Customer European Commission

Subject Report on a new policy framework to support and promote flexibility in the electricity system and market

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0	04/08/2021		Draft Final version
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1 INTRODUCTION

This report is the first deliverable (corresponding to Output 2.1) of:

- Outcome 2 – “Active participation of customers and increase of flexibility in the electricity market and in the power system, in line with Cypriot Integrated National Energy and Climate Plan”

foreseen by the Grant Agreement:

- Implementation of the EU regulatory framework in the area of electricity in Cyprus.

The goal of the deliverable is to:

- report on a new policy framework to support and promote flexibility in the electricity system and market, also addressing the following aspects:
  - dynamic electricity price contracts (as in Article 11 of Directive EU 2019/944);
  - aggregation and independent aggregators including from demand response (as in Articles 13 and 17 of Directive EU 2019/944);
  - active customers (as in Article 15 of Directive EU 2019/944);
  - energy communities (as in Article 16 of Directive EU 2019/944);
  - incentives for the use of flexibility in distribution networks (as in Article 32 of Directive EU 2019/944);
  - the ownership of energy storage facilities (as in Articles 36 and 54 of Directive EU 2019/944).

To this aim, the following documents have been taken as a reference:

- Regulation EU 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) (hereinafter the “IEM Regulation” or “Regulation”);
- Directive EU 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast) (hereinafter the “IEM Directive” or “Directive”);
- Electricity Market Regulation act of 2021 of the Republic of Cyprus in accordance with Article 52 of the Constitution (hereinafter the “Cypriot Law” or “Law”) that has been in force since 7/10/2021;
- Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast);
- Cyprus’s Integrated National Energy and Climate Plan – version 1.1 issued in 2020.

Possibly, references will be made also to the deliverables results of the following actions carried out by RSE to the benefit of MECI and already financed by the Directorate General for Structural Reform Support (DG REFORM) of the European Commission:

- SRSS/C2016/005 - "Technical and policy/regulation support to the Ministry of Energy, Commerce, Industry and Tourism with regard to its participation in the process for amending the existing Trade and Settlement Electricity Market Rules", carried out in 2016 and in 2017;
- SRSS/S2017/048 - "Technical support to improve the penetration of renewable energy sources and energy efficiency in Cyprus"
  - Work package 1 – "Review and amendment of the Trade and Settlement Electricity Market Rules", carried out in 2018 and in 2019.

The report deals with the following main topics:

- overview of the Directive EU 2019/944 on the internal market for electricity, namely empowerment of consumers, aggregation contracts and demand response, dynamic electricity price contracts, metering and billing, flexibility in distribution networks and storage facilities;
- customer participation and increase of flexibility in the Cypriot Integrated National Energy and Climate Plan;
- new policy framework to support and promote flexibility in the electricity system and market, namely active customers and renewable self-consumers, energy communities, incentives for the use of flexibility in distribution networks, dynamic electricity price contracts, aggregation of distributed resources and evolution of ancillary services markets.

2 DIRECTIVE EU 2019/944

The Electricity Directive EU 2019/944, alongside with the Electricity Regulation EU 2019/943 and with the RED II Directive 2018/2001, concerns the update of the existing electricity markets in order to adapt their design to new market structures in line with the ambitious 2030 European goals.

In particular, the main purpose of the new electricity market design is to integrate new technologies and new actors in a more flexible way without putting at risk the security of supply, as well as the increasing share of renewable energy sources, mainly photovoltaic power plants and wind farms. Besides, new roles of consumers, enabling their active participation in the electricity market, is emphasized as well.

Specifically, in order to carry out an assessment of the Cypriot framework as specified by the Grant Agreement, the core elements – which are laid down by the EU Directive – that will be taken into account are the following:

- Empowerment of consumers (active customers / renewables self-consumers, possibly jointly acting, and Energy Communities);
- Aggregation and Demand Response;
- Dynamic electricity pricing, metering, and billing;
- Flexibility in distribution networks and storage facilities.

Therefore, a brief analysis of the aforementioned topics as dealt with in the Directive is reported in the following.

2.1 Empowerment of consumers

As reported in the recital (10) of the directive, **consumers have an essential role** to play in achieving the flexibility necessary to adapt the electricity system to variable and distributed renewable electricity generation. Technological progress in grid management and the generation of renewable electricity has unlocked many opportunities for consumers.

Art. 2(8) of the IEM Directive defines an **active customer** as a final customer, or a group of jointly acting final customers, who consumers or stores electricity generated within its premises located within confined boundaries or, where permitted by a Member State, within other premises, or who sells self-generated electricity or participates in flexibility or energy efficiency schemes, provided that those activities do not constitute its primary commercial or professional activity.

Art. 2(14) of the RED II Directive defines a **renewables self-consumer** as a final customer operating within its premises located within confined boundaries or, where permitted by a Member State, within other premises, who generates renewable electricity for its own consumption, and who may store or sell self-generated renewable electricity, provided that, for a non-household renewables self-consumer, those activities do not constitute its primary commercial or professional activity.

Art. 2(15) of the RED II Directive outlines **jointly acting renewables self-consumers** as a group of at least two jointly acting renewables self-consumers in accordance with point (14) who are located in the same building or multi-apartment block.

In accordance with art. 15(1) of the IEM Directive, Member States shall ensure that final customers are entitled to act as **active customers** without being subject to disproportionate or discriminatory technical requirements, administrative requirements, procedures and charges, and to network charges that are not cost-reflective.

As per art. 15(2), Member States shall ensure that **active customers** are:

a) **entitled to operate either directly or through aggregation**;
b) entitled to sell self-generated electricity, including through power purchase agreements (PPAs);
c) entitled to participate in flexibility schemes and energy efficiency schemes;
d) entitled to delegate to a third party the management of the installations required for their activities;
e) subject to cost-reflective, transparent and non-discriminatory network charges that account separately for the electricity fed into the grid and the electricity consumed from the grid;
f) financially responsible for the imbalances they cause in the electricity system.

As specified by art. 15(5), Member States shall ensure that active customers that own an energy storage facility:

a) have the right to a grid connection within a reasonable time after the request, provided that all necessary conditions, such as balancing responsibility and adequate metering, are fulfilled;
b) are not subject to any double charges, including network charges, for stored electricity remaining within their premises or when providing flexibility services to system operators;
c) are not subject to disproportionate licensing requirements or fees;
d) are allowed to provide several services simultaneously, if technically feasible.

According to art. 2(11), a **Citizen Energy Community (CEC)** is defined as a legal entity that:

a) is based on voluntary and open participation and is effectively controlled by members or shareholders that are natural persons, local authorities, including municipalities, or small enterprises;
b) has for its primary purpose to provide environmental, economic or social community benefits to its members or shareholders or to the local areas where it operates rather than to generate financial profits;

c) may engage in generation, including from RESs, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders.

In addition, with reference to Citizen Energy Communities (CECs), art. 16 affirms:

- Member States shall provide an enabling regulatory framework for CECs ensuring that participation in a citizen energy community is open and voluntary;
- Member States shall ensure that CECs are able to access all electricity markets, either directly or through aggregation, in a non-discriminatory manner;
- CECs are financially responsible for the imbalances they cause in the electricity system;
- Member States may decide to grant CECs the right to manage distribution networks in their area of operation;
- DSOs have to cooperate with CECs to facilitate electricity transfers within the CEC.

Furthermore, the article 2(16) of the RED II Directive defines a **Renewable Energy Community (REC)** as a legal entity:

a) which, in accordance with the applicable national law, is based on open and voluntary participation, is autonomous, and is effectively controlled by shareholders or members that are located in the proximity of the renewable energy projects that are owned and developed by that legal entity;
b) the shareholders or members of which are natural persons, SMEs or local authorities, including municipalities;
c) the primary purpose of which is to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits;

Moreover, with reference to Renewable Energy Communities (RECs), article 22 of the RED II directive states that:

- Member States shall ensure that final customers, in particular household customers, are entitled to participate in a renewable energy community while maintaining their rights or obligations as final customers, and without being subject to unjustified or discriminatory conditions or procedures that would prevent their participation in a renewable energy community, provided that for private undertakings, <u>their participation does not constitute their primary commercial or professional activity</u>;
- Member States shall ensure that RECs are entitled to a) produce, consume, store and sell renewable energy, including through renewables power purchase agreements; b) share, within the renewable energy community, renewable energy that is produced by the production units owned

by that REC and to maintaining the rights and obligations of the REC members as customers; c) access all suitable energy markets both directly or through aggregation in a non-discriminatory manner;

- Member States shall provide an enabling framework to promote and facilitate the development of RECs. (e.g. relevant DSO cooperates with RECs to facilitate energy transfers within RECs; the participation in the RECs is accessible to all consumers, including those in low-income or vulnerable households, etc);
- Member States shall carry out an assessment of the existing barriers and potential of development of RECs and may provide for RECs to be open to cross-border participation.

2.2 Aggregation Contract and Demand Response

In accordance with art. 13(1), Member States shall ensure that **all customers are free to purchase and sell electricity services**, including **aggregation**.

"Aggregation" is defined as a function performed by a natural or legal person who combines multiple customer loads or generated electricity for sale, purchase or auction in any electricity market. This activity can be carried out by an "independent aggregator", i.e. a market participant engaged in aggregation who is not affiliated to the customer's supplier.

Art. 13(2)[1] states that Member States shall ensure that, where a final customer wishes to conclude an aggregation contract, the final customer is entitled to do so without the consent of the final customer's electricity undertakings. Member States shall ensure that **market participants engaged in aggregation fully inform customers of the terms and conditions of the contracts** that they offer to them.

Art. 13(3) states that **Member States shall ensure that final customers are entitled to receive all relevant demand response data** or data on supplied and sold electricity free of charge at least once every billing period if requested by the customer.

With reference to demand response, according to the art. 17, Member States shall allow and foster participation of **demand response through aggregation**. Member States shall allow final customers, including those offering demand response through aggregation, to participate alongside producers in a **non-discriminatory manner in all electricity markets**.

[1] Member States shall ensure that these rights are granted to final customers in a non-discriminatory manner as regards cost, effort or time. In particular, Member States shall ensure that customers are not subject to discriminatory technical and administrative requirements, procedures or charges by their supplier on the basis of whether they have a contract with a market participant engaged in aggregation.

Member States shall ensure that **TSOs and DSOs, when procuring ancillary services, treat market participants engaged in the aggregation of demand response in a non-discriminatory manner** alongside producers on the basis of their technical capabilities.

Market participants engaged in **aggregation shall be financially responsible for the imbalances** that they cause in the electricity system.

2.3 Dynamic electricity price contract, metering, and billing

As specified by art. 2(15), a **dynamic electricity price contract** is defined as an electricity supply contract between a supplier and a final customer that reflects the price variation in the spot markets, including in the day-ahead and intra-day markets, at intervals at least equal to the market settlement frequency.

Art. 11(1) states that Member States shall ensure that the **national regulatory framework enables suppliers to offer dynamic electricity price contracts**. Member States shall ensure that final customers who have a smart meter installed can request to conclude a dynamic electricity price contract with at least one supplier and with every supplier that has more than 200000 final customers.

Art. 11(2) states that Member States shall ensure that **final customers are fully informed by the suppliers of the opportunities, costs and risks of such dynamic electricity price contracts**, and shall ensure that suppliers are required to provide information to the final customers accordingly, including with regard to the need to have an adequate electricity meter installed. NRAs shall monitor the market developments and assess the risks that the new products and services may entail and deal with abusive practices.

Art. 19(1) states that in order to promote energy efficiency and to empower final customers, Member States or, where a Member States has so provided, the regulatory authority shall strongly recommend that electricity undertakings and other market participants optimize the use of electricity, inter alia, by providing energy management services, developing innovative pricing formulas, and introducing smart metering systems that are interoperable, in particular with consumer energy management systems and with smart grids, in accordance with the applicable Union data protection rules.

Art. 19(2) states that **Member States shall ensure the deployment in their territories of smart metering systems that assist the active participation of customers in the electricity market. Such deployment may be subject to a cost-benefit assessment**.

In addition, art. 19(5) affirms that where the deployment of smart metering systems has been negatively assessed as a result of the cost-benefit assessment, Member States shall ensure that this assessment is revised at least every four years, or more frequently, in response to technological and market developments. Member States shall notify to the Commission the outcome of their updated cost-benefit assessment as it becomes available.

Art. 19(3) states that Member States that proceed with the deployment of smart metering systems shall adopt and publish the **minimum functional and technical requirements** for the smart metering systems. Member States shall ensure the **interoperability** of those smart metering systems, as well as their ability to provide output for consumer energy management systems.

Art. 20 states that **smart metering systems shall accurately measure actual electricity consumption and shall be capable of providing to final customers information on actual time of use**. Validated historical consumption data shall be made easily and securely available and visualized to final customers on request and at no additional cost.

According to art. 20 on functionalities of smart metering system, security of the smart metering systems and data communication shall comply with relevant Union security rules.

Art. 23(2) on data management states that Member States shall organize the management of data in order to ensure **efficient and secure data access and exchange**, as well as **data protection and data security**.

Art. 18(1) states that Member States shall ensure that **bills and billing information are accurate, easy to understand, clear, concise, user-friendly** and presented in a manner that facilitates comparison by final customers.

Besides, art. 18(2) affirms that Member States shall ensure that final customers receive all their bills and **billing information free of charge**.

In addition, art. 18(3) states that Member States shall ensure final customers are offered the option of electronic bills.

2.4 Flexibility in distribution networks and storage facilities

According to art. 32(1), Member States shall provide the necessary regulatory framework to allow and provide incentives to **distribution system operators to procure flexibility services**, including congestion management in their areas, in order to improve efficiencies in the operation and development of the distribution system. In particular, the regulatory framework shall ensure that distribution system operators are able **to procure such services from providers of distributed generation, demand response or energy storage** and shall promote the uptake of **energy efficiency** measures, where such services cost-effectively alleviate the need to upgrade or replace electricity capacity and support the efficient and secure operation of the distribution system. **DSOs shall procure such services in accordance with transparent, non-discriminatory and market-based procedures** unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion.

As stated by art. 32(2), **DSOs**, subject to approval by the regulatory authority, or the regulatory authority itself, **shall**, in a transparent and participatory process that includes all relevant system users and TSOs, **establish the specifications for the flexibility services procured and**, where appropriate, **standardized**

market products for such services at least at national level. The specifications shall ensure the effective and non-discriminatory participation of all market participants, including market participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation.

DSOs shall exchange all necessary information and shall coordinate with TSOs in order to ensure the optimal utilization of resources, to ensure the secure and efficient operation of the system and to facilitate market development. DSOs shall be adequately remunerated for the procurement of such services to allow them to recover at least their reasonable corresponding costs, including the necessary information and communication technology expenses and infrastructure costs.

According to art. 32(3)[2], the development of a distribution system shall be based on a transparent network development plan that the **DSO shall publish at least every two years and shall submit to the regulatory authority**. The network development plan shall provide transparency on the medium and long-term flexibility services needed and shall set out the planned investments for the next five-to-ten years, with particular emphasis on the main distribution infrastructure which is required in order to connect new generation capacity and new loads, including recharging points for electric vehicles. The network development plan shall also include **the use of demand response, energy efficiency, energy storage facilities or other resources that the distribution system operator is to use as an alternative to system expansion**.

Art. 32(4) states that the **DSO shall consult all relevant system users and the relevant TSOs on the network development plan**. The DSO shall publish the results of the consultation process along with the network development plan and submit the results of the consultation and the network development plan to the regulatory authority. The regulatory authority may request amendments to the plan.

With reference to storage facilities, as a rule, **Distribution System Operators** – in line with art. 36 – as well as **Transmission System Operators** – in harmony with art. 54 – **shall not own, develop, manage, or operate energy storage facilities**. Nevertheless, some exceptions under limited conditions may be applied in accordance with the cited article of the Directive under analysis.

Accordingly, **Member States may allow DSOs as well as TSOs to own, develop, manage or operate energy storage facilities, where they are fully integrated network components** and the regulatory authority has granted its approval, **or where all of the following conditions are fulfilled**:

a) other parties, following an open, transparent and non-discriminatory tendering procedure that is subject to review and approval by the regulatory authority, have not been awarded a right to own,

[2] Member States may decide not to apply this obligation to integrated electricity undertakings which serve less than 100000 connected customers, or which serve small isolated systems.

develop, manage or operate such facilities, or could not deliver those services at a reasonable cost and in a timely manner;

b) such facilities are necessary for the distribution system operators as well as transmission system operators to fulfil their obligations under this Directive for the efficient, reliable and secure operation of the distribution system and **the facilities are not used to buy or sell electricity in the electricity markets**; and
c) the regulatory authority has assessed the necessity of such a derogation and has carried out an assessment of the tendering procedure, including the conditions of the tendering procedure, and has granted its approval.

The regulatory authority may draw up guidelines or procurement clauses to help distribution and transmission system operators ensure a fair tendering procedure.

The decision to grant a derogation shall be notified to the Commission and ACER together with relevant information about the request and the reasons for granting the derogation.

The regulatory authorities shall perform, at regular intervals or at least every five years, a public consultation on the existing energy storage facilities in order to assess the potential availability and interest of other parties in investing in such facilities. Where the public consultation, as assessed by the regulatory authority, indicates that other parties are able to own, develop, operate or manage such facilities in a cost-effective manner, the regulatory authority shall ensure that transmission system operators' activities in this regard are phased-out within 18 months. As part of the conditions of that procedure, regulatory authorities may allow the transmission system operators to receive reasonable compensation, in particular to recover the residual value of their investment in the energy storage facilities.

The above paragraph shall not apply to fully integrated network components or for the usual depreciation period of new battery storage facilities with a final investment decision until 2024 in case of transmission system operators and until 4 July 2019 in case of distribution system operators, provided that such battery storage facilities are:

a) connected to the grid at the latest two years thereafter;
b) integrated into the distribution system as well as transmission system;
c) used only for the reactive instantaneous restoration of network security in the case of network contingencies where such restoration measure starts immediately and ends when regular re-dispatch can solve the issue; and
d) not used to buy or sell electricity in the electricity markets, including balancing.

3 CUSTOMER PARTICIPATION AND INCREASE OF FLEXIBILITY IN THE CYPRUS INTEGRATED NATIONAL ENERGY AND CLIMATE PLAN

Although the Cyprus Integrated National Energy and Climate Plan (i.e. INECP) will be updated according to the target of the European Green Deal, national objectives and targets as well as policies and measures to achieve the decarbonization are reported in the version 1.1 issued in 2020 in accordance to the European regulatory framework. The main targets stated in the INECP are shown in the following figure.

Reducing greenhouse gas emissions and environmental objectives

- Emissions in the non-ETS sectors to be reduced by 20.9% compared to 2005. The non-ETS national target is going to be achieved by the use of flexible mechanisms provided by the ESR.
- Emissions from land use, land use change or forestry are offset by at least an equivalent removal of CO_2 from the atmosphere
- Emissions in ETS sectors to be reduced by 24.9% compared to 2005
- Attaining quantitative targets for reducing national emissions of specific air pollutants

Increasing the share of RES in energy consumption

- Share of RES in gross final energy consumption to reach 23%
- Share of RES in gross final electricity consumption can reach at least 26%
- Share of RES in heating and cooling to reach 39%
- Share of RES in the transport sector to reach 14%

Impoving Energy Efficiency

- Final Energy Consumption of 2.0 Mtoe in 2030, representing 13% reduction in final energy consumption*
- Primary Energy Consumption of 2.4 Mtoe in 2030, representing 17% reduction in primary energy consumption*
- Achieving cumulative energy saving of 243.04 ktoe during 2021-2030

** compared to the respective projection for Cyprus in the 2007 in the EU PRIMES 2007 Reference Scenario*

Figure 1 - Main targets of the Cyprus Integrated National Energy and Climate Plan

In detail, in the Cyprus INECP, Figure 2 and Table 1 are included which describe the estimated trajectories of the sectoral share of renewable energy in the final energy consumption from 2020 to 2030 in the electricity, heating and cooling and transport sectors under the Planned Policies and Measures (i.e. PPM) scenario.

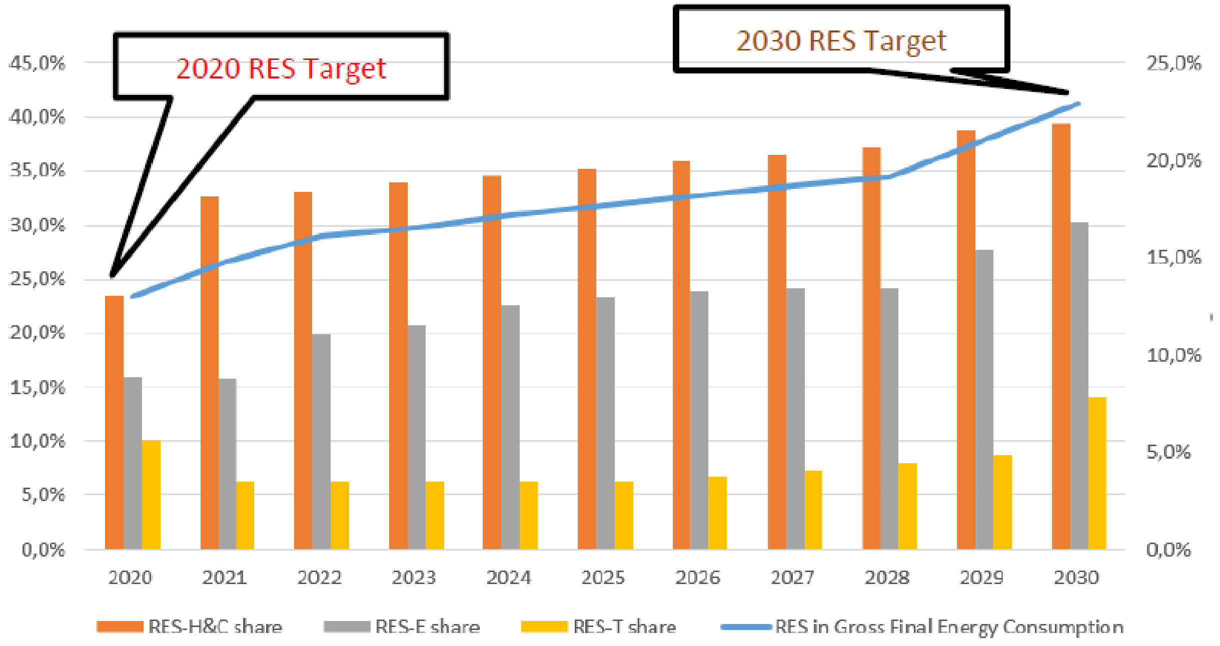

Figure 2 - Evolution of RES shares from 2021-2030, estimated trajectories in the Planned Policies and Measures – PPM Scenario

Table 1 - Trajectories for the sectoral share of renewable energy in final energy consumption from 2021 to 2030 in the electricity, heating and cooling, and transport sectors in two Planned Policies and Measures – PPM Scenarios (Scenario PPM with and without interconnector)

Scenario PPM	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
RES in Gross Final Energy Consumption	14.8%	16.1%	16.5%	17.2%	17.7%	18.2%	18.7%	19.1%	21.0%	22.9%
RES-H&C share	32.6%	33.1%	33.9%	34.5%	35.2%	35.8%	36.5%	37.2%	38.7%	39.4%
RES-E share	15.8%	19.9%	20.8%	22.6%	23.3%	23.8%	24.1%	24.1%	27.6%	30.3%
RES-T share	6.3%	6.3%	6.3%	6.3%	6.3%	6.6%	7.3%	8.0%	8.8%	14.1%
Scenario PPM with interconnector										
RES in Gross Final Energy Consumption	14.8%	16.1%	16.5%	16.9%	17.3%	17.8%	20.8%	23.5%	26.6%	29.7%
RES-H&C share	32.6%	33.1%	33.9%	34.5%	35.2%	35.8%	36.5%	37.2%	38.7%	39.4%
RES-E share	15.8%	19.9%	20.8%	21.4%	22.1%	22.7%	31.4%	38.2%	45.1%	51.3%
RES-T share	6.3%	6.3%	6.3%	6.3%	6.3%	6.5%	7.1%	7.9%	9.2%	14.8%

In addition, the INECP states that, as shown in Table 1, the electrification of heating and cooling and electricity sectors are boosted in the first short term period (2021-2023). RES in the heating and cooling sector continues to grow almost constantly during the whole period, mainly due to heat-pumps and solar energy, while an increase of the RES share in the transport sector is observed during the end of the period.

In particular, the share of RES in the electricity sector is expected to double by 2030 in the PPM scenario without the EuroAsia interconnector and to more than triple in the scenario with the EuroAsia interconnector, thus requiring a significant amount of flexibility in the system in order to cope with the non-dispatchability of the sources.

More in detail, Table 2 shows that solar PV installed capacity will more than double by 2030 and will dramatically increase again by 2035, while wind generation will grow at a slower pace. In terms of flexibility for the power system, the foreseen availability of a significant amount of pumped storage hydro power plants and especially of battery storage systems by 2035 is very important.

Table 2 - Capacity projections in the electricity supply sector (MW) for the Planned Policies and Measures – PPM Scenario

(in MW)	2020	2021	2025	2030	2035	2040
New CCGT[25]	0	216	432	432	432	648
Solar PV	360	380	460	804	1.653	1.892
Solar Thermal	0	0	50	50	50	500
Wind	158	158	198	198	198	198
Biomass & waste	17	22	42	58	58	58
Pumped Hydro	0	0	0	0	130	130
Li-Ion Batteries	0	0	0	0	211	655

Figure 3 shows the projected generation mix, where gas-fired generation (i.e. new CCGTs) are expected to play a dominant role. Of course, their contribution to the flexibility of the system will be very important as well.

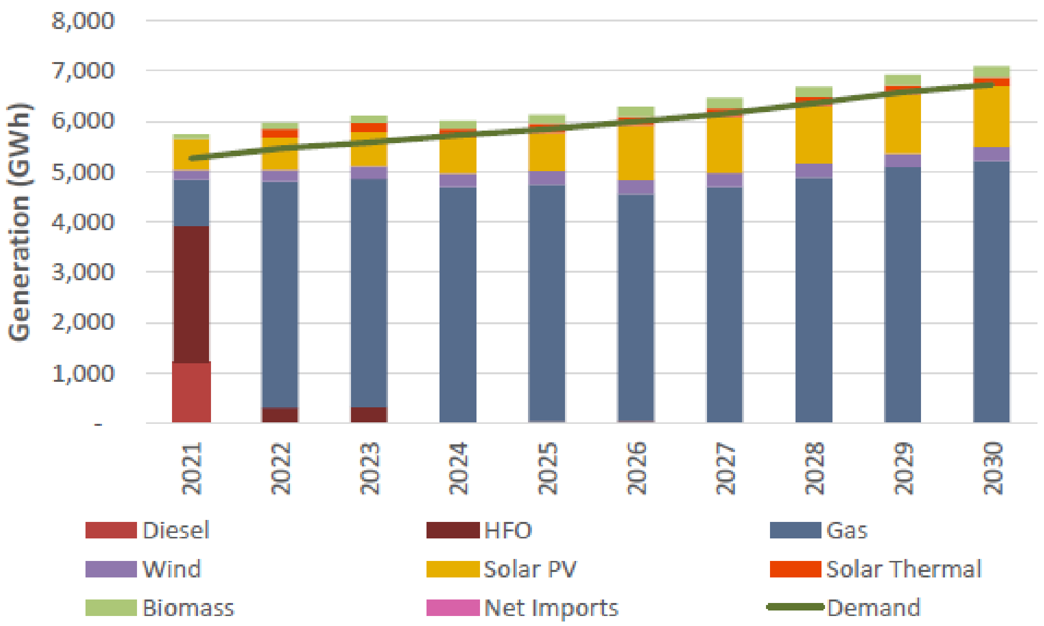

Figure 3 - Projected generation mix till 2030 – Planned Policies and Measures – PPM Scenario, with all available technologies contribution

At the current date, the electricity market in Cyprus cannot support neither flexibility services nor aggregation and demand response. Therefore, the INECP affirms that aggregators, flexibility services as well as demand response will be able to participate through a fully functioning competitive electricity market which is under implementation. Currently the Cyprus regulatory framework allows for the aggregation of RES and CHP units (from 1 to 20 MW), storage (from 1 to 20 MW) as well as demand response (i.e. demand response is entitled to participate in the electricity markets – both energy and ancillary services markets – by cumulative portfolios of at least 300 kVA each); however it is not allowed to mix these three types of resources in one single aggregate. To expand the aggregation of sources of generation irrespective of the primary type of fuel or technology, demand response and storage as well as to allow the participation in the energy markets, TSRs will be reviewed and amended. For reaching this goal, a timeframe of 8-12 months after the transposition of the Directive EU 2019/944 on the internal electricity market into the national legislation has been estimated by the Cyprus Authorities in the INECP. Moreover, as far as storage regulation is concerned, TDRs and TSRs have been amended and published on CERA's website on 30/12/2021 and on 5/1/2022, respectively.

As affirmed by the Cyprus INECP, in order to allow the participation of active customers, energy communities, aggregators as well as demand response, in addition to the electricity market, the roll out of smart meters alongside with a better control of the distribution system should be completed.

In addition, in line with the introduction of dynamic-pricing retail contracts as per the European Directive, the INECP states that Cyprus shall provide the necessary regulatory framework to ensure that final customers who have an installed smart meter can request to conclude a dynamic electricity agreement with a supplier that has more than 200000 final customers. However, suppliers with less than 200000 final customers will not be obliged to offer dynamic-pricing retail contracts.

In this regard, about 8-12 months have been estimated as the timeframe for reaching this goal after the installation of 200000 smart meters, namely September 2025 – December 2025. In addition, according to the latest estimations, the roll-out of 400000 smart meters will be completed by June 2026.

Besides, an untapped Demand Response potential of around 50 MW has been estimated by 2030 in the Cyprus Integrated National Energy and Climate Plan.

Another relevant issue is the electrification of end-uses: in particular, the INECP foresees a penetration of more than 58000 Battery Electric Vehicles by 2030 in the PPM scenario (about 12% of the whole projected car fleet).

4 NEW POLICY FRAMEWORK TO SUPPORT AND PROMOTE FLEXIBILITY IN THE ELECTRICITY SYSTEM AND MARKET

As far as the new policy framework to support and promote flexibility in the electricity market is concerned, this work – in line with the Grant Agreement – shows some options which have been discussed / implemented in Italy and/or other European countries. Nevertheless, detailed policies and measures, objectives and targets with specific reference to the dimension of the Internal Energy Market will be reported in Output 2.2, again as foreseen by the Grant Agreement, on the basis of the content of the present report.

4.1 Active customers & renewables self-consumers

The main definitions of active customers and renewable self-consumers are reported in the following table according to the IEM and RED II Directives.

Table 3 - Definitions of active customers and renewable self-consumers according to IEM and RED II Directives

IEM Directive	RED II Directive
Active customer: a final customer, **or a group of jointly acting final customers**, who consumes or stores electricity generated within its premises located within confined boundaries or, where permitted by a Member State, within other premises, or who sells self-generated electricity or participates in flexibility or energy efficiency schemes, provided that those activities do not constitute its primary commercial or professional activity	**Renewables self-consumer**: a final customer operating within its premises located within confined boundaries or, where permitted by a Member State, within other premises, who generates renewable electricity for its own consumption, and who may store or sell self-generated renewable electricity, provided that, for a non-household renewables self-consumer, those activities do not constitute its primary commercial or professional activity. **Jointly acting renewables self-consumers** means a group of at least two jointly acting renewables self-consumers who are located in the same building or multi-apartment block.

In the following, some relevant issues concerning active customers / renewables self-consumers, possibly jointly acting, are discussed.

4.1.1 Ownership of generation plants

The RED II directive, in case of “renewables self-consumers”, allows that the generation plants be owned by a third-party or managed by a third-party for installation, operation, including metering and maintenance, provided that the third-party remains subject to the renewables self-consumer's instructions. With the aim of obtaining the benefits of self-consumption, the coincidence between producer and consumer is in fact not necessary.

Moreover, it might be discussed whether only one or more third-party producers should be allowed: in fact, the uniqueness of the third-party producer might be a limit to competition, preventing the self-consumer from developing further production projects devoted to on-site consumption, both by himself and by other producers, different from the one already present. It seems therefore appropriate to make possible also a “N to 1” self-consumption configuration, characterized by N different producers (possibly including the self-consumer itself), dealing with it in the same way as a “1 to 1” configuration.
Summarizing, the generation plants used for self-consumption might be property of and/or managed by the self-consumer itself or by third parties, even different from each other, provided that they remain subject to the self-consumer's instruction. It is necessary to define how to formalize the concept of “subject to the self-consumer's instructions” (e.g. the presence of specific clauses in the contract signed by the parties). This task could be assigned to the regulatory authority.
The same considerations concerning the single self-consumer hold for collective self-consumers as well.

4.1.2 Benefits of self-consumption

Self-consumption allows for a reduction of grid losses and, potentially, of network operation and expansion costs (where it reduces the flows on the network and the maximum power required on the connection point), of connection costs and, in theory but not necessarily, of dispatching costs. Therefore, it seems appropriate to compensate every self-consumption configuration, independently from the generation source, for the abovementioned avoided costs that it implies for the power system. In particular, the Italian Regulatory Authority (ARERA), with Resolution no. 318/2020/R/eel, identified the tariff components to be discounted for compensating for the avoided costs on grid usage and grid losses in collective self-consumption and energy community schemes. The discounted network tariff components are around 0.8 €cent/kWh, while, in case of collective self-consumption, avoided grid losses are also discounted, which are equal to 1.2% of the energy shared in case of generation plants connected to the medium voltage distribution grid and to 2.6% in case of generation plants connected to the low voltage distribution grid.
As above mentioned, the directives define active customers and renewables self-consumers as final customers operating within their premises located within confined boundaries or, where permitted by a Member State, **within other premises**[3]. In principle, the on-site production and consumption is not the only one to provide benefits to the system: for example, production and consumption with different connection points both located under the same MV/LV substation avoid losses at the higher voltage levels. In this regard, the possibility of using a “virtual” model (that implies self-consumption through the public network: see paragraph 4.1.4) even for the “1 to 1” self-consumption configurations might be considered

[3] The Law for the Regulation of the Electricity Market of 2021 allows active customers to operate also within other premises.

(for example, an artisan having his home separate from his workshop and willing to supply the workshop with the PV plant installed at home, with home and workshop both connected to the same MV/LV substation).

Apart from the general system charges[4], that will be discussed in the following paragraph, the current tariff structure in force in Italy to cover network and dispatching costs already exempts the energy self-consumed under the same connection point from the payment of the variable parts of the aforementioned tariff components. As for Cyprus, according to CERA's Decision 28/2020, for the electricity withdrawn from the network, the following approved fees shall apply for all support schemes related to the generation of electricity from renewable energy sources for self-consumption:

- transmission network UoS,
- distribution network UoS (1kV to <36kV), including a billing element associated with the Distribution System Operator,
- distribution network UoS (<1kV), including a billing element associated with the Distribution System Operator,
- charge for the provision of Ancillary Services and long-term reserve,
- charge for the recovery of the expenses of the TSOC,
- the applicable charges for Public Service Obligations and any other charges provided in relevant decisions of CERA.

4.1.3 Promotion of self-consumption

The RED II directive (Article 21) as a general principle foresees that the self-consumed energy, within the same premises, should not be subject to any charges or fees, with the exception that the Member States may apply for specific cases (i.e. if the self-generated renewable electricity is produced in installations with a total installed electrical capacity of more than 30 kW or from 1 December 2026, if the overall share of self-consumption installations exceeds 8% of the total installed electricity capacity of a Member State, and if it is demonstrated, by means of a cost-benefit analysis performed by the national regulatory authority of that Member State and the exemption from charges and fees either results in a significant disproportionate burden on the long-term financial sustainability of the electric system, or creates an incentive exceeding what is objectively needed to achieve cost-effective deployment of renewable energy, and that such burden or incentive cannot be minimized by taking other reasonable actions).

[4] General system charges are a quite relevant component of the Italian electricity tariff, usually amounting to more than 20% of the overall electricity cost, accounting for costs related to incentives to renewable sources, cogeneration, energy efficiency in end-uses and energy-intensive industries, to dismantling of nuclear power plants, to support to vulnerable consumers, etc.

This is valid for renewable plants, while for the other plants, that would be included in the more general definition of "active customer", the IEM directive does not explicitly foresee any exemption from charges or fees.

In Italy, the current self-consumption discipline (that foresees the application of general system charges only to the energy withdrawn from the network), on the contrary, applies not only to renewable sources, but also to High Efficiency Cogeneration, due to the benefits in terms of efficiency and of dispatchability that this technology allows.

Moreover, as above mentioned, renewables self-consumption, according to the RED II directive, can have access to support schemes[5] to ensure the economic sustainability of the projects, while for active customers the access to support schemes is not explicitly foreseen (but neither explicitly excluded) by the IEM directive. As far as the promotion of self-consumption is concerned (regarding new generation plants or repowered old ones, for the additional power) we deem that an explicit incentive model, i.e. a model that provides direct incentives on the self-consumed energy, is preferable w.r.t. a model that foresees the non-application of specific charges[6] on self-consumed energy itself. In fact, the implicit incentive model determines higher charges for the rest of consumers who do not have access to self-consumption schemes and does not provide certainty to investors, since it is inherently variable over time. On the contrary, an explicit model can be adequately calibrated according to the objective to achieve, for example, differentiating it for each source/generation technology. This approach has in fact been adopted concerning the energy shared in the collective self-consumption and in the renewable energy community experimental schemes foreseen by article 42 bis of the Italian Decree Law 162/19 described in paragraph 4.2.7.

[5] The RED II directive states that Member States shall put in place an enabling framework to promote and facilitate the development of renewables self-consumption, a framework that "grant renewables self-consumers, for self-generated renewable electricity that they feed into the grid, non-discriminatory access to relevant existing support schemes as well as to all electricity market segments".

[6] Preamble (69) of the RED II directive states that "Member States should as a general principle not apply charges to electricity individually produced and consumed by renewables self-consumers within the same premises. However, in order to prevent that incentive from affecting the financial stability of support schemes for renewable energy, that incentive could be limited to small installations with an electrical capacity of 30 kW or less. In certain cases, Member States should be allowed to apply charges to renewables self-consumers for self-consumed electricity, where they make efficient use of their support schemes and apply non-discriminatory and effective access to their support schemes. Member States should also be able to apply partial exemptions from charges, levies, or a combination thereof and support, up to the level needed to ensure the economic viability of such projects."

Nevertheless, it must be highlighted that the tariff structure currently in force in Cyprus, described in the previous paragraph, does not contain a component similar to the Italian general system charges, whose exemption, for its quantitative relevance, would correspond to a significant incentive to self-consumption. Moreover, the RED II directive specifies that Member States shall put in place an enabling framework able to address accessibility of renewables self-consumption to all final customers, including those in low-income or vulnerable households, for which specific support schemes could therefore be established.
Finally, it has to be noted that the implementation of a self-consumption scheme requires tools for energy management able to maximize the self-consumption itself. Such maximization can be obtained through:

- storage systems, that moreover are able to provide also additional services (e.g. reduction of imbalances, ancillary services, etc.);
- automation systems for control[7] of loads and of generation (if dispatchable) and, jointly, of storage systems, able to achieve load profiles as much as possible corresponding to generation profiles, as well as to answer to possible requests by an aggregator for the provision of ancillary services.

In fact, it is not reasonable to assume that the consumer directly and "manually" reacts all over the day in an optimal way to the variations of generation using the available sources of flexibility, such as a storage system or the thermal inertia of the building. An automation system can continuously optimize the generation/load balance to maximize self-consumption, carrying out also complex computations (for example reacting in advance to weather forecasts impacting electricity generation and heating/cooling demand), on the basis of models of the available devices and of the building.
In this regard, specific support schemes[8] could be defined both for storage systems and for automation systems.
As for the energy that is not self-consumed, the RED II directive states that "renewable self-consumers are entitled to receive a remuneration, including, where applicable, through support schemes, for the self-generated renewable electricity that they feed into the grid, which reflects the market value of that electricity and which may take into account its long-term value to the grid, the environment and society". Thus, provided that support schemes are already in place for the self-consumed energy, the remaining energy, if it is not sold bilaterally to third parties, might be remunerated at the day-ahead market price.

[7] Both local and remote control, in this latter case for example operated by an independent aggregator.

[8] MECI is in the process of drafting a related Aid Scheme for storage systems downstream the meter, i.e. combined with RES generation. Furthermore, an Aid Scheme for the installation of up to ca. 130 MW-150 MW/2h of storage systems in-front-of-the-meter has been pre-notified to DG Competition. The total budget is €40m to €80m intended to cover the "funding gap", as defined in the Climate, Energy and Environmental Aid Guidelines (CEEAG).

4.1.4 *Physical versus virtual models*

In particular with reference to jointly acting active customers and jointly acting renewables self-consumers, physical versus virtual self-consumption models have been analyzed.

In the following, for the sake of simplicity we will refer to the case of a condominium, while the reported considerations hold also for the case of a generic building. In a "physical" model producers and consumers would be directly connected through private links without third-party access. In such a case it would be necessary to group generation and loads behind a single Point Of Delivery – POD (in purple in the following Figure 4), like if the condominium was a single prosumer connected to the network with that POD.

This would require that the condominium owns/manages/develops the internal wirings that would otherwise be owned/managed/developed by the DSO (in blue in the following Figure 4), in order to make the internal network fully private[9], as well as the substitution of the meters of each apartment and of the common services, previously owned/managed by the DSO, with meters owned by the condominium to be used to carry out a sub-metering[10] activity, in order to determine the bills of each user.

In addition to such complications, the most critical point of this scheme is that each user would not be allowed to choose a supplier different from the one of the condominium[11], since it would not have a private POD, and would not have the possibility to decide not to participate to the collective self-consumption scheme or to get out of it.

[9] In Italy, in about 40% of condominiums, corresponding to the most recent buildings, meters are not located in each apartment, but are centralized in a single room, typically located in the basement, from which private links connect the meters to the apartments. In this case, no portion of the public network is present inside the building.

[10] With respect to the meter connected in the POD.

[11] The RED II directive foresees that renewables self-consumers maintain their rights and obligations as final consumers, while the IEM directive foresees that final customers are entitled to act as active customers.

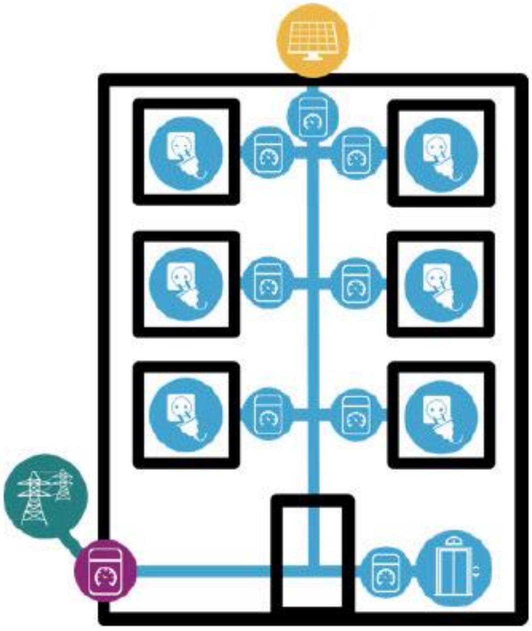

Figure 4 - "Physical" collective self-consumption model

It is therefore preferable to favor, especially in a first phase, a "virtual" self-consumption model, where the connection and metering infrastructure do not need to be modified or owned/managed/developed by the condominium, keeping the traditional architecture as shown in the following Figure 5[12].

In fact, in this scheme the measurements taken in each POD allow to attribute to each user its share of self-consumed energy, on the basis of criteria freely defined among the participants to the collective self-consumption scheme (for example, proportionally to the consumption of each user in each measurement time interval).

Another important advantage of the "virtual" model is that each user keeps its rights as a final consumer, including the freedom of choosing its preferred supplier and not to participate to the collective self-consumption scheme.

[12] As above mentioned, the meters may be centralized in a single room in the basement.

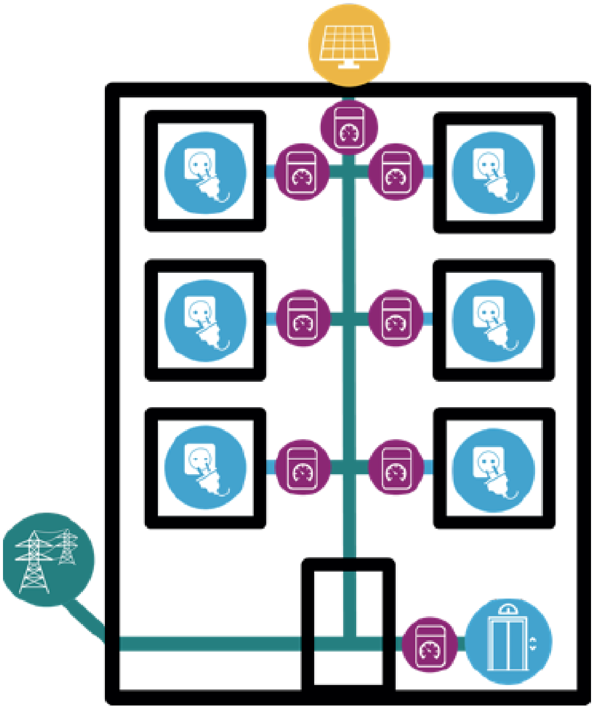

Figure 5 - "Virtual" collective self-consumption model

The abovementioned article 42 bis of the Italian Decree Law 162/19 in fact foresees that the participants to the collective self-consumption scheme "share the energy generated using the existing distribution network. The shared energy is equal to the minimum, in each hourly period, between the electric energy produced and injected into the network by renewable generation plants and the electric energy withdrawn by all the associated final consumers".

In this regard, it must be noted that the second generation (2G) meters that are being installed all over Italy will allow to measure on 15 minutes time intervals, instead of hourly ones, thus allowing to evaluate with a higher precision the self-consumption occurring at the same time as generation and to facilitate the participation to the ancillary services market, characterized by such time granularity.

Wherever the 2G meters are already installed, it would be opportune to determine the energy shared in collective self-consumption schemes in each 15 minutes time period.

The same holds for the half-hourly smart meters that are progressively being deployed in Cyprus.

4.2 Energy communities

The main definitions of energy communities have been reported in the following table according to the IEM and RED II Directives.

Table 4 - Definitions according to IEM and RED II Directives

IEM Directive	RED II Directive
Citizen Energy Community means a legal entity that: (a) is based on voluntary and open participation and is effectively controlled by members or shareholders that are natural persons, local authorities, including municipalities, or small enterprises[13]; (b) has for its primary purpose to provide environmental, economic or social community benefits to its members or shareholders or to the local areas where it operates rather than to generate financial profits; (c) may engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders; Member States may provide in the enabling regulatory framework that Citizen Energy Communities are entitled to own, establish, purchase or lease distribution networks and to autonomously manage them. Member States shall ensure that Citizen Energy Communities are entitled to arrange within the community the sharing of electricity that is produced by the production units owned by the community, subject to other requirements laid down in this Article[14] and subject to the community members retaining their rights and obligations as final customers.	**Renewable Energy Community** means a legal entity: (a) which, in accordance with the applicable national law, is based on open and voluntary participation, is autonomous, and is effectively controlled by shareholders or members that are located in the proximity of the renewable energy projects that are owned and developed by that legal entity; (b) the shareholders or members of which are natural persons, SMEs[15,16] or local authorities, including municipalities; (c) the primary purpose of which is to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits. Member States shall ensure that Renewable Energy Communities are entitled to: (a) produce, consume, store and sell renewable energy, including through renewables power purchase agreements; (b) share, within the renewable energy community, renewable energy that is produced by the production units owned by that renewable energy community, subject to the other requirements laid down in this Article[17] and to maintaining the rights and obligations of the renewable energy community members as customers; (c) access all suitable energy markets both directly or through aggregation in a non-discriminatory manner.

