UNIVERSITÀ DEGLI STUDI DI CASSINO
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SCUOLA DI DOTTORATO IN INGEGNERIA
DIPARTIMENTO DI INGEGNERIA ELETTRICA E
DELL'INFORMAZIONE

Risorse distribuite e servizi ancillari per le reti di distribuzione dell'energia elettrica

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A mio padre, per avermi donato l'interesse per la realtà. A mia moglie, per averlo sostenuto. A mio figlio, per averlo reso lieto.

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Contents

Executive Summary

The replacement of fossil energy sources with renewable ones has become an even more pressing necessity, in a context in which the security of gas supplies, the foundation of the Italian economic system, is jeopardized. In this context, the electricity dispatching reform launched in Italy with the approval of the TIDE is inserted; an all-encompassing document, in force from 1 January 2025 with a gradual implementation timetable, it has the aim of modifying the structure of the electricity market by combining pre-existing regulatory elements and numerous innovations.

The ARERA, in presenting this integrated text, summarized its objectives with a single sentence: "to preserve the right to turn on the light at will, we must build a new world in which turning it off is an opportunity." This slogan contains, in its simplicity, the fundamental concept that modifies the structure of the electricity market, and in particular that of the ancillary services market.

With the new integrated electricity dispatching framework, a series of significant changes have been introduced aimed at enhancing market efficiency, flexibility, and participation. Among these, global ancillary services have been opened both to consumption units and to production units with a capacity of less than 10 MW, marking a substantial broadening of market access. Additionally, the framework allows for the establishment of UVAs, facilitating aggregated participation in the electricity system. DSO resources can now also be activated through local flexibility markets, promoting a more dynamic and decentralized grid management. The dual role of the production/consumption units, the main one of producing/consuming energy and the ancillary one of providing services, has made it necessary, in line with the European regulatory framework, to define two potentially (but not necessarily) distinct subjects who carry out the two activities independently. In particular, in accordance with [1] and [2], the following are introduced into the Italian regulation: BRP (responsible for production or consumption planning) and BSP (responsible for the "ancillary" part relating to the services). Users, owners of production or consumption unit, are guaranteed to choose their BSP regardless of the BRP and the coordination scheme introduced by TIDE provides that the action of the former does not hinder the operation of the latter. The TIDE systematizes a distinction already introduced in the pilot projects launched with [3] which, for the first time in Italy, had opened participation in dispatching services to the figure of the "aggregator". The regulatory framework for the global ancillary services market is more advanced than that for the local ancillary services market. Markets for local ancillary services have been already set up in certain European contexts (e.g., UK's Piclo, Enera, GOPACS); a few pilot projects have been initiated in Italy by three of the country's main DSOs (EDGE by e-distribuzione S.p.A., RomeFlex by Areti S.p.A., and MindFlex by Unareti S.p.A.). At their completion, the results of these pilot projects will be reported to ARERA, and the introduction of TIDE is expected to also encompass aspects related to local ancillary services markets. A primary area of research interest in these markets is the definition of resource aggregation perimeters and, consequently, the DSO's procurement model within these perimeters. In this thesis, the application of the LA concept is proposed to identify these perimeters and to study their effectiveness from both technical and market perspectives.

Load Area and Flexibility Aggregation Perimeter for Local Ancillary Services

The flexibility required by DSOs has a strong local character. For the exploitation of flexibility, it is therefore relevant to identify the grid buses where flexibility can be provided for a service requested by the DSO. To this end, the flexibility perimeter can be defined as the set of the grid buses such that a given ancillary service can be provided by any set of prosumers connected to them, while grid operation remains secure; the perimeter may vary according to the ancillary service to be provided.

The concept of flexibility perimeter is relevant for the activity of a flexibility market; in particular, for an aggregator of prosumers connected within the flexibility perimeter who can offer the market a local ancillary service the volume of which is realized with the provisions by such prosumers. In a radial system, it is straightforward to state that a congestion relieving flexibility service can only be provided by prosumers connected downstream of the overloaded component; in the procurement of the service, the identification of the flexibility perimeter for this service immediately follows.

For a flexibility service intended to solve voltage profile problems, deciding on suppliers and volume of flexibility is not so simple, as the actual impact of flexibility in changing the voltage profile depends on the location of the prosumers as well as the electrical characteristics of the grid, in a way that is not easy to assess even in a radial grid. The DSO could calculate the values of volumes and positions to be procured by minimizing the total volume of flexibility, based on the usual nodal representation of the distribution grid; the result would be the flexibility volume to be procured in every single node of the grid such that the voltage profile is good. This is a technically sound solution, but very ineffective from a market point of view, as it hardly allows for effective competition between flexibility providers. It is indeed a nodal market splitting; in terms of flexibility perimeters, each grid bus is a perimeter. A new, systematic approach is necessary to determine flexibility perimeters for the provision of distribution grid ancillary services; it has to respond to the needs, on the one hand, of the DSOs for a correct representation of the grid and its operation, and, on the other hand, of the market for flexibility aggregation perimeters as wide as possible. The application of the LA concept can meet these requirements since LAs consist of grid buses the power injection of which has a similar impact on the grid operation. The LA approach can be usefully adopted to identify the flexibility aggregation perimeter for any required service. A LA is a set of buses in a grid such that the power injection there has a similar impact on the operation of the grid, in particular on loading conditions and voltage profile: an OLA in a radial grid is made of the buses downstream of the overloaded relevant component; a VLA is made of the buses where (a change of) power injection has a similar impact on the grid voltage profile. In the following, we recall the key points of the approach for the identification of LAs in balanced grids:

A. Overload Load Areas

In the usual case of a radially operated distribution grid, the impact of the power injection into any node on an overload is derived with simple graph navigation techniques. In all the buses downstream of the relevant component, the power injection has the same impact on that congestion: these buses form the corresponding OLA. An OLA can include other OLA(s); this is the case of two (or more) relevant components the loading of which is of concern that are downstream from each other.

B. Voltage Load Areas

A VLA is made of the buses where a change of power injection has a similar impact on the grid voltage profile. The impact can be evaluated with a sensitivity analysis on the dominating spectral components of the nodal admittance matrix [4–7]; VLAs can be recognized by clustering grid buses based on this sensitivity. By the very meaning of VLA, each VLA can be an aggregation perimeter for voltage support services: in fact, an aggregator of prosumers connected within a VLA could offer the market a voltage support service with a volume realized with the provisions of these prosumers.

Flexibility procurement and provider aggregation perimeter

This work considers a simplified grid model and two different models for flexibility procurement.

Grid Model

There are various models of an electrical grid, either general, based on the nodal admittance matrix, or specific for radial systems, based on feeders and laterals. The buses within a LA and the lines connecting them form a subgrid; it can be useful to reduce the modeling of the LA subgrids, as proposed in [8–10] for the single-phase representation of a balanced network and in [11, 12] for the three-phase representation of an unbalanced network, with a modeling error due to the reduction which is widely acceptable [13]. The proposed reduced modeling allows retaining only the edge buses and other relevant buses; the whole grid can be represented with a reduced equivalent modeling by composing the reduced modelings of the LA subgrids.

Market Model 1: Active Power Minimization

The DSO could evaluate the minimum amount of flexibility, $\overline{\Phi}_\Gamma$, for a given partition Γ adopting the reduced modeling of the grid and solving the minimization problem proposed in the Chapter 3. With (3.11), the overall minimum volume of flexibility is computed, the correct operation of the (reduced grid) is enforced, the flexibility by each LA can be provided by the prosumers within that LA and the correctness of the reduced modeling of the grid through LAs is maintained. **Market**

Model 2: Cost Minimization

The procurement of flexibility availability can be also obtained by solving the optimization problem in the Chapter 4, which, for a given partition Γ, the expected value of the service cost is minimized while the grid constraints are satisfied, the partition itself is qualified, and the flexibility volume and provision durations (activation and recovery) by the providers are taken into account.

With (4.2), we consider a pay-as-bid auction where the DSO is the buyer of flexibility services [14] with long-term agreed capacity availability during the required time windows, and utilization either scheduled or activated upon the DSO's request in operation (with appropriate lead time, for example, the day before). The time horizon can span months/seasons/years ahead, and each auction refers to a specific flexibility service requested by the DSO to counteract a specific poor grid operating condition; for example, a voltage support service to resolve an undervoltage condition expected for weekdays in the next winter season [15, 16]. The expected value of the service is the sum of the cost of the availability and the expected cost of the activation. Here, we simply express the latter through a given estimate of the probability of future activation; for scheduled utilization, the probability is equal to one. Furthermore, in a long-term horizon the possibility that flexibility providers do not adequately respect the scheduled demand diagram or do not adequately respond to activation requests must be considered; here, we account for this possibility by simply introducing an overprocurement factor [16], by which the DSO procures more availability than is strictly necessary.

Market competitiveness and technical efficiency

These optimal procurement models are applied to several case studies with different grid partitions, the results show the influence of grid partition on market outcomes:

A-priori Competitiveness index

To evaluate the competitiveness in the different partitions an index, based on the structural characteristics of the grid, is introduced.

Adopting the HHI approach [17, 18], each partition of the grid in LAs is characterized by the market concentration index H_Γ:

$$H_\Gamma = \frac{\sum_{\gamma\in\Gamma} H_\gamma \overline{\Phi}_\gamma}{\sum_{\gamma\in\Gamma} \overline{\Phi}_\gamma} = \frac{\sum_{\gamma\in\Gamma} H_\gamma \overline{\Phi}_\gamma}{\overline{\Phi}_\Gamma}, \tag{1}$$

in which H_γ measures the share of the providers' flexibility capabilities in each LA,

$$H_\gamma = \sum_{h\in\gamma} \left(\frac{\Phi_h^{max}}{\sum\limits_{j\in\gamma} \Phi_j^{max}} \right)^2, \tag{2}$$

and $\overline{\Phi}_\Gamma$ is the minimum volume of total flexibility that would allow solving the voltage problem, with the corresponding $\overline{\Phi}_\gamma$ in each LA.

It is only a proxy of the measure of the effective market concentration and competition between service providers. The results demonstrate its ability to provide a quantitative measure of market and technical aspects of flexibility aggregation.

Expected minimum cost

Using the second procurement model, a total of 15 market operators acting as flexibility aggregators were considered, with offered prices (a_{b_γ} and u_{b_γ}) obtained from information available in [19], maximum activation duration ($n_{b_\gamma}^{on}$) less than the service duration requested by the DSO (n_T), minimum recovery duration ($n_{b_\gamma}^{off}$) such that the flexibility can be activated only once a day. Hundreds of runs,associating operators to different positions in the grid, were carried out in order to adopt a statistical approach and evaluate the minimum cost in the different case studies. The median value of the expected minimum cost, $\overline{C}_\Gamma$, is evaluated in the various scenarios.

Case studies evidence different results for undervoltage problem due to different causes and with different spread: undervoltage conditions caused by local increases in loads and poor voltage conditions across a large portion of the grid.

The simulations also highlight how, in the case of voltage support services, the possibility for flexibility providers to participate in the provision of voltage support services even if not located in or close to the area with the voltage issue.

Introduction

The electricity system is going through a phase of profound changes; the widespread development of renewable sources, especially nonprogrammable ones, the ever-increasing diffusion of distributed generation and the expected increase in final demand lead to a complete revision of the system management paradigm, with inevitable repercussions on electricity markets and ancillary services.

In Italy, the TSO, Terna S.p.A., procures resources to resolve congestions, balance the system, keep appropriate reserve margins, and generally ensure system security in the MSD. It has historically been characterized by the predominant presence of units defined as "relevant", i.e. programmable UPs with an efficient net power of at least 10 MW. These units, identified as strategic, in a historical phase in which the production mix was mainly made up of thermoelectric and hydroelectric plants, determined for years the perimeter of the resources to which the TSO referred for the provision of services.

Geopolitical events and environmental needs are pushing towards a progressive replacement of fossil fuels with renewable ones, which are essentially nonprogrammable. In this context, the current European regulation (Directive 2019/944, Regulation 2015/1222 and Regulation 2019/943) has raised the issue of maintaining the stability of the electricity system while promoting greater market efficiency and, therefore, the reduction of dispatching costs for end customers.

In Italy, also in relation to the European objectives for 2030 and in line with the integration between the wholesale electricity markets of the Member States, consultations have been underway for some time now to identify the main interventions to make dispatching suitable for efficiently guaranteeing the security of an electrical system in continuous evolution. The reform of electricity dispatching in Italy began in 2019 with ARERA Consultation Document no. 322/2019; it continued to evolve during the 2020s until the publication of the TIDE (ARERA Resolution no. 345/2023), which defines the guidelines for updating market procedures starting from 1 January 2025.

A strong innovation concerns the role of the DSO. Already in the consultation document no. 322/2019, in addition to the role of neutral facilitator for Terna's procurement of global ancillary services, the DSO shall also assume the role of a buyer of resources for local ancillary services. The possibility of opening the dispatching services market, in particular for local ancillary services, to consumption units, storage, and production plants connected to the distribution network, to meet the needs of the DSO opens up new scenarios for the management of distribution networks: it introduces competition between these resources, opens up a different way of designing distribution networks, promises to be a decisive element for a non-negligible reduction in the expected costs for the end customer.

This Ph.D. thesis addresses the markets for ancillary services and the potential and critical aspects of participating in such markets; in particular, the research focused on flexibility perimeters for the provision of local ancillary services. Inspired by the concept of "Load Area", already known in literature as a set of buses whose power injection has a similar impact on the operation of the network, models for the optimal procurement of local ancillary services with market mechanisms have been studied, also evaluating the influence of different flexibility perimeters on the market outcomes.

Chapter 1

Evolution of Electricity Markets and Role of Distributed Resource

1.1 Italian wholesale electricity market

In Europe, the European Commission initiated the liberalization of the electricity market in 1996 to unbundle the generation, transportation, and sale of energy under *Directive 96/92/CE* [20–22]. Market monopolies are prevented in favor of a more efficient competitive market, which in particular allows the participation of small, decentralized generation units. Both ACER [23] and ENTSO-E [24] play a central role in creating common regulations throughout Europe.

The Italian electricity market was established with *Legislative Decree 79/1999* (the “Decreto Bersani”) [25], which initiated the liberalization of the Italian electricity sector as part of implementing the first European directive [20]. The operation and economic management of the electricity market, guided by the principles of neutrality, transparency, objectivity, and competition between producers, as well as the economic management of adequate power reserve availability,

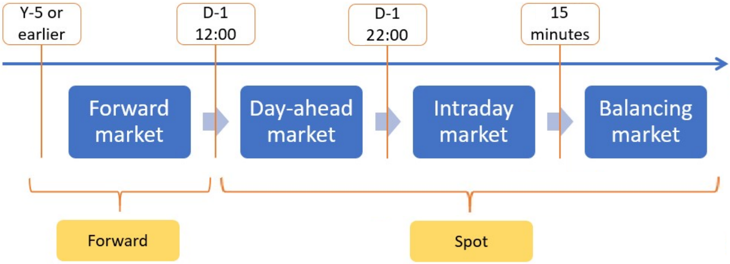

Figure 1.1: Italian electricity market time frame.

are entrusted to GME. Market operations began on 31 March 2004. Market operations are detailed in the TIDME [26], developed by GME and approved by the MASE. The Italian electricity market is divided into two main segments: the *forward* market MTE and the *spot* market MPE (Fig. 1.1).

Forward Market – MTE

In the MTE, negotiations are made on forward electricity supply contracts with supply and withdrawal obligations. Baseload and peakload contracts can be negotiated in MTE with delivery periods equal to a month, a quarter, and a year. In the forward market time frame, trading occurs from several years in the future to two days before delivery.

The MTE allows participants to stabilize and hedge their future cash flows, thereby protecting their businesses against the risks of future price changes [27].

Spot Market – MPE

The MPE is divided into:

- *Day Ahead Market MGP* - Producers and end customers buy and sell wholesale volumes of electricity for the following day; they submit offers, indicating for each hour the quantity and the maximum/minimum price at which they are willing to buy/sell. All accepted bids are valued at the *system marginal price.*

- *Intraday Market MI* - Operators can modify MGP programs through additional purchase or sale offers through three auction sessions (MI-A or MI-CRIDA) and one continuous trading session (MI-XBID).
- *Market for Dispatching Service MSD* - Terna procures essential services for the management of the entire electrical system. It is divided into a planning phase (MSD ex-ante) and an implementation phase (MB).

Day-Ahead Market – MGP

The MGP hosts the majority of electricity transactions. On the MGP, hourly energy blocks for the next day are bought and sold. Operators participate by submitting bids indicating the quantity and the maximum/minimum price at which they are willing to buy/sell. Bids are accepted after the market session closes, based on economic merit and within transit limits between zones. The MGP is therefore an auction market and not a continuous trading market. All accepted sales are valued at the marginal equilibrium price of the zone to which they belong. This price is determined, for each hour, by the intersection of the demand and supply curves (Fig. 1.2) and differs from zone to zone in the presence of saturated transit limits.

Purchase and sale offers are accepted or rejected based on the results of the maximization of the social welfare of the system (as expressed by buy and sell bids), while considering transmission constraints through a zonal representation of the relevant grid. The electricity system is divided into *bidding zones*, with physical energy transit limits between them reflecting the actual circumstances. The interconnections between the geographical and virtual zones are shown in Figure 1.3. In this zonal structure, in force since January 2021, the system is divided into 7 geographical zones and 9 foreign virtual zones.

Accepted sale bids related to production units belonging to Italian geographical zones are valued at their zonal price, while purchase bids

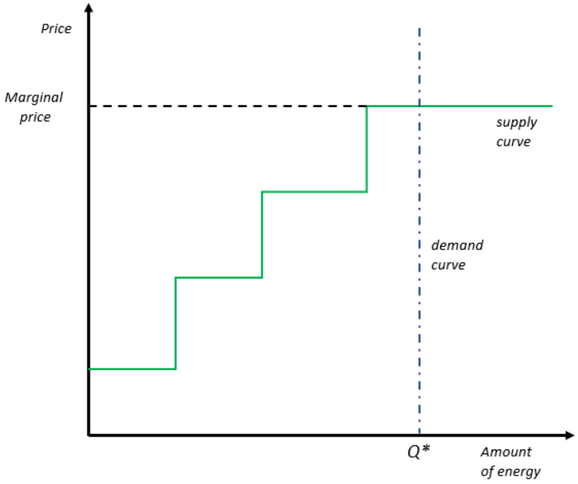

Figure 1.2: Example of intersection between demand and supply curves

related to consumption units are all valued at the same PUN. [1]

Intraday Market – MI

The MI begins after the closure of the day-ahead market MGP, and represents the second phase of the spot market. The MI is primarily used by operators who participated in MGP to modify their injection or withdrawal schedules through additional purchase or sale offers that can be submitted up to one hour before the physical delivery of energy. Like MGP, the MI is a zonal market, as it considers transmission constraints between market zones. All operators can participate in MI, except those who, having taken part in the MSD ex-ante (see afterwards), may face limitations due to the *feasibility intervals* imposed by Terna.

The MI is an hourly market; energy is bought and sold for each

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[1] During the revision of this doctoral thesis, the PUN was overcome with the introduction of a similar index (PUN Index GME) and an equalization mechanism provided for by the ARERA *Resolution 304/2024* [30], which is the weighted average of the single zonal prices based on the quantities purchased in those zones.

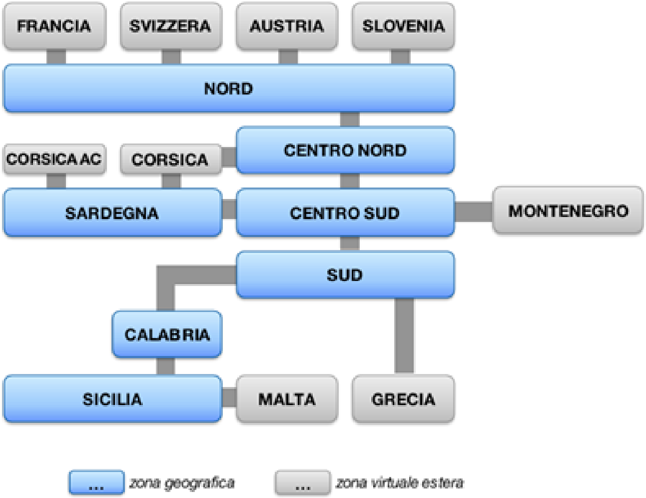

Figure 1.3: Division into bidding zones of the Italian Transmission Grid [28, 29].

hour of the considered day. The MI session opens at 12:55 on the day before the delivery day and closes one hour before the delivery hour. [2]. In the previous auction-based configuration, market solutions were determined by matching demand and supply curves, just as in MGP. Since September 2021, Italy has been part of the European market coupling SIDC , which allows continuous trading among all European market operators across bidding zones up to one hour before the actual delivery, provided transmission capacity is available. As a result, MI has adopted a hybrid model combining continuous trading with three auctions (similar to the previous model - Fig. 1.4).

MI transactions occur through three CRIDA auction sessions (MI-A), and one continuous trading session XBID (MI-XBID).

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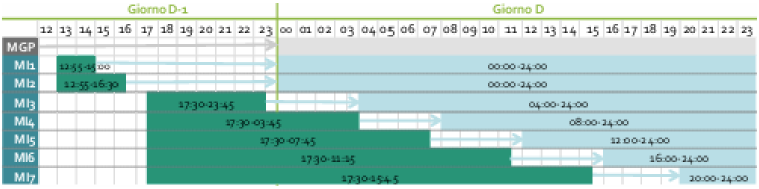
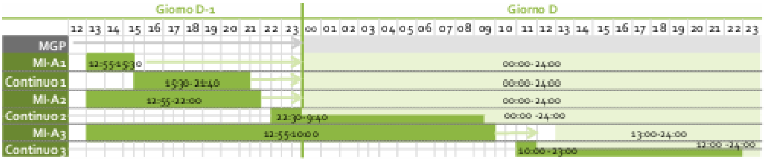
[2] During the revision of this doctoral thesis, the market time unit of energy markets in Italy changed from 1 hour to 15 minutes. Consequently, from 2025, MI will be quarter-hourly. Historically, the Italian market consisted of seven auctions that allowed energy trading up to 4 hours before delivery [31].



(a) before



(b) after

Figure 1.4: MI structure before and after the starting of the SIDC operation [31].

In the MI-A auction sessions, simultaneous with the negotiation of purchase and sale offers, intraday interconnection capacity is allocated between all Italian market zones and other geographically connected areas involved in Market Coupling. Purchase and sale offers are selected based on the same criteria as MGP. Unlike MGP, accepted purchase offers are valued at the zonal price.

The MI-XBID continuous session consists of three phases where, along with the negotiation of purchase and sale offers, intraday interconnection capacity is allocated between all Italian market zones and the other active XBID geographical areas. Purchase and sale offers can be submitted per unit or per portfolio. For each continuous trading phase of MI-XBID, GME organizes a negotiation book structured by geographical and/or virtual zones. The MI-A auction sessions and MI-XBID trading phases take place sequentially and don't overlap [26].

