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Working Group Report

Flexibility in distribution grids with a large share of distributed energy resources – with a special focus on microgrids

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WORKING GROUP

Final Report

Flexibility in distribution grids with a large share of distributed energy resources – with a special focus on microgrids

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Glossary

Abbrev.	Definition	Abbrev.	Definition
AEMO	Australian Energy Market Operator	**ETIP SNET**	European Technology & Innovation Platform Smart Networks for Energy Transition
ACE	Area Control Error	**ETV**	Energy Trading Volume
AMI	Advanced Metering Infrastructure	**EV**	Electric Vehicle(s)
ANM	Active Network Management	**EVR**	Electronic Voltage Regulator
ARD	Active-Reactive Droop	**FENIX**	Flexible Electricity Networks to Integrate the Expected Energy Evolution”
ATV	Average Trading Volume	**FSP**	Flexibility Service Provider
BRP	Balancing Responsible Party	**G2H**	Gas-to-Heat
CC	Central Controller (microgrids)	**G2P**	Gas-to-Power
CEC	Citizen Energy Community	**GHG**	Greenhouse Gas (contextual)
CEP	Clean Energy Package	**HMU**	Home Management Unit (customer device)
CHP	Combined Heat and Power	**HP (gas)**	High Pressure (gas network)
CP	Customer Plant	**HV**	High Voltage
CPMU	Customer Plant Management Unit	**HVG**	High Voltage Grid
CSC	Collective Self-Consumption	**HV/MV**	High Voltage / Medium Voltage
CVR	Conservation Voltage Reduction	**Hz/W SC**	Hertz/Watt Secondary Control
DG	Distributed Generation	**IEA**	International Energy Agency (contextual)
DER	Distributed Energy Resources	**IEC**	International Electrotechnical Commission
DSO	Distribution System Operator(s)	**IEEE**	Institute of Electrical and Electronics Engineers
D-FACTS	Distribution Flexible AC Transmission Systems	**INTERACT**	Integration of Innovative Technologies of Positive Energy Districts into a Holistic Architecture
DLR	Dynamic Line Rating	**IoT**	Internet of Things
DMS	Distribution Management System	**IPS**	Interconnected Power System (contextual)
DNSP	Distribution Network Service Provider	**IVR**	Inline Voltage Regulator
DR	Demand Response	**IVVO**	Integrated Volt-VAR Optimisation
DSM	Demand Side Management	**LCOE**	Levelized Cost of Electricity
DSO	Distribution System Operator(s)	**LC**	Local Control
DTR	Distribution (MV/LV) Transformer	**LEC**	Local Energy Community
EH	Energy Hub	**LP (gas)**	Low Pressure (gas network)
EMCS	Energy Management and Control System	**LV**	Low Voltage
EMS	Energy Management System	**LVG**	Low Voltage Grid
EnC	Energy Community	**LV/MV**	Low Voltage / Medium Voltage
EPO	Electricity Producer-Link Operator	**LVC**	Low Voltage Control (contextual)
ESS	Energy Storage System	**LRM**	Local Retail Market

LFC	Load Frequency Control	**RES**	Renewable Energy Sources
MG	Microgrid	**RPD**	Reactive Power Devices
MP	Medium Pressure (gas network)	**SAIDI**	System Average Interruption Duration Index
MV	Medium Voltage	**SAIFI**	System Average Interruption Frequency Index
MVDC	Medium Voltage Direct Current	**SC**	Self-Consumption or Secondary Control (contextual)
MVG	Medium Voltage Grid	**SCADA**	Supervisory Control And Data Acquisition
NEM	National Electricity Market (Australia)	**SG**	Smart Grid
NESO	National Energy System Operator (UK)	**SNG**	Synthetic Natural Gas
NLTC	No-Load Tap Changer	**SoC**	State of Charge (contextual)
N-1	Single Contingency Security Criterion	**StO**	Storage-Link Operator
OLTC	On-Load Tap Changer	**SVR**	Step Voltage Regulator
PCC	Point of Common Coupling	**T&D**	Transmission and Distribution
PC	Primary Control	**TSO**	Transmission System Operator
PID	Proportional–Integral–Derivative	**TOTEX**	Total Expenditure
PhST	Phase-Shifting Transformer	**UPS**	Uninterruptible Power Supply
PMS	Power Management System	**V2G**	Vehicle-to-Grid
PQ	Power Quality	**V2H**	Vehicle-to-Home
PV	Photovoltaic	**VPP**	Virtual Power Plant
P2G	Power-to-Gas	**VRU**	Voltage Regulation Unit
P2H	Power-to-Heat	**VVC**	Volt/VAR Control
P2T	Power-to-Thermal	**Vv SC**	Volt/var Secondary Control
P2X	Power-to-X (generic cross-vector conversion)	**WG**	Working Group
QoS	Quality of Service	**WSC**	Watt Secondary Control
RAP	Remedial Action Plan (contextual)	**ZUQDE**	Austrian project “Zentrale Volt/Var Regelung bei Durchdringung mit Erzeugern” (Central Volt/VAR Control in presence of DGs)
REC	Renewable Energy Community		

Executive summary

Recent changes in the global political landscape, impacting energy and food security, have made the integration of Distributed Energy Resources (DER), especially rooftop Photovoltaic (PV) systems, imperative. These systems occupy land already in use and are located near the point of consumption, thus decreasing grid losses. The increase in distributed power generation, primarily through rooftop photovoltaic systems, pushes power grids to the limits of voltage stability, which is associated with power oscillations and even power outages. All this indicates that **the large-scale implementation of renewable and distributed generation poses considerable technical challenges, while their flexibility leaves much to be desired**. The JRC's 2024 DSO survey found 81% of EU DSOs report frequent voltage violations (over- or under-voltage) in their networks [1].

This report outlines current experiences with using flexibilities in operating distribution systems, based on a survey. It also provides an overview of innovative solutions, such as Microgrids, self-consumption versus Transmission and Distribution (T&D), and *LINK*, to address existing challenges. The report focuses on the technical aspect by highlighting the control strategies that enable flexibility in practice, and only mentions others, such as regulatory, in passing. The report neither addresses any economic aspects, increased cybersecurity risks with more active systems, nor issues such as resilience and telecommunications dependencies for command and control, under any circumstances. Therefore, a cost-benefit analysis and an end-to-end technical assessment encompassing all dependencies should be performed before deciding to implement any technical solution.

Distribution System Operators (DSO) experience is collected from a global survey conducted among utility companies in 2024, focusing on DER integration. The Working Group developed and refined the study with the CIRED committee, gathering responses from 24 utilities across 19 National Committees. Key insights include the widespread presence of DERs, particularly rooftop solar panels, and the expected significant increase in DER installations over the next decade. DSOs employ countermeasures to maintain network stability, including On-Load-Tap-Changer (OLTC) and reactive power control. Under others, **several DSOs reported that the transformers' local controls** (OLTCs, tap-changing transformers) **were reaching their end settings**. The survey also highlights challenges at the Transmission System Operator (TSO)-DSO interface and the effectiveness of energy market rules. Additionally, **the impact of large-scale rooftop PV in Australia is discussed, emphasising the need for reforms to ensure system security and dynamic resilience.** The survey results underscore the importance of national regulations and policies in shaping DER integration practices.

This report presents a comprehensive analysis of **Microgrids**, focusing on their architecture, classification, control strategies, and operational roles in modern power systems. Once conceived primarily as isolated systems for backup or emergency use, microgrids have evolved into smart, grid-interactive assets that actively support energy management, grid reliability, and DER integration. This transition—from grid independence to grid integration—has been driven by advances in control technologies, the rise of renewables, and growing demands for system flexibility and resilience. The report examines how microgrids are categorised by control strategy, energy source, topology, application, and operating mode. It highlights their flexibility to operate in both island- and grid-connected modes, dynamically switching between them based on system conditions. Additionally, microgrids can mitigate voltage and thermal constraints, manage local generation and demand, and enhance real-time balancing through storage and demand response. With these integrated capabilities, microgrids are critical in modernising distribution networks and transitioning

[1] A. Meletiou, J. Vasiljevska, J. and S. Vitiello, DSO Observatory 2024 - Unlocking Flexibility in Europe, Publications Office of the European Union, Luxembourg, 2025, https://data.europa.eu/doi/10.2760/7123923, JRC141953.

toward a more decentralised energy system, providing that the benefits of implementing microgrids outweigh their cost, encompassing TOTEX in an end-to-end perspective, including obsolescence and renewal. Nevertheless, *despite the long duration of research (over 20 years), a detailed definition of microgrids is still being debated in expert forums*. **Microgrids' intertwined controlling structure with primary, secondary, and tertiary controls to consider also the "main system" leads to extremely complex and multifaceted technical solutions that are difficult to implement on a large scale.**

Self-Consumption vs. T&D discusses the individual and collective Self-Consumption schemes. Nevertheless, it can be underlined that there is a **lack of research** to assess how the proposed schemes could increase the DER hosting capacity; what would be the technical challenges, which incentives must be set, and what would be the required evolutions in the national regulations?

LINK paradigm and the corresponding holistic architecture, built on the fractal geometry of the grid, redefine its technical and market structures. It considers all grid voltage levels, including customer plants and electrical appliances, i.e., electricity producers and storage, regardless of size (ranging, e.g., from MW to kW) and technology (e.g., waterpower plants, photovoltaics, etc.). ***LINK*** **architecture postulates a coordinated chain network of controls (comprising secondary, primary, and local controls) on the primary quantities of power systems, namely frequency and active power, as well as voltage and reactive power, thereby enabling large-scale grid flexibility through power modulation and resilience.** It facilitates describing all power system operation processes such as load-generation balance, voltage assessment, dynamic security processes, price- and emergency-driven demand response, etc. The chosen distributed *LINK*-based architecture overcomes data privacy and cybersecurity challenges. Its key principle is to prohibit access to all resources by default, allowing access only to a minimum of data. *LINK* is characterised by clear guidelines regarding ownership and operating conditions, as well as standardised and modular structures. *LINK* enables Sector Coupling and Energy Communities and can thus effectively counteract the growing trend toward negative prices across Europe. However, **it is essential to refine the holistic architecture on-site by implementing it in its entirety. This step will highlight its strengths and help to formulate concrete steps for the large-scale implementation.**

1. Introduction

The electricity grids are undergoing fundamental changes in response to the growing need to decarbonise the energy system and support the increasing electrification of various sectors, including transport, industry, and heating. Distribution System Operators (DSOs) are now expected to be more proactive in managing this transition by deploying various flexibility solutions. These include the procurement of flexibility services, the implementation of flexible connections, and the use of operational network flexibility measures. Where appropriate, traditional network reinforcement will continue to be employed, but only when it represents the most efficient and cost-effective solution for consumers.

Looking ahead, distribution networks are facing unprecedented changes in how electricity is consumed and produced. The increasing penetration of Renewable Energy Sources (RES), such as solar and wind, introduces greater variability and uncertainty into the system. At the same time, electrification of heating, driven by the adoption of low-carbon technologies such as electric heat pumps and hybrid heating systems, is reshaping traditional demand profiles. These developments are particularly evident in the winter, when peak demand is expected to rise significantly.

Furthermore, the proliferation of digital technologies and smart appliances is enabling more responsive and distributed energy use, but it also adds complexity to system planning and operation. This shifts present challenges for DSO, particularly in managing voltage levels, avoiding thermal overloads, and ensuring the long-term sustainability of the network infrastructure.

To address the technical challenges associated with the operation of DERs in the evolving context of flexibility, CIRED established a working group from 2023 to 2025. This group focuses on enhancing the operational flexibility of distribution grids that incorporate a significant share of distributed generation (DG).

1.1. Scope of the Working Group

The working group concentrated on distribution networks within European countries and expanded the analysis to include global perspectives depending on the available data.

The first object of the Working Group (WG) is to provide an overview of the key challenges and experiences that DSOs encounter when integrating DERs. The focus is on exploring how flexibility might offer potential solutions. This analysis will consider recent developments in the network from both a technical perspective, including innovations such as micro-grids and energy hub solutions, and a regulatory standpoint, including the implications of European directives and Grid Codes. Meanwhile, the second objective is to provide an overview of existing and emerging solutions, taking into account the latest technologies.

As agreed with the CIRED Committee, the WG’s activities have been broken up into two main work parts as follows:

1) Identifying DSO experience on the operation of grids with distributed RES through a survey;
2) Providing research results to overcome the existing operational challenges[2].

[2] **Note:** The scope voluntarily focuses solely on the technical aspects: what existing or emerging solutions can or could do, and technical challenges that enable further possibilities. The scope does not address the conditions to implement such solutions, such as cost (CAPEX and OPEX, build and run, private vs socialized costs, change in all affected processes and tools, in particular for TSOs and DSOs) and benefits (collective welfare vs private gains, new businesses), the necessary change in cybersecurity, dependencies on the resilience of other systems (such as telecommunication), change management by system users (possibility or willingness to participate)

Designing the survey was the first step to get information about the current situation through a questionnaire on:

- The extent of the actual distributed RES (generation, storage, e-mobility) penetration;
- Countermeasures to maintain network voltages within statutory/legal limits;
- Countermeasures to minimise thermal and other constraints at the TSO-DSO interfaces;
- Effectiveness of energy market/trading rules that enable or constrain DG;
- Data privacy and cybersecurity;
- Grid Codes and Distribution Codes of practice;
- How can the added value of flexibility solutions be identified compared with the traditional T&D network investment plan (defer traditional network investment)?

The WG sincerely appreciates the contributions of all DSOs who participated in the survey, and the results have been compiled and presented independently and autonomously. The survey gathered insights from 24 utilities across 19 countries. The findings reveal a significant presence of DERs, particularly rooftop solar panels, and a substantial increase in DER installations over the next decade. DSOs employ various countermeasures, including On-Load Tap Changers (OLTC) and reactive power control, to maintain network stability. The survey also addresses challenges at the Transmission System Operator (TSO)-DSO interface. It evaluates the effectiveness of current energy market rules. For example, the case study on the impact of large-scale rooftop photovoltaic (PV) systems in Australia has been extensively discussed, emphasising the need for technical and regulatory reforms to ensure system security and stability.

The second work step focused on three distinct research categories: a) Microgrids, b) Total self-consumption vs T&D share, and c) Holistic solutions.

a) <u>Microgrid solution</u>
Microgrids have emerged as a pivotal component of future energy systems. Designed initially as isolated backup systems for critical loads, microgrids have evolved into smart, grid-interactive assets capable of enhancing energy management, improving grid reliability, and facilitating the DER integration.

This report categorises microgrids based on:

- Control strategy (centralised vs decentralised);
- Topology (AC, DC, hybrid);
- Application (residential, commercial, industrial, community);
- Operating mode (grid-connected vs islanded).

Microgrids offer operational flexibility and resilience, making them essential in urban and rural areas. The coordination with the “main system” may limit the large-scale implementation.

b) <u>Total Self-Consumption vs T&D Share</u>
This research stream explores the balance between local energy consumption and reliance on centralised grid infrastructure. As DERs, such as rooftop solar, battery storage, and electric vehicles, become more widespread, consumers can increasingly meet their own energy needs-leading to higher levels of self-consumption.

Key consideration discussed in the report:

- Total Self-Consumption: The proportion of locally generated energy consumed on-site without exporting to the grid. High self-consumption reduces grid dependency but may limit system-wide efficiency if not coordinated; and
- T&D Share: The portion of energy that flows through transmission and distribution networks. A higher T&D share supports grid-wide balancing and resource sharing but may incur greater infrastructure and operational costs.

c) <u>*LINK* holistic solution</u>

LINK considers the entire power system, spanning all voltage levels, asset types, technologies, and customer plants. It emphasises system-wide coordination rather than isolated interventions, aiming to optimise performance across generation, storage, consumption and grid infrastructure.

A dynamic market environment is created by aligning market structures with fractal grid design principles- where energy systems are modular, scalable, and self-similar across levels. In such a system:

- Energy transactions occur in real time;
- Resource applications are optimised locally and system-wide, minimising the exchanged data;
- Market signals reflect both operational and locational value.

The holistic model supports the transition to a flexible, decentralised and decarbonised energy system, enabling DSOs and other stakeholders to manage complexity while delivering value to consumers. The “Link” connection between modular parts has been extensively discussed.

1.2. Report structure

This report consists of 7 chapters. After this introduction, an overview of flexibility from the DSOs' perspective is given in Chapter 2. Chapter 3 is dedicated to the DSOs' operating experience in the presence of DERs. While Chapter 4 provides an overview of challenges and possible remedies. Chapters 5-7 outline three primary research outcomes: microgrids, total self-consumption versus T&D share, and the *LINK* holistic solution. The report is completed by appendices on local voltage control techniques, control strategies and detailed survey outcomes. A reference section relative to each research outcome category.

2. Flexibility definition used in this report

In this report, experts have decided to use the CIRED broad flexibility definition [1], as given below.

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 optimise their operational conditions (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, batteries of electric vehicles, etc.), industrial customers, production and storage systems, etc.
- 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 the grid reinforcement, frequency service (in real-time), schedule balancing support, voltage support, synthetic inertia, power loss reduction, optimisation of self-consumption, phase balancing, increasing the hosting capacity of DERs, etc.

3. DSOs' operating experience in the presence of DERs

This chapter analyses a global survey of utilities conducted in 2024. The survey aimed to assess the similarities, differences, strengths, and weaknesses of various practices in integrating DERs. Additionally, it aimed to recognise common challenges and share best practices across the industry.

The survey was developed by the Working Group and refined in collaboration with the CIRED committee. It was distributed through national committees to utility companies in participating countries. A total of 24 responses were received, representing utilities from 19 different countries. The sizes and operating voltage levels, as shown in Figure 3.1, of the DSOs vary significantly, reflecting the global distribution of DSOs participating in the survey. Not all utilities answered all questions; therefore, some data are missing, and in some cases, the corresponding topics are discussed more broadly.

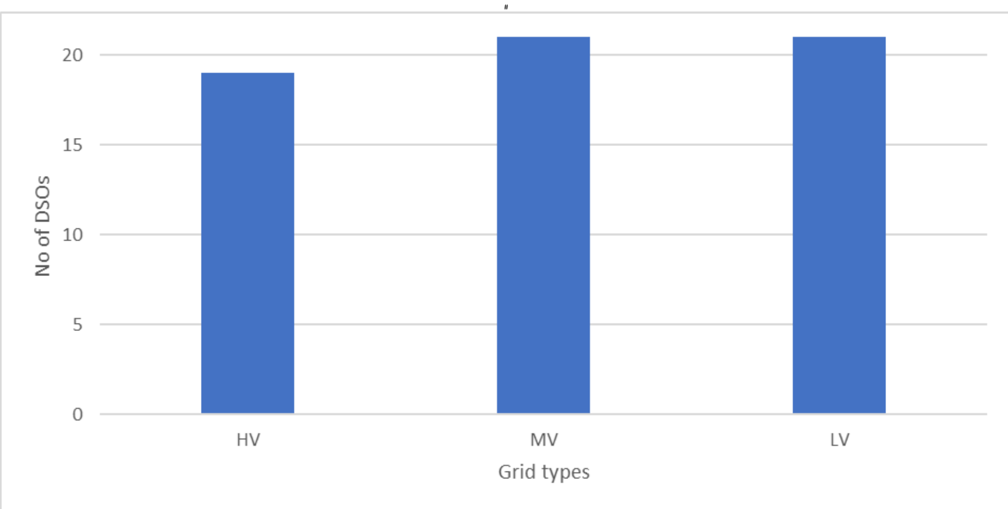


Fig. 3.1. Number of utilities operating at different voltage levels.

The statements in this chapter are based solely on the survey data, as the answers are considered representative of DSOs due to the wide range of countries covered. Despite the differences among DSOs within a country, they typically must adhere to the same national rules and regulations.

The interest in integrating DERs is universal and follows national rules, regulations, and policies. For detailed information about the survey results, please refer to Appendix C.

3.1. The actual spread of distributed energy resources

DERs are now a reality for all DSOs, as shown in Figure 3.2. The most common are low voltage connected rooftop PV panels, but DERs are present at all voltage levels. At high voltage levels, hydropower and wind are most common, while at medium voltage, ground-mounted PV plants and combined heat and power plants (cogeneration) are prevalent. The number of rooftop PVs and ground-mounted PV plants is often high, particularly at low voltage levels. Information on DERs behind the meter is usually known, but not for all DSOs. The results also indicate diversity in DERs across all distribution grids: all DSOs have different technologies connected to their grids.

The number of DERs is expected to increase significantly in the coming years, as shown in Figure 3.3 for the low-voltage grid. The most significant increase is expected at the medium voltage level, with an average increase of 75%, 140%, and 800% over the next 2, 5, and 10 years, respectively. The expected increase at low voltage and behind the meter is projected to be up to 100% over the next ten years. Some DSOs have indicated that they also expect an increase in storage installations, but from a relatively low level. Again, the most significant increase in storage installations is expected at the medium voltage level.

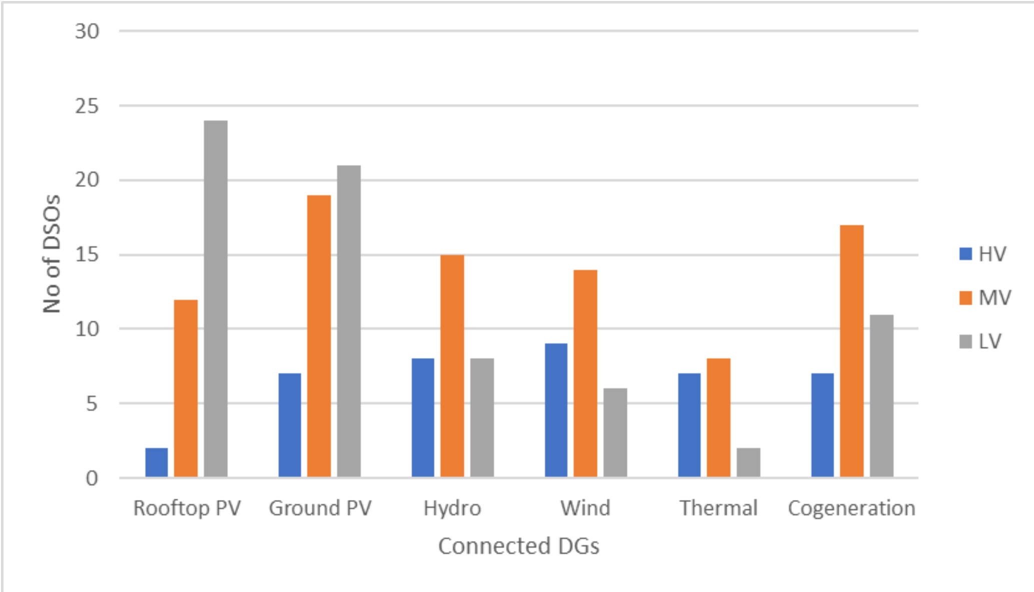


Fig. 3.2. Types of the distribution generation connected at different voltage levels.

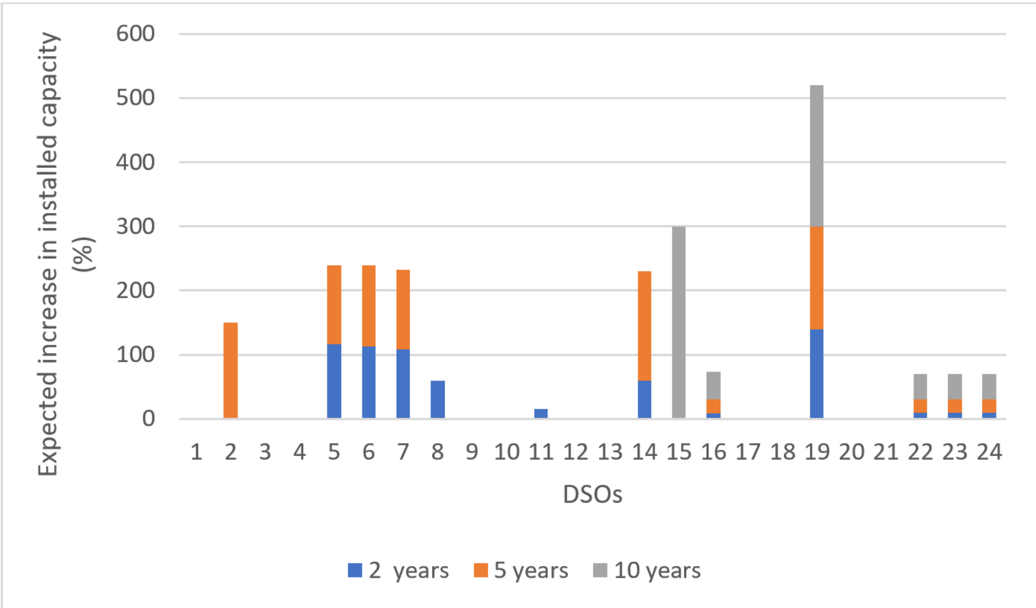


Fig. 3.3. Expected increase in DGs' installed capacity in the LV grid.

3.2. Challenges provoked by DER penetration

DER is expected to provoke challenges, such as reversed flow, voltage level violations, and harmonics. Almost all DSOs have experienced reversed active power flow at the connection point with customers. Still, some have experienced reverse power flow at the TSO/DSO connection points, as seen in Fig. 3.4. Voltage violations are also most common at low voltage levels. Their effect is propagated upwards, as shown in Fig. 3.5. **Voltage limit violations are particularly problematic if OLTCs have reached their end settings; several DSOs report that this has already occurred in their grids, as illustrated in Figure 3.6.**

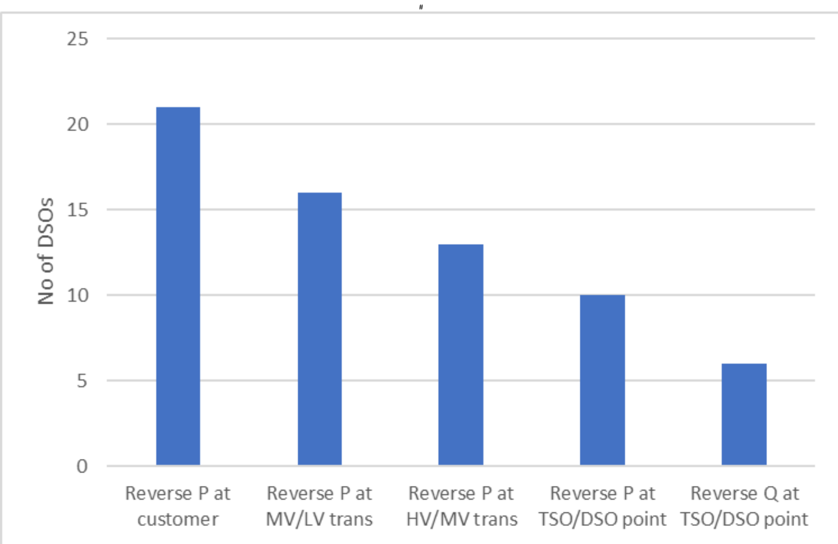


Fig. 3.4. The DSOs number that experienced reversed power flow in the different parts of the system.

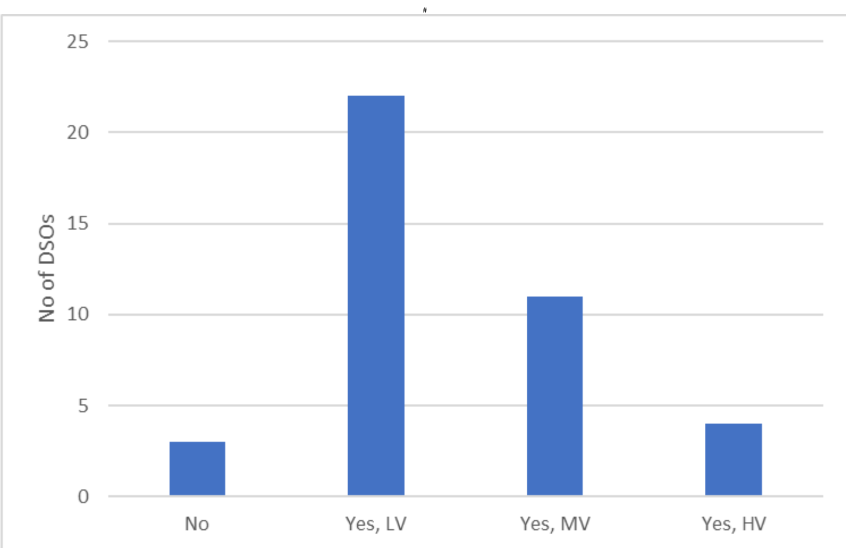


Fig. 3.5. The number of DSOs that have experienced voltage limit violations.

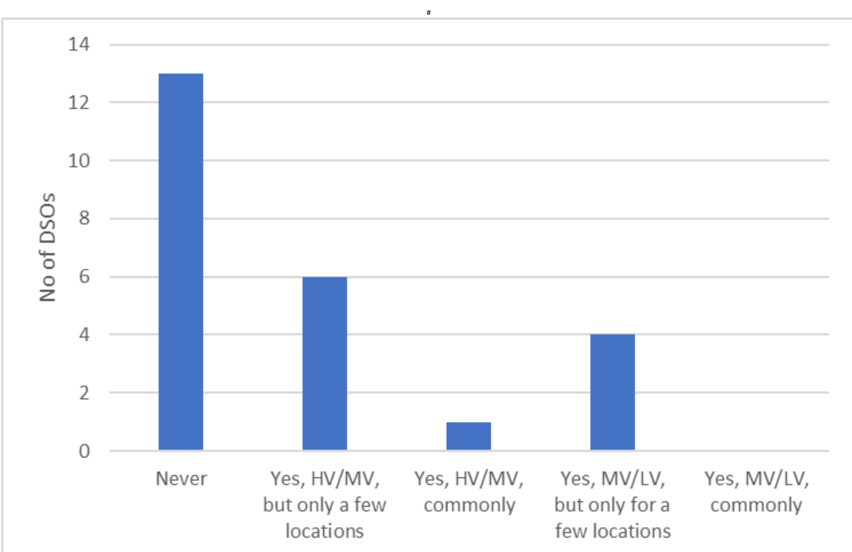


Fig. 3.6. The DSOs number that has experienced the OLTC have reached their end-setting.

Harmonics have been found to exceed admissible levels by several DSOs, especially in low voltage grids. However, not all DSOs monitor harmonics in their grid, as seen in Figure 3.7.

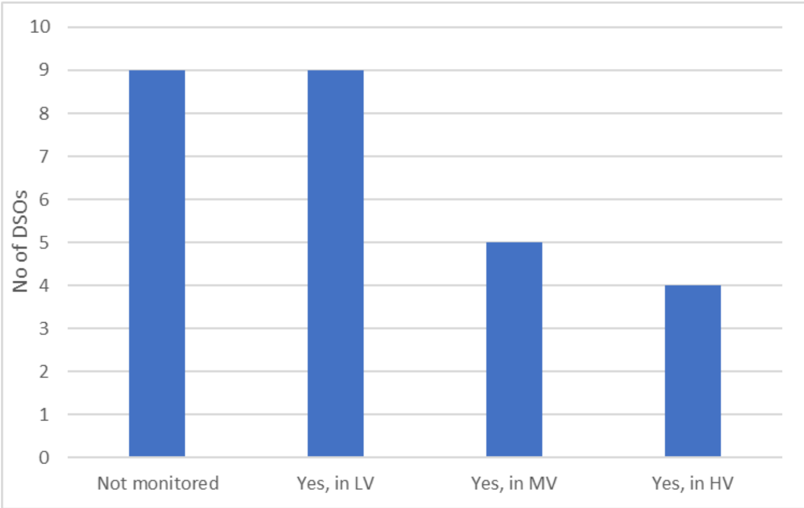


Fig. 3.7. The DSOs number that has identified harmonics at different voltage levels.

3.3. Countermeasures to maintain network voltages within statutory/legal limits

All DSOs use local controls almost in open loop to maintain the voltage within the specified limits. The most used local countermeasures are OLTC for high and medium voltage. Fixed cos(φ) and reactive power control are widely used medium-voltage countermeasures. In-line voltage regulators and active power control are most used for low voltage, but fixed cos(φ), reactive power control and in-line voltage regulators are also quite common at low voltage, as shown in Figure 3.8.

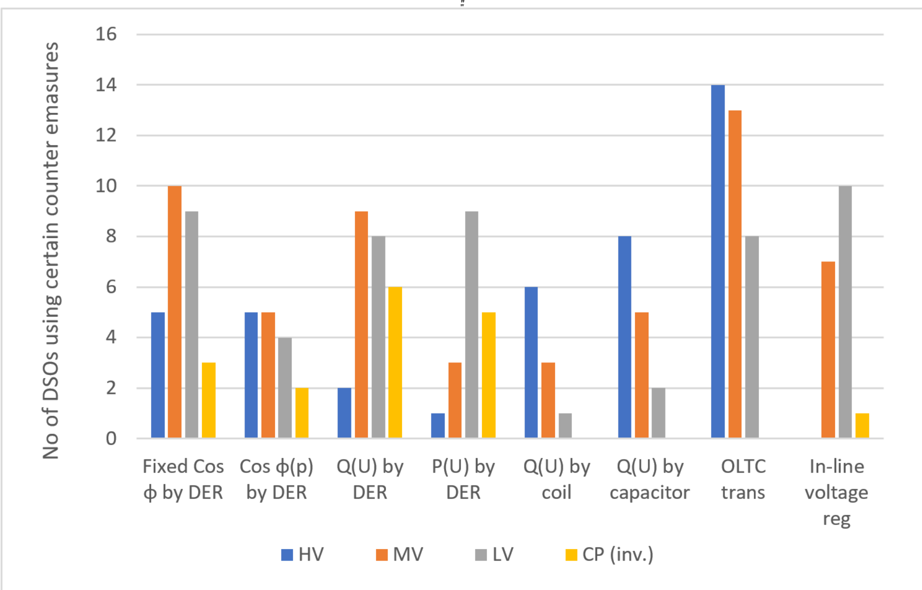


Fig. 3.8. Counter measures used to maintain the voltage levels.

A SCADA system is needed to provide central countermeasures. Most DSOs have high- and medium-voltage SCADA systems, but only a few have low-voltage ones. While most DSOs use local voltage and/or reactive power controls, SCADA state estimation is rarely used. Not a single DSO has reported the application of SCADA state estimation at low voltage.

Most DSOs are forced to limit or restrict new grid connections of DER (see Figure 3.9 for the share of DSOs imposing restrictions on grid connections at the medium voltage level).

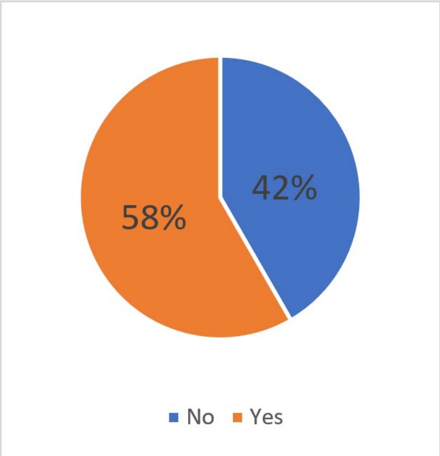


Fig. 3.9. Share of DSOs that restrict the distributed generation connections due to limitations in the medium voltage grid.

3.4. Countermeasures to minimise thermal and other constraints at the TSO-DSO interface.

Restrictions on new DER connections are the most common countermeasure to minimise load problems at the DSO/TSO interface, as shown in Figure 3.10. Some DSOs have curtailment agreements with the TSO, while others have different types of agreements. Around one-third of the DSOs indicated that they have not experienced any load problems at the TSO/DSO interface.

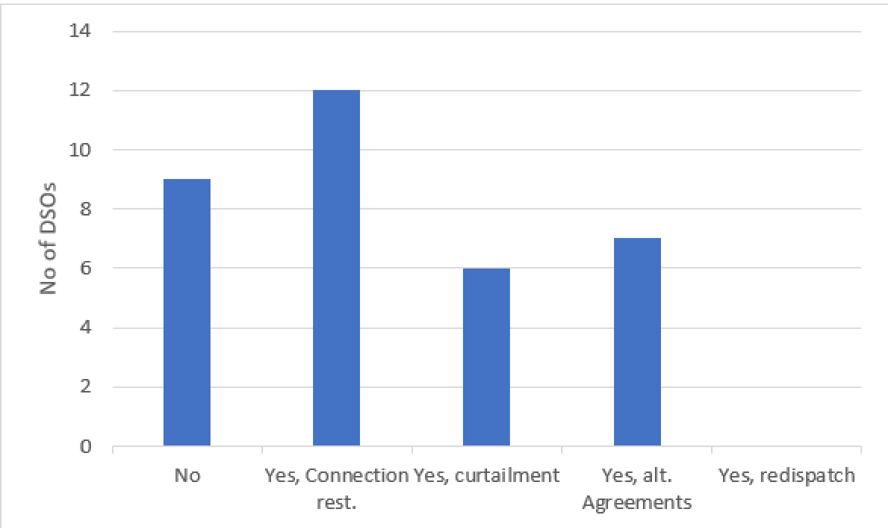


Fig. 3.10. The DSOs number that has experienced any load problems at the TSO/DSO connection point.

Even fewer have problems with voltage at the DSO/TSO interface. Countermeasures are typically reactive power control using capacitors and/or coils. However, measures, including not allowing any further connection or temporary production curtailment, are used by individual DSOs.

3.5. Effectiveness of market-based rules where these enable or constrain DG

In general, the DSOs experience that the TSO is promoting DER, but not all. For only a few DSOs, the DER installed has triggered contingency cases, and they had to resolve them by rescheduling.

Some DSOs can utilise market-based flexibility to support their operation, as shown in Figure 3.11. In most cases, the procured flexibility (achieved through incentives) is not a substitute for infrastructure reinforcement. However, the DSOs have found additional value in participating in these markets.

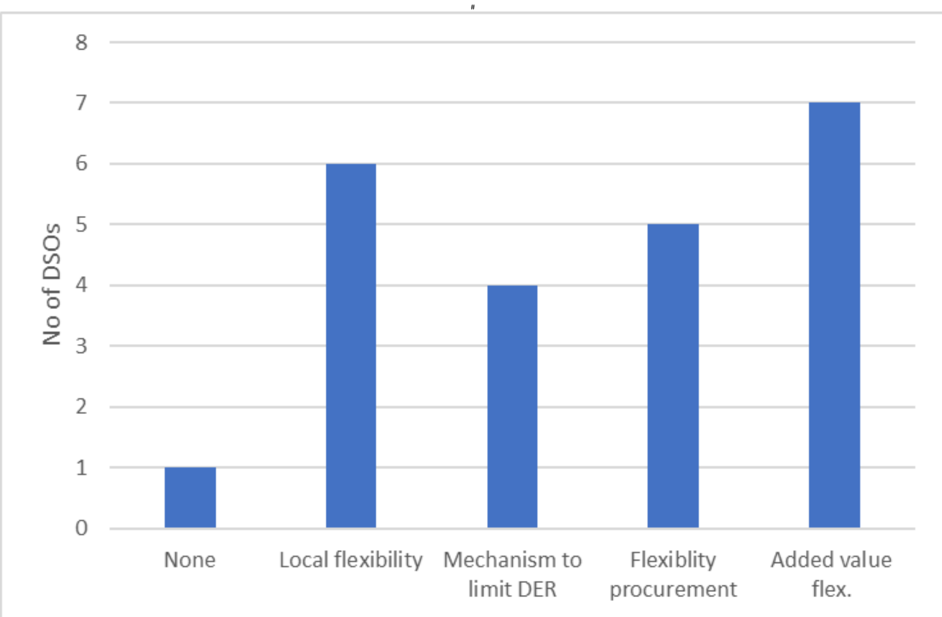


Fig. 3.11. The DSOs number per type of market/trading rule that promote DER flexibility.

In practice, the time horizon for asset planning typically ranges from one to ten years. Most DSOs consider several time horizons, normally one and ten years. However, this may vary across different areas within a DSO, depending on the risk of potential problems.

3.6. Grid codes and distribution codes of practice

All DSOs work out a code of practice. But only one performs calculations on network limitations for connections, and only two use rules of thumb. Calculations are typically used to determine voltage increases, thermal limits, and n-1 criteria.

All DSOs have limits on the maximum size of plants that can be connected to different voltage levels. In the low voltage level, these typically range from 10-250 kVA, but there are exceptions up to 692 kVA. The limitations for medium voltage usually range from tens to hundreds of MVA, with a significant spread. For high voltage, only a few DSOs have limits.

3.7. DSO approaches to weighing flexibility against grid reinforcement

Few DSOs have identified the flexibility added value. They, for example, extended control centres with smart meters, gave examples of how to make Net Present Value (NPV) calculations, and so on. However, some DSOs requested more information, indicating an interest. A DSO participates in various types of markets.

4. Challenges overview and possible remedies

4.1 Identified challenges

The large-scale deployment of DERs is leading to structural changes. Reverse power flows can occur in both steady-state conditions and during faults, preventing traditional radial distribution grids from functioning as designed. Their impact on the distribution grids depends on the technology used, the installed power size, the grid's connection location, and the power flow management. Violations of voltage limits, malfunction of protection, fault detection and service restoration applications, and so on, may be provoked. Furthermore, although the DERs connect at the distribution level, the transmission grid is also affected because the behaviour of the entire distribution grid changes drastically. The grid's stability may be affected because the transmission grid has intersection points (TSO-DSO intersections) with each distribution grid or sub-grid.

4.1.1 Bi-directional power flow

In traditional power systems, electricity flows unidirectionally from the transmission grid, where large power plants connect to customers through the distribution grid, which has a radial structure. The large-scale DER penetration changes the electricity flow in both directions. Figure 4.1 illustrates the different impact levels of the DERs on the grid. Electricity producers and storage are present at all voltage levels.

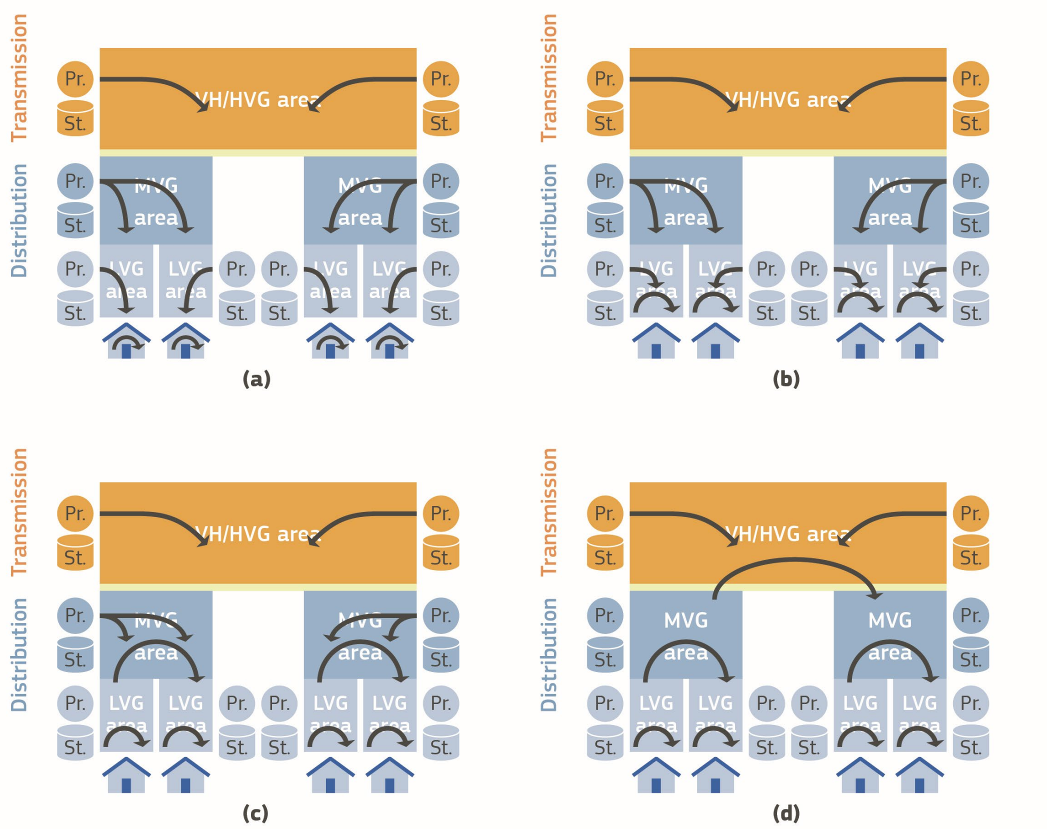


Fig. 4.1. Different levels of DERs impact on the grid (a) Full self-consumption in customer plant level.; (b) Penetrate into the superordinated LVG area; (c) Penetrate into the superordinated MVG area; (d) Penetrate into the superordinated HVG area.

Figure 4.1a) shows the full self-consumption case. The distributed generators, e.g. rooftop PVs, must cover only the load of the customer plant where they are installed. In this case, the grid is unaffected because the electricity flow does not reverse, thus not penetrating the superordinated LVG area. In the case of Collective Self-Consumption (CSC) schemes, the grid remains unaffected. Its loading is usually drastically reduced. Figure 4.1b) shows the case when only the load of the customer plant is PV supplied, and the electricity surplus circulates only in the network connected to the low voltage bus of the distributed generators. Electricity flows in Figures 4.1c) and 4.1d) correspond to the cases of DER integration on a large scale. The power flows are bi-directional throughout the entire distribution grid, sometimes reversing direction at TSO-DSO intersections and penetrating the transmission grid. DSOs are transforming into a power hub because the distribution grid serves as the direct electrical link between the transmission grid and customer plants, as well as between the transmission grid and Energy Communities (EnC). Changing the power flow direction from unidirectional to bidirectional provokes severe challenges in the operation of distribution systems. The latter is designed for radial operation with the possibility of a temporary loop configuration, especially at lower voltage levels (high and medium voltage distribution grids are increasingly more meshed and taking advantage of automatic operation, i.e. automatic reactive control at MV substations or on-load tap changer MV transformers). Significant technical challenges may arise due to extensive DER generation if the local generation and consumption are unfavourably distributed on the grid, such as maintaining voltage within limits, managing thermal congestion in both standard and fault conditions, adapting protection and fault indicators, and revising recovery schemes after blackout events. Therefore, continuous revisions of grid codes for connection, operation, and other aspects may become necessary to accommodate the implementation of large-scale DERs.

4.1.2 Identified challenges in the distribution level

4.1.2.1. Violation of upper voltage limit

The violation of the upper voltage limit is a common challenge that DSOs are experiencing in the presence of a large, distributed generation share, especially in rural areas with long radial feeders. Figure 4.2 shows the dynamics of the voltage profiles of several feeders with a large DG share over the day. Simulations are performed for a real LV voltage level grid with four feeders; the longest feeder is approximately 2 km. All customers have installed rooftop PVs. At night (03:00), when the load is low, the voltage profiles of all four feeders are in the middle of the permissible voltage interval with a slight downward slope. At nine o'clock (09:00), when the PV production increases and a reverse power flow occur, the voltage profile's slope changes from downward to upward. At noon (12:00), the upper voltage limit is violated by the voltages of the longest feeder. As the solar zenith is passed, PV generation decreases, and the voltage profile moves to the lower half of the permissible voltage interval. To overcome this challenge and to increase the hosting capacity of grids on DGs, DSOs are taking various measures.

R&D studies have shown that DER installation and integration require various countermeasures at different integration stages to ensure a reliable and sustainable grid operation [2][3][4]. The DER installation process may be divided into three phases, as shown in Figure 4.3. In the **first phase**, the green area, where DER installations in the LV subsystem reach the critical value, do not require countermeasures. There are cases in practice where the PV or DER installation is permitted as long as its power production is equal to or less than the load of customer plants at each point in time. In this case, the voltage profiles of all feeders are almost bundled and have nearly a straight course [5]. No voltage limit violation occurs. The existing infrastructures are underutilised. In the **second phase**, the yellow area, where the PVs or DERs installed power exceeds a critical value, voltage violations occur, and countermeasures are necessary to ensure reliable and sustainable operation.

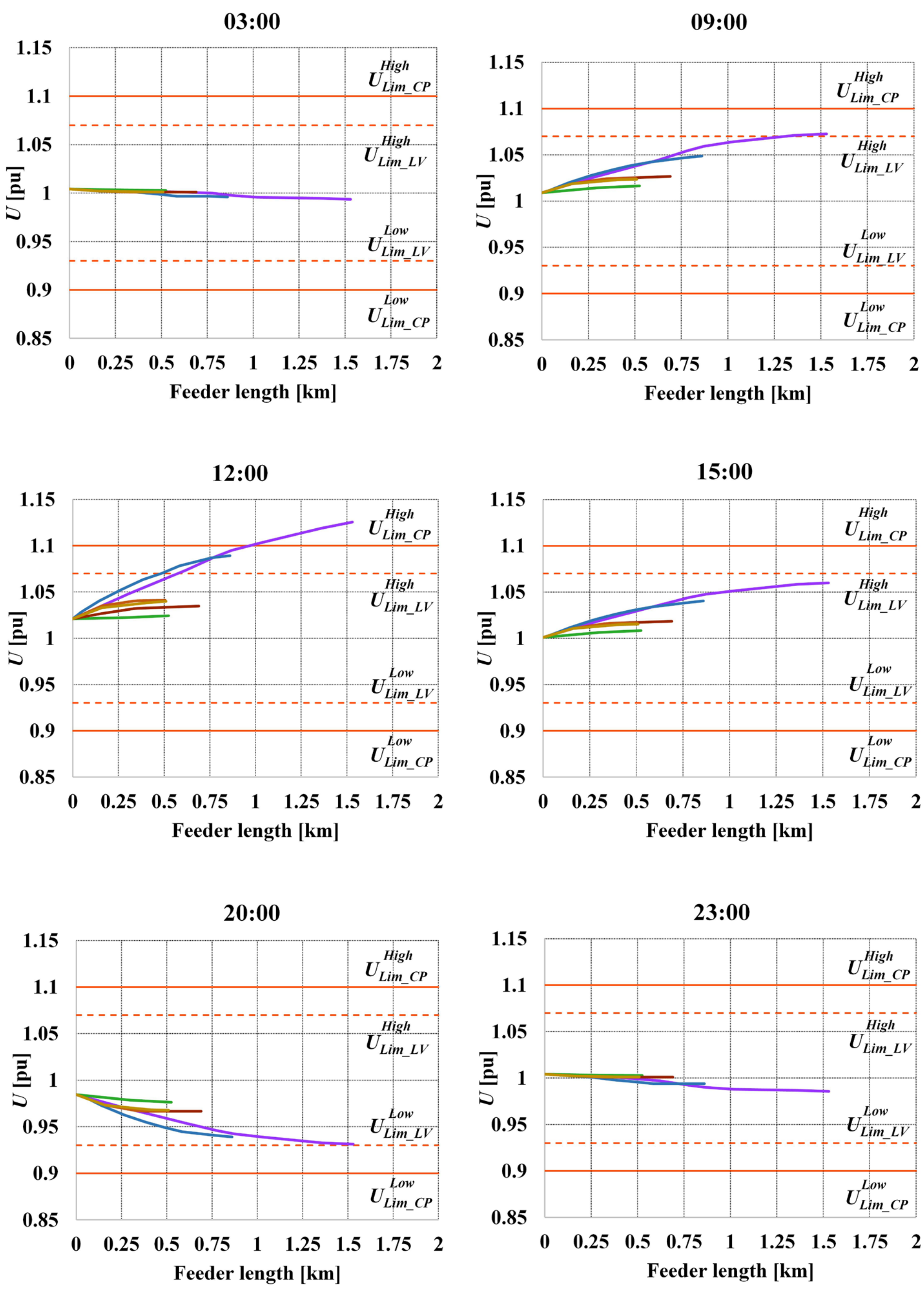


Fig. 4.2. Shape changes over the day of the voltage profiles in LV feeders with large DG share supplied from the same busbar.

Survey results (see § 3.3) indicate that reactive power control is growing in importance for distribution networks, medium- and LV voltage levels, notwithstanding the high R/X value in low voltage, as the loads are also becoming more capacitive.

There are two strategies for reactive power control: distributed and concentrated. The distributed control strategy in radial structures postulates upgrading the customer PV-inverters with different local Volt/var control strategies ($Q(U)$ [6] or $cos\phi(P)$ [7]) or their combination [8]. The reactive power provoked by these controls causes an uncontrolled and excessive reactive power flow in the superordinated grids. The concentrated control strategy [9] in radial structures postulates installing $L(U)$ local controls at the end of the violated feeders. Their combination with the self-supplying customers regarding reactive power (Q-autarkic) unloads the grid from the reactive power flow of the load. It reduces the amount of data to be exchanged because DSOs use a couple of inductive devices for voltage control in radial structures. The secure grid operation may be guaranteed by setting up the Volt/var chain control on the superordinated grids (see § 7.3.2). In the **third phase**, the red area, the installed power of the PV systems or distributed generation exceeds the saturation value. The latter means the infrastructure (transformers and cables or lines) is overloaded from this value: more power is generated than the grid may handle. In addition to the countermeasures to eliminate voltage violations, further actions are required to ensure secure infrastructure utilisation at this stage. The steps may be diverse and realised by different stakeholders. The DSO may reinforce the infrastructure (e.g. change distribution transformers, etc.), or Sector Coupling may be applied using the surplus of electricity to produce hydrogen or biomethane, thus helping the economy's decarbonisation [10].

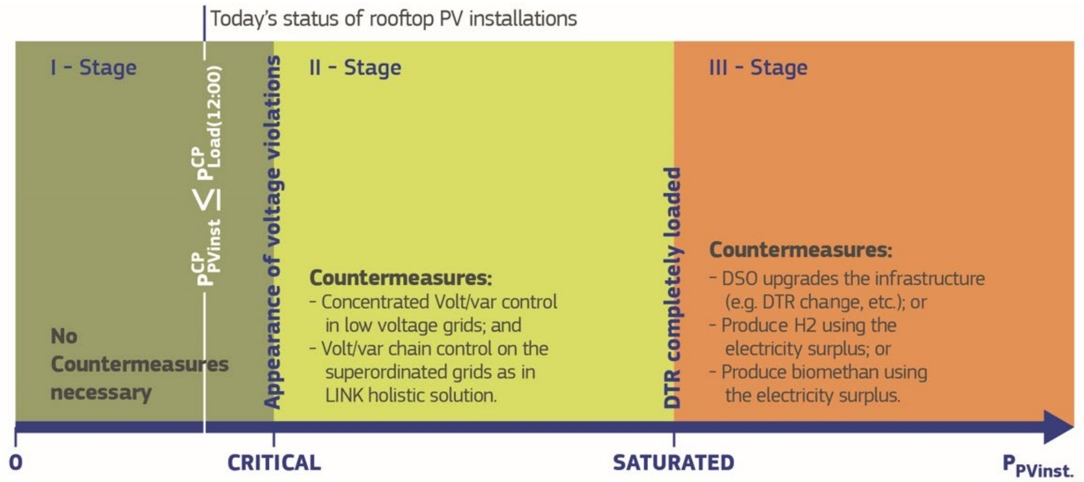


Fig. 4.3. Critical parameters for the uptake capacity of distributed generation facilities in a radial configuration and the countermeasures for their maximum expansion.

4.1.2.2. Thermal congestions in the standard and fault conditions

Thermal constraints refer to the physical limits of any equipment on the power grid regarding how much power it can sustain in the long term (normal conditions) or short term (fault conditions). These limits result from the fact that when current flows through cables and wires, heat is generated due to the resistance of the metals that make up the conductors. Overheating grid assets causes them to fail and accelerates the ageing of insulating/dielectric materials. In overhead feeders, heat causes conductors to expand and possibly sag, violating safety clearances and increasing the risk of equipment and property damage, as well as line shutdowns. PVs, especially, pose a danger to the thermal loading of grid assets since they produce power simultaneously; the simultaneity factor is one, whereas residential areas have a demand factor lower than one. The increased installed power of distributed generation above the saturated value provokes congestion on the distribution grids. The DSO should implement countermeasures to prevent exceeding operation limits in both standard and fault conditions. Although quite unusual, operators may be forced to curtail electricity generation if the grid parameters are at risk. System operators need to have sufficient data to estimate thermal congestion on the grid more accurately and approve DER connections on time.

4.1.2.3. Phase Unbalances

Installing one-phase PVs may provoke a voltage imbalance that exceeds the acceptable limits at some nodes in the low-voltage distribution networks [11].

4.1.2.4. Harmonic distortions

Although the harmonic content of the output from PV inverters is low, high penetration may result in unacceptable harmonic currents [12]. The single-phase PV inverters also generate high unbalanced harmonics between the phases, resulting in unequal total harmonic distortion values for each phase voltage [13]. Although the transformer may not be overloaded, the increased PV share on the grid may lead to thermal breakdown of the insulation or accelerated ageing of grid assets due to the increased harmonic currents.