[13] Unlike RECs, medium enterprises cannot be members of CECs with decision-making powers.

[14] Article 16 of the IEM directive.

[15] According to the European Commission (https://ec.europa.eu/growth/smes/sme-definition_en), a small enterprise has a staff headcount < 50 and a turnover or balance sheet total ≤ 10 M€, while a medium enterprise has a staff headcount < 250, a turnover ≤ 50 M€ or a balance sheet total ≤ 43 M€.

[16] The participation of private enterprises must not be their main commercial or professional activity.

[17] Article 22 of the RED II directive.

4.2.1 Participation to energy communities and rights of members

The IEM directive specifies that "Membership of Citizen Energy Communities should be open to all categories of entities. However, the decision-making powers within a Citizen Energy Community should be limited to those members or shareholders that are not engaged in large-scale commercial activity and for which the energy sector does not constitute a primary area of economic activity."

Thus, as confirmed also by a presentation by the European Commission[18] (see Figure 6), the participation to a CEC is open to all categories of entities, while the decision-making powers are reserved to natural persons, local authorities, including municipalities, or small enterprises, provided that, as above mentioned, they are not engaged in large-scale commercial activity and for which the energy sector does not constitute a primary area of economic activity.

On the other hand, the participation to a REC is limited to natural persons, local authorities, including municipalities, or SMEs (whose participation must not be the main commercial or professional activity), while decision-making powers are reserved to shareholders or members of such categories that are located in the proximity of the renewable energy projects that are owned and developed by the community.

	CEC	REC
Energy	Electricity	Renewable energy
Membership	Any entity	Natural persons, local authorities, SMEs
Control	Effective control by natural persons, local authorities, SEs	Effective control by natural persons, local authorities, SMEs located in the proximity of the projects
Purpose	Primary purpose to provide environmental, economic or social community benefits for members or the local area	
Activities	Generation, storage, selling, sharing, aggregation or other energy services, distribution	

Figure 6 - Comparison between CEC and REC

The abovementioned presentation by the European Commission states that the RECs dealing only with electric energy "are a subset of CECs, meeting more stringent criteria", among which, for example, the proximity to the plants required to members with decision-making powers or the membership possible only for certain categories of entities.

[18] European Commission: presentation "Energy communities – implementation of the Clean Energy Package".

A synthesis of membership and effective control criteria is reported in the following Figure 7.

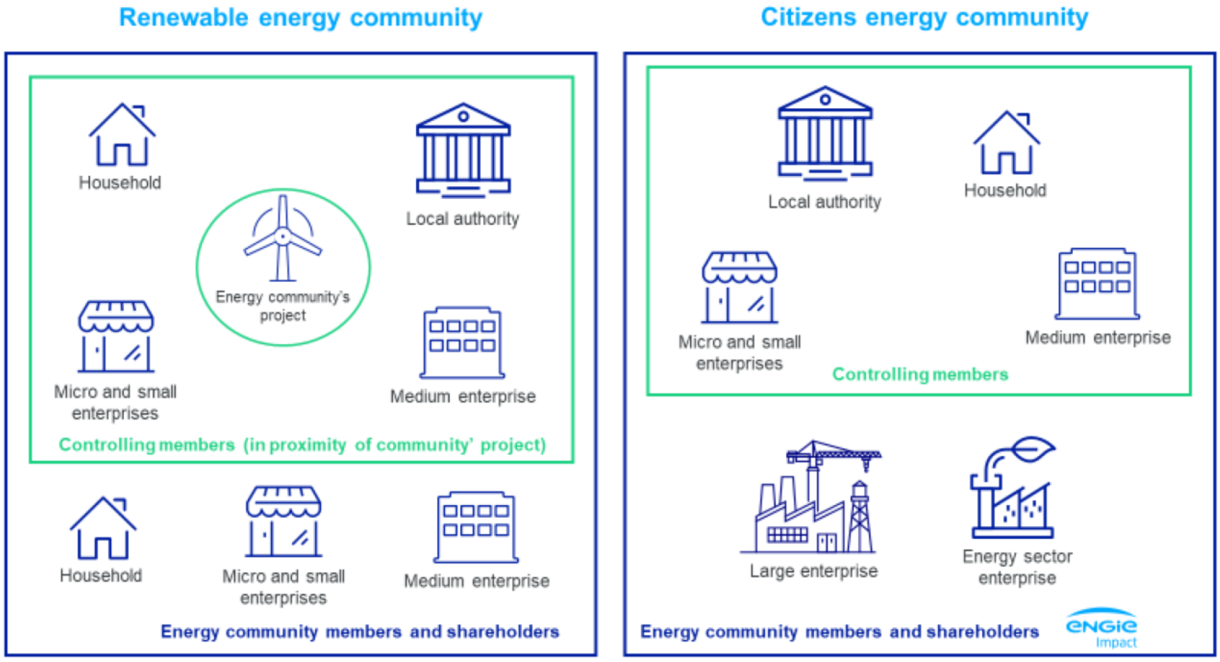

Figure 7 - Membership and effective control criteria of RECs and CECs (source: European Commission - ASSET Study on Energy Communities in the Clean Energy Package: Best Practices and Recommendations for Implementation)

The RED II directive introduces for RECs also the concept of "autonomy" with respect to its members private interests. This means that the governance model must ensure that each member is adequately represented and that a minority of members should not have the power to impose their will to the whole community. This could be obtained for example by imposing a cap on voting rights or even to apply the principle of one member – one vote. In this regard, the abovementioned ASSET Study of the European Commission, as relevant examples, reports that:

- the Greek Energy Communities framework limits the financial participation of members to 20% of the community capital, except for local authorities which are limited to 40% of the community capital if located on the mainland, and to 50% of the community capital for islanded municipalities of less than 3500 inhabitants,
- in Germany, no individual member of "Citizens' Energy Companies" can hold more than 10% of voting rights,
- in the Netherlands and in Belgium there are examples of energy communities that apply the principle of one member – one vote,
- moreover, In Lithuania, at least five members must be natural persons, holding a minimum of 51% of all votes.

We might ask why RECs, characterized by renewable generation plants that are, in terms of sustainability, superior to the ones based on fossil fuels that might be included in a CEC, must comply with more stringent criteria with respect to CECs. The compensation for the more stringent criteria seems to be the possibility for RECs to access support schemes, explicitly mentioned in the RED II directive, but never mentioned (while not explicitly excluded) in the IEM directive concerning CECs[19].

In fact, the RED II directive specifies that: "Member States should ensure that Renewable Energy Communities can participate in available support schemes on an equal footing with large participants. To that end, Member States should be allowed to take measures, such as providing information, providing technical and financial support, reducing administrative requirements, including community-focused bidding criteria, creating tailored bidding windows for Renewable Energy Communities, or allowing Renewable Energy Communities to be remunerated through direct support where they comply with requirements of small installations.", as well as that: "Without prejudice to Articles 107 and 108 TFEU[20], Member States shall take into account specificities of Renewable Energy Communities when designing support schemes in order to allow them to compete for support on an equal footing with other market participants."

Anyway, it has to be noted that the impossibility for medium enterprises to be members with decision-making powers in CECs is a more stringent constraint with respect to what foreseen for RECs where, however, such rights granted also to medium enterprises are limited by the proximity requirement to the plants of the community.

Moreover, the IEM directive explicitly specifies that the shareholders or members of a CEC have the right to quit the community and they keep their rights and obligations as final customers and as active customers (see definition in the Table 3). In case of leaving the community, what is foreseen by Article 12 of the directive on change of supplier applies, with a possible payment of a fee[21].

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[19] In this regard, the document by REScoop.eu ("*Q&A: what are 'citizen' and 'renewable' energy communities?*", July 3, 2019, https://www.rescoop.eu/toolbox/q-a-what-are-citizen-and-renewable-energy-communities) pinpoints that: "The Electricity Directive guarantees that Citizen Energy Communities can participate across the electricity market without discrimination on a level playing field with other market actors, but it does not require Member States to actively promote the development."

[20] Treaty on the Functioning of the European Union, 2012/C 326/01, https://eur-lex.europa.eu/legal content/EN/TXT/?uri=celex%3A12012E%2FTXT

[21] Member States may permit suppliers or market participants engaged in aggregation to charge customers contract termination fees where those customers voluntarily terminate fixed-term, fixed-price electricity supply contracts before their maturity, provided that such fees are part of a contract that the customer has voluntarily entered into and that such fees are clearly communicated to the customer before the contract is entered into. Such fees shall be proportionate and shall not exceed the direct economic loss to the supplier or the market participant engaged in

The above-mentioned presentation of the European Commission states that it must be possible to quit CECs and RECs and that the exact conditions can be established in the statutes of the communities.
In this regard, the provisional Italian transposition law[22] specifies that the final customers may quit at any time, but with possible fair and proportionate fees that has been agreed for an anticipated exit in order to compensate for the investments carried out by the community. The RED II directive does not mention the right to quit a REC, but it confirms the fact that members keep their rights as final customers.
More in general, therefore, it would be reasonable to assume that the members of each kind of community keep their rights and obligations as final customers or active customers and have the right to quit the community, possibly paying a pre-defined fair and proportionate fee.
Moreover, since it seems opportune to promote the development not only of renewable sources, but also of natural gas High Efficiency Cogeneration – HEC, CECs that access support schemes for HEC might be requested, in terms of minimum requisites for the access, the same characteristics requested for the RECs (i.e. participation limited to natural persons, local authorities, including municipalities, or SMEs, whose participation must not be the main commercial or professional activity and with decision-making powers reserved to the members of such categories located in the proximity of the plants of the community).

4.2.2 Ownership of generation plants

The RED II and IEM directives make reference to the plants "owned" by the communities, while for example in the Italian version of the directives "owned" is translated in some parts with the meaning of "property" and in other parts with the meaning of "possession / availability". This is ambiguous, nevertheless in the English version the term "owned" is always used, and it can correspond to both the concept of "property" and to the concept of "possession" or "availability" [23].

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aggregation resulting from the customer's termination of the contract, including the costs of any bundled investments or services that have already been provided to the customer as part of the contract. The burden of proving the direct economic loss shall be on the supplier or market participant engaged in aggregation, and the permissibility of contract termination fees shall be monitored by the regulatory authority, or by another competent national authority.

[22] Testo coordinato del decreto-legge 30 dicembre 2019, n. 162 con la legge di conversione 28 febbraio 2020, n. 8 recante: «Disposizioni urgenti in materia di proroga di termini legislativi, di organizzazione delle pubbliche amministrazioni, nonché di innovazione tecnologica», https://www.gazzettaufficiale.it/eli/id/2020/02/29/20A01353/sg

[23] Merriam-Webster dictionary – definition of *own*: a) to have or hold as property, b) to have power or mastery over. Oxford dictionary – definition of *own*: a) to have something that belongs to you, b) to manage and take responsibility for something.

In line with what foreseen for individual and collective self-consumption and with the interpretation of the Italian regulatory authority ARERA, we deem that the energy (both electric and thermal) generation plants at the service of a community, besides being property of the community itself, may also be property of and managed by third-parties, even different from each other (typically, they cannot be members of the community, since their participation would be their main commercial or professional activity)[24].

It should be assessed whether it is necessary to define some specific criteria to better ensure the "instruction and control" power of the community towards the third parties having the property or managing the plants owned by the community.

4.2.3 *Activities carried out by energy communities*

As it is evident from the definitions reported above, the set of activities that an energy community can carry out is defined in a more detailed manner by the IEM directive: in particular, they "may engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders".

Moreover, as previously reported, the IEM directive specifies that Member States, in the enabling regulatory framework, may provide that CECs are entitled to own, establish, purchase or lease distribution networks and to autonomously manage them. In this regard, the RED II directive does not contain any specific provision, except simply mentioning (Article 22, paragraph 4) the possible role of the REC as distribution system operator[25].

Of course, in the improbable case that a community establishes in an area where a distribution network is not available, there would be no discussion about its possibility of building a new network and operating it as a DSO. On the other hand, if a community establishes in an area where a public distribution network is already available, of course it would not make sense for the community to build its own new distribution network, thus duplicating the infrastructure and the related costs.

In such a case, as foreseen by the IEM directive, in principle the community might purchase or lease the network from the DSO and operate it, but to do so it should acquire all the technical competences that are already available to the DSO and, moreover, in terms of operation and maintenance costs, it could not benefit from the economies of scale that characterize the DSO that is in charge of a much larger network.

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[24] In Austria it is possible to sign contracting or leasing arrangements that allow the community to exert a sort of control over the installations of non-community members. Also in Portugal, different options for an "external" ownership, including contracting, are discussed, where the energy community may be responsible for the operation while the involvement of external investors would be possible.

[25] In Austria RECs as well as CECs can own and operate electricity grids but need to fulfil the same obligations as other DSOs. In addition, RECs are entitled to operate local heating grids.

Moreover, the benefits for a community of directly operating the distribution network are not clear, taking also into account that the RED II directive requires that "the relevant distribution system operator cooperates with Renewable Energy Communities to facilitate energy transfers within Renewable Energy Communities". The IEM directive, on the other hand, requires that "subject to fair compensation as assessed by the regulatory authority, relevant distribution system operators cooperate with Citizen Energy Communities to facilitate electricity transfers within Citizen Energy Communities".

As far as Cyprus is concerned, according to Article 123 of the Law for the Regulation of the Electricity Market of 2021, Citizen Energy Communities have the right to own, set up, purchase or lease distribution networks and to operate them autonomously, but, as above mentioned, for the sake of efficiency, even in terms of management, and in order to avoid duplications of costs, we deem opportune that energy communities use the public distribution network to exchange energy within them and, therefore, no specific incentives are provided to them to play the role of a DSO. Also, the provisional Italian transposition law concerning RECs states that "the members share the energy produced using the existing distribution network", in a "virtual" configuration (see paragraph 4.1.4). This provision has been confirmed in the final Italian transposition law with a possible exception for CECs only that, when there are "specific technical reasons, taking into account the cost-benefit ratio for final customers", may lease or buy portions of the existing distribution network or build new networks.

Finally, it must be noted that while the CECs defined by the IEM directive deal with electric energy, the RECs defined by the RED II directive deal with renewable energy in general, therefore also with thermal energy. It is therefore opportune to allow energy communities also to produce (with renewable or High Efficiency Cogeneration plants), distribute (with district heating / cooling networks) and supply thermal energy to their members and to the local communities.

4.2.4 Exchange / sharing of energy within the community

The RED II directive specifies that the RECs have the right to share within the community the renewable energy produced by the generation plants owned by the community. Similarly, the IEM directive states that the CECs are entitled to arrange within them the sharing of electricity that is produced by the production units owned by the community.

From such provisions we could deduce that the flow of the shared energy always goes from the plants owned by the community towards its members: this would exclude the possibility that single members of the community may share (just in their role of members, and not being simple self-consumers that would sell their excess production to the community) with the other members energy produced by their own plants.

On the contrary, the presentation, which has been already mentioned, by the European Community explicitly states that the sharing may happen also from members having generation plants towards other members of the community. This interpretation is supported also by others, like the reference in footnote[26], that defines “sharing” as “transfers of electricity produced by units owned by either the energy community or community members between members and/or the community itself”.

Moreover, it is necessary to clarify the concept of “sharing”: the abovementioned presentation by the European Commission wonders whether “sharing” of energy is equivalent to “supply” of energy, concluding that it’s not for sure, since considering sharing like supply might be disproportionate and therefore not in line with Article 16 paragraph 1[27] of the IEM directive. In case sharing is not a supply, should fiscal charges be imposed on the shared energy?

According to an impact assessment carried out for the ASSET project[26], the main difference between sharing and supply[28] is that when consumers engage in a supply contract with a supplier, they transfer their responsibility of imbalances caused on the system to the supplier, while this should not be the case when sharing energy, that should look more like behind-the-meter production, from a supplier’s point of view.

In our opinion, “sharing” is not “supply” and fiscal charges should not be paid on the shared energy: this would be an additional element of promotion.

4.2.5 Extent of energy communities

As already mentioned in the previous paragraphs, the RED II directive does not impose explicit constraints to the extent of RECs, anyway it requires that they are effectively controlled by shareholders or members that are located in the proximity of the renewable energy projects that are owned and developed by the community. Such constraint of a “local” control makes hard to envisage that a REC may have a much larger extension, unless also the community’s generation plants are dispersed in a large territory and the proximity constraint of the members with decision-making powers does not apply at the same time for all the plants of the community.

Anyway, it must also be noted that the RED II directive states that: “Participation in renewable energy projects should be open to all potential local members based on objective, transparent and non-

[26] ASSET project – Tractebel Impact: “Energy communities in the clean energy package: best practices and recommendations for implementation”, 2020, https://op.europa.eu/en/publication-detail/-/publication/4b7d5144-91c9-11eb-b85c-01aa75ed71a1/language-en?WT.ria_f=3608&WT.ria_ev=search

[27] Member States shall provide an enabling regulatory framework for Citizen Energy Communities ensuring that: (e) Citizen Energy Communities are subject to non-discriminatory, fair, proportionate and transparent procedures and charges, including with respect to registration and licensing, and to transparent, non-discriminatory and cost-reflective network charges in accordance with Article 18 of Regulation (EU) 2019/943, ensuring that they contribute in an adequate and balanced way to the overall cost sharing of the system.

[28] Article 2.12 of the IEM directive defines “supply” as “*the sale, including the resale, of electricity to customers*”.

discriminatory criteria", thus using the concept of "locality" not only concerning the control of the community, but also to the simple participation to the community.

On the contrary, the IEM directive does not impose any explicit constraint neither to the extent of CECs[29], nor to the localization of the members with decision-making powers. Anyway, the fact that they may be controlled by local authorities, including municipalities, and the fact that in the initial versions of the directive the CECs were called Local Energy Communities let us think that also the CECs, to better bring their benefits, are to be limited to a "local" extent.

In any case, the RED II directive does not define precisely the concept of "proximity" to the plants of the community of the members with decision-making powers: it might be a "physical" proximity (to be defined, e.g. within X kilometers), an "administrative" proximity (e.g. in the same municipality, since local authorities can be shareholders or members of a REC[30]) or even an "electric" proximity (for example a community with all the injection and withdrawal points connected under the same primary substation[31]). If, on one hand, defining a precise "electric" extent (such as the above-mentioned primary substation) would facilitate the assessment of the avoided costs[32] for the system deriving from the energy sharing

[29] In Ireland for example, CECs are proposed to be clusters of RECs that can be dispersed throughout the entire country.

[30] The Greek law requires at least 50% plus one of the community members to be related to the district the community headquarters are located in, while in the German "Citizens' Energy Companies" framework at least 51% of the voting rights must belong to natural persons who have been residing in the district where the wind energy installation is to be installed. Lithuania requires that 51% of members are residents in the municipality where the production plant is located or in a neighbouring municipality.

[31] The provisional Italian transposition law foresees that the withdrawal points of the consumers belonging to the community and the injection points of the related generation plants are located on low voltage distribution networks connected to the same MV/LV secondary substation. This provision, that is adequate for the experimental phase that the law intended to start, appears to be quite restrictive, from the dimensional point of view, for the future development of energy communities. Similarly, Wallonia in Belgium requires community member injections/withdrawals of electricity to be downstream of one or several MV/LV secondary substations, but connection points must also "be located within a geographic perimeter mobilising the technically, socially, environmentally and economically optimal portion of the network to promote local collective self-consumption of electricity". In Austria, two different limitations of RECs relating to the energy system architecture are defined: low voltage as well as medium voltage RECs. The scope may be chosen by the community, however leading to different levels of grid fee reductions.

[32] The regulatory authority should determine the value of the regulated tariff components that either partially or entirely must not be applied to the energy shared and instantaneously self-consumed within the community, corresponding to avoided costs for the system, in function of the localization on the electricity network of the injection and withdrawal points of the community.

carried out within the community, on the other hand it might not be completely coherent with the social / territorial context where the community should develop.

The social / territorial extent appears to be of prevailing importance, since the main aim of the communities, as explicitly established by the directives, is to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits. In fact, the IEM directive, dealing with the experiences already made in cases similar to energy communities, states that: "Where they have been successfully operated such initiatives have delivered economic, social and environmental benefits to the community that go beyond the mere benefits derived from the provision of energy services".

Thus, among the "physical", "administrative" or "electric" extents, the "administrative" ones seem to be the most adequate to the concept of energy community: for example, one or more neighboring municipalities, a province, etc.[33] Nevertheless, the Italian transposition of the IEM and of the RED II directives opted for an "electric" definition of the extent, requiring that injection and withdrawal points of a CEC / REC are connected under the same primary substation.

The Cyprus Authorities, on the basis of their deep knowledge of the administrative, social and territorial contexts, as well as of the "electrical" ones, may select the optimal option on the basis of the aforementioned general principles.

Nevertheless, if at the same time the community respected also an "electric" constraint, the corresponding avoided costs for the system should be acknowledged.

In any case, a combination of the abovementioned kinds of constraints might be envisaged. Moreover, constraints should be defined considering the variety of the characteristics of the territories where communities might be established (e.g. urban vs. rural vs. mountain areas, population density, natural resources, etc.)[34].

The following table summarizes the types of boundaries set for RECs and Collective Self Consumption schemes in some EU Member States.

[33] It must also be remembered that both the RED II directive for the RECs and the IEM directive for the CECs foresee that the communities must be open to the cross-border participation.

[34] As a further example, the draft Polish law foresees that no more than three energy communities are directly adjacent to each other, while the number of members of an energy community should be less than 1000.

Table 5 - Types of boundaries set for RECs and Collective Self Consumption schemes in some EU Member States (source: D. Frieden et al., "Are We on the Right Track? Collective Self-Consumption and Energy Communities in the European Union", 12 November 2021, Sustainability)

Country	Approach to Physical Boundaries
Austria	LV/MV
Belgium/Wallonia	LV/MV and distance
Belgium/Flanders	LV/MV and activity
Hungary	MV/HV
Slovenia	LV
Italy	LV /MV
Ireland	LV/MV
Croatia	Municipality, LV
Lithuania	Municipality
Poland	Municipality
Greece	Regional or system-related, depending on location.
France	Distance (up to 20 km) (only CSC)
Spain	LV, cadastral area, distance (500 m) (only CSC)
Portugal	System-related, individual decisions (RECs and CSC)

4.2.6 Imbalances

The IEM directive explicitly foresees that CECs "are financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943".

The RED II directive does not contain any explicit provision concerning imbalances, but it is reasonable to assume that also RECs should be subject to the same rule that applies to CECs, in line with Regulation (EU) 2019/943.

Therefore, all energy communities shall either be balance responsible parties or shall contractually delegate their responsibility to a balance responsible party of their choice. Each balance responsible party shall be financially responsible for its imbalances and shall strive to be balanced or shall help the electricity system to be balanced.

In a "physical" configuration (see paragraph 4.1.4), where all the injection and withdrawal points of the distribution network managed by the community correspond to generation plants owned by the community and to Points of Delivery of members of the community, the community itself might in principle be considered as a single entity (a sort of large self-consumer) interfacing with the rest of the network (and with the market) through the connection point of its network to the external distribution/transmission network. In such a case, the community would be a sort of black box, being the internal energy flows not relevant from the system/market point of view and being the imbalances calculated on energy flows across the border of the community.

It must be taken into account that, according to Article 16, paragraph 1.(c) of the IEM directive, transposed into article 123, paragraph 1.(c) of the Law for the Regulation of the Electricity Market of 2021, members or shareholders of a Citizen Energy Community do not lose their rights and obligations as household customers or active customers: this means that potentially each member of the community, besides consuming the energy shared within the community, might purchase energy from an external supplier that would act as a BRP: this would prevent the community from being considered a black box.

This situation would be similar to what would happen in a “virtual” configuration (see paragraph 4.1.4), where the community (or a delegated third party) would be responsible for the imbalances caused by its generation plants and each member will have its supplier as a BRP. In fact, in the “virtual” configuration, injections and withdrawals take place on the public distribution network and energy “sharing” is only conventional, therefore the usual imbalance regulation can be applied[35].

4.2.7 Benefits and promotion of energy communities

The main aim of energy communities, as explicitly stated by the directives, is to provide environmental, economic or social community benefits for their shareholders or members or for the local areas where they operate, rather than financial profits. In fact, as already mentioned, the IEM directive, dealing with the experiences already made in cases similar to energy communities, states that: “Where they have been successfully operated such initiatives have delivered economic, social and environmental benefits to the community that go beyond the mere benefits derived from the provision of energy services”.

This means that, when defining and calibrating support schemes for the development of energy communities, it would be opportune to take into account not only the energy-related aspects (i.e. for example adequately valuing the energy produced from renewable sources or by High Efficiency Cogeneration and consumed at the same time by the members of the communities), but also the economic, social and environmental benefits not only for the members of the communities, but also for the whole territory where they operate, possibly providing for such aspects additional rewards or support. In this regard, a very important issue that can be tackled by energy communities is energy poverty. In fact, Article 22 of the RED II directive states that Member States shall provide an enabling framework that shall ensure that the participation in the Renewable Energy Communities is accessible to all consumers, including those in low-income or vulnerable households. In fact, the self-production of energy by the community and the possibility of sharing it at a lower cost than the market and the possibility for the community to promote energy efficiency interventions, thus reducing energy consumption, are key factors to reduce the bill of energy-poor consumers.

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[35] This is also the position of the Italian regulatory authority ARERA, since the “virtual” configuration has been privileged in the Italian transposition process concerning energy communities and collective self-consumption.

Therefore, the possibility of defining specific Key Performance Indicators – KPI to quantify such categories of benefits[36], on the basis of which to quantify possible additional rewards or support (paying attention not to overlap with other existing support schemes), should be taken into account.

As far as the current Italian framework is concerned, an explicit incentive of 100 €/MWh for collective renewable self-consumption schemes[37] and of 110 €/MWh for Renewable Energy Communities is granted on the “shared” energy.

More in details, the “premium on self-consumed energy” is related to the Decree Law 162/19 (converted into law 8/2020) with which the Italian Government implemented a provisional transposition of articles 21 and 22 of the RED II directive concerning collective renewable self-consumption and Renewable Energy Communities, in order to enable a first limited and experimental implementation of such schemes. The article states that monitoring the results of the first implementations of these new production and consumption schemes, allowed by the decree, will be useful for the full transposition of the RED II and of the IEM directives[38].

In particular, according to the decree:

- the participants to the collective self-consumption schemes and to Renewable Energy Communities must produce electric energy for their consumption with generation plants from renewable sources with an overall installed power not greater than 200 kW[39], put in operation after 1 March 2020 and within 60 days following the entry into force of the law concerning the transposition of the RED II directive;
- the participants share the produced energy using the existing distribution network, thus implementing a “virtual” self-consumption model where the energy “shared” is equal, in each hour, to the minimum between the energy produced and injected into the network by the RES generation plants and the energy withdrawn from the network by all the final customers participating to the scheme;
- the self-consumption of the energy shared may occur also through storage systems;

[36] For example, reduction of local NOx emissions achieved by the community due to the electrification of end uses, number of families no longer in condition of energy poverty among the members of the community, number of charging points for electric vehicles installed by the community, reduction of consumption / emissions due to energy efficiency interventions, etc.

[37] Taking place in the same building or condominium.

[38] The two directives have been transposed into the Italian law, but the implementation decree concerning the incentive scheme and the relevant decisions by the regulatory authority have still to be finalized.

[39] The size has been increased to 1 MW with the recent transposition of the RED II directive.

- in case of Renewable Energy Communities, the final customers' withdrawal points and the RES generation plants' injection points must be connected to low voltage networks underlying the same medium voltage / low voltage secondary substation[40];
- in case of collective self-consumption schemes, all the self-consumers must be located in the same building or condominium;
- all the customers associated in a collective self-consumption scheme or in a Renewable Energy Community keep their rights as final customers, including the right to choose their supplier, and regulate their relationships with a private law contract which identifies also a delegated subject ("referent"), responsible to subdivide the energy shared;
- on the energy withdrawn from the public network, including the energy shared, general system charges must be paid;
- a specific incentive scheme (managed by Gestore dei Servizi Energetici – GSE, a state-owned company in charge of managing incentives to renewable sources and energy efficiency) is set up with a specific decree of the Ministry of Economic Development, while it is allowed to access neither the current incentive mechanism for renewable sources established by the decree 4 July 2019 (so-called "FER 1"), nor the "Scambio Sul Posto" (net metering) scheme[41];
- the specific incentive scheme is aimed at rewarding the instantaneous self-consumption and the use of storage systems, it is granted for a maximum time period (20 years) and is modulated differently for collective self-consumption (100 €/MWh) and for Renewable Energy Communities (110 €/MWh), in order to ensure the profitability of investments;
- the Regulatory Authority ARERA determines the value of the regulated tariff components and of the components related to the cost of electric energy that are not technically applicable to the energy shared[42], since it is instantaneously self-consumed in the same portion of the low-voltage distribution

[40] The recent transpositions of the IEM and of the RED II directive allow for schemes implemented under the same primary substation.

[41] The "Scambio Sul Posto" (net metering) incentive scheme discourages the installation of storage systems, because it allows to use the network as a "virtual" storage. This is the reason why it has been considered not compatible with the above described mechanism and why the Italian NECP foresees its abolition.

[42] In Austria, reduced grid tariffs are foreseen for electricity sharing in RECs at MV and LV level. In principle, fees for using grid levels that are superordinate to the grid level in which the REC is located will be deducted for the electricity exchanged within the REC. The tariff reduction will be defined as a percentage of the tariff in place at a national level for LV and MV communities applying to all network areas (in Austria, different tariff structures apply to the different geographical network areas). For the capacity-based share of the network fee, the power drawn from the public network will be reduced by the power drawn from the REC in the respective quarter-hour. In addition, the volumetric tariff element earmarked for renewables support, as well as an electricity tax are supposed to be deducted

network and, therefore, comparable to on-site self-consumption. Basically, such avoided costs refer to the reduction of losses and of the use of the network[43] consequent to the "local" generation and consumption that takes place in a collective self-consumption scheme and in an energy community (see below).

Following the Decree Law 162/19, the regulatory authority ARERA, with the deliberation 318/2020/R/EEL, established that:

- in case of collective self-consumption within the same building or condominium, the tariff components that must be returned by GSE to the "referent"[44] of the scheme, since they are representative of avoided costs, are:
    - the variable parts (expressed in c€/MWh) of the transmission and distribution tariffs calculated on the energy shared; in particular, the sum of the TRASe tariff component for

from the tariff. Due to the unknown impact of energy communities on the electricity system, the regulator is required to carry out a cost-benefit analysis by the end of the first quarter of 2024. Thereby, it is to be determined whether RECs, as well as CECs, contribute to an appropriate extent to the system costs or benefits. In particular, this has to include the costs for balancing energy. In Wallonia and Flanders, the government demands a cost-benefit analysis investigating the impact of energy communities on the distribution network, including avoided investments in the network. Based on these assessments, specific tariff reductions may be applied. In Portugal, consumption-based grid fees related to the voltage levels above the one where the REC is connected do not need to be paid. See the abovementioned paper by D. Frieden et al.

[43] In this regard, the ACER Report on Distribution Tariff Methodologies in Europe of February 2021 mentions the case of Portugal, where a legal framework has been implemented at national level in 2019 according to which renewable energy communities can apply for a specific tariff regime for self-consumption, in place since 2020. In Portugal the charging of distribution tariffs for a renewable energy community depends on the extent to which the public grid is used. The more an energy community is using the public grid, the more it will contribute to the payment of distribution tariffs. The Portuguese NRA mentions the example where both the consumption and production units are connected to LV: in that case distribution tariffs may be due only for the use of the LV grid, but not for the use of higher voltage levels, such as MV and HV (as is applicable to consumption-only units). However, this circumstance is conditional on the non-observation of reverse power flows (from lower to higher voltage levels). Similarly, a tariff was introduced in France in 2018 for participants to what is described as "collective self-consumption operations", where LV consumers and producers share the power produced within a given perimeter. According to this tariff, local withdrawals are cheaper in order to reflect the fact that they only burden the local LV network infrastructures. This tariff incentives the participants to such operations to synchronise their consumption with the time of production of the producers taking part to the same scheme. To make sure that network costs are really saved with such operations, this tariff option is only available to operations that take place downstream of the same MV/LV transformer.

[44] It is up to the "referent" of the scheme to refund the participants of such tariff components.

low-voltage customers (0.761 c€/kWh) and of the highest value of the variable distribution tariff for non-household users BTAU (0.061 c€/kWh);

   - the product between the avoided losses coefficient (equal to 1.2% for generation plants connected to the medium-voltage network and to 2.6% for generation plants connected to the low-voltage network), the day-ahead zonal price and the energy shared;

- in case of Renewable Energy Communities, the tariff components that must be returned by GSE to the "referent" of the scheme, since they are representative of avoided costs, are the variable parts (expressed in c€/kWh) of the transmission and distribution tariffs calculated on the energy shared; in particular, the sum of the TRASe tariff component for low-voltage customers (0.761 c€/kWh) and of the highest value of the variable distribution tariff for non-household users BTAU (0.061 c€/kWh); it is not possible to take into account also the grid losses, like in the case of collective self-consumption, since the energy is shared using the distribution network.

Moreover, as above mentioned, following the Decree Law 162/19, the decree of the Ministry of Economic Development of 16 September 2020 established that, for a period of 20 years:

- the energy shared in a collective self-consumption scheme will have the right to a feed-in premium incentive of 100 €/MWh;
- the energy shared in a Renewable Energy Community will have the right to a feed-in premium incentive of 110 €/MWh[45].

Summarizing, in such a "virtual" configuration:

- the RES generation plants own by the community inject energy into the public distribution network; the energy is paid to the community at the day-ahead market hourly zonal price[46];
- the "shared" energy is calculated, for each hour, as the minimum between the energy produced and injected into the network by the RES generation plants owned by the community and the energy withdrawn from the network by all the final customers members of the community;
- the final customers members of the community receive their usual bill from their suppliers, on the basis of their metered consumptions;
- the community receives by GSE the incentive of 110 €/MWh for each MWh of "shared" energy, as well as the refund of about 8 €/MWh of the network tariff components corresponding to avoided

[45] This incentive is considered an "Operating Aid" under the GBER regulation, since it is applied to small-sized projects (plants < 200 kW under the same MV/LV substation). The new incentive scheme, still to be defined, consequent to the full transposition of the RED II directive, involving much larger projects (plants < 1 MW under the same HV/MV substation) will have to be notified under the CEEAG guidelines.

[46] In practice, it is sold to GSE through a simplified mechanism named "dedicated withdrawal".

network usage costs and share such income among the members of the community on the basis of a specific internal agreement.

In conclusion, we recommend that:

- the promotion of energy communities (with respect to the production of energy from new or repowered plants, for the share of additional power) should be carried out through explicit incentives on the energy shared[47] within the community, in order to promote its maximization, using also storage and automation systems (that, in turn, might have access to specific support schemes);
- the explicit incentives may be differentiated by source/technology; as far as generation technologies are concerned, only renewable sources and High Efficiency Cogeneration should have access to support schemes;
- on the shared energy all charges, fees and regulated tariffs are applied; these latter should be determined taking into account the avoided costs for the power system due to the sharing itself;
- the energy produced by the community, if it is not sold to third parties, should be remunerated at the day-ahead market price;
- assess the possibility of defining specific Key Performance Indicators – KPI to quantify the economic, social and environmental benefits not only for the members of the communities, but also for the whole territory where they operate, on the basis of which to quantify possible additional rewards or support (paying attention not to overlap with other existing support schemes), in addition to the valuation of the shared energy.

4.2.8 The Greek Law 4513/2018 on energy communities

We report in the following a description of the Greek Law 4513/2018 on energy communities, for which we took as a reference the publication *"Buliding Energy Communities – energy in the hands of citizens"* by the Heinrich Böll Foundation, 2019.

The Law 4513/2018 on energy communities enables citizens, local governments and small and medium enterprises to establish urban cooperatives operating exclusively in the fields of energy, at local and regional level. The law promotes the social and solidarity economy in the energy sector, the treatment of energy poverty, the promotion of energy sustainability, production, storage, self-consumption, energy distribution and supply, enhancing energy self-sufficiency and security in island municipalities, as well as improving end-use energy efficiency at local and regional level. The above objectives are achieved

[47] I.e. produced and at the same time (in each measurement time interval) consumed by the members of the community.

through the development of Renewable Energy Sources (RES), High Efficiency Electricity and Heat Cogeneration, the rational use of energy, energy efficiency, sustainable transmission, sustainable demand and generation, distribution and supply of energy.

The central elements of the law are:

- the **locality**, which is a necessary condition for the creation of synergies and partnerships for the implementation of energy projects that meet local needs, utilizing local renewable energy resources, in order to diffuse the benefit to the members and to produce added value for local communities;
- the **insularity**, in the framework of which special regulations and privileges are introduced for the case of very small islands[48], in order to address issues such as the high cost per kWh produced as well as the environmental, economic and social issues raised by the use of conventional forms of electricity generation;
- the activation and enhancement of **technological tools**, such as net metering and virtual net metering, especially for the protection of vulnerable consumers living below the poverty line and the treatment of energy poverty;
- the provision of **financial incentives and support measures**, which mainly concern the development of RES power plants, in order to utilize the domestic potential with the participation of local communities, as defined in the national energy targets.

Members of a community, that are established in a cooperative form, can be:

- natural persons with full legal capacity;
- legal entities under public law or legal entities under private law;
- first degree local authorities of the same Region in which the headquarters of the community are located;
- second degree local authorities within the administrative boundaries of which the headquarters of the community are located.

Legal entities under public law, first and second degree local authorities can participate in more than one community; legal entities under private law and natural persons can participate in only one community.

The criterion of locality translates into the obligation of at least 50%, plus one, of the members to be related to the place where the headquarters of the community are located. Specifically:

- natural persons are required to have full or partial ownership or usufruct in a property which is located within the Region of the headquarters of the community or to be citizens of a municipality of this Region;

[48] With a population of less than 3100 inhabitants.

- legal entities are required to have their registered office within the Region of the registered office of the community.

The law sets certain safeguards for the democratic governance of the communities, such as the ceilings of the participation percentage of each member in the cooperative capital and the possibility of equal participation of the members in the general assembly. In particular:

- no member can exceed 20% in the participation in the cooperative capital (shares), with the exception of the first and second degree local authorities that can participate with a maximum of 40% and of the first degree local authorities island areas with a population of less than 3100 inhabitants, according to the latest census, whose maximum participation is set at 50%;
- each member, regardless of the number of cooperative shares it holds, participates in the general assembly with only one vote.

Moreover, there are two types of communities: two types of communities, the **non-profit** and the **for-profit** ones, which differ in terms of the composition of the members and their minimum number, as well as concerning the possibility of distributing surpluses, in case of the for-profit ones. In the non-profit communities the surpluses are not distributed to the members, but are saved in the form of reserves and are available for the purposes of the communities, by decision of the general assembly. At least 10% of surpluses is withheld for the formation of the regular reserve. The withholding is not obligatory when the amount of the reserve is at least equal to the amount of the cooperative capital.

The possible fields of activity, their geographical scope of development, the locality criterion as well as the participation in the cooperative capital, do not differ between the non-profit and the for-profit communities.

As for the field of activity, the following are <u>mandatory</u>: production, distribution, supply of RES energy, energy efficiency, supply chain (biomass, etc.), electric mobility, desalination of water with RES, energy services. In addition, they can carry out information and education services, participation to funded programs, etc. In any case, the statutes of the communities may not include activities other than those mentioned, while the maximum geographical scope of the activity is defined as the region in which the community is based.

More in detail, the mandatory field of activity of a community, must include <u>at least one</u> of the following:

1) Production, storage, self-consumption or sale of electricity or thermal or refrigeration energy from RES or HECHP stations or hybrids installed within the Region where the headquarters of the community are located or within a neighboring Region for the communities based in the region of Attica.
2) Management of raw material for the production of electrical or thermal or cooling energy from biomass or bioliquids or biogas or through the energy recovery of the biodegradable fraction of

municipal waste. 'Management' refers to the collection, transport, processing, storage or disposal of raw materials.

3) Supply for members of energy products, appliances and facilities, with the aim of achieving better prices for their members, reducing energy consumption and use of conventional fuels as well as improving energy efficiency.
4) Supply for members of hybrid or non-hybrid electric vehicles, and in general for vehicles that use alternative fuels (electric, hybrid, gas), in order to achieve better prices for their members.
5) Distribution of electricity within the Region where its headquarters are located.
6) Supply of electricity or natural gas to final customers, within the Region where it is located.
7) Production, distribution and supply of thermal or cooling energy within the Region where it is located.
8) Demand management to reduce the end use of electricity and representation of producers and consumers in the electricity market, i.e. to operate in the market of aggregation.
9) Development of network, management and operation of alternative fuel infrastructures (e.g. charging stations for electric vehicles), or management of sustainable means of transport (e.g. fleet of electric vehicles, etc.) within the Region where the headquarters of the community are located.
10) Installation and operation of water desalination units using RES within the Region where the headquarters of the community are located.
11) Provision of energy services (Energy Services Company - ESCo).

In addition, they can carry out additional activities such as:

- Attracting funds for the realization of investments for the utilization of RES or HECHP or interventions for the improvement of the energy efficiency within the Region where the headquarters of the community are located.
- Preparation of studies for the utilization of RES or HECHP (techno-economic studies) or implementation of interventions to improve energy efficiency or provision of technical support to members in the above areas.
- Management or participation in programs funded by national resources or EU resources about the purposes of the community.
- Providing advice on the management or participation of its members in programs funded by national or EU resources. about the purposes of the community.
- Information, education and awareness at local and regional level on energy sustainability issues.
- Actions to support vulnerable consumers and address the energy poverty of citizens living below the poverty line, within the Region where the community is based, regardless of whether they are

members of the community, such as energy supply or compensation, energy upgrade housing or other actions that reduce energy consumption in the homes of the above.

Addressing energy poverty within the region in which the headquarters of aa community are located, is, according to the legislation, the main purpose of establishing a community. A very important regulation of the legislator is the activation and expansion of the tool of virtual net metering (with a maximum installed power limit of 1 MW for RES and HECHP plants) to combat energy poverty.

4.2.9 Other national frameworks for energy communities

The information reported in the following comes from the paper *"Are We on the Right Track? Collective Self-Consumption and Energy Communities in the European Union"*, by D. Frieden et al., published on 12 November 2021 on the journal *"Sustainability"* (https://www.mdpi.com/journal/sustainability). As far as Switzerland is concerned, information comes from the manual *"Guida pratica per il consumo proprio"* by Svizzera Energia – Federal Office of Energy, version 2.2, July 2021.

4.2.9.1 Croatia

It is foreseen that CECs will be limited to operate behind a single MV/LV substation and in the same municipality, effectively blurring the distinction with RECs.

The draft of the RED II transposition law defines RECs rather generally and fully according to the EU definitions and requirements. It sets, however, a limit for the total connected power of all production facilities of 500 kW. For both, RECs and CECs, the production capacity is limited to 80% of the consumption capacity of the members.

At this moment, no incentives for CECs or RECs are foreseen, which could hinder the deployment of CECs and RECs, especially considering the very low electricity prices for households.

4.2.9.2 Portugal

The Portuguese legislator has started the transposition of the EU framework introducing RECs and Collective Self Consumption (CSC) schemes in the Decree Law 162/2019 from October 2019. With this legislation, the Portuguese government renewed the previous regulatory framework on individual self-consumption introducing the concepts of RECs and CSC. As RECs are defined as part of this CSC framework, their scope is currently limited to generation and self-consumption of electricity. There are currently no other pieces of legislation including RECs. CECs have not yet been introduced.

In Portugal, CSC activities can be performed by RECs and by a group of singular or collective entities organised and located in the same building or area, close to the shared renewable energy power plants. Both solutions require:

1) an internal regulation that needs to include at least basic management and sharing rules (for self-consumption and potential revenues);
2) an entity responsible for the operational management of the self-consumption activities and the communication with the respective operators;
3) a responsible technician.

4.2.9.3 Slovenia

Slovenia has adopted a bylaw (*Regulation on self-supply with electricity from RES*) that entered into force on 1 May 2019 and defined CSC and "RES communities". In addition to individual self-consumption that was already possible for owners of individual houses, it allows for two forms of CSC:

- CSC in multi-apartment buildings, where the inhabitants can share energy from a RES generation unit connected to the LV network of the building. All the consumption metering points (of the individual consumers and of the building common services) are connected to the LV network of the building. The RES production unit is located on the building and is connected through its own metering point to the point of common coupling of the building network with the LV distribution grid.
- CSC in 'RES communities' can be formed by customers in various types of dwellings. The RES production unit can be located in a separate building and is connected to a dedicated production metering point on the LV distribution grid. The consumers participating in the RES community can consume electricity through two or more consumption metering points that are connected to the metering point of the RES production unit by the LV distribution grid connected to the same MV/LV substation. It is important to highlight that the RES production unit is not (and has never been) taking part in any RES support scheme. As opposed to the EU rules for RECs, no legal entity needs to be formed; only a contract must be signed between the members of the CSC scheme, defining how the RES production is divided internally.

4.2.9.4 Spain

The Royal Decree 23/2020 served as the kick-start for the transposition of the EU energy community frameworks. In that document, the RECs were introduced into the national framework, however not yet

providing for specific details. CECs are currently not yet defined in Spain. Thus, this decree sets out only the first step towards an actual mature and fully deployed framework for energy communities.
The definition of a framework on CSC, in contrast, is significantly advanced in Spain. According to the Spanish Royal Decree 244/2019, published on 5 April 2019, groups of several consumers may collectively supply themselves in an agreed manner with electrical energy that comes from production facilities close to the consumption point and associated with them.
In the same way as for conventional self-consumption, the consumers participating in CSC can adhere to any of the current self-consumption schemes in force (all consumers from one RES installation must adhere to the same scheme), which are:

1) self-consumption without feeding the surplus electricity into the grid;
2) self-consumption, feeding the surplus electricity into the grid;
    a) with remunerated surplus electricity: in this case, the produced electricity must come from RES, with a rated power no higher than 100 kW and must not be subject to any special retributive scheme for RES;
    b) without remunerated surplus electricity.

The most common scheme is the one listed under 2) a) above, where consumers receive a price linked and very close to the price of the day-ahead spot market. Additionally, to be able to belong to a CSC scheme, both production and consumption connection points must fulfil the following requirements:

1) their low voltage distribution lines must be connected to the same MV/LV secondary substation;
2) both, production and consumption connection points must be within a geographical range of 500 meters;
3) their cadastral reference must be under the same sector (first 14 digits): this may lead to cases where two potential participants are in proximity but registered in two different sectors and hence are not able to perform CSC.

