSOs should coordinate themselves and exchange information in order to enable efficient use of these resources without hindering network security and quality of supply.

Voltage regulation, power flow and congestion control are localized services, mainly offered to SOs. At transmission level, these markets have been already established for long time, where flexibility is provided by conventional bulk generation. In the future distribution network, the DSO would choose to reduce the costs of keeping the network constraints, by means of flexibility products, instead of improving the network components. Currently, there are no organized markets to trade this kind of services at the DSO level. Some pilot projects across Europe, however, are proposing innovative schemes that can be of interest for further deployment of flexibility services at distribution network level.

In the Netherlands, an alternative has been developed by the Universal Smart Energy Framework (USEF), which offers a new Market-based Control Mechanism (MCM) that creates a market for flexibility [12]. The energy market becomes a single integrated market, where both the physical supply chain, responsible for the physical transport and distribution of energy, and the energy value chain, that implements the commercial processes for the energy produced, play an active role. Similarly to ADDRESS and IDEAL approaches, on the USEF flexibility market the DSO can buy products from a third party Aggregator that enable him to avoid congestion in predefined areas. This way, the DSO can delay or avoid costs for grid reinforcement. The end customer in turn is rewarded by the Aggregator for offering his flexibility.

Other pilot projects in UK and Belgium also recently took place aiming at testing distribution network uses of flexibility services. In the U.K., a National Grid’s program aimed at relieving grid congestion at the distribution network operator (DNO) level was set up. Successful results motivated the further deployment of demand response services at a set of hotels, hospitals, commercial offices, water treatment plants and public buildings. In Belgium, Linear Project included a research platform designed and deployed by a consortia of industry and research partners to investigate user behavior and acceptance. Two business cases related to distribution network demand response services were tested: transformer aging and line voltage management.
Given the novelty of these markets, in the beginning, there will not be enough liquidity, so the DSO can procure flexibility products by means of bilateral contracts. At a later stage, the DSO could establish regular call for tenders, in order to exploit the increased liquidity. The final stage is the implementation of an organized flexibility market for the trading of flexibility products. The added liquidity would occur by interconnecting various distribution networks with a larger amount of local DER connected to them.

With regard to the so-called flexibility market, a single marketplace for flexibility where TSOs and DSOs can access should be envisaged. This approach seeks to avoid fragmentation of markets giving CAs the opportunity to value their flexibility potential where it is the most efficient for them (balancing and/or congestion management at TSO/DSO level). Creating exclusive, fragmented markets per DSO and per TSO could lead to a lack of economic optimisation, the absence of a systemic view, and could ultimately jeopardize the efficiency of the energy market and overall effectiveness of system operation [13]. In addition it’s worth to note that the single market option could probably lead to further system savings given the economies of scale of the required IT infrastructure for the market operator itself, and the lower cost for DSOs and CAs who could benefit of unique market rules and common IT tools for all distribution networks.

It is also worth to mention that direct demand side management actions to be directly undertaken by DSO could also co-exist within the proposed CA framework for technical purposes. In those cases, the DSO has the ability to effectively control and verify the response from the consumer/prosumer: for example, setting up an agreement with customers which empowers them to directly control consumer appliances such as air conditioners or electric heaters by reducing or turning off consumption subject to a certain agreed price or other criteria. This kind of demand response, known as direct load control, is currently very common in demand response markets. Nordic countries have been among the leaders in developing this kind of demand-response programmes within the OECD European region. These programmes were often initially implemented as small-scale pilot programmes with the aim of educating customers in order to inform and improve consumer behaviour. Some of these pilots have been developed into successful programmes [14].

As a summary, the following flexibility opportunities are identified for congestion management purposes:

- Network Upgrading Optimization
- Long-term Operational Planning
- Constraints management after day-ahead and intra-day markets
- Real-time Network Operation Contingencies
- Grid losses reduction

### 2.5.4 Flexibility in the wholesale markets

Portfolio optimisation is used by market players to meet their energy obligations resulting from energy markets at minimum costs. In the presence of flexibility services, portfolio optimization can be performed by means of arbitrating between generation and flexibility resources on all different time horizons. For CAs, the use of its own flexibility resources can be released both at day-ahead and intra-day markets. In that way, CAs will be able to maximize their profits taking into consideration wholesale market prices and their flexibility portfolio, i.e. using sending economic incentives to its prosumers in order to shift their loads to
low price periods. Additionally, CAs will be able to minimize their own potential deviations (from loads and/or renewable energy generation) by means of managing their own resources.

From third parties perspective, it could also be of interest to trade flexibility services with CAs for the same purposes. For other market participants it could be more difficult to decrease or increase outputs for certain types of generation units such as wind or solar, than trading flexibility with CAs. For that reason, flexibility services are expected to be a key asset for BRP portfolio optimisation.

The different applications that flexibility services can have for portfolio optimisation purposes are listed below:

- To assist in meeting balancing commitments by means of modification in power consumption at short term.
- To optimize medium and short term purchases and sales in day-ahead and intra-day markets.
- To minimize short term risks by flexibility reserve.
- To facilitate structuring long-term purchasing contracts.

### 2.6 Summary of potential markets for flexibility services

In previous sections, an overview of potential markets for flexibility services is provided. It is worth to note, that each market purpose will require different time response levels, as well as different trading horizons. This allows for the classification of these different market applications as a function of the flexibility product (SRP/CRP) better fitting the specific requirements for each application (see Table 2-3).

<table>
<thead>
<tr>
<th>Market domain</th>
<th>Application</th>
<th>Grid level</th>
<th>Type of contracts</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Control Area Level</td>
<td>Local Grid Level</td>
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<tr>
<td>Long-term capacity auctions</td>
<td>Capacity auctions</td>
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<tr>
<td>Balancing markets</td>
<td>Frequency containment reserves (FCR)</td>
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<td>Frequency restoration reserves (FRR)</td>
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<td>Replacement reserves (RR)</td>
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<td>Emergency reserves</td>
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<td>Constraints management</td>
<td>Network Upgrading Optimization</td>
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<td>transmission and distribution level</td>
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<td></td>
<td>Constraints management after day-ahead and intra-day markets</td>
<td>X</td>
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3 Operational processes

As discussed in the previous chapter, flexibility services for different applications may be realised by means of scheduled re-profiling products (SRPs) or conditional re-profiling products (CRPs). Having a clear idea about how these products can be procured and activated is key for the implementation of the Commercial Aggregator concept.

Within this chapter, operational processes for SRP and CRP procurement and activation are described in detail. When describing the processes, a set of specific CA and DSO algorithms are mentioned. A detailed description of these algorithms is included in chapter 4.

3.1 SRP procurement and activation

SRPs are traded through day-ahead and intra-day markets, and the so-called flexibility market. Grid operators (DSOs/TSOs) can access flexibility markets for solving potential congestions arising from day-ahead market results as well as long term forecast. CAs activate these products by means of price incentives sent to their prosumers. A detailed description of SRP products can be found in section 2.3. In order to thoroughly explain the approach that is adopted by the IDE4L project, a sequence diagram for trade and activation of SRP is described in Figure 3-1.
Actors appearing in the left column are described below:

- **TSO** is the Transmission System Operator.
- **DSO** is the Distribution System Operator.
- **FM** (Flexibility Market) is a market where the flexibility requests and bids are solved. It can belong to the network operator as it is the current case for most of the countries (belonging to TSO as system operator) or be a separate entity. Within IDE4L project it is proposed that this market is run in coordination by TSOs/DSOs as network operators (see discussion in 2.5.3).
- **MO** (Market Operator): matches the purchase and sale energy bids. It receives the bids from the commercial aggregator and other market agents. The output of its market clearing is the market price and a schedule that must be checked because it does not take into account the possible congestions in the grid.
- **CA** (Commercial Aggregator): As already defined in section 2.1, CA represents prosumers in electricity markets. It assumes the functions of a Retailer and Balance Responsible Party as well as flexibility coordinator. By means of price incentives create SRP products that can be sold both in wholesale markets and flexibility markets.
**CONSUMERS/PROSUMER:** Consumers having the ability to choose between buying electricity from the grid and producing it themselves.

The process described below corresponds to the SRP procurement and activation on day-ahead markets using as a reference Spanish network codes. Network codes present many similarities across European countries, and the trend is that they will fully converge after the ongoing European network codes harmonization is fulfilled. The same process would apply for intra-day markets with minor changes:

1. **Customer needs/flexibility:** CAs, by means of their Flexibility Forecasting functions, estimate base load profile and flexibility availability from their customers portfolio, along with their response to different price incentives. Results from Flexibility Forecasting will be used for daily market and flexibility market bidding processes.

2. **Energy bids:** After daily market gate opening, CAs and other market agents (neither DSOs nor TSOs) submit their sale and purchase bids. CAs use their Commercial Optimal Planning functions to calculate the energy bids (normally purchase bids) to be submitted to the market. As an input, Flexibility Forecasting results will be used. Energy bids will include its load area and macro load area identifier for program validation purposes afterwards.

3. **Market clearing:** From the bids received, the Market Operator calculates the system (or zone) price and the bids accepted and rejected. The Matches Result Schedule is published.

4. **Inclusion of bilateral contracts:** The daily Base Operating Schedule is drawn up by each TSO/DSO where the result of the daily market matching is accompanied by the notifications of the executions of the bilateral contracts (if any).

5. **Flexibility bids:** When flexibility market gate opens, CAs submit SRP flexibility bids to the flexibility market. These bids can include both flexibility “up” and flexibility “down”, and will include an identifier showing the Load Area they belong to. Again, CAs rely on their Flexibility Forecast function for computing the flexibility bids to be submitted. From Flexibility Forecast, CAs obtain the available flexibility to be offered to the market together with its price level, which will vary as a function of the amount of flexibility offered.

6. **Flexibility needs:** The DSO, in coordination with the TSO, studies the Operating Schedule technical viability to ensure the safety and reliability of the supply. For doing so, it relies on the Off-line validation function. If the resulting programme complies with safety requirements, no flexibility is called from the flexibility market. If safety requirements are not fulfilled, the Market Agent Unit within the Off-line validation sends to the flexibility market those requests needed by the DSO to alleviate congestion.

7. **Flexibility clearing:** From the flexibility bids received, in coordination with the TSO, the DSO selects those solving its flexibility needs at the lowest cost. Daily market energy bids from CAs and other market agents can be curtailed or rejected. Whether curtailment and rejection should have a cost or not is a very complex issue. In IDE4L we have chosen to work with a “no cost” approach. The modifications to the Base Operating Schedule are the Provisional Viable Schedule, which after the inclusion of the Ancillary Service markets results, will become the Viable Daily Schedule.

8. **Send price incentives to energy markets:** The Commercial Aggregator enforces accepted energy bids and flexibility offers by means of sending out the required prices incentives among its prosumers portfolio.
It is worth to mention that once flexibility market is cleared, CAs and the other daily market participants can receive one of three signals regarding each energy bid (Approved, Rejected or Need for curtailment). The assumption here is that DSOs/TSOs have the right to reject or curtail the bids that will cause violation of network constraints with no compensation for the market participant, as it is for the Spanish markets and other European wholesale markets. Regarding flexibility offered by CAs, in addition to the demand reduction curtailment, the outcome of the validation could also be a DER production curtailment.