Market for Dispatching Service – MSD

In the MSD , Terna procures essential services for the management of the entire electrical system, ensuring security, adequacy, quality, and efficiency of the operation.

The electricity system requires an instantaneous balance between supply and demand, with respect to operating limits. These limits refer to the main electrical quantities that characterize the entire system, in particular voltages, currents, and frequency. TSOs counterbalance plant outages, load fluctuations, and forecast errors by procuring and activating a reserve, also referred to as balancing power. The reserve compensates for short-term contingencies and is essential for the stability of the power grid [32].

In the MSD ex-ante , Terna acquires the resources necessary for the management and control of the system (*energy reserve*), resolves any intrazonal congestion, and, in the MB , activates them in real time to guarantee the balance between injections and withdrawals (*balancing*). In this market, Terna acts as the central counterpart; accepted offers are paid at the submitted price, according to the 'pay-as-bid' principle. Electricity dispatching in Italy has been historically regulated by [33] and by the technical discipline reported in the Terna Grid Code [34] [3].

Figure 1.5 shows the types of services procured by the TSO, which differ in the maximum reaction time to the grid; also the minimum service duration to be guaranteed is different. Not all generation unit types are equally capable of providing control reserve services; for example, thermal power plants often struggle with short activation times, whereas long provision periods make stationary BESS uneconomic [37].

Service qualification

In the current regulation, participation in the MSD is allowed only to relevant production units, i.e. programmable plants (generally thermoelectric, reservoir or storage hydroelectric) with a net efficient power

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[3] The TIDE [35] entered into force on 1 January 2025. While this doctoral thesis was under revision, part of the provisions of [36] were superseded by the new integrated text.

Reserve	**Activation time (within)**
FCR	30 seconds
aFRR	5 minutes
mFRR	15 minutes
RR	45 minutes

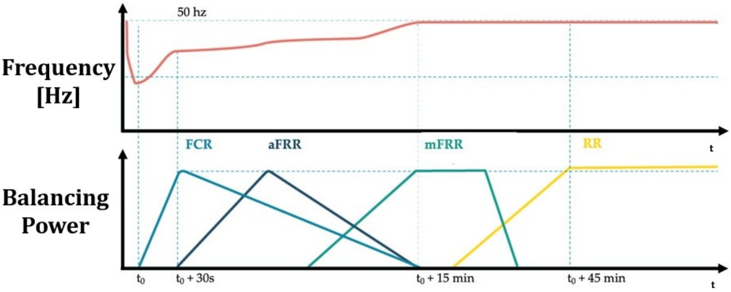


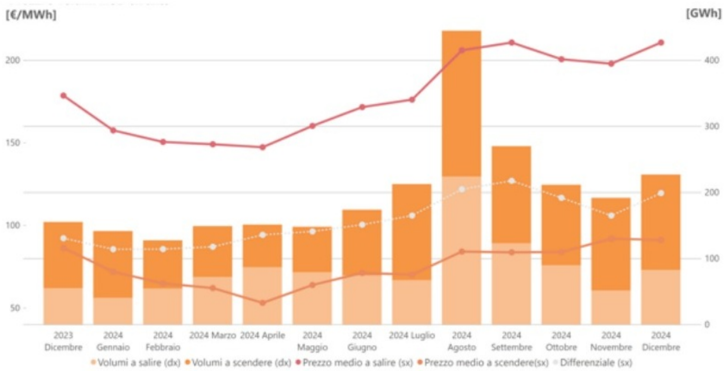
Figure 1.5: Reserve types and activation times.

of no less than 10 MW; the activation of the resources is carried out exclusively for the needs of the TSO.

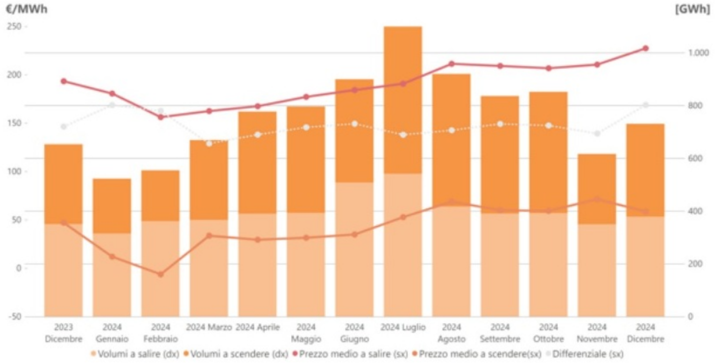
Service remuneration

Based on the actual Italian regulation, the ancillary services supplied in the MSD are aFRR, mFRR, RR and congestion resolution. Unlike the MGP and MI, based on the marginal price approach, in the MSD the services are remunerated on *pay-as-bid* basis. Figure 1.6 shows the average prices recorded in Italy in 2024 for MSD ex-ante and MB .

The cost incurred by Terna to ensure a secure operation of the electricity system is charged in full to end customers through a specific cost item in the electricity bill (cost of dispatching services). Among the cost items that make up this service, there is the *uplift fee*, calculated by Terna quarterly and specifically designated to cover the costs incurred for the procurement of the exchange of resources on the MSD .



(a) MSD ex-ante



(b) MB

Figure 1.6: Average prices and volumes for MSD – year 2024 [31].

Balancing European Platoforms

In addition to the national MSD framework, European initiatives have progressively fostered the creation of common balancing platforms to enhance cross-border efficiency and security of supply. Among these, three main projects are currently in place:

- MARI (Manually Activated Reserves Initiative) for the exchange of manual frequency restoration reserves (mFRR);
- PICASSO (Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation) for the coordination of automatic frequency restoration reserves (aFRR);
- TERRE (Trans European Replacement Reserves Exchange) for the procurement of replacement reserves (RR).

These platforms aim to harmonize balancing mechanisms across TSOs, allowing resources from different countries to be activated in a coordinated manner. For Terna, participation in MARI, PICASSO, and TERRE represents a fundamental step towards the integration of the Italian electricity system into the European balancing market, improving liquidity, optimizing reserve activation, and contributing to the overall stability and cost-effectiveness of the interconnected grid.

Services not provided through markets mecahisms

Not all ancillary services are supplied and remunerated in the MSD . There are in fact additional services that the TSO procures through unpaid supply obligations or fees in an administered form.

Frequency Containment Reserve – FCR All production units consisting of at least one synchronous generator or an electrochemical storage system are technically suitable to provide resources for the FCR. Units that are mandatorily enabled for the ancillary services market (relevant units, see above) must ensure, at all times, the availability of a half-band of their power range to be reserved exclusively for FCR (primary reserve – Table 1.1).

Table 1.1: Half-band reserve obligations for FCR [38].

Area	**Half-band reserve obligation** (percentage of net efficient power)
Sardegna	10%
Sicilia (if synchronized with the mainland)	1.5%
Sicilia (if not synchronized with the mainland)	10%
Other zones	1.5%

The FCR (either upward or downward) contributes to the automatic correction in normal operating conditions of instantaneous imbalances between withdrawals and injections of the entire interconnected European electricity system. The activation occurs automatically through a regulation device capable of modulating the active power exchanged with the grid in response to a frequency variation detected locally.[4]

For the FCR there is no remuneration. However, a voluntary procedure can be activated solely for the assessment of the energy exchanged with the grid during the provision of the service [39].

Voltage support services The voltage support service consists of controlling the injection of reactive power by generation units to regulate the grid voltage. Specifically, through an automatic system the plant modulates automatically the reactive power output based on the voltage deviation at the terminals of the generation unit versus a reference value. The plants required to provide this service are high-voltage connected plants that meet specific requirements set by Terna [40]; this service does not involve any remuneration,[5] nor the procurement through market procedures.

Emergency reserve The TSOs also maintain an *emergency reserve*, which involves mainly power plants included in the procedures of the *defense plan* of the electrical system [32], described in Table 1.2.

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[4] Annex A.15 of the Italian Grid Code stipulates that a broader set of resources must contribute to the service in emergency conditions, i.e., when the frequency imbalance exceeds 200 mHz.

[5] With the entry into force of TIDE [35] from 1 January 2025, while this PhD thesis was under revision, a regulated remuneration mechanism was introduced, detailed in paragraph 1.2 of this work.

Table 1.2: Main procedures of the electricity system defense plan

Procedure	**Description**
Telescatto, Riduzione produzione, Stimolazione produzione	The control is activated in those network areas where an immediate reduction of the production is necessary to deal with fast electromechanical dynamics events (time constants range from hundreds of milliseconds to tens of seconds). It includes actions like direct disconnection of generators, slow reduction of production, or upward modulation of power.
Banco Manovra Interrompibili – BMI	Remote-controlled interruption system for user loads as per contracts under Annex A.62 to the Grid Code. Load shedding is managed automatically or manually by the control room operator.
Banco Manovra Emergenza – BME	Allows localized load shedding in small areas and generalized disconnection over larger areas, creating load islands for stability and frequency recovery.
Riduzione della Generazione Distribuita – RIGEDI	Ensures system security by disconnecting or reducing distributed generation units, such as wind or photovoltaic plants with power ¿ 100 kW connected at the MT level.
Riduzione della Generazione da fonte eolica e fotovoltaica afferente alla RTN	Requires producers to reduce the delivered power slowly upon request, using remote signaling or automatic local devices for faster disconnection in emergencies.

1.2 Dispatching reform in Italy

The increasing exploitation of non-programmable energy sources leads to a reduction of the contribution of programmable plants to the energy market; this causes criticalities in the procurement of dispatching services. In addition, the growing penetration of DG has increased the level of uncertainty in the operational planning phase, making additional resources necessary for ancillary services.

To counteract the lack of resources able to provide services in MSD, for some years the possible expansion of the number of authorized units has been hypothesized and tested (pilot projects by ARERA *Resolution n. 300/2017/R/eel* [3], discussed in the next paragraph), taking into account both the growth of distributed generation from renewable sources, and the technological development for the control of widespread resources. The TIDE [35], an all-encompassing document in force from 1 January 2025 with a gradual implementation timetable, has the aim of modifying the structure of the electricity dispatching by combining pre-existing regulatory elements with numerous innovations.

The ARERA, in presenting the TIDE, summarized its objectives with the sentence "to preserve the right to turn on the light at will, we must build a new world in which turning it off is an opportunity." This slogan contains, in its simplicity, the fundamental concept that modifies the structure of the electricity market, and in particular that of the ancillary services market.

With the new integrated electricity dispatching framework, the following changes have been introduced:

- Opening of global ancillary services to consumption units.
- Opening of global ancillary services to production units of less than 10 MW.
- Possibility of establishing UVA.
- Activation of DSO resources through local flexibility markets.
- Market procurement of the primary frequency reserve service.
- Remuneration for the provision of voltage regulation services.

- Review of services currently not supplied in the MSD , including the introduction of “Modulazione Straordinaria” services.

Introduction of BRP and BSP

The dual role of the production/consumption units, the main one of producing/consuming energy and the ancillary one of providing services, has made it necessary to define two potentially (but not necessarily) distinct subjetcts who carry out the two activities independently.

In particular, in accordance with [1] and [2], the role of the former *dispatching user* that stipulated the dispatching contract for injection and/or withdrawal with end customers and producers, is lost in Italy, to the benefit of:

- BRP: the entity responsible for marketing the quantity of energy traded on the MGP and MI, including the responsibility of taking a position consistent with base agreed program, with economic penalties for imbalances (the energy bought or sold by the BRP must actually be delivered).
- BSP: the entity that is entrusted with the provision of ancillary services, with economic penalties in case of failure.

Users, owners of production or consumption units, are guaranteed to choose their BSP regardless of the BRP, and the coordination scheme introduced by TIDE provides that the action of the former does not hinder the operation of the latter. The TIDE systematizes a distinction already introduced in the pilot projects launched with [3] which, for the first time in Italy, had opened participation in dispatching services to the figure of the *Aggregator*.

The expected structural change involves that the imbalance fee, previously paid by the dispatching user, is now divided into two components: the actual imbalance and the failure to provide the service, the first being the responsibility of the BRP, the second of the BSP. Consistently, the the BRP is remunerated exclusively for the energy bought or sold on the markets, while BSP is remunerated only for the provision of the service. Since the BRP manages the relationships with producers and end customers, who, conversely, ”see” the actual injec-

Table 1.3: Roles of BRP and BSP

BRP	**BSP**
Buys and sells on wholesale markets the energy related to the estimate of injections and withdrawals of the units under its responsibility.	Offers on the ancillary services market the flexibility of the units and receives a single remuneration: "delivered energy" + "ancillary service".
Is assigned an imbalance net of actual balancing actions carried out following the ancillary services market.	Transfers to the BRP (indirectly through TERNA) the value of the dispatched energy via specific compensation fees.
Receives from the BSP (indirectly through TERNA) the value of the dispatched energy resulting from balancing actions.	Keeps the value of the service and, based on bilateral agreements, shares it with users who provided flexibility.
Regulates with the producer or final customer the economic value of actual injections and withdrawals.	

tions and withdrawals, it must be adequately compensated for the economic value of the energy underlying the service provided by the BSP. In the following paragraph, where the BRP- BSP model is explained with the description of the UVAM pilot project.

Table 1.3 summarizes the roles of BRP and BSP.

Participation to global ancillary services

One of the main innovations introduced by TIDE is the expansion of participation in the provision of global ancillary services to resources that were previously not enabled, in particular of distributed ones.

Starting in 2017 [3], with the aim of experimenting with an expansion of the eligible pool of resources for such services, pilot projects were launched. They allowed enabling of distributed resources on an aggregate basis through the establishment of UVAM. With TIDE, ARERA sought to complete the innovation process by proposing a merit-order dispatch model in which all network resources can assume a dual role:

- The 'primary' role of producing or consuming energy;
- The 'ancillary' role of providing services by modifying or shifting production and consumption in time relative to a reference point.[6]

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[6] The reference is represented, for dispatchable sources, by the 'program' and, for non-dispatchable sources, by the so-called 'baseline', which essentially reflects

The resulting framework envisions the formation of an ancillary services market with the participation of numerous distributed resources, thereby incentivizing the most efficient flexibility resources—those capable of adjusting production or load at the lowest cost.

To support this market-based approach, TIDE :

- Promotes a level-playing-field competition between UPs and UCs in the ancillary services market, based on the principle of *technological neutrality*, meaning no priority is given to one flexibility source over another (e.g., whether it is a UP or a UC, or whether it is renewable). The only differentiating factor should be the price requested for service provision.
- Eliminates the minimum power requirements for participation in the ancillary services market. Historically, ancillary services were only provided by plants with a capacity of at least 10 MVA, a threshold defined by TERNA at the dawn of the market.[7]
- Allows each resource to participate 'as it can'[8].
- Grants the possibility of providing services on an aggregate level through the establishment of UVA.

UVA – The introduction of UVAs is undoubtedly one of the key innovations of TIDE . Although the regulation allows for the enabling of distributed units, establishing a UVA represents an advantage for distributed resources. In particular:

- The operators of small units may lack the necessary expertise to participate in organized markets, nor would it be efficient for thousands, or potentially millions, of users to do so. With UVAs, the BSP acts as an aggregator for these resources, optimally orga-

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the operation in the period immediately preceding the service provision.

[7] With the pilot projects, the minimum threshold for aggregates was reduced to 1 MW; with TIDE, even a few hundred W can contribute to grid regulation, as long as they meet the qualification requirements for service provision.

[8] Historically, ancillary services were provided only by plants that offered a symmetric bandwidth upward and downward. This constraint had already been gradually relaxed in the Grid Code, allowing each resource to provide only upward or only downward flexibility; with TIDE, this limitation is definitively removed.

nizing the service provision by distributing the modulation across individual units. The aggregated solution is the most suitable for such units: in this way, the Grid Operator 'sees' a single enabled entity and a single responsible party, the BSP.

- Even small units, in order to participate in the market individually, would need to interface their plant with TERNA's and DSO[9] control systems to receive remote commands for modifying their output.

As shown in Fig. 1.7, a UVA may consist of UPs and UCs of different types and associated with different BRPs. They enter into a contract with an aggregator, the BSP, who operates them exclusively for service-related transactions. Starting from a reference *baseline*, the BSP schedules and dispatches quantities in the MSD .

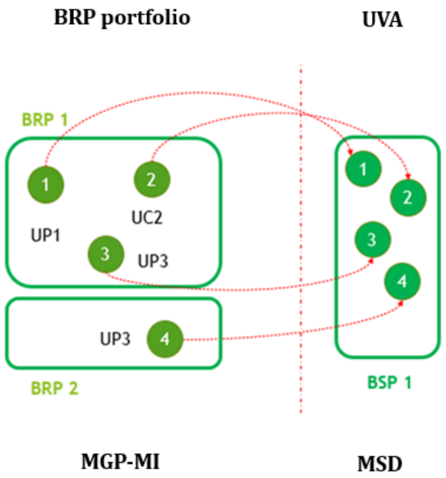

Figure 1.7: Example of the structure of a UVA and the BRP/BSP relationship.

The TIDE allows for the establishment of two types of UVAs, which

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[9] in the case of participation in local ancillary services

reflect the nature of the ancillary services provided:

- Nodal, for services related to the relevant grid nodes (e.g., congestion management) – referred to as UVAN.
- Zonal, for services provided over a broader perimeter such as bidding zones (e.g., frequency balancing services)– referred to as UVAZ.

UVAN – The UVANs represent the aggregates for nodal-scope dispatching, although they can also provide services with broader perimeters. They are the evolution of the UVAM-type B introduced through the pilot projects as per [3]. Unlike the UVAM, the UVAN do not have the constraint of UP relevance (in general, in the TIDE the concept of relevance has been surpassed). The UVANs maintain the constraint that all resources must be located on the same node (or on a set of adjacent nodes) of the relevant grid. Some possible examples of UVAN are:

- An aggregate of UPs and UCs directly connected to the same node of the relevant grid; typically, at least one UP is powered by a programmable source to enhance the controllability of the aggregate, which is crucial for providing global ancillary services.
- An aggregate of UPs and UCs connected to a DSO grid and associated with the same relevant grid node or a set of adjacent nodes within the same nodal service perimeter.

UVAZ – The UVAZs represent the aggregates for global ancillary services with a zonal scope. They are the evolution of UVAM-type A introduced through the pilot projects as per [3]. A UVAZ may include only UPs, only UCs, or a combination of both. The only requirement is the ability to provide aggregated global ancillary services within a zonal delivery perimeter. It should be noted that a UVAZ cannot be enabled to provide global ancillary services with a nodal delivery perimeter; for such services, the aggregate of UPs and UCs must qualify as a UVAN.

Markets for DSO needs

An additional important innovation introduced by TIDE is the provision that distributed resources can participate not only in the provision of global ancillary services but also in the delivery of local ancillary services, whose markets can be operated directly by DSO.

Indeed, *EU Directive 944/2019* [2] assigns DSOs the role of procuring resources for local ancillary services as a possible alternative to network reinforcements. DSOs are required to consider the use of flexibility in the preparation of development plans to avoid unjustified expansion of the network infrastructure and to create conditions for a fully functional flexibility market. The *Legislative Decree 210/2021* [41] implementing the above Directive reaffirms the obligation for DSOs to identify and publish their flexibility needs.[10]

ARERA has initiated the implementation process of *EU Directive 944/2019* [2], launching pilot projects for the procurement of flexibility by DSOs with *Resolution 352/2021* [42]. The pilot projects aim to experiment with the most appropriate solutions for procuring and remunerating local ancillary services, designed by DSOs. At the end of the experimental phase, ARERA will define the regulatory framework, updating sections 7 and 16 of TIDE [11].

New remunerated services

TIDE also innovates the regulatory framework regarding the classification of services and their remuneration.

Procurement of FCR and Fast Reserve – One main discontinuity with the previous approach is the provision[12] that Terna procures power bands for the FCR and *ultra-fast frequency reserve* (also called *fast*

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[10] Article 23: 'The Distribution System Operator shall ... present a network development plan for its area of responsibility (. . .). As part of the development plan ..., flexibility needs shall also be identified, referring to services that can be provided by demand-side management, storage facilities, and generation units connected to the distribution network, as well as the expected evolution of network congestion ....'

[11] During the review of this doctoral thesis, ARERA published ARERA Report 343/2025/I/EEL, with further details of the trial results.

[12] effective August 1, 2028

reserve) through market-based marginal price auctions, where BSPs submit bids in €/MW[13]. In these competitive procedures, BSPs can submit bids referring to qualified UAS, UVAN, and UVAZ that have been qualified. [14]

TIDE establishes the general criteria for organizing competitive procedures, entrusting Terna with defining the detailed rules, the timing for bid submission, and the publication of results. Specifically, it provides for a day-ahead spot procurement with at least one market procedure conducted before the deadline for submitting bids on the MGP, while allowing Terna to organize additional spot market procedures even after the publication of MGP results, as well as forward market procedures on a weekly, monthly, or annual basis.

Voltage support – Starting from January 1, 2025 [43], power plants connected to the HV grid required to provide the service of controlling voltage profiles and reactive power flows on the RTN will be entitled to compensation. The compensation, introduced by Terna in Chapter 7 of the Grid Code, marks the first instance in Italy of remuneration for a service not related to frequency, which was previously provided by on a mandatory and unpaid basis.

The remuneration is based on an estimate of the additional active energy that a power plant must generate in order to provide the necessary reactive energy for voltage support. This compensation is granted as reimbursement for energy losses; nevertheless, it represents an initial form of economic recognition for this type of service.[15]

Consideration

The TIDE [35] is a profound and comprehensive reform of electricity dispatching regulation. With the aim of ensuring greater security, efficiency, resilience, and sustainability of the whole electricity system, it

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[13] Terna may still impose a minimum power band offer obligation for each enabled unit.

[14] These units are identified with the acronym UFCR.

[15] During the review of this doctoral thesis, ARERA launched a consultation [44], exploring the possibility — aligned with [2] — that the TSO could introduce more remunerative market-based procedures for such services.

has introduced changes and innovations in the energy market so as to make more suitable for the rapidly and continuously evolving generation mix. For dispatching, defines a level playing field for centralized and distributed resources, following the principle of technological neutrality; in this way the selection of the most efficient flexibility resources is ensured, those capable of adjusting production or load at the lowest cost for the system.

Other relevant market innovations

Within the reform by the TIDE reform, two innovative mechanisms promoted by ARERA and MASE have been introduced to enhance the efficiency and performance of the electricity system: the *Capacity Market* [45] and the *MACSE* [46]. Both mechanisms act as incentives for the construction and availability of generation or storage plants capable of providing grid services at competitive prices.

