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Active Distribution System Management

A key tool for the smooth integration of distributed generation

FULL DISCUSSION PAPER

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Active Distribution System Management

A key tool for the smooth integration of distributed generation

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TF Active System Management
Per HALLBERG (SE) Chair
Juan Jose ALBA RIOS (ES); Christer BERGERLAND (SE); Aurelio BLANQUET (PT); Marcel CAILLIAU (BE); Conor CLIFFORD (SE); Paul DE WIT (NL); Ellen DISKIN (IE); Håkan FEUK (SE); Bruno GOUVERNEUR (BE); Mike KAY (GB); Pauline LAWSON (GB); Marina LOMBARDI (IT); Pavla MANDATOVA (EURELECTRIC Secretariat); Ruud OTTER (NL); Pablo SIMON CABALLERO (ES); Jorge TELLO GUIJARRO (ES); Walter TENSCHERT (AT); David TREBOLLE (ES); Siegfried WANZEK (DE)

Contact:
Gunnar LORENZ, Head of Networks Unit – glorenz@eurelectric.org
Pavla MANDATOVA, Adviser Networks Unit - pmandatova@eurelectric.org

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Introduction

The expansion of decentralised and intermittent renewable generation capacities introduces new challenges to ensuring the reliability and quality of power supply. Most of these new generators (both in number and capacity) are being connected to distribution networks – a trend that is set to continue in the coming years.

This development has profound implications for distribution system operators (DSOs). Until recently, DSOs designed and operated distribution networks through a top-down approach. Predictable flows in the electricity network did not require extensive management and monitoring tools.

But this model is changing. Higher shares of distributed energy sources lead to unpredictable network flows, greater variations in voltage, and different network reactive power characteristics. Local grid constraints will occur more frequently, adversely affecting the quality of supply. Yet DSOs are nevertheless expected to continue to operate their networks in a secure way and to provide high-quality service to their customers.

This EURELECTRIC report addresses a number of fundamental questions that arise from the integration of distributed generation (DG) and other distributed energy resources (DER) into the energy system:

- **How can DSOs make the most efficient use of the existing network?**
- **When are new infrastructure and changes in system architecture needed to better integrate DG and DER?**
- **Which types of system services are needed and how can they be procured?**
- **How can renewable energy sources (RES), DG, and DER contribute to system security?**
- **How should the regulatory framework develop?**

Active distribution system management may provide some answers to these questions. Indeed, distribution management will allow grids to integrate DER efficiently by leveraging the inherent characteristics of this type of generation. The growth of DER requires changes to how distribution networks are planned and operated. Bi-directional flows need to be taken into account: they must be monitored, simulated and managed.

The report sets out implications for the tasks of system operators (TSOs and DSOs) and DG/RES operators and outlines options for system planning and development, system operation, and information exchange, thereby opening the door for further analysis. It focuses on outstanding technical issues and necessary operational requirements and calls for adequate regulatory mechanisms that would pave the way for these solutions.

The paper focuses largely on distributed generation – a challenge many DSOs are already facing today. However, the presented possible solutions will generally also be applicable to other flexibility providers like loads and electric vehicles, which fall under the umbrella of flexibility offered by DER.

1. Integration of Distributed Generation: A Key Challenge for DSOs

Distributed energy resources (DER) include distributed/decentralised generation (DG) and distributed energy storage (DS)[1]. With the EU on its way to meeting a 20% target for RES in total energy consumption by 2020, the share of electricity supply from RES is on the rise. Intermittent RES like solar and wind add an additional variable to the system that will require more flexibility from generation (including RES) and demand and investments in network infrastructure. Such intermittent RES will be connected largely to European distribution systems. At the same time, electrification of transport will be needed to further decarbonise the economy. For a significant deployment of electric vehicles by 2050, Europe needs to target a 10% share of electric vehicles by 2020. These vehicles will need to be charged through the electrical system. Together with the electrification of heating and cooling, these trends will contribute to further evolution of European power systems.

1.1. Distributed Generation: Facts and Figures

Distributed/decentralised generation (DG) are generating plants connected to the distribution network, often with small to medium installed capacities, as well as medium to larger renewable generation units. Due to high "numbers", they are important compared to the "size" of the distribution network. In addition to meeting on-site needs, they export the excess electricity to the market via the local distribution network. DG is often operated by smaller power producers or so-called prosumers.

Unlike centralised generation, which is dispatched in a market frame under the technical supervision of TSOs, small DG is often fully controlled by the owners themselves. The technologies include engines, wind turbines, fuel cells and photovoltaic (PV) systems and all micro-generation technologies. In addition to intermittent RES, an important share of DG is made up of combined heat and power generation (CHP), based on either renewables (biomass) or fossil fuels. A portion of the electricity produced is used on site, and any remainder is fed into the grid. By contrast, in case of CHP the generated heat is always used locally, as heat transport is costly and entails relatively large losses. Figure 1 provides an overview of generation types usually connected at different distribution voltage levels.

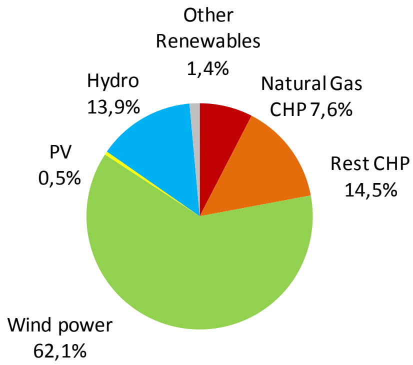
Usual connection voltage level	Generation Technology
HV (usually 38-150 kV)	Large industrial CHP Large-scale hydro Offshore and onshore wind parks Large PV
MV (usually 10-36 kV)	Onshore wind parks Medium-scale hydro Small industrial CHP Tidal wave systems Solar thermal and geothermal systems Large PV
LV (< 1kV)	Small individual PV, Small-scale hydro Micro CHP, Micro wind

Figure 1 Common voltage connection levels for different types of DG/RES

[1] Storage is not only a resource but also an off take/load. Electric vehicles could be used as storage in the future.

The following examples demonstrate that a move from mere DG connection to DG integration is a must already today in some countries. As illustrated in Figure 2, in **Galicia, Spain**, the installed capacity of DG connected to the distribution networks of Union Fenosa Distribución (2,203 MW) represents 120% of the area's total peak demand (1,842 MW).[2]

	Installed Capacity (MW)	Percentage (%)
CHP (Natural Gas)	**166,9**	**7,6**
Rest CHP	**319,4**	**14,5**
Wind Power	**1.369,5**	**62,1**
Photovoltaic (PV)	**10,3**	**0,5**
Hydro	**306,1**	**13,9**
Other Renewables	**31,4**	**1,4**
TOTAL Generation	**2.203,6**	**100**

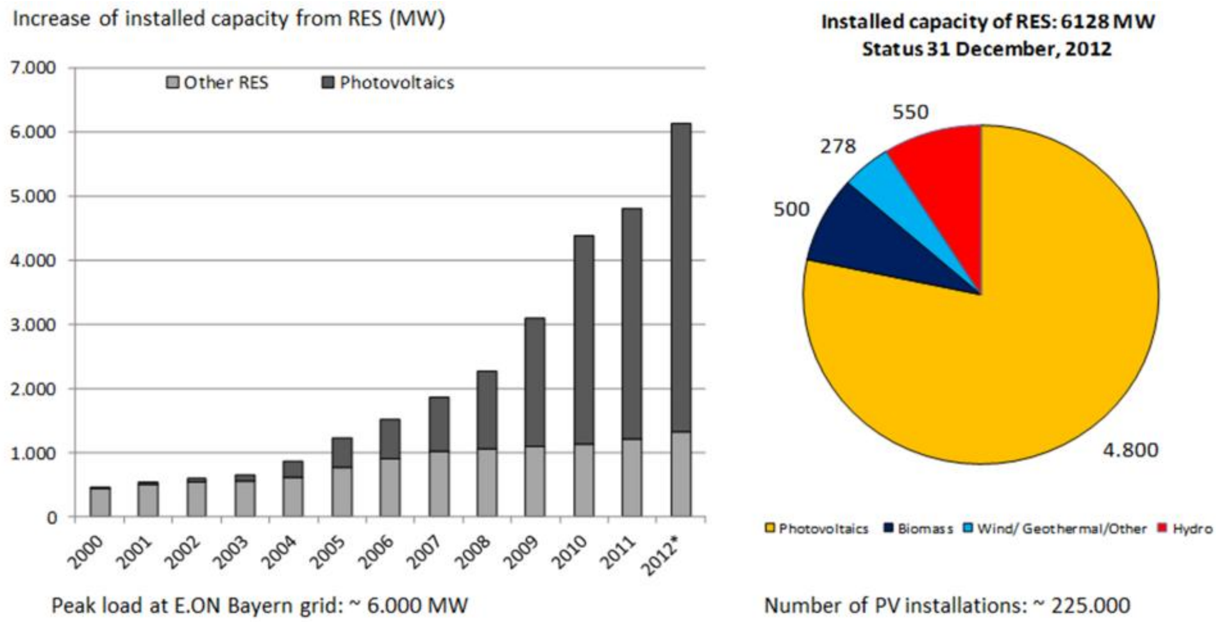


	Max. Hourly Average capacity (MW)
Galicia Demand	**1.842**

Figure 2 Distributed generation installed capacity and peak demand in Galicia, Spain

(Source: Union Fenosa Distribución)

In the regional distribution network in the **south of Germany** (see Figure 3), the installed capacity of intermittent renewable DG already represents a large percentage of the peak load. In many places, the DG output of distribution networks already exceeds local load – sometimes by multiple times. From the TSO point of view, the DSO network then looks like 'a large generator' in periods with high RES production.