CSC schemes connected to the public grid must sign a document to inform the public administration of the percentages of property of the installation and the way in which the electricity is allocated to each connected consumer. With that information and a bidirectional smart meter attached to the generation plant, the DSO and retailers automatically clear the balances.
Thus, the current CSC scheme in Spain has an important similarity with RECs, in particular due to possible use of the public grid under defined conditions. In contrast with RECs, CSC schemes however do not have to be organised as a legal entity.

4.2.9.5 Switzerland

In Switzerland a federal law of 2018 introduced the so-called “Raggruppamenti ai fini del Consumo Proprio – RCP” (in English “Groups aimed at self-consumption”), in principle similar to RECs. The main characteristics of a RCP are the following:

- a RCP is considered a single final customer and has a single point of connection with the public network (it has therefore an internal private network); the members of the RCP loose their rights as individual final customers and are represented as a whole by the RCP;
- it can be established on different neighbouring areas, provided that the owners of the areas participate to the RCP, that they are final customers at least on one of the areas and that they do not use the public network for their own consumption of electricity; the neighbouring areas may be separated by a road, a railway or a river;
- the generation capacity of the power plants of the RCP must be at least 10% of the sum of the power capacities of the connections to the network of its members; only power plants operating for more that 500 hours/year are considered for the calculation of the generation capacity;
- the internal organization concerning production, distribution, metering and supply of energy is in charge of the RCP, that must apply the federal laws on energy and metering;
- a RCP with an annual consumption greater than 100 MWh can access the free market;
- for the self-consumed energy, the RCP does not pay taxes and network tariffs.

4.3 Incentives for the use of flexibility in distribution networks

As well-known, the increase of the Distributed Energy Resources (DER)[49] results in a higher need for flexibility services for Transmission System Operators (TSOs), Distribution System Operators (DSOs) as well as Balance Responsible Parties (BRPs). These resources, mainly connected at the distribution level, provide an additional opportunity for TSOs and DSOs for the procurement of services (e.g. frequency control, voltage control and congestion management).

Within this context, article 32 - *Incentives for the use of flexibility in distribution networks* of the IEM directive specifies that "Member States shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services". Such services should not only "support the efficient and secure operation of the distribution system" but should also "cost-effectively alleviate the need to upgrade or replace electricity capacity". In fact, the same article specifies that DSOs' network development plans "shall also include the use of demand response, energy efficiency, energy storage facilities or other resources that the DSO is to use as an alternative to system expansion". Moreover, DSOs "shall procure such services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion".

The key issue here is that a DSO would in general prefer network expansion (that increases its Regulated Asset Base and therefore its profits) to buying flexibility services on a specific market and be simply refunded of the corresponding costs. In this regard, article 32 states that "DSOs shall be adequately remunerated for the procurement of such services to allow them to recover at least their reasonable corresponding costs, including the necessary information and communication technology expenses and infrastructure costs". In order to incentivize the use of flexibility in distribution networks for the purpose of avoiding network expansion it is therefore necessary to reward the DSO not only to allow it to recover the costs related to the purchase of flexibility services, but also taking into account to some extent the avoided costs of network expansion. This is a typical task of the regulatory authority; we do not see a specific role of the government in this regard, other than providing general indications to the authority about tackling this issue.

Of course, this is only the demand side of services, but it is necessary to promote also a significant development of the supply side. In this regard, the role of the government might be relevant, for example incentivizing the purchase of storage systems or of automation systems able to exploit the flexibility potential of the demand side.

[49] I.e. distributed generation, flexible loads and storage systems.

As above mentioned, flexibility services by Distributed Energy Resources are precious not only for the DSO, but also for the TSO, in order to ensure the secure operation of the whole system. In this regard, article 32 states also that “Distribution system operators shall exchange all necessary information and shall coordinate with transmission system operators in order to ensure the optimal utilisation of resources, to ensure the secure and efficient operation of the system and to facilitate market development”.

The choice of the appropriate TSO-DSO coordination scheme for an efficient and effective exploitation of DER flexibility is dependent on multiple factors, such as the type of ancillary services, normal operation versus emergency situations, the state of the grid, the amount of RES installed, the current market design and the regulatory framework.

The issue of TSO-DSO coordination has been deeply analyzed by the Horizon 2020 SmartNet project[50], coordinated by RSE, where five different coordination schemes have been designed, characterized by specific sets of rules, operational processes and information exchanges, as well as simulated, to assess their effectiveness. In the following such five schemes are described.

4.3.1 Centralized Ancillary Services market model

In this case, as shown in Figure 8, the TSO operates a market for ancillary services for both resources connected at distribution and transmission level, without extensive involvement of the DSO: there is no separate local market for distribution, and the TSO is responsible for the operation of its own market for ancillary services. Indeed, the TSO does not take DSO constraints actively into account. A system prequalification process could be installed to guarantee that the activation of resources from the distribution grid by the TSO does not cause additional constraints to the grid managed by the DSO. The DSO is not procuring local flexibility in real time or near to real-time.

[50] http://smartnet-project.eu

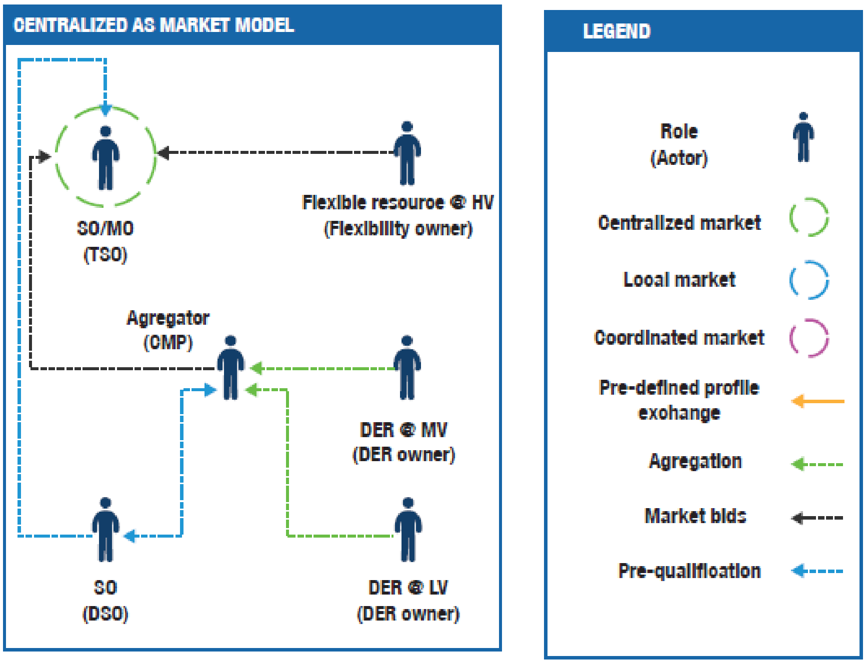

Figure 8 - Centralized Ancillary Services market model.

Such scheme limits the involvement of the DSO to a possible role in the system prequalification process. To be noted that in exceptional cases, the DSO might want to include distribution grid constraints in the TSO market clearing process. Thus, the DSO will need to provide the necessary data to the TSO, or the TSO should have full observability of the DSO's grid.

4.3.2 Local Ancillary Services market model

As shown in Figure 9, the DSO organizes a separate local market for resources connected to the distribution grid. The DSO is the operator of a local market for flexibility, clears the market and selects the necessary bids for local use. The DSO has priority to use the flexible resources from the local grid. The DSO aggregates and transfers the remaining bids to the Ancillary Services market managed by the TSO, after all local constraints are solved, while ensuring that only bids respecting the distribution grid constraints can take part in the Ancillary Services market. The TSO is responsible for the operation of its own market for Ancillary Services, where both resources from the transmission grid and resources from the distribution grid can take part.

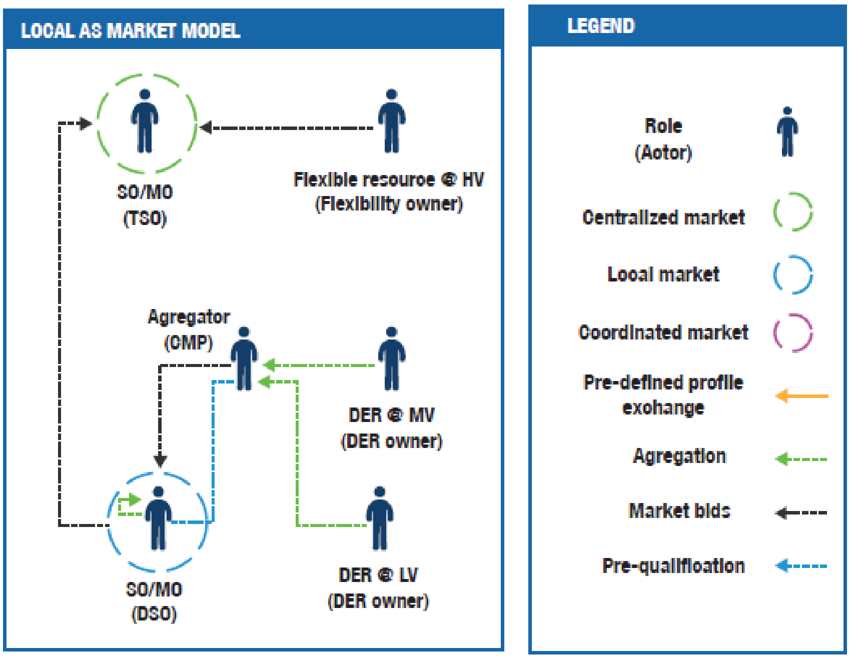

Figure 9 - Local Ancillary Services market model.

The Local Ancillary Services model deviates from the Centralized one by promoting a local market. The implementation of such a market shifts priority towards the DSO.

All flexibility not needed/procured in the local market, where the DSO is the market operator, is sent to the central market, where the TSO acts as the market operator, in an aggregated form, taking into account that the distribution network constraints are respected (some local market bids could possibly not be transferred to the TSO if that would jeopardize the distribution grid operation).

4.3.3 Shared balancing responsibility model

In such model, as described in Figure 10, balancing responsibilities are shared between DSO and TSO according to a predefined schedule.

The TSO transfers the "balancing" responsibility for the (local) distribution grid to the DSO, on the basis of a pre-defined profile of power exchange between the distribution and the transmission network. The TSO remains responsible for the balancing of the transmission grid. The DSO organizes a local market to respect the exchange schedule agreed with the TSO. Distribution network constraints are integrated in the market clearing process of the local market. There is a separate Ancillary Services market for resources connected to the transmission grid, managed by the TSO. Resources from the distribution grid cannot be offered to the market for the transmission grid.

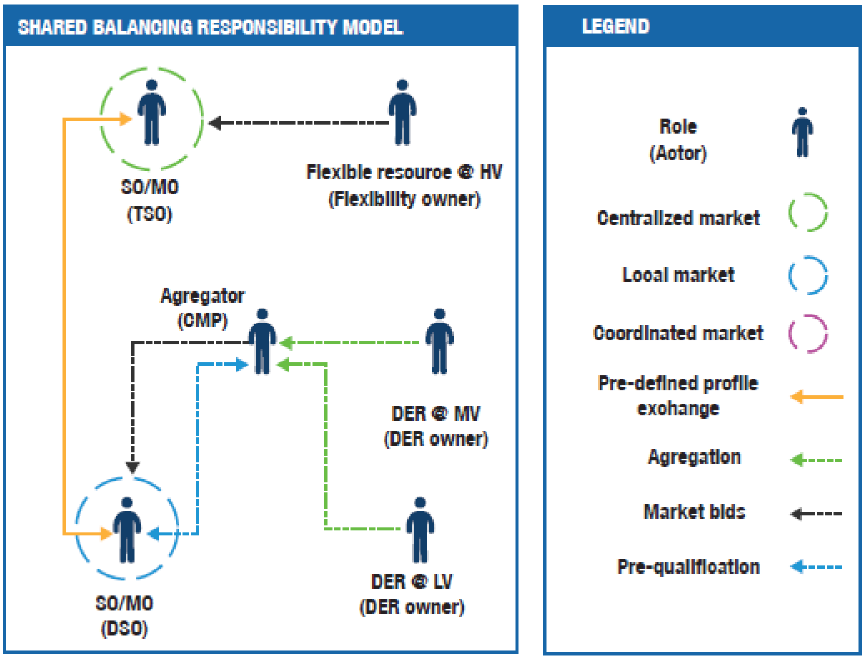

Figure 10 - Shared balancing responsibility model.

This Shared balancing responsibility model is the only coordination scheme where the TSO has no access to resources connected to the distribution grid. Flexibility from the distribution grid is reserved exclusively for the DSO, in order to fulfill its responsibilities with respect to local grid constraints and local grid balancing, in order to respect the power exchange profile agreed with the TSO.

4.3.4 Common TSO-DSO Ancillary Services market model

In the Common TSO-DSO Ancillary Services market model, as shown in Figure 11, the TSO and the DSO have a common objective to decrease costs to satisfy both the need for flexibility resources of the TSO and of the DSO. This common objective could be implemented by the joint operation of a common market (centralized variant) or the dynamic integration of a local market, operated by the DSO, and a central market, operated by the TSO (decentralized variant). Both resources connected at transmission level and resources connected at distribution level participate to the same marketplace. Distribution network constraints are integrated in the market clearing process. There is no priority a priori for the TSO or for the DSO. The choice of which resources are to be used by the DSO to solve local constraints will depend on the combined optimization of both needs for flexibility at distribution level and needs for flexibility at transmission level. The resources are allocated based on minimization of total system costs, leading to increased social welfare.

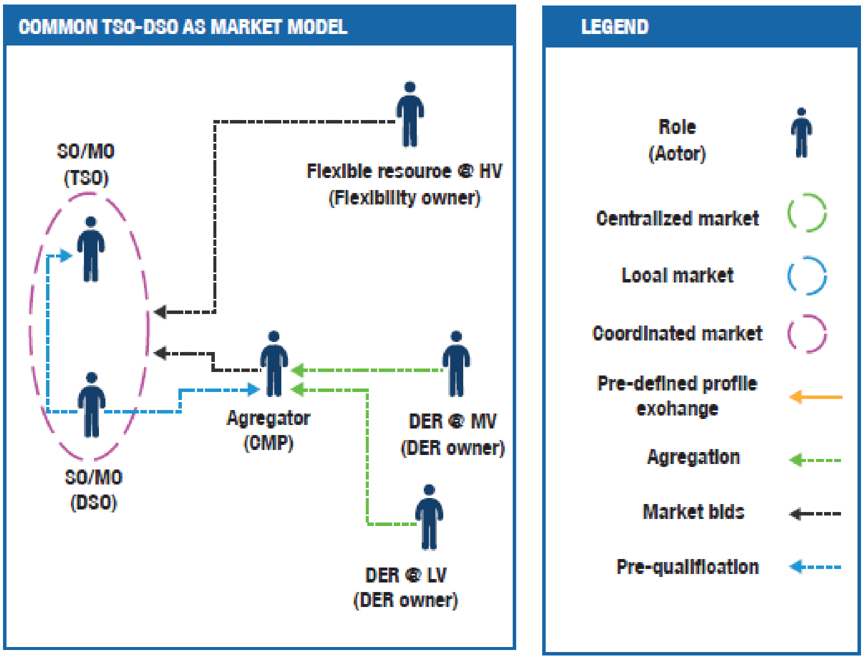

Figure 11 - Common TSO-DSO AS market model.

4.3.5 Integrated flexibility market model

As shown in Figure 12, in the Integrated flexibility market model the market is open for both regulated (TSOs, DSOs) and non-regulated market parties (Balance Responsible Parties, Balancing Service Providers). The common market for flexibility is organized according to several discrete auctions and is operated by an independent/neutral market operator. There is no priority for any party. Resources are allocated to the party with the highest willingness to pay (i.e. the highest bid price). There is no separate local market. Distribution network constraints could be integrated in the market clearing process, which requires the introduction of an Independent Market Operator to guarantee neutrality. In addition, TSOs and DSOs can sell the flexibility of previously contracted DERs to the other market participants.

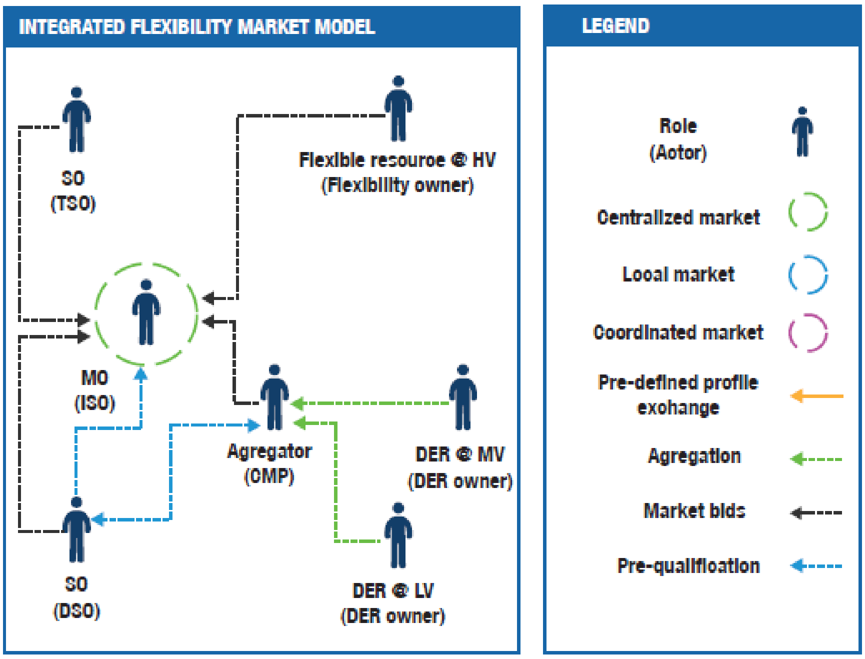

Figure 12 - Integrated flexibility market model.

The Integrated flexibility market model proposes a market mechanism where available flexibility can be procured by system operators and commercial market parties under the same conditions. There is no distinction between regulated and liberalized actors. Market forces dictate how flexibility will be allocated.

4.4 Dynamic electricity price contracts

Directive 2019/944 on common rules for the internal market for electricity entitle all final customers who have a smart meter installed to conclude a dynamic electricity price contract with at least one supplier in their market and with every supplier that has more than 200,000 final customers. According to the directive, ‘dynamic electricity price contract’ means *“an electricity supply contract between a supplier and a final customer that reflects the price variation in the spot markets, including in the day-ahead and intraday markets, <u>at intervals at least equal to the market settlement frequency</u>”*. This means that simple time-of-use tariffs that are already applied in some countries, that differentiate prices between peak and off-peak hours (e.g. day, night, weekends) with prices set in advance for long time periods, are not to be considered a truly dynamic pricing.

In this regard, CEER[51] recommends that dynamic price contracts refer to day-ahead market prices, that are published on the day before delivery and can therefore be communicated to the customers in advance. This makes it easier for consumers to adapt their electricity consumption, whether manually or automatically. As above mentioned, according to the 2019/944 directive contracts can also refer to prices on the intraday market, however this will be more complex to implement, taking also into account that the continuous trading used in the Single Intra Day Coupling does not set a unique reference price.

While the directive is not explicit on whether a dynamic price contract could include any ceiling or floor to the reference price variation, CEER cautions against the use of such restrictions, since by their very nature, dynamic price contracts are intended to give consumers effective price signals, in order to incentivise them to manage and adjust their energy consumption. Placing ceilings and/or floors on these signals reduces their effectiveness as it waters down the price signal. Nevertheless, suppliers should be allowed to propose additional spot-based offers that could better mitigate the price risks through, for instance, price caps while adding a hedging cost.

Moreover, dynamic price contracts should be based on actual meter data, since profiled customers will not have the same level of incentive for demand response activities if they are not charged specifically for the times at which they consume. Therefore, in order to access a dynamic price contract, the customer must have a smart meter that records consumption data at the same time granularity as the relevant reference price.

The directive 2019/944 also requires that consumers must be fully informed by suppliers of the opportunities, costs and risks of dynamic price contracts, and suppliers must obtain each final customer's consent before that customer is switched to such a contract. For this purpose, CEER recommends:

- to inform consumers that the reference spot price is subject to a wide range of variation over time, within the year and from one year to another;
- to provide customers with an estimate of the magnitude (maximum/minimum) of past dynamic prices that a consumer would have paid per month / per year, etc., based on his/her consumption profile over the previous year, if such data is available to the supplier, and the prices recorded historically over a long period of time (typically 5 years minimum). If such historic consumption data is not available to the consumer, an average consumption profile could be used. Even then, the customer should be informed that the price may still exceed these limits in the future;
- if actual customer consumption data is not available, then the supplier should provide access to a tool that would enable consumers to predict their approximate consumption profile, depending on

[51] Council of European Energy Regulators – CEER: Recommendations on Dynamic Price Implementation, Ref: C19-IRM-020-03-14, 3 March 2020, https://www.ceer.eu/documents/104400/-/-/2cc6dfac-8aa7-9460-ac19-4cdf96f8ccd0

property type, number of occupants (including children), equipments owned, consumption characteristics, etc., in order to better estimate the suitability of the dynamic price contract for them;

- to inform consumers of the importance of managing consumption in order to prevent potential bill increases, and that automation devices could be useful in this regard.

In order to provide clarity to customers, information on consumption levels and reference prices could be provided at an aggregated time interval on the main billing document, such as using daily or weekly averages. The essential information for the consumer for the average time interval period is the level of consumption and the price average over the period weighted by the consumption. Moreover, billing information should be provided on a frequent basis, at most monthly. If the customer requires further information, the supplier must provide them free access to a data repository and adequate reporting tools, so that they can analyse their actual consumption and the prices charged at time intervals at least equal to the market settlement frequency.

In addition, since the wholesale reference price is the same across suppliers, they will compete on the basis of the price add-on that reflects suppliers' operational costs and profit margin. According to CEER, the impact of these add-ons on the final price of a dynamic price contract (e.g. structure, magnitude, etc.) should be made clear to the customers when they choose a supply contract, as this is one of the most relevant parameters they will use to compare suppliers, taking also into account that comparison tools will not be able to compare fixed price contracts, where the price is known beforehand, with dynamic ones, that are based on future prices that should be predicted.

There are examples of dynamic pricing in Finland[52], where consumers have hourly metering and pay the hourly day-ahead spot market price of the Finnish market zone, plus the retailer's premium and a monthly fixed fee. Consumers can check the prices the day-before, after the gate closure of the day-ahead spot market on the corresponding website.

In Estonia[52] there are supply offers where all the energy price is linked to the power exchange hourly price or where 50% of consumption is paid at a fixed pre-determined price and the other 50% is valorized at the power exchange hourly price.

In Norway[53] dynamic pricing is widely adopted: already in 2018 71% of households adopted dynamic pricing contracts since they were the cheapest ones on the market and allowed to change supplier at any time, while other kinds of contracts had a minimum duration of one year.

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[52] Dynamic pricing in electricity supply – a Eurelectric position paper, February 2017, http://www.eemg-mediators.eu/downloads/dynamic_pricing_in_electricity_supply-2017-2520-0003-01-e.pdf

[53] Ecofys – Asset, Dynamic electricity prices, February 2018, https://asset-ec.eu/wp-content/uploads/2018/10/Dynamic-electricity-prices.pdf

In Spain[52] the "Voluntary Price for Small Consumers" scheme has been in force since April 2014 and can only be contracted by consumers with contractual power less than 10 kW through so-called "reference retailers". It is a default tariff which consumers can opt out of and subscribe to another supplier or contract structure. The tariff is composed of three components: the hourly wholesale electricity price, the regulated network charges and a regulated retail margin.

In addition to time-varying prices of the energy component of the bill, also time-varying network tariffs can be taken into account. In fact, Article 18, paragraph 7 of Regulation 2019/943 states that *"Where Member States have implemented the deployment of smart metering systems, regulatory authorities shall consider time-differentiated network tariffs when fixing or approving transmission tariffs and distribution tariffs or their methodologies in accordance with Article 59 of (EU) 2019/944 and, where appropriate, time-differentiated network tariffs may be introduced to reflect the use of the network, in a transparent, cost efficient and foreseeable way for the final customer".*

As described in the report of the Council of European Energy Regulators – CEER on electricity distribution tariffs supporting the energy transition[54], time-differentiated "static" tariffs are characterised by offering different price signals for energy and power, based on discrete time periods (or "time-bands") that are fixed in advance, possibly differing between relevant locations on the network. Typically, these tariff types can be either time-of-use energy or time-of-use power. Time-of-use, whether energy, power or any mixture, are generally considered to be more cost-reflective than time independent tariffs, as they are aligned to predicted peak times. ACER[55] reports that several European countries apply time-differentiated network tariffs, as shown in Table 6.

[54] Council of European Energy Regulators – CEER on electricity distribution tariffs supporting the energy transition, Ref: C19-DS-55-04, 20 April 2020, https://www.ceer.eu/documents/104400/-/-/fd5890e1-894e-0a7a-21d9-fa22b6ec9da0

[55] ACER, Report on Distribution Tariff Methodologies in Europe, February 2021, https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Report%20on%20D-Tariff%20Methodologies.pdf

Table 6 - Application of time-differentiated network tariffs in Europe (source: ACER)

	Injection charge:		Withdrawal charge:	
	Energy-based	Power and energy-based	Energy-based	Power and energy-based
Member States	FI (some DSOs)	SE	AT, BE, EE[130], IE, LV, LT, MT[131], PL, SI	FI (some DSOs)[132], HR, CZ, DK, FR[133], PT, ES[134], SE
Total	1 MS	1MS	9MS	8MS

However, CEER highlights that static time-of-use differentiated tariffs could also pose a challenge if they lead to large loads being shifted in and out of the network simultaneously (e.g. at the change of hours). For example, such shifts could happen when the price variation in the energy charge is high between two hours and an increasing degree of home automation results in a large number of users responding at once. Tariffs giving such signals could lead to new network peaks, therefore tariff designs would need to avoid these sudden load changes. Moreover, the price signal has the potential to be counterproductive if it is set for an area that is larger than the congested zone, e.g. by incentivising a response from customers where it is not needed, although it is unlikely that this will be more distortive than a flat tariff.

According to CEER, improvements in the available information about the real-time status of the network and the consumption of each individual customer make it more realistic to implement dynamic tariffs. A dynamic tariff means that the price signal is defined at shorter notice, possibly close to real-time. This contrasts with static tariffs, where the price signals are associated with predetermined time periods. Dynamic tariffs are one way that DSOs could make use of flexibility to avoid or defer reinforcements, which is due to increasing intermittent production and variation in consumption/load.

The objective of a dynamic network tariff is to promote a more efficient network use under a scenario that has become more uncertain and where new technological solutions are enabling demand response (i.e. smart meters, storage). Being dynamic, the price signals can be sent closer to real time, increasing the cost-reflectiveness of the network tariff, which should enable the achievement of a more cost-efficient system, benefitting all network users.

A truly dynamic end-user price is the sum of a dynamic network tariff and a dynamic (spot market) electricity price. The sum of the two price signals would enable the consumer to decide at each moment how much to consume for a given price. Obviously, the two price signals would not always be aligned since they are measuring scarcity on different levels: while a dynamic retail price measures scarcity in the wholesale market at system level (which could be regional, encompassing several countries), the dynamic network tariff measures scarcity on the distribution (or transmission) network at a local level.

The introduction of dynamic network tariffs shares the same pre-requisites as dynamic retail prices, namely:

- introduction of smart meters in order to measure consumption in short time intervals, according to the time unit, as determined by the imbalance settlement period. This is on track across Europe with the widescale roll-out of smart meters;
- feedback about metering data to enable users to control their energy use (e.g. through an app or a technical device);
- technological solutions for flexible use and power reduction in residential/commercial/industrial contexts (e.g. automation and storage).

However, the introduction of dynamic network tariffs also requires a second layer of pre-requisites:

- a detailed forecasting model, which would be used by the DSO to determine the critical periods by network area/point. The complexity needs for these models to accurately forecast critical periods would be exponentially greater where the tariffs also vary within a DSO area. Notably, DSOs need to become increasingly responsible for the operation of their networks, and this includes modelling of future congestions;
- robust estimates about long-term avoided costs related to the reduction of the needs for network reinforcement;
- IT infrastructure to send price signals to network users, possibly differentiated by network area/point, in order to ensure that users[56] are able to predict charges and respond to them.

Dynamic tariffs raise numerous regulatory questions. These issues include how customers should be informed of tariffs (possibly through their supplier, who needs to sum up the dynamic energy component with the dynamic network tariff component of the bill), how regulators should regulate tariff setting, and how they should be integrated into the system of tariff or revenue cap incentive regulation applied in most Member States of the EU. National Regulatory Authorities – NRAs should also carefully consider the fact that dynamic tariffs come with administrative costs and complexity, as it is a difficult task to calculate the required tariffs for a specific place and/or time.

Finally, the consequences for cost distribution could be unclear, especially between customers with and without automation. If a high degree of cost recovery is done through the dynamic tariff signal, customers who are unable to respond through technology are likely to pay higher network costs. This depends on a

[56] Article 11 of the IEM directive states that *"Member States shall ensure that final customers are fully informed by the suppliers of the opportunities, costs and risks of such dynamic electricity price contracts, and shall ensure that suppliers are required to provide information to the final customers accordingly"*. We interpret this in relation to information that suppliers have to provide to final customers in a pre-contractual phase, and not in real-time: see the above described CEER recommendations on dynamic pricing.

number of aspects, e.g. on whether the dynamic tariffs are voluntary for customers and how the costs would be distributed between dynamic and static tariff users. Through the resulting tariffs it should be ensured that a reasonable distribution of costs among all network users is achieved. CEER emphasizes that principles such as simplicity and predictability are especially important for small customers, while other principles have more weight for larger customers at the DSO level.

CEER concludes that NRAs should consider dynamic network tariffs as one of the tools to improve the cost-reflectiveness of network tariffs but, as a starting point, should consider whether technology is sufficiently mature within the Member State to allow the efficient use of such tariffs on smaller users as it requires a sufficient smart meter roll-out and a high level of automation. The option of dynamic tariffs will become more viable as data systems develop. Implementing dynamic tariffs requires piloting of such tariff structures to test their ability to promote a more efficient electricity system. Finally, implementation of dynamic network tariffs must be preceded by a thorough cost-benefit analysis, namely to account for the monitoring and communication requirements needed to implement such a scheme.

According to CEER, a true real-time dynamic network tariff has not been implemented anywhere, yet.

4.5 Aggregation of distributed resources

As well-known, a characteristic of every power system is the need to guarantee continuously a real-time balance between electricity supplied by power plants and electricity demand. The TSO guarantees this balance using a complex control system and acquiring dedicated services from the Ancillary Services Market. Traditionally, the main suppliers of these flexibility services, namely ancillary services, were large fossil-fuel or hydro power plants. However, with the progressive decarbonization of power generation, in line with the European goals, new flexible resources will be required as well in order to guarantee the security and adequacy of the electricity system.

4.5.1 A European picture on distributed flexible resources

Flexible resources include aggregated and decentralised load units, generation units and storage units, such as for example back-up generators, combined heat and power (CHP) generators, batteries, industrial processes, heating, ventilation & air conditioning (HVAC) devices, electric vehicle/chargers and district heating. These behind-the-meter sources are collectively termed *Demand Side Flexibility (DSF)*.

The EU Market Monitor 2020[57] of the SmartEn association reports the scores of the markets of Demand Side Flexibility for 21 national European energy markets. In particular, the score levels are:

- "*High*" (*mature market*), where the country can be considered as a highly developed market in terms of:
  - unbundled and competitive markets
  - multiple value streams exist and accept behind-the-meter and aggregated assets
  - high needs for flexibility
  - high innovation from industry
  - higher value for DSF and therefore higher incentive for DSF across a range of customers, assets and competitors
  - barriers and market uncertainties exist
- "*Medium*" (*active market*)), where a country can be considered as a generally active market undergoing development in terms of:
  - varying degrees of accessibility and openness to value streams for DSF
  - high barriers for DSF and independent stakeholders, compared with "traditional" methods of flexibility (i.e. generation assets) and incumbent players
  - low incentives for businesses and/or customers to engage in DSF
  - limited engagement, or pockets of engagement where it makes sense, of industry and end users
  - barriers to entry exist
- "*Low*" (*emerging market*), where a country can be considered as a market which is not established or is yet to open fully to DSF in terms of:
  - there is evidence of some activity in demand side flexibility
  - sometimes trials rather than commercial activity
  - limited needs for demand-side flexibility, mainly due to excess generation capacity
  - limited or, in some cases, no value streams established, available and/or accessible to behind-the-meter resources
  - limited engagement in DSF by industry and end-users

Asset diversity used for DSF. In "*high*" score level markets there is evidence of DSF activity in the majority of flexible resource types (mainly around industrial loads and distributed generation units); in particular,

[57] SmartEn, Delta-EE, "EU Market Monitor for demand side flexibility 2020", 2020, https://smarten.eu/wp-content/uploads/2021/03/EU_Market_Monitor_2020_1-32.pdf

there is evidence of a “*high*” score level in: France, the Netherlands, Denmark and United Kingdom. For example, in Denmark there are 1÷40 MW electric boilers and CHPs (often installed in combination), mostly located within district heating; these DSF resources are optimised for ancillary services and day ahead energy markets. Others DSF activities, at trial stage in 2019, are with EV flexibility (with fleets and private vehicles for commercial FCR with minimum requirement of 100 kW for ancillary services participation), batteries (in order to support the increasing RES penetration), cold storage and heat pumps (commercial/industrial loads); from the small domestic loads side, DSF activities are expected by 2021 from the new domestic dynamic electricity tariffs. In “*low*” score level markets the DSF activity tends to be limited to very few flexible resource types.

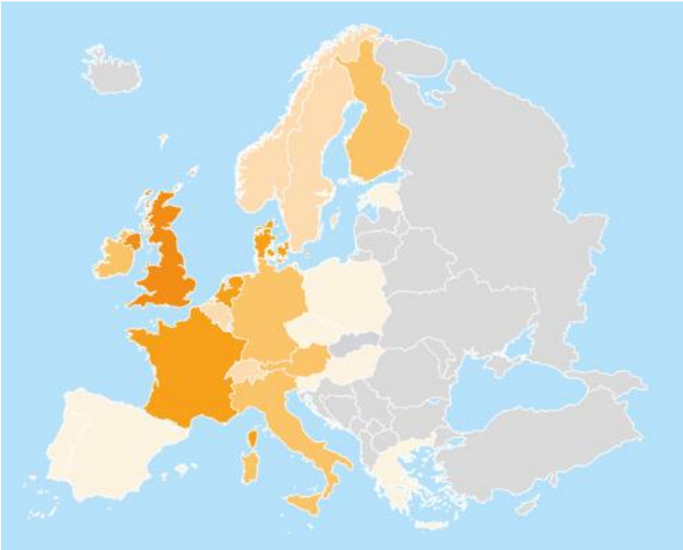

Figure 13 - Asset diversity used for DSF (SmartEn 2020).

Customer segments engaged for DSF. Customer segments include industrial, commercial and residential. In “*high*” score level markets there is significant evidence of DSF activity in all three customer types; in particular, there is evidence of a “*high*” score level in: France, Finland, Ireland and United Kingdom. In Finland, large industrial loads (more than 1 MW) can participate in DSF activity with a total 300 MW available; in commercial customers with loads below 1 MW the experience with batteries in shopping centres is significant; building automation technologies and domestic electrical water heaters are emerging trends, with aggregation of residential assets. It is also interesting the case of the Netherlands, where commercial and industrial customers with back-up generators, CHP and industrial loads are active in ancillary services provision and optimising wholesale and imbalance energy positions; in the residential sector and at trial stage, there is DSF activity with EV chargers, batteries and electric heating loads (there are few players with thousands of aggregated residential scale assets).In “*low*” score level markets the DSF is limited to one segment, or there is a limited engagement across multiple customer segments.

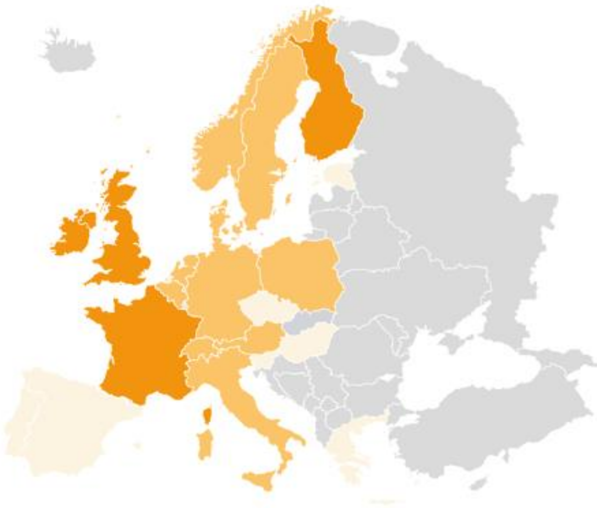

Figure 14 - Customer segments engaged for DSF (SmartEn 2020).

Competitive landscape for DSF. In aggregated and decentralised resources, the aggregators and energy suppliers dominate the European landscape. The score level is evaluated in terms of number of players active in DSF so that in "*high*" score level markets there are more competitive/innovative business models (in 2020 no country has more than 50 players); in particular, in UK the market is highly competitive with a high number and broad mix of players active in DSF (45-50 players). The landscape is dominated largely by aggregators and energy suppliers, but energy services companies, battery companies and technology companies (both hardware and software manufacturers and service providers) are also engaged. In "*low*" score level markets the DSF activity is limited to very few players.

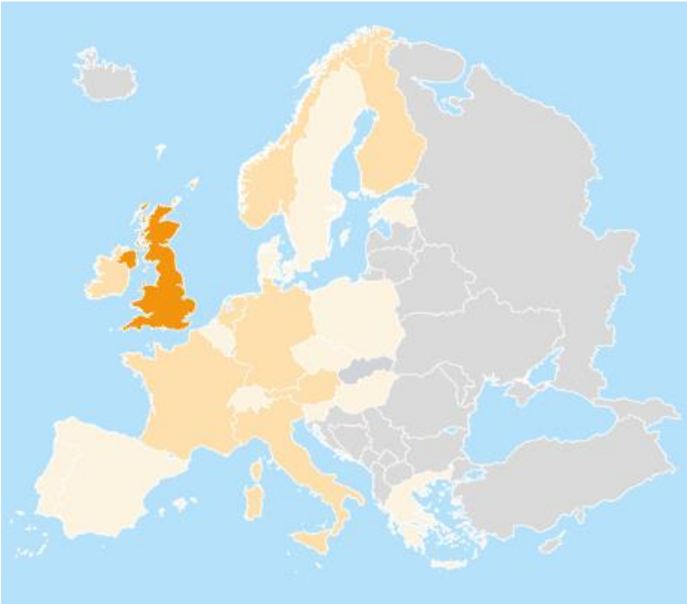

Figure 15 - Competitive landscape for DSF (SmartEn 2020).

Value stream availability and accessibility for DSF. The value stream includes day-ahead/intraday energy products, ancillary services products, interruptible loads, capacity mechanisms, DSO specific products and TSO/DSO network charges. In "*high*" score level markets multiple value streams are open to DSF activity (with low barriers to entry); in particular, there is evidence of a "*high*" score level in: France, Belgium, Ireland and United Kingdom. For example, in France the majority of the above value streams are open to DSF activity (e.g. the *Notification d'Échange de Blocs d'Effacement* - *NEBEF* mechanism, which has been created to allow virtual pools of loads to be traded in the wholesale market). In Switzerland, that is part of the EU FCR Cooperation, around 25% of FCR procurement comes from DSF; DSF can participate also in a-FRR and m-FRR. In "*low*" score level markets the DSF activity limited in number and/or accessibility for DSF.

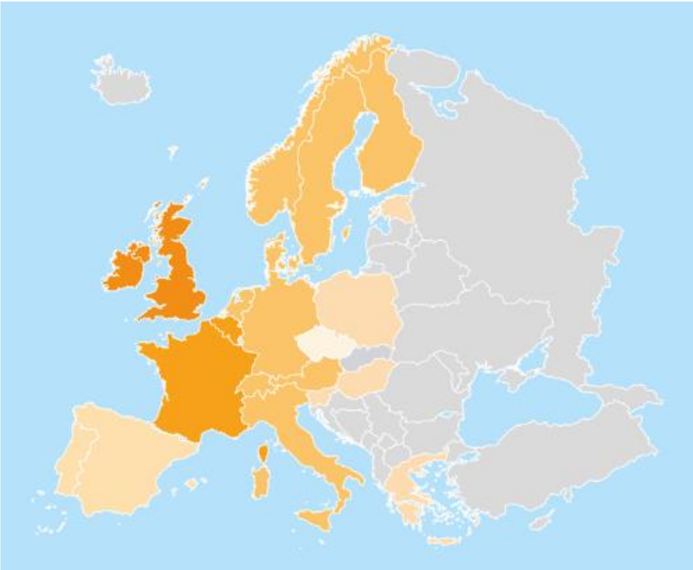

Figure 16 - Value stream availability and accessibility for DSF (SmartEn 2020).

Monetisation of DSF. The monetisation is related to the value streams including day-ahead/intraday energy products, ancillary services products, interruptible loads, capacity mechanisms and TSO/DSO network charges. In "*high*" score level markets there is evidence of DSF activities being monetised in the majority of available value streams; in particular, there is evidence of a "*high*" score level in: France, Denmark, Germany, Ireland and United Kingdom. For example, in France there is 600 MW (2020) of DSF (by *Appel d'offres Effacement*) with tender prices increase from €30,000/MW/year to €60,000/MW/year resulting in a procurement increase of 96% (this increase is encouraging as France has an ambitious DSF target of 6.5 GW by 2028).

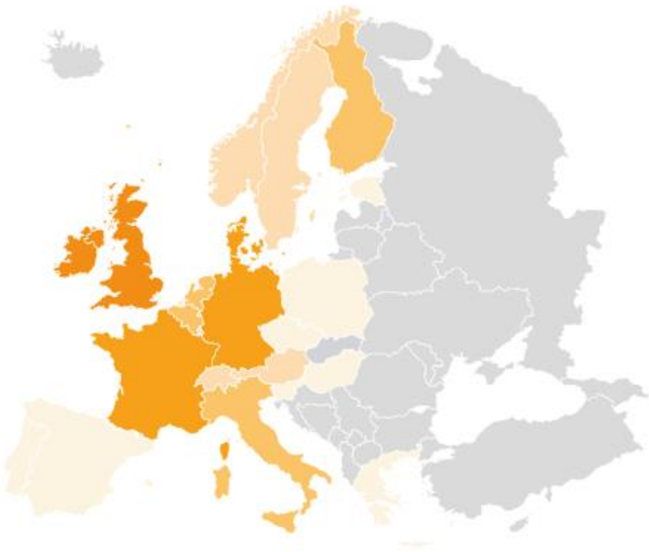

Figure 17 - Monetisation of DSF in value streams (SmartEn 2020).

Overall, France and Great Britain are the highest ranking countries for DSF market activity, followed by Ireland, Germany and the Netherlands.

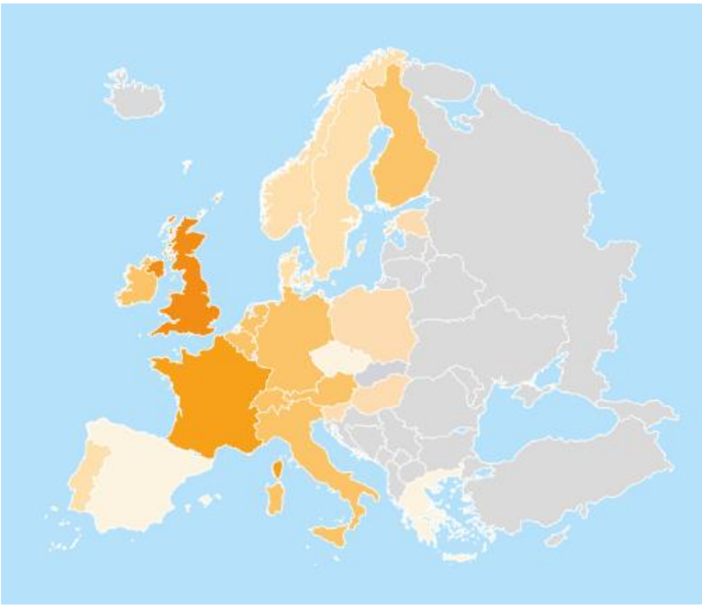

Figure 18 – Overall ranking for DSF market activity (SmartEn 2020).

In 2021 across 30 European markets, most countries have commercial and remunerated ancillary services. However, only 50% allow DSF and fewer still allow participation from aggregated assets. In order to meet the requirements of the Clean Energy Package most countries will need to make significant improvements.

Even those countries where the markets are accessible (for example Germany) have additional regulatory barriers that hinder participation to DSF.

Poland and Greece followed by Spain, Italy and Romania are the most prominent emerging markets due to opening of value steams to DSF and a high need/value of flexibility. Broadly there are three routes to future development of DSF markets:

a) countries that are currently closed but have formalised plans for opening to DSF (e.g. Poland, Greece),
b) countries that are open to DSF but due to technical and administrative barriers have limited participation (e.g. Spain and Portugal),
c) countries with existing open and accessible market but have high renewable targets so there is scope to grow (e.g. France, Germany and United Kingdom).

4.5.2 DSF/DER aggregation schemes

Starting from the USEF[58] framework, in the following we deal with aggregation schemes for the exploitation of flexibility as a tradeable commodity in the market[59,60,61].

4.5.2.1 General context

Aggregators have the main task to collect the flexibility obtained from the DSF / DER resources owned by a set of industrial, commercial and residential end users (including local generation units and local storage systems). The pooling process allows to collect and then to turn the flexibility into products

[58] The *USEF (Universal Smart Energy Framework) Foundation* was founded in 2014 by seven key players, active across the smart energy industry. It grew out of the SEC (Smart Energy Collective), a Dutch multi-partner collaboration, developing smart energy technologies. USEF had one goal: to accelerate the establishment of an integrated smart energy system which benefits all stakeholders, from energy companies to consumers. The USEF Foundation ended its activities on 1 July 2021. Website: https://www.usef.energy/usef-foundation/ (last update: June 2021).

[59] USEF, "Framework Explained", 2015, https://www.usef.energy/app/uploads/2016/12/USEF_TheFrameworkExplained-18nov15.pdf

[60] USEF, "Work stream on aggregator implementation models", Update September 2017, https://www.usef.energy/app/uploads/2017/09/Recommended-practices-for-DR-market-design-2.pdf

[61] USEF, "The framework explained", Update 25 May 2021, https://www.usef.energy/app/uploads/2021/05/USEF-The-Framework-Explained-update-2021.pdf

(energy/ancillary services) to serve the needs of the other various stakeholders (TSOs, DSOs, BRPs, BSPs).

The flexibility collected must be evaluated in order to compare the cost of the flexibility of the asset with that of the possible alternative solutions. In this way the aggregator can negotiate the price for the flexibility and trade the flexibility as market products.

Large and medium-sized end consumers (e.g. industrial and commercial consumers) can more easily participate in wholesale markets (energy markets, balancing services markets) by the activation of flexible resources. However, the lack of interface standardization is a barrier for medium and small-sized companies. A prerequisite for the large-scale market participation of small and medium-sized players such as the aggregators and residential end users is the commoditization of products, services and solutions so that they become commercially viable (that is, it is essential to reduce the cost to serve those end users and reduce the cost to connect their appliances). In other words, it is essential an open standardization framework that prevents vendors, aggregators and energy service providers lock-in and enables the commoditization of the required technology.