Capacity Market – With the *Capacity Market* Terna acquires capacity by long-term agreements awarded through competitive auctions. The auctions, organized by Terna, are open to operators holding production units (both dispatchable and nondispatchable). For the capacity selected through the auction process, the participants have:

- The obligation to offer their capacity in the energy and ancillary services markets.
- The right to receive a fixed annual premium from Terna.
- The obligation to return to Terna the positive difference between the electricity price realized in the energy and ancillary services markets and an exercise price defined by ARERA.

Also demand-response units and foreign resources can participate in the auctions, subject to specific obligations and rights [47].

MACSE – Storage resources will play a fundamental role in the operation of the electricity system in future scenarios, characterized by an increasing penetration of renewable non-dispatchable energy sources. They will enable their full exploitation while contributing to providing the dispatching services necessary to ensure the security and adequacy of the system.

The *Legislative Decree 210/2021* [41] introduced a new mechanism, designed to integrate renewables with an efficient level of overgeneration (i.e., electricity production exceeding demand) based on planned grid developments. This mechanism will allow the system to acquire new storage capacity through long-term procurement contracts awarded through Terna-organized competitive auctions, in which operators of new storage systems can participate. Selected entities following the auction process will:

- Build the storage plants.
- Make the storage capacity available to third-party market operators for use in the energy market through a platform managed by GME.
- Offer this capacity on the MSD.
- Receive a fixed annual premium from Terna.

1.3 UVAM pilot project

To fully understand the regulatory aspects of TIDE related to the participation of distributed resources in global and local ancillary services markets, it is useful to analyze the most significant completed Italian pilot project in this field, the UVAM pilot. The analysis, published in [47], delves into the principles introduced by TIDE on the separation of roles between BRP and BSP, the creation of virtual enabled resources through the aggregation of single physical units, the definition of the baseline, and the financial settlements.

The pilot project UVAM was launched in 2017 by ARERA with the aim of investigating technical and economic feasibility of the provision of ancillary services for Terna by units not already enabled [48]. As already mentioned, the previous regulatory framework had been built with reference to a system based on concentrated programmable resources; it was not suitable to intercept the changes underway, especially those linked to the progressive replacement of traditional sources with renewable ones, typically distributed and uncertain. To overcome these limitations, in 2017 pilot projects were launched that have made it possible to enable distributed resources on an aggregate basis, the UVAM. Although the experiment had a modest practical impact on dispatching (the number of activated resources was limited), it showed the enormous potential deriving from the aggregation of dispatching resources; the UVAMs can have, in fact, an upward-regulating potential comparable to that of some large-scale power plants.

The pilot project provided voluntary participation in the MSD, in aggregate form of small-scale power plants, loads, large production units in the availability of a final consumer not subject to mandatory participation, stationary energy storage systems, and electric vehicles. A UVAM is a virtual unit consisting of one or more PODs enclosed within an aggregation perimeter defined by the TSO; Italy has been divided by Terna in eighteen aggregation perimeters composed of sets of provinces [49], as the result of a simplified approach regarding congestions [50].

A UVAM does not participate in the energy markets, nor in the settlement of imbalances, but only in the MSD; it has a capacity of at least 1 MW and can participate in the provision of the following ancillary services, in upward and/or downward mode: congestion management, aFRR, mFRR and RR. To be qualified, a UVAM must be able to provide at least one service with the possibility of asymmetric mode (only an increase or a decrease of its power injection). The schedule of injections and withdrawals of the units included in the UVAM remains the responsibility of the BRP responsible for these PODs, which negotiates the relative quantities in the energy markets and regulates the imbalances with Terna. Appropriate mechanisms (see below) are put in place to coordinate MSD participation by the BSP and energy settlement by the BRP.

The UVAM project is an explicit DR mechanism. Participation is possible either through an offer of services in the MSD, paid for the activated energy, or with a forward contract, paid for the capacity, through auctions conducted by the TSO to secure upward services at a price below a strike level fixed by the Regulator.

In the following, the way UVAMs participate in the spot market is first illustrated, with reference to the offer and remuneration of the service. The forward mechanism of UVAM capacity is then described. The section ends with a description of the overall profit function of the users participating in the forward product.

Participation in the ancillary services market

The quantity accepted in the MSD in the i-th quarter-hour, $Q_{MSD}(i)$, is the result of the negotiations in the MSD :

$$Q_{MSD}(i) = \sum q_{MSD}^{sell}(i) - \sum q_{MSD}^{buy}(i) \tag{1.1}$$

where the summation extends to all the MSD market sessions for the i-th period and all the different offers by the BSP.

To participate in the MSD, the BSP must communicate to Terna the daily withdrawal or injection quarter-hour schedule of the PODs in the UVAM ("baseline"), net of withdrawals of the loads providing the instantaneous interruptibility services (if any). The choice to set the baseline declaration as a BSP's responsibility (and not BRP's) reflects the need to allow participation of third parties in the ancillary services offer (the BSP) while limiting changes to the current scheduling regulation (responsibility of the BRP).

In details, the BRP current scheduling area includes all UPs and UCs belonging to a bidding zone, whilst the UVAM includes typically one or few units, possibly aggregating units of different BRPs. The choice (confirmed at the end of the pilot in the TIDE regulation for the UVAZ) to entrust the BSP with the baseline definition avoids introducing further changes to the regulatory framework, such as reshaping the scheduling perimeters (e.g., setting the UVAM as the scheduling unit), which would impact BRP scheduling units. A similar rationale determines the simplified separation of roles between participation in energy markets and imbalance settlement (BRP's responsibility) and participation in the MSD and accepted quantity settlement (BSP's role).

The communicated baseline can be corrected by Terna to obtain the corrected baseline, $E_o(i)$:

$$E_o(i) = \frac{Baseline(i) \cdot 1h}{4} + \Delta Baseline(i), \tag{1.2}$$

where $\Delta Baseline(i)$ is the correction term calculated as:

$$\Delta Baseline(i) = \begin{cases} \max\left\{0, \frac{1}{n}\sum_{j=1}^{n}\left(Ene_{mis}(j) - \frac{Baseline(j)}{4}\right)\right\} & \text{if } Q_{MSD} > 0, \\ \min\left\{0, \frac{1}{n}\sum_{j=1}^{n}\left(Ene_{mis}(j) - \frac{\text{Baseline}(j)}{4}\right)\right\} & \text{if } Q_{MSD} < 0, \end{cases} \tag{1.3}$$

with n equal to the number of quarter-hours before the i-th one; the correction is kept constant for the whole period following the i-th quarter-hour in which the ancillary service is provided. The difference between the energy withdrawn/injected by the PODs within the UVAM and the energy scheduled for withdrawal/injection by the BSP, as communicated to Terna is represented by $\left(Ene_{mis}(j) - \frac{Baseline(j)}{4}\right)$.

The quantity Q_{MSD} in (1.1) is remunerated on a pay-as-bid basis, like all the quantities accepted in the MSD. The assessment of the quantities supplied is carried out by comparing, in the i-th quarter-hour, the $Q_{MSD}(i)$ and the difference between the energy exchanged by the UVAM, $Ene_{mis}(i)$, and $E_o(i)$.

Although there is no explicit penalty in this mechanism for a baseline programming error, a penalty is implicitly introduced in the calculation of the executed quantities, since the baseline programming error affects the quantification of the volumes realized. Explicit penalties are applied in case of underperformance (i.e., energy supplied less than the accepted quantity), while no penalties are applied in the case of overperformance.

Underperformance – The quantities not correctly supplied, $Sbil_{UVAM}$, are valued through fees for non-compliance. For significant imbalances (higher than 5% of $Q_{MSD}(i)$), penalties are applied. In addition to not receiving any remuneration, the BSP pays the extra system cost on the quantities not executed, quantified in the difference between the MSD maximum accepted price and the price for which the quantities have been accepted on the MSD (p_{MSD}), according to a dual price logic. For minor imbalances (less than or equal to 5% of Q_{MSD}), a refund fee is in place, for which the BSP fully returns the accepted MSD price, resulting in no remuneration or penalty for non-compliance with the order.

Overperformance – In the case of overperformance, no penalties are applied, but the overperformance quantity (more energy injected) is accounted for in the quantification of the BRP imbalance and is remunerated to the BRP at an imbalance price based on a single price rationale.

Financial Compensation

The separation of roles between BSP, responsible for participation in MSD, and BRP, responsible for scheduling and imbalance settlements, which are possibly separate entities, has required the definition of appropriate coordination mechanisms. They aim to avoid that the action on the MSD of the units included in a UVAM, modifying their operation compared to the schedule, generates unexpected imbalances and improper allocation of costs and rewards between the parties involved.

The financial compensation is aimed at correctly settling the energy between BSP and BRP. In case of a positive quantity accepted in MSD, the BSP restores through Terna the previously purchased energy to the BRP, with a payment of the same energy (formally resold) at the MGP hourly price, assumed as a standard representative value of the energy. In case of $Q_{MSD} < 0$, the BRP refunds the BSP for the incremental value of energy delivered.

In both cases the BRP is not affected by the exchanges of energy in the MSD. However, there is an impact on the net income of the BSP, which makes a revenue on the Q_{MSD} at the pay-as-bid value, while pays a rebate for the BRP equal to Q_{MSD} multiplied by the MGP system wide consumption energy price (PUN), or the MGP zonal price (p_{MGP}). This term constitutes the variable revenue of UVAM, denoted as R_{UVAM}, and is defined as follows:

- upward service:

$$R_{UVAM_{MSD\uparrow}} = \sum_i \left(Q_i \cdot (p_{MSD,i} - p_{MGP,i}) - SbilUVAM_i\right) \tag{1.4}$$

- downward service:

$$R_{UVAM_{MSD\downarrow}} = \sum_i \left(Q_i \cdot (p_{MGP,i} - p_{MSD,i}) - SbilUVAM_i\right) \tag{1.5}$$

Forward Product

The UVAM pilot project provided for the possibility of forward contracts, for upward services only. The purpose of this product for the TSO is to acquire the upward reserve availability, i.e., the guarantee to get an offer from the UVAM in the MSD in specific time periods. The BSP is awarded a prize for the availability of modulation, divided as shown in Table 1.4.

Table 1.4: Features of upward forward products

Product	Availability (Mon–Fri)	Offer commitment [h]	Strike price [€/MWh]	Reservation premium [k€/MW/year]
Afternoon	15:00 – 17:59	3	200	22.5
Evening 1	18:00 – 21:59	4	400	30.0
Evening 2	18:00 – 21:59	4	200	30.0

With the award of the fixed premium, Pr_f, the UVAM undertakes to offer upward energy in the MSD at a price below the strike price. If the BSP does not present compliant offers for at least two consecutive hours of the product availability range, or if the offers presented were not executable as assessed in the ex-post verification of the actual reserve margins, penalties Pen_f can be imposed that imply the reduction or even the withdrawal of the premium.

To summarize, the remuneration of a UVAM participating in the forward product market, R_f, consists of two distinct revenue factors: the remuneration of the capacity and the possible remuneration of the energy activated on the MSD (capped at a strike price):

$$R_f = Pr_f - Pen_f + R_{\mathrm{UVAM}_{\mathrm{MSD}\uparrow}}. \tag{1.6}$$

Results and Considerations

Results – Figure 1.8 reports the number of qualified UVAMs as of August 2021. The 272 total UVAMs are mainly made up of just one POD, and almost 80% are made up of no more than two PODs; out of 272 UVAMs, 173 benefit from forward contracts.

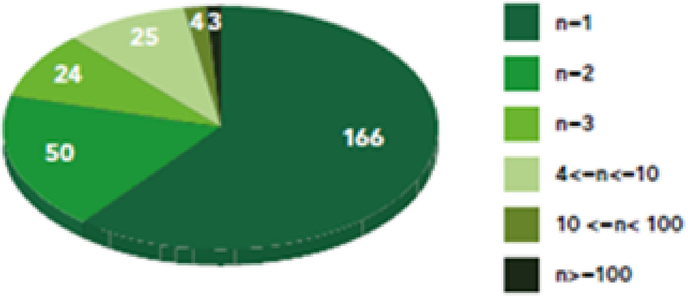

Figure 1.8: Number of UVAMs qualified for the number of underlying PODs in August 2021 [51].

Between September 2020 and July 2021, Terna sent 598 upward dispatching orders for over 6.85 GWh (involving 184 UVAMs and 27 BSPs). Of these, 249 were issued just for testing purposes, while the remaining 349 had the following performances [51]:

- 66% perfectly executed;
- 16% partial execution of at least 70%;
- 28% execution below 70%.

In the same period, the total energy activated by Terna for the MSD was 15.2 TWh (elaboration from [52]).

Considerations – From the analysis in [47] it emerged that the forward product played an important role in the development of the UVAM pilot project. In fact, most of the UVAMs had access to forward products, which consequently limited their offer prices to the strike price (see Table 1.4). In fact, for these resources, the value of the strike price, in conjunction with a period of high energy prices, had a negative impact on the profitability of these resources in MSD

Indeed, the variable reward term $R_{\mathrm{UVAM}_{\mathrm{MSD}\uparrow}}$ in 1.4 could have been too low or even negative, inappropriately forcing the dispatching of UVAM resources at prices below their short-run marginal costs.

With the entry into force of TIDE, the UVAM pilot project has ceased to exist [16], the voluntary participation, in aggregate form, of the UCs and UPs in MSD is now only possible through the UVANs and UVAZs. Consequently,

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[16] Only during the TIDE transitional period is the BSP entitled to convert UVAMs into "Transitorily Enabled Virtual Units" (UVATs), which may remain in operation only until 1 February 2026.

these UVAs will not benefit, unless otherwise provided by future regulatory decisions, from a forward product as an incentive to participate in MSD. However, their offer will be free of strike price constraints.

Chapter 2

Distributed resources and ancillary services for distribution networks

2.1 Flexibility and the new role of distribution system operators

The profound changes in the electricity sector underway all over the world, and in particular in Europe require the reconsideration of the management of the electricity system and in particular of the distribution networks. We are increasingly witnessing the phenomenon of congestion on both transmission and distribution networks; in the United Kingdom, for example, congestion management costs increased by 74% from 2010 to 2017 [53]. Phenomena of this type have triggered an Europe-wide debate on the most appropriate market design to manage issues such as network overload and voltage profile control.

The ongoing transformations are strongly highlighting the challenges that distribution networks may face: the significant growth of decentralized generation assets and the increasing penetration of new widespread consumption loads (e.g., electric vehicles, heat pumps) make network management more complex and problematic than before. The DNOs have historically chosen to reinforce the grid through significant investments. These decisions were made because traditional alternatives to network reinforcement (e.g. reactive power management, voltage setpoint control) quickly reached their technical limits in the presence of high levels of decentralized generation. In addition, near-real-time management was typically limited to physical reconfiguration of the grid, as there were no flexible resources capable of responding quickly. The widespread deployment of DERs, particularly from renewable sources, at the local level, combined with the high costs associated with grid reinforcement, has sparked a debate on whether to continue with this fit-and-forget approach or to explore alternative solutions, such as leveraging the flexibility of distributed resources.

The Clean Energy Package [54], first proposed in 2016 and entered into force in 2019,[1] indicates the adoption of market-based solutions to purchase flexibility resources to meet these needs as an alternative solution to network reinforcement. In this scenario, the DNO is called upon to innovate its role, expanding its scope beyond the management of network infrastructures to become a buyer of network services from resources connected to its network, thus transforming itself into a real DSO. Article 3 of the Regulation 2019/943 [1] requires the adoption of market rules that will “facilitate the development of more flexible generation, sustainable low carbon generation, and more flexible demand” and calls for incentives for DSOs, “for the most cost-efficient operation and development of their networks including through the procurement of flexibility services”. Article 53 [1] goes even further by establishing a new entity, the EU DSO, with one of its tasks to facilitate demand-side flexibility and response and distribution grid users’ access to markets. In parallel, the directive [2] promotes the active participation of consumers — individually or collectively via energy communities — in all energy markets. Article 32 [2] highlights the importance of the development of an adequate regulatory framework “to allow and provide incentives to distribution system operators to procure flexibility services, including congestion management in

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[1] In 2019, the EU revised its energy policy framework to phase out fossil fuels and promote cleaner energy, aiming to fulfill the EU’s commitments under the Paris Agreement to reduce greenhouse gas emissions. The agreement on this new regulatory package, known as the Clean Energy Package, marked a significant step toward implementing the European strategy for energy transition. The package consists of a set of legal acts, including the *Renewable Energy Directive* [55], calling for “additional investments in various sources of flexibility (e.g., demand response and flexible generation) to allow for cost-effective integration of additional renewable energy capacity”. The market-based approach envisions solutions based on a local flexibility market, which would provide flexibility services to meet DSOs’ needs, following a model like the well-established ancillary services markets operated by TSOs. The implementation of this new market will see the direct involvement of DSOs as buyers of local ancillary services.

their areas, in order to improve efficiencies in the operation and development of the distribution system" [56].

If the penetration of DERs and the increase in MV and LV consumption can in fact determine new network constraints, they can also be a potential resource for local flexibility. Several studies [57–61] demonstrate that the use of local flexibility sources as alternatives to grid reinforcement can lead to significant savings for DSOs. In fact, since demand and injection peaks are of short cumulative duration, conventional grid expansion is not economically reasonable for all situations; with flexibility, problems such as congestion and voltage/frequency variations, as well as power imbalances, can be managed more efficiently. This approach is called *fit and manage*.

Historically, the exploitation of flexibility resources has been mainly aimed at the needs of TSOs and not those of distributors (see the case of virtual power plants [62–65]). In recent years, however, the regulatory and scientific discussion has led to encouraging the launch of pilot projects and regulatory initiatives in favor of the exploitation of flexibility resources also on LV networks; in particular, the CEER mentioned the value of deploying and using flexibility at both transmission and distribution grid levels in many documents [57–59].

In Italy, mechanisms such as the UVAM illustrated in Chapter 1, have been introduced since 2017, and permanently inserted in the regulation with the TIDE [66], making these aggregated resources available to the TSO for its network needs, in competition with the plants that historically provided these services. The experience with the TSOs can be a starting point to define the operating paradigms of these new processes and the structures of the new markets, but it is necessary to take into account the differences between the participation of distributed resources in the global ancillary services markets and in the local ones [53]. In particular:

- Location-specific flexibility needs – The need for flexibility is highly location-specific since DNOs/DSOs have extremely localized requirements. Therefore, it is essential to consider not only the price of the service offer but also its effectiveness based on the location of the resource.
- Grid characteristics – Information on grid status, technical characteristics, and operational constraints is fundamental to the management of any network. However, the distribution grid differs significantly from the transmission grid in terms of topology: distribution networks are typically radial, whereas transmission networks have a meshed structure.
- Operational Management Constraints – The operational constraints of distribution networks also differ due to the high number of assets, each

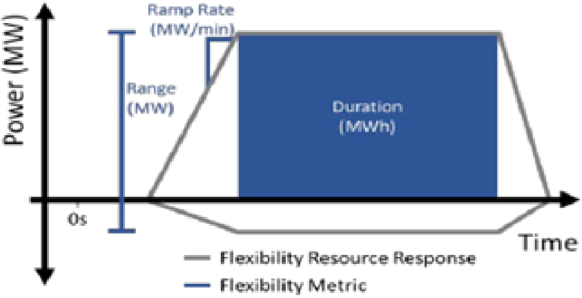

Figure 2.1: Features of flexibility

with a lower capacity compared to transmission-connected assets. Consequently, distribution grid management must rely on different types of resources and procure distinct services from those used at the transmission level.

- Congestion Frequency – The frequency of distribution-level congestion is expected to rise with the decentralization and increasing connection of renewable distributed resources. This will require more frequent and precise management actions, aiming for near real-time congestion control.

Furthermore, extending the management of congestions and voltage profile of the transmission system to the needs of the distribution system may not be the optimal solution, while it would be more appropriate for DSOs to develop their own mechanisms for the procurement of flexibility products that can be used for their own needs [53].

In literature, the concept of flexibility is illustrated in several studies [67, 68]; a user is defined as flexible if, at a specific operating point, it is able to respond to a series of uncertain future events (such as requests for modulation of energy supplied/withdrawn), taking relevant actions within an acceptable cost threshold and time frame. Eurelectric reports the following definition [69]: "At the individual level, flexibility is the modification of generation and/or consumption injection patterns in reaction to an external signal (price or activation signal) in order to provide a service within the energy system.". The flexibility of a single operator can therefore be characterized by different properties such as the value of the modulating power, the duration of the response, the intervention time or the recovery time, as illustrated in Fig. 2.1.

The flexibility of a single subject, sometimes characterized by low potential and high uncertainty [70], can be reconsidered in the context of aggregation to form aggregate units characterized by their own intrinsic flexibility [71]. In fact, aggregation is the main way to ensure that the principles of nondiscrimination are implemented for participation in the electricity markets for ancillary services of small or mobile systems such as domestic consumers, small batteries and electric vehicles [72, 73].

In the following, first, we present the main characteristics of some local flexibility markets started or being tested with pilots across Europe; then, we focus on the pilot projects underway in Italy.

2.2 European context

This paragraph looks at the role of regulation in promoting the use of flexibility at the distribution network level in some European countries [2]. The presentation is based on the studies [56, 74], which analyze the local flexibility markets in:

- France
- Germany
- Netherlands
- Norway
- Sweden
- United Kingdom

All EU countries analyzed in [56] have an incentive DSO with revenue/price cap schemes and efficiency benchmarking (Table 2.1). In such schemes, the regulator sets the overall revenue that the DSO can earn (revenue cap) or the price it can charge (price cap) for the period of price control (regulatory), considering the expected efficient cost during the regulatory period, based on the costs of the network operator's own costs, but also on the performance of other comparable DSOs (yardstick competition). In this sense, the DSO can either benefit from cost savings or receive reduced revenue allowance for not reaching the target values [3]. This can limit investments in infrastructure, which normally have a payback time longer than the regulatory period [75].

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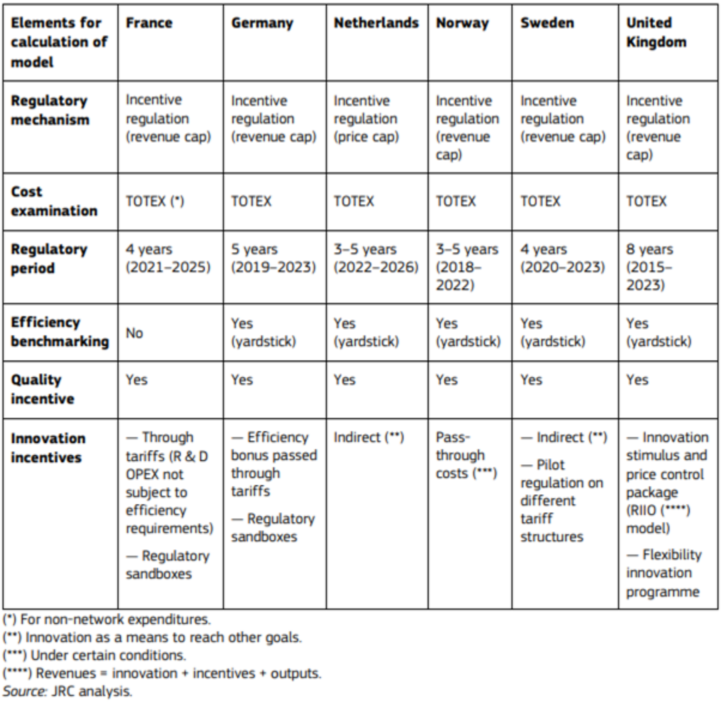
[2] Another local flexibility project worthy of attention is the one developed by the DSO E-REDES in Portugal.