It is also important to mention that the DSO OLV functionality plays here two main roles, the first of which is the technical viability assessment role. In this role, the DSO in coordination with the TSO studies the Operating Schedule technical viability to ensure the safety and reliability of the supply. If safety requirements are not fulfilled, it comes the second role of DSO off-line validation: business role. The business role calculates and determines how much flexibility is required to alleviate congestion in the DSOs grid, using flexibility offers submitted by CAs to the flexibility market.

3.2 CRP Procurement and activation
The main complexity related to the trading of CRPs in an organized market is that they usually have two prices:
- Price for purchasing the CRP, i.e. having the capacity available ($p_{\text{CRP}}$)
- Price to activate it ($p_{\text{activation}}$)

Due to the reduced number of prosumers providing flexibility services independently or by means of CA, liquidity of local distribution network CRP markets during the coming years will be very low (that will not be the case for SRPs given that the scope is the entire system, not local distribution networks). Therefore, in a fist stage, the exchange of CRPs is considered to be made by means of bilateral contracts or on call for tenders. However the possibility of creating a pool market for the CRPs should be considered as a future option.

A detailed description of CRP products can be found in chapter 2.3. In order to thoroughly explain the approach that is adopted by the IDE4L project, a sequence diagram for trade and activation of CRP is included in Figure 3-2.
There is no specific time where CRP products can be traded or activated. DSO and TSO activation requests can appear independently or simultaneously, without any specific order. The sequence of events for CRP purchasing and activation is as explained in the points below:

1. **CRP Purchasing**
   A. Communication between CRP purchasers (e.g. DSO or TSO) and CAs is established.
   B. Contracts are made between CRP sellers and purchasers. However, it should be noted that no validation process is established yet.

2. **The process differs for DSO CRP activation and TSO CRP activation**
   A. DSO CRP activation:
      a. For the DSO, the activation procedure can be simplified when CRP levels are below a certain threshold to be agreed with the TSO. In that case, as there is no need for validation of the DSO’s own CRP purchases, the DSO simply sends a CRP activation request to the Commercial Aggregator. This threshold should be defined in such a way that it is ensured that the activation of a CRP under that threshold will not cause any effect on transmission system.
      b. In the case that the CRP level is above the aforementioned threshold:
         i. The DSO sends a CRP validation request to the TSO before its activation.
         ii. When TSO real time validation is finished, it sends one of three signals to the Commercial Aggregator unit: approved, rejected or need for
curtailment. It is also assumed here that TSOs have the right to reject or curtail the bids causing network constrains with no compensation for CAs.

B. TSO CRP activation:
   a. TSO (or another market actor) sends a CRP activation request to the Commercial Aggregator.
   b. The Real-time unit of the Commercial Aggregator communicates with the DSO/TSO market agent requesting real time validation of the CRP product before its activation.
   c. When real time validation is finished by the DSO market agent unit, it sends one of three signals to the Commercial Aggregator unit (approved, rejected or need for curtailment). It’s also assumed here that DSOs/TSOs have the right to reject or demand curtailment of the bids that will cause violation of network constrains with no compensation for CAs.

4 Algorithms

In chapter 2, the new functions to be incorporated into currently existing DSOs automation systems have been described along with those functions that the proposed CA concept would integrate. Accordingly, in chapter 3, the role and interaction of these new functions is depicted when realizing SRP and CRP flexibility products. The aim of this chapter is to provide a detailed description of the algorithms used to realize these functions within IDE4L project. Given that the scope of this Deliverable is focused on the CA side, DSO related algorithms are summarized. Further details of DSO related algorithms can be found in [7].

Algorithms described in this chapter rely on state-of-the-art research, giving special attention to previous EC founded projects. Specifically, FP7 ADDRESS project, as the largest EC founded project in this topic, and a key reference on current demand aggregation developments at European level, has been used as a starting point.

Specifically, these following are the main contributions regarding the Commercial Aggregator topic:

- Previously available commercial aggregator models have been adapted to the latest regulatory framework as proposed by major European organizations (e.g. ENTSO-E, Eurelectric), and the Advanced Distribution Network concept developed within IDE4L project.
- Commercial aggregator’s “Flexibility Forecast” and “Commercial Optimal Planning” tools, as key topics for further research identified in FP7 ADDRESS project are improved:
  - Regarding the Flexibility Forecast, a sensitivity analysis procedure is included in order to investigate prosumer’s responses to the different price incentives, improving commercial aggregator’s portfolio optimization.
  - Concerning the Commercial Optimal Planning Tool, the prosumer model is extended taking into consideration further flexibility sources beyond pure demand response, meaning: electric vehicles, energy storage and on-site generation.

4.1 Commercial aggregator algorithms

As stated in section 2.2, the Commercial Aggregator Architecture consists of the following functions:
• Consumption Forecasting
• Consumer Segmentation (Clustering)
• The Flexibility Forecast Tool
• Market Forecasting
• The Commercial Optimal Planning Tool

Within the scope of this project, Flexibility Forecast Tool and the Commercial Optimal Planning Tool have been further developed. Main reasoning behind is the high impact they have in relation to the rest of the project, as well as the fact that they have been identified as key further research topics in previous EC founded projects.

The other functions (Consumption Forecasting, Consumer Segmentation and Market Forecasting) have been implemented following the algorithms proposed in ADDRESS Project. Further details on how all CA functions are implemented can be found in D6.1 Part III.

4.1.1 Flexibility forecast
Main objective of the flexibility forecast module is to estimate the available flexibility of every cluster, upon the different price signals (i.e. SRP flexibility products). This is achieved by forecasting the response of the consumers to these price signals. These forecasted values of flexibility are fed to the Commercial Optimal Planning (see section 4.1.2), where an optimization problem is solved to choose those incentives to be activated maximizing CA profits (section 3.1 step 2, “Energy bids”). In addition, as exposed in the previous section, forecasted values of flexibility are also used for preparing flexibility offers to be submitted to the flexibility market (section 3.1 step 5, “Flexibility bids”).

The module uses a bottom-up approach by simulating consumer’s behaviour. For that purpose, the EMS required by any consumer/prosumer willing to participate in any flexibility service provision program is used for the simulation. For doing so, an average consumer for every cluster (see cluster concept description in section 2.2) is used as a reference, taking also into consideration the reliability of each cluster. The term reliability refers to the probability of a number of consumers to ignore the price signals thus contributing to the flexibility response less than what was forecasted. The use of historical data for the consumers consumption and behaviour is mandatory, in order to estimate the reliability.

It may be assumed that the EMS can be provided by the CA, therefore being the same for all the prosumers. Similarly, it can be considered that despite the EMS is provided by a different manufacturer, it will seek for the cost minimization of the consumer/prosumer. In both cases, the algorithm is assumed to be known and easily predictable. Furthermore, the availability of historical data after several months/years of operation, would lead to an increased accuracy of the EMS simulation models.

The following steps are followed:

1. The EMS calculates the load profile for the different average prosumers corresponding to the set of clusters composing the CA portfolio when no incentives are applied. This is used as a reference and is called the base load. This profile corresponds to the normal consumption of the prosumers when no action is taken by the CA.
2. The same EMS algorithm is repeated several times. Each time a different price signal, i.e. incentive sent by the CA, is introduced to the objective function and a corresponding load profile is calculated. This sensitivity analysis procedure is included in order to investigate prosumer’s responses to several price incentives, improving commercial aggregator’s portfolio optimization. Further details on how this sensitivity analysis is performed, can be found in [15].

3. Afterwards, every load profile (corresponding to a price signal) is compared to the base load profile, i.e. to the initial load profile, where no incentive is sent by the CA. This comparison gives an estimation of the achieved re-profiling of the average prosumer, which is in fact the available flexibility. Hence, the load profiles of the average consumer and consequently the aggregated load profile of the whole cluster can be analyzed.

Analytically:

\[ flexi_{t,h} = p_{t,1}^{\text{purch}} - p_{t,h}^{\text{purch}} \]

Where:

\( h \) Request

\( flexi_{t,h} \) Flexibility for the request \( h \) kW

\( p_{t,1}^{\text{purch}} \) Base Load: kW

\( p_{t,h}^{\text{purch}} \) Power purchased from the grid (consumption) for \( h=1 \) kW

\( p_{t,h}^{\text{purch}} \) Power purchased from the grid (consumption) kW

Hence, the energy surplus \( E_{t,h} \) that can be offered by the Commercial Aggregator into wholesale markets and/or flexibility markets is:

\[ E_{t,h} = \begin{cases} flexi_{t,h}, & flexi > 0 \\ 0, & flexi \leq 0 \end{cases} \]

The algorithm focuses on the demand reduction service because it is currently the most common request. However, the demand increase service will be included in future versions of the algorithm.

Current version of the algorithm that was developed for the flexibility forecast is based on the EMS used in [16]. The objective function was slightly modified to include the new parameters, while a new term was added, to reflect the incentives that are provided by the Commercial Aggregator. Since the algorithm is simulating the response of the EMS, the objective function aims to minimize the electricity bill of the consumer. The new objective function is:
\[
\begin{align*}
\min\left(\sum_{t=1}^{T} \Delta t \left[ C^I (p_{t}^{\text{purch}} + p_{t}^{\text{sell}}) + Pr_t (p_{t}^{\text{purch}} - p_{t}^{\text{sell}}) \right] \\
+ \sum_{t=1}^{T} \sum_{w=1}^{W} \Delta t [C^{EV\text{disch}} p_{t,w}^{EV\text{disch}}] + \sum_{t=1}^{T} \Delta t [K^A d^A_t] - \sum_{n=1}^{N} \sum_{t_s}^{t_e} (1 - x_{n,t}) I_{n,t} \right)
\end{align*}
\]

where:

\begin{align*}
p_{t}^{\text{purch}} & \quad \text{Power purchased from the grid} \quad \text{kW} \\
p_{t}^{\text{sell}} & \quad \text{Power sold to the grid} \quad \text{kW} \\
p_{t,w}^{EV\text{disch}} & \quad \text{Power flexibility from the EV battery} \quad \text{kW} \\
Pr_t & \quad \text{Day-Ahead spot price} \quad \text{€/kWh} \\
C^I & \quad \text{Network Interconnection tariff} \quad \text{€/kWh} \\
C^{EV\text{disch}} & \quad \text{Cost of EV battery wear} \quad \text{€/kWh} \\
K^A & \quad \text{Economic penalty for undelivered demand} \quad \text{€/kWh} \\
d^A_t & \quad \text{Critical demand not delivered} \quad \text{kW} \\
\Delta t & \quad \text{Duration of the time intervals} \quad \text{hours} \\
I_{n,t} & \quad \text{Incentive per time interval and consumption level} \quad \text{€} \\
t_s & \quad \text{Starting time of incentive signal} \\
t_e & \quad \text{Ending time of incentive signal} \\
W & \quad \text{Number of EVs} \\
n & \quad \text{Number of consumption levels (as described in next paragraph)} \\
x_{n,t} & \quad \text{Binary variable representing the incentive activation} \\
& \quad (\text{The incentive is activated when } x_{n,t}=0. \text{ This is to comply with the mathematical formulation used in General Algebraic Modelling System (GAMS)})
\end{align*}

This objective function is subject to various constraints that describe the operation of the EVs, the loads and the other elements composing specific prosumers typologies (including different loads, storage systems and generation assets). These constraints are described in [16].