*status for 31 December 2012

Figure 3 Installed capacity of photovoltaic installations in the E.ON Bayern grid (Source: E.ON)

[2] Overall, DG covers more than 30% of Union Fenosa Distribución regional energy (MWh) demand already today.

In 2011, 10 GW of PV were newly connected to Italian distribution grids (Enel Distribuzione), the highest yearly increase in distributed generation connected to the grid worldwide.

In northwest Ireland with a peak demand of 160 MW, 307.75 MW of distributed wind generation are already connected to the distribution system, and a further 186 MW are contracted or planned. Beyond this, another 640 MW of applications have been submitted.

1.2. Key Challenges for Current Distribution Networks

In theory, due to its proximity to the loads, distributed generation should contribute to the security of supply, power quality, reduction of transmission and distribution peak load and congestion, reduced need for long distance transmission, avoidance of network overcapacity, deferral of network investments and reduction in distribution grid losses (via supplying active power to the load and managing voltage and reactive power in the grid).

In reality, integrating distributed generation into DSO grids represents a capacity challenge due to DG production profiles, location and firmness. **DG is not always located close to load and DG production is mostly non-dispatchable (cannot control its own output). Therefore, production does not always coincide with demand (stochastic regime) and DG does not necessarily generate when the distribution network is constrained. In addition, power injections to higher voltage levels need to be considered where the local capacity exceeds local load.** This poses important challenges for both distribution network development and operation.

1.2.1. Network Reinforcement

The ability of DG to produce electricity close to the point of consumption alleviates the need to use network capacity for transport over longer distances during certain hours. However, the need to design the distribution networks for peak load remains undiminished and the overall network cost may even increase. For example, peak residential demand frequently corresponds to moments of no PV production. Figure 4 shows the situation in the southern Italian region of Puglia. It indicates the incredible increase in the power installed and energy produced from PVs in recent years and the subsequent evolution of power flows at the connection point between the transmission network and the distribution network. As the peak load corresponds to literally zero PV production, there is no reduction in investment ("netting" generation and demand).

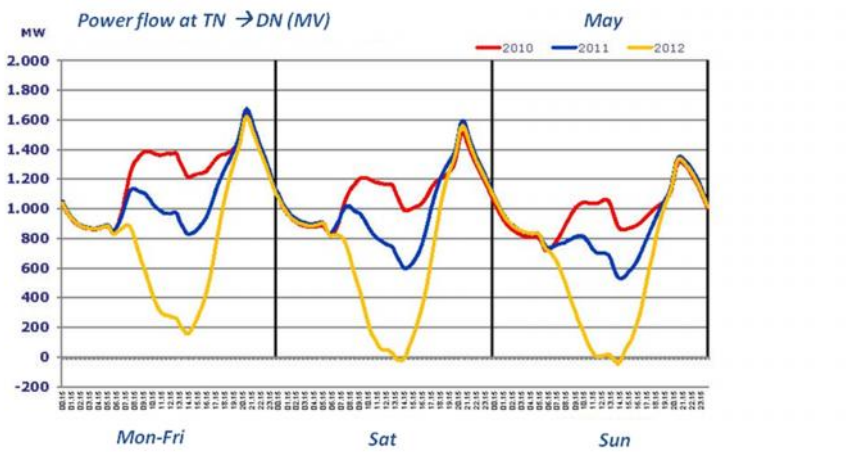


Figure 4 Power flows between transmission and distribution network in Italy, 2010-2012 (Source: Enel Distribuzione)

Generally speaking, distribution networks have to be prepared for all possible combinations of production and load situations. They are designed for a peak load that often only occurs for a few hours per year, in what this paper refers to as the fit-and-forget approach. Even constraints of short duration trigger grid adaptations (e.g. reinforcement).[3] Distribution networks have always been designed in this way, but with DG the utilisation rate of network assets declines even more.

Network connection studies and schemes for generators are designed to guarantee that under normal operation all capacity can be injected at any time of the year.[4] The current European regulatory framework provides for priority and guaranteed network access for electricity from RES (Art. 16 of RES Directive 2009/28/EC) and RES-based CHP (Art. 14 of the new Energy Efficiency Directive 2012/27/EC). RES-E is mostly connected on a firm/permanent network access basis (but cannot be considered as firm for such design purposes). Generation and load of equivalent sizes imply different design criteria as e.g. wind and PV has lower diversity than load. In addition, wider cables to lower the voltage might be needed. **Overall, this can lead to higher reinforcement cost and thus a rise in CAPEX for DSOs and/or higher connection costs for DG developers.** The contribution of DG to the deferral of network investments holds true only for a relatively small amount and size of DG and for predictable and controllable primary sources.

The lead time needed to realise generation investment is usually shorter than that for grid reinforcement. Article 25.7 of Directive 2009/72/EC requires DSOs to take into account distributed energy resources and conventional assets when planning their networks. This may be complicated when applications for connection are submitted at short notice and DSOs receive no information on connection to private networks. Situations will occur when DSOs have large amounts of DER connected to their network and the resulting net demand seen further up the system hierarchy is lowered. Virtual saturation – a situation when the entire capacity is reserved by plants queuing for connection that may not eventually materialise – may also occur as generator plans cannot be firm before the final investment decision. However, even in the cases when the project is not built, it occupies an idle capacity which may lead new grid capacity requests to face increased costs in case network reinforcements are needed. **Temporary lack of network capacity may result in 'queuing' and long waiting times, delaying grid connection of new generators.**

The situation is similar in case of grid losses (related costs are part of DSOs' OPEX). Figure 5 demonstrates that with a low share of DG these losses drop, but once there are large injections of DG into the DSO network and load flows over the network, grid losses tend to increase. DG can reduce network costs in transport levels but entails higher costs in the level to which it is connected.

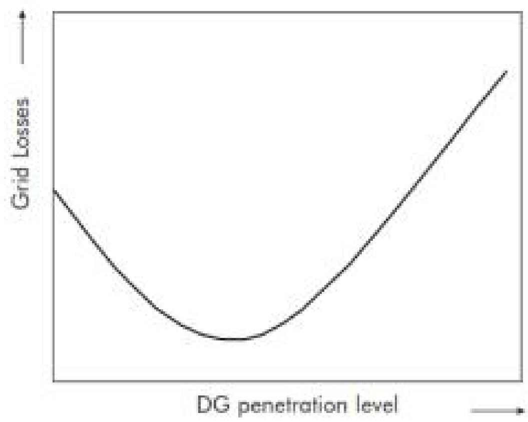


Figure 5 Relation between the degree of DG penetration and grid losses (Source: van Gerwent)

[3] In some countries, this regulation is part of the regulation for feed-in of renewable energy or other preferential power production and remuneration.

[4] In some countries this is also the case for the N-1 contingency state which is typically considered in a meshed network and represents the fail of a grid element. Many MV networks are meshed even when they are operated radially, so some N-1 is also possible in MV.

1.2.2. Distribution Network Operation

In addition, distributed generation, in particular intermittent RES, poses a challenge not only for system balancing, but also for local network operation. **The security and hosting capacity of the distribution system is determined by voltage** (statutory limits for the maximum and minimum voltage ensure that voltage is kept within the proper margins and is never close to the technical limits of the grid) **and the physical current limits of the network** (thermal rates of lines, cables, transformers that determine the possible power flow).

A distribution system can be driven out of its defined legal and or physical operating boundaries due to one or both of the following:

- **Voltage variations:** Injection of active power leads to voltage profile modifications. **Voltage increase (overvoltage) is the most common issue at the connection point for DG units and the relevant grid area.** Reversed power flows (flows from distribution to transmission) occur when DG production exceeds local load. The more local production exceeds local demand, the stronger the impact on voltage profiles. Figure 6 illustrates such situations.

  DSOs may have difficulties in maintaining the voltage profile at the customer connection points, in particular on LV level, as active voltage control is not in place. In most countries, monitoring of grid values is missing and most distributed generators are not equipped to participate in system management – no active contribution of generation to network operation is expected.[5] As a result, operational system security may be endangered and security of facilities (both customers' installations and the network as such) put at risk.

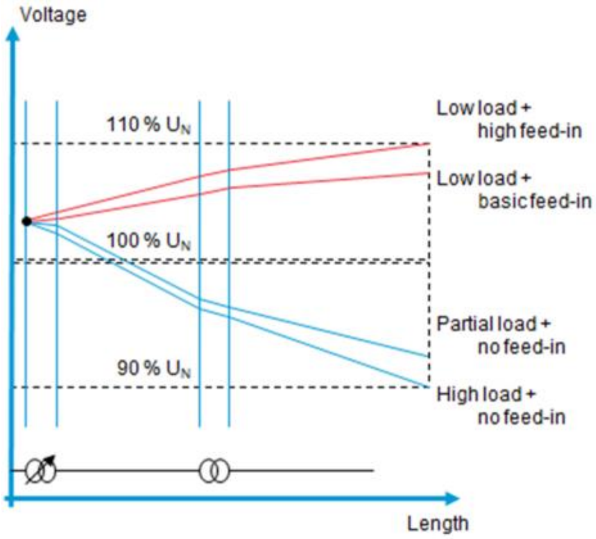


Figure 6 Instability in distribution system (Source: Mainova)

- **Congestions:** When excessive DG feed-in pushes the system beyond its physical capacity limits (P_G - P_L > P_{max}), congestions may occur in distribution networks. This may lead to necessary emergency actions to interrupt/constrain off generation feed-in or supply. A similar situation can occur in case of excessive demand on the system (P_L - P_G > P_{max}). This could apply to high load incurred e.g. by charging of electric vehicles, heat pumps and electrical HVAC (heating ventilation and air-conditioning).

