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Working Group

Final Report

Network Planning and System Design With Flexibility

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Working Group

Final Report

Network Planning and System Design with Flexibility

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List of Acronyms

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
aFRR	automatic Frequency Restoration Reserve
AI	Artificial Intelligence
ANM	Active Network Management
BESS	Battery Energy Storage System
BRP	Balance Responsible Party
CAPEX	CAPital EXpenditure
CBA	Cost Benefit Analysis
CBR	Cost Benefit Ratio
CEER	Council of European Energy Regulators
CIM	Common Information Model
DC	Direct Current
DER	Distributed Energy Resource
DLDN	Dynamic Loadability of Distribution Network
DNO	Distribution Network Operator
DS	Distribution System
DSF	Demand-Side Flexibility
DSO	Distribution System Operator
DT	Digital Twin
EDM	Energy and Data Management
EESP	Electric Energy Sales Partner
ENS	Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
ERP	Enterprise Resource Planning
ESS	Energy Storage System
EU	European Union
EV	Electric Vehicle
FACTS	Flexible Alternating Current Transmission System
FCR	Frequency Containment Reserve
FL	Flexible Load
FMO	Flexibility Market Operator
FMP	Flexibility Market Platform
FOR	Feasible Operation Region
FSP	Flexibility Service Provider
GIS	Geographic Information System
HC	Hosting Capacity
HEMS	Home Energy Management System
HL	High Level
HV	High Voltage
ICT	Information and Communication Technology
ISMS	Information Security Management System
KPI	Key Performance Indicator
LA	Load Aggregator

LEC	Local Energy Community
LFM	Local Flexibility Market
LL	Low Level
LTE	Long-Term Evolution
LV	Low Voltage
mFRR	Manual Frequency Restoration Reserve
MQTT	Message Queuing Telemetry Transport
MV	Medium Voltage
NPV	Net Present Value
NRAs	National Regulatory Authorities
OLTC	On-Load Tap Changer
OPEX	Operational Expenditure
OPF	Optimal Power Flow
PCC	Point of Common Coupling
PLF	Probabilistic Load Flow
PLC	PowerLine Communication
PF	Power Flow
PV	Photovoltaic
RES	Renewable Energy Source
RP	Reinforcement Plan
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCO	Smart Connection Offer
SD	Storage Device
SL	Shiftable Load
S3REnR	Schéma Régional de Raccordement au Réseau des Energies Renouvelables i.e. Regional Renewable Energies Connection Master Plans, I. E., Regional Renewable Energies Connection Master Plans
SS	Secondary Substation
TLC	Thermostatic Load Control
ToU	Time-of-use
TS	Transmission System
TSO	Transmission System Operator
UK	United Kingdom
VoLL	Value of Lost Load
VDE	Verband der Elektrotechnik, Elektronik, Informationstechnik, i.e., German Association of electrical engineering, electronics and information technology
VSE	Verband Schweizerischer Elektrizitätsunternehmen, i.e., Association of Swiss Electricity Companies

EXECUTIVE SUMMARY

Proliferated integration of Renewable Energy Sources (RES), driven by the decarbonization and the decentralization of energy generation, as well as the rise of new loads (heat pumps, electromobility), which are, to some extent, inherently flexible, require consideration of novel grid operational principles. Lower voltage levels, i.e., Medium Voltage (MV) and Low Voltage (LV), are predominantly expected to accommodate an increased share of RES in the overall generation mix, thus introducing significant uncertainties in generation profile characteristics due to their intermittent and stochastic nature. High penetration of distributed RES may provoke significant network operational issues (violation of current and voltage limits, reduced power quality, reversed power flows, complications in voltage regulations of transformers supplying feeders of different natures, etc.). Due to these adverse effects, Distribution Systems Operators (DSOs) may still rely on conservative approaches to network planning, which can limit the development of Distributed Energy Resources (DERs) and cause high costs for society. Flexibility from DERs and other smart devices could help face these issues but raises many challenges, making its integration into planning complex.

In this report, the working group first defined the scope of flexibility and studied its integration at all planning scales, from short to long-term and local to global flexibility. Through the analysis of worldwide use cases, several outcomes have been driven:

- **Technical outcomes**
  - Several research projects have shown that **the use of flexibility is possible to manage congestion (both current and voltage)**.
  - **Advanced metering infrastructure** seems to have a crucial role for the development of flexibility and there are **delays in their implementation.**
  - **Locations of resources are important**: the flexibility sources to solve congestion must be connected on a defined portion of the grid.
  - **A key element** for the **flexibility usage** is **grid observability for operators,** obtained by **digitalizing network models**.
  - **Need for coordination and priorization rules (local versus global)**: The same resource can address several issues (congestion, stability for example) at different levels (LV, MV and HV). Coordination is mandatory to ensure a safe operation of the power systems.
  - **The planning process with flexibilities must include the following**:
    - Multiple scenarios approach
    - Improvement of power curve modelling to better model new types of resources (electric vehicles, self-consumption, heat pump) as well as their operation modes
    - Defining and integrating key performance indicators related to flexibility, risk and willingness to pay
    - Both stochastic approaches capture uncertainties and value risks associated with flexible assets.

- **Regulatory outcomes**
    - There is **no universal regulation** on the **integration of flexibility** which should be based on tariffs, rules, connection agreements or market.
    - **Different regulations** could lead to **segmented markets** with different rules, ultimately **hindering optimal utilization of resources**.
    - **The main drawbacks** that are observed in the addressed **regulations** are:
        - The high competition in the ancillary services market makes access to new parties difficult.
        - Economic obstacles, namely: volatility of prices, low profit for large generators, and absence of clear price signals for flexibility products for DSOs.
        - Complex markets (if market-based): the number of players and interactions is expected to increase requiring prioritization rules. Also, market and reliability of flexibility require professional skills, which may not be accessible to small individual customers, but through aggregators.

Finally, these outcomes have led to seven recommendations split into 2 topics presented in the last section of this report:

T_1 - Development of proper simulation methodology and tools to integrate flexibility into planning

- **R_1 - Cross-sectoral models and tools to integrate other energy sectors**
- **R_2 - Network observability**
- **R_3 - Integration of new metrics related to risk, reliability, uncertainties, hosting capacity and market into planning**
- **R_4 - Prosumer modelling and involvement thanks to collaboration around flexibility with the social science community**

T_2 - Technical and economic enablers

- **R_1 - Dynamic tariffs as a game changer**
- **R_2 - Compatibility and/or standardization of communication networks and protocols**
- **R_3 - Development of a flexibility market to accelerate the integration of flexibility**
- **R_4 - The exchange of flexibility must operate across organization boundaries**

1. What is flexibility?

1.1. Power systems challenges

Recently, the objectives of climate protection led to massive changes in the generation and load structure both in the transmission and distribution networks. This results in new challenges to maintain network security and supply quality in decreasing conventional generation plants with the simultaneous massive expansion of renewable energy sources. The increasing integration of renewable energies into power systems and the increasing electrification of heat and transport sectors represent new challenges for the operation and planning of the electricity supply system. In this context, the consumers' peak loads and the uncertainty in generation and load forecast are increased, and the energy is fed from the low-voltage grid to higher grid levels. Also, there is a concern about the growing costs of congestion at the distribution level due to the development of the DERs. However, DERs can provide services to improve network management. To counteract this development, network planning techniques are being extended and are becoming the focus of current research projects through the consideration of decentralized systems' network flexibility to avoid capital-intensive conventional grid planning methods.

Historically, the power generated in large and centralized power stations would flow on High Voltage (HV) transmission networks and be stepped down to LV distribution networks before reaching the end consumer as shown in the traditional system of Figure 1. In the future, smaller-scale generation will increasingly be closer to the point of consumption on the distribution grids. Driven by European Union policy, the electricity mix will consist of renewable sources, increasing the variability of electricity supply. Therefore, the European electricity markets must assess how emerging flexible resources are incorporated into them and propose new market operation approaches that facilitate the participation of variable renewable energy sources and other flexible assets.

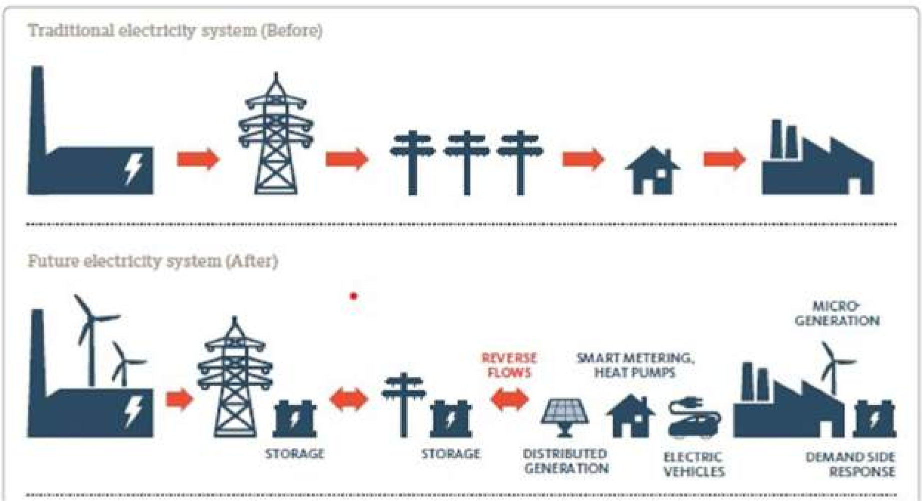

Figure 1: Energy system in transition [1]

With the development of DERs mainly connected to the distribution system, planning methods (load and production forecast, network reconstruction and development) need to be more flexible:

- *In the short-term,* to anticipate power flow fluctuations whose uncertainties will increase and operate the network "as it is" with flexibility in operations.
- *In the long-term,* to plan and reinforce the network as "it will be", and use flexibility, for example to alleviate the need for reinforcements due to constraints.

The main challenges of the power systems regarding the space and time scales can be summarized in Figure 2.

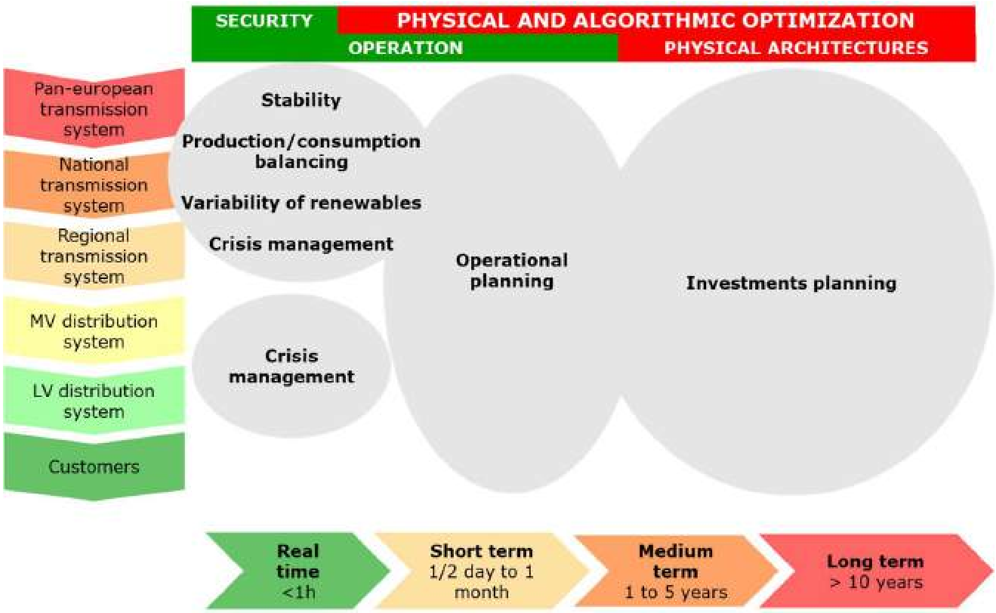

Figure 2: Power systems challenge as a function of space and time scales

1.2. DEFINITION OF FLEXIBILITY

1.2.1. Some examples across the world

a) International Energy Agency

In [2], the International Energy Agency defines power system flexibility as "the ability of a power system to reliably and cost-effectively manage the variability and uncertainty of supply and demand across **all relevant timescales**."

Article 32 of the Directive (EU) 2019/944 [3] on "Incentives for the use of flexibility in distribution networks" states that:

- Member states must develop a **regulatory framework** to encourage DSOs (Distribution System Operators) to use flexible services if profitable.
- DSOs or the regulator should define the **specifications of the flexibility services** and the associated **standardized products**.
- These flexibility services must be **market-based** unless the regulator grants an exemption.

- The **coordination between DSOs and TSOs** (Transmission System Operators) is necessary to avoid uncoordinated actions that may result in adverse situations. Similarly, it also contributes to avoiding the double use of flexibility at the transmission and distribution level, solving the same problem. Also, **priority access** to flexible resources needs to be defined, depending on the problem's criticality and coverage of the problem to solve (e.g. **local** problem vs. **systemic** problem).

b) Germany

The Association of Swiss Electricity Companies, Verband Schweizerischer Elektrizitätsunternehmen (VSE), defines flexibility as follows: the ability to **directly** (control) **or indirectly** (incentives or usage restriction) influence the injection into (or consumption from) the grid by a generation (or consumption) unit at the instigation of the grid operator or another actor [4].

The German Association of Electrical Engineering, electronics and information technology, Verband der Elektrotechnik, Elektronik, and Informationstechnik (VDE) defines flexibility in the position paper of the task force flexibility [5]. Flexibility is understood "to be the ability of users of the electrical power supply system, i.e. generation, consumption and storage facilities, to specifically influence their electricity withdrawal from the supply network and/or their electricity feeds into this network. This includes changes in the **active and reactive power**. Flexible facilities are characterized by the fact that **their application does not completely predetermine their mode of operation**. In a narrower sense, **only flexibility that can potentially be used for third-party purposes**, i.e., in response to control signals or price signals from other actors, is of interest for the flexibilization of the power system."

The above study **classifies flexibility** and its use as follows: "In addition to the classification into generation-side, consumption-side and storage-side flexibility, which can further be subdivided into positive and negative flexibility concerning the direction of the desired change of behaviour, the categorization of the form of use is crucial:

- ***Own use*** means the use of flexibility for purposes within the sphere of the operator of a flexible facility[2] and provision exclusively by the operator's own sources of flexibility.
- ***Grid-oriented* use** refers to the use of flexibility by a grid operator to specifically influence the state of the grid[3]. The location of the flexibility provision is crucial for its effect.
- ***System-oriented* use** summarizes all forms of use that serve **system operation** and thus also the compliance with active power balance[4]. The place of provision is not important.

Consequently, flexibility can be used for different purposes and is a scarce resource."

[2] producer, for example
[3] i.e., both DSOs and TSOs constraint management
[4] i.e., in the perimeter of both TSOs and BRPs

c) France

Flexibilities can address 3 different business cases as shown in Table 1 depending on the time horizon and process involved for network operators:

- **Structural flexibilities**: for both TSO and DSO, this relates to defining the network “as it will be”, that is with network planning and processing of connection applications, or “shaping the load curve” by shifting the consumption in a predictable and reliable way.
- **Operational flexibilities**: for both TSO and DSO, this relates to operating the network “as it is”. One can further distinguish flexibilities which would be used according to forecast, and flexibilities which handle forecasting errors or unexpected unavailability of assets.
- **Safeguard flexibilities**: for both TSO and DSO, it is to handle exceptional situations.

Similarly, from a supply and demand perspective, the major French DSO Enedis and RTE the French major TSO have defined 4 types of flexibility from a system perspective:

- **Structural flexibility (long term horizon)**: it consists in shifting the consumption in a predictable and reliable way for supply from an adequacy prospective.
- **Dynamic flexibility (year, month, day ahead and intraday horizon)**: it can handle consumption and production fluctuations, such as due to the weather.
- **Balancing flexibility (real-time or near-real time horizon)**: to cope with forecast uncertainty or errors, and real-time hazards.
- **Safeguard flexibility (in case of exceptional events)**: it enables do deal with emergency situation such as the “5% voltage drop alert”. Assets flexible operation can be activated to manage such outage. This type of flexibility is most likely non-market based.

Systems needs and network needs interact with each other. The earlier an issue is solved, the cheaper and less CO_2 content a solution is. Therefore, one shall solve issues as much and as early as possible, to leave residual issues to be solved later and so on until real-time.

At each time horizon, all for 4 models can be used:

- Tariff based
- Market-based
- Rules-based, identical per category of customers
- Flexible connection agreement, which are also called conditional

An efficient and inexpensive way to address structural flexibility, both for systems needs and network needs is using time-of-use tariffs (ToU) on water boilers and EV charging. In France, static ToU tariffs have been implemented in 1965 in conjunction with the nuclear program and enabling to “flatten the load curve” as it may be preferable for nuclear plant operations. It proved to be a very efficient solution to better balance production and consumption for balancing purposes. Beyond balancing, it alleviates the need for grid reinforcement thanks to charging cars or heating water boiler at night when other electrical usages are off. The load profiles resulting from such flexibility are input of grid planning and reinforcement.

Table 1: French system operators' vision of flexibilities and potential economic models with examples

	Tariff-based	Rules-based	Flexible Connection agreements	Marked-based
Structural flexibility	**Off-peak time in winter** at night (for hot water boilers and recharging electric vehicles). **"Solar" off-peak time in summer** in phase with the PV peak.	**Definition of limitation quotas in contracts** allowing works.	**Permanent smart connections**, i.e., more customers can be connected to the same structure. Examples: • Optimization of MV feeders. • Optimization of primary substations thanks to flexibilities (ReFlex).	**Flexibility contracts with capacity reservation** to postpone the reinforcement date.
Operational flexibility (dynamic and balancing from systems perspective)	**Dynamic time ToU**	**Optimization of the unavailability of assets and the use of quotas.** Use of capacity short term reservation contracts (a few months or weeks). Examples: • Avoidance of power cuts during works • To get through cold peaks	**Activating forward capacity allocation (FCA).**	**Flexibility with or without capacity.**
Safeguard flexibility	X	• **Emergency disconnection** • **Rotating outages** Example: "temporary power limitation" tested with positive feedback during winter 2023-2024 on 100 000 Linky customers.	X	X

1.2.2. In this CIRED working group

In the previous CIRED working group on “Flexibility in active distribution systems” [6] in 2019, experts decided to focus “on the flexibility provided by the **resources** that are **connected to the distribution network** and **not** on the **flexibility of the assets** of the distribution network. Also, they “have given priority to the **flexibility referred to the active power**, as it is considered the most valuable to the network”.

In this report, experts (DSOs, academics and service providers) have decided to broaden the definition of flexibility to encompass all the insights provided by those mentioned in international and national roadmaps since this working group focuses on integrating flexibility into planning.

Flexibility is a power modulation of any flexible resources in voluntary response to a need (a signal). This response allows the power system operator or other third parties to optimize their operation condition (e.g. costs, voltage profile) without affecting their security and reliability. It can be specified that:

- The power modulated can be either active, reactive or both;
- The modulation consists of an increase or a decrease in power output/input;
- The resources can be a customer through the control of its devices (heaters, electric vehicles, etc.), industrial customers, a production, a storage system, an energy community, or a microgrid;
- Assets owned by the DSO can be seen as a source of flexibility in some countries;
- The signal can be direct (control action) or indirect (incentives or restrictions on use);
- Services can be defined as use cases which will not be covered extensively in this report: congestion management, peak management, postponing or avoiding grid reinforcement, frequency service (in real-time), schedule balancing support, voltage support, synthetic inertia, power loss reduction, optimization of self-consumption, phase balancing, increasing hosting capacity of DERs.

This definition is broad and reactive power management could be considered as another strategy for some actors and not as a flexibility.

1.3. STRUCTURE OF THE REPORT

Given the definition of flexibility taken by this working group, many challenges concern the integration of flexibility at all scales of the planning process. In this context, the following report is structured into the following sections:

- **Section 2** provides a **mapping of the players** involved in the flexibility mechanisms and their interactions to analyze the general landscape of flexibility and the challenges.
- **Sections 3 and 4** are dedicated to **local flexibility**, i.e. for **DSOs**. Section 3 addresses the short-term scale called operational planning. In contrast, section 4 addresses the medium to long-term planning and the challenge to integrate operational planning into long term planning. Feedback from projects worldwide enables us to draw some recommendations summarized at the end of each section.

- **Section 5** is dedicated to **global flexibility,** i.e. encompasses **some missions of the TSOs** related to the operation of the interconnected network. In particular, this section discusses the DSO/TSO coordination and frequency support services.
- **Section 6** gives the working group's **final recommendations**.

2. PLAYERS AND REGULATION INTERACTION

The participation of the flexibilities in the electricity grid depends on two different layers: the market and the technical. Based on the market conditions and requirements, the electricity market requires the flexibility to support planning and maintaining the electrical energy balance. The flexibilities are also required to provide support to solve the grid congestions in the short-term and ancillary services to the higher voltage levels. Regulations facilitate the participation of emerging flexible resources in the electricity market and propose new market operation approaches that will facilitate the integration of more renewable and flexible assets into the electricity grid. In an ideal world, the regulating authorities predefined and standardised all these transactions and communication between the various actors. However, since this is a new field of operation, there is **no uniform regulation** to deal with **how flexibilities can be requested** and **how they are compensated**.

There are several players and actors at various levels of this flexibility provision. The subsequent sections will provide more information on the different types of actors and the country-wide regulations available for flexibility provision. Furthermore, an **open question regarding the flexible actors within the network planning process remains and needs to be addressed**. Uncertainties and risk-related issues brought to the network planning process by the flexibility must be assessed using proper methodologies to ensure optimal network operation. At this level, the research and development organizations also play an important role through their research work on advanced approaches to network modelling and analysis and developing innovative solutions for grid flexibility.

2.1. *PLAYERS DEFINITION TABLE*

Currently, the forecasted and emerging congestions in distribution networks are primarily managed by DSOs through grid reinforcement. DSOs conservatively increase the capacity of the power lines, feeders and transformers existing in their networks. This capacity increase will result in additional costs for DSOs. A more active way to manage congestion problems in distribution networks is to use end-user side local flexibility. Flexibility implementation depends on the system's loads, generators, storage units and electric vehicles to compete for selling or buying exchanged energy. Potential flexibility stakeholders are the DSO, the Balance Responsible Party (BRP) and the end-users. However, these parties may not lead to effective congestion relief in distribution networks, as dispatching is more complex in distribution than in transmission due to the high penetration of small-scale distributed generators with intermittent output. From the end user's perspective, Demand-Side Flexibility (DSF) can be defined as modifying generation and/or consumption patterns to provide services to the system operator.

Implementing **LFMs (Local Flexibility Markets)** that trade flexibility from the DERs to system operators **seems to be a rising solution to tackle congestion issues complementary to ToU tariffs**. LFMs can be defined mostly as marketplaces that operate in geographically limited areas and in which flexibility is traded from its suppliers (DERs) to flexibility users (DSOs, TSOs, etc.). By using local flexibility markets, customers can actively participate in how the electricity network is operated and earn income. In [1], the European Network of Transmission System Operators for Electricity Association (ENTSO-E) deeply reviewed flexibility platforms, comparing their structures, player interactions, products and functions. In Europe, flexibility platforms are quite heterogeneous, being operated either by TSOs, DSOs, both or by independent third parties, and can be split into two kinds of platforms:

- **Market-based platforms: intermediary** and **marketplace platforms** (see Table 2 for their distinction).
- **Administrative flexibility scheme coordinators (not market-based)**: provide support for a centralized cost-based allocation of flexibility based on the facilitation of data exchange. DA/RE is an example of administrative platform in Southern Germany.

In particular, [1] points out that flexibility platforms could help address challenges related to DERs integration, TSOs/DSOs coordination and market design. **These platforms can help the integration of flexibilities into all scales of planning, but there are still some issues to address:**

- ***Need for more homogeneity and standardization***: the profusion of flexibility platforms can increase complexity. There is a need to define common rules from the structure of the platforms to the products. Nevertheless, there is still divergence in approaches to LFM across member states. In particular, harmonization across Europe has to be done regarding, for example, flexibility in product classification, connection, agreement structures, aggregation rules, dynamic energy tariff structures, etc.
- ***Players need to develop interoperable tools***: which could be interfaced with flexibility platforms and avoid issues related to data sharing.
- ***The risk of Flexibility Service Providers' (FSPs) strategic gaming*** [1] has to be addressed by defining appropriate market rules.
- **The risk of liquidity issues** caused by fragmented local flexibility markets. An increased level of coordination across markets is necessary. Also, better integrated local and national flexibility markets may increase the overall number of FSPs' participation.
- **The coordination's need depends on the organization structures which depend on countries** (see Figure 3). For a given country, the number of TSOs and DSOs, their size, their structure and the number of physical interfaces between them increase the need for coordination.

The main actors of the flexibility market architecture are:

- regulators
- market participants & BRPS (sellers, buyers),
- prosumer, producer,
- aggregator and FSP,
- market operators and an interface enabling player's interactions and transactions.

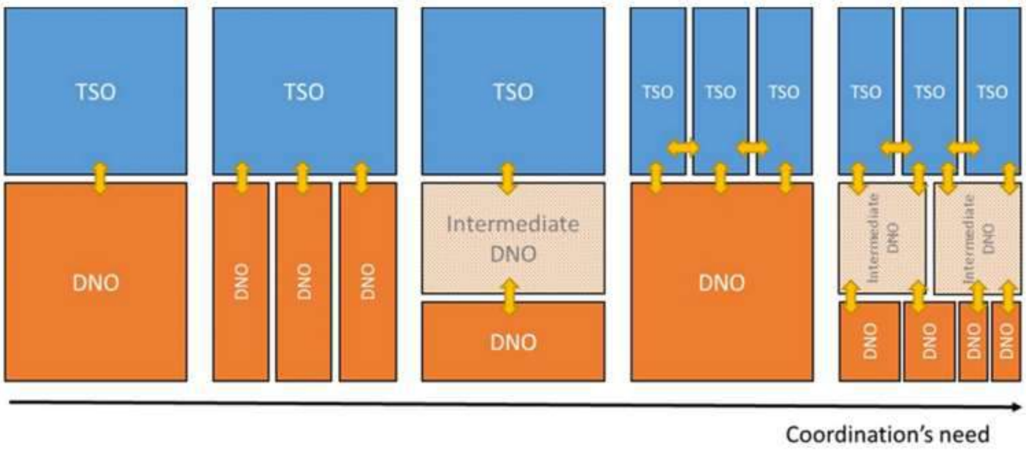

Figure 3: Coordination's need as a function of organization structures [7].