This optimization algorithm calculates the optimal scheduling of the average prosumer per cluster by means of cost reduction (from the prosumers’ perspective) and given the critical load, the production and the spot prices of the electricity market. The time period of the optimization is 24 hours and the time-steps used are quarter hours (15 minutes).
The output of the algorithm is the flexibility profile of the prosumer for a time horizon of 24h hours, with a resolution of 15 minutes. The flexibility profile is in fact calculated as the difference between the initially forecasted load profile, where no incentive is applied, and the modified load profile, after the application of the incentive.

Following the methodology of the ADDRESS project [8], the Commercial Aggregator applies a specific incentive policy for every cluster, by sending the price signals for specific timeslots. The incentives correspond to specific predetermined levels of consumption. That means that the incentive received by every consumer in each time-interval depends on the total energy purchased by the grid.

\[
\begin{align*}
&\text{if } 0 \leq p_{t}^{\text{purch}} \leq Q_{t1} \quad \Rightarrow I_{t} = I_{1,t}, \quad \forall t' \in [T_{1}, T_{2}] \\
&\text{if } Q_{t1} \leq p_{t}^{\text{purch}} \leq Q_{t2} \quad \Rightarrow I_{t} = I_{2,t} \\
&\text{if } Q_{t(n-1)} \leq p_{t}^{\text{purch}} \leq Q_{tn} \quad \Rightarrow I_{t} = I_{n,t}
\end{align*}
\]

where:
- \(Q_{t,n}\) Consumption Levels \(\text{kW}\)
- \(p_{t}^{\text{purch}}\) Power purchased by the grid, i.e. Consumption \(\text{kW}\)
- \(I_{n,t}\) Incentive for every consumption level \(\text{€}\)
- \(n\) Number of consumption levels
- \(t\) Time Hours or 15 minutes periods

The signals sent are multi-level signals, since there are multiple consumption thresholds and corresponding prices for each one. The EMS of the consumers chooses the best level of consumption that minimizes their costs, within each time interval. Actual consumption/generation levels will be measured afterwards by means of an official electricity meter for billing purposes.

Therefore, for a specific time-step if the consumption is within the interval \((0, Q_{1})\) the consumer will receive an incentive of \(I_{1}\) for that time slot, and so on.

The behaviour of the clusters need to be analyzed under the effect of many different incentive polices. Every incentive policy is formed as a different combination of starting-ending time of the incentive, prices and levels of consumptions. Each one of these combinations is called a request. Hence, several different requests are examined and the results for each one are supplied to the Commercial Optimal Planning. Results for different requests are also used by the CA for flexibility bidding to flexibility markets.

The determination of the requests requires a statistical investigation, which takes into account all the possible combinations and keeps the ones that balance the benefits for both the Commercial Aggregator and the consumers.

The following table illustrates an example of the matrix that is used to feed the different incentive policies to the algorithm.
Request 1: Corresponds to the base load, since no incentive is applied and prosumer’s scheduling depends on the electricity price only.

Request 2: The incentive is applied for the time interval between the 2nd and the 13th timestep.

The price incentive sent is:
- \(I=0.5\, \text{€},\) for a consumption \(0 \leq p_{\text{purch}} < 1\, \text{kW}\)
- \(I=0.4\, \text{€},\) for a consumption \(1 \leq p_{\text{purch}} < 2\, \text{kW}\)
- \(I=0.3\, \text{€},\) for a consumption \(2 \leq p_{\text{purch}} < 3\, \text{kW}\)
- \(I=0.2\, \text{€},\) for a consumption \(3 \leq p_{\text{purch}} < 4\, \text{kW}\)
- \(I=0.1\, \text{€},\) for a consumption \(4 \leq p_{\text{purch}} < 5\, \text{kW}\)

Request 3: The incentive is applied for the time interval between the 13th and the 24th timestep.

The price incentive sent is:
- \(I=1\, \text{€},\) for a consumption \(0 \leq p_{\text{purch}} < 1\, \text{kW}\)
- \(I=0.8\, \text{€},\) for a consumption \(1 \leq p_{\text{purch}} < 1.75\, \text{kW}\)
- \(I=0.6\, \text{€},\) for a consumption \(1.75 \leq p_{\text{purch}} < 2.5\, \text{kW}\)
- \(I=0.4\, \text{€},\) for a consumption \(2.5 \leq p_{\text{purch}} < 3.25\, \text{kW}\)
- \(I=0.2\, \text{€},\) for a consumption \(3.25 \leq p_{\text{purch}} < 4\, \text{kW}\)

The same logic is applied to all the incentive policies.

### 4.1.2 Commercial Optimal Planning

The Commercial Optimal Planning module is key for the analysis of the inputs and the decision making of the Commercial Aggregator when dealing with wholesale markets participation. The resulting consumption profiles for each request, obtained by the flexibility forecast module, are used by the Commercial Aggregator for choosing the optimal ones in order to maximize its profit in wholesale markets. The main results given by this optimization algorithm are the market bids and the price signals to be sent to the clusters of consumers.
As discussed in section 2.6, CA participation in wholesale markets (mainly daily market) would be by means of SRPs. Given that the available flexibility is shared between the SRPs and the CRPs, the algorithm subtracts from the total available flexibility, the already committed CRPs.

Due to the higher resolution of the algorithm’s outputs compared with the market data (15 minutes instead of 1 hour resolution), the bids must be aggregated to form hourly bids suitable for trading in the current markets. The reason for performing all the calculations having a resolution of 15 minutes, is for more accurate and optimized scheduling of the microgrid.

The optimization algorithm for the Commercial Optimal Planning that was developed is described in this section. Using as a basis the original optimization problem proposed in ADDRESS Project [8], the prosumer model is extended taking into consideration further flexibility sources beyond pure demand response, meaning: electric vehicles, energy storage and on-site generation. These additional flexibility sources are included in the optimization problem by means of taking them into consideration when computing the Flexibility Table. A detailed model of the EMS model used for introducing these new flexibility sources is further described in [16]. In this way, the scope of the Commercial Aggregator algorithms proposed in this document is extended taking into consideration key flexibility sources that will be available at prosumer’s premises in the near future (i.e. on-site generation, storage and electric vehicles).

The algorithm was implemented using the GAMS. In order to facilitate the data import, export and the graphical illustration (graphs, tables, etc.), an interface between GAMS and MatLab was introduced. The data handling is performed by MatLab and is then fed to the GAMS to execute the optimization. Then the results are returned to MatLab for further edit and storage.

4.1.2.1 Optimization Problem

The Commercial Optimal Planning module is in fact one optimization algorithm aiming at maximizing the profits of the Commercial Aggregator, subject to some constraints. The profit maximization is achieved in two ways: by selling the available flexibility and by moving the consumption towards the low price hours, in order to procure cheaper energy. During this procedure, the Commercial Aggregator evaluates the set of incentive polices coming from the Flexibility Forecast algorithm and finally picks the most profitable ones, in order to plan its bids. The bids are formed as energy to be sold in the wholesale market. This energy corresponds to the surplus caused by the re-profiling of the consumption.

4.1.2.2 Objective function

Analytically, the objective function is given by:

$$\max \sum_{t=1}^{T} E_t \cdot P_t - \sum_{k=1}^{K} \sum_{i=1}^{H} C_{ik} \cdot x_{ik}$$

Where:

- $E_t$ energy sold by the Commercial Aggregator to the market for the timeslot $t$. This available energy corresponds to the energy surplus, i.e. positive flexibility, after the load re-profiling. In order to comply with the current market rules, the bids must be aggregated in such a way to form hourly bids of energy.
The main variables used in the optimization are the following:

- $Y_t$: Boolean variable to represent a bid in the Market. When it is 1, the Commercial Aggregator is able to submit a bid; else the bid is 0.
- $x_{hk}$: Binary variable to show the activated request $h$ for cluster $k$. When it is 1 the $h$-th request of the $k$-th cluster has been chosen.
- $E_t$: Continuous variable representing the energy to be bid in the electricity market by the Commercial Aggregator, at the timeslot $t$.
- $R_t$: Continuous variable representing the difference between the base load (load profile when no incentive is applied) and the actual load (load re-profiling after applying the incentive). $R$ is in fact the available flexibility at the timeslot $t$. It can either be positive, when the consumers reduce their consumption, or negative, when the consumer increase their consumption for instance during the pay-backs.
- $Z_t$: Binary variable depending on the sign of $R$. It is 1 when $R>0$, otherwise it is 0.

The objective function is subject to the following functional constraints:

- Each cluster ($k$) must receive only one request. Thus, only one incentive policy is chosen for every cluster and one multi-level price signal, as the one described in the previous chapter, is sent. $x_{hk}$ is the binary variable representing the chosen request ($h$) for a specific cluster ($k$) [$x_{hk}=1$].

$$\sum_{h=1}^{H} x_{hk} = 1, \quad \forall k$$

- The bids submitted by the Commercial Aggregator to the market must be over a minimum and below a maximum value, according to the regulation of the market. If $Y=0$ then no offer is presented in the market, thus the Commercial Aggregator cannot sell any energy

$$\omega Y_t \leq E_t \leq \Omega Y_t, \quad \forall t$$

- The risk tolerance of the Commercial Aggregator to unreliable clusters must be taken into account. Depending on the reliability of each cluster, an upper bound is set to their collected reliability. The higher the reliability, the higher this bound.

$$(1-\sigma_t^k)\sum_{h=1}^{H} x_{hk} \sum_{t\in[t_i,t_{i+1}]} (\text{flexi}_t^i,h,k) \leq \rho_k, \quad \forall k$$

- The available flexibility is shared between the SRPs and the CRPs, since this algorithm calculates the optimal amount of SRPs only, the flexibility reserved for the already sold CRPs, must be
subtracted from the total available flexibility. M is an arbitrary big number, used to formulate the mathematical expression of the relation of Z and R.

\[ E_t + CRP_t \leq \Delta_t R_t + (1 - Z_t)M, \quad \forall t \]

- The flexibility R is defined as the difference between the base load and the actual load after the application of the incentive. So, this difference corresponds to the maximum flexibility that can be traded to the market.

\[ \sum_{k=1}^{K} [P_{t,1,k}^{purch}(t) - \sum_{h=1}^{H} x_{hk} P_{t,h,k}^{purch}] \geq R_t, \quad \forall t \]

- This constraint links the sign of R with the binary variable Z. If R>0 then Z=1.

\[ (1 - Z_t)(-M) \leq R_t \leq Z_t M, \quad \forall t \]

- If Z=0, i.e. R<0, then no CRP or SRP can be traded, since it corresponds to an increase of consumption. This study deals with flexibility products formed by decreasing the consumption.

\[ E_t + CRP_t \leq Z_t M, \quad \forall t \]

- This constraints guarantees that only when R is positive (Z=1) can the Commercial Aggregator submit a bid in to the market.

\[ Y_t \leq Z_t, \quad \forall t \]

### 4.1.2.5 Assumptions in the Simulation

Since the module contains several parameters that change the results if modified, some assumptions should be made for the sake of simplicity. Taking into consideration further developments and/or adaptations, the algorithm has been formulated in a generic fashion so that it can be easily modified for more realistic approaches or new data inputs. The assumptions made are the following:

- SRPs are formed as the surplus of energy resulting by the load re-profiling. Only bids for positive flexibility, i.e. decrease in consumption, are offered to the market.
- No thresholds are considered for bidding in the market. The scope of the simulation is to simulate the possibility of offering flexibility to the network. Thus every positive value for the flexibility is offered to the market.
- The risk tolerance of the CA is assumed to be infinite, so the respective constraint is deactivated (\(\sigma_k = 1, \rho_k = 0\)).
- The payback effect is not taken into consideration. The SRPs are formed as simple energy bids.
- The time resolution used by the EMS algorithm is 15 minutes. The market resolution according to the current regulations is 1 hour. Hence, the bids must be aggregated to form hourly bids, suitable for trading in the energy markets.