[5] Where DSOs are already in the 'reactive DSO' phase (see section 2.1), these solutions have been implemented.

Generation curtailment is used in cases of system security related events (i.e. congestion or voltage rise). The regulatory basis for generation curtailment in such emergency situations differs across Europe.[6] In some countries (e.g. in Italy, Spain, Ireland), the control of DG curtailment is *de facto* in TSO hands: the DSO can ask the TSO, who is able to control active power of DG above a certain installed capacity, to constrain DG if there is a local problem.[7] As the TSO is not able to monitor distribution network conditions (voltage, flows), DSOs can only react to DG actions. This can result in deteriorating continuity on the distribution system which will impact both demand customers and DG. Annex 3.B provides an overview of the situation in different countries.

In systems with a high penetration of DG, both types of unsecure situations already occur today. As a result, DSOs with high shares of DG in their grids already face challenges in meeting some of their responsibilities[8]. These challenges are expected to become more frequent, depending on the different types of connected resources, their geographic location and the voltage level of the connection.

Figure 7 shows the reverse power flows on an Irish substation in an area with high wind penetration.

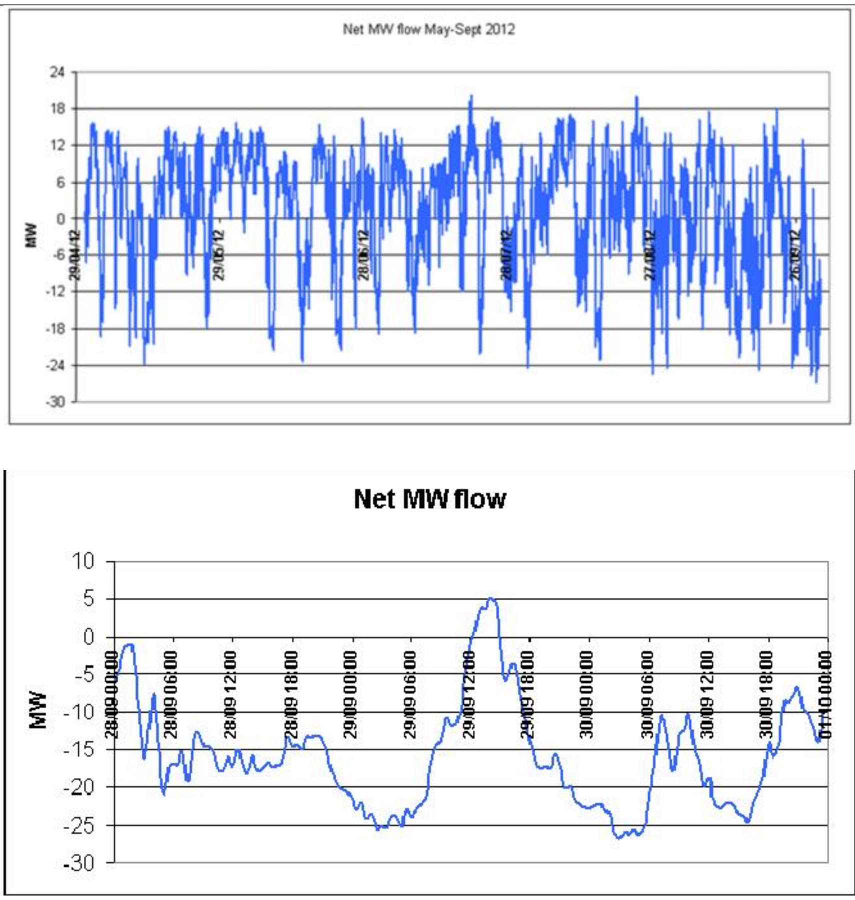


Figure 7 Reverse power flows at a substation in northwest Ireland (Source: ESB Networks)

[6] Curtailment/feed-in management rules are either not defined by law at all (e.g. Austria), defined at the TSO level only (e.g. Spain or Italy) or defined at both the TSO and the DSO level (e.g. UK or Germany according to the revised feed-in law).

[7] The TSO might even issue V, Q or pf set points to DG on the distribution system.

[8] DSOs are responsible for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity and for operating, maintaining and developing under economic conditions a secure, reliable and efficient electricity distribution system in their area with due regard for the environment and energy efficiency (Article 25(1) of Directive 2009/72/EC).

In sum, the key challenges for DSOs include

- **Increased need for network reinforcement** to accommodate new DG connections:
  - Network operators are expected to provide an unconditional firm connection which may cause delays or increase costs for connecting embedded generation;
  - Increased complexity for extension (including permitting procedures) and maintenance of the grid may require temporary limitation for connection of end customers.
- **Problems with operation of the distribution grid:**
  - **Local power quality/operational problems, in particular variations in voltage** but also fault levels and system perturbations like harmonics or flickers;
  - **Rising local congestions** when flows exceed the existing maximum capacity, which may result in interruptions of generation feed-in or supply;
  - **Longer restoration times** after network failure due to an increased number and severity of such faults.

BOX 1: Current DSO responsibilities

- *Distribution planning, system development, connection & provision of network capacity*
  DSOs are in charge of developing their network. They design new lines and substations and ensure that they are delivered or that existing ones are reinforced to enable connection of load and decentralised power production. Depending on the size of a DG/RES & DER system, DSOs may require a new connection at a particular voltage level. **They are obliged to provide third party access to all end customers and provide network users with all information they need for efficient access and use of the distribution system.** They may refuse access to the grid only when they can prove that they lack the necessary network capacity (Art. 32 of Directive 2009/72/EC).

- *Distribution network operation/ management and support in system operation*
  DSOs maintain the system security and quality of service in distribution networks. This includes control, monitoring and supervision, as well as scheduled and non-scheduled outage management. DSOs are responsible for operations directly involving their own customers. They support the TSOs, who are typically in charge of overall system security, when necessary in a predefined manner, either automatically or manually (e.g. via load shedding in emergency situations). Such systems of cooperation for intervention in generation and demand in cases of system security events are defined in detail in national regulations. A common basis for these rules is now being set in the EU-wide network codes (operational security, balancing, congestion management, etc.).

- *Power flow management: Ensuring high reliability and quality in their networks*
  - **Continuity and capacity: DSOs are subject to technical performance requirements for quality of service including continuity of supply** (commonly assessed by zonal indexes such as average duration of interruptions per customer per year (SAIDI) and average number of interruptions per customer per yea (SAIFI) or individual indexes like number and duration of interruptions) **and power quality laid out in national law, standards and grid codes.**[9] **They are also responsible for voltage quality in distribution networks** (maintaining voltage fluctuations on the system within given limits). In planning, the DSO ensures that networks are designed to maintain these standards regardless of power flow conditions. However in cases of network faults, planned outages or other

[9] National regulatory authorities (NRA) have the duty of setting or approving standards and requirements for quality of supply or contributing thereto together with other competent authorities (Article 37(1h) of Directive 2009/72/EC).

anomalous events, the DSO must undertake switching actions so that adequate supply quality is maintained. While to date this has been rather static, increasingly automation or remote switching will need to be undertaken to ensure near real-time fault isolation and restoration of supply.

- **Voltage and reactive power:** Voltage quality is impacted by the electrical installations of connected network users. Thus the task of the DSO in ensuring voltage quality must account also for the actions of network users, adding complexity and the need for both real-time measurement and mitigating resources (i.e. on-load voltage control) and strict network connection criteria. European standard EN 50160 specifies that the maximum and minimum voltage at each service connection point must allow an undisturbed operation of all connected devices. Voltage at each connection should thus be in the range of ± 10% of the rated voltage under normal operating conditions. In some countries, compliance with these or other specified national voltage quality requirements that can be even more restrictive represents part of DSOs' contractual obligations and quality regulation. In some countries, network operators are required to compensate customers in case the overall voltage quality limits are breached.[10]

1.2.3. Traditional Design of Distribution Networks

The fundamental topological design of traditional distribution grids has not changed much over the past decades. Up until recently, DSOs have distributed energy and designed their grids on a top-down basis. Under the paradigm "networks follow demand", their primary role was to deliver energy flowing in one direction, from the transmission substation down to end users. This approach makes use of very few monitoring tools and is suitable for distribution networks with predictable flows.

Because of the different development of electrification, distribution networks characteristics differ from country to country. Voltage rate levels are usually distinguished as LV, MV or HV.[11] As illustrated in Figure 8 the level of supervision, control and simulation in HV distribution networks is close to that of TSOs in their networks. MV and LV networks are mostly rather passive – here DSOs lack network visibility and control. The lower the monitoring level, the lower the operational flexibility. For more detailed information on automation and control see results of a survey conducted among EURELECTRIC members in Annex 3.A.