Table 2: Comparison of market-based platforms

	Intermediary platforms	**Marketplace platforms**
Products	**Balancing products** • *Balancing reserves: Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (aFRR), manual Frequency Restoration Reserve (mFRR).* • *Balancing market* • *Capacity remuneration schemes* • *Emergency* • *TSO/DSO redispatch* **Congestion management (by TSOs & DSOs)** • *Congestion management* • *Voltage control* • *Network investment deferral* • *Pre-fault, post-fault and restoration*	**Congestion management (by DSOs only)** • *Congestion management* • *Voltage control* • *Network investment deferral* • *Pre-fault, post-fault and restoration*
DSO/TSO coordination	**Explicit coordination in a single plateform** • *Hierarchically rules* • *Networks' optimization*	**Coordination between several plateforms**
Examples	**Crowd Balancing Platform** *Germany, The Netherlands, Italy, Austria and Switzerland* **INTERRFACE project** Latvia, Estonia, Finland **GOPACS** *The Netherlands* **INTERRFACE project**	**Piclo Flex** *UK* **NODES-IntraFlex** *UK* ***Enedis*** *France* **eSIOS-CECRE-CoordiNet** Spain

According to the sectors where these actors are active, it's possible to describe in a detailed way their exact roles in Table 3 and to map their interactions in Figure 4.

Table 3: Definition and role of players in a flexibility market structure

Actors	Definition	Role
Regulators	**Normally, government entities** set the rules and regulations and ensure fair market operation; for example, National Regulatory Authorities (NRAs), Agency for the Cooperation of Energy Regulators (ACER)	Monitor the players' activities and their operations. Setting the **rules, regulations** and policies so that the **market operates in a fair and efficient way**
System Operator (TSO, DSO)	The entity responsible for the network concession and/or owners of the electricity network, independent of the voltage level and type of customer, are typically the main buyers of flexibility from the network perspective.	**Ensure the efficiency and reliability of the electricity network**.
TS (transmission system) and DS (distribution system) planners	They are within the System Operator actors.	**Facilitate the optimal and reliable network operation and planning** and the integration of flexible resources.
Aggregators and Flexibility Service Provider (FSP)	Actors who have the ownership or aggregate flexibility resources to exploit their flexibility in the flexibility market. It could be consumer, producer, prosumer, aggregator or energy community.	**Provide and/or offer flexibility services** to the entity requesting the flexibility (e.g. market agent or operator)
Flexibility Market Operator (FMO)	The entity is responsible for managing the purchase and sale of flexibility services in the flexibility markets.	**Ensure that market clearing is done** according to the rules. Ensure coordination with system operators regarding the market results (technical validation).
Flexibility Market Platform (FMP)	The interface between the FSP, FMO and system operator.	**The digital infrastructure** that connects the availability of the flexibility provider sets the need of a system or a market operator, and enables the buying and selling of flexibility between these roles.
Technical coordination platform	Responsible for the FSP, Flexibility Service Aggregator interface and flexible resources.	**The digital infrastructure** coordinates the needs of the system operators and energy market, optimizing the flexible resources and ensuring the efficiency and reliability of the power system.

In addition, a few players and actions belong to the flexibility market.

Aggregators

The various roles of aggregators are listed as follows:

- Organizing flexibility exchanges and maintaining the trading platform.
- Managing all risks, such as energy deviations and technical failures.
- Receiving information about the current grid status and how the Thermostatic Load Control (TLC) strategy for primary and secondary frequency regulation can contribute

to enhancing the grid performance, using heating, ventilation, air-conditioning units and electric water heaters.
- Helping BRPs to balance their portfolio and commitments in wholesale markets.

Prosumer Services [8]
Flexible assets behind the local meters can be used to minimize prosumer electricity costs. An aggregator can implement a Home Energy Management System (HEMS) in the aggregator's platform. The potential flexibility services of prosumers are the following:
- *ToU* optimization to use flexibility from high-price intervals to low-price intervals.
- *"kWmax" control* to reduce prosumer consumption peaks within a predefined duration.
- *Self-balancing* uses the price difference for consuming, producing and selling electricity favourably since the home's load is compensated by the energy generated.
- *Controlled islanding* to maintain electricity supply behind the meter through static transfer during grid outages. In France, a few experiments (sandbox mode) are ongoing in rural networks such as Corrèze Resilient Grid using a Battery Energy Storage System (BESS) connected to the MV/LV substation [9].
- *Optimizing/maximizing self-consumption* to reduce payment of network fees and other fees and taxes depending on the regulatory framework.

Producer services emerge when renewable generation is paired with storage (i.e. hybrid generation"), allowing new optimization services.

Local Energy Communities
LECs can be classified by:
- Legal status: Citizen Energy Community and Renewable Energy Community
- Activities: Collective Self-Consumption and Energy Sharing

Their roles are:
- Fulfilling the established contracts.
- Providing the required information about flexible resources.
- Installing local control devices connected to the aggregator platform.

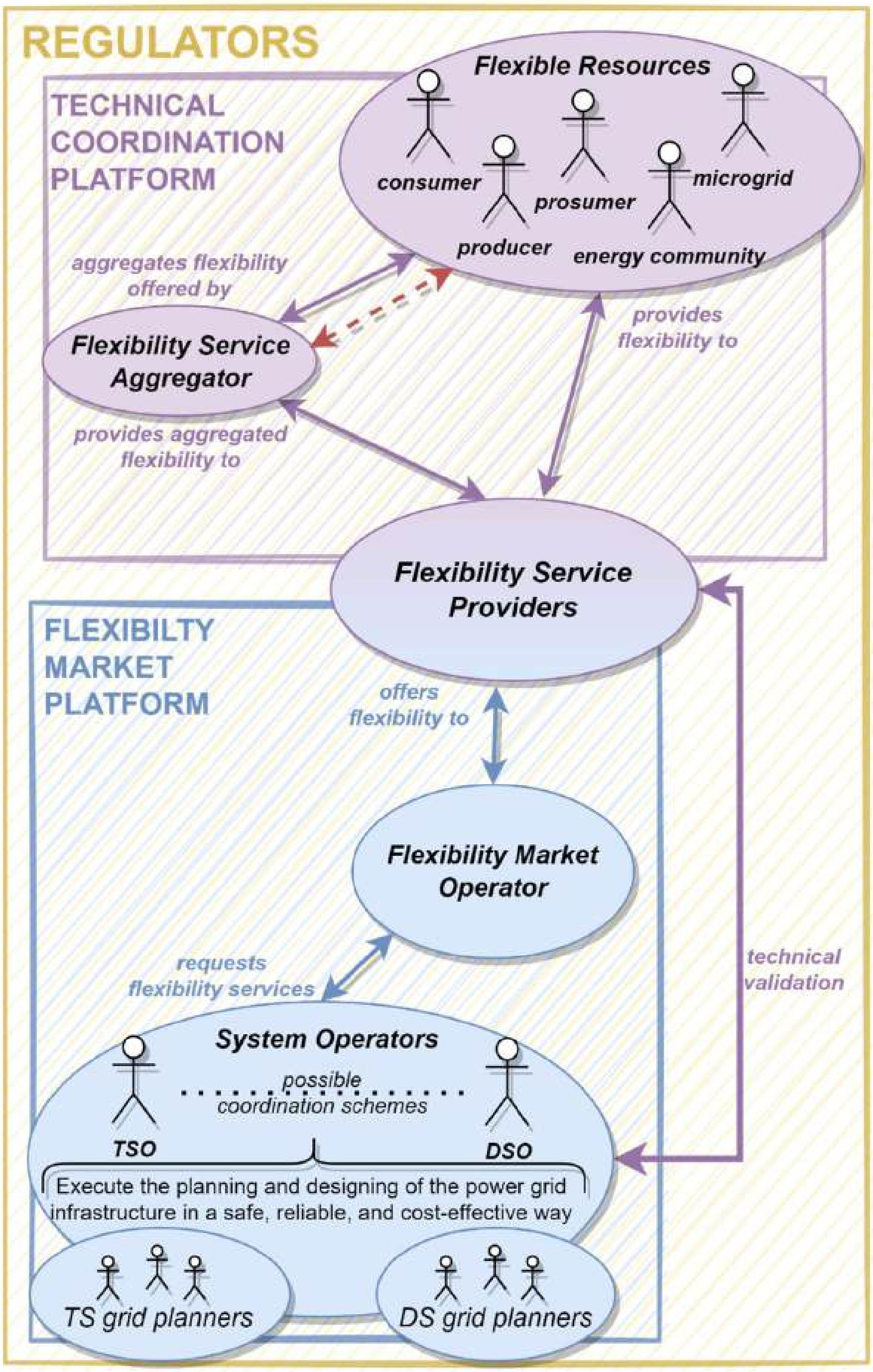

Figure 4: Players interactions diagram in the context of flexibility services exchange

2.2. EUROPEAN/WORLDWIDE REGULATIONS FOR FLEXIBILITY IN THE MARKET

The European Union has funded research projects in different countries in Flexible Energy Production, Demand and Storage-based Virtual Power Plants for Electricity Markets and Resilient DSO Operation (FEVER) [10]. The **fundamental role** of any **flexibility platform** is to provide market participants with **efficient access to** and visibility over **flexibility requirements and availability**. This context demonstrated a wide variety of local flexibility projects led by TSOs, DSOs and third parties, each trialling and implementing their vision of flexibility management beyond the traditional market platforms for TSOs (e. g., procurement of balancing reserves). This refresh includes recently implemented mechanisms and commercial solutions insights from initiatives focused on integrating DER in various European member states and the UK. While many of these solutions have come out of TSO innovation projects, others have been developed independently by DSOs through TSO-DSO coordination, and other third parties such as power exchanges, technology developers, and suppliers. In order to access an LFM, a flexibility provider must comply with pre-determined eligibility criteria to assure potential procurers that they can deliver the selected product. These eligibility criteria may be set at the platform level, the market level or by individual procurers.

As explained in the previous sections, there is no common regulation for providing flexibility.

2.2.1. Country-level analysis

This section provides a country-level analysis of the existing regulatory provisions based on [11] and [12]. Figure 5, made by [12], shows the level of flexibility development across Europe. In particular, it is pointed out that only three countries have commercial markets (Great Britain, the Netherlands and France), and 2 countries have advanced trial offerings with quite high volume (Norway and Sweden). The scoring considers whether there are commercial DSO flexibility markets and/or the number of flexibility pilot projects and the associated volume of flexibility being traded.

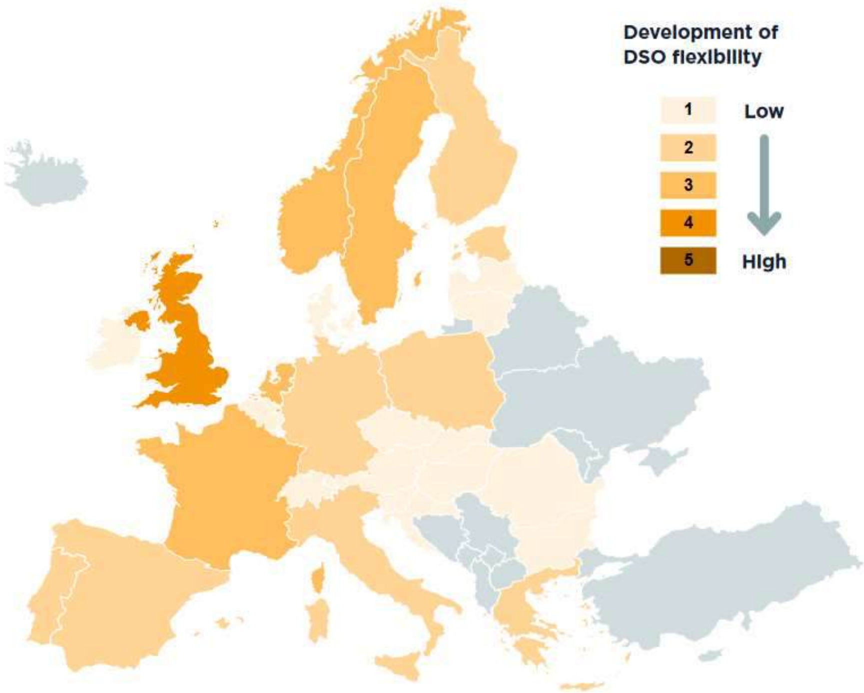

Figure 5: Development of distribution system flexibility in Europe [12].

a) UK

- **Consumers are eligible** to participate (individually or via aggregators in the **wholesale** electricity markets (including day-ahead and intra-day) and the **balancing market**.
- **Local flexibility markets** are particularly developed in the UK, with flexibility projects funded through national funding mechanisms undertaken by several DSOs. Since 2018, the DSOs have been tendering and procuring various flexibility services to help solve congestion in the local electricity grids. Hence, the exploitation of flexibility is now business as usual for the DSOs, with local flexibility markets already established to purchase flexibility through **online platforms**.
- The consumers' participation in the market is facilitated through various mechanisms. The most common include **financial incentives like exemptions in payments of network tariffs and taxes** for prosumers and certain categories of electricity producers. Such incentives mainly concern self-consumed electricity. Excess electricity can be sold under different pricing schemes.
- The reassessment of actors responsible for balancing costs and delivery/ imbalance risks emerges as a need for enhancing the participation of aggregators in the capacity market.
- Cons:
  - **The main economic obstacles are the volatility of prices, low profit for big size generators, and the absence of clear price signals for flexible products for DSO**s.
  - The **high competition** in the ancillary services market makes access to new parties difficult.
  - On the technical side, the most important obstacles are:
    - The **prequalification requirements** for aggregators
    - The highly complex market
    - The lack of transparency by the operators
    - The **delay in smart meters roll-out**

b) Nordics (Denmark, Finland, Norway, Sweden)

- **Consumers** are **eligible** to participate (individually or via aggregators in the **wholesale** electricity markets (including day-ahead and intra-day) and the **balancing market**.
- The consumers' participation in the market is facilitated through various mechanisms. The most common include financial incentives, such as exemptions in payments of network tariffs and taxes for prosumers and certain categories of electricity producers. Such **incentives mainly** concern **self-consumed electricity**. Excess electricity can be sold under different pricing schemes. In Norway, most prosumers can often receive the hourly spot price for their excess electricity under specific contracts.
- In Finland, smart electricity meters were installed for all customers in 2013. Thus, the country has been at the forefront of promoting **real-time price signals** for consumers, and all customers can choose **an electricity contract with dynamic pricing**. Also, in Norway, the smart meter roll-out has been completed across all customer types since January 2019. The smart meters installed provide 15-minute measurements, allowing

the Norwegian tariff design to move towards capacity-based tariffs (charging consumers based on peak loads). This has become a more **cost-reflective tariff structure** where customers can valorize their flexibility potential.

c) The Netherlands

- Since 2019, GOPACS (Grid Operators Platform for Congestion Solution) is a short-term flexibility platform allowing better coordination between DSOs and TSOs by considering local constraints on a national scale. The platform is connected to a wholesale market platform, EPTA and works in 4 steps:
  - First, the distribution system operators estimate the locations and dates of future congestion on their system and enter them into GOPACS;
  - GOPACS generates a signal on the markets to which the flexibilities suppliers can respond (reduction/increase of production or consumption). The imbalance generated by this modification is compensated for by other offers outside the congested area;
  - These offers are transmitted to GOPACS, which checks:
    - respect for local constraints;
    - non-degradation of the global system;
  - The system operators then pay the difference between the two previous costs to resolve the congestion.

d) France

- The major French DSO, Enedis, created in 2019 an internal flexibility platform [13], i.e. without intermediaries between the DSO and FSPs, where it launches flexibility calls for tenders, both rising and upward bids. This led to the signing of 2 contracts in 2020, 1 in 2022, 4 in 2023. In 2024, 51 contracts have been awarded, which represents a total of 46 MW of flexibility which will be provided by 3 FSPs before end of May 2025.
- Cons: hard to replicate for countries with many small DSOs

e) Spain and Portugal

- **Demand-side and the storage** installations were recently (end of 2019) included in the **balancing market**.
- The Iberian Market Operator, OMIE, has started a pilot project on local flexibility markets named IREMEL.
- Cons:
  - In regulatory terms, the market is **not yet open for aggregators**.
  - The **high competition** in the ancillary services market makes access difficult to new parties.

f) Italy

- The **market opening to DERs** was done through three pilot projects (UVAC, UVAP and UVAM). The UVAM project, which is the most recent one, aggregates demand response and non-relevant production to participate in the ancillary services market.

- Cons:
  - In regulatory terms the market is not yet open for aggregators.
  - Barriers to demand-side flexibility are mainly examined within the UVAM project. The **main barriers are economic** and relate to the high remuneration of capacity in parallel with the high energy price caps for bids which lead to an unbalance between offers for availability and the offers for energy.

g) Belgium

- Consumers are eligible to participate (individually or via aggregators in the wholesale electricity markets (including day-ahead and intra-day) and the balancing market.
- **Aggregators are blocked** from full participation in the balancing and wholesale markets because they **must have the retailer's permission to enter these markets** with a given consumer.
- Cons:
  - Economic barriers concerning:
    - price caps based on specific technologies,
    - not flexible and very high network tariffs
    - Belgian scheme that determines transmission and distribution fees based on energy consumption.
  - On the technical side, the most important obstacles are:
    - The prequalification requirements for aggregators
    - The highly complex market
    - The lack of transparency by the operators
    - The **delay in smart meters roll-out**

h) Greece

- Demand can contribute to the **stability** of the system only through **interruptible loads**. The interruptible load service can be offered by consumers connected to the electricity transmission and MV network of the interconnected system via their participation in auctions.
- Cons:
  - In regulatory terms the market is **not yet open for aggregators**.
  - A comprehensive regulatory framework for integrating storage systems and EVs should be developed. Similarly, demand management and response schemes should be implemented.
  - On the technical side, the most important obstacle is the delay in the smart meter roll-out.

i) Cyprus

- Currently, the **electricity market cannot support flexibility services, aggregation, or demand response**. Flexibility-related mechanisms will be able to participate in a fully functioning competitive electricity market, which was planned to become operational by the end of 2021.

- Cons:
  - In regulatory terms the market is **not yet open for aggregators**.
  - A comprehensive regulatory framework for integrating storage systems and EVs should be developed. Similarly, demand management and response schemes should be implemented.
  - On the technical side, the most important obstacle is the **delay in the smart meter roll-out.**

j) Germany

- **Consumers** are **eligible** to participate (individually or via aggregators in the **wholesale** electricity markets (including day-ahead and intra-day) and the **balancing market**.
- The Federal Network Agency is currently speaking out **against the introduction of flexible network charges**, and determining regional fees is seen as a procedure of high effort.
- Barriers for market participants are the accounting period's duration and the time between the close of trading and the delivery date.

k) Switzerland

- **Customers can participate under certain conditions and requirements** (individually or via aggregator)
- The flexibility belongs to the customer, and its use must be explicitly agreed upon (contract, Art. 17b of the Swiss Electricity Supply Act).
- The remuneration must be based on objective criteria and must not be discriminatory. This information must be publicly accessible. (Art. 8c of the Swiss Electricity Supply Ordinance)
- To prevent an immediate and significant threat to secure grid operation, the grid operator may also install an intelligent control and regulation system without the consent of the end consumer. In case of such a threat, he may also use this system without the consent of the end consumer. This control has priority over any other control systems installed by third parties. (Art. 8c of the Swiss Electricity Supply Ordinance)

l) Portugal

- E-REDES (the largest DSO in Portugal) and Piclo (an independent flexibility services marketplace) organized the **first pilot for a transversal flexibility service platform in Portugal** that **joins system operators and flexibility service providers (FSPs) in the same marketplace**.
- This pilot allows operators to procure flexibility directly from aggregators or individual FSPs for global or local purposes through a set of competitions. The operator defines the product (service) being sold, characterizing the service requirements (e.g. type of service, amount needed, minimum aggregated asset size, minimum run time, etc.) and the FSP pre-qualifies its assets to be able to provide the service. The FSPs can bid on the Piclo platform for qualified assets, allowing them to sell the service to the operators.

2.2.2. Discussion

The barriers for market participants are the duration of the accounting period and the time between the close of trading and the delivery date. In Nordic countries, consumers are encouraged to participate in the electricity market through financial incentives, network tariffs and tax exemptions, and dynamic pricing schemes. **Smart meters are crucial** in empowering consumers by providing real-time price signals. In Finland and Norway, smart meters with **15-minute measurements** have enabled more **cost-reflective tariff structures** and the **valorization of flexibility potential**. In Spain, including demand-side and storage installations in the balancing market is a recent development, but regulatory openness for aggregators remains limited. High competition in ancillary services and regulatory hurdles make access for new parties challenging. Italy has initiated market opening to distributed resources through pilot projects, allowing demand response and non-relevant production to participate in ancillary services. However, **regulatory constraints and economic barriers**, such as capacity remuneration and energy price caps, hinder progress.

The UK has made substantial strides in facilitating consumer and aggregator participation in the electricity market. **Local flexibility markets** have been established, and consumers are incentivized through exemptions from network tariffs and taxes. **Challenges include price volatility, market complexity, lack of transparency, and delays in smart meter rollouts**. Belgium allows consumer and aggregator participation in the wholesale and balancing markets. Nevertheless, aggregators face obstacles, including the requirement of retailer permission, economic barriers, **complex prequalification requirements**, and the lack of smart meter deployment. In Greece, demand contributes to system stability through interruptible loads, but regulatory barriers exist for aggregators. Developing a comprehensive framework for integrating storage systems, EVs, and demand management is crucial. Cyprus lacks support for flexibility services and aggregation due to a competitive electricity market and regulatory gaps. The regulatory framework for aggregators, storage systems, EVs, and demand management remains a priority. In Germany, consumers and aggregators can participate in wholesale and balancing markets. However, the Federal Network Agency opposes flexible network charges, and regional fees are seen as administratively burdensome. Challenges also include the accounting period duration and the gap between trading and delivery.

In summary, the **European electricity market landscape is diverse**, with various countries adopting **different approaches to encourage flexibility** and consumer participation. Common challenges include **regulatory barriers for aggregators, economic obstacles, and delays in smart meter rollouts**. A consistent focus on overcoming these challenges and promoting a more open, transparent, and flexible market environment is essential for the future of the European electricity market.

2.3. GOVERNANCE

Several procurement mechanisms can be applied to flexibility services described by the Council of European Energy Regulators (CEER) [14]. These mechanisms are listed and defined in Table 4.

Table 4: Procurement mechanisms types

	Procurement mechanisms	Description	
Not market-based procurement mechanisms	Rules-based Approach (network codes)	Obligation with/without compensation	When a third party is obligated to supply a system service by the system operator, they must do so either **without being paid or with a financial compensation**. This is an obligatory mechanism and is not based on a market practice. However, the price for compensation can be based on energy market-prices.
		Cost-based	A cost-based method **compensates service providers** for their actual service costs. Auditing the providers' expenses and establishing a sufficient margin for the providers' return is often necessary for cost-based methods.
	Connection Agreements	The flexible access and connection agreements (also known as dynamic grid connection agreements) address the formalisation of an agreement between the system operator and the service provider. The power exchange at the point of connection can be lowered according to the operator’s needs. For new connections, flexible access and connection agreements are often made.	
	Dynamic network tariffs	Differentiating **network tariffs on a time and spatial basis** defines the dynamic network tariffs mechanism. As a result, the third parties provide system services by customizing their electric consumption behaviour according to the price signal they get.	
Market-based procurement	Bilateral contract	A bilateral contract process includes the **TSO or DSO and the service provider** signing a legally binding agreement. The contract outlines conditions mutually agreed upon for the service provider and established through **bilateral negotiations**. The bilateral contract method is typically used for restricted circumstances and connected resources that are already available. The mechanism of the bilateral contract is a market-based approach.	
	Flexibility market	The focus of the flexibility market method is the definition of a market for the exchange of flexibility. The corresponding market may be regional or system-wide, depending on the flexibility traded. The auction and exchange market mechanisms are both included in the flexibility market category. Flexibility markets can be auction markets when there is just one or a small number of buyers (such as TSOs, DSOs, FSPs, or any other commercial party) and many sellers (such as FSPs and any other commercial party), or when their is a need for a contract with capacity reservation (in particular, to differ the date of reinforcement, a system operator is likely to rely on contracts with capacity reservation).	

There are multiple possible forms of governance, from centralized to local. Nonetheless, there are also other aspects to consider, such as the direct access to DER from the TSO, sub-markets, and the type of need.

2.4. MAIN OUTCOMES

As seen, there is **no universal regulation** on the integration of flexibilities. While some countries have made some progress in the last few years, several are still lagging. The roles of the flexibility actors and the uncertainties and risks they bring to network planning must be addressed. Drawbacks that are observed in the addressed regulations are listed below:

- In regulatory terms, the market is not yet open for aggregators in many countries [12] .
- The high competition in the ancillary services market makes access difficult to new parties.
- The volatility of prices, low profit for large generators and absence of clear price signals for DSOs flexibility products are the main economic obstacles to developing flexibility services.
- Many technical obstacles exist (delays of advanced metering infrastructure implementation, complex markets).
- Different regulations could lead to segmented markets with different rules, ultimately hindering optimal utilization of resources.

Standardized regulations can speed up renewable integration and facilitate the utilization of available flexibilities at the MV and LV levels. The fast development of electric vehicles and heat pumps as part of the clean energy transition has added enormous stress to the traditional distribution grids. While these non-conventional “loads” can be used as flexibilities, a universal standard can accelerate the energy transition. **One recommendation would be to define common flexibility business rules, metrics, and key performance indices for flexibility trading.**

3. Local flexibility for operational planning

The increased DER penetration opens up new opportunities for network operation optimization and ancillary services provision, such as power loss minimization, voltage and frequency regulation, and offering emergency support to the bulk power system. **Local flexibility describes the usage of flexible assets to ensure a safe distribution network operation**. In contrast to a system or market flexibility, the activation is **DSO-centric**, so the activation of flexibility services is used to solve **local congestion** within the grid section where the actual assets are installed. Congestion can be the **current overloading of branch elements (lines and transformers) or a voltage limit violation**.