4.5.2.2 Roles relevant in flexibility service exchange

It is necessary to identify the roles and responsibilities of the players involved in the trading activity of flexibility products in order to detect the best business model for the aggregator. With reference to an industrial/commercial/residential end user it is possible to define various roles involved in the flexibility trading process.

Prosumer (or Active Customer). It represents the "end user" that no longer only withdraws energy from the grid, but also injects energy. The end user can be a residential, a small, medium or large-sized commercial or industrial customer. The prosumer owns the devices and delegates responsibility for controlling its flexibility to the aggregator. In particular, the prosumer has final control over its assets so that aggregator's control space is limited by the prosumer's comfort settings. In fact, the main assumption is that prosumer is always in control of its "comfort level" and, if the associated remuneration for the flexibility provision is high enough, the prosumer might be willing to compromise on its comfort levels. From the viewpoint of prosumers, the flexibility provided by assets in terms of *Demand Response (DR)* can be defined as Implicit DR or Explicit DR where:

- *Implicit DR* (also called *"Price-based" DR*) refers to consumers choosing to be exposed to time-varying electricity prices or time-varying network grid tariffs (e.g. Time-of-Use - ToU tariffs) that reflect the value and cost of electricity and/or its transportation and distribution in different time periods (depending on the specifications of suppling contracts, they respond to wholesale market price variations; in some cases they respond also to dynamic grid fees contracted with the DSO);

- *Explicit DR* (also called *"Incentive-based" DR*) refers to the aggregated flexibility directly traded in the wholesale, balancing and capacity markets: consumers receive direct payments to change their consumption or generation patterns upon request, triggered by, for example, activation of balancing energy, differences in electricity prices or a constraint on the network.

With Implicit DR the prosumers (or active customers) can profit from flexibility services for in-home optimization (implicit valorisation of the prosumer's flexibility), allowing them to shift their flexible assets to periods with relatively low electricity prices or grid tariffs. Instead, in presence of Explicit DR the BRP/TSO/DSO can profit from flexibility services, through the aggregator, for portfolio optimization and system management by exchanging market products (energy services) or system operation products (ancillary/system services).

Active Demand & Supply (ADS). It represents all types of system devices that either demand energy or supply energy and which can be actively controlled. In particular, the controllable ADS device enables to respond to signals by network/market operators (e.g. price signals, network signals, other signals by the aggregator) and to provide flexibility to the energy markets and/or to network operators via the aggregator.

Supplier. The main task of the supplier is to source, supply, and invoice energy to its customers. The supplier and its customers agree on commercial terms for the procurement and supply of energy.

Energy Service Company (ESCo). It offers auxiliary energy-related services to prosumers (e.g. energy optimization service, remote maintenance service of ADS assets). For example, the ESCo can provide energy optimization services based on the time-of-use (ToU) tariffs (Implicit DR).

Allocation Responsible Party (ARP). It is responsible for establishing consumption and production volumes per imbalance settlement period and for communicating the realized volumes per imbalance settlement period, either on the consumer level or on the aggregated level. The realized volumes are primarily based on actual measurements but can also be based on estimates. The allocation volumes are input for the flexibility settlement process and the wholesale settlement process. In most countries this role is played by the TSO.

Meter Data Company (MDC). It is responsible for acquiring and validating meter data. The MDC plays a role in the flexibility settlement process and the wholesale settlement process. In many countries this role is performed by the DSO.

Producer. The role is to feed energy into the grid and so its primary objective is to operate its assets at maximum efficiency.

Balance Responsible Party (BRP). It is responsible for balancing supply and demand for its portfolio; the portfolio consists of producers, aggregators and prosumers. A BRP is contracted by the supplier and holds the imbalance risk on each connection in its portfolio of prosumers.

Trader. It buys energy from market parties and re-sells to other market parties on the wholesale market, either directly on a bilateral basis (over the counter) or via the energy exchange (day-ahead, intraday).

Exchange. It provides brokering between electricity Traders, Suppliers, BRPs and aggregators.*Imbalance Settlement Responsible (ISR)*. It is equivalent to the ARP and is responsible, for a certain scheduling area[62] which often corresponds with a bidding zone[63]), for establishing and communicating the realized consumption and production volumes per imbalance settlement period (ISP), either on the consumer level or on the aggregated level. The realized volumes are primarily based on actual measurements but can also be based on estimates. The allocation volumes are input for the flexibility settlement process and the wholesale settlement process.

Balancing Service Provider (BSP). It is a market participant with reserve-providing units able to provide balancing services to the TSO. The BSP is the trading counterparty through which the aggregator provides Balancing Services to the TSO; the BSP is contracted by the TSO and is responsible for procuring balancing energy. BSP and aggregator, as well as BSP and BRP can coincide.

Congestion Management Service Provider (CMSP). The role of CMSP is to provide constraint management to a DSO or to a TSO. In the provision of its services, the CMSP takes on specific responsibilities in communicating and coordinating flexibility transactions to effectively manage constraints between DSOs and/or the TSO.

Capacity Service Provider (CSP). The role of CSP is to provide adequacy services to either the TSO or a BRP. This role is similar to the BSP and CMSP roles and is applicable for adequacy services only.

Distribution System Operator (DSO). It is responsible for the management of the distribution grid; in particular, the DSO is responsible for the cost-effective distribution of energy by maintaining the stability of the grid. To this end the DSO will use the flexibility resources by checking that DSF/DER activation within its network can be safely executed without grid congestion and by purchasing the flexibility from the aggregators.

[62] With reference to the Commission Regulation EU 2017/1485, ‘Scheduling area’ means an area within which the TSOs' obligations regarding scheduling apply due to operational or organisational needs. This area consists of one or more Metering Grid Areas with common market rules for which the settlement responsible party carries out an imbalance settlement and which has the same price for imbalance.

[63] With reference to the Commission Regulation EU 2017/1485 (Article 110): Where a bidding zone covers several control areas, TSOs within that bidding zone may jointly decide to operate a common scheduling process, otherwise, each control area within that bidding zone is considered a separate scheduling area.

Transmission System Operator (TSO). It is responsible to manage the transmission network, to keep the system in balance by procuring and deploying regulating capacity, active/reactive power reserve capacity, and emergency capacity, as well as to safeguard the system's long-term ability to meet electricity demand.

Aggregator. It is the new player who interfaces with the relevant roles described above in order to collect flexibility and sell it as flexibility services to the BRP/DSO/TSO. More details are presented below in sub-section 4.5.2.3.

4.5.2.3 The new role of the aggregator

The main role of the aggregator is to collect flexibility from prosumers and their ADSs and sell it as explicit flexibility services. In particular, the aggregator is responsible for acquiring flexibility from prosumer's distributed energy resources, aggregating it into a portfolio of flexible resources, creating market services (energy services, ancillary services or flexible services) with the flexibility margin and offering these in terms of flexibility services to different market players such the BRP/Supplier (energy services), the DSO (flexibility services), or the TSO (ancillary services) (see Figure 19). Here the interaction with the prosumer refers to a demand response programs by means the control of load profile and self-balancing with local generation (named Demand Side Flexibility - DSF), including the islanding service during the main grid outages.

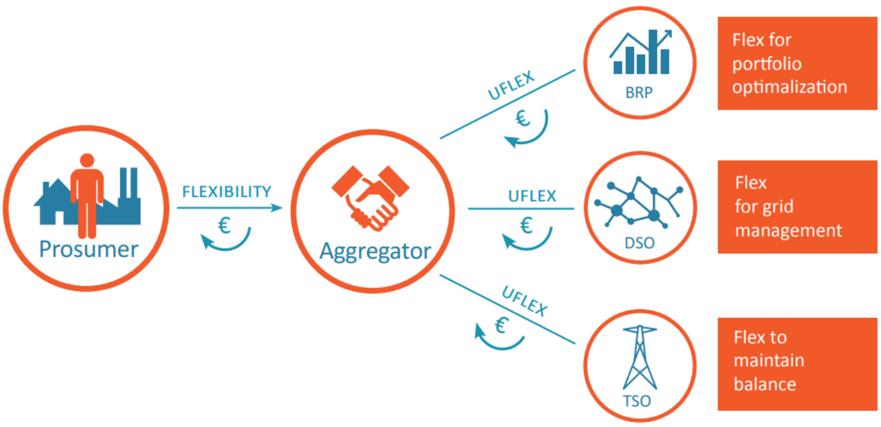

Figure 19 - Basic aggregation scheme and market exchange of the flexibility resources (Source: USEF).

The aggregator's goal is to maximize the (economic) value of the flexibility resources collected in terms of existing and future flexibility services for the market; in particular, the aggregator builds a portfolio of assets to meet the minimum technical requirements (e.g. size and timing constraints of specific flexibility products) and may choose to specialize on a single flexibility product or offer multiple products within the same portfolio. The aggregator and its prosumers agree on commercial terms and conditions for the procurement and control of flexibility; in particular, prosumers will receive a remuneration based on the flexibility they offer through their assets.

In general, the prosumer's assets are connected on the distribution network and the DSO will be directly affected by the flexibility activation. So, the flexibility will be identified as distributed explicit flexible services.

Within the flexibility value chain process, after the collection stage of the flexible resources and the relevant flexibility services detection stage, the aggregator can offer the distributed flexibility as service products to the:

- BRP in order to optimize its portfolio (wholesale services, adequacy services);
- DSO in order to increase its performance and efficiency in managing the distribution grid (constraint management services);
- TSO in order participate to system stability and capacity management (constraint management services, balancing services, adequacy services).

This interaction between the aggregator and other relevant roles can be based on the following scheme (see Figure 20):

- the prosumer contracts the energy supply and the flexibility provision (Explicit DR) with the supplier and the aggregator, respectively;
- the aggregator associated with a specific type of BRP as BSP (e.g. BRP aggregator) contracts the flexibility resource with the prosumers (Explicit DR) and offers the flexibility services to the TSO (ancillary services), DSO (flexibility service) and other BRPs (energy service) [64, 65];
- the aggregator contracts also the balancing energy with the BRP associated with the supplier (e.g. BRP supplier) of the prosumer contracted by the aggregator (in fact, the activation of flexibility changes the energy profile of the prosumer so that the BRP associated with the supplier of the prosumer may be affected; hence, the relationship between the aggregator and the BRP supplier is very important: typically there are two contracts, one between aggregator and supplier about the transfer of energy and one between BRP aggregator and BRP supplier about perimeter corrections, i.e. the differences between the original profile of the prosumer contracted with its supplier and the profile resulting after the activation of the flexibility).

[64] Introducing the right to flexible prices for consumers does not require the role of the aggregator so that, in case of Implicit DR, the flexibility of the prosumer is not contracted by the aggregator, but it can be managed by an ESCo.

[65] Implicit DR and Explicit DR should co-exist, yet may interfere.

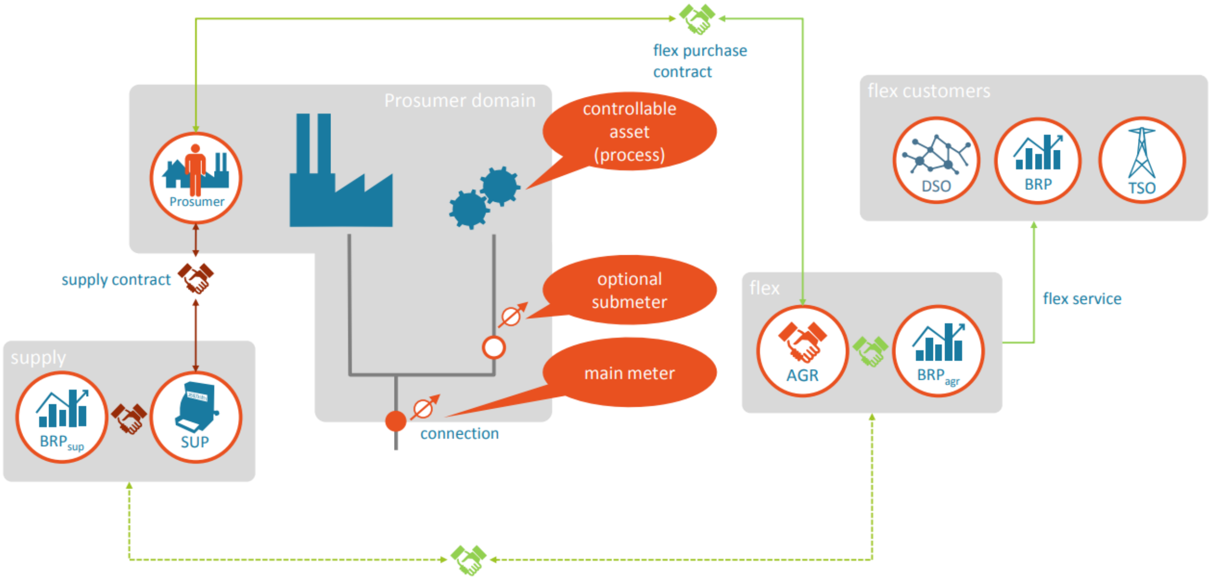

Figure 20 - Relevant roles and relationships of the aggregator (Source: USEF).

4.5.2.4 Sources of flexibility

In order to offer the explicit distributed flexibility an aggregator should have an excellent insight in both the characteristics of the ADS technologies installed at their prosumers premises, as well as the behavior of these prosumers. In particular, the main target of the aggregator is to extract the maximum value from the flexibility by finding the optimal match between the flexibility services in the market and the flex sources from its prosumers. So, the aggregator can map the right characteristics of the flexibility services provided by source of flexibility at the right time. Flexibility resources include:

- controlled load (e.g. heat pumps, air conditioning, heating-ventilation air conditioning - HVAC systems, cold stores, heating or cooling processes, industrial production processes) for load shifting, on/off switching, variable power consumption;
- local generation (e.g. solar photovoltaic systems, combined heat&power - CHP systems, micro-CHP systems, fuel cells, gas turbines, uninterruptible power supply units) for variable and controllable power generation;
- storage (e.g. residential battery units, district storages) for variable and controllable power exchanges during charge/discharge stages;
- electric vehicles (e.g. cars, buses, trucks) for smart charging/discharging.

4.5.2.5 Characteristics of flexibility

In general, flexibility trading defines the way flexibility is delivered and how it is remunerated, also taking into account the possibility to use the value stacking approach.

Flexibility delivering way. The delivering way can be split into availability and activation requirements, where the availability requires that enough flexibility (expressed in kW or MW) is available within the specified time period (settlement periods contracted), while the activation refers to the actual control of ADS assets (expressed in kWh or MWh).

The availability typically includes activation requirements (e.g. terms and conditions for activating), although the activation frequency strongly depends on the type of flexibility service product. The availability can be required in terms of market availability (the aggregator makes sure that the asset is available in one or more markets) or exclusive availability (the aggregator reserves capacity for activation on specific request of the aggregator-BRP/BSP). The flexibility requesting party (TSO, DSO or BRP) may use prequalification tests, audits of assets and control equipment, and (random) activation tests to verify the availability of flexibility offered by the aggregator.

The activation can be performed in two ways, with and without energy transaction between the ADS assets (aggregator) and the power grid (TSO/DSO). In case of energy transaction, the aggregator delivers the required energy based on the requested volume (e.g. wholesale market trading) or the activated volume (TSO/DSO command), while in case of without energy transaction, the aggregator only delivers a service but not the energy. In particular, the second case is suitable for constraint management services because the aggregator offers load reduction or generation increase which are of interest to the DSO/TSO (e.g. services to prevent congestion) while the first case is suitable for services where it is accepted to organize the deviation in the energy profile in its preferred way (e.g. by registering another trade with an energy transaction to settle the energy, by activating other assets in its portfolio as a countermeasure, or by accepting the ‘imbalance’).

Both availability and/or activation of flexibility can be requested and validated by the TSO/DSO or BRP in different ways:

- *drop-to services*, where the TSO/DSO or BRP request that the aggregator ensures the availability and required activations are managed to keep the load or generation exchange below or above a specific limit (no need for a baseline and, so, the aggregator does not need to quantify the delivered energy volume);
- *drop-by services*, where the TSO/DSO or BRP request that the aggregator manages a decrease or increase in load/generation according to a baseline with the requested volume in MWh.

The advantage derived by no-need baseline for drop-to service can be limited when a baseline is still required for other purposes (e.g. the TSO/DSO may still decide to remunerate based on activated flexibility volumes).

Flexibility remuneration way. The remuneration scheme of flexibility can be based on the performance of the aggregator during the availability or activation period in various ways.

Flexibility availability remuneration is typically paid per contract period and based on:

- *availability remuneration*, where the aggregator receives a fixed price for the availability of capacity (kW/h or kW/Imbalance Settlement Period);
- *assessment of delivery requirements compliance* (performance requirements, e.g. ramp rate, kW-max/min, response time, duration, partial delivery, overshoot, etc.).

The TSO/DSO can issue test activations to assess the quality of the availability service. Moreover, if the aggregator does not meet the performance requirements, it can result in penalties or disqualification of service delivery.

Flexibility activation remuneration is typically based on

- *energy volume remuneration*, where the remuneration depends on the requested volume or the activated volume (baseline minus measurements) in kWh;
- *power performance remuneration*, where the remuneration is dependent on the delivered power (kW) according to a baseline.

To compare flexibility services on the remuneration of the activated volume, the baseline methodologies should also be compared as different products and generally use different baseline methodologies, which means that the same activation may result in different activated volumes for different products.

Note that a flexibility service may have multiple remuneration elements.

TSO/DSO can also request tests or audits outside activation/availability periods:

- prequalification assessment of delivery requirements compliance and quality of the baseline;
- assessment of the availability or quality of the baseline during non-activation within availability periods.

Value stacking approach. The net profit for distributed explicit flexibility services exchange depends also on the estimation of the cost related to the delivery of the flexibility (e.g. the cost of availability reservation, the cost of flexibility activation, the opportunity cost, i.e. the amount of benefit missed when choosing to deliver the flexibility over an alternative). In this case the aggregator could increase the economic value of flexibility services using the value stacking approach: the provision of multiple services to one or multiple grid operators (TSO, DSO) from the same portfolio of ADS assets. Different ways of value stacking can be implemented such as the value stacking “in time”, value stacking “in pools”, and value stacking “in double serving”. Value stacking “in time” means that different flexibility services are provided during distinct time periods (distinct Settlement Periods); for example, the provision of balancing services such as a-FRR to the TSO in the morning time intervals and of congestion management services to the DSO in the afternoon time intervals. Value stacking “in pools” means that different flexibility services are provided by using distinct pools or sub-blocks of ADS assets during a single time period (single Settlement Period). In this case the aggregator splits its portfolio in pools or sub-blocks of ADS assets in order to activate one pool (one sub-block of ADS assets) for one service and another pool (one sub-block of ADS assets) for another. The value stacking “in double serving” means the provision of multiple flexibility services during the same time period (same Settlement Period) by stacking activations from one pool/sub-block of ADS assets or one portfolio; moreover, this value stacking type can be performed with single or multiple energy transactions. The single energy transaction implies the combination of different flexibility services with and without energy transactions; for example, a congestion management service is provided to the DSO without energy transaction so that the amount of the reduction or increase in load/generation resulting from the planned activation can be offered on the wholesale market with energy transaction. The multiple energy transaction implies the combination of different flexibility services with multiple energy transactions; for example, x% of wind curtailment can be sold on the wholesale market and the remaining (1-x)% can be activated for balancing services such as a-FRR.

Another important characteristic of the value stacking approach is the direction of activation for different services (same direction, opposite direction); for example, the constraint management services typically supports value stacking in the same direction but disallow value stacking in the opposite direction (e.g. the balancing activation in the opposite direction could cancel out the effect of a congestion management activation). For all three ways of value stacking approach (in time, in pools, in double serving) it is possible to implement the “dynamic pooling”; in this case the aggregator can have the ability to decide real-time what ADS assets activate to deliver each flexibility service. In general, all types of value stacking can be implemented, but, in case of value stacking “in double serving” approach with multiple energy transactions, the complex nature of the interactions between the aggregator and other different market parties involved can make it challenging to distinguish and quantify the individual stacked services (in fact, these complex interactions involve the trading and validation of product delivery and settlement)[66].

[66] In the white paper “Flexibility Value Stacking” (version 1.0, 18 October 2018) USEF provides a comprehensive method to distinguish and quantify individually stacked services (while avoiding double selling of energy): https://www.usef.energy/app/uploads/2018/10/USEF-White-Paper-Value-Stacking-Version1.0_Oct18.pdf

4.5.2.6 Explicit flexibility services

As result of the flexibility value chain process the explicit flexibility services offered by the aggregator include[67]:

- wholesale services;
- constraint management services;
- balancing services;
- adequacy services.

Wholesale services. They help BRPs to decrease procuring costs (purchase of electricity) mainly on Day-Ahead and Intraday markets. In particular, the BRP aims to balance its portfolio (energy balancing at its generation and withdraw points) by reducing the energy sourcing cost as closely as possible to avoid imbalance charges during real-time network operation. The flexibility provided by the assets of prosumers can be used to optimize the BRP's portfolio; typical services required by a BRP are day-ahead/intraday portfolio optimization (e.g. load shifting services from a high-price time interval to a low-price time interval on a day-ahead/intraday basis), load-generation optimization (e.g. optimization of the behavior of load centers and generation units for the next hourly planned energy exchange) and self-balancing (e.g. actions to reduce of imbalance to avoid imbalance charges).

Constraint management services. They help the grid operators (TSO and DSO) to optimize grid operation. For TSO/DSO, traditional services are congestion management (e.g. optimal control of current flows in order to avoid the thermal overload of system components), voltage profile management (e.g. optimal control of nodal voltage profile by increasing the load or decreasing generation in order to avoid exceeding the voltage limits) and power quality support (e.g. activation of fast devices and local control loops in order to avoid the impact of rapid phenomena that occur in the sub-minute to millisecond range such as harmonics, flicker, voltage dips). Additional services are the grid capacity management (e.g. optimization of the operational performance and of the asset dispatch in order to reduce peak load amplitude, extend component lifetimes, reduce grid losses), controlled islanding (actions to prevent supply interruption during fault event) and redundancy support (actions to reduce the frequency and duration of outages, e.g. supplying emergency power or shedding loads, or supplying backup power during grid maintenance activities). For TSO, traditional services include congestion management, islanding services and redundancy support. One can observe that the voltage control and power quality support cannot be provided directly by aggregated resources. In fact, the transmission grid needs significant amounts of reactive power the reactive power cannot be transported over long distances. Instead, power quality is not an issue in the high-voltage grid, so that services related to power quality are not required.

[67] Note that the term system operation services can be used to refer to balancing and constraint management services.

Balancing services. They include all ancillary services specified by the TSO for frequency regulation: Frequency Containment Reserve (FCR), Automatic Frequency Restoration Reserve (aFRR), Manual Frequency Restoration Reserve (mFRR), Replacement Reserve (RR). Balancing service definitions are contained in the European Network code on Load-Frequency Control and Reserves.

Adequacy services. They aim is to increase security of supply by organizing sufficient long-term peak and non-peak generation capacity. Explicit distributed flexible services are very suitable for these mechanisms offering either load shedding, or distributed generation, to reduce the need for generation capacity. In this case, adequacy services can be provided by the aggregator through the role of CSP to either the TSO or a BRP, depending on market design. Four different adequacy services can be distinguished:

- capacity market;
- capacity payment;
- strategic reserve;
- hedging product.

The capacity market is an adequacy service, introduced by an authority to increase security of supply on a long-term basis to an area over a specific time period; in other words, the generation capacity is secured against long-term demand development. Running a capacity market ensures that lowest cost assets are built or remain in operation on a long-term basis. Capacity markets can be organized in terms of centralized or decentralized ones; in centralized capacity markets the TSO procures the required capacity generation by contracting all generation assets that are accepted below the clearing price (e.g. the UK capacity market), while in decentralized capacity markets, the BRP/Supplier has a capacity obligation and is thus responsible for procuring the capacity (e.g. the French capacity market); the clearing price is the point where demand for capacity and supply for capacity meet. Moreover, in decentralized capacity markets, flexibility can be procured on the distributed flexibility resources, to help a BRP to reduce its capacity obligation. In this case, the aggregator can also choose to add flexibility margin as a 'supply' asset to the capacity market and, where this is the case, the aggregator will receive the capacity-clearing price when its bid is accepted.

Capacity payment is a centralized adequacy mechanism to help achieve enough liquidity in an energy market; in particular, for capacity to deliver to a market (long-term ahead) at a certain time period, the TSO pays the capacity provider (e.g. as provided to wholesale market participants in Ireland). Respect to the capacity market, capacity payment is focused on liquidity (on the supply side), while the capacity market is focused on clearing supply capacity towards expected demand.

Strategic reserve is capacity requests by an authority for specific periods. Running the strategic reserve is the responsibility of the TSO; in particular, the procured capacity can be activated by a (day-ahead) price trigger or a technical trigger. The difference between strategic reserve and capacity market is that strategic reserve is dedicated for activation by the TSO (and is kept out of the market until the TSO provides the signal), while capacity market ensures that procured assets are in operation (i.e. bid into wholesale markets).

Hedging product is a way for a BRP to mitigate price risks associated with volatile energy supply and demand; in particular, during high prices (typically occur in periods of scarce generation), hedging can be considered an adequacy mechanism. Hedging product is typically done via over-the-counter contracts (e.g. contracts for difference, fixed price fixed volume, fixed price variable volume, options) or via futures exchanges. Distributed flexible services can be used as an instrument in these hedging products or can be traded as a hedging product itself (e.g. the aggregator offers the opportunity to activate flexibility resources at a certain price level).

The Figure 21 shows a preliminary list of flexibility services which may be of interest to the aggregator.

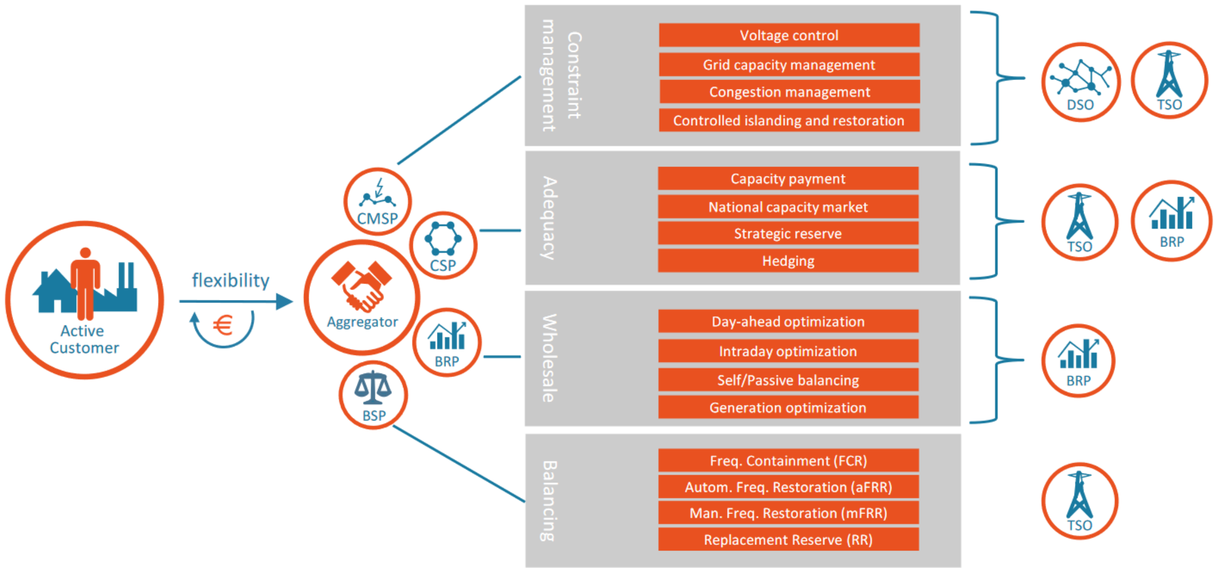

Figure 21 - Potential flexibility services list for the aggregator (Source: USEF).

4.5.2.7 General scheme of the aggregator's operation

In order to optimize the value of flexibility across all roles in the system, the aggregator needs to access to a new market-based coordination mechanism that from the viewpoint of implementation can be split in five phases:

- <u>*Contract*</u> signed between prosumer and aggregator regarding the prosumer's flexibility capacity and how it will be activated by the aggregator;

- *Plan* where the aggregator examines its portfolio clients in terms of energy demand and supply forecasting (in this phase both the BRP and the aggregator carry out an initial portfolio optimization; in fact, during this phase the BRP may procure flexibility from its aggregators) in order to obtain the aggregator plan (A-plan);
- *Validate* where during a scheduled stage the DSO checks possible limitations on the grid (e.g. congestions, imbalance issues) taking into account the transmission interface (TSO perimeter) and evaluates the procurement of flexibility from aggregator (iteration between A-plan and DSO-prognose);
- *Operate* where the aggregator adheres to DSO-prognose with its A-plan (when needed, DSO and BRP can procure additional flexibility from the aggregator);
- *Settle* where any contracted flexibility services sold to the DSO and BRP is settled.

The time scales in these five phases range all the way from years and months down to just hours before the operate phase starts. This broad window facilitates trading on different energy markets (such as the forward market, day-ahead spot market, and intraday spot market) and the ability to accommodate changes in the required grid capacity.

4.5.2.8 Implementing the aggregator role

The aggregator role can be implemented in three models: standard model, virtual transfer points model and Flex-BR model.

Standard model. This model refers to an addition of a new market player (aggregator) to the existing European liberalized energy market model. In this case, the aggregator establishes a contract:

- with the Prosumer (Flexibility Purchase Contract);
- with the BRP (Flexibility Service Contract; in fact, the aggregator acts as a BSP and it is associated with a special type of BRP who acts as an intermediary for the TSO’s ancillary services);
- with the Supplier (in order to invoice the flexibility service to the Prosumer; in fact, the aggregator is only formally responsible for invoicing flexibility to the Prosumer);
- with the DSO (Flexibility Service Contract; in fact, the main assumption is that prosumer’s assets are connected on the distribution network, so also the DSO will be directly affected by the flexibility activation).

The above contracts will be implemented in accordance with one of possible aggregator business models.

Virtual transfer points model. With this model the aggregator prefers to manage only a single type of prosumer’s ADS asset. A typical example is a commercial/industrial or residential consumer who already has a digital connection to its process and is well suited to aggregate the flexibility from all its devices in the field. One possible way to realize this model is by separating the flexible load component (ADS assets) from the base load component (Non-ADS assets) in order to obtain two virtual transfer points (VTPs): VTP1 for Non-ADS assets and VTP2 for the ADS assets. The VTP2 can be obtained by installing an accountable submeter, while the VTP1 will refer to the remaining Non-ADS assets (in other words the VTP1 is obtained by subtracting the flexible load component from the main meter). This means the Non-ADS assets on VTP1 will managed by a contractual relationship between BRP1 and SUP1, and ADS assets on VTP2 by a contractual relationship between AGR2, BRP2 and SUP2 (similar to the standard model; with respect to the Non-ADS assets on VPT1, the ADS assets can be under the full control of a third party aggregator (TPA) called independent aggregator[68], a new market player currently being discussed throughout the European energy market). So, in general, to make use of the flexibility from the controllable assets, the controllable load supplier can either partner with an aggregator or perform the aggregator role itself.

Flex-BR model. With this model, named flex-only balance responsibility model, the flexibility is completely separated from the supply of energy. For the energy component the supplier (SUP1) is responsible for the supply of energy on the prosumer's main connection and the corresponding BRP (BRP1) is responsible for the balance at the prosumer's main connection. For the flexibility services an independent aggregator (AGR2) offers the prosumer a flex-only service to control the flexibility of ADS assets. In this case, when the prosumer's ADS flexibility is activated, the BRP associated with AGR2 (BRP2 who acts as BSP2 to the TSO) is responsible for the imbalance it causes; in particular, the activation of flexibility will change BRP1's balance position. Hence BRP1 must somehow be compensated by BRP2 (AGR2) so that the activation of flexibility by AGR2 remains neutral for BRP1 and SUP1. So, BRP1 acts as supply-BRP who holds the responsibility for imbalances related to the supply and/or generation of energy on the prosumer's connection; in particular, the supply-BRP manages the balance position of its portfolio of producers, aggregators and prosumers and is identical to the existing BRP role in the market. The BRP2 acts as flex-BRP who is responsible for any imbalances caused by flexibility when it is activated; in particular, the flex-BRP manages the flexibility balance position of its portfolio of producers, aggregators and prosumers and is identical to the existing BRP role in the market. From the viewpoint of interaction model the Flex-BR model is almost identical to the virtual transfer points model, but within this interaction model the BRP role is split into separate flex-BRP and supply-BRP roles. The aggregator

[68] In fact, typically the utility supplying the energy to a prosumer has a logical position to take the role of aggregator, but other market parties should be able to take this aggregator role on prosumer's assets. This concept is described by the term independent aggregator or third party aggregator (see USEF position paper on "The independent aggregator", v. 1.1, June 2015).

associated with the flex-BRP might establish a flexibility service contract with the supply-BRP that describes how the supply-BRP will be compensated during flexibility activation periods for any negative effects on its portfolio; alternatively, this might be formalized in the market's regulatory codes. To this end the supply of energy needs to be fully separated from the flexibility. As soon as the aggregator wants to activate flexibility, in the flex-BR model a baseline must be set to separate the flexibility from the remaining load as measured on the main meter. Since BRP1 and BRP2 are competitors, an independent third party will need to set that baseline to prevent conflicts. The flex-BR model is still under discussion throughout Europe.

Final considerations[69]. Although the energy supply can be separated from the flexibility supply, ensuring that in the grid the energy transactions involved in the flexibility services do not disturb the balance position of the supply-BRP is not straightforward. In fact, the aggregator implementation requires technical considerations, regulatory aspects, information exchange requirements, and contractual relationships amongst others; in particular, from the viewpoint of technical requirements the flexibility only manifests itself once it is activated by the aggregator and alters a part of the commodity supply. However, the implementation of the aggregator role can be summarized with two main models, the Split Supply model (also called Virtual transfer points model) and the Full Separation model (also called Flex-BR model).

As for the first model, the main drivers for implementing are 1) relatively less impact on regulation (compared to other aggregator models), 2) the enabling regulatory framework might have been partly developed under Directive 2014/94 of the deployment of alternative fuels infrastructure (Article 4.12 Electricity supply for transport), 3) the implementation of the Directive 2019/944 (Article 59 clause p), and 4) the feed-in of renewable energy, allowing active customers (or prosumers) to choose different suppliers for energy consumption and energy production.

As for the second model, the implementation is more complex, but the separation may lower the market entry barriers for aggregators since they would not be obliged to associate with a supplier. In fact, the aggregator takes responsibility for the activation of flexibility and the supplier for the energy supply. The main driver for implementing is focused on the responsibility of the aggregators (and their associated BRP); in fact, this responsibility is restricted to the activation services (no responsibility for energy supply), the control of the flexibility assets and, for each asset, the deviation from its baseline. Furthermore, measurement and validation stages can be performed by installing sub-metering devices to have a better visibility of the asset performance and quantify the delivered flexibility. Any effect of the

[69] USEF, "The framework explained" (update 25 May 2021).
https://www.usef.energy/app/uploads/2021/05/USEF-The-Framework-Explained-update-2021.pdf

flexibility activation for the supplier-BRP should be identifiable such that the supplier-BRP could be compensated (these aspects can be solved between aggregator, BRP and supplier relationship, e.g. information exchange, effects on sourcing and balancing position).

4.5.2.9 Aggregator business models

The above several roles involved in flexibility service exchange can be combined into six main aggregator business models.

1. Aggregator – Supplier model. The supplier and aggregator roles are combined to offer prosumers a supply contract including flexibility options. Advantage: reduced complexity (the supply and flexibility provisions can be aligned from the start); no need of compensation (the impact of flexibility activation on the supplier's sourcing and sales position does not need to be compensated by the aggregator, because the two roles are combined). The supplier can be the incumbent supplier, but the aggregator can also propose a new supplier to the prosumer, or take on the role of supplier itself.

2. Aggregator – BRP model. The aggregator and BRP roles are combined; all portfolio optimizations are generated directly within the portfolio of the combined business. As there is no need for further formal interaction between independent parties. The BRP can be the incumbent BRP, but the aggregator can also propose a new BRP to the prosumer or take on the role of BRP itself.

3. Aggregator – BSP model. The aggregator acts purely as a flexibility provider for one of the other roles. The aggregator provides the means to access flexibility, but instead of selling this flexibility at its own risk, the aggregator offers its access to one of the other players in the value chain. This will most likely be a long-term relationship, but it need not be an exclusive one and it might be terminated at some stage. Different degrees of partnership may develop, depending on how willing both parties are to disclose their portfolio and optimization information.

4. Delegated Aggregator model. A third-party aggregator buys flexibility from prosumers and sells it at its own risk to potential buyers (the DSO and BRP). This means all interactions with other market players have to be formalized, making this a more complex model. The aggregator and the BRP seek synergy in optimizing the value of the flexibility. This value is shared between the two parties based on mutually agreed conditions.

5. Prosumers as Aggregator model. Prosumers with sufficient flexibility can adopt the aggregator role for their own portfolios (directly enter the flexibility markets). Practically speaking, only commercial and industrial prosumers can opt to take on this role; for residential prosumers, the burden is too high and the volume too low.

6. Aggregator based on Flex-BR model. The aggregator controls the prosumer's ADS during the flexibility activation period. To cover the balance responsibility during flexibility activation, the aggregator must contract a BRP (the Flex-BRP). The aggregator and Flex-BRP are competitors of the supply-BRP and of the supplier active on the customer's main connection. The balance position of the supply-BRP and the supply profile are only affected during flexibility activation The supply-BRP and supplier must be compensated to neutralize the impact on their balance and supply positions. This compensation can be achieved in different ways: through a regulatory framework, through a contractual relationship, or through corrections to the prosumer's metering data.

7. E-mobility role as Aggregator model. EVs are an apt source of flexibility. In public charging situations, there is a market organization with specific e-mobility roles and business models. Two roles are key in most market organizations: the Charging Point Operator (CPO) and the E-mobility Service Provider (EmSP).

4.5.2.10 Aggregator as new market party

The aggregator needs to be embedded into the existing energy market organization. This can be done in many ways, with different relationships to other stakeholders and with varying responsibilities. USEF identifies 7 different schemes, named Aggregator Implementation Models (AIM), based on the following key aspects of the relationship between the aggregator and the supplier-BRP:

- contractual relationship;
- balance position/balance responsibility;
- sourcing position;
- information exchange and confidentiality.

When the relationship between aggregator and supplier is based on a contract, most aspects can be arranged bilaterally; however, the contract can affect the level playing field for aggregators.

An aggregator, as a market party trading flexibility, can cause imbalance in the energy system by over or underdelivering flexibility. In addition, the aggregator's activity can cause a deviation from the expected behaviour of the prosumer (active customer), thus impacting the balance position of the supplier-BRP; in this case, both the aggregator's balance responsibility and supplier-BRP's balance position need to be specified. According both to the internal electricity market regulation (Regulation EU 2019/943, Article 5) and the internal electricity market directive (Directive EU 2019/944, Article 17), all market participants, including the market participants engaged in aggregation of DER and DSF, shall be responsible for the imbalances they cause in the system. In particular, all market participants engaged in aggregation and offering demand response to TSO/DSO, are obliged to be financially responsible for imbalances. More precisely, the need to assign the BRP role is specifically relevant for aggregators that are active at other markets at the same time (e.g. energy wholesale markets); instead, the aggregators that are only active in balancing service markets (in combination with the BSP role), may experience the need to perform or assign the BRP role as an administrative burden[70]; in this case, the aggregator could be exempted from this obligation. As such, the aggregator may need to assign a balance responsible party[71].

The sourcing position refers to the balance between the sourced and sold energy of an energy market role. In particular, the sourced energy refers to the energy service provided by the supplier, while the sold energy refers to the flexibility service provided by the aggregator. In other words, the supplier-BRP delivers the energy (energy previously sourced) in order to satisfy the end user (prosumer), while the aggregator sells the flexibility in terms of energy variation (load/generation reduction or increase previously sourced) to the end user (network operator or BRP). In particular, the energy variation required could not happen automatically (e.g. reduction of load of a customer that is part of another market player's perimeter). Therefore, in order to ensure the sourcing positions are balanced between aggregator and supplier-BRP there should be a specific balancing mechanism, called Transfer of Energy (ToE) where the price formula must be contracted.

The information is relevant for different market roles; in particular, this information on the aggregation level requires to be exchanged ensuring the maximum confidentiality. So, it is key to identify what aggregation level is deemed commercially sensitive[72].

The AIM focus on the valorization of flexibility by defining a clear allocation of balance responsibility during times of activation (activation time interval window); instead, the Split Supply model or Full Separation model focus only on the separation between controllable assets and non-controllable assets. In general, the Split Supply/Full Separation model and AIM are complementary, allowing for any combination of the two concepts.

AIM 1 – Integrated model. There are two existing contract relations (see Figure 22): 1 contract between BRP (BRP of the supplier) and Supplier, 1 contract between Prosumer and Supplier; two new contract relations: 1 contract between BRP (BRP of the supplier, called supplier-BRP) and aggregator, 1 contract between aggregator and Prosumer. Based on the new contract relations the roles of Supplier and aggregator are combined in one market party (includes BRP, aggregator and supplier) without a specific contract between aggregator and Supplier (the compensation for imbalances and the open supply position

[70] Regulation (EU) 2017/2195 of 23 November 2017 (Guideline on electricity balancing) contains details on BSP role and correction of the perimeter of the BRPs affected by the BSPs energy activations.
[71] The USEF White Paper on "Flexibility deployment in Europe" contains more details on specific implementation in Member States.
[72] "Towards an expanded view for implementing demand response aggregation in Europe" (interim result). https://www.usef.energy/app/uploads/2016/12/USEF-Aggregator-Work-Stream-interim-results-1.pdf

are not necessary). In particular, the Supplier/Aggregator combination has a contract with the Prosumer in order to sell energy (Supplier-Prosumer) and buy flexibility against a reward (Aggregator-Prosumer). The aggregator's balance position is ensured by the supplier-BRP. The flexibility provision to TSO can be contracted between supplier-BRP and BSP or directly between supplier-BRP and TSO. For example, we can consider an electric mobility service provider who could use the electricity meter in the charging unit of the electric vehicle as a sub-meter, supply the energy and trade the flexibility of the charging process (see Split Supply model); in this case the roles of aggregator, Supplier and associated BRP are combined in a single market party (integrated model). If an aggregator (as market party) prefers not to combine the roles (see Full Separation model), then any of the AIM presented below could be applied to each of the virtual supply points.

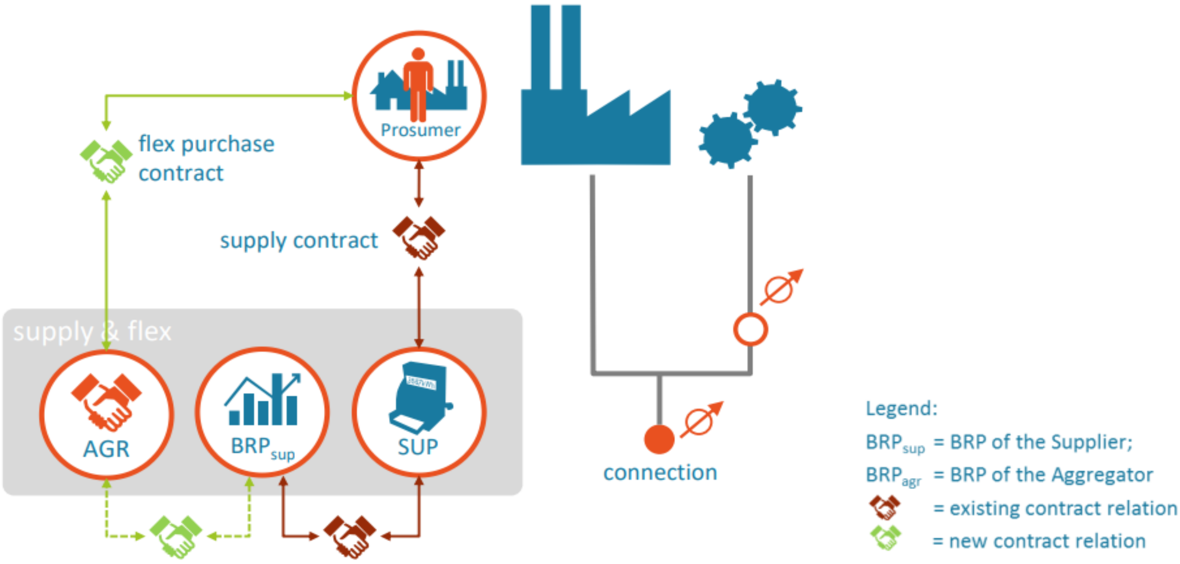

Figure 22 - Integrated model (AIM 1 scheme): existing and new contract relations (Source: USEF).

AIM 2 – Broker model. There are two existing contract relations (see Figure 23): 1 contract between BRP (BRP of the supplier) and Supplier, 1 contract between Prosumer and Supplier; two new contract relations: 1 contract between Supplier/BRP and aggregator, 1 contract between aggregator and Prosumer. Based on the new contract relations the aggregator transfers the balance responsibility to the BRP (Supplier is associated with BRP); the compensation for the open supply position and the caused imbalance is settled bilaterally based on contractual arrangements (bilateral contract between aggregator and Supplier/BRP). Perimeter correction: no perimeter correction by ISR (equivalent to ARP) needed[73]. The aggregator

[73] If aggregator is participating in ancillary service provision to the TSO, it needs to nominate the activated volume per BRP. Perimeter of BRP needs to be corrected by the ARP according to nomination, analogously to current active balancing mechanism.

transfers the balance responsibility for the flexibility to the BRP of the Supplier (called supplier-BRP); in other words, the full balance responsibility of the connection lies with the supplier-BRP (no need for ToE, any financial settlement occurs bilaterally as specified within the bilateral contract). Note that since the supplier-BRP can profit from the activations (initiated by the aggregator), the supplier-BRP may choose to share the profit with the aggregator; in this case the supplier-BRP can stimulate the aggregator to activate the flex resource more often (e.g. by lowering its position on the merit order). The aggregator can have a flexibility service contract with a BSP, who is offering the flexibility to the TSO. The supplier-BRP should receive information regarding the activated flexibility in its portfolio on prosumer level.