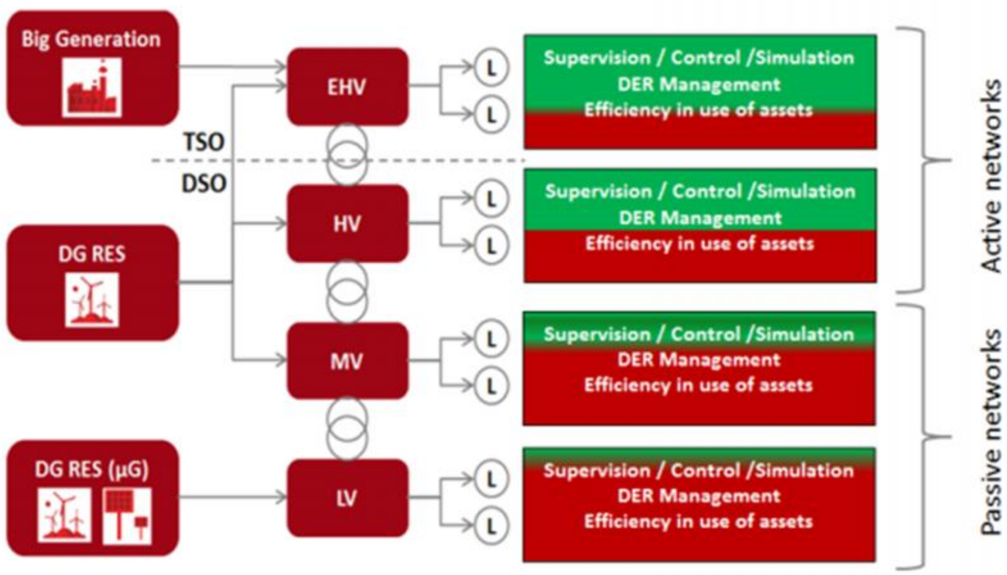


Figure 8 Current DSO networks

[10] CEER Benchmarking report, 2011.
[11] CENELEC standard EN 50160 (2010) uses following the classification: LV < 1 kV, MV 1 kV – 36 kV, HV 36 - 150 kV.

BOX 2: Traditional distribution networks

Traditional distribution networks have different characteristics in topology (meshed or radial), operation type (meshed or radial), number of assets and customers, operational flexibility and monitoring level:

- *HV networks* (also called sub-transmission) are quite similar to transmission networks. The topological design of the grid is meshed and may be operated as radial or meshed depending on the situation. HV networks are operated in a similar way all around Europe: N-1 or N-2 contingency criteria[12] are usually in place for rural and urban areas, respectively. The monitoring level at HV is very high. DSOs operating HV grids are able to supervise and control the HV network from the control room centres.

- *MV distribution networks* significantly differ in their characteristics with respect to urban and rural grids. Mostly, meshed topology is used that can be operated either as meshed (closed loop) or radial (open loop). In some countries or depending on the network type in a region, MV operation may always be radial. A high density of loads and relatively high demand typically causes high equipment load factors (transformers, cables) for urban areas. Rural areas are characterised by larger geographical coverage and lower load density and thus longer lines, high network impedances and lower equipment load factors. **The proportion of European MV networks with remote monitoring, control and automated protection/fault sectionalisation is currently low but increasing by necessity.**

- *LV networks* are usually radially operated. Similar to MV networks, urban and rural LV networks have different characteristics. **The proportion of LV monitoring and control is typically even lower than in MV. Measurements usually rely on aggregated information from substations and are only available with a significant time lag. Profile information will not be available.**

2. Active Distribution Networks

Once DG in distribution networks surpasses a particular level, building distribution networks able to supply all load & DG within the existing quality of service requirements will frequently be too expensive and inefficient. For example, in many places the network would only be constrained for few hours per year. In addition, the security of supply and quality of service problems will no longer be limited to specific situations.

Integrating the high amount of existing and projected DG and, later, other DER will require new ICT solutions and an evolution of the regulatory framework for both network operators and users. Network planning and operation methodologies need to be revised to take the new solutions into account.

2.1. Key Building Blocks

There is no one-size-fits-all solution because distribution networks are rather heterogeneous in terms of grid equipment and DG density at different voltage levels. Every distribution network should be assessed individually in terms of its network structure (e.g. customers and connected generators) and public infrastructures (e.g. load and population density). Nevertheless, the needed development towards future distribution systems which meet the needs of all customers can be described in the three schematic steps pictured below: from (1) passive network via (2) reactive network integration to (3) active system management.

[12] Rule according to which elements remaining in operation after a fault of a distribution system element must be capable of accommodating the new operational situation without violating the operational limits.

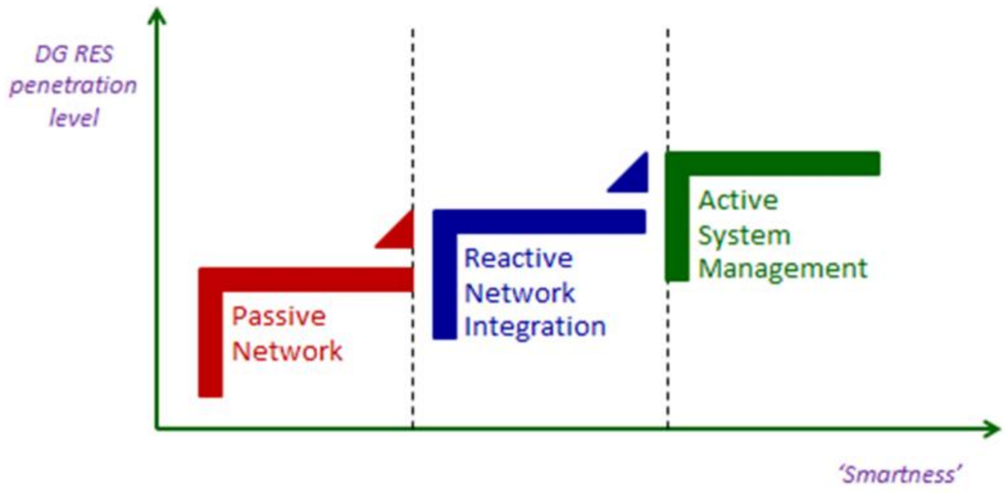


Figure 9 Three-Step Evolution of Distribution Systems

(1) Passive distribution networks make use of the so-called 'fit and forget' approach. This approach implies resolving all issues at the planning stage, which may lead to an oversized network. DSOs provide firm capacity (firm grid connection and access) that may not be fully used anymore due to local consumption of the electricity produced by DG. This approach has the advantage of requiring low flexibility, control and supervision, but is only possible for a network with very low DER penetration. Once DER penetration rises, the system cannot be designed to cater for all contingencies without very significant investment in basic network infrastructure, making this approach less economical.

(2) Reactive network integration is often characterised by the 'only operation' approach. This approach is used today in some countries with a high share of DG. The regulation requires connecting as much DG as possible with no restrictions. Congestions (or other grid problems) are solved at the operation stage by restricting both load and generation. This solution could restrict DG injections during many hours per year and lead to negative business case for DG if they are not remunerated for the restrictions. Already today, some 'front-runner' countries with high DG penetration levels can be considered as having reached the interim 'reactive network integration' stage at which DSOs solve problems once they occur (largely only in operation).

(3) The active approach would allow for interaction between planning, access & connection and operational timeframes. Different levels of connection firmness and real-time flexibility can reduce investment needs. The existing hosting capacity of the distribution network can be used more optimally if other options including ICT, connection & operational requirements guaranteeing adequate performance of DER towards the system (i.e. via grid codes) and market-based procurement of ancillary services from DER are considered. Operational planning of distribution networks (similar to that at transmission level) would be in place in networks with high DER shares in order to incentivise dispatch in a way that is compatible with the network. Improved network capacity planning and congestion management at distribution level at different times and locations will be required to maximise the level of generation which is injected in the most economical way for all parties, while maintaining network stability. DSOs must have tools for overseeing maintenance of network standards. Additionally they should have the possibility to buy flexibility from DG and load in order to optimise network availability in the most economic manner or to manage network conditions which are beyond the contracted connection of the customers. DSOs should have the possibility to buy flexibility from DG and load on so-called 'flexibility platforms' in order to solve grid constraints. The network reinforcement could be deferred until the moment when it becomes more cost-effective than the on-going cost of procuring services from DER. Interactions between DSOs, TSOs and market actors at different stages are depicted in Figure 10.