4.1.2.5. Protection system philosophy

A protection system aims to detect certain system anomalies to ensure the reliable and safe operation. Protective devices, such as circuit breakers and fuses, and fault indicators characterise the protection system of radial-operated distribution grids, which are traditionally set up based on unidirectional power flow. The widespread deployment of distributed generation results in bidirectional power flows (see § 4.1.1, Bi-directional power flow): the actual protection philosophy in distribution grids becomes inefficient. Fault detection and selectivity problems may arise, leading to serious miscoordination, damage to grid assets, saturation of current transformers, and failure to detect or prevent unintended islanding. Distribution grid fault diagnoses, such as Fault Location, based on fault indicators, may wrongly react because they traditionally indicate that a fault has occurred somewhere downstream from its location, indicating erroneously in the presence of distributed generation: The protective devices, the algorithms of Fault Location, Isolation, and Service Restoration, etc. must be adapted for correct operation in the new conditions.

4.1.2.6. Revising the recovery planes after blackout events

The large-scale integration of DERs, for example, rooftops in residential areas, changes the structure and behaviour of distribution grids, making the actual recovery plans ineffective. System operators continually adapt and update those plans to fit the new conditions.

4.1.2.7. Temporary self-sufficient operation of grid parts

Another non-negligible concern for DSOs is the undesirable effect of unintended islanding, in which distributed generators, primarily connected to medium- and low-voltage distribution networks, can end up feeding distribution customers if a portion of the network to which they are connected becomes disconnected from the primary source, for whatever reason. This unintended islanding presents a challenge for DSOs in securing and maintaining a robust network.

4.1.2.8. Planning

DSOs typically require toolboxes that comprise various solutions for addressing grid constraints, such as congestion management and voltage instability, to ensure efficient network planning. For this reason, DSOs need a framework to use flexibility, optimise network investment decisions, and handle the challenge of facilitating the integration of renewables on the electricity networks more efficiently [14]. This framework is relevant as market design is critical to ensure that EnCs have incentives to develop in a way that reduces system costs and supports grid operation. There is a risk that, given inefficient incentives, community coordination will lead to increased network use or inefficient market outcomes.

4.1.3 Identified challenges in the transmission level

The extensive integration of DERs drastically changes the behaviour of the distribution subsystems connected to the transmission grid, thus strongly impacting and challenging the latter's behaviour.

4.1.3.1. Load-generation balancing process

One of the most essential TSO tasks is balancing power injections with consumption to keep the frequency within the limits set by the grid codes. Shortly after the Russian war in Ukraine and the associated increase in energy prices, there has been a massive expansion of DER plants, driven by people's willingness to become energy-autonomous and by legislation. In these conditions and despite the introduction of balancing groups at the distribution level, the load patterns in the connection points TSO/DSO change continuously, impacting the load-generation balancing process.

4.1.3.2. Voltage–reactive power management

In many countries, legislation requires DSOs to provide grid access to owners of DERs within a specific period. However, the increasing number of DERs is causing the upper voltage limits in the distribution networks to be violated. According to the Grid Codes, DSOs can apply $Q(U)$ regulation to increase the feeders' intake capacity, creating an uncontrolled reactive power flow in the superordinated grids, which refers to the transmission grids. TSO faces significant challenges in managing voltage-reactive power. However, the Grid Code on TSO connection conditions imposes strict requirements, usually $\cos(\phi)$, which puts DSOs in a bind, getting into a vicious circle.

4.1.3.3. Load-shedding schemes need adaptations

Although this is not a favourable approach for maintaining the power grid's stability, TSOs prepare emergency strategies for load shedding under low-frequency conditions to maintain the grid's security during massive outages. It performs automatic or manual load rejection or disconnection of predefined grid parts. The load-shedding schedules are individually configured and depend on the historical loading patterns of the surrounding grid parts. The extensive DER integration alters these loading patterns, making them dynamic and dependent on weather conditions. The current static load-shedding strategies are inaccurate and need to be adapted to meet new requirements.

4.1.3.4. N-1 security calculations

N-1 security calculations are used to ensure the security of supply, even if a facility of the operating system is out of service for any reason. The DERs increase the challenge of maintaining N-1 security. The power flows through the interconnection points between TSOs, and the instantaneous composition of the load that the distribution subsystems represent is uncertain because the TSOs do not have an overview of the DSOs. Depending on the weather conditions in the regions where these subsystems extend, they may behave as a load or an injection to the transmission grid.

4.1.3.5. Impact on power system dynamics

To this day, conventional power plants are essential for power system stability. Their large synchronous generators provide voltage source characteristics and inertia and contain voltage and frequency control to ensure a feasible and reliable power system operation. The immanent active and reactive power dependence of many loads on voltage and frequency acts as system feedback in addition to the control mechanisms and is known as the self-regulating effect. The accurate estimation of the latter plays a crucial role in determining the fast reserve power needs. It includes implementing the DR process, which entails a significant increase in distributed generation and controllable loads. The existing models for considering the self-regulating effect in the system dynamics become questionable. The dynamic equivalent models encompass the entire distribution grid, which is typically connected to the transmission grid at a single point. Traditionally, the model equivalents in the literature consider almost the classical load. The load behaviour seen from the transmission grid changes radically compared to the classical one because of the increase in RES connected to the distribution grid, such as PVs, energy storage devices, electric vehicles, controllable loads, etc. The used dynamic equivalents are becoming questionable.

4.1.3.6. Restoration strategies from a blackout

In traditional power systems, where electricity flows from the transmission to the distribution grids and then to customers, operators rely on offline recovery plans developed for selected contingency scenarios. Since the details of a blackout are hard to predict, restoration plans serve as a guide for system restoration. These plans need to be adapted when DERs are in place and even more so when EnCs propel their further integration. The restoration strategies and procedures should be elaborated in the new conditions.

4.1.3.7. Grid protection

The dual function of grid protection ensures the reliability of the power system and protects the equipment from damage. The protection remains inactive as long as no fault occurs. However, when a fault occurs, the protection relays should respond correctly: only the faulty devices should be disconnected, allowing the rest of the system to operate reliably. Although the protection schemas in the transmission grids are designed for bidirectional flows, changes, e.g. in the level of short-circuit currents, can affect their correct response. The increased DERs presence can drastically affect the superordinated grids' short-circuit currents and nullify the relays' accurate reaction.

4.1.3.8. Change in the current market patterns

Prosumers and EnCs can alter some market patterns due to P2P trading, thereby reducing energy flows on public grids up to transmission grids.

4.2. System-wide impact of large-scale rooftop PV implementation: Australian case

Australia currently has the world's largest installed capacity of rooftop PV per capita. About 3 million households – or one in three – currently have a solar system on their roof across the National Electricity Market (NEM), which services Australia's eastern seaboard through an interconnected power system. These solar panels have a cumulative capacity of 21 GW (as of July 2024), nearly equal to the 21.3 GW of coal-fired generation installed capacity. With the ongoing retirement of coal-fired power stations, collectively, rooftop solar will soon represent the largest generation source in NEM.

Australian experts report, "*The rapid **rise of rooftop solar** in Australia's NEM has been a renewable juggernaut, lowering energy costs for homeowners and reshaping wholesale markets, but distributed PV has not been without consequences at the system level.*" Moreover, further, "*As rooftop solar installations have continued apace, the daytime demand for power from the grid has dropped lower and lower, heading towards a point where the demand on the system **will lead to system security breaches and power instability***" [15].

Figure 4.4 shows the generation mix and electricity price development in South Australia as of 28 February 2025. Interestingly, at about 15:00, although there were negative electricity prices, two gas steam units, presented in orange in the figure, were online to provide system security services (including voltage/reactive power management) rather than to supply electricity.

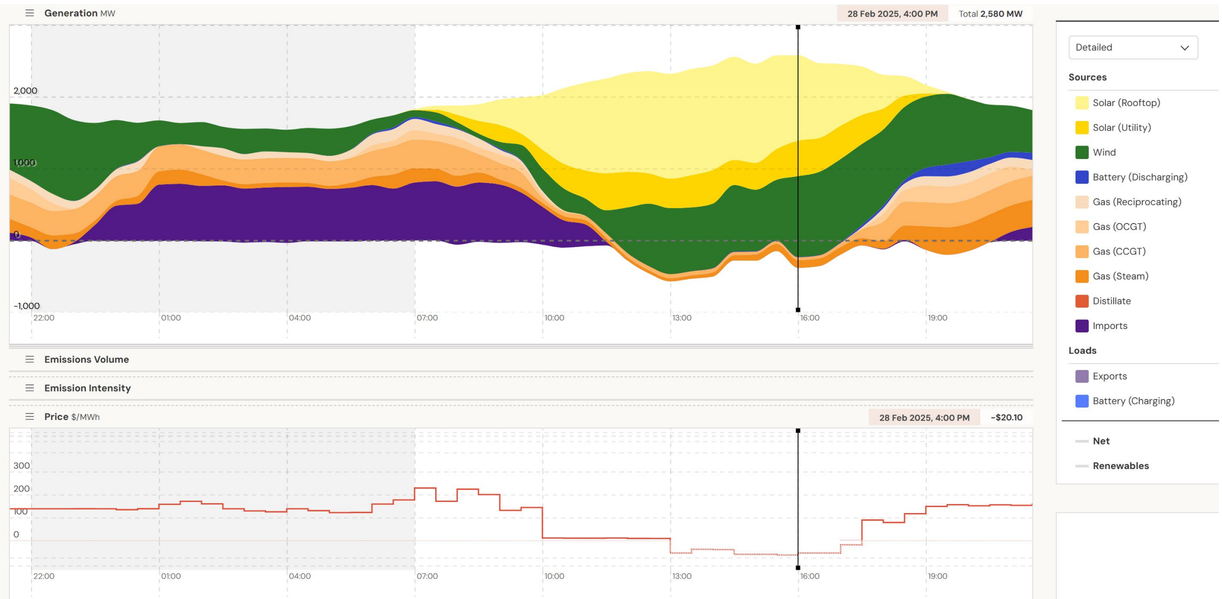


Fig. 4.4. Overview of the generation mix and electricity price development in South Australia, 28 February 2025. (**Source:** AEMO and OpenNEM (https://openelectricity.org.au/analysis/welcome-open-electricity)

DNSP/DSO in Australia installed Volt-var, $Q(U)$, and Volt-Watt, $P(U)$ (see A.2.3 and A.2.4) to increase the PV hosting capacity in the radial distribution structure. However, apart from addressing the violation of the upper voltage limit and overloads caused by high reverse power flow, the system security issue faced by the TSO requires the DNSPs/DSOs to implement an active power export curtailment capability triggered remotely on all new/updated rooftop PV systems. The TSO will call upon the ability when the system's minimum demand drops below a pre-determined threshold.

Recently, AEMO has reduced the minimum number of synchronous generating units required to be online in South Australia from two to one. Synchronous condensers instead provide the system security services (reactive power) previously supplied by the synchronous generating units. The orange area in Figure 4.5 [16] becomes very slender at approximately 15:00.

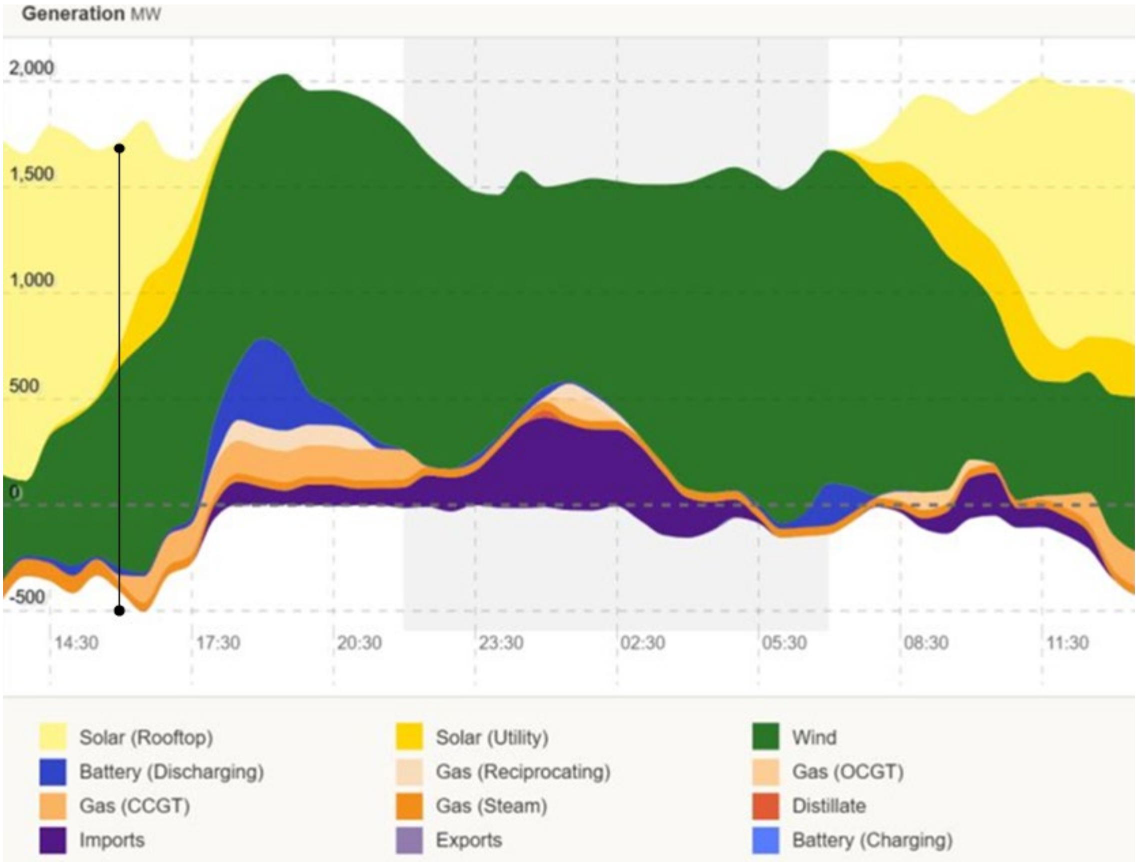


Fig. 4.5. Generation composition in south Australia, 2-3 September 2025.

The experiences in South Australia outline that:

- It is hard to encourage a meaningful 'market response' based on zero or even negative electricity prices;
- Security service becomes a significant challenge when there is a high penetration of renewables, forcing out synchronous generators;
- Proper management of reactive power in the distribution grids and adequate coordination with the voltage and reactive controls in the transmission grid can help overcome security challenges;
- The further expansion of renewable and distributed energy sources and shunning curtailments on electricity generation requires a comprehensive solution that couples all three energy systems—electricity, gas, and heating and cooling—to form a System of Systems (SoS).

4.3. Reasons for power system challenges

The most crucial reasons for the challenges that system operators are facing nowadays are:

- The rise of distributed resources and their everyday share-increase drastically changes the structure of the power system, impacting its overall behaviour in normal and faulty conditions;
- Broad use of renewable energy resources throughout the entire power system and customer level, which:
  - Decreases the system inertia because of their connection through inverter,
  - Increases the simultaneity in the electricity production,
  - Decreases the production and consumption diversity over several time intervals;
- The creeping change of the load nature from inductive to capacitive;
- The cable structure of the European grid.

4.4. Possible remedies

Locally implemented solutions to mitigate violations of the upper voltage limit and overloads caused by high reverse power flows are effective to a certain extent in promoting the penetration of distributed and renewable energy sources. The further penetration of the latter provokes significant problems in the power system operation, which can lead to power outages [17]. RED Electrica "*system operator makes fifteen recommendations, especially implementing* ***a dynamic voltage control service that covers all generation activities***" [18]. All generation activities mean the generation connected to transmission and distribution grids.

For more than 25 years, it has been recognised that appropriate system and market countermeasures are necessary to integrate decentralised energy sources into the DER. Therefore, over time, various concepts were brought onstage to tackle the ever-increasing challenges in the electricity industry, such as Virtual Power Plants in 2001 [19][20], Microgrids in 2001 [21][22], Cellular Approach [23], Web of Cells [24], Digital Grids [25], Self-consumption, and *LINK* paradigm [26].

This report discusses the research outputs related to microgrids, the balance between self-consumption and T&D share, and the holistic solution, *LINK*.

5. Research outcomes: Microgrids

5.1. Definition

Earlier, microgrids were envisioned as energy systems capable of operating independently within a defined geographic area, generating, consuming, and distributing energy. The early definitions were almost exclusively concerned with their grid independence, emphasising island mode operations. Over time, the understanding of certain key microgrid concepts has evolved, as illustrated in Figure 5.1. With the development of intelligent control devices, the integration of renewables, and increasing concern about grid security, present-day microgrids are increasingly described in terms of their adaptability and intelligence. Originally designed primarily as emergency standby systems, microgrids have evolved by integrating DERs and intelligent functionalities to become active tools for energy management. Today, microgrids are seen as active units that can operate within the larger grid or autonomously, facilitating more decentralised energy distribution and reducing dependence on centralised systems.

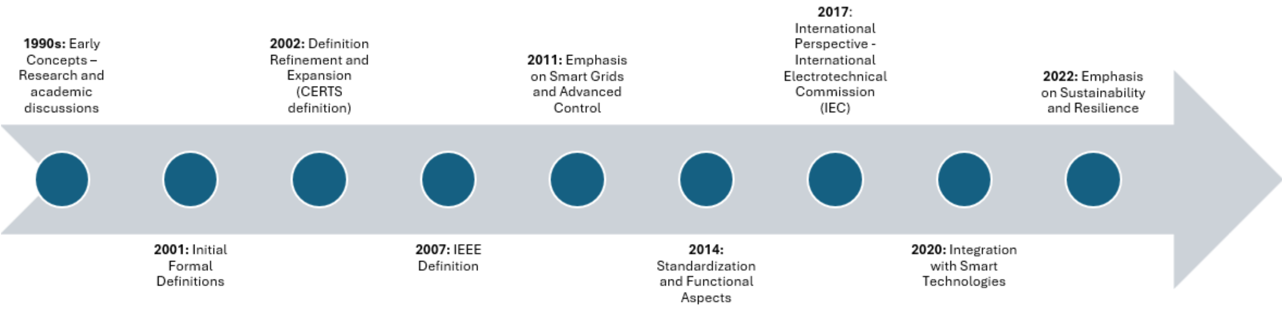


Fig. 5.1. Evolution of the Microgrids Concept: Enabling the Transition to Clean, Reliable, and Flexible Grids.

The importance of this transition demonstrates how the purpose of Microgrids is expanding once again, with new challenges of energy modernisation, in other words, how they embrace next-generation principles.

- **1990s: Early concepts** - The term "microgrid" starts to surface in research and academic discussions, initially associated with distributed generation and small-scale localised grids.
- **2001: Initial formal definitions - Robert H. Lasseter** introduces a formal definition: "A microgrid is a cluster of loads and micro-sources operating as a single controllable system that provides both power and heat to its local area."
- **2002: Definition refinement and expansion** - **Consortium for Electric Reliability Technology Solutions (CERTS)** defines a microgrid as "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that act as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode."
- **2007: IEEE definition** - The **IEEE** (Institute of Electrical and Electronics Engineers) characterises a microgrid as "a group of interconnected loads and distributed energy resources with clearly defined electrical boundaries that act as a single controllable entity with respect to the grid."
- **2011: Emphasis on smart grids and advanced control** - With the rise of smart grids, the definition evolved to include advanced control capabilities: "A microgrid is a small-scale power grid that can operate independently or collaboratively with other small power grids. It employs renewable energy sources and advanced control systems to improve the resilience and efficiency of the power supply."

- **2014: Standardisation and functional aspects** - The **U.S. Department of Energy (DOE)** provides a comprehensive definition: "A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity concerning the grid. A microgrid can connect and disconnect from the grid, enabling it to operate in both grid-connected and island modes."
- **2017: International perspective** - The **International Electrotechnical Commission (IEC)** defines a microgrid as "a group of distributed energy resources and loads that operate as a single controllable system. A microgrid can connect and disconnect from the grid to operate in both grid-connected and island mode."
- **2020: Integration with smart technologies** - The definition incorporates smart technology aspects: "A microgrid is a local energy system integrating various distributed energy resources such as renewable energy, combined heat and power (CHP) systems, energy storage, and flexible loads, managed through smart control systems to enhance energy reliability and sustainability."
- **2022: Emphasis on sustainability and resilience** - This definition highlights sustainability: "A microgrid is a localised grid that can disconnect from the traditional grid to operate autonomously, incorporating renewable energy sources, energy storage, and advanced control systems to enhance resilience, reliability, and sustainability of energy supply."

MGs can operate in three distinct modes. In the first mode, the MG is connected to the main grid, allowing for improved stability and cost efficiency. In the second mode, the MG operates independently of the main grid, functioning as a self-sustained grid to supply local loads during emergencies or in islanded conditions. The third mode involves a complete shutdown of the MG, serving as a protective measure to prevent damage to system components. These operational modes are illustrated in Figure 5.2.

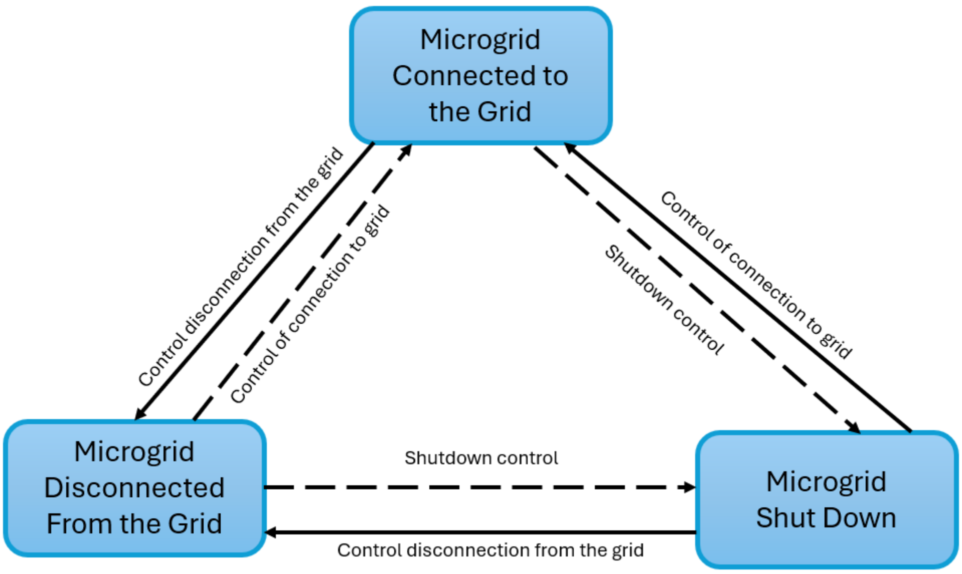


Fig. 5.2. Operating models of an MG: grid-connected, islanded, and shutdown.

According to [27], microgrids can be categorised by their applications, infrastructure, end-user needs, control strategies, size, power supply, energy source, location, and specific application contexts [28]Error! Bookmark not defined.. Figure 5.3 shows a structured classification system for microgrids.

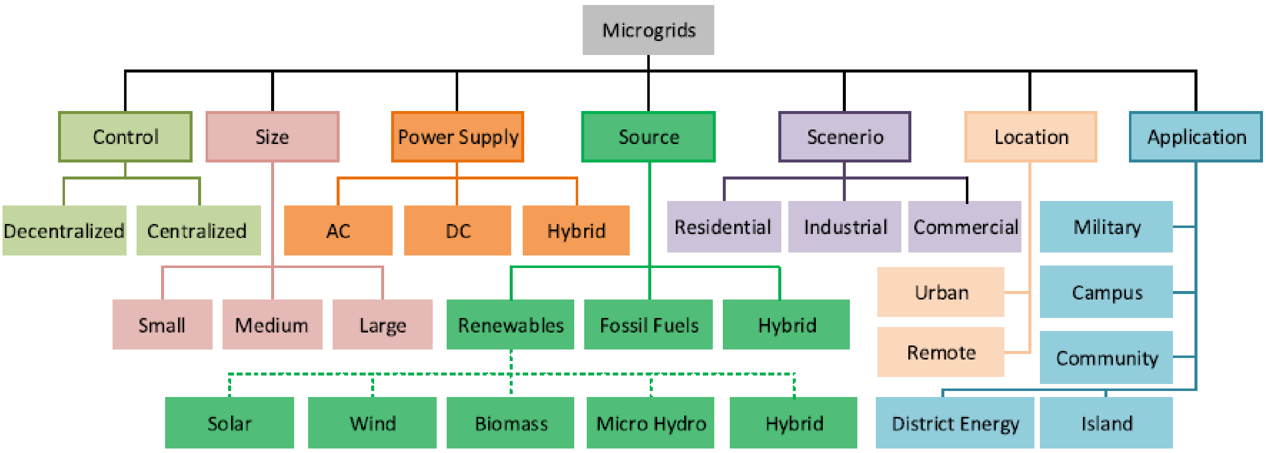


Fig. 5.3. Microgrid Classification Framework: From Control Strategies to Application Scenarios.

Classification by control strategy

Based on control strategies, MG systems can generally be classified into two main types [28]:

- **Centralised control:** A central controller (CC) directs local controllers (LC) via two-way communication in centralised microgrids. While this approach simplifies control, it limits reliability and scalability.
- **Decentralised control:** Decentralised microgrids employ a multi-agent system where each component operates independently, enhancing flexibility. Communication languages, such as Java and Jade, often support coordination.

Classification by size

MGs can be divided into three categories [29]. Based on their size: small-scale, medium-scale, and large-scale MGs.

- **Small-Scale Microgrids**: Typically designed for individual homes or small commercial applications.
- **Medium-Scale Microgrids**: These cater to small communities, industrial campuses, or larger commercial operations.
- **Large-Scale Microgrids**: Serve as substantial infrastructure, such as industrial complexes or district energy systems.

Classification by Power Supply Type

MGs can be classified into three categories based on the type of connected power supply: AC, DC, and hybrid MGs [30], [31].

- **AC Microgrids**: Operate on AC power, either connected to the main grid or independently, and are easily integrated into existing AC power systems. Types include single-phase, grounded three-phase, and ungrounded three-phase systems. In an AC-coupled microgrid, depicted in Figure 5.4, distributed generators, energy storage systems, and the utility grid are interconnected via the main AC bus. Energy storage systems and DC loads are integrated using bidirectional interfacing converters. This topology is widely adopted globally due to its simplicity and the prevalence of AC generation systems. However, the interfacing converters contribute to inefficiencies within this configuration.
- **DC Microgrids**: These use DC power, benefiting applications such as telecom, electric vehicles, and maritime systems. They have fewer synchronisation and power quality issues and higher efficiency than AC microgrids, though they require converters to interface with AC grids. In a DC-coupled microgrid, illustrated in Figure 5.4, distributed generators, energy

storage systems, and loads are interconnected via a primary DC bus. An interfacing converter enables the connection of AC-distributed generators to the main grid.

- **Hybrid Microgrids**: Combine AC and DC systems to reduce conversion stages and improve efficiency. They require sophisticated controls, especially in islanded operation, to manage AC-DC interfaces effectively. In this topology, shown in Figure 5.4, AC and DC buses are connected to distributed generators, energy storage systems, and loads. Interlinking converters act as the interface between the AC and DC subgrids. By minimising the need for multiple interfaces, this configuration reduces costs and enhances overall efficiency.

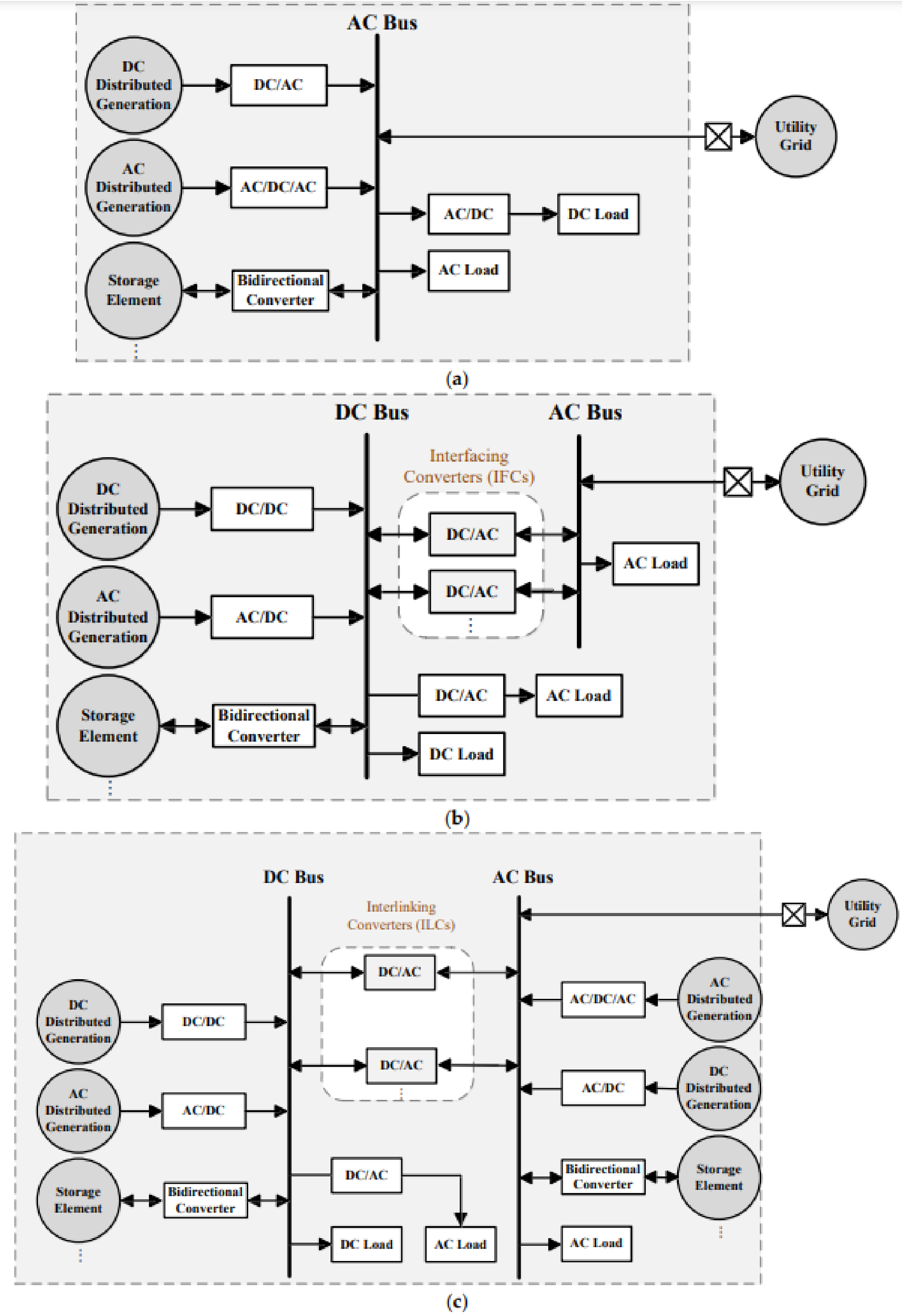


Fig. 5.4. Configuration of hybrid microgrids: a) AC-coupled; b) DC-coupled; and c) AC-DC coupled microgrids [32].

Classification by Energy Source

An MG powered by distributed renewable energy sources is called a renewable MG. These systems typically consist of RESs and energy storage systems, such as batteries. Renewable MGs supply electricity to end-users with a reduced carbon footprint, making them increasingly popular and widely adopted globally. However, the uncertain and intermittent nature of most RES adds complexity to the effective operation of these MGs [32]. Additionally, managing time-varying demand poses a significant challenge for isolated MGs. Energy storage systems are a key technology for maximising the utilisation of renewables and are widely used to balance supply and demand in microgrids [33]. The main challenge lies in coordinating storage systems, distributed RESs, and variable power demands.

Renewable Microgrids: Use renewable energy sources (RESs) such as solar or wind, often paired with Energy Storage Systems (ESS) to balance supply and demand despite the variability of RES output. Therefore, the MG can be grouped based on sources as follows:

- **Fossil Fuel-Based Microgrids**: Rely on diesel or natural gas generators, commonly used in remote or islanded areas, but are less environmentally friendly and face fuel transport challenges.
- **Hybrid Renewable-Fossil Microgrids**: Combine RESs, fossil fuels, and/or batteries to enhance reliability and reduce emissions. These systems can operate both on and off the grid.

Classification by Location

Microgrids can be categorised based on their location and operational context [28]:

- **Urban Microgrids**: Found in urban settings, they can operate in both grid-connected and islanded modes, providing stability and quality power for hospitals, universities, industries, and malls.
- **Remote Microgrids**: Located in isolated regions, such as islands or military installations, and typically operate independently, often using a mix of diesel and renewable sources.

Classification by Scenario

Microgrids are versatile energy systems tailored to meet the unique needs of different sectors, offering enhanced reliability, resilience, and efficiency. They can be broadly categorised into [28] residential, industrial, and commercial microgrids, each designed to address specific energy requirements and operational challenges:

- **Residential Microgrids**: Designed for homes, these provide emergency backup and coordinate customer demand, distributed resources (e.g., solar, batteries), and grid interaction.
- **Industrial Microgrids**: Ensure power reliability to prevent production interruptions in sectors such as chip manufacturing or chemical production, often incorporating renewable energy sources and energy efficiency measures.
- **Commercial Microgrids**: Serve single-use facilities (e.g., airports, data centres) that may function independently of or in tandem with the main grid, reducing costs through load management and backup power.

Classification by Application

Microgrids are designed for various applications, including military bases, campuses, communities, islands, and urban districts [28]. Each type addresses unique needs, from secure autonomous power to sustainable energy integration and efficient heating and cooling solutions.

- **Military Microgrids**: Provide secure, autonomous power to military installations.

- **Campus Microgrids**: Common on corporate and university campuses, frequently including combined heat and power (CHP) systems.
- **Community Microgrids**: Serve local communities with high renewable integration to meet sustainability goals.
- **Island Microgrids**: Fully disconnected from the main grid, generating all required power independently.
- **District Energy Microgrids**: Provide electricity, heating, and cooling for facilities, thereby increasing energy efficiency in urban settings.

The Energy Hub (EH) concept extends beyond electricity to encompass a wide range of energy carriers, including electricity, heat, gas, and others—enabling a holistic approach to meeting diverse energy demands across sectors such as heating, cooling, transportation, and industry [34][35]. By integrating and optimising multiple energy vectors (e.g., thermal, mechanical, chemical), EHs promote efficient, flexible, and sustainable energy use within a unified system. Recent developments reflect a shift from independent generation units to multi-carrier energy systems. EHs contribute to this transition by supporting the integration of renewable energy, energy storage, and coordinated energy management—addressing challenges related to fuel scarcity, environmental concerns, and system efficiency. While EHs and microgrids (MGs) both enhance local energy resilience and system flexibility, the secure and efficient transmission of energy remains a key challenge.

As illustrated in Figure 5.5, the Energy Hub can operate under three distinct supply modes for meeting electrical load demand:

1. **Direct Supply from the Upstream Network**: The entire energy demand is met directly from the upstream grid, with no local generation or energy conversion within the hub;
2. **Hybrid Supply from the Network and CHP**: The load is partially supplied by the upstream grid and partially by a combined heat and power (CHP) unit, which produces both electricity and heat using natural gas;
3. **Full Supply via CHP Using Natural Gas**: The entire energy demand is fulfilled locally using natural gas, with a CHP unit converting it into both electricity and thermal energy to meet the load.

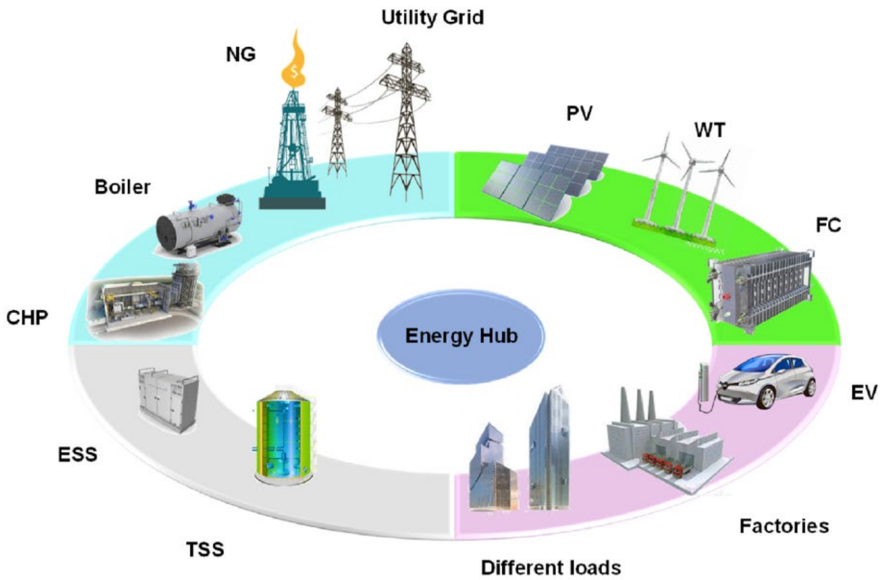


Fig. 5.5. Simplified schematic of an Energy Hub configuration [36].

Microgrids are increasingly modeled as *energy hubs* that manage electricity, gas, and heat supply through integrated DER, CHP units, storage, and converters [37]. A hierarchical EMS approach for multicarrier microgrids integrates electrical, thermal, and gas subsystems, balancing economic and reliability objectives- under real-world constraints. Reviews of energy hub methodologies emphasise converter/storage modeling, energy flows, and network interactions. Geidl et al. originally introduced the hub concept as a greenfield design tool; subsequent frameworks support planning and operation of multi-vector systems through matrix models and multi-objective optimisation techniques [38]. Research on hybrid multi-energy systems demonstrates that surplus electricity can be converted to thermal energy (via heat storage or CHP), improving economic performance. Multi-energy extensions support distributed optimisation in buildings and residential hubs [35]. Comprehensive literature surveys summarise EMS methods involving EV integration, AI techniques, multi-objective optimisation, forecasting, and real-time control—underscoring the convergence between microgrids and energy hubs [39].

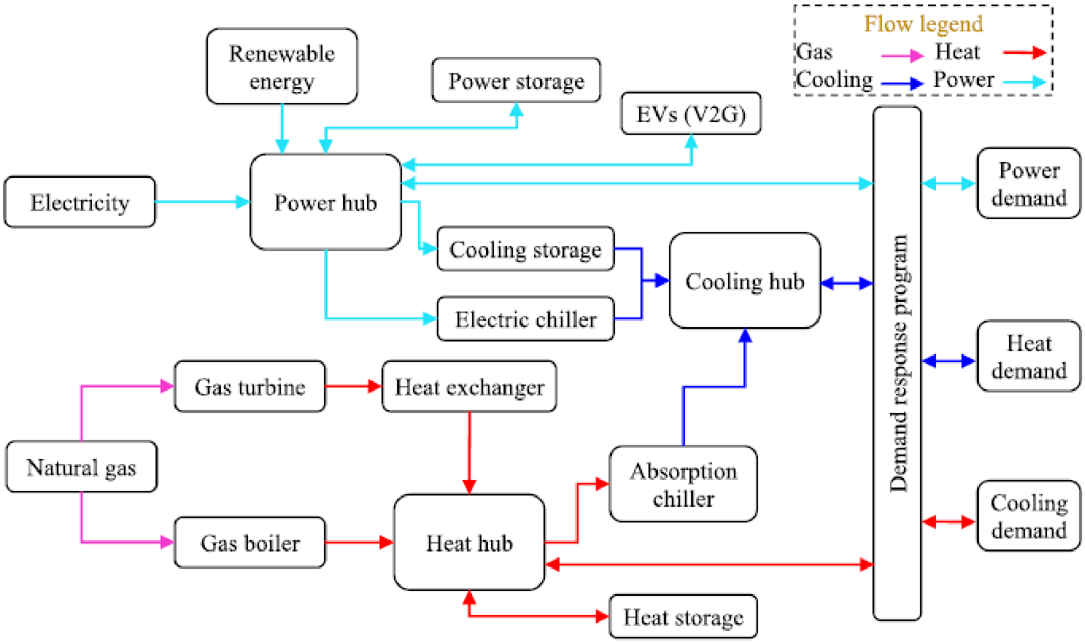


Fig. 5.6. Schematic representation of the Energy Hub model applied to a microgrid [40].

Figure 5.6 is a schematic representation of the Energy Hub model applied to a microgrid. Integrating multiple energy carriers such as gas and electricity, the system combines converters (e.g., gas turbines, boilers, chillers), storage units, and outputs for electricity, heating, and cooling. It efficiently transforms input resources into usable energy to meet diverse demands [41]. Centralised dispatch coordinates operations by gathering data from smart meters, historical consumption, weather conditions, and market prices to optimise performance. Renewable generation forecasts are also factored into refining energy dispatch decisions. Electricity, cooling, and heating are then delivered to users through power lines and thermal pipelines.

5.2. Architecture

An MG is a controllable unit with respect to a larger grid. The typical scheme of an MG is depicted in Figure 5.7, illustrating its integration with the electricity power system through a Point of Common Coupling (PCC). This connection allows the MG to exchange energy or operate in island mode during maintenance or unintentional disconnection scenarios. The MG integrates various components, including loads, DERs, and ESS, which enable both power storage and delivery. The generation units within an MG are selected based on the available primary energy sources, with common types including PV, wind, hydro, diesel, and hybrid systems.

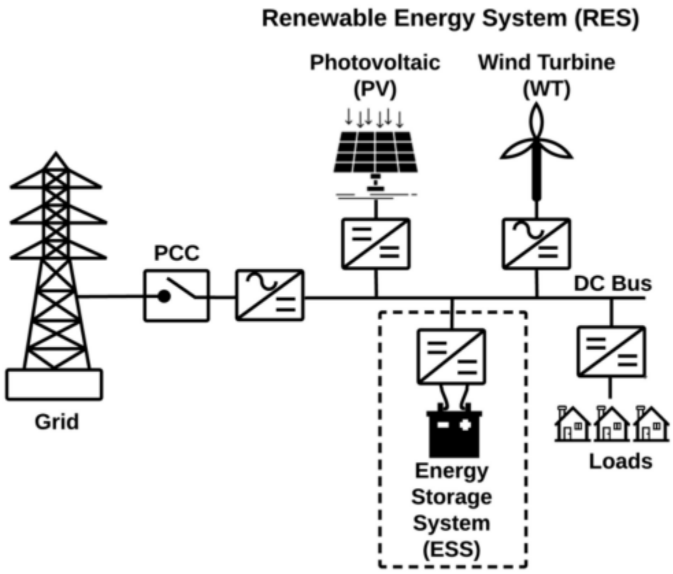


Fig. 5.7. General scheme of an MG [42].

Within its boundaries, a microgrid may integrate generation, responsive loads, and storage systems, and should be considered a single controllable entity by the main grid. The key difference lies in its islanded capability. Microgrids are often located at the LV level, although some may operate at medium voltage (MV).

The microgrid concept is a modern version of traditional local power systems. Like centralised electric grids, microgrids generate, distribute, and regulate the electricity supply to customers on a much smaller and localised scale. Microgrids provide "grid-interactive solutions" to address utility grid flexibility and resiliency challenges related to meeting the continuous demand for electric power supply. Figure 5.8 illustrates an example of substation- and feeder-based microgrid architectures.

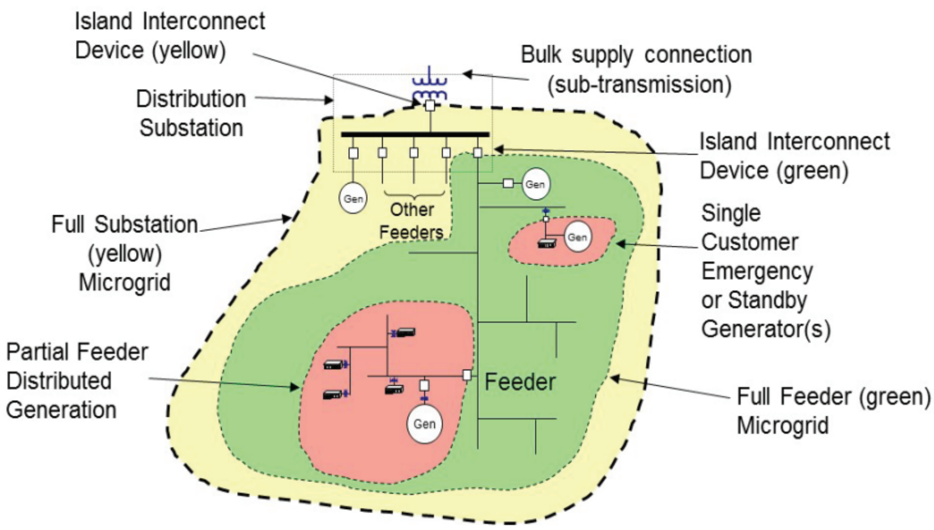


Fig. 5.8. Example of Microgrid Architectures in Radial Distribution Systems [43].

Importantly, microgrids are not meant to replace utility distribution infrastructure but instead form a self-contained organisation of DG and load management capable of self-balancing within an isolatable portion of utility or non-utility infrastructure. While most microgrids operate in grid-tied mode, with power flowing both ways between the microgrid and the surrounding system, the option to disconnect from the grid provides backup power during emergencies. It also facilitates greater integration of DERs since local resources such as solar PV, storage, and demand response can be coordinated to support the local load even when the microgrid is disconnected from the main grid due to disturbances, thereby reducing reliance on centralised infrastructure.

Microgrids may contain dispatchable and non-dispatchable renewable generation, controllable loads, energy storage, electric vehicle-to-grid (V2G) discharging, and advanced grid modernisation technologies, such as advanced metering infrastructure (AMI) and distribution automation. However, thermal generation, using local waste fuels, diesel, or natural gas, remains the primary power source in many cases, often configured for combined heat and power (CHP). In some applications, legally required backup systems, such as diesel generators in hospitals, may operate in parallel with the grid. Some of the basic building blocks of microgrids already exist in many existing networks.

Microgrids can be classified into distinct operational configurations, each designed to address specific technical and resilience requirements. These configurations—single-master, multi-master, networked, and droop-based—highlight different approaches to managing DERs, coordinating grid support, and ensuring stability during both connected and islanded operations. The following overview outlines the key features and benefits of each configuration:

- **Single-Master Microgrids:** In this configuration, all DERs act as grid-following resources during grid-connected operations. The microgrid controller allocates grid service requests from operators among the DERs, considering their status, constraints, and local objectives (e.g., maximising renewable energy use, minimising battery wear). During planned islanding, the controller selects DERs with grid-forming capabilities to manage net demand. However, high or low load changes can push voltage and frequency beyond nominal limits, particularly if the island master is not adequately sized. Secondary controls help restore these parameters to nominal levels.
- **Multi-Master Microgrids:** This configuration features multiple DERs with grid-forming controls, allowing several to act as island masters during islanded operations. Like single-master microgrids, they provide grid support in connected mode and economically dispatch DERs. During islanding preparation, the controller can designate multiple DERs as island masters, enhancing resilience against transients from load or generation changes.
- **Networked Microgrids:** Networked microgrids consist of multiple single-master or multi-master systems coordinated by a central controller. This controller facilitates power exchanges between microgrids, addressing needs like voltage support and reducing system losses. It also manages black start capabilities after outages and balances load and generation for critical system sections.
- **Droop-Based Microgrids:** Droop-based microgrids operate with decentralised intelligence, allowing peer-to-peer power sharing without reliance on an external controller. Each DER autonomously responds to system changes, enabling plug-and-play integration of new units without re-engineering. This design increases the microgrid's resilience, allowing continued operation during crises such as floods or storms.

An Energy Management and Control System (EMCS) is a crucial component of a microgrid, primarily due to the distributed nature of its energy resources. The primary objective of an EMCS is to optimise the use of these diverse resources to meet specific goals within system constraints, employing centralised, decentralised, or distributed computational methods [44]. Additionally, the EMCS must effectively implement the results of these computations within the microgrid system. This is accomplished using a real-time control system that sets operational points generated by the EMCS. Typically, an EMCS operates through a process that includes forecasting data, utilising these forecasts for energy management optimisation, and generating operational setpoints to be applied in the real-time control phase.

The objectives of microgrid control encompass: (a) the independent control of active and reactive power, (b) rectification of voltage sag and system imbalances, and (c) meeting the load dynamics requirements of the grid. Effective power system operation hinges on the implementation of appropriate control strategies. Microgrid control comprises: (a) controllers for individual micro sources and loads, (b) a central controller for the entire microgrid system, and (c) a distribution management system. The role of microgrid control encompasses three main areas: (a) interfacing with the upstream network, (b) managing the microgrid's operation, and (c) providing protection and local control. The classification of EMCS structures is based on the organisation of computing platforms and communication networks, which can follow centralised, decentralised, or distributed models, Figure 5.9.

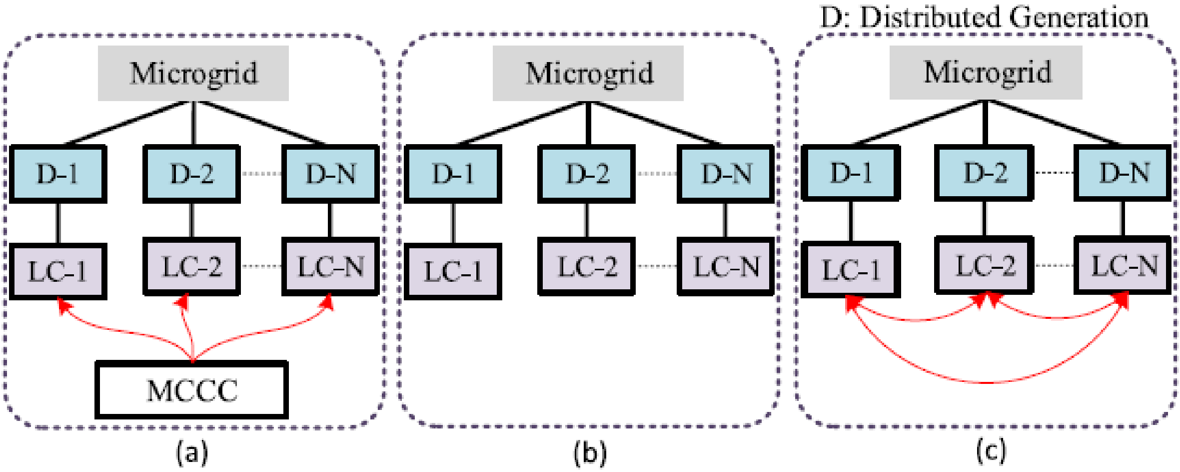


Fig. 5.9. Microgrid control structures categorised into three types: a) Centralised; b) Decentralised; and c) Distributed [27].

In centralised systems, Figure 5.9a, the management system is located at a central station and connected to DERs via communication lines. Measurement and status data from DERs are sent to the central controller, where monitoring and control computations are performed, and commands are then sent back to the DERs for execution. Additionally, the central controller can connect to other ancillary workstations, such as distribution network operators or forecast stations, depending on the system architecture. This centralised setup facilitates overall system supervision and global optimisation, but may face challenges with system expansion and potential system-wide failures due to central controller or communication faults.

In decentralised systems, Figure 5.9b, each DER operates independently using a local controller, eliminating the need for communication with a central station. Local measurements such as bus voltage, frequency, and DER power output are taken by the controller, which then implements proportional power sharing and maintains microgrid stability. However, after extended operation and exposure to disturbances, DER operational setpoints may drift from stable values, necessitating resynchronisation across DERs.

Distributed systems, Figure 5.9c, combine the advantages of centralised and decentralised structures, mitigating their respective drawbacks. Each DER has computation capability in its local controller while communicating with adjacent DERs and possibly a central EMCS server. This approach typically requires minimal communication bandwidth and provides improved system redundancy, as neighbouring controllers can take over computations in case of failures. Multiple communication paths can also be established to support this. However, this method incurs additional costs due to redundant communication links and distributed computation. Table 5.1

provides a comparative overview of different control architectures for microgrids, highlighting their key features, control strategies, and suitability for various operational contexts.

Table 5.1.EMCS architectures for microgrids

Structure	Description	Advantages	Disadvantages
Centralized	All processing and decisions are taken at a central controller, where each DER sends operational data. Suitable for smaller microgrids	• More effective at global optimisation • Focused on the point of maintenance • Easier monitoring and control of the whole system • Easily monitoring the applicable hierarchy in operations • Well-established communication and operation protocols	• Cannot function without a communication network • Communication lines can become expensive • Slower response • Heavy computational burden • Problems with the expansion of the system • Single point of failure
Decentralized	Each DER has a local controller. All control functions are carried out independently, without the need for communication. Bus frequency or voltage is often used for power sharing or voltage support. Suitable for larger microgrids	• More reliable because a communication network is not required • Faster control response • System modularity, flexibility, and plug-and-play capability improved • Cheapest option • Better suited against cyber-attacks	• Problems with the drift of system setpoints can occur. It will then require a secondary system (which is usually centralised and therefore requires communication) • Offers limited capabilities. There is no option for global optimisation • Little to no overall MG supervision • Prone to instability and requires fast synchronisation
Distributed	A highly connected system, where each DER has its own computing capability. All local controllers also interact with each other and possibly a central controller to manage different tasks. Suitable for larger microgrids.	• Improved redundancy and robustness, as another controller can take over for the DER in case of failure of the local controller • Improved reliability of EMCS • Fast control response • Better for scaling up the system • Better for scaling up the system • Better suited against cyber-attacks • Computational burden shared between the various DERs	• Most expensive option due to the requirement of a more comprehensive communication network • Difficult to monitor and manage due to multiple entities participating

Hierarchical control of microgrids has been explored in numerous studies. The control structure of a microgrid is typically organised into three levels, each with distinct objectives [33]. Various methods for operating these levels have been proposed, and the controllers for each level must be carefully designed and calculated. Figure 5.10 depicts the hierarchical control structure of the microgrid.

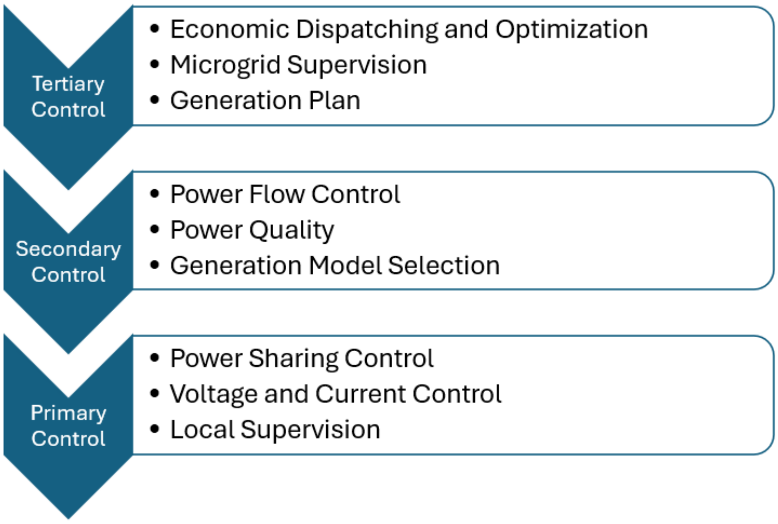


Fig. 5.10. Hierarchical control Strategy.

The primary control is responsible for ensuring the reliability of the microgrid system while enhancing the performance and stability of each converter's local voltage control system. This control level regulates the reference voltage needed for the internal voltage and current loops, ensuring the optimal distribution of active and reactive power among DG sources. The most widely used method at the primary control level is droop control, Figure 5.11, which addresses power imbalances by compensating for mismatches between generated power and demand. Droop control generates a reference voltage signal for the source, and the internal control loops (voltage and current) then work to align the actual voltage with the reference value. In grid-connected mode, the primary controller manages the active and reactive power output of each DG unit. In islanded mode, it takes on the additional responsibility of regulating both voltage and frequency to maintain stable and reliable microgrid operation.

The secondary control addresses the limitations of primary control by handling frequency deviations and voltage ranges, especially when primary control cannot return the system to desired values, Figure 12. This level of control includes synchronisation mechanisms to connect the microgrid with the main grid. Secondary control can be classified into three main categories: distributed, centralised, and decentralised.

A centralised control method involves a central microgrid controller that allows communication between DG units and the distribution management system. While this approach benefits from simplified communication and reduced network traffic, it is vulnerable to failure of the central controller. In grid-connected mode, the frequency and voltage of DGs are compared with reference values from the main grid, ensuring synchronisation and system stability. In contrast, the decentralised and distributed control methods are more resilient. In a decentralised system, control is distributed across the microgrid, with each unit autonomously managing its power and voltage. This is advantageous in scenarios where communication might be weak or unreliable. A consensus-based secondary control method can also be employed to manage frequency in islanded microgrids, improving system stability even under challenging conditions. Additionally, innovative methods like time-varying control gains and wireless power sharing for DGs offer further improvements in system performance.