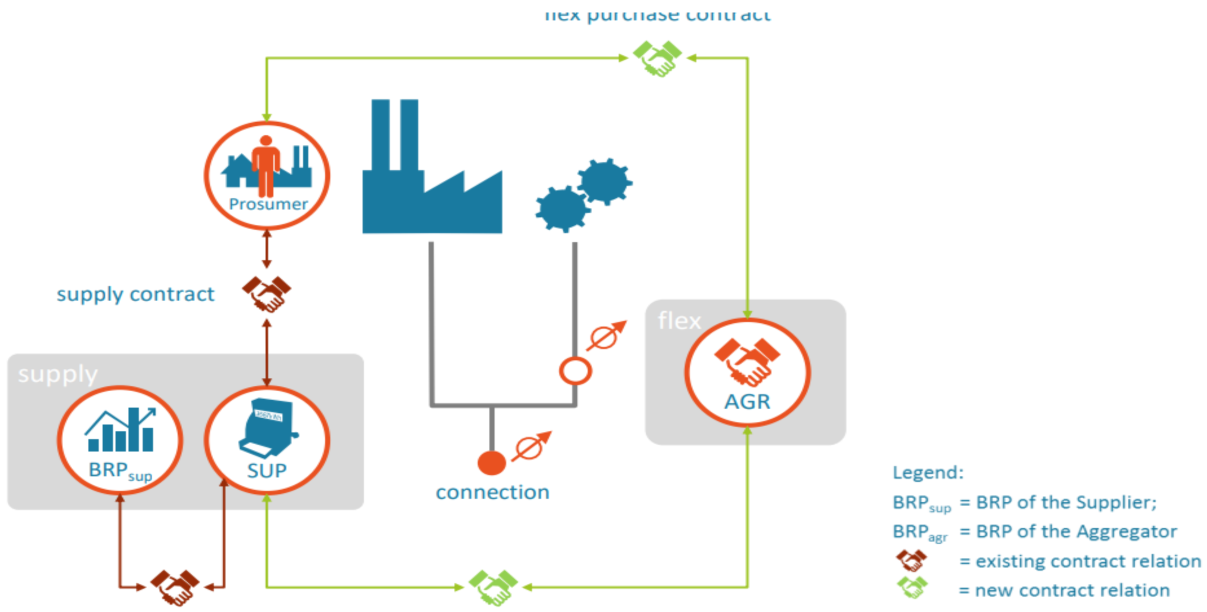

Figure 23 - Broker model (AIM 2 scheme): existing and new contract relations (Source: USEF).

AIM 3 – Contractual model. There are two existing contract relations (see Figure 24): 1 contract between BRP (BRP of the supplier, called supplier-BRP) and Supplier, 1 contract between Prosumer and Supplier; three new contract relations: 1 contract between Supplier/BRP and aggregator, 1 contract between aggregator and prosumer; 1 contract between aggregator and BRP (BRP of the aggregator, called aggregator-BRP). Based on the new contract relations the aggregator has relationship with its BRP (aggregator-BRP) for entering energy markets and to cover imbalance, and with the Supplier (bilateral contract) about the ToE. The aggregator-BRP holds balance responsibility for the flexibility during activation periods, while the supplier-BRP holds full responsibility outside activation periods. Perimeter correction: no perimeter correction by ARP needed, this is covered by the hub-deal. In particular, during the activation periods, the flexible response impact of ADS assets is neutralized with supplier-BRP through the hub-deal; the aggregator sources the energy ex-post from supplier-BRP through a hub-deal so that balancing parameters are corrected through an ex-post hub-deal between aggregator-BRP and supplier-BRP; the sourcing energy volume equals the difference between measurement and baseline (in fact, during activation periods the allocation of the flexibility resource is set equal to the corresponding baseline); a price formula to remunerate the energy needs to be agreed upon. The aggregator can have a flexibility service contract with a BSP, who is offering the flexibility to the TSO. The supplier-BRP should receive information regarding the activated flexibility in its portfolio on prosumer level.

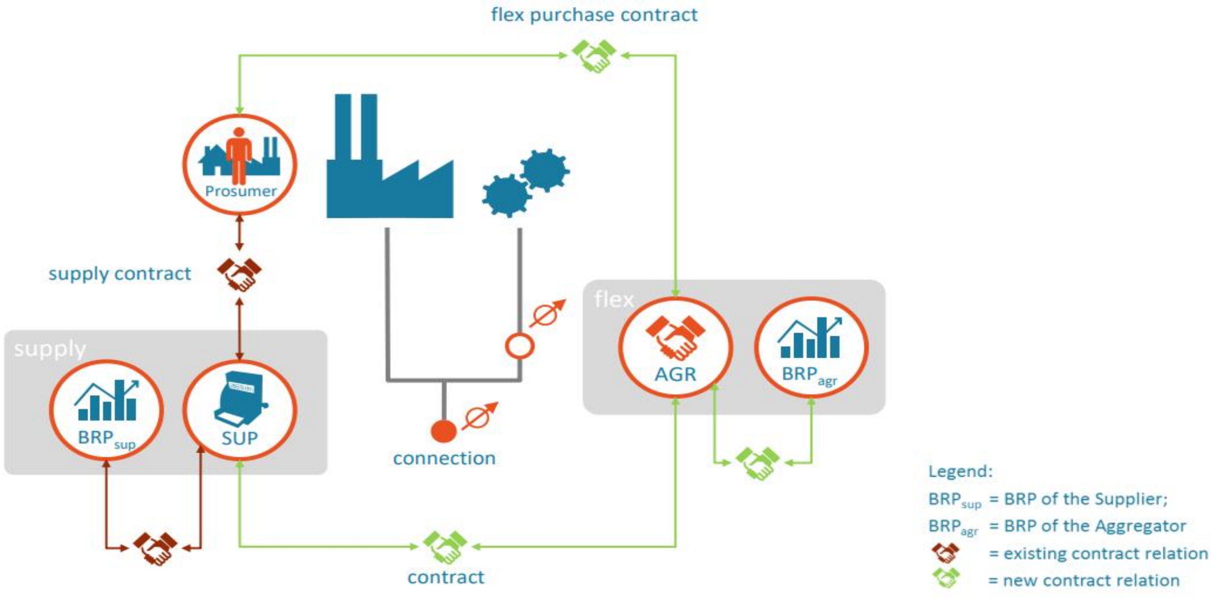

Figure 24 - Contractual model (AIM 3 scheme): existing and new contract relations (Source: USEF).

AIM 4 – Uncorrected model. There are two existing contract relations (see Figure 25): 1 contract between BRP (BRP of the supplier, called supplier-BRP) and Supplier, 1 contract between Prosumer and Supplier; one new contract relation: 1 contract between aggregator and Prosumer. Based on the new contract relation no volume transfers of energy occur between the aggregator and the Supplier (no contract specific between aggregator/aggregator-BRP and Supplier/supplier-BRP about ToE) so that the potential effect of flexibility activation in the supplier-BRP‘s balance position is not corrected; in general, the flexibility activation will result in imbalance for the supplier-BRP; in case of balancing service, the activated volume is settled through the regular balancing mechanism (from the viewpoint of sourced energy there is no explicit compensation, yet implicitly energy is remunerated through the imbalance mechanism; the supplier-BRP can also be remunerated through the regular balancing mechanism, if passively contributing to balance restoration is incentivised by the balancing mechanism). Perimeter correction: no perimeter correction is performed by ARP (therefore named “uncorrected”). Balance responsibility for the connection is with supplier-BRP at all times. If the flexibility offered by the aggregator is included in the balancing products required by the TSO, the aggregator can contract a flexibility service with a BSP, who is offering the flexibility to the TSO; if the aggregator is active directly on balancing (or adequacy) services, the remuneration takes place against balancing prices. No need for information exchange between aggregator and supplier-BRP regarding the activated flexibility in portfolio on prosumer level.

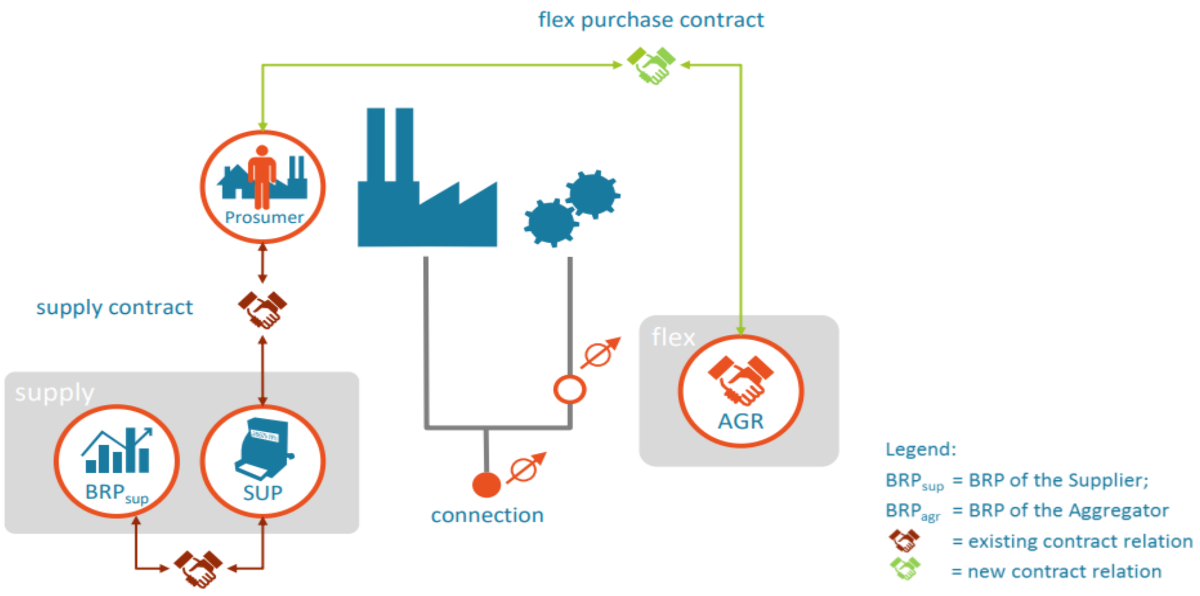

Figure 25 - Uncorrected model (AIM 4 scheme): existing and new contract relations (Source: USEF).

AIM 5 – Corrected model. There are two existing contract relations (see Figure 26): 1 contract between BRP (BRP of the supplier, called supplier-BRP) and Supplier, 1 contract between Prosumer and Supplier; two new contract relations: 1 contract between aggregator and Prosumer, 1 contract between aggregator and BRP (BRP of the aggregator, called aggregator-BRP). Based on the new contract relations the energy volume is transferred through the Prosumer (without a specific contract between aggregator and Supplier/BRP about ToE); in fact, the aggregator remunerates the sourced energy from the Supplier through the Prosumer (the aggregator compensates the Prosumer for the activated flexibility, for sourcing and for the service and the Supplier bills the Prosumer the adjusted energy, i.e. not taking into consideration the activated flexibility); in particular, the Prosumer's consumption profile is modified, based on the amount of flexibility that has been activated by the aggregator; the amount of flexibility is calculated by directly modifying the meter reading by the MDR or by the ISR. The remuneration of flexibility takes place through the prosumer, based on retail prices; in particular, the aggregator will compensate the Prosumer for the energy that has been billed, but not consumed (or vice versa in case of load increase), depending on contract conditions. In other words, no specific financial remuneration is needed, since the Supplier can bill the same energy volume as if no activation has occurred. The aggregator has a contract with the BRP (BRP of the aggregator, called aggregator-BRP) for entering energy markets and to cover imbalance. The supplier-BRP holds full responsibility for the connection, where the allocation is based on the measurements (i.e. during activation periods on the corrected measurements or baseline); during activation periods, the aggregator-BRP holds balance responsibility for the activated flexibility, the difference between the actual consumption (non-corrected measurements) and the baseline. Perimeter correction: The ISR (also called ARP) needs to correct the perimeters (or balancing position) of the supplier-BRP and aggregator-BRP with the activated energy; in particular, the supplier-BRP's perimeter can be corrected in two ways: a) the MDR corrects the Prosumer's consumption profile (this value will be communicated to the Prosumer by the Supplier), based on the amount of flexibility that has been activated by the aggregator (meter readings of the connection with the increased or decreased amount of energy triggered) and informs the TSO both about the corrected values, as well as of the amount of increased/decreased energy, per imbalance settlement period; b) the ISR communicates the Supplier/BRP the activated volumes and the Supplier makes the correction to bill their customers. Then the Aggregator compensates the Active Customer for the activated flexibility (for sourcing and for the service). The aggregator or its BRP does not need to inform the Supplier/BRP about the closed (new) flexibility contract. Only, in case of perimeter correction by means ISR, the ISR should inform the Supplier the activated flexibility in its portfolio on Prosumer level.

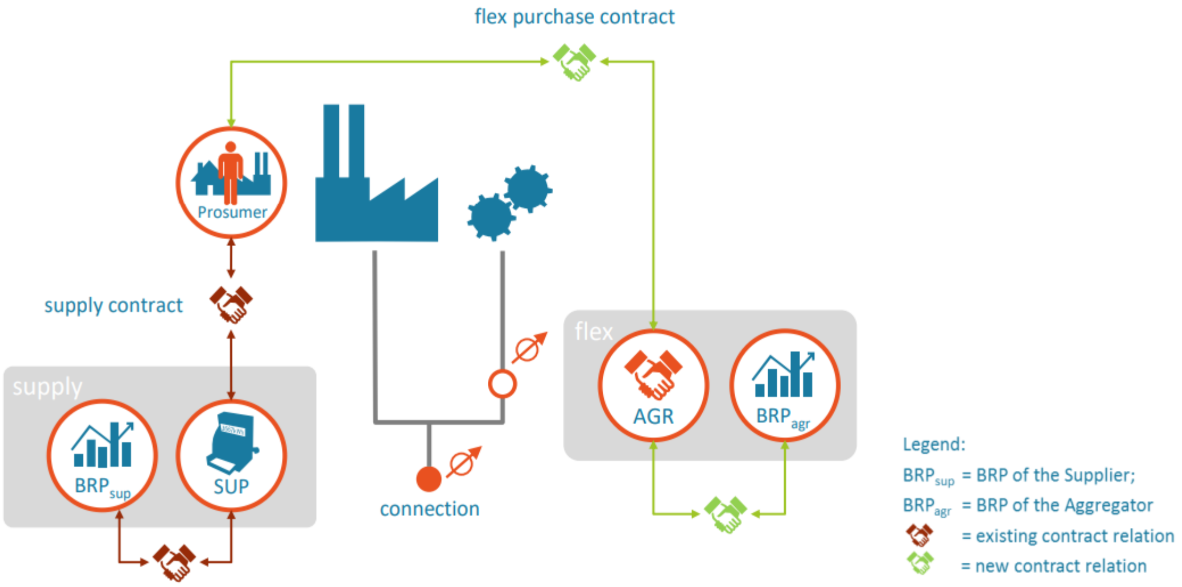

Figure 26 - Corrected model (AIM 5 scheme): existing and new contract relations (Source: USEF).

AIM 6 - Central settlement model. There are two existing contract relations (see Figure 27): 1 contract between BRP (BRP of the supplier, called supplier-BRP) and Supplier, 1 contract between Prosumer and Supplier; two new contract relations: 1 contract between aggregator and Prosumer, 1 contract between aggregator and BRP (BRP of the aggregator, called aggregator-BRP). The aggregator contracts with its BRP for entering energy markets and to cover imbalance. Based on the new contract relations, the ISR (central entity) transfers the energy between aggregator-BRP and supplier-BRP (without a specific contract between aggregator and Supplier/BRP about ToE; in fact, the Supplier's sourcing position is compensated through ToE via the ISR intervention). In this case, rules are required to enable the ISR to transfer the energy between aggregator-BRP and supplier-BRP[74]; in addition, a price formula (pre-defined price formula) is needed that is applied for the transferred energy and paid by the party into whose perimeter the energy is transferred into. So, the ISR corrects perimeters of both aggregator-BRP and supplier-BRP (including the settlement of the compensation for the open supply position); in particular, during activation periods, the aggregator-BRP holds balance responsibility for the difference between the actual consumption and the baseline, while the supplier-BRP holds full responsibility outside activation periods (during activation periods the allocation of the flexibility resource is set equal to the corresponding baseline); the ISR corrects the balancing perimeters following the flexibility activation. The aggregator/aggregator-BRP does not need to inform the Supplier/supplier-BRP about the closed (new) flexibility contract. Moreover, the supplier-BRP should receive information on activated flexibility in its portfolio on aggregated level (i.e. not revealing the Prosumers or aggregator involved).

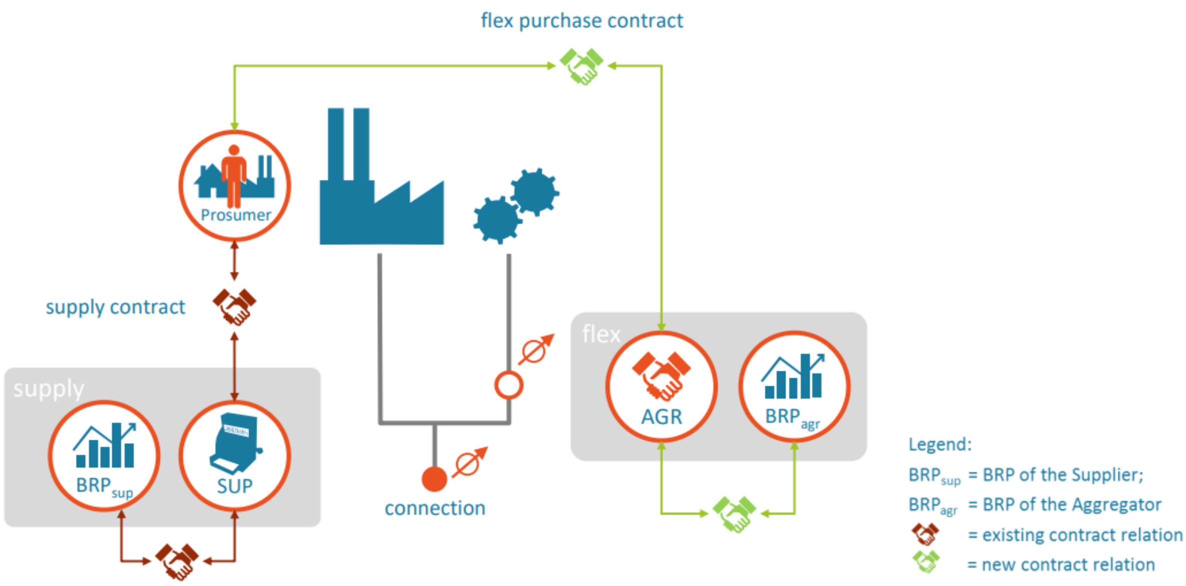

Figure 27 - Central settlement model (AIM 6 scheme): existing and new contract relations (Source: USEF).

AIM 7 - Net benefit model. It is similar to the AIM 6 model. The main difference is the cost of compensating the supplier-BRP: this cost component is not borne by the aggregator but partly or entirely socialized. In particular, the impacted Supplier is compensated for the sourced (but not delivered) energy based on a regulated price formula; the socialization level depends on the energy savings obtained by

[74] In most countries the ARP role is performed by the TSO.

flexibility activation[75]. Note: although the AIM 7 is classified as a sub-model of the AIM 6 (Central settlement model), the net benefit principle can in principle also be applied to other models where a ToE is in place (for example the AIM 5 Corrected model). A specific financial flow can be implemented in order for the aggregator not to bear the entire cost of the ToE, and to reimburse part of it. In order to determine if it is worth socializing the cost of the ToE, some preconditions are implemented: a net benefit test in the US or % of energy savings of flexibility in France. Those preconditions ensure that flexibility is only dispatched according to this socialization principle when the added value for the system is higher than the cost of the compensation. Underlying principle: when the total sourcing costs diminishes (because of lower spot price) by an amount higher than the cost of ToE, the latter is taken in charge by the society (net benefit positive).

Reference Profile (RP) model. The AIM described above are based on the principle that the aggregator takes responsibility during times of activation (activation time interval window). This might be difficult (or even impossible) when activation takes place on a day-to-day basis. In these situations, it becomes difficult to hand-over balance responsibility to the aggregator's BRP and defining a baseline that represents the (normal) behaviour becomes challenging, as flexibility activation becomes part of the 'normal behaviour'. So, another way of separating energy supply from flexibility is to use a Reference Profile (RP) model where the supplier-BRP still holds full responsibility for the connection. With the RP model there are two existing contract relations (see Figure 28): 1 contract between BRP (BRP of the supplier, called supplier-BRP) and Supplier, 1 contract between Prosumer and Supplier; three new contract relations: 1 contract between aggregator and Prosumer, 1 contract between aggregator and BRP (BRP of the aggregator, called aggregator-BRP), 1 optional contract between aggregator and Supplier. Based on the new contract relations, the Supplier needs to procure (sourcing stage) and supply the energy for a customer (delivering stage), as in AIM; however, instead of handing over balancing responsibility for the activation times only, here the balance responsibility is transferred ex-ante from the supplier-BRP to the aggregator-BRP. In particular, the RP is known upfront by the BRP during the sourcing/balancing stage towards the corresponding timeframe (e.g. Year ahead, Month ahead, Day ahead); so, the RP is the baseline defined ex-ante and serves as basis for the allocation of the aggregator; after agreement on the RP, the balancing risk is transferred to the aggregator/aggregator-BRP. The RP model is useful for flexibility in the residential setting where the activation takes place on a daily or hourly basis (e.g. the case of heat pumps in the residential setting); here the aggregator can optimize the load profile of the customer compared to the RP (optimization stage of the actual profile) and may deviate from the RP by activating

[75] In the US, a net benefit model has been tested in order to determine the price level from which the cost gets socialized; under that price it is paid by the aggregator. "Demand Response Compensation in Organized Wholesale Energy Markets", FERC Order No. 745, 15-3-2011.

flexibility for specific services such as energy services and/or balancing services (selling stage); in case of deviation from the RP the differences between RP and actual (measured) profile is within the balance responsibility of aggregator-BRP.

In other words, the RP serves as a separate baseline for splitting of imbalance volumes and is likely to be different from baselines defined for the service product (which is still used for checking delivery performance). The Supplier supplies and sources the energy for the actual consumption (i.e. the RP plus deviations), while the imbalance risk for all deviations from the reference profile resides at aggregator-BRP. After delivering stage, the aggregator is free to use the flexibility in different products, each with its own product-defined baseline, as shown in Figure 29.

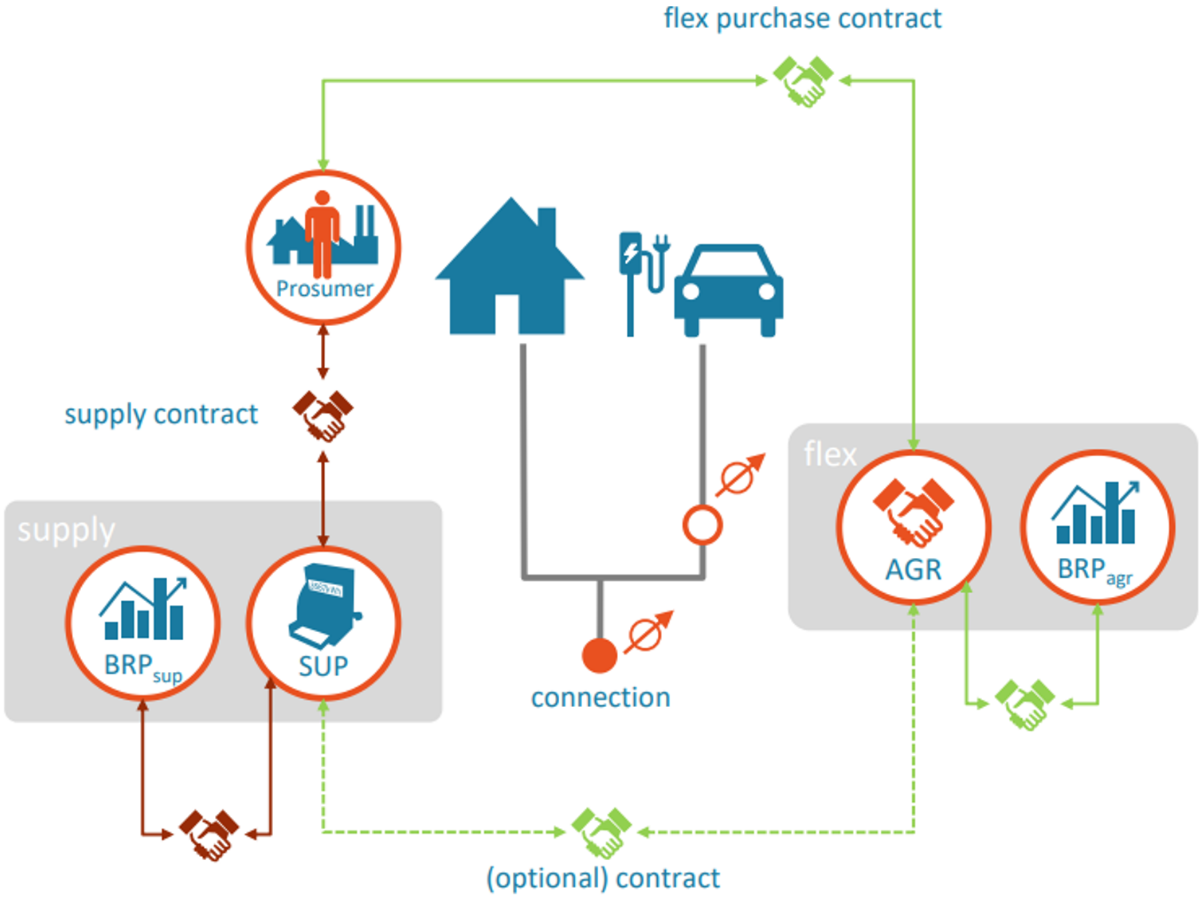

Figure 28 - Reference profile model: existing and new contract relations (Source: USEF).

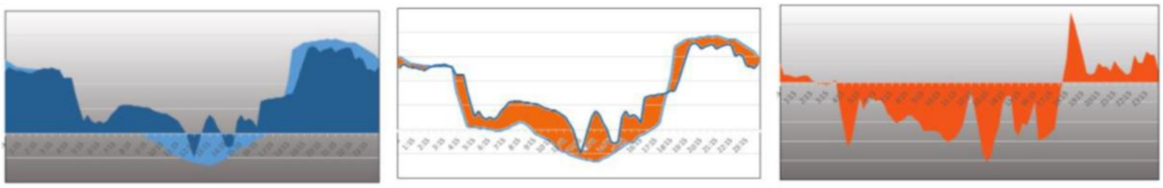

Figure 29 Example of RP model with residential customers (with solar PV). Left picture: RP (light blue) and actual profile (dark blue); middle picture: difference between RP and actual profile; right picture: flexibility allocation. (Source: USEF)

Similar to the AIM, the ToE can be organized in three different ways, which gives the following variants for RP model:

- contractual RP model (ToE conditions are part of the contract);
- corrected RP model (ToE via the Prosumer);
- central settlement RP model (ToE via perimeter correction by the ISR).

In the contractual variant, the RP is established between Prosumer, Supplier, and aggregator, while in the non-contractual variants (corrected, central settlement), the profile is determined by the regulator.

The RP models have been introduced to provide an alternative for specific situations where the AIM may prove insufficient (e.g. flexibility that is activated on daily basis). For the rest, the RP model follows the same logic as AIM.

Note that it is also possible to organize RP in an alternative way, in which the Supplier supplies and sources according to the RP and aggregator supplies the deviations (hence becoming a supplier as well). This way of separation has similarities with Split Supply models with a time-dependent separation of responsibilities based on the RP; in this case, there is no ToE needed and consequently no distinction between a central settlement variant and a corrected variant (so, the main question is who bears responsibility for defining the profile, leading to either a contractual or a non-contractual variant).

4.5.2.11 Flexibility deployment in Europe[76]

The “Clean Energy for All Europeans Package” encourages Member States to enable the participation of DSF in wholesale energy and ancillary services markets. In particular, the EU Directive on electricity market design[77] addresses the need to implement aggregators, develop the regulatory framework for their

[76] USEF, “White Paper: Flexibility Deployment in Europe” (March 2021).
https://www.usef.energy/app/uploads/2021/03/08032021-White-paper-Flexibility-Deployment-in-Europe-version-1.0-3.pdf

[77] Directive EU 2019/944, Article 17 and 32.

participation in wholesale and services markets and use of flexibility for the mitigation of congestion phenomena, including the deployment of flexibility at distribution system level.

In response to the above European addresses each Member State is adopting best practices or is taking a regulatory framework.

Below a brief review of the current (status at 2020) deployment of flexibility in European countries is reported; the deployments are mapped according to the USEF flexibility analysis (i.e. Flexibility Value Chain, Aggregation Implementation Models and market roles).

Belgium. The regulation framework recognizes the main following roles: aggregator (called Flexibility Service Provider), BSP and Capacity Service Provider (called Capacity Provider). Recently the role of Voltage Service Provider has also been introduced. Moreover, the coordination of assets and the associated data exchanges are vitally important to the operational activities of the TSO ELIA. To that end, ELIA launched the iCAROS (*Integrated Coordination of Assets for Redispatching and Operational Security*) project[78]; once the iCAROS project is implemented, the Scheduling Agent role will be responsible for bidding for redispatch to solve congestion problems at transmission level. Both Voltage Service Provider and Scheduling Agent roles would fall into the Congestion Management Service Provider role identified by USEF. There is an additional role for the provision of restoration services (called Restoration Service Provider), not yet recognised by USEF.

Wholesale services, balancing services, and adequacy services can be offered at pool level, but each asset should be pre-qualified and the bid must include a list of those assets; pre-qualification of demand response and storage is not mandatory. The distributed explicit flexibility services include:

- wholesale services (energy services on day-ahead and intra-day energy markets);
- balancing services (FCR called R1, a-FRR called R2, m-FRR called R3);
- constraint management services (i.e. services for the mitigation of congestion phenomena).

Prosumers (also called Grid Users) can valorise their flexibility on the day-ahead and intra-day energy markets via their Supplier/BRPs, with or without the collaboration of third parties (e.g. aggregators). In

[78] In 2017 ELIA launched the iCAROS (*Integrated Coordination of Assets for Redispatching and Operational Security*) project to develop the coordination of assets for system operations and market procedures in accordance with the EU Network Codes. In particular, ELIA Task Force's iCAROS project aims to discuss topics related to future asset coordination procedures with the relevant stakeholders; the iCAROS project aims also to define the required IT and operational developments. Elia set up the iCAROS implementation project in mid-2018.

particular, demand (including distributed flexible resources) and aggregation can only be utilized if agreed with the Supplier/BRP; so, independent aggregation is not allowed.

While participation in balancing services by demand (including aggregated distributed flexible assets) is theoretically possible, it is very complex and there are few providers offering it.

Regarding adequacy services, a capacity remuneration mechanism is currently being designed to ensure security of supply. The current rule proposal allows for load units and storages, and aggregation, including DSO connected capacities (with a derating factor).

Concerning the constraint management services, ELIA manages congestion on the transmission system via re-dispatching actions by using system services sourced mainly from non-contracted reserves offered by production units under a Contract for the Injection of Power Units (CIPU) contract. However, with the iCAROS project ELIA aims to open to storage and demand facilities the provision of constraint management services; moreover, this extension to new flexible resources could be supported by the ioEnergy initiative[79] (initiative supported by ELIA and major DSOs).

Concerning the aggregation model in place, each flexible service is described by the aggregation scheme (see Table 7).

Regarding the value stacking approach, the balancing services can be offered with value stacking "in time". Moreover, the dynamic pooling gradually becomes more practically plausible as TSO is moving to shorter-term procurement; for example, FCR and a-FRR moved from a weekly auction to a daily auction procurement in July 2020; in addition, m-FRR and a-FRR can also be offered with free bids in near real time. This change in the procurement stage allows aggregators to better optimize the portfolio. The provision of capacity procured via the capacity remuneration mechanism (currently being designed) is expected to be stackable with other services.

[79] The ioEnergy initiative aims to facilitate the development of new energy services by market parties and to drive the power system towards end users (consumers/prosumers). So, ELIA expects to develop a DSO/TSO platform that will unlock flexibility resources for balancing services and wholesale energy at transmission level.

Table 7 - AIM implemented in Belgium

Flex. Service	AIM	Notes
Wholesale services	Contractual or Integrated	DSF and aggregation can only be utilized if agreed with the Supplier/BRP. A Central Settlement model and a Corrected model are being studied.
Balancing services	Uncorrected for FCR (R1). Contractual or Corrected for a-FRR (R2). Integrated, Contractual or Central Settlement for m-FRR.	FCR service is a symmetric product and so, also taking into account the network frequency characteristic, the energy component related to the FCR activation is cancelled (ToE is negligible). Concerning the a-FRR service, the aggregator can only offer under a contractual model or corrected model. The need for regulated ToE is being reassessed. Concerning m-FRR, the aggregator and Supplier are initially encouraged to negotiate a Contractual model. If negotiations fail, the Central Settlement model acts as a fall back, with a ToE formula set by the regulator.

Denmark. The regulation framework recognizes formally the main following roles: aggregator and BSP; in particular, both parties need to be either BRP or assign balance responsibility to another BRP to provide flexibility.

Different balancing services (FCR, a-FRR, m-FRR) and wholesale services can be offered at pool level with generation or demand flexible resources. In particular, distributed exp|licit flexibility services include:

- wholesale services (energy services on day-ahead and intra-day energy markets);
- balancing services (FCR, a-FRR, m-FRR);
- constraint management services (i.e. services for the mitigation of congestion phenomena).

Demand (including distributed flexibility resources) and its aggregation are allowed for intra-day and day-ahead optimisation but only within the BRP portfolio (independent aggregation is not allowed).

FCR, a-FRR and m-FRR services are open to demand (including distributed flexibility resources) and (independent) aggregation. In particular, in DK2 area (Denmark East) there is also an energy transaction and remuneration for the activated volume. However, for a-FRR the minimum bid size (5 MW) and the market design (e.g. pooling of assets is allowed, but they cannot mix in the same bid generation and consumption units) make it difficult for new market players to bid into the market.

Congestion at transmission level is regulated by the TSO by using also demand side flexibility (taking into account the entry barrier). Congestion at distribution level is not yet a problem; but the Danish ambition to increase renewable generation is envisaged to cause congestion problems in the near future. In this case, to explore local flexibility trading for solving congestion at transmission level, the TSO has set up a project in cooperation with stakeholders such as Danish Energy, DSOs and market participants; moreover, the long-term objective is to implement similar flexibility trading also at DSO level.

Adequacy services are not currently available.

As for the aggregation model in place, each flexible service is described by the aggregation scheme (see Table 8). In addition to the models implemented (uncorrected, contractual or integrated), a Split Supply model (i.e. flexibility service model with energy supply) is being piloted to facilitate independent aggregation (relevant discussions ongoing about the cost of sub-metering for distributed assets which can be quite expensive; in fact, certain assets, like EVs and heat pumps, can use their own integrated meter but DSO approval is a problem).

Regarding the value stacking approach, it is possible to stack different balancing services from committed availability windows, but dynamic pooling is not yet allowed.

Table 8 - AIM implemented in Denmark

Flex. Service	AIM	Notes
Wholesale services	Contractual or Integrated	The aggregator needs be a BRP or appoint a BRP and have a contractual agreement with the Supplier’s BRP.
Balancing services	Uncorrected for FCR. Contractual or Integrated for a-FRR and m-FRR.	Based on the frequency stabilization model implemented as pilot project (trialled stage), FCR service involves no significant energy transfer and hence non imbalance implications for BRP. For a-FRR/m-FRR the aggregator needs be a BRP or appoint a BRP and have a contractual agreement with the Supplier’s BRP.

Finland. The regulatory framework recognizes formally the main role of BSP; no specific role assigned for either the Capacity Service Provider or Constraint Management Service. Aggregator role is expected to be recognized during 2020.

Different balancing services (FCR, m-FRR), wholesale services, adequacy services (i.e. strategic reserve) and constraint management services (i.e. congestion management) can be offered at pool level with generation/demand flexible resources. In particular, distributed explicit flexibility services include:

- wholesale services (energy services on day-ahead and intra-day energy markets);
- balancing services (FCR, a-FRR, m-FRR);
- adequacy services;
- constraint management services (i.e. services for the mitigation of congestion phenomena).

Demand (including distributed flexibility resources) and its aggregation are allowed for intra-day and day-ahead optimisation but only within the BRP portfolio (independent aggregation is not allowed).

FCR service is divided into two products (FCR-N, for normal operation, and FCR-D, for disturbances); both FCR services and a-FRR/m-FRR services are open to demand (including the distributed flexible resources) and (independent) aggregation. In particular, for a-FRR/m-FRR the independent aggregation is in pilot phase and larger scale testing.

Regarding the adequacy services, in Finland there is a strategic reserve service operated by Fingrid TSO; this product is open to demand (including distributed flexibility resources) but not to independent aggregation.

Congestion management at transmission level is open to demand and aggregation but independent aggregation is not allowed; at the distribution level, there have been innovation projects trialling demand-side response but, due to grid over-dimensioning, there is no real need yet for congestion management.

As for the aggregation model in place, each flexible service is described by the aggregation scheme (see Table 9).

Regarding the value stacking approach, portfolio bidding is allowed in all reserve products and multiple flexibility markets, but the same capacity cannot be sold multiple times; the share of capacity coming from different BRPs is reported in the bidding phase by the BSP. Dynamic pooling is allowed in balancing services.

Table 9 - AIM implemented in Finland

Flex. Service	AIM	Notes
Wholesale services	Contractual or Integrated	The aggregator can participate only within the BRP portfolio (it requires an agreement with power exchange, as well as an agreement with an open electricity provider, which also covers balance responsibility).
Balancing services	Integrated, Contractual and Central settlement for FCR/m-FRR.	The ToE price relate to FCR energy activation is currently fixed at the imbalance price. For a-FRR/m-FRR the independent aggregation is being piloted; the ToE price level is referred to the DAM price.

France. The regulation framework recognizes formally the main following roles: aggregator (called *operateur d'effacement*), BSP and Capacity service providers (called *responsable de périmetre de certification*). In particular, the BSP role is divided into two separate roles: *responsable de reserve* for FCR and a-FRR services, and *acteur d'adjustement* for m-FRR and RR services.

Different balancing services, wholesale services, adequacy services (i.e. capacity market) and constraint management services (i.e. congestion management) can be offered at pool level with generation/demand flexible resources. In particular, distributed explicit flexibility services include:

- wholesale services (energy services on day-ahead and intra-day energy markets);
- balancing services (FCR, a-FRR, m-FRR/RR);
- adequacy services;
- constraint management services (i.e. services for the mitigation of congestion phenomena).

In 2015 the block exchange notification of DR mechanism (called *Notification d'Échange de Blocs d'Effacement - NEBEF*)[80] was introduced to regulate independent aggregation for the wholesale energy market and balancing services such as m-FRR/RR. The NEBEF mechanism allows consumers to participate in energy markets through load reductions; in particular, all end users (prosumers) connected to the mainland grid may participate by providing flexible load response in exchange for remuneration on energy markets (either via day-ahead and intraday power exchanges or OTC platforms), on fair and equal terms with generation and this without the agreement of Suppliers being required. The participation in NEBEF can take place directly by becoming a (DR) aggregator (if the prosumer has a minimum load reduction capacity of 100 kW) or indirectly via a third party (DR) aggregator (in this case the prosumer receives payment according to the terms of the contract with the aggregator); the aggregator may combine several sites within its perimeter. To become a flexibility load aggregator in the NEBEF mechanism the prosumer must (a) sign a participation agreement to NEBEF Terms, (b) obtain a technical approval (pre-qualification) that certifies the ability to manage load reductions, based on tests, and (c) have a balance perimeter (by being BRP or with a third party BRP). The aggregator sells the load reduction block on the energy market and declares its load schedules to the TSO RTE (from 9 a.m. the day before, until 1 hour before the start of the load reduction on day D). Loads reductions in energy markets are remunerated by means of payment from the aggregator to the electricity Suppliers of the consumption sites concerned. After the activation of load reduction, the TSO RTE verifies the actual load reduction based on the agreed method (i.e. based on forecast data, based on historical data). The (DR) aggregators thus can trade blocks of load reduction in the day-ahead and intra-day markets and provides an additional economic area to the balancing mechanism.

FCR and m-FRR/RR services for balancing are open to demand-side participation, (independent) aggregation, while a-FRR is mandatory for generators and open to aggregation for generation only (generators can source through a secondary market aggregated load reduction to fulfil their a-FRR obligation but this market is never used in practice). Moreover, both m-FRR and RR services are divided into two types (*Réserve Rapide* and *Réserve Complementaire*); these services are procured via special tenders (called *Appel d'Offres Annuel and Appel d'Offres Iournalier*).

Regarding the adequacy services, the capacity mechanism (*mécanisme de capacité*) is intended to safeguard the security of electricity supply during peak winter periods (the service is based on an obligation, with obligated parties required to cover consumption during peak periods). The capacity mechanism is solved by means of contracts (certificates) related to generation and demand response capacities. In fact, the TSO organizes special tenders (called *Appel d'Offres*). The arrangement allows

[80] NEBEF Mechanism.
https://www.services-rte.com/en/learn-more-about-our-services/participate-nebef-mechanism

(independent) aggregators to trade capacity certificates with obligated parties. This capacity can be activated through the balancing mechanism or NEBEF mechanism on the wholesale energy market.

Constraint management services for high voltage level are open to demand aggregation, however there is little to no participation due to the low revenues associated with it. Demand flexibility for constraint management services at distribution level are not yet business as usual although there have been several trials. Enedis (DSO covering 95% of national connections) has published a roadmap for using flexibility for grid capacity management via market-based mechanisms.

As for the aggregation model in place, each flexible service is described by the aggregation scheme (see Table 10).

Regarding the value stacking approach, all service products can be offered at pool level (including the dynamic pooling) in wholesale and capacity markets and partially for balancing mechanism. The aggregator also needs to provide baselines for non-activated ADS assets; moreover, the aggregator is responsible for the full pool of assets even if the activation was limited to a subset of assets.

Table 10 - AIM implemented in France

Flex. Service	**AIM**	**Notes**
Wholesale services	Corrected, Contractual, Central Settlement	Corrected where applicable to remote sites connected to the TSO grid or connected to the DSO grid with a CARD (*Contrat d'Accès aux Réseaux publics de Distribution*) > 36 kVA. Central Settlement where applicable to DSO connected sites not included in Corrected model. Contractual where aggregator and Supplier-BRP have a contractual agreement.
Balancing services	Corrected, Contractual, Central Settlement for FCR, m-FR, RR.	Corrected where applicable to remote sites connected to the TSO grid or connected to the DSO grid with a CARD (*Contrat d'Accès*

		aux Réseaux publics de Distribution) > 36 kVA. Central Settlement where applicable to DSO connected sites not included in Corrected model. Contractual where aggregator and Supplier-BRP have a contractual agreement. For a-FRR the AIM depends on the activation process (i.e. if load reduction is traded through the secondary market, the same AIM as for the other balancing services applies).
Adequacy services	Capacity Market: depends on the activation process.	A model is only applicable for energy utilisation: if the activation takes place through the balancing mechanism or wholesale market, the rules will apply then.

Germany. The regulatory framework recognizes formally the main following roles: aggregator and BSP. There is no specific role assigned for either Capacity Service Providers or Constraint Management Service Providers.

Different balancing services (FCR, a-FRR, m-FRR), wholesale services and adequacy services (i.e. capacity market) can be offered at pool level with generation/demand flexible resources. In particular, distributed explicit flexibility services include:

- wholesale services (energy services on day-ahead and intra-day energy markets);
- balancing services (FCR, a-FRR, m-FRR/RR);
- adequacy services;
- constraint management services (i.e. services for the mitigation of congestion phenomena).

Wholesale products aggregation and optimization can only be offered via the Supplier's BRP (not yet open to independent aggregation).

FCR/a-FRR/m-FRR (Minute Reserve) are open to demand flexibility and (independent) aggregation. Moreover, the m-FRR includes Minute Reserve and Interruptible Loads (called *AbLaV*); the Minute Reserve is open to (independent) aggregation, while the Interruptible Loads service does not allow the aggregation.

Regarding the adequacy services, there is a Strategic Reserve (called *Kapazitätsreserve*) which is activated if the electricity demand cannot be met through market-based mechanisms. The first auction, for 2 GW, took place in October 2019 and delivery began in October 2020. Although the tender is open to all types of domestic capacity providers (generators, storage facilities and loads), technical requirements were impeding demand participation. In order to overcome this barrier, in 2018 the EU ruled that industrial load must be allowed to participate in the strategic reserve and all technologies must be treated equally; in response, Germany amended the rules to allow for aggregation of distributed loads by lowering the minimum bid size and number of tests but stating that only inflexible loads can participate in the strategic reserve (which means they cannot be active in other balancing services).

Constraint management services, at both transmission and distribution level, are not open to (independent) aggregation. In fact, to manage congestions, system operators use a cost-based mechanism to directly control generation with a minimum size of 10 MW. The new Redispatch 2.0 model (planned for implementation in 2021) will allow to control distributed generation and storage units with a minimum size of 100 kW. Moreover, from 2021 there will be a new market for non-frequency ancillary services (mainly for reactive power and black start capability); the Federal Energy Ministry BMWi recently published a draft regulation for the new products and for technology-neutral and market-based auctions.

As for the aggregation model in place, each flexible service is described by the aggregation scheme (see Table 11).

Value stacking of balancing services is possible (even where multiple aggregators delivering balancing products are active on the same asset/unit). Furthermore, pooling of ADS assets is allowed after a prequalification procedure at asset level (but dynamic pooling is not possible as aggregators need to notify the assets delivering a service one week in advance).

Table 11 - AIM implemented in Germany

Flex. Service	AIM	Notes
Wholesale services	Integrated	
Balancing services	Integrated, Corrected, Contractual	Usually, there is a contract between aggregator and Supplier's BRP. If not, there is a framework to correct the Supplier's balance position and to compensate for the energy sourced through the prosumer's contract. The price of the ToE matches that in the prosumers' retail contract.

Great Britain (UK). The regulatory framework recognizes formally the main following roles: aggregator, BSP and Capacity Provider. In particular, the aggregator is recognized as an independent organisation or a market actor combining roles such as Prosumer, Supplier or Generator; thus, an aggregator performing independent aggregation is referred to as Virtual Lead Parties when participating in the Balancing Mechanism or in the Replacement Reserve market introduced by the project TERRE. BSP is a recognized role in accordance with the European Electricity Balancing Guideline but the term is not commonly used by UK market participants. Capacity Provider is the designated role for parties providing capacity in the UK Capacity Market. There is not yet a role for provision of constraint management services.

Different balancing services, wholesale services, adequacy services (i.e. capacity market) and constraint management (i.e. congestion management) can be offered at pool level with generation/demand flexible resources. In particular, distributed explicit flexibility services include:

- wholesale services (energy services on day-ahead and intra-day energy markets);
- balancing services (FCR, a-FRR, m-FRR/RR);
- adequacy services;
- constraint management services (i.e. services for the mitigation of congestion phenomena).

Currently, in the wholesale market demand flexibility and aggregation can only take place where there is agreement with the Supplier/BRP (therefore independent aggregation is not allowed).

Current balancing services include mainly Firm Frequency Response/Dynamic Containment (equivalent to FCR), Fast Reserve (equivalent to a-FRR) and Short-Term Operating Reserve (equivalent to m-FRR). Firm Frequency Response is traditionally required by NG ESO, while Dynamic Containment is a new product ‘soft launched’ by NG ESO in 2020. All services area are open to demand flexibility participation and to independent aggregation (if technical requirements are fulfilled); in particular, the minimum requirement for Fast Reserve (25MW) creates a barrier for aggregators. Moreover, the Short-Term Operating Reserve uses capacity coming from demand flexibility. Traditionally, this mechanism has been closed to independent aggregators, but this has recently changed (Balancing and Settlement Code modification which allows them to participate as Virtual Lead Parties) so that, for most of the above-mentioned services, any technology able to fulfil a service’s technical requirements can offer it (including generators connected to the transmission and distribution networks, storage providers and aggregated demand side response).