In the presence of substantial DER penetration, DSOs face significant challenges in maintaining voltage within specified limits, prompting them to advocate for more stringent requirements for DER grid connections. Unlike historical voltage control methods, the Information and Communication Technology (ICT) infrastructure has introduced numerous possibilities. The involvement of DERs in controlling distribution grid voltage is contingent upon factors such as their characteristics, size, and control capabilities. This implies that the system's behaviour varies depending on the specific DER technology employed. A comprehensive understanding of control capabilities becomes essential for identifying opportunities to leverage optimal flexibilities offered by DERs and other grid components. Additionally, it is crucial to acknowledge the associated risks of heavy dependence on the ICT infrastructure.

3.1. Congestion management using flexibilities

3.1.1. Traffic light concept

C**ongestion management** can be separated into **predictive** and **curative** congestion management. Therefore, the position paper of BDEW proposes a grid traffic light concept. The traffic light concept differentiates between the green, amber and red phases. The **green or market state** does not require any intervention by the DSO as no critical network situation exists. The **red traffic light** phase indicates a **direct risk to the system's stability**. Hence, immediate measures neglecting market processes must be taken to ensure a secure supply. A potential future network shortage is detected in the defined grid segment in the amber phase. The impending violation of the grid constraints **relies on forecasts**. With the help of network flexibility, it can be remedied in advance, and hence, the occurrence of a red traffic light phase is avoided. While the red phase refers to online grid operating only, and the amber phase is always based on forecasts, the green phase is used for online operation and scheduling.

Project example: FlexQgrid (Germany)

Project description: Quota-based congestion management was implemented within the project flex grid. Therefore, the grid state was predicted six hours in advance in a 15-minute resolution. Whenever a violation of the grid restrictions was detected, a quota was calculated to curtail the active power (load or generation) and eliminate the bottleneck using the existing flexibility, as shown in Figure 6.

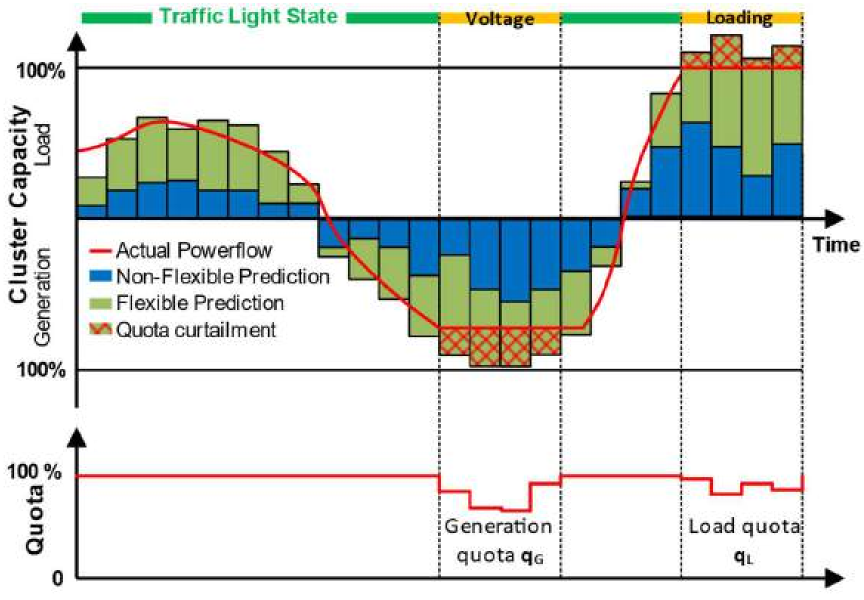

Figure 6: Schematic of the grid traffic light concept using load and generation quotas in case of impending congestion in a distribution grid [15]

Curative congestion was used whenever the calculated quota could not avoid the congestion during the grid operation. Thereby, the available flexibility was used directly to prevent grid harm. These curative measures required full knowledge of the grid state at any time, which was achieved by an online state estimation. Furthermore, the grid's Feasible Operation Region (FOR) was calculated continuously to evaluate the LV flexibilities' ability to provide services to the overlaid grid. This includes congestion management for the MV and sub-transmission and transmission levels.

Project outcomes: **The project results showed that implementing a predictive and curative approach is possible down to the LV level**. With an increasing amount of smart metering infrastructure and a better ability to control flexible units, teething problems can be overcome, and the processes can be automated. However, **several challenges** have to be handled. The main problem within predictive congestion management is the **volatile generation and stochastic load behaviour in the LV grid**. A high resolution and exact forecast are not possible, so obligatory measures for flexibility providers derived from this prediction are unreasonable. Further information and results can be found, among others, in [16], [17] and [15].

3.1.2. Voltage margins definition

Maintaining the voltage levels within the distribution grid is crucial, and typically, it must be kept within ± 10% of the nominal voltage across the entire grid. While these values are set for Europe, these margins may vary for other countries. However, it's important to note that this margin is not uniformly available at all points within the grid. According to a study conducted by the German Energy Agency (Dena)[5], this 10% voltage band is divided into three segments:

- The MV grid allows for a tolerance of up to 4%.

[5] German Energy Agency, "Dena-Verteilnetzstudie: Ausbau- und Innovationsbedarf der Stromverteilnetze in Deutschland bis 2030," 2012.

- The distribution transformer permits a variation of up to 2%.
- The LV grid accounts for the remaining 4%.

It's worth mentioning that the Dena study doesn't consider any control tolerance at the substation level. Nevertheless, some DSOs in Germany consider implementing an additional control tolerance band of 2% at the primary substation is considered in another study, Stadtwerke Ulm/Neu-Ulm (SWU). The DSOs can decide this level of 10% based on their actual grid configuration.

These variations in voltage band splits, as suggested by Dena and implemented by various DSOs in Germany, illustrate the nuanced approaches to managing voltage levels within the distribution grid, as explained in Figure 7. The Dena study has a 4%-2%-4% voltage band distribution, while the SWU has a 2 % regulation bandwidth at the primary substation, leading to a 5%-1%-5% voltage band distribution.

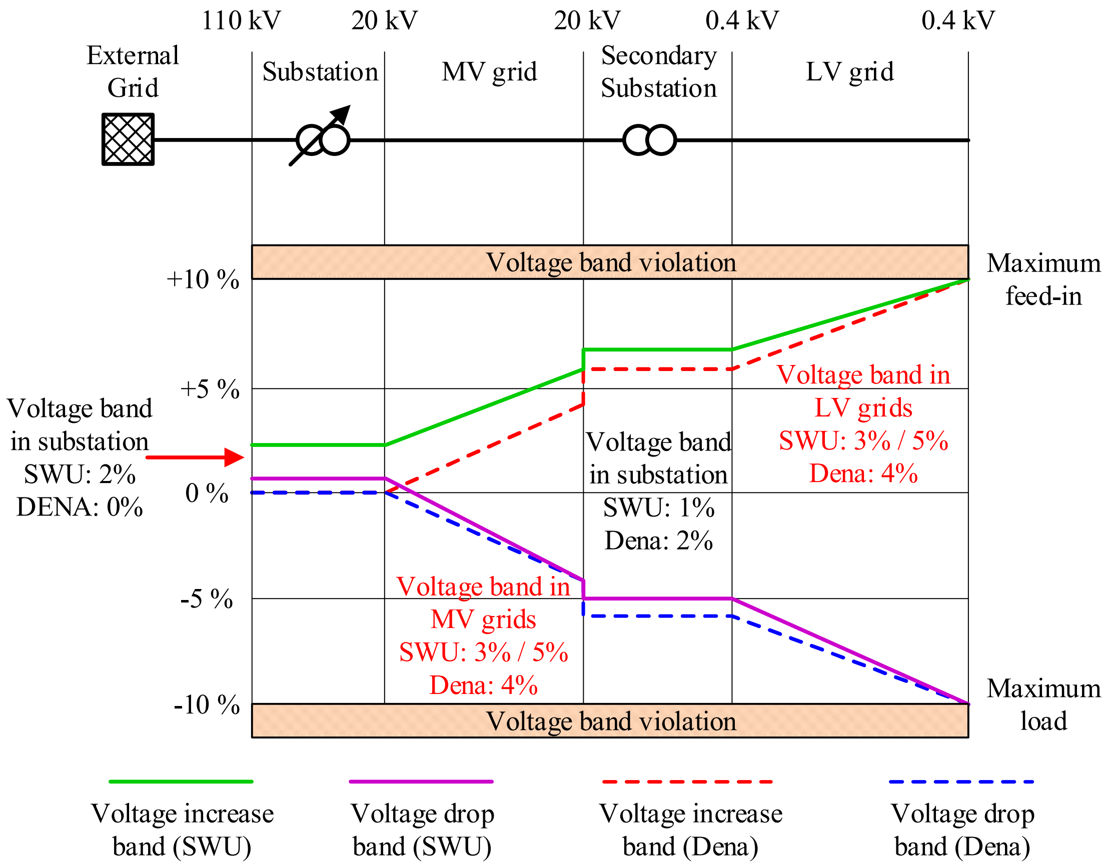

Figure 7: Voltage band split at the different voltage levels with examples from Dena and SWU studies.

3.1.3. Voltage regulation technologies

Various technologies and devices can be employed to offer **voltage control** within the distribution grid. It is essential to note that the **ENTSO-E** envisions a market design and system operation strategy for 2030. This vision emphasizes the need for **coordinated operation** among different system components, focusing on collaboration **between TSOs and DSOs**.

The **future landscape of system operators** will necessitate a configuration where all **available flexibilities** and diverse **grid components** operate in **synchronization**. This harmonious operation will ensure efficient and effective voltage control within the distribution grid.

Depending on their type and operational capabilities, DERs can be connected to the electrical grid using various technologies. Since the electrical grid operates on alternating current (AC), DERs that produce direct current (DC) energy, such as photovoltaic (PV) panels, BESS, and fuel cells, necessitate a DC-to-AC power converter interface to synchronize with the grid.

Some AC-type DERs can be directly connected to the grid, but those with variable-speed generators, like wind turbines and high-speed micro-turbines, require an AC-to-AC power converter. This converter aligns the voltage and grid frequency at the Point of Common Coupling (PCC) to ensure seamless integration. Wind turbines, for instance, can be connected directly to the grid using induction generators, albeit with reduced flexibility. Alternatively, they can employ doubly-fed induction generators for greater system flexibility. To provide additional P (active power) and Q (reactive power) flexibility to the grid, additional components can be integrated:

- *Capacitor Banks*: These devices help regulate reactive power and voltage levels.
- *Static Var Compensators (SVCs)*: SVCs are used for dynamic voltage and reactive power control.
- *Static Synchronous Compensators (STATCOMs)*: STATCOMs provide reactive power support and voltage stabilization.

Physical flexibilities also play a role and include:

- *On-Load Tap Changers (OLTCs)*: These devices adjust transformer taps to regulate voltage.
- *Line Voltage Regulators (LVRs)* help maintain voltage levels along distribution lines.
- *Battery Energy Storage Systems (BESSs)*: BESSs store and release electrical energy as needed, aiding in voltage and frequency regulation.
- *Smart Inverters*: These inverters can adjust active and reactive power flow, enhancing grid stability. In addition to the conventional Q(V), $\cos\varphi$(V) and P(V), they can provide both P and Q independently. While conventional methods can autonomously control the flexibilities, with the help of direct control methods, P and Q can be controlled according to the grid situation.
- *LV Var Controllers*: LV Var controllers manage voltage and reactive power at the distribution level.
- *Charging Stations and Heat Pumps*: The latest regulations in several countries mandate the possibility of real-time control of EV charging patterns and heat pumps.

These various technologies and components contribute to the flexibility and stability of the electrical grid, accommodating the integration of DERs and maintaining reliable power delivery.

3.2. ARCHITECTURE AND REQUIREMENTS

For a **grid leveraging flexibility services**, the **interactions** between **all actors** has to be defined and clear roles has to be allocated. Every actor involved in the flexibility provision through distribution networks must fulfil various requirements to establish a functional architecture. **These requirements can be divided into hardware, software and processes.**

Some flexibilities are **autonomous** and operated dependent on a **local measure** unit, like an inverter that controls the reactive power dependent on the voltage. **However, other flexibilities must be directly controlled by an external system** to manage the congestion (current or voltage). To harness the full potential of these flexibilities and effectively manage the congestion, **DSOs** must attain a **good degree of transparency** in the medium and low voltage grid. This transparency is essential for making informed decisions and optimizing the operation of the grid and is used as a basis for triggering these flexibilities.

3.2.1. From digital twin to digital process twin of the grid

Conventionally, there were very few measurements in the distribution grid, and the DSOs had to operate the grid based on experience. However, introducing DERs in the distribution grid has increased the necessity of **decentralized measurements**. Using these measurements, the DSOs can **optimize grid operations** by avoiding congestion and utilizing the available flexibilities.

The availability of measurements from hardware devices necessitates proper software to process all the available information. With the appropriate data and software, the DSOs can perform grid planning and operations effectively. **This presence of hardware and software in the distribution grid leads to a question of using a virtual grid representation in the cloud or on-premise solution, i.e. hosted within the company**.

A digital twin (DT) of the grid is a virtual representation of the physical grid, providing Information about the grid based on algorithms for state estimation and enabling monitoring. This can be implemented with different data resolution and calculation frequency. Although real-time monitoring is not a mandatory criterion for planning purposes, network operation functionalities like state estimation and flexibility deployment require near real-time monitoring. These systems are usually designed to integrate and process large amounts of data compared to classical SCADA (Supervisory Control and Data Acquisition) systems. A basic and minimal configuration for a digital twin is provided in Figure 8.

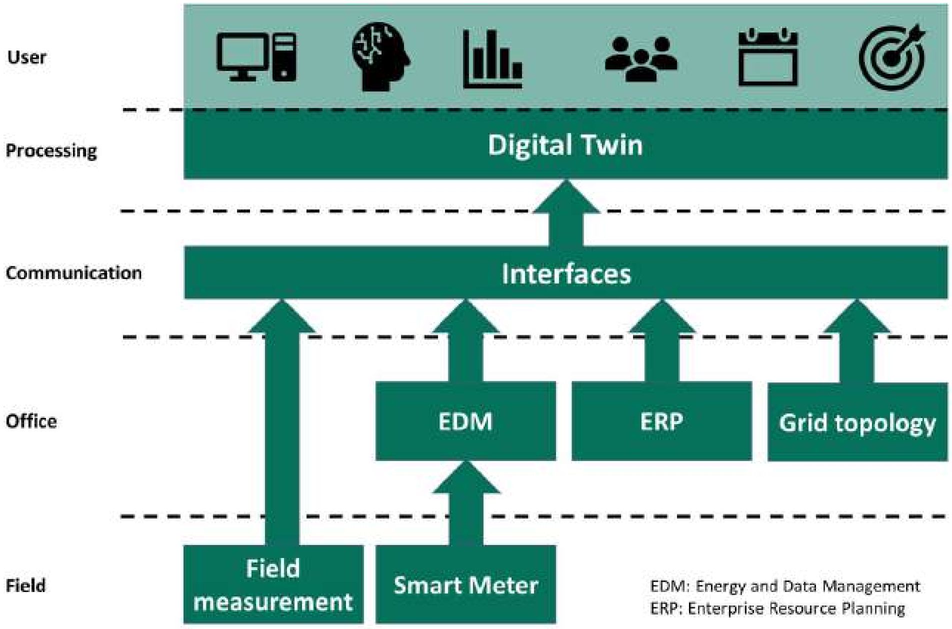

Figure 8: Minimal requirements of a digital twin

Creating a digital architecture incorporating distributed computational devices and algorithms requires **meticulous data management** for system modelling and functional descriptions. Network planning, asset management, and system operation processes **are intricately linked**, and the **same data** is required in **various formats** throughout these processes. A huge amount of data would be available in digitalised MV and LV systems. It is essential to identify what data is relevant for digital twins and flexibility management subsequently.

While the conventional definition of a digital twin typically describes the monitor of the grid condition, the concept of a "**digital process twin**" broadens this definition. It encompasses **equipment and** the **entire operational process** involving all the flexibilities and their potential. This expanded definition includes elements such as using digital twins of equipment and systems, applying statistical data analysis, and suggesting actions for operational planning to enhance the reliability and efficiency of electricity supply and demand. Figure 9 gives an example of this **cellular structure of a DT**.

Developing a DT for grid monitoring, operation, optimization, and control presents a promising avenue. This approach has the potential to usher in future advancements in grid control centre technology, ultimately leading to improvements in system efficiency and reliability. **Power system DTs** can serve as **valuable tools** for **assessing and simulating the outcomes of different scenarios within the network**. These scenarios might include introducing new generation resources, responding to extreme events, integrating new transmission lines, and providing insights critical for informed decision-making and grid management.

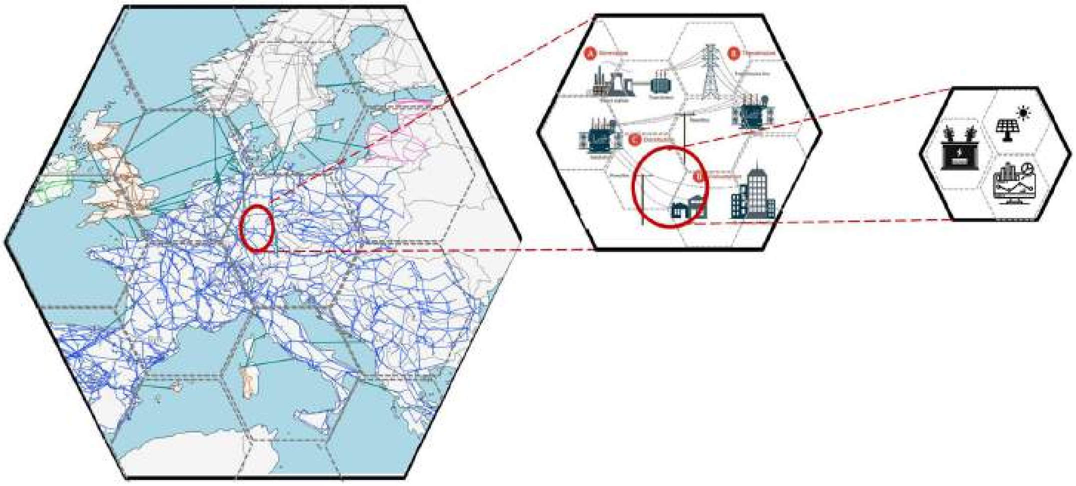

Figure 9: Cellular structure of a DT for power systems [18].

Establishing a DT for enhanced flexibility usage in the distribution grids is very helpful for the system operators. However, such a solution brings with it **multiple challenges**, including:

- *Data protection/security*: a digital twin would also process personal data (smart meter data). Without the customer's consent, these data may only be used in aggregated/pseudonymized or anonymized form. This minimizes the usefulness of this data for the network. **Anonymizing smart meter data with a clustering** algorithm or similar has to be considered and simultaneously a challenge to obtain satisfying results.
- Data quality: data quality is a key challenge for a digital twin. Missing or poor data from the Enterprise Resource Planning (ERP) or Geographic Information System (GIS), for example, can lead to a massive deterioration in the accuracy of the state estimation of the grid. A practical example is the generation of synthetic profiles for the computation of the grid state. If the data used as input for this profile generation is of poor quality, the synthetic profiles would, at best, not represent the connection points and thus distort the results. **Significant effort** may be required to be able to **assess the quality of the data and improve** it.
- *Data processing*: The data to be processed are numerous, usually from different sources and structured differently. If not part of the digital twin concept, a **data lake and single source** of truth should also be implemented. The effort to create the processing system for the digital twin is vital to process the data as quickly as possible and integrate this information into the software sustainably. On the other hand, creating a data lake is not to be underestimated and **can take years.**
- *Field measurements*: Field measurements are important for a real-time network monitoring system. However, due to the large number of network elements, they also represent a **major investment**. It is, therefore, necessary to find an **optimum balance between accuracy and investment**, which may vary depending on the network configuration and type of prosumers.

Overcoming these challenges is crucial for the successful implementation and utilization of DTs.

Project example: Digital Twin of the low voltage grid (Switzerland)

Project description: The Swiss Energy Strategy 2050 is technically ambitious and involves major LV grid-level changes, such as increased distributed generation and consumption behaviour mainly due to heat pumps, e-mobility and batteries.

Primeo Netz AG, a Swiss DSO operating in northwestern Switzerland, is already experiencing the effects of the Swiss Energy Strategy and has identified at least 50 of its low-voltage grids that are currently recording a strong increase in PV installation (production in summer) and heat pump and e-mobility (load in winter).

To meet these challenges, and to also contribute to the energy strategy, Primeo Netz AG decided to achieve a high level of transparency of the low voltage grid with its digital twin as depicted in Figure 10. To this end, an internal pilot project has been started to digitalize 5 low-voltage grids and reach the best possible transparency with compromise accuracy costs. The pilot started with five grids and will be extended to all the critical grids.

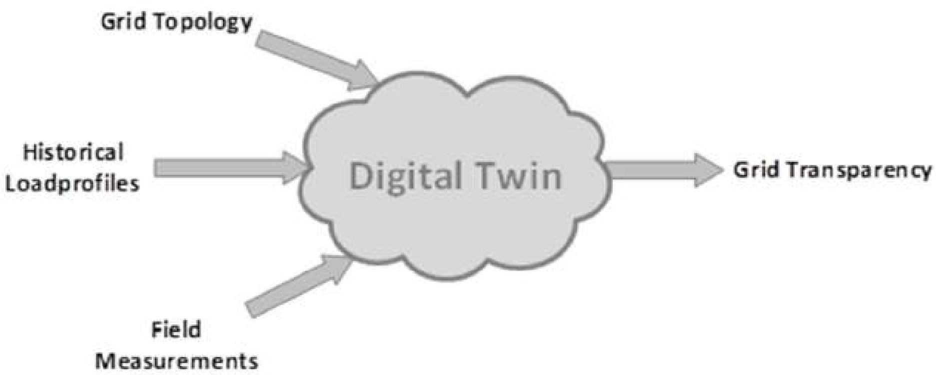

Figure 10: Schematic structure of the project

The project has been implemented as follows:

- **Transformer station and distribution cabin measurement**: PQ measuring devices or comparable devices were installed in the transformer substation, where all outgoing feeders are measured with a current bus system. In the distribution cabins, however, only the main cable was measured. For scalability reasons, the established IEC 60870-5-104 protocol was not used, and the Message Queuing Telemetry Transport (MQTT) protocol was selected, offering greater flexibility for other applications.
- **Smart meters**: Load profiles and register values can easily be exported from the Energy and Data Management (EDM) system. The load profiles are aggregated and statistically analyzed. Customers with register values, on the other hand, are modelled using the standardized load profiles of the German Electricity Association VDEW [19].
- **Customer installation**: this data represents the information and characteristics of the customer systems, such as the nominal output of the systems or the setting for the inverter of a $\cos\varphi$(V) curve. This data can be easily exported from the ERP system and serves as a supplement to the prosumer modelling.

- **Grid topology**: the grid topology was already available in Common Information Model (CIM) format due to an existing internal application. The CIM export is based on IEC 61970-301 and IEC 61968-11.

The power distribution network is under-determined in terms of measurement technology. All the data is implemented in the digital twin (third-party software), which combines simulations with real-time measured values to determine the grid status in real-time using a bottom-up approach. The results are then displayed according to a traffic light system.

Despite the many advantages the transparency can bring to the grid's operational and planning activities, significant challenges must be dealt with in implementing this project.

- **Data protection/security**: The Data Protection Act applies as soon as personal data is processed. This data may only be used in aggregated or anonymized form without the customer's consent. This procedure minimizes the usefulness of this data for the network. Customer clustering or similar must be considered.
- **Network topology:** recording network changes can take several days, depending on priority and resource utilization. However, an updated network topology is crucial to achieve network transparency. The changes should, therefore, already be recorded in the field or during project planning.
- **Field measurement assets such as transformer stations or distribution cabins are generally not designed to use measuring devices permanently**. Due to their compact size and limited equipment, finding suitable space for measuring devices that fulfil the safety requirements can be challenging.
- **Measurements in distribution cabins require high investments**: The number and placement of measurements are difficult to evaluate as they are highly dependent on the structure of the network and the connected equipment.
- **Data processing:** the different data streams to be processed are numerous and structured differently. The complex house connection structure due to special tariffs (e.g. heat pump) or the linking of load profiles/register values in the event of a meter change must be considered.

The state estimation of the digital twin has been verified with control measurements in distribution cabins and the following conclusions can be made.

- *Voltage*: **Very good estimation of the voltage for all control measurements**. The deviation is within +/- 2 % for 90 % of the values and +/- 1 % for 13 of the 15 tested distribution cabins.
- *Current*: The **deviation is very different and varies from distribution cabin to distribution cabin**, depending on the connected systems (type and number) and the type of grid topology. In the case of heating systems and charging stations, influencing factors such as heat demand, arrival time, etc., are particularly difficult to map/estimate. Detailed analysis showed that **a higher number of measuring devices does not guarantee a better quality of the network status analysis**. It has also been found that **high deviations** are achieved when the **load of the grid element is low**. On the other hand, when the load increases, which is relevant to the state of the grid and the use of flexibility, the deviation decreases and reaches a good, if not very good, range.

Project outcomes: The pilot project was completed, and critical points for successful implementation were identified. An initial rollout phase was approved, in which 45 networks are to be integrated into the digital twin.

3.2.2. State prediction and flexibility forecasting

To use flexibility and enable operational grid planning, implementing an **accurate forecasting system** is one of the key elements. At this moment, the prediction of the non-flexible load and generation and the available flexibility potential is important. With the help of a complete state prediction, bottlenecks in the distribution networks can be detected. These affect the necessary network flexibility and the limits for a system serving flexibility provision. The day-ahead operation and market participation can be planned based on a high-quality forecast.

A set of suitable parameters must be found to find the best prediction models for load and generation forecasts. This approach is done by calculating **the correlation matrix between the parameters and the output variable**. Figure 11 shows a variety of possible parameters.

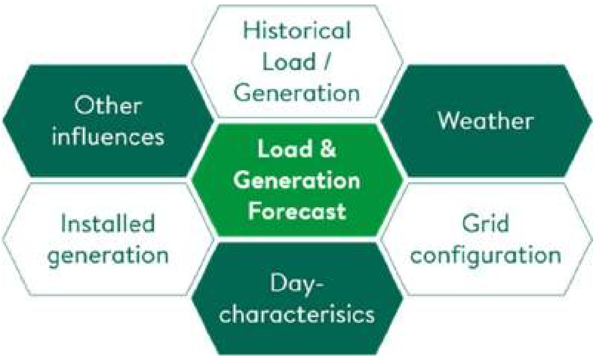

Figure 11: Possible parameters for a load and generation forecast

a) Load forecast

Load forecasts rely on the portfolio effect. The forecast accuracy of each load is very low. Therefore, it is necessary to aggregate customers into a merged group, for instance, each secondary substation. With this approach, the accuracy will increase significantly.