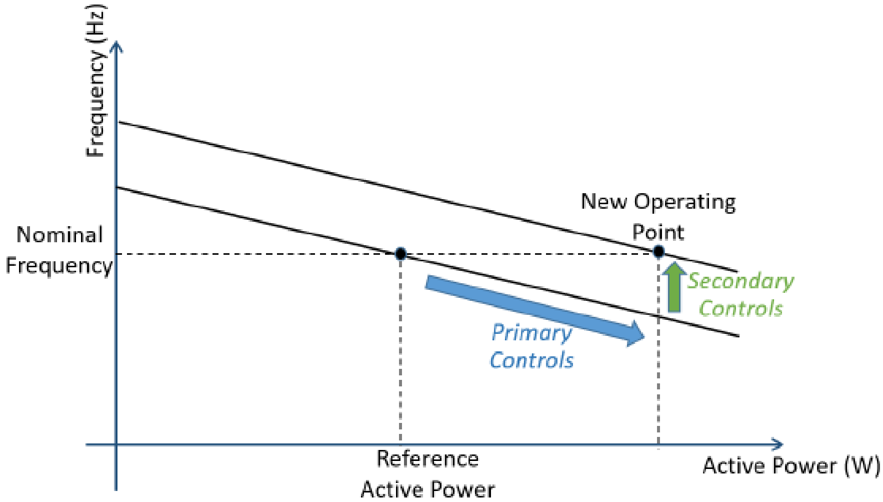


Fig. 5.11. Illustration of primary and secondary frequency control in microgrids.

Tertiary control in microgrids is responsible for optimising power flow management in the grid-connected mode. This control layer adjusts the voltage and frequency, as determined by the secondary controller, and monitors the active and reactive power at the PCC. By comparing the grid's power values with desired reference points, tertiary control ensures the efficient operation of the microgrid. It is the slowest and final layer of control, focusing on the economic and technical performance of the system. In case of errors or unplanned islanding, tertiary control seeks to manage power absorption from the grid, stabilising the system by reducing frequency if the main grid is unavailable. Depending on how active and reactive powers are allocated, this control level can either draw power from the main grid or supply it back. Thus, tertiary control ensures that the microgrid operates optimally, balancing both economic and technical considerations for efficient energy management.

5.2.2 Assets required to set up a Microgrid

To effectively evaluate and design an MG, it is crucial to understand the foundational assets and technologies that ensure its successful operation. This overview explores the essential components of a microgrid:

- **Generation:** MG generation systems can include both dispatchable and non-dispatchable sources. Dispatchable generation options include technologies like natural gas generators, biogas generators, storage hydropower and combined heat and power (CHP) systems. Non-dispatchable sources typically consist of renewable energy, such as solar, wind, and run-of-river hydropower.
- **Energy Storage System:** ESS plays multiple roles in microgrids, such as ensuring power quality, shaving peak loads, regulating frequency, smoothing the output of renewable energy sources (RES), and providing backup power;
- **Energy Management System (EMS):** EMS is responsible for the smart management of the microgrid by utilising energy meters and communication tools. It manages generation and load dispatch based on economic and reliability criteria.
- **Loads:** Microgrids typically handle two types of loads:
    - Critical loads, which must be served under all circumstances,
    - Deferrable loads, which can be adjusted to balance the microgrid’s load and achieve the most cost-effective power generation;
- **Grid Interconnection Equipment (for grid-tied microgrids):**
    - Point of Common Coupling (PCC): The PCC is a key element in microgrids, serving as the physical connection point between the microgrid and the main grid. It enables

the exchange of electrical energy between the two systems and incorporates devices like circuit breakers, protective relays, and synchronisation equipment to manage connection, power transfer, control, and protection. Isolated microgrids do not have a PCC,
    - Protection Systems: Includes relays, circuit breakers, and isolation devices to maintain safety and stability when transitioning between grid-connected and islanded modes;
- **Communication Infrastructure:**
    - Communication Network: Allows components to communicate with each other and the main control systems, using protocols such as Wi-Fi, Ethernet, fiber optic, or cellular networks.
    - Data Communication Protocols: Standards like Modbus, DNP3, IEC 61850, or custom protocols allow data exchange between microgrid components, supporting coordination and stability.

5.2.3. Assets-ownership in a Microgrid

Ownership of microgrid assets depends on the type of microgrid and its primary purpose. Community or utility microgrids are generally owned and managed by utilities, municipalities, or cooperatives, sometimes complemented by individual customers with their own renewable generation. Campus or institutional microgrids are usually owned by universities, hospitals, or research facilities that invest in onsite DERs to meet reliability or sustainability objectives. Military microgrids are typically owned and operated by defence agencies, with a strong focus on resilience and security. Remote off-grid systems, finally, are usually developed and owned by local communities, governments, or private developers to serve isolated areas with little or no access to the main utility grid. This is because the different microgrid types operate under different reliability grades, thereby affecting the level of sophistication and expenses for their respective safety mechanisms [27].

5.2.1 Microgrid size

MGs can be categorised based on their generation capacity and application scope, as follows:

- **Small-Scale Microgrids**: These systems generate low-capacity electricity, primarily using renewable energy sources (RESs), though diesel generators (DGs) may be incorporated as supplementary or alternative power sources. Small-scale MGs typically have a generation capacity of up to 10 MW [45]. Moreover, they are well-suited for residential buildings, small regional grids, and island or remote areas;
- **Medium-Scale Microgrids**: Producing electricity at medium capacity, these MGs typically utilise a combination of RESs, oil, or coal, with generation capacities ranging from over 10 MW to approximately 100 MW [28][35]. They are commonly used to power industrial zones;
- **Large-Scale Microgrids**: Designed to generate high-capacity electricity, these systems primarily rely on large power stations such as hydropower or a combination of RES-based units with oil or coal units. With generation capacities exceeding 100 MW [*28*][35], large-scale MGs are intended for industrial site applications.

5.2.4. Microgrid operators

Microgrid ownership and operation can be classified into three main models, each influencing how the microgrid functions to meet stakeholder objectives [46]. In the utility-owned model, where DSOs manage the microgrid, the focus is typically on maximising technical benefits for the distribution system, such as improving reliability, stability, and managing congestion. In contrast, participant-owned microgrids, owned by a single customer or a consortium of customers, are usually operated to align with the owners' economic or strategic goals. These goals might include reducing energy costs, enhancing resilience, or achieving specific sustainability targets. Independently owned microgrids present a more complex dynamic, as their operation involves balancing the needs of various stakeholders. Each ownership model thus shapes the priorities and operational strategies of a microgrid based on the interests of its stakeholders.

The operation of microgrids varies depending on their type and context, with ownership and management structures tailored to the specific needs of the community, institution, or location they serve. Below is an exploration of the different models and their defining characteristics.

- **Community/Utility Microgrids:**
    - **Ownership Model:** Typically, assets are owned either by the local utility or by a community cooperative. In some cases, a partnership between the utility and community members can manage assets,
    - **Asset Breakdown:** Utilities may own central infrastructure such as control systems and storage, while residential and business users may own individual renewable energy resources like rooftop solar,
    - **Deployment Areas:** These microgrids can operate in urban, suburban, or rural areas and may rely on customer-owned DERs integrated with utility-owned systems;
- **Campus/Institutional Microgrids:**
    - **Ownership Model:** Assets are generally owned by the institution, which could be a university, corporate campus, or research facility,
    - **Asset Breakdown:** On-site renewable energy resources, backup generators, and energy storage systems are typically institution-owned. In research contexts, specific assets may be funded through grants or public-private partnerships;
- **Remote Off-Grid Systems:**
    - **Ownership Model:** Ownership can vary between local governments, private companies, or community cooperatives, depending on the location and funding sources,
    - **Asset Breakdown:** Historically diesel-based, these microgrids are increasingly incorporating renewable energy assets, especially where reliable grid access is unavailable;
    - **Deployment Context:** Remote microgrids often operate independently of the utility grid, serving isolated communities, island nations, or remote facilities. As they shift toward renewable sources, ownership models may include international development agencies or nonprofits in addition to local stakeholders.

5.2.5. Scalability and reproducibility of the Microgrid solution

MGs are versatile energy systems that offer significant advantages in scalability and reproducibility, two critical aspects that enable their deployment across a variety of contexts and energy demands. They are inherently scalable, making them suitable for both small-scale and large-scale applications. Their modular architecture allows for gradual expansion by integrating additional DERs, Energy Storage Systems (ESS), and loads as needed. For instance, a small residential microgrid powered by solar panels and batteries can be scaled up to accommodate growing demand by adding more solar capacity, storage units, or even integrating wind turbines. This flexibility ensures that microgrids can evolve alongside changing community needs, industrial requirements, or regional energy goals. Scalability also makes microgrids financially accessible, allowing stakeholders to invest incrementally rather than committing to a large-scale project upfront.

Additionally, microgrid scalability supports technological advancements, as newer, more efficient energy technologies can be integrated without overhauling the entire system. For example, as battery technologies improve or renewable energy equipment becomes more efficient, microgrids can incorporate these upgrades seamlessly, enhancing their overall performance and lifespan.

The reproducibility of microgrid solutions is another key strength, enabling their deployment across diverse geographical locations and use cases. Combined with modular components, standardized designs and configurations make it possible to replicate successful microgrid implementations in other settings. For instance, a microgrid designed for a remote island community can serve as a model for similar deployments in isolated areas with similar energy needs and resource availability. Reproducibility is further supported by advancing control systems and communication protocols that ensure interoperability between various components. This standardisation reduces design complexity, shortens project timelines, and lowers implementation costs. Moreover, reproducible microgrid solutions are instrumental in fostering global adoption of clean energy technologies by providing reliable and adaptable frameworks that can be tailored to local energy landscapes.

5.3. Mitigation of technical challenges

5.3.1. Voltage violations

MGs may help in mitigating some voltage issues, particularly in the context of integration with the larger grid:

- **Voltage Regulation via DERs:** Microgrids can use distributed generators and storage systems to regulate voltage locally. Inverters used in DERs, particularly in solar PV and battery storage systems, can provide reactive power support and voltage control, helping maintain voltage levels within permissible ranges;
- **Dynamic Voltage Control:** The energy management system (EMS) in a microgrid can dynamically adjust the output of DERs or energy storage systems to address real-time voltage fluctuations. Voltage regulators and on-load tap-changing transformers can be controlled to stabilise voltage in grid-connected and islanded modes;
- **Active Power Curtailment:** If voltage rises due to excess generation (often from solar PV), the microgrid can curtail renewable energy production or shift energy to storage systems, thereby preventing the violations of the upper voltage limit.

This control function allows the grid operator to request microgrid support for various voltage requirements. The operator can specify a target voltage or request an adjustment, such as an increase or decrease, which the microgrid controller will implement. The controller can achieve this by adjusting the settings of individual DERs, such as modifying the target voltage or turning on/off or adjusting reactive power functions. One potential use case for this function is feeder-level conservation voltage reduction, which can be dispatched as needed to reduce peak load.

5.3.2. Thermal limit violations

Thermal limit violations occur when grid components, such as transformers or lines, carry more current than they are rated to handle, potentially leading to overheating and equipment failure. Microgrids play a crucial role in preventing these issues by employing various strategies aimed at load management, energy storage, and distributed generation:

- **Load Management:** Microgrids can reduce stress on the distribution network by using demand response mechanisms to shed non-critical loads or shift loads to off-peak periods. By controlling load in real-time, thermal limit violations are avoided;

- **Energy Storage Systems (ESS):** By storing excess generation during peak periods and discharging during off-peak periods, ESS can smooth out load variations and prevent thermal overloading of grid components;
- **Distributed Generation:** Microgrids can reduce the burden on specific transformers or feeders by generating power close to the load, thus minimising the amount of current flowing through grid infrastructure, avoiding thermal limit violations.

5.3.3. Balancing problems

Microgrids are designed to handle various operational challenges, including balancing supply and demand, regulating frequency and voltage, and compensating for system fluctuations. These functions are crucial for maintaining system stability, especially in scenarios such as islanding or sudden load changes:

- **Real-time demand-supply matching** - The microgrid's Energy Management System (EMS) ensures that supply and demand are balanced in real-time. By adjusting the output of DERs or the discharge of energy storage systems, the EMS maintains system equilibrium. In the event of supply shortages, critical loads are prioritised, while deferrable loads are either shifted or curtailed to avoid strain on the system.
- **Flexible generation -** MGs integrate dispatchable (e.g., natural gas generators, combined heat and power systems) and non-dispatchable (e.g., solar, wind) generation sources. This combination allows microgrids to adjust generation flexibly based on current load requirements. This flexibility is especially important during periods of high demand or renewable generation variability.
- **Energy storage and demand response** - ESS stores excess energy generated during periods of low demand and releases it when demand increases, providing short-term balancing of supply and demand. In parallel, demand response programs are used to shift or curtail load during peak periods, ensuring that supply and demand are balanced without overwhelming the system.

Frequency regulation is essential for maintaining system stability, particularly in a microgrid. This is independent of primary frequency response and involves adjusting the power output symmetrically for bi-directional regulation—either increasing or decreasing power as needed. It can also be configured to provide either upward or downward regulation services.

Secondary control in MG is responsible for managing DER output in response to external power system events, such as changes in voltage, frequency, or power. Unlike primary control, which relies on local measurements, secondary control uses data collected remotely. Secondary control ensures stable operation, especially when the microgrid operates in islanded mode, where it is disconnected from the main grid. In islanded microgrids with multiple grid-forming DERs, system frequency and voltage are initially determined by the droop control settings and real/reactive power setpoints of each DER. While primary control ensures basic regulation, it may struggle to maintain voltage and frequency within nominal ranges during changes in load or generation. Secondary controls, which respond more slowly to these changes, correct deviations caused by primary droop controllers. These controls are typically managed by a central controller (e.g., the microgrid controller), which communicates intermittently with the DER's primary controllers to ensure frequency and voltage remain within acceptable limits:

- **Real-time demand-supply matching -** The EMS in a microgrid ensures real-time balancing of supply and demand by adjusting DER output or energy storage discharge. In cases of supply shortages, critical loads are prioritised, while deferrable loads are shifted or curtailed.

- **Flexible generation -** Microgrids can integrate both dispatchable (e.g., natural gas generators, combined heat and power) and non-dispatchable (e.g., solar, wind) resources, allowing for more flexible and adaptive control of generation based on load requirements;
- **Energy storage and demand response:** Energy storage systems provide short-term balancing by storing excess generation and discharging when needed. Demand response programs help shift load during peak times to ensure balance.

Frequency regulation is a function where the microgrid controller provides regulation services to system operators or balancing authorities. This service is linked to managing the Area Control Error (ACE) signal and operates independently of the primary frequency response. The microgrid controller adjusts power output symmetrically for bi-directional regulation, meaning it can increase or decrease power as needed, or in a single direction for upward or downward regulation services.

5.3.4. Thermal and Volt-var control at the TSO-DSO interface

In modern power systems, the integration of DERs such as solar panels, wind turbines, and ESS into microgrids presents new challenges at the interface between the TSO and DSO. One of the critical concerns is managing thermal limits and voltage regulation while ensuring that the local grid operates efficiently and safely. This is especially important in situations where microgrids are connected to both the transmission and distribution grids.

- **Power flow management**: At the TSO-DSO interface, microgrids equipped with bi-directional inverters and sophisticated control systems can help manage reverse power flow. By adjusting the output of DERs or shifting excess power into storage systems, microgrids can limit the flow of power back into the transmission grid. Active power curtailment is another method that can be used to prevent the injection of excess power into the transmission system, thus maintaining the balance and avoiding overloads.
- **Energy storage as a buffer**: ESS play a crucial role in stabilising power flow by absorbing excess generation during periods of low demand. This capability is particularly useful during times of high renewable generation, such as sunny or windy periods, when local consumption may be lower than the available generation. By storing excess energy, ESS prevents reverse power flow, helping to maintain the stability of both the microgrid and the larger grid.
- **Local consumption and self-sufficiency**: Microgrids can also promote self-consumption by managing local loads more effectively. Through advanced load management strategies and optimised energy storage use, microgrids can minimise the amount of excess power that flows back into the grid, enhancing their self-sufficiency. By controlling local consumption and storage, microgrids reduce the reliance on the central grid, helping to alleviate potential voltage and thermal issues at the TSO-DSO interface.

5.3.5. Power Quality

MGs face several power quality challenges, which can significantly impact their stability and reliability. These challenges include issues like harmonics, transients, voltage unbalances, and waveform distortion, which are particularly critical due to the integration of DERs and power electronics.

Harmonics are caused by non-linear loads, such as inverters used to manage DERs [47]. These harmonics can lead to equipment overheating, increased system losses, and reduced efficiency. To mitigate these effects, active power filters (APFs) can be used to absorb or cancel harmonic currents. Additionally, properly sizing DER inverters and deploying harmonic traps can help minimise harmonic distortion. Continuous monitoring using indices like Total Harmonic Distortion (THD) is also essential to ensure harmonics remain within acceptable limits.

Transients, both impulsive and oscillatory, are short-duration electrical disturbances that can arise from external sources like lightning or internal events like switching actions. In MGs, rapid switching of power electronics can generate medium- and low-frequency transients, affecting equipment reliability and system stability [47]. Surge protection devices (SPDs) can be used to absorb high-voltage spikes, while snubber circuits in power electronics can limit transient voltage spikes. Advanced control algorithms can also help detect and suppress transients, minimising their impact. ESS can provide short-term power during voltage spikes, while SPDs protect sensitive equipment from high-voltage impulses. The distributed nature of microgrids allows them to quickly respond to switching events or external disturbances, minimising transient impacts and improving overall resilience.

Short-duration RMS variations, such as voltage sags, swells, and interruptions, are often caused by load changes or faults. These disturbances are especially problematic in microgrids with limited capacity and sensitive equipment. Dynamic Voltage Restorers (DVRs) can quickly correct voltage sags and swells, helping maintain stability. ESS and Uninterruptible Power Supplies (UPS) can provide temporary power during voltage interruptions, ensuring the continuous operation of critical loads. Long-duration RMS variations, including overvoltage, undervoltage, and sustained interruptions, can have significant effects on microgrid operation. These disturbances often result from load fluctuations or system switching. Voltage regulators and tap-changing transformers can adjust voltage levels to mitigate low and high voltage limit violations. Microgrid controllers can optimise generation, load, and storage coordination to maintain stable voltage levels, while fault detection and isolation systems can prevent sustained interruptions by quickly isolating faulty grid sections.

Voltage and current imbalances, particularly in three-phase systems, can reduce system efficiency, increase equipment wear, and affect power quality. In microgrids, imbalances are more common due to the uneven distribution of loads or improper equipment operation. Balancing loads across phases can minimise these imbalances, while power factor correction devices can reduce current imbalance. Monitoring systems that detect imbalances can help take corrective action before significant damage occurs.

Waveform distortion, including notching and noise, can cause signal interference and equipment malfunctions. In microgrids, this is often a result of power electronics like inverters and switching devices. Low-THD inverters can reduce harmonic generation, while filters designed to target specific harmonic frequencies can mitigate waveform distortion [47]. Electromagnetic Interference (EMI) shielding can be used to protect sensitive equipment, and proper power electronics design can further minimise distortion.

5.3.6. Fault Level Challenges

Fault level management is a key technical challenge in the design and operation of microgrids, particularly as these systems integrate high shares of inverter-based resources (IBRs) and operate under multiple configurations, including grid-connected and islanded modes. Conventional short-circuit analysis and protection philosophies, developed for networks dominated by synchronous generation, are increasingly inadequate in microgrids where fault current magnitude and duration are limited, variable, and highly dependent on control mode[48][49].

A fundamental issue arises from the restricted fault current contribution of inverter-based DER**.** Grid-following inverters typically limit fault current to a narrow multiple of rated current, while grid-forming inverters, although capable of improved fault response, still provide lower and fasterdecaying currents than synchronous machines. This behaviour can compromise protection sensitivity and selectivity in islanded or weakly connected microgrids, particularly when conventional overcurrent protection is applied [50],[51].

In contrast, during grid-connected operation, microgrids embedded in strong distribution or sub-transmission networks may experience excessive fault levels due to the aggregate contribution of multiple DER units and strong upstream infeeds. This challenge is well documented in Great Britain, where increasing distributed generation has led to prospective fault levels approaching or exceeding the ratings of legacy switchgear [52]. UK DNOs have mitigated this through network segmentation and reconfiguration, such as the use of normally open points, to maintain fault levels within planning limits[53]. While effective from a security perspective, these measures can constrain network flexibility and hosting capacity.

Similar issues have been reported in other jurisdictions. In Australia, studies by AEMO and CSIRO [54] indicate that high DER densities can lead to elevated fault levels in grid-connected operation and insufficient fault current in islanded microgrids, driving the need for revised protection coordination and advanced inverter requirements [55]. In North America, utility experience with community and resilience microgrids has highlighted protection performance challenges under low-fault-current conditions, prompting the adoption of differential, directional, and communication-assisted protection schemes aligned with IEEE Std 1547-2018 [56] . In continental Europe, German and Danish experience shows that fault levels can vary significantly with network topology and operating mode, complicating protection coordination in active and reconfigurable distribution networks [57][58].

The dynamic and reconfigurable nature of microgrids further exacerbates fault level challenges. Topology changes driven by islanding, fault isolation, or optimisation objectives can significantly alter network impedance and fault current paths, making static protection settings increasingly inadequate [59].

Mitigation strategies therefore require an integrated approach combining network planning measures, advanced protection schemes, and enhanced inverter capabilities. Across jurisdictions, this includes operational reconfiguration, deployment of higher-rated assets or fault current limiters, adaptive and directional protection, and the progressive adoption of grid-forming inverters with improved fault current response [60][61]. From a planning and operational perspective, fault level constraints must be explicitly addressed through multi-mode short-circuit studies, protection validation under both low and high fault current conditions, and coordination with upstream network protection and fault level limits.

5.4. Enabling flexibility and resilience

5.4.1. Operation

Microgrids operate in various modes, each requiring specific protection strategies. These modes are illustrated in Figure 5.2, which shows the transition between grid-connected operation, islanded operation, and reconnection. In normal grid-connected operation, the microgrid remains tied to the main grid and coordinates distributed energy resources (DERs) to provide grid-support services such as energy supply, regulation, and voltage control. At the same time, protection devices stay in their grid-connected configuration.

When preparing to island—for example, during scheduled maintenance or planned switching—the microgrid controller coordinates with the main grid controller, DERs, and adaptive protection devices to ensure a smooth transition. At this stage, protection settings typically shift toward their island-mode configuration. The actual transition to islanding involves disconnecting from the main grid, with DERs changing from grid-following to grid-forming control, secondary control functions addressing voltage and frequency deviations, and grounding transformers usually being engaged.

Once the microgrid is stabilised in islanded mode, it operates independently with voltage and frequency regulated by grid-forming DERs. The microgrid controller continues to manage DERs and local loads to balance supply and demand and optimise performance. Finally, when the main grid supply is restored, the microgrid prepares to reconnect. This involves synchronising voltage, frequency, and phase angle with the utility grid, disconnecting grounding transformers, and adjusting controller set points before reclosing the interconnection breaker.

MG should ideally automate down to the LV level, as this depth of automation is key to enabling flexibility at the distribution level. Automating LV networks helps manage DERs like solar panels, battery storage, and electric vehicles, which are typically connected at the LV level. This approach improves coordination of local loads and generation, directly benefiting end-users. Automation at the LV level offers several advantages:

- **Local energy generation and consumption coordination -** Low-voltage networks are where most DERs—such as rooftop solar, EVs, and battery energy storage systems —are typically connected. Automating these LV networks enables precise control over local energy generation and consumption, ensuring that energy flows efficiently within the microgrid. This is crucial for residential or commercial areas, where energy usage patterns may be unpredictable and variable. Automation at this level ensures that energy is produced, stored, and consumed at optimal levels, reducing waste and improving energy efficiency;
- **Enhancing flexibility at the distribution level -** With microgrids designed to operate both in grid-connected and islanded modes, LV automation enables the grid to be more flexible in managing local loads and generation. For instance, in islanded mode, where the microgrid is disconnected from the main grid, it must be capable of balancing local generation (e.g., solar) with local consumption. By automating LV networks, microgrids can effectively "island" when necessary, and reconnect to the main grid when conditions permit, maintaining a reliable energy supply without manual intervention;
- **Dynamic load management and demand response -** Automation at the LV level facilitates dynamic load management and demand-side response. By utilising real-time data, the system can adjust the energy supply to match demand, thereby optimising the operation of DERs and battery systems. For example, in response to high local energy consumption or low renewable energy generation, the system can call on stored energy from batteries or adjust the output of local generation sources, ensuring continuous balance. This becomes especially important when integrating EVs, which can serve as mobile storage units for excess energy generated by DERs;
- **Advanced fault detection and improved grid reliability -** Another major advantage of automating LV networks is the enhanced detection of faults and the ability to respond rapidly. In traditional distribution networks, faults can cause prolonged service interruptions. However, automated systems in LV networks can detect issues instantly, isolate the affected areas, and quickly restore power, minimising downtime. This feature is particularly valuable for microgrids, where the quick identification of faults and immediate recovery ensures grid stability and supports critical loads;
- **Enhanced integration with consumer-level energy systems -** Microgrids that are automated at the LV level are better equipped to integrate consumer-level energy systems, such as smart thermostats, appliances, or home energy management systems. These systems can communicate with the microgrid's central controller to optimise energy usage within a home or building, enhancing both energy savings and system efficiency. For example, when excess

solar energy is available, the system can trigger the charging of EVs or increase storage in battery systems.

A microgrid can provide significant flexibility, helping to delay or even eliminate the need for major grid reinforcement. By effectively managing local energy generation, storage, and consumption, microgrids reduce stress on the larger grid, thereby postponing costly upgrades and expansions. One of the primary ways microgrids contribute to this goal is through localised energy generation and consumption. When integrated with renewable energy sources, such as solar and wind, and energy storage systems, microgrids supply power locally, reducing congestion on the transmission and distribution networks. This ability to generate power locally helps alleviate peak demand on the grid, which in turn reduces the need for upgrading infrastructure such as transformers and transmission lines. By generating power within the microgrid itself, reliance on centralised power plants is minimised, which reduces the need for grid expansion or reinforcement to meet rising demand in specific areas.

In addition to localised generation, microgrids use ESS to absorb excess power during off-peak times when generation exceeds demand. This stored energy can then be used during peak periods, helping to smooth out fluctuations in demand. By doing so, microgrids reduce the pressure on the grid to handle these peaks, which would otherwise necessitate investment in new grid capacity. Advanced energy management systems within microgrids also allow for load shifting, where non-essential loads can be moved to off-peak periods, reducing strain on the grid during high-demand times. This load management capability ensures that the grid does not experience overloads, which can also delay the need for reinforcement.

Microgrids may also provide valuable grid-supportive services, including voltage regulation, frequency stabilisation, and reactive power support. These services enhance grid stability and help integrate more renewable energy into the system. By offering these services locally, microgrids reduce the need for grid reinforcement to accommodate voltage and frequency fluctuations, particularly in areas with high renewable energy penetration where generation is often variable. Furthermore, microgrids can participate in demand response programs or provide flexibility services, adjusting local energy consumption based on signals from the grid operator. This capability helps balance supply and demand in real-time, reducing the need for additional grid capacity to accommodate fluctuations, ultimately delaying the need for costly upgrades to grid infrastructure.

By acting as a "local buffer" to grid stress, microgrids can help defer large-scale infrastructure investments, such as new transmission lines, expanded substations, or upgraded transformers. Rather than reinforcing the grid to meet growing energy demands or the intermittency of renewable generation, microgrids provide a more efficient, localised solution. This allows grid operators to manage energy resources more cost-effectively, postponing expensive infrastructure upgrades.

In addition to their role in grid management, microgrids enhance grid resilience by providing islanding capabilities. In areas prone to power outages or with ageing infrastructure, microgrids can continue to operate independently from the main grid when failures occur. This ability to operate autonomously during grid disruptions reduces the need for extensive grid hardening or costly upgrades to improve reliability. By maintaining operations during power outages, microgrids reduce pressure on the larger grid and extend the time before reinforcements are necessary.

5.4.2. Planning

Incorporating flexibility needs into the planning of the distribution grid is essential for optimising performance and integrating DERs. Here are some key strategies to effectively include flexibility in the planning procedure:

- **Assessment of demand and supply dynamics:**
    - **Load forecasting** - Analyse demand patterns to identify peak load periods and fluctuations. This can help determine the necessary flexibility resources needed to balance supply and demand,
    - **Generation Forecasting** - Assess the potential contributions of renewable energy sources and other DERs, considering their variability and intermittency;
- **Integration of flexibility resources:**
    - **Diverse Resource Mix** - Plan for a variety of flexibility resources, including energy storage, demand response, and flexible generation sources, to meet changing needs.
    - **Multi-Use Solutions**: - Encourage solutions that serve multiple purposes, such as energy storage systems that can provide grid support and backup power.
- **Enhanced grid infrastructure:**
    - **Smart grid technologies** - Invest in smart grid infrastructure, including advanced metering and communication systems, to enable real-time monitoring and control of grid operations,
    - **Automated control systems**: Implement automated systems that can dynamically manage loads and resources based on real-time conditions;
- **Regulatory and market mechanisms:**
    - **Flexibility markets** - Establish market mechanisms that incentivise the provision of flexibility services, allowing different stakeholders to offer and monetise flexibility,
    - **Clear policies and standards** - Develop regulatory frameworks that promote investment in flexible resources and ensure fair access to grid services;
- **Stakeholder engagement:**
    - **Collaborative planning** - Involve various stakeholders, including utilities, regulators, consumers, and DER operators, in the planning process to understand their flexibility needs and capabilities,
    - **Community involvement** - Engage local communities to identify opportunities for demand response and local generation that can enhance grid flexibility;
- **Scenario planning and simulation:**
    - **Flexible planning scenarios** - Use scenario analysis to assess how different configurations of DERs and loads will impact grid flexibility under various conditions,
    - **Impact assessments**: Evaluate the potential impact of flexibility measures on grid stability, reliability, and economic performance;
- **Monitoring and continuous improvement:**
    - **Performance metrics** - Establish metrics to evaluate the performance of flexibility resources and their effectiveness in meeting grid needs.

In the context of distribution planning, microgrids can be incorporated as part of the solution to enhance grid flexibility. When assessing grid requirements and forecasting future energy needs, microgrids can contribute by providing localised demand response and distributed energy generation, which can reduce the pressure on the larger grid. These localised resources can be integrated into load forecasts as part of the demand flexibility components, enabling grid operators to account for the ability of microgrids to mitigate peak demand, balance supply and demand, and improve overall grid stability.

The trade-off between traditional reinforcement and flexibility can be effectively integrated into distribution planning by considering demand flexibility as a key factor in each step of the process, Figure 5.12. Distribution planning traditionally focuses on determining the least cost means of meeting forecasted peak system demand, with the typical planning horizon ranging from 1 to 10 years. The planning process often involves risk analysis and scenario forecasting to identify the most appropriate solutions for grid needs, which are usually based on worst-case snapshots of demand. However, when considering the role of demand flexibility, several adjustments can be made to balance traditional reinforcement with flexible solutions. First, demand flexibility should be incorporated into load forecasting. For customers participating in demand flexibility programs such as Time-of-Use (TOU) tariffs or dynamic pricing, their flexible load should be retained in load forecasts. However, it is crucial to separate the flexible components (e.g., demand response resources) from non-flexible components, which allows planners to account for the potential of demand flexibility in reducing peak loads and minimising the need for grid reinforcement.

In the scenario forecasting and risk analysis steps, a shift from relying on worst-case snapshots to time-series analysis is necessary. This approach better captures the temporal aspects of demand flexibility, such as how load patterns might shift or decrease during peak times due to demand response programs. By simulating different scenarios that include flexible demand responses, planners can assess how much flexibility can contribute to grid reliability and reduce the need for traditional reinforcement.

When identifying mitigation solutions, demand flexibility should be considered to reduce the need for infrastructure upgrades. While traditional grid solutions encompass physical assets such transformers, capacitor banks, or new overhead lines, flexibility measures such as demand-side management, energy storage, or local generation can act as non-wire alternatives that can address grid challenges without the need for infrastructure investments. These flexible resources can provide short-term and long-term solutions to grid congestion, system balancing, and resilience.

Fig. 5.12. Overview of the distribution planning process.

Additional data is required to model demand flexibility as a non-wires alternative in distribution planning. Key data includes:

- **Customer resource availability** - Information on customer technology adoption, load profiles, flexible resource availability, and customer-driven constraints;
- **Response characteristics** - Data on the magnitude and duration of demand flexibility, load shifting constraints, variations in response by time, and long-term persistence of flexibility;
- **Program parameters** - Information on use cases, actuation methods (e.g., rate structures, dispatch signals), response frequency and duration, and locational granularity;
- **Program economics** - Costs related to implementation, operation, customer enrollment, and participation.

The availability of this data varies, and assumptions may be necessary. Modelling demand flexibility approaches range from simplified load profile analysis for non-feeder-level use cases to complex power flow analysis for feeder-level use, including static and dynamic modelling. The choice of approach depends on application type, dispatch method, and available data.

Power flow analysis may require dynamic modelling for responsive loads, which involves understanding customer behaviours and ensuring adequate data. For dynamic modelling, a time-series load forecast is used, with flexibility triggered by system measurements or control signals. Constraints are applied based on data availability and program parameters.

The development of a flexible energy market is critical for integrating both traditional grid reinforcement and innovative flexibility solutions. This can be achieved by enhancing sector coupling, which refers to the interconnectedness of various energy sectors—such as electricity, heating, cooling, transport, and gas—into a cohesive and flexible energy system. By linking these sectors, surplus energy in one domain can be used to address demand in another, thereby improving overall system flexibility and efficiency.

Depending on the regulatory framework, Energy Communities may also play an important role in this flexible market by enabling local energy production, consumption, and storage within a specific geographic area. These communities can provide significant flexibility to the grid by allowing localised management of energy resources and facilitating demand response initiatives.

At the same time, sector coupling can further enhance the flexibility of the system. For example, integrating EV charging with local energy storage can allow EVs to act as mobile energy storage units, helping to balance grid demand and supply. Additionally, coupling heating and cooling systems with renewable energy sources and storage can provide load-shifting capabilities, reducing peak demand on the grid and minimising the need for costly grid upgrades.

5.5. Opportunities and barriers

MGs offer numerous opportunities, including energy independence, renewable energy integration, resilience during outages. They enable local energy generation and support grid stability. However, challenges exist, including operational complexities such as maintaining system frequency and voltage, effective energy management, and power quality. Economic barriers, like high installation costs for DERs and cost-effective operation, also pose difficulties. Additionally, microgrid protection, market regulation, and security issues require attention. Despite these challenges, microgrids have significant potential to transform energy systems, provided regulatory and technological advancements are made.

Opportunities:

- **Energy independence -** MG can enhance energy security by enabling communities to generate and use their own power, reducing reliance on centralised grids;
- **Integration of renewable energy -** MG facilitate the incorporation of renewable energy sources, such as solar and wind, promoting sustainability and reducing carbon footprints;
- **Resilience to outages -** They provide a backup power source during grid outages, ensuring critical facilities (like hospitals and emergency services) remain operational;
- **Grid support services -** MG can offer ancillary services, such as frequency regulation and voltage support, to the main grid, enhancing overall grid stability;
- **Community empowerment -** They promote local engagement and investment in energy resources, allowing communities to have more control over their energy systems;
- **Technological innovation -** The development of microgrids encourages advancements in energy management technologies, smart grid solutions, and battery storage systems;

- **Market participation -** MG can participate in energy markets, enabling users to sell excess power back to the grid or engage in demand response programs;
- **Economic development -** Investments in microgrid infrastructure can stimulate local economies by creating jobs in construction, operation, and maintenance of energy systems.

Barriers:

- **Operation and management:**
  - **System frequency and voltage -** During the initial stages of island mode start-up, sudden current intake can disrupt frequency and voltage, potentially causing generators to trip. To mitigate this, it is essential to investigate suitable energy generation methods and develop specialised controls for MG operations,
  - **Energy management -** Effective energy regulation involves fine-tuning various parameters, which can be complex due to the variability and uncertainty in microgrid conditions. Simulations are necessary to identify optimal settings,
  - **Appropriate design -** Renewable energy-based MGs require a different design, modelling, and planning compared to conventional systems. Poor design can significantly reduce their longevity, so it is crucial to understand available energy resources and user demands,
  - **Identifying operational modes -** Each power source and load scenario within the MG must be clearly defined for various situations, such as temporary switches or emergency load shedding. This is particularly challenging due to the diverse nature of loads and generators,
  - **System security -** To maintain security, contingency planning and emergency measures (like demand-side management and load shedding) are needed. Economic rescheduling of generation is essential during contingencies to manage loading and voltage/frequency levels,
  - **Maintaining power quality -** Short-term balance of active and reactive power is crucial for ensuring power quality within the microgrid,
  - **Supervisory Control and Data Acquisition -** MG control centres should utilise SCADA for metering, control, and protection, along with state estimation functions for system diagnostics,
  - **Control system analysis:** A well-designed control system is vital for optimising microgrid performance. This involves considering various operational modes and configurations,
  - **Load flow analysis -** Analysing load flow under different operating conditions helps determine current flow and voltage levels, although variable load profiles can complicate it,
  - **Balancing generation and load -** A key challenge is maintaining a continuous balance between load and power generation, as instability can arise from sudden changes in load,
  - **System stability analysis -** Ensuring MG stability is crucial. It involves forecasting and monitoring transient events caused by both normal and unexpected disruptions. Stability is particularly challenging with various power sources and components, including inertia-based generators and renewable sources. Comprehensive studies and close integration of equipment are essential for maintaining stability;
- **Protection issues in microgrids:**
  - **Short-circuit current evaluation -** Determining short-circuit current (SCC) limits can be challenging due to significant variations in SCC across different operating configurations, which result from the diverse power sources and loads in a microgrid,

- **Earthing -** Neutral earthing is a critical and complex aspect of microgrid protection. The transition between various power sources, including spinning machines and converters, complicates earthing. Local grid regulations govern installation, but issues can arise in the distribution and maintenance of neutral earthing;

- **Economic challenges:**
  - **Ensuring economic operation -** Cost-effective MG operation relies on effective generation scheduling, economic load dispatch, and optimal power flow management.
  - **Increased Power Generation Costs:** Implementing hybrid systems adds complexity, potentially leading to higher electricity production costs,
  - **Fixed cost reimbursement:** Network tariff design when net metering is in place - in particular, the balance between the capacity and energy components should be adapted to ensure that microgrid system users contribute their due share of the funding of the network, as the tariff should reflect the cost borne by system users on the network;
  - **Additional costs for remote MGs -** Installing MGs in rural areas complicates maintenance and raises transportation costs;

- **Market challenges -** If microgrids are allowed to supply energy to priority loads during main grid outages autonomously, a significant concern arises regarding energy pricing during these interruptions. With the main grid disconnected, the traditional electrical market would lose control over prices, potentially allowing MGs to charge excessively high rates, leading to a market monopoly situation. To ensure the sustainable development of microgrids, it is essential to establish and implement an appropriate market infrastructure that regulates pricing and maintains fairness;

- **Regulatory challenges -** As a relatively new industry, MGs require a thorough review of existing standards and protocols for integrating micro-sources and participating in both traditional and deregulated power markets. It is important to develop safety and protection recommendations, as well as to restructure standards like G59/1 and IEEE 1547 for effective integration with active distribution networks. Additionally, research is needed to assess IEEE 2030.7-2017, which specifies microgrid controllers. On the regulatory side, many countries lack standard legislation governing MG operations. While some governments are promoting the development of green electricity microgrids, formal regulations for future implementation are still in the drafting stage.

6. Research outcomes: Self-consumption vs T&D share

The objective of this chapter is to analyse and discuss how self-consumption can (or could) contribute to a large DG share in electrical distribution networks while preventing risks of grid constraints. The objective is to enable the deployment of renewable distributed generation without a huge investment of grid operators in grid assets (what is called the T&D share) to mitigate constraints and then reduce the global cost of renewable energy policy.
In Europe, the EU Directives 2019/944 on *common rules for the internal electricity market* (IEMD) and 2018/2001 on *the promotion of the use of energy from renewable sources (REDII) have paved* the way for enabling the consumer to become a prosumer. Any citizen is allowed to produce electricity from renewable energy sources for their own consumption as a single self-consumer and inject the surplus into the public grid, or share with other grid users within an organisation to form a Collective Self-Consumption (CSC) scheme. As discussed in this chapter, the distances between the prosumers/consumers who participate in a CSC operation will be a key issue in preventing important grid constraints that can be costly to mitigate for the DSO. Organisational issues are discussed in [62].

6.1. Definition

At the beginning of the deployment of the local renewable distributed generation at the building scale (residential, commercial or industrial buildings), some countries stated rules to enable the full injection of electricity into the grid with a dedicated meter. Due to the huge capex of such generation capacities, a special feed-in tariff much higher than market prices was proposed to incentivise investments. Then, at the building scale, there was originally no economic interest in putting loads and generation below the same meter. Thus, one meter measured the generated energy sold at a high tariff, and another one measured the loads' consumption purchased at a lower tariff (or price). In such a scheme, the objective of the users was to maximise the energy fed into the grid, whatever the state of the distribution grid, and independently of their local demand profiles. However, with the strong drop in the generation cost for PV installations, support schemes have been cut and feed-in tariffs reduced. Simultaneously, we have observed an increase in the electricity prices. Thus, local generation and self-supply have become increasingly competitive, and self-consumption approaches are now becoming the main use case at the building scale. Usually, in an individual residential case, an individual self-consumption operation is characterised by a generation unit (PV panels) connected behind the "consumption" meter. Self-consumption must not be seen from a global net-metering at the year scale, but at a smaller time step (1 hour, 30min or 15min) to better match with the grid issues. Usually, the smart meters enable the measurement at each time step of whether the building is consuming energy or is feeding energy into the grid. The injected energy is called the "energy surplus". Depending on how much the remuneration of this surplus is, the user will be more or less incentivised for shifting a part of their consumption to optimise their electricity bill. Depending on the national regulation, prosumers may not be interested in the valorisation of this surplus that is "offered" to the DSO.

Self-consumption can be seen as individual when behind a single metering point (grid connection point). Some years ago, collective self-consumption was proposed, where a local generation is shared amongst several users in the same area. Collective self-consumption may be limited by grid constraints, depending on the distances between the participants and the network topology. From a prosumer point of view, it can help to valorise the individual energy surplus better.

In CSC schemes, the generation and demand remain in a short geographical area, which should enable the reduction of the risk of physical constraints (voltage or current constraints) that can appear in case of power flows over longer distances.

6.1.1 T&D share

This section is dedicated to presenting shares that can be taken by transmission and distribution grid operators to improve the grid flexibility in case of a large deployment of RES.

As is known, the voltage difference between the ends of a branch is given by the following relation, where *P* and *Q* are the active and reactive power received at node 2 from node 1, and R_{br} and X_{br}. Are the resistance and reactance of the branch between the nodes 1 and 2:

$$U_1^2 - U_2^2 = 2(R_{br}P + X_{br}Q) \tag{6.1}$$

To mitigate grid constraints (voltage or current constraints) due to distributed generation connection, a grid operator can make several types of shares (called T&D shares) that can be based on asset directly operated by it or owned by it (typically capacitor or reactor banks connection or disconnection, grid reconfiguration with remotely controlled switch), or it can also include the contributions of customers connected to the grid (whether they are consumers or producers or both) with active or reactive power setpoints modification (what can be included as flexibility services). Whatever the considered contribution, it covers expenditures either in CAPEX, OPEX, or a specific operation rule.

If we only analyse the previous well-known formula of a voltage deviation, it can be deduced that four parameters enable us to reduce a voltage constraint: R_{br}, X_{br}, P, Q . For each parameter, the grid operator can take one or several shares. Let's consider the following examples:

- **Share on values R_{br} and X_{br} through a grid reinforcement**
  - Replace overhead lines with cabled lines as their reactance value is different, respectively $0.35\ \Omega/km$ versus $0.1\ \Omega/km$
  - Increase the section of the conductors to reduce R_{br}
  - Reduce the line length, but this will require the installation of new substations. Such a policy has the advantage of increasing the power quality by reducing the SAIDI or SAIFI indicators.
- **Share on reactive power flow**
  - Shares operated and/or owned by the DSO
    - Installation of reactors on some "near optimal" nodes
    - Deployment of OLTC on MV/LV transformers to partially dissociate the voltage profile from MV and LV.
    - In-line voltage regulators
  - Shares from customers connected to the grid
    - Reactive power control from inverter-based resources (generators or loads). Different control laws are possible (see Appendix A.2)
    - Economic issues
      - Cost of inverters over-sizing to enable reactive power exchange
      - Services paid by the DSOs or regulated settings imposed by grid codes

- **Share on grid reconfiguration**
  - MV grids are operated with a radial topology with 2 or 3 controlled switches along each feeder that enable a more optimal feeder configuration or customer re-supply after a fault.

  - Installation of more controllable switches
  - Installation of MVDC links to change the power flows according to the constraints.
  - Needs for state estimation. State estimators will be the key point to enable a smarter operation of the distribution grids

- **Flexibility to purchase from stationary batteries**
  - Reactive power control or compensation
  - Active power control
    - Battery can be charged or discharged for local constraints mitigation. A signal from the DSO is required to activate such flexibility via a third party (an aggregator)
    - The effectiveness of the action highly depends on where the battery is connected to the nodes under constraints.
    - When a battery participates in the energy arbitrage in the wholesale market (day-ahead market). Can it be a natural help?
      - If the local area production is similar to the market zone area, energy arbitrage may have a positive impact on the local grid.
      - If the local area has low (or zero) generation in comparison to the market zone area (the market gives a signal for the battery charging), energy arbitrage can induce voltage droop.
      - If the local area has high generation in comparison to the market zone area (the market gives a signal for the battery to discharge), the battery will not mitigate the voltage rise, or it could even increase the voltage rise if the battery is discharging.
      - As a conclusion, a global signal (from the wholesale market) is unlikely to solve a local constraint.
  - Any flexibility share from batteries will depend on the grid topology and the location of the battery regarding where the grid constraint is. Each case must be analysed in detail with a specific methodology.

6.1.2 Self-consumption

Distributed generation units in distribution grids are mainly small PV installations connected in low voltage grids: small PV rooftops (typically less than 10kW), or larger PV rooftops (up to 100-200 kW for farmer buildings in rural areas). At the peak generation time, power injection from the LV grid into the MV grid is often observed. Presently, as LV grids are usually not controlled, DSOs must reduce the MV voltage range to take into account the occurrences of voltage rise at noon and voltage droops for the evening peak demand, Figure 6.1. Some DSOs may operate their MV grid in a reduced range (for example, [+2.5%; -2.5%] around the rated voltage) to ensure compliance with the LV limits at the remote end of the LV feeders. Clearly, this strategy can be seen as a limitation of the hosting capacities for RES.

Thus, it is critical to be able to shift a part of the electrical demand during periods of RES production. As load demand must be triggered as close as possible to the local generation, self-consumption is clearly a good candidate to reduce grid constraints due to local generation. So, initiatives must be focused on self-consumption.

Overview of flexible loads for self-consumption. First, let's consider two indicators that are usually used for assessing the ability of a user to produce a part of their own energy, the self-consumption ratio (SCR) and the self-sufficiency ratio (SSR):

Self-Consumption Ratio (SCR)

$$SCR = \frac{generated\ electricity\ that\ is\ consumed\ onsite}{total\ energy\ produced\ onsite} \tag{6.2}$$

Self-Sufficiency Ratio (SSR)

$$SSR = \frac{Generated\ electricity\ that\ is\ consumed\ onsite}{total\ energy\ consummed} \tag{6.3}$$

As can be seen, it is much more difficult to get a high SSR than a high SCR: with a small PV installation, it will be easier to consume 100% of the generated power, but it will only contribute to a small part of the total consumption. Then the reduction of the energy bill will be low. If the local generation capacity is increased, the demand profile will have a huge impact on SSR.

The simplest way to increase the SCR and SSR is to shift loads such as dishwashers, washing machines, dryers or electric water heaters during periods of local production. However, if these loads can be “easily” shifted with an App, they cannot be modulated in the sense that we cannot control precisely their power. However, with the deployment of electric vehicles, EV charging enables the control of precisely (or more precisely) the charging power. However, individual self-consumption may not be enough to prevent (or reduce) surplus injection into the grid (because household appliances are not used every day, or because EV is not parked at home, or any other reason). In that case, for areas with a large amount of generation, collective self-consumption should enable better absorption locally of the main part of the generation by controlling more loads and reducing the risk of “lack of demand”.

The organisation of collective SC operation is governed by national legislation or rules set by national regulatory authorities.

From a power network point of view, SC can help to mitigate distribution grid constraints if the demand is close enough to the generation points. This is more likely in densely populated areas. In rural areas where the density of the demand (kW/m²) is low and where there can be multiple farm hangars with PV rooftops or ground-mounted PV installations, the potential of reducing grid constraints with collective self-consumption is often rather limited.

Typically, commercial grid users with higher demand during daytime are well-suited for self-supply based on solar power. An illustration is given in Figure 6.1, illustrating the demand profile of a plastics manufacturing facility, which shows a good match with the PV generation profile of an adequately sized PV plant on a sunny day.

When the matching is less between demand and local generation, load shifting actions or storage may be required to improve the SSR. The technological solution that will be deployed will depend on the economic analysis: investment costs for PV, storage or demand response actions, and electricity price bought from the grid and income from the selling of the surplus energy into the grid.

Self-consumption and energy communities from the European directives REDII and EMDII

In the framework of the “Clean Energy for all Europeans” package, the EU has given two definitions for the Energy Communities: “renewable energy communities” (defined in the REDII) and “citizen energy communities” (defined in the EMDII), which allow citizens to organise their participation in the energy system collectively. The main objective is to expand the role of consumers in the energy market. According to the directives, Energy Community members can be natural persons, small and medium enterprises, large enterprises (only for CEC), and local authorities (including municipalities).

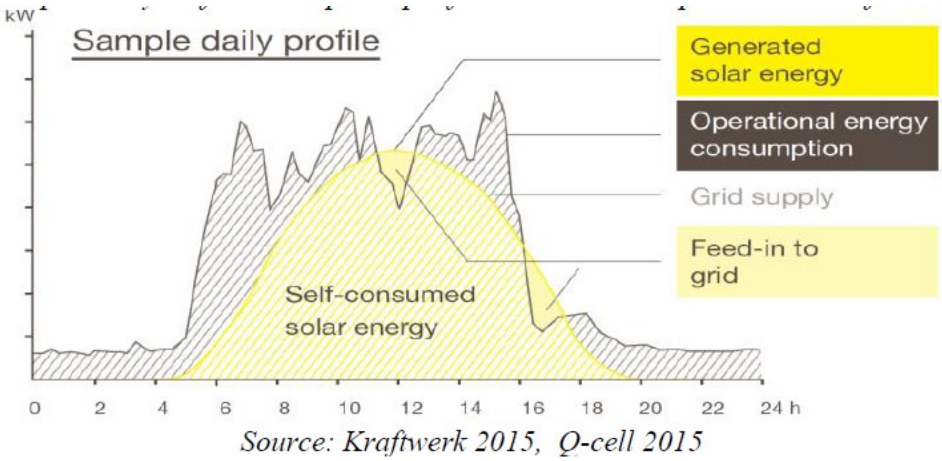


Fig. 6.1. Sample daily self-consumption profile in a German plastics-manufacturing facility [63].

In REDII, an individual SC is defined as a renewables self-consumer. In contrast, collective SC is defined as "jointly acting renewables self-consumers", in which consumers are located in the same building or multi-apartment block.

In reference [47], three concepts are addressed: collective self-consumption (CSC), renewable energy communities (REC), and Citizen Energy Communities (CEC). Usually, self-consumption schemes are different from energy communities in the sense that they do not focus on organisational format. However, an organisational format is required to enable a CSC operation. This format is usually an energy community. The two types of energy communities have both similarities (a legal entity must be created, and a specific governance is required) and differences (proximity location for REC, and no geographic limitation for CEC; renewable generation for REC, and technology neutral for CEC). For a REC, energy generation or supply must not be the main activity of its members, and the size of generation plants (owned and developed by the legal entity) is limited and must be located in the proximity of the members of the legal entity. Self-consumption may occur as a specific activity in the context of an energy community.

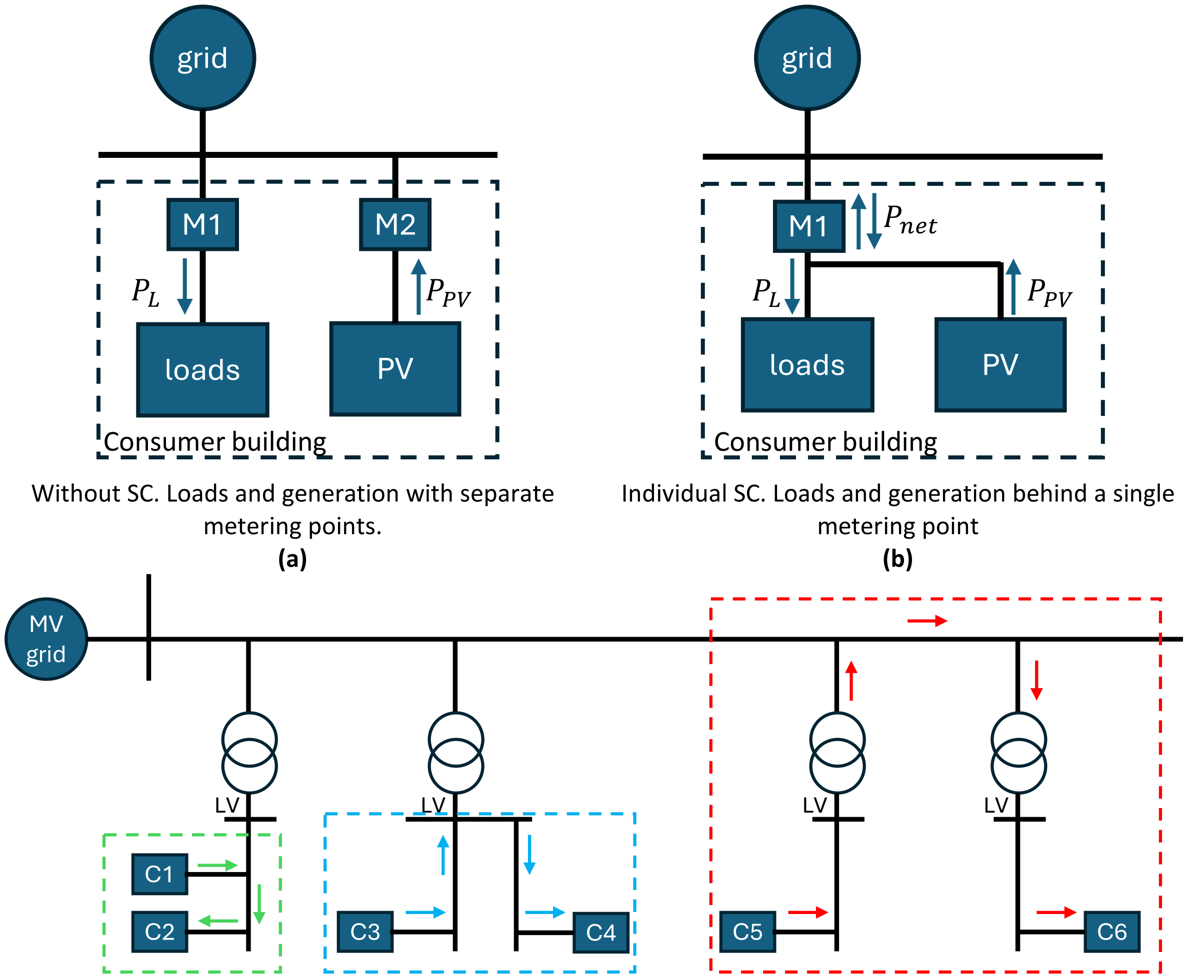
Finally, the document (2) gives an overview of the different frameworks in EU member states. It is interesting to note that rules for CSC differ from one country to another, both in terms of geographical area and use of the public grid. Let's see some examples:

- CSC in Austria - The use of the public grid for energy sharing is not permitted;
- CSC in Belgium - In Wallonia, the law defines a "local perimeter" as a grid segment whose connection points are located downstream of one or more stations of public electricity transformation of medium and/or low voltage. Public grid can be used for power sharing;
- CSC in Denmark - CSC is allowed on the building scale. All consumers, as well as the generation plant, have to be linked by a private grid and thereby have to be behind a common utility meter, covering all consumers who will use the electricity locally produced. Public grid cannot be used for power sharing;
- CSC in France - A contract needs to be established between the DSO and the legal entity, which identifies the different participants and determines the sharing scheme between the involved consumers. For CSC, the maximum geographic distance is 2 km between the injection and consumption points. Initially, the participants should be located downstream of the same LV substation. This constraint has been removed. The power sharing can use the public grid;
- CSC in Germany - Collective self-consumption operations were initially limited to the scale of a building. The reform carried out in 2021 allows an extension of these operations to the scale of a district, determined by the fact that the electricity does not transit through the public network, within the limit of an installed capacity of 100 kW;

- CSC in Italy - CSC of renewable energy is focused on condominiums. Participants are natural persons or commercial actors, for whom generation and energy exchange is not the core business and who are located in the same building or condominium;
- CSC in Spain - CSC is regulated by Royal Decrees 15/2018 and 244/2019. CSC using the public grid is physically and geographically limited, as the participating entities must be located within the low-voltage distribution grid derived from the same centre of transformation. Moreover, the maximum distance between the production and consumption meters is 1000 meters.