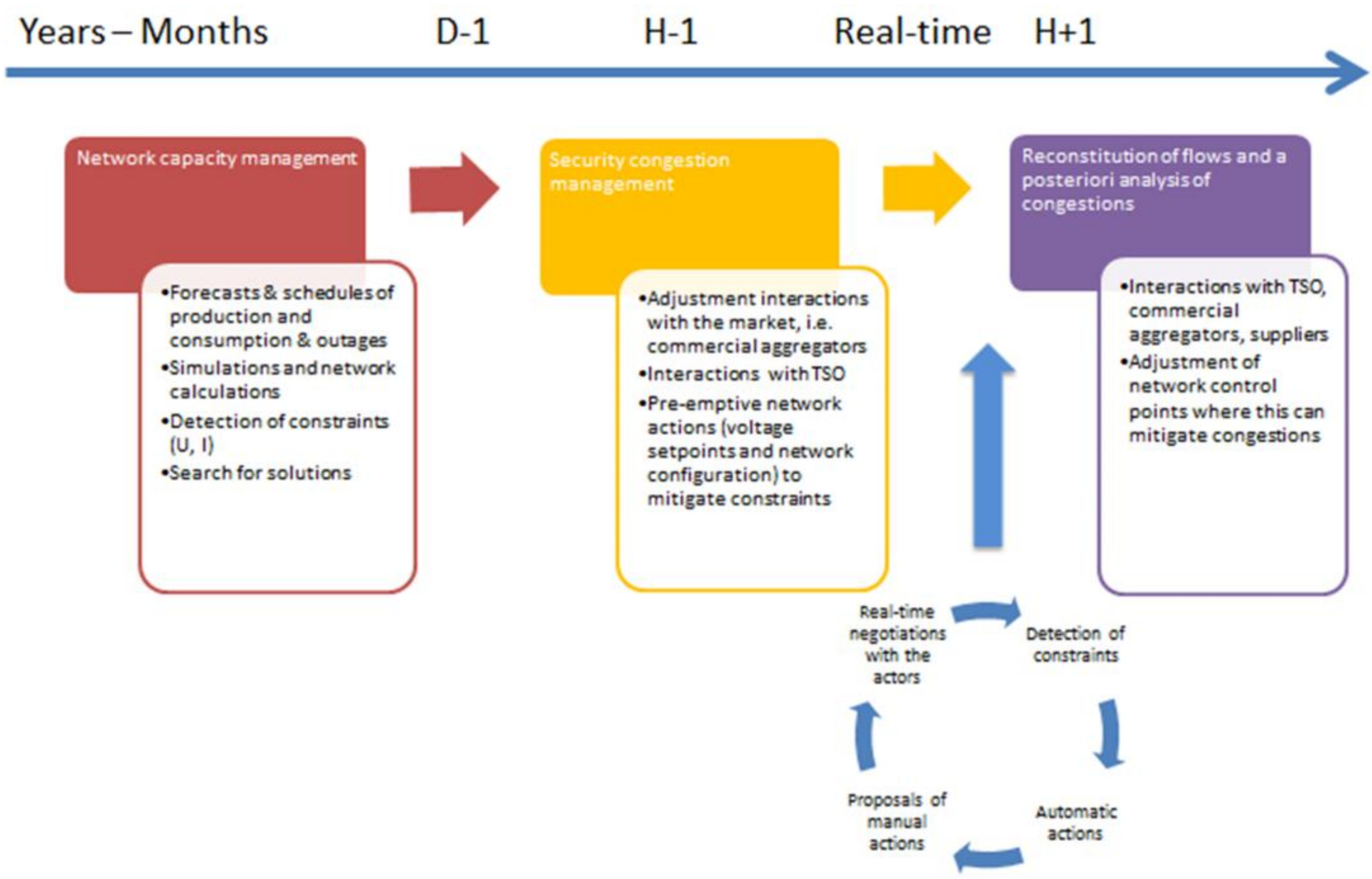


Figure 10 DSO interactions with markets & TSO at different time frames

Using the active system management approach would allow maximal integration of DER, making the most of the existing grid while enabling DSOs to fulfil the security standards and enabling DER to find the right conditions for their business plan in the most cost-effective way.

Table 1 highlights the key features of each phase, broken down into the different 'layers': development & planning, operations, information exchange and technical development. The subsequent sections of the report discuss the active system management approach within the individual layers in detail.

Layer		Passive Distribution network	Re-active distribution network integration	Active distribution system management
Network development (planning, connection & access)		Fit and forget approach: everything 'solved' at the planning stage	Only operation approach: connection with no restrictions and solutions at the operations stage *Or* Fit and forget approach	*Combined planning and operational solutions:* Active capacity and loss management through commercial interaction with market actors selling flexibility services
Network operation		Low monitoring & control of DG RES, often only by the TSO Missing rules & services for DG contribution to quality of service, security of supply & firmness	Emergency generation curtailment by DSO Active voltage control distribution networks. Grid codes for DG to meet connection criteria and be able of voltage based control and reactive power contribution	Connection and access criteria combined with operation tools to manage DER Flexibility support from DSO to TSO and from TSO to DSO when required New system services for DSOs arranged via commercial ancillary services and grid codes.
Information exchange		Little information exchange from TSOs/DER to DSOs (small DER do not send information)	High-level information exchange from TSOs/DER to DSOs	Structured and organised off-line and where needed real-time information exchange (standardised interfaces with DER required)
Technical development	Network	Limited monitoring & control capabilities (usually only HV) Conventional SCADA for HV network and DMS/OMS for MV and LV	Increased monitoring and control at HV & MV via telecommunications SCADA/DMS/OMS with the measurement of certain new DG	Increased monitoring, simulation and control down to LV via telecommunications Advanced Distribution Management Systems[13] for DSOs/ SCADA and Distribution Management System (DMS)
	DER	DG often not prepared for power factor control Storage & EV not developed	Enhanced DG protection systems/ inverters enabling voltage & reactive power control	Configurable settings: e.g. protection / fault ride through settings, voltage droop Presence of storage & EVs

Table 1 Three-Step Evolution of Distribution Systems in detail

[13] New SCADA and DMS/OMS could be integrated in a single system called Advance Distribution Management System (ADMS).

2.2. Distribution Network Development, Planning, Access & Connection

2.2.1. Coordinated Network Development

DSOs should be able to plan their grids well in advance to prevent bottlenecks in the most cost-effective way. Data acquired within distribution network monitoring and information exchange with TSOs and distributed energy resources (see sections 3.4 & 3.5) could be very beneficial in this respect.

In addition, every connection request should be analysed and considered in the planning process in order to make the best of the existing network. According to the traditional regulatory approach to connection requests analysis currently applied in most countries, the network operator performs an individual analysis and provides an individual solution to each connection. The first connections may make use of the available capacity of the existent network. But once there is an increased demand for new DG connections in the same area and the available network capacity is limited this approach is not always optimal from the overall cost and network development perspective.[14]

One way to tackle this issue is to allow for coordination of all relevant actors, including network operators, investors and local authorities in the analysis of connection requests (see Box 3 for Spanish example).

BOX 3: Coordination for efficient RES and network development: Spanish "Evacuation Boards" approach

To rationalise the RES expansion and optimise the available energy resources, some Spanish regions created so-called "Evacuation Boards". They are characterised by a coordinated grid connection request process. RES installation plans are deployed and coordinated between the administration, RES investors and transmission and distribution system operators. In these evacuation boards the TSO or DSO do not receive individual requests; they are collected by the Regional Administration and after a validation process submitted for an aggregated analysis to be made together by the DSO & TSO. The positive impact of the new networks for consumption (extra capacity for consumers) is also considered. In addition to the cost-sharing mechanism (proportionally to the capacity assigned to each RES project), the covenants for the development of such infrastructures contain the necessary guarantees, payment and execution terms. Benefits of this approach include overall minimised network development and project cost, reduction of project risks thanks to the possibility to correctly analyse both the costs and timetables needed for the different RES penetration scenarios, and reduced time for acquiring all necessary administrative permits.

Coordination between TSOs and DSOs is likely to play a particular role. Whilst in some cases modifications required by DSOs from TSOs or vice versa do not considerably affect the capabilities of one or the other to maintain their network performance, the impact may be substantial in other cases. For example, when the HV or UHV (ultra high voltage) network is saturated, connection of generation to the MV network cannot be planned without taking into account the conditions at HV network. An optimal network development is also key to minimise losses in the electrical system. Transmission or distribution network conditions which require regular (or conditional) exchange of information between TSOs and DSOs should be defined. Standard reciprocal data exchange arrangements about the expected development of generation/load at the different voltage levels and about the network reinforcements needed at the TSO level, not directly related to the lower voltage planning activities, should be put in place.

[14] First requests for connection get the available capacity of the existent network at a low cost, but as they increase they require more complex and expensive network development solutions. In countries where generators bear grid connection as well as grid reinforcement/extension costs (deep connection charges), this may make the individual projects economically unviable. In countries where generators bear grid connection cost but not the grid reinforcement cost (shallow connection charges) and do not pay any use of system charge, those reinforcement network costs are socialized.

Coordinated planning as per the Irish "Gate" process (see box below), batch planning of DG connection applications at TSO and DSO level as appropriate, may see the most economical net cost of connection. Coordination between the TSO and DSO in Schleswig-Holstein (northern Germany), where 9,000 MW of wind should be connected by 2015, are another example in this respect.

BOX 4: Coordination in planning between TSO & DSO - The Group Processing Approach in Ireland

Up to 2003, applications to system operators for connection of wind were processed sequentially. Since 2004, following a moratorium on wind connections, DG is planned in 'Groups' based on their network location and capacity and processed in batches known as 'Gates'. This system was introduced to deal with the massive number of applications. The queue for connection comprises both DSO and TSO applicants. Applications are processed by the system operator (TSO or DSO) most suited to their group connection irrespective of which system operator they originally applied to. The connection method is determined by the Least Cost Technically Acceptable (LCTA) method for the defined sub-group. The cost of the network reinforcement for the group is shared by the different wind farms proportionally to their capacity. Connections below 500 MW have a different planning process and are treated as individuals with a quicker process, reflecting their connection generally being less onerous and costly. The regulator (with input from both system operators and wind industry) determines criteria for eligibility for inclusion of "Gate". This method facilitates large quantities of RES being processed in a structured manner and rationalises allocation of scarce capacity. Transmission and distribution systems are developed in co-ordinated fashion.

2.2.2. Network Capacity Management

Network capacity management would encompass optimisation of network capacity via improved consideration of DERs in network planning. The DSO ability to identify areas with possible overload problems well in advance as described within the active approach is a precondition for this.

The options that should be further investigated include:

- **New network access options such as variable network access contracts; and**
- **Alternatives involving close to real-time operation solution such as DSO tendering for a flexibility service.**

Variable access contracts

DG developers could have a possibility to select firm or variable access contracts based on their own business plan. **Variable network access** rights could be offered as a discounted connection contract for generation customers, with pre-defined mechanisms for DG to reduce their output to a predefined limit in infrequent situations, expected only for few hours per year. If only several hours of re-dispatching per year are needed to limit peaks of production and use network capacity more efficiently, those would be more than offset by an additional DG output in all other hours due to a higher installed DG capacity up to a certain point where the cost of net losses and curtailed generation become relevant to justify network reinforcement.

A model example in Figure 11 illustrates that limiting peak power in-feed of e.g. 5% of the time would give an opportunity to connect 220% more DG. In these cases, generation operators should be incentivised to choose this option, e.g. by reduced connection cost (cheaper but with limited guarantee of injection within a clearly defined framework) or other form of compensation. This could be executed either via direct contracts between DSOs and generators/load or indirectly between DSOs and aggregators who would pay a yearly option premium to DG/load and then offer flexibility to the DSO.