### 4.1.3 Software implementation

The tools described in the previous 2 subchapters, have been implemented using a combination of Matlab and GAMS software. The Flexibility Forecast and the Commercial Optimal Planning modules were both implemented in GAMS, since they consist of Optimization problems. MatLab was used as a user interface.
and an interconnection, to feed in the inputs and save the outputs, to plot the figures. The whole structure of the developed algorithm is illustrated in Figure 4-1.

Figure 4-1 Illustration of the developed algorithm (interconnection between MatLab and GAMS)

For further information about the accessibility and use of both algorithms, please refer to D6.1 Part II.

4.2 DSO new algorithms

The tertiary controller is a DSO’s toolbox specified, designed and implemented within IDE4L WP5. It aims for alleviating congestions and for network optimization, and fulfils all the different roles that DSOs are expected to play within the CA concept. Therefore, Tertiary controller can be considered as the DSO system that interfaces DSOs and CAs. The tertiary controller is composed of three units – Network Reconfiguration Algorithm, Dynamic Tariff and Market Agent. For the realization of the commercial aggregator approach, only Network Reconfiguration Algorithm and Market Agent are required:

- **Network Reconfiguration Algorithm (NRA):** The network reconfiguration algorithm is part of the technical solutions available to the DSO for network optimization and congestion management. It does not rely on markets, customers or other actors and is therefore a very reliable solution for the DSO. The NRA reconfigures the medium voltage network in order to optimize the network conditions (loading and voltage) and alleviate any congestion that may be present in the network. In this process, it also considers the control available from lower lever controllers.

- **Market Agent (MA):** This algorithm facilitates the DSO’s roles towards the market. It serves both as the business role and as the validation role. As explained in chapter 2.6, the business role buys flexibility services (SRP and CRP products). The validation role does offline (OLV) and real time (RTV) validation. This unit is the DSO’s interface to the market.

While Primary and Secondary controllers (to be described in section 4.3) are running in real-time, the Tertiary controller is running both day-ahead/intra-day basis and real-time, where off-line validation and
real-time validation algorithms are used respectively. The following sequence is followed for both algorithms, with minor changes:

1. Initialization: updated topology, active and reactive power flow from the state estimator and or the real measures (for the real time run), and flexibility availability.

2. Check MV grid constraints: run power flow to check the technical validation of the schedule coming from the market clearing program.

3. Send request message to NRA: in case of congestion problems the tertiary controller manager will send a request message to the NRA to execute the network reconfiguration algorithm.

4. If the NRA is not able to solve the congestion, the MA algorithm is run (in one of its options depending on the time frame):
   a. Off-line validation algorithm: by means of an AC Optimal Power Flow the MA will seek for the cheapest solution by means of rejecting/activating SRPs and/or CRPs from the market and/or from previous bilateral contacts. The validation algorithm is run for timeslots of one hour independently both for day-ahead and intra-day markets.
   b. Real-time validation algorithm: an Optimal Power Flow is activated but in this case only the activation of already procured CRPs is considered, and similarly to the Off-line validation new CRPs requested to be activated by third parties can be refused/curtailed.

5. Once a solution is obtained, the accepted/rejected bids and activation requests are sent to the CAs and the final schedule is stored in the DSO data base. A solution will always be obtained because generation or load curtailment is always a feasible solution.

The previous algorithms are implemented in Matlab. Further details on its implementation as well as some application examples can be found in [7].

4.3 Interaction between CA and DSO algorithms within the IDE4L control architecture

The control concept within the IDE4L project is based on a hierarchy of controllers. These controllers are primary, secondary and tertiary controllers:

- Primary controllers (PC) operate autonomously and have the fastest response. The set points of them may be adjusted remotely. Primary control operates in IEDs and DERs, the latter subject to secondary control decisions directly, when owned by the DSO, or indirectly, when privately owned and managed by the CA.

- Secondary controllers (SC) coordinate the operation of primary controllers within a control area specifying set points. SCs are located at primary or secondary Substation Automation Units (SAUs) depending on which network, MV or LV grid, they are managing.
Tertiary level (TC) manages the whole system. TC is located in the Distribution Management System (DMS) at control centre and it is in charge of interfacing CAs and DSOs to validate and to request flexibility services. It adjusts network topology remotely via SCADA/DMS and locally via workforce management system. It may also advise SCs from system and day-ahead viewpoints.

Figure 4-2 presents a detailed description of the interactions between hierarchical levels of the control system and functioning of congestion management in different periods (day-ahead, intra-hour, and real-time). This figure has been adapted from a representation previously introduced in Section 3 of IDE4L deliverable D5.2/3 [7], in order to highlight the role played by the CA.

CA functions are represented in yellow colour. The TC is indicated by dark blue colour and consists of the off-line validation, slow restoration (real-time implementation of network reconfiguration), and real-time validation. SC building blocks are indicated by light blue colour and consist of secondary power control, BOT (block OLTC of transformers) and power control parameter update. PC functions are indicated by white colour. In addition to controllers, this figure includes supporting functionalities like forecasting (orange), monitoring/estimation (green), and markets (purple).
After the day-ahead market bidding process, the DSO will validate if proposed schedules for load demand and production will fit in local distribution network constraints i.e. validate if there exists congestion during next day. If congestion does not exist then market may be closed, otherwise the TC will try to mitigate congestion by reconfiguring the network (by means of the NRA) or requesting help from the market agent function (MA) to seek for the cheapest solution. This solution can be provided by means of purchasing SRPs in the flexibility market or rejecting energy bids from the day-ahead market. Ideally, the DSO would coordinate with the TSO when performing these operations.

Intra-hour time frame links day-ahead decisions to real-time frame. Power control parameters update functionality, modifies the cost parameters of OPF within real-time SCs in order to adapt them to changes in forecasted network state and in MV network topology. Formulation of OPF is a multi-objective problem which may have multiple optimal operation points dependent on the preferences of DSO. Preferences are indicated in the form of OPF cost parameters. During intra-hour time period, the CA can receive requests for activation of CRP from other agents (e.g. TSOs, BRPs), prior to its real-time realization.

Real-time time frame follows similar structure as previous time frames except real-time monitoring is utilized instead of forecasting. Real-time SCs may also request help from the TC (slow restoration and real-time validation) to solve the congestion problem. Slow restoration will reconfigure the network to solve the problem. If this is not enough, then the real-time validation is requested. OPF of market agent is activated but in this case only the activation of already procured CRPs is considered, and new CRPs requested to be activated by third parties can be refused/curtailed.

Day-ahead, intra-hour and real-time optimization and adjustments are incremental. The benefit of integrating these time scales according to the operation of CA, DSO, TSO (and possibly third parties) as described in this deliverable, leads to minimal adjustments in real time, primarily linked to the truly unforeseeable occurrences. Conversely, foreseeable occurrences are anticipated and corrected based on historic knowledge and longer term forecasting. And this is a good result, as real time decision and operation is the most demanding. Finally, the proposed operation merges technical and business knowledge and decisions, while maintaining the interests and competences well separated.

5 Comparison and combination of Commercial Aggregator and Dynamic Tariff approaches for congestion management at distribution level

5.1 Dynamic Tariff concept

Within IDE4L project, a dynamic tariff approach is developed within IDE4L Deliverable 5.4 (to be released on 2016) as a means for congestion management at distribution network. The proposed dynamic tariff approach calculates and publishes a new dynamic tariff before the day-ahead market gate closes.

The most important step of the DT method for congestion management is for the DSO to determine the appropriate DT that can alleviate the potential congestions. First of all, the DSO needs to predict the energy price of the spot market. Second of all, the DSO needs to predict the energy demands and availability of the flexible demands, such as EVs and HPs. After having all the information, including the grid model, the DSO can use an optimization model to calculate the DT.
This is the first method that the already described tertiary controller could use in the process of finding a solution for network congestion. The dynamic tariff model would still calculate and publish the dynamic tariff even if no congestion is expected. This may be done for network optimization purposes.

As for the case of the Commercial Aggregator, the implementation of the dynamic tariff concept faces several challenges when current market and network regulatory frameworks are considered. Some of these challenges are listed below:

- DSOs are not allowed to discriminate customers based on their location in the grid.
- The income of DSOs is regulated as they are a natural monopoly. With the dynamic tariff, which varies from day to day and hour to hour, it is very difficult to ensure that the income stays within regulation limits.
- Grid tariffs are usually a very small part of the overall energy price seen by customers. Due to this, it will likely be necessary to have very large changes in tariff price in order to change consumption patterns of customers.

On the other hand, there are several advantages associated with the use of a dynamic tariff, naming:

- It is capable of reaching all customers, regardless of whether these are associated with a Commercial Aggregator or not. It is “free” for the DSO – i.e. it is not a product that needs to be purchased, but is equivalent in nature to the ordinary grid tariff.
- It is not necessarily dependent on any of the other actors – i.e. it can be used as long as customers are price sensitive, so they are willing to move their consumption or production e.g. with an EMS and are on a contract that reflects the dynamic price.
- The dynamic tariff reflects the strength of the grid. In that sense, it visualizes the strength of the grid for the DSO and can provide a guideline to where in the grid congestion management is necessary.

Therefore, similarly to the Commercial Aggregator approach, Dynamic Tariff, despite presenting some challenges when current market and regulatory frameworks are considered, it is a promising approach that can potentially solve many of the problems that distribution networks will face in the coming years.

Bearing that in mind, in the next section an integrated approach ensuring a good interaction and harmony between the dynamic tariff approach and the Commercial Aggregator approach is proposed. Main objective is to further investigate if this combined approach can effectively enable demand response in the energy markets, as one of the key objectives of IDE4L project.