Even though the load prediction is based on merged groups, flexibility can be planned for the medium and high voltage levels. Next, the most suitable prediction model is selected. **The possible models vary from linear regression models boosted trees to neural networks**. A crucial factor which each model must consider is the supplied area. It makes a huge impact if the right model is used for the specific supplied area like urban, rural or industrial.

b) Generation forecast

Generation forecasts are influenced by each generation type's supply or demand dependency. As examples:

- The **prediction of photovoltaic power generation** has a very strong correlation between the global radiation, the temperature and the installed power. Therefore, a linear **regression model** is suitable for the photovoltaic generation prediction. However, although this model provides high accuracy, the model cannot cope with

faults or influences from, e.g., **snow coped modules**. Therefore, a factor is needed which corrects according to previous measured generations.

- The prediction **of a small run of river power station generation** relies on the precipitation and water inflow of the area as well as the historical generation. Bigger hydro power plants are obligated to provide schedules of the planned production.
- The forecast of **wind energy** is correlated with the windspeed of the specific area. The generation will be determined according to the generation graph of the wind park. However, the wind energy forecast is **very complex** due to the **uncertainty** of the windspeed forecast and the occurrence of gusts of wind.

Even though **forecasts** provide the fundamentals of the day-ahead operation planning of a grid, it is still necessary to provide **a real time monitoring** of the grid to verify the forecast and use the flexibility where it is **needed.**

3.2.3. Hardware-independent implementation across voltage levels

In the foreseeable future, distribution grids are anticipated to **become increasingly automated**, at least in part. However, up to this point, manufacturers can rely on no standardized, universally applicable installation concepts as a reference. As a result, existing solutions tend to be specialized and tailored to specific field conditions. Given the many components involved and the diverse challenges encountered during grid operations, achieving complete standardization is complex. To date, **a comprehensive standardization framework does not exist**, and the specifics of what such standardization should entail, particularly for components with adaptive behaviour, have not been defined.

Many of the **solutions** suggested **in the existing literature** have a notable **drawback**: most **control applications are proprietary and lack modularity**. This situation implies that the **software** is **tailored to specific hardware**, making updating or integrating new algorithms from different users a challenging and cumbersome task each time.

A **hardware-independent solution** will establish a template for an industry-standard approach to the deployment of smart grid automation systems in the field. This initiative aims to **minimize the efforts and costs** associated with developing automation systems for manufacturers and reduce the challenges DSOs face in establishing smart grids. The primary focus revolves around standardizing the systems and associated processes. This design provides modularity and allows multiple users to develop diverse applications that can seamlessly collaborate on the same hardware device. The innovative system architecture consolidates different protection and control functions onto industrial hardware platforms, emphasizing the importance of achieving hardware independence.

Automation systems incorporating software and hardware offer a solution for identifying bottlenecks and optimizing existing grid capacity through load management applications. However, there is still uncertainty about the specific types of new software applications needed in the long term to ensure adequate grid observability, process automation, and the optimal system level for deploying such applications. As a result, long-term grid planning strategies must demonstrate adaptability to evolving requirements, including diversification and deployment of software applications, adherence to Information Security Management System (ISMS)-relevant security specifications, and compliance with market regulations.

Given the challenges posed by the compact design, widespread geographical distribution, a high number of secondary substations, and limited technical staff for troubleshooting, upgrading, or replacement, there is **a particular need for efficient application rollout and monitoring strategies**.

Recognizing these challenges, a **core group comprising grid operators, hardware manufacturers, software developers, and research institutes has initiated a collaborative effort**. The objective is to develop an **automated integration process that anticipates future requirements for hardware, software, and engineering processes**. This collaborative approach aims to address the complexities of the evolving energy landscape and ensure a seamless transition to more advanced and adaptable grid management systems. The idea was introduced in [20] and extended in future publications [21] and [22].

A crucial aspect of this proposal involves the **division between hardware and software** by implementing **virtualization solutions**. Consequently, the standardized hardware device must fulfil this requirement while delivering a robust engine supporting diverse functionalities. The **separation of hardware and software** becomes particularly **advantageous** when considering future deployments and the **operation of third-party applications**. This approach enhances flexibility and facilitates the integration of various applications from external sources, making the system more versatile and adaptable to evolving technological landscapes.

Project example: i-Autonomous[6] (Germany)

Project description: In the **i-Autonomous project**, comprehensive research is being conducted to formulate an overarching concept for **standardizing the integration of smart grid functionalities**. The primary objective is to develop a template that facilitates the standardized integration of smart grid capabilities within medium and low-voltage grids. As part of this project, a standardized protection and automation system for application in medium and low-voltage electrical grids is being designed. To ensure the effectiveness of this system, requirements are being collaboratively developed with DSOs. These requirements encompass hardware, software, communication protocols, functionality, and security considerations. Subsequently, the project team derives and documents system specifications within an integration guide. Hardware and software components are then developed to implement the required protection and automation functions, interface adaptations, an appropriate engineering process, and automated testing procedures. Figure 12 presents an example of the overall integration of hardware-independent software.

The ultimate goal is to assess whether these functions can operate within their designated containers on predefined hardware and communicate seamlessly with each other, as depicted in the figure. Following this, **a prototype protection and automation system** will be deployed and validated within a selected grid area, adhering to the specified processes. Also, containers

[6] https://www.offis.de/en/offis/project/i-autonomous.html

featuring various other automation functions are being procured from independent developers to test their performance within the implemented strategy.

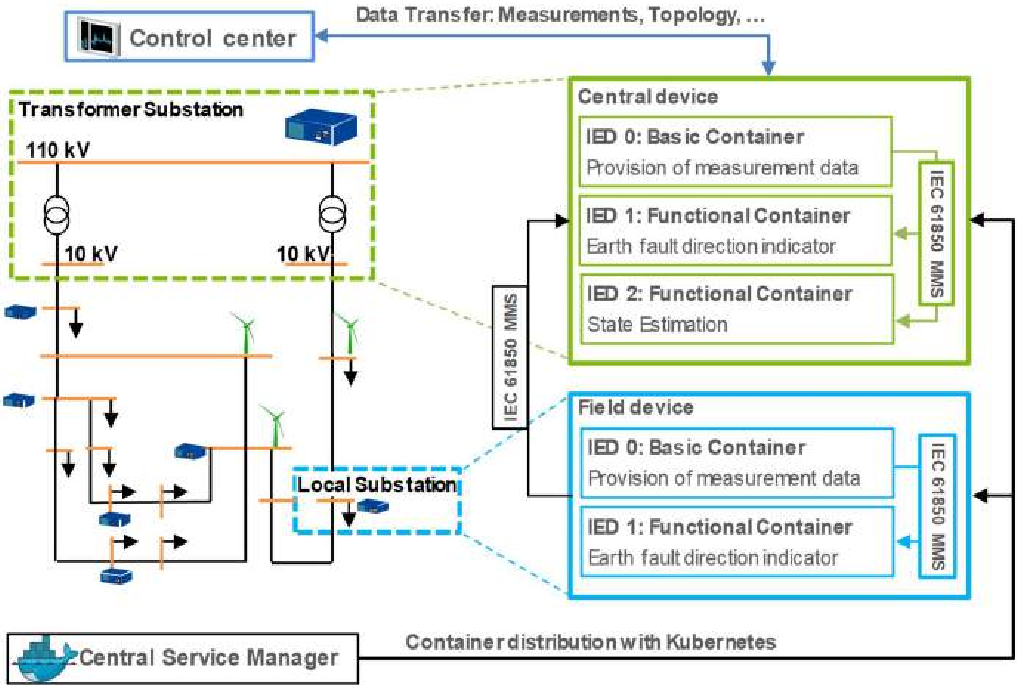

Figure 12: Overall integration process of a hardware-independent software implementation [22].

3.2.4. Flexibility aggregation and feasible operation region as DSO-TSO interface

To simplify operational flexibility across voltage levels, it is possible to aggregate each flexible asset's flexibility potentials to a grid's flexibility. Hence, all flexibilities within a grid area, e.g., a single LV grid, are aggregated to the FOR, in which this LV grid can change its operation without violating any grid restriction (voltage limits or element loading). Suppose a flexibility service is required in the upstream MV grid (or higher). In that case, it can be solved based on the aggregated flexibility of the LV grid without requiring knowledge about the grid topology, the grid state or the flexibility of the individual plants. Thus, the **communication effort between the different voltage levels can be significantly reduced**, which is the **key to a decentralized approach** of different grid cells, especially involving different grid operators.

Each flexible asset is described by a convex area or function in the complex PQ coordinated system for aggregation. Typical flexibility potentials within distribution networks can be found, for example, in [23]. Figure 13 shows a schematic representation of flexibility aggregation with different plant types and potentials. The result of the aggregation is the flexibility of the grid, defined by all adjustable complex power flows across the grid interconnection point, usually the transformer. If all operating point pairs of active and reactive power are found, the **flexibility of the grid can be represented as a polygon in the PQ coordinate system**.

Different methodologies are developed for the aggregation, including analytic, geometric or random sampling approaches. An overview and comparison of different types can be found in [24]. The **fastest methodologies are based** on **linear optimization**, so an online application is possible, as shown in [25]. Several voltage levels can be included in the aggregation within a multi-stage process. Based on the same optimization problem, a disaggregation has to be included, which assigns a flexibility service to the individual units. As a result, different objective functions can be implemented so that prioritization of flexibilities is possible, e.g., the avoidance of renewable energy curtailment. Hence, with the presented concept, the many flexible units in the distribution networks can provide services up to the transmission level.

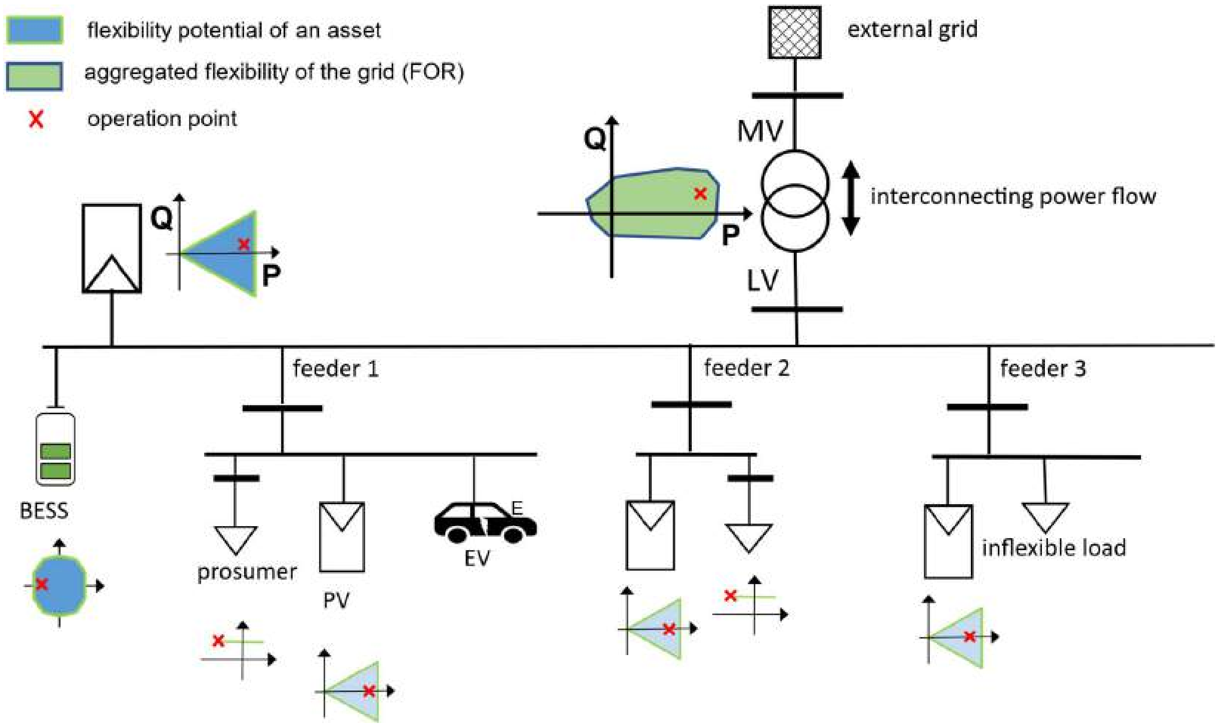

Figure 13: Concept of the feasible operation region (FOR) obtained from a flexibility aggregation as an interface to the upstream grid

3.3. MAIN OUTCOMES

As shown in several research projects and field tests, the integration of congestion management into an active distribution network management is possible. However, it requires actions from all participating actors, which can already be included in planning principles.

The key element for flexibility usage is full **grid transparency** obtained by **digitalization of network models and production and consumption forecasts**, installation and processing of measurements and the ability to control flexibility units. **Safe communication** must always be ensured, as providing a service can be crucial for network and system stability.

The **required architecture** for an operational, network-orientated usage of flexibility is also the basis for a superimposed deployment of distribution network flexibility at a transmission level. Having all these requirements fulfilled, local flexibilities could be directly used for TSO-oriented service. Another model could be to define a global flexibility offer aggregating part of distribution assets capacities.

4. LOCAL FLEXIBILITY FOR MEDIUM/LONG-TERM PLANNING

4.1. TRADITIONAL INVESTMENT PLANNING

The investment decision-making methodology is quite homogeneous from country to country and can be summarized in 4 main steps as detailed in [26]:

- *Identification of network constraints* over or under-voltage areas, over-current areas or poor quality of service areas;
- *Definition of strategies to solve the constraints* such as reinforcement of lines, creation of new feeders or substations;
- Use of the Net Present Value (NPV) criteria to *select the best investment strategy:* The NPV between two strategies is defined by equations eq. 1 to Eq. 3.

$$NPV = TOTEX_{strategy\ 1} - TOTEX_{strategy\ 2} \quad \text{eq. 1}$$

$$TOTEX_k = \sum_{i=1}^{N} \frac{CAPEX_k(i) + OPEX_{losses,k}(i) + OPEX_{operation,k}(i) + OPEX_{failures,k}(i)}{(1+r)^i} - \frac{U}{(1+r)^N} \quad \text{eq. 2}$$

$$U = V_f + \left(V_0 - V_f\right) \times \frac{(1+r)^T - (1+r)^t}{(1+r)^T - 1} \quad \text{Eq. 3}$$

With:

i: index of year	$CAPEX_k(i)$: capital expenditure of strategy k i.e. investment done at year i.
N: last year of the studied period	$OPEX_{losses,k}$ (i): operational expenditure, i.e. cost of the Joule and iron losses at year i
R: discount rate (in %)	$OPEX_{operation,k}$ (i): maintenance and repair costs following an incident at year i
T: lifetime of the equipment	$OPEX_{failures}$(i): cost of the failures at year i reflecting the imperfect quality of supply seen by the users of the distribution grid
t: current year of the equipment	U: residual value of the equipment at the end date, N, when the studied period is different from the lifetime of the equipment.
V_0: *the* value of the equipment when it is new	V_f: residual value of the equipment at year t

- *Computation of the optimal investment year* with the Cost Benefit Ratio (CBR) criteria. The optimal investment year, t_{op}, is the first year when the criteria of eq. 4 are satisfied. In this case, the CBR is always lower than $\frac{r}{1+r}$, the DSO may decide not to invest and wait for further information depending on the severity of the constraints. Indeed, for example, current constraints endanger the networks, whereas quality constraints "only" bother customers.

$$CBR = \frac{\Delta OPEX_{tot}(t)}{CAPEX} \geq \frac{r}{1+r} \quad \text{eq. 4}$$

This methodology requires some hypotheses related to the load growth rate over the planning period, power losses assessment, the failure rate of equipment and the sizing scenarios (usually maximal consumption - minimal production and maximal production - minimal consumption.

4.2. INTEGRATING FLEXIBILITY INTO PLANNING

To ensure safe and reliable network operation on the one hand and to avoid oversizing of the networks on the other hand, local flexibility of MV and LV networks has to be integrated into network planning. With the increasing expansion of DERs, particularly at the MV and LV level, DSOs are facing major operational challenges which could be met by local flexibility such as active and reactive power control. As explained by [27], **some threshold effects are expected to be linked with the dynamic development of DERs and the rise of new loads, necessitating technical and regulatory evolutions of power systems.** In particular, if the rate of DERs is low, traditional planning is still optimal and no particular updates must be done. If this rate is medium, then DERs need to be integrated into planning as well as the use of flexibility. Finally, if this rate is high, then major regulatory evolutions are necessary such as new market models [28]. The estimation of the rate of DERs corresponding to low, medium and high.

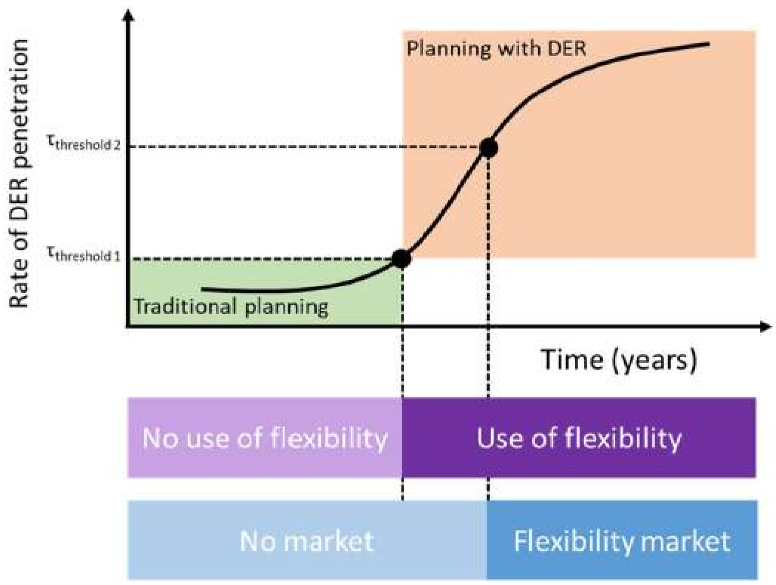

Figure 14: Evolution of the distribution network according to the development of DERs [28]

In this context, the raised question is **how local flexibility affects distribution grid expansion and to what extent the use of flexibility by grid users can counteract grid expansion**. Such operational measures, listed in Table 5[7], must be integrated into the network planning of the distribution network operators to ensure high supply reliability.

[7] It has to be mentioned that network (re)-configuration (switchgear operation) could be used as a complementary lever to flexibility, such as network equipment activation (ex : inductance, voltage regulation in primary substation for feeder constraints).

Table 5: Local flexibility options (inspired by [28])

Type of solutions	Definitions/Advantages/Drawbacks
New or existing device	_Definitions_: OLTC, voltage regulators, Flexible Alternating Current Transmission System (FACTS), capacitors, inductances, dynamic phase rebalancing _Type of controls_: decentralized or centralized _Advantages_: Simple (in case of decentralized) and/or already industrialized solutions _Drawbacks_: • high CAPEX, only solve voltage constraints (except for dynamic phase rebalancing) • dynamic phase rebalancing: economic benefit for the moment not quantified • centralized: complexity increased due to the need for sensors and communication systems • decentralized: less optimal solution
Active power management producers	_Definitions_: control of active power of sources in a centralized or decentralized approach and with different rules. It could be fixed (as in some countries, such as Germany and France) or dynamic. _Advantages_: remuneration costs directly depend on the energy not produced _Drawbacks_: • in the case of P(U) control, the computation of the energy curtailed could be complex • business model of the producer complex to set up • centralized: complexity increased due to the need for sensors and communication systems • decentralized: less optimal solution
Reactive power management of producers	_Definitions_: control of reactive power of sources in a centralized or decentralized approach and with different rules. Examples of rules are: • **Depending on the active power fed into the grid (Q=f(P), decentralized):** With that strategy, the feedback of the behaviour of a certain generation unit is minimized by the generation unit itself. • **Depending on the local voltage (Q=f(U) or $\cos\varphi = f(U)$, decentralized):** That strategy acts on the local voltage. Keeping a certain voltage profile within a grid will be the most effective. The generation units must provide reactive power independently of their active power generation or the availability of power sources for possible active power generation. • **Depending on a Q set point given by the control center (centralized):** This is the most flexible strategy. Depending on the current local and global situation in the grid, the control center can set the set point so that the reactive power

	source can best support the network operation. The generation units must provide reactive power independently of their active power generation or the availability of power sources for possible active power generation. *Advantages*: solutions already industrialized in some countries *Drawbacks*: • can only solve voltage constraints, risk of interaction between producers • the energy curtailed must be minimized not to reduce the share of renewable production • centralized: complexity increased due to the need for sensors and communication systems • decentralized: less optimal solution
Load shifting and dynamic peak shaving	*Definition*: modulation of active power consumed directly or via a third party, such as an aggregator. *Advantages*: • Increases the degree of utilization of the distribution grids and significantly reduces the necessary grid expansion • In the case of tariffs, simple to implement *Drawbacks*: • Availability of flexibility not guaranteed • in the case of tariffs, the definition of time slots and associated tariffs dependent on the network and the DERs development • centralized: complexity increased due to the need for sensors and communication systems • decentralized: less optimal solution
Active management prosumers	*Definitions*: electric vehicles, heat pumps, storage devices *Advantages*: multi-services for several actors with both injection and absorption operation *Drawbacks*: • Complexity related to the operation and priority among the actors (storage operators, DSO, TSO, etc.)

4.2.1. Increasing the number of scenarios

Traditional planning only considers **one scenario** called the **"reference scenario",** which has to be completed with additional scenarios integrating flexibilities and defined as follows:

- ***Reference scenario***: the distribution network was planned using conventional methods (worse case scenarios, i.e. maximal consumption - minimal production and minimal consumption - maximal production) and the obtained results represent the comparison basis to highlight the benefit of flexibility implementation.
- ***Reference scenario with production*****:** considering more realistic assumptions on the ratio consumption/production could avoid the overestimation of constraints
- ***Reference scenario with reactive support***: the reactive power control of both renewable energy systems and controllable local network transformers are considered. Across Europe, some regulations now impose that DERs in both MV and LV provide reactive power support to the grid.
- ***Flexibility scenario***: the implementation of power modulation is considered.

If **flexibility** brings **new opportunities** to the DSO, it brings **more complexity**. Indeed, assessing the flexibility and ensuring its availability when the DSO needs it are big challenges. Integrating flexibility options into planning **increases the level of uncertainties** (already increased by the development of DERs) and the **level of technical and economic risks**. Indeed, if flexibility fails, then the probability of network constraints increases. As the DSO will have to find a B plan, the cost may be more expensive than a traditional investment. One of the key questions is: **what level of risk is the DSO willing to take? The traditional method needs to evolve from a deterministic to a probabilistic approach to encompass both uncertainties and risks.**

4.2.2. Change of power curve patterns

The development of DERs, but also local energy communities and the use of flexibility **change the pattern of the load curve,** i.e the **peak power** (value and time of occurrence) and **shape of the load curve**. In particular, the **impact of self-consumption** on planning decisions is **complex**.

Optimization of self-consumption means that **flexibilities are used to maximize the use of self-generated power**. The profit is generated by the price difference between power consumed from the public network (containing generation cost, network fees, taxes, and allocated cost) and power consumed from the own generation (containing only generation cost) [6].

The following conditions are necessary to apply this use case:

- The customer should have its generation units;
- Bill the electrical energy according to the power flow via the grid connection point

A customer can be a single household, an apartment house or an energy community if it has one single grid connection point. Generation units usually are photovoltaic systems or small cogeneration units. Flexibility units usually are batteries, thermal storage, heat pumps, and electric vehicles. Even dishwashers, washing machines, etc., can act as flexibility units.

However, these consumers usually are not controlled by energy management systems but by adapting the customer's behaviour. The control is usually realized with local energy management controlling local flexibilities. The energy flow (not necessarily the power flow) via the grid connection point is minimized, and the amount of self-consumed energy is maximized.

- Possible business cases/economical applications

The business case results from the fact that there are different prices for energy generated locally and energy consumed from the grid. The energy generated locally is available at the cost of production. If it is fed into the public network, a market price or compensation will be paid. If the energy is consumed from the public grid, the energy generation price must be paid, as well as network usage fees, taxes, allocated costs, etc.

As in many countries, the surcharges on the energy price are quite high, self-consumption is often an attractive business model, for example, the following table:

Country/customer group	**Cost of generation (without investment cost) [€/kWh]**	**Price for energy fed into the public grid [€/kWh]**	**Price of energy drawn from the public grid [€/kWh]**	**Difference of prices = revenues [€/kWh]**
Germany Household customers 01/2023	• 0 (for PV) • 0.15[8] (for battery discharging) • 0.3 … 0.4[9] (for small cogeneration units)	0.082 (<10kW PV, fixed compensation scheme)[10]	0.3875 (household, basic tariff without basic charge)[11] (pre-2022 energy price rises app. 0.25)	0.3055 (maximizing use of PV)

- Effects on network planning and system design

The **electricity grids** are dimensioned according to the **maximum expected power flow**. The amount of energy does not (or nearly does not) influence the grid capacity required.

The optimization of self-consumption with photovoltaic-(battery)-systems cannot guarantee that the power generation peak is always used and/or that the power consumption peak is never drawn from the grid as depicted in Figure 15.