6.2 Different schemes for local generation

Figure 6.2 gives a representation of three schemes in the case of local generation (typically PV rooftops).



Without SC. Loads and generation with separate metering points.
(a)

Individual SC. Loads and generation behind a single metering point
(b)

Three configurations of collective self-consumption operation
(c)

Fig. 6.2. Different schemes for local generation: a) Full injection (feed-in tariff type), b) Individual SC with net-metering, c) Collective SC with different locations of the participants (they can be members of an Energy Community).

- **Case a)** is the typical former situation when feed-in tariffs were much higher than electricity prices. Consumers were encouraged to have a dedicated measure of the generated electricity that was bought by an energy supplier (mainly the company that historically held the monopoly on electricity supply, i.e. EDF in France).
- **Case b)** has developed with the decrease of feed-in tariff and the increase of electricity prices, which made self-consumption more profitable. The meter only measures the net power consumption (P_{net} : load demand minus local generation for each time step, typically

15min or 30min. In case of surplus (if $P_{PV} > P_L$The consumer can offer the surplus to the grid or contract with an energy supplier that will buy the surplus.

- **Case c)** represents three situations of collective SC between two consumers (following the previous section, this can be seen as a CSC operation of a REC). In each case, the dotted lines give the area that the SC operation will influence:
  - C1 and C2 belong to the same energy community and are located downstream of the same LV substation and on the same LV feeder. If C1 has an energy surplus, it can be sold to C2. As C1 and C2 are very close, the power exchange will impact the LV grid locally and can reduce the surplus generation transfer back to the head of the feeder;
  - C3 and C4 belong to the same energy community and are located downstream of the same LV substation, but on two different LV feeders. If C3 has an energy surplus, it can be sold to C4. The power surplus of C3 will (or may) change the power flow (and voltage profile) between C3 and the substation, but the power and voltage issues are unchanged in the second feeder;
  - C5 and C6 belong to the same energy community and are located downstream of two different LV substations. If C5 has an energy surplus, it can be sold to C6. The power surplus of C5 will (or may) change the power flow (and voltage profile) between C5 and the substation, but also in the MV grid. The power and voltage issues are unchanged for the LV grid that connects C6.

Whatever the case, the local power profiles will be modified in the coming years. For DSO, the forecast of demand profiles (we should say *net demand profiles*) will be highly challenging as it depends on how the demand will change, the local generation will develop (where and which size), and the SC schemes will develop with a specific issue on how consumers (residential, commercial, buildings) will be able to modify their load profile to reduce power export to upper grids.

Besides the forecasting issues of the local demand and generation, the energy dispatching mechanisms inside the community must also be considered. Three types of models are discussed: graph theory models, optimisation techniques, and market-based models. This paper recalls that.

The definition of the objective function is crucial. Several common objective functions are mentioned: maximising the self-sufficiency ratio (= minimising the dependency on the main electricity grid), maximising the consumption of locally generated energy within the community, minimising the cost considering grid fees and prices of electricity from the main grid, minimising the carbon footprint, and finally, smoothing the demand profile to reduce the stress on the main grid.

6.2.1 Size of the self-consumption or collective self-consumption area

As said in section 6.1.2, the size of the geographic area differs between countries. In some cases, the public grid can be used, and sometimes it cannot. Presently, France is the country that allows the largest area (2 km and up to 20 km with special derogation) for power exchange that can use the public grid. Additionally, special grid tariffs have been set for the stakeholders of an SC operation. Two specific points must be mentioned: the stakeholders must be connected to a grid operated by a single DSO, and the maximum generation power of the energy community must be less than 3 MW.

In many countries, CSC is limited to the same building without any use of the public distribution grid.

Thus, the REC concept enables a larger geographic area and the use of a public distribution network. For example, in Austria, a REC needs to be located within the territory of one DSO that is made responsible for the metering and the attribution of the generated electricity to the community members, following a defined sharing key. A time interval of 15 minutes is considered when using smart meters.

National rules can set a maximum value for the size of the generation plants in the Energy Community. For example, in Greece, energy communities can produce, distribute and supply renewable energy from installations of up to 1MW. In Italy, participants of a REC must have their main commercial activity that is not energy generation/supply, and generation plants must be located in the LV or MV grid behind the same substation.

6.2.2 Assets required to set up a self-consumption or collective self-consumption area

For an energy community under a collective SC agreement, each stakeholder must be equipped with a smart meter that will allow (i) to measure the consumed/generated power (for a prosumer we consider the surplus that the owner of the generation unit does not consume) with a short time step (15min, 30min or one h), and (ii) to share the local generation between the consumers of the community following an allocation key that was initially defined. An energy/power optimiser must use/define the generation and demand forecasts (this can be a service delivered by a third party, from historical data and machine learning algorithms) that will enable the strategy optimisation of the consumers.

For an individual SC, the meter must be able to measure separately the power taken from the grid and the energy surplus injected into the grid. This will enable the payment of the surplus according to a local tariff. Typically, the surplus is measured with a 15-minute, 30-minute or 1-hour time-step. The distinction between the sign of the power (injection or consumption) allows for the application of an adapted “grid connection fees” according to the local rules.

Additionally, the participants need Apps to control their loads (EV, dishwashers, …) and to get information about the generation forecast.

In the case of SC, a stationary battery is not mandatory, but it could improve the power management if it is economically viable. With the next generation of EVs that will integrate V2G capability (as an example, the new Renault 5 can embed a bidirectional AC on-board charger), additional levers will be available to optimise SC management.

Finally, as for any distributed generation, a protection is required for the disconnection of the generator in case of a grid fault and islanding mode (if islanded operation is not allowed by the DSO).

6.2.3. Assets-ownership in a self-consumption or collective self-consumption area

A key point is the meter. The meter ownership depends on the country. In France, the meter belongs to the DSO. In the UK, it belongs to the energy supplier, the customer, or a third party.

We can also talk about the PV panels or the stationary battery that are owned by the participants of the SC operation or by the legal entity of the Energy community. (1) states that the EU Law clearly establishes that to have sharing *of energy* within an energy community (EC), it is required that the renewable energy (or just electricity in the case of a citizen EC) must be produced by the production units owned by such legal entity communities. According to [64], “two-thirds of EC initiatives stated that their organisation *owns the RES installations*”.

6.2.4. Operators of the self-consumption or collective self-consumption area

For individual SC, it is mainly operated by the customer themselves. Nevertheless, a customer can contract with an energy service operator (i.e. an aggregator) that can propose services to valorise the load flexibility better. Probably the decision will be different, whether it is a residential customer or a commercial customer. Suppose the customer has a stationary (or mobile) battery. In that case, a third party (aggregator) can be useful to take more economic value with grid services or shares on the electricity markets (energy arbitrage between low market prices in the middle of the day due to PV generation, and peak prices in the evening).

For collective self-consumption, there can be an EMS (energy management system) or PMS (power management system) at the level of the community to enable the members to optimise their load profile. Tools such as PV forecasting can be very useful. Energy companies (newcomers or historic companies) can propose services to help members reduce their energy bill and optimise their self-consumption or self-sufficiency ratios. The optimisation of the sharing keys remains an open issue, even if basic solutions exist.

6.2.5. Scalability and reproducibility of the self-consumption or collective self-consumption solution

From DSO perspectives, it seems that SC must not be operated only in “open-loop” without any view of what happens in the grid. Suppose participants in a CSC operation are connected to the same node (the public grid is not used for power sharing). In that case, the way participants optimise their behaviour will impact the power profile seen by the DSO at the connection node. If participants are not connected to the same node, shared power flows may generate congestion, voltage rise or voltage drop. So, in case of large-scale development of CSC, DSO will have to invest in state estimators better to assess the constraints (in MV and LV), and DSO will have to send signals to users and/or buy local flexibility to prevent risks of constraints.

6.3. Technical challenges

The objective of this section is to assess how “Total self-consumption vs T&D share” can mitigate the challenges in the presence of the large DG share identified in § 4.1.

Roughly, it can be mentioned that individual SC will only optimise the user’s electricity bill (or other criteria depending on the definition of the optimisation function) if the users do not receive direct or indirect signals from the DSO. Numerous research works can be found on the bill optimisation for households with PV and controllable loads (as heat pumps or electric vehicles). Some papers integrate bidirectional electric vehicles in V2H (vehicle-to-home) mode to better optimise the bill [65][66][67].

For CSC, research works are mainly focused on the users’ point of view with the aim of profit maximisation. Sometimes the grid constraints are considered with an optimal power flow. However, the objective is not to increase the RES hosting capacity. In reference [68], authors consider a local energy community (LEC) that has an internal low-voltage distribution network, which is connected to the external utility grid. In this paper, physical constraints of the local grid are not considered, nor the constraints of the public utility grid. Reference [69] analyses REC through two case studies. The first one is a real-world REC with five customers connected to an LV distribution grid, and the second case involves prosumers connected to the MV distribution grid. However, as in [20], the grid constraints are not considered in the analysis.

It can be said that there is a lack of research work to assess how individual or collective SC could enable increasing the RES hosting capacity: what would be the technical challenges, which incentives must be set, and what would be the required evolutions in the national regulations?

Anyway, a key point will be the deployment of state estimators by the DSO to get a better view of the grid constraints and to be able to send relevant signals to users. When a public grid links the members of an energy community, the energy/power optimiser would need local limitations that can only be given by the DSO. Another approach could be the deployment of local droop control for specific loads (such as EVs) or PV inverters.

6.3.1. Voltage violations

DSO must keep the voltages inside the rated ranges from the primary substation (HV/MV) to the remote ends of the LV feeders. Depending on how and where the distributed generation is deployed, and how and where users adopt new loads (EVs and heat pumps), DSO may experience more and more voltage drops (below the lower limit) or voltage rises (above the upper limit). If the DSOs remain largely unaware of the precise state of their grid (mainly in LV networks), they must maintain margins for grid operation. Thus, it will reduce the hosting capacities of distributed generations and new loads.
A well-designed self-consumption operation with the right signals sent by the DSO to users should be able to reduce the risk of constraints. The optimisation function for the self-consumption operation should be adapted to these signals.

6.3.2. Thermal limit violations

In areas where a huge amount of distributed generation (wind or solar MW capacities) has been connected, the transformer's peak load in primary or secondary substations may have shifted from a peak-demand to a peak-generation—Idem for the cables' limits. For reducing transformer peak-load (in primary or secondary substation), any action downstream of the transformer may be useful.

6.4 Opportunities and barriers

6.4.1. Technical challenges for T&D shares

The technical challenges for T&D shares are identified as follows:

- Trade-off between investment and reactive power contribution from loads and RES;
- Optimal sizing and installation of reactors;
- Forecast of the development of RES in the area of a primary substation;
- development and deployment of state estimators in distribution grids to get a more precise view of the grid and to be closer to the limits (less margin).

6.4.2 Technical challenges for self-consumption and demand flexibility

The technical challenges for self-consumption and demand flexibility are identified as follows:

- How can big data analytics and Machine Learning be leveraged to predict and manage the impact of DER on the grid? → Forecasting of the users' profiles (net demand profiles) that will depend on how users can shift or control their loads. More volatility in the LV customers' profiles;
- Set incentives for users;
- Energy suppliers must propose variable prices;
- Definition of the priority areas for deployment of PV generation for a better match with the demand.

7. Research outcomes: Holistic solution – *LINK*

The energy transition, which must meet climate and environmental requirements and simultaneously boost the economy and competition, is an extremely complex challenge. It **requires holistic thinking, collaboration and solutions across the energy sector**, from homeowners and local businesses in their communities to regional, national and international stakeholders [70]. The large-scale integration of distributed RES as a fundamental element in meeting climate and environmental requirements and as a resource for flexibility and resilience in the energy sector can only be achieved through a holistic approach.

The *LINK* holistic approach considers the whole power grid, including customer plants, their electrical devices, and the market, thus enabling flexible operation, sector coupling, and energy communities. It allows the large-scale integration of distributed energy resources by minimising data exchange, hence considering privacy and cybersecurity by design. It has its roots in the research projects FENIX [71] and ZUQDE [72] and cross-research in architecture, physics and electrical engineering. The architectural paradigm for Smart Grids "*LINK*" is derived from the signature of their fractal geometry [73]. *LINK* architecture was the foundation of the INTERACT project.

7.1 Definition

Over time, the meaning of the Smart Grid term has evolved and now stands for modernising power systems and meeting all the requirements of our times. The Smart Grid's definition of EPRI in 2009 [74] and their fractal geometry formed the solid basis for developing the architectural paradigm *LINK* (Figure 7.1a).

> The ***LINK*-Paradigm** is a set of one or more electrical appliances, i.e., a grid part, storage or producer device, the controlling schema, and the interface.

The *LINK* paradigm encompasses the three main components of any technical system, i.e. the hardware, the automation and the communication required for autonomous or self-sufficient operation. In the power system case, the hardware encloses the electrical appliances, such as the lines, transformers, generators, batteries, etc. The automation is represented through the automation schemes, while the communication is depicted through the interfaces.

The *LINK* paradigm is the instrument for creating the technical holistic model of smart grids:

> “**Energy Supply Chain Net**” [75] is a set of automated power grid parts intended for Chain-Links (abbreviated as Links), which fit into one another to establish a flexible and reliable electrical connection (see also §7.2.3.1). Each Link or Link-bundle[3] operates autonomously or self-sufficiently and has contractual arrangements with other relevant boundary Links or Link-bundles.

Figure 7.1b) shows schematics of the holistic model with Links set up in the High Voltage in Transmission and Sub-transmission levels, HV^T_ and HV^S_Links, in Medium- and Low Voltage levels, MV_ and LV_Links, and even at the Customer Plant level, CP_Links. As explained later, the well-defined Link size is dynamic and can, for example, combine the low and medium voltage levels into one Link, LV-MV_Link (Figure 7.1c). Figure 7.1d) illustrates the flexibilities between the various Links achieved through the targeted exchange of active and reactive power (*P* and *Q*) between Links.

[3] Link-bundle is a set of neighboring Links.

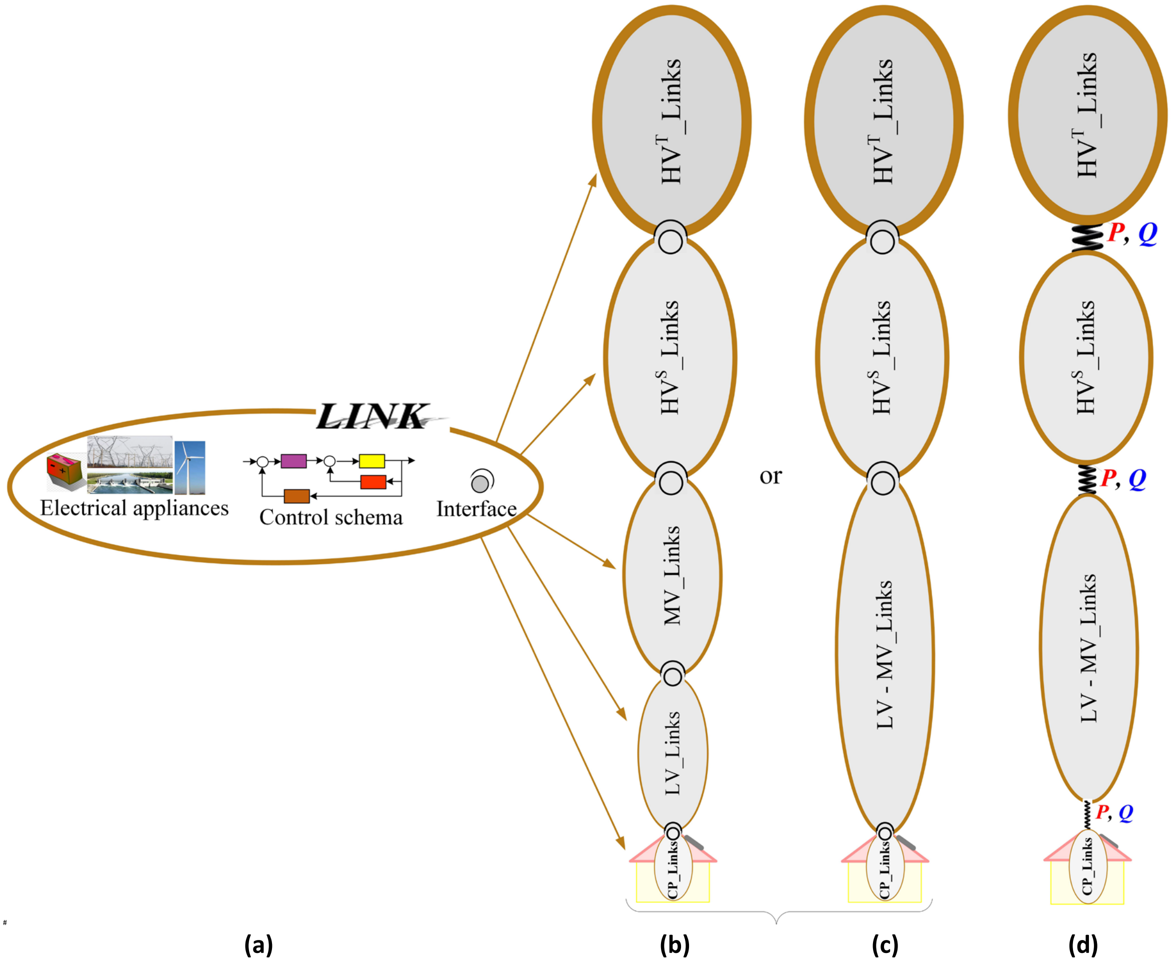


Fig. 7.1. Overview of the: a) Architectural paradigm; b) Example of Links set up in five levels; c) Example of Links set up in four levels; and d) Flexibility model.

7.2 Architecture

The **holistic power system architecture** is one in which all relevant components of the power system are merged into one single structure. These components could comprise the following:

- **Electricity producers** (regardless of technology or size, e.g. big power plants, distributed generations, etc.);
- **Electricity storage** (regardless of technology or size, e.g. pumped power plants, batteries, etc.);
- **Electricity grid** (regardless of voltage level, e.g. high-, medium- and low voltage grid),
- **Customer plants;** and
- **Electricity market.**

Holistic architecture unifies all interactions within the power system, between the network, generation, and storage operators, consumers and prosumers, and the market, thus creating the possibility to harmonise them without compromising data privacy and cyber security. It facilitates all processes necessary for a reliable, economical and environmentally friendly operation of smart power systems. It allows a clear description of the relationships between different actors. It creates conditions to go through the transition phase without causing problems [76].

7.2.1 Elements

Figure 7.2 outlines an overview of the architectural elements derived from the *LINK* paradigm [77][78]. Its component "Electrical Appliances" consists of three parts: the Producer, the Storage and the Grid, which, combined with the other two elements of the paradigm, the control schema and the interface, form the three architectural elements:

- Producer-Link
- Storage-Link, and
- Grid-Link.

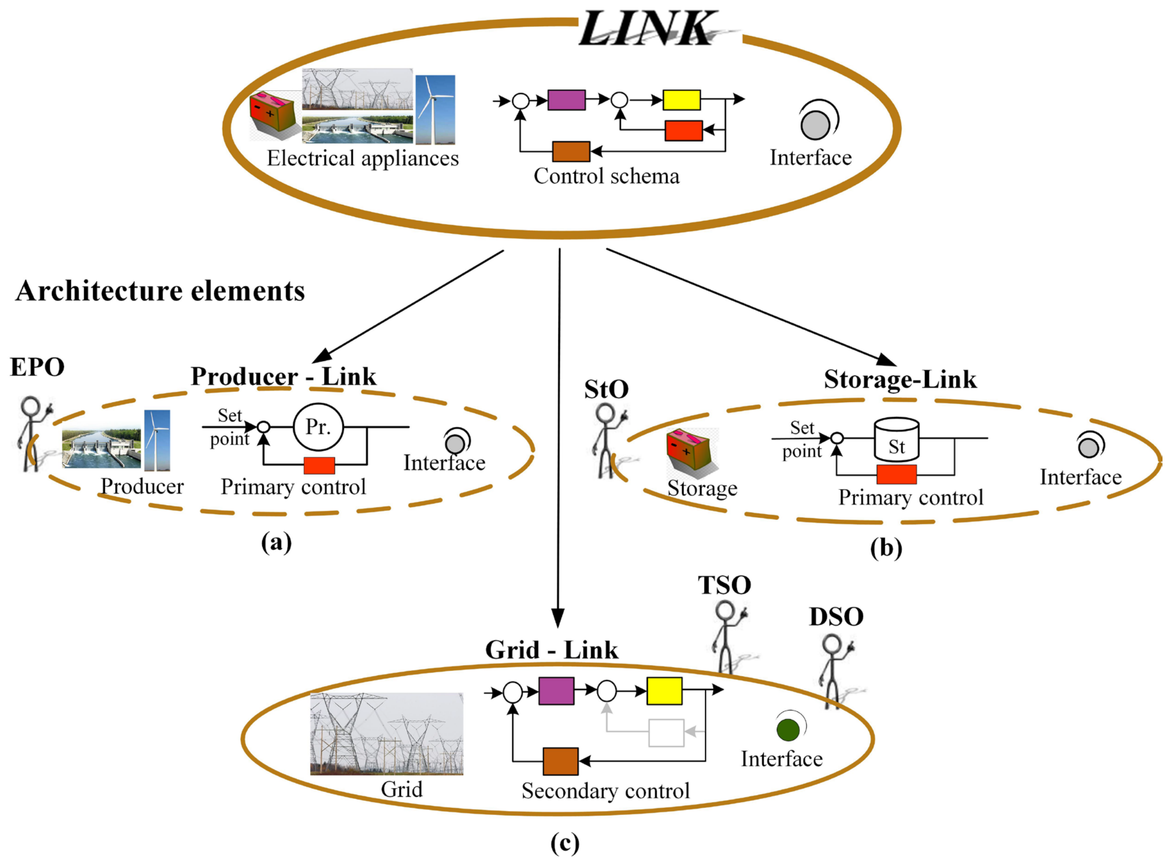


Fig. 7.2. Overview of the architectural elements derived from *LINK* paradigm: a) Producer-Link; b) Storage-Link; and c) Grid-Link.

7.2.1.1. Size of Producer-Links and the associated assets

The first fundamental element of holistic architecture is the Producer-Link (Figure 7.2a).

> ***Producer-Link** is a composition of an electricity production facility, its Primary Control (PC), and the interface.*

The electricity production facility may be a generator regardless of the primary resource used and size. PVs are widely used today. They are also subject to a Producer-Link regardless of size. Meanwhile, Primary Control refers to closed-loop control actions taken locally (device level, see Annexe B) to control the active and reactive power flow production and the voltage. The interface comprises the data, which should be exchanged with neighbouring Links to ensure a reliable and flexible operation of the connected Links, as well as adequate communication protocols and technologies.

The electricity production facility may also comprise several generators, power conversion systems, and private grids (as long as the latter are not extended and producers' control may consider their effect on the *P* and *Q* exchange with the public grid. Otherwise, a Grid-Link should also be set on the private grid; see § 7.2.1.3. Size of Grid-Links and the associated assets.

7.2.1.2. Size of Storage-Links and the associated assets

The second fundamental element of *LINK* architecture is the Storage-Link (Figure 7.2b).

***Storage-Link** is a composition of a storage facility, its Primary Control, and the interface.*

The storage facility may be the generator of pumped hydroelectric storage, batteries, etc., regardless of the technology and size. Meanwhile, Primary Control refers to closed-loop control actions taken locally (device level, see Annexe B) to control the active and reactive power flow production and the voltage. The interface comprises the data, which should be exchanged with neighbouring Links to ensure a reliable and flexible operation of the connected Links, as well as adequate communication protocols and technologies.

The storage facility may also comprise several storage units, power conversion systems, and private grids (as long as the latter are not extended and the storage units' control may consider their effect on the *P* and *Q* exchange with the public grid. Otherwise, a Grid-Link should also be set on the private grid; see § 7.2.1.3. Size of Grid-Links and the associated assets.

7.2.1.3. Size of Grid-Links and the associated assets

The third and most complex element of the new architecture is the Grid-Link, Figure 7.2c.

***Grid-Link_Grid** is a composition of a grid part, the corresponding Secondary Control (SC) and the interface, Figure 7.3.*

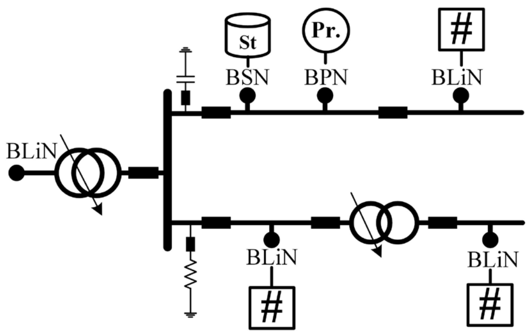


Fig. 7.3. Overview of all asset types that may be included in a Grid-Link_Grid.

The grid part considered in the Grid-Link refers to electrical equipment such as lines and cables, transformers, and Reactive Power Devices (capacitors and coils) (RPD) that are directly connected and form an electrical unity, Figure 7.3. This grid part, the Grid-Link_Grid, determines the area where the Secondary Control operates. The area borders are different and characterised by different boundary nodes, depending on the types of electrically connected Links. The Producer-Links are connected through Boundary Producer Nodes (BPN); meanwhile, the Storage-Links are connected through Boundary Storage Nodes (BSN). Each Grid-Link has many Boundary Link Nodes (BLiN) through which it connects with neighbouring Grid-Links. The symbol $\boxed{\#}$ represents the neighbouring Grid-Link_Grids.

*The **size of the Grid-Link_Grid** is variable, whereby the associated grid can only be selected on the condition that a secondary control element is placed on it.*

Therefore, the Grid-Link can be set up on any part of the grid, i.e., in the high-voltage, medium-voltage, low-voltage grid or a combination of these. It can even be set at the customer plant level, as a radial grid exists from the meter to the sockets. For example, the Grid-Link_Grid may include one subsystem (the supplying transformer and the feeders supplied from it) or a part of the sub-transmission network, as long as the SC is set up in the respective area.

Figure 7.4 shows the control schemes set on a typical Grid-Link_Grid. Figure 7.4a) depicts the Hertz/Watt, while Figure 7.4b) depicts the Volt/var Secondary Control (Hz/W**SC,** Vv**SC**).

*The **Grid-Link_Grid** is upgraded with secondary control for both significant power system entity pairs: frequency/active- and voltage/reactive power.*

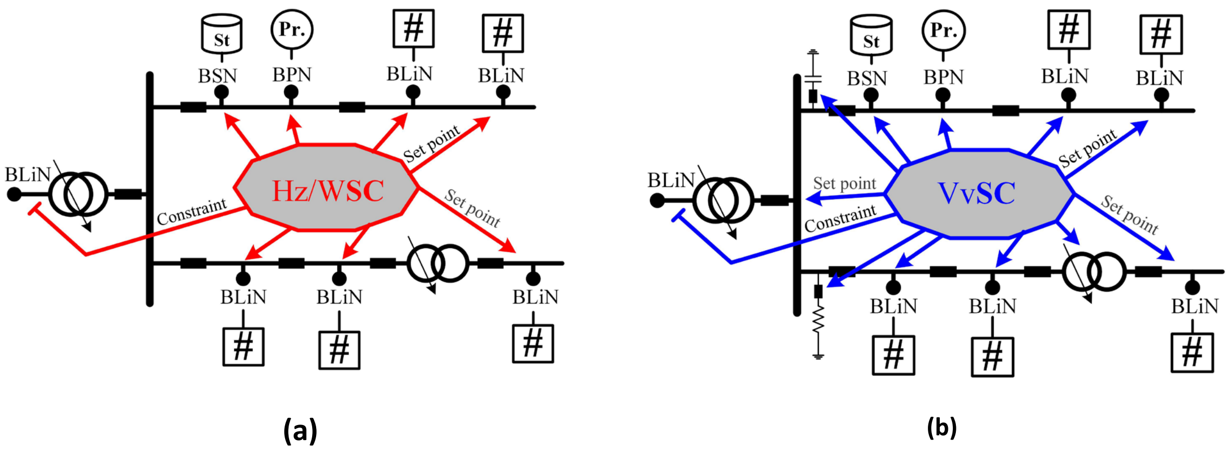


Fig. 7.4. The secondary control schemes set on a Grid-Link_Grid: a) Herz/Watt; b) Volt/var.

The secondary control algorithm of Grid-Link must fulfil technical issues and calculate the setpoints of connected facilities' primary controls by respecting the dynamic constraints necessary to enable a stable operation. Grid-Link's facilities, such as transformers and RPDs, should have been upgraded by primary or local control. Thus, SC sends setpoints to its facilities and all entities connected at the boundary nodes.

Each Grid-Link has an interface that includes the data to be exchanged with neighbouring Links to ensure a reliable and flexible operation of the connected Links. It also comprises adequate communication protocols and technologies.

7.2.2. Fractal-based structures

The large-scale DER integration is quite limited. The transformation of the resource mix from fossil fuels to renewables and the rise of distributed resources call for a review of the technical management of power systems and market structures. Although the electricity markets are undergoing radical change, the current re-dispatch process for congestion management is still costly and drives the transmission grid operation to its limits. On the other hand, most electricity producers connected to the distribution grid do not have any market access. Meanwhile, most DSOs do not participate in the market operation to manage their congestion.

7.2.2.1. Fractal-based technical management structure

Significant data transfer and data privacy are the two biggest challenges that Smart Grid technologies face today. The distributed *LINK*-based architecture meets these two challenges. Figure 7.5 depicts an overall overview of the structure of this architecture.

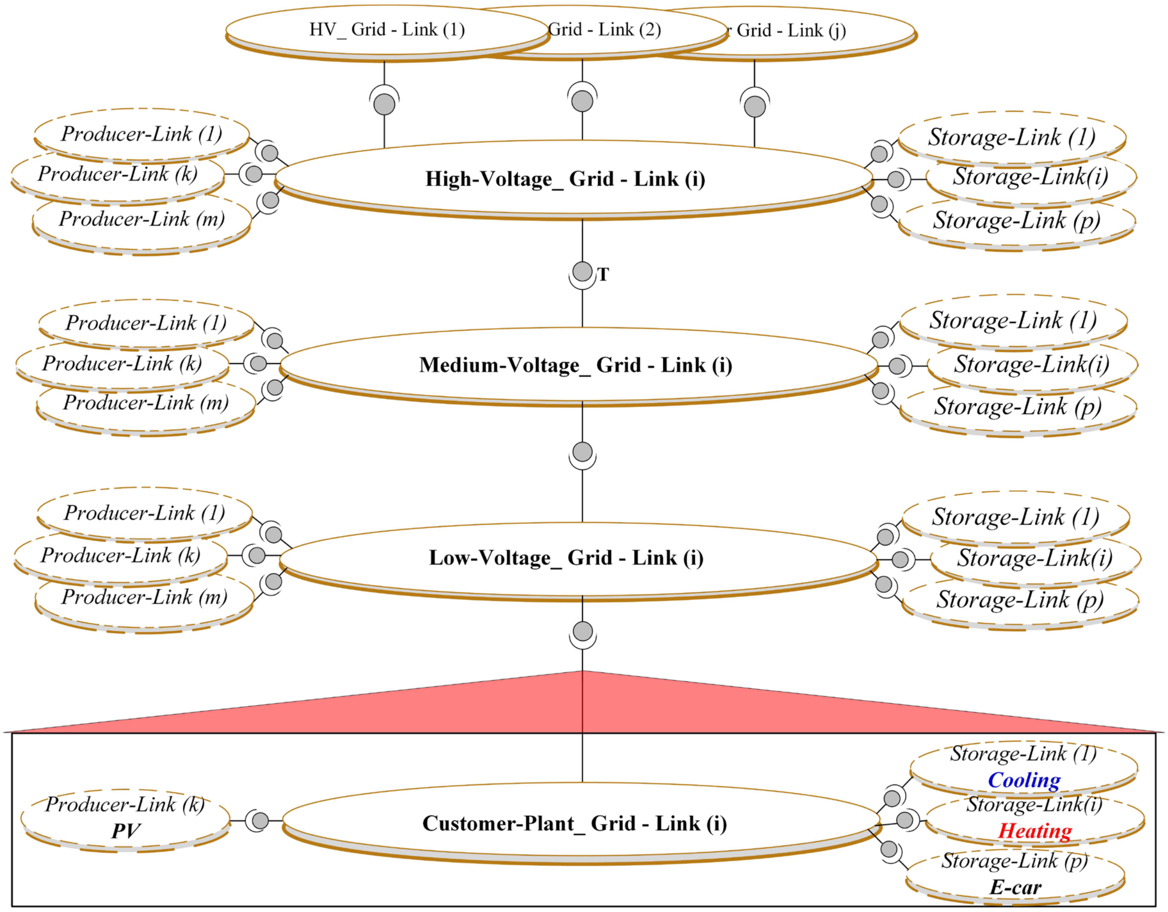


Fig. 7.5. The overall overview of the architecture structure based on *LINK*.

LINK architecture's fundamental principle forbids access to all resources by default, *allowing access only through well-defined boundary points via interfaces.*

The different Links communicate via well-defined technical interfaces "T".

Each Link is a black box *exchanging a predefined minimum data set with the other Links.*

This new structure includes the conjunction of all three architectural elements, Producer-, Grid-, and Storage-Links, in four fractal levels: high-, medium-, low-voltage grid, and customer plant. They must communicate via external interfaces that are subject to data privacy and cybersecurity. The Grid is the central element that connects Producers and Storage across the entire Smart Grid. Producer- and Storage-Links communicate with the Grid-Links via interfaces. Neighbouring Grid-Links communicate with one another via interfaces. The customer plants act as virtual vertically integrated entities, with various Link types (Producer-, Storage-, and Grid-Links) in their ownership.

Some Producer-Links and Storage-Links are electrically connected to the High-Voltage_Grid-Link and communicate through the "T" interfaces. The neighbouring Grid-Links, be high- or medium voltage, also communicate via "T" interfaces. The Medium- and Low-Voltage_Grid-Link are set up on medium and low grid parts, respectively. Some other Producer-Links and Storage-Links are electrically connected to these grid parts and communicate through the "T" interfaces. The neighbouring Grid-Links, whether high and low voltage or medium voltage and customer plants, also communicate via "T" interfaces. At the customer plant level, it repeats the same structure. The Customer-Plant-Grid-Link is set up on the CP grid. The Producer-Links, e.g., rooftop PV-facilities, and Storage-Links, e.g., the battery of an Electric Vehicle (EV) electrically connected to this grid, communicate through the "T" interfaces. LV_Grid-Link is the only neighbour of a CP_Grid-Link, which communicates through "T" interfaces.

> ***Practical Grid-Links areas*** *do not have to be limited to the traditional categorisation of the power grid, such as high-, medium- and low voltage levels. The area size is variable and may contain only a particular part of the corresponding voltage level grid or comprise grids from various voltage levels.*

For example, **one Grid-Link may be set up over an MV and LV grid** if the applications required to set up the secondary control on this grid part are available. Additionally, suppose Producer- and Storage-Links are connected to transmission or distribution grids via their private grid (part of lines/cables, transformer, etc.). In that case, they can establish a Grid-Link in their private grids. Otherwise, they must adjust the setpoints sent by the secondary control of the transmission or distribution Grid-Links to the primary controls of their devices in accordance with the behaviour of the private grids.

Figure 7.5 highlights the standardised *LINK* structure throughout the smart grids.

> ***LINK standardised structure*** *greatly benefits customers, utilities and industry partners as it simplifies the implementation and operation of smart grids and enables the production of technologies at affordable prices.*

It helps engineers and experts worldwide to understand each other better so that they can react and act more quickly.

LINK has several architectural levels representing different degrees of abstraction on which the system can be modelled. Figure 7.6 shows the holistic architectural level, including all Smart Grid and the market [79]. It postulates a market structure based on fractal principles [80] that increases the space granularity of the electricity market. *LINK* establishes different market categories, such as the national/international markets in the transmission area facilitated by TSO, regional markets in the distribution area facilitated by DSO, and the local markets in customer plants, also known as the Energy Community area, facilitated by the Energy Community. The architecture allows customers to participate individually or as Energy Community members in the local market [4]. All Links communicate with relevant markets through "M" interfaces.

7.2.2.2. Fractal-based market structure

Although the electricity markets are undergoing radical change, the current re-dispatch process for congestion management is still costly and drives the transmission grid operation to its limits. On the other hand, most electricity producers connected to the distribution grid do not have any market access. Meanwhile, DSOs are not responsible for any market except for the local flexibility market.
The fractal-based market restructuring aims to pursue two main objectives in the design. The first objective of the restructuring is operational efficiency, making the best use of existing resources.

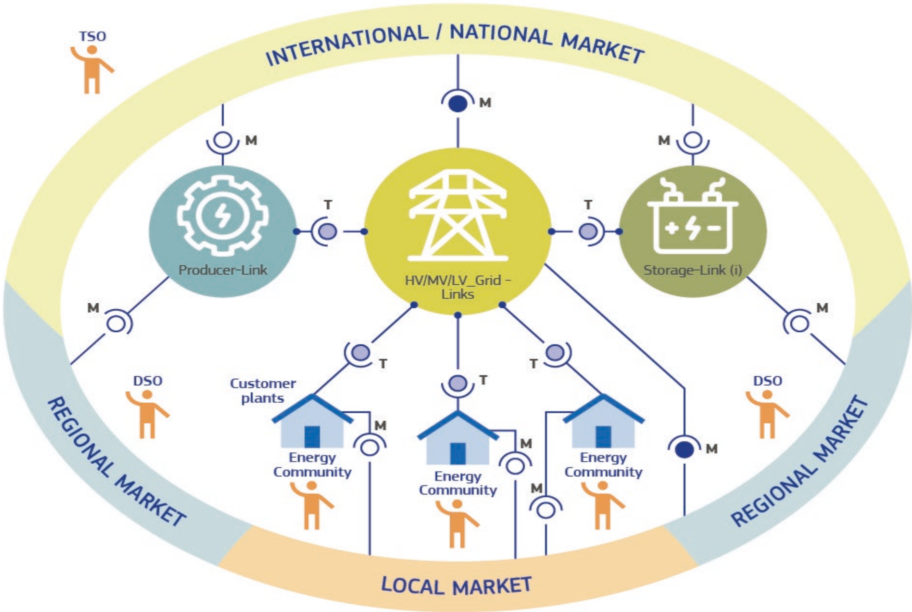


Fig. 7.6. The overall overview of the *LINK* architecture structure considering market.

The second objective is stimulating capital investment by providing appropriate incentives for its efficient use. Efficient capital investments are usually prompted by suitable price mechanisms, e.g., spot prices. However, electricity is not an ordinary commodity; it is a unique property with high reliability. It requires a power reserve to meet demand when supply and demand uncertainties would otherwise create electricity shortages. Intelligent pricing mechanisms should be developed to take this feature into account. A capacity market could also coordinate investments.
The new market design, shown in Figure 7.7, is harmonised with the fractal structure of Smart Grids. It increases the space granularity of the electricity market, establishing different market categories such as the national/international markets in the transmission area, regional markets in the distribution area, and the local markets in customer plants in the EnC area. It is set up in line with the structure, which is simple, promoting the direct and equal participation of the fractal principle:

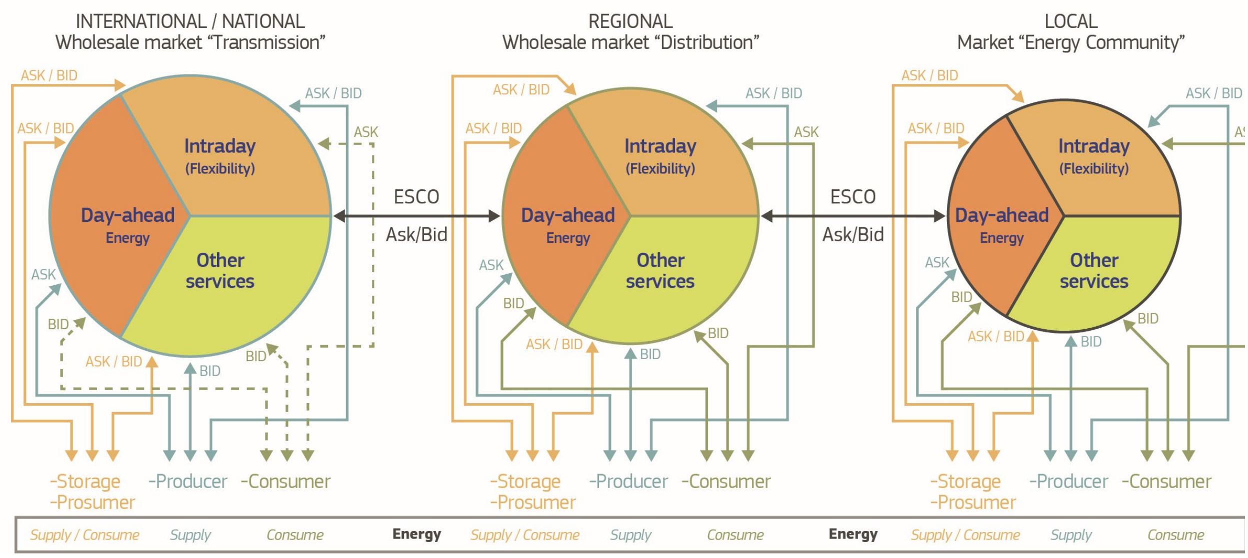


Fig. 7.7. Overview of the electricity market structure derived from the fractal *LINK*-structure.

Similar market patterns and shapes repeated in ever-smaller sizes. The market includes all actors in the market, regardless of the size of their units, making it fair. Splitting markets at the national/international, regional, and local levels significantly reduces the current complexity due to the variety and economics of the resources, their uncertainties, and power system constraints. Furthermore, an efficient welfare-maximising outcome is achieved by optimising each market area and the area's coordination.

The trading volume defines the market size. It refers to the total energy traded during a specific period. The Average Trading Volume (ATV) is calculated by dividing the total Energy Trading Volume (ETV) over a period by the length of the period (h). The result is the average daily trading volume per unit of time.

$$ATV = \frac{ETV(Period) \cdot 24}{Period} \text{ [GWh], [MWh], [kWh]} \tag{7.1}$$

The ATV for the national market ranges from GWh; the TSO facilitates it. For the regional one, facilitated by the DSO, the ATV goes to MWh, while the local market, facilitated by the energy community, ranges to kWh.

TSOs, DSOs, and EnCs enable the corresponding markets in all segments, such as energy (day ahead), flexibility (intraday), balancing market, congestion management market, capacity market, and other services. Market participants have a similar nature in all three market categories. Based on *LINK*-Architecture, production and storage facilities are available in all Smart Grid fractal levels. Their operators participate in all three market categories. Producers supply energy and ask in the day-ahead market, ask and bid in the intraday market, and bid for other services. Storage supplies or consumes energy, and their operators ask and bid in all market segments. Markets have two peculiar additional participants: the prosumers and consumers. Prosumers behave in the market similarly to storage operators because they can supply or consume energy, i.e. they ask and bid in all market segments (prosumers are treated as black boxes). While consumers only consume energy and bid in the day-ahead and intraday markets, they also ask for other services. Energy Service Companies (ESCO) bid and ask between markets.

Each market category is defined as a pricing area, as the largest geographical area within each market participant trades without capacity allocation: i.e. a Grid-Link Grid area where congestion at the boundaries is controllable through the *LINK*-control strategy. The regulator, the TSO, DSO and EnC define these areas. This structure leads to fundamentally new DSO tasks. Unlike in [81], where the TSO transfers the "balancing responsibility for the (local) distribution network to the DSO, who must adhere to a predefined schedule" for the entire DSO area, the schedules in the fractal-based market should be set and negotiated at the level of the TSO-DSO interconnection points.

The local EnC market is designed to allow neighbours to supply each other with electricity and democratically set the pricing rules. This approach makes them more independent of international and regional electricity market developments.

The components to be defined to construct a market mechanism are the format of the bids, the clearing rule, the pricing rule and the information the market participants have access [82].to. The pricing mechanism refers to the process by which forces of demand and supply determine the prices of commodities and the changes therein. It is the buyers and sellers who determine the price of an item. The EnC, as a facilitator of the local retail market, may have a portfolio of pricing mechanisms which may be applied in different circumstances: Merit Order based on arbitrary price offers, Merit Order based on Levelized Cost of Electricity (LCOE) price offers, and Power Purchase Agreements.

7.2.2.3. Grid-Link arrangement versus the current designation of seven grid levels

The German [83], Austrian [84] and Swiss [85] power grids are divided into seven levels, Figure 7.8a:

Level 1: Extra-high voltage grid with 380/220 kV, including 380/220 kV transformation, normally called “Transmission grids”;
Level 2: Transformer between extra-high and high voltage level;
Level 3: High-voltage grid with 110 kV, normally called “Trans-regional distribution grids”;
Level 4: Transformer between high and medium voltage;
Level 5: Medium-voltage grid up to usually 10 to 35 kV, normally called “Regional grids”;
Level 6: Transformer between medium and low voltage;
Level 7: Low-voltage grid, usually 400 V, normally called “Local distribution grids”.

Figure 7.9b) shows the Grid-Link arrangements considering five levels. As discussed in § 7.2.1.3, the size of Grid-Links and the associated assets, the transformers are involved with the part of the feeders or lines for which they can adjust the voltage. In addition, transformers with OLTC are equipped with local voltage control, the setpoints of which can be subjected to Volt/var secondary control,Figure 7.8c).

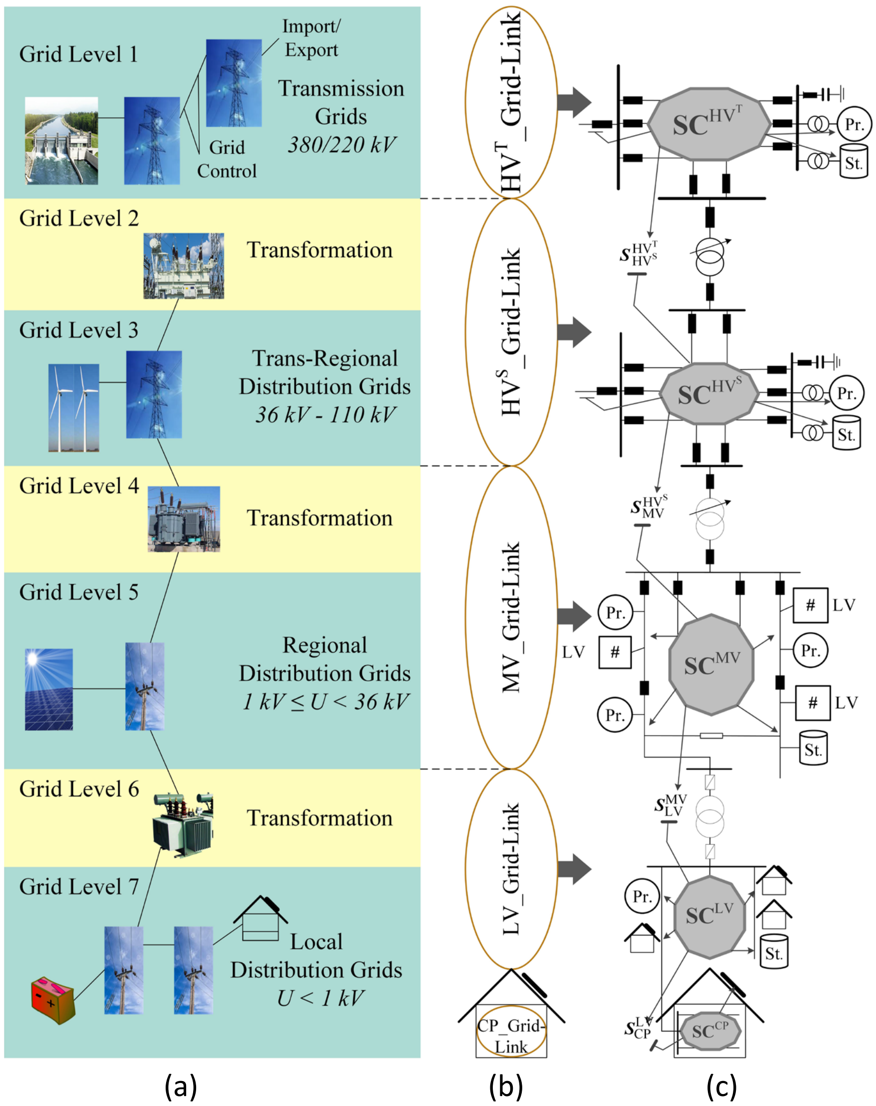


Fig. 7.8. Grid-Link arrangement versus the current designation of seven grid levels: a) Current designated seven grid levels; b) Link set up for five levels; c) Control chain for the five level Link set up.

7.2.3. Operators and asset ownership

This chapter highlights the Link-asset ownership and the operational responsibilities.

7.2.3.1. Operators

Link operators' primary objective is to operate their own Links in a safe, reliable, economical and environmentally friendly manner, in coordination with the other neighbouring Links, to ensure the overall system's safety, reliability, economy and environmental friendliness.

A Link-Operator is a generic term for diverse specialisations. The architecture components Producer, Storage, and Grid define their domain.

1. The **Electricity Producer-Link Operator** (EPO) operates the Producer-Links set up on every power plant regardless of technology and size (excluding very small power plants, such as PVs installed on the customer side). He is responsible for the operational planning and maintaining the power generation schedule, Figure 7.2a).
2. The **Storage-Link Operator** (StO) operates the Storage-Links set up on every storage facility regardless of technology and size (excluding very small storage facilities, for example, batteries installed on the customer side). He is responsible for the operational planning and maintenance of the storage schedule, Figure 7.2b).
3. The **Grid-Link Operators** (TSO, DSO and customers) operate the grid regardless of the voltage level. Figure 7.2c) shows an overview of the vertical chain of Grid-Links. Nowadays, the TSO generally operates the High Voltage Grid (HVG), so in the *LINK*-Architecture, it takes over the operation of HV_Grid-Link. Similarly, the DSO generally operates Medium (MVG) and Low Voltage Grids (LVG). Customers use the CP_Grid-Link and all appliances connected to it.

This architecture allows TSOs to maintain their backbone function by controlling frequency. At the same time, DSOs become the hub between TSOs and prosumers and consumers or energy communities, provided they are established as reliable stakeholders. Each Link or Link-bundle Grid-Operators should:

<u>TSO: </u>Control the frequency.

<u>TSO, DSO, Customer:</u>

- Balance the load and the injection as far as possible, where:
    - The load represents the summation of the system's native load and the scheduled exchange to other Links,
    - The injection represents the generation's summary, injection from storage devices, and the scheduled exchange to other Links (see § 7.3.1 for an illustrative example);
- Resolve thermal limit violations in their Grid-Link by controlling and coordinating the (active or even reactive) power flows with the neighbouring external Links (see § 7.3.2 for an illustrative example);
- Keep the voltage in their Grid-Link or the Grid-Link bundle within limits by controlling and coordinating the reactive power flows with the neighbouring external Links- (see § 7.3.2 for an illustrative example). In extreme cases, the demand response process may drive the curtailment of active power flows;
- Actively manage its Grid-Link or the Grid-Link bundle;
- Monitor its Grid-Link_Grid or the bundle of Grid-Link_Grids;
- Access all the data of the Grid-Link;
- Exchange the data with the neighbouring external Grid-Links and all devices connected;
- Have the right to use and offer services to the neighbours;
- Have the right to dispute with the neighbours to guarantee a reliable and stable operation of his Grid-Link Grid or the bundle of Grid-Link Grids;

- Decide the actions that should be taken for a secure and optimal operation of the own Grid-Link or Grid-Link bundle;
- Be incentivised to invest in adequate solutions beyond physical reinforcements to increase the flexibility of the Grid-Link or Grid-Link bundle.

<u>TSO, DSO, Energy Communities</u>
- Facilitate effective and well-functioning markets.

Operating modes
LINK architecture facilitates two normal operating modes:

1. **Autonomous** - each Link or Link-bundle operates independently by respecting the contractual arrangements with other relevant boundary Links or Link-bundles. All Links are connected, creating an extensive power system.
2. **Autarkic or self-sufficient** – It is an optional normal operating mode that applies in any Link-bundle, consisting of at least one Grid-Link and one Producer-Link Storage-Link. It is self-sufficient and –sustainable without any dependency on electricity imports.
   Recovery - is an option of this operating mode that applies after a blackout (see § 7.4.1.2. Resilient operation structures) to supply electricity to a minimum of appliances.

A familiar resynchronisation process should be established to switch the operating mode from autonomous to autarkic successfully. Each Grid-Link has a secondary control of active and reactive power that may support synchronisation. Depending on the properties of the Links, the resynchronisation with other Links may be automatic or manual. However, the resynchronisation philosophies should be investigated and further developed to determine the most appropriate approach in practice.

In the holistic decentralised *LINK* architecture, all parts of the electricity grid, transmission and distribution, and customer installations are equally important and have a common purpose.

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*The main principle of the LINK architecture is the reliable operation using **dynamic optimisation** of the Smart Grid **by coordinating and adapting the locally optimised Links**.*

7.2.3.2. Assets-ownership

The identification of ownership of the physical assets and control over their data is essential for smart grids' reliable and secure operation. The issue becomes controversial because electricity end-users and their devices are to be included in the operation of smart grids.

In the distributed *LINK* architecture:

- **When TSOs and DSOs own the physical grid assets, they have all the needed static** (electrical parameters, static topology, etc.) **and dynamic** (measurements, switch and tap positions, etc.) **data**. When they operate the grids as concessionaires, the operators must know all the equipment data they operate. Link they operate acts as a black box that exchanges a limited amount of data with other external neighbouring Links, thus guaranteeing their data privacy and a reliable and safe operation of the whole system.
- **Electricity producer operators own the physical electricity-production assets** (including all power plants regardless of technology) **and their static** (electrical parameters, etc.) **and dynamic** (measurements, switches, etc.) **data**. Each Link they operate acts as a black box that exchanges a limited amount of data with the neighbouring Grid-Link, thus guaranteeing their data privacy and a reliable and safe operation of the whole system.

- **Electricity storage operators own the physical electricity-storing assets** (including all storage facilities regardless of technology) **and their static** (electrical parameters, etc.) **and dynamic** (measurements, switch, etc.) **data**. Each Link they operate acts as a black box that exchanges a limited amount of data with the neighbouring Grid-Link, thus guaranteeing their data privacy and a reliable and safe operation of the whole system.
- **Customers own the physical electricity-producing assets,** e.g. rooftop PVs**, storage assets,** e.g. batteries**, flexible household devices,** e.g. heating and cooling facilities **- (**power plants regardless of technology) **and their static** (electrical parameters) **and dynamic** (measurements, switch positions, etc.) **data**. The CP_Grid-Link_Grid they operate acts as a black box that exchanges a limited amount of data with the neighbouring LV_Grid-Link, thus guaranteeing their data privacy and a reliable and safe operation of the whole system.
- **Energy Communities** (provided they are established as reliable stack holders) - may own production and storage assets and, in the given case, grid assets.

7.2.4. Control chain net strategy for the entire power system and customers

LINK stipulates a chain net of controls to enable a flexible, reliable and resilient grid operation with the large scale involvement of the electrical devices of all its end users.