5.2 Integration of the two approaches

The goal here is to integrate the Commercial Aggregator approach and the dynamic tariff approach into one combined approach. Given that the roles of the actors in the two approaches do not conflict with each other, its integration is quite straightforward. There is however a minor issue to be taken into consideration: the market for the CA will become smaller after the introduction of the dynamic tariff approach. That is because the dynamic tariff will solve some of the congestion issues in the grid, so the
services of the CA are only of interest to the DSO in situations where the dynamic tariff approach isn’t sufficient.

Even though the dynamic tariff and the CA can be seen as two separate approaches, the goal here is to unify them in one integrated model (Figure 5-1):

As seen in Figure 5-1 there are only two interactions tying the two approaches together. The first is the DSO sending the dynamic tariff to the retailer part of a Commercial Aggregator. That means that the Commercial Aggregator can take the dynamic tariff into account when performing its flexibility forecast.

The customer is also an actor that can be involved in both the dynamic tariff approach and the Commercial Aggregator approach at the same time. This means that the same customer can react to both the tariff and to the control of a CA. In the same manner, the customer can choose to react only to one method or neither method. If the customer does not want to be part of a CA portfolio, but chooses just to have a retailer, then the customers can choose to be on a dynamic price, and thus react to the DT. Alternatively, customers can choose to be on a flat rate and not react to the DT. A more complex example could be that the customer has a CA: the customer can choose to offer their flexibility as a CRP, while having a flat rate contract for energy. In this way, the customer would not react on the DT, but only react on specific requests from their CA.

So the conclusion here is that the two approaches can easily be integrated. But that it also makes sense to simply consider the dynamic tariff as a new market condition, and then add the Commercial Aggregator on top of that.

Final decision to be taken by national energy regulatory agencies, however, should balance advantages and disadvantages taking into consideration regulatory frameworks in place. It should be mentioned that the implementation of both congestion management approaches independently would keep the challenges to the ones coming from only one of the approaches. The combined approach, however, would imply to face at the same time the challenges posed by both alternatives, increasing the list of regulations to be reviewed.
Nevertheless, it can be concluded that there could be a good interaction and harmony between them, and therefore it would be of interest to further investigate its combination as a means for enabling demand response at distribution network level.

6 Identification of future challenges from DSOs prospective

6.1 Current role of the DSOs

As discussed above, there is a current need of change in the roles and responsibilities of all stakeholders of the power system, due to the new scenarios that are appearing, e.g. the high penetration of RES. Specifically, DSOs are facing new necessities in the network planning, mode of operation, and maintenance, in order to maintain the quality of service and guarantee the stability and reliability of the grid in these new scenarios.

Within this section, specific practices that DSOs are developing to cope with these changes are described in order to further understand the starting point previous to the potential implementation of flexibility markets.

- **Network planning**

  DSOs can provide information of desired location of the new RES, where DSOs can take the most of them (close to users, in grids with congestion, etc.). These are called locational signals, and they can improve grid management and reduce network reinforcements. Also, DSOs are progressing with the smart metering roll-out all over Europe. Although this is fostered by a regulatory obligation in most cases, it can help handling RES at distribution level.

- **Forecasting, operational scheduling and grid optimization**

  The aim of forecast is to predict possible critical situations (voltage problems, grid congestion, etc.), and design proper network management actions to prevent them. The forecasted values are mainly based on real measurements, so smart meters are essential in this matter. In other cases, the forecasted values can be received from the TSO.

  There is also a regulatory limit for network losses. In some cases, DSOs must buy the lost energy at the wholesale market in order to comply with this requirement. If not, the DSO assumes the correspondent economic loss. Occasionally, the DSO has a penalization if losses are higher than the permitted ones. When RES are present in the power system, a fluent interaction between DSO and TSO is needed. However, in most cases DSOs do not receive scheduling information about generation units. There are some alternatives, e. g., receiving operational information, information up to a specific voltage level, etc. In conclusion, the exchange of information between operators is insufficient in most cases.

- **Real time operation**

  A good practice for real time operation would be an active control of the output of generation resources, being this control performed by a third party. The current situation is that this control is not allowed, or it is limited (with a previous approval of the TSO). This situation is not correlated with the
increase of RES penetration, which can create more situations where the DSO needs to curtail RES to avoid security problems.

Net metering would also be helpful, but it is not permitted in all countries. It allows users to compensate their consumption with on-site generated electricity.

6.2 Future challenges for DSOs
The DSO responsibilities have not changed with the recent evolution of the power grids: they must develop, operate and maintain the power grid guaranteeing quality of service and security of the system. However, the complexity of the networks has increased, due to the high integration of RES, the continuous growth of the peak load in most European countries, and the appearance of new uses of electricity (Electric Vehicles, demand response, Demand Side Management Systems, etc.).

In order to adapt itself to these changes, DSOs will have to modify the way they operate, becoming more proactive than traditional. As discussed in previous sections, the assistance to DSOs in activating flexibilities in the most capillary parts of the grid is expected to gain importance. This is possible thanks to flexibility operators, i.e., CAs acting as intermediary service facilitators that, given the available technologies in their portfolio, will establish a fluent communication between DSO and prosumers, combine different types of flexibility and make them available to the market.

This leads to an Active Distribution Management System where, as discussed above, the DSO acquires new roles to face the challenges that are present now. Beyond the already discussed roles as flexibility procurer and flexibility validation (see section 2.4), the following roles should be assumed in order to realize the proposed commercial aggregator framework:

- **Distribution System Optimizer**: This system performs network planning and operation processes in an optimized way, so that the investments are reduced and to take the most of the flexibility offered by the network, the supply or demand side. It is an evolution of the current role of the DSO to face the current needs of the system. The Distribution System Optimizer provides services such as the elaboration of the distribution network multiannual plan, the optimization of the network development using tariff structures or phase balance optimization, the optimization of work programs, the optimization of network operation until market gate closure based on a schedule, or the decision on asset renewal priorities and maintenance optimization. These services require the interaction with the TSO, grid users and flexibility operators.

- **Data Manager**: This role is already partially played by (some) European DSOs. The reason behind is that higher observability of the network is causing that DSOs have to handle huge amounts of information. Different sources provide data to the DSO, such as the smart metering infrastructure. However, not only come these data from the meters for billing purposes, but they are also required to optimize the use of flexibilities. This leads to a new necessity of the DSOs: receiving, aggregating, validating, processing, analyzing, storing and providing data in a cost-efficient and secure way. Hence, within the Data Manager, three roles are identified: Meter Data Manager (Collector, Responsible and Aggregator), Network Data Manager, and Contracts Data Manager. This system would provide data to the Distribution System Optimizer.
A third party could also take the role of Data Manager. However, allowing another entity to act as Data Manager and handle data from the whole power chain could require additional effort from the regulatory authorities, so that new laws for this interchange of information would have to be implemented.

- **Neutral Market Facilitator/Enabler:** This functionality of the DSO would cover the administration of market information exchange, and also the validation of market participants. Traditionally, this role is in charge of providing access to the network and consumption information to other market actors. Now it should include also the facilitation of flexibility services in the network. Authorizing the participation of market players, and certifying and managing the impact of flexibilities activated in Balancing and Flexibility markets on the Distribution network, the well-functioning of electricity markets (and, for instance, the system) is ensured.

- **Contributor to System Security:** DSO must be also responsible of informing the TSO about network structure data and its evolution, and forecasted measurements, in order to help TSO in the operational planning and scheduling, and to provide cost-efficient solutions to system wide problems by responding to TSO’s operational planning, scheduling and security requests (emergency situations included). In the case of reactive power, this functionality manages the provision of reactive power at DSO-TSO boundaries, in order to support the mechanisms for voltage control at the transmission level (see Network Code on Demand Connection [17]).

- **Distribution Constraints Market Operator:** This new role is aimed to manage and coordinate the flexibility offered by the grid (distributed generation, demand response) at distribution level, used to cope with network constraints. It is necessary to select, contract and send signal to the flexibility asset in order to provide the selected flexibility. This activation would depend on forecasted scenarios and contractual arrangements, and need also the coordination with other market players and grid operators. There are two ways to perform the Distribution Constraints Market Operator: either as an extension of the existing TSO balancing market, or as an independent market mechanism (but coordinated with the rest of the markets). Being a part of TSO market can simplify flexibility needs and procurement efforts, e.g., when an overlapping of flexibilities needed in transmission and distribution levels occurs. In this case, a unique platform permits that DSO and TSO cooperate in order to pool resources and avoid conflicts.

- **Smart Meter Operator:** DSOs have also the function of administrator of smart metering systems. As the roll-out of smart meters in Europe is very advanced, there is a necessity of installing, testing, maintaining and managing the meters, that would be assumed by the DSO. In addition, it would be also in charge of the information exchange between the metering infrastructure and the communication system. This role is already assumed in some European countries where electronic meters are in place.

- **Customer Relationship Manager:** Customer Relationship Manager would be responsible of managing contracts at distribution level, such as access contracts and requirements for grid users, DSO-Supplier contracts and requirements, and DSO-Balance Responsible Party contracts and requirements, needed for certain processes performed by third parties (e.g. TSO). This task involves
the communication with grid users (consumers and producers), suppliers, BRPs, flexibility providers and the TSO. Currently, network codes do not fully consider certain roles as the aggregator role (dispatching aggregators, demand aggregators, or active power aggregators), so this lack of consideration elevates the costs of dealing with DER. The Customer Relationship Manager can help to reduce this cost. Moreover, it could provide the basis for the consideration of these roles in the network codes.

- **Other Third Parties Relationship Manager**: DSOs would also be in charge of the interaction with regulators, local authorities, service providers, etc. This is not a new practice, but it should evolve with the deployment of smart metering infrastructures and the collection of a higher amount of data.

Therefore, it can be observed how in order to adapt themselves to these changes, DSOs will have to modify the way they operate, becoming more proactive than traditional. However, the implementation of technical solutions that permit this way of operation is limited by the lack of framework in several issues:

- Rules forbidding RES energy curtailment except for security issues, so that the flexibility that this kind of assets can provide is not utilized. DSO should be capable of control the production, either by itself or through third entities such as aggregators.
- Insufficient self-consumption frameworks
- Insufficient DSO access to advanced PV inverter capabilities
- Insufficient framework for prosumer storage solutions. Storage at a consumer level could help network critical situations, but a control with a global visibility would be needed.
- Insufficient framework for demand response. DSO could take the most of demand response by managing the energy consumption in an active manner.
- Regulatory framework with little/no incentives for smart grid solutions: DSOs are currently remunerated by reinforcing the network, so there is no immediate need for finding different solutions apart from reinforcements, i.e., smart grid solutions. In this sense, regulation linked to performance is a key element for the evolution of the smart grids.

Thus, it is required that regulatory authorities define a clear model which implements the aforementioned roles, and the rules, incentives and unbundling requirements for DSO and other stakeholders.
7 Conclusions

This chapter concludes the report by providing an overview of the main contributions of IDE4L Deliverable D6.1 – Part 2.

- Flexibility Commercial Aggregation is considered as a key innovation on the power system to face future challenges posed by growing demand and RES integration. In Europe, in response to Directive EC/2012/27, some countries have already started implementing CA concept, especially for system balancing purposes.