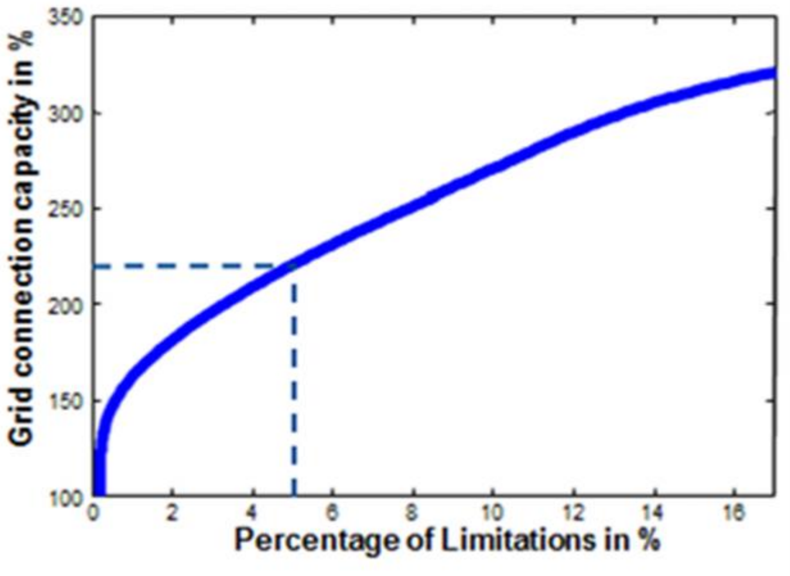


Figure 11 Variable access approach (Source: EWE Netz)

Today, variable access is precluded by obligation to compensate generators for any energy they are not allowed deliver in many jurisdictions. As outlined above, curtailment is often possible only to deal with short duration constraints; it is only temporary and automatically triggers grid adaptations such as reinforcement if they are deemed economically justifiable by the connected parties or DSO. A form of variable network access for DG/RES exists e.g. in the UK (known as non-firm access). The conditions where a DSO can issue a curtailment instruction are set out in a connection contract agreed at the time of connection in return for a lower cost of connection. For example, the feed-in management rules in Germany (see box below) define a flexibility obligation in form of a capped connection.

BOX 5: Mandatory integration of feed-in management system in Germany

The flexibility obligations, including the technical and regulatory possibility to be curtailed are spread over all production facilities above a certain capacity. The PV installation owner can choose to install a technical receiver device allowing for feed-in reduction by the network operator or to reduce the feed-in power to 70% of the nominal power (installed power). In practice, this measure leads to the loss of about 5% of energy feed-in from PV but allows connecting more DG to the network (and thus overall increased DG production). The producers are compensated for lost production. This curtailment regime enables an optimised use of the existing network, without jeopardising the business cases of new producers. It applies until the relevant grid development is made.

Practical modalities of such arrangements may differ from one country to another. In any case, the following aspects would have to be considered before implementation of a variable access scheme:

- It might be necessary to review the value of the discount from time to time, or it might be possible to have an "auction" giving a kind of merit order list (i.e. those who pay most for the grid use would be curtailed less often). A risk of changing conditions over time could be mitigated, e.g. by participation via aggregators.
- DG developers should be provided with information on expected curtailment so that it can be included in the risk analysis and economic viability analysis of projects prior to investing in these projects. This should be based on the best available information and analytical techniques, to ensure that generation developers can base their decision on an informed business plan.
- Establishment of procedures for assessing when the investment deferral is more cost-effective. As expectations change depending on the amount of RES already connected and the amount of RES that will be connected later on, it might also be necessary to have insight under what conditions the DSO will undertake reinforcements, because additional RES might be added at each reinforcement (depending on the "geographical" possibilities). If RES developers have sufficient

transparency, they will take possible interruptions into account, as well as the value they need to earn back on a flexibility platform.

- The manner in which to curtail generators (pro rata, market based etc.) and the operational rules for the constraint location where more than one generator contribute to the constraint would have to be specified.

'Firm DG production and load off take management' via ahead tendering for commercial services

Assessment of firm capacity is important for network operators to foresee how much generation can contribute to peak consumption. A mechanism incentivising DG to generate or the consumption to stop consuming when the peak on the network takes place would enable more efficient use of the existing distribution assets and deferral of grid reinforcement, as illustrated in Figure 12. Provision of certain firm capacity would be rewarded as an extra service for the system. Remuneration for this service could be determined through an open commercial tendering process organised by DSOs, e.g. via a local auction for necessary services (DG to bid certain amount of capacity reliably available). In any such cases, the party (DG or other commercial operator) deemed reliable and contracted to deliver certain firm capacity must be held financially responsible for its delivery.

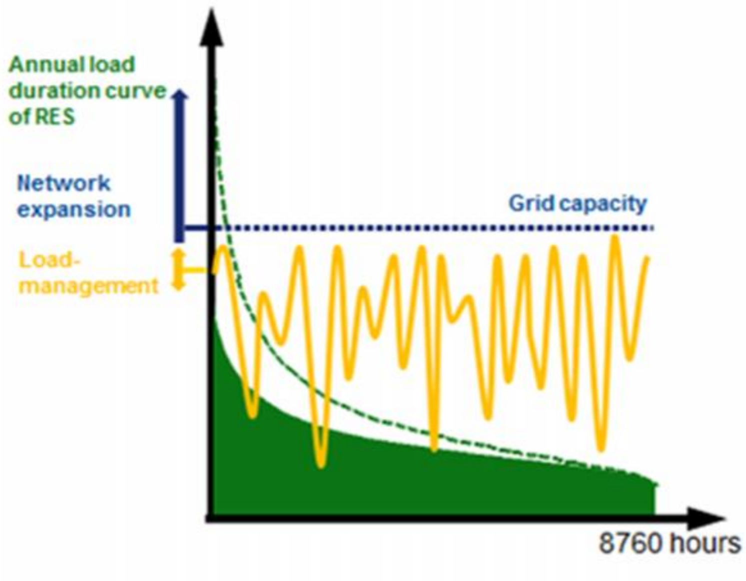


Figure 12 Extension of network capacity for peak load versus a load management solution (Source: EWE Netz)

All in all, due to various generation mixes, distribution of generation over different voltage levels and geographic distribution of the resources, a one-size-fits-all approach may not be adequate from the social welfare point of view. The option of giving network customers a choice between firm injection and higher connection charges and non-firm injection and considerably lower connection charges should be assessed against other solutions.

2.2.3. Connection

For proper integration into the network, distributed generation needs to fulfil minimum technical criteria: the equipment and its protective relays must be able to resist voltage dips and prevent islanding and there should be separate metering for production and consumption. DG should also bear the same costs as other generators, including adequate connection fees. DSOs must know what is on-line when they are working to prevent accidents. Therefore, they should have a possibility to verify compliance with requirements. Distributed generation should thus 'be registered' with the DSO, and remote disconnection by the DSO to prevent damage to facilities of other clients while manoeuvring should be technically possible under conditions defined by regulation. To secure safe operation of the distribution grid, DSOs should also be able to define control schemes and settings for generators connected to their grids, in coordination with the TSO where necessary in order to ensure compliance with overall system requirements.

Recommendations:

- In order to make the best of the existing network, **all relevant actors should be involved in the analysis of connection requests. Network development coordination between TSOs and DSOs should be enhanced.** Practical modalities of these arrangements may differ from one country to another.
- Future production on DSO level should be taken into consideration when developing the ENTSO-E Ten Year Network Development Plan and the relevant national plans. DSOs should be consulted accordingly.
- Market-based **network capacity management options such as open commercial tendering processes or optional variable access contracts should be further investigated as an initial tool for accommodating large amount of DG** in situations when it is proven to be more cost-effective than waiting for provision of connection and access to the grid until any curtailment is ruled out.
- Distributed generation needs to fulfil minimum connection criteria.

2.3. Active Distribution Network Operation

Distributed generation should be incentivised to sell their production into the electricity market[15]. Aggregation of DG in form of so-called Virtual Power Plants (VPPs) or of distributed generation, flexible loads and possibly decentralised storage is expected to play an important role in facilitating access of small customers to the market and addressing the uncertainty of availability and providing enhanced capability to manage the risk of not being able to meet the contracted scheduled output. The aggregator role could also be taken up by electricity service companies (ESCO) or suppliers. The aggregator would provide an interface between DER and other market actors and system operators. In addition, DG should be obliged to meet scheduling, nomination and balancing obligations as other power generators do, including payment of balancing charges. DG should also be responsible for their imbalances on equal terms with other Balancing Responsible Parties. It is highly beneficial for system stability and cost reduction if variable RES technologies are incentivised to reduce forecast errors and to minimise imbalances in the market and take up necessary responsibilities towards the system as other generation technologies do.[16]

The network plays an important service role of supporting the market. Operational barriers may arise, characterised by one or more violations of the physical, operational, or policy constraints under which the grid operates in the normal state or under contingency cases. They are transient – associated with a specified point in time. As such, they may be detected before or during the day-ahead, the hour-ahead markets or during real-time system operation. **In order to facilitate secure network operation and smooth functioning of the future market with high DER penetration, DSOs need to become active operators of their networks.** This means that they need adequate tools to operate their networks. In addition, network users need to actively participate in network usage optimisation. In this way, the possible abovementioned violations can be eliminated.

[15] Today, small DG typically sells their electricity output at fixed prices to the TSO, an electricity supplier or other third party market participant. Different economic *support schemes* for the production of electricity from RES and combined heat and power (CHP) have been implemented at national level. Where fixed feed-in tariffs are in place, generators are exempted from market signals & prices. Support schemes shall be made more market-oriented, based on production rather than investment. Support schemes which expose RES generators to market prices are more compatible with well-functioning of electricity markets, thus providing the correct price signals.