[8] https://solarenergie.de/stromspeicher/preise visited January 16, 2023, only degeneration of battery, assumption: no cost for electricity for charging
[9] https://www.buderus.de/de/bhkw/kosten visited January 16, 2023, cost depending on price of fuel, actual cost depend on the amount of combined use of heat and electricity
[10] https://solarbuero-amrum.de/eeg-einspeiseverguetung-2023-als-tabelle/ visited January 16, 2023
[11] https://www.drewag.de/wps/portal/drewag/cms/menu_main/privatkunden/produkte/strom visited January 16, 2023

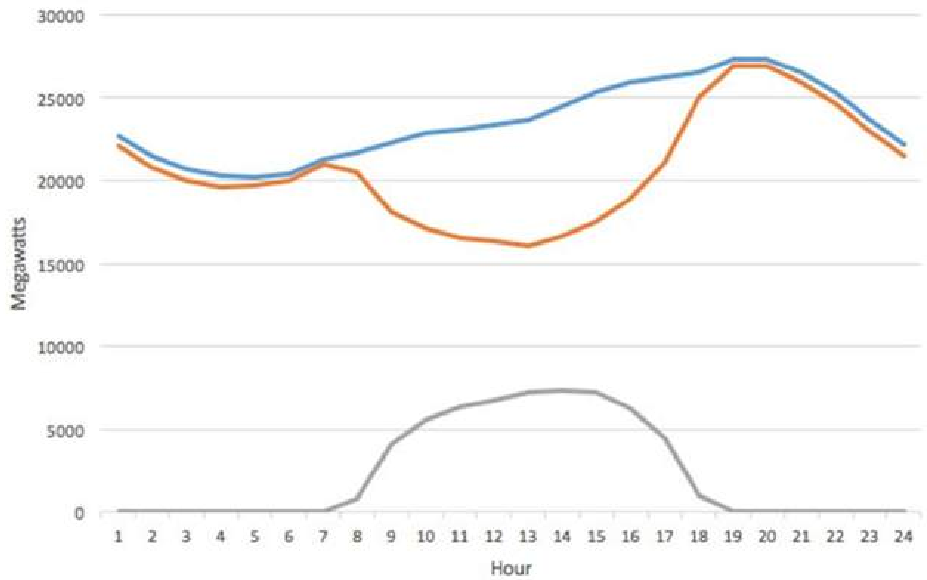

Figure 15: Demand for electrical power (blue curve), supply of electrical power from dispatchable sources (orange curve), supply of solar electrical power (grey curve)

These high peaks and deep valleys result in continued trends of further flatting the load curve as renewable energy production continues growing. At midday, large amounts of solar energy are available, partially contributing to a lower demand for additional electricity. Increasing battery storage can store solar abundance during the day. When this excess solar energy is stored and used in the evening, the price disparity between inexpensive midday and expensive evening energy can be reduced.

Therefore, the use case of maximizing self-consumption does not reduce the amount of grid capacity required. From a regulatory point there is the effect **that the customers that optimize their self-consumption pay less network usage fees as a large share of the grid fee is paid based on the consumed energy**. **As the grids' total cost is not reduced, these fees are shifted to other customers**.

4.2.3. Evolution of planning methods

a) Integration of operational planning into long-term planning

Distribution network planning can be formulated as **a mathematical optimization problem** like a mixed-integer optimization problem. In the literature, Artificial Intelligence (AI)-based optimization techniques such as Genetic algorithms, Ant Colony Algorithms or the Particle Swarm Algorithm have proven their suitability regarding the network planning problem. These algorithms deliver good solutions based on detailed network modelling with acceptable computing time. These algorithms have been modified to find an acceptable solution to use flexibility to eliminate network congestion.

b) From the deterministic method to the probabilistic method

The **recent techniques** in the literature, for distribution network planning are based on **probabilistic and time-series-based calculations**, which can replace the conventional approaches. A time-series-based Monte Carlo Simulation is beneficial for estimating the line loadings in the probabilistic distribution network planning since the real-time network operation can be modelled in detail. The high computational burden can be reduced by linearising power flow calculation and contingency analysis. The above-mentioned technical constraints must still be considered when considering flexibility options in expanding distribution networks. The Probabilistic load flow (PLF) is used within the network planning to give planning engineers a better "feeling" for the future network generation, load and their probability of occurrence. In an analytical calculation of the PLF, the loads and generators are described using distribution functions. The linearization of the load flow calculation makes it possible to represent the power flows using a linear mapping of the nodal powers. It follows that the PLF can be calculated from the sum of the distributions of the individual random variables. Accordingly, the sum of two independent distributions is calculated via the convolution. Table 6 summarizes existing methods to integrate uncertainties into planning.

Table 6: Existing methods to integrate uncertainties [28]

	Advantages	Disadvantages	Applied Example
Worst Case Method (Fit and Forget, Copper Plate)	• Risk close to 0 • Simpler in terms of calculation	• Oversizing	• Sizing of the conductors
Analytical Probabilistic Method	• Very fast	• Independent normal laws • Linearization of the problem • Strong dependence on the data used • The positive effect of uncertainties is not valued • Uncertainty modelling	• Load Balancing Calculation • Hosting capacity • Cost-benefit analysis of flexibility
Monte-Carlo Method	• Simple to implement • It can be used in co-simulation	• High computation time • Strong dependence on the data used • The positive effect of uncertainties is not valued • Uncertainty modelling	• Load Balancing Calculation • Hosting capacity • Cost-benefit analysis of flexibility
Possibilistic Method	• Very fast • Several types of laws can be defined • Simple arithmetic laws	• Linearization required • Strong dependence on the data used • The positive effect of uncertainties is not valued • Uncertainty modelling	• Load flow calculation
Real Option Method	• Robust • Allows values for the different options considered • Allows to value the arrival of new information • Accurate resolution	• Complex (needs to model all equations) • Requires simplifying assumptions • Uncertainty modelling	• Only for investment decision problems

4.3. EXAMPLE OF ONGOING PILOT PROJECTS

Some ongoing projects are studying flexibility integration in their planning studies. In the following sections, they have been structured into case studies.

4.3.1. Planning tools with the integration of uncertainties and scenarios

a) Chinese pilot project: Integration of flexibility into the planning process

Project description: This pilot project led by the Chinese DSO State Grid Jiangsu Electric Power Company presents an innovative methodology that integrates the potential flexibility of DERs into the planning process, attempting to bridge the gap between current network operation approaches and planning methods. It includes an **analysis of future scenarios**, providing different **reinforcement plans** considering the realistic network operation for those scenarios. The proposed optimal design of the reinforcement plans has two complementary processes: (i) optimization of flexible resources from their owner's perspective and (ii) rescheduling of the flexible resources' operation when DSO needs to solve technical problems.

The developed methodology consists of two interactive modules: the "network operation and reinforcement planning module" and the "risk assessment module", as depicted in Figure 16. For each year, different network reinforcement plans are provided, one for each future scenario of DER integration.

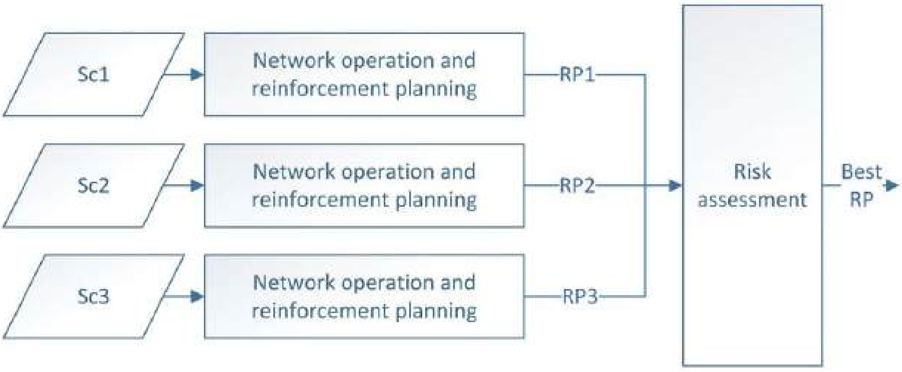

Figure 16: Methodology flowchart

- **Network operation and reinforcement planning module**

This module enables the obtention of different Reinforcement Plans (RP) which considers:

- *Traditional options*: changing transformer taps, reinforcing cables or overhead lines
- *Active network management*: operation of Flexible Loads (FL), namely EV, Storage Device (SD), and domestic Shiftable Load (SL), which includes dishwashers, washing machines, tumble dryer, heating ventilation and air conditioning, and electric water heaters).

This module includes three optimization problems:

- *secondary substation optimization*: definition of the consumption profiles and flexibility margins,
- *flexibility utilization*: network operation and clients' resources rescheduling
- *network reinforcement*

These resources are assumed to be connected to HEMSs and automatically scheduled according to the energy tariffs and owners' requirements. The resources are aggregated by type and represented as a single element at the secondary substation level.

- **Risk assessment module**

This module is performed for each plan, evaluating its performance across the other possible scenarios for that year. The RP that presents a lower risk of Energy Not Supplied (ENS) is selected to be implemented for that year.

The full description of the developed algorithm and the hypotheses of the use case are described in Annex 7.1.

<u>*Project outcomes*</u>: The model has been tested in a typical medium voltage network. The results, summarized in Table 7, conclude that the proposed methodology leads to cost-effective solutions, which provide a better use of flexible resources, deferring high capital investments in network reinforcement, especially in the long term with a high penetration of DERs.

Table 7: Summary of the outcomes of the project

<table>
<tr><th>Year</th><th>2030</th><th>2040</th></tr>
<tr><td>Constraints without flexibility</td><td rowspan="2">One branch overloaded during 152 h</td><td>14 branches overloaded during 598 h</td></tr>
<tr><td>Constraints with flexibility</td><td>6 branches overloaded during 485 h</td></tr>
<tr><td>Reinforcement required without flexibility</td><td rowspan="2">25.4 k€</td><td>482 k€</td></tr>
<tr><td>Reinforcement required with flexibility</td><td>243.5k€ (-50%)</td></tr>
</table>

b) Egyptian pilot project: deterministic approach

A real 20 kV distribution network planning study is used to test a new distribution grid planning method and compare it with the conventional approach. The MV network is connected to the HV network via two HV/MV transformers operated in parallel. With these transformers, the voltage magnitude can be adjusted with the OLTC from +16 % to -16 % of the voltage on the upper voltage side, with 19 steps under load. The voltage on the MV side of the transformers is regulated at a target voltage of 20.5 kV. In the MV level, 8 rings are operated open, which consist of the corresponding 16 MV feeders. Over 110 MV/LV transformers are connected, feeding 11197 LV loads.

<u>Project outcome</u>: By applying scenarios described in section 4.2.1, the following conclusions could be drawn:

- **Integrating renewable presence enables better estimating the real voltage drop**: the minimum consumer voltage increases from 0.893 pu (without renewable) to 0.911 pu (with renewable). In addition, the network losses decrease by 8.3% when renewable are considered. Reinforcement costs are consequently reduced by 23%.

- Considering the **reactive power control of renewable units** and **local transformers**, this minimum voltage was **further increased** to 0.954 pu.
- If all **flexibility options,** including RES, reactive power control and load management, are integrated, the minimum load voltage can be **improved** to 0.971. The network losses can be reduced by 27.9% through additional flexibility. Reinforcement costs can be reduced by up to 63% compared to the reference scenario.

4.3.2. Active power management to postpone investment

a) Slovenian pilot project: demand response to postpone network investment

Project description: A sawmill is expanding, increasing its consumption from 1.7 MW to 2.7 MW in the short term and even more in the long term. The existing distribution network in this area does not allow increased electrical connection power due to too high voltage drops, so reinforcement of the distribution grid is necessary. The company must build a new MV power line from the nearest substation to the location of the company. It is also necessary to strengthen the existing distribution network by building a new MV power line with a total length of 11 km. The DSO proposed temporarily enabling an increase in electrical power through demand response because the construction of the distribution network is a long and demanding process.

Since rapid response is key to relieving the distribution network, the customer has agreed that the distributor switches off the devices without human intervention. The list of devices was established by prior arrangement with the sawmill. However, device activation will be manual when the conditions for switching on are met.

Possible options for sending a signal to turn off specific devices were:

- **Option 1: remote terminal unit (RTU) used in remotely controlled switches** to entail additional RTU procurement and communication costs.
- **Option 2 (most universal and cheap): use of relays digital outputs and billing meter input installed at each distribution network user.**

Option 2 was selected. Since SCADA does not communicate directly with the billing meter, the DSO has established a flexibility management system with an automatic activation based on billing meter measurements and SCADA data. Following the technical tender conditions, the flexibility management system is set up on a “flexible server” that communicates with the measuring center, SCADA system and server for sending SMS messages. Figure 17 shows the architecture of this solution.

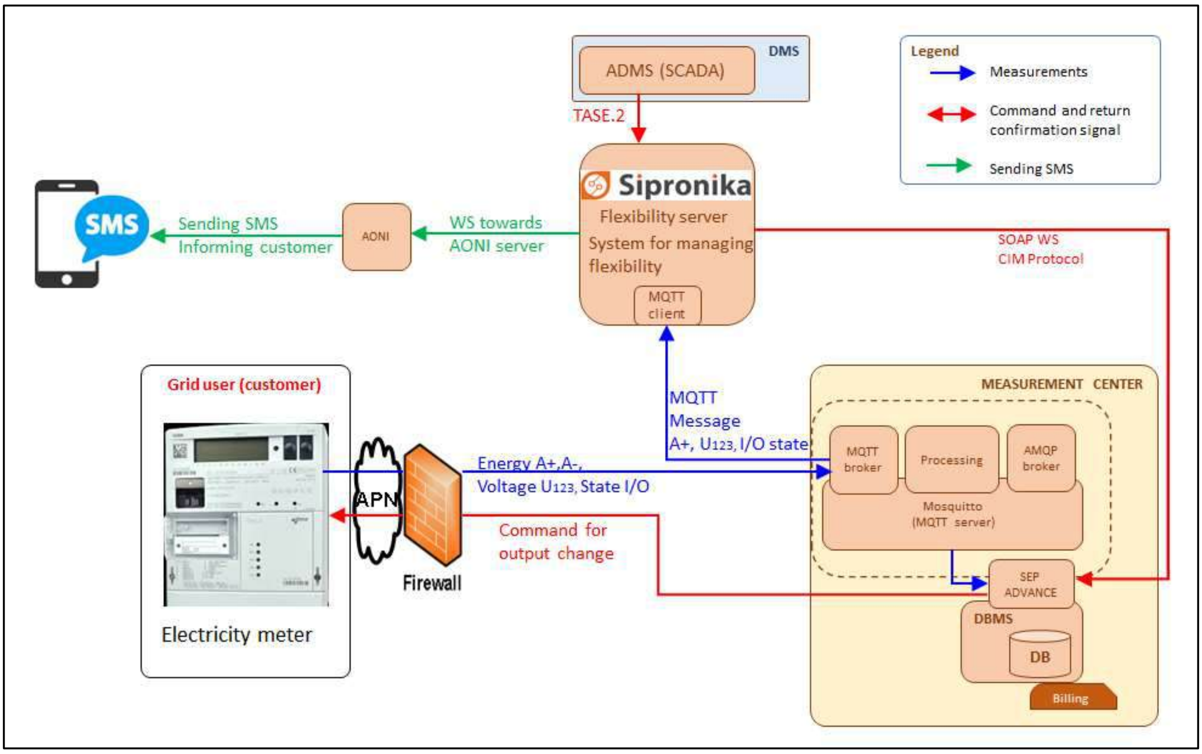

Figure 17: Flexibility server

To shut down devices at the user side, three conditions must be met simultaneously:

1. The distribution substation to which the sawmill is connected must be turned on (failure of one of the power lines that power the substation)
2. The voltage at the user must be below a certain limit
3. The peak load of the sawmill must be greater than the existing connection power of 1,7 MW

The sawmill is neither shut down if one of the power lines fails during a period of lower load (e.g., at night), when the voltage is high enough nor if its current power does not exceed its current connection power.

The sawmill made four production devices or parts that can be turned off on demand. When all three conditions are met, the flexibility control system checks how much the power of the sawmill exceeds the current connection power and sends a request to switch off the load (meter output). After each shutdown, the algorithm checks whether the power has decreased. If it has not decreased sufficiently, the algorithm requests to turn off the next load according to priority. The confirmation that the shutdown has occurred can be seen in the counter's input register every minute.

Simultaneously with sending the command to the billing meter, an SMS message is also sent to the shift manager of the sawmill to inform them that their device has turned off due to network restrictions. SMS shall also be sent in cases where the billing meter would be unavailable at the time of sending the request.

When an algorithm in the flexibility management system determines that the restriction conditions are no longer met, it sends a signal to the billing meter to turn it back on and, at the same time, an SMS to the shift manager of the sawmill that they can turn the devices back on.

Before receiving a reactivation signal, the client cannot and should not turn on the device again, as this could cause poor voltage conditions or, in the worst case, overload of the entire distribution substation.

Project outcomes: **The pilot is a good example of whether the time it takes to reinforce the distribution network can be bridged with flexibility**. **This bridge is a win-win situation for both parties. The customer can immediately expand his business/production and does not have to wait for the network to be built, while the DSO, on the other hand, receives needed funds to reinforce the network.**

b) Part of OneNet pilot project: demand response to postpone transformer replacement

Project description: In recent years, the distribution company Elektro Ljubljana has been facing **overloads of some distribution transformers in winter**. These overloads are short-lived, usually lasting from **a few minutes to a maximum of several hours**. Overloads of transformers occur in settlements where heat pumps heat residential units. **With a traditional approach, such a transformer would be replaced, although 99% of the time, it would work normally**. We decided to examine through a pilot project the possibility of purchasing a demand response service to reduce the peak power of the transformer.

We chose one transformer, which supplies electricity to a smaller village with 156 customers. The selected MV/LV substation has a distinctive peak power in winter when residential units with heat pumps heat their homes. The aggregator provided contracts with customers willing to cooperate and reduce their peak power when needed. The condition was that the household used a heat pump for heating. Based on analyses of previous years' consumption, a maximum of two adjustments per day has been determined, with a maximum duration of 75 minutes per activation. Thus, we defined the product of the customization service we were looking for on the market.

In cooperation with an external contractor, we **assessed** the **static thermal operating limit of the transformer**, which was carried out based on the upgraded standard thermal model IEC 60076-7, parametrized by type transformer heating test. The static thermal load characteristic for the type of transformer installed in the considered substation showed that at an **ambient temperature of 0 °C, the transformer could be overloaded by 40% before reaching its thermal operating limit**.

As part of the pilot project, an external contractor validated thermal model of the transformer by using measurements and data and comparing them with their existing thermal model (TRMA). This was done by installing a mobile control system for transformers in the substation and on the transformer. The mobile network enabled remote measurements of ambient temperatures and transformer housing. A Long-Term Evolution (LTE) modem and a built-in temperature sensor on the transformer housing were installed in the low-voltage space. Phase current and voltage measurements were made via concentrator in the substation with a 10-minute capture period. Current and temperature measurements are transmitted and processed on a server of an external contractor on which the calculation of modelled transformer temperature is calculated considering current meteorological parameters (insolation, wind speed and rainfall intensity). In addition, the calculation of transformer load is carried out in real time. Comparison of the model calculation of transformer temperature with real-time measurements of transformer temperature enables both validation and optimization of the accuracy and reliability of the thermal transformer model.

The external contractor granted the DSO access to a graphical display of the transformer's actual and thermal current (loadability) and temperature measurements from the TRMA system. When the flow measurement approached or exceeded the value of the thermal flux, the DSO initiated the aggregator by a phone call and subsequent written notification by e-mail. During the pilot, it turned out that **overloads occur even outside the periods determined based on overloads in previous periods**. Due to schooling and working from home, the typical daily load profile of the substation has also changed. It should be emphasized that from the distributor's point of view, nothing has changed at the measuring point. Measurement data and communication remained the same (15-minute measurement and PowerLine Communication, PLC). Billing data was usually read the next day. The only change at the measuring points with the heat pump installed was the additional installation of the **IoT device,** which the aggregator did. With this device, the aggregator could monitor real-time consumption and response at the measuring site. During the project, the aggregator **equipped all heat pumps** with **an additional controller**, sending signals for switching on/off heat pumps.

In most cases of activations, there was an increase in load after activation was completed (rebound effect). Based on experience, we will create an algorithm to determine the appropriate activation time. Because if we activate too quickly, there may be an even greater overload than without activation.

The calculation of activation was usually done the next day when measurements from PLC meters were read. To determine the reduced consumption, only 15-minute measurements by heat pump consumers were considered, and not all consumers were included in the substation. The aggregator sent a timetable (timetable, baseline) every 5 minutes to customers with heat pumps. Since actual consumption may deviate from the forecast timetable, a timetable correction is determined based on comparing the average consumption and the forecast timetable during the last four full 15-minute intervals before activation. Energy reduction demand is determined based on the difference between the corrected timetable and the measured power of customers by heat pumps.

The aggregator predicted that the total power of customers with a heat pump would be constant at 25 kW. Based on the difference between the forecast and the actual load of customers with a heat pump, the timetable was corrected.

At the end of the provided service, the aggregator made an impact analysis of various timetables calculating methods because customer consumption with a heat pump is very stochastic. If the prediction is incorrect, activation may fail, even if the total power of customers has decreased by the required power.

Project outcomes: As part of the OneNet project, the system will be upgraded at the end of 2023 so that activation will be automatic, without human involvement. Thus, the distributor does not require human action to control the load of the substation. Also no one is needed on the aggregator side. Based on minute measurements of total substation consumption and outdoor temperature forecasts, the advanced algorithm will automatically activate the aggregator, automatically activating (switching off) heat pumps from users. In doing so, the algorithm must also consider all restrictions (response time, maximum number of daily activations, agreed appointments).

c) Major French DSO use cases on DER's active power management

In [29], the major French DSO, Enedis, preses the outcomes of its R&D activities and experiments on local flexibilities. This report considers flexibility related to active power management through four use cases summarized in Figure 18. In particular, the DSO assessed the value of flexibility, the importance of location, the sources of flexibility, the duration of activation and time of occurrence, contractual principles and remuneration principles for each use case.

- *Smart Connection Offers (SCOs)* connect customers (consumers and producers) to the MV grid faster and at a lower cost. Bilateral contracts between Enedis and the customer fix the remuneration rule and flexibility services to reduce investment for Enedis and connection costs for the customer.
- *Optimization of investments in S3REnR* (Regional Renewable Energies Connection Master Plans): S3REnR provides visibility on renewable hosting capacity (HC) for transmission and distribution networks. Renewable active power curtailment will be added to increase renewable HC.
- *Investment postponement:* some investments could be deferred or avoided using flexibility. To consider the risk associated with the non-availability of flexibilities, the customer remuneration model has a fixed part with associated penalties in the event of non-availability.
- *Avoidance of work planning outages*: flexibility availability must be guaranteed in this case. Hence, the customer remuneration model has a fixed part with associated penalties in the event of non-availability.
- *Incident management*: in case of very low probability of congestions: In case of extreme events such as cold spells, flexibility could be used (i) before the event (up to 4 days ahead when the forecast is reliable) and (ii) during an outage to help resupply customers. In this case, flexibility activation would be without availability payment.

	Connection agreement		Market-based procurement (internal platform)		
	Connections	Optimisation of investments in S3REnR	Investment postponement	Work planning	Incident management
Value of the flexibility	Connection costs and reduction of the delay for the customer	Maximum value for society of €250M by 2035 *(alternative to investments)*	Maximum value for society from €0 to €24k/MW/year* *(Investment postponement)*	Maximum value for society from €0 to 20K/MWh* *(must be compared with the alternative usual solutions, such as power generators)*	
Importance of the location	Yes whatever the use case				
Sources of flexibility	MV site to be connected	Producers, storage, electric vehicles, demand response, with active or reactive power for voltage congestions - Enedis is technologically neutral			
Duration of activation and occurrence	Depends on the case	0.06% of limitations	Between 0 and a few hours per year depending on the case	During the work *(according to network needs)*	A few hours per year *(low occurrences)*
Contractual principles	Bilateral contract	Competitive process according to the defined call for flexibility process and in compliance with the existing rules enforced**			
Remuneration principles	Remuneration included in the connection offer	Contract with guaranteed availability** Minimum size of the offer: 500 kVA *(obligation of result)* *Guaranteed availability, remunerated with a fixed part, with associated penalties*			Framework contracts without guaranteed availability: *variable part depending on activation*

* *According to the examples studied in the Economic assessment of smart grids solutions report.*
** *For the S3REnR, if competition is unsuccessful, curtailement of connected producers according to terms to be defined in the contract for access to the grid.*

Figure 18: Summary of Enedis research activities on local flexibilities [29]

Main outcomes: the four use cases previously described have been tested in several areas and enable to draw the following conclusions:

- For **MV producers**, a **connection cost reduction** of around €90k/installed MW was noticed for the SCO.
- In the S3REnR, the **renewable HC was immediately increased** with an additional capacity of 2.5 GW, which is expected to reach 7,4 GW. The **renewable curtailed energy is low** and assessed at most 0.06% of the yearly maximal potential production. The benefit for the society is expected to be around 250 M€ by 2035.
- **Depending on the availability of flexibilities**, the **benefit for society of using flexibility** to avoid planning outages and incident management use cases is **quite uncertain** since it varies from 0€ to 20 k€/MWh.
- The **assessment of the benefit of using flexibilities to defer investments is complex** and highly **dependent** on both the **network characteristics** (local congestions, the structure of the network, incident statistics, weak/strong areas, etc.) and the **type of flexibilities available** (location, time to set up etc.). It has been estimated between 0€ to 24 k€/year/MW.

These pilot projects led to the industrialization of the SCO, i.e. contractual flexibilities with producers and of the Enedis internal flexibility platform, which consists of local flexibility calls for tenders (see section 2.2.1c)). Until 2023, Enedis tendered for upwards services (less consumption or more injection) to solve issues stemming from too high consumption issues (normal scheme or during planned or unplanned outages). From 2024 and on, Enedis will also procure services for downwards services (less injection or more consumption), to solve issues for excess DER injection and HV/MV transformer congestions. These downwards services will be the preferred solution to solve these issues, while production curtailment is the technical and economic back-up solution.

4.3.3. Increasing hosting capacity

With the desire to increase the integration of DERs, it becomes important to develop objective means to determine the maximum amount of DERs (usually renewable production or load such as electric vehicles) connected to a power distribution system, namely the hosting capacity (HC). The amount of DER the network can host depends on several parameters such as the characteristics of the generation units, the configuration and operation of the network, the requirements of the loads as well as national and regional requirements.

The hosting capacity is recommended by the European energy regulators and by the European network operators as a way to quantify the performance of the future electricity network. The latter also mentioned developing methods for calculating the renewable hosting capacity in distribution networks as a prioritized activity in their roadmap towards the future power grid in Europe. The impact of additional DER in a network can be quantified by using a set of **performance indicators** such as power quality measurements like voltage magnitude, voltage dips and risk of overload.

a) Chinese project: a two-stage optimization operation strategy to increase PV hosting capacity

Project description: A two-stage optimization operation strategy for integrating PV generation and storage in the network to promote the consumption of distributed PV in a 10kV distribution system of the Chengde power grid.