7.2.4.1. Chain Links throughout the entire Smart Grids

Figure 7.9 shows the holistic technical model "Energy Supply Chain Net" with Link chains over the entire Smart Grid. It illustrates the links' compositions and their relative position horizontally and vertically in space. The interconnected HVGs are arranged on the horizontal axis. MV Grids (MVG), LV Grids (LVG) and Customer Plant Grids (CPG) are set vertically. Electricity producers (hydroelectric power plants, wind and PV plants, etc.) and storage (pumped hydroelectric power plants, batteries, e-cars batteries, in the form of heating and cooling, hydrogen production, etc.) are connected at all levels: All Links contain control schemes.

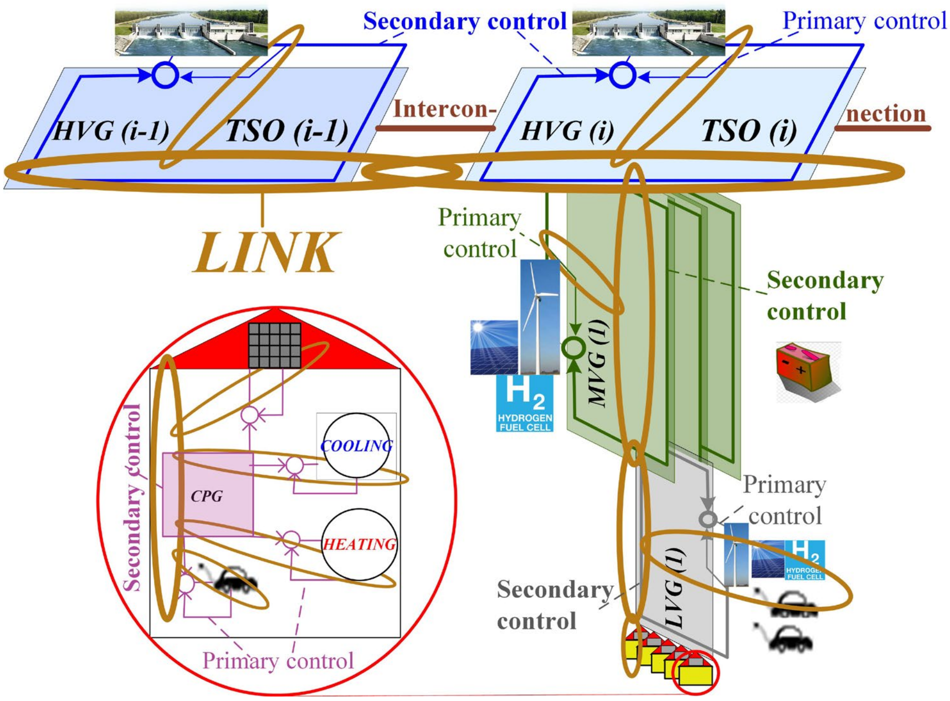


Fig. 7.9. Holistic technical model "Energy supply chain net" with control chains over the entire Smart Grid.

7.2.4.2. Control chains

LINK architecture's standardised structure enables a compact and precise representation of the control strategy, designed as a chain net. The most popular control strategies in power systems are local, primary, and secondary control (see Annex B). They are mainly used in the transmission part of power systems. The chain net control strategy constitutes a coordinated control set, including direct, primary, and secondary control loops throughout the Smart Grid.

***Secondary control** loops enable the coordination and reliable operation of the Grid-Links throughout the Smart Grid.*

Each SC loop in the set calculates the corresponding set-points by respecting the dynamic grid constraints. Equation 7.2 presents SC-loops' union, each containing a subset of primary and direct controls and constraints.

$$Pp\boldsymbol{SC}_{Chain}^{Axis} = \bigcup_{i=1}^{M} \{Pp\boldsymbol{SC}^{Area_i}(\boldsymbol{PC}_{Appl}^{Area_i}, \boldsymbol{DiC}_{Appl}^{Area_i}, \boldsymbol{Cns}_{NgbsArea}^{Area_i})\} \tag{7.2}$$

where *Pp* - the parameter pair Herz/Watt and Volt/var, $Pp \in \{HzW, Vv\}$;

$\boldsymbol{SC}_{Chain}^{Axis}$ - the chain of Secondary Controls on the horizontal, X, and the vertical, Y, axes.

The “Energy Supply Chain Net” holistic model stipulates SC sets in both axes;

Area - the Grid-Link area where the secondary control is set;

M – the number of secondary controls;

Appl – the appliance such as producer, storage, RPD, On-Load Tap Changers (OLTC), or Phase-Shifting Transformer (PhST);

$\boldsymbol{PC}_{Appl}^{Area_i}$ – Primary controls of all appliances connected at $Area_i$;

$\boldsymbol{DiC}_{Appl}^{Area_i}$ – Direct controls of all appliances connected at $Area_i$;

$\boldsymbol{Cns}_{NgbArea}^{Area_i}$ – Constraints between the $Area_i$ and neighbouring areas.

Figure 7.10 shows a schematic presentation of the Grid-Links in the *Y*-axis with the corresponding HzW**SC** and Vv**SC** chain schemas. Since frequency is a global parameter of power systems, the sub-process load-frequency control that happens minute-to-minute is attributed only to HV^T_Grid-Links (set up on today's transmission grids). $HzW\boldsymbol{SC}^{HV^T}$ is stipulated for this Grid-Link. Meanwhile, both sub-processes, operation planning and economic dispatch, apply to all Grid-Links. Consequently, the load-generation balance process in Grid-Links at the distribution and customer plant levels includes only the operation planning and economic dispatch sub-processes. For them, only W**SC** is stipulated. Figure 7.10b) shows the HzW**SC** loops of each Link: $HzW\boldsymbol{SC}^{HV^T}, W\boldsymbol{SC}^{HV^S}, W\boldsymbol{SC}^{MV}, W\boldsymbol{SC}^{LV}, and\ W\boldsymbol{SC}^{CP}$. Each **SC** algorithm calculates the relevant set points by optimising its own decisions that are subject to:

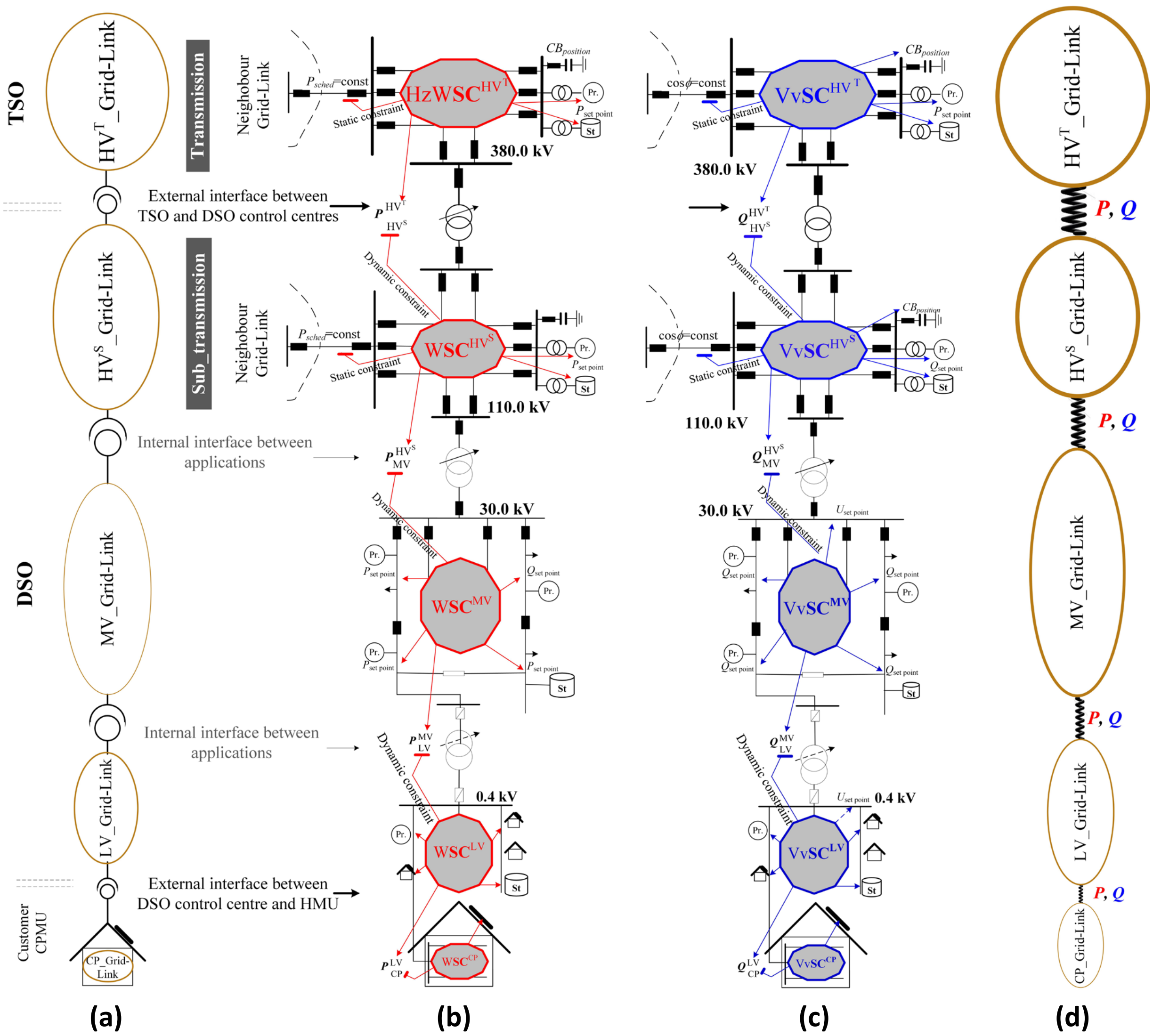
- Its constraints; and
- Dynamic constraints imposed by neighbouring Grid-Links.

Dynamic constraints control the active power flow in a HzW**SC** chain. Depending on the current situation, they should be recalculated in real-time.

The behaviour of the Vv**SC** chain schemas is similar to that of HzW**SC**, Figure 7.10c)).

Table 7.1 shows the control variables and constraints of chained SC loops. They are classified depending on the relevance of the HzW**SC** and Vv**SC** loops. Frequency is an area constraint relevant to the HzW**SC**. The operation active power *P* of the appliances, such as producers and storages connected to the Grid-Link_Grids set up the control variables. *PQ* diagrams of generators and inverters, maximal step number of OLTC for PhST, etc., set up the usual constraints. In the case of Vv**SC**, control variables are the operation reactive power *Q* of generators, inverters, and RPDs, as well as the switch position of capacitors and coils, the transformer tap step, and so on. Like the HzW**SC**, *PQ* diagrams of generators, inverters, maximal step number of OLTCs, installed rating of capacitors and coils, etc., are the Vv**SC** constraints. The electrical coordination of neighbouring Grid-Links occurs through the controlled exchange of the active and reactive power P_{ex} and Q_{ex} between them. These exchanging powers make up the dynamic variable controls of the SC chain. Figure 7.10d) illustrates the flexible interactions of the Links through *P* and *Q* exchanges.

The exchanged active and reactive power P_{ex} and Q_{ex}, on the Grid-Link_Grid boundaries, have a dual nature in the applications' algorithm. Depending on the required action, they can be converted from a grid control variable to a grid constraint and vice versa. Illustrative examples are provided in § 7.3.



(a) (b) (c) (d)

Fig. 7.10. Schematic presentation of the: a) Grid-Links structure in the vertical axis, b) HzW**SC** chain schemes; c) Vv**SC** chain schemes; d) Flexible connection through the active and reactive power.

Table 7.1. Relevant control variables and constraints of chained secondary control loops.

		Control variables	Constraints
HzWSC	Area		Frequency
	Appliances	Operation value of the active power, *P* (producers, storage)	*PQ* diagrams of generators and inverters, maximal step number of OLTC for PhST, etc.
	Grid-Link_Grid	Active power exchange P_{ex} between neighbouring Grid-Links	Active power exchange P_{ex} between neighbouring Grid-Links
VvSC	Appliances	Operation value of the reactive power, *Q, of* producers, inverters, and reactive power devices Switch position of the capacitors and coils.	*PQ* diagrams of generators and inverters, maximal step number of transformers, installed rating of reactive power devices, etc.
	Grid-Link_Grid	Reactive power exchange Q_{ex} between neighbouring Grid-Links	Reactive power exchange Q_{ex} between neighbouring Grid-Links

7.2.4.3. Different strategies to realise secondary control in LINK solution

Secondary controls, which act in a chain in the *LINK* solution, form the highest control level. Each secondary control deals with control variables and constraints defined within its acting area. It sends adjustments via predefined communication channel setpoints to each relevant device equipped with a primary control and area border nodes. The grid behaviour may or may not be considered in the secondary control algorithm, Figure 7.11.

A- Secondary control without consideration of the grid

An example of secondary control without consideration of the grid is Load Frequency Control (LFC), which is used in almost all interconnected electricity grids. LFC needs fewer measurements from the generator units considered in the control scheme and the relevant tie lines. It calculates the required active power output (setpoint) of selected electric generators within a predefined area of an electrical network in response to changes in system frequency and/or tie-line flows, as well as their reference values to meet the area's obligations to contribute to system regulation and/or to consider interchange agreements with other areas without considering the grid. Penalty factors consider transmission grid losses.

The HzW**SC,** like LFC, is set up on the transmission grid but extended with the flows on the intersection TSO-DSO (usually flows in supplying transformers). It can also be realised without consideration of the grid.

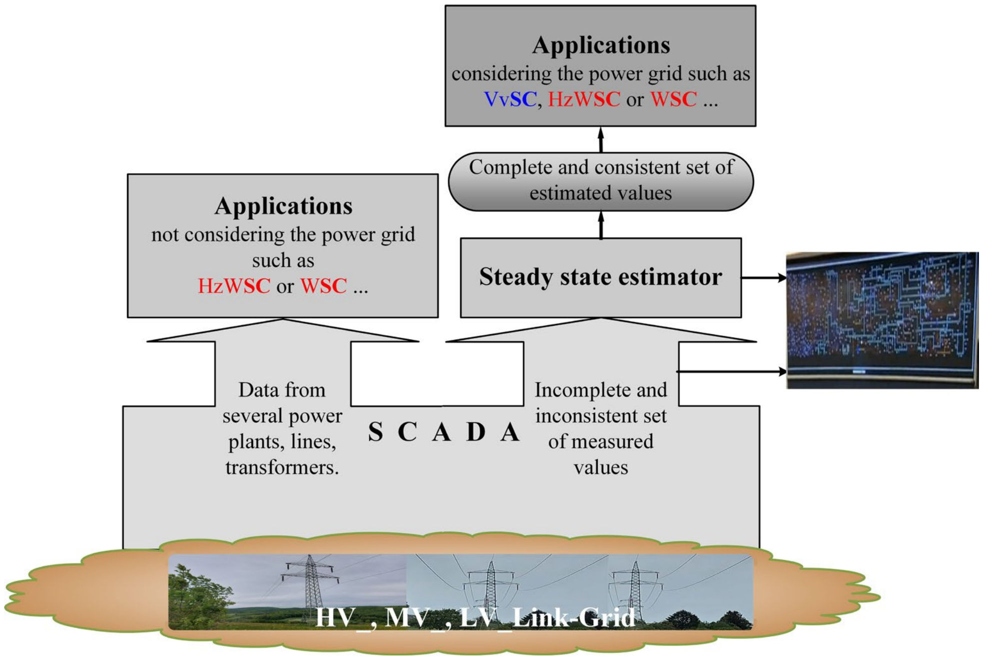


Fig. 7.11. Overview of different realisation strategies of Secondary Control.

The W**SC** may be set at the distribution level and customer plant levels. It calculates the needed flows from the selected DERs, customers (prosumer and/or consumer) and electrical equipment to meet the area's obligations and/or to consider interchange agreements with other neighbour areas (e.g. agreements with the subordinated area that may be the transmission area). Distribution losses may be taken into account by penalty factors. ZUQDE-Project demonstrated the successful implementation of Vv**SC** at a medium voltage level, realised using a Distribution State Estimator [86].

Opposite to HzW**SC** and W**SC**, the Vv**SC** cannot be realised without considering the grid.

Advantages: It is relatively easy and cheap to realise. Fewer measurements are necessary. Active power measurements are only required at the points at which the setpoints are calculated, and the boundary conditions are taken into account.

Disadvantages: The calculation accuracy is not very high. Vv**SC** cannot be realised.

B- Secondary control with consideration of the grid

The secondary control with grid consideration requires measurement and switch position acquisition, and the systematic use of various computer software. The static State Estimator is the heart of the management systems running in real-time based on a mathematical model to clean the data (by treating small random errors, bad data, modelling errors, and parameter errors), and to compute (estimate) quantities and variables which are not directly measured. The static State Estimator provides a complete real-time database that is as clean as possible with the given measurement system.

Advantages: It takes advantage of various measurements to determine the best (optimal) VVC actions during certain time periods with a very high calculation accuracy. It enables Vv**SC** and HzW**SC** to perform, e.g., real-time loss minimisation, conservation voltage reduction and so on.

Disadvantages: The high software sophistication and the large number of measurements.

Secondary control can be realised in open- or closed-loop.

Secondary control in the open loop delivers recommendations to the operator. The control of all devices is not optimised; they operate based on local data.

Secondary Control in the closed loop acts adaptively to dynamic system changes by optimising in real time the set-points of all control devices available in its area.

7.2.5. Scalability and reproducibility

The **scalability and reproducibility of the *LINK* solution is guaranteed from the holistic outset**, as it is designed as a modular system with modules, or Links, that have the same structure and may be repeated in ever smaller sizes, as dictated by fractal principles. Therefore, the distributed *LINK* architecture copes with growth and expansion without any performance loss.

7.3. Mitigation of technical challenges

This chapter describes how *LINK* addresses challenges such as voltage violations, thermal limit violations, balancing problems, reverse power flow between the TSO and DSO, short circuit capacity, and harmonics

7.3.1. Balancing challenges

Balancing is the best-known and most elaborate challenge arising from the distributed and renewable energy sources connected to the distribution grid and at the customer plant levels. It represents a market and technical challenge. *LINK* makes use of the Shared Balancing Responsibility model [87] .

7.3.1.1. Balancing market challenge

LINK stipulates the restructuring of the current whole market, which has a centralised design, to a decentralised design reflecting the fractal geometry of the smart grids [4]. It increases the space granularity of the electricity market by introducing new market categories to the existing ones in the transmission area, renamed national/international market. The new markets are the regional markets in the distribution area and the local markets in the EnC-area of customer plants. The regional market is a whole market with DERs and customers, or an EnC, whose members are connected in the distribution grid, as players. The DSOs take over the role of market facilitators for the regional markets. All market categories share the balancing responsibilities. This form of balancing process would potentially prevent TSO-DSO conflicts that arise now or may arise soon.

7.3.1.2. Balancing technical challenge: Demand response

The secondary controls chain for active power (Watt**SC**) ensures real-time balancing of supply and demand throughout the entire chain from high-up to low-voltage grid and customer plant by adjusting the production output or energy storage charge and discharge. In cases of supply shortages, critical loads may be prioritised, while deferrable loads may be shifted or curtailed as foreseen in the SC algorithm. Frequency control will be carried out in the transmission grid as before. *LINK* supports the flexible operation of electricity producers, storage and customer plants by enabling the demand response. Demand Side Management (DSM) and DR are processes that try to modify the electricity consumption shape of customers. DSM was coined following the 1970s energy crisis, and since then, it is continuously used by electricity utilities as an instrument for increasing efficiency and shaving peaks [88]. It includes almost medium to long-term countermeasures. With the progress of technology and the rise of distributed generation, other perspectives have opened, such as on-demand shifting and the reduction of total energy consumption. DR rose and dedicates to short-term load reduction in response to a signal from the power grid operator or a price signal from the electricity market. Nowadays, DR is being introduced very slowly, especially in the residential, commercial, and small business sectors [89]. The proposed structures are pretty complicated and require significant data exchange [90][91] that provokes a remarkable increase in the complexity of system operation.

LINK allows the proper launch of the emergency and price-driven DR. In the case of price-driven DR, the demand change is triggered by a price signal from the electricity market. While in the case of emergency DR, the Grid-Link operator triggers, e.g. the demand reduction to alleviate overloading in their own area.

The activation of residential, commercial, and small business sectors, which join the real-time pricing demand response process through already concluded contracts, may be triggered at any time. Their degree of participation in the demand response process may be different depending on the time of the day, duration interval, price value, etc.

Price-driven demand response: The electricity price in the market decreases due to an electricity surplus. All market participants and market operators are notified so that they can act on time. Figure 7.12 shows the information flow during price-driven demand response. It enables residential, commercial, and small business sectors to perceive transparent energy prices and contribute to the reliable and efficient operation of Smart Grids. Let us assume that conditioned from weather and the minimal load consumption, the electricity surplus in the market provokes a price decrease. The new, reduced price is sent via the aggregator or EnC through the market interface "M" to the HMU of each customer. After checking the possibilities of demand increase in CP, HMU-123 requests to increase the consumption by 0.4% via the technical interface T to the BLiN A1^L of LV_Grid-Link_1. Consequently, the Low Voltage System Grid-Link Operator-B (LVSO-B) checks power flow limits under the new conditions at its own Grid-Link. If the power exchange in the BLiN A2^M with the MV_Grid-Link_2 is affected, LVSO-B should pass over the request to the Medium Voltage System Grid-Link Operator-A (MVSO-A). After collecting all incoming requests, MVSO-A calculates power flow in its own Grid-Link. He requests the High Voltage Grid-Link System Operator (HVSO) for a flow increase of 0.6% in the BLiN B^H. HVSO collects all incoming requests and performs the necessary calculations, i.e. power flow, n-1 security, etc. If no limits are violated, HVSO approves the new setpoints and notify the MVSO-A. The last one accepts the new set points in BLiNs A2M and B2M and notifies LVSO-B. The latter, in turn, approves the new set points in BLiNs A1L, A2L, and B2L and notifies the respective HMUs to execute the demand increase. The one flow diagram of emergency-

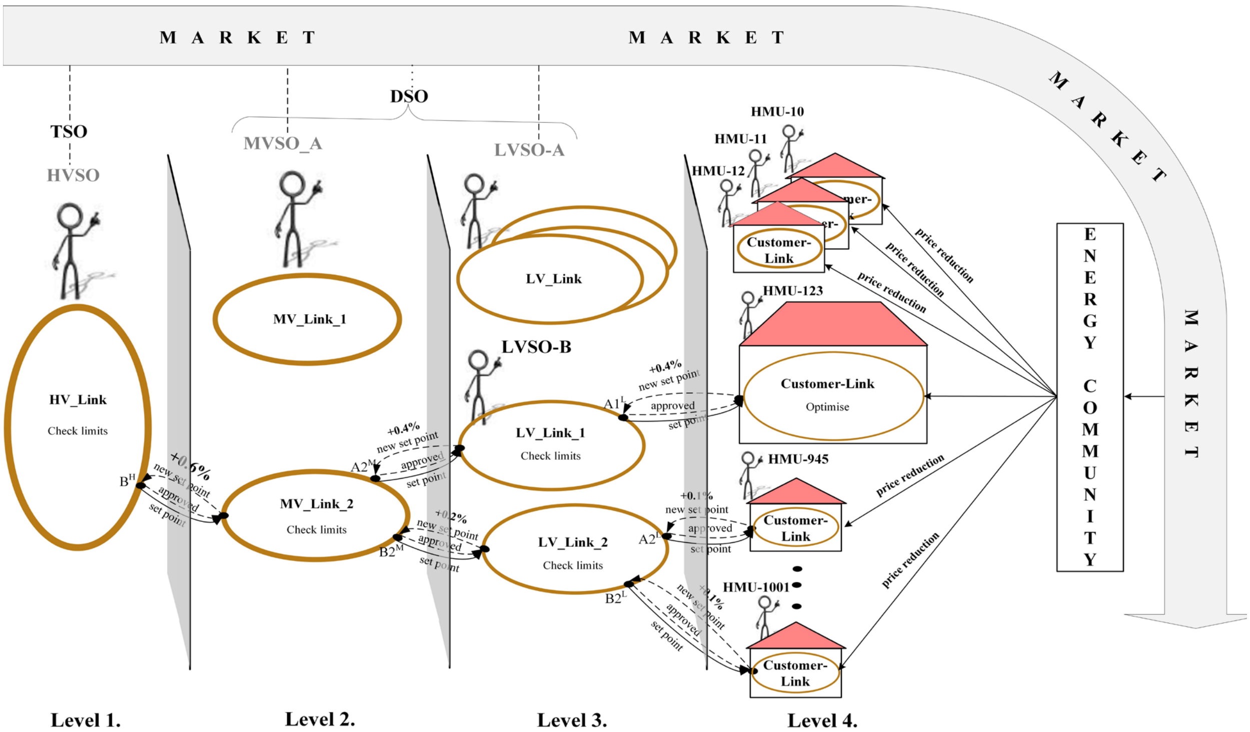


Fig. 7.12. Information flow of the price driven DR process.

and price-driven demand response enables residential, commercial, and small business sectors to perceive transparent energy prices. It contributes to the reliable and efficient operation of the electric power system.

Figure 7.13 shows the use case of the DR process supporting the congestion alleviation process. In a high-voltage transmission line, a forthcoming overload is assumed. TSO starts the congestion alleviation process and notifies the DSO after defining the relevant TSO-DSO connection points. DSOs can use the Conservation Voltage Reduction (CVR) to decrease the consumption from the transmission grid in the relevant connection points. If this action is not sufficient to fulfil the TSO needs, the request to change the setpoints goes to EnC or is directly sent to the customers. The latter can reduce demand at the charging point by using the smart charger to change the charging patterns of e-cars, shifting energy consumption to a different time.

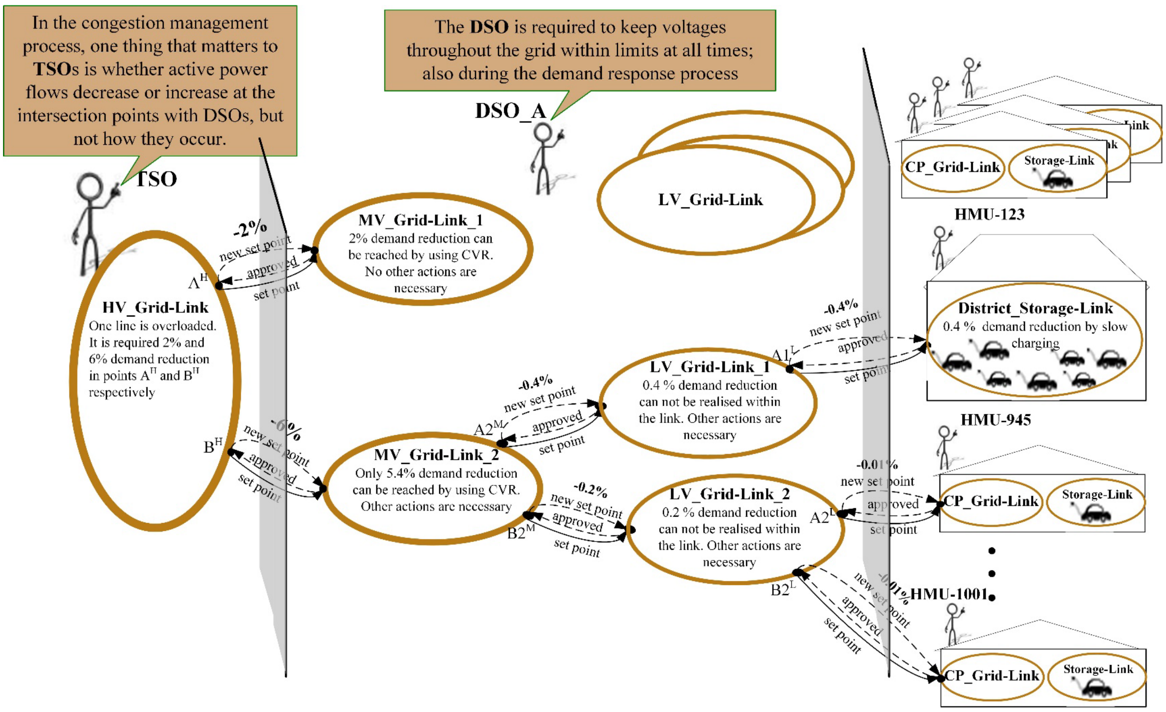


Fig. 7.13. Information of emergency-driven DR process: Congestion alleviation - line overload on HVG.

7.3.2. Voltage violations

Violating the voltage upper limit is one of the most crucial challenges the DSOs are experiencing for a high penetration of the distributed generation.

7.3.1.1. Voltage violation elimination using VvSC chains

Volt/var control is essential in operating a power grid and, consequently, Smart Grids. In *LINK*-Solution, the Volt/var control or management occurs in each Grid-Link. The control loops outlined on each Grid-Link create a Volt/var interaction chain.

The dynamic grid constraints are introduced to enable a resilient interaction of Vv**SC** loops on the chain. They have a dual nature as they can be converted from grid constraints to grid control variables depending on the action to be performed.

This dual nature is illustrated through the use-case voltage monitoring and control, Figure 7.14. HV^T_Grid-Link is connected to BliN-B of HV^S_Grid-Link via the BLiN-A. Between them flows $Q_{HV^S}^{HV^T}$. Figure 7.14a) shows the system operation in the presence of a contingency: Voltage violation in the sub-transmission grid. The $VvSC^{HV^S}$A runs to find an adequate solution without violations: The actual $Q_{HV^S}^{HV^T}$ constraint is not optimal for the HV^S_Grid-Link operation. The application relaxes the operation constraint on point B by changing the status of $Q_{HV^S}^{HV^T}$ from grid constraint to the grid control variable. The $Q_{HV^S}^{HV^T}\_new$ is calculated, and a change request is sent to HV^T_Grid-Link, Figure 7.14b). HV^T_Grid-Link checks the new request by treating the $Q_{HV^S}^{HV^T}\_new$ like a constraint and vice versa; The grid controls are set in dynamic lists. Figure 7.14c) shows the approving and setting process of the new desired set point. The same procedure is used to alleviate the violations or optimise the operation in other Link types (other grid parts).

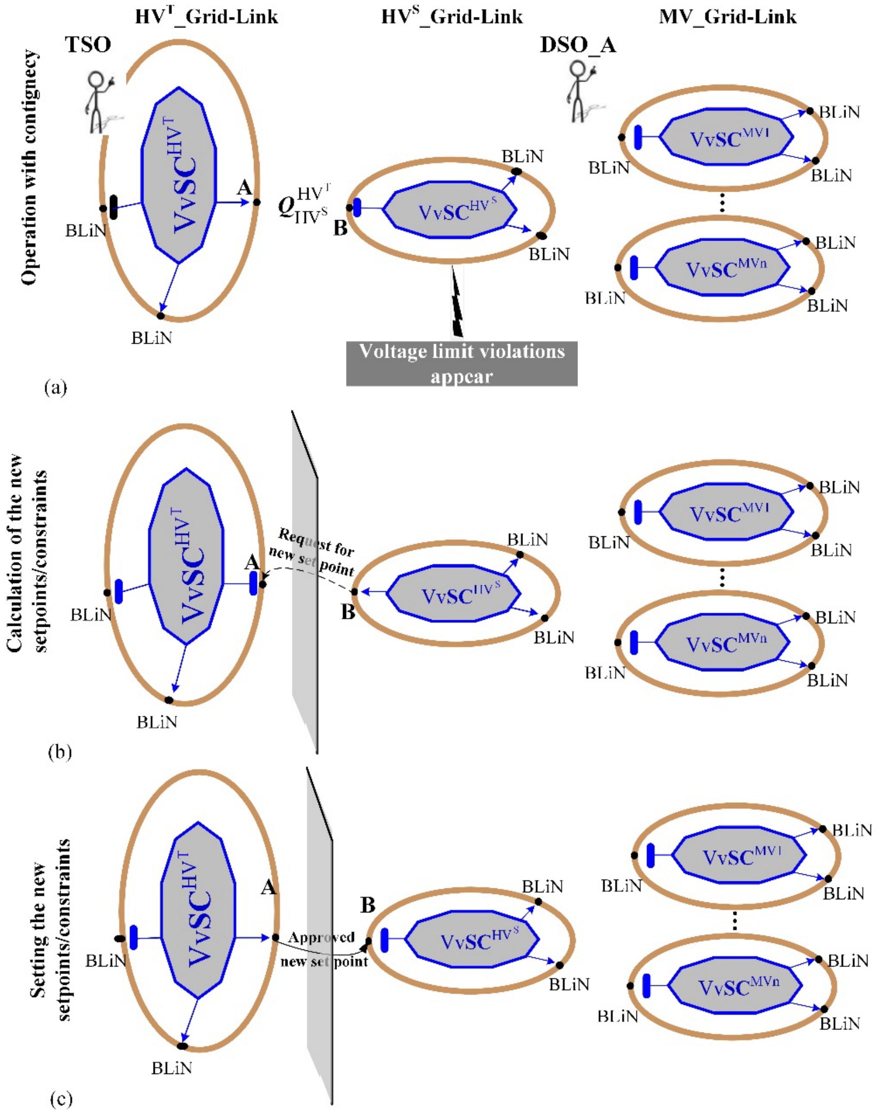


Fig. 7.14. Use case - voltage violations in the sub-transmission grid: a) Operation with contingency; b) Calculation and change request of the new set-points/constraints; c) Approving and setting of the new setpoints/constraints.

*7.3.1.2. Practical implementation of the Vv**SC** at the MV level*

The Vv**SC** at the MV level is realised in the frame of the industrial research project ZUQDE (Central Volt/var Control in the presence of DGs), Salzburg, Austria [58], Figure 7.15.

The applied algorithm calculated the set points by respecting the constraint, which was set to the HV/MV transformers through a constant cosϕ. The set points, reactive power Q and voltage were sent to all four “run of river” Distributed Generators (DG) and to the feeder head bus bar, respectively, Figure 7.16. All relevant generators were upgraded along with the primary control, thus building up the Producer component. All distributed transformers were modelled as loads. As a result, the voltage in the Lungau region was automatically controlled, and the grid was dynamically optimised in real-time for more than one year.

The

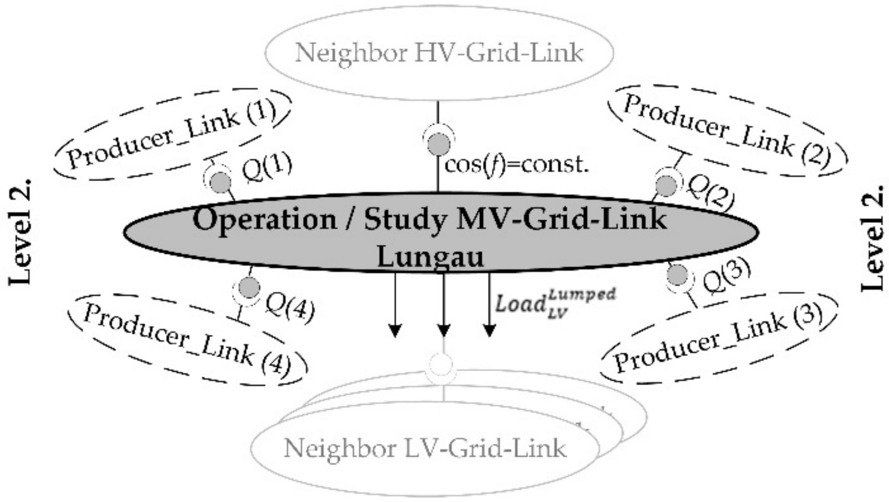


Fig. 7.15. The implemented technical/functional *LINK*-based architecture in ZUQDE project.

$$VVC^{Y-axis} = \{VV\boldsymbol{SC}^{MV}(Volt\boldsymbol{PC}_{OLTC}^{MV}, var\boldsymbol{PC}_{DG}^{MV}, \cos(\varphi)\boldsymbol{Cns}_{HV}^{MV})\} \quad (7.3)$$

voltages, power and current during the CVR switching process are shown in Figure 7.17. The snapshot is taken using the SCADA system of the control centre. The voltage curves in one of the 30kV bus bars and of the active, measured on the supplying transformer level, are highlighted.

The curves shown in blue, green and yellow are significant in the consideration. The blue curve shows the voltage set point on the 30kV side of the supplying transformer. At 10:18 am, the VVC set in the CVR-mode calculated new set points for the 30 kV bus voltage calculated new set points for the 30 kV bus voltage and the reactive power of DGs. The voltage set point changed from 31.7 kV to 30.5 kV. This corresponds to an adjustment of the On-Load-Tap-Changer by two steps. The green curve shows the measured voltage on the 30 kV bus bar. Due to the reaction time of the OLTC, the new voltage set point was reached after about one minute. The yellow curve shows the active power, which decreases from 19.9 MW to 19.0 MW. This corresponds to a reduction of the active

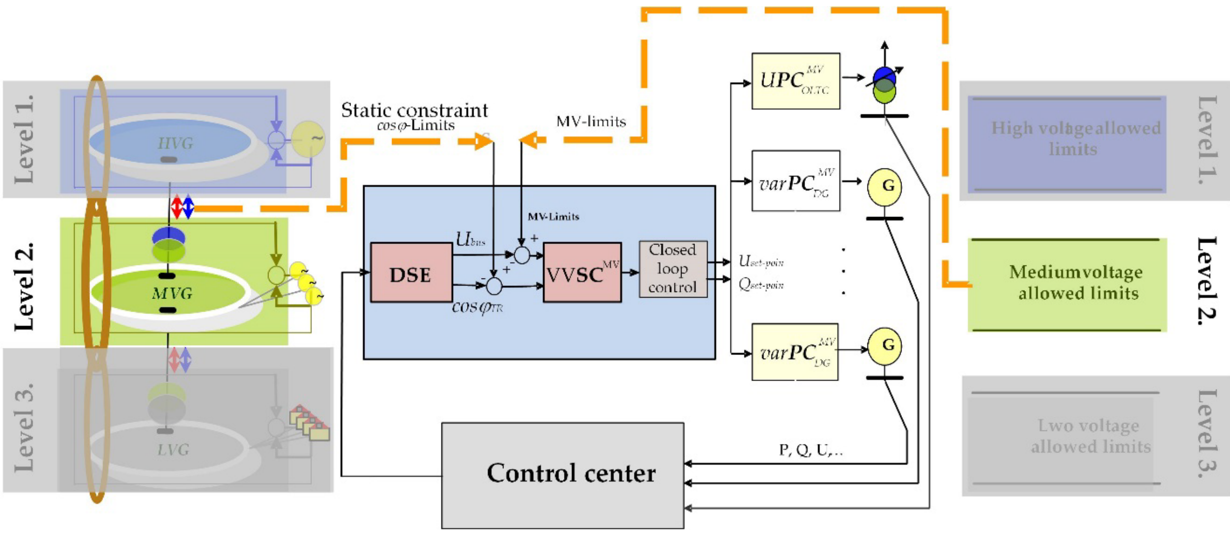


Fig. 7.16. The realized Volt / var control scheme in management system level in ZUQDE project [86].

power by 4.7%. The light blue or turquoise curve shows that the voltage reduction slightly increases the current.

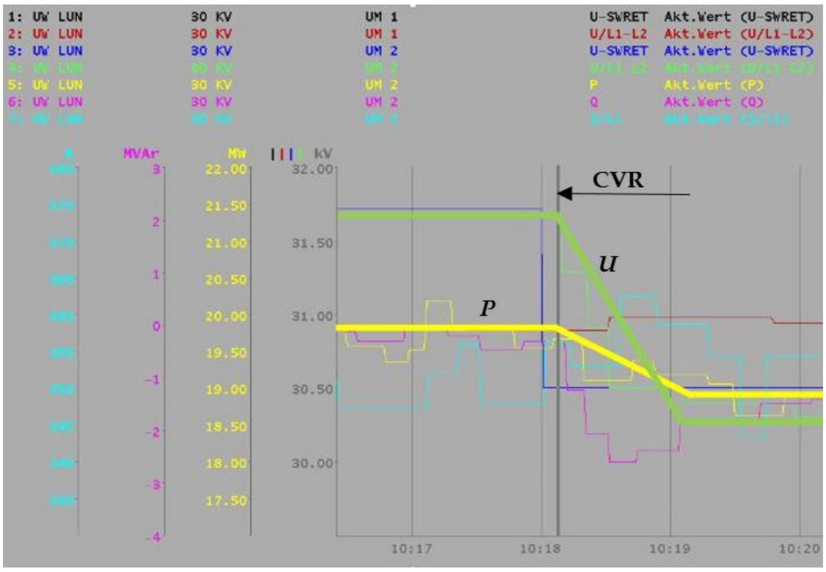


Fig. 7.17. Voltage and active power course during the execution of CVR process in ZUQDE project [95].

7.3.1.3. Optimal Volt/var control arrangement

The control ensemble *X*(*U*) local control combined with *Q*-Autarkic customer plants performs better than the cos*φ*(*P*) and *Q*(*U*) local control strategies applied on photovoltaic inverters and the on-load tap changers in distribution substations [92]. It provokes the lowest voltage limit distortion, requiring the least amount of action to maintain the voltage throughout the day. It sufficiently widens the upper voltage limits to be respected at the distribution and supplying substations around midday. Consequently, voltage limit violations at the customers' delivery points are eliminated, provoking relatively low reactive power exchanges between the medium and low voltage grids, lower losses, and lower distribution transformer loading.

Figure 7.18 shows the setup where the *X*(*U*) local control is combined with CP_Q-Autarky. To realise CP_Q-Autarky, the Vv**SC**^{CP} adapts the primary control settings of the corresponding producer- and storage-Links always to eliminate the reactive power flow through the BLiN$^{LV\text{-}CP}$ at all times. RPDs

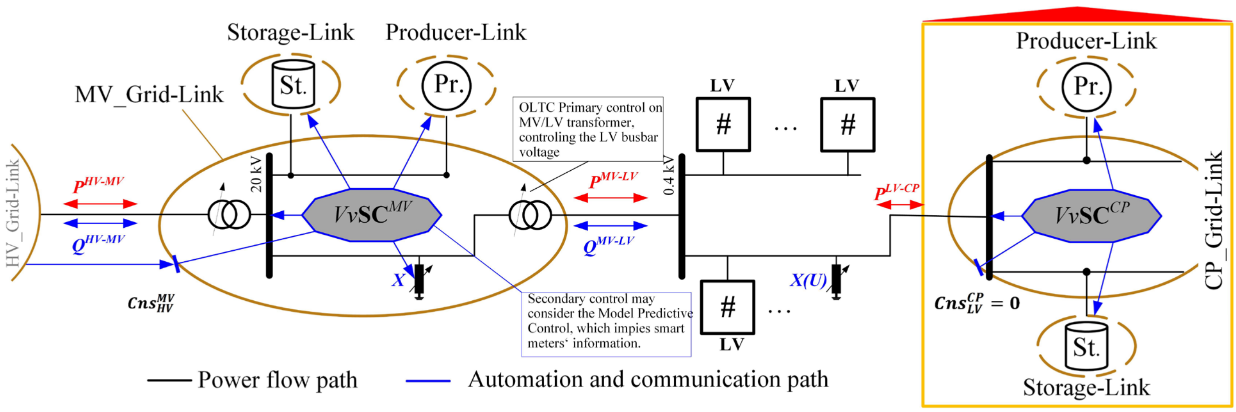


Fig. 7.18. Overview of the optimal Volt/var control arrangements in MV, LV and CP levels.

equipped with the *X*(*U*) local control are connected to selected LV feeders. Equation (7.4) compactly presents the resulting Volt/var control setup.

$$VVC^{MV-LV-CP} = \begin{cases} VV\boldsymbol{SC}^{MV}\left(Volt\boldsymbol{PC}^{MV}_{OLTC}, Volt\boldsymbol{PC}^{LV}_{OLTC}, var\boldsymbol{PC}^{MV}_{DG}, \cos(\varphi)\boldsymbol{Cns}^{MV}_{HV}\right), \\ \boldsymbol{LC}^{LV}_{RPD}, \\ var\boldsymbol{SC}^{CP}\left(var\boldsymbol{PC}^{CP}_{Pr}, var\boldsymbol{PC}^{CP}_{St}, var\boldsymbol{Cns}^{CP}_{HNgbLV} = 0\ kvar\right). \end{cases} \tag{7.4}$$

Usually, the distribution transformers (MV/LV transformer) are not equipped with OLTC. If they are equipped with it, they can control the LV busbar voltage locally. The algorithm of secondary control may also consider the Model Predictive Control, which implies that the consumption information of smart meters is used to define the voltage setpoints of the OLTC.

7.3.2. Thermal limit violations

The following shows an example of overloading elimination on HV or MV grids. Figure 7.19 is a schematic example of generators (producers) connected to the MV network, causing a backflow of such magnitude that in an N-1 state, the transformer can lead to overloading in the HV/MV (e.g. in 110kV/22kV) Substation. Then the DSO can intervene if it has a method for it; even if the PVs, for example, have a specific droop regulation, it can be overridden.

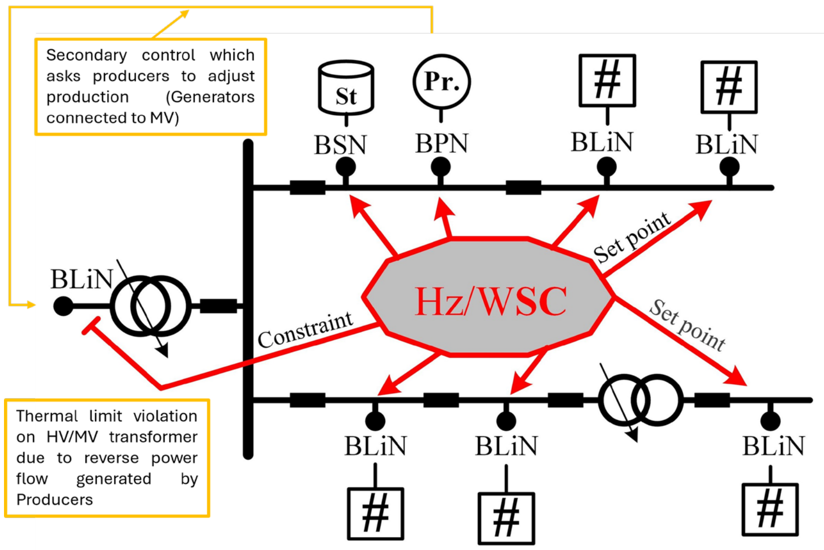


Fig. 7.19. Overview of the optimal Volt/var control arrangements in MV, LV and CP levels.

Then the DSO intervenes through a secondary control, measuring the current on the transformer, and e.g. it predicts the expected load with a kind of forecast method (which can also be a heuristic), and issues the command depending on this.

This secondary control can be realised in a closed loop, where the SCADA issues the command, or in an open loop, where a platform issues instructions (on a market basis, an agreement is the basis, while in the case of curtailment, this is the final solution, and legal obligation).

7.3.3. Controlling TSO-DSO intersection points

LINK enables the cooperation and interaction of the TSOs with the corresponding DSOs to perform all processes necessary for the systems' reliable, secure, flexible and resilient operation.

The interface between the HV_ and MV_Grid-Link is in Figure 7.5, § 7.2.2.1. The fractal-based technical management structure denotes the instrument for coordinating the TSOs and DSOs. Interface parameters are defined based on a meticulous investigation of all processes needed for the safe, reliable, and efficient operation of power systems. Table 7.2 shows all power system operation processes and the corresponding interface parameters on the TSO-DSO cross-border that are needed to perform them. For example, the exchange of the real-time values V_{meas}, δ_{meas}, P_{meas}, and Q_{meas} on boundary nodes is necessary for the **monitoring process**. Frequency f_{meas} is also required for this process, almost when MV_Grid-Link operates autonomously. Docking of the MV_Grid-Link into the HV_Grid-Link requires a synchronisation process and a frequency monitoring of both Links. It is necessary for the **load-generation balance process** $P_{des}^{nexthour} \pm \Delta P$. For **voltage assessment, it** is essential $Q_{des}^{nexthour} \pm \Delta Q$. For **short circuit calculation** and static security, processes are required in the online calculated parameters like I_{equiv} and Z_{equiv}. For the **dynamic security** (angle, voltage) calculation process, online calculated parameters like dynamic equivalent generator parameters are required. For the **reserve management** and **demand response processes**, different schedules are necessary for secondary and tertiary reserves and demand response capability.

Table 7.2. Interface parameters on the TSO-DSO cross-border

Operation processes	**Data exchange between HV_Grid-Link and MV_Grid-Link**
Monitoring	f_{meas}, V_{meas}, δ_{meas}, P_{meas}, Q_{meas}
Load-generation balance	$P_{Schedule}^{dayahead} \pm \Delta P$, $P_{des}^{nexthour} \pm \Delta P$
Voltage assessment	$Q_{Schedule}^{dayahead} \pm \Delta Q$, $Q_{des}^{nexthour} \pm \Delta Q$
Short circuit calculation	I_{equiv}, Z_{equiv}
Static security (n-1)	I_{equiv}, Z_{equiv}
Dynamic security (angle, voltage)	Static and dynamic load characteristic k_{PV}, k_{QV}, k_{Pf}, k_{Qf}, … Dynamic equivalent Generator parameters like x_d, x'_d, …, T'_{d0}, … Equivalent governors, turbine parameters like K_1, T_{G1}, … Equivalent voltage regulator, static exciter parameters like K_A, T_A, …
Reserve management	Schedule for secondary, tertiary reserves
Demand response	Schedule for demand response capability

Real-time controlling on the TSO-DSO intersection points is realised through the chain of the secondary controls in the vertical axis, see Figure 7.10 in § 7.2.4.2. Control chains.

7.3.4. Harmonics

The operation or use of non-linear systems or devices causes harmonics. As these elements are expected to increase in power grids, harmonics are also likely to increase. LINK postulates the use of control loops on a large scale, but their effects on harmonics have not yet been thoroughly investigated. The link arrangement is expected to facilitate the detection of harmonics and contribute to an appropriate relief solution. The first laboratory investigation on the effect of the secondary control at vars in customer plant level (var**SC**^{CP}) shows that the reactive power is properly compensated to transform customer plants into a self-sufficient reactive power unit. No effect on harmonics has been observed.

Nevertheless, the consumption or injection of high reactive power values indicates a reduction in harmonics. This behaviour shows a good suitability of using inverters as *X*(*U*) controls at the feeder end, see Figure 7.18, [93]. Further investigations are needed to analyse the interdependencies.

7.4. *Flexibility and resilience*

7.4.1. Operation

The concept of automation is ancient; it was introduced around 270 BC. With the emergence of computer technologies in the mid-20th century, digitisation has become an inseparable part of automation. In contrast, digitalisation results from Internet Technologies, which developed at the beginning of the 21st century.

From the beginning, different parts of power systems (for example, generation) were automation objects. Later, the introduction of SCADA and various management systems made it possible to increase the automation level. The integration of distributed generation and the highly volatile nature of the new renewable energy sources (wind and solar) require more automation in power systems and at the customer level.

***Automation is the core of the LINK holistic architecture** and a prerequisite for successful market design and the effective implementation of digitalisation Figure 7.20.*

Automation shapes the physical behaviour of power systems, followed and respected by the human-made market rules. Digitalisation is necessary to enable the active participation of customers, electricity producers, and storage operators into the market.

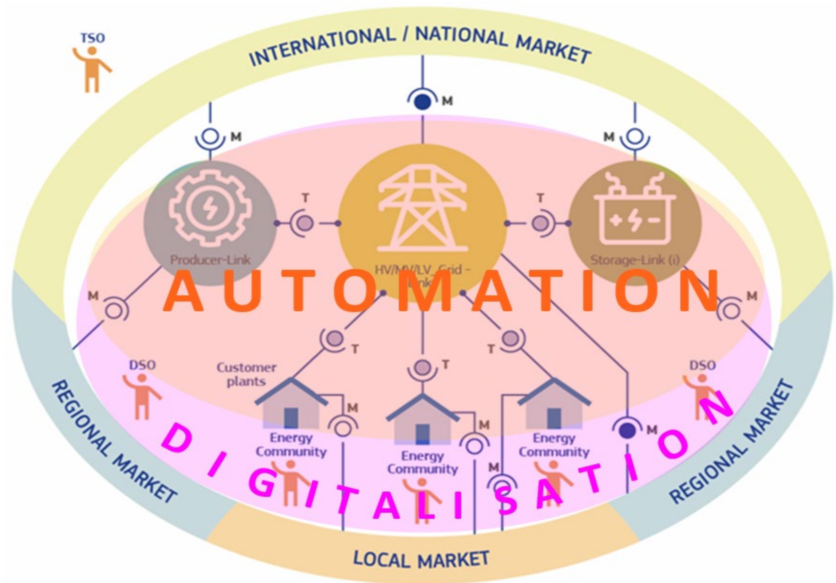


Fig. 7.20. Overview of the application areas of automation and digitalisation techniques in the *LINK*-architecture.

7.4.1.1. Flexible operation

LINK allows for flexible interaction between the different parts of the grid and between the grid and the customer plants—the latter are changing their nature from passive to active. It reliably coordinates the operation of the grid and the distributed energy resources. It uses the secondary control as a base interaction instrument set up on a large scale throughout the different regions or parts of the grid, enabling a flexible operation in large scale.

By design, all actors, TSOs, DSOs, EnCs or prosumers may equally provide flexibility and ancillary services to each other in normal operation processes, especially during planned outages and unplanned disturbances. The legislation and the technical and commercial framework conditions between the actors within the ecosystem must be established. *LINK* may be an alternative that enables effective EnC deployment and sector coupling, which is a decisive flexibility source for future power systems. This architecture facilitates TSOs to retain their backbone function for the electricity grid while transforming the DSOs into the hub between the TSOs and the EnCs.

The flexibility enabled by the Link arrangement of the power system and CPs allows for robust resilience. The chains of secondary controls enable the decentralised recovery process even after a total blackout.

7.4.1.2. Resilient operation structures

The comprehensive DR integration combined with *LINK* offers a tremendous opportunity to increase resilience by reducing recovery time after a partial or total blackout, Figure 7.21.

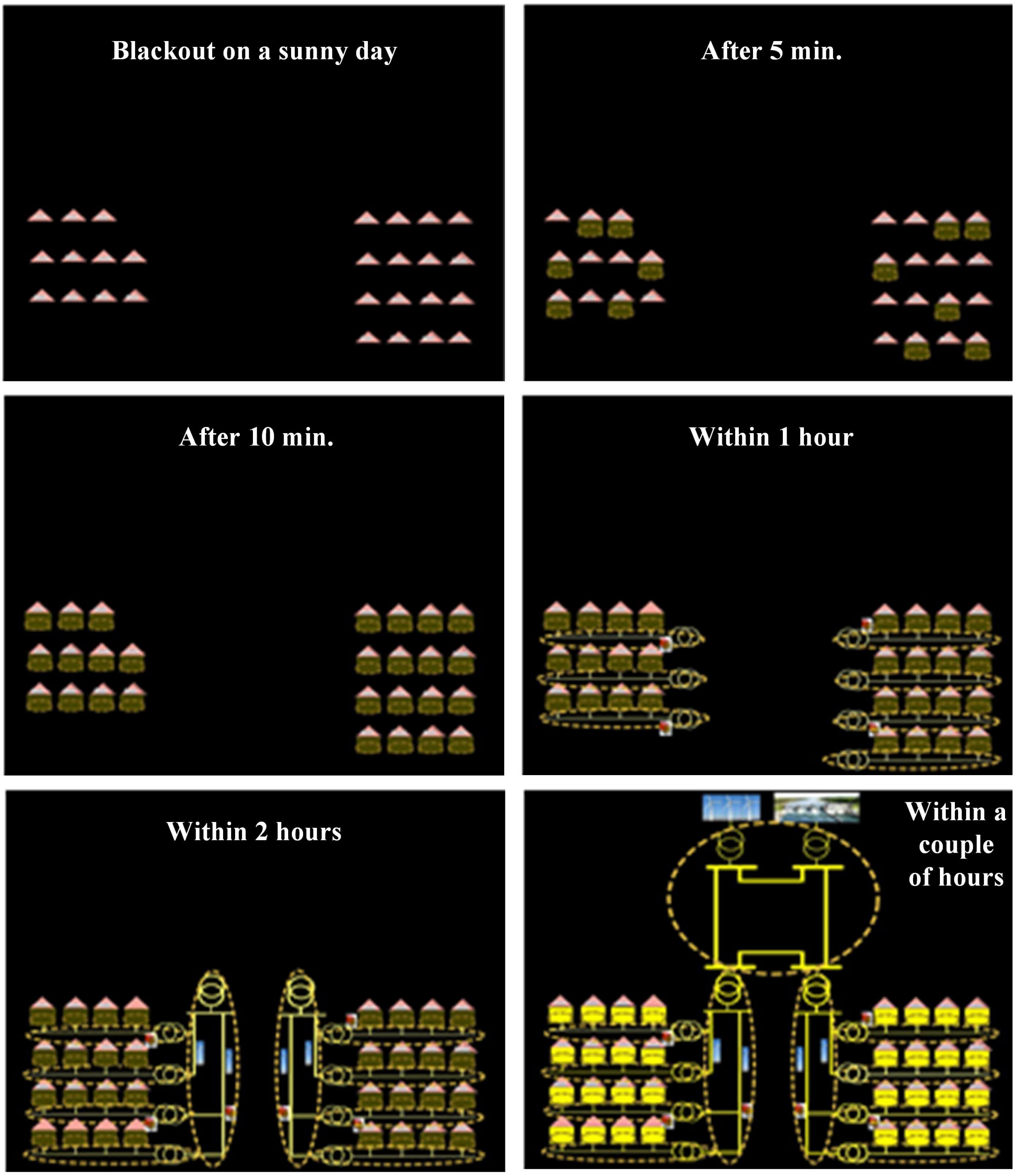


Fig. 7.21. Resiliency increase: Recovery steps after a total blackout.