[16] These obligations can mean new costs (which should be taken into account in adjustment of the support mechanism), but can also mean new sources of revenues. See EURELECTRIC report *RES Integration and Market Design: Are Remuneration Mechanisms Needed to Ensure Generation Adequacy?* May 2011.

2.3.1. DSO System Services & 'Traffic Lights' Approach

Active DSOs should be allowed to coordinate the offering of new system services, as required by the new Energy Efficiency Directive (Art 15.1 of 2012/27/EC) while ensuring the security, integrity and quality of supply in their networks. The DSO is best placed to facilitate this mechanism as the data need to be gathered at substation level and in-depth knowledge of the grid layout and its behaviour is required. Moreover, the DSO has a legal responsibility to ensure that such technical constraints are mitigated.

The blue area in Figure 13 schematically outlines the stages in the electricity market in which the network operators do not interfere, but act as mere behind-the-scene facilitators. The green area depicts the system services that are to be administrated by network operators (for both transmission and distribution system needs). **Such system services could be defined in grid codes (voltage and reactive power contribution) or procured as ancillary services from DER within a transparent and non-discriminatory regulatory framework.**[17] Table 1 provides a more detailed overview of such system services including their possible form of delivery.

Today, ancillary services are procured by the TSO, largely from large power producers, to manage the system as whole. **In future, flexibility platforms where flexibility is offered (usually via aggregators) to DSOs for relieving congestion in their networks but also to TSOs to provide balancing and redispatching in transmission grids will play an important role, in particular for close to real-time flexibility.**

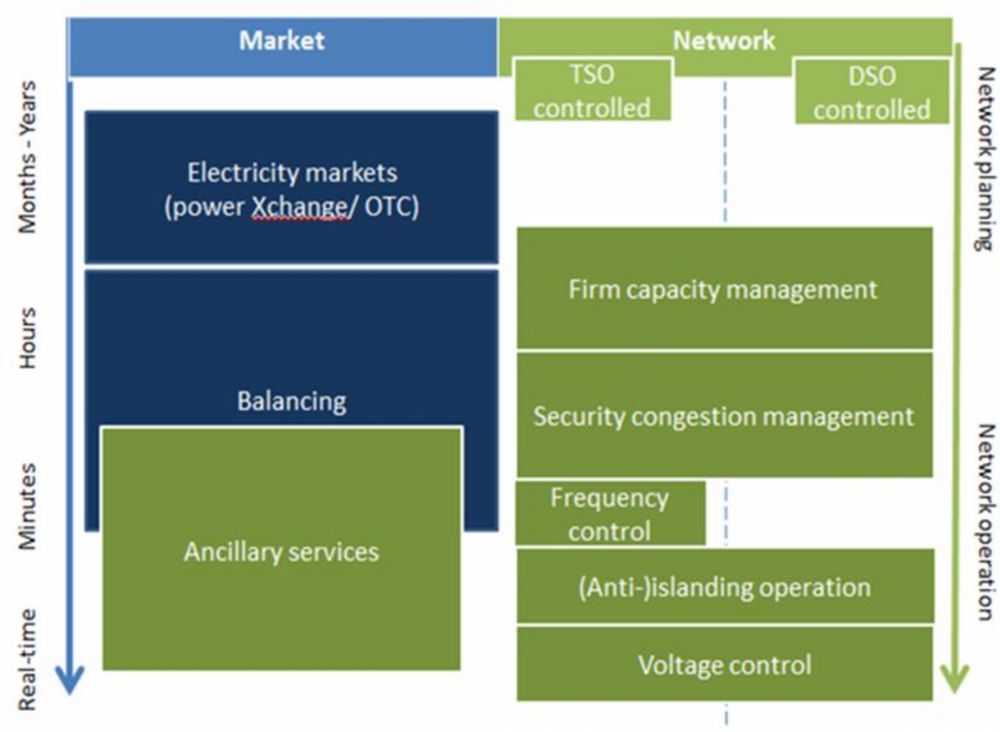


Figure 13 Market and network operations

[17] For definitions see Glossary.

System service	Purpose	Provision by which type of DER	Information exchanges	Form of delivery
Firm capacity management (long-term)	DSO planning purposes; optimize of network capacity utilisation DG with a view to using assets most efficiently	CHP, small hydro, stochastic RES with integrated storage Aggregated demand providers, DSM	• DG outage programs and availabilities information (DG->DSO) • Real time generation output (DG->DSO) • Real time demand flexibility information (DER->DSO) • Firmness periods (DSO->DER)	Commercial
Losses compensation	Increased system efficiency	DSO, DG, demand customers	• Real time load and network voltage or fault conditions (DSO->DSO) • Real time generation output (DG->DSO) • V, Q, pf setpoints (DSO->DG) • Demand reduction signals (DSO->Aggregators)	Commercial
Security congestion management (short-term)	Operate the grid within the security standards	RES, CHP, distributed storage, DSM	• Real time load and network voltage or fault conditions (DSO -> DSO) • Real time generation output & load flexibility (DG -> DSO) • Reduced setpoint/ reduction signal (DSO -> DG) • DG outage programs and availabilities information (DG->DSO)	Mandatory with compensation or by commercial arrangement (non-firm access contracts)
Anti-islanding operation	Avoid unsafe, unbalanced and poor quality distribution electric islands	DG, storage, DSO (local network controls)	• Local automatic signal generated in case of fault or triggering conditions -> all local DG, storage, network control points • Local signal generator -> DSO SCADA or central control (and local / regional control depot), notification signal by DSO	Mandatory without compensation (grid connection rules defined in grid codes)
Frequency control	Under extreme situations of system strain, TSO to call upon DSO to deliver support – DSO as a conduit but needs to see what is happening	DG & load to TSO via DSO	• Real time active and reactive power flows information exchange at the T/D interface (DG & load -> DSO ->TSO) • Load/generation to adapt (TSO-> DSO -> DG & load)	Commercial (at TSO level)
Islanding operation	Improve continuity of supply when higher voltage source is unavailable	DG, storage, DSO (local network controls), DSM	• Real time active and reactive power flows information exchange (DER -> DSO) • V, P, Q setpoints (DSO->DER)	Mandatory with compensation
DSO Voltage control	Local supply quality security and increasing amount of DG power that could be injected in the grid	PV, Wind power, CHP, distributed storage, DSM	• Reactive requirement (amount and electrical or geographical delivery location) (TSO -> DSO) • Real time load and network voltage or fault conditions (DSO -> DSO) • Real time generation output (DG -> DSO) • V, Q, pf setpoints (DSO -> DG)	Mandatory without compensation to maintain defined limits for distribution system stability. Commercial for purposes beyond maintenance of network stability or outside the scope of the customer's own connection
Information exchange	Optimise DSO and TSO control supervision, and scheduling	DER, TSO	• TSO Real time and off-line measurements and topology information (TSO -> DSO) • Real time generation output (DG->DSO) • DG and TSO outage programs and availabilities information (TSO->DSO). • DG generation forecasting (DG-> DSO-> TSO)	Mandatory with compensation

Table 2 New System Services at Distribution Level

To manage the operation of distribution systems, similarly to the usual practice in transmission networks, basic system states should be defined, e.g. within security standards or grid codes. A "**traffic light scheme**" could be used to distinguish between system states and selecting appropriate type of actions (see Figure 14 and the box below):

- The *'secure operating region'* (1) results from overlaying the stable operating points on an illustrative power-voltage curve for abstracted two-bus system. It represents an area where the network is secure and the power can flow either towards the consumer (because demand is greater than generation) or back to the system (when generation exceeds demand). If the system is at the *secure operating point 1*, the market operates and the DSO has clear visibility of this. The boundaries of this secure operating region depend on the physical characteristics of the network and system dynamics.

- *'Unsecure operating points 2 and 4'* illustrate the situations hampering secure operation of the distribution system: voltage increase and congestion (the plane has been rotated to align it with a time-varying load profile).

- *'Operating points 3'* indicate alert network states in which congestion management should be conducted in order to keep the grid from entering the red emergency state. When possible the DSO actively engages with the market (DG or load) to procure flexibility to relieve grid constraints.

All in all, market principles should work in the first place when the system is in the 'green' and 'yellow' states. That should be the case most of the time. DSOs should override control (directly or indirectly) of supply or demand only in strictly defined emergency cases (when the system enters into the red state). Actions in this state must be specific and well defined by e.g. regulation or contracts and be temporary in nature. Transparency is needed (each time of occurrence and reasons); and analysis should be made if indeed DG/load were not able to offer sufficient services.