The 10kV distribution system of the Chengde power grid has 4 distribution lines and contains 12 distributed photovoltaic power stations and 83 power user areas. Distributed photovoltaics were installed in 45 power user stations, with the total installed capacity of distributed photovoltaics reaching 8624kW and the installed penetration rate of photovoltaics reaching 140%. The summer distribution system with four flexible loads, including air conditioning, water heater, electric vehicle and large cold storage was selected.

A power trading game model is proposed to increase distributed photovoltaic (PV) hosting capacity. In the first stage of the game, to promote distributed PV power consumption distributed PV power stations and distribution companies signed a cooperative agreement group to form an Electric Energy Sales Partner (EESP) and developed a scheme to promote distributed photovoltaic power consumption in the site through Stackelberg game with electric Load Aggregator (LA). The trading electricity boundary condition of the game between EESP and LA, $[P_{min} \times \Delta t\,;\; P_{max} \times \Delta t]$, is determined by the adjustable potential of demand-side resources managed by LA, the normal power demand of users, the maximum power generated by distributed PV and Dynamic Loadability of Distribution Network (DLDN) where:

- P_{max} and P_{min} Are the maximum and minimum power of LA, respectively;
- Δt is the period during which LA can participate in adjusting the system.

Project outcomes: A **two-stage optimization strategy** was proposed for distributed photovoltaic systems to enhance their consumption. This strategy integrates **power trading**, **active/reactive power control**, and **storage**. It **mitigates power flow issues**, **ensures network stability**, and **improves stakeholder income**. Detailed results are provided in Annex 7.2.

b) The H2020 European research & innovation project FEVER: Increasing RES hosting capacity

Project description: Among other objectives, project FEVER [30] also addresses the possibility of the utilization of flexibility for purposes of increasing the hosting capacity of the networks in the following matter:

- DSOs may still rely on conservative network planning approaches and appear reluctant to allow high RES penetration levels.
- DSOs have lately started using a metric called "RES Hosting Capacity" to indicate the maximum power capacity of distributed RES that can be integrated into a distribution network without violating the network-specific parameters and limits imposed by international standards and/or regulatory frameworks. Project FEVER cites an indicative sensitivity analysis of the distributed RES impact on the network operation (Figure 19) to illustrate how **DSO can identify three operational areas (safe, risky and prohibited)** when increasing DER installed capacity and diversity in RES allocation per installed capacity while considering network operational parameters. The **yellow section** in the figure indicates the **network operational limitations on the RES hosting capacity**.

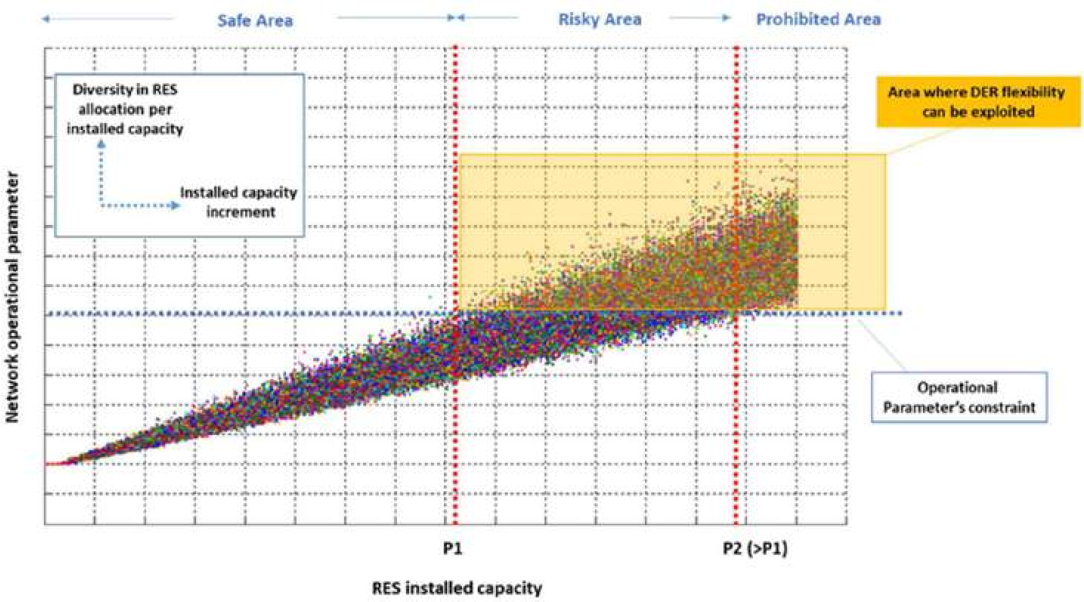

Figure 19: Sensitivity analysis of the RES deployment impact on distribution network operation [30]

By helping to keep the network stable, flexibility services could, in some areas, increase the distributed generation hosting capacity of the grid. The value here is determined by avoided investments and maintenance costs in voltage control [30].

DSOs should be encouraged to implement innovative grid planning solutions. The focus of regulation should shift from ensuring that companies invest sufficiently in networks to assessing grid operators based on their performance, as measured by an extended **set of key performance indicators (KPI)** (one of them being the hosting capacity). Once these indicators are objectively measured and controlled by the DSOs, **incentive (and penalty) mechanisms** could also be implemented [31]. When determining the KPI Feeder Hosting Capacity, deterministic (snapshot/static) approaches should be avoided as they cannot consider various operation scenarios or active network elements and result in underutilized capacity. **Stochastic or uncoordinated and coordinated dynamic approaches** to determining hosting capacities should rather be used, as they enable the behaviour of DER, loads, and grid devices over time and can account for the fact that some over-voltages and thermal overloading are acceptable for short periods and during a limited number of time points during the year as explained by NREL [32]. As such, they can be used in planning analytics, real-time operations, operational planning the distant future (strategic planning) analysis.

c) Other hosting capacity studies

[33] proposes new solutions and adaptive settings and management schemes to increase DER (PV) hosting capacity and the capability of distribution network connected DER to provide flexibility services, predominantly frequency support for system-wide (TSO) needs. In particular, the paper proposes frequency adaptive PU-droops and the role of PU-droops implementation logic with different DER configurations. How unwanted interactions between DER units and their control functions can be avoided is shown, and novel real-time adaptive management of DER PU-and QU-droops and HV/MV substation transformer’s OLTC settings is proposed.

Paper [34] presents a digitalization of LV networks, which does not require any information about network characteristics, i.e. by creating a network digital twin built only from metering data. These digital twins can estimate the voltages corresponding to a specific power consumption/production. Digital twins of distribution networks can be used to evaluate the benefits that utilization network flexibilities could have on hosting capacity.

d) German pilot project: reactive power support to increase HC

Project description: The goal in the past was to **reduce the reactive power in the grid as much as possible as it causes losses**. Therefore, the loads were requested to operate with a power factor of close to one. The grids were designed to handle the voltage drop from the feeding substation to the loads without violating the voltage limits. The tap changer of the feeding transformers controlled the voltage. The reactive power was provided on request of the control center by large power plants to balance the reactive power balance of the transmission grid and control the voltage distribution within the transmission grid.

With the increasing shift of the generation in the distribution grids, the topic of voltage control in these grids becomes more important. The distribution grids are designed to handle a voltage drop from the infeed to the load but not to handle a voltage rise. Especially **in extensive rural networks, the voltage limits usually limit the generation** that can be connected much more than the current carrying capabilities.

With reactive power for coordinated voltage control, either the amount of generation power connected to an existing network can be increased, or the amount of network enforcement can be reduced (or both simultaneously). [35] an example in Figure 19 illustrates the possibilities that reactive power flexibility can provide in rural networks.

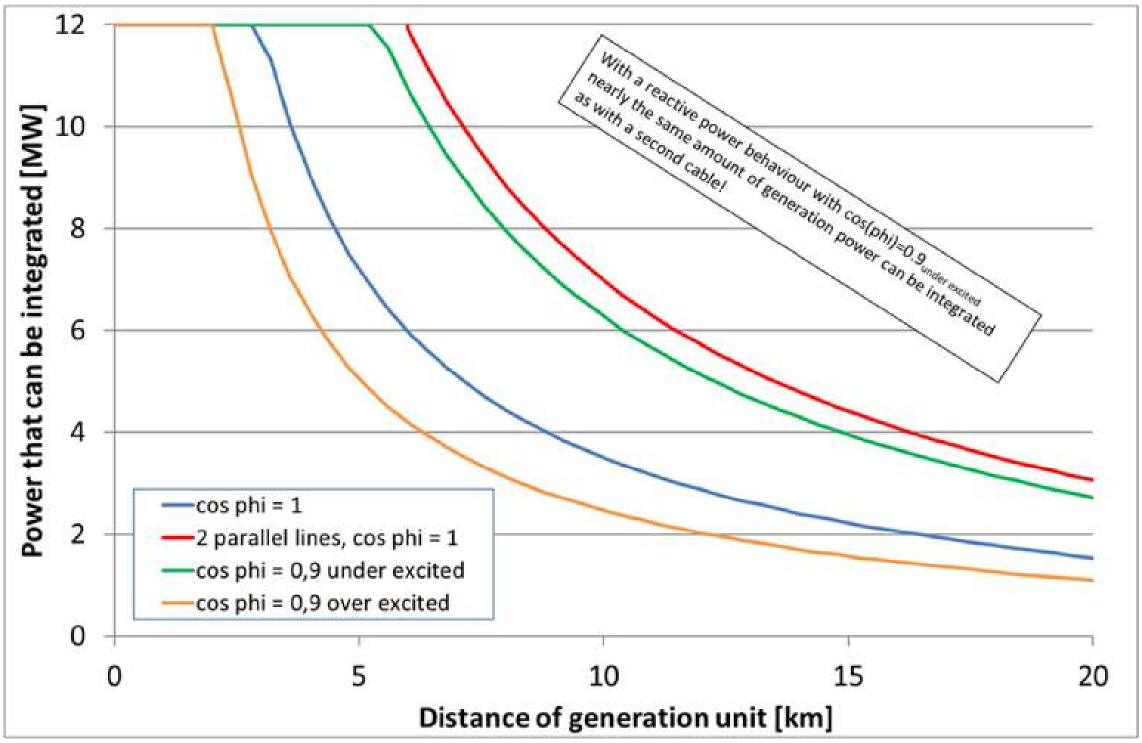

Figure 20: Generation power that can be integrated with reactive power use (translated from [35])

<u>*Project outcomes*</u>: **It shows that with a reactive power characteristic of cos(phi)=0.9 under excited, nearly the same amount of active power can be integrated with a given network as with the extension of the network by a second line.**

The different strategies for providing reactive power are described in Table 5. Technical rules can determine these strategies and the associated functions and set points. Such rules will be without discrimination on every unit connected to the network. **The actual amount of reactive power to be delivered might depend on the actual location of the unit within the network** (connected to a remote feeder the unit might have to provide more reactive power than connected directly to a substation). With the choice of the connection point, the unit's operator can control this in a certain range. The network operator can rely on the provision of the reactive power and consider it in its grid planning, as each unit must provide the determined amount of reactive power at each time.

A reactive power market can also determine these strategies and set points. In such a market the customers able to provide reactive power can offer this capability to the grid operator. He can buy the offered power at a market price if he needs the offered power.

4.4. MAIN OUTCOMES

Distribution network planning has become increasingly **challenging** in the last decades, as the **uncertainties** related to the **DERs**, new load development, and their utilization patterns are gradually growing. Despite these problems, if properly used to benefit the networks, the flexibility provided by DERs and flexible loads may facilitate the planning process and reduce investments in network assets. However, the optimal utilization of customers' flexibility will require the existence of faster, cheaper and more reliable **data acquisition**, **communication solutions** and **automated equipment** integrated with smart grids. In this new paradigm, the planned operation of FL will be straightforward and allow better use of the available resources, yielding important savings in network reinforcement.

The planning process with flexibilities must include the following:

- *Multiple scenarios approach*
- *Flexibility forecasting with load and generation*
- *Improvement of power curve modelling* to better model new types of resources (electric vehicles, self-consumption, heat pump) as well as their operation modes
- *Diversification of key performance indicators*
- *Stochastic approach* to capture uncertainties and value risks associated with flexible assets with high-quality data

5. GLOBAL FLEXIBILITY

The unified power system can be divided into a central and a decentralized level: the central system includes the conventional power plant and storage park with a predominant interfaced point in the transmission network. On the other side, the decentral level contains decentralized generation plants operating in the distribution networks (plants based on renewable energies, combined heat, power generation, etc.). At the same time, new, controllable consumers (e.g., electric vehicles and heat pumps) are increasingly connected to the distribution grid. As a result of this development, **there is a need to consider the interactions between the central and decentralized levels within the planning process**.

A possible approach to reducing HV grid reinforcement costs is to consider the effects of decentralized feed-ins from the distribution system on the grid behaviour. The active network operation of low-level MV and LV networks should be considered. With the increasing expansion of renewable energy systems, the distribution system operators face major operational flexibility of active, reactive power control, voltage regulators and controllable local grid transformers. **The question is to what extent the use of this flexibility by grid users can counteract grid expansion planning**. To quantify these counteractions, the question that arises is **how the operation of decentralized flexibility options can be coordinated**. In this context, it is assumed that the flexibility potential of decentralized small systems is bundled by aggregators and marketed on the existing markets. The answers are not straightforward and depend on local contexts, especially the **coordination mechanism between the DSOs and the TSOs**.

5.1. TSO-DSO COORDINATION POSSIBILITIES

5.1.1. Flexibility Utilization for TSO-DSO Needs - Related Projects

Some projects are dedicated to the TSO/DSO coordination. For instance, the SmartNet project [36] aims to provide tools to improve the coordination between the DSOs and TSOs and **the exchange of information between them**. One required contribution is categorising and evaluating different **TSO/DSO coordination mechanisms**. Other projects are still under development, and the results are not yet available, but some insights are already provided. This is the case of the CoordiNet project [37], which will **test different collaboration schemes between TSOs, DSOs and consumers**. **Standardized products** will be defined to enable a **seamless pan-European electricity market**. The INTERRFACE project [38] aims to develop a common architecture to connect existing data hubs, improving **data sharing** between the network operators.

Based on simulation, a three-stage process chain can be used to determine the contribution of decentralized flexibility options to the network for given network expansion variants.

- *Stage 1: Market simulation method* without considering grid-side restrictions;
- *Stage 2: Identification of grid bottlenecks* because of the market results from Stage 1;
- *Stage 3: Market-related congestion management*: derivation of a new market result considering the network congestion from Stage 2.

By comparing the market results of stage 3 and stage 1, the effect of grid- flexibility and the associated cost saving can be estimated.

By considering the flexibility management that is beneficial to the grid in the expansion simulation of the third stage, **the sensitivities of the market flexibilities to the existing limit value** violations are determined. For this purpose, the power flow equations are linearized at the operating point. In addition, certain network-related restrictions and several network expansion constraints must be considered. For example, an entire line section that would otherwise have to be strengthened is relieved. Especially in network areas where bottlenecks are omitted by several flexibility options, which offer the possibility of saving many expansion measures. Thereby, the technical design criteria and boundary conditions must still be considered when considering flexibility options as an expansion alternative, such as:

- Consideration of a suitable network topology to ensure the reliability of supply
- Adherence to the resilience of equipment
- Keeping the voltages in the grid within permissible voltage ranges

5.1.2. Potential Approach: Frequency level-dependent coordinated TSO-DSO flexibility services provision

In the future, flexible DERs control and active network management (ANM) functionalities (e.g. coordinated voltage control with OLTCs) can be increasingly used for flexibility services provision to the needs of the DSOs and TSOs. Typical flexibility services DERs can support the power system frequency (*f*) and local voltage (*U*) or congestion management at the corresponding voltage levels. The effective utilization of different active (*P*) and reactive power (*Q*) control or voltage level control-based **flexibility services requires coordinated utilization of different types and sizes of DER at all voltage levels (LV, MV and HV) with the OLTCs**. Effective ANM and DER utilization for different local and system-wide flexibility services provision also requires **new collaborative DSO and TSO operation and planning principles** based on active utilization of flexibilities.

Possible conflict of interest between DSO and TSO in utilising the *P* and *Q* control-related flexibility services from distribution network connected resources **should be avoided** by **improved TSO-DSO coordination**, state-monitoring and state forecasting. For example, *P* and *Q* control modes and settings of different DERs and coordination with OLTC settings and other ANM functionalities should be increasingly considered at the operational planning stage. Figure 21 shows active DER and OLTC management possibilities to increase flexibility services availability for TSOs and DSOs and enhance DSO networks' PV and EV hosting capacity.

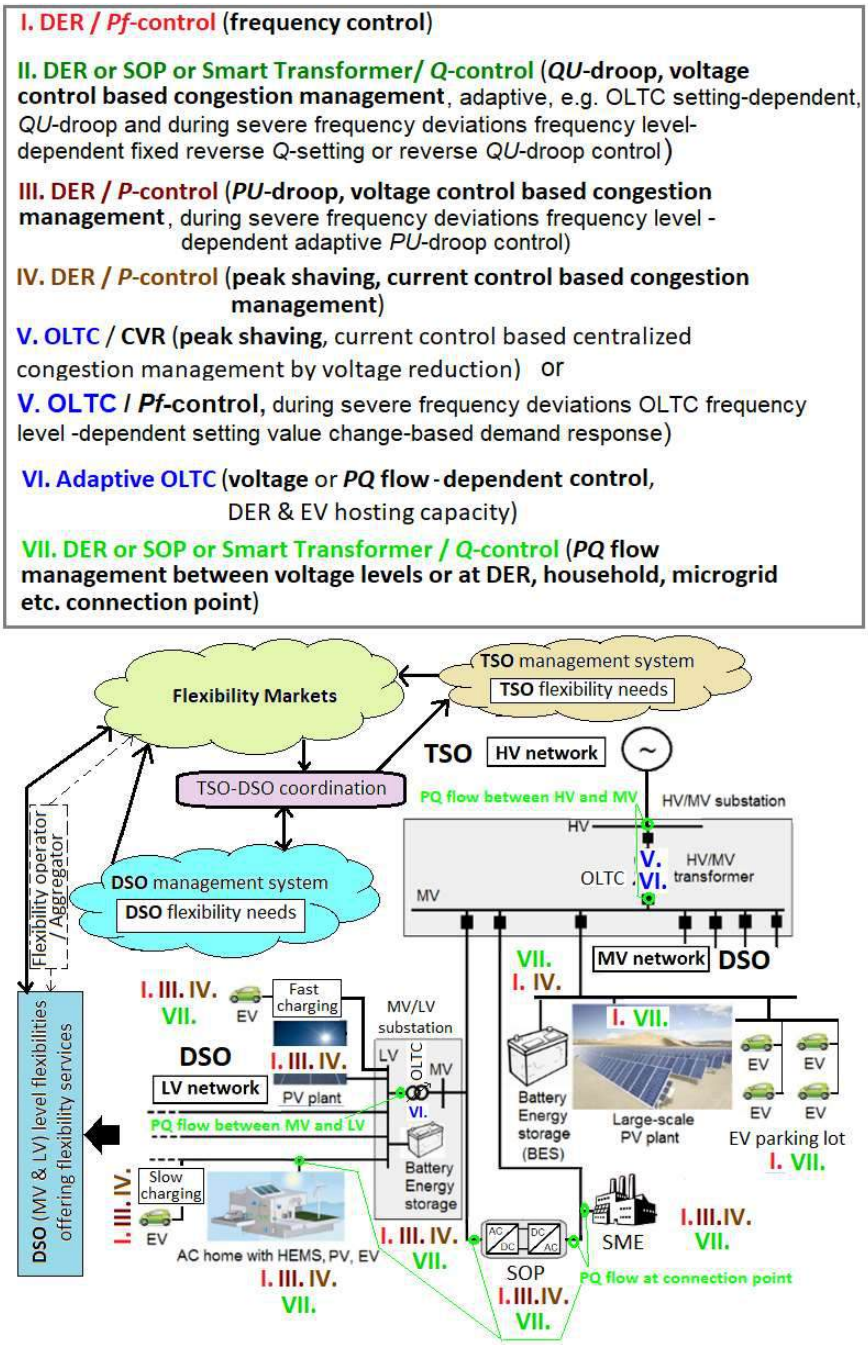

Figure 21: Active DER and OLTC management possibilities to increase flexibility availability for services provision/hosting capacity enhancement [39].

Previously, in sections 3 and 4, flexible energy resources utilization for local DSO flexibility needs, for example, through improved ANM functionalities (like voltage and congestion management) as part of future distribution network operational planning, has been discussed. Now, in this section, the purpose is to take even one step further and briefly describe one possible scheme for how the coordination of flexibility utilization between DSOs and TSOs could be done in the future depending on the severity of the situation from whole power system viewpoint in terms of **frequency deviation severity** from the nominal system frequency, i.e. TSO-DSO coordinated and frequency level-dependent DER inverter and adaptive OLTC management scheme **to prioritized flexibility services provision for the TSOs and DSOs**.

In the proposed scheme, DER *QU*, active power-voltage (*PU*) and active power-frequency *(Pf)* droops and OLTC management principles are adapted depending on the frequency deviation severity, i.e. level so that in case of larger frequency deviation at level 3 or 4 support for the whole power system and TSO needs are prioritized (see Figure 22). In addition, the connection point of each DER in the distribution network (i.e. location of DER) is considered when feasible active control methods and droop settings are determined and chosen. Location of flexibilities affects, for example, in most feasible use cases and potential restrictions in utilising DSO network-connected flexibilities. For example:

- the utilization of DSO network-connected reactive power control resources located close to the HV/MV substation to support HV network (TSO) reactive power needs could be more feasible than the utilization of reactive power resources located far away from HV network connection point, i.e. deep in MV or LV network;
- the utilization of reactive power resources deep in the MV or LV (DSO) network in providing local technical services, i.e. voltage control through their reactive power control, is more feasible than their utilization to provide services for HV network (TSO) needs.

Therefore, **forecasted and real-time knowledge about local needs and availability of flexibilities (active *P* and reactive *Q* power) at each voltage/zone level is one key input for the active utilization of flexibilities in the operation and planning of future DSO and TSO networks** [39], [40] and [41].

	Frequency Levels			
	Level 1	Level 2	Level 3	Level 4
Frequency (*f*) Deviation from Nominal *f*	≤ ± 0.1 Hz	± 0.1 - 0.2 Hz	± 0.2 - 0.5 Hz	≥ ± 0.5 Hz
Market or Grid Code based Control	Market	Market	Market	Grid Code

a)

Flexibility Service	Local (DSO) or System wide (TSO) Service	Frequency Levels for Flexibility Services Utilisation	
DER reactive power-voltage control (e.g. *cos(φ)- / QU-control*)	DSO	1 & 2	
DER active power-voltage control (*PU*-control)	DSO	1 & 2	
Traditional CVR-based demand reduction (centralised congestion management by voltage reduction)	DSO	1 & 2	
DER active power *P*-control based congestion management (current thermal limit related)	DSO	1 & 2	
DER reactive power (*Q*) control for *P&Q*-flow management between HV and MV networks (Reactive Power Window, RPW-control) & seasonal or real-time *P&Q* –flow-dependent OLTC setting value	DSO/TSO	1 & 2 (Disabled at level 3 & 4)	
DER active power-frequency control (*Pf*-control)	TSO	1 =>	4
DER frequency level -dependent adaptive *PU*-droop control*)	TSO	3 =>	
OLTC frequency level -dependent setting value change-based demand response	TSO	3 =>	
DER frequency level -dependent reverse *QU*-droop control*)	TSO	3 =>	

*) To support frequency control-related voltage level change-based demand response at level 3

b)

Figure 22: a) Frequency levels for frequency control services provision and b) Different flexibility services for DSOs and TSOs & frequency levels for their utilization [40]

As mentioned, some potential DSO and TSO flexibility services and related functionalities may have mutual effects and momentary conflicts of interest. Partially, this challenge could be avoided by utilising different flexibility services and functionalities only at predefined frequency deviation levels (see Figure 23). For example, DER Q -control is used for P&Q-flow management between HV and MV networks (RPW-control) and seasonal or real-time PQ-flow-dependent OLTC setting value (Figure 24). These functionalities should be only used during frequency level 1 and 2 deviations and disabled at levels 3 and 4 (Figure 22 and Figure 23) to avoid conflict between the level 3 frequency-dependent OLTC control-based demand response (Figure 25). Potential mutual effects between all the different functionalities should be carefully considered, but some of the functionalities may also complement each other, i.e. be in the same direction [39], [40] and [42].

	DSO / TSO service
Level 1 & 2 (market-based service)	
• DER active power-frequency control (*Pf*-control) (at level 1 or higher) • Traditional demand response (e.g. household, campus, industrial) at level 2	TSO*)
• Centralized BESS units connected at HV/MV substation are utilized for *Pf*-control at frequency deviation level 1 and	TSO
• Distributed BESSs connected at MV/LV substations and LV network at level 2	TSO*)
=> Distributed BESSs could be utilized primarily for DSO needs (through *P*-/*PU*- and *QU*-control) during frequency level 1 deviations	DSO*)
• DER reactive power-voltage control (e.g. *QU*-control)	DSO
• DER active power-voltage control (*PU*-control)	DSO*)
• Traditional CVR-based demand reduction (centralized congestion management by voltage reduction)	DSO**)
• DER active power *P*-control-based congestion management (current thermal limit related) (or EV adaptive charging based peak shaving / congestion management)	DSO*)
• DER reactive power (Q) control for P&Q-flow management between HV and MV networks (Reactive Power Window, RPW-control) & Seasonal or real-time P&Q -flow-dependent OLTC setting -value (Disabled at frequency level 3 & 4)	DSO/ TSO
• <u>Flexibility services provision by increased sector-coupling</u> (*Pf*-control)	
• Electric heating/electric heat storages (heat sector) at level 2	TSO*)
• Electrolysis to produce greed hydrogen (gas/transportation sector) at level 2	TSO*)
• EVs active power control by disconnecting or by stopping charging at level 2 under-frequencies (transportation sector)	TSO*)

*) Mutual effects and conflict of interest between these DSO and TSO services are possible depending on the network capacity, location and size of DER units etc.