[3] A few outputs, such as quality and reliability of supply, may account for an increase or decrease of the revenue or price cap, thus incentivising the DSOs to improve quality of service Under revenue (or price) capping schemes, as costs are estimated for each regulatory period (typically a few years ahead), DSOs may be

Table 2.1: DSO revenue models [56].



Elements for calculation of model	France	Germany	Netherlands	Norway	Sweden	United Kingdom
Regulatory mechanism	Incentive regulation (revenue cap)	Incentive regulation (revenue cap)	Incentive regulation (price cap)	Incentive regulation (revenue cap)	Incentive regulation (revenue cap)	Incentive regulation (revenue cap)
Cost examination	TOTEX (*)	TOTEX	TOTEX	TOTEX	TOTEX	TOTEX
Regulatory period	4 years (2021–2025)	5 years (2019–2023)	3–5 years (2022–2026)	3–5 years (2018–2022)	4 years (2020–2023)	8 years (2015–2023)
Efficiency benchmarking	No	Yes (yardstick)	Yes (yardstick)	Yes (yardstick)	Yes (yardstick)	Yes (yardstick)
Quality incentive	Yes	Yes	Yes	Yes	Yes	Yes
Innovation incentives	— Through tariffs (R & D OPEX not subject to efficiency requirements) — Regulatory sandboxes	— Efficiency bonus passed through tariffs — Regulatory sandboxes	Indirect (**)	Pass-through costs (***)	— Indirect (**) — Pilot regulation on different tariff structures	— Innovation stimulus and price control package (RIIO (****) model) — Flexibility innovation programme

(*) For non-network expenditures.
(**) Innovation as a means to reach other goals.
(***) Under certain conditions.
(****) Revenues = innovation + incentives + outputs.
Source: JRC analysis.

In all cases there is a TOTEX approach, which allows the DSO to choose OPEX or CAPEX or a mix of both to meet network needs: in this way, DSOs are incentivized to choose the most efficient combination of resources to achieve several regulatory goals using, for example, less capital-intensive innovative expenses and higher OPEX in the short term (e.g., flexibility procurement), instead of traditional network investments [61].

2.2.1 France

ENEDIS, the main French DSO, launched its flexibility tenders in 2019 to support grid congestion management and defer network reinforcements[76].

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incentivised to reduce costs as early as possible rather than considering the longterm effect of the investment

The initiative aligns with France's national energy strategy to increase the use of DERs and enhance local flexibility markets.

Pre-qualification

FSPs must register on ENEDIS' digital platform and provide technical specifications for their flexibility assets. The pre-qualification process includes verification of asset location and connection to the distribution grid, compliance with regulatory and technical standards and testing of activation and response capabilities. Assets must have a minimum bid size of 100 kW, though smaller resources can participate through aggregation.

Flexibility products

ENEDIS tenders focus on services tailored to local network constraints, including congestion management (reducing or shifting consumption at critical times), voltage support (helping to stabilize voltage levels in constrained zones) and network reinforcement deferral (avoiding costly infrastructure upgrades). Contracts can range from short-term (seasonal) to long-term agreements spanning several years.

Market architecture

ENEDIS operates flexibility tenders in a structured process: (i) identification of flexibility needs in specific regions; (ii) call for tenders specifying required services and participation criteria; (iii) submission of bids by FSPs; (iv) evaluation and selection based on price, technical feasibility, and grid impact; (v) contract signing and service activation. The platform follows a pay-as-bid mechanism, ensuring that flexibility procurement remains cost-effective.

Activation and settlement

Activation signals are sent via API, email, or SMS. FSPs must respond within predefined timeframes, depending on the contract type (e.g., congestion management may require activation within minutes, while reinforcement deferral services operate on longer schedules). Settlement is based on actual delivered flexibility, with payment structures including availability payments for being ready to provide flexibility, and activation payments based on the amount of energy shifted or reduced. Penalties for non-compliance or underperformance are minimal but may result in a reduction of payments.

The flexibility market organized by Enedis has not been very successful: of the nine auctions held in the last two years, only one received offers.

In particular, following the last auction without participants in March 2021, Enedis launched an appeal to collect the contribution of all interested parties to improve the design of the local flexibility services market [77].

2.2.2 Germany

Enera was a German pilot project [78] running from 2017 to 2020. The project aimed to establish a regional flexibility market and integrate high shares of renewable energy while enhancing grid stability. The key stakeholders included EPEX SPOT (market operator), Avacon (DSO), and TenneT (TSO).

Pre-qualification

FSPs were required to register their flexibility assets, providing technical details such as capacity, response time, and grid connection. The minimum bid size was 100 kW, but aggregators could bundle smaller resources to meet this threshold. DSOs and TSOs conducted pre-qualification tests to ensure that assets could reliably provide the requested flexibility services.

Flexibility products

Enera treated a range of products aimed at congestion management and grid balancing: congestion management services (for DSOs and TSOs), redispatch and balancing products integrated into the wholesale electricity market and day-ahead and intraday flexibility trading. Products had varying activation times, ranging from near-instantaneous response (for balancing) to several hours ahead (for congestion management).

Market architecture

The enera flexibility market was structured into local congestion zones, aligning with grid constraints. The process provided that DSOs (and TSOs) forecasted congestion risks and published flexibility needs, and FSPs submitted bids via the spot market platform. Bids were evaluated based on price and grid impact, and selected offers were activated to counteract constraint violations. The platform was based on a pay-as-bid mechanism, with no predefined price caps. Market integration allowed DSOs and TSOs to coordinate flexibility procurement.

Activation and settlement

Activation occurred via API communication, and assets had to respond within predefined timeframes; measurement data was collected in real-time to verify delivery. Compensation was based on delivered flexibility, with reduced payments for partial fulfillment. Settlement was aligned with existing market practices on the spot market EPEX.

The project demonstrated the potential for regional flexibility markets to support grid stability but also highlighted challenges, such as regulatory barriers and limited liquidity. During the project, over 4,000 orders were placed, resulting in 130 transactions. The platform successfully enabled flexibility trading, but challenges remain in scaling and integrating it into broader market structures. Future developments will focus on improving market liquidity, enhancing interoperability with other flexibility markets, and addressing regulatory barriers to increase participation.

2.2.3 Netherlands

GOPACS is a congestion management platform launched in 2018 by the Dutch TSO TenneT in collaboration with DSOs (Liander, Stedin, Enexis, and Westland Infra) [79]. It was designed to alleviate congestion in the Dutch electricity network by coordinating flexibility procurement across different grid levels.

Pre-qualification

FSPs must connect to GOPACS via an existing market platform, such as intraday markets. They must demonstrate the ability to deliver flexibility within specified timeframes and register their assets with the relevant DSO or TSO. The platform does not impose a minimum bid size, allowing a broad range of participants, including industrial users and aggregators.

Flexibility products

GOPACS primarily facilitates the trading of congestion management services through the intraday electricity market. Unlike traditional flexibility markets, it does not create a separate auction system but instead integrates with existing energy trading platforms. This enables to implement a coordination between DSOs and the TSO to optimize grid stability.

Market architecture

GOPACS operates as an intermediary that connects flexibility demand from grid operators with supply from market participants. A DSO or TSO identifies a congestion issue and submit a request in the intraday market. FSPs can respond by placing bids, the most cost-effective ones are selected to resolute congestion. DSOs have priority in flexibility procurement, but unfulfilled requests can be passed to TenneT for system-wide balancing. The platform operates on a pay-as-bid mechanism.

Activation and settlement

Once an offer is accepted, activation occurs through the trading platform; FSPs must ensure timely delivery, with settlements based on actual flexibility delivered. Penalties for non-compliance depend on the market platform rules, but compensation is adjusted for partial deliveries. The settlement process is in accordance with standard intraday market practices.

2.2.4 Norway

The pilot NorFlex was a demonstration initiative running from 2019 to 2022, deployed by two Norwegian DSOs Agder Energi and Glitre Energi, and the national TSO Statnett through the flexibility market platform NODES [80].

Pre-qualification

Flexibility assets are registered in the NODES platform byFSPs. Before assets can be offered in the market, the local DSO must approve and confirm that the asset exists in its grid and that they are in the right location. As a general principle, the regulatory compliance and financial capacity of the flexibility service providers is pre-qualified, as are the technical characteristics of their flexibility assets. The NODES market platform does not envisage minimum or maximum nominal capacity limits for the flexibility assets; in the pilot NorFlex, the minimum bid size was 1 kW.

Flexibility products

The NODES platform accommodates trading of products aimed at network deferral, congestion management and enhancement of network resilience. The common feature is that the flexibility assets have to offer real power injections/withdrawals. NODES envisages both a long-term market (LongFlex) and a short-term market (ShortFlex); products could have both an availability and an activation component. NorFlex traded both availability and utilization products; the former were purchased one month in advance for weekly contracts, while the latter were traded on a rolling basis. Both availability and utilization prices were predetermined by the buying DSO, reflecting investment deferral costs.

Market architecture

In its full implementation, NODES aims to offer a market platform for an integrated flexibility marketplace in which FSPs trade with BRPs, DSOs and TSOs.[4] The services offered include portfolio optimisation (for BRPs), congestion management (both long term and short term, primarily for DSOs) and frequency regulation services (for the TSO). In principle, all these actors would compete for flexibility services, even though in most actual pilot implementations the DSO has precedence over the TSO in the procurement of flexibility (i.e. only the unused offers are passed to the TSO, often in aggregated form). So far, in the projects in which the NODES market platform has been deployed, only network operators are buyers of flexibility services (i.e. the BRPs' can not be buyers of flexibility).

Within the NODES market platform, products with weekly and seasonal availability (2 to 4 months) have been implemented. In the LongFlex market, availability products (possibly with activation components) are traded; the ShortFlex market is a continuous, pay-as-bid market. The buyer network operator announces its flexibility needs in advance and rquires FSPs to submit offers, but the latter can also submit offers proactively. Trading of utilization products usually opens 7–10 days and closes 1–2 hours before physical delivery. Technically, the MTU can be as low as 1 minute, but a common practice is to align the MTU with the imbalance settlement period. Regarding the spatial setup of the flexibility market, this is based on congestion zones, inside which an FSP can aggregate its resources.

The definition of congestion zones, and thus the acceptable perimeter of aggregation, is left to network operators for each specific test case. The possibility exists of congestion zones defined differently byn the DSO and the TSO; then, each TSO can aggregate offers from several DSO congestion zones.

Offers in the flexibility markets adopting the NODES platform are cleared

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[4] The NODES platform is used in the Norwegian NorFlex pilot project, as well as in the Swedish Sthlmflex (section 2.2.5) and UK Intraflex (section 2.2.6) projects. General considerations for NODES are similar for the two following examples, and will not be repeated there.

based on their price (per congestion zone). Conceptually, there are no price caps, and pay-as-bid is the pricing mechanism for activation products. Nominally, domestic end-customers could participate directly in the NODES flexibility markets; however, this is very rare in practice, due to the lack of financial incentives and necessary technical tools. Therefore, the participation of residential consumers is made possible through aggregators [81].

While, in principle, DSOs and TSOs can compete for flexibility based on price, the coordination of network operators has not yet been addressed in detail. NODES envisages that the lower level network operator (e.g. a local DSO) could restrict the higher level network operator (e.g. TSOs) to activate flexibility in its grid if this could cause problems.

In the NorFlex market, the flexibility services were procured per congestion area in the 132 kV grid and below, DSOs procured flexibility first, and residual offers were aggregated and forwarded to the TSO's mFRR market in minimum blocks of 1 MW (starting winter 2021/2022), redispatching and countertrading were managed through the Nordic mFRR order book, allowing residual flexibility to be used for both redispatching and system balancing.

Activation and settlement

The activation of flexibility resources is made by FSPs upon successful clearance of their offers. It occurred automatically through the buying network operator without prior notice. The measurement period was 1 minute, ensuring granular tracking of the flexibility delivered. Baseline adjustments could be made up to 2 hours before activation, ensuring coordination with the wholesale balancing market. No penalties are applied in the case of partial delivery of flexibility, but there is a reduction in compensation. The financial cost of imbalances caused by the activation of flexibility is borne by BRPs.

2.2.5 Sweden

Sthlmflex is a flexibility market platform deployed in the Stockholm area to address network capacity constraints [82]. It continues previous local flexibility market pilots developed under the CoordiNet Horizon 2020 project[83]; the project started on 1 December 2020 and remains ongoing. The network operators involved include the national TSO Svenska kraftnät, regional DSOs Ellevio and Vattenfall Eldistribution, and local DSO E.ON Energidistribution AB [5]. Initially planned for one winter season, the project was extended

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[5] The two regional DSOs operate the network in the voltage ranges between 24 kV and 220 kV, while E.ON Energidistribution AB is one of the local DSOs that

for two more winters to refine details and increase market participation. Like NorFlex, it is also developed on the flexibility market platform NODES[80].

Pre-qualification

FSPs interested in participating must register their assets, specifying installation identification, asset type, nominal capacity and network jurisdiction. DSOs validate metering points and approve the *baseline* methodology. The pre-qualification process includes a minimum bid step size of 0.1 MW and communication verification with the NODES platform. Seasonal contracts require an activation test of one hour each season. FSPs must sign a power of attorney agreement on metering data and a contract with the market operator. The process typically takes 14 days. Participation in the balancing market requires an agreement with the respective BRPs, who receive financial compensation from the TSO.

Flexibility Products

Currently, only upward flexibility services (increased generation or decreased consumption) are traded. There are three types of products:

- Seasonal contracts (LongFlex market) include availability compensation and an utilization price, with free bidding on both components; The availability price determines the clearance of the offer of the offer and utilization has a price cap at 950 €/MWh).
- Weekly contracts (ShortFlex market) were introduced in 2021/2022, with predetermined availability prices and free bidding for utilization (capped at EUR 266 €/MWh); designed to increase market liquidity, availability compensation follows a stepwise structure up to 40 MWh per week.
- Free bids, for only utilization products in a continuous market with no price cap.

Availability contracts require FSPs to offer flexibility when external temperatures are -5°C or lower due to heating loads. Availability products are limited to Stockholm north and Stockholm city congestion areas.

Market Architecture

Flexibility assets are aggregated into congestion-area portfolios (Stockholm north, Stockholm south, and Stockholm city). The highest voltage level

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operating below 24 kV.

is 220 kV. Regional DSOs can activate flexibility anywhere in the region by swapping subscription rights, but when both DSOs need flexibility, they compete. Seasonal contracts are procured via auction based on availability price. Weekly contracts are auctioned ad hoc, covering the next seven days, with email notifications from the market platform. Free bids are traded continuously in a pay-as-bid format, with bids accepted from one week to two hours before delivery.

Network operators procure flexibility primarily between 9:30-10:30 on the day before delivery. Unused offers qualifying for mFRR services are passed to the TSO.

Activation and settlement

Activation occurs upon a signal from the NODES platform via API, email, or SMS. FSPs can either declare a baseline or use an automatic calculation based on historical data; the default baseline is the average of the last five working days. Industrial users typically declare schedules, while aggregators of smaller assets prefer automatic baselines.

The measurement and settlement periods are 60 minutes, aligned with the imbalance settlement period (to be reduced to 15 minutes in the future).

Independent aggregators are not required to compensate suppliers for pre-bought energy. For partial delivery, there are no penalties but compensation reduction. Availability compensation is validated monthly. The financial penalty for exceeding network subscription limits effectively caps DSO demand for flexibility.

2.2.6 United Kingdom (IntraFlex)

IntraFlex is a pilot project conducted by Western Power Distribution (DSO) from October 2019 to November 2021, in collaboration with NODES and Smart Grid Consultancy. The project aimed to link flexibility provision to network operators with participation in the wholesale market, focusing on imbalance risks for BRPs when independent aggregators activate flexibility [84].

Pre-qualification

In the prequalification process, an FSP had to sign a membership agreement with the NODES market platform, accepting the latter's rulebook, and had to perform a test trade. FSPs had to register their assets, specifically the type of asset, metering point identification, and location. The end-to-end system test had to be performed with prequalified assets, based on which the buying DSO decided on the FSP qualification [85]

Flexibility products

In the IntraFlex flexibility marketplace, only an utilization product was developed; measurements with a granularity of 1 minute have been employed. The minimum bid size was 1 kW. The flexibility product was divisible, but FSPs could also submit fill-or-kill and minimum quantity offers [86, 87].

Market architecture

The IntraFlex market operated on a continuous basis, with the DSO announcing flexibility needs seven days in advance and FSPs offering flexibility services competitively. The market aimed to integrate distribution-level flexibility with wholesale trading, allowing BRPs to adjust their positions in response to activated flexibility [56].

Activation and settlement

Offers by FSPs were submitted in the NODES market platform either manually in a web portal or through an API. The activation of flexibility was made by FSPs after a dispatching signal by the market platform. Metering data were gathered and sent to the market platform through an API: in most cases, readings from the connection point meter were used, but, in certain cases, FSPs opted for assets' submeter measurements (especially for EVs). Settlement was carried out for every minute of the delivery period. The baseline methodology defined by the network operator employed daily profiles with 48 half-hourly periods; the baseline for each period was calculated from the average of the prior five completed weekday measurements for that same period.

In the case of partial delivery of flexibility, there was no penalty, but there was a reduction in compensation [86].

2.2.7 United Kingdom (UK Flexibility Tenders)

UK Flexibility Tenders refer to the structured procurement processes organized by UK DSOs since 2018. The tenders aim to integrate flexibility services into local grid management to defer network reinforcements and improve operational efficiency. Major DSOs (UK Power Networks, Western

Power Distribution, Scottish and Southern Electricity Networks, and Northern Powergrid) actively participate in flexibility procurement. The main platforms for tendering are PicloFlex and Flexible Power [88].

Pre-qualification

Interested FSPs must register on the respective DSO platforms, providing technical details such as asset location, capacity, and response times. Each DSO has slightly different pre-qualification criteria, but most require proof of regulatory compliance, evidence of financial stability, verification of technical capability (via test activations), and a minimum bid size of 100 kW, with aggregators permitted to bundle smaller assets.

Flexibility products

The UK Flexibility tenders offers a variety of services, primarily designed for congestion management and network balancing, like the pre-fault congestion management, procured seasonally or annually, the post-fault congestion management, activated when needed, the support to grid restoration after major faults, and the demand reduction during system peaks. Contracts can vary in duration, from short-term (monthly) to long-term (several years), depending on the DSO and the type of flexibility required [56].

Market architecture

Flexibility procurement is conducted through competitive tenders, where DSOs specify their requirements for different grid zones. The DSO identifies areas requiring flexibility and publishes procurement opportunities (Needs assessment) and FSPs submit bids detailing the flexibility they can offer. Bids are assessed based on price and technical suitability. Selected providers enter agreements to deliver flexibility services. DSOs dispatch flexibility based on real-time grid conditions (Activation) [56].

Activation and settlement

Activation signals are sent via platform APIs, email, or SMS. Response times vary by contract type, with some requiring near-instantaneous reaction times, and others allowing scheduled activation. Settlements are processed based on the actual flexibility delivered, with payments following a pay-as-bid mechanism. Some DSOs offer availability payments to ensure readiness in long-term contracts. Penalties for non-compliance are generally minimal but can result in reduced compensation for partial fulfillment. UK Flexibility Tenders have rapidly expanded in recent years, with growing participation from independent aggregators, industrial consumers, and renewable energy producers [56].

Conclusion

The flexibility procurement for distribution network operation and planning is is still a niche practice in most countries. It is under development at various degrees of maturity among European countries, with a variety of methods employed.

In particular, France, the Netherlands, and the United Kingdom take a business-as-usual approach to market-based procurement; Norway and Sweden have developed pilot projects; in Germany (2.2.5), a rule-based approach was, in the end, chosen as the main option. Nevertheless, even where market-based procurement can be considered to have reached a business-as-usual stage, there are significant discrepancies in terms of volumes procured and level of market maturity [56].

In the UK, DNOs systematically procure local flexibility services and in increasing volumes year, after year, backed by a supportive regulatory mandate. In the Netherlands, GOPACS is a well-established mechanism, and the recent collaboration with EPEX SPOT is expected to further increase the liquidity in the market for local flexibility services [56]. On the other side, the flexibility tenders in France have produced rather disappointing results so far; it is due to, among other things, more attractive business alternatives for flexibility service providers (e.g. participation in the capacity remuneration mechanism), the design of the tenders (specific, non-divisible products) and the price caps imposed by the major DSO in France (ENEDIS) [56].

2.3 Pilot projects in Italy

In Italy, the distribution activity is considered a natural monopoly; distribution networks in different areas have been entrusted to concessionaires (Table 2.2).

Table 2.2: Electricity distribution by Italian utilities

Utility	**Energy distributed [MWh]**	**Number of customers [thousands]**
E-distribuzione	219,352	31,545
Unareti	10,582	1,163
Areti	8,938	1,655
Ireti	3,212	701
V-Reti	2,800	244
Edyna	2,372	238
Set Distribuzione	2,280	337
Inrete Distribuzione Energia	2,154	264
Other Operators	5,546	919
TOTAL	**257,236**	**37,066**

Local distributors play a fundamental role in the electricity supply chain, as they are responsible for connecting customers [89] and producers to their networks [90], planning, maintaining, and operating the network, and ensuring a quality power supply [91].

DSOs also collect and validate measurement data; they are responsible for the installation and maintenance of the measurement meterand making them available to external stakeholders [92]. Through the meter, it is possible to collect, validate, and transmit the measurement data of the customers to the SII [93] for the invoicing of consumption by sellers and to the GSE for incentives for the production from renewables [94]. The second generation meters installation plan was started in 2021 [95], allowing the collection, validation, and sending of daily and quarterly measurement data to the SII, also for customers; it is proven to be an enabling factor for the full operation of flexibility markets. Using the measurement data, DSOs can better forecast demand, thus improving network planning and management. Such data can also help consumers understand their consumption and production trends and make efficient decisions on energy use. The quarter-hour granularity of the measurements and their timely availability on the SII portal make the meter an enabling tool also for third parties such as aggregators and BSPs, which could use such data to provide better energy management services to end consumers, helping them provide greater flexibility to the system and increasing their energy efficiency.