- In addition to system balancing, value can be created from demand side flexibility by tapping into other value pools: capacity markets, congestion management, and portfolio optimization. It is imperative to understand that for realizing this value, further coordination among CA, DSOs and TSOs is required.

- Within this document, a Commercial Aggregator concept is proposed relying on previous research and current regulatory tendencies. Not only is the commercial aggregator concept described, but also its interaction with the rest of power system entities.

- Main objective is the definition of an optimal scheduling tool for day ahead operation and intraday adjustment. For doing so, optimal management tools for commercial aggregators are described and developed, aiming at modelling effects and potential benefits created by tapping into the different market pools.

- The integration of the proposed commercial aggregator approach into the holistic distribution network automation architecture proposed within IDE4L project is described. Two are the new roles that IDE4L distribution network automation architecture introduces for realising Commercial Aggregation:
  - Procurement of flexibility products: The DSO can access and procure flexibility products offered by commercial aggregators to use them for a number of purposes (e.g. distribution network reinforcement deferral, congestion management, etc.).
  - Validation of flexibility Products: to validate flexibility products prior to its activation, when used by other agents different to the DSO itself.

- Following mainstream state of the art research, the proposed CA architecture is composed of the following functionalities aiming at maximizing CA profits when trading flexibility: Consumption Forecasting, Consumer Segmentation (Clustering), Flexibility Forecast, Market Forecast, and Commercial Optimal Planning.

- Besides integration of the CA approach into IDE4L network automation concept, the following improvements on commercial aggregator's “Flexibility Forecast” and “Commercial Optimal Planning” tools are implemented:
• Flexibility Forecast: a sensitivity analysis procedure is included in order to investigate prosumer’s responses to the different price incentives, improving commercial aggregator’s portfolio optimization.

• Commercial Optimal Planning: the prosumer model is extended taking into consideration further flexibility sources beyond pure demand response, meaning: electric vehicles, energy storage and on-site generation.

• Developed CA algorithms are tested for day-ahead and intra-day operation in Deliverable D6.1-Part III. In addition, the CA concept will be tested in real time operation within Task T6.4, and reported into Deliverable D6.3.

• Within this document, Commercial Aggregator and Dynamic Tariff approaches as two means that independently or jointly can be used for distribution network congestion management, are compared. It is concluded that there could be a good interaction and harmony between them, and therefore it would be of interest to further investigate its combination as a means for enabling demand response at distribution network level.

• Finally, when dealing with challenges for DSOs from a regulatory perspective, it should be noticed that in order to adapt itself to the changes identified in this document (and IDE4L project in general), DSOs will have to modify the way they operate, becoming more proactive than traditional. DSOs must maintain their core responsibilities, but also achieve a more active approach across their activity. Hence, there is a need to implement an Active Distribution System Management approach, to be able to:
  o Improve network planning
  o Optimize the use of flexibilities to solve network constraints
  o Foster TSO-DSO cooperation
  o Facilitate and enable energy markets

In order to implement the Active Distribution System, DSOs must evolve and take new roles that have been described, and an adaptation of the current regulatory framework is needed. It is expected that regulatory authorities define a clear model which implements these roles, and the rules, incentives and unbundling requirements for DSO and other stakeholders.
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ANNEX 1: Electricity market organization

Liberalization of Electricity Markets

The electricity market was initially vertically integrated, and then the liberalization process started [18]. After the separation of competitive activities and monopoly activities the ancillary services were created.

When the market was vertically integrated the electricity used to be delivered as one single product and all the services required to transport the energy were supplied by one integrated utility. After the separation of activities, the created companies did not have the possibility to manage by their own resources for the needed services. As a result, ancillary services were created as tradable products [18].

Traditionally, the electric power has been generated by large power stations then it is transmitted to the loads at distribution level. In order to ensure the operational stability and safety of the power that is transmitted ancillary service are provided mainly by these large power stations. Today the power grids and electricity market are facing a change in the generation of electric power due to an increase of penetration of Distributed Generation (DG) and Renewable Energy Sources (RES) which are connected at the distribution grid mainly. Because DGs are connected in the distribution grid have many effects in the operating mechanics of the power grid and imposing changes in the electricity market.

In the next section a brief introduction of the electricity market actors is presented and the main interactions between them is explained.

Electricity Market Main Actors

Current electricity market has been developed under the concept that electricity is centrally generated and consumed. This means that it is considered with unidirectional power flow from generation towards demand. When DER are introduced in the distribution grid the interaction between generation and demand is changing. Also changes in the market need to be considered in order to have an efficient integration of these DERs into the power grid.
The main actors of the current electricity market are [19]:

(a) Central generator: Central generators functions are to generate electrical energy, contribute with inertia to ensure sufficient frequency quality (since a higher inertia will yield a slower frequency change) and also provides ancillary services to ensure the system stability.

(b) Transmission system operator (TSO): the TSO is responsible for the balance between load and generation in the transmission power grid. The TSO also reports the transmission capacity to the market operator so that the market auctions and clearance do not violate any transmission constraints. The TSO operates the grid in real time and based on the frequency deviation balancing power is activated.

(c) Distribution system operator (DSO): The DSO is in charge of distributing the electricity to the load, and ensures that the required grid capacity is available in order to perform this service properly with the expected level of quality. The DSO could be responsible for the metering consumption and/or production of a certain grid, and afterwards it would send this information to the pertinent actor. Usually the DERs are installed in the distribution grid with a “fit and forget” approach. This type of approach usually limits the capacity and the integration of the DERs into the power grid.

(d) Supplier: The main task of a supplier is to provide clients with electricity. In order to do this they acquire the electricity from traders and/or generators, then they sign wholesale agreements with their clients. The supplier has obligations when supplying clients with electricity and for each supplier there must be a balance responsible party.
(e) Balance responsible party: The balance responsible party (BRP) receives the generation schedule plan, the demand forecast and with this information resolve any unbalance between them. After operation the BRP collects meter data from the suppliers and generators and then invoices the energy balance of the suppliers and generators. Is it expected that this role will be more complex in the future as the DERs integration becomes more successful.

(f) Consumers: The end consumers represent the demand. End consumers have had the electricity available for consume from the grid, and usually there has been a unidirectional flow of electricity from the grid towards them. Many operational costs (e.g. ancillary services, variations in the spot price) have been flattened out and have none or little pass-through in the retail and distribution cost of electricity.
ANNEX 2: Flexibility requirements from DERs

As it was explained above an increasing penetration of DERs due to different reasons is changing the interaction of actors in the electricity market. DERs are often not integrated in the network’s operation because they are considered to have a small capacity, unreliable and costly when looked individually. Up to some years, most of the DERs were installed following the fit and forget approach and are only injecting the available power into the interconnected network.

However, it is only through a proper aggregation and the integration into power system management that DERs will be able to provide the same capacity and flexibility of the conventional power plants [20]. With the adequate integration and aggregation of DERs a many different services to support technically the grid can be provided as well as it will allow the participation on electricity markets of DERs [21].

According to [21] the increase penetration of DERs and the need of a more reliable and cost efficient network operation will require new ancillary services to properly operate the distribution and transmission grids. This means that the future ancillary services should include the DSO and its infrastructure in addition to the TSO. From [21] the future expected ancillary services are:

- Frequency Control (provided by TSO)
  - Primary Frequency Control
  - Secondary Frequency Control
  - Tertiary Frequency Control
- Voltage Control (provided by the TSO and DSO)
  - Primary Voltage Control
  - Secondary Voltage Control
  - Tertiary Voltage Control
- Congestion Management (provided by the TSO and DSO)
- Network Restoration / Black Start (provided by the TSO and DSO)

And additional service will be required for providing more grid stability is the fault ride-through. The fault ride-through capability would be required for whenever a fault occurs in the grid, the voltage will drop (or have a dip) until the protection system locate the fault and isolates it from the rest of the grid. Commonly, grid codes requires that power plants stay connected to the grid to inject reactive power into the grid and help maintaining the voltage and also to ramp up the active power after the fault clearance with a limited gradient to harmonize the natural recovery of the grid.
The possibility of providing ancillary services from Wind Energy, Photovoltaic Energy and other flexibility products is discussed in Section 4.1.

The feasibility of distribution grids offering ancillary services to TSO depends on the RES hosted by the distribution grid, on the capacity of the distribution grid to operate stably while offering the ancillary service, and on the readiness of the automation system.

The minimum amount of Frequency Control Reserves in the EU for the transmission, for different ancillary markets is 1 to 2 MW for primary reserves and 10–20 MW for secondary and tertiary reserves [22].

Considering that the capacity of typical micro-sources connected to the distribution system or to microgrids is 10–100 kW [23], it follows that aggregation of such resources is necessary. The major considerations regarding the feasibility of the ancillary service schema are related to: aggregation, actual availability of the RES, operation of the distribution grid while the ancillary service is activated. Regulatory challenges are linked to the pre-qualification of the aggregated system and possible modifications to be introduced to the grid code of the distribution system.

The feasibility of the aggregation is linked to the willingness of the individual RES to participate. Technically, in an Aggregator-ready environment, the communication and control of RES should not be an issue. Furthermore, given the well laid out interaction of the IDE4L CA scheme and the DSO’s DMS, the coordination is enabled. For what concerns the feasibility in terms of total power of RES in one distribution system, some exemplary numbers reported in section 3.1.

For what concerns the actual availability of the RES, this depends on the portfolio. In some cases may require storage, which could be achieved by leveraging on existing flexibilities, such as EVs.

The operation of the distribution grid while the ancillary service is activated is the key to feasibility. In fact, the operation of RES for ancillary service may lead to congestion and other violations and increased losses. The IDE4L architecture, which realizes deep penetration of monitoring and control in the distribution grid,
down to the LV level, is designed to cope with these issues automatically. However, conflicting control behavior may emerge in the “ancillary service mode”, so the actual feasibility should be tested extensively.

The feasibility of the distribution grid to offer services as interruptible load is bound to the ability to operate as a microgrid. The generation-load balance capacity depends on the particular features of the grid. But from the automation standpoint, the IDE4L architecture and control structure, with primary-secondary-tertiary control and the DMS-CA connection, may be adapted to meet the requirements of this operation. In this sense, the presence of microgrids may facilitate the realization.

Assuming that the ancillary service requirements are reverberated downward, from the TSO to the DSO to the individual RES, then the RES would be operated for providing the ancillary service, while the coordination and control for maintaining safety and continuity of service in the distribution grid is provided by the DMS. In this perspective, we provide in the following an overview of the feasibility of main DERs to provide ancillary services.

**Contribution of Wind Turbines to Ancillary Services**

According to [24] for wind turbines a three level hierarchy is proposed: first the wind turbine, second wind farm and lastly power system controls. At the primary control would be considered the wind turbine, other controllers are installed on the power electronics converters of the variable speed or in the pitch controllers wind turbines, i.e. inertial, droop and deloading controllers. The wind farm, second level control, the central controller receives the power command from the system operator and then send this command to the local controllers of the wind turbines and energy storages.