Regarding the adequacy services, NG ESO organizes a capacity market to ensure long-term supply and generation capacity; this mechanism is open to traditional generation, demand flexibility and independent aggregation. Aggregated units connected to the transmission or distribution network can participate in Capacity Market Auctions; in particular, it is possible to trade capacity obligations via ‘Secondary Trading’ which allows capacity providers to cover unavailability of their contracted capacity. Depending on the nature of the technology providing capacity, de-rating factors are applied to the asset capacity to determine the contracted, and therefore the remunerated, capacity. The de-rating factor applied to demand flexibility response is only of 86.1% (which is relatively low given that nuclear capacity has an 80% de-rating factor); for example, if an aggregator offers 1 MW of demand response capacity, only 86.1%, i.e. 0,861 MW, will be remunerated.

Constraint management at transmission level is managed, amongst other methods, by Bid-Offers through the Balancing Market that is now open for participation to distributed demand and independent aggregation. At distribution level, additional services can be procured by DSOs by means of tender procedures for flexibility through the match-making flexibility platform Piclo Flex. The Electricity Network Association (ENA) is attempting to standardise DSO constraint management products as part of the Open Networks (ON) project; current DSO flexibility classification identifies four main services: Secure, Sustain, Dynamic and Restore.

As for the aggregation model in place, each flexible service is described by the aggregation scheme (see Table 12).

Value stacking approach is possible depending on the service and type of contract and/or procurement. NG ESO has published some high-level principles for revenue stacking and initial options in the Balancing Services; these options allow providers to offer multiple services, to multiple entities, and allow for the same assets to offer two services at the same time (if they are not conflicting). Value stacking is also compatible with capacity market rules. Moreover, the ENA published the current overview of permitted revenue stacking per service; the review includes balancing, capacity and DSO constraint management services. In particular, constraint management services are being discussed as part of the ENA Open Networks project; ENA review concludes that while products are readily stackable ‘in time, they are less stackable for ‘double serving’; in fact, generally reserve capacity, RR and BM services allow double serving but the assets offered for each service are fixed and thus cannot be modified in real time (dynamic pooling is not possible).

Table 12 - AIM implemented in Great Britain

Flex. Service	AIM	Notes
Wholesale services	Contractual or Integrated	
Balancing services	Uncorrected, Broker, Integrated, BSP-IA (as independent aggregator)	The broker and integrated model are always an option. Where the aggregator and Supplier do not have a contract, the ‘BSP-IA’ arrangement applies. ELEXON (Balancing and Settlement Code Company corresponding to ISR in USEF terminology) corrects the balance position of the BRPs affected by flexibility activation from aggregators to avoid them causing imbalance charges. In addition, aggregators are only responsible for under-delivery but not for over-delivery. Regarding ToE there are two possible cases: (a) Prosumer “opts-in” and (b) Prosumer “doesn’t ‘opt-in”. In “opts-in” relevant data will be shared with their Supplier for billing purposes (in this case, the ToE will be done through the

		prosumer and thus this could be mapped as a type of corrected model). In “doesn’t opt-in”, there is not a standard procedure to arrange ToE (it could be considered a free-riding model).
Adequacy services	Depends on the activation	The capacity market does not offer activation payment. When the energy is activated it can be done through another ‘relevant Balancing Service’ or through wholesale to get a remuneration. Therefore, the AIM will correspond to that of the selected service.

The Netherlands. The regulatory framework recognizes formally the role of BSP. The aggregator is under consideration in the Energy Law (proposal currently under consultation) while for the Constraint Management Service Provider there is a proposition to implement in the grid code to designate the party providing grid capacity management services to the DSOs.

Different balancing services (FCR, a-FRR, m-FRR), wholesale services and constraint management (i.e. congestion management) can be offered at pool level with generation/demand flexible resources. In particular, distributed explicit flexibility services include:

- wholesale services (energy services on day-ahead and intra-day energy markets);
- balancing services (FCR, a-FRR, m-FRR/RR);
- constraint management services (i.e. services for the mitigation of congestion phenomena).

Demand flexibility can be traded and aggregated in day-ahead and intraday markets to perform self-balancing or passive balancing (but only via the Supplier’s BRP, so it is not yet open to independent aggregation).

FCR, a-FRR and m-FRR are open to demand flexibility and aggregation via BSP; distributed flexible resources can also participate in the service.

There are no adequacy services (and are not foreseen before 2025).

Congestion management services at transmission and distribution level are open to demand flexibility and aggregation. The TSO TenneT and DSOs have worked together in the creation of the GOPACS platform in order to facilitate the coordination of the TSO and DSOs in the procurement stage.

As for the aggregation model in place, each flexible service is described by the aggregation scheme (see Table 13).

For all balancing products, pooling is allowed; in particular, when offering the FCR service from a pool, a message on Planned Resource Schedule related to the allocation information for each contributing reserve unit and/group has to be provided. Dynamic pooling for a-FRR and m-FRR is allowed; more precisely, the aggregator must notify the TSO about the units used for activation within 5 minutes of the activation.

Table 13 - AIM implemented in Netherlands

Flex. Service	AIM	Notes
Wholesale services	Integrated or Contractual	Aggregator may be contracted by BRPs to control their flexibility. Passive balancing is rewarded via imbalance settlement mechanism.
Balancing services	Uncorrected for FCR. Integrated, Broker, Contractual or BSP-IA (as independent aggregator) for a-FRR. Integrated or Broker for m-FRR.	As for a-FRR service, when the BSP/aggregator does not have a contractual arrangement with the supplier-BRP, the TSO applies the 'BSP-IA' model; the TSO corrects the BRP perimeter; however, ToE is not arranged by regulation. Assuming the Supplier would require a form of remuneration, there is one option: the Supplier seeks compensation from the customer. But, since the customer typically would know the activated volume, the customer can remunerate the Supplier (this

		arrangement would correspond to the Corrected model). As for m-FRR service, BRP perimeter is corrected on the called volume; in particular, the compensation of open supply position has to be agreed upon between the aggregator/BSP and prosumer as well as prosumer and Supplier/BRP. Thus, the aggregator is remunerated for the delivered energy.
Congestion management services	Uncorrected, Integrated or Contractual	Integrated or contractual is applicable for flexibility deployed under the GOPACS platform.

Spain. The regulatory framework recognizes formally the following roles: aggregator and BSP. In particular, the aggregator role was defined in national legislation in June 2020 (regulatory changes to allow for independent aggregators are expected in 2021), while the BSP role has been defined only at legislation level (currently BSP is equal to the BRP; but this situation will change in 2021 once the independent aggregator starts participating in balancing markets). There is no defined role for parties offering Constraint Management services.

Different balancing services (a-FRR, m-FRR) and wholesale services can be offered at pool level with generation/demand flexible resources. In particular, distributed explicit flexibility services include:

- wholesale services (energy services on day-ahead and intra-day energy markets);
- balancing services (FCR, a-FRR, m-FRR/RR);
- constraint management services (i.e. services for the mitigation of congestion phenomena).

At present, demand flexibility participation and aggregation are only possible in day-ahead and intra-day markets within the BRP portfolio.

FCR is a mandatory service for relevant dispatchable production units and is not remunerated. The a-FRR and m-FRR have just been opened to storage, demand flexibility and aggregation (aggregated resources connected to the distribution grid is able to participate in the auctions). Currently aggregation is delivered by the energy Supplier (but changes in 2021 are expected to include an independent aggregator).

There are no adequacy services yet.

The high voltage constraint management is handled by REE with technical restrictions so market access is limited for demand flexibility and aggregation (it is expected to change in 2021 allowing storage, demand flexibility and aggregation). There is no immediate need for medium and low voltage constraint management (but this is expected to change in the future, based on the results of innovation projects such as the IREMEL project aiming to demonstrate a local flexibility market where DSOs would request congestion management services from aggregators).

As concerns the aggregation model in place, each flexible service is described by the aggregation scheme (see Table 14).

Pool of aggregated assets has been recently approved (option to offer balancing services); however, combining assets of different nature (i.e. generation and load) is not allowed yet.

Table 14 - AIM implemented in Spain

Flex. Service	AIM	Notes
Wholesale services	Integrated	
Balancing services	Integrated or Broker	The aggregator/BSP would delegate the balance responsibility to the supplier-BRP (Broker model).

Switzerland. The regulatory framework does not recognize formally the role of the aggregator; in particular, currently, the aggregator acts as a BSP that is performed by ancillary service providers or virtual generation units.

Different balancing services and wholesale services can be offered at pool level with generation/demand flexible resources. In particular, distributed explicit flexibility services include:

- Wholesale services (energy services on day-ahead and intra-day energy markets);
- Balancing services (FCR, a-FRR, m-FRR/RR);
- Constraint management services (i.e. services for the mitigation of congestion phenomena).

Aggregated demand flexibility can be traded in day-ahead via the Supplier's BRP (not open to independent aggregation).

FCR, a-FRR and m-FRR are open to demand flexibility (including distributed resources) and independent aggregation.

There are not yet adequacy services in Switzerland.

Constraint management at transmission level is handled by the TSO Swissgrid via grid reconfiguration and non-market-based redispatch. This arrangement does not allow for the participation of demand flexibility or aggregation. At distribution level, some areas in Switzerland are expected to suffer future congestion due to renewables generation and so there are several local flexibility markets projects and pilots underway (e.g. the Romande Energie smart grid project).

As for the aggregation model in place, each flexible service is described by the aggregation scheme (see Table 15).

Pooling (concept introduced in Switzerland in 2013) is allowed in balancing markets; in particular, prequalification procedure for balancing market participation is designed for small generating units and flexible loads that would not meet the requirements individually. Dynamic pooling is allowed since the aggregator assigns the activated assets ex-post. This option requires a baseline per asset; in particular, for small assets such as residential consumer, it is possible to group multiple assets into a single asset with a single baseline. In case of dynamic pooling, the aggregator is also responsible for assets that were not activated.

Table 15 - AIM implemented in Switzerland

Flex. Service	AIM	Notes
Wholesale services	Integrated	
Balancing services	Integrated, Contractual or Central Settlement	If the aggregator and the Supplier have an agreement, the contractual model or integrated model applies; otherwise, the Central settlement model applies. In the latter case, the ToE price is the day-ahead spot price (i.e. the exchange stock price for applicable 15-min period).

Czech Republic. The regulatory framework recognizes only the role of the aggregator; in particular, only integrated aggregators exist. They can offer balancing services to the TSO (m-FRR and a-FRR) by aggregating from flexibility providers of any type and size (having specific measurement and communication requirements met - minutes for m-FRR and seconds for a-FRR); the required minimum size of an aggregation block is 1 MW.

The aggregator provides a flat baseline (quality is evaluated in all periods when no flexibility services is activated) and is responsible for collection and validation of the data (the IT system of the aggregator is certified and tested individually). The information exchange is ensured by sub-meter data with at least minute or seconds granularity for m-FRR and a-FRR respectively (data for the whole aggregation block must be submitted to the TSO online; hourly delay is possible for individual meter data when the individual flexibility provider is smaller than 1.5 MW). Balancing energy per aggregation block is evaluated as measurement-baseline point; financial compensation for each flexibility provider is contractually managed between the provider and the aggregator/supplier.

The independent aggregator model is being prepared together with the new Data Hub project. The Data Hub project shall facilitate not only aggregation of flexibility by independent aggregators, but it shall also provide data and process support for other new market model features like energy communities, storage services, etc. In particular, the independent aggregator model shall be based on the correction principle, where the baseline is used not only to evaluate the activated flexibility but also to correct the market settlement position of suppliers and aggregators. In this case, suppliers and aggregators shall not need to enter in any contractual relationship and both supplier and aggregator shall be balance responsible parties (BRP). This model has to be implemented by 2024.

Based on the new aggregator model:

- the independent aggregator will be separate from the supplier;
- the independent aggregator will not need to have any contract with the supplier;
- both supplier and independent aggregator will have their own BRP;
- conflicts between aggregator and supplier shall be resolved by separating their settlement positions using baseline and measured values of flexibility providers (correction model).

If the participation is allowed, the following service/market products can be exchanged:

- wholesale services (forward, day-ahead, intraday);
- balancing services (FCR, a-FRR, m-FRR, RR in energy and capacity);
- redispatching/voltage services by TSO and DSO;

The participation to services provision implies prequalification (e. g. prequalification of the IT system and of individual measurement devices). Various methodologies are considered for the baseline methodology.

Aggregator and DSO will be responsible for collection and validation of the data, while, as above mentioned, the IT system of the aggregator will be certified and tested individually. Meter data must have at least minute and second granularity for m-FRR and a-FRR, respectively.

In conclusion, the brief overview on AIM implemented in some European countries highlighted the following:

- As for roles involved in the explicit flexibility services exchange in wholesale, balancing services, constraint management services and adequacy services markets,
  - most countries have implemented the aggregator and BSP roles;
  - few countries have implemented the Capacity Service Provider (i.e. Great Britain, Belgium and France) and Constraint Management Service Provider roles (potentially the Netherlands);
- as for the opening of the participation of demand flexibility and aggregation in the explicit flexibility services provision,
  - all countries are starting to open up balancing services (but the participation of distributed flexible resources, including generation, demand and storage assets, is still not allowed in some countries);
  - all countries are open to wholesale energy trading (day-ahead, intraday) mainly via the integrated model or, in some cases, contractual model (only France allows independent aggregation via the NEBEF mechanism; soon Belgium also will follow);
  - adequacy service is open in four countries (France, Germany, Great Britain and Finland) in terms of capacity service (theoretically to demand flexibility participation);
  - constraint management services for the TSO are not generally open, while constraint management services for the DSO are still at trial stage in most countries (only in Great Britain and the Netherlands these services are more developed and allow the participation of demand flexibility and aggregation);
- as for the value stacking approach, in most countries the balancing service stacking with pooling assets is applied and, in some cases, with dynamic pooling (i.e. Great Britain and Switzerland);
- there is a lack of standardisation across the aggregator role implementation and, in most countries, the need for some sort of contractual relationship with the Supplier (see Figure 30).

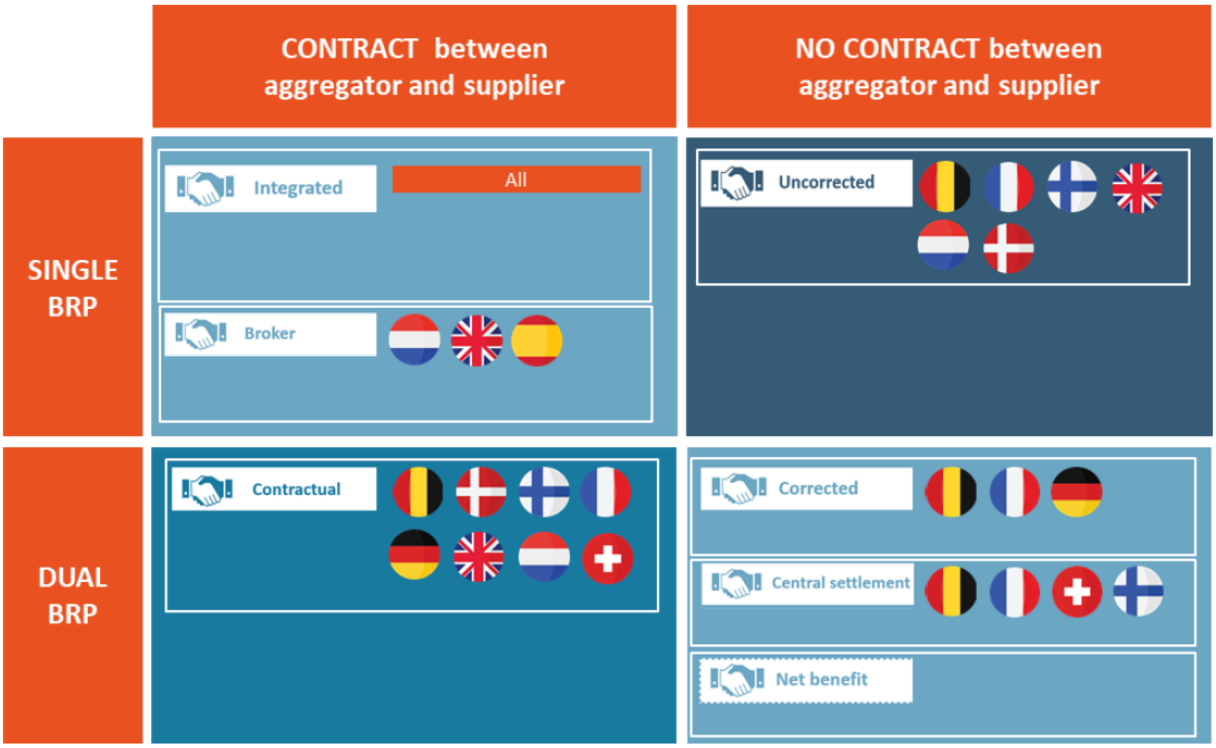

Figure 30 - Overview of AIM implemented in some European countries (Source: USEF).

The following figures, extracted from *"The implementation of the electricity market design to drive demand-side flexibility"*, by SmartEn, March 2022 (https://smarten.eu/wp-content/uploads/2022/03/The_implementation_of_the_Electricity_Market_Design_2022_DIGITAL.pdf) show the most updated picture in terms of progress of different European countries about:

- market-based procurement of all Decentralised Energy Resources by System Operators;
- non-discriminatory participation of all Decentralised Energy Resources in all markets and mechanisms;
- frameworks for innovative services;
- access to price signals for end-users.

Figure 31 - Market-based procurement of all Decentralised Energy Resources by System Operators (Source: SmartEn).

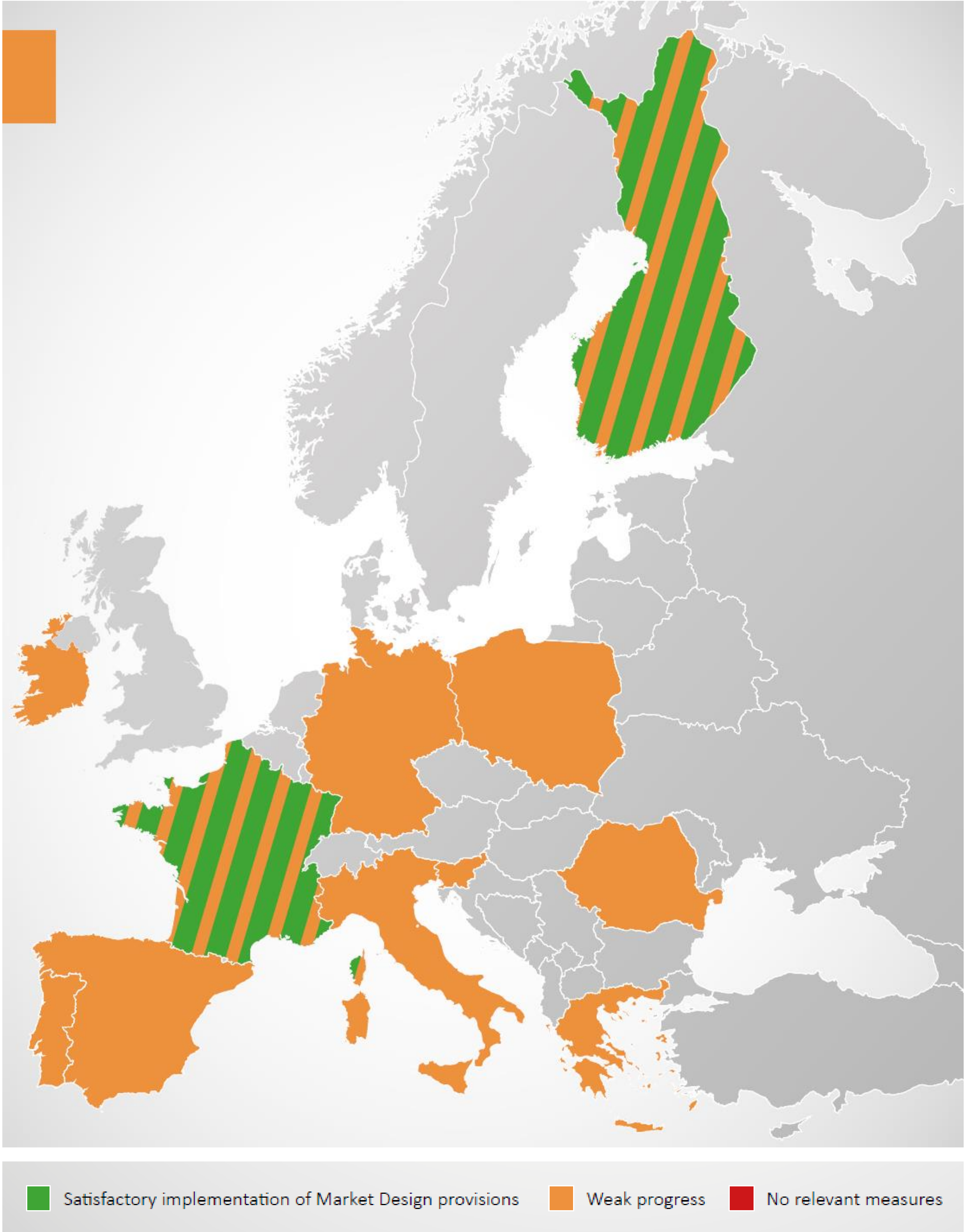

Figure 32 - Non-discriminatory participation of all Decentralised Energy Resources in all markets and mechanisms (Source: SmartEn).

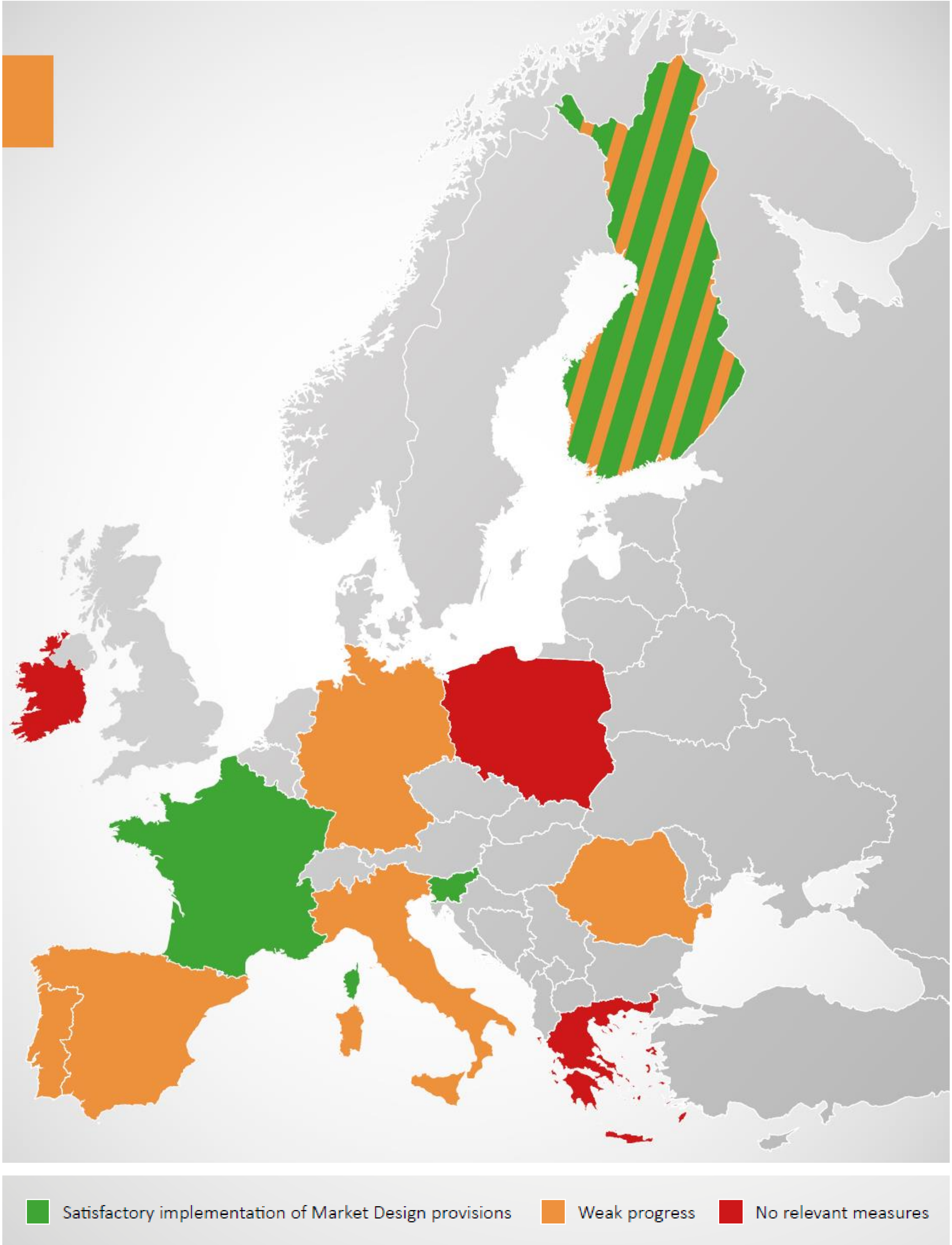

Figure 33 - Frameworks for innovative services (Source: SmartEn).

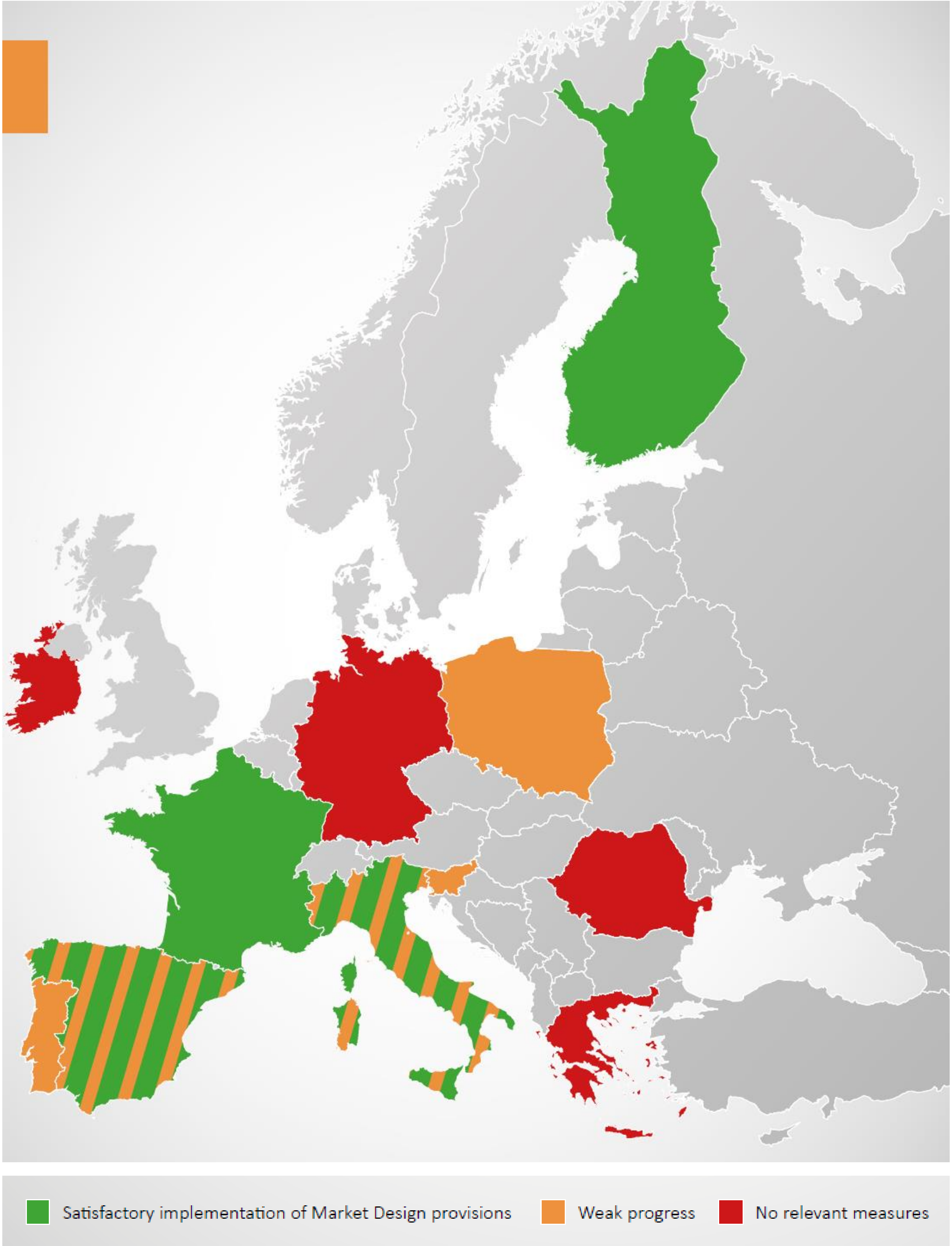

Figure 34 - Access to price signals for end-users (Source: SmartEn).

4.5.3 The Italian pilot projects for aggregation of distributed resources

With the resolution no. 300/2017, the Italian Regulatory Authority intended to initiate a process of progressive opening of the Ancillary Services Market (MSD) to resources that were not enabled, through the definition of pilot projects aimed at collecting useful elements for the reform of dispatching. Therefore, as a consequence of the aforementioned resolution, the Italian TSO launched several pilot projects to allow the participation to the Ancillary Services Market of:

- flexible demand;
- non-dispatchable renewable sources;
- distributed generation;
- storage systems.

In particular, distributed resources both consumption and generation units and storage systems, participate as aggregates in the Ancillary Services Market through a Balancing Service Provider (BSP).
In the following figure a schematic representation of the pilot projects in line with the resolution no. 300/2017/R/eel is shown. Note that, before such pilot projects, only "relevant" (≥ 10 MVA) and dispatchable generation units were enabled to provide ancillary services.

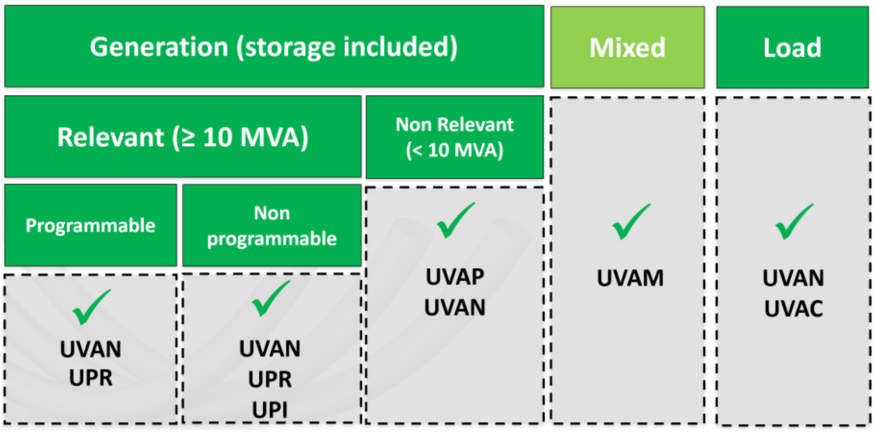

Figure 35 - The Italian pilot projects as per resolution no. 300/2017 issued by the National Regulatory Authority

In detail:

- UVAN (i.e. Nodal Virtual Enabled Units) are aggregate of relevant and non-relevant (both dispatchable and non-dispatchable) generation units, as well as of consumption units[81] connected to the same node of the transmission network;
- UPR (Relevant Generation units) are relevant generation units not yet enabled to provide ancillary services, including non-dispatchable renewable sources;

[81] I.e. flexible loads.

- UPI (Integrated Generation units) are relevant generation units integrated with storage systems for the provision of Frequency Containment Reserve (primary regulation);
- UVAC (Load Virtual Enabled Units) are aggregate of consumption units;
- UVAP (Production Virtual Enabled Units) are aggregate of non-relevant generation units (both dispatchable and non-dispatchable), including storage systems;
- UVAM (Mixed Virtual Enabled Units) are aggregate of non-enabled relevant and non-relevant (both dispatchable and non-dispatchable) generation units, consumption units and storage systems, including charging stations for electric vehicles (V2G).

In addition, the main elements of the UVAC, UVAP, and UVAM projects are listed in the table below:

Table 16 - The main elements of the UVAC, UVAP, and UVAM projects

Pilot project	Minimum regulating power	Ancillary services provided
UVAC	In a first phase 10 MW, subsequently reduced to 1 MW	Provision of tertiary reserve and balancing service exclusively in the "upward" regulation by reducing withdrawal and/or increasing any generation present within the plant up to the amount of its internal consumption
UVAP	In a first phase 5 MW, subsequently reduced to 1 MW	Resources for solving congestion, tertiary frequency reserve, and resources for balancing (all in upward and downward regulation)
UVAM	1 MW	Resources for solving congestion, Tertiary frequency reserve (i.e. spinning tertiary reserve and replacement tertiary reserve), and Resources for balancing. All ancillary reserves in upward and downward regulation.

UVAMs have replaced and incorporated UVACs and UVAPs. The UVAMs currently have a perimeter defined by the TSO on a provincial or regional basis and the same UVAM may contain production and/or consumption units under the contract of different Balance Responsible Parties (BRPs).
The services that can be provided by an UVAM are shown in the following table.

Table 17 - Ancillary services provided by an UVAM project

Services	«upward» regulation	«downward» regulation	Time for implementing the dispatching order	Minimum duration «up» and «down» regulation
Congestion management	✓	✓	<15 min	120 min
Spinning tertiary reserve	✓	✓	< 15 min	120 min
Replacement tertiary reserve	✓	✓	< 120 min	480 min
Balancing	✓	✓	< 15 min	120 min

UVAM movements following a dispatching order are made with respect to a baseline defined by the BSP and corrected by the TSO taking into account the actual measurements of the aggregate over the previous eight quarters of an hour. The BSP is responsible for the non-compliance with dispatching orders with respect to the corrected baseline (w.r.t. which, precisely, the service actually provided is evaluated), while the BRP is responsible for the actual imbalances with respect to its own aggregate injection/withdrawal program defined on a market zone (with the exception of the relevant generation units, if any, for which the injection program is referred to the generation unit itself) as if the UVAM did not exist (this is the same way as production programs are defined, in general, in the regulation currently in force): the need not to modify, for the purposes of the pilot projects, the general regulation in force has led to the need to introduce a baseline, independent of the injection/withdrawal programs, for the purposes of participation in the ancillary services market. Actual imbalances continue to be valued on the basis of the regulation applied to units not enabled to provide ancillary services.

UVAMs are selected and remunerated for their capacity with an annual premium (in k€/MW/year) on the basis of auctions for specific products, differentiated on the basis of the time period and the duration of the supply of the service. When participating to the ancillary services market, their remuneration cannot exceed a specific strike price.

Auctions are held for the following three products:

- Monday to Friday 15:00 ÷ 17:59
  - ✓ bid for at least 3 hours, max premium 30 k€/MW/year times the % availability on the 4 hours, strike price 200 €/MWh
- Monday to Friday 18:00 ÷ 21:59
  - ✓ bid for at least 4 hours, max premium 30 k€/MW/year, strike price 400 €/MWh

- Monday to Friday 18:00 ÷ 21:59
    - ✓ bid for at least 4 hours, max premium 30 k€/MW/year, strike price 200 €/MWh
- Bids may be for 2 consecutive hours, but with a reduction of the premium

In addition to the "Virtual Units" pilot projects, the Italian TSO started also the "Fast Reserve" pilot project (see also 4.6.2.2.1 for more details). In fact, the conventional coal-fired units, that have to be phased-out by 2025 in Italy, have the capability of rapidly increasing their power by about 3% of their maximum power in less than 1 second in response to a sudden frequency variation. On the other hand, Combined Cycle Gas Turbines (CCGTs), constituting the bulk of thermal generation in Italy, are much slower. To compensate for the loss of coal-fired units, the TSO proposed the Fast Reserve pilot project.
In particular, Fast Reserve Units (FRUs) may be one or an aggregate of the following devices:

- "stand alone" generation units;
- "behind the meter" generation units that share the Point of Delivery (POD) with consumption units and/or with storage systems;
- consumption units (excluding the interruptible ones);
- storage systems, either "stand alone" or coupled with generation/ consumption units.

Each device included in a Fast Reserve Unit may be connected to Low Voltage (LV), Medium Voltage (MV), High Voltage (HV). Besides, the minimum size of the aggregate is equal to 5 MW, whereas the maximum size of the aggregate is equal to 25 MW, in order to avoid concentration of resources.
A Fast Reserve Unit must be able to carry out a continuous and automatic frequency regulation as well as to respond to a frequency deviation with an activation time less than 300 ms and a full activation time less than 1 second.

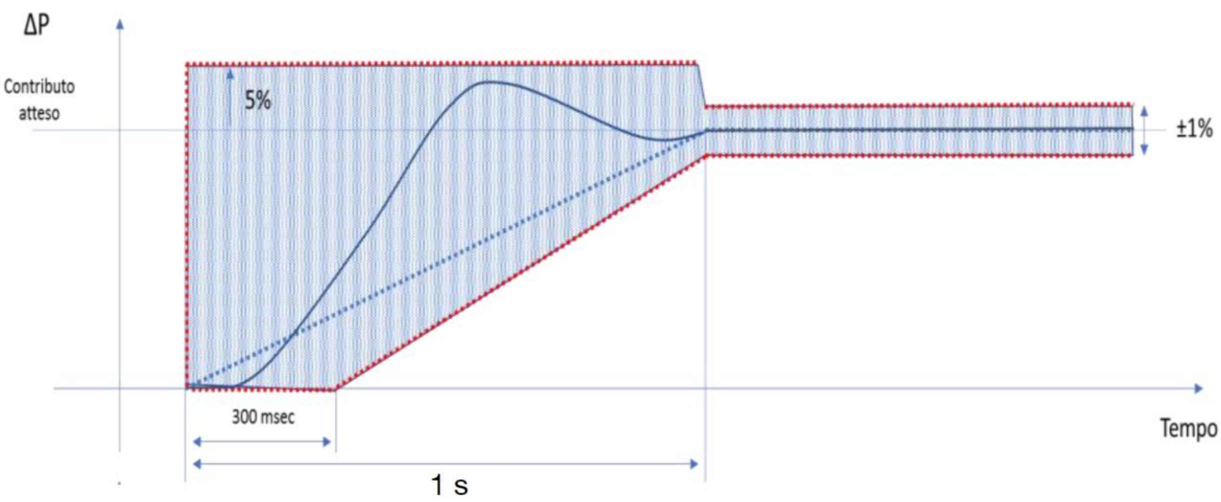

Figure 36 Provision of the service by a Fast Reserve unit

The unit must also be able to regulate the required power profile for 30 seconds, waiting for the intervention of primary regulation – FCR, then carry out a linear ramp towards zero in 5 minutes. If the Fast Reserve Unit is composed of at least one device with limited energy capacity (e.g. battery), it should be able to make available the qualified upward/downward power for at least 15 minutes every 2 hours.

The Italian TSO awarded 250 MW of Fast Reserve capacity though an auction with average capacity remunerations ranging from about 23000 to 61000 €/MW/year, according to the market zone. Only battery storage systems were selected to provide the service because they are basically the only technology able to comply with the technical requirements of the service.

Recently, secondary regulation (i.e. automatic Frequency Restoration Reserve – aFRR) and voltage regulation have been proposed by the Italian TSO as new pilot projects. The significant elements of these experimental projects have been summarized in the following table.

Table 18 - Secondary regulation and voltage regulation pilot projects

Secondary regulation (aFRR)	Voltage regulation
Test the provision of aFRR by resources currently not enabled: • non-dispatchable (renewable sources) • with limited energy (storage systems) • aggregated (i.e. UVAM) Provision may be asymmetric (only upward, only downward, different value between upward and downward, at least 1 MW)	• the network code Requirements for Generators (RfG) states that “existing” (in operation after July 13th, 2018 according to the Italian NRA) generation plants must be revamped to provide voltage regulation, if a Cost-Benefit Analysis shows that benefits are larger than costs • The Italian TSO wants to test the provision of voltage regulation by resources, both dispatchable and non-dispatchable, currently not enabled, that might be revamped to this aim • a “premium” (€/MVAr/year) correlated to revamping costs will be granted on the basis of auctions

4.5.4 The Italian dispatching reform

The consultation document no. 322/2019/R/eel issued by the Italian Regulatory Authority (i.e. ARERA) deals with the reform of the TIDE – Testo Integrato Dispacciamento Elettrico (Integrated Text of Electricity Dispatching).

The purpose of this consultation document is to identify the main lines of action aimed at making the regulation of dispatching activities suitable for efficiently guaranteeing the security of the electricity system in a context of rapid and continuous evolution as a result of the spread of non-dispatchable renewable sources and distributed generation, as well as the gradual disappearance of dispatchable plants that have historically made available the resources to guarantee the balance between supply and demand for electricity. In addition, the Integrated Text of Electricity Dispatching aims at completing the integration of the Italian markets with the European ones, with specific reference to the coupling of intra-day markets and to the harmonization and sharing of ancillary services.

In this Italian consultation document, it is highlighted that the regulation has to overcome the current distinction between relevant units and non-relevant units, both for the purposes of defining the dispatching points to which the injection or withdrawal program by the BRP and for the purposes of identifying the units enabled to provide ancillary services, the latter activity being the responsibility of the BSP. Therefore, the Italian regulatory authority proposes to identify the following types of units both single and "virtual" (i.e. aggregated"), both non enabled to provide ancillary services and enabled to do so:

a) **Virtual Non-Enabled Unit** (i.e. **UVNA** – Unità Virtuale Non Abilitata): a set of production or consumption units (including storage systems), not enabled to provide ancillary services, whose operators (producers or final consumers) gave a mandate to the same BRP to sign with the TSO a dispatching contract, whose connection points are located in the same market zone.
b) **Single Enabled Unit** (i.e. **UA** – Unità Abilitata): a single production or consumption unit, qualified to supply at least one ancillary service for which the reference perimeter[82] is nodal, whose operator (producer or final customer) operates as a BRP and as a BSP or gave mandate to a BRP to sign a dispatching contract and to a BSP (even different from the BRP) to sign a contract for the provision of ancillary services. At each Single Enabled Unit a single dispatching point is associated, that coincides with the injection or withdrawal point of the unit.
c) **Virtual Enabled Unit** (i.e. **UVA** – Unità Virtuale Abilitata); a set of one or more consumption and/or generation units whose connection points are located in the same *"aggregation perimeter for the purposes of qualification"* and whose operators (producers or end customers) gave mandate to the same BRP to stipulate the dispatching contract and to the same BSP (also different from the BRP) to stipulate the contract for the supply of ancillary services. The *"aggregation perimeter for the purpose of qualification"* is the minimum between the market zone and the smallest reference perimeter for the provision of the ancillary services for which the qualification is requested. For example, if the UVA is enabled only for the provision of secondary reserve (assuming that this service has a national reference perimeter excluding the major islands, namely Sardinia and Sicily), the aggregation perimeter for the purpose of qualification is the market zone;

[82] The "reference perimeter" of a service is the perimeter within which that service can be provided by production / consumption units, single or aggregate, without compromising the secure operation of the power system.
The reference perimeter might be a node, for example in case of the congestion management service, or a market zone or a set of market zones in case of secondary regulation, or the whole continental area in case of primary regulation.

on the other hand, if the UVA is also enabled for congestion management and/or balancing (assuming that these services have a nodal reference perimeter), the aggregation perimeter for the purposes of qualification is the node on the relevant grid. Generally speaking, at each UVA, two dispatching points are associated, namely one for consumption units and one for generation units: the former is the withdrawal point or the set of withdrawal points relating to consumption units that belong to the same qualified unit; the latter is the injection point or the set of injection points relating to generation units that belong to the same qualified unit. With reference to the definition of the programs of the UVA, there are two alternative ways: 1) the BRP defines the injection and the withdrawal programs for each dispatching point; 2) the BRP defines a single program; only after real time the single program is split into an injection and a withdrawal program for the reconciliation of the commercial position and the sum of the physical positions.

d) **Mixed Virtual Enabled unit** (i.e. **UVAM** – Unità Virtuale Abilitata Mista): a set of UA and/or UVA having the same aggregation perimeter for the purpose of qualification and managed by the same BSP for the purpose of providing ancillary services. Thus, in order to allow the greatest possible aggregation, in this case a BSP, if it plays this role for a number of UAs/UVAs having the same aggregation perimeter for the purpose of qualification, may submit offers for the provision of ancillary services "jointly" for the set of UAs/UVAs it represents (i.e. for all the UVAM), subsequently evaluating which UAs/UVAs to use for the execution of dispatching orders deriving from the accepted offers.

Figure 37 shows the different possible aggregation levels foreseen in the Italian dispatching reform.

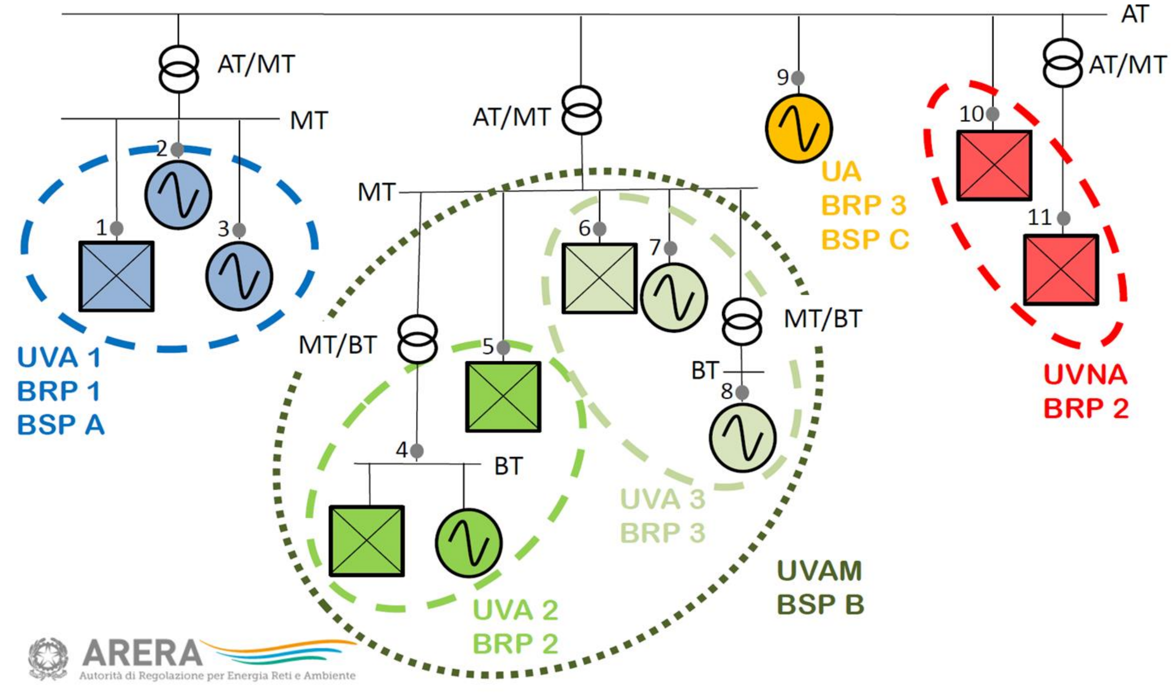

Figure 37 - Different possible aggregation levels in the Italian dispatching reform (AT = HV, MT = MV, BT = LV)

This means that the BRP schedules, referring to the individual UA/UVA, would be modified according to the choices made by the BSP and communicated by it to the TSO. Therefore, this represents an important evolution of the UVAM pilot project from at least two points of view: 1) the perimeter of the new UVAM is not linked, as in the pilot projects, to provinces or regions, but has to be in line with the real characteristics of the electrical grid; 2) the perimeter of the new UVAM would be relevant both for the purposes of defining the injection and/or withdrawal programs (and, consequently, also the actual imbalances) and for the purposes of providing the ancillary services for which each unit is enabled. The BSP and the BRP may continue to be different entities, with different roles, but they would operate differently from the current pilot projects, in that the BRP would no longer continue to submit programs for each market zone, but would submit schedules related to the dispatching points specific to the UVAMs; the BSP would no longer submit a baseline unrelated to the BRPs' programs, but would limit itself to submitting bids for the provision of ancillary services and evaluating the most effective solutions for the implementation of the accepted bids, acting on the set of UA/UVA composing the UVAM, on which it operates. It is reasonable to assume that such point of view would overcome the complexities encountered in the pilot projects deriving from the presence of a baseline not related to the programs that are relevant for the regulation of imbalances, and that it will help to reduce the difficulties associated with the relation between the BSP and the BRPs.