	DSO / TSO service
Level 3 (market-based service)	
• DER frequency level-dependent adaptive *PU*-droop control	TSO
• OLTC frequency level-dependent setting value change based demand response	TSO**)
• DER frequency level-dependent reverse *QU*-droop control	TSO
• Fast EV-charging stations could also participate on frequency control at frequency level 3 deviations (as well as soft-open points, SOPs) • One-directional chargers during frequency level 3 under-frequencies • Bi-directional chargers during level 3 under- and over-frequencies	TSO*)
• Reverse *QU*-droops also with fast EV-chargers and SOPs	TSO
Level 4 (grid-code-based service)	
• DER active power-frequency control (*Pf*-control) • Demand response by disconnecting large loads, MV feeders etc.	TSO*)
• *Pf*-droops also with EV chargers (both slow and fast, one and bi-directional)	TSO*)

**) Conflict of interest between these DSO and TSO services are possible

Figure 23: Summary of different flexibility services for the DSOs and TSOs, which could be realised collaboratively and coordinated different frequency levels/ranges (see also Figure 22) [40].

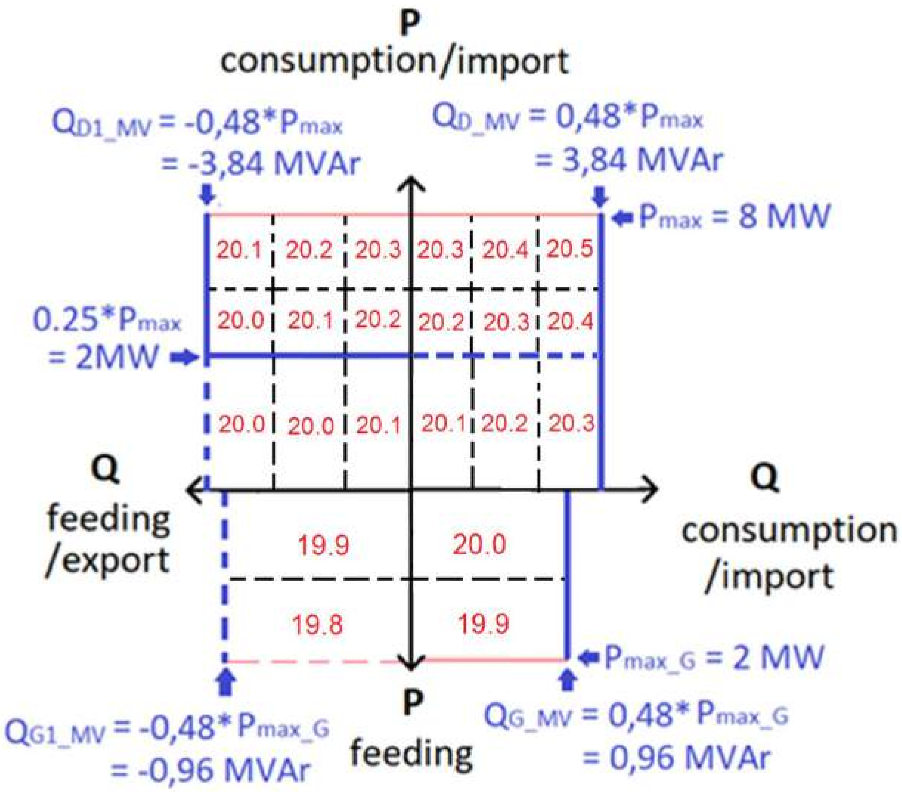

Figure 24: Real-time HV/MV substation *PQ*-flow-dependent OLTC setting value (kV).

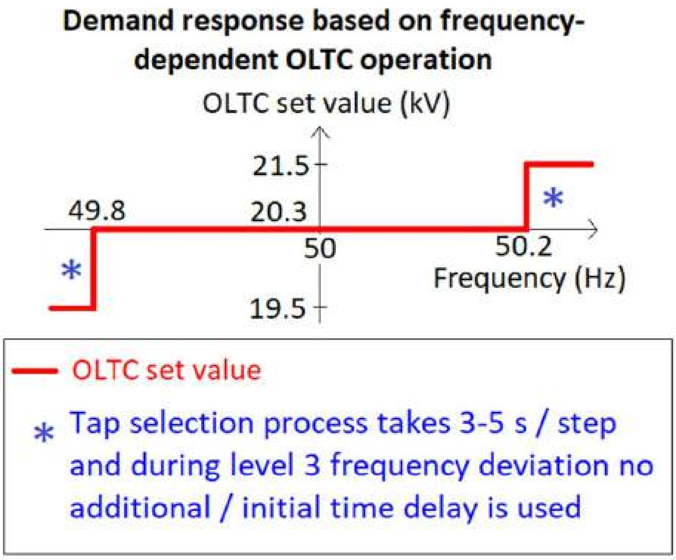

Figure 25: Example of the proposed frequency-dependent OLTC setting change-based demand response principal with an OLTC set value of 20.3 kV [40].

5.2. TSO POWER BALANCE AND FREQUENCY MANAGEMENT

5.2.1. Scheduled balancing support

Scheduled balancing support means that **flexibility is enabled at the level of the electricity market**. End-users are incentivized to provide flexibility purely on **price mechanism**, which is a powerful motivation, but may not be the only one depending on the considered situations. Thereby, it can supply positive or negative energy. Flexibilities can act on all kinds of electricity markets:

- *In the futures market* the products can be sold/bought years in advance.
- *In the day ahead market*, the products are sold/bought for the following day.
- *In the intraday market,* the products are sold/bought in blocks of quarterly hours up to 5 min before real-time (within one control zone) to 60 min before real-time (between European countries).
- *The balancing market* closer to real-time and within real time is done by controlling power products not in this section's focus.

As the products usually require guaranteeing a power delivery of several MW for at least a quarter of an hour, individual flexibilities are aggregated and traded by an aggregator.

a) Typical Business cases: Battery energy storage systems

Prices at day ahead and intraday market vary considerably for one day. As illustrated in the example in Figure 26, within around 12 hours, the price can vary between nearly 0 and 186 €/MWh.

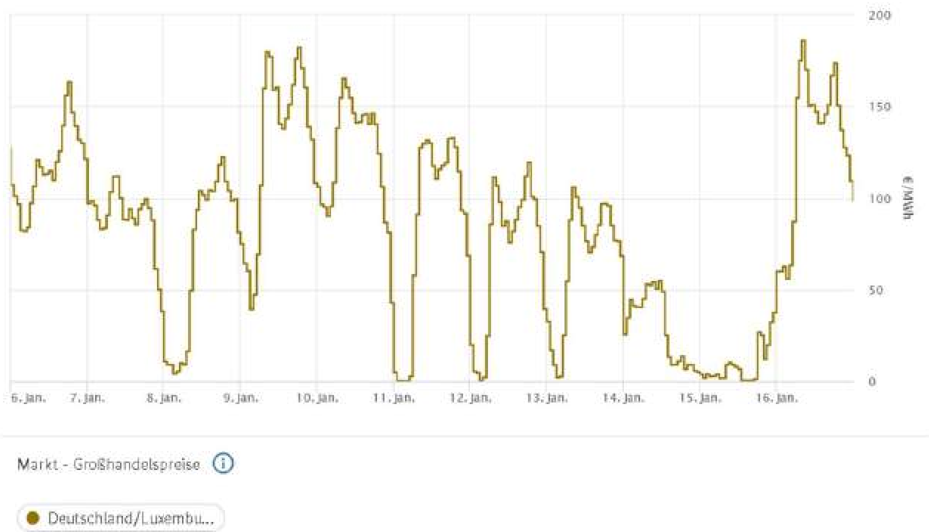

Figure 26: Day ahead prices in market area Germany, Luxembourg for the second week of January 2023[12]

12 https://www.smard.de/page/home/marktdaten/78?marketDataAttributes=%7B%22resolution%22:%22hour%22,%22region%22:%22DE-LU%22,%22from%22:1672959600000,%22to%22:1673909999999,%22moduleIds%22:%5B8004169%5D,%22sel

The business case for a flexible load would be to consume the electricity at the daily price minimum. The business case for a flexible generation would be to produce electricity when the daily price is maximum. An Energy Storage System (**ESS)** can buy electricity during low-price periods and sell it during high-price periods (arbitrage business). Depending on the regulation, storage might pay the market price, network usage fees, taxes, etc., for charging but only receive the market price for discharging. In these cases, the arbitrage margin must cover all the fees, taxes, etc.

More precisely, **BESS** has emerged as a prominent technology, offering dynamic and adaptable approaches to **address the challenges related to grid stability** while actively participating in various energy markets [43].

BESS has the potential to play **various roles in power systems, such as frequency regulation, peak shaving, voltage control, transmission and distribution system equipment deferral, and energy arbitrage** [44]. Hence, there has been a surge in the number of entities, such as thought aggregators, that can actively participate in the energy markets by utilizing their localized assets, such as photovoltaics and batteries. This has resulted in an increased number of stakeholders who may require the implementation of BESSs, particularly transmission or distribution operators to maintain grid stability, energy suppliers to minimize losses and maximize profits, and consumers who seek to lower their energy expenses or earn additional revenues through their active participation in the energy markets [45].

BESSs provide scheduling balancing services as a powerful flexibility lever for power system grid**s**. These services are essential for ensuring grid reliability and efficiency. BESS's characteristics make them suitable for this task, benefiting both the grid and BESS operators. For instance, BESS can promptly inject or absorb power in direct response to frequency fluctuations [46]. Their inherent agility is considered a well-suited candidate for grid flexibility services, where **immediate regulatory actions** are **imperative** to prevent frequency deviations that could potentially trigger widespread disruptions [47].

Additionally, BESS's high energy density and scalability make them versatile assets for grid operators. Their capacity can be easily adjusted to match the specific needs of the grid, providing flexible scheduling balancing support. This adaptability minimizes the reliance on conventional fossil fuel power plants for balancing services, reducing emissions and operational costs.

From the **grid's perspective**, integrating **BESS for scheduling balancing support** enhances reliability and resilience. BESS can act as **a buffer during peak demand periods** or when intermittent renewables experience lulls in generation. This **reduces the risk of blackouts** and ensures uninterrupted power supply for consumers. **Grid stability improves**, and the need for costly infrastructure upgrades is minimized. For **BESS operators**, offering scheduling balancing services to the grid presents a **lucrative revenue opportunity**. BESS can participate in various electricity markets such as FCR and aFRR for earning income through

ectedCategory%22:null,%22activeChart%22:true,%22style%22:%22color%22,%22categoriesModuleOrder%22:%7B%7D%7D visited January 16, 2023 this frequency regulation. Indeed, the FCR reserve has emerged as one of the most lucrative applications for BESSs [43]. Also, there are further opportunities in services such as voltage support, self-consumption, and grid congestion relief services. This revenue stream helps offset BESS's initial investment and operational costs, making them economically viable assets.

b) Effects on network planning and system design

As shown in Figure 26, the price maxima and minima have only a short duration. Therefore, the optimal strategy will be to consume or produce power with the highest possible value. As all market participants react to the same price signal, they will have strong synchronisation. That means that during low price phases all flexible loads will consume power with their rated power. During high-price phases, all flexible generation units will infeed power with their rated power.

These synchronizing effects will be a little bit relaxed because:

- <u>*There will be feedback on the offers regarding the price*</u>. If many loads offer to consume power, the prices will increase, and it will be less attractive to offer additional loads at the same time slot. It can be more attractive to use a neighbouring time slot.
- <u>*Not all flexible loads are available at the optimal time slot*</u>. Heat pumps depend on the heating demands. The heat pump cannot consume additional power if the rooms are sufficiently warm. Electrical vehicles are not at their charging point but driving around with a certain probability.

But in general, a high synchronizing effect is expected. This leads to the necessity to enforce the networks by additional investments to handle loads that might synchronously react to external price signals. Currently, they stress the grid only with a load according to their diversity factor.

It also might lead to congestion. **Solving local congestion needs to be prioritized over solving a global balancing problem. If the flexibility is shed because of local congestion, it can no longer contribute to a global problem**.

5.2.2. The trade-off between balancing and network requirements

There will be **opposite incentives** between using **flexibility for balancing** and **network purposes**. The flexibilities that act on the balancing market all react on the same price signal (market price). This leads to a synchronization of the behaviour of the flexibilities which will lead to a high loading on the network. In low-price situations, all flexibilities will consume energy with maximum power, leading to extreme load peaks. **From a network point of view, a levelled loading curve would result in the best use of the equipment**.

In markets with a considerable price elasticity, there will be a feedback loop between price and demand. A low price will trigger a high demand, increasing the price. This might lead to flexible demand for different time slots with lower prices. This mechanism will level the load curve to a certain extent, acting in a self-stabilizing way.

But in power systems with zero price generation capacity exceeding the maximum demand by far it can be assumed that there are time phases without any price elasticity. Such system configurations are to be expected with the intended energy transition. Suppose solar power plants should generate a considerable amount of energy. In that case, the installed PV power must be much higher than the peak demand (for example, currently, in Germany, the goal is to install about 600 GW in PV power for a load peak of about 70 GW). At times with high solar irradiation, there will be an excessive surplus of power in the market, with a marginal cost of about zero. In such situations, it can be questioned if there is a levelling feedback loop as described above, as all demand can be matched at zero price. In such (not unrealistic) scenarios, extreme load synchronisation is expected.

Therefore, for the safe operation of the power networks, there is essential to coordinate between operators of the balancing market and network operators to avoid overloading of the network. Network operators must always be able (by rules but also factual) to override any flexibility requests from the balancing or other markets if the network is in danger. **The "local stability overrides global stability" rule must be safely implemented in all market and coordination designs. If there will be local failures the units cannot provide global services**.

5.2.3. TSO Frequency Stability Support by Synthetic Inertia from Inverter-based Resources

With increasing access to a high proportion of power electronic equipment and renewable energy generation, the power system is gradually transforming into a new system with high uncertainty. Meanwhile, the power system gradually demonstrates low inertia characteristics by replacing traditional thermal power units with renewable energy generation.

The frequency of a power system is a continuously changing quantity whose derivative indicates the balance between consumed and produced power. A momentary imbalance between these results in a system frequency change where kinetic energy is stored or released in rotating masses. When a disturbance in the form of disconnection of load or production occurs, the system's frequency response depends on the size of the disturbance, inertia and response of controlled frequency responses. Inertia prevents system frequency from experiencing sudden changes, which can, in turn, cause stability issues.

We refer to **synthetic inertia** as the **contribution of additional electrical power from a source that does not inherently release energy as its terminal frequency varies but mimics the release of kinetic energy from a rotating mass**.

From the angle of power deficiency and frequency, synthetic inertia, H_{syn}, is defined as the contribution of active power from a unit that is proportional to the Rate of Change of Frequency (RoCoF) at the terminals of the unit. The mathematical equation can be expressed with Equation 1.

$$H_{syn} = -\frac{\Delta P_{ei}}{2RoCoF} \quad \text{Equation 1}$$

Where, ΔP_{ei} Is the active power (as the normalized value) from a unit and $RoCoF$ in Hz.

5.2.4. Example - Inertia estimation for East China Power Grid

The composition of synthetic inertia in East China can be analyzed comprehensively using the Bonneville Power Administration (BPA) program. Since renewable energy units and DC frequency modulation are not required to participate in the inertia response of power systems in East China, the current inertia response components in East China mainly include traditional units and loads.

General renewable energy power stations do not have inertial control links to provide inertial response. For wind turbines and other renewable energy sources, virtual inertia control can be adapted for renewable energy power stations to produce an inertia response similar to that of a synchronous generator when the frequency drops. **This project simulates the result of low inertia from the increasing penetration of renewable energy**.

According to the simulation in Figure 27, with the increase of the induction motor time constant, the equivalent calculated inertia of the power system approximately increases linearly. Therefore, a linear expression is used to measure the inertia response ability of the induction motor and is provided by Equation 2.

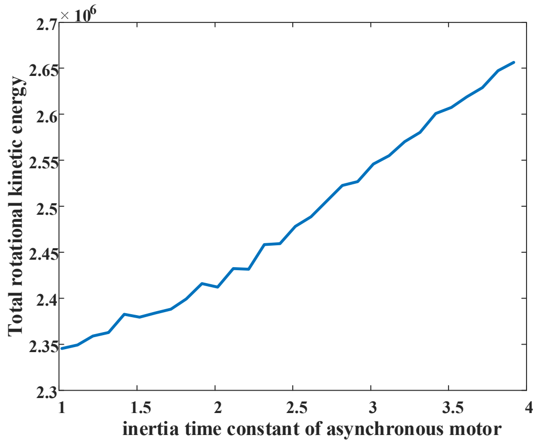

Figure 27: Response capability inertia of an induction motor.

$$E_{asy} = \alpha \cdot \sum K_i \cdot H_{motor,i} L_i$$
$$H_{asy} = \frac{E_{asy}}{S_{base}} \qquad \text{Equation 2}$$

Where K_i is the load proportion of the asynchronous motor of bus *i*, L_i is the total load of bus *i*. $H_{motor,\,i}$ is the mean inertia constant of the asynchronous generator of bus *i*. The value of α is related to the internal parameters of the induction motor and is given by the simulation results in the calculation. S_{base} is the rated capacity.

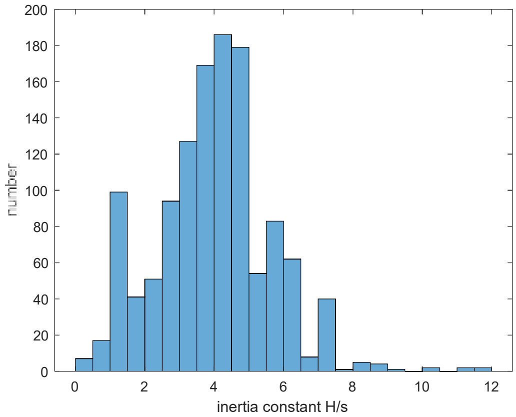

Figure 28: Inertia constant distribution of traditional generators.

It can be seen from Figure 28 that the time constants of traditional units are mostly distributed in the interval of 3-6 s, and the rotational kinetic energy of these units constitutes the energy source of the grid's inertia response.

As depicted in the 2nd column of Table 8, the inertia constant of East China Power Grid is about 5 s, among which the equivalent inertia constant provided by thermal power units is about 4.5 s and the equivalent inertia constant provided by loads is about 0.5 s. The base capacity is 461.24 GW; the corresponding equivalent kinetic energies of rotation are obtained in the 3rd column of Table 8.

Table 8: Theoretical inertia composition.

Source	Provided equivalent inertia constant (s)	Equivalent kinetic energy of rotation (MWs, i.e. MJ)
East China Power Grid	4.9805	2.3×10^6
Generator	4.4927	2.07×10^6
Induction motor	0.4878	2.25×10^5

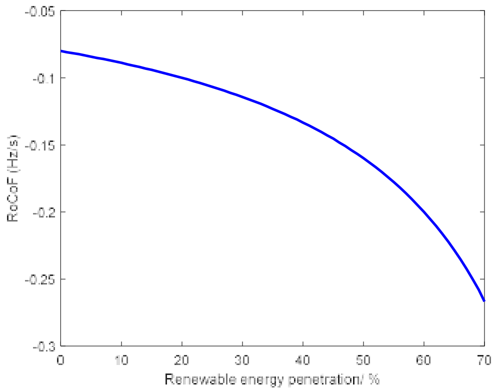

Figure 29: Relationship between renewable energy injection rate and RoCoF.

The calculation results of RoCoF are shown in Figure 29 as renewable energy penetration increases. If the limit of frequency decline rate is calculated as 0.2 Hz/s, the maximum allowable permeability after the Jinsu block (i.e., power deficiency is 6630 MW) is 60 %.

This project analyses the **composition of rotational kinetic energy and the capacity of inertia response in East China** from the perspective of source and load. Then, this project simulates the result of low inertia from the increasing penetration of renewable energy. In the future planning and operation of a new power system, inertia should be primarily considered.

5.3. MAIN OUTCOMES

In the future, efficient **utilization of all potential flexible energy resources (flexibilities) from different voltage levels is needed to fulfil the local DSO and system-wide TSO flexibility needs**. Local DSO needs can be related to congestions (voltage or current limit violations), and system-wide TSO needs are typically related to the power system balance and frequency management. **Effective DS-connected flexibilities**, like DER, **utilization for** different local and system-wide **flexibility services provision requires collaborative DSO and TSO operation and planning principles**, DER location / DS connection point consideration, improved TSO-DSO coordination, DS state-monitoring and state-forecasting.

From the DSO and DS perspective priority during normal power system operation should be on solving local problems locally by DS-connected flexibilities (like DERs and OLTCs in a coordinated manner). Therefore, **new ANM schemes and DER control principles** are needed to improve the DN's DER hosting capacity and the availability of the DN connected DER for the TSO flexibility services provision.

New approaches are required to avoid conflicts of interest between DSO and TSO in utilising the P and Q control-related flexibility services from distribution network-connected resources. Therefore, this chapter presents **one potential approach,** i.e. **“Frequency level-dependent coordinated TSO-DSO flexibility services provision”**. The main idea is that the coordination of flexibility utilization between DSOs and TSOs could be done depending on the severity of the situation from the whole power system’s viewpoint regarding frequency deviation level. **During smaller frequency deviations** (e.g. > ± 0.2 Hz from nominal frequency), **DSO needs are prioritised**. **During larger frequency** deviations, **priority would be on TSO needs**, in order to support momentarily the stability of the whole power system.

6. CONCLUSIONS AND RECOMMENDATIONS

Electric distribution networks will require major changes to support increasing demand levels and renewable generation in the coming years. Flexibility will be directed to improve network operation and reliability, reduce investments and optimize the use of green production, including storage. Nevertheless, major challenges remain and must be investigated deeper to ease the full integration of flexibility into planning. Some R&D efforts must support flexibility evolution based on existing and coming policies. In this context, recommendations can be made and structured into two main topics: (T_1) development of proper simulation methodology and tools to integrate flexibility into planning and (T_2) technical and economic enablers.

T_1 - Development of proper simulation methodology and tools to integrate flexibility into planning

- **R_1 - Cross-sectoral models and tools to integrate other energy sectors**
- **R_2 - Network observability**
- **R_3 – Integration of new metrics related to risk, reliability, uncertainties, hosting capacity and market into planning**
- **R_4 - Prosumer modelling and involvement thanks to collaboration around flexibility with the social science community**

From the system operators' viewpoint, flexibility can be contracted due to long-term planning. However, it will be necessary to consider the possible adoptions in the operational time frames. At this level, research institutions should be encouraged to participate with both the system operators and the regulator in developing the proper simulation methodologies and tools not only in the area of operational-level flexibility but also in consideration of flexibility in the network planning process. Current network planning strategies must be improved and updated by integrating active network elements capable of participation in network operation through flexibility as an alternative to passive approaches such as network reinforcement. For example, modelling the future peak-loading scenarios used in the planning process should not be limited to only considering DER integration and electrification of transportation and heating but also how active network elements respond to some internal or external signal and how this affects the expected peak-loads.

Furthermore, the direct inclusion of operational constraints, increasing temporal and spatial resolution in planning models and linking planning and operational models might also benefit the planning process. Some working groups, such as ISGAN [48] and ENTSO-E [49], proposed methodologies to integrate flexibility into planning. The main drawback is the lack of genericity, which required strong improvements to adapt to other power systems. At the same time, this requires a deep evolution of methodologies and tools traditionally used. Novel methods available in the literature could be applied to consider the high level of complexity and uncertainties related to integrating flexibility into planning. Also, investment decisions must be updated more often when operators get more information and visibility on the future.

- **R_1: Cross-sectoral models and tools to integrate other energy sectors**

There have already been cases where failures in an “adjacent” network have impacted electricity network customers, including failure relating to Western Australia’s gas network in 2004[13] and 2008 [14]. These tools must be cross-sectoral, i.e. integrate directly with other energy sectors such as heat and gas, or be adapted for co-simulation. Cost-benefit analysis cannot be silo-based anymore to take advantage of the complementarity of energies fully. For example, electricity cannot be efficiently and economically largely stored but can be transmitted over long distances. On the contrary, thermal energy can be easily stored but cannot be transmitted over long distances. Another example is the hydrogen vector, which could provide short-term and seasonal storage options. A bidirectional coupling with the hydrogen infrastructure, including hydrogen-fired power plants and power-to-hydrogen plants, can provide this flexibility. A comprehensive understanding of interactions between the hydrogen and electricity infrastructures in operation is required to design the future system.

For example, this kind of tool could profit territories trying to decarbonize their industry. Great efforts are required to understand the relations between energies, modelling and optimisation. Also, questions around data are important: what kind of data is necessary to develop this kind of tool? What is the regulatory context of data exchanges? Cost Benefit Analysis (CBA)-based methods could be applied to analyse, evaluate, and compare different concepts of the integrated energy networks. Such analyses require dispatch simulation to determine key indicators such as costs, emissions, or energy not served by the coupled infrastructure. Optimizing the distribution network is already complex, and this recommendation increases this complexity even more.

- **R_2: Network observability**

A key element for flexibility usage is network observability obtained by digitalising network models (such as digital twins), production and consumption forecasts, installation and processing of measurements, and the ability to control flexibility units. Safe communication must always be ensured, as providing a service can be crucial for network and system stability.

The required architecture for an operational, network-orientated usage of flexibility also is the basis for a superimposed deployment of distribution network flexibility at a transmission level.

- **R_3: Integration of new metrics related to risk, reliability, uncertainties, hosting capacity and market into planning**

If flexibility is integrated into planning, there is a need for standards to provide a common and strict definition of flexibility, depending on spatial scale (HV, MV or LV) and time scale. Typical indicators used in planning studies are CAPEX, OPEX (related to power losses and for some DSO related to the energy not supplied and power cuts) and some reliability index, i.e., System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index

[13] Cronin Report is somewhere in the web... references here: https://parliament.wa.gov.au/Hansard/hansard.nsf/0/f55d2a865b43bf8fc825758a001a987d/$FILE/C37%20S1%2020050825%20All.pdf

[14] https://en.wikipedia.org/wiki/2008_Western_Australian_gas_crisis

(SAIFI) and Value of Lost Load (VoLL). If flexibility is integrated into planning, these indicators are not enough to capture some effects related to flexibility, and new ones must be defined to help the decision-maker. Examples of metrics could be:

- *Risk*: quantify the risk when flexibility fails the service it was supposed to provide (for example, solving congestion)
- *Extension of the VoLL (*Value of Lost Load*)*: The Clean Energy Package defines VoLL as the €/MWh estimate of the highest price customers are willing to pay to prevent a power outage. This index tries to represent people's willingness to pay for a given service. The willingness to accept that they might not be served for a certain period (e.g. number of hours per year) should also be considered. If people or governments are prone to have this period close to zero, then their willingness to pay is very high.
- *Willingness to be payed to be flexible*: Another KPI could be related to people's willingness to reduce or shift their consumption or use any other assets differently to provide or contribute to a flexibility service.
- *Widening cost-benefit- and multi-criteria analysis*: demand for other decision support tools to develop a framework for goal analysis and estimate the economic impact of adding flexibility in smart grids. This multi-dimensional merit order implies that several strategies, i.e., flexibility, topology and smart network device, must be coordinated with DSOs and TSOs.
- *Uncertainties*: update current frameworks to include guidance about handling complex uncertainties, e.g., by moving from defined scenario analysis (e.g. worst-case scenario) to a probabilistic approach.
- *Availability of flexibility:* it describes the amount of flexibility that responds to a call compared to the amount of flexibility offered.
- Power market simulations: for example, the percentage of annual load covered by the power market.