Finally, the third level control the power system level, would perform a better frequency behavior by coordinating the complete power system and the wind farms.

**Technical Capabilities for Frequency Support**

In this section the technical capabilities required from all the three level hierarchy (wind turbines, wind farms and wind power plants) will be discuss in order to enable the technical services required for the frequency support.

**Technical capabilities regarding the Active Power Control Mode**

Wind power plants should be able to perform active power control functions. This comply all the functions for controlling the active power output to supply the electric grid accordingly with the system operator requirements (i.e. set points, ramps and gradients). Those control capabilities are required to control the power output up to a certain limit if schedules are defined and to implement frequency control. Wind power plants are also required to have active power constraint functions, to avoid overloading of the electricity network during congestions.

According to [24] study about less than 20% of the current wind turbines installed in Europe were installed with the earlier designs. This earlier design installed has fixed speed and limited variable speed, thus active power is not possible or probably very limited (up to 1-2% active power variation [24]).

The wind turbines with a more modern design have the capability to reach full capability from the lowest power level in 6-10 seconds [24]. When considered at wind farm level, the active power control capability
is can be available and also a very fast ramp rate control, approximately between 10-20 seconds when considering any possible delay [24].

Technical Capabilities regarding the Frequency Sensitivity or Droop Control
To maintain the balance between generation and demand, the traditional large generators use a droop control [24]. One term use to understand the droop control is the Frequency sensitivity mode that according to [24] is defined as “the ratio of the steady state change of power output (referred to Maximum Capacity) to the steady state change in frequency (referred to nominal frequency)”.

To procure frequency control the transmission grid the TSOs and DSOs requires a “deadband” frequency response, this deadband is purposely used to cause the frequency control unresponsive to minor frequency changes, and it is also adjustable. On the other hand, according to [24] “the (in)sensitivity is the inherent feature of the control system defined as the minimum magnitude of the frequency (input signal) which results in a change of output power (output signal)”.

One specific example of this requirement is given in figure 2 from the Spanish Grid Code.

![Figure 2: Deadband requirement from the Spanish Grid Code](image)

The newest wind turbine models can execute frequency control and change between modes that might be required by the TSO and the system operator (i.e. under, over frequency operation mode and set deadband for frequency control).

Technical Capabilities for Voltage Support
To evaluate the technical capabilities for voltage support and reactive power support is important to consider the type of coupling mentioned in the previous section.

Technical Capabilities regarding the Reactive Power Provision
To provide reactive power from generators usually PQ diagrams are used, since reactive power supplied can be supplied up to a limited value. From all the different coupling technologies discussed before, the converters offer good properties for control reactive power. By means of self-commutated switching devices converters can provide reactive power independently from active power.
The wind turbines with squirrel cage induction generation coupling or with synchronous generator as coupling technology have no major hardware limitations to provide reactive power limits at low or no active power feed-in. By means of larger dimensioned converters the reactive capabilities can be maximized. From figure 3 several possibilities are compared.

![Diagram showing reactive capability of a commercial Full Scale Converter wind turbine.](image)

Figure 3: Reactive capability of a commercial Full Scale Converter wind turbine.

The point of view of the wind turbine manufactures and developers regarding the most appropriate equipment to provide reactive power are presented in figure 4. It can be seen that both groups consider that wind turbines have the capability to it adequately.

![Graph comparing capacitive and inductive compensators, FACTS, and wind turbine generators](image)

Figure 4 More suitable methods to provide and control reactive power at wind farm level.

Technical Capabilities for System Restoration Support

In order to analyze the technical capabilities of a wind turbine to provide system restoration support to the system, more specifically the TSO, the stochastic nature of this technology needs to be considered. Since the nature of the primer mover it’s not controllable and its weather dependent. To determine if this service is possible and reliable from wind turbines more investigation is required.

An approach proposed by [22] is that wind turbines would not be part of the first line restoration, instead it is proposed that wind turbines could be part of the large stage process, when some generators are already online.
Contribution of PVs to Ancillary Services

Nowadays PV must fulfill technical requirements to be able to provide some types of ancillary services [22]. Therefore technically speaking there are no considerable challenges to provide ancillary services from PVs. Nevertheless, it is important to consider the economical aspect, when looked PVs individually frequency control services can be costly and less competitive. On the other hand, frequency control services provided by a larger PV portfolio are able to provide more competitive prices.

PV systems are not able to fulfill the requirements for reserve services which might be contracted during night periods (in order to fulfill this requirement storage systems can be implemented but this will increase the cost of the PV system). This issue is a barrier for the PVs to be considered for providing frequency control services to the TSOs. One possible solution proposed by [18] could be to limit the ancillary services contracted to a day ahead and time blocks without night hours, by considering this limitation it could allow a better integration of PVs.

In contrast to frequency control services, the voltage support is better to be offered by small local PV systems [22]. The aggregation of systems for this specific case will only be advantageous because of the possibility to offer a coordinated control [18].

Technical Capabilities regarding Frequency Support

The technical capabilities required to provide frequency support from PVs are described.

Technical Capabilities regarding the Active Power Control Models

As mentioned before, PVs are required to have technical capabilities for ancillary services, in the case of Germany, it is required PVs are able to provide active power management. With this capability, local congestion can be possible corrected. According to [18], the modern functions for active power control allows the PV to reduce the actual power output to a defined percent of the rated response signal defined/required by the TSOs and DSOs.

Active power control capability is required to be provided by all size systems. According to [23]: “small scale units (less than 30 kWp) can choose either to be remotely controlled by the DSO or to be permanently curtailed at 70%”.

The network operator is able to reduce the active power injected from PV whenever it is affecting the stability and operation of the grid. Thus PVs must be able to reduce their active power output in steps of maximally 10% of the agreed active power connection (Pac) [18]. This active power reduction capability must be available from any operating point to the defined value set by the TSO and at any operation condition.

According to [18] when looking at the inverter depending on the design, a time response of <500ms to 1 second is possible, from the lower power level to the full maximum power level available. According to [18], all manufacturers nowadays offer the active power control, since there are not technical limitations from the inverter point of view.

Technical Capabilities regarding the Frequency Sensitivity or Droop Control

Whenever there is an over frequency event, the PV are able to provide frequency support by means of reducing its active power output. From [18] while in operation all generation units must reduce
instantaneous active power, at a frequency of more than 50.2 Hz. This reduction of active power must be
performed with a gradient of 40% of the available power per Hertz, shown in figure 5. Only when the
frequency returns to 50.05Hz the active power may be increased again – only if the actual frequency does
not surpass 50.2 Hz.

\[
\Delta P = 20 P_m \frac{50.2 \text{ Hz} - f_{grid}}{50 \text{ Hz}} \quad \text{at } 50.2 \text{ Hz} \leq f_{grid} \leq 51.5 \text{ Hz}
\]

\[P_m = \text{Generated Power} \]
\[\Delta P = \text{Power Reduction} \]
\[f_{grid} = \text{System Frequency} \]

at 47.5 Hz \(\leq f_{grid} \leq 50.2 \text{ Hz}\) \(\rightarrow\) No restrictions
at \(f_{grid} \leq 47.5 \text{ Hz}\) or \(f_{grid} \geq 51.5 \text{ Hz}\) \(\rightarrow\) Disconnection

Figure 5: Active power reduction in case of over-frequency

The modern inverters have the capability to perform frequency droop, and also can define a deadband
mode of operation to provide frequency control. When considering a PV system, it is necessary to
considered a delay due to communication and processing time of the plant controller. This will have an
impact in the time response which might be around 500ms to 2 seconds plus the delay at the inverter level.

**Technical Capabilities for Voltage Support**

As discussed before the ENTSO-E [25] requires voltage set point capabilities covering at least 0.95 to 1.05
pu. It is also require that the set point is reached in steps no greater than 0.01 pu. The slope has to be in
range of at least 2 to 7% and with steps no greater than 0.5% and has to achieving 90% of the change in
reactive power output with a response frame of 1-5 seconds. Finally in a time frame of 5-60 seconds it must
settle at the value defined by the operating slope, a steady-state tolerance not greater than 5% of the
maximum reactive power is required. Such requirements are to be extended to PVs installed at all voltage
levels, including the ones in distribution; according to [18] this capability is present in almost all modern
inverters.

**Technical Capabilities regarding the Reactive Power Provision**

When PV systems are connected to the MV level it is possible to provide reactive power independently or
via remote control. A PV system when generating can operate with a range of \(\cos \varphi = 0.95\) underexcited to
0.95 overexcited for the reactive power output at the coupling point. Thus the system operate is able to
define a target value for the reactive power provision. This can be performed via remote control with any
of the following options: a fixed power factor \(\cos \varphi\), a power factor \(\cos \varphi\) as a function of \(P\), a fixed reactive
power in MVar or a reactive power/voltage characteristic \(Q\) as function of \(V\) (Volt / Var Control).

In order to provide reactive it is necessary that the generating unit is able to adjust its reactive power
production or absorption and have the capability to reach the fixed reactive power range in a time frame of
few minutes, whenever it is required. According to [18] PV inverters can provide all the different reactive power control schemes.

Reactive power is commonly delivered by the inverters but as stated in [18] the developers consulted believe that for large ground systems its required devices that can be centrally controlled such as: FACTS, on load tap changer (OLTC) and synchronous compensator.
ANNEX 3: Ancillary services in the electricity market

Ancillary Services can be defined as those services necessary to support the transmission of energy from the generation site to its final customer.

A formal definition is provided by EURELECTRIC in which ancillary services are defined as:

“Ancillary services are those services provided by generation, transmission and control equipment which are necessary to support the transmission of electric power from producer to purchaser. These services are required to ensure that the System Operator meets its responsibilities in relation to the safe, secure and reliable operation of the interconnected power system. The services include both mandatory services and services subject to competition” [26].

The task of the system operator or in the case of Europe, the Transmission System Operator (TSO) can be summarized as [18]:

- Balance the system from minute to minute
- Ensure operational security and stability

To perform these tasks the TSO needs ancillary services. According to [27] the TSO acts to ensure that the generation is equal to the load in near real time, to maintain this TSO procures to contract ancillary services, some the ancillary services includes: black start capability, frequency response, fast reserve, provision of reactive power and other. Thus often there will be one buyer of the ancillary services, the TSO [18].

Types of Ancillary Services

The ancillary services can be classified in the following three categories: frequency response, generation demand imbalances services and local services [18].

a. Interconnection response services

I. Frequency Response services

The generation units and the consumption loads connected to the grid need to be controlled and monitored for secure high quality operation of the grid. The frequency control is one essential task to allow TSOs to perform daily operational business. Different control actions are performed to maintain the frequency at its target value; the frequency control diagram is shown in figure 1.

- **Primary Control** main objective is to maintain a balance between generation and consumption. Primary control stabilizes the system frequency at a stationary value after a disturbance or incident in time frame of seconds, but without restoring the system frequency and the power exchanges to their reference values.
- **Secondary Control** maintains a balance between generation and consumption of the grid and its frequency taking into account the schedule programmed exchange, without harming the primary control. Secondary control makes use of a centralized continuous automatic generation control and modifies the active power set points typically 15 minutes after an incident.