4.6 Evolution of Ancillary Services

The secure operation of a transmission system requires the use of appropriate ancillary services, which can be provided on a mandatory or on a voluntary basis.

In general, voluntary ancillary services are negotiated between the TSO and the providers (Balancing Service Providers - BSPs); the negotiation can occur according to bilateral or competitive market arrangements (e.g. auction process on Balancing Market, organized tender process, etc.). In case of market negotiation, bids can be remunerated according to a marginal pricing (or pay-as-clear) mechanism or to a pay-as-bid mechanism, while in case of bilateral contracts the remuneration can be in form of freely negotiated prices or regulated prices. Mandatory ancillary services, instead, can have a regulated remuneration (regulated prices), or they must be supplied without remuneration.

The participation to the market can be open to all kinds of providers (independently of the voltage level, of the technology, of the rated power value, of the energy processed, etc.) or restricted to few enabled participants.

Traditionally, the main suppliers of the ancillary services are dispatchable large thermal or hydro power plants; only in case of emergency conditions large load units can provide the interruptible service, being curtailed.

However, with the progressive decarbonization of power generation and with the progressive transition of the energy production from large power plants to distributed energy resources, in line with the European energy and climate targets, new flexible resources will be required to participate to ancillary services provision.

4.6.1 Standard Ancillary Services provision

With refence to the corresponding European Network Code, Balancing Markets include products for network frequency regulation and active power balancing (*Balancing Services*): *Frequency Containment Reserve - FCR*, *automatic Frequency Restoration Reserve – aFRR*, *manual Frequency Restoration Reserve – mFRR* and *Replacement Reserve – RR* (this latter is used only in some countries, such as Italy).

As above mentioned, traditionally the main suppliers of balancing services in Balancing Markets are dispatchable large thermal or hydro power plants (large load units can provide interruptible load services only in case of emergency conditions). However, with the progressive increase of RES generation (large wind farms and medium-small photovoltaic systems) and with the progressive development of new flexible technologies such as storage systems, the participation to Balancing Markets can be extended to new flexible and decentralized energy resources (DER), including flexible load units for Demand Response (DR).

With reference to the last European Balancing Market Map (2018)[83], the most advanced balancing markets for DR and DER are: Belgium, France, Ireland and Switzerland; in the United Kingdom there are several possibilities to participate to the Ancillary Services Market but there are complicated products and market structure. In general, Balancing Markets still show a lack of transparency, an incomplete provision of market relevant data, an opaque contracts, conditions and payment structures.

From the payment point of view, with the exclusion of bilateral contracts (where the payments are opaquely negotiated or set directly by the TSO) and of mandatory services (in some case payment is received as a regulated price), the balancing services can be remunerated by adopting a pay-as-bid scheme or a marginal pricing scheme. In presence of competitive market conditions, marginal pricing seems to be the preferred option for independent market actors, allowing them to best monetise flexibility, and take advantage of price variations, so that this price scheme is progressively more and more being implemented.

In all Balancing Markets a penalty is applied for the non-delivery or non-availability of the committed capacity. Usually, penalties are proportional to the non-delivered part and, in the best cases, linked to imbalance settlement prices or to the bid price (in some cases, penalties are also linked to the spot prices). In balancing service products where the net revenue is small, and the business case heavily relies on many activations, these kind of penalties disincentivise participation to the Balancing Market. Usually, if penalties are repeated, it ends up in loss of the prequalification or the reduction of the prequalified capacity.

In terms of access to the Balancing Markets for DER and DR, Figure 38 reports the 2018 map for FCR, aFRR and mFRR in 16 European countries; the score level 0-5 of each country is based on the following criteria:

- Level “0”, no products in a Balancing Market (only mandatory services);
- Level “1”, balancing services are procured via mandatory provision or via bilateral agreements, no access for DER and DR;
- Level “2”, balancing services are procured via Balancing Market with limitations, high entry barriers, small access for DER and DR, no aggregation allowed;
- Level “3”; balancing services are procured via Balancing Market or via Pilot Projects, technology neutral, some entry barriers in requirements or procurement structure, access for DER and DR (mostly through large assets), aggregation allowed;

[83] SmartEn, “European Balancing Market 2018”, 2018, Report.
https://smarten.eu/wp-content/uploads/2020/03/the_smarten_map_2018.pdf

- Level “4”, balancing services are procured via Balancing Market, technology neutral, few entry barriers in requirements or procurement structure, wide access for DER and DR (including small consumers), aggregation allowed;
- Level “5”, balancing services are procured via Balancing Market, no entry barriers, technology neutral requirements, wide access for DER and DR, aggregation allowed.

There is evidence of a relatively “*high*” score level for:

- FCR in France, Belgium, Germany, Finland and Great Britain;
- aFRR in Switzerland, Belgium, Germany, Ireland and the Netherlands;
- mFRR in Switzerland, Belgium, Great Britain, France, Italy, Austria, Germany, Finland and Estonia.

In general, at the European countries level the trend of balancing services is clearly towards opening the Balancing Market and creating products accessible to DR and DER. In particular, the general trend shows a lowering of the entry barriers (especially minimum bid sizes), the creation of market products where only bilateral agreements were previously available, and the creation of aggregator frameworks giving legal certainty about the relationships and responsibilities between aggregators, BRPs and suppliers, and the consumers. Barriers still exist in many markets, even the ones with accessible technical requisites, due to outdated procurement methods or the lack of the proper frameworks. This progressive development is achieved thanks to the recent implementation of European network codes (in particular the *Electricity Balancing Guideline - EB GL*), the European initiatives for standardised European products to be traded on Europe-wide balancing platforms (the so-called PICASSO, MARI and TERRE projects for the harmonisation of aFRR, mFRR and RR, respectively) and national experiences (for example, in Italy the recent introduction of Pilot Projects by the national regulatory authority ARERA in order to open the Balancing Market to DER and DR).

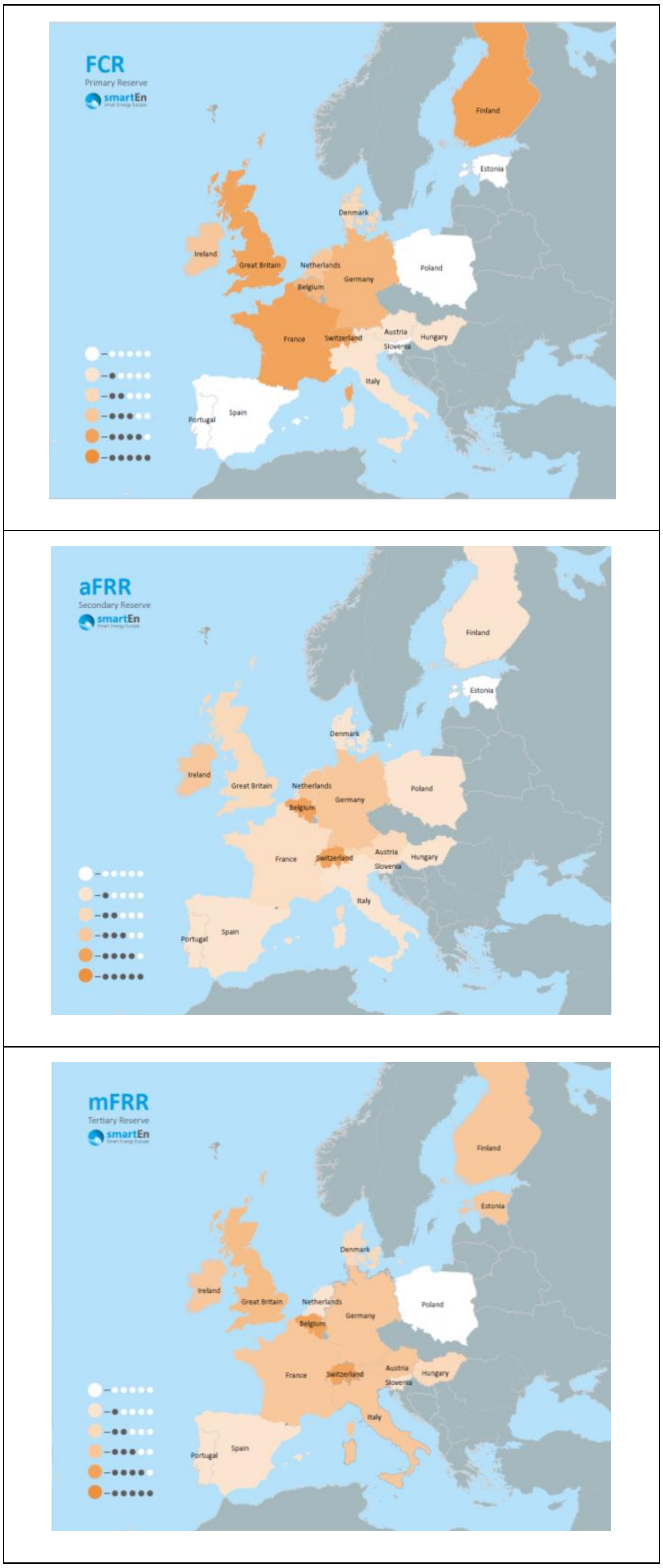

Figure 38 - Map of the access to Balancing Markets (SmartEn 2018)

In terms of measurement and prequalification requirements Figure 39 reports the 2018 map for 16 European countries; the score level 0-5 of each country is based on the following criteria:

- Level “0”, no measurement and prequalification requirements existing for DER and DR;
- Level “1”, existing measurement and prequalification requirements act as prohibitive barriers for DER and DR, no pooling allowed;
- Level “2”, existing measurement and prequalification requirements limit participation in one or more balancing service products for DER and DR, pooling allowed;
- Level “3”; existing measurement and prequalification requirements are, in general, welcoming to new DER/DR participants, some requirement condition might be negative for one or more balancing service products, pooling allowed;
- Level “4”, measurement and prequalification requirements are standardised and performed at aggregated level (very good for DER/DR), some minor details might need improvement;
- Level “5”, measurement and prequalification requirements are standardised and performed at aggregated level (very good for DER/DR), no issues identified by new DER/DR participants.

There is evidence of a relatively “*high*” score level in Switzerland, France, Belgium, Italy, Germany, Denmark, Finland, Austria, Hungary and Ireland.

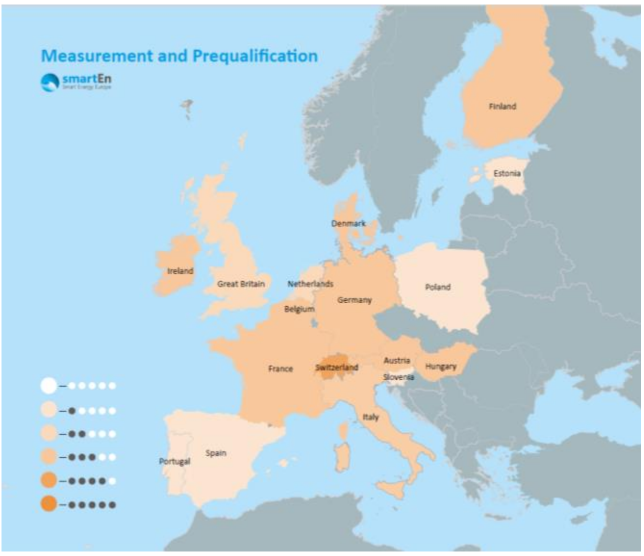

Figure 39 - Map of the measurement and prequalification requirements (SmartEn 2018)

In general, more and more countries are moving to centralised measurement, allowing independent aggregators to manage their own pools and be responsible for them, without the need to individually measure each asset providing the balancing service. However, technical requirements are still not as homogeneous as would be desirable (the lack of standardisation could be solved once the EB GL and the different standardised balancing products are implemented); moreover, several TSOs state that their Balancing Markets are technology neutral but in practice technical requirements are set in a way that de facto exclude many new technologies and participants (e.g. minimum bid sizes still too high in many countries, ramping requirements in several products still tailored to the capabilities of traditional generation plants).

In terms of market penetration of DER and DR, Figure 40 reports the 2018 map for 16 European countries; the score level 0-5 of each country is based on the following criteria:

- Level “0”, no existing balancing services (vertically integrated system);
- Level “1”, no existing Balancing Market, balancing services procured via mandatory provisions or via bilateral contracts, only large suppliers (mainly generation units) providing balancing services (no access to DER/DR);
- Level “2”, existing Balancing Market, some balancing services procured via mandatory provisions or via bilateral contracts, only large suppliers (mainly generation units) providing balancing services (low access to DER/DR, e.g. interruptible load service through large loads), aggregation not allowed;
- Level “3”; balancing services are mainly procured via Balancing Markets, access to DER/DR (but few technology options, e.g. DR through industrial loads), aggregation allowed, no presence of independent aggregators;
- Level “4”, all balancing services procured via Balancing Markets, wide access to DER/DR (including storage systems, residential consumers), aggregation allowed, little presence of independent aggregators;
- Level “5”, all balancing services procured via Balancing Markets, wide access to DER/DR (all technologies, asset connected at all voltage levels of the grid), aggregation allowed, large presence of independent aggregators.

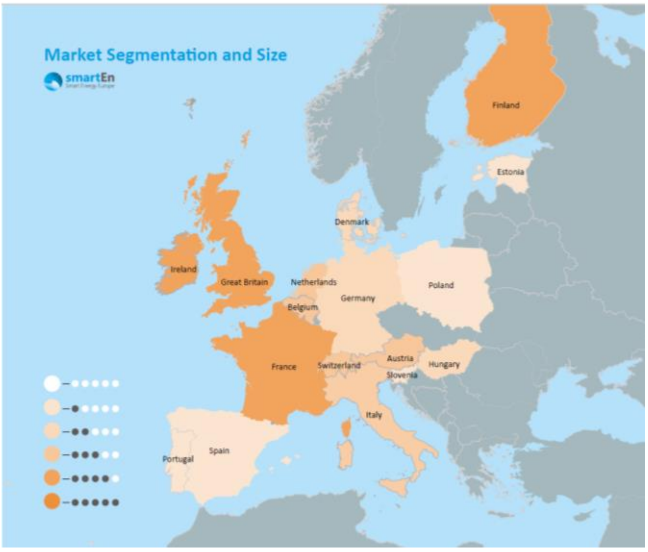

Figure 40 - Map of the market penetration of DER and DR providing balancing services (SmartEn 2018)

There is evidence of a relatively "*high*" score level in France, Ireland, Great Britain and Finland.

In general, with the progressive opening of Balancing Markets and adapting of technical requisites, a wide range of technologies have started to participate across Europe, including the presence of independent aggregators; only a few countries restrict participation to generation (e.g. Portugal, Spain, Poland, Estonia).

In conclusion, barriers still exist in access (e.g. market products for DER/DR, aggregator frameworks, lack of transparency or lack of publicly available information on the market participation of different DER/DR technologies and products exchanged, on bilateral contracts not compliant with EB GL, on capacity payment mechanisms) and measurement/prequalification requirements (e.g. lack of standardisation for technical requirements, technical requirements that de facto exclude many new technologies, minimum bid size, ramping requirements). These barriers could be removed after the full implementation at national level of EB GL.

Table 19 summarizes the main characteristics of Balancing Markets for a selection of European countries.

Table 19 - Balancing Markets in relevant countries (Source: SmartEn).

Country	Comment
Belgium	Belgium has a balancing market with good access for different technologies and independent aggregators, although this does not yet apply to all products (e. g. a-FRR excludes smaller aggregators). Balancing services are procured through competitive tenders (daily basis for FCR, a-FRR and m-FRR). For FCR the only possible payment is for availability (no extra payment is given for activation because Belgium uses the uncorrected model for volume allocation, where the activated energy is not paid to the BSP). The a-FRR has payments for both activation and availability. The m-FRR has availability and activation payments (this latter since the 1st of December 2018) with the application of ToE for independent aggregators. For a-FRR and m-FRR products pay-as-bid is the price scheme used for settlement, while pay-as-cleared is for FCR (since July 2019). Penalties are imposed based on two different criteria: on the resource's availability and on the correct activation (time and form). The size of the penalty is based on the monthly remuneration. Recently penalties for declared unavailability have been raised for m-FRR (ELIA performs random availability tests, that if not passed are penalised, including reduction of prequalified capacity or complete loss of prequalification). There is a good access to all balancing services for different technologies connected to the distribution system. However, in practice no flexibility is delivered with assets connected to the low voltage; in particular, a-FRR is still limited to large generators (above 25 MW). The range of the technologies they use is quite varied, from CHP and biogas to batteries, hydropower or load management in industrial sites. Storage is allowed to participate in the markets under the same conditions as other technologies. Pooling is allowed. The minimum bid size to participate to FCR, a-FRR and m-FRR is 1 MW.

	Full activation time (after the frequency drop): 15-30 s (FCR), 5-7 minutes (a-FFR), 10-15 minutes (m-FRR); maximum activation time: 4 hours (FCR[84]), 4 hours (a-FRR), 4 hours (m-FRR). The measurement is usually performed at the connection point of the asset delivering the balancing energy, but under certain conditions, especially for small assets with a small contribution to the pool, a central frequency measurement is allowed. The prequalification system allows for easy expansion of portfolios, not having to go through the entire process again, only with the new asset. DR play a significant role in providing FCR and m-FRR, but is excluded from a-FRR.
Finland	Balancing markets are reasonably accessible for independent actors and different technologies; in particular, the aggregation of distributed resources is accepted for all balancing products with participation of load management; however, there are requisites that are limiting the full participation. There are two different FCR products: FCR-D (frequency containment reserve for disturbances) and FCR-N (frequency containment reserve for normal operation). TSO procures all balancing services in openly accessible reserve markets; in particular, FCR-N, a-FRR and m-FRR are mainly procured from an hourly market, while FCR-D is procured on a yearly basis. There are both availability and activation prices for different balancing products. The price scheme adopted is the marginal pricing. In case of non-delivery for a-FRR and m-FRR products the penalty is settled through the imbalance settlement process based on the imbalance price, while in the case of FCR-D and FCR-N services, the BSP is sanctioned for the non-delivered capacity based on 100% of the price for which the reserve was sold.

[84] Within the FCR cooperation mechanism, the TSOs from Austria, Belgium, Netherlands, France, Germany, Slovenia, Switzerland and West Denmark currently procure their FCR in a common market. The product characteristics in the cooperation are defined as follows: symmetric product, duration of product delivery (usually 4 hours), maximum bid size in all the participating countries (25 MW), minimum bid size (1 MW). https://www.entsoe.eu/network_codes/eb/fcr/

	Domestic loads, storage and other flexible loads can participate to FCR, a-FRR and m-FRR; pooling is allowed. In particular, the participation includes hydro generation, CHP, industrial load management, household water boilers, data centres and batteries. The minimum bid size for FCR-D is 1 MW, while for FCR-N is 100 kW; for a-FRR the minimum bid size is 1 MW, while for m-FRR is 5 MW (variation of 10 MW in 15 minutes)[85]. Full activation time (after the frequency drop): 5-30 s (FCR-D) and 3 minutes (FCR-N), 2-5 minutes (a-FFR), 10-15 minutes (m-FRR); maximum activation time: 30 minutes (FCR), 3 hours (a-FRR), 3 hours (m-FRR). The measurement is performed on a local level or aggregated level. For aggregated assets a single meter reading is required for the measurement to be able to verify the correct delivery of the reserve (approved during the prequalification stage); this mechanism facilitates the access for small consumers. The prequalification process can be performed for an asset or pool. If the aggregator has a specific operations model, it can present it to the TSO Fingrid for approval. For pools where a new asset is incorporated, if it affects the capacity that the aggregator wants to provide, the prequalification process must be performed again; in that case, the physical test might be performed on the whole pool or on the specific asset.
France	Almost fully open Balancing Market for an effective participation of DER and DR in almost all balancing services products. Technical prerequisites are reasonable enough for independent parties to be able to bid into the market through pooling. In particular, the independent aggregator framework has been quite developed, allowing aggregators and end users (prosumers) to provide flexibility without having to sign a contract relation in parallel with the supplier/supplier-BRP. This regulatory evolution has been introduced in 2014 with the implementation of the Block Exchange Notification of the DR mechanism (called *Notification d'Échange de Blocs d'Effacement* - *NEBEF*),

[85] FinGrid, "Reserves and balancing power".
https://www.fingrid.fi/en/electricity-market/reserves_and_balancing/

	a framework for the valuation of demand flexibility on the wholesale energy market in order to support the balancing mechanism). FCR is procured on weekly auctions (in addition, FCR is tendered through the FCR cooperation on a weekly basis), while m-FFR (called Tertiary Fast Reserve[86]) is performed through a yearly tender. As for a-FRR, it is a mandatory service for large generators; a secondary a-FRR market can be organized by generators to cover the amount assigned to them by the TSO; in practice, a-FRR is not open to market players directly. The remuneration scheme is based on activation and availability payments. In particular, the price scheme adopted for the availability component is based on pay-as-bid (FCR[87]), regulated price (a-FRR) and pay-as-clear / marginal pricing (m-FRR), while the activation component is based on the spot price (FCR, a-FRR) and on pay-as-bid (m-FRR). The remuneration based on marginal pricing for m-FRR (in some cases, also for RR) represents the main revenue stream for DR and DER. In addition, the m-FRR/RR from demand flexibility can be procured by annual exclusive tenders (called *Appel d'Offres Effacement - AOE*) with a remuneration scheme based on capacity and availability payments; in particular, a capacity payment is provided to participants available for at least 20 days (plus an extra remuneration of 2.000 €/MW for participants available for 60 days). Penalty is applied for unavailability; in particular, for FCR and a-FRR the penalty is equal to the availability fee component plus the spot price component, while for m-FRR the penalty is based on the spot price level for declared unavailability. This definition of penalty exposes the BSP to significant risks in case of spikes in the market price (due to the limited possibilities to find a backup of the flexible resources); besides, as for the m-FRR penalty, the low price and the low probability of activation disincentivise the declaration of unavailability. Currently industrial/commercial and residential consumers as well as aggregators pooling flexible resources can participate in the FCR and m-FRR

[86] TSO RTE distinguishes the Primary Reserve (equivalent to FCR), Secondary Reserve (equivalent to a-FRR) and Tertiary Reserve (Fast Reserve, Complementary Reserve); the Tertiary Fast Reserve is equivalent to m-FRR.

[87] FCR will move in July 2019 to a pay-as-cleared.

	market. Instead, a-FRR is mainly open to large dispatchable generation units (in practice no demand flexibility and aggregation can participate). The minimum bid sizes are 1 MW (FCR/a-FRR) and 10 MW (m-FRR); pooling is allowed for FCR and m-FRR. Full activation time: 30 s (FCR[84]), a few minutes (a-FFR with pro-rata activation), 15-30 minutes after notification (m-FFR). Measurement of FCR/a-FRR is performed on a continuous basis (using a linear regression on the available 10 s telemetry measured points), while for m-FRR measurement requires a telemeasure with points every 10 minutes. The prequalification process for FCR and a-FRR is fair and well known, while for m-FRR it is a barrier for new technologies. In fact, the TSO RTE requires five activations to be performed with a four out of five-success rate and measurement requires a telemeasure with points every 10s. Besides, these tests are not paid at full costs (at most at the marginal balancing price, and in some cases not paid at all). In the prequalification stage, the accuracy of measure (0.5% both for head and sub-meter) still constitutes a barrier (sub-meters are often less accurate) and m-FRR prequalification requirements represent a barrier for new technologies and competition between BSPs. For a-FRR the transparency is lacking where participation is mandatory for large generators and prices are regulated, not reflecting correct investment signals.
Germany	In Germany all balancing services are open to all market parties and all technologies, as long as they fulfil the technical requirements. However, the statistics regarding prequalified capacity show a very small share of DR and storage (with most of the balancing capacity coming from hydropower and conventional generation). Balancing services are procured through auctions on a daily basis for FCR, a-FRR and m-FRR. FCR only has capacity payments available, while a-FRR and m-FRR have capacity and energy payments. The price scheme is based on pay-as-cleared for FCR (since 2019) and based on pay-as-bid for a-FRR and m-FRR. There are penalties for the different services.

	All balancing services are open to all technologies. In particular, there is no limitation on the connection point of the resource (assets connected to the low voltage grid can participate in equal conditions); however, assets in the distribution grid need to get approval by the DSO before participating in the balancing markets. Pooling is allowed. Full activation time (after the frequency drop): 15-30 s (FCR), 2-5 minutes (a-FFR), 10-15 minutes (m-FRR); maximum activation time: 4 hours (FCR[84]), 4 hours (a-FRR), 4 hours (m-FRR). The prequalification must be obtained in terms of single reserve unit and of reserve groups. Assets must undergo an additional post-qualification every five years. The marketable capacity can be determined at pool level by the provider.
Great Britain (UK)	One of the first European countries to allow *Demand-Side Flexibility (DSF)* to participate in their electricity markets. But there is no true Balancing Services Market. So, this opening process has not been completely developed for all balancing service products (some of balancing services do not have a proper market and in others DSF is not allowed to participate). Balancing services are procured by National TSO through competitive tenders and bilateral deals. In particular, the primary Frequency Response Service, called Firm Frequency Response product, is partly procured on monthly tenders and partly through technology-oriented contracts. The procurement of secondary Frequency Response Service, named Fast Reserve, is similar to FFR (on a monthly basis), while the Reserve Service, named Positive/Negative Reserve, is procured through extremely complex pay-as-bid tenders several times a year. Regarding the last additional Frequency Response Service introduced by NG ESO, the Enhanced Frequency Response (EFR), this product was contracted to fit the capabilities of storage (4-year contracts awarded in a tender and in bilateral deals). The remuneration scheme is based on availability (availability fee) and activation (utilisation fee). The payments are too complicated to assess; in general, the payment scheme is based on bilateral pay-as-bid tenders (but it varies significantly between products). In particular, the price signals of balancing services are difficult to understand due to a complex mechanism

	with many different tenders/auctions at the same time period. As for the penalty, the non-delivery below 95% of the contracted MW flexibility will forfeit the availability payment; in cases of repetition of non-delivery of the service, this can lead to termination and rescission of qualification. All parties can participate in the tenders after passing the prequalification process; however, the TSO (NG ESO) has introduced products whose requirements are tailored to different technologies. This characterization of balancing services has created a highly fragmented market with different flexible technologies encapsulated in very specific service products; thus, many balancing products are in principle technology neutral and. aggregation is partially allowed for Frequency Response Services. There is a high fragmentation in balancing products[88]. The frequency regulation includes two main services, Response Services (equivalent to FCR and a-FRR) and Reserve Services (equivalent to m-FRR and RR). Response Services can be split into Primary-Secondary Response (under-frequency control)/High Frequency Response (over-frequency control), while Reserve Services can be splt into Fast Reserve-Reserve (over-frequency control)/Negative Reserve (over-frequency control). The frequency response service can be distinguished in dynamic (continuous activation) and static (activated only when the frequency drops below a fixed threshold). As for the procurement, NG ESO distinguishes two typologies of service, mandatory and optional services, called System Ancillary Services (e. g. Mandatory Frequency Response) and Commercial Ancillary Services (e. g. Firm Frequency Response, Enhanced Frequency Response, Fast Reserve, Short Term Operating Reserve-STOR) respectively. The FCR refers to the (primary) Frequency Response Service; in particular, the balancing service related to the market product is the Firm Frequency Response (FFR), composed of dynamic FFR and static FFR (typically threshold fixed at 49,7 Hz). The a-FRR related to the secondary Frequency Response Service procured as a market product corresponds to a quota of Firm Frequency Response (FFR) and of the Fast Reserve products, while the m-FRR/RR

[88] Ricerca sul Sistema Energetico - RSE SpA, «Servizi ausiliari per la sicurezza del sistema elettrico. Stato dell'arte a livello internazionale,» Dicembre 2020, prot. 20009906, Piano Triennale di Realizzazione 2019-2021, website: https://www.rse-web.it/rapporti/.

	refers to the Reserve Services such as the Fast Reserve and STOR services. In addition to the standard primary Frequency Response Service, NG ESO has introduced the Enhanced Frequency Response (EFR) with a faster response over a shorter time. The minimum bid size to participate to: • FFR for primary/secondary frequency response is 1 MW (to be delivered in six daily 4-hour blocks), including the EFR tender participation; • a-FRR (Fast Reserve) is 50 MW (expected to be lowered to 25 MW); • m-FRR (STOR) is 3 MW. Full activation time (after the frequency drop): 10 s (FCR: FFR) and 1 s (FCR: EFR), 120 s (a-FFR: Fast Reserve), 20-240 minutes (m-FRR: STOR); maximum activation time: 20 s (FCR: dynamic FFR) and 30 minutes (FCR: static FFR) and 15 minutes (FCR: EFR), 15 minutes (a-FFR: Fast Reserve), 2 hours (m-FRR: STOR). In general, for FFR the pooling is allowed to reach the 1 MW minimum bid size (however, the aggregation of small and large units is only allowed under limited circumstances). Measurement is performed at pooled level (the aggregator can submit aggregated data once the individual asset has been tested). The prequalification process includes signing a framework agreement with NG ESO, the submission of a tender and a frequency injection testing prior to delivery. The requirements for the testing procedure are the use of the correct frequency injection profile (tolerance of +-0.01 Hz), sustained through 30 minutes and with a deviation that does not exceed the 2.5% of the contracted load. Even though many balancing products are in principle technology neutral, NG ESO has created a highly fragmented market with different technologies encapsulated in very specific products. Prequalification is considered to be too strict for the technical capabilities (there is no margin for noise or baseline errors and the established sampling rate every 100 ms is too costly and not justified for the provision of the services required). In principle STOR

	(equivalent to m-FRR) is one of the more technology inclusive products (allowing generation, load management, pumped storage and batteries to provide balancing services, as well as aggregation, only requiring one-way response); in practice, it is dominated by generation. Transparency is lacking in several aspects, especially with regards to the procurement through bilateral agreements (e. g. payment structures are not openly available for FFR and in general the procurement schemes are not easy to assess for independent aggregators).
All-island (Northern Ireland, Republic of Ireland)	A wholesale and balancing market, called *Integrated Single Electricity Market (SEM)*, for the Republic of Ireland and Northern Ireland exists. All balancing services are contracted through the TSO run programme, called *Delivering a Secure, Sustainable Electricity System (DS3)* (a reconfigured ancillary services arrangement). With the TSO run programme the scheduling of generation and consumption as well as the dispatching of services is performed by the TSO. *Demand-Side Flexibility (DSF)* through the flexible resources (aggregated and decentralised load units, generation units and battery units) is allowed to be offered to the grid. The remuneration scheme is based on activation (energy payments); in particular, all eligible providers are paid at a regulated price level, approved by the national Regulatory Authority, for the delivered volume of balancing services in each trading period. The payment rates (tariff rates) are fixed by the TSO for all balancing service products; the payment rate can be only altered under certain conditions. As for the penalty, contracts for balancing services include performance scalers that can be applied to payments in case of non-delivery balancing services; in fact, these performance scalers change the received payment in a proportional manner to the non-delivered energy (up to the point where the full payment can be cancelled). These performance scalers take into account different factors, including monthly and dynamic time factors.

The procurement process within the TSO run programme takes two forms: a regulated tariff process that is open to all technologies, but has a budgetary risk, and a tender process. Contracts have a duration of 5-6 years[89].

All parties can participate for a particular balancing service product on the TSO run programme after passing the prequalification process.

The FCR is provided across two system services, Fast Frequency Response (FFR) and Primary Operating Reserve (POR); the a-FRR is known as Secondary Operating Reserve (SOR); the m-FFR is provided across two Tertiary Operating Reserve (TOR1, TOR2).

The minimum bid size is 4 MW (FCR: FFR, POR, a-FFR: SOR, m-FFR: TOR1, TOR 2) which can be reached through aggregation (pooling).

Full activation time (after the frequency drop): 2-5 s (FCR: FFR, POR), 15-90 s (a-FFR: SOR), 5 minutes (TOR1) and 20 minutes (TOR2); maximum activation time: 10-15 s (FCR: FFR, POR), 75 s (a-FFR: SOR), 210 s (TOR1) and 900 s (TOR2).

Pooling of individual assets below 10 MW is allowed as *Aggregated Generating Unit (AGU)* or *Demand Side Unit (DSU)*; individual assets equal to or larger than 10 MW must participate as stand-alone units. The AGU is composed of on-site generation only, while DSU is composed of Individual Demand Sites (IDS) where the IDS uses a combination of on-site generation and consumption units to deliver the demand reduction.

Measurement is performed on each single asset providing the service (alternatively, measurement can be at the connection point in case of several assets in the same site; in case of aggregation the measurement will be done for the whole portfolio).

The prequalification process includes also a trial stage for new technologies contained in the DS3 System Services Proven Technology List; in particular, the trial stage tests new technologies' capacity to deliver any given product as well as the requirements for a proper measurement.

[89] https://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Services-Volume-Uncapped-Gate-3-Bidders-Conference-Call-Slide-Deck-23-June-2020.pdf

	There are special requirements for storage assets before the meter in order to provide five balancing service products (FFR, POR, SOR, TOR1, TOR2). There are no special requirements for storage assets if they are batteries behind the meter. There are still barriers that limit the participation of DER and DR providers with small assets (minimum bid size for FCR-a-FFR/m-FFR, no access to energy payments once activated by DSF). In particular, aggregation of residential DSF is not allowed to participate to the TSO run programme (DS3 programme); in fact, only industrial size units can be aggregated in DSU. Currently residential consumers can participate only in *Demand Side Management (DSM)* through tariff-based schemes where they are encouraged to move their usage to cheaper off-peak times (e.g. Economy 7 Tariff in Northern Ireland, NightSaver in Ireland)[90].
Switzerland	One of Europe's leading countries regarding their access to the Balancing Markets. All balancing service products are procured on open markets. Aggregation is allowed. Technical requirements are technology neutral. All balancing services (FCR, a-FFR, m-FFR) are procured on a weekly/daily tender basis. The remuneration scheme is based on availability (called capacity payment: FCR, a-FFR, m-FFR) and activation (called energy payment: a-FFR, m-FFR) payment respectively. The price scheme is pay-as-bid. There is a financial penalty for non-availability and non-delivery, respectively; in case of non-availability (availability below 99.9%), the penalty is the capacity price times a penalty factor; in case of non-delivery, the energy non-delivered counts as an imbalance evaluated at the imbalance price. All parties can participate in the tenders after passing the prequalification process. The minimum bid size is 1 MW (FCR)/5 MW (a-FFR, m-FFR) which can be reached through aggregation (pooling).

[90] EIRGRID GROUP, "Demand Side Management and Demand Side Unit". https://www.eirgridgroup.com/customer-and-industry/becoming-a-customer/demand-side-management/#:~:text=A%20Demand%20Side%20Unit%20consists,for%20at%20least%20two%20hours.

	Full activation time: 30 s (FCR), a few minutes (a-FFR with pro-rata activation), 15-20 minutes after notification (m-FFR); maximum activation time: 15 minutes (FCR), unlimited (a-FFR, m-FFR). Asymmetrical bids are allowed for a-FFR and m-FFR making these products more flexible for different types of technologies and consumer sizes. Measurement is performed on a central basis for the entire pool, but each unit is measured individually. Minimum size and minimum technical requirements are only required for the pool (not for individual assets: generators, load units, batteries, pumped storages). There are no restrictions as to what voltage level the resources are connected to. For load units the baselining methodology used considers the measured value of the load before the DR activation. There are still barriers that limit the participation of DER and DR providers with small assets (minimum bid size for a-FFR and m-FFR, metering business not liberalised yet for small installations, in particular for combined PV and battery installations, technical requirement such as the weekly product FCR and a-FRR that requires the availability 24/7 limiting for some aggregators to pool on residential and commercial size customers).

4.6.2 Innovative Ancillary Services provision

With reference to the current European context of regulation and electricity market implementation, the ancillary services presently required by the European Transmission System Operators (TSOs) to ensure an adequate control of system frequency and nodal voltage, as well as system restoration after a black-out event are constantly evolving. Particular attention has to be paid also to some services or control functions that have been recently implemented or still under definition or testing by European and extra-European TSOs whose controlled systems are most affected by the penetration of non-dispatchable renewable energy sources.
As a general consideration, it can be assessed that balancing services (i.e. services related to network frequency control) are mainly traded on markets with daily or weekly auctions, while voltage control and restoration services are procured from specific power plants according to periodic tender schemes; in relation to the participation, in ancillary service provision it is mainly voluntary and extended to all types of flexible resources.

In fact, in the absence of other resources, TSOs must rely on the remaining more flexible conventional plants, even at the cost of incurring higher regulatory costs and operating complexity. Alternatively, a countermeasure already adopted by numerous European transmission network operators consists in enlarging the range of suppliers of regulation resources, first of all involving the units hitherto excluded (e.g. distributed generation, non-dispatchable generation, flexible consumption units, storage systems). The next step, as already highlighted by the recent experience of some European and extra-European TSOs, consists in the introduction of new regulation services and special control functions to be requested from units with particular flexibility or new functions that allow a smarter interaction between the transmission system and the distribution system, also including a sharing of regulation resources. This may also involve redefining the minimum technical requirements to qualify new entrants.

With respect to reactive power reserve service, on the other hand, the European Network Code requires that each TSO have sufficient reactive power capacity from connected facilities to ensure voltage control. Therefore, the individual local transmission system operator can define its reactive power reserve appropriately. To give an idea, in the Italian electricity system, voltage control, as the frequency case, is hierarchical and organized into primary regulation (nodal regulation) and secondary regulation (regional regulation). This means that the grid operator may appropriately set up a reactive power reserve to carry out the two types of voltage regulation.

It should be noted that upon implementation of both the legislative and technical provisions dictated in the European Network Code, each transmission grid operator may redefine in greater detail the ancillary services on the basis of its own system requirements and the peculiarities of the underlying system, such as the level of interconnection with other adjacent systems, the characteristics of the technological mix of the generation and withdrawal plants, the meshing degree of the transmission network, the level of penetration of non-dispatchable renewable sources, the degree of variability of demand and the presence of special equipment such as direct current transmission systems or other flexible controlled devices, but always in accordance with the indications of the European grid code with a view to harmonizing ancillary services.

In particular, the grid operator may introduce more specific definitions and technical requirements for ancillary services.

In the following, a focus on innovative system services implemented worldwide that could be beneficial also for a power system like the Cyprus power system, currently isolated and, also in perspective, non-synchronous with the continental system, is reported.

4.6.2.1 Ancillary services in Great Britain

In the island system of Great Britain, non-synchronous with the continental system, the classification adopted by the National Grid ESO (NGESO) for system balancing services is as shown in Figure 41.

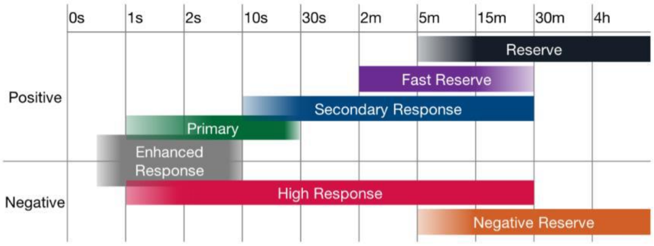

Figure 41 - Services required for frequency regulation and their timing in the island system of Great Britain (Source: NGESO[91]).

Following a power deficit event in the system, the hierarchical frequency control activates first the Primary Frequency Response and then the Secondary Frequency Response.

Subsequently, the reserve-replenishment service intervenes with the Fast Reserve and Reserve, two services equal to the tertiary reserve identified in the continental European synchronous system (i.e. the automatic-FRR and RR in the new European network code). In the case of a perturbation with power surplus, instead, the hierarchical control intervenes by activating the High Frequency Response and Negative Reserve regulations; the first replaces the regulation and reserve services of Primary, Secondary and Fast Reserve described, while the second is the equivalent of the Reserve. The Enhanced Response refers, instead, to the reaction of the system due to the effect of the mechanical inertia of the rotating machines; in conditions of reduced inertial contribution, the operator NGESO has also identified a specific ultra-rapid regulation service, Enhanced Frequency Response - EFR, which anticipates the standard primary regulation related to the ancillary services provided in the system of Great Britain.

This ultra-rapid frequency regulation service was introduced in 2015 and aims at using the high-performance resources such as storage systems particularly. The delivery of this service must occur within 1 s and be maintained for at least 15 minutes in the required direction of regulation (e.g. upward). The minimum supply size is set at 1 MW. The expected remuneration refers to the availability and use of the resource. NGESO is also evaluating a further future reclassification of the ultra-rapid service into Low Frequency Static - LFS, a distinct service from Dynamic Low High - DLH, which shall instead include the current Primary Response, Secondary Response and High Response.

[91] NGESO, «Future Requirements for Balancing Services,» Tech. Report, 2016, https://www.nationalgrideso.com/document/88586/download

These different types of reserve will then have to be aligned with FCR, FRR and RR services in the new European network code.

4.6.2.2 Fast Frequency Response Service

As a result of the massive development of non-dispatchable renewable generation, whose plants are connected to the transmission/distribution grids by means of power conversion systems, and the progressive dismantling of conventional generation, the electricity system will no longer be able to rely on the inertia and the regulatory contribution of traditional generators, with a consequent more severe impact on the frequency in the event of sudden imbalances; therefore, it is necessary to find new reserve capacity and, if compulsory, also set up innovative ancillary services. In particular, the containment of the transient frequency deviation requires power reserves to be activated extremely quickly. This can be achieved by installing machines such as synchronous compensators, or by defining new control functions to be implemented in systems interfaced to the grid via inverters[92] [93] [94].

The new control functions can emulate the inertial response of conventional systems, build a quasi-instantaneous primary control (proportional to frequency deviation), or implement other logics (such as power variations implemented quasi-stepwise) very fast, on the same time line where the inertia and transient phase of the primary control take effect (Synthetic Inertia capability provided by static generators or HVDC systems[95], Very Fast Active Power Control provided by flexible load units[96]). These control functions are often indicated by grid operators as Fast Frequency Response to distinguish them from the

[92] Electrical Energy Systems, «Effects of decreasing synchronous inertia on power system dynamics—Overview of recent experiences and marketisation of services,» [Online]. Available: https://onlinelibrary.wiley.com/doi/full/10.1002/2050-7038.12128

[93] Springer, «State-of-the-art review on frequency response of wind power plants in power systems» [Online]. Available: https://link.springer.com/article/10.1007/s40565-017-0315-y

[94] IRENA, «Innovative ancillary services: Innovation landscape brief,» Tech. Report, 2019, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Feb/IRENA_Innovative_ancillary_services_2019.pdf?la=en&hash=F3D83E86922DEED7AA3DE3091F3E49460C9EC1A0.

[95] European Union (EU), «Network code on requirements for grid connection of generators,» *Regulation (EU) 2016/631 of 14 April 2016*, Official Journal of the European Union, L 112/1 EN, 27.4.2016, https://www.entsoe.eu/network_codes/rfg

[96] European Union (EU), «Network Code on Demand Connection,» Regulation (EU) 2016/1388 of 17 August 2016, Official Journal of the European Union, L 223/10, 18.8.2016 (EN).

natural response of machine rotors (Synchronous Inertial Response) and traditional primary regulation (Primary Frequency Response)[97].

The "synthetic" response is obtained as an additional control function, implemented in the control system of the AC/DC converter (inverter) interfacing with the grid, at plants connected to the grid with this technology. In general, any plant equipped with an inverter interface is able to provide a Fast Frequency Response: for the downward response there are no special requirements; for the upward response an adjustment margin is needed, possibly in the form of energy storage with ready release. For NPRES, in fact, maintaining an upward margin with respect to maximum power means not exploiting, ordinarily, all the energy available from the primary source.

Using wind turbines, it is possible to exploit the kinetic energy of the rotating parts to deliver a short power pulse (a few seconds) following a sub-frequency perturbation.

Another potential provider of Fast Frequency Response is the electrochemical storage system[98] [99]. The instantaneous power is obtained by appropriately driving the inverter with a signal on the grid frequency error or frequency gradient. Neglecting latency phenomena, a storage system is able to respond in 5 ms[100]. It is noted that in this case, unlike the performance of a wind generator, the duration of power delivery can be set based on the level of battery charge at the time of the activation.

Photovoltaic power plants can be set up to provide Fast Frequency Response for upward adjustments as well, without having to maintain a margin with respect to maximum output, as long as they are coupled with storage systems to ensure the greatest power delivery in the event of under-frequency. Other potential providers of Fast Frequency Response are super-capacitors and flywheels. These devices can respond in 10 ms.

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[97] NERC, «Fast Frequency Response Concepts and Bulk Power System Reliability Needs,» Tech. Report, March 2020, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

[98] Electrical Energy Systems, «Effects of decreasing synchronous inertia on power system dynamics—Overview of recent experiences and marketisation of services,» [Online]. Available: https://onlinelibrary.wiley.com/doi/full/10.1002/2050-7038.12128

[99] IRENA, «Innovative ancillary services: Innovation landscape brief,» Tech. Report, 2019, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Feb/IRENA_Innovative_ancillary_services_2019.pdf?la=en&hash=F3D83E86922DEED7AA3DE3091F3E49460C9EC1A0

[100] H. Thiesen, C. Jauch e A. Gloe, «Design of a System Substituting Today’s Inherent Inertia in the European Continental Synchronous Area,» Energies, 2016, 9, 582; doi:10.3390/en9080582, www.mdpi.com/journal/energies

- Conventional power plants (gas units, steam units, hydro units) with electrochemical storage system;
- Wind power plants with storage systems or super-capacitors or flywheels;
- Combinations of generators, flexible loads, and storage systems [101].

The above technologies can also be found connected to the distribution grid. Therefore, if the provision of ancillary services is extended to plants connected to distribution networks, the assets connected there, even in aggregate form represents a potential supplier. Hence, the central role that distributed generation could play together with storage systems and load units (i.e. demand side response) in the provision ofFast Frequency Response services. In this case, it will be necessary to consider the local distribution system operator (DSO) as another new actor in the exchange of ancillary services with the transmission system operator, but also for the management of local problems (e.g. voltage, congestions).