- **R_4: Prosumer modelling and involvement thanks to collaboration around flexibility with the social science community**

Explaining to customers the interest in being flexible for society is most important to increase the amount of flexible assets and their availability. Also, in the same way, we have models for different kinds of loads. We need models of different kinds of flexibility, depending on customer incentives. A classic example is the value of non-distributed energy. Every DSO has its cost criteria based on social studies defining how much people are willing to pay to have access to electricity all the time.

Deploying interfaces or other means to communicate the possibility of local power outages to avoid full blackouts and/or minimize costs could improve the appreciation of a reliable power system, as it is already implemented in some countries.

Social science combined with artificial intelligence can help understand customers' response to incentives through data analysis of user behaviours with identification of network usage patterns, peak times, and areas of high demand. Furthermore, it must be ensured that local social and cultural norms and practices, which might affect network usage and willingness to provide flexibility, are properly included within the network planning process. Gamification approaches have also proved their contribution to consumer engagement.

We could also imagine ways to communicate information on local power outages via smart meters or a dedicated application to avoid full blackouts and/or minimize costs, thus improving the appreciation of a reliable power system.

T_2 - Technical and economic enablers

- **R_1 - Dynamic tariffs as a game changer**
- **R_2 - Compatibility and/or standardization of communication networks and protocols**
- **R_3 - Development of a of a flexibility market to accelerate the integration of flexibility**
- **R_4 - The exchange of flexibility must operate across organization boundaries**

- **R_1: Dynamic tariffs as a game changer.**

Studies have to be made to link tariffs with network constraints, which depend on the spatial scale (local versus global) and time (seasons, weekday, hour of the day), ensuring they do not have to bring complexity for end-users. Some countries have already deployed the concept of nodal prices. This nodal process might not be the same for flexibility, in which local problems are highly dependent on the locations of constraints (e.g. congestion management or voltage control). In addition, implicit flexibility (customers react to signals) and explicit flexibility (automatic i.e. a third party operates the customers' assets) have to be deployed to help solve problems related to flexibility availability. Dynamic tariffs require local markets. If not, it could only be used for global problems, e.g. grid balancing. Congestion management/redispatch measures could be worsened. Small, local markets, however, offer a high risk of market manipulations.

- **R_2 - Compatibility and/or standardization of communication networks and protocols**

Many different communication protocols depend on the network (HV, MV or LV) and countries. Even for assets with the same communication protocols, issues can be related to their different age and generations. Communication issues could limit the deployment of flexibility. Too many different interfaces are currently preventing the smooth operation of smart grids. Therefore, standardization towards compatible and well-documented interfaces is essential for broad development and control of flexibility. Some early standards are emerging, such as those described in [50] on functionality, architecture and demand-side response operation of energy smart appliances. These standards include the interfaces between energy management systems and smart metering systems, especially between energy management systems and household installations (e.g. PV inverters, wall boxes, battery storage, heat pumps). With a lifetime of customer installations of up to 20 years, pragmatic solutions should be found for existing systems, and particular attention should be paid to future standardized interfaces.

- **R_3 - Development of a flexibility market to accelerate the integration of flexibility.**

Some flexibility platforms are currently under operation or used in pilot projects. The interest is the transparency they can offer when proposed by a neutral third party. The transactions are easy and clear; all players can interact at all scales (from end-users to TSOs). Communication can be reduced to a minimum, and critical data must not be shared with all partners, but only with the market operator/coordinator. The regulatory framework has to be defined for fast progress and to exploit the full potential of flexible assets, especially loads. This approach includes remuneration for the flexibility offer and activation, responsibilities for all stakeholders, the role of the system operator and a transparent decision-making process. Nevertheless, it is quite complex to implement both on the technical and regulatory sides. Other issues related to the prioritization of flexibility services, the coordination between players and the share of responsibilities in case of outages due to the wrong usage of flexibilities have to be clearly defined.

- **R_4 - The exchange of flexibility must operate across organization boundaries**

There is a need for coordination between network operations, especially at the interface between DSO (or Distribution Network Operator, DNO) and TSO, since the operation of transmission and distribution networks is managed quite independently. The deployment of flexibility at one location may lead to issues elsewhere, i.e., usage for system or market purposes can give rise to a nonvalid grid state in the distribution system. On the one hand, free market access for flexibility assets installed in the distribution system requires a discrimination-free handling of all flexibilities, disregarding all network constraints. On the other hand, this can lead to unnecessarily high curtailment of the flexibility potential due to congestions in the distribution network and high compensation payments, as known from redispatch measures. For distribution systems, local constraints will likely involve resolution by local assets, which may expose any flexibility market to gaming; this will be a challenge for distribution-level flexibility services. Defining the rules of flexibility services between DSO and TSO could help them better manage their system and maybe mutualize investments.

7. ANNEXES

7.1. ANNEXE 1: CHINESE PILOT PROJECT: INTEGRATION OF FLEXIBILITY INTO THE PLANNING PROCESS

7.1.1. Algorithms description

For each year, different network reinforcement plans are provided, one for each future scenario of DER integration. The network operation and reinforcement planning module is further detailed in Figure 30.

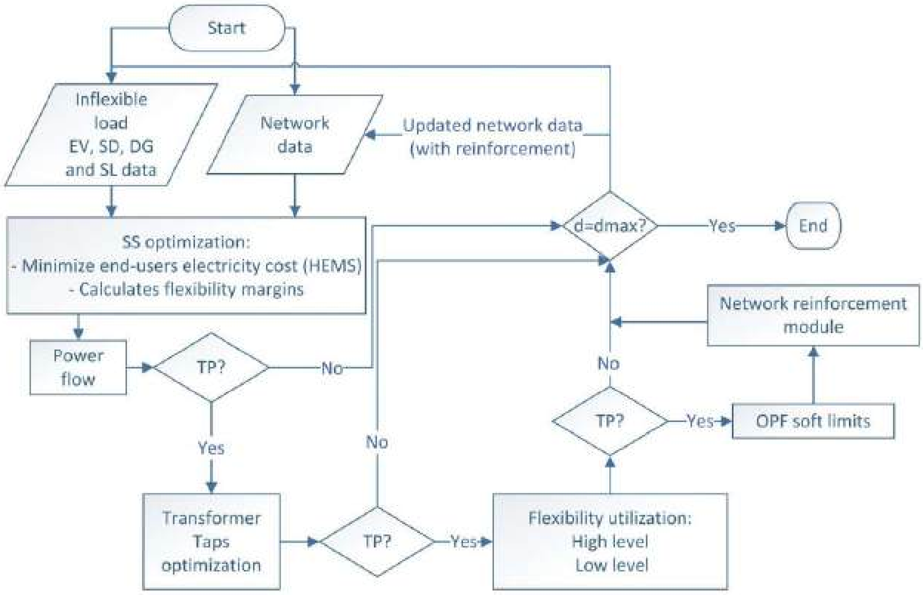

Figure 30: Network operation and reinforcement flowchart

As shown in Figure 30 to Figure 32, network reinforcement planning is performed in several steps. It includes three optimization problems: Secondary substitution (SS) optimization (which defines the consumption profiles and flexibility margins), flexibility utilization (that includes network operation and clients' resources rescheduling) and network reinforcement.

First, the FL schedule in each SS is optimized, and the output of this module is the hourly consumption profile and respective flexibility margins in each SS for an entire day. Then, a Power Flow (PF) is used to evaluate if the operation point resulting from the previous optimization originates technical problems in the network. If not, the analysis for that day is concluded. Otherwise, the transformer taps are optimized first, and if the problems persist, the FL flexibility is used afterwards.

The use of flexibility is an iterative process where, at first, an optimal Power Flow (OPF) optimization defines the amount of flexibility needed to solve the problems in the High Level (HL) optimization function. Then, the Low Level (LL) optimization function verifies if it is possible to use the requested flexibility for all the required periods (some incompatibilities may occur due to intertemporal constraints). If possible, the flexibility is used as determined by the

HL optimization. If not, the network reinforcement module is triggered. This process is repeated for all the typical days considered in the planning exercise.

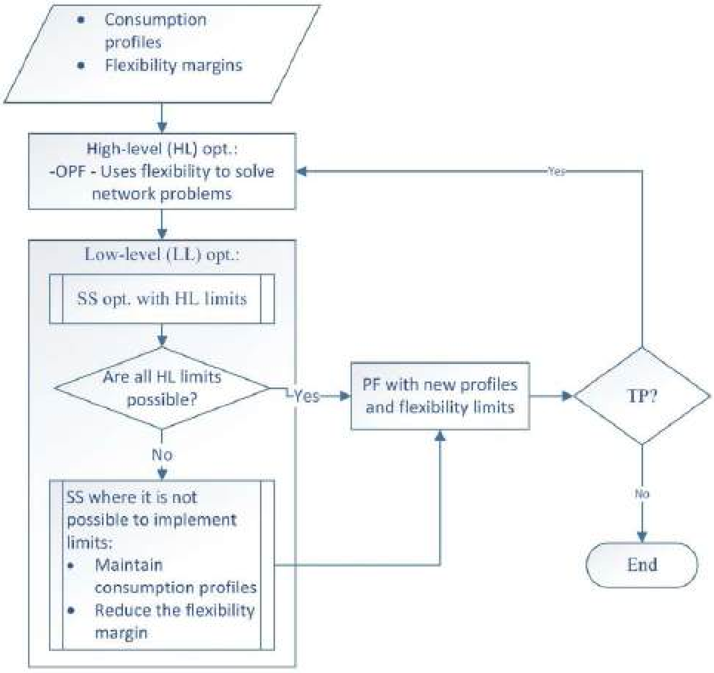

Figure 31: Flexibility utilization flowchart

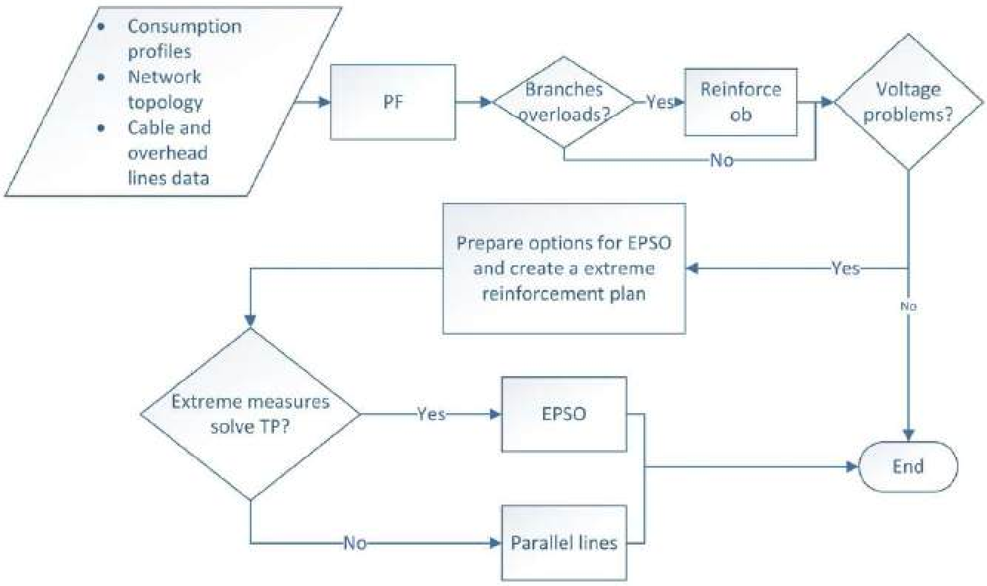

Figure 32: Reinforcement module flowchart

7.1.2. Data and hypotheses of the case study

a) Hypothesis on flexible load

In the project performed, it was assumed that each EV has a battery with 30 kWh capacity and a charging power of 7.5 kW. The EV charging points are considered to be located on the downstream LV network, and EVs can freely charge between 8 p.m. and 7 a.m. It is assumed that each storage battery can fully charge within an hour. SD can freely charge during the whole day. Its charging patterns are optimized depending on the node's energy tariffs and other energy needs (such as EV charging periods or domestic load profiles). Batteries charging and discharging efficiency are assumed to be 90% for EV or SD.

b) Hypotheses on load modelling and evolution

As previously mentioned, LV resources are aggregated and represented at the SS level. Each SS has a consumption profile, and the respective flexibility margins are constrained by the resources allocated to that SS. The resource integration is assumed to be proportional to the average consumed power in the SS. As the analyzed network represents 0.22% of the total national consumption, the load increase and the EV, SD and PV integration levels were computed accordingly, as shown in Table 9.

Six typical days are analyzed: two typical winter days (week and weekend), two typical summer days, a peak consumption day (during winter without PV production) and a minimal consumption day (with maximum PV production). The representativeness of each typical day in a year is the following:

- Winter weekday – 24%
- Winter weekend day – 12%
- Summer weekday – 42%
- Summer weekend day – 15%
- Peak consumption day – 6%
- Minimal consumption day – 1%

Table 9: Scenarios applied to MV network

ENTSO-E scenarios		2030			2040		
	Resource	DG	ST	EUCO	DG	ST	GCA
PT	PV (MW)	6,581	1,816	2,076	14,323	4,303	17,572
	SD (MWh)	329	0	0	3581	0	78
	Annual demand (TWh)	56.36	52.32	41.02	65.41	4.65	54.65
	EV (n)	694,778	84,500	423,568	1,305,056	144,147	952,972
MV net	PV (MW)	14.7	4.1	4.6	32.0	9.6	39.3
	SD (MWh)	1.5	0.0	0.5	16.0	0.0	3.9
	Annual demand (GWh)	126	117	92	146	122	122
	EV (n)	1,552	189	946	2,916	322	2,129

Hourly residential and industrial load profiles were defined for each typical day, as shown in Figure 33. In the considered scenarios, flexibility is assumed to increase in the future, but the total amount is not specified. Given the lack of data, it was assumed for SL a flexibility margin of 5% of the total residential load (upwards and downwards).

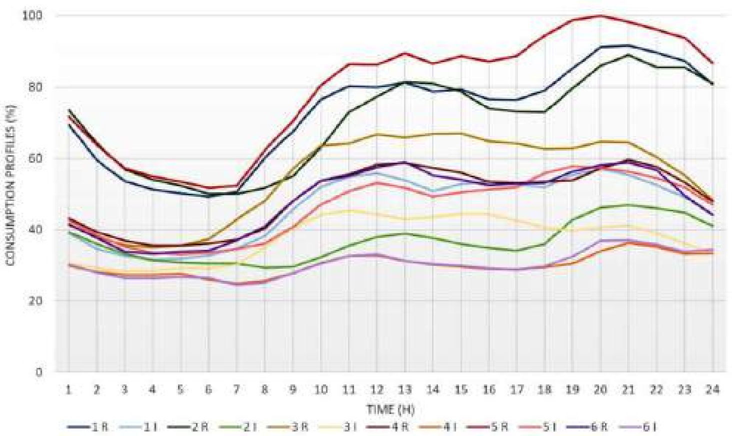

Figure 33: Residential and industrial consumption profiles

7.1.3. Results

In 2030

In 2030, technical problems occurred only in the DG scenario. Only one branch was overloaded for nearly 150 hours, as shown in Table 10. DG implied a line replacement, requiring an investment of 25.4 k€. The results obtained with the risk assessment method are shown in Table 11 to Table 15. RP_ys is the network reinforcement plan for year y, preparing the network for scenarios. Considering the flexibility provided by FL, the initial network can operate without problems if scenario ST or EUCO occur. Thus, $RP_{1,\ ST}$ and $RP_{1,\ EUCO}$ do not present any costs, as they do not require any reinforcement measure. However, the network is unprepared for the DG scenario and will present an annual ENS of 1096 MWh if this happens. In this case, RP, DG is the chosen RP, as it presents minimal risk since ENS is zero for all the scenarios (see Table 11).

In 2040

In 2040, the network (already reinforced by $RP_{1,\ DG}$) presents branch overloads in DG and GCA scenarios (see Table 10). DG scenario presented the most severe technical problems, requiring a higher investment cost. However, this scenario again leads to the most robust network reinforcement plan, as the risk of ENS is zero, as shown in Table 4.

Table 10: Network technical problems for different scenarios using FL

	2030 DG	ST	EUCO	2040 DG	ST	GCA
Buses with voltage problems	–	–	–	–	–	–
Overloaded branches	1	–	–	6	–	3
Hours per year	152	–	–	485	–	474

Table 11: RP for 2030 scenarios considering loads flexibility

2030 Plan		$RP_{1,DG}$	$RP_{1,ST}$	$RP_{1,EUCO}$
Cost (€) :		25,412	0	0
ENS (MWh/year)	DG	0	1,096	1,096
	ST	0	0	0
	EUCO	0	0	0
	Max	0	1,096	1,096
RP Selected: $RP_{1,DG}$				

Table 12: RP for 2040 scenarios considering load flexibility

2040 Plan		$RP_{2,DG}$	$RP_{2,ST}$	$RP_{2,GCA}$
Cost (€) :		243,473	0	80,130
ENS (MWh/year)	DG	0	5,980	3,716
	ST	0	0	0
	GCA	0	3,763	0
	Max	0	5,980	3,716
RP Selected: $RP_{2,DG}$				

Table 13: Network technical problems for different scenarios considering traditional approach

	2030 DG	ST	EUCO	2040 DG	ST	GCA
Buses number	–	–	–	–	–	–
Branches number	1	–	–	14	–	3
Hours per year	152	–	–	598	–	517

Table 14: RP for 2030 scenarios considering the traditional approach

2030 Plan		$RP'_{1,DG}$	$RP'_{1,ST}$	$RP'_{1,EUCO}$
Cost (€) :		25,412	0	0
ENS (MWh/year)	DG	0	1,096	1,096
	ST	0	0	0
	EUCO	0	0	0
	Max	0	1,096	1,096
	Selected: $RP'_{1,DG}$			

Table 15: RP for 2040 scenarios considering the traditional approach

2040 Plan		$RP'_{2,DG}$	$RP'_{2,ST}$	$RP'_{2,GCA}$
Cost (€) :		481,972	0	80,130
ENS (MWh/year)	DG	0	6,801	5,037
	ST	0	0	0
	GCA	0	4,142	0
	Max	0	6,801	5,037
	Selected: $RP'_{2,DG}$			

7.2. ANNEXE 2: CHINESE PROJECT: A TWO-STAGE OPTIMIZATION OPERATION STRATEGY TO INCREASE PV HOSTING CAPACITY

Project outcomes: This project verifies the typical scenarios clustered when the distributed PV power generation has the phenomenon of power flow foldback. As shown in Figure 34, in the distributed PV scenario, the maximum backfed power from the distribution system to the superior network reached up to 1795 kW, and the total backfed power reached up to 2206 kWh. In the 39th period, the 10kV distribution system returned power to the 110kV grid for the first time. In the 38th period, the interaction between network load and storage of reserve source was started. The dynamic cooperative game demand response reduced the load power consumption on the premise of ensuring that there would be no power flow back in the current period and adjusted the flexible load state to reserve the adjustable potential on the demand side. After the flexible load state is adjusted through the interaction of load and storage of the reserve source network, the normal power demand of the load, maintaining the state set by the user, increases slightly in the 39th period, eliminating the phenomenon of power flow foldback. There was no need to start the demand response again. In the 52nd period, the foldback power reaches the maximum. After the interaction of reserve source network charge and storage in the 51st period, serious foldback power still existed in the 52nd period under the normal power demand. Then, the dynamic cooperative game demand response was adopted to increase the load power consumption and eliminate the phenomenon of power flow foldback.

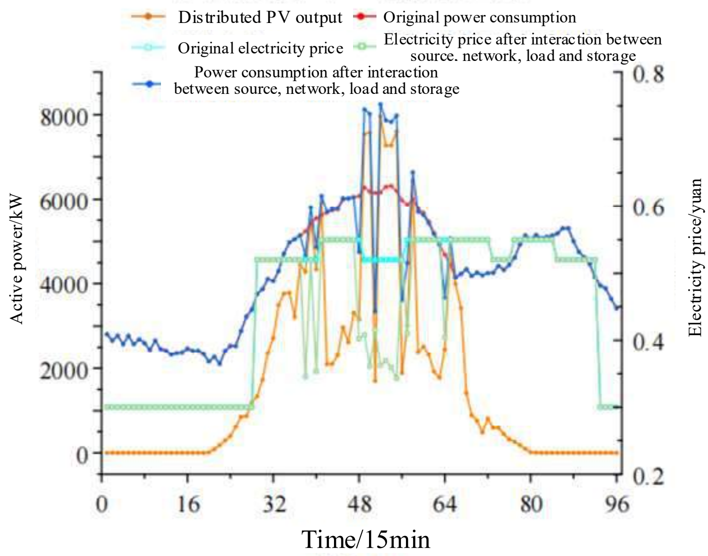

Figure 34: Game results of demand response in typical photovoltaic power generation scenarios

Figure 35 to Figure 36 show the voltage of each node of the distribution system before and after the interaction of source network charge and storage in PV generation scenario 1. As shown in Figure 35, there are serious voltage over-limit and fluctuation problems in distributed photovoltaic power distribution networks with a high proportion, which affect the safe and stable operation of the power network. As shown in Figure 36, the interactive operation strategy of source network load storage proposed in this project eliminates the phenomenon of node voltage over-limit in the distribution network, inhibits voltage fluctuation, and maintains the safety and stability of the distribution network. As shown in Figure 37, the active power loss of the distribution system in the period of severe backflow of the original distributed photovoltaic power generation was significantly reduced because the power-storage interaction in the source network eliminated the phenomenon of power flow backflow. The transfer of the flexible load led to the reduction of active power loss in subsequent periods. In the case of PV generation scenario 2 and scenario 3, the interaction strategy of source network charge storage proposed in this paper can eliminate voltage overlimit and reduce active power loss.

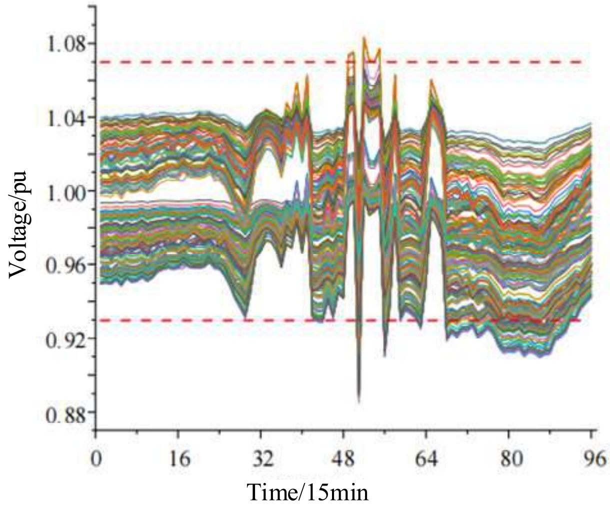

Figure 35: Power distribution network nodes before interaction of source-network-load-storage

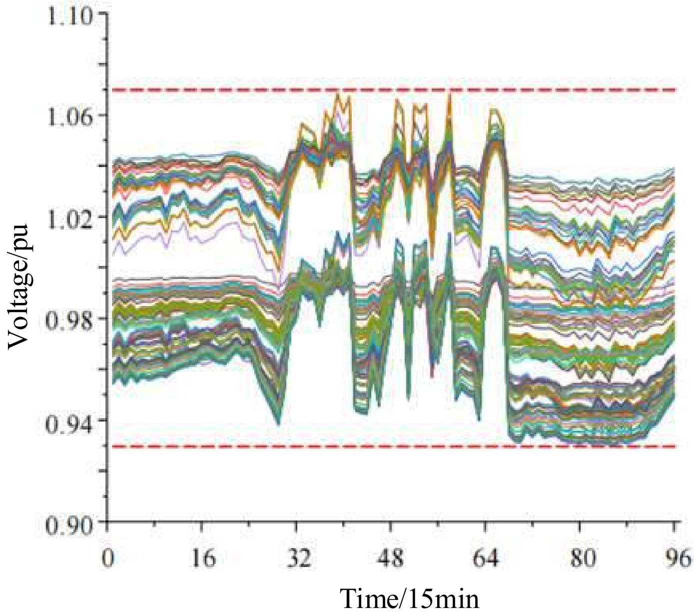

Figure 36: Power distribution network nodes after interaction of source-network-load-storage

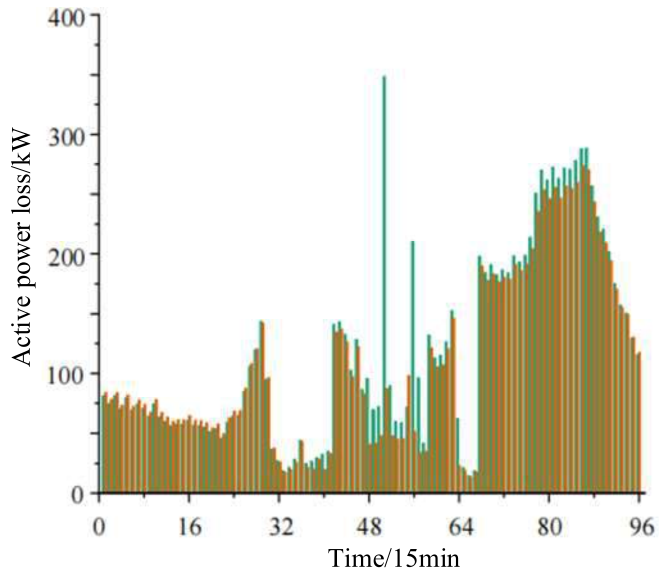

Figure 37: Active power loss of power distribution system before and after interaction of source-network-load-storage

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