- **Tertiary Control** is any automatic or manual change in the working points of generators (mainly re-scheduling) in order to restore adequate secondary control reserve. It is primarily used to free up the secondary reserves in a balanced system situation, but also activated as a supplement to secondary reserve after larger incidents to restore the system frequency and consequently free the system wide activated primary reserve. Tertiary control is typically operated in the responsibility of the TSO.

Figure 1: Organization of frequency control in a power system, Source: [28].
b. Generation demand imbalance services

I. Regulation response: is the ability to respond to a computed imbalance between resources and obligations (including load, interchange and frequency response). Regulation uses on-line generation that is equipped with automatic generation control (AGC) and that can change output quickly to track the moment-to-moment fluctuations in customer loads and correct for the unintended fluctuations in generation. Regulation helps to maintain interconnection frequency, manages differences between actual and scheduled power flows between balancing areas and match generation to load within the balancing area.

II. Load following: uses the on-line generation to track the intra- and inter-hour changes in customer loads. The load following is relative to regulation and responds to a slow demand signal. The non-spinning reserve is generation and responsive load that is offline and can become fully responsive after 30 minutes. The non-spinning reserve can be used for load following.

III. Contingency reserve: is the ability to respond to unexpected events. The contingency reserves needs to be sufficient to cover the unexpected events (e.g. trip of a large generator) to maintain the system balance. These reserves usually are made up between spinning and non-spinning reserves and have to be big and fast.
c. Local Services

I. Reactive services

By means of reactive power several services can be provided to the transmission network, one of them is voltage control. The control of voltage and reactive power has to be done to maintain voltage at terminals of all equipment within desired levels. The reactive power flow has to be minimized to reduce losses ($R^2$ and $X^2$) to its practical minimum. Because reactive power has big losses when moving through big distances is a service that needs to be provided locally. Different to the frequency control there are different voltages levels across the grid, thus is more complicated to monitor.

The control of voltage levels is performed by controlling the production, absorption and flow of reactive power at all levels of the system. The generating units provide the basic means of voltage control, which can be called voltage primary control. Additional devices and means are used in the system to control the voltage [18]. The devices are:

- Sources or sinks of reactive power i.e. shunt capacitors, shunt reactors, synchronous condensers and static var compensators (SVCs).
- Line reactance compensators, i.e. series capacitors.
- Regulating transformers, i.e. on load tap changers.

When operating, planning and controlling voltage in real time the TSO has two mainly two targets:

- Voltage profile management and reactive power dispatch (steady state) [29]: the main function is to maintain the voltage profile within the acceptable range and within the tolerance margins. This will allow a minimization of power losses and keep a steady state security. In table 1 and 2 is shown the voltages ranges set by the ENTSO-E [30].

<table>
<thead>
<tr>
<th>Synchronous Area</th>
<th>Voltage range</th>
<th>Time duration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continental Europe</td>
<td>0.9 pu – 1.118 pu</td>
<td>unlimited</td>
</tr>
<tr>
<td>Nordic</td>
<td>0.9 pu – 1.05 pu</td>
<td>unlimited</td>
</tr>
<tr>
<td>Great Britain</td>
<td>0.9 pu – 1.10 pu</td>
<td>unlimited</td>
</tr>
<tr>
<td>Ireland</td>
<td>0.9 pu – 1.118 pu</td>
<td>unlimited</td>
</tr>
<tr>
<td>Ireland offshore</td>
<td>0.9 pu – 1.10 pu</td>
<td>unlimited</td>
</tr>
<tr>
<td>Baltic</td>
<td>0.9 pu – 1.12 pu</td>
<td>unlimited</td>
</tr>
</tbody>
</table>

Table 1: Voltages Ranges for reference voltages defined by TSO between 110kV to 300kV, according to ENTSO-E . Source: [31]
Maintaining voltage stability dynamic [29]: this is referred to the grid voltages from a dynamic time frame (seconds to minutes). As explain in the objective is to avoid a slow voltage collapse event or when possible to limit its heaviness and spread in case of an event. (i.e. loss of generation unit).

d. Black Start

Black start capabilities is the services provided to restart a unit or an area without external supply. The Black Start Capability is a critical functionality that is required in all power systems, but it is not mandatory, because it is only necessary for the generation units which initiate the restoration process. After the connection of these generation units, the system will be back to stable conditions and the other generation units that will reconnect subsequently do not require Black Start Capability. The number of generation plants needed for the initiation of the restoration process is a function of the local electric system topology and characteristics. Usually the TSOs define emergency plans in case of contingencies and also restoration plans in case a major blackout occurs.

Generators technical specifications from ENTSO-E

To classify the different types of generators and its technical capabilities the ENTSO-E uses four types of generators: A, B, C and D. This classification considers both the capacity of the power station and the voltage level of connection (below or above 110kV). Generally, the technical requirements increment with the type of generator. In table 3 is shown the mentioned classification.
The growth of RES according to is led by three main drivers: environmental, commercial and national/regulatory.

For energy security and sustainability RES have an attractive position for the following reasons [32]:

- It is distributed around the network close to customers; the failure of a DG station may have a limited impact on the whole system compared with a larger power station.

- Diverse technologies and primary sources. The diversification of the primary sources, especially with renewable energies, does give a sense of control over the satisfaction of future energy needs of each nation or organized group of nations.

For what concerns the commercial drivers, one of the consequences of introducing competition and choice in the electricity market with deregulation has increased the risk for all market players. The capital required to build and put in operation a bulk power station is very large, and risky, because return on investment is much longer. As a consequence generation projects with smaller capacities appear favorable yielding less financial risk.

The balance of commercial drivers would change with the feasibility of DERs and distribution system direct participation to the market of ancillary services.
Growth tendency of RES in the Power Grids of the European Union

The Head of State and Government of the EU27 resolved in March 2007 a binding target of 20% final energy consumption from renewable energy by 2020. This target entered into force in June 2009 after the European Parliament and Council approved upon the RES Directive.

Some examples about DG penetration level today are presented in Table:

<table>
<thead>
<tr>
<th>DG installed</th>
<th>Nominal active power</th>
</tr>
</thead>
<tbody>
<tr>
<td>Germany, PV installed at LV level</td>
<td>21.5 GW</td>
</tr>
<tr>
<td>Germany, PV installed at MV level</td>
<td>11 GW</td>
</tr>
<tr>
<td>Germany, Wind Power installed at LV level</td>
<td>2 GW</td>
</tr>
<tr>
<td>Germany, Wind Power installed at MV level</td>
<td>30 GW</td>
</tr>
<tr>
<td>Italy, Wind Power and PV installed at MV and LV level</td>
<td>20 GW</td>
</tr>
<tr>
<td>Spain, Wind Power installed at MV and LV level</td>
<td>2.6 GW</td>
</tr>
</tbody>
</table>

*Table 4: DG installations in some European regions, from [33].*

In 2013 the gross electricity generated from renewables was 823 TWh and it was an increase of 11% compared with 2012, with electricity generation from solar power having the most significant growth when compared with the previous year (20%).

In 2013, renewable electricity generation accounted for almost 26% of total EU gross electricity generation. According to [34]:

- Hydropower plants generate by far the largest share of electricity from renewable energy sources, while their share of total renewable electricity shrank from 94% to 43% over the 1990-2013.
- Wind power generation has more than tripled over the period 2005-2014 and it is the second largest supplier to renewable electricity, surpassing biomass. Germany, Spain and UK are the EU’s top 3 producers of wind power.
- Solar electricity generation has also grown quickly and in 2013 had the 10% of all renewable electricity. Also, in 2013 the electricity generated from photovoltaic energy exceeded solid biomass and it has become the third most important contributor to the electricity production from renewable sources.
- Solid renewables (solid and other solid biomass) are also used in conventional thermal generation power plants; their share in electricity grew from 3.5% in 1990 to 9.5% in 2013.

According to [28] a total installed capacity of renewable electricity generation has significantly increased during the last 20 years, especially the wind and PV capacity. This is very important because, the generation capacity from renewable sources in 2013 reached around 380 GW while the existing electricity generation capacity of fossil fuel plants in the EU was around 450GW in 2013.

Acknowledging the main reasons for an increase of RES into the electricity market and the targets approved by the EU countries is imminent an increasing penetration of RES to generate electricity. According to [29] the RES growth tendency for the next 15 years in the European Union is shown in figure 4. The figure 4 displays an historic development and forecast evolution of electricity generation in the EU and the
expectation for the 2030 target. From figure 3 it can be seen it is expected a decrease in generation of electricity from fossil fuels and an increase in generation from Renewable Energy Resources (RES).

![Figure 3: Growth tendency of Energy generation by source in EU. Generation by Primary Energy 2030 Outlook in the EU, Source: Eurelectric Power Statics & Trends 2013. Study from the ENTSO-E evaluating current DGs impact in the system frequency.]

The study from the ENTSO-E is aimed to: “assess the risk for the security of the interconnected system in relationship with the high penetration of RES with disconnection settings (under and over frequency) that may compromise the system security”. Notice that this study may provide useful hints in understanding the feasibility of DERs in offering ancillary services. In fact, knowing what critical network quantities they influence adversely, we gain insight in what quantities they can actually contribute to regulate.

In [35] a dynamic model of the European Continental system was developed in Matlab/Simulink, this to be able to represent the dynamic frequency behavior. As basics and for scenario selection was used the principles of the RG CE Policy 1 “Load Frequency control”, as mention in [35] the scenarios were realistic but pessimistic assumptions were also considered.

According to this study the main factors affecting the frequency stability are:

- Amount of generation capacities tripping at given thresholds
- Primary frequency behavior
- Total system inertia given from the traditional large power plants considering the system load demand and the amount of dispersed generation.
- The load characteristic during transient frequency deviation

From the simulations performs was identified that the risk of frequency deviations is higher at low load also for high generation by DG units, this is because of a smaller inertia in the system due to less large power plants with rotating electric machines.

According to [35] the most critical thresholds are at 49.5Hz, 49.6Hz, 49.7Hz, 49.8Hz and 50.2Hz, 50.3Hz, 50.4Hz and 50.5 Hz. Also from [35], “normal type contingency” -loss of 2GW of load or 3GW of generation-
the chances to get at one of the critical frequency thresholds is much higher if deviation of the steady-state frequency is higher than 50 to 100 mHz. If the initial deviation does not exceed 50 mHz, this probability is decreases except at very low demand periods.

The recommendations from [35] are: (a) new RES and DG installations should fulfill the requirements provided by the network code requirements for Generators; (b) the member states of the ENTSO-E should all together make sure that the maximum admissible non-retrofitted generation disconnecting at 50.2 Hz should not exceed 4500MW (around 6000MW installed capacity) or the cascading effect between 49 and 50 Hz is maximum 2350MW (around 3000MW of installed capacity) of non-retrofitted DG infeed; and (c) ENTSO-E recommends allocating for maximum loss of DG in over and under frequency in each country proportional to the share of the capacity at risk.