4.6.2.2.1 Fast Reserve Service (TERNA, Italy)

In order to contain the high ROCOF (Rate Of Change Of Frequency) values in the power system, a Fast Reserve Service (FRS) has been introduced by the Italian TSO (TERNA) as a pilot project[102].

Purpose. The FRS is to contain the frequency deviations and high ROCOF values in the power system during critical time intervals identified by the TSO (TERNA).

Main technical requirements. The FRS must be activated within 300 ms from an initiating event (pertubation event), with full activation time of 1 s and with maximum duration time of 30 s (see Figure 42 and Figure 43). After such 30 s and if the frequency does not exceed a suitably large frequency threshold (large frequency threshold range value: deadband-1000 mHz, where deadband range: 0-500 mHz), the FRS can be stopped with a linear de-ramping regulating power exchange (lasting e.g. 300 s); if the frequency exceeds the mentioned threshold, instead, the FRS regulation must be kept, up to 15 minutes. The FRS requires a symmetrical active power exchange capability, by means of an automatic power-frequency response (via a droop controller) and/or a manual power output set-point tracking (via a command sent directly by the TSO; in this case, the initial activation time is 1.3 s and the full activation time is 2 s); the two responses can also be superposed to each other.

The FRS is required within critical time intervals identified by TERNA; the critical time intervals are divided into blocks of consecutive hours. At the beginning of each block, the ability to keep regulating by the FRS provider at the awarded power for 15 minutes upwards and 15 minutes downwards is required.

[101] NGESO, «Future Frequency Response - Industry update» Tech. report, February 2019, https://www.nationalgrideso.com/document/138861/download.

[102] ARERA, Deliberation n. 200/2020/R/EEL, https://www.arera.it/it/elenchi.htm?type=atti-21

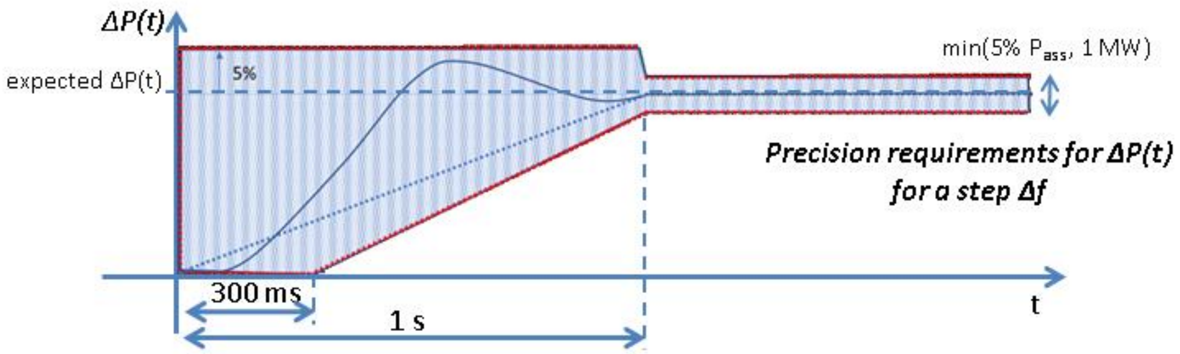

Figure 42 - Fast active power output, for the FRS, in response to a measured network frequency error step: precision requirements

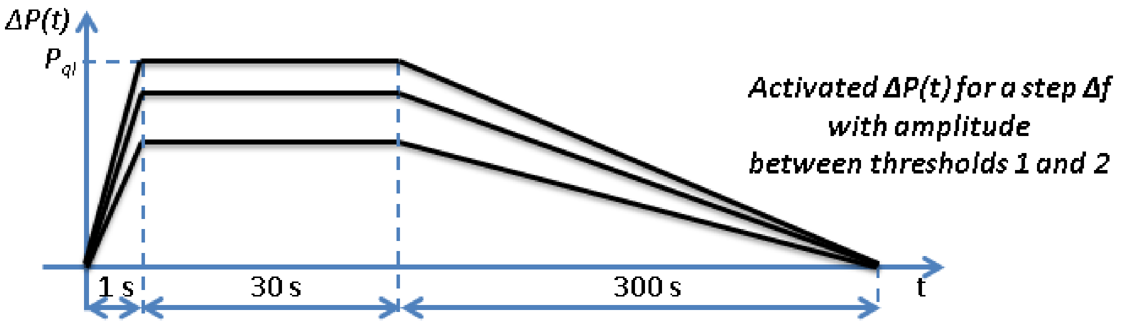

Figure 43 - Transient active power response, for the FRS, to a measured network frequency error step with the linear de-ramping period

Providers. The FRS is supplied by Fast Reserve Units (FRUs), which can include stand-alone assets like generation units, consumption units, BESS (Battery Energy Storage Systems) units, or aggregated assets of the previous technologies; such assets can also be Disributed Energy Resources - DERs.

Procurement mechanism. The FRS procurement is based on an annual tender scheme with pay-as-bid settlement rules. The tender is open to FRUs whose minimum and maximum qualified power is 5 MW and 25 MW respectively. The tender procurement takes place through a multiple session (up to five) based on a reverse auction scheme with a price cap (called reserve price). Each FRS potential provider can bid up to 40% of the FRS amount required by TSO.

Remuneration scheme. The FRS is remunerated based on the capacity, i.e. the power, made available (availability price) and on the energy actually exchanged for the service (activation price). The availability price refers to the tender results (expressed in €/MW/year) according to the pay-as-bid mechanism; the activation price refers to effective activation intervals and to the Day Ahead Market zonal energy price of the area where the FRU is located. Furthermore, in the case of total/partial failure in delivering the FRS or unavailability, the FRU owner (or BSP) must pay a penalty.

Initial FRS sizing. The Italian TSO (TERNA) initially identified an annual reserve requirement for 230 MW, divided into 200 MW in the Peninsula synchronous area + Sicily and 30 MW in Sardinia; the requirement for the continental area is divided into 100 MW in the Continental Centre-North area (composed of two market zones: Northern Italy and Central Northern Italy) and 100 MW in the Continental Centre-South area (composed of four market zones: Central Southern Italy, Southern Italy, Sicily and the most recently introduced zone called Calabria). The FRS has been sized in order to contain the frequency deviation during critical time intervals identified by TERNA, initially amounting to 1000 h/y for 2025-2030.

Initial price cap. The price cap for FRS during tender running is currently fixed at 80 k€/MW/y; this value is determined on the basis of the expected benefits from the FRS according to 2025 and 2030 energy scenarios. In particular, the FRS must ensure the secure operation of the Italian power system during critical time intervals with very high non dispatchable RES generation output and minimum conventional generation output. In fact, in the absence of the FRS, the activation of a minimum conventional capacity (mainly by open-cycle gas turbines and combined cycle gas turbines) would be needed to keep the system secure, which would imply the curtailment of about 150-210 GWh by non dispatchable RES and the procurement of additional ancillary services on the Ancillary Services Market, which in turn would cost 18-25 M€/y.

In the end, TERNA assigned a total of about 250 MW, of which:

- 118.2 MW in the Centre-North area at a weighted average price of 23418 €/MW/year
- 101.7 MW in the Centre-South area at a weighted average price of 27279 €/MW/year
- 30 MW in the Sardinia island at a weighted average price of 61016 €/MW/year

4.6.2.2.2 Enhanced Frequency Response (National Grid ESO, GB)

This is a new frequency adjustment service, called Enhanced Frequency Response-EFR, introduced for the GB system by NGESO in 2015.

Purpose. The EFR service is to improve management of system frequency pre-fault (to maintain the system frequency closer to 50 Hz under normal operation) and post-fault (as a dynamic service to frequency containment after large disturbances).

Main technical requirement. The EFR service must be fully activated by a regulation unit within 1 s, i.e. much faster than the traditional Primary Frequency Response (PFR) contribution (in the GB system, the traditional PFR has to be a ramp for the first 10 s and then it must be kept for 30 s [103]). The full activation time includes the time that the frequency monitoring device takes to detect a frequency deviation plus the time for instructing a response and the time for the assets to deliver the MW change in output (the time delay for detection and instructing response no greater than 500 ms). Besides, a regulation unit eligible for EFR provision must be able to deliver the maximum power contracted for up to 15 minutes, both in injection and in absorption. The upward and downward half-band for the EFR service must be symmetrical. If frequency ≤ 49.5 Hz or frequency ≥ 50.5 Hz for 15 consecutive minutes, the time period immediately following this period and lasting until the frequency has returned to the deadband plus 30 minutes is called an "extended frequency event".

Power-frequency characteristic and delivery envelopes. The asset must deliver continuous active power to the grid as a proportional response to a change in system frequency outside of the deadband. The EFR service, in terms of active power response (power request), has to be within an "envelope" region defined by the upper and lower power-frequency characteristic curves[104] [105]. The values of the coordinates of the main points defining the envelope region are tuned by the TSO in order to obtain a service with milder or stronger requests. So, the centre curve has been conceived to be the reference one for devices without finite energy capacity, i.e. the ones which do not need to manage a finite State of Charge. Table 20 reports the values of the coordinates of the main points defining the envelope region. Two sets of coordinate values are foreseen, referred to as "Service 1" (with milder EFR requests) and "Service 2" (with stronger EFR requests). The NGESO also specifies ramp rate limits in the different parts of the power-frequency plan.

[103] European Union (EU), «Network code on electricity emergency and restoration,» Commission Regulation (EU) 2017/2196 of 24 November 2017, Official Journal of the European Union, L 312/54 EN, 28.11.2017, https://www.entsoe.eu/network_codes/er/.

[104] European Union (EU), «Network code on requirements for grid connection of generators,» Regulation (EU) 2016/631 of 14 April 2016, Official Journal of the European Union, L 112/1 EN, 27.4.2016, https://www.entsoe.eu/network_codes/rfg/.

[105] European Union (EU), «Network Code on Demand Connection,» Commission Regulation (EU) 2016/1388 of 17 August 2016, Official Journal of the European Union, L223/10 EN, 18.8.2018, https://www.entsoe.eu/network_codes/dcc/.

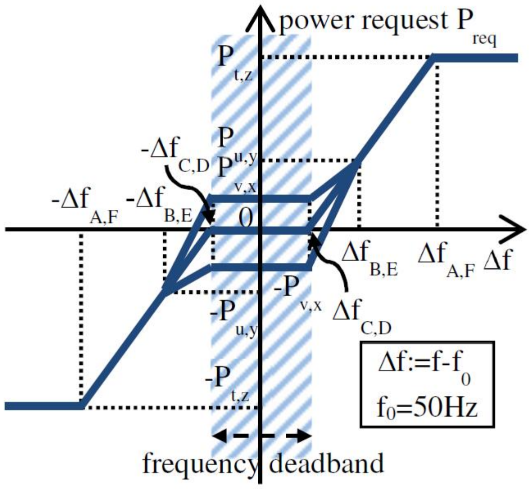

Figure 44 - The envelope region for the EFR service (load convention for the sign of power) and its parameters

Table 20 - EFR service and values of the parameters for the envelope region (load convention for the sign of power).

	Service 1	**Service 2**
	[mHz]	***[mHz]***
$\Delta f_{A,F}$	500	500
$\Delta f_{B,E}$	250	250
$\Delta f_{C,D}$	50	15
	[%Capacity]	***[%Capacity]***
$P_{t,z}$	100	100
$P_{u,y}$	44.44444	48.45361
$P_{v,x}$	9	9

Performance indicators. Resources for the EFR service are procured by the NGESO in the form of power capacity. To measure performance in service supply and to pay for the resource availability to do the service, the TSO computes suitable performance indicators, called Service Performance Measure (SPM) and Annual Service Performance Measure (ASPM). In such computations, reference is made to the contracted half-hourly settlement periods.

For the SPM computation, in each settlement period, a SPM index is computed, which is defined as the average of a Second By Second Performance Measure (SBSPM) index. The SBSPM is defined in each second as

$$SBSPM\% = \begin{cases} 100\ (if\ the\ actual\ response\ is\ within\ the\ envelope\ limits) \\ 100 - abs(R\% - C\%)\ (if\ the\ actual\ response\ is\ outside\ the\ envelope\ limits) \end{cases}$$

Where:

- R% is the actual response to EFR normalised with respect to the operational capacity, i.e. to the tendered power (in MWs);
- C% is the envelope limit closest to R%.

For example, if the actual response in response to frequency F is 70% of the tendered power and the envelope limits at frequency F are 68%-71%, therefore the SBSPM is set at 100%; otherwise, if the envelope limits were 72%-75% or 65%-68%, then the assets would have under-delivered or over-delivery and the SBSPM would be calculated using the closest relevant limit, i.e. SBSPM =100-abs(70% - 72%) = 98% or SBSPM =100-abs(70% - 68%) = 98%.

In case of "extended frequency event", EFR assets may continue to deliver EFR but the event itself is not taken into account in the calculation of the SPM.

The Annual Service Performance Measure (ASPM) is defined as the average of all SPMs over a rolling 12-month period; the calculation of the ASPM includes also settlement periods during planned maintenance.

Procurement mechanism. The EFR procurement is based on tender mechanism with pay-as-bid settlement rules as specified within "Tender rules". The contract awarded is for a duration of up to four years from the commercial operations date. Each pre-qualified party is capped at a total of 50 MW of accepted tenders and with minimum tender side of 1 MW. Tender responses are evaluated and compared against the forecast cost of alternative action for the time periods specified as being available for the provision of enhanced frequency response.

Remuneration mechanism. In consideration of the provider making the EFR available, the TSO pays to the provider in accordance with the "Payment Procedure" a payment calculated in accordance with the Average Deemed Available Capacity and Service Performance Measure. No further payment is made in respect of the delivery of Enhanced Frequency Response. In particular, in case of a reduction of the MW capacity for the service or in case of operation outside the envelope, the availability payment is reduced (respect to the maximum availability payment), for any affected settlement period, via an Availability Factor (AF): the actual payment is equal to the product of the AF and of the maximum availability payment. The AF is related to the SPM via a set of threshold values: e.g., if SPM $\geq$ 95%, then AF = 100%, so no penalty is applied (maximum availability payment), while if SPM < 50% then AF = 0%, so no payment is received by the service supplier. Settlement periods during planned maintenance have AF = 0%, so they yield no payment. In case of "extended frequency event", assets stopping the EFR service supply in this period are not penalized. As to measuring performance in service supply from the half-hourly SPM index one can compute the AF index, according to Table 21. Moreover, if ASPM < 95%, the TSO tries to identify with the provider the causes of the underperformance and possible mitigation measures; if ASPM < 50%, this process could result in contract termination.

Table 21 - SPM and AF, for both the considered power systems

SPM	AF
SPM < 50%	0%
50% ≤ SPM < 75%	50%
75% ≤ SPM < 95%	75%
SPM ≥ 95%	100%

Initial FRS sizing. The maximum MW capacity of tender responses that NGESO awarded contracts to was 200 MW. The 200 MW cap applies to both Service 1 and 2 together. All the 200 MW were awarded to battery energy storage systems at the prices reported in the following Table 22.

Table 22 – Awarded capacity and price in the EFR tender

Company	Capacity (MW)	Tender price £/MW per EFR hr
EDF ER	49	7
Vattenfall	22	7.45
Low Carbon	10	7.94
Low Carbon	40	9.38
E.ON UK	10	11.09
Element Power	25	11.49
RES	35	11.93
Belectric	10	11.97

4.6.2.3 Ramp Service

Given the high speed of variation that often characterizes the "net load", namely demand minus renewable generation, it is interesting to consider a possible innovative service dedicated expressly to address load ramps. Typically, this is not identified as a stand-alone service, but as a requirement that contributes to the quantification of other ancillary services, typically the m-FRR and RR type reserves. As a result of the massive increase of the non-dispatchable renewable generation, however, conventional power units are forced to chase the net load profile with frequent and large modulations of the generated power and, often, also with frequent start/stop cycles.

Currently, in order to face this situation, conventional power plants are used for this specific purpose. However, by increasing the share of non-dispatchable renewable generation, accompanied by the gradual decommissioning of conventional plants, the flexibility made available by the remaining conventional plants will sooner or later no longer be sufficient: the grid operator will therefore need a specific ancillary service to provide the ramp, which will necessarily have to involve non-conventional plants as well. The service may be defined in quantity (i.e. gradient in MW/min) and in duration (i.e. duration of the ramp service).

Ramp services can potentially involve all plants capable of modulating power exchange with the grid according to a predefined gradient for a certain duration, for example distributed generation, non-dispatchable renewable generation, consumption systems and storage systems.
It should be noted that, in general, if equipped with appropriate controllers, all types of generation plant (including storage systems) and flexible load unit can also provide other ancillary services such as aFRR and RR regulation services; the only caution to be taken into account is the possible presence of a reserve band, which for non-dispatchable renewable generators could lead to a condition of de-loading operation.

4.6.2.4 Experiences of specific transmission system operators

With reference to these specific innovative services, experimental applications as well as studies by transmission system operators for the implementation of new grid frequency control functions are shown as follows.

4.6.2.4.1 Hydro-Québec TransÉnergie (Canada)

A first application of a Fast Frequency Response by using wind generators was in 2006 by the Canadian grid operator Hydro-Québec TransÉnergie, which controls the Quebec region[106] [107]. In anticipation of a high penetration of wind generation in its system, where generation is predominantly hydroelectric, the grid operator arranged for the introduction of an inertia emulation feature for all wind plants greater of 10 MW. At the time of delivery, the power transient to be released in the instants of strong frequency deviation (i.e. mainly under-frequency) must be equivalent to that obtainable from a conventional plant with start-up time constant of at least 7 s. Moreover, the regulating power must be supplied for at least 10 s and the power variation must be at least 6% of the maximum deliverable power (nominal power); after the supply of the service, the plant starts the recovery phase with reduction of the supplied power (up to 20% of the maximum deliverable power) that can last from a minimum of 15 s to a maximum of 40 s; between the regulation and recovery phase the plant must wait for at least 3.5 s (transition time).
Similar solutions have also been introduced by other operators (i.e. Ontario, ERCOT, Ireland, Brazil, New Zealand and Australia). In the continental European synchronous system, the new network code provides for the provision by a regulating facility also of an ultra-rapid service that emulates an inertial response

[106] AEMO, «International review of frequency control adaptation» Tech. Report, 14.10.2016, https://preprod.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/FPSS---International-Review-of-Frequency-Control.pdf

[107] J. Brisebois e N. Aubut, «Wind farm inertia emulation to fulfill Hydro-Québec's specific need» IEEE Power and Energy Society General Meeting, Detroit, MI, USA, 2011, pp. 1-7, doi: 10.1109/PES.2011.6039121.

(Synthetic Inertia capability)[108]; however, the specific requirements are left to individual European TSOs. However, there is a great interest in the Nordic countries where wind penetration is high[109].

4.6.2.4.2 EIRGRID/SONI (Ireland)

As part of the Delivering a Secure, Sustainable Electricity System - DS3 program initiated in 2009[110], the two Irish grid operators (SONI for Northern Ireland, EIRGRID for the Republic of Ireland) conducted an analysis of the technical requirements of the island's electricity system to facilitate the penetration of non-dispatchable renewable generation (primarily wind power plants). The two Irish TSOs arrived at the identification of the following innovative services[111].

4.6.2.4.2.1 Synchronous Inertial Response

This is the active power contribution that the rotor of a rotating machine "in line" (generator, synchronous compensator, etc) is able to exchange directly with the system following a perturbation (instantaneous power imbalance). This contribution of transient power has a stabilizing effect on the system since the instantaneous exchange of power with the system contributes to the containment of the frequency gradient (df/dt) and therefore to the containment of the initial deviation of the grid frequency from the set-point value (50 Hz). Transient power exchange is considered particularly valuable during under-frequency deviations due to sudden power deficits in the system. Increasing the penetration of non-synchronous generation (i.e. power generators connected to the grid via an inverter interface), it is necessary to maintain stable the electricity system operation making an inertial reaction that has so far been provided free of charge, especially by conventional generators. The proposed remuneration of the new service refers to a volume of resource calculated as the product of the kinetic energy supplied by the machine at the nominal frequency and the time of delivery. In addition, the definition of the new service excludes the synthetic

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[108] European Union (EU), «Network code on requirements for grid connection of generators» Regulation (EU) 2016/631 of 14 April 2016, Official Journal of the European Union, L 112/1 EN, 27.4.2016, https://www.entsoe.eu/network_codes/rfg/

[109] EnergiForsk, «Synthetic inertia to improve frequency stability and how often it is needed» Report, 2015, https://energiforskmedia.blob.core.windows.net/media/21406/synthetic-inertia-to-improve-frequency-stability-and-how-often-it-is-needen-energiforskrapport-2015-224.pdf

[110] AEMO, «International review of frequency control adaptation» Tech. Report, 14.10.2016, https://preprod.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/FPSS---International-Review-of-Frequency-Control.pdf

[111] EIRGRID, «DS3 System Services: Portfolio Capability Analysis» Tech. Report, November 2014, https://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Services-Portfolio-Capability-Analysis.pdf

inertia response, namely the power response artificially obtained by a specific control logic of a machine that interfaces to the system via an inverter. Flywheel-type devices are considered attractive for their speed of response but are not included in the new service unless they are directly connected to the network.

4.6.2.4.2.2 Fast Frequency Response

This is the active power contribution that a generator/load can exchange almost instantaneously with the system. In this case, power delivery refers to an emulation action of the mechanical inertia of a rotating machine (synthetic inertia). The service is particularly valuable during a sub-frequency disturbance: the transient power injection must occur within 2 s of the instant of disturbance and must be sustained for at least 10 s. To enable the service, the energy handled during the transient phase must be greater than the recovery energy in the following 10 s required to restore the initial condition. The new service is to be placed just after the contribution of physical inertial reaction of rotating machines and just before the intervention of traditional primary control. In the proposal for remuneration of the service, an economic recognition is assumed commensurate with the actual speed of delivery of the transient power provided by the plant.

4.6.2.4.2.3 Ramping Margin

This is a margin of incremental injection into the grid that can be assured with a certain accuracy within a time horizon and be maintained for a certain interval of time.

The service is considered particularly valuable to cope with the uncertainty and variability of non-dispatchable generation (mainly wind power). In order to incentivize a sufficient portfolio of resources, the new service is divided into three sub-products: RM1 (time horizon of 1 hour and duration of 2 hours), RM3 (time horizon of 3 hours and duration of 5 hours) and RM8 (time horizon of 8 hours and duration of 8 hours). The remuneration can be applied to a single service or to the entire portfolio of the three services. Conventional generating units, wind units, storage systems, and flexible demand units may participate in the provision of the services.

4.6.2.4.3 MISO

In the area of the North American system managed by the Mid-continent Independent System Operator-MISO, the relevant period for dispatching the regulatory units is set at 5 minutes.

Within each relevant period, the regulating plants are activated on the basis of their capacity to cover the variation in the expected net demand (energy ramp constraint) evaluated in the previous interval but without taking into account a ramp capacity able of facing a possible evolution of the net demand in subsequent intervals (ramp capability constraint).

However, as the share of non-dispatchable renewable generation increases, MISO considers increasingly plausible the increase of situations characterized by unexpected rapid deviations of generation and, consequently, by rapid deviations from the expected value also of the net demand in subsequent time intervals.

In particular, if these unexpected deviations lasts more than 5 minutes, the operator could be in a situation of regulatory capacity deficit, especially if the unexpected deviation in generation were of significant magnitude (some regulatory plants could in fact not be sufficient or at least not sufficiently rapid to change). This situation could lead to an evident repercussion on the volatility of market prices.

As a countermeasure to this eventuality, in 2016 MISO decided to introduce a ramp capability product service to be procured on the Day-Ahead Market and Real-Time Market[112]. In practice, MISO identifies the ramp requirements to be met for each relevant period and then presents its ramp demand to the market. Conventional units (ramp up / down), consumption units (ramp up / down) and intermittent source units (ramp down only) can participate in the supply of the ramp service; on the other hand, batteries are not contemplated. The service has to be provided for at least 10 minutes after the period to be dispatched.

4.6.2.4.4 CAISO

In 2016, the CAISO network operator began offering a ramp service called “Flexible Ramping Product”[113]. Flexible Ramp Up and Flexible Ramp Down products are ancillary products/services created to have up and down capacity availability at five- and fifteen-minute intervals. Therefore, those services are procured in terms of capacity variation (MW) in a 5-minute interval; any resource capable of providing such a service can participate. This experience allows us to note that the availability of the plants to provide ramp increases with the possibility of exchanging these types of products in the ancillary services markets and, consequently, it allows reducing the occurrences of price spikes associated with ramp capacity shortages.

[112] MISO, «Ramp Capability Product Design for MISO Markets» Tech. Report, 2013, https://cdn.misoenergy.org/Ramp%20Capability%20for%20Load%20Following%20in%20MISO%20Markets%20White%20Paper271169.pdf

[113] AEMO, «International review of frequency control adaptation» Tech. Report, 14.10.2016, https://preprod.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/FPSS---International-Review-of-Frequency-Control.pdf

4.6.2.5 Voltage control services

In the near future grid operators will also need resources for voltage control, under both normal and perturbed conditions. In particular, for an adequate containment of voltage drops during faults, the system must also have a sufficient amount of short-circuit power.

The voltage at the delivery point must be kept within an allowable range of values around the nominal value (typically ± 10% of the nominal value). This voltage control takes place by resorting to the reactive power control provided by regulating units located in different points of the network (generators, compensators, capacitors, reactors, transformers, etc.).

In the near future there will be fewer conventional generation power plants, so there will be less availability of reactive power resource by these plants[114]. On the other hand, an increase of non-dispatchable renewable sources with connection to the grid via inverter (non-synchronous generators)[115] is expected. This occurs in sites very rich in resources but far from consumption centers, as is the case in the North Sea for generation wind power or how it could happen for sunny areas in Africa. In these possible scenarios it would be necessary to increase the reactive resources to be used both for long-distance transport and for the maintenance of the local voltage profile near the consumption centers.

The provision of the reactive services can be done by resorting to:

- static devices (capacitors, reactors);
- dynamic devices (eg synchronous compensators, variable impedance devices such as the Static Var Compensator-SVC, the Static Synchronous Condenser-STATCOM);
- HVDC devices equipped with a reactive power support;
- other solutions that foreseen a different use of existing power plants, such as rapid and short-term activations of some of the generation units for voltage support limited to specific relevant load intervals.

Furthermore, some studies show how it is possible to use installations via inverters for a decoupled exchange of active/reactive power between the distribution network and the transmission network[116]. Obviously, it is also necessary to pay attention to the connection point of the plants with respect to the

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[114] DENA, «Security and reliability of a power supply with a high percentage of renewable energy» Final Report, 2014, https://www.dena.de/fileadmin/dena/Dokumente/Themen_und_Projekte/Energiesysteme/dena-Studie_Systemdienstleistungen_2030/dena_Ancillary_Services_Study_2030.pdf

[115] ENTSO-E, «TYNDP 2018,» Tech. report, 2018, https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/tyndp-documents/TYNDP2018/consultation/Main%20Report/TYNDP2018_Executive%20Report.pdf

[116] DENA, «Security and reliability of a power supply with a high percentage of renewable energy» Final Report, 2014, https://www.dena.de/fileadmin/dena/Dokumente/Themen_und_Projekte/Energiesysteme/dena-Studie_Systemdienstleistungen_2030/dena_Ancillary_Services_Study_2030.pdf

network; in fact, only the plants closest to the HV/MV transformer may be able to provide a reactive contribution to the transmission grid. In particular, it is necessary to ensure that the new installations on the transmission system of non-dispatchable renewable source generation plants are able to regulate the voltage as is the case today with conventional plants.

With regard to the ability of photovoltaic systems and batteries to provide reactive power in the distribution system at a large scale, it has to be taken into account that the injection of reactive power has to occur without an impact on losses or on the phenomena of power loops. Therefore, it is necessary that reactive power is provided, where possible, near the consumption centers. This turns out to be one of the reasons why market mechanisms are conventionally well suited for the exchange of active power and less for the procurement of reactive power. The enabling of distributed resources would allow the use of reactive power near the consumption centers. The design of mechanisms that allow these resources to contribute to the management of reactive power is therefore of primary importance, also taking into account the fact that enabling the provision of the service could involve a review of the requirements for network connections, an aspect that could have an impact also on investment costs. It should be noted that distributed generation has already been treated on an equal footing with other market players and therefore enabled to participate, in terms of capacity, in the active power reserve markets both directly and through aggregators, even if small ones. The same thing could occur for the reactive service, also in the perspective of a local market for services for a better decentralized management of the system by the DSO.

With regard to the availability of short-circuit power, this resource must be adequate to ensure prompt intervention of the protection devices. Furthermore, the short-circuit power must be sufficient to guarantee the transient stability of the rotating machines and avoid an excessive voltage drop in the nodes adjacent to the fault point.

Considering that today the contribution to the fault current by inverter systems is not much greater than the operating current, in the future a progressive decrease of the short-circuit power in the system is expected unless these systems are also enabled to supply the short circuit power. With current technology, however, such a requirement would result in oversizing the converters. In any case, it is necessary firstly to investigate the impact of the short-circuit power reduction on the current intervention methods of the protection systems and on the management by the network manager, and secondly investigate which possible countermeasures could be adopted; these aspects have been studied in the European MIGRATE project[117].

[117] MIGRATE, «The Migrate Project» [Online]. Available: https://www.h2020-migrate.eu/

Therefore, if we want to summarize the possibility of new services for the provision of reactive power, we can have the following elements of innovation[118]:

- all plants equipped with an inverter interface, including photovoltaic systems and storage systems, can participate in the reactive service;
- distributed resources will also be able to participate in the reactive services.

Regarding the implementation of some innovative services, we can recall the example of EIRGRID / SONI and NGESO.

4.6.2.5.1 Fast Post-Fault Active Power Recovery

As part of the DS3 program[119] [120], the two Irish grid operators (SONI, EIRGRID) conducted an analysis of the technical requirements for the insular electricity system in order to facilitate the penetration of non-dispatchable renewable energy (mainly wind). This analysis led to the identification of the innovative service for maintaining the voltage profile under fault identified as Fast Post-Fault Active Power Recovery. In fact, during a grid failure event, the supply of active power by a generator could be interrupted due to the sudden drop in the voltage level at the point of connection to the grid. This power interruption could thus evolve into an imbalance of active power in the entire system with the consequent triggering of a severe frequency transient phenomenon. The new solution proposed by the Irish TSOs therefore has, as primary objective, the immediate restoration of the supply of active power just after the recovery of the nodal voltage (Fault-Ride-Through conditions). In particular, the new service required is a restoration of at least 90% of the pre-failure power value in less than 250 ms after the recovery of at least 90% of the pre-failure voltage level. In this way it is possible to sustain large frequency deviations in the system even up to 900 ms before the fault is eliminated. In addition, the system must be able to remain connected to the network in this mode for at least 15 minutes.

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[118] IRENA, «Innovative ancillary services: Innovation landscape brief» Tech. Report, 2019, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Feb/IRENA_Innovative_ancillary_services_2019.pdf?la=en&hash=F3D83E86922DEED7AA3DE3091F3E49460C9EC1A0

[119] AEMO, «International review of frequency control adaptation» Tech. Report, 14.10.2016, https://preprod.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/FPSS---International-Review-of-Frequency-Control.pdf

[120] EIRGRID, «DS3 System Services: Portfolio Capability Analysis» Tech. Report, November 2014, https://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Services-Portfolio-Capability-Analysis.pdf

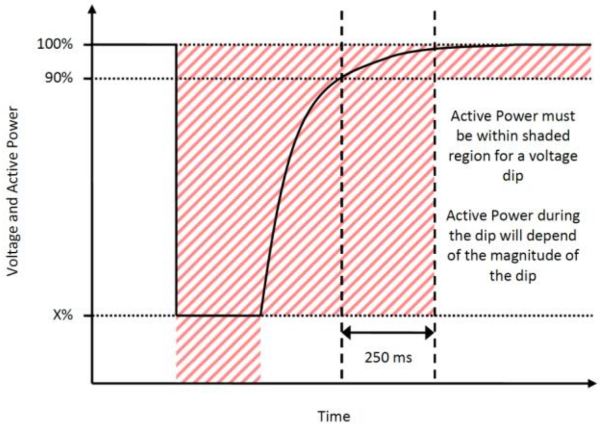

Figure 45 - Operating diagram of the new Fast Post-Fault Active Power Recovery service proposed by the Irish TSOs SONI / EIRGRID

4.6.2.5.2 Reactive resource supplied with regional tender

The NGESO operator is putting great efforts to make the procedures for the procurement of reactive power more transparent and simple (also in terms of price signals)[121], also extending its participation to non-conventional power plants (i.e. inverter systems) and resources located on the distribution network.

In this sense, tenders have recently been launched for a regional reactive power procurement and this scheme should evolve into a regional reactive market scheme[122]. In particular, the reactive resource procured in the Mersey area for the period 1 April 2022 - 31 March 2031 refers to a request by NGESO of at least 230 inductive Mvar; this resource can be provided by plants with a size of at least 5 Mvar and activation can be requested within a maximum time of 30 minutes. As a result of this auction, a 40 Mvar electrochemical storage plant has been selected.

[121] NGESO, «Product Roadmap for Reactive Power,» Tech. Report, May 2018, https://www.nationalgrid.com/sites/default/files/documents/National%20Grid%20SO%20Product%20Roadmap%20for%20Reactive%20Power.pdf

[122] NGESO, «Transmission constraint management,» [Online]. Available: https://www.nationalgrideso.com/transmission-constraint-management?market-information=&order=field_publication_date&search=&sort=asc

4.6.2.5.3 Potential Innovation Project

This is the test by NGESO of a market services portfolio for reactive support towards the transmission network through distributed energy resources and the direct involvement of the local distributor[123, 124, 125]. Both conventional power plants (synchronous generators) and non-conventional ones (non-synchronous generators, such as photovoltaic, wind and electrochemical storage systems) are called to participate in the test; in this case, also small power plants can also participate in aggregated form.

For power ratings of at least 1 MW a connection point with a voltage level of at least 33 kV is desirable. When applying for participation, it is possible to choose whether to participate in active power services or both. The enabled system must be able to modulate the reactive exchange with the network by means of a voltage droop type control of the voltage with intervention within 2 s from the new voltage set-point signal. In addition, the maximum range of reactive power modulation (in advance/delay) must be such that the ratio between the exchanged reactive power and the active one is equal to 32% (power factor 0.95). In particular, distributed generation plants are required to be able to carry out the complete inversion of the reactive within the admissible range in less than 2 s. It is noted that PV and wind power plants can contribute to the exchange of reactive even when the external source is zero (Q at night operating mode for PV and STATCOM mode for wind turbines). Similarly, electrochemical storage systems are able to contribute with STATCOM mode operation even under full charge and full discharge conditions.

4.6.2.5.4 Phoenix Innovation Project

This is the development of an innovative machine obtained by coupling a synchronous compensator (traditional machine) with a STATCOM type dynamic device[126]. The coupling allows the new machine to contribute to mechanical inertia, voltage control, short-circuit power and grid frequency control.

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[123] NGESO, «Product Roadmap for Reactive Power,» Tech. Report, May 2018, https://www.nationalgrid.com/sites/default/files/documents/National%20Grid%20SO%20Product%20Roadmap%20for%20Reactive%20Power.pdf

[124] NGESO, «Power Potential,» [Online]. Available: https://www.nationalgrideso.com/future-energy/projects/power-potential

[125] NGESO, «The Power Potential Project - A guide to participating,» [Online]. Available: https://www.nationalgrideso.com/document/115351/download

[126] ABB, «Phoenix project rises to inertia challenge» [Online]. Available: https://new.abb.com/news/detail/41482/phoenix-project-rises-to-inertia-challenge

4.6.2.5.5 Products Scalars

This is a particular form of revenue of a service in which, for example, any request for the supply of reactive power could be valued more than the exchange of active power. In this way, some plant owners may find it convenient to offer a reactive power resource [127].

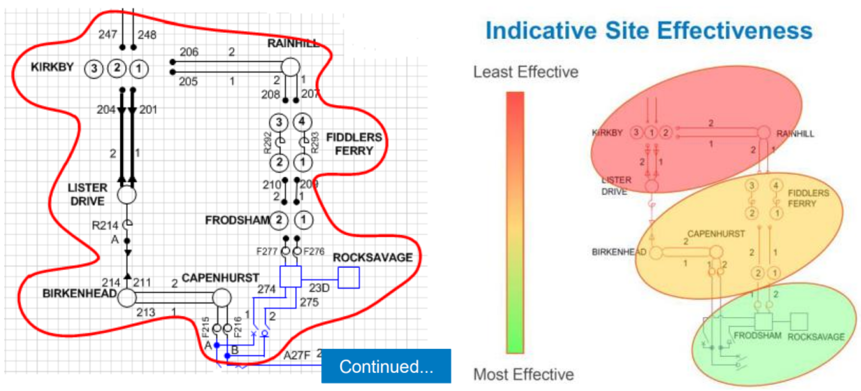

Figure 46 - Critical area of Mersey (Great Britain) where the reactive resources were procured according to an auction scheme[128]

4.6.2.6 Remuneration schemes

Belgium

Until 2020, the reactive service, procured with an annual auction, was considered as a non-mandatory service but remunerated in relation to the availability of the system and the activation of regulation with movement of reactive energy. The annual fixed price generally refers to a share of the specific investment cost incurred by the plant owner for the supply of the voltage regulation service. The price, on the other hand, refers to the operating costs of the system for the provision of the service. From 2021, the service is considered mandatory with remuneration for activation only but with different price levels depending on the band offered (possibly differentiated for controllable and non-controllable plants and with synchronous or non-synchronous compensator mode).

[127] NGESO, «Product Roadmap for Reactive Power» Tech. Report, May 2018, https://www.nationalgrid.com/sites/default/files/documents/National%20Grid%20SO%20Product%20Roadmap%20for%20Reactive%20Power.pdf

[128] NGESO, «Mersey Voltage 2022 –2031 Tender Interactive Guidance Document» [Online]. Available: https://www.nationalgrideso.com/document/157126/download

France

With reference to the period 2017-2020, the voltage regulation service is considered mandatory but remunerated at a regulated price established by the regulatory Authority (CRE)[129] [130]: the network operator makes an estimate of the overall cost of the services for voltage control and submits it for evaluation by CRE; In this case, CRE then establishes the maximum amount of expenditure to be paid annually to the network operator.

The remuneration scheme refers to a subdivision of the electrical system into two reactive sensitivity zones ("normal" zone, i.e. the zone in which the reactive resources have a normal stress, and in this case the minimum allocation set up by the TSO is sufficient; "reactive sensitivity" zone, i.e. the area where the TSO is forced to use additional resources) and foresees[131] [132]:

- a fixed component to cover the investment costs necessary for the availability of reactive power;
- a variable component, proportional to the duration of the service, to cover the operating costs of providing the voltage regulation service (additional maintenance costs and losses relating to regulation).

Therefore, the following elements contribute to the determination of the remuneration: the reactive power margin made available, the maximum active power of the plant, the type of regulation provided (primary, secondary). Wind and photovoltaic units also participate in voltage control.

The fixed annual remuneration component (*Part Fixe - PF*) is calculated with the following ratio:

$$PF = \frac{1}{0{,}32} K_{PF} \frac{Q_+}{P_{max}} (Q_+ - Q_-) \cdot d$$

where

- K_PF is a unit cost parameter set annually by the Authority (CRE); for 2017 this parameter was set at 521.3 €/Mvar/year;
- d is the value of the coefficient of availability to perform the service (default value equal to 1 for non-intermittent plants);
- P_MAX is the maximum active power of the system;

[129] ENTSO-E, «Survey on Ancillary services procurement, balancing 2018», Tech. Report, 2019, https://www.entsoe.eu/publications/market-reports/#survey-on-ancillary-services-procurement-and-electricity-balancing-market-design

[130] CRE, «Evolutions des Règles Services Système sur le réglage de la tension», Tech. Report, 2016, www.cre.fr

[131] RTE, «Règlès Sèrvicès Systèmè Tènsion,» Tech. Report, Avril 2017, www.cre.fr

[132] CRE, «Orientations sur le système de rémunéra-tion des Services Système Tension», Délibération de la Commission de régulation de l'énergie du 23 septembre 2016, https://www.cre.fr/Documents/Deliberations/Orientation/services-systeme-tension

- Q _ + - Q_- is the reactive power margin made available.

The formula considers a ratio between the maximum reactive power and the maximum active power equal to 0.32 as a minimum condition for the provision of the service.
Therefore, the remuneration is proportional to the reactive power margin made available. The remuneration received by the owner is on a monthly basis.
The variable annual remuneration (Part Variable - PV) is determined with the following ratio:

$$PV = K_{PV} \cdot (Q_{+} - Q_{-}) \cdot D_{h} \cdot d;$$

Where:

- K_PV is a unit cost parameter set annually by the Authority (CRE); for 2017 its value was set at 2.325 Euro cents/Mvar;
- The term D_h is the number of half hours of operation of the system in primary regulation.

Particular attention is paid to the service as a synchronous compensator and this type of service is treated as a specific service, also as remuneration.
The remuneration scheme is composed of:

- a variable component for the regulation service;
- a fixed component in the form of reimbursement for the use of the network (connection cost, cost of energy withdrawn);
- a fixed component of specific remuneration of the synchronous compensator function;
- a variable component of specific remuneration for hours of use as a synchronous compensator.

The plant technologies considered are

- Hydroelectric Units:
  - Francis Type;
  - Pelton type.
- Thermoelectric Units.

Hydro power plants must be able to operate as a motor with an air-vacuum impeller, while the thermoelectric units must be able to function as a motor with turbine/alternator decoupling.

United Kingdom (UK)

The Obligatory Reactive Power Service provides for an activation fee according to the Default Payment Rate formula (regulated price scheme):

$$DPR\left(\frac{£}{Mvarh}\right) = \frac{46270000 \cdot I_m \cdot \mathrm{X}}{42054693}$$

Where:

- Im = index factor of the month;
- X = utilization factor in the Settlement Period, corresponding to an interval of 30 minutes (1 if the system has responded adequately in the entire relevant period; otherwise 0.2). There are 48 Settlement Periods for each Settlement Day.

In addition, the Indexing Factor of the month is defined as follows:

$$I_m = C \cdot [\left(0{,}5 \cdot \frac{FRPI_m}{RPI_x}\right) + 0{,}5 \cdot PI_m]$$

Where:

- $C = RPIx / RPI_1$;
- RPIx = Retail Price Index recorded in March 2003;
- RPI_1 = Retail Price Index recorded in March 1994;
- $FRPI_m$ = Retail Price Index estimated for the month of interest;
- PI_m = wholesale energy price index.

The wholesale price index is defined by means of monthly average OTC price indices of the Heren power Index (HPI), Petroleum Argus power Index (PAPI) and Platts power Index (PPI) with weight 30% each and first reference value of the September 30, 2003.
The optional Enhanced Reactive Power Service is instead awarded on the basis of an auction scheme with pay-as-bis rule. The same scheme is applied in regional auctions for the supply of reactive in the long term in the most critical areas. The remuneration includes a component in capacity and/or one in activation.

Spain
The remuneration of the reactive service is foreseen only for offers in excess of the mandatory part.
Remuneration takes place at a regulated price defined annually for the following year according to the following scheme.

A) *Remuneration of the availability of additional bandwidth*

In each hour h of annual service of the control unit, the RDBA[133] remuneration share of the band made available in injection (G) and in absorption (A) of reactive power is evaluated according to the formula:

$$RDBA_G = \frac{1}{8760} \sum_{h=1}^{N_G} [CQ_G h \cdot p_G]$$

$$RDBA_A = \frac{1}{8760} \sum_{h=1}^{N_A} [CQ_A h \cdot p_A]$$

[133] Retribución por Disponibilidad de Banda Adicional (RDBA).

Where:

- NG, NA are the annual hours in which the regulating unit became available for an injection (G) and absorption (A) band;
- CQ_G, CQ_A additional reactive power band [Mvar];
- p_G, p_A are the unit prices of the reactive capacity [€ / Mvar].

B) Remuneration of the actual use of the additional bandwidth availability

In each hour h of annual service of the control unit, the RUB[134] remuneration share of the use of the band made available in injection (G) and in absorption (A) of reactive power is evaluated according to the formula:

$$RUB1_{Qgen} = K_{sinG} \sum_{h=1}^{N_G} [Q_{gen}(h) \cdot p_{Qgen}]$$

$$RUB1_{Qabs} = K_{sinA} \sum_{h=1}^{N_A} [Q_{Qabs}(h) \cdot p_{Qabs}]$$

Where:

- Q_{gen}, Q_{abs} are the hourly quantities of reactive injected or absorbed within the additional band offered;
- p_{Qgen}, p_{Qabs} are the hourly prices of generation and absorption of the reactive
- K_{sinG} ,K_{sinA} are the coefficients that take into account the operating mode of the control unit (from generator or from synchronous compensator).

C) Penalty for non-compliance

$$RUB2_{Qgen} = \sum_{h=1}^{N_G} [K_{uG}(Q_{cap\_ave\_gen}(h) - Q_{tot\_gen}(h)) \cdot p_{Qgen}];$$

$$RUB2_{Qabs} = \sum_{h=1}^{N_A} [K_{uA}(Q_{cap\_ave\_abs}(h) - Q_{tot\_abs}(h)) \cdot p_{Qabs}]$$

Where:

- $Q_{cap\_ave\_gen}$, $Q_{cap\_ave\_abs}$ they are the hourly quantities of reactive injected or absorbed referring to the effective hourly average capability;
- Q_{tot_gen}, Q_{tot_abs} are the total hourly quantities of reactive injected or absorbed as per telemetry;
- p_{Qgen}, p_{Qabs} are the hourly prices of generation and absorption of the reactive ;
- K_{uG} ,K_{uA} are the hourly service compliance coefficients.

The total remuneration is then calculated as follows:

[134] Retribución por Uso de Banda Adicional (RUB).

$$RTQ = RDBA_G + RDBA_A + RUB1_G + RUB1_A - (RUB2_G + RUB2_A).$$

5 CONCLUSIONS

Here we highlight the main issues relevant for the definition of a new policy framework to support and promote flexibility in the electricity system and market of Cyprus, as discussed in this report. Each of these issues will be dealt with in the following Output 2.2, with appropriate suggestions about which solution best fits the Cyprus electricity market, taking into account the legislative and regulatory frameworks already in force.

Topic	Points of attention
Active customers & renewable self-consumers	• ownership / management of generation plants by third parties • acknowledgement of avoided costs for the power system • implementation of the “virtual” self-consumption model through the public network • implicit vs. explicit incentive schemes to promote self-consumption
Energy communities	• ownership / management of generation plants by third parties • possibility of including also existing generation plants • differentiation between CECs and RECs • acknowledgement of avoided costs for the power system • ownership / management of the distribution network • implementation of the “virtual” production and consumption model through the public network • implicit vs. explicit incentive schemes to promote energy communities • activities that energy communities can carry out • sharing of energy within the community • extent / size of energy communities
Incentive for the use of flexibility in distribution networks	• TSO-DSO coordination schemes
Dynamic electricity price contracts	• implementation of dynamic energy prices and of dynamic network tariffs
Aggregation of distributed resources	• implementation of pilot projects • regulation of aggregation
Evolution of ancillary services	• opportunity of introducing new ancillary services, taking into account the penetration of non-dispatchable renewable energy sources and the future availability of the Euro-Asia interconnector • market / remuneration schemes for ancillary services