The evolution of the electrical system in Italy and the impact of distributed generation

Until 1950s, almost all the electricity demand in Italy was met by hydroelectric sources [96]. As demand grew, hydroelectric generation was replaced by thermoelectric generation as the main source of electricity production; by 1970, thermoelectric power represented 60% of demand, while hydroelectric sources covered approximately 35%. The remaining demand was met by geothermal (2.3%) and nuclear generation (2.7%), the latter of which was abandoned in 1987 following a national referendum.

In the following years, thanks to significant incentive mechanisms such as feed-in tariffs (e.g. 'green certificates' and 'all inclusive tariffs') and feed-in premiums (e.g. 'Conto Energia'), as well as market rules (such as feed-in obligations and priority dispatch at the same offered price), the production of electricity from RES – particularly wind and photovoltaic – gradually took hold in Italy [96, 97].

Incentive mechanisms ended in 2013; from 2018 onward, there has been a renewed increase in the installation of renewable plants, particularly photovoltaic systems.[6] This growth has been driven by new incentive mechanisms (e.g., the "Superbonus") and the economic advantage of self-consuming energy (thus savings on grid charges for self-consumed energy).

This massive penetration of RES has also imposed in Italy a rethinking of distribution network management methods, with a new model of regulation and dispatching management involving distributed generators in the provision of ancillary services also on LV and MV grids.

Pilot projects

In implementation of [2], ARERA has started an experimental phase for the purchase of flexibility by the DSO [42]. Pilot projects could be proposed by one or more DSOs (jointly) with the aim of experimenting with the most appropriate solutions for the supply of local ancillary services and the related remuneration. At the end of the experimentation, ARERA will define the regime regulation, within the scope of sections 7 and 16 of the TIDE [42].

Pilots are prepared by the DSOs following the preliminary activities and in compliance with the criteria indicated by [42] and subject to prior consultation with the stakeholders. DSOs must identify in advance the type of

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[6] In 2019, there was a significant increase in requests for low- and medium-voltage connection of production plants. In 2020, approximately 72,700 requests were recorded for a total capacity of around 9.4 GW, marking a sharp rise compared to the historic lows of previous years.

local ancillary services required and the related needs. All production and consumption units, and storage systems that comply, even on an aggregate basis, with the technical performance requirements set by the DSOs and not included in the AU's dispatching contract may be authorised to provide services.

The service providers are the BSPs. They must equip themselves with suitable devices to ensure the exchange of data with the DSOs; the flexibility product providers (and the related aggregates) are subjected to qualification procedures defined by the DSO aimed to verify their actual capacity to supply the service [42].

The DSOs' procedures must be transparent, non-discriminatory and based on market criteria, including forms of forward procurement to be carried out according to competitive procedures. The mechanisms can be of various types: implicit or explicit auction, based on long-term contracts (forward) or short-term markets (spot). ARERA, due to the absence of consolidated good practices and with the ultimate goal of evaluating which services are necessary, the most appropriate procedures, and the related remuneration, leaves the DSOs the possibility of defining the methods and implementation for the procurement of local services.

At the end of 2023 two projects were approved:

- The *EDGE* project started by e-distribuzione [98].
- The *RomeFlex* project started by Areti [99], which also supports the regulation of the *MindFlex* project [100] started later by Unareti.

The *EDGE* project is based on long term contracts, while the *Romeflex* project introduces both long term contracts and the use of short term markets for closer to real time activation [98, 99]; in both pilots, the services are characterized by active power products. In particular:

- The flexibility of forward MLF are used by DSOs to procure the availability of BSPs to provide the requested services when and where needed. Therefore, according to market results, contracts are defined such that the BSP does not know a priori whether it will be selected for the activation of the service or not, but makes itself available in the defined time windows for the provision of the service. Based on the cost-benefit analysis resulting from the negotiated service, the DSO defines the auction bases and the assignment prices, both for availability and for use, determining the final price with a pay-as-bid criterion (as in the case of the *EDGE* and *RomeFlex* projects) or pay-as-clear. During contractualization, the following are defined:
    - The availability price for the power committed to the provision of the service (expressed in terms of €/kW x h).

  - The utilization price for the modulated energy, the one actually selected by the DSO for the provision of the service (expressed in terms of €/kWh).

  The BSP will therefore receive a fixed remuneration based on the capacity committed and a variable remuneration based on the actual activation of the service by the DSO. The BSPs' offers are collected and selected based on an economic classification criterion. Once an offer is accepted, the service can be requested by the DSO without any further market session but only by sending an activation order within the pre-established timeframe.

  Long-term contracts have several advantages, such as preventing periods of low supply and reducing large price fluctuations of the service. The market mechanism characterized by capacity remuneration ensures a profit to the BSPs, thus increasing its interest in the provision of the service and, consequently, increasing the liquidity of the market. Furthermore, in a context where the flexibility park has to be incentivized to make it grow, remuneration mechanisms of this kind allow for a long-term vision of investment decisions, supporting the increase of flexible resources. Finally, long-term contracts allow for a direct comparison with network enhancement, which represents the other planning option [101].

- The spot MLF refers to the exchange of flexibility products with immediate settlement (or with a deferral of a few days). Therefore, like the energy market, the DSO buys and the BSPs sell the flexibility products for which they have requested prequalification. The offers are characterized by a single price, the equivalent of the usage price of the forward markets. The BSP receives a remuneration depending on the acceptance of its offers on the spot market at a price that can be equal to the offer price (pay-as-bid) or the clearing price (pay-as-clear). In the case of the flexibility market, a market for the supply of services, the sale and purchase will be initiated periodically or whenever the DSO detects the need to activate a certain volume of flexibility. Market participation is guaranteed to all assets that have passed the pre-qualification and verification test. At the moment, none of the Italian pilot projects is based exclusively on the spot market. The Romeflex project leaves the possibility for BSPs that do not have a long-term contract to participate in spot markets.

- In a hybrid approach there are both procurement methodologies. Some flexibility resources are contracted on a long-term basis for the supply of services (forward) for a defined period in which the asset must submit offers on the spot market; in addition, other resources can freely decide to participate directly in the spot market. Both the offers of the forward MLF and those of the spot MLF can be valued according to the pay-as-clear or pay-as-bid criterion (in the case of the Rome-Flex project, the pay-as-bid approach was preferred). The presence of forward products guarantees the DSO a minimum liquidity in the spot market, taking into account that the selection of offers for the actual use takes place within the latter. On the other hand, the presence of spot products leaves room for a better economic optimum and leaves open the participation of other resources that did not participate in the previous phase [101].

Chapter 3

Load Area and Flexibility Aggregation Perimeter for Local Ancillary Services

This chapter is based on the papers [102, 103], in which the flexibility aggregation perimeters for local ancillary services are determined through the application of the concept of LA, extensively studied at UNICAS by the Power Systems Group [8–10, 13, 104].

The flexibility required by DSOs has a strong local character. For the exploitation of flexibility, it is therefore relevant to identify the grid buses where flexibility can be provided for a service requested by the DSO. To this end, the flexibility perimeter can be defined as the set of the grid buses such that a given ancillary service can be provided by any set of prosumers connected to them, while grid operation remains secure; the perimeter may vary according to the ancillary service to be provided.

The concept of flexibility perimeter is relevant for the activity of a flexibility market; in particular, for an aggregator of prosumers connected within the flexibility perimeter who can offer the market a local ancillary service the volume of which is realized with the provisions by such prosumers. In a radial system, it is straightforward to state that a congestion-relieving flexibility service can only be provided by prosumers connected downstream of the overloaded[1] component; in the procurement of the service, the identification of the flexibility perimeter for this service immediately follows.

For a flexibility service intended to solve voltage profile problems, deciding on suppliers and volume of flexibility is not so simple, as the actual impact of flexibility in changing the voltage profile depends on the location of the prosumers as well as the electrical characteristics of the grid, in a way that is not easy to assess even in a radial grid. The DSO could calculate the values of volumes and positions to be procured by minimizing the total volume of flexibility, based on the usual nodal representation of the distribution grid; the result would be the flexibility volume to be procured in every single node of the grid such that the voltage profile is good. This is a technically sound solution, but very ineffective from a market point of view, as it hardly allows for effective competition between flexibility providers. It is indeed a nodal market splitting; in terms of flexibility perimeters, each grid bus is a perimeter.

A new systematic approach is necessary to determine flexibility perimeters for the provision of distribution grid ancillary services; it has to respond to the needs, on the one hand, of the DSOs for a correct representation of the grid and its operation, and, on the other hand, of the market for flexibility aggregation perimeters as wide as possible. The application of the LA concept can meet these requirements since LAs consist of grid buses whose power injection has a similar impact on grid operation.

3.1 Load Areas

The LA approach can be usefully adopted to identify the flexibility aggregation perimeter for any required service. A LA is a set of buses in a grid such that the power injection there has a similar impact on the operation of the grid, in particular on loading conditions and voltage profile. An OLA in a radial grid is made of the buses downstream of the overloaded relevant component; a VLA is made of the buses where (a change of) power injection has a similar impact on the grid voltage profile.

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[1] The term "congestion" can be understood as two different concepts. In Italy, Terna defines congestion as a situation of operation, even potential, of an electricity network "characterized by a deficiency of the electricity transport service due to network constraints" [105]. In other contexts, congestion has a more specific meaning, it "occurs when, due to the outage of network elements, the demand for cross-border trading capacities or for transport capacities for power plant output cannot be fully met."[106]. This more specific concept of congestion, which in this work is defined as "overload".

In the following, we recall the key points of the approach for the identification of LAs in balanced grids, modeled as single-phase grids; the reader is referred to [8, 10, 13, 107] for more details and applications, and to [11, 12] for the treatment of unbalanced grids.

3.1.1 Overload Load Areas

In the usual case of a radially operated distribution grid, the impact of the power injection into any node on an overload is derived with simple graph navigation techniques. In all the buses downstream of the relevant component, the power injection has the same impact on that congestion: these buses form the corresponding OLA.

An OLA can include other OLA(s); this is the case of two (or more) relevant components the loading of which is of concern that are downstream from each other.

3.1.2 Voltage Load Areas

The impact of each nodal injection on the grid voltage profile can be evaluated in the framework of the Inherent Structure Theory of Networks [4–8]: the impact of the variation of a nodal injection is evaluated by its influence on the voltage dominating spectral component(s).

Nodal voltages and currents injected into the buses are related by the well-known equation:

$$\bar{J} = \dot{Y}\bar{U}. \tag{3.1}$$

Matrix $\dot{Y}$ can be expressed as:

$$\dot{Y} = \dot{\Lambda}\, diag\{\dot{\lambda}_i\}\dot{\Lambda}^{-1}; \tag{3.2}$$

if no eigenvalue is zero, the L_2-norm of the node voltage vector can be expressed as follows:

$$||\bar{U}|| = ||\dot{Y}^{-1}\bar{J}\,|| = \Big|\Big|\sum_{i=1}^{n} \frac{1}{\dot{\lambda}_i}\dot{S}_i'\bar{J}\,\Big|\Big|, \tag{3.3}$$

with

$$\dot{S}_i = \begin{bmatrix} \frac{\partial\dot{\lambda}_i}{\partial\dot{Y}_{11}} & \cdots & \frac{\partial\dot{\lambda}_i}{\partial\dot{Y}_{1n}} \\ \vdots & \ddots & \vdots \\ \frac{\partial\dot{\lambda}_i}{\partial\dot{Y}_{n1}} & \cdots & \frac{\partial\dot{\lambda}_i}{\partial Y_{nn}} \end{bmatrix}. \tag{3.4}$$

For sensitivity analysis in a single-phase grid representation, it is acceptable to consider only the dominant spectral component of $\dot{Y}$, which is associated with the eigenvalue of minimum magnitude [4–6, 8]:

$$||\bar{U}|| \simeq \frac{1}{|\dot{\lambda}_1|}\left|\left|\dot{S}_1'\bar{J}\right|\right|. \tag{3.5}$$

Each matrix element in $\dot{S}_1$ represents the sensitivity of the first eigenvalue to the corresponding element of the nodal admittance matrix [4]. A variation of the injection at the generic i-th node is seen as a variation of the i-th self-admittance element, $\dot{Y}_{i,i}$; thus, the i-th diagonal element of matrix $\dot{S}_1$ in Equation (3.4), $\dot{S}_1(i,i)$, represents the sensitivity of the dominant eigenvalue, $\dot{\lambda}_1$, to the variation of the injection at the i-th node.

For the i-th bus, the quantity $S_r(i)$:

$$S_r(i) = \frac{\left|\dot{S}_1(i,i)\right|}{\max_j\left|\dot{S}_1(j,j)\right|} \tag{3.6}$$

is the normalized impact of the variation of the injection at that bus on the most significant component of the nodal voltages; it is a score of the sensitivity of the voltage profile to nodal injection in the i-th bus. With this view, buses are ordered based on S_r [7, 8]; two consecutive buses in this ordering, h and k, are considered to belong to different VLAs if

$$|S_r(h) - S_r(k)| > S_l, \tag{3.7}$$

where the threshold value S_l is given.

The grouping of buses into VLAs is a kind of data clustering method [11]. In these methods, there is some degree of arbitrariness [108] in deciding the closeness of points/measurements, and common sense is required to get significant results. Criterion (3.7) derives from the observation that gaps are usually encountered in the plots of S_r, and in [11] a “common sense” method for finding the value of S_l has been proposed. In the following, we go a step further and propose a method to group buses into VLA which starts from (3.7) and qualifies the VLAs through the acceptability of the grouping.

Voltage Load Area qualification

The qualification of VLAs considers the acceptability of the voltage error and the corresponding maximum flexibility.

Voltage error

The clustering of buses into VLAs is based on sensitivities; then, it provides acceptable results only for small variations of the power injections. To this aim, for a given load variation a partition Γ can be considered acceptable if

$$\left|U_i^s - U_i^t\right| \leq \varepsilon,\ \forall i \in grid,\ \forall s, t{\in}VLA_\gamma,\ \forall\gamma{\in}\Gamma, \tag{3.8}$$

where ε is a given value. Through (3.8), the clustering Γ is acceptable if (the absolute value of) the difference between the voltage magnitude in any bus of the grid due to different buses within any VLA where power variation takes place is acceptable.

The value of ε in (3.8) can be set as follows. According to [109], the uncertainty corresponding to the smallest tap changer step of OLTCs in the grid sets the accepted error in the voltage magnitude on any grid bus. We assume that this uncertainty, due to the dead band of the OLTC control, can be considered as the maximum accepted error also in the computation of the voltages; for example, for a 32-step voltage regulator with a range of ±10%, a one-step tap change corresponds to 0.00625 pu, and this can be the value of ε in (3.8).

Qualifying flexibility volume

The variations of the power injections we are interested in are the flexibilities of prosumers. If the flexibility provider is a pure consumer, it can control and change the withdrawn active power, and the reactive power follows. In the case of generating and storage units, the change of reactive power depends on their characteristics and the grid code [8, 13, 107]: it can be bound to active power, or it can be null, or it can depend on the voltage. The possibility of setting up a flexibility market explicitly addressed to reactive power is under study [110]. In the following, as in the existing implementations and pilot projects [42, 76, 79, 111–113], we consider the flexibility as the change in the active demand profile.

It is evident that for any given bus in the grid, i, and any given buses in a VLA, s and t, the lhs in (3.8) depends on the considered power variation; the bigger the magnitude of such variation, the bigger the lhs in (3.8).

We can envisage a method to qualify a partition for it to be correctly taken into account. Let F_Γ be the maximum variation of active power such that (3.8) holds; a partition Γ is said to be qualified as far as the active flexibility within any VLA in such partition Φ_γ is such that:

$$0 \leq \Phi_\gamma \leq F_\Gamma \qquad \gamma \in \Gamma. \tag{3.9}$$

Number of VLAs and qualifying flexibility volume

It is easily seen that as the number of VLAs gets bigger and bigger, the number of buses within each VLA gets smaller and smaller, and the difference in voltage profiles for a given load variation is smaller and smaller.

It follows that the qualifying flexibility volume grows as the number of VLAs grows. To obtain partitions with high qualifying flexibility volume, low values of S_l in (3.7) should be adopted, since the lower the value of S_l the higher the number of VLAs. Nevertheless, the lowering of S_l cannot be pushed too far, when no further significant gaps are recognized in the graph of S_r. In such a case, a partition with more VLAs can be obtained simply by splitting in two the VLA(s) where the voltage error (3.8) is maximum.

3.2 Flexibility aggregation perimeter

The flexibility aggregation perimeter may differ according to the ancillary service to be provided.

3.2.1 Congestion relief

In a radial grid, any prosumer connected within an OLA can provide flexibility useful to solve the congestion to which the OLA refers. The identification of the flexibility aggregation perimeter for an ancillary service intended to relieve congestion follows immediately: it is the OLA for that congestion.

3.2.2 Voltage support

For a flexibility service intended to solve voltage profile problems, deciding on suppliers and volume of flexibility is not that simple. In the following, we focus on the identification of the aggregation perimeter of flexibility for voltage support services.

The VLAs are clusters of buses; within any VLA, the flexibility can be supplied at any bus, provided that (3.9) holds. It is possible that within a VLA there are subclusters not directly connected; however, in most cases, each VLA is made of contiguous buses.

The buses within (the internally connected parts of) a VLA and the lines connecting them constitute a subgrid; it can be fruitful to represent the subgrids with reduced modeling, as shown in [9]. A reduced compact model of a subgrid may consist of only the edge buses; nevertheless, some further buses may be retained either to preserve some topological properties of the original grid or to represent buses the voltage of which is relevant for monitoring or control purposes [107]. Once the compact representation of each subgrid has been obtained, the whole grid can be represented with a reduced equivalent modeling made of the composition of the reduced modelings of the subgrids. For example, the small IEEE 13-bus test feeder [114] of Fig. 3.1, in which three LAs are identified, can be represented with the reduced modeling of Fig. 3.2 (in this case, only edge buses are retained); the details of the methods to get the values of the equivalent generators and impedances can be found in [9, 10]. The modeling error introduced by the reduction is largely acceptable [13].

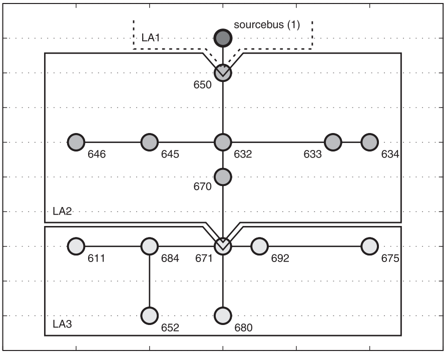

Figure 3.1: IEEE 13-bus test feeder [9].

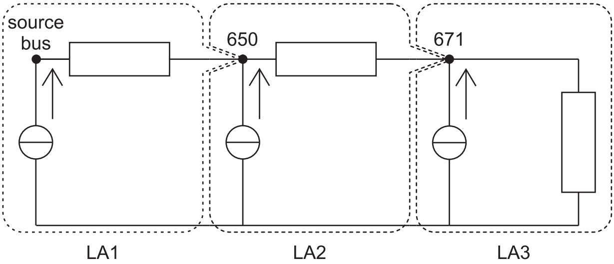

Figure 3.2: An equivalent reduced network of the grid in Fig. 3.1 [9].

3.2.3 Congestion relief and voltage support

To consider both grid issues, we can intersect OLAs and VLAs to get an overall partition Γ of the grid in LAs; each LA in this partition is made of buses the flexibility of which has a similar impact on both the congestions and the voltage profile. It has to be noticed that the perimeters of the OLAs do not depend on the flexibility volume within it, while the perimeter of the qualified VLAs depend on such volume.

In general terms, it can be written

$$\Gamma = f(\Gamma_O, \Gamma_V); \tag{3.10}$$

since the issue of partition qualification applies to partition Γ_V, the same issue applies to overall partition Γ.

The buses within (the internally connected parts of) a LA and the lines connecting them constitute a subgrid; it can be fruitful to represent the subgrids with a reduced modeling, as shown in [9]. A reduced compact model of a subgrid may consist of only the edge buses; nevertheless, some further buses may be retained either to preserve some topological properties of the original grid or to represent buses of which is relevant for monitoring or control purposes [107].

The compact representations of the subgrids can be combined to form a combined reduced equivalent modeling of the whole grid; the modeling error introduced by the reduction is by far acceptable [13].

3.3 Flexibility procurement with volume minimization

The DSO could evaluate the minimum amount of flexibility, $\overline{\Phi}_\Gamma$, for a given partition Γ adopting the reduced modeling of the grid and solving the following minimization problem:

$$\begin{aligned} \overline{\Phi}_\Gamma : \min \sum_{\gamma\in\Gamma} \Phi_\gamma \\ \text{subject to} \\ &\pi_\Gamma(\dot{A}, \dot{\Psi}_{\gamma\in\Gamma}) = 0, \\ &\xi_\Gamma(\dot{A}, \dot{\Psi}_{\gamma\in\Gamma}) \geq 0, \\ &0 \leq \Phi_\gamma \leq \sum_{j\in\gamma} \Phi_j^{max} \quad \forall\gamma\in\Gamma \\ &\Phi_\gamma \leq F_{\Gamma_V}, \ \forall\gamma\in\Gamma. \end{aligned} \tag{3.11}$$

With (3.11):

- the overall minimum volume of flexibility is computed;
- the correct operation of the (reduced grid) is enforced;
- the flexibility by each LA can be provided by the prosumers within that LA;
- the correctness of the reduced modeling of the grid through LAs is maintained.

From the meaning of LA, each LA would be an aggregation perimeter for grid support services. When procuring and activating flexibility services, attention has to be paid to avoid paying for the same flexibility product for two different services.

3.3.1 A-priori competitiveness index

The last two inequalities in (3.11) set limits on the flexibility for each LA. In general terms, the bigger the number of LAs, the lower the number of buses in the LAs, the lower the volume of flexibility available in each LA, $\sum_{j\in\gamma}\Phi_j^{max}$, but the bigger the flexibility that qualifies the partition, F_{Γ_V}.

The best partition of the grid in flexibility perimeters could be the one with the smallest value of $\overline{\Phi}_\Gamma$. However, searching for this smallest value would miss the important market aspect of the competition among flexibility providers.

The competitiveness of a market can be determined with the HHI [17, 18]: the higher the value of HHI , the higher the market concentration, the lower the competitiveness. Based on the HHI approach, the market concentration for the provision of flexibility ancillary services, in [102] the share of the providers' flexibility capabilities in each LA is measured with the index H_γ:

$$H_\gamma = \sum_{h\in\gamma}\left(\frac{\Phi_h^{max}}{\sum\limits_{j\in\gamma}\Phi_j^{max}}\right)^2. \tag{3.12}$$

For the whole grid, the market concentration for a given partition in LAs considers for each zone both the concentration index H_γ and the solution of problem (3.11) with the index H_Γ:

$$H_\Gamma = \frac{\sum_{\gamma\in\Gamma} H_\gamma \overline{\Phi}_\gamma}{\sum_{\gamma\in\Gamma}\overline{\Phi}_\gamma} = \frac{\sum_{\gamma\in\Gamma} H_\gamma \overline{\Phi}_\gamma}{\overline{\Phi}_\Gamma}. \tag{3.13}$$

Based on (3.11) and (3.13), any partition of the grid into LAs can be characterized with the minimum volume of flexibility to procure, $\overline{\Phi}_\Gamma$, and the market concentration index, H_Γ.