This use case describes the service restoration process after a blackout in-volving distributed resources. With the associated chain of secondary controls, the Grid-Link structure enables a flexible distributed operation of the Smart Grid for recovery after a large blackout. Figure 7.21 describes the recovery process after a large blackout on a sunny day.

Blackout on a sunny day: All customer plants with installed PVs have the opportunity to supply individually at least their minimal load by changing the operation mode from normal-autonomous to autarkic-recovery. **Within 5 min**, some of the customer plants with PV have set the operation mode to autarkic-recovery and have partially supplied the load. **After 10 minutes, a**lmost all customer plants with PV have set the operation mode autarkic recovery and have partially supplied the load. **Within one hour, i**n each LV_Grid-Link is set the operation mode to autarkic-recovery, thus supplying partially the customer plants without PV installation.

7.4.2. Planning

Although the power grid is a unique, interconnected vast electromagnetic machine, its operation is highly fragmented. The increasing share of distributed energy sources makes its reliable operation even more complex than it already was and poses significant challenges for grid operators. The holistic approach allows for flexible interaction between the different parts of the grid and between the grid and the customer plants—the latter are changing their nature from passive to active. It reliably coordinates the operation of the grid and the distributed energy resources. Figure 7.21 illustrates the flexibility for resilience based on the holistic *LINK* architecture for the operation in real time or online, the operation planning in the short term, and the investment planning in the medium or long term [94]. The holistic architecture is designed based on the fractal principle of repeating the fractal pattern or shape in ever-small sizes.

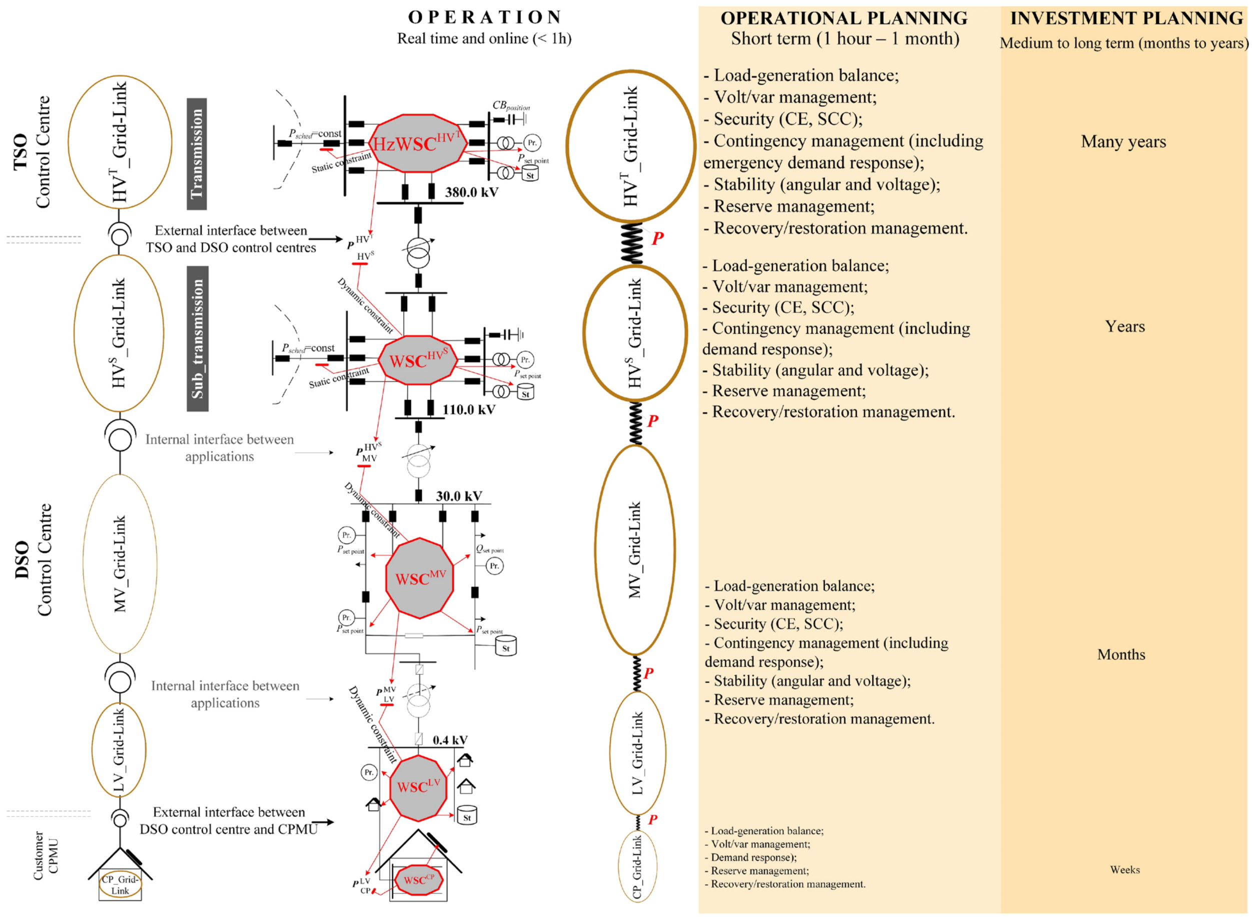


Figure 7.22. Flexibility for resilience based on the holistic *LINK* approach.

The holistic *LINK* solution uses the secondary control as a base interaction instrument set up on a large scale throughout the different regions or parts of the grid. It is set up for both Hz/Watt and Volt/var quantities. Figure 7.22 shows only the Hz/Watt control chain strategy. Based on the fractal principle, the Hz/Watt or Watt Secondary Controls (Hz/WSC or WSC) are set up in all voltage levels, High-, Medium- and Low Voltage (HV, MV and LV), and Customer Plant (CP) levels. SC loops enable the coordination and reliable operation of the Smart Grid-Links (Smart Grid includes the power grid and the grid of the customer plant premises). Each of the SC loops in the set calculates the corresponding set points by respecting the assets constraints and the dynamic constraints imposed by Grid-Links. The dynamic grid constraints enable a flexible interaction of Hz/WSC or WSC loops on the chain in real-time or online operation. They have a dual nature as they can be converted from grid constraints to grid control variables depending on the action to be performed. Having the Autonomous and Autarkic or Self-sufficient operation modes, the *LINK* solution enables a flexible, decentralised operation of the Smart Grid for recovery after a large blackout and, thus, sustainable operation even in these extreme cases. Functional flexibility in real-time or online operations is also considered in operational planning. Based on the fractal feature, the same bundle of calculations, such as load generation balance, Volt/var management, reserve management, etc., should be performed in all voltage levels to guarantee reliable short-term planning for the whole Smart Grid and the participation of all actors in this process. The same logic applies to investment or long-term planning, where the time of project development at different levels also fulfils the fractal property of repeating in smaller sizes. The investment planning process in transmission typically takes years, in distribution months, while in customer plant levels, weeks.

Nowadays, DSOs plan the network based on worst-case scenarios. If the load exceeds e.g. 100% of the load capacity of a transformer, then a transformer upgrade is the solution. This planning must start a few years before the replacement due to the turnaround time of the projects. If flexibility is also considered by the DSO, then at least probabilistic design principles must be introduced, the extreme case of which is when the DSO performs time series network calculations. The time factor gives the uncertainty. In this way, the probabilistic approach is perhaps more viable, while moving to the operation phase (e.g. Flexibility platform, SCADA, Redispatch system), the time series approach is already important due to the accuracy of the forecasts. It is difficult for DSO to somehow use closed-loop control together with secondary control. This probably requires the most attention. Closed-loop control (OLTC, IVR) and secondary control (e.g. flexibility platform with DSSE) should be used in parallel by DSO; their harmonisation is important. Furthermore, these can also be competitors; the DSO must perform an NPV calculation. Which examines not only financial issues, but also uncertainties. A DSO cannot optimise solely for market procurement due to uncertainties; in addition to this, there is, e.g. in the case of the producer, curtailment, or closed loop PVs controls.

7.4.3. Flexibility to postpone grid investments

The ZUQDE project (see § 7.3.1.2. Practical implementation of the VvSC in MV level) has shown that *LINK* reduced the costs of connecting renewable generation plants to the grid and supported an increase in the share of renewable energy sources. In the cases specified in the project, the direct costs of the grid connection based on a mixed cabling price (open land, residential area, road, etc.) will be reduced from 2011 by the reduction in length of the grid connection cables of ~EUR 2.6 million [95], p. 80.

7.5 Enabling sector coupling for extended flexibility

Multi-energy systems, which include various electricity, gas, heating and cooling technologies and storage systems, are well-suited to increasing and expanding flexibility by increasing the share of renewable energies. Their coupling enables the coordination and efficient use of existing energy resources, which is associated with challenges in terms of modelling and strategic operating solutions. As shown below, *LINK* provides a systematic solution for the coordinated operation of energy systems to make them more flexible and resilient.

7.5.1. Structural transformation of the power industry and electricity customers

Figure 7.23 illustrates the structural transformation of the power industry and of the electricity customer. The traditional structure of power systems is shown in Figure 7.23a. The decentralisation process of the electricity industry was in progress in the 1990s. At that time, from the vertically integrated utilities, various legal entities such as generation, transmission and distribution companies, market operators, political decision-makers, etc., emerged. Storage, almost pumped hydro plants, were treated as a generation company.

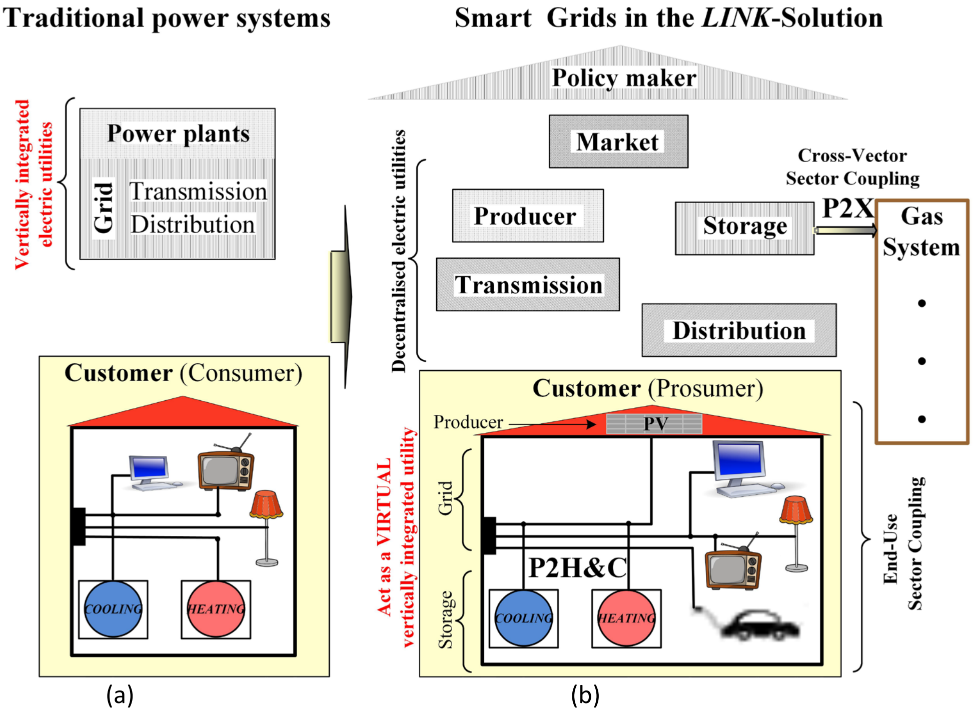


Fig. 7.23. Overview of the structural transformation of power industry and electricity customers: a) Traditional power systems; b) Smart Grids and Sector Coupling.

The last 30 years have been characterised by an extraordinary development of various technologies that have a major impact on the structure of the power industry. This changes the perception of the components of the power supply system. In addition to dividing the vertically integrated utilities into different legal entities, there are two other fundamental issues affecting their structure:

Nowadays, storage is undergoing an intensive development process. Diverse technologies are developed, and they are available in different sizes and can be integrated into any voltage level of the grid. The electricity power surpluses might be stored in other sectors, P2X. That means that from the perspective of the power system, Sector Coupling is a storage process. Treating storage as part of a power plant is no longer appropriate. It cannot be used to describe P2X processes. Therefore, in the LINK-based holistic architecture, the storage is separated from the electricity producer (power plant) component. Storage is perceived as an own, main component of Smart Grids.

Additionally, customers are experiencing radical changes. They are not only the owner of devices that consume electricity, but they also own electricity producers, such as PV facilities, and storage devices, such as batteries. Additionally, the customer has the option of storing the renewable power surplus on heating and cooling devices (P2H&C) or Power-to-Thermal (P2T). Based on these facts and on the definition of the vertically integrated utility, in the holistic LINK- architecture, prosumers are perceived as virtual vertically integrated utilities, Figure 7.23b). They behave as black boxes against the power system by exchanging a minimal amount of data. The data privacy is guaranteed.

The main principle of the *LINK*-based holistic architecture is the optimisation of the whole smart grid by coordinating and adapting the locally optimised Links.

7.5.2. Integrated energy systems

Figure 7.24 shows the integrated energy systems through sector coupling, as the *LINK*-Solution postulates [96]. The coupling through the electricity, gas and thermal networks is realised through the coupling components. For example, electrolysers combined with methanation reactors couple the electricity grid with the gas network, enabling the P2G process. Fuel cells couple the electricity with the gas grid, allowing the Gas to Power (G2P) process. Heat pumps couple the electricity and

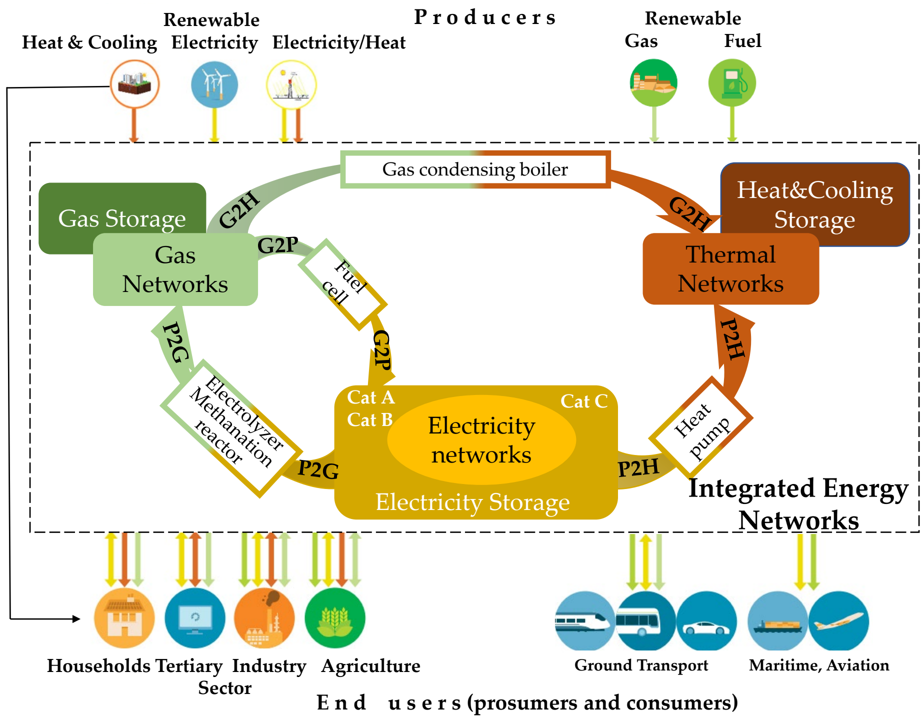


Fig. 7.24. Integrated energy systems through sector coupling, as given by the *LINK*-Solution.

heat networks, enabling the Power to Heat (P2H) process. The coupling between the gas and heating networks is realised through the gas condensing boilers and CHPs that allow the Gas to Heat (G2H) process.

Through Power-to-X solutions, Sector Coupling has enormous storage potential, contributing directly to the decarbonisation of the economy. They only claim the excess electricity, representing thus a storage solution from the point of view of the power systems. Storage is one of the main components of *LINK* architecture. It is categorised into three categories: In "Cat. A", the stored energy is injected at the charging point of the grid, such as pumped hydroelectric storage, stationary batteries, etc.; In "Cat. B" the stored energy is not injected back at the charging point on the grid, such as Power-to-Gas (P2G), batteries of e-cars, etc.; and In "Cat. C", the stored energy shortly reduces the electricity consumption at the charging point, such as cooling and heating systems (consuming devices with energy storage potential). In this case, it is treated as the Cat. B of storage. Because gas networks have a large storage capacity, they have attracted the attention of power engineers to use them to extend flexibility and increase the security of supply in the presence of renewable and distributed energy resources.

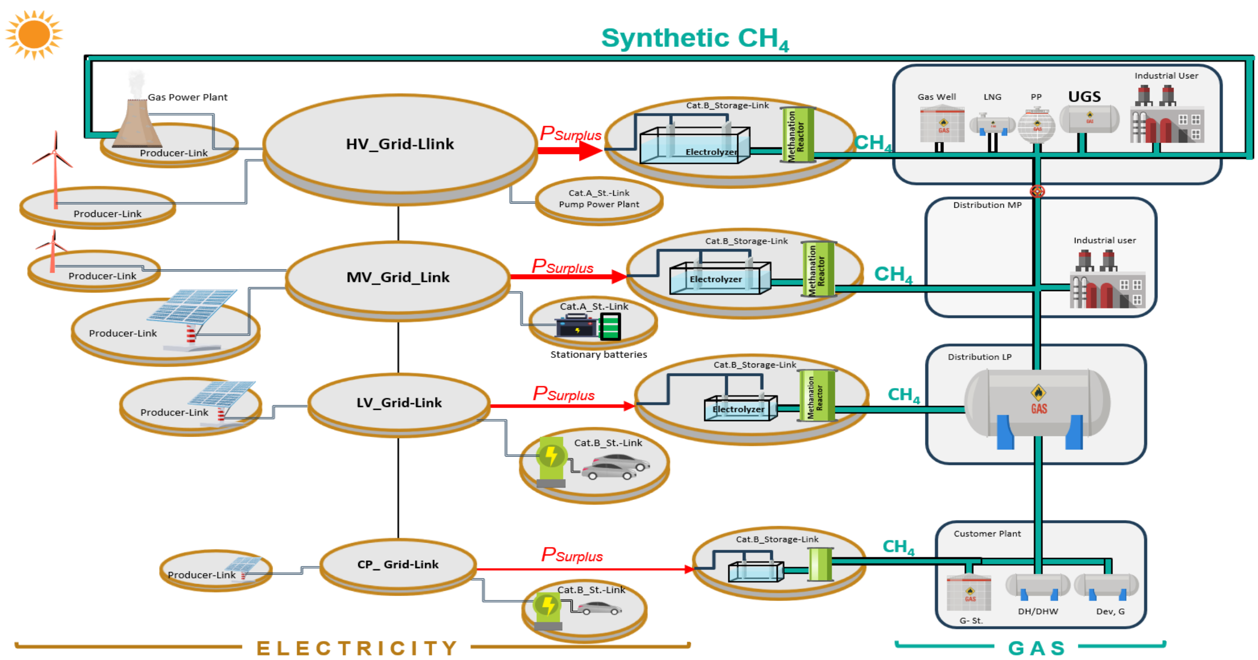
7.5.3. Electricity surplus to gas vector (Power to Gas)

Research studies show that *LINK* architecture enables the integration of electricity and gas systems to fill, e.g., the available gas storage facilities with Synthetic Natural Gas (SNG) on a large scale, produced from the electricity surplus [97]. This synthetic natural gas can then be used to operate gas turbines and to compensate for the fluctuating production of renewable energy sources or supply gas customers.

7.5.3.1. Integration architecture

Figure 7.25 shows the combination of *LINK* architecture with the gas grid structure. This combination helps to identify the coupling possibilities between the electricity and gas systems. Both systems can be coupled grid-wide through Coupling Components (CC) to realise the Cross-Vector Sector Coupling and at the CP level to realise so-called End User Sector Coupling. The Cross-Vector Sector Coupling may be realised at different levels as follows: The EHV or HV grids may be coupled with High Pressure (HP) gas grids; The Medium Voltage (MV) grids may be coupled with Medium Pressure (gas grids; and the LV grids may be coupled with Low Pressure (LP) gas grids. The SNG produced using the electricity surplus in the power system may be stored in the Gas Storage (G-St) available in the gas vector. Therefore, from the design point of view, it is possible to couple the grids also at the end-user level in the customer plants connected with the gas grid. The electricity surplus of rooftop PVs may also be used to produce SNG, which can be injected into the gas grid. Results show that an electrolyser set up at the customer plant level can be supplemented with a methanation reactor to produce synthetic natural gas. The latter will cover the momentary thermal load, and the surplus will be injected into the low-pressure grid. In this way, customer plants transform into gas prosumers. To realise this solution on a large scale, each pressure reduction group in the gas system should be upgraded with a compressor to allow the bidirectional gas transfer. This will help to increase the rooftop PV installations drastically and, in the summer, when the electricity and synthetic natural gas production exceeds electrical and gas demand, it may be possible to fill the underground gas storage so that, at least for some time, gas no longer needs to be imported from abroad. Additionally, the stored synthetic natural gas may be used without hesitation to run the gas turbines, which are crucial for the flexibility and security of supply in the presence of highly volatile resources.

Economically, investments at the CP level for electrolysis and methanation systems are necessary. Furthermore, upgrading gas grids with compressors to allow gas to flow from low- to medium-pressure networks involves additional costs.



Once the hydrogen infrastructure, turbines and equipment are in place, the same architecture can be used to couple the electricity and hydrogen vectors.

Fig. 7.25. P2G and G2P processes embedded in the *LINK* architecture.

In the summer, when the electricity and synthetic natural gas production exceeds electrical and gas demand, it may be possible to fill the underground gas storages so that, at least for some time, gas no longer needs to be imported from abroad. Additionally, the stored synthetic natural gas may be used without hesitation to run the gas turbines, which are crucial for the flexibility and security of supply in the presence of highly volatile resources.

Because CO2 is needed to run the methanation process, a CO2 market could be developed, encouraging big power plants to adopt carbon capture. Therefore, the emissions will be cut not only from the end-user level but even from the production level.

The feasibility assessment of the proposed solution will be subject to further work considering the energy trilemma. Additionally, possible safety scenarios should be ana-lysed, as hydrogen systems pose risks that have discouraged their widespread use in some sectors.

7.5.3.2. Demand response in P2G

Figure 7.26 shows the price driven P2G response. P2G is classified in the Cat. B of the storage. The operator of the storage Cat.B, who for ex. is responsible for H_2 production, receives from the Market Agent a notification for low electricity price. Consequently, he sends a request to the operator of the Gas System (GasO) to increase for e.g. the H2 production. After having checked the availabilities in the Gas System, GasO approves the request of StO_Cat.B. The latter sends a request to the operator of the Grid-Link (GriLiO) where the charging point is located. After having verified the effectiveness of this action in its own Link, the GriLiO approves the request and the StO_Cat.B procures the P2G.

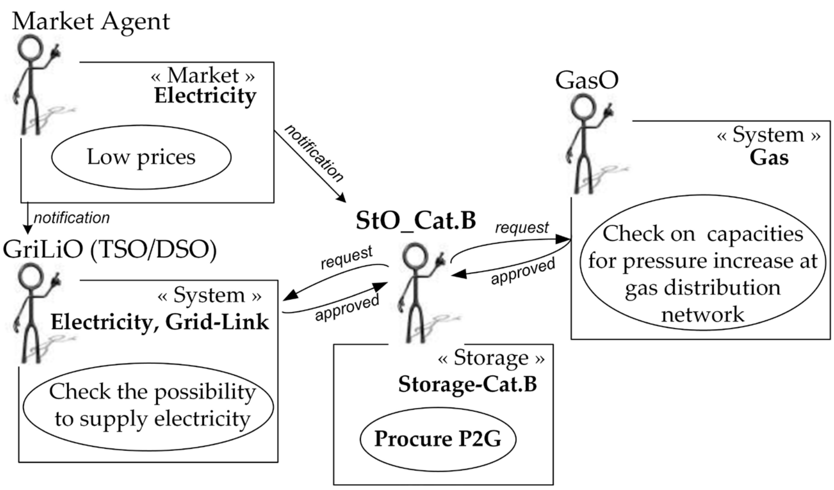


Fig. 7.26. Use Case: Price driven P2G response.

7.6 Facilitating Energy Communities to promote DERs

LINK with its technical and market structure approaches (see § 7.2.2 Fractal-based structures) enables the deployment of EnCs, Figure 7.27. Grid-Links are set up in all voltage and CP levels. A technical interface "T" joins them with the corresponding Storage and Producer-Links. The electricity market comprises the entire architecture so that all actors can participate in the market on a non-discriminatory basis via the "M" market interfaces. Market facilitators, i.e., TSOs, DSOs, etc., are connected to it via the orange interfaces.

The EnC participants act as black boxes, disclosing only the exchanges with the grid, thus guaranteeing the privacy of each customer. A local electricity market can be established with the participation of all EnC members. They can trade electricity with each other, whereas the total EnC energy surplus or deficit can be handled in the neighbouring markets. In this case, the EnC acts as a retailer. Any market actor, i.e., consumers, prosumers, and DER operators' service providers that are not EnC members trade their electricity in the whole market directly or through an aggregator.

The Local Retail Markets (LRM) creation attracts the Demand Response (DR) bids and stimulates investment in the Energy Communities areas.

The standardised chain control structures allow for a flexible and coordinated operation of the entire power system, including CPs, organised in the EnC structures. The Customer Plant Management Unit (CPMU) is to be deployed at the CP level, including the Secondary Control Unit set up in the CP-grid area to interact with the higher-level secondary control units as envisioned in the *LINK* solution, Figure 7.28. The CPMU acts as a black box that does not provide information about the CP devices. It is responsible for realising the interaction between the LVG and CPs.

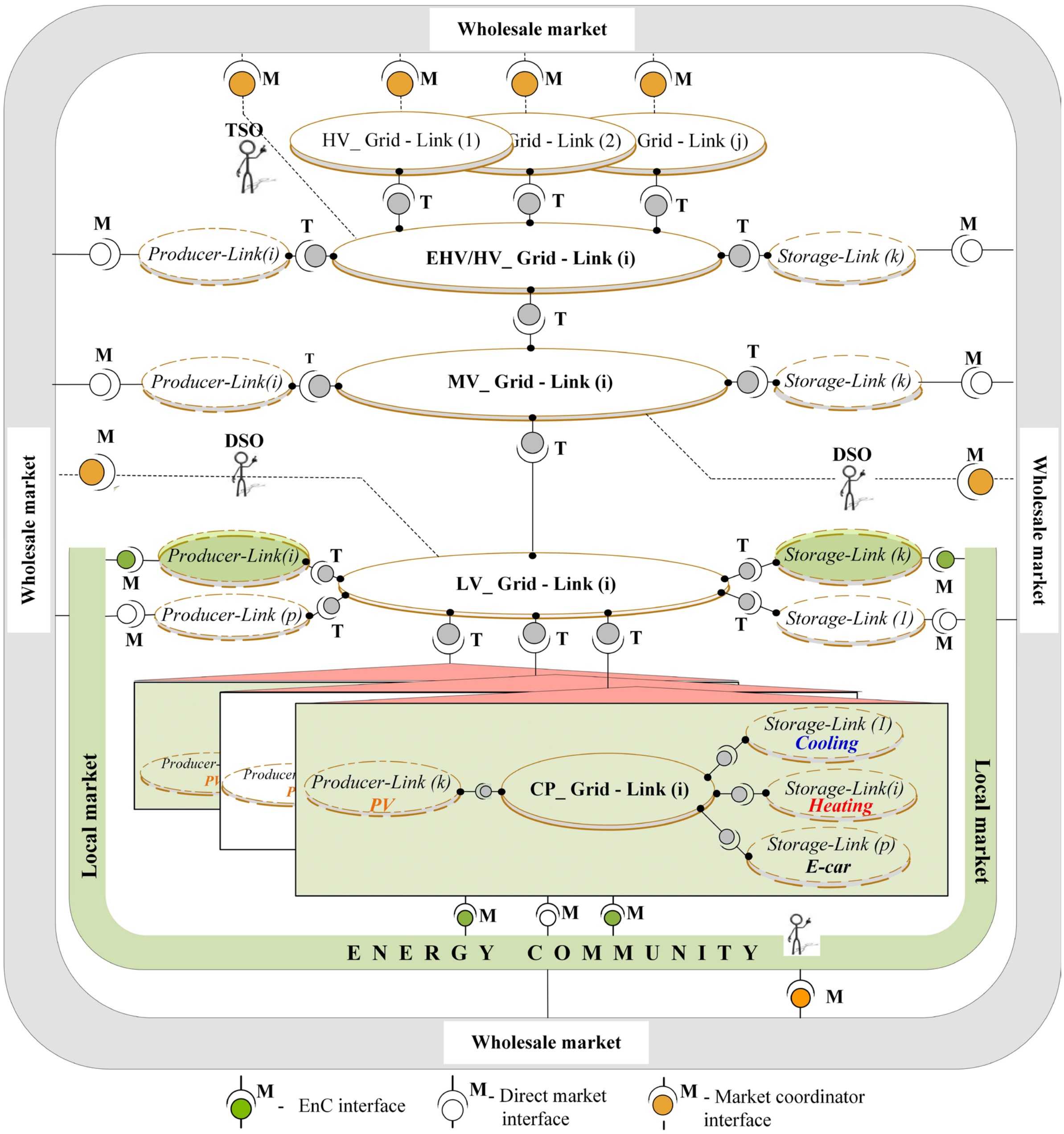


Fig. 7.27. EnC embedded in the *LINK*-Architecture.

Communication with the grid occurs only through secure channels, thus protecting the power delivery system from cyberattacks. The LV_Grid-Link sends negotiated set points P_{set_point}, Q_{set_point} to the CPMU. It supervises the exchange with the grid in real-time and generates and delivers the daily and hourly generation of P schedules. The latter is fundamental for the Production-Load balance process, one of the basic operation processes in power systems. The CPMU controls the reactive power within the CP, realising their *Q*-autarkic behaviour. It is the hub for realising the End-Use Sector Coupling by optimising electricity production and consumption combined with hydrogen or biomethane production and heating and cooling resources.

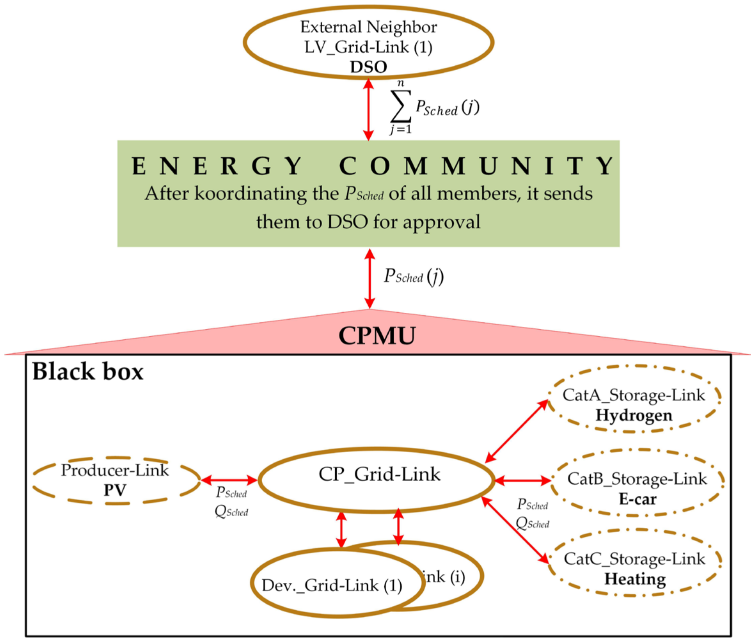


Fig. 7.28. Functional/technological architecture in CP level; production load balance process (INTERACT project [5]).

7.7 DSO possibilities for a fast practically use of LINK control mechanisms

7.7.1. Upgrading the existing power grid architecture to the holistic *LINK* architecture

The upgrade of the existing power system architecture is compelling but won't be built in a day – or a decade. Consequently, the upgrade process will be accompanied by a transition period with a hybrid architecture. During all this time, the upgrade will be done stepwise to ensure a secure, reliable, and feasible operation of the entire power system. The essential upgrade steps are presented in the following using two methods:

- **Top-down method** - HVG and the power plants that are feeding it build the power system's backbone. Consequently, the consolidation of the Volt/var loop in medium voltage level with well-defined constraints on the boundary with the high voltage level has the highest priority. After that, the HV- and the LV levels may be consolidated simultaneously. The consolidation of the loops concerning active power/frequency should follow the Volt/var ones. The developments in the CP level will follow, and it is expected that they will last longer;
- **Bottom-up method** - The development starts at the CP level by employing energy communities. Tackling voltage challenges and the uncontrolled reactive power in the superordinated grids is the first challenge to be managed in the vertical axis (see §4), followed by the active power balance. Development on the transmission grids follows.

7.7.2. Some practically use cases

The figures below show different possibilities for the DSO to use control mechanisms postulated by the *LINK* approach.

The Figure 7.29 shows a secondary control mechanism where a flexibility platform (already realised in E.ON Hungary DSOs) issues an activation instruction (schedule) in D-1, e.g. for MV-connected PVs so as not to overload the HV/MV transformer. This is conceivable both on a market basis and on a curtailment basis, and the two can be optimized together.

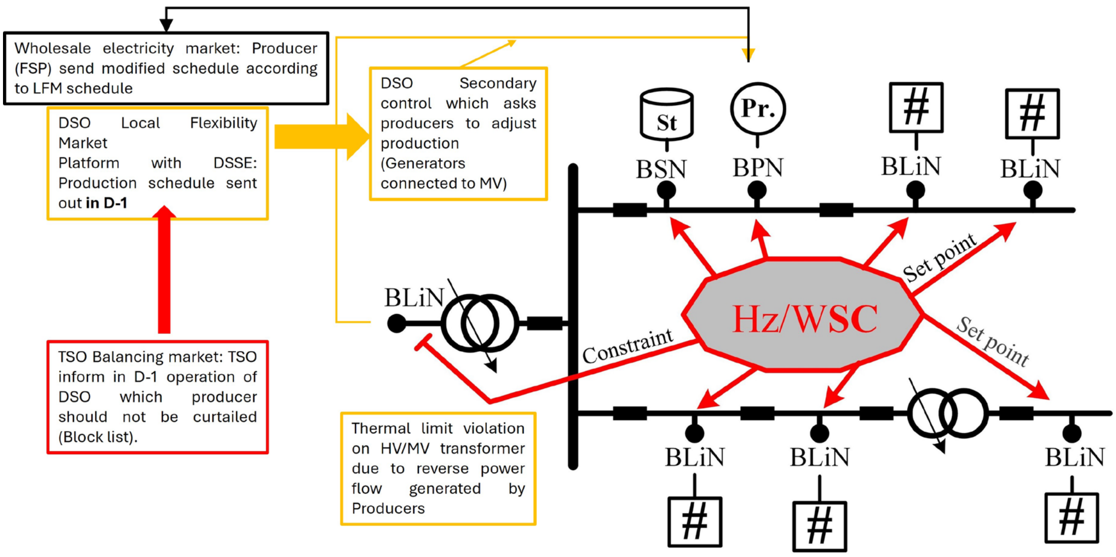


Fig. 7.29. Functional/technological architecture in CP level; production load balance process.

In the case of curtailment, the CEP states that, in the case of renewable producers, curtailment can be applied up to a maximum of 5% of their annual production. So, you must watch each PV to see how big the yearly curtailment was. In addition, the D-1 operation has many disadvantages and advantages, some of which are listed below.

Disadvantages:

- More inaccurate forecast, so you have to "err" in favour of safety;
- There is no producer schedule yet, so the network calculation must be performed based on other data, which indicates the need for flexibility (e.g. historical data, enriched with other measurements).

Advantages:

- In D-1, the Flexibility Service Provider (FSP) has time to submit its changed schedule to the wholesale market so that the TSO will take this into account during the Balancing market mechanism. So, DSO will not pay for the imbalance;
- The FSP has time to prepare for the next day's intervention. This is important if you do not have a SCADA system or staff that ensures quasi-online execution. Attention: DSO does not directly intervene in the inverter of foreign (3rd party) production equipment; you have to do this yourself.

The FSP can still change the schedule intraday. However, it is limited, both in terms of system and resources, as well as time. In this way, you can avoid paying due to the imbalance, or you can mitigate it. The question here is who pays in case of an imbalance: DSO, FSP, or TSO (who socialises the cost through the tariff system)?

In the case of intraday operation, it will eliminate the disadvantages of D-1 operation, i.e. we can provide a more accurate forecast with the producer schedules. However, it entails the difficulty that the producers must be given a schedule for the DSO. Now, this varies from country to country, but they must move towards the wholesale market and the TSO. Moreover, below a certain size, the Balancing Responsible Party (for example, an electricity sales company) prepares the schedule, the PV owner pays for it, but you do not have to deal with it. Providing the schedule to the DSO is an additional task not only for the FSP, but also for the DSO, e.g. if in an area of 40,000 square kilometres there is approximately. 2,000 small power plants (larger than household-sized PV, but smaller than 50MW), then the challenge for a DSO is how to involve them in the automation.

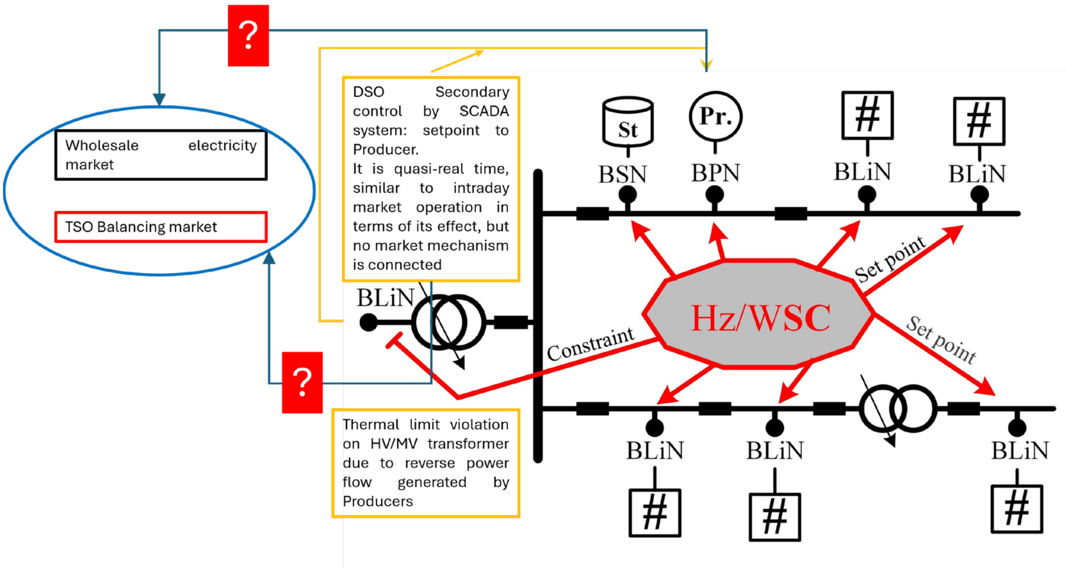


Fig. 7.31. Functional/technological architecture in CP level; production load balance process.

Furthermore, the FSP must act promptly, which requires either automation or staff. Automatism is also an issue because a business decision has to be approved, although this is solved in the case of the TSO Balancing market; however, producers/storage facilities are typically connected there through aggregators. For smaller producers without an aggregator, this is a challenge.

It is very similar to the market intraday case, when a SCADA system exercises secondary control for producers connected to the MV network. Although primary control is also possible here, SCADA monitors the load of the HV/MV transformer.

It is important to emphasise here that it is a near-real-time operation; in this way, automation is required between the PV producer and the DSO SCADA. This requires not only ICT, but also the fact that the PV producer's agent must agree in advance on which cases he will allow the intervention. Alternatively, the PV SCADA system carries out the final intervention, but then a PV SCADA system is also necessary, which is not typical for smaller power plants (e.g. 499kVA).

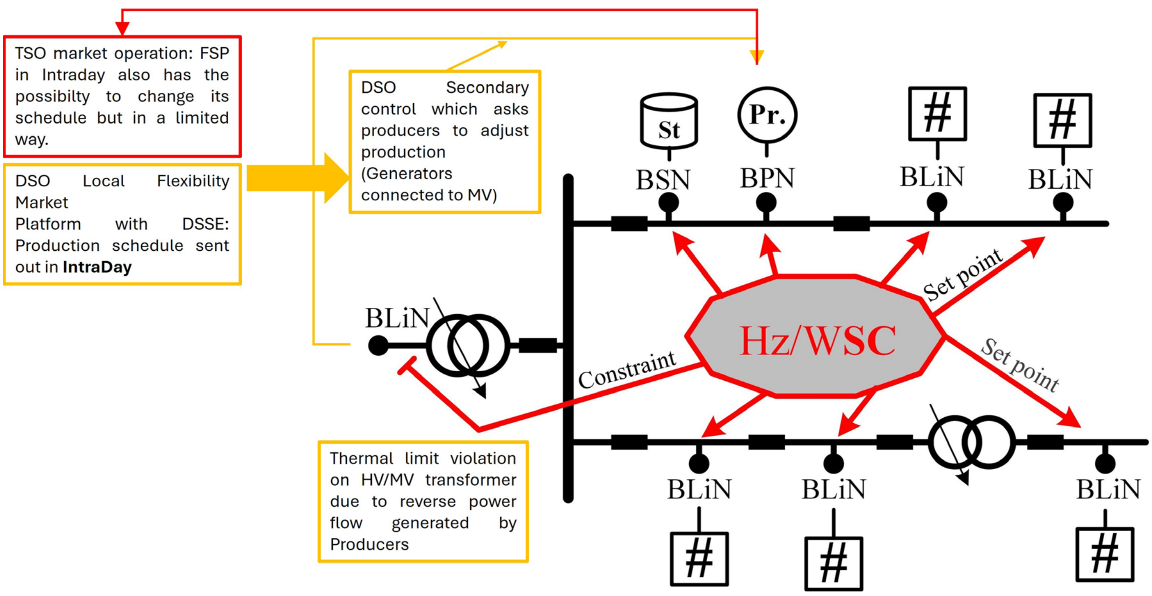


Fig. 7.30. Functional/technological architecture in CP level; production load balance process.

7.8 Opportunities and barriers

7.8.1. Opportunities

LINK is a unique, innovative solution that uses the fractal geometry of the grid to strengthen it for the energy transition. It considers the entire power system from high-, medium- and low-voltage levels, including customer plants and the market. It facilitates all processes necessary to operate the power system in normal and emergency conditions. *LINK* enables a large-scale implementation of distributed and renewable energy resources by facilitating Energy Communities and Sector Coupling. Data privacy and cybersecurity is guaranteed by design. It is characterised by standardised structures, making its implementation comprehensive and economical. Aligning market structures with the fractal grid design creates a dynamic market environment where energy transactions and resource allocations occur in real-time. Outages and fluctuations are thus better contained without disrupting the entire network. Thanks to the chain control strategy, today's load-shedding strategy with interruptible customers transforms into an intelligent one that offers modulated load reduction in real time through the demand response process. The actual top-down restoration process from the transmission grid with black start capability, which is only available for large generation plants, can be converted into a bottom-up process. LINK enables the latter by utilising the distributed resources that are available at almost no additional cost. Therefore, it reduces the blackout footprint. N-1 criterion as minimum static security (sometimes N-2) associated with expensive assets kept as reserve transforms in N condition acceptable with automatic reactions of several flexibility devices or processes with no extra cost for extra reserve.

7.8.2. Barriers

Implementation of the LINK solution requires significant structural reforms and regulatory updates. In terms of secondary control, it is challenging for a DSO to use ICT technology that causes difficulties compared to a TSO due to the large number of nodes.

Furthermore, the measurement infrastructure required for secondary control is also a hindering factor due to costs. The inclusion of distributed producers in a secondary control is an interesting question not only because of ICT, but also because of the agreement of the customers.
Another challenge is whether the DSO uses near-real-time primary and secondary control or market-based flexibility, although they can also operate in parallel. Synchronisation is then a bigger challenge. Running them side by side naturally also raises economic and predictability issues.

8. Final remarks and outlook

The increase in distributed power generation, primarily through rooftop photovoltaic systems, frequently provokes: Reverse power flows up to the TSO/DSO intersection points; the violation of the upper voltage limit; and the reaching of end settings of OLTCs. All this indicates that the large-scale implementation of renewable and distributed generation poses considerable technical challenges, while their flexibility leaves much to be desired. Urgent and far-reaching technical measures are necessary across the entire power grid, including customer facilities, to ensure the stability and reliability of the power supply and enable flexibility.

While Microgrids' intertwined controlling structure with primary, secondary, and tertiary controls to consider also the "main system" leads to highly complex and multifaceted technical solutions that are difficult to implement on a large scale, for *LINK*, with its comprehensive control strategy on the entire power system and customer plants, it is essential to refine the holistic architecture on-site by implementing it in its entirety. This step will highlight *LINK*'s strengths and help formulate concrete steps for large-scale implementation.

ANNEXES

Annex A: Voltage control techniques in distribution

In general, Voltage Regulation Units (VRUs) in distribution networks can be divided into two categories with different modes of regulating the operating voltage (see fig.3): direct VRUs that regulate voltage directly, and indirect VRUs that manage voltage by acting on another measure, e.g., active or reactive power. For example, On-Load Tap Changers (OLTCs) and Electronic Voltage Regulators (EVRs) are seen as direct voltage regulators, whereas conventional VAR compensation and STATCOM are seen as indirect voltage regulators since they manage voltage by the delivery or absorption of reactive power.

A.1. Direct control

Transformers are passive electrical devices used to change AC voltage levels. They are usually composed of two separate coils, called the primary coil at the MV side and the secondary coil at the LV side. Electrical energy can be transferred between the two coils via electromagnetic induction. The ratio of voltage transformation of a transformer is equal to the number of turns on the secondary coil divided by the number of turns on the primary coil.

A tap changer is a mechanism in transformers that enables the selection of predefined variable turn ratios by adding or removing a fixed number of turns in the primary or secondary coil. There are two types of tap changers: No-Load-Tap-Changers (NLTC) can adjust the ratio only if the transformer is de-energized, whereas On-load-tap changers (OLTC) may change the ratio during operation. This kind of control affects all feeders connected to the busbar where the voltage is controlled.

A.1.1. OLTC by supplying transformer

Transformers are called supplying transformers or HV/MV transformers when they are installed between HV and MV networks. They usually have a local voltage control to adapt the voltage ratio between the HV and MV grids. Previously, DSOs used the voltage regulator only to offset voltage fluctuations on the HV side and maintain the voltage of the MV side at a predefined constant level. The latter is sometimes defined through a Line or Load Drop Compensation (LDC) when there is little

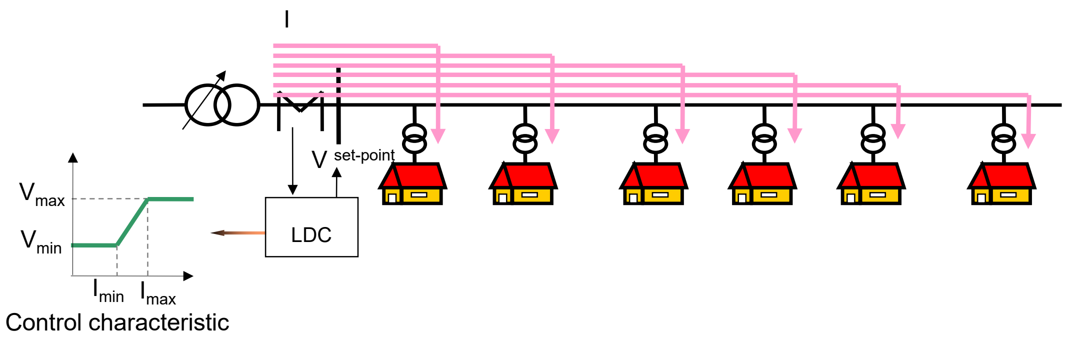


Fig. A.1. Supplying transformer with OLTC and LDC.

or no generation on the downstream feeders, Figure A1. (LDC is not recommended in the presence of distributed generation, as the current flowing through the transformer is no longer representative of the level of consumption and therefore of the voltages along the downstream feeders.)

Due to the increasing capacity of renewable energy systems at the MV level, five DSOs mentioned that they have updated the electronics and software of the voltage regulator to adjust the voltage on the MV side depending on the feed-in of renewables and the load flow at the substation. The principal aim is to reduce the voltage on the MV side of the transformer in times of high feed-in.

This scheme varies the voltage at the MV side to account for the load flow through the transformer. It can work with feed-in of renewable generation if the compensation is made bi-directional so that the voltage is lowered when there is feed-in of generation.

A.1.2. OLTC by distribution transformer

Transformers are called distribution transformers or MV/LV transformers when installed between MV and LV networks. Most distribution transformers are equipped with NLTC, and their ratio or tap position is rarely updated as it involves deploying backup power sources during the operation.

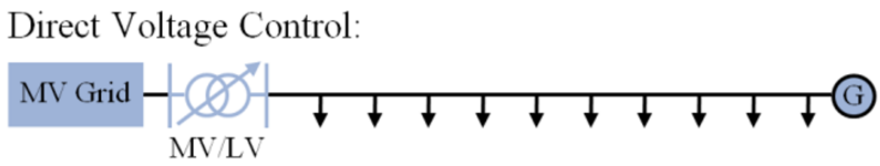


Fig. A.2. Distribution transformer equipped with OLTC.

Therefore, the LV voltage profile depends on the MV voltage profile, and high/low voltage on the MV network may lead to increased or decreased voltages on the LV network.
Using OLTC, it is possible to automatically adjust the tap position of the distribution transformer, and thus to partially decouple the secondary voltage from the primary voltage, Figure A.2. The aim is to use a larger part of the ±10% voltage bandwidth in the MV grid, as the OLTC distribution transformers can offset the voltage deviations (within their operating range) thereafter.

Advantages:

- OLTC distribution transformers are owned by the DSO and thus can be installed where it is most beneficial for the distribution network;
- They allow LV voltage profile to be partially decoupled from the MV voltage profile (within their operating range);
- They are effective in restricting the violation extent of the lower and upper voltage limits on the downstream LV feeders (unless the violation of low and high voltage limits occur at the same time).

Disadvantages:

- Additional investment cost by the DSO is required. OLTC distribution transformers are expensive solutions in most cases;
- They are too heavy to replace the No Load Tape Changer transformers installed on electrical poles;
- There are early wear and tear and increased maintenance cost in case of improper design of the OLTC inner control.

Tabelle A.1. Effects of the distribution transformer with OLTC on the grid performance

Controlled device	**Owner**	**P-Curt.**	**$Q_{ex.}^{MV-LV}$ increase**	***P_{Loss}* *increase***	***DTR Loading***	**Separately feeder control**	**Needed centralised control**	**Disadvantages**
Distribution transformer (DTR)	DSO	No	-	-	No	No*	No	Separated feeder control is not managed / Investment burdening DSO /Additional maintenance compared to traditional transformer.

* All downstream feeders have the same voltage setpoint at their head.

A.1.3. In-line voltage regulator unit

The aim of an in-line Voltage Regulation Unit (VRU) in distribution networks is to usually adjust the voltage on the secondary side to a preset value. It is connected in series to an MV or LV feeder. The in-line VRU can be realised through a transformer with OLTC or an Electronic Voltage Regulator (EVR). Therefore, the in-line VRU decouples the operating voltage on the secondary side from the primary side. In-line VRUs in the MV and LV networks are rarely implemented in European distribution grids.

The optimal location, layout and dimension of an in-line VRU depend on the degree of the voltage violation. If voltage violations are of a long-range nature, an in-line VRU in an MV feeder might be the best solution. If the voltage violations are seldom and located in the LV network, an in-line VRU in the LV feeder is optimal.

Unlike the OLTC transformers, the EVR does not need a transformer with several tapings.

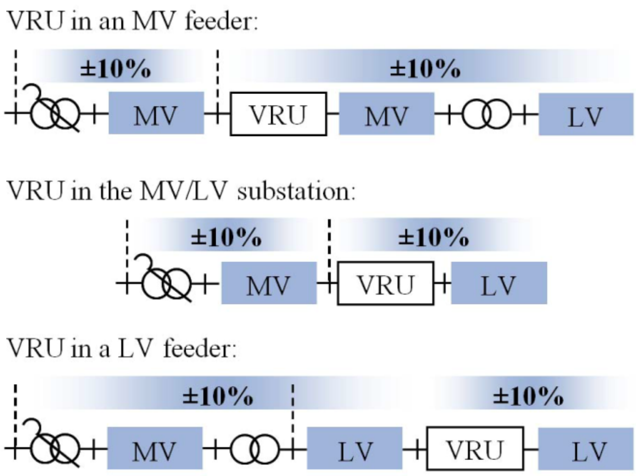


Fig. A.3. Potential locations for voltage regulation units.

Step-Voltage Regulator

Step-Voltage Regulator (SVR) is a normal autotransformer equipped with an automatic tap-changing mechanism [98]. Standard SVR provides ±10% voltage regulation in 32 steps of approximately 5/8% each. The tap of maximum raise position is 16R, while 16L is the tap of minimum lower position. The SVR has an automatic tap-changer able to switch from 16R to 16L and vice versa in less than 10 s.

Electronic Voltage Regulator

The EVR operates as follows to increase the voltage during a voltage drop on the output side of the EVR, the equipment extracts power via the optional autotransformer. Through controlling the rectifier and inverter, the EVR regulates the voltage by injecting a compensation voltage with the aim of obtaining a constant operating voltage on the output side according to the reference value. If there is a voltage increase in the output side, the EVR operates correspondingly.

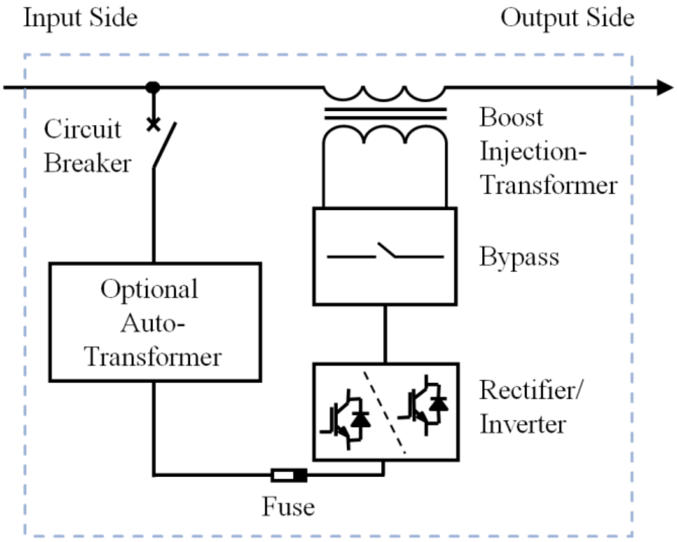


Fig. A.4. Schematic view of EVR

Advantages / Disadvantages:

EVR and IVR are equipment owned by DSOs and thus can be installed where they offer the greatest benefit to the distribution network. On the other hand, they require additional investment cost by the DSO.

The EVR has several advantages compared to the OLTC. The EVR regulates the voltage within milliseconds, while the OLTC needs at least several seconds. Furthermore, the OLTC is normally used with a timing relay to reduce the number of tap settings. The EVR regulates the voltage continuously, while the voltage is set in stages by the OLTC. Furthermore, the EVR can regulate each single phase. The advantage of implementing the EVR instead of OLTC is, on the one hand, the flexible modular design for realizing solutions ranging from a few kVA to several MVA, and on the other hand, the keeping of the MV/LV transformer in the MV/LV transforming station. The economic evaluation shows that both solutions for voltage regulation have similar investment as well as operating costs.