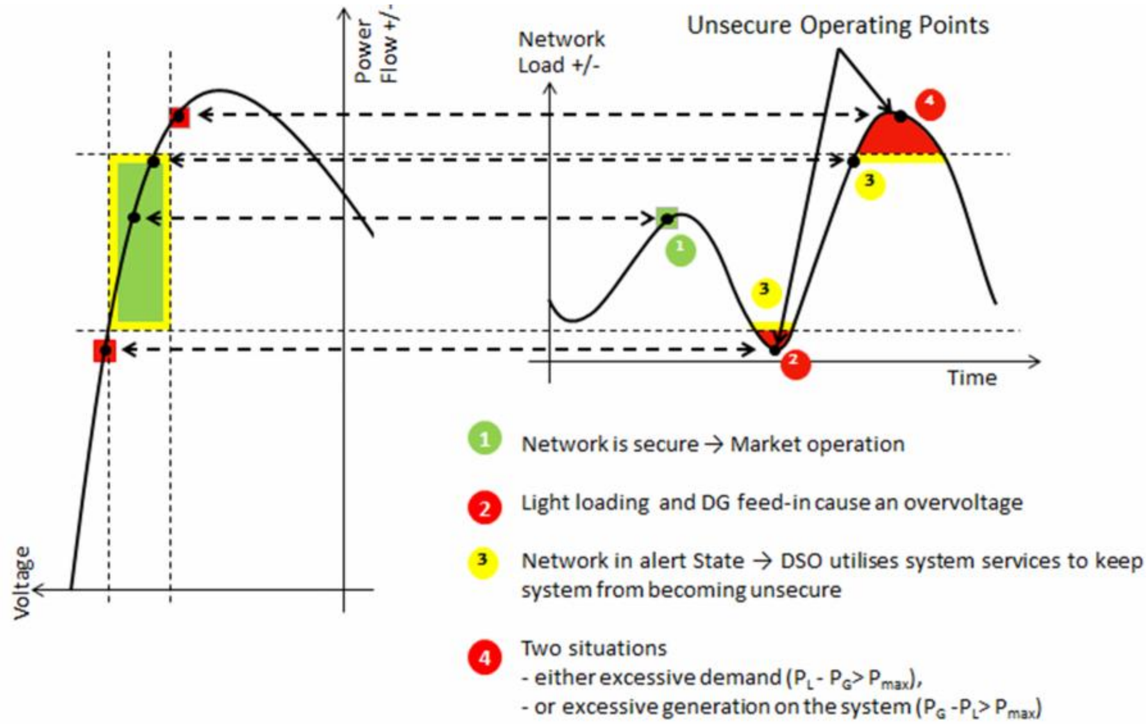


Figure 14 Instability in the distribution system

The Traffic Light Concept

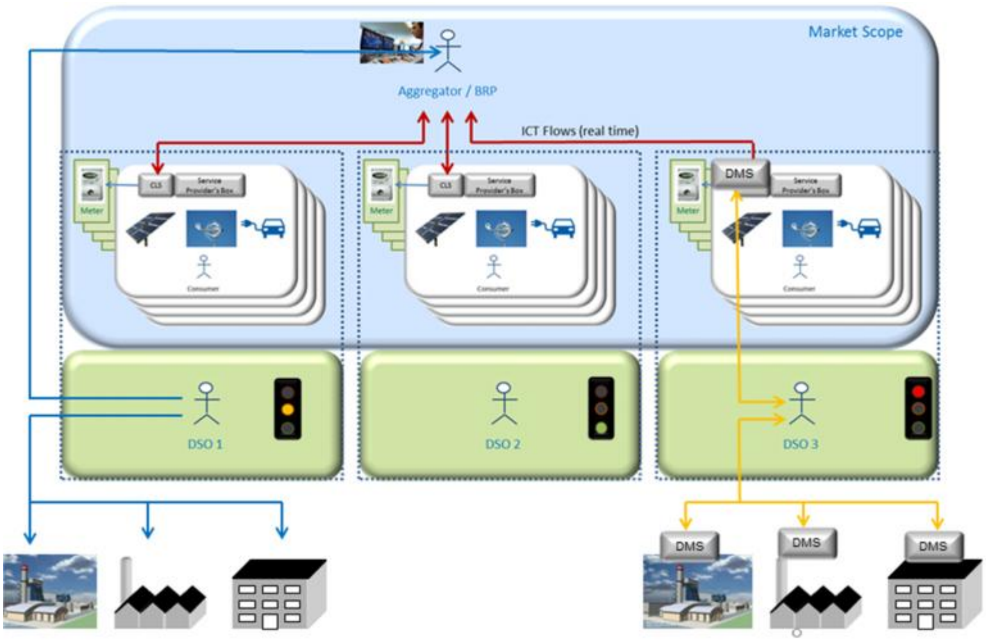
1. **Green:** Normal operating state
2. **Yellow:** Alert state – DSO has an emerging congestion. DSO actively engages with the market (DG or load) to procure flexibility to relieve grid constraints:

    a) Via flexibility platform: a methodology has to be developed which links the offers of aggregators with identification for the location. For example, aggregators could divide their Virtual Power Network capacity into local pools. A DSO can contract an aggregator for delivering local generated electricity or load from the local capacity pool. This can be facilitated by the DSO data hub.

    b) Directly: A DSO could contract the customer (including DER) in order to maximise the utilisation of distribution assets in planning and operational timescales where locally needed with ensuring transparency and non-discrimination for example via tenders.

3. **Red:** Unsecure operation – Emergency cases

    In strictly defined emergency cases, the DSO would be able to manage distributed renewable generation, to implement grid efficiency improvement measures, and to control the isolation and restoration of outages. This is the last measure taken by the DSO when every other option has failed to restore system integrity.



[18]

Distribution congestion

Security congestion management would be used to solve the technical constraints at distribution level close to real-time in the alert state ('yellow light'). In these defined cases, the DSO could deviate from the merit order, but ex-post justification and compensation should be provided. This could be executed by pre-agreed contracts for instance. The DSO should then pay the "up regulating" cost elsewhere in the system, and should remunerate the downward cost to the local generator that is constrained off in his grid (including the missed income from the support scheme and the costs of keeping balanced position).

[18] For definitions of CLS and DMS see glossary.

Emergencies

Emergency tools including direct load management (load shedding) and emergency DG curtailment should be used only in well-defined emergency states/once the contracted options are exhausted. When the grid stability is at risk, DSOs should be able to act physically to control and constrain off both local consumption and production (as is already the case in some countries – e.g. Germany or Sweden). Priority access rules should not restrict network operators' ability to flexibly respond to emergency situations.

Any action on distribution network users requested by the TSO should be agreed with the DSO as system operators. TSOs should not act on any individual DER connected to the distribution system. Any direct order from the TSO to DER embedded in distribution networks targeted to safeguard operation of the system will be executed by the DSO, not the TSO.

2.3.2. Information Exchange

Today, DSOs have no systems installed for acquiring data from DG of smaller size in particular. In some cases, the TSO receives information from DG in real time while DSOs do not have real-time access to this information. There is not usually an operational exchange between the TSO and the DSO.[19]

In the future, a well-structured and organised information exchange between relevant actors will be necessary to operate the distribution network with high DG penetration in real-time or close to real-time. Such information exchange will be used for DSO planning and asset management purposes (to optimise network capacity and availability in the most economic manner) while ensuring that all customers feel the absolute minimum impact of DG on power quality and continuity. It is the first and potentially most effective step which can be taken to reduce the cost of DG connection and integration.

At the transmission level, generators already send schedules to the TSO for system balance purposes and to gurantee that their realisation is technically possible. In systems with high DG penetration, the DSO will need information about DG forecast, schedules and active dispatch to improve their visibility and to assist with real-time or close to real-time management of the distribution network including local network constraints. DSOs should have managed access to communication and monitoring assets of DG to collect information that will be necessary for operation of their networks. The granularity of the data exchange will depend on the size of the generating unit. The necessary information should be then exchanged between the DSO and the TSO (in both directions). DSOs should provide the TSO with information on active power that the TSO needs to facilitate secure system operation. DSOs operating sub-transmission networks may also require TSO information in real time.

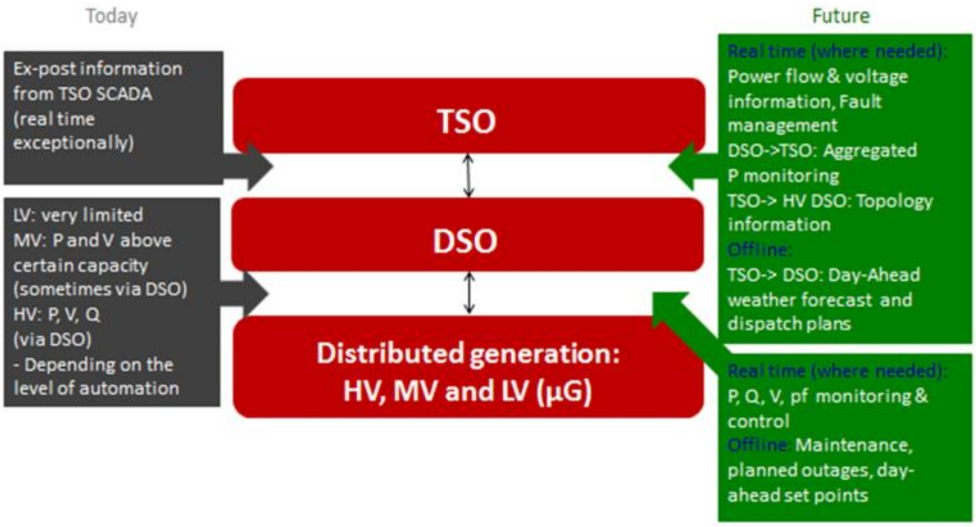


Figure 15 Information Exchange Today and in the Future

[19] Exchange between TSOs and DSOs operating HV networks exists in some countries.

In addition the fact that the participation of DG and load connected to the distribution grid in TSO balancing markets could create constraints in the distribution grid should be taken into account. Generators and flexible loads connected to the distribution grid should be able to also provide these ancillary services for system balancing and transmission system congestion management purposes. Aggregators may be able to achieve certain modifications in the demand and in the generation of the consumers and producers in their portfolio, in order to offer services to system operators. However, the issue that an area managed by an aggregator may not correspond to the distribution network responsibility area (forecasts and schedules are delivered at a portfolio level for a bidding zone) needs to be addressed. In these situations, the DSO needs to have adequate visibility to ensure that this activation does not impede security of supply in its own network. Similarly, actions