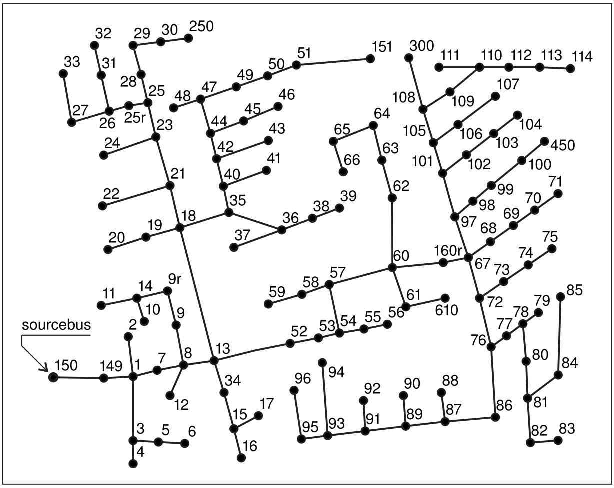

Figure 3.3: IEEE 123-bus test feeder.

3.3.2 Case studies

The test cases examine the IEEE 123-bus test feeder [114], [115] (Fig. 3.3). A starting partition in VLAs is represented in Fig. 3.4.

The presence of two congestions (on lines 23-25 and 97-101) is considered, which determines the two OLAs depicted in Fig. 3.5. The analysis includes the evaluation of the partition (Sect. 3.1.2) and the characterization of the LAs as flexibility aggregation perimeters (Sect. 3.2).

First case

A uniform increase of the reference load results in the operating conditions summarized in Table 3.1. A low grid voltage profile can be recognized, with the lowest voltage located at bus 114.

Table 3.2 reports the results of the partition qualification; in the first column, symbol Γ_V represents a partition of the grid in VLAs, while symbol Γ represents the corresponding partition after considering the two OLAs. The power factor of the qualifying flexibility is calculated as the average value of the reference total load. It is worth to note that, as the number of LAs in a partition increases and the LAs become smaller, the value of the qualifying flexibility becomes larger.

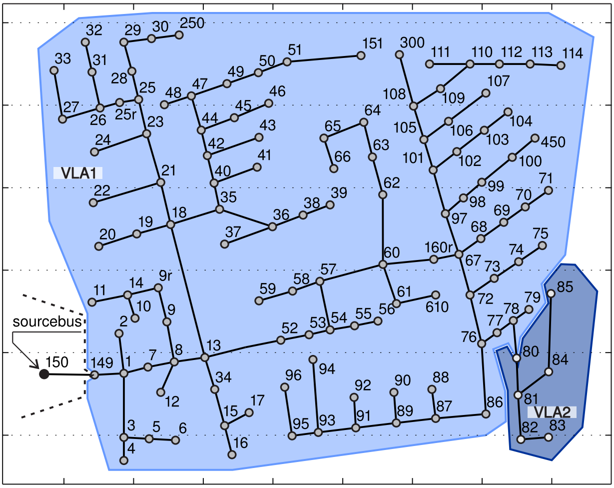

Figure 3.4: Voltage Load Areas for IEEE-123 bus grid – First partition.

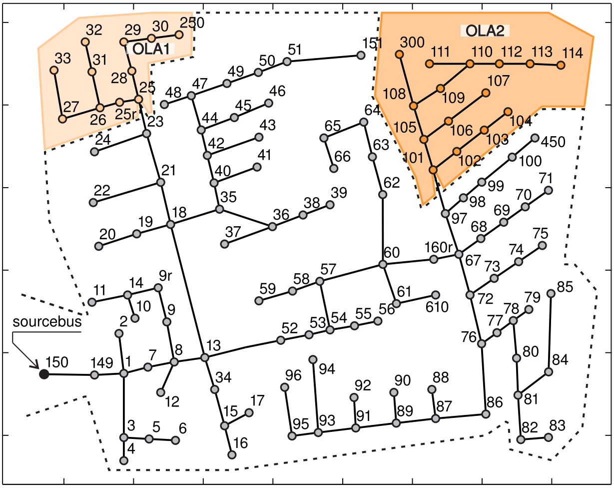

Figure 3.5: Overload Load Areas for IEEE-123 bus grid.

Table 3.1: Operating condition with voltage issue - First case.

	active power [kW]	voltage (@ bus) [pu]
min	11.2	0.943 (@ 114)
max	136.8	1.037 (@ 149)
average	22.9	0.968 -

Table 3.2: Qualification of the partitions - First case.

	partition			
partition VLA, LA	number VLA, LA	no. of buses LA min, avrg, max	F_{Γ_V} [kW]	p.f.
Γ_{V2}, Γ_4	2, 4	6, 31, 91	5	0.89
Γ_{V3}, Γ_5	3, 5	6, 25, 50	10	
Γ_{V7}, Γ_{10}	7, 10	1, 12, 50	35	
Γ_{V11}, Γ_{14}	11, 14	1, 9, 50	45	
Γ_{V14}, Γ_{16}	14, 16	1, 8, 25	60	
Γ_{V15}, Γ_{17}	15, 17	1, 7, 25	65	
Γ_{V18}, Γ_{20}	18, 20	1, 6, 25	70	

Table 3.3: Characterization of the partitions - First case.

partition	$\overline{\Phi}_\Gamma$ [kW]	H_Γ
Γ_4	no solution	
Γ_5	no solution	
Γ_{10}	43.3	0.24
Γ_{14}	46.4	0.37
Γ_{16}	41.1	0.59
Γ_{17}	40.8	0.60
Γ_{20}	40.0	0.71

The minimum flexibility volume is obtained by solving problem (3.11); the maximum possible flexibility by each provider Φ_j^{max} is set at 50% of its active consumption.

Each partition of the grid into LAs of Table 3.2 is characterized by the results of the problem (3.11) $\overline{\Phi}_\Gamma$ and the index of provider concentration H_Γ (3.13) in Table 3.3. Figure 3.6 illustrates the partition Γ_{V7} for VLA only; for the same partition, the contribution of OLAs is depicted in Fig. 3.7, where three new LAs are identified for Γ_{10}. Partitions Γ_4 and Γ_5 do not have a solution to problem (3.11) due to a too small qualifying power F_{Γ_V}; solutions for partitions Γ_{10} to Γ_{20} are possible. It can be seen that as the number of LAs increases, the value of $\overline{\Phi}_\Gamma$ decreases, then stabilizes, while the value of H_Γ increases.

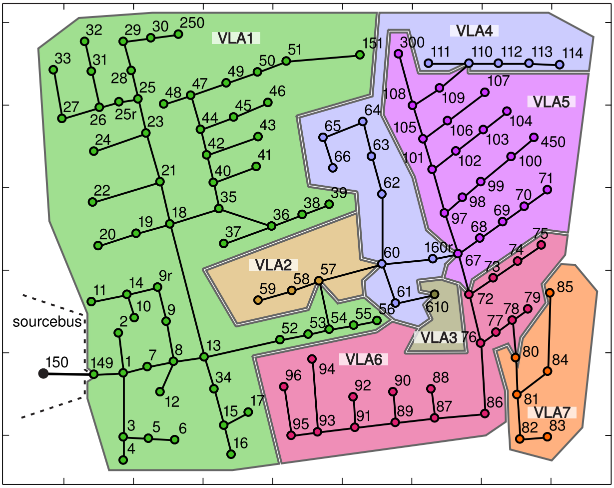

Figure 3.6: Voltage Load Areas for IEEE-123 bus grid – Partition Γ_{V7}.

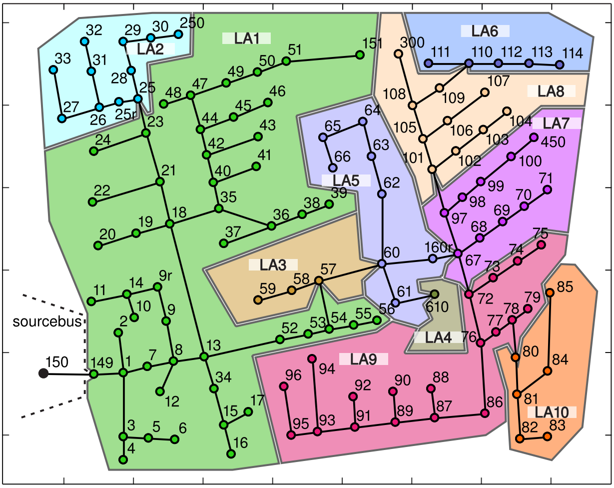

Figure 3.7: Load Areas for IEEE-123 bus grid – Partition Γ_{10}.

Table 3.4: Operating condition with voltage issue - Second case.

	active power [kW]	voltage (@ bus) [pu]
min	6.7	0.934 (@ 114)
max	133.3	1.037 (@ 149)
average	17.2	0.985 -

Second case

In the second case, an increase in the reference load in the feeder, including buses 110 to 114, led to the operating condition summarized in Table 3.4. As a result, some voltages in the grid are low, with the lowest voltage again at bus 114.

Table 3.5 reports the results of the partition qualification. As the number of LAs increases, the value of the qualifying flexibility increases also in the second case.

Table 3.6 summarizes the solution to the problem (3.11) and its characterization with (3.13); as an example, Figure 3.8 shows the partition Γ_{V11}. As in the first case, it is assumed that each consumer has the ability to supply a volume of flexibility equal to half its demand. The contribution of OLAs is reported in Figure 3.9, where still three new LAs can be identified for Γ_{14}.

Table 3.5: Qualification of the partitions - Second case.

	partition			
partition VLA, LA	number VLA, LA	no. of buses LA min, avrg, max	F_{Γ_V} [kW]	p.f.
Γ_{V2}, Γ_4	2, 4	6, 31, 91	5	
Γ_{V3}, Γ_5	3, 5	6, 25, 50	10	
Γ_{V7}, Γ_{10}	7, 10	1, 12, 50	35	
Γ_{V11}, Γ_{14}	11, 14	1, 9, 50	40	0.89
Γ_{V13}, Γ_{15}	13, 15	1, 8, 50	50	
Γ_{V14}, Γ_{16}	14, 16	1, 8, 25	60	
Γ_{V15}, Γ_{17}	15, 17	1, 7, 25	65	

Table 3.6: Characterization of the partitions - Second case.

partition	$\overline{\Phi}_\Gamma$ [kW]	H_Γ
Γ_4	no solution	
Γ_5	no solution	
Γ_{10}	136.8	0.20
Γ_{14}	88.3	0.58
Γ_{15}	70.9	0.99
Γ_{16}	70.9	0.99
Γ_{17}	70.9	0.99

Also in the second case, the partitions Γ_4 and Γ_5 do not present a solution to the problem (3.11). For partitions Γ_{10} to Γ_{17}, solutions were found, and they show a decreasing value of $\overline{\Phi}_\Gamma$ and an increase in value (up to saturation) of H_Γ.

Discussion

VLAs are typically composed of contiguous buses, but not always; for instance, VLA4 in Fig. 3.6 and VLA8 in Fig. 3.8 are made up of non-contiguous buses.

Different starting loading conditions can result in different values of the qualifying flexibility, as seen in partition Γ_{14} (compare F_{Γ_V} in Tables 3.2 and 3.5). This is because flexibility represents a variation of power injection, and different initial load values can have slightly different impacts on voltages in response to load variations.

From Tables 3.3 and 3.6, it is apparent that less flexibility is needed in the first case (uniform load increase) compared to the second case (concentrated load increase) to solve the same problems. The overall loading condition has a significant effect on the amount of flexibility required.

From Tables 3.3 and 3.6 it is apparent that the minimum volume of flexibility decreases (and then stabilizes) as the number of LAs increases. The opposite behavior can be observed for the value of the market concentration index, H_Γ. The results demonstrate the ability of the method to identify and evaluate the perimeters of aggregation of flexibility providers to provide a quantitative measure of the market and technical aspects of aggregation of flexibility.

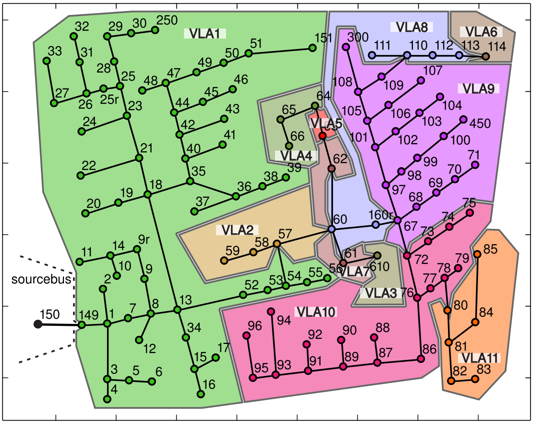

Figure 3.8: Voltage Load Areas for IEEE-123 bus grid – Partition Γ_{V11}.

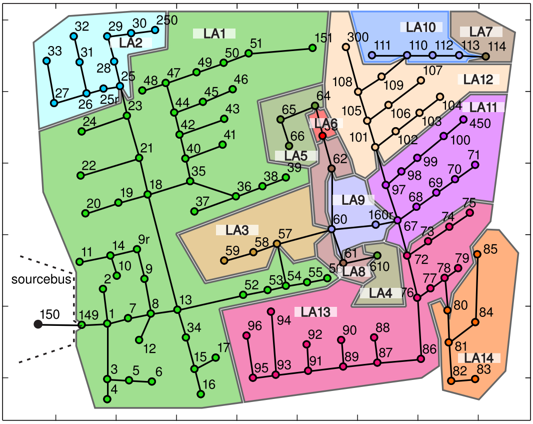

Figure 3.9: Load Areas for IEEE-123 bus grid – Partition Γ_{14}.

Chapter 4

Flexibility procurement with cost minimization

This chapter is based on the paper [116]. The process of procuring and delivering flexibility for the DSO needs can be split into four phases with specific time horizons and details of the representation of the products, services, and system: prequalification, procurement, activation, and settlement [117, 118]. In the following, we will focus on the procurement phase.

The flexibility useful to the DSO for congestion relief and voltage support services is highly localized, as an alternative to grid reinforcement. The DSO should therefore acquire flexibility services over a long-term horizon, in order to have the availability of necessary resources at the required locations over a long period of time [117]; future critical operating conditions are foreseen that can be alleviated through flexibility, and market mechanisms are put in place to procure the necessary flexibility capacity at the minimum cost.

In addition to the economic aspects of flexibility providers' offerings, their technical capabilities must be taken into account. Along with the amount of flexibility each provider is capable of (possibly in aggregate), the maximum duration of flexibility provision must also be considered, as both may be less than the DSO's needs; furthermore, any minimum recovery time before a service can be called up again must be taken into account. It follows that the procurement model must also consider the temporal dimension of service provision.

In the procurement phase, the decision maker faces uncertainty, for two main reasons. While a critical operating condition can be expected for a given period of time in the future (e.g., the middle hours of summer weekends), it is possible that one can only estimate the probability that the condition will actually occur (in the example, how many days of all summer weekends). Furthermore, it cannot be taken for granted that providers will be able to provide the agreed flexibility when needed.

Methods often adopted for decision-making process that must address uncertainties about the future [119], [120] are two-stage stochastic programming [121], [122], and robust optimization [123], [124]. In [116], we formulate an optimization problem for the procurement of flexibility with a scenario approach for the first source of uncertainty and a simplified treatment of the second one. This reflects the approach of some pilots [16], and allows us to avoid the details and computational burdens of more complex methods for managing uncertainty, as we want to focus on the impact of different aggregations of flexibility providers in perimeters on the outcomes of the procurement.

4.1 Grid model

There are various models of an electrical grid, either general, based on the nodal admittance matrix, or specific for radial systems, based on feeders and laterals. The buses within a LA and the lines connecting them form a subgrid; it can be useful to reduce the modeling of the LA subgrids, as proposed in [8–10] for the single-phase representation of a balanced network and in [11, 12] for the three-phase representation of an unbalanced network, with a modeling error due to the reduction which is widely acceptable [13]. The proposed reduced modeling allows retaining only the edge buses and other relevant buses; the whole grid can be represented with a reduced equivalent modeling by composing the reduced modelings of the LA subgrids.

The reduced modeling of the whole grid for a given partition in LAs, Γ, can be put in the compact form:

$$\begin{aligned} \pi_\Gamma(\dot{A}, \dot{\Psi}^t_{\gamma\in\Gamma}) = 0,\ \forall t, \\ \xi_\Gamma(\dot{A}, \dot{\Psi}^t_{\gamma\in\Gamma}) \geq 0,\ \forall t, \end{aligned} \tag{4.1}$$

with evidence of the dependence of the acceptability of the operating condition on the base-case power injections ($\dot{A}$) and flexibility ($\dot{\Psi}^t_{\gamma\in\Gamma}$). The real part of $\dot{\Psi}^t_{\gamma\in\Gamma}$ is the active flexibility $\Phi^t_{\gamma\in\Gamma}$; the imaginary part depends on the characteristics of the providers and/or the grid code. Here, we do not consider a flexibility market explicitly addressed to reactive power, as in the existing implementations and pilot projects [15, 16, 76, 79, 112, 113, 125]. In the long-term procurement of flexibility availability, a linear model can be assumed for the grid; we consider the load-flow equations and the inequalities on voltages and inter-area currents linearized around the base-case point.

4.2 Cost minimization model

The procurement of flexibility availability can be obtained by solving the following optimization problem in which, for a given partition Γ, the expected value of the service cost is minimized while the grid constraints are satisfied, the partition itself is qualified and the flexibility volume and provision durations (activation and recovery) by the providers are taken into account:

$$\begin{aligned} \overline{C}_\Gamma : \min D_a \sum_{t=1}^{n_T} \sum_{\gamma=1}^{n_\Gamma} \sum_{b_\gamma=1}^{n_\gamma} \Big(& y_{b_\gamma} m_{b_\gamma} a_{b_\gamma} \Phi_{b_\gamma}^{bid} + \\ & \sigma u_{b_\gamma} \Phi_{b_\gamma}^{t} \Big) \Delta t, \end{aligned} \tag{4.2a}$$

$$\begin{aligned} \text{s.t. } \; & \pi_\Gamma(\dot{A}, \dot{\Psi}^t_{\gamma\in\Gamma}) = 0, \;\forall t, \\ & \xi_\Gamma(\dot{A}, \dot{\Psi}^t_{\gamma\in\Gamma}) \geq 0, \;\forall t, \end{aligned} \tag{4.2b}$$

$$\Phi_\gamma^t = \sum_{b_\gamma=1}^{n_\gamma} \Phi_{b_\gamma}^t \leq F_\Gamma, \;\forall \gamma, \;\forall t, \tag{4.2c}$$

$$\begin{aligned} & x_{b_\gamma}^1 = w_{b_\gamma}^1, \forall b_\gamma, \forall \gamma, \\ & x_{b_\gamma}^{t+1} - x_{b_\gamma}^t = w_{b_\gamma}^{t+1} - z_{b_\gamma}^{t+1}, \forall t \neq n_T, \forall \gamma, \;\forall b_\gamma, \\ & w_{b_\gamma}^t + z_{b_\gamma}^t \leq 1, \;\forall t, \forall \gamma, \;\forall b_\gamma, \\ & x_{b_\gamma}^t \leq y_{b_\gamma}, \forall t, \forall \gamma, \;\forall b_\gamma, \\ & x_{b_\gamma}^t \Phi_{b_\gamma}^{min} \leq \Phi_{b_\gamma}^t \leq x_{b_\gamma}^t \frac{\Phi_{b_\gamma}^{bid}}{\omega}, \;\forall t, \forall \gamma, \;\forall b_\gamma, \\ & w_{b_\gamma}^{t+1} + z_{b_\gamma}^{t+1} \pm \frac{(\Phi_{b_\gamma}^{t+1} - \Phi_{b_\gamma}^t)}{\Phi_{b_\gamma}^{bid}/\omega} \geq 0, \forall t \neq n_T, \forall \gamma, \;\forall b_\gamma, \\ & w_{b_\gamma}^t \leq \sum_{\tau=t+1}^{min\{t+n_{b_\gamma}^{on};\, n_T\}} z_{b_\gamma}^\tau, \quad t \in [1, n_T - n_{b_\gamma}^{on}], \forall \gamma, \;\forall b_\gamma, \\ & \sum_{\tau=max\{t-n_{b_\gamma}^{off}+1;\, 1\}}^{t} z_{b_\gamma}^\tau \leq 1 - x_{b_\gamma}^t, \;\forall t, \forall \gamma, \;\forall b_\gamma, \\ & x_{b_\gamma}^t, w_{b_\gamma}^t, z_{b_\gamma}^t \in \{0, 1\}, \;\forall t, \forall \gamma, \;\forall b_\gamma. \end{aligned} \tag{4.2d}$$

With (4.2), we consider a pay-as-bid auction where the DSO is the buyer of flexibility services [14] with long-term agreed capacity availability during the required time windows, and utilization either scheduled or activated upon the DSO's request in operation (with appropriate lead time, for example, the day before). The time horizon can span months/seasons/years ahead, and each auction refers to a specific flexibility service requested by the DSO to counteract a specific poor grid operating condition; for example, a voltage support service to resolve an undervoltage condition expected for weekdays in the next winter season [15, 16].

The expected value of the service is the sum of the cost of the availability and the expected cost of the activation. Here, we express the latter through a given estimate of the probability of future activation; for scheduled utilization, the probability is equal to one. Furthermore, in a long-term horizon the possibility that flexibility providers do not adequately respect the scheduled demand diagram or do not adequately respond to activation requests must be considered; here, we account for this possibility by simply introducing an overprocurement factor [16], by which the DSO procures more availability than is strictly necessary.

In particular:

- for a given partition in VLAs, Γ, the overall minimum expected cost of flexibility service, $\overline{C}_\Gamma$, is computed (4.2a) – The payment method for availability is defined by the market rules; for example, for a payment for the entire service duration requested by the DSO it is $m_{b_\gamma} = 1, \forall\gamma,\ \forall b_\gamma$;
- the correct operation of the reduced grid is enforced with the (linearized) load-flow equations and limits on voltages and currents (4.2b), and the correctness of the reduced modeling is maintained by limiting the flexibility deployed in any VLA (4.2c);
- for each provider, the expected operation is taken into account (4.2d):
  - the provided flexibility is within the technical minimum and the derated bidding value (4.2d.5);
  - once activated, the provided flexibility remains constant until deactivation (4.2d.6);
  - the maximum activation duration (4.2d.7) and the minimum recovery time (4.2d.8) are respected; moreover,
  - in the first time interval, the state of provision and activation depend on each other (4.2d.1);
  - provision state change and activation/deactivation depend on each other (4.2d.2);

  - activation and deactivation cannot occur in the same time interval (4.2d.3);
  - the offer acceptance indicator is non-zero whenever flexibility is provided (4.2d.4).