IVR mitigates voltage issues caused by high DG penetration, enhances grid efficiency, maximizes hosting capacity even under asymmetrical and unbalanced conditions. Pilot site studies demonstrate its effectiveness in stabilizing voltage, symmetrizing phases, and preparing the grid for future PV expansions [99].

Tabelle A.2. Effects of the In-line Voltage Regulator SVR/EVR on the grid performance

Controlled device	Owner	*P*-Curt.	$Q_{ex.}^{MV-LV}$ increase	P_{Loss} increase	*DTR* *Loading*	Separately feeder control	Needed centralised control	Disadvantages
Auto-transformer	DSO	No	No	No	No	Yes	No	Investment burdening DSO

A.2. Indirect control

This annex gives an overview of several (indirect) control techniques to mitigate voltage rise issues in radial distribution grids. Basically, main techniques are based on reactive power control/management to compensate the impact of active power injection by distributed generators. Additional techniques are presented based on active power control or voltage regulators equipment.

A.2.1 Fixed cos(φ) by inverter

For fixed power factors ($cos\varphi$) of a DER inverter, the reactive power output (Q) of the inverter is direct proportional to the current active power (P) generation of the inverter. In general, a fixed $\cos\varphi = 0.95$ is assumed, which relates to a factor of 0.33*P or –0.33*P. The generation of Q starts with P>0 and the sign of Q depends on the fixed phase angle. For only generating inverters, this implies that the sign of reactive power will change with active power and one has to decide in beforehand if reactive power needs to be over- or under excited which relates to injection or absorption of Q.

$$Q = S * sin\varphi$$

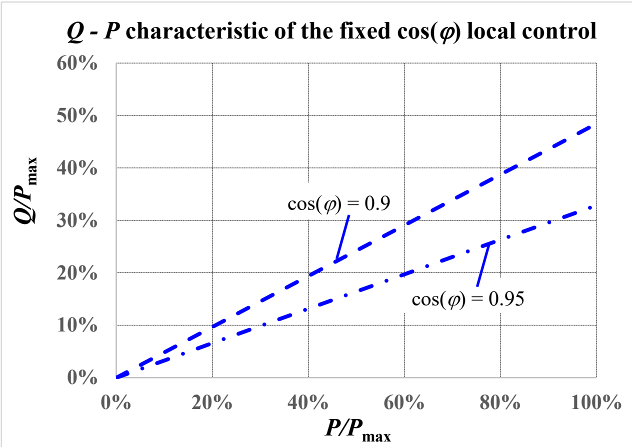


Fig. A.5. *Q* - *P* characteristic of the fixed cos(φ) local control.

Fixed power factors a DER inverter for reactive power supply in distribution grids offer both advantages and disadvantages that must be considered when discussing it in the context of DERs.

Advantages

The advantages include its suitability for older inverters, allowing for broader applicability. Additionally, it requires no maintenance or external control, which reduces operational costs and simplifies system complexity. Another benefit is the local compensation of voltage drops caused by active power generation, improving the voltage profile of the distribution grid. From the DSO perspective, this method is often viewed as "plug and forget," as it is easy to implement and functions without constant monitoring.

Disadvantages

However, several disadvantages should not be overlooked. The fixed behaviour of DER inverters remains unchanged regardless of the actual grid situation and evolution of the grid, which can lead to inefficient responses to grid fluctuations. Furthermore, the lack of external real-time control limits the flexibility and adaptability of the systems. This may result in uncontrolled reactive power flows in higher-level grids, potentially having negative impacts on grid stability.

Overall, the decision to implement an active power-dependent reactive power supply requires careful consideration of the mentioned advantages and disadvantages to ensure optimal control of renewable energy plants in distribution grids.

Table A.3. Effects of the fixed cosφ*(P)* by inverter on the grid performance

Controlled device	**Owner**	$P_{Curt.}$	$Q_{ex.}^{MV-LV}$ **change**	P_{Loss} ***change***	***DTR*** $_{Loading}$ ***change***	**Separate feeder control**	**Needed centralised control**	**Disadvantages**
Inverter	DER	No	Yes, mostly increase	Yes, mostly increase	Yes, mostly increase	Not possible		Uncontrolled reactive power flow in the superordinated grids

A.2.2. cosφ(P) by inverter

Power factor (*cosφ)* as a function of active power (*P*) actively controls the reactive power output of a DER inverter as a function of the active power output according to a characteristic. Figure A.6 shows the standard characteristic for the *cosφ (P)* by the inverter [100]. This control mode allows for the *Q* to be adjusted non-linearly, i.e., not a constant cosφ. The inverter operates in an under-excited mode when the feed-in active power passes over a threshold of 50% of P_{max} to mitigate the related voltage rise.

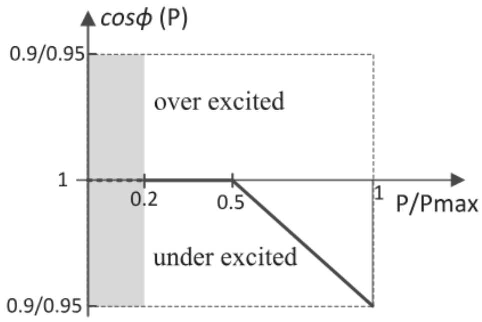


Fig. A.5. Standard characteristic curve for *cosφ (P).*

Advantages / Disadvantages

- Mitigation of the violation of upper voltage limit at high DERs' *P* output:
    - DER-caused voltage issues typically occur at high *P* output,
    - Absorbing *Q* outside critical voltage conditions can lead to unnecessary losses and *Q* supply from elsewhere in the power system (T&D),
    - cosφ (*P*) mode allows for unity power factor until critical P level reached, after which Q absorption can be introduced as a linear function of increasing P;
- Can be a suitable solution for weak networks:
    - Two-slope characteristic allows for matching optimal nonlinear *Q-P* curve for weak systems with constant X/R ratio.

Table A.4. Effects of the fixed cosφ*(P)* by inverter on the grid performance

Controlled device	Owner	*P*-Curt.	$Q_{ex.}^{MV-LV}$ change	*P_{Loss} change*	*DTR Loading change*	Separate feeder control	Needed centralised control	Disadvantages
Inverter	DER	No	Yes, mostly increase	Yes, mostly increase	Yes, mostly increase	Yes	No	Uncontrolled reactive power flow in the superordinated grids

A.2.3. Volt-var (Q(U)) by inverters

This control already reflects the voltage conditions at the connected point. So, the voltage value defines the setpoint for the *Q* control at the DER inverter meaning that DERs at the beginning of a radial feeder participate less in the voltage regulation compared to those at the end, which experience the voltage rise. The local *Q*(*U*) control uses the reactive power of the inverter to reduce or increase the feeder voltage to a certain level.

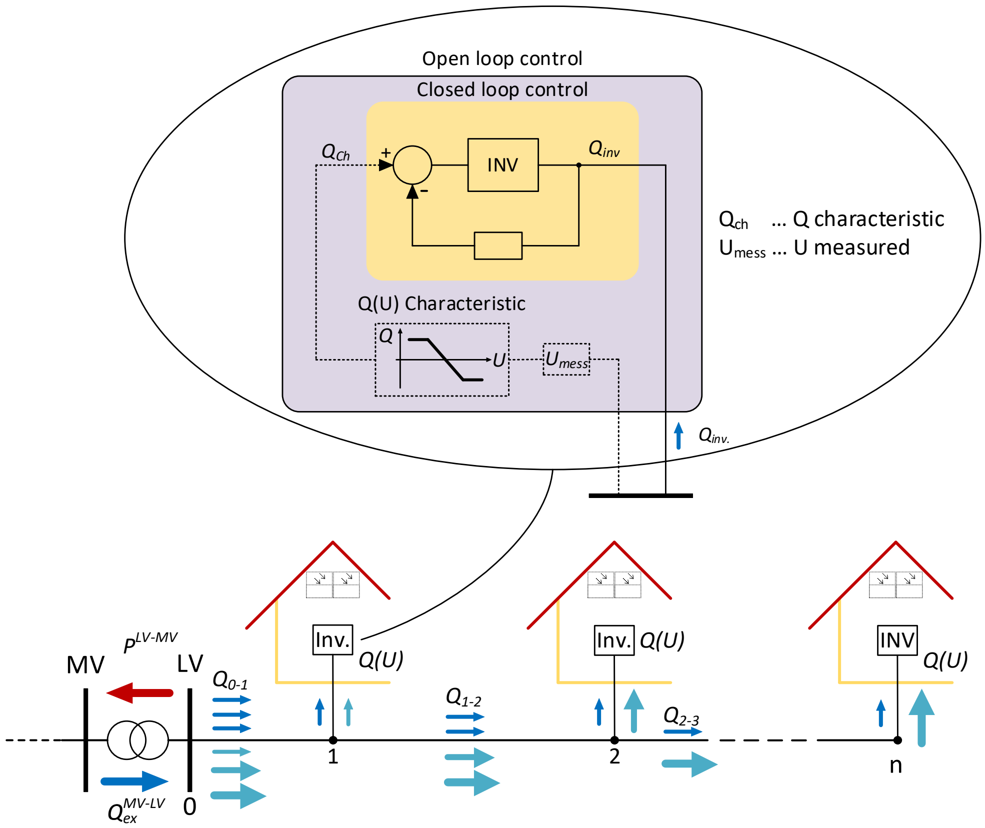


Fig. A.7. Overview of the open and closed loops by the *Q*(*U*) control by the inverter.

Two control loops, one in a closed loop and the other in an open loop, are set up in the solution with *Q*(*U*) control. The *Q* controller in the closed control loop dynamically sets the desired reactive power, the *Q* setpoint, in the inverter output. Meanwhile, the *Q*(*U*) control acts in an open loop.

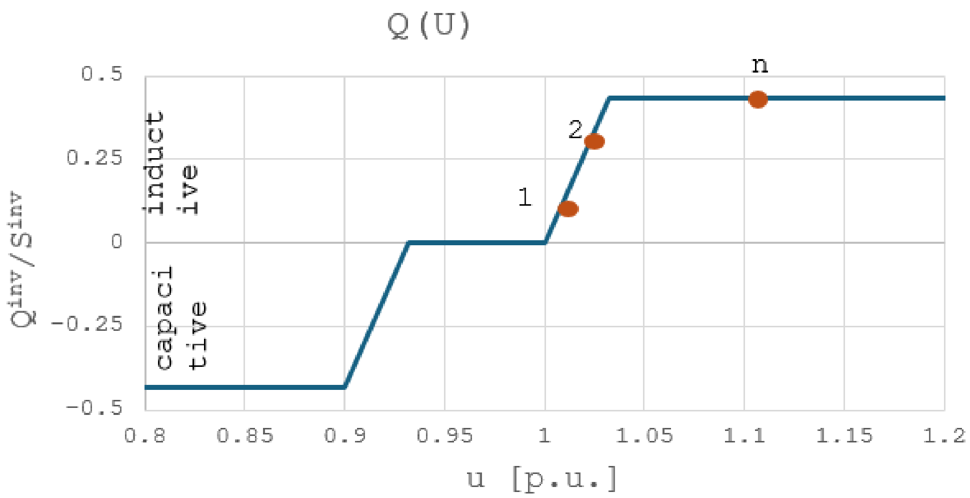


Fig. A.8. Standard curve characteristic for *Q*(*U*) control by inverter.

The input variable, *U*, is different from the output variable, Q_{inv}, which is injected into the grid. Based on the *Q(U)* curve, Q_{inv} is determined by the voltage at the measuring point, which is location-dependent.

The reactive power controlled by *Q*(*U*) is determined by the voltage at the measuring point.

Advantages

- Mitigation of the violation of upper, through *Q* absorption, or low, through *Q* injection, voltage limits at the connection point.

Disadvantages

- Provokes an uncontrolled reactive power flow in the superordinated grids;
- It may increase losses and the distribution transformer loading.

Tabelle A.5. Effects of the *Q(U)* by inverter on the grid performance

Controlled device	**Owner**	P_{Curt}	$Q_{ex.}^{MV-LV}$ **change**	P_{Loss} **change**	$DTR_{Loading}$	**Separately feeder control**	**Needed centralised control**	**Disadvantages**
Inverter	DER	No	Yes, mostly increase	Yes, mostly increase	Yes, mostly increase	Yes	No	Uncontrolled reactive power flow in the superordinated grids

A.2.4. Volt-Watt (P(U)) by inverter

In the $P(U)$ control mode, DER inverters are monitoring terminal voltage and gradually decrease (curtail) active power output according to the setpoints defined by the utility. The relationship between the active power output and the voltage is usually defined by a piecewise linear curve, as illustrated in Figure A.9.

With this control, the distributed generation hosting capacity of a distribution grid is increased significantly, as the distributed generators will shut down in case of over-voltage, while the curtailments required is a minor portion of the annual yield when considering all installations in the examined MV or LV grid. However, care should be taken as this control discriminates against distributed generators at technically unfavourable connection points where often over-voltages occur. This kind of control may curtail significant energy by large DG penetration.

The Volt-Watt control function changes the DER's active power output in response to the local

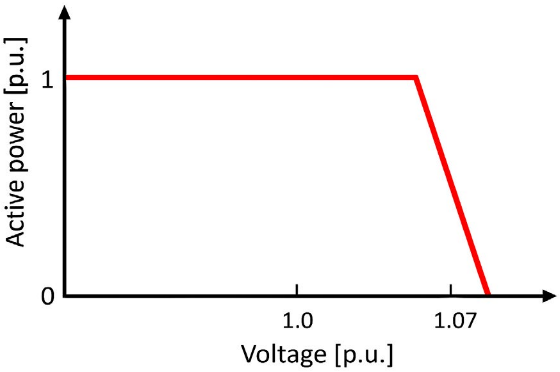


Fig. A.9. $P(U)$ Curve Characteristics

service voltage. If the local service voltage is in a high range, the active power output is reduced. There is a maximum voltage upper limit at which the DER generates no power at all. This is based on the volt-watt curve, an example shown below, configured for that inverter. Depending on the curve chosen, the voltage regulation performance desired could be achieved.

Advantage from DSO point of view: Volt-Watt: can be especially useful at LV level where automation is needed due to the large number of players. In this case, a predefined droop regulation is used, and e.g. reduces the production from a given voltage to 0 (when the producer already violates the upper voltage limit). However, the calculation of compensation is difficult. Furthermore, the location dependence on the radial network also makes fair treatment questionable (those who are further from the power point increase the voltage to a greater extent and reach the limit sooner). Nevertheless, regulators allow it in several countries, also to guide prosumers towards greater self-consumption during peak production periods.

Disadvantage from DSO point of view: Volt-Watt: The DSO must compensate for lost production. It is quite difficult to calculate in advance, otherwise it is needed a baseline.

Tabelle A.6. Effects of the *P(U)* by inverter on the grid performance

Controlled device	Owner	*P*-Curt.	$Q_{ex.}^{MV-LV}$ change	*P*P_{Loss} change	*DTR* *Loading*	Separately feeder control	Needed centralised control	Disadvantages
Inverter	DER owner	Yes	No	No	No	No	No	The DSO must compensate for prosumers' lost production

A.2.5 Q(U) – coil

Coils banks are the dual component of the capacitor banks, but in opposition to the capacitor banks that were commonly installed in HV/MV primary substation to manage the power factor at the

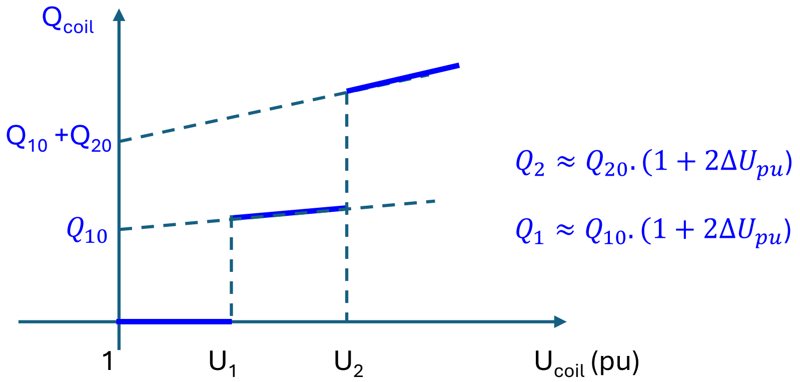


Fig. A.10. Curve characteristic of a *Q*(*U*) control with two coil banks.

TSO/DSO interface, coil banks will have to be installed at some specific nodes of the MV grid. Coils are compensative equipment: they absorb reactive power at the node of connection. The level of reactive power depends on the coil sizing and the node voltage. A coil bank can be seen as a discrete equipment where the level of reactive power depends on the number of connected coils at the node. Figure A.10 shows a case with two coils of rated value Q_{10} and Q_{20} at $U = 1pu$).
Coil banks can also be installed in HV/MV primary substations to compensate for the reactive power flowing from the MV network to the HV network, thereby limiting high voltages on the HV network.

Advantages:

- The DSO owns such equipment and thus can be installed where it is most beneficial for the network;
- Direct remote control (energisation) by the DSO is possible;
- It provides a partial compensation of the reactive power produced by underground cables (much higher than for overhead lines).

Disadvantages:

- It requires additional capex investment;
- There is a need to find the optimal node of connection, which can sometimes be complex;
- All grid nodes are not available to connect coil banks;
- It is not easy to change the node of connection of the coil banks if the voltage constraint is changing (due to new loads or news producers);
- There is a risk of transient phenomena when the coils are energised.

Tabelle A.7. Effects of the *Q(U)* by coil on the grid performance.

Controlled device	**Owner**	P_{Curt}	$Q_{ex.}^{MV-LV}$ **change**	P_{Loss} **change**	***DTR Loading change***	**Separate feeder control**	**Needed centralised control**	**Disadvantages**
Coil	DER	No	Yes	Yes	No	Yes	No	Investment burdening DSO; Careful calculation of the location of connection node; Uncontrolled reactive power in the superordinated grids

A.2.6. Q(U) by capacitors

Capacitors are electrical devices enabling to supply reactive power at their connection point. A capacitor bank is a group of several capacitors that are generally of the same sizing and connected in parallel. The level of reactive power supplied by a capacitor bank depends on the size and the number of connected capacitors.

Reactive power flow strongly influences the voltage levels across the network: the higher the reactive power consumed (produced, respectively) at a given bus, the lower (higher, respectively) the bus voltage will be. Therefore, by supplying reactive power, capacitors lead to increase voltage at their connection point and thus the voltage profile of the surrounding network. They can also help reducing power losses caused by inductive current.

DSOs commonly install capacitor banks at mainly two network locations, for different reasons:

- In HV/MV substations where high reactive power flows are supplied from the HV network and drawn by the downstream inductive distribution network structures and electrical loads (e.g., transformers, overhead lines, motors). In normal operation, the switching of capacitor banks in HV/MV substations can be:
    - Either automatically controlled by varmeter relays, e.g., to manage lagging power factor at the TSO/DSO interface, or
    - Remotely controlled by the DSO, e.g., to connect them at the request of the TSO and thus prevent undervoltage in the HV network.
- In long overhead MV feeders (as in the United States) to compensate for reactive power absorbed by high inductive loads or overhead lines and thus prevent deep voltage drop on the feeder. They can be easily switched on and off using a local or remote-control law.

Advantages:

- It is owned by the DSO and thus can be installed where it is most beneficial for the grid;
- Direct remote control by the DSO is possible;
- It is simple, cheap and easy to install and maintain compared to other reactive power compensation devices;
- It is effective to limit undervoltage.

Disadvantages:

- It is ineffective against reverse reactive power flows and voltage limit violations;
- In case of improper design, the switching of capacitors causes overcurrent and increased voltage that may damage some sensitive devices;
- If capacitors are to be installed in MV feeders:
    - There is a need to find the optimal node of connection, which can be complex,
    - All grid nodes are not available to connect to capacitor banks,
    - It is not easy to change the node of connection of the capacitor banks if the voltage constraint is changing (due to new loads or new producers).

Tabelle A.8. Effects of the *Q(U)* by coil on the grid performance

Controlled device	**Owner**	***P*-Curt.**	**$Q_{ex.}^{MV-LV}$ change**	***P$_{Loss}$* change**	***DTR$_{Loading}$* change**	**Separate feeder control**	**Needed centralised control**	**Disadvantages**
Capacitors	DER owner	No	Yes	Yes	Yes	Yes	No	Investment burdening DSO; Careful calculation of the location of connection node; Uncontrolled reactive power in the superordinated grids

A.2.7. tgφ = f(U) by inverter

tgφ = f (*U*) controls the tangent of ϕ (i.e., the ratio of *Q* to *P*) of the DER inverter according to voltage at the connection point of the DER inverter [101]. Figure A.11 shows the characteristic curve of this local voltage control strategy. At constant active power, higher reactive power absorption (respectively, injection) is required if the voltage at the connection point is high

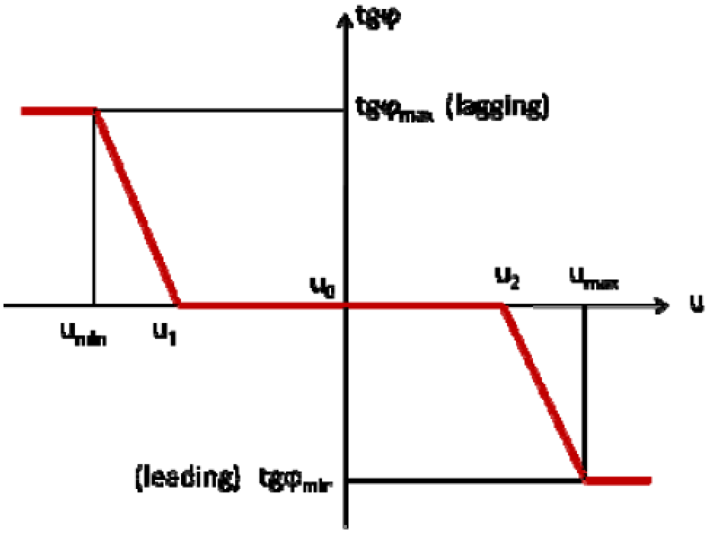


Fig. A.11. Characteristic curve of the local voltage control strategy *tgφ* = f (*U*).

(respectively, low).

Generally, the reactive modulation is based on local measurements available at PCC (voltage or real power injections). The first possible solution is depicted in Fig. A.11. This method involves two conditions: a normal operating situation, where no control action is required and a situation where first voltage thresholds (u1 and u2) are violated. In the latter case the generator operates at tgφ different from zero according to the local voltage i.e., avoiding double repletion of tgφ. The reactive power injected/absorbed from the network is given by q = p.tgφ, therefore it is determined both by voltage and by real power injections. By this strategy it is possible to have a meaningful impact on voltage profile only if the DG unit injects a real power value close to the nominal one.

Disadvantage from DSO point of view: Increased loss due to Q.

Advantage from DSO point of view: the reactive power generated by the DG is null when the network voltage is within acceptable levels, limiting the current flow and avoiding real power losses increase.

Tabelle A.9. Effects of the *tgφ* = f (*U*) by inverter on the grid performance

Controlled device	Owner	P_{Curt}	$Q_{ex.}^{MV-LV}$ change	P_{Loss} change	*DTR Loading change*	Separate feeder control	Needed centralised control	Disadvantages
Inverter	DER	No	Yes, mostly increase	Yes, mostly increase	Yes, mostly increase	Yes	No	Addresses voltage rise for high power injection

A.2.8. tgϕ = f(P) by inverter

*tg*φ = f (*P*) controls the tangent of φ according to the real power injected at the connection point of the DER inverter [101]. Figure A.12 shows the characteristic curve of this local voltage control strategy. The higher active power injection is, the higher reactive power absorption is.

This control is like the A.2.7 but the reactive power is directly modulated according to the voltage measured at PCC. By this strategy the DG unit can operate, in case of low power injections, at a power factor lower than the one imposed by tgφ = f(U). This strategy causes a greater stress on generators to provide a better mitigation of the voltage limit violations in the network.

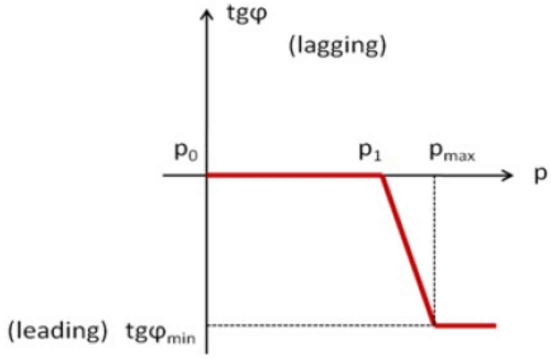


Fig. A.12. Characteristic curve of the local voltage control strategy *tgϕ* = f (*P*).

Tabelle A.10. Effects of the *tg*φ = f (*P*) by inverter on the grid performance

Controlled device	**Owner**	P_{Curt}	$Q_{ex.}^{MV-LV}$ **change**	P_{Loss} **change**	***DTR*** *Loading* ***change***	**Separate feeder control**	**Needed centralised control**	**Disadvantages**
Inverter	DER	No	Yes, almost increase	Yes, almost increase	Yes, almost increase	Yes	No	Uncontrolled reactive power flow in the superordinated grids.

A.2.9. Watt-var Q= f (P) by inverter

The Watt-var Q = f (*P*) controls the reactive power according to the real power injected by the DER inverter [101]. Figure A.13 shows the characteristic curve of this local voltage control strategy. The

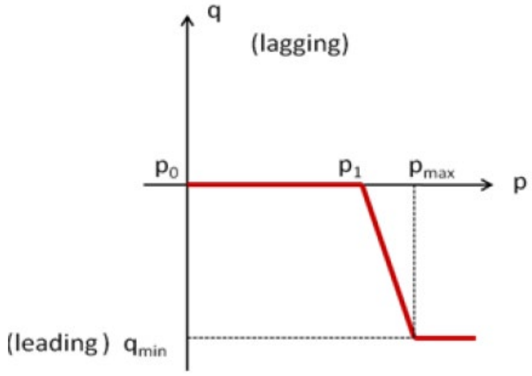


Fig. A.13. Characteristic curve of the local voltage control strategy *Q* = f (*P*).

higher the active power injection is, the higher the reactive power absorption is.

Watt-var *Q* = f (*P*) is similar to tgφ = f (*P*): Control of the tangent of ϕ according to the real power injected. Still, the only difference is that the control is achieved by directly modulating the reactive power.

Disadvantage from the DSO point of view: Watt-Var: Since *P* is the measured parameter, but *U* is controlled via *Q*, there is an assumption that *U* depends on *P*, which requires extensive preliminary calculations; it provokes uncontrolled reactive power in the superordinated grids.

Advantage from the DSO point of view: “plug and forget”.

Tabelle A.11. Effects of the *Q* = f (*P*) by inverter on the grid performance

Controlled device	**Owner**	P_{Curt}	$Q_{ex.}^{MV-LV}$ **change**	P_{Loss} **change**	***DTR*** ***Loading change***	**Separate feeder control**	**Needed centralised control**	**Disadvantages**
Inverter	DER	No	Yes, mostly increase	Yes, mostly increase	Yes, mostly increase	Yes	No	Extensive preliminary calculations; Uncontrolled reactive power flow in the superordinated grids.

A.2.10. Active-Reactive Droop (ARD)

In the droop-based Active Power Curtailment (APC) approach, the PV inverter curtails its active power output as a function of the deviation of the local voltage, *V*, from a critical voltage, V_{cri} [102]. The most common method for implementing APC uses a linear droop coefficient, m (kW/V), proportional to the deviation of the voltage from V_{cri}. Although reactive power has less of an impact on voltage in LV distribution systems (R >> X), absorbing more reactive power can reduce the curtailed active power required to prevent voltage ölimit violations. In active-reactive droop (ARD), both reactive power absorption and APC are used to prevent local voltage limit violations.

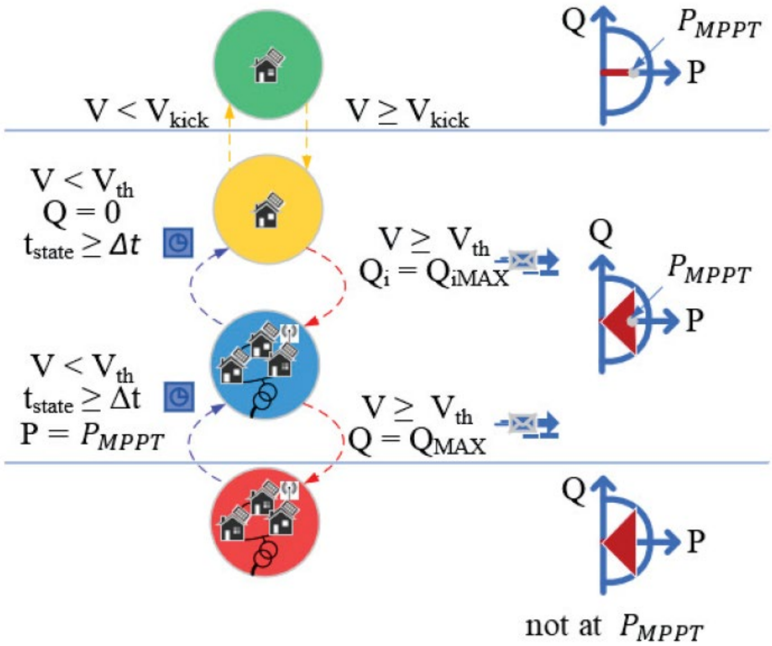


Fig. A.14. Overview of ARPM state diagram.

ARD absorbs reactive power alongside active power curtailment to reduce voltage increase while maximizing *P* injection output. It performs well in maintaining voltage within the limits.

The coordinated Active and Reactive Power Management (ARPM) controller also uses the inverter reactive power capacity before curtailing active power, but a communication signal is used to coordinate distributed inverters. The ARPM state diagram is presented in Figure A.14.

ARD outperformed other methods, maintaining voltage below critical thresholds through efficient reactive power absorption. ARPM was less effective due to its inherent delay in activating coordinated adjustments. Increased *Q* means additional load for the transformer, but it causes less loss than Q(U) because it uses two optimised droop curves.

Disadvantage from the DSO point of view: Increased loss due to *Q* both on the feeder and the transformer; uncontrolled reactive power flow in the superordinated grids.

Advantage from the DSO point of view: Effective voltage control.

Tabelle A.12. Effects of the ARD on the grid performance

Controlled device	Owner	*P*-Curt.	$Q_{ex.}^{MV-LV}$ change	P_{Loss} change	*DTR Loading change*	Separate feeder control	Needed centralised control	Disadvantages
Inverter	DER	Yes	-	-	-	Yes	No	Uncontrolled reactive power flow in the superordinated grids.

A3. Summary of different voltage-controlling technologies in radial grid structures

Many studies have been performed to compare the different local control strategies that may be used in distribution (medium- and low-voltage levels). Their evaluation is mainly focused on alleviation of the violation of the upper voltage limit, losses, equipment overloading and increasing the DER hosting capacity of distribution grids [103][104][105][106][107][108]. However, the last events have shown that strong interdependencies exist between the transmission and distribution grids, and the different control strategies must be coordinated to guarantee a secure power grid operation. The large-scale use of several local controls at the distribution level provokes an uncontrolled reactive power flow in the superordinated grids, which impacts the reactive power margin at the transmission level. The latter drives the power systems to the voltage instability [109].

Table A.13 gives an overview of the effects of different local control strategies on the grid performance. The focus is on the impact on the reactive power exchange with the superordinated grids. The extent of its influence is roughly estimated based on some results from [110]: The effect is represented by the different number of strokes. The greater the number of strokes, the greater the uncontrolled reactive power flow in the higher-level networks.

Nevertheless, to choose the most appropriate voltage control strategies, it is advisable to conduct a thorough study that takes into account:

- The specific characteristics of networks subject to voltage constraints;
- A sufficiently detailed model of any neighbouring (HV/MV/LV, public/private) network or user equipment that may be affected by these control strategies and their coordination;
- The likely future changes, e.g., in electricity usage, DER penetration, network structure, etc.

Tabelle A.13. Effects of different local control strategies on the grid performance

Local control type	Controlled device	Ownership	P-Curt.	$Q_{ex.}^{MV-LV}$	P_{Loss}	DTR *Loading*	Separate feeder control	Needed centralised control	Disadvantages
OLTC	*Transformer*	DSO	No	No	No	No	No	Yes	Separated feeder control is not managed / Investment burdening DSO,/Additional maintenance compared to traditional Tr.
IVR	Auto-transformer	DSO	No	No	No	No	Yes	No	Investment burdening DSO
Fixed cos(φ)	inverter	DER owner	—	|||||	Yes |||||	Yes |||||	no	Not possible	Increased loss due to Q /it is not dynamic, so loss is higher than in the case of the below Q/ φ / assumption that Voltage depends on P output
cos φ (P)	inverter	DER owner	—	Yes ||||	Yes ||||	Yes ||||	No	No	Increased loss due to Q / assumption that Voltage depends on P output
Q(U) Volt-Var	inverter	DER owner	—	Yes |||	Yes |||	Yes |||	No	No	Increased loss due to Q / Assumption that feeder voltage is always higher / lower at the DER connection point.
P(U) Volt-Watt	inverter	DER owner	Yes	No	No	No	No	No	Prosumer Lost Production / Assumption that feeder voltage is always higher / lower at the DER connection point.
Q(U)-coil	Coil	DSO	No	Yes |	Yes |	Yes |		No	Investment burdening DSO / careful calculation of the location of the connection node

Q(U) by capacitors	Capacitor	DSO	No	Yes ||	Yes ||	Yes ||	No	Yes	
tg φ =f(U)	inverter	DER owner	No	Yes ||	Yes ||	Yes ||	No	No	Increased loss due to Q
Q= f(U)	inverter	DER owner	No	Yes ||	Yes ||	Yes ||	No	No	Increased loss due to Q /Reactive power is directly controlled; therefore it stresses generators more than tg φ =f(U)
tg φ =f(P)	inverter	DER owner	No	Yes ||	Yes ||	Yes ||	Yes	No	Addresses voltage rise for high power injection, but less effective for overall voltage quality than tg φ =f(U) or Q=f(U)
Q=f(P)	inverter	DER owner	No	Yes |	Yes |	Yes |	Yes	No	Since the *P* is the measured parameter, but *U* is controlled via *Q*, it has an assumption that U depends on P.
P-Q Droop (ARD)	inverter	DER owner	Yes	Yes |	Yes |	Yes |	Yes	No	Increased loss due to Q and Prosumer Lost Production

Annex B: Control strategies

The following describes the most popular control strategies used in power systems and the control set used in the *LINK*-Solution.

B.1. Local control

The most popular control strategies in power systems are local controls. They refer to control actions carried out locally without considering the holistic real-time behaviour of the relevant grid part. Its action path may be realised in open- or closed-loop:

- **Open-loop path** – The input variable usually differs from the output one; the output variables are influenced by the input variables but do not act on themselves continuously and again via the same input variables. Figure B.1. shows the open-loop action path of a switched-capacitor bank, where the output variable is always reactive power. In contrast, the input variable may be voltage, current, time, etc.

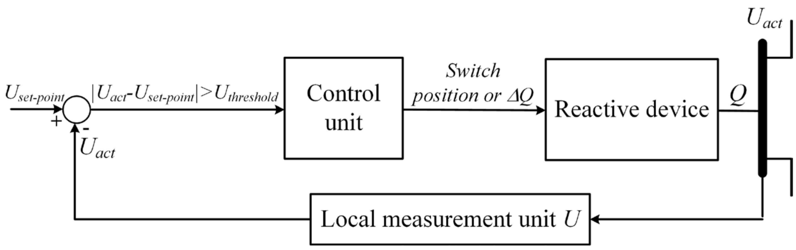


Fig. B.1. Open action path of the Local Control of switched capacitor banks controlled by the actual voltage.

- **Closed-loop path** – In this case, the controlled variable continuously influences itself. The deviation of the measured value from the set-point results in a signal affecting the valves or frequency, excitation current or reactive power, transformer steps, etc. In such a way that the desired power is delivered or the desired voltage is reached. Figure B.2. shows the closed-loop action path of the Local Control of OLTC. It keeps the voltage to the $U_{set\text{-}point}$.

LC automatically adjusts the corresponding control device's active/reactive power contributions, tap and switch positions, etc., based on local measurements or time schedules. They usually maintain a power system parameter, which is locally measured or calculated based on local measurements, equal to the desired value. The fixed control settings are calculated based on offline system analysis for typical operating conditions. LCs are simple, reliable, and quickly respond to changing operating conditions without the need for a communication infrastructure.
When the secondary control loops are set, the local controls in closed loops are usually called primary controls.

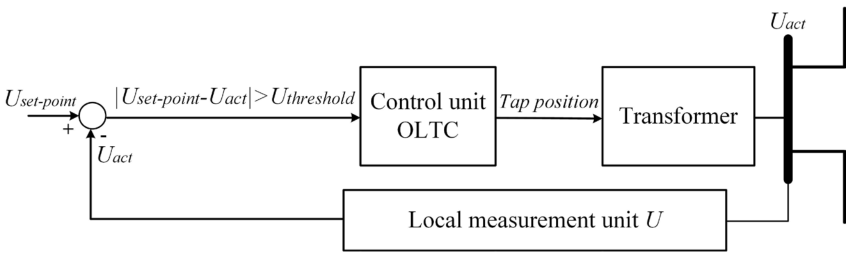


Fig. B.2. Closed action path of the Local Control of OLTC.

B.2. Secondary control

SC strategy in power systems is used for Load Frequency Control (LFC). LFC's significant purposes are maintaining the operation area's frequency and keeping power exchange in the tie lines conforming to the schedules. PC's objective is to maintain a balance between generation and consumption (demand) within the synchronous area. SC maintains a balance between generation and consumption (demand) within each control area and the synchronous area's system frequency. Tertiary control is primarily used to free up the SC reserves in a balanced system situation by considering the economic dispatch.

B.3. Control set used in *LINK*-Solution

The control set used in the LINK-Solution consists of Direct, Primary, and Secondary Controls, Figure B.3. **Local controls in the open-loop** can be used. Still, their global impact on the flows through the boundaries of the secondary control area should be manageable by the secondary controller.

- **Primary Control** refers to local control actions in a closed-loop: the input and output variables are the same. The output- or control-variable is locally measured and continuously compared with the reference variable, the setpoint calculated by secondary control. The deviation from the setpoint leads to a signal that influences the valves or frequency, excitation current or reactive power, transformer steps, etc., in a primary-controlled power plant, transformer, etc., so that the desired power is delivered or the desired voltage is reached.

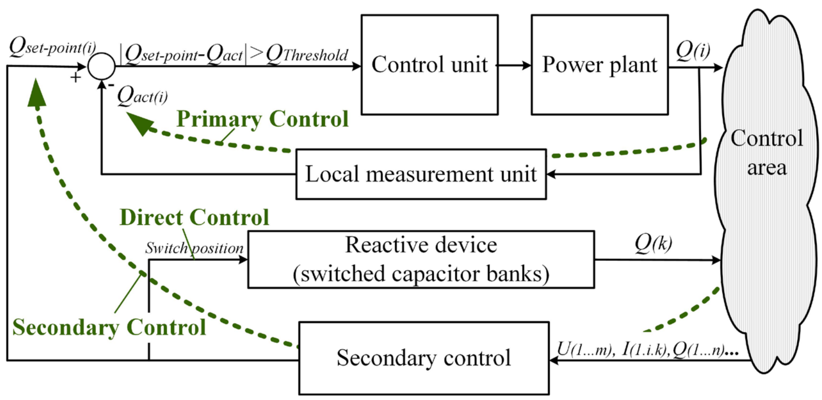


Fig. B.3. Overview of the control set used in *LINK*-Solution.

Direct Control (DiC) refers to control actions performed in an open-loop, taking into account the real-time holistic behaviour of the grid part it belongs. Secondary control calculates its control action.

- **Secondary Control** (SC) refers to control variables calculated based on a control area's current state. It fulfils a predefined objective function by respecting the static, i.e., electrical appliances' constraints (PQ diagrams of generators, transformer rating, etc.), and dynamic conditions dictated by neighbouring areas. At the same time, it calculates and sends the setpoints to PCs and the input variables to DiC, acting on its control area.

Annex C: Survey results

This annexe provides a summary of the results from a global survey conducted among utility companies. The purpose of the survey was to assess the similarities, differences, strengths, and weaknesses of various practices in DERs integrating. Additionally, the survey aimed to identify common challenges and share best practices across the industry.

The survey was developed by the Working Group and refined in collaboration with the CIRED technical committee. It was distributed via National Committees to utility companies in participating countries. A total of 21 responses were received, representing utilities from 24 different countries. Not all utilities answer all questions, and therefore some data are missing in the presentation.

C.1. Base data

Some basic data was collected among the participating utilities.
In Figure C.1 Is the distribution of the grid types that the answering utilities operate. The definition of the grid is according to IEC 50160 and 60038 standards:

• Low voltage (LV): up to 1 kV
• Medium voltage (MV): above one up to 35 kV
• High voltage (HV): above 35 kV

It is quite evenly distributed among the different grid types, and it can be seen that several utilities operate more than one type of grid.

In

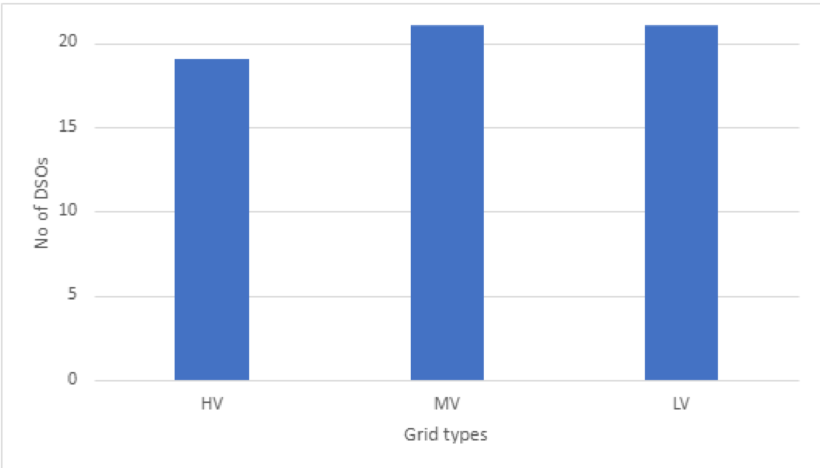


Fig. C.1. Number of the utilities that operate the different voltage level.

Figure C.2 Can the distribution of distributed generation be seen, and at which voltage level each utility has generation connected? As expected, PV is mainly connected at the LV level. The lower levels of the wind, thermal and hydro at HV might be dependent on the fewer participating utilities that operated HV grids.

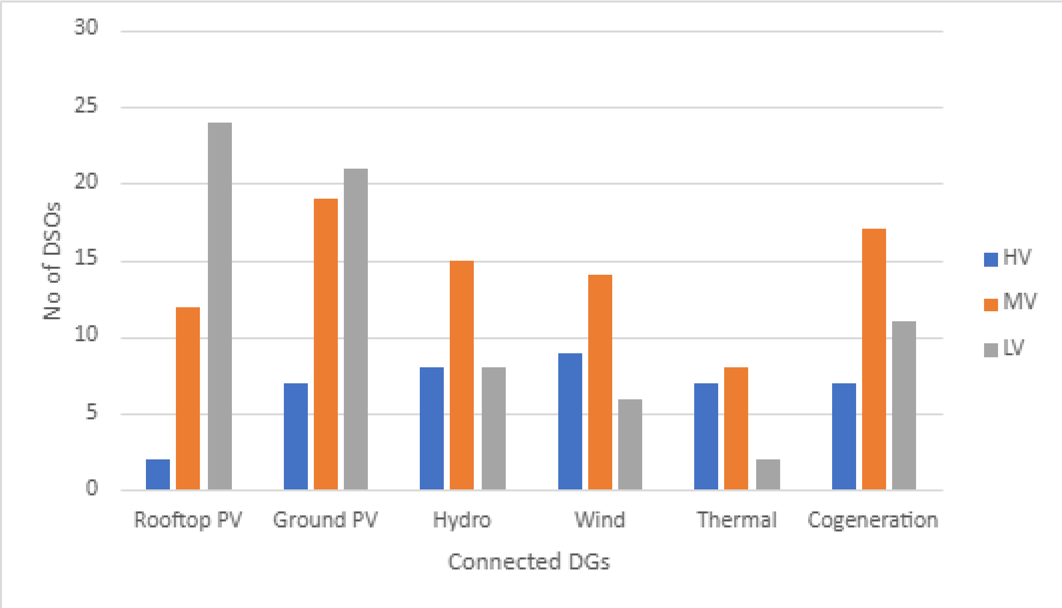


Fig. C.2. Types of the distribution generation connected at different voltage level.

C.2. Current DER penetration

This chapter focuses on the current and expected future penetration of the DER and the information provided to the DSOs.

In Figures C.3 – C.5 can be seen the number of production and storage units connected at HV, MV and LV levels for each participating utility, respectively? It can be seen that the variation is significant, when some have a large amount, and some have only a few. It might have implications for the internal experience of handling generation units and perhaps also connecting additional units. As expected, the number of units is higher for the lower voltage levels than for the higher voltages. However, the size of the individual units is expected to be higher at higher voltage levels, but no data was available on the matter.

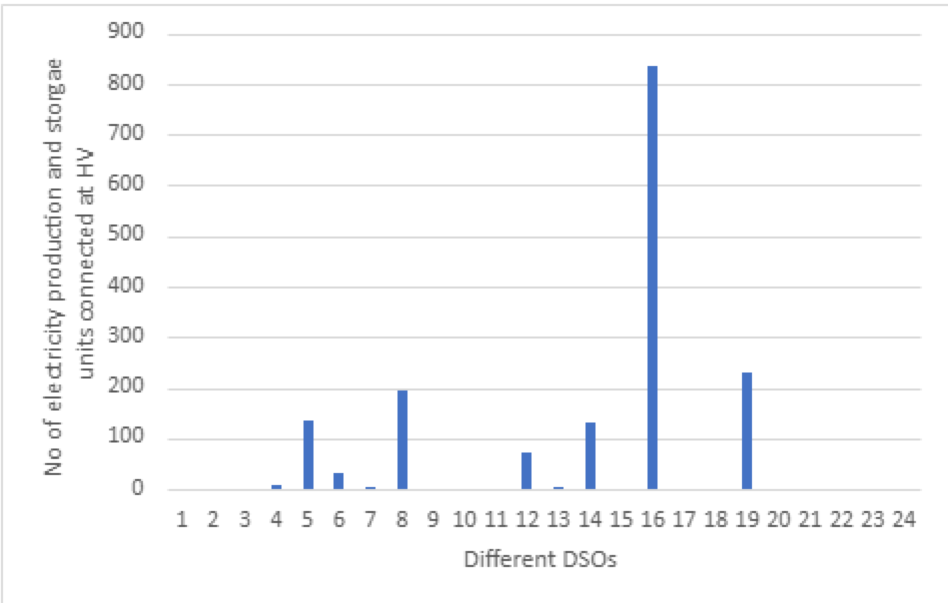


Fig. C.3. Number of the production and storage units connected at HV level for each participating utility.

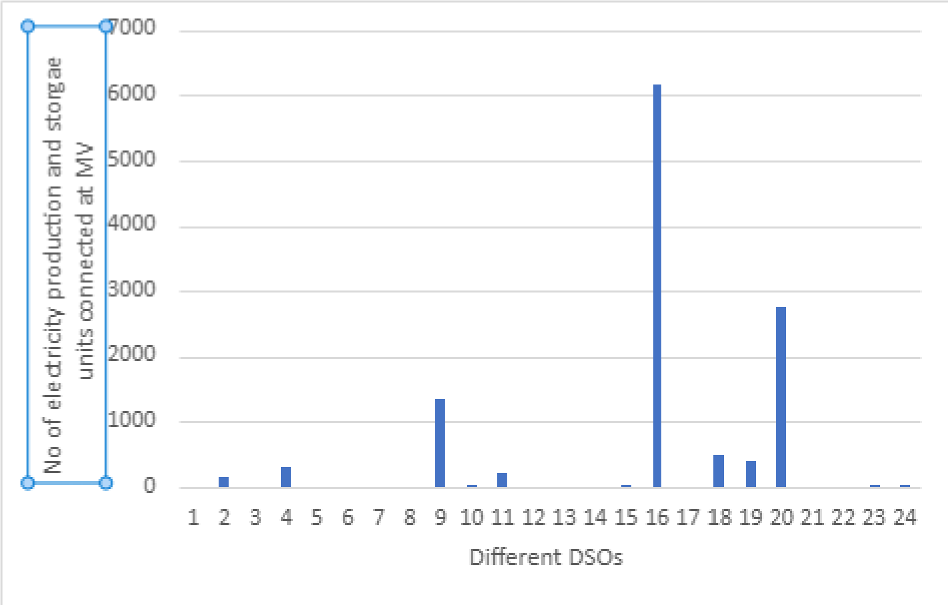


Fig. C.4. Number of the production and storage units connected at MV level for each participating utility.

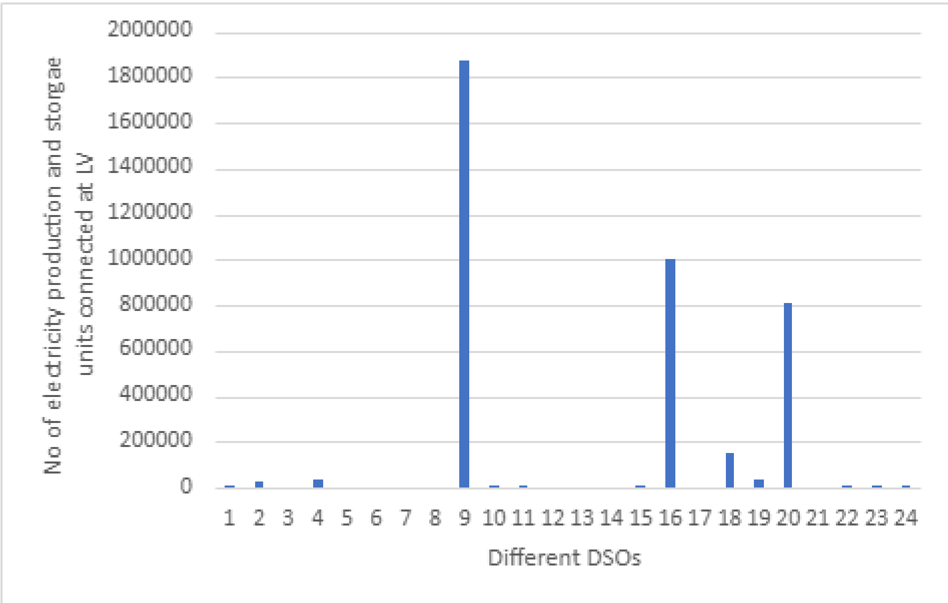


Fig. C.5. Number of the production and storage units connected at LV level for each participating utility.

Figure C.6 shows that around a quarter of all participating utilities have no information about the rooftop PV and/or storage that are installed behind the meter. The lack of data and thereby awareness of the generation or storage behind the meter might be an issue, from both an operational and safety perspective.

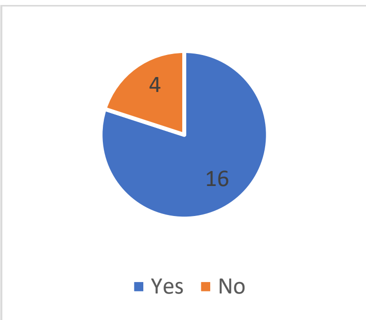


Fig. C.6. Numer of utility having information on rooftop PV and storage if connected behind the meter.

The data on current number of connected distribution electricity producers and storage facilities are extremely scarce. **The longest MV feeders for DSOs range from 20 up to 80 km** and the feeders are mainly OH lines and only small part of each of the long feeders are cable. **For LV is the maximum feeder length 4 km** and all long LV feeders also are built of a vast majority of OH lines.

C.3. Future development of DER penetration

This chapter focuses on the expected development of DERs, like DG, heat pumps and EV charging. The time horizon is 2, 5 and 10 years.

C.3.1. To what extent do you expect DG to penetrate the grid in the next few years?

There is only a few DSOs that are expecting massive DG penetration in HV grid the next 2, 5 and 10 years as can be seen in Figure C.7 and Figure C.8. However, even if the expansion looks great it should be reflected on the fact that the DSO has extensive grids. Figure C.7 shows the number that

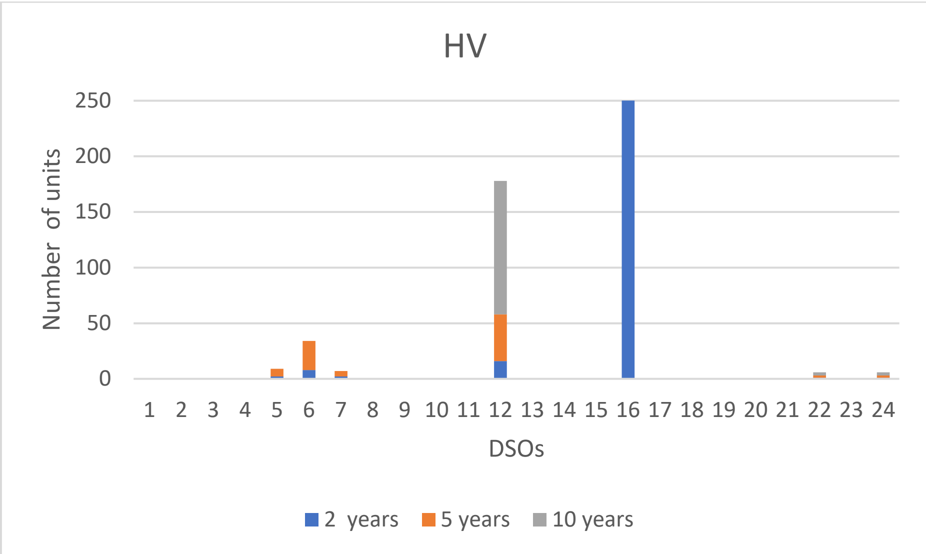


Fig. C.7. Whatever utility has information on rooftop PV and storage if connected behind the meter.

are expected to be connected. DSO 16 is out of scale of the figure and is expected 42500 units for the coming 10 years. The expected the installed capacity can be seen in Figure C.8.

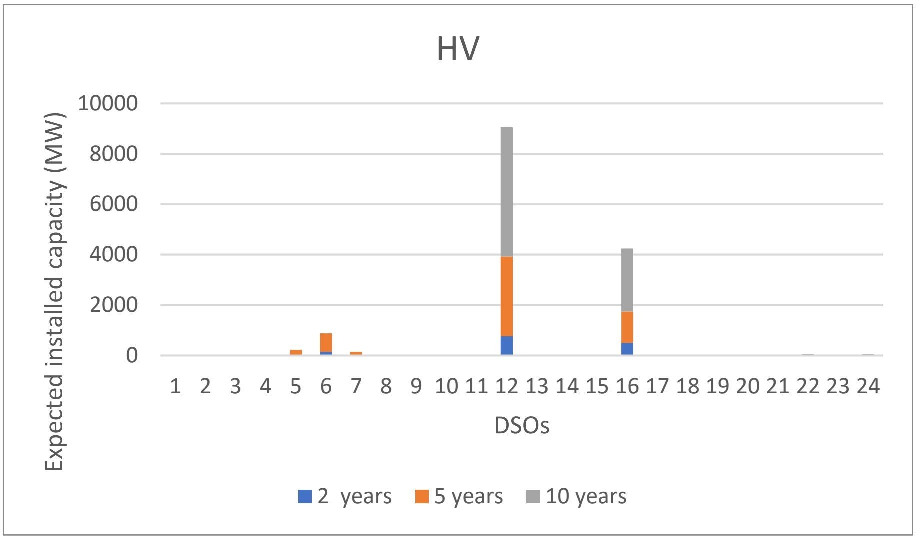


Fig. C.8. The expected installed capacity in HV grid.

For the MV grid is the expected increase more even distributed in among the DSOs, Figure C.9. This could be related to the higher number of DSOs that has MV grids but also that more DG are expected in the MV grid.