Any flexibility provider can participate in the provision of the voltage support ancillary service, and no constraint is directly imposed on its position in the grid. At the same time, the competition among flexibility providers is limited by the grid constraints (4.2b) and the limit on total flexibility in any VLA (4.2c).

Let us consider the case of flexibility services provided by aggregators of prosumers; in general terms, the larger the VLAs and therefore the fewer their number:

- in each VLA, the greater the number of prosumers, and therefore the greater the number of likely aggregators, the unconstrained competition between them, and the flexibility the aggregator(s) could provide; but
- the less flexibility that qualifies the partition and therefore the less flexibility that each aggregator would be allowed to provide.

A relationship between competition among flexibility providers and the division of the grid into VLAs is evident (the flexibility available in each LA and the flexibility that qualifies the partition behave in opposite ways as the number of LAs in the partition varies); It has been characterized in [102] with an indicator of market concentration in the provision of flexibility services. For each partition of grid in VLAs, the market concentration index H_Γ is evaluated, based on the Herfindahl-Hirschman index approach [17, 18]:

$$H_\Gamma = \frac{\sum_{\gamma\in\Gamma} H_\gamma \overline{\Phi}_\gamma}{\sum_{\gamma\in\Gamma} \overline{\Phi}_\gamma} = \frac{\sum_{\gamma\in\Gamma} H_\gamma \overline{\Phi}_\gamma}{\overline{\Phi}_\Gamma}, \tag{4.3}$$

in which H_γ measures the share of the providers' flexibility capabilities in each LA,

$$H_\gamma = \sum_{h\in\gamma} \left(\frac{\Phi_h^{max}}{\sum\limits_{j\in\gamma} \Phi_j^{max}} \right)^2, \tag{4.4}$$

and $\overline{\Phi}_\Gamma$ is the minimum volume of total flexibility that would allow solving the voltage problem, with the corresponding $\overline{\Phi}_\gamma$ in each VLA. The index H_Γ is only based on the structural characteristic of the grid and the flexibilities likely available; being evaluated a-priori, the index is only a proxy of the measure of the effective market concentration and competition between service providers. For further details, please refer to [102].

4.3 Case Studies

Three case studies analyzed the IEEE 123-bus test feeder of Fig. 4.1 [114]. In the first, a poor voltage condition in a large portion of the grid is considered, while in the second and the third only a few buses show poor voltage values. Many grid partitions were considered, with the number of VLA ranging from 2 (Fig. 4.2) to 15 (Fig. 4.3). The VLAs were obtained as in [8], [102] and qualified as in [102]; their reduced representation was obtained as in [8, 9, 13] (see Sect. 4.1). It was assumed that the power variation representing flexibility maintains the same power factor as the overall base-case power injection. The optimization problem (4.2) was solved with Gurobi [126].

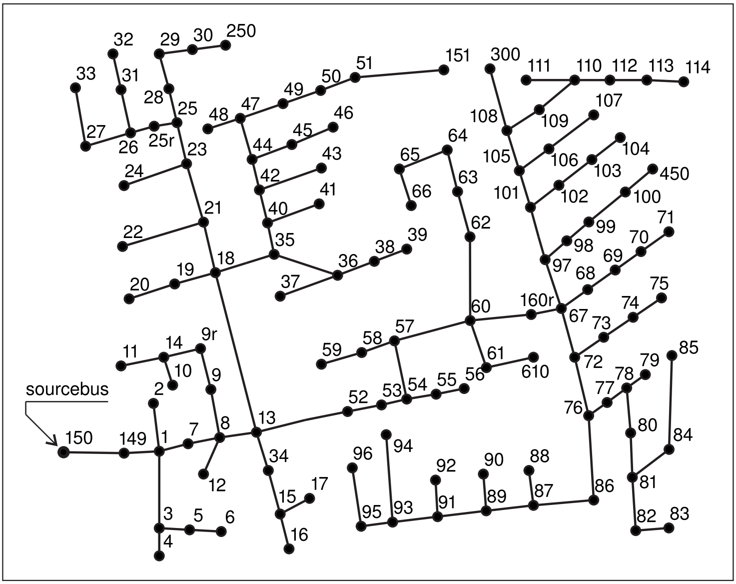

Figure 4.1: IEEE 123-bus test feeder.

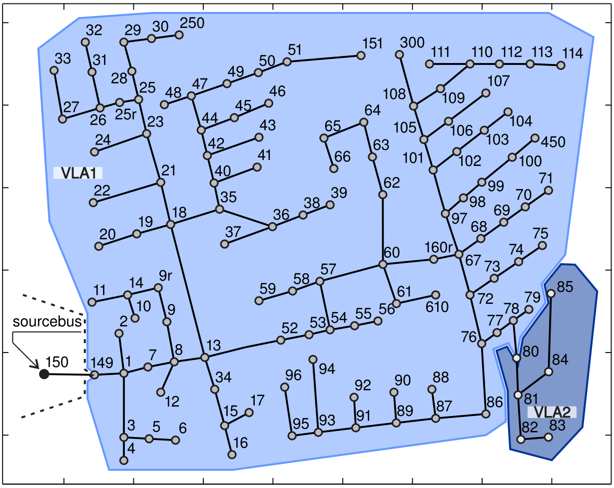

Figure 4.2: Voltage Load Areas for IEEE-123 bus grid – Partition Γ_2.

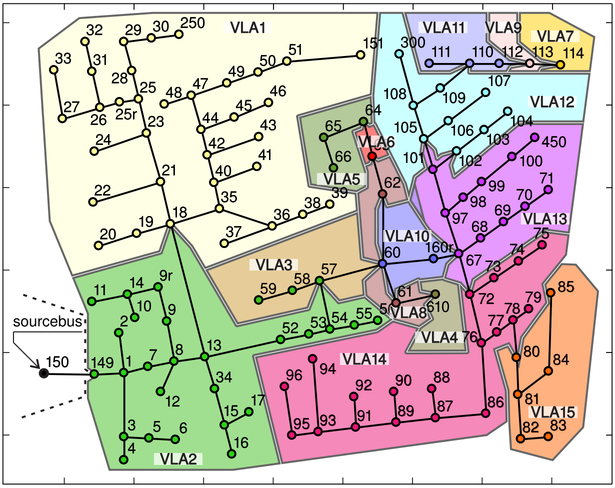

Figure 4.3: Voltage Load Areas for IEEE-123 bus grid – Partition Γ_{15}.

Table 4.1: Auction parameters

Operator	a_{b_γ} [€/kW/h]	u_{b_γ} [€/kWh]	$\Phi_{b_\gamma}^{min}$ [kW]	$\Phi_{b_\gamma}^{bid}$ [kW]	$n_{b_\gamma}^{on}$	$n_{b_\gamma}^{off}$
# 1	0.10	0.51	3.0	see text	8	20
# 2	0.10	0.63	3.0		8	20
# 3	0.20	0.51	3.0		8	20
# 4	0.20	0.63	3.0		8	20
# 5	0.30	0.39	3.0		8	20
# 6	0.40	0.15	3.0		8	20
# 7	0.40	0.27	3.0		8	20
# 8	0.50	0.15	3.0		8	20
# 9	0.50	0.27	3.0		8	20
# 10	0.10	0.51	3.0		12	20
# 11	0.10	0.63	3.0		12	20
# 12	0.20	0.51	3.0		12	20
# 13	0.20	0.63	3.0		12	20
# 14	0.30	0.39	3.0		12	20
# 15	0.40	0.15	3.0		12	20
D_a=40 *days*	$n_T = 20$	m_{b_γ}=1	σ=0.5	Δt=0.25 *h*	ω=1	

The auction parameters are summarized in Table 4.1; a total of 15 market operators acting as flexibility aggregators were considered, with offered prices (a_{b_γ} and u_{b_γ}) obtained from information available in [19], maximum activation duration ($n_{b_\gamma}^{on}$) less than the service duration requested by the DSO (n_T), minimum recovery duration ($n_{b_\gamma}^{off}$) such that the flexibility can be activated only once a day.

Hundreds of runs were carried out; in each run:

i. the market operators were casually placed one in each VLA of the partition Γ_{15};

ii. the bidding values were set as $\Phi_{b_\gamma}^{bid} = \min\{F_\Gamma, \Phi_{\gamma\in\Gamma_{15}}^{avail}\}$, with the value of the available flexibility $\Phi_{\gamma\in\Gamma_{15}}^{avail}$ equal to 50% of the total load in the γ-th VLA $\in \Gamma_{15}$;

iii. the problem (4.2) was solved;

iv. VLAs were merged into larger VLAs, corresponding to a qualified grid partition with fewer VLAs; the operators kept the values of the offered prices and durations;

v. computations continued from step ii., until no new VLA merging was possible.

The flow chart in Fig. 4.4 summarizes the steps of the computing process.

1. VLA identification	Sensitivity analysis of the bus admittance matrix [19] and admissible voltage error [20]
2. VLA qualification	Admissible voltage error and qualifying maximum flexibility [20]
3. Reduced grid modeling	Reduced modeling of VLA subgrids and of whole grid [19] [22] [25]
4. Optimal procurement	Run the following, as many times as necessary for statistical purposes: i. casually place operators in the VLAs of the more numerous partition ii. set operators' biddings iii. solve problem (3) iv. merge VLAs into larger VLAs v. continue from step ii. until no new VLA merging is possible

Figure 4.4: Computing process.

4.3.1 First case

In the first case study, a uniform increase in the reference load was considered throughout the grid (Table 4.2). The corresponding voltage profile is shown in Fig. 4.5: in many buses, the voltage is below the lower limit of 0.95, and the lowest value is observed on bus 114.

Table 4.2: Operating condition with voltage issue - First case

	min	max	average	$\sum \lvert 1 - U_i \rvert$
active power [kW]	11.2	136.8	22.9	–
voltage [pu] @ bus	0.94 @114	1.04 @149	0.97	4.34

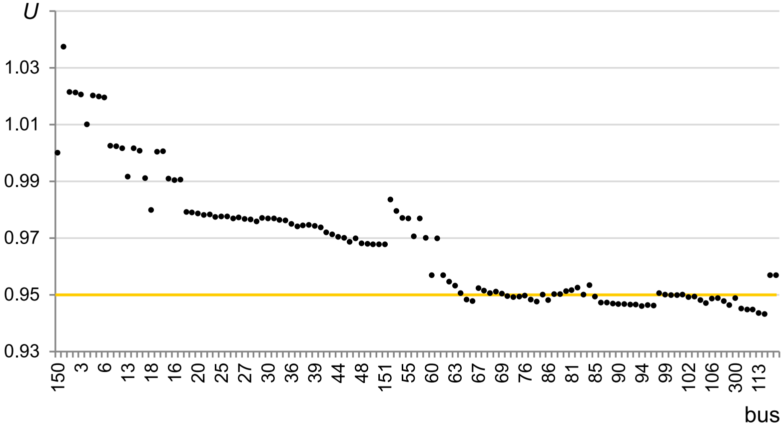

Figure 4.5: Initial voltage profile, first case.

Table 4.3: Qualification of the partitions - First case

	VLA			
partition	number	no. of buses min, avrg, max	F_Γ [kW]	p. f.
Γ_2	2	6, 62, 117	5	
Γ_3	3	6, 41, 61	10	
Γ_7	7	1, 18, 61	35	
Γ_{11}	11	1, 11, 61	45	0.89
Γ_{14}	14	1, 9, 36	60	
Γ_{15}	15	1, 8, 36	65	

Qualification The qualification of partitions is summarized in Table 4.3. The power factor value of the qualifying flexibility corresponds to the average value of the total reference load. It is evident that as the number of VLAs increases, the individual VLAs become smaller, and the value of the qualifying flexibility increases (see *no. of buses* and F_Γ in Tab. 4.3).

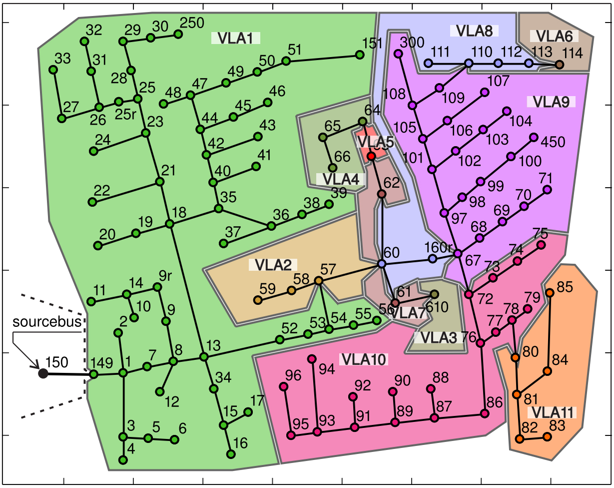

Figure 4.6: Voltage Load Areas for the IEEE-123 bus grid – Partition Γ_{11}.

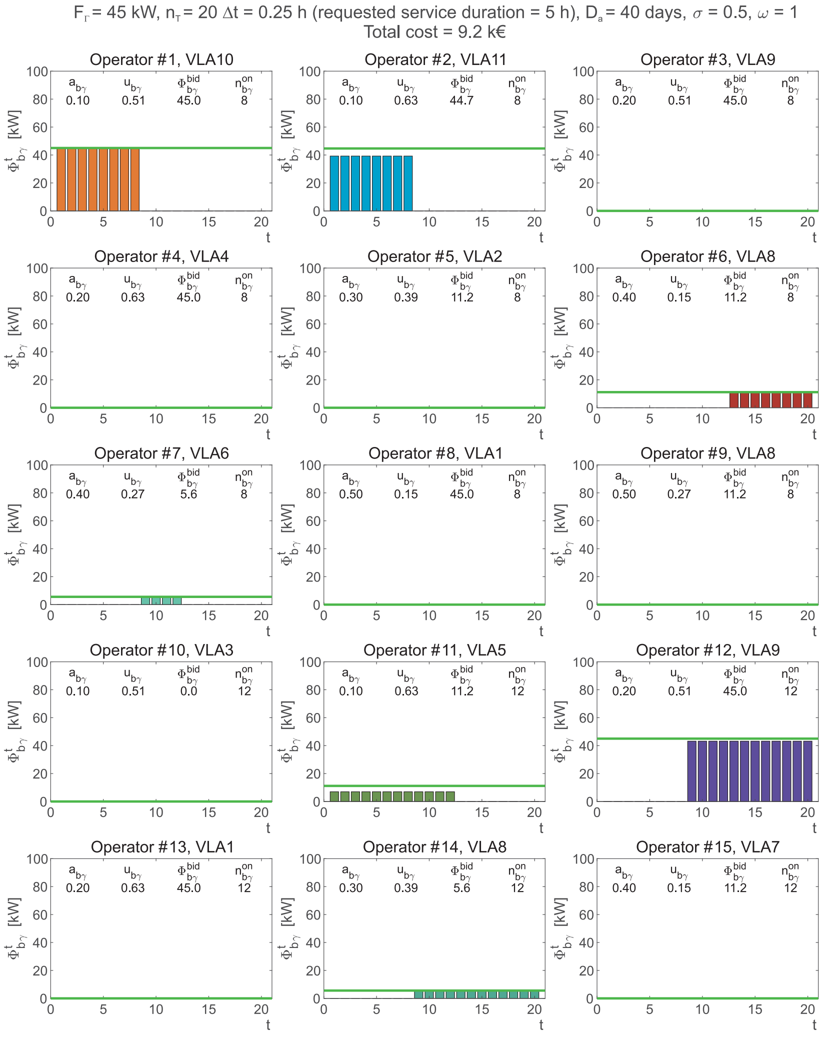

Figure 4.7: Sample solution of (4.2) in partition Γ_{11}, first case.

Characterization A sample solution of (4.2) for partition Γ_{11} of Fig. 4.6 is shown in Fig. 4.7; in this partition, the buses with the starting voltage value below the lower limit belong to VLAs no. 4, 6, 8, 9, 10, and 11. In the sample solution of Fig. 4.7, among the flexibility providers located in areas with undervoltage, some are selected (#1, #2, #6, #7, #12, #14) and some are not (#3, #4, #9), and an operator located in an unaffected area is selected (#11).

By repeatedly solving the procurement problem (4.2) we obtained the expected minimum cost of the service, $\overline{C}_\Gamma$, for different positions in the grid of different aggregators and for different partitions of the grid. The box plot of Fig. 4.8 shows the minimum, maximum, median, 10th and 90th percentile of $\overline{C}_\Gamma$ for various partitions.

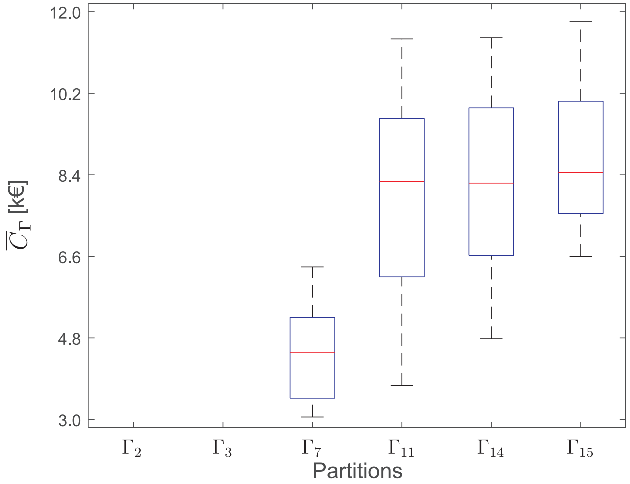

Figure 4.8: Minimum expected cost – First case.

For each partition, the value of the concentration index H_Γ (4.3) has been computed as in [102]; Table 4.4 summarizes the values of the median minimum procurement cost and the concentration index. For partitions Γ_2 and Γ_3 no solution is possible, due to the too small value of the qualifying power F_Γ. For partitions Γ_7 to Γ_{15}, a solution is found; it can be noted that in Γ_7 the median optimal cost is lower than that of the other partitions, where the value stabilizes around a value equal to approximately double that of the Γ_7. With a lower number of VLA the value of H_Γ is lower [102].

Table 4.4: Characterization of the partitions - First case

partition	med $\overline{C}_\Gamma$ [k€]	H_Γ
Γ_2	no solution	
Γ_3	no solution	
Γ_7	4.5	0.27
Γ_{11}	8.3	0.48
Γ_{14}	8.2	0.84
Γ_{15}	8.5	1.00

4.3.2 Second and third cases

In the second and third case studies, we consider local increases in the loads to have localized undervoltage conditions.

Second case

In this case study, we consider a uniform increase in the load on the branch from bus 110 to bus 114; the operating condition is summarized in Table 4.5. In this case, low voltage values are localized in the zone of increased load (Fig. 4.9), and the lowest voltage is registered on bus 114, as in the first case study.

Table 4.5: Operating condition with voltage issue - Second case

	min	max	average	$\sum\lvert 1-U_i\rvert$
active power [kW]	6.7	133.3	17.2	–
voltage [pu] @ bus	0.93 @114	1.04 @149	0.99	2.45

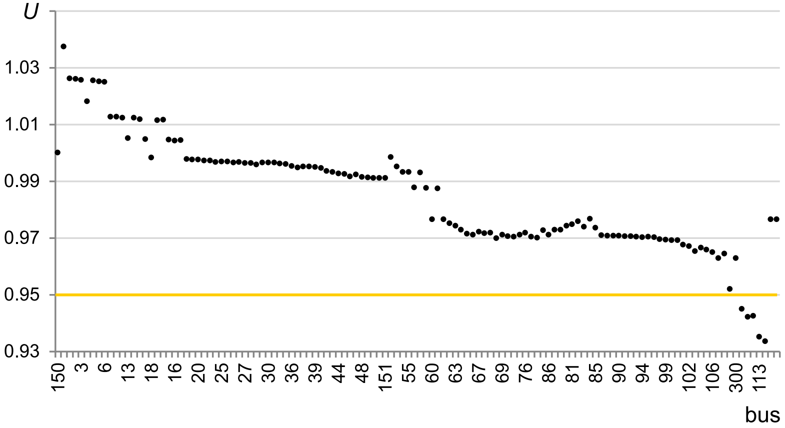

Figure 4.9: Initial voltage profile, second case.

Table 4.6: Qualification of the partitions - Second case

partition	VLA number	VLA no. of buses min, avrg, max	F_Γ [kW]	p. f.
Γ_2	2	6, 62, 117	5	0.89
Γ_3	3	6, 41, 61	10	
Γ_7	7	1, 18, 61	35	
Γ_{11}	11	1, 11, 61	40	
Γ_{13}	13	1, 9, 61	50	
Γ_{14}	14	1, 9, 36	60	
Γ_{15}	15	1, 8, 36	65	

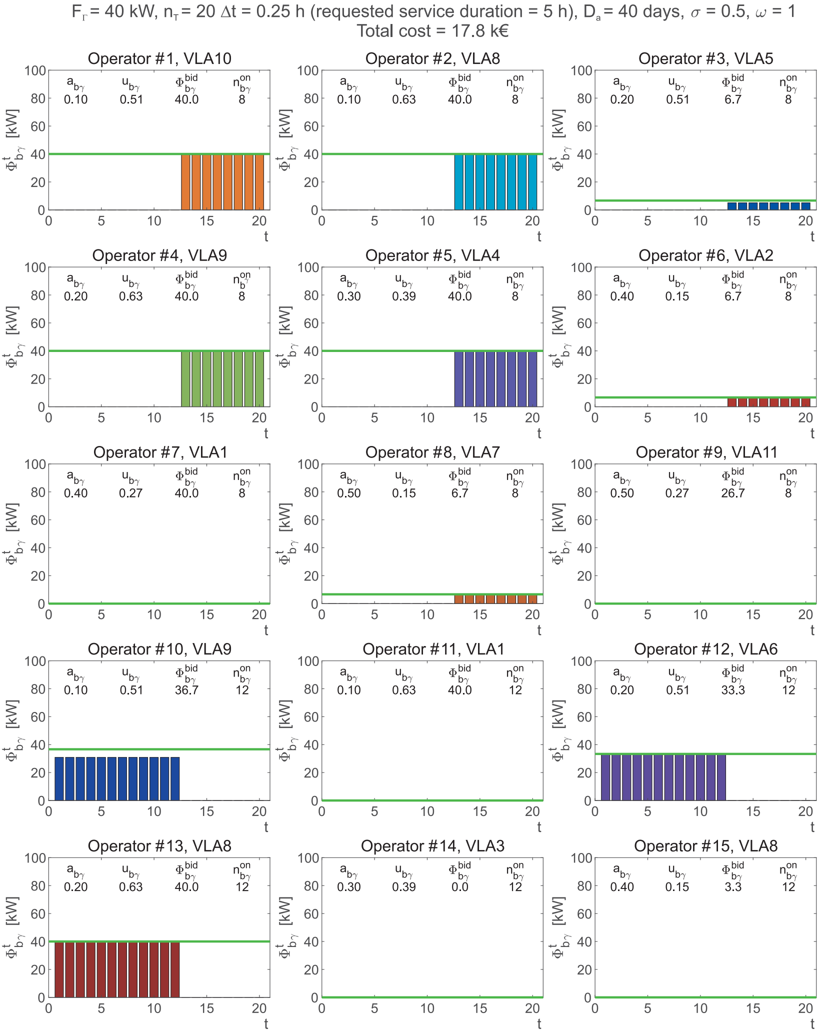

Figure 4.10: Sample solution of (4.2) in partition Γ_{11}, second case.