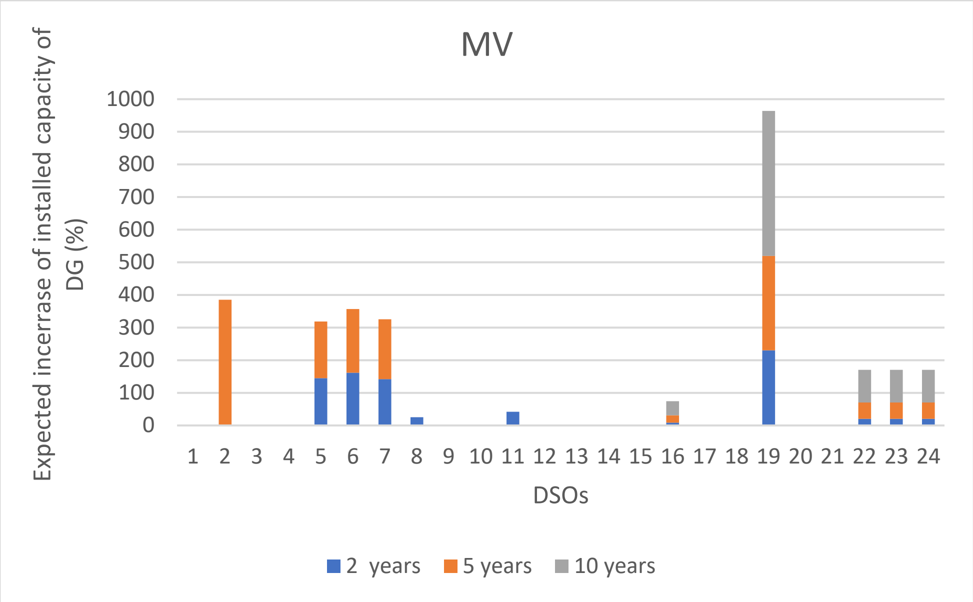


Fig. C.9. Expected increase in installed capacity in the MV grid.

In the LV grid is there also a great expected increase in DG as can be seen in Figure C.10.

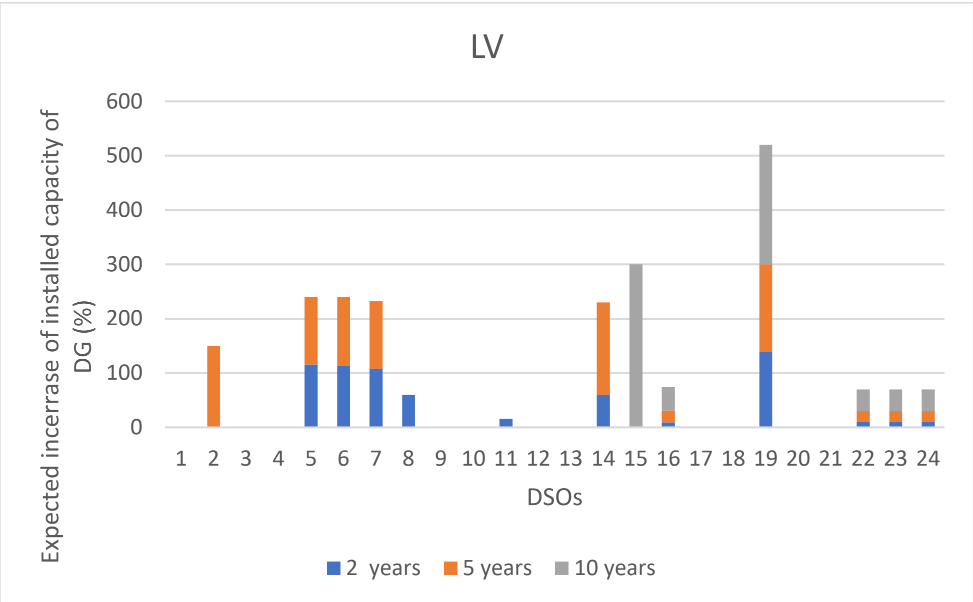


Fig. C.10. Expected increase in DGs' installed capacity in the LV grid.

In Figure C.11 can it been seen that the there is also great increase of DG on customer power level. Only a few DSO has answers that not all DSO that has information about this as it is the system of customer.

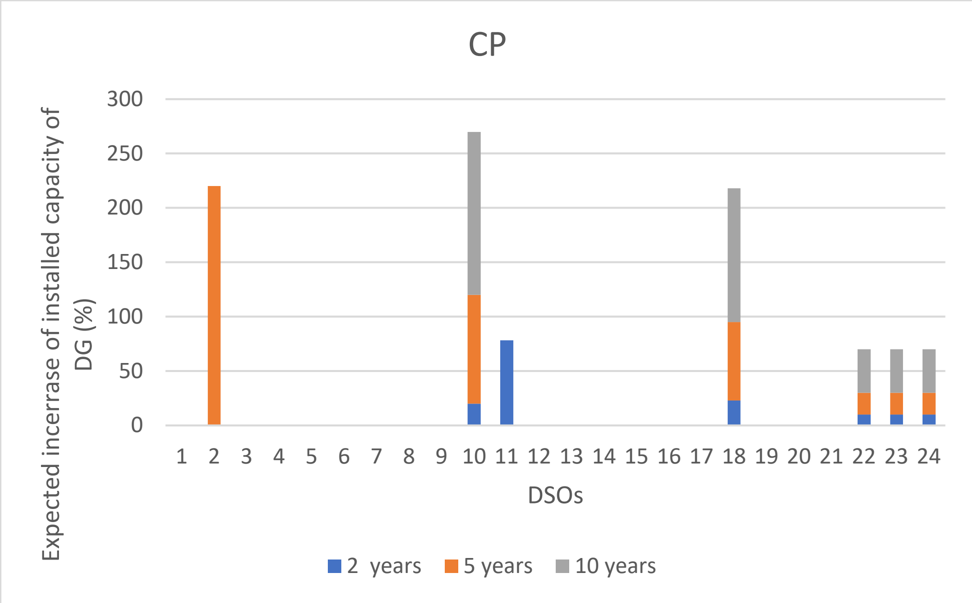


Fig. C.11. The expected increase of the DG installations in customer plants.

C.3.2. To what extent do you expect the distributed storage (excluding electric vehicles) to penetrate the grid in the next few years?

The data in the survey was very scarce. However, there were a few DSOs that indicated that there could be a huge increase >1000 % in the coming two to five years.

C.3.3. To what extent do you expect the total current load to increase because of heat pumps, e-mobility and other consumption in the next few years?

The data in survey was very scarce, and no conclusions could be drawn.

C.4. Challenges provoked by DER penetration

This chapter focus on the challenges with DER, like reverse power flow, voltage rise, harmonics and protection settings. The DSOs specify their challenges quantitatively.

C.4.1. Reverse power flows in different parts of the network

As can be seen in Figure C.12 DSOs have reported reverse power flows in all parts of their grid. The most DSOs has experience reverse active power flow at the customer connection point, but some has also seen it all the way up to connection to the TSO grid. Some has also reported a reverse reactive power at the TSO/DSO connection point.

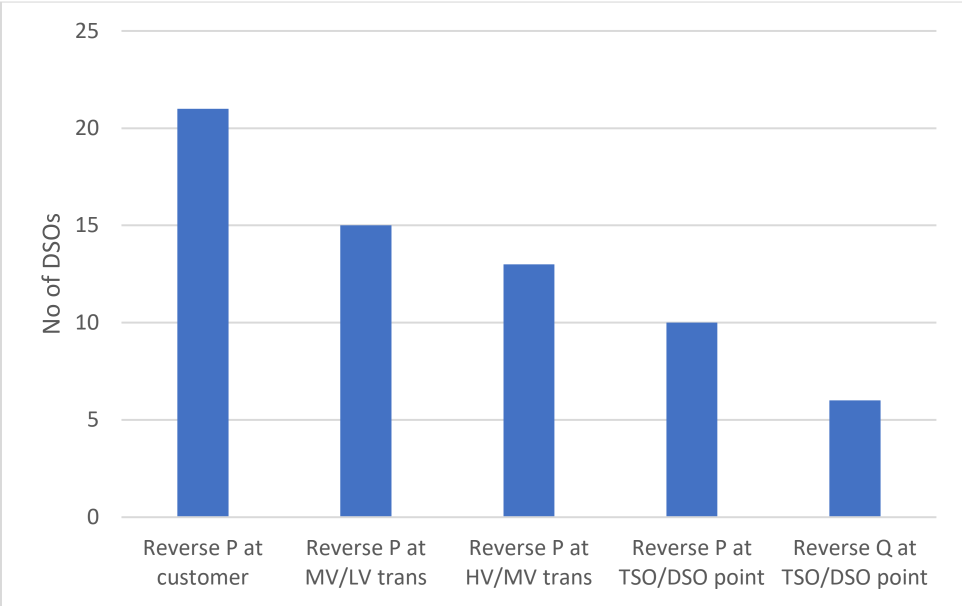


Fig. C.12. The number of DSOs that experience reserved power flows in different parts of the system.

C.4.2. Have there been violations of the upper voltage limits due to DERs?

Figure C.13 shows where DSOs have experienced violations for the upper voltage limits due to DERs in different parts of the grid. Most DSOs have experienced violations, especially in the LV grid. But some have seen it also in the MV and HV grids. Remember that there are fewer DSOs that operate HV than MV grids of those that has answered the survey.

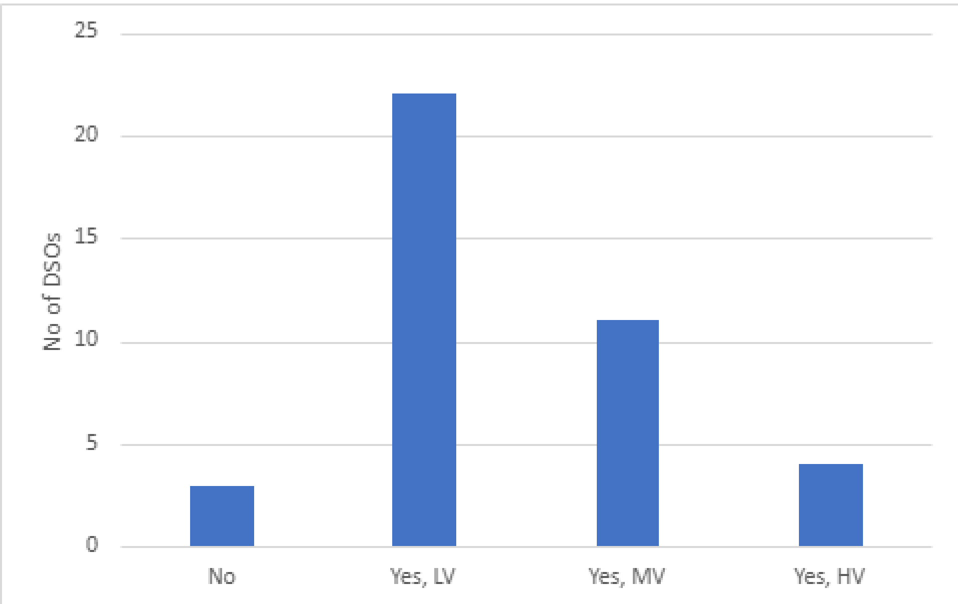


Fig. C.13. The number of DSOs that has experienced voltage limits violations due to DERS in different parts of

C.4.3 Voltage limits

Figure C.14 shows the base of the different voltage limits. Eleven DSOs have fixed ranges while 7 have not. Most of the DSOs state that they have national requirement of voltage limits but there are mainly based on IEC standard.

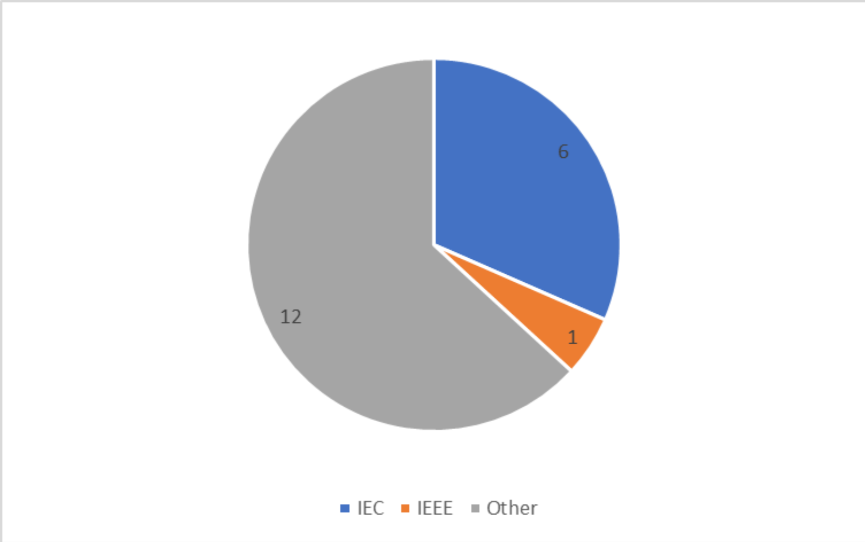


Fig. C.14. Base of the voltage limit for different DSOs.

C.4.4. Are you monitoring harmonics on the grid?

Several DSOs are not monitoring harmonics in the grid in any part of their grid, as can be seen in Figure C.15. The most common part to monitor is in the LV grids but there are DSO that monitor in all parts of the grid.

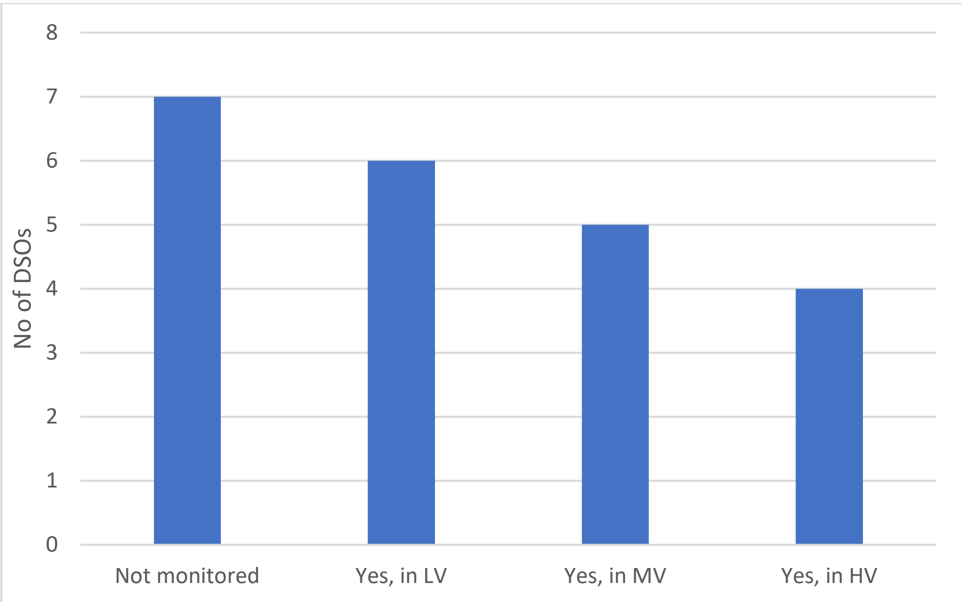


Fig. C.15. Monitoring of harmonics in the different parts of the grid.

There are only a few DSOs that has reported violations of the harmonic limit as can be seen in Figure C.16. Current harmonics seems to be the most common.

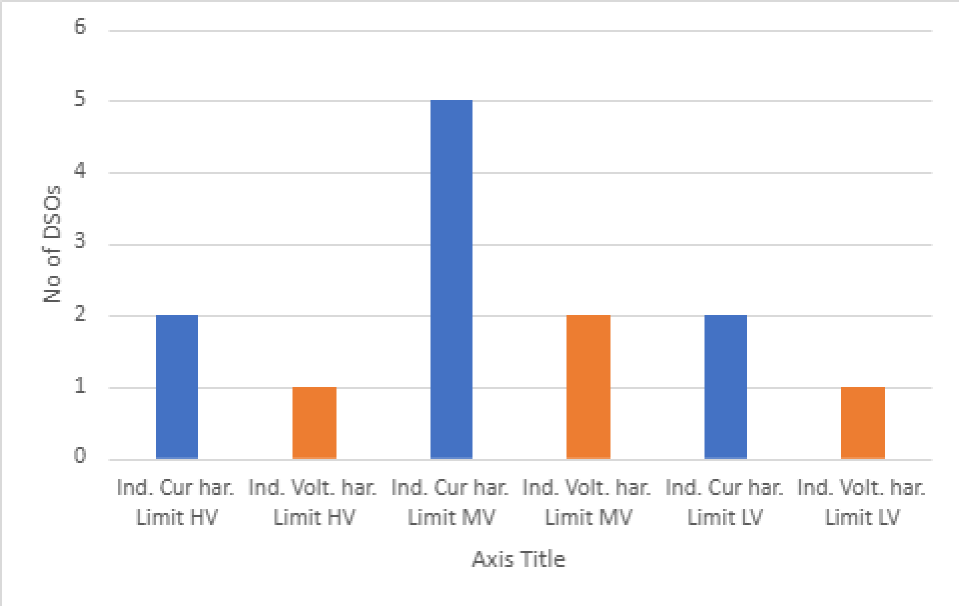


Fig. C.16. Number of DSOs that has experienced current and voltage harmonics violations.

C.4.5. Have there been identified violations of current limits of network components, i.e. overloading problems due to the DERs?

Eleven DSOs have not identified overloading problems in the grid but the most common is in the LV and then decrease with increased voltage level, as can be seen in Figure C.17. A few DSOs have also experienced that the short-current level (ISC) in the HV have increased above limit of network equipment. The equipment identified is mainly switchgear but a single DSO has also encountered challenges related to OH lines.

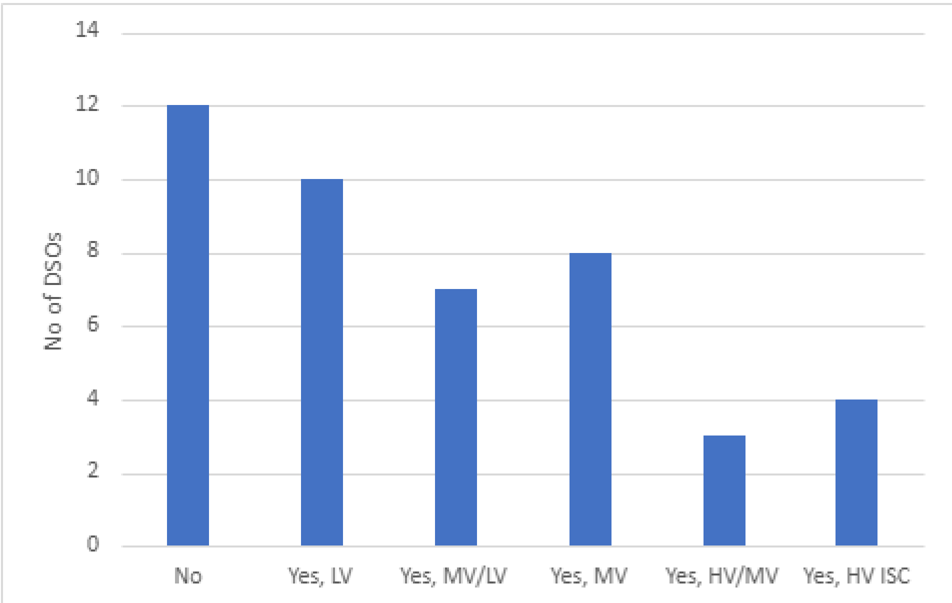
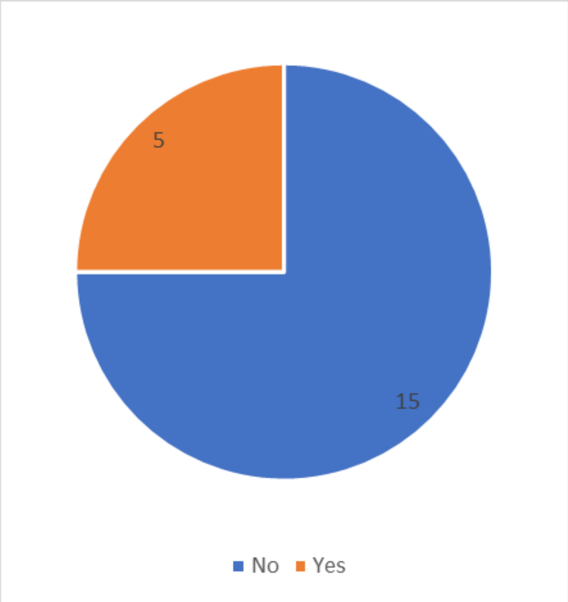
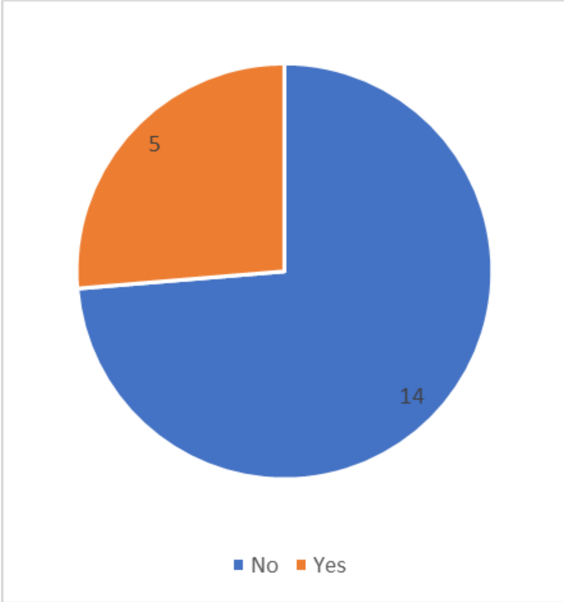


Fig. C.17. Number of DSOs that has identified violations of the current limits of network components.

C.4.6. Have you experienced protection-related problems due to DERs?

Some DSOs have an increase of short circuit power above limitations as can be seen in Figure C.18a).





(a) **(b)**

Fig. C.18. Number of DSOs that has experienced: a) A short circuit power above limitation due to DER ; b) protection related problems.

Quite few DSOs have experienced protection-related problems due to DERs, as can been seen in Figure C.18. Issues with anti-island protection system and sympathetic tripping has been identified.

C.4.7. Are some On-Load Tap Changers (OLTC) unable to maintain their voltage setup because they are in the lowest tap position?

Most of the DSOs have not experienced that some OLTC have been unable to keep the voltage down, according to Figure C.19. Some have experienced it but it seems not to be a common issue.

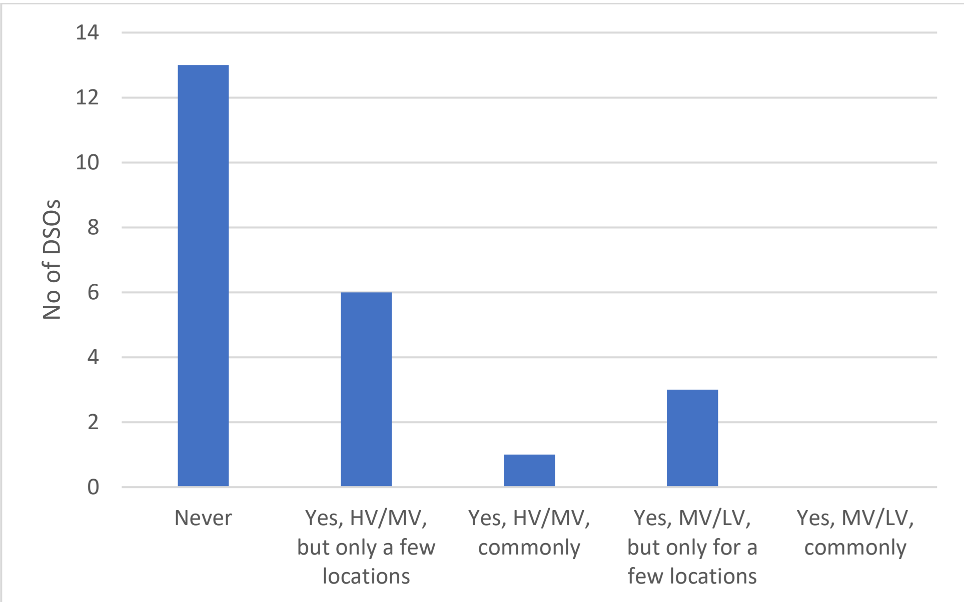


Fig. C.19. Number of DSOs that has experienced that the OLTC have reached their end setting

C.5. Countermeasures to maintain network voltages within statutory/legal limits

This chapter focuses on the countermeasures that are used to mitigate the challenges from the DER. The chapter deals with both the use of active and reactive power control.

C.5.1. Which local control strategy is used to eliminate voltage violations?

Different DSOs use different countermeasures for voltage violations, see Table C.1. OLTC is most commonly used at HV and MV, while a more diverse selection of measures is used at LV.

Table C.1. Number of DSOs per countermeasure and voltage level.

	Fixed cos (φ) by DER	Cosϕ(P) by DER	$Q(U)$ by DER	$P(U)$ by DER	$Q(U)$ - coil	$Q(U)$ by capacit.	OLTC equipped transf.	In-line voltage regulators
HV	5	5	2	1	6	7	13	0
MV	10	5	9	3	3	4	12	6
LV	9	4	8	9	1	1	8	9
CP inv.	3	2	6	5	0	0	0	-

C.5.2. Are you using central control strategies to eliminate voltage violations?

Most of the DSOs have a SCADA system at HV and MV parts of the grid, but not on LV, according to Figure C.20.

Around two-thirds of the DSOs do not use state estimators in the HV and MV grid for the Volt/var

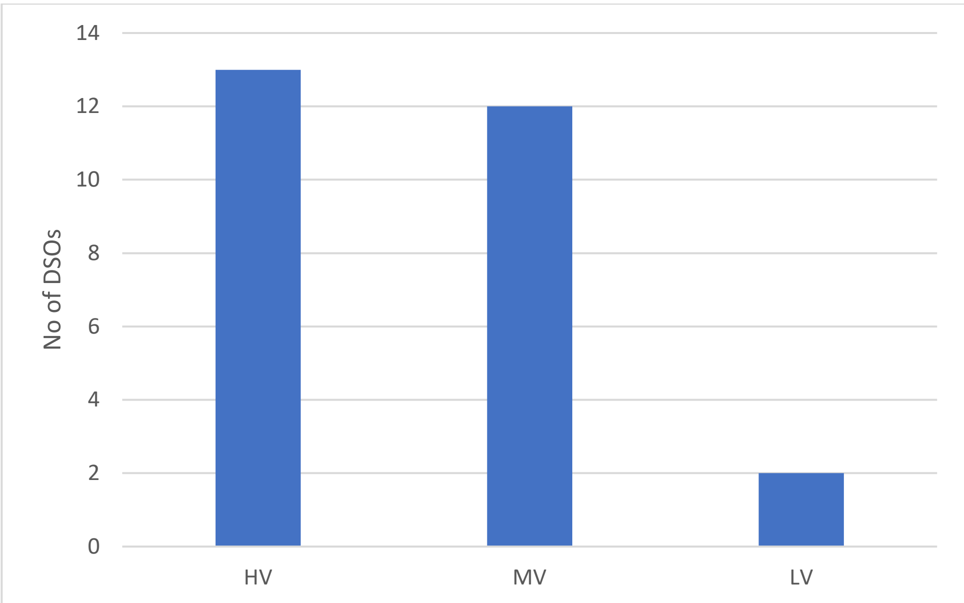


Fig. C.20. Number of DSOs that have SCADA systems at different grid parts (24 DSOs involved in the

controller, according to Table C.2. None uses it at the LV grid level.

Table C.2. Number of DSOs per countermeasure and voltage level.

	Volt/var control without state estimator	Volt/var control with a state estimator
HV	10	5
MV	10	6
LV	3	0

C.5.3. If you use central control strategies, which levers (control variables) are used to eliminate voltage violations?

OLTCs are the most used levers to control voltage at HV and MV, combined with local controls of reactive power control by capacitors or DERs, see Table C.3. For LV, reactive power local control by DERs is mostly used.

Table C.3. The number of DSOs using the different control variables (levers) to eliminate voltage variations.

Voltage violation location	P by DER	Q by DER	*P* by consumer	*Q* by consumers	*Q* by capacitors	Q by coils	HV/MV OLTC volt. ref.	MV/LV OLTC volt. Ref.
HV	1	4	0	1	9	2	11	1
MV	3	9	0	1	8	3	10	2
LV	3	6	3	0	1	1	2	3

C.6. Practical countermeasures constraints at the TSO-DSO interface.

This chapter focuses on the interface between the TSO and DSO, both the challenges and the countermeasures used.

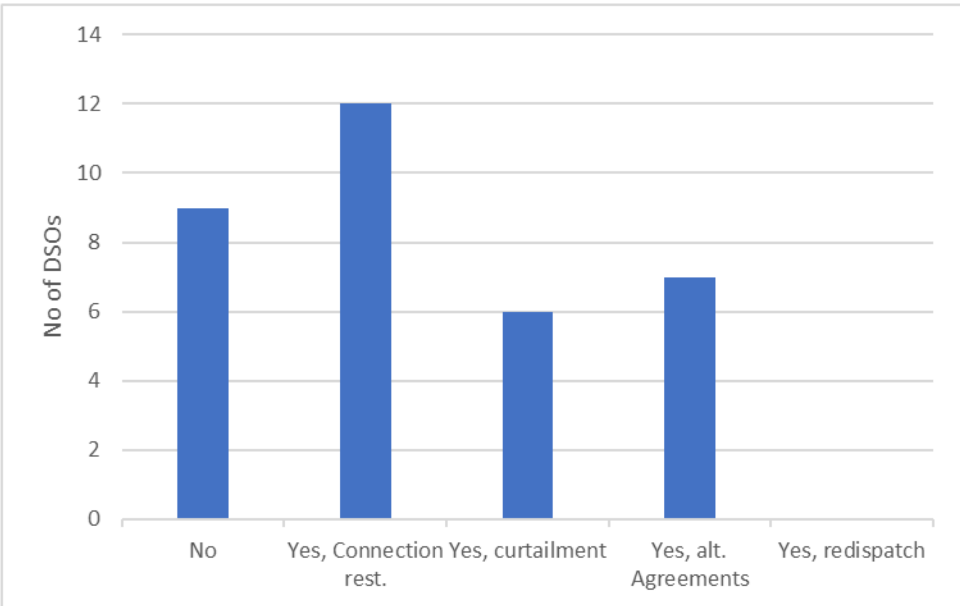


Fig. C.21. Number of DSOs that have experienced any load problems at the TSO/DSO connection point.

A majority of the DSOs have encountered problems with the capacity in the TSO/DSO connection due to DER, according to Figure C.21. The most common countermeasure is connection restrictions. Only a few DSOs have experienced voltage violation problems at the TSO/DSO connection point that required adjustment in the network operation, as can be seen in Figure C.22. No specific countermeasure is more commonly used to mitigate the challenges.

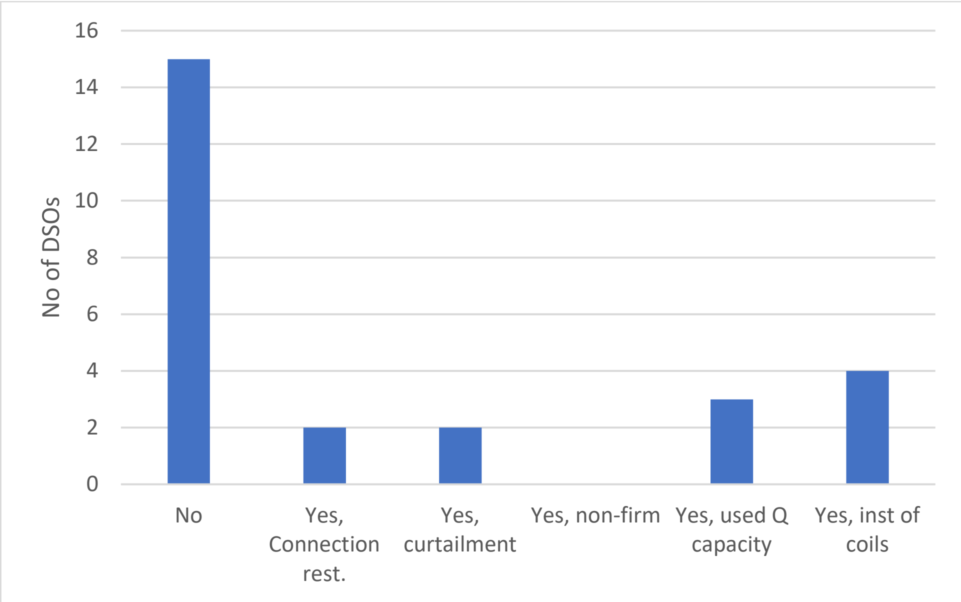


Fig. C.22. DSOs number restricting DER due to voltage problems at the TSO/DSOs connection point and their counteraction.

C.7 Grid Codes and Distribution Codes of Practice

In this chapter, the grid and distribution codes of practice are presented and compared. This data focuses on DER connection conditions.

C.7.1. Connection conditions on LV network

In Figure C.23, the maximum size for households DERs can be seen. For DSO 22-24, the subscribed power the limit is 80 % of connected power. It can be seen that the variation is large.

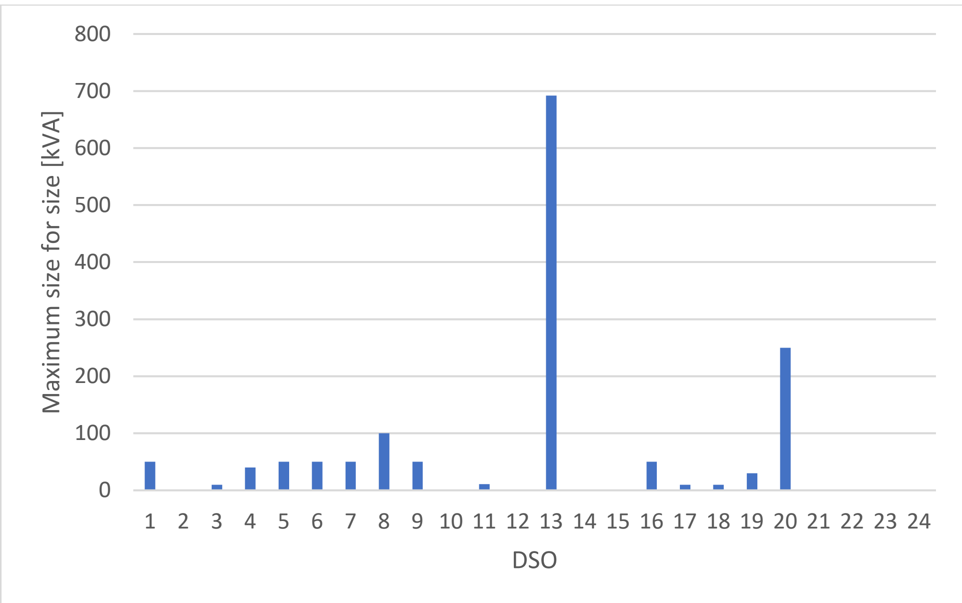


Fig. C.23. Maximum size for the household-sized power plants.

Most of the DSOs, see Figure C.24, have restrictions due to limitations in the grid, such as voltage increase and thermal limit.

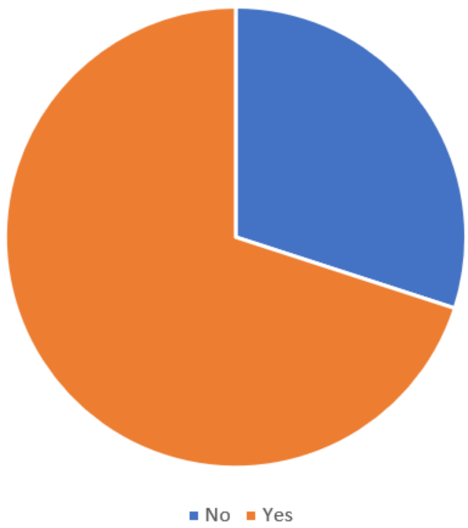


Fig. C.24. Parts of DSOs that has restrictions on the power plant connection due to limitations in the LV grid.

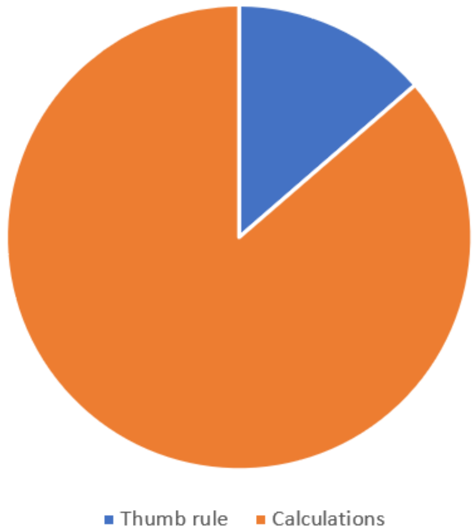


Fig. C.25. Part of the DSOs that make calculations for connections at LV

Most of the DSOs also make calculations, Figure C.25. However, one of the DSOs only does calculations when the DER size is above six kVA.

C.7.2. Connection conditions on MV network

In Figure C.26, the minimum and maximum power limits for connection to MV for each DSO are shown. The variation is great for the LV. Most of the DSOs, Figure C.27, have limitations on the size of power plants due to limitations in the MV.

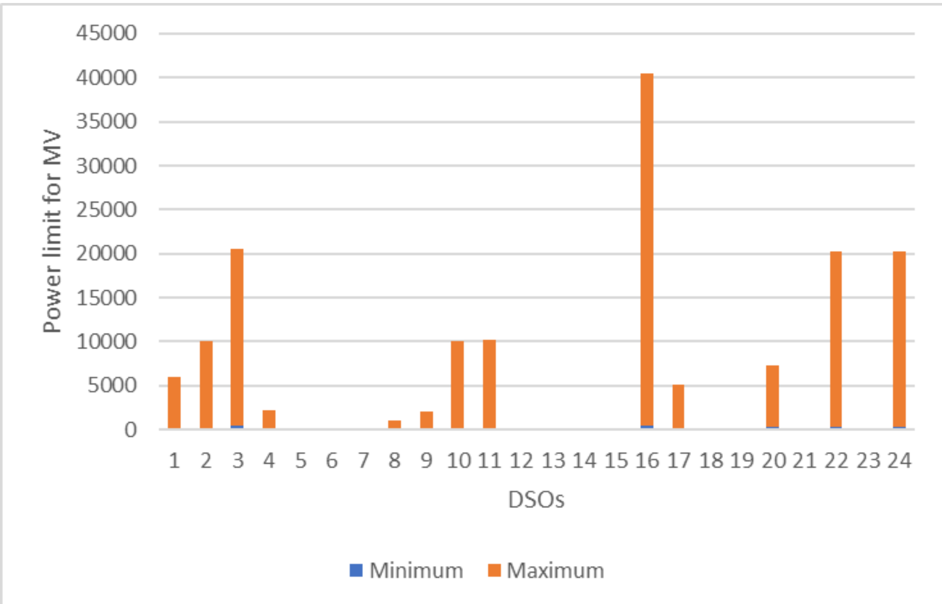


Fig. C.26. Minimum and maximum size of limit for power plants' connection to MV for each DSO.

Examples of the limitations are voltage increase, thermal limits, n-1 criteria or the size of the connected plant shall be less than the maximum consumer load. All DSOs except one make calculations for each connection.

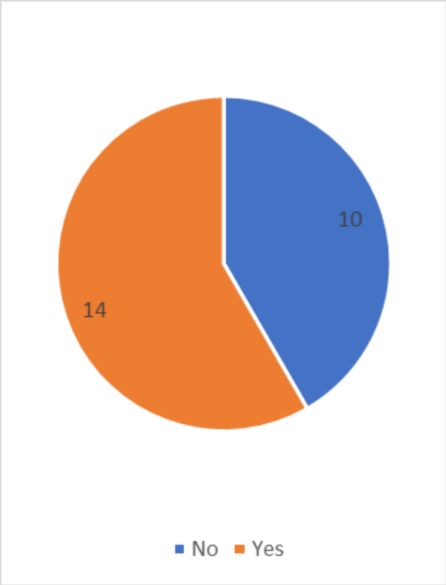


Fig. C.27. Parts of the DSOs that have restrictions on the power plant connections due to limitations in the medium voltage grid

C.7.3. Connection conditions on HV/MV substation

In Figure C.28 Can the minimum and maximum power limits for connection to MV for each DSO be seen? The variation is great for the LV. Most of the DSOs, Figure C.29, have a maximum size of power plants due to limitations in the HV/MV substation.

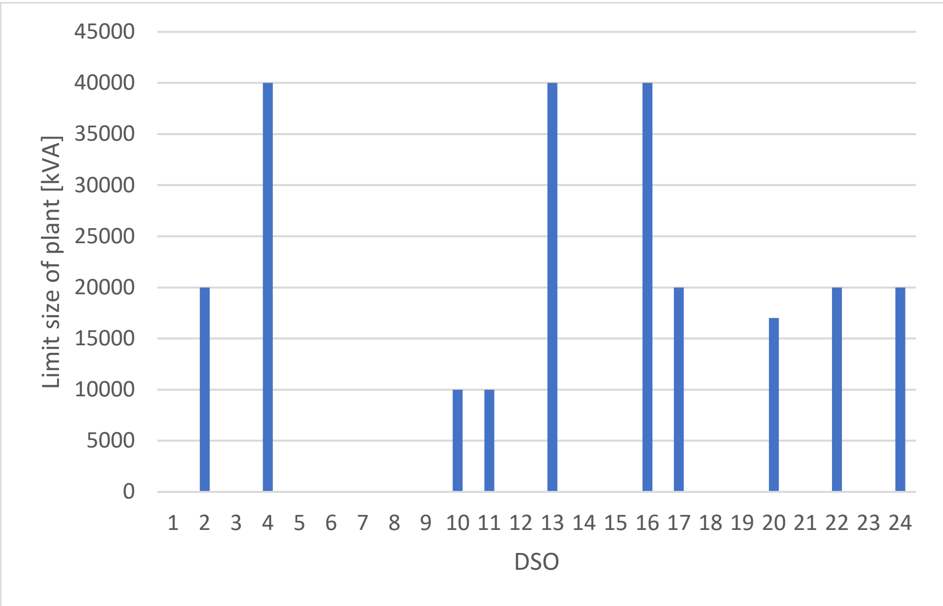


Fig. C.28. Maximum size for power plants connected to the HV/MV substations.

Examples of the limitations are voltage increase, thermal limits, n-1 criteria, no reverse power flow and transformer power. All except one make calculations for each connection.

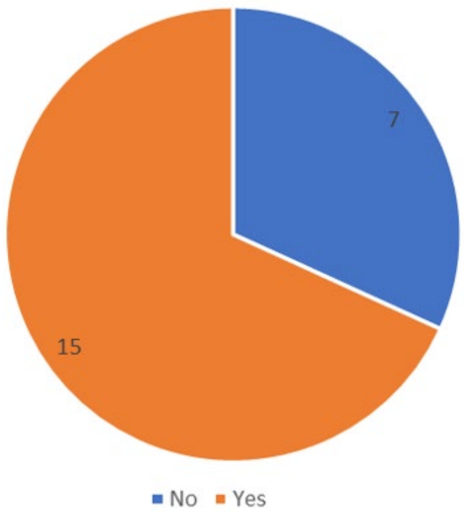


Fig. C.29. Parts of DSOs that have a restriction on the power plant due to limitations in the HV/MV substation.

C.7.4. Connection conditions on the HV network

The situation is similar for connection to HV. Only one DSO have stated that they have an upper limitation in size of 60 MVA, and four have limitations due to the limitations of the grid. All except one make calculations.

C.8 Effectiveness of energy market/trading rules to promote the DER flexibility

This chapter is on the energy market and trading rules to promote DER flexibility. Both the attitude and actual considered and used flexibility mechanisms are presented. The coordination possibilities and time interval with the TSO are presented.

In Figure C.30 Can it be seen that most DSOs consider their TSO to promote DER? An even greater majority have experienced contingency cases due to market decisions that have required rescheduling, Figure C.31. One DSO has only experienced it in parts of their grid, and one has only experienced it during a pilot.

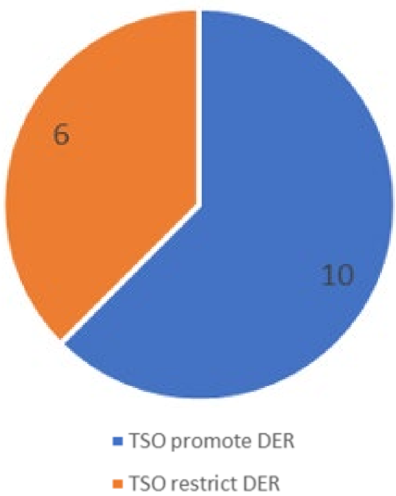


Fig. C.30. Parts of the DSOs that consider the TSO as a promoter of DER.

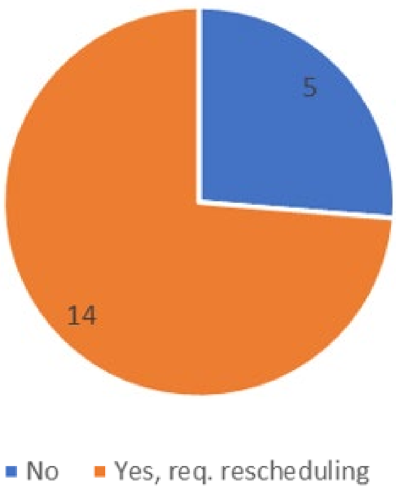


Fig. C.31. Parts of the DSOs that experienced contingency cases provoked by market decisions.

Several DSOs have or consider using different market or trading rules to promote DER, as can be seen in Figure C.32, but not all.

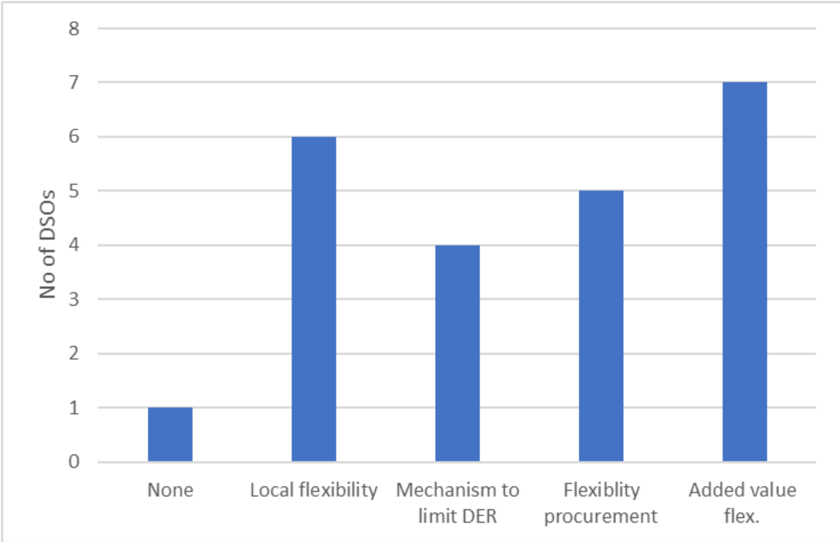


Fig. C.32. Number of DSOs per type of market/trading rule that promote DER flexibility.

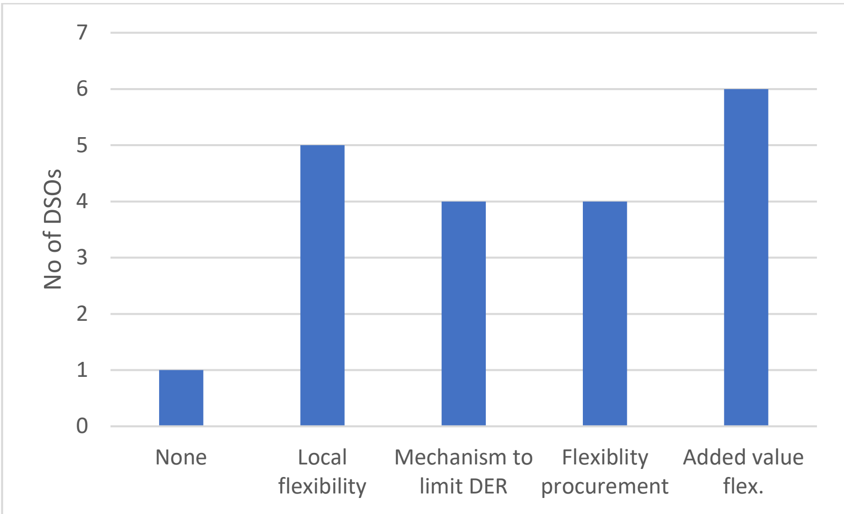


Fig. C.32. Number of DSOs for each type of market/trading rule that could promote DER flexibility.

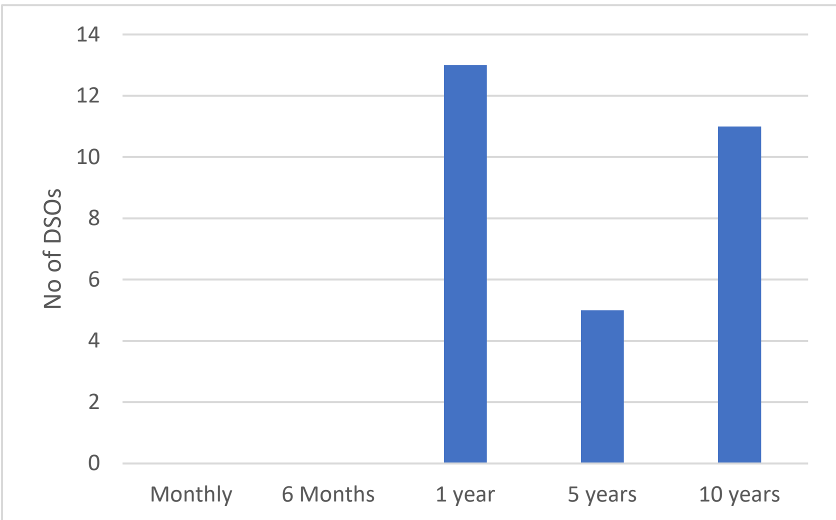


Fig. C.33. DSOs number using various time horizons for the asset planning.

Two-thirds of the DSOs do regular asset planning with their TSOs. However, the time horizon is considered very different, as can be seen in Figure C.33. A DSO could have more than one-time horizons. A majority of the DSOs harmonise and coordinate asset planning with the relevant TSOs, according to Figure C.34.

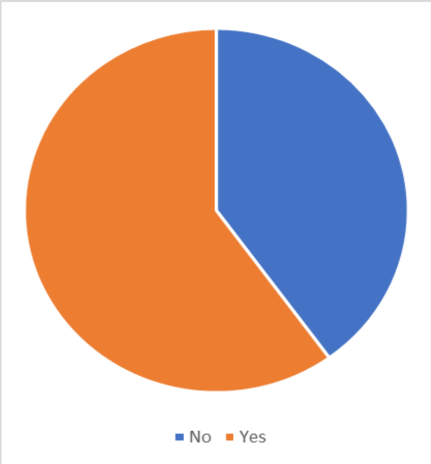


Fig. C.34. Parts of DSOs that harmonise and coordinate asset planning between them and relevant TSO.

The time horizon varies among the DSOs, and some DSOs have more than one time horizon. Figure C.35. The harmonisation and coordination are done either via Ten-Year Network Development Plan regular meetings.

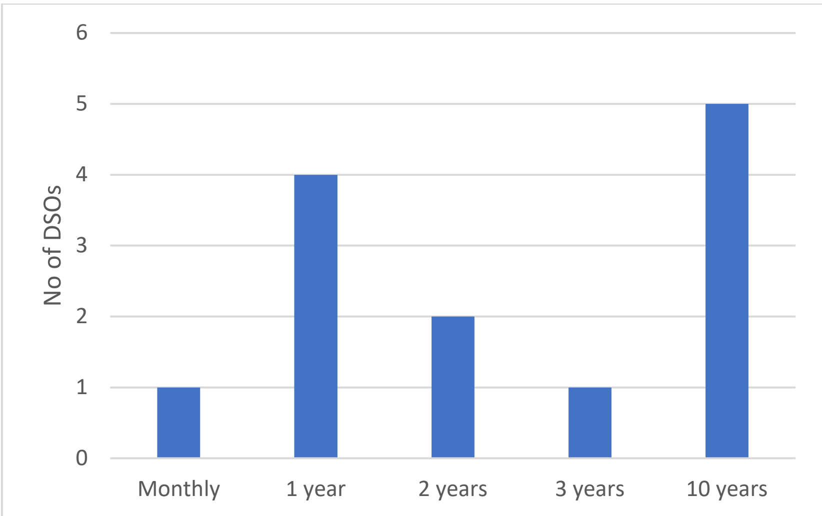


Fig. C.35. Time period that DSO consider for harmonisation and coordinate asset planning between them and relevant TSO. A DSO could have more than one time horizon.

Almost two-thirds of all DSOs already procure flexibility, or where they think flexibility can be beneficial. In Table C.3 are summarised the kind of flexibilities used in different cases presented in Figure C.36.

Table C.3. Number of DSOs using different kinds of flexibilities.

		Significant users	Small users
DSO Nr. using	DR for load shaving	5	8
	DR for load reduction	8	8
	DR for load increase	5	4

Five DSOs are considered flexible already in the planning process, while 9 DSOs not.

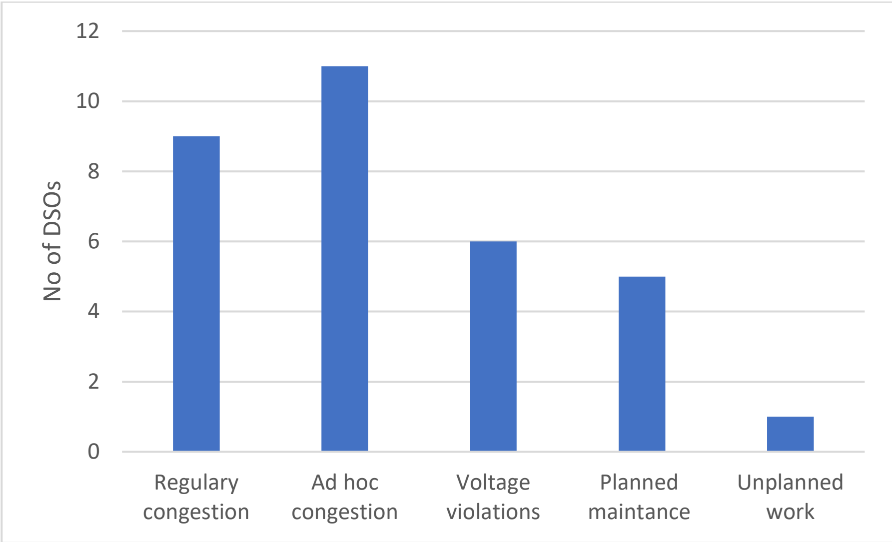


Fig. C.36. Number of DSOs procuring various flexibility services.

C.9. Additional information: Grid characteristics

		Length HV		Length MV		Length LV					
DSO	No costumers	OH lines [km]	UG lines [km]	OH lines [km]	UG lines [km]	OH lines [km]	UG lines [km]	No. HV/MV substations	Inst. capa HV/MV transformers [MVA]	No. MV/LV substations	Peak demand [MW]
1	10000	882000									1370000
2	2484575			23315	19149	43999	18670	144	4622,5	29510	3100
3	40700000			89083	150851	194155	144501			221356	33800
4	3300000	200	1500	0	41600	0	51200	277	19500	33000	6500
5	778225	1300	3	9068	1518	9980	2637	31	1884	8574	602
6	1072145	2006	5	10873	2276	11265	3820	59	4044	11418	1441
7	1897500	732	105	3500	6261	8240	4864	49	10554	12604	2060
8	31700000										33000
9	14403939			275881	14573456	140152	584783	587	24366	1877763	
10	450000			4640	1309	11341	1549	25	1327	4982	560
11	3763655	8	6	37351	14573	97161	17083	207	10912	35700	5231
12		14348	884	17037	32151	11759	53594	600	28400	449900	
13	48300	0	6	52	640	79	1280	5	445	595	126
14	970000	6000	400	6000	22000	6000	41000	500		25000	5000
15	101000	10	95	112	1000			24	1300	1484	220
16	22500000	85863	16197	724331	61042	624828	50000	765	252836	0	82736
17	7904985	765,8	227	102492	11,895	113869	15660	241		165571	8000
18	24121875	18470	1072	129787	9323	31659	20254	508		150829	11036
19	4649439	8817	321	15924	31677	3667	98048	650	22653	42289	7707
20	37500000			317000	350000	412000	360000	2754		807000	82000
21	500000	2000	100	3500	5000	4200	18000	76		8500	
22	352639	387	12	3248	2610	4614	6494	31	1940	5698	762
23	177728	72	0	2485	1395	5685	7400	19	1940	3611	366
24	92526	156	6	537	1630	443	3238	12	609	1593	215

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