Qualification The results of the partition qualification are shown in Table 4.6. As in the first case, the power factor for the qualifying flexibility is the average of the total reference load. Again, as the number of VLAs increases the qualifying flexibility increases.

Characterization A sample solution of (4.2) is shown in Fig. 4.10, obtained for partition Γ_{11} of Fig. 4.6. In this partition, the buses with the starting voltage below the lower limit belong to VLAs no. 6 and 8; in the sample solution of Fig. 4.10, among the flexibility providers located in the areas with undervoltage, some are selected (#2, #12, #13) and some are not (#15), and operators located in unaffected areas are selected (#1, #3, #4, #5, #6, #8, #10).

For the second case study, the solutions of the optimization problem (4.2) obtained with different positions in the grid of different aggregators and with different partitions of the grid are summarized in the box plot of Fig. 4.11.

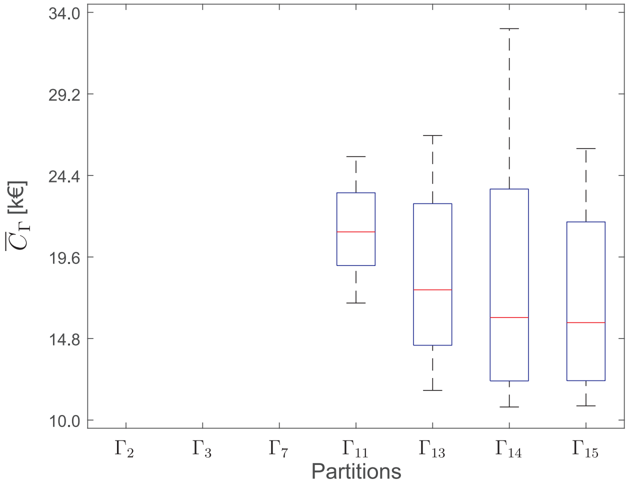

Figure 4.11: Minimum expected cost – Second case.

As for the first case, Table 4.7 summarizes the values of the median minimum procurement cost and the concentration index H_Γ (4.3). Similarly to the first case study, no solution is possible for partitions with large VLAs and small value of the qualifying flexibility; in this case, Γ_2 to Γ_7. For partitions Γ_{11} to Γ_{15}, solutions exist; lower values of the median minimum cost are obtained as the number of VLAs increase, with a growing value of F_Γ and H_Γ.

Table 4.7: Characterization of the partitions - Second case.

partition	med $\overline{C}_\Gamma$ [k€]	H_Γ
Γ_2	no solution	
Γ_3	no solution	
Γ_7	no solution	
Γ_{11}	21.1	0.67
Γ_{13}	17.7	1.00
Γ_{14}	16.0	1.00
Γ_{15}	15.7	1.00

Third case

In this case study, we consider a uniform increase in the load of the buses of VLA11 (see Fig. 4.6); the corresponding operating condition is summarized in Table 4.8. Low voltage values are localized in the area of increased load and nearby (Fig. 4.12), and the lowest voltage is registered on bus 85.

Table 4.8: Operating condition with voltage issue - Third case

	min	max	average	$\sum \lvert 1 - U_i \rvert$
active power [kW]	6.7	133.3	19.3	–
voltage [pu] @ bus	0.93 @85	1.04 @149	0.97	3.61

Qualification The results of the partition qualification are shown in Table 4.9. As in the previous cases, the power factor for the qualifying flexibility is the average of the total reference load; the qualifying flexibility increases as the number of VLAs increases.

Characterization A sample solution of (4.2) is shown in Fig. 4.13, obtained for partition Γ_{11} of Fig. 4.6. In this partition, the buses with the starting voltage below the lower limit belong to VLAs no. 10 and 11; in the sample solution of Fig. 4.13, the flexibility providers located in the areas with undervoltage are selected (#2, #5) as well as operators located in unaffected areas (#1, #4, #7, #8, #9, #11, #13, #14, #15).

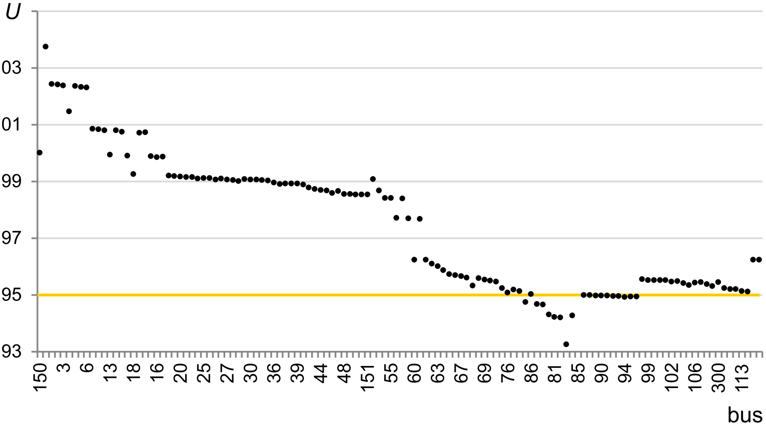

Figure 4.12: Initial voltage profile, third case.

Table 4.9: Qualification of the partitions - Third case

	VLA			
partition	number	no. of buses min, avrg, max	F_Γ [kW]	p. f.
Γ_2	2	6, 62, 117	5	0.89
Γ_3	3	6, 41, 61	10	
Γ_7	7	1, 18, 61	35	
Γ_{11}	11	1, 11, 61	45	
Γ_{13}	13	1, 9, 61	50	
Γ_{14}	14	1, 9, 36	60	
Γ_{15}	15	1, 8, 36	65	

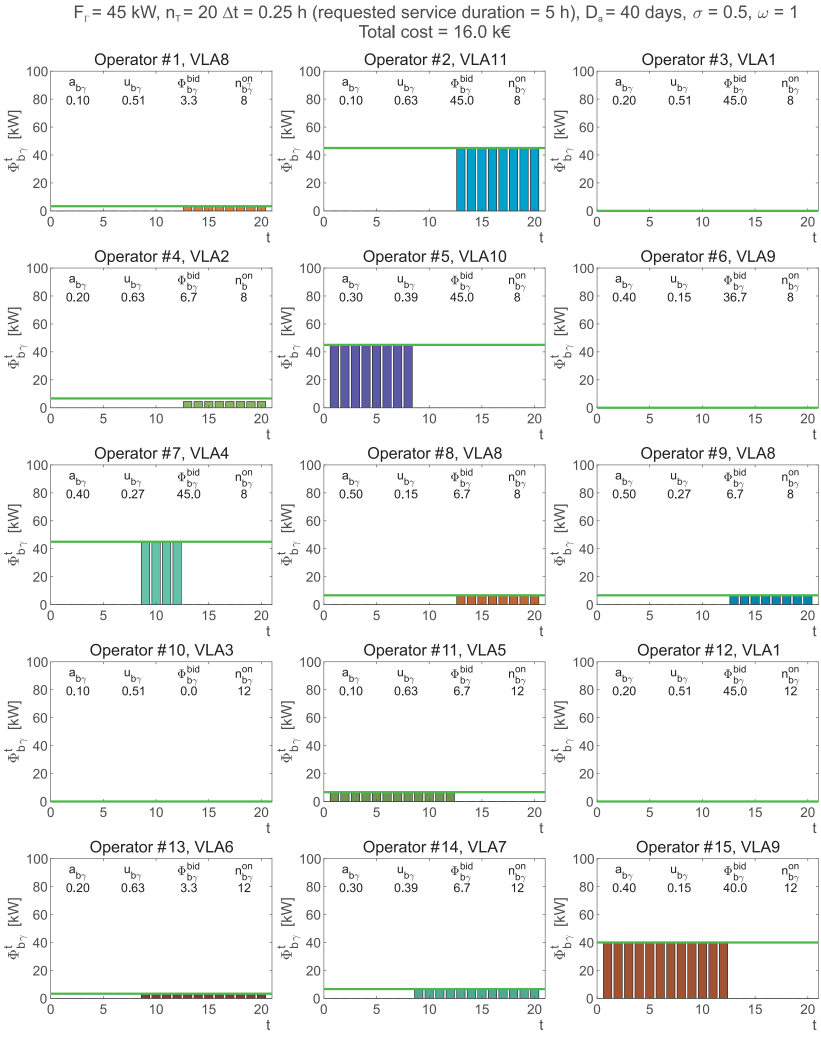

Figure 4.13: Sample solution of (4.2) in partition Γ_{11}, third case.

For the third case study, the solutions of the optimization problem (4.2) obtained with different positions in the grid of different aggregators and with different partitions of the grid are summarized in the box plot of Fig. 4.14.

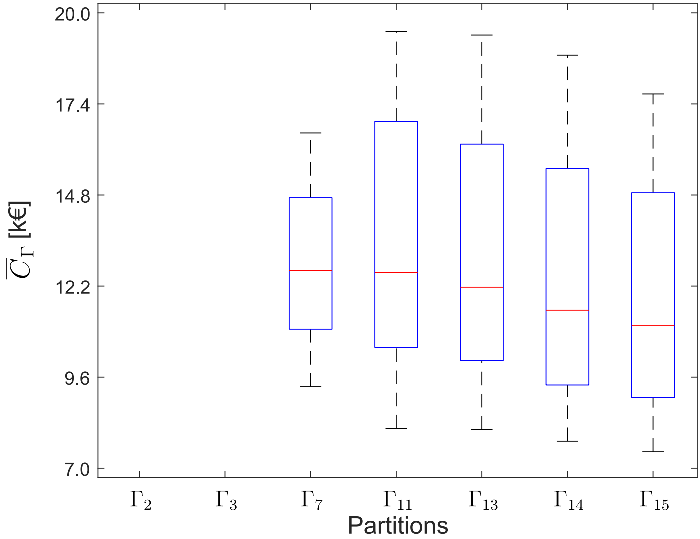

Figure 4.14: Minimum expected cost – Third case.

As for the previous cases, Table 4.10 summarizes the values of the median minimum procurement cost and the concentration index H_Γ (4.3).

Table 4.10: Characterization of the partitions - Third case

partition	med $\overline{C}_\Gamma$ [k€]	H_Γ
Γ_2	no solution	
Γ_3	no solution	
Γ_7	12.6	1.00
Γ_{11}	12.6	1.00
Γ_{13}	12.2	1.00
Γ_{14}	11.5	1.00
Γ_{15}	11.0	1.00

Similarly to the second case study, no solution is possible for partitions with large VLAs and small value of the qualifying flexibility; in this case, Γ_2 to Γ_3. For partitions Γ_7 to Γ_{15}, solutions exist; lower values of the median minimum cost are obtained as the number of VLAs increase, with a growing value of F_Γ (H_Γ is always at its maximum).

Computational effort – Simulations were carried out on an Intel(R) Core(TM) i9-10980HK CPU @ 2.40GHz with 32 GB of RAM, run in Matlab® [127] under Windows 10.0 OS. Table 4.11 reports the mean values of the computation times of the four steps of the computing process of Fig. 4.4.

Table 4.11: Computing times

step	mean computing time [s]
1. VLA identification	0.5 s
2. VLA qualification	1.9 s
3. Reduced grid modeling	0.5 s
4. Optimal procurement	14.2 s (per run)

For the three case studies, most of the computation time has been spent in step 4, where hundreds of runs were performed to simulate different offers, in different areas, for different partitions in VLAs.

4.3.3 Discussion

The median value of the expected minimum cost versus the aggregation perimeter has a different trend in the three case studies, representative of different causes and spread of undervoltage: it originates in the first case from a uniform load increase involving all the buses, and in the second and third cases from localized load increases. In the first case, the median value increases as the number of VLA increases; in the second and third cases, the opposite behaviour is observed. On the other hand, the value of the proxy index H_Γ increases as the number of VLAs increases. The expected minimum cost of the flexibility service in the first case study is generally much lower than in the second and third cases.

In the first case, the worst undervoltage (on bus 114) occurs with poor voltage in a large part of the grid. The flexibility in any VLAs has a similar impact on the voltage profile; competition between providers deploys at a great extent, and the larger the VLAs the better the competition. It allows the auction mechanism to select the most convenient offers and to procure flexibility at a lower cost than one would expect if the same operators operated in distinct VLAs, since in this case grid constraints would not allow for well-developed competition.

In the second case, the same worst undervoltage as in the first case comes instead with a good voltage in almost the entire grid. The observed decrease in the median value of $\overline{C}_\Gamma$ as the number of VLAs increases could be due to the greater impact on undervoltage resolution by flexibility providers located within or close to the affected area (observe also the values of H_Γ, generally higher than in the first case); it could not be fully exploited if these suppliers operate in big VLAs, since big VLAs are characterized by low values of qualifying flexibility.

The results of the third case study show relevant similarities with those of the second: lower median values of $\overline{C}_\Gamma$ are associated with a greater number of VLAs, and the variation in the market outcome is always smaller for partitions with the fewest VLAs.

From another point of view, it can be seen that in all cases, although to a different extent, flexibility providers not located in VLAs directly involved in the undervoltage condition (and in some cases not even close) can participate in alleviating it.

The median value of the expected minimum cost is a straightforward indicator of the market outcomes. But it alone misses the relevant aspect of their sensitivity to the location of providers. From both Fig. 4.8 and Fig. 4.11 one can easily see that the range of variation of the market outcome is always smaller for the partition with the smallest number of VLAs (which guarantee feasibility). This means that the lower the number of VLAs, the lower the probability of a market outcome with a very high minimum expected service cost and the lower the uncertainty of market behaviour.

In summary, in all case studies it was possible to resolve voltage issues with a market-oriented approach and different network partitions of the grid in VLA; flexibility suppliers were able to participate even if they were not located in or near the area where the undervoltage occurred.The convenience about the number of VLAs in which partitioning the grid depends on both cause and spread of undervoltage and on the preferable behavior of the market.

Conclusions

The work presented in this thesis refers to the transformation of the electricity system, dictated by the growing diffusion of non-programmable renewable sources and the need for greater efficiency in network management. In this work, attention has been focused on the use of distributed resources for the provision of local ancillary services, with particular reference to the definition and evaluation of the aggregation perimeters.

With reference to the Italian context, the reform of electricity dispatching promoted by ARERA has been analyzed, within which the role of distributed resources for the provision of global and local ancillary services is redesigned. In parallel, the main mechanisms for the provision of local ancillary services in the various European states have been reviewed, highlighting the peculiarities of the mechanisms, market models and regulatory maturity.

Starting from this framework, at the heart of the experimental work we wanted to delve deeper into the identification of the flexibility perimeters. In the first instance (see Chapter 3), a method was proposed for identifying and evaluating the aggregation perimeters of flexibility providers in the case of ancillary services intended to relief same-time problems of congestions and poor voltage profile. The identification is based on the concept of Load Area.

The assessment takes into account the prospects of the distribution system operator and the market, by measuring the two sides of technical efficiency and market efficiency. The method is used to analyze two case studies. The numerical results highlight the features of the proposed method, with its ability to give a quantitative measure of the technical and market aspects of flexibility aggregation.

The method allows quantitatively assessing technical and market efficiency of the size of the aggregation; a big perimeter is favorable from the market point of view, but can be technically inefficient, and vice-versa. The method can help decision-makers choose aggregation flexibility perimeters, in particular for voltage support services, as a compromise between technical and market aspects.

Secondly (see Chapter 4) the thesis work has proposed a model for the optimal long-term procurement of flexible services in a market environment, and the assessment of flexibility aggregation perimeters from the perspective of market outcomes.

The flexibility aggregation perimeters, also in this case, are identified on the basis of the Load Area concept. Based on the partition of the grid with the identified perimeters, an optimization model is however proposed for the auction-based, long-term procurement of the flexibility by the DSO; it considers both the limited volume and activation duration of the flexible providers and the grid operation as well.

The numerical results of three case studies are presented and discussed. The results highlight the characteristics of the market outcomes; they evidence different results for undervoltage problem due to different causes and with different spread, and the possibility for flexibility providers to participate in the provision of voltage support services even if not located in or close to the area with the voltage issue.

Future research will focus on the computational complexity of the proposed method to optimize its application to large-scale grids, and consider the possible adoption of different approaches to address the uncertainties in the procurement of flexibility-based local ancillary services.

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Symbols

γ	Index for voltage load area.
π_Γ	Load flow equations for the reduced grid of partition Γ.
ξ_Γ	Voltage and current inequalities for the reduced grid of partition Γ.
σ	Probability of activation of flexibility.
ω	Overprocurement factor.
Γ	Partition of grid into voltage load areas.
Δt	Duration of the elementary time interval.
Φ_γ^{avail}	Available prosumers' flexibility in the γ-th voltage load area.
Φ_γ^t	Total active power flexibility expected to be activated in the γ-th load area during the t-th time interval.
$\Phi_{b_\gamma}^t$	Active power flexibility expected to be activated by the b_γ-th provider in the γ-th load area during the t-th time interval.
$\Phi_{b_\gamma}^{bid}$	Offered active power flexibility by the b_γ-th provider.
$\dot{\Psi}_\gamma^t$	Total complex flexibility expected to be activated in the γ-th load area during the t-th period.
a_{b_γ}	Availability price of the b_γ-th provider in the γ-th load area.
b_γ	Index for the b-th flexibility provider in the γ-th voltage load area.
m_{b_γ}	Market rule for the payment of the availability of the b_γ-th provider.
n_γ	Number of offers submitted for the γ-th area.
n_Γ	Number of load areas in partition Γ.
n_T	Number of elementary time intervals in the requested service daily duration.
$n_{b_\gamma}^{off}$	number of elementary time intervals of the minimum recovery duration of the b_γ-th provider.

$n_{b_\gamma}^{on}$	number of elementary time intervals of the maximum activation duration of the b_γ-th provider.
t	Index for time interval.
u_{b_γ}	Utilization price of the b_γ-th provider.
$x_{b_\gamma}^t$	State of the b_γ-th provider in the t-th time interval.
y_{b_γ}	Offer acceptance indicator of the b_γ-th provider.
$w_{b_\gamma}^t\,(z_{b_\gamma}^t)$	Activation (deactivation) of the flexibility provision by the b_γ-th provider in the t-th time interval.
$\dot{A}$	Complex power base-case injections by prosumers during the requested service duration.
$\overline{C}_\Gamma$	Minimum expected cost for the ancillary service by flexibility, for partition Γ.
F_Γ	Active power flexibility that qualifies partition Γ.
D_a	Number of days in the procurement time horizon in which the flexibility service availability is requested.
H_γ (H_Γ)	Market concentration index for voltage support services for the γ-th market zone (for the whole grid with partition Γ).

Acronyms

ACER	Agency for the Cooperation of Energy Regulators.
aFRR	Automatic Frequency Response Reserve.
API	Application Programmable Interface.
ARERA	Autorità di regolazione per energia reti e ambiente.
AU	Acquirente Unico.
BESS	Battery Energy Storage System.
BRP	Balance Responsible Party.
BSP	Balance Service Provider.
CAPEX	Capital Expenditure.
CEER	Council of European Energy Regulators.
CRIDA	Complementary Regional Intra-Day Auctions.
DER	Distributed Energy Resource.
DG	Distributed Generation.
DNO	Distribution Network Operator.
DR	Demand Response.
DSO	Distribution System Operator.
ENTSO-E	European Network of Transmission System Operators for Electricity.
EU DSO	Association for all sizes of Distribution System Operators (DSOs) in Europe.

FCR	Frequency Containment Reserve.
FSP	Flexibility Service Provider.
GME	Gestore Mercati Elettrici.
GOPACS	Grid Operator Platform for Congestion Solutions.
GSE	Gestore Servizi Energetici.
HHI	Herfindahl-Hirschman Index.
LA	Load Area.
LV	Low Voltage.
MACSE	Mercato a termine degli stoccaggi, Forward Market for Electrical Storage.
MASE	Ministero dell'ambiente e della sicurezza energetica.
MB	Mercato del Bilanciamento, Balancing Market.
mFRR	Manual Frequency Response Reserve.
MGP	Mercato del Giorno Prima, Day-Ahead Market.
MI	Mercato Infragiornaliero, Intraday Market.
MI-A	Complementary Regional Intra-Day Auctions.
MI-CRIDA	Complementary Regional Intra-Day Auctions.
MI-XBID	Cross Border Intra Day Market.
MLF	Mercato Locale della Flessibilità; Local Service Markets.
MPE	Mercato Elettrico a Pronti, Spot Electricity Market..
MSD	Mercato dei servizi di dispacciamento, Ancillary Services Market.
MSD ex-ante	Mercato dei servizi di dispacciamento ex ante, Ancillary Services Market ex-ante.
MTE	Mercato Elettrico a Termine.
MTU	Market Time Unit.
MV	Medium Voltage.

OLA	Overload Load Area.
OPEX	Operating Expense.
POD	Point of Delivery.
PUN	Prezzo Unico Nazionale, Italian reference price for electricity purchased.
RES	Renewable Energy Sources.
RR	Replacement Reserve.
RTN	Rete di Trasmissione Nazionale, National Transmission Network.
SIDC	Single Intraday Coupling.
SII	Sistema Informativo Integrato.
TIDE	Testo Integrato del Dispacciamento Elettrico.
TIDME	Testo Integrato della Disciplina del Mercato Elettrico.
TOTEX	Total Expense.
TSO	Transmission System Operator.
UAS	Unità Abilitata Singolarmente, Individually Enabled Unit.
UC	Unità di Consumo, Consumption Unit.
UFCR	FCR Enabled Unit.
UNICAS	University of Cassino and Southern Lazio.
UP	Unità di Produzione, Production Unit.
UVA	Unità Virtuale Abilitata, Enabled Virtual Unit.
UVAM	Unità Virtuale Abilitata Mista, Mixed Enabled Virtual Unit.
UVAN	Unità Virtuale Abilitata Nodale, Nodal Enabled Virtual Unit.
UVAZ	Unità Virtuale Abilitata Zonale, Zonal Enabled Virtual Unit.
VLA	Voltage Load Area.
XBID	Cross Border Intra Day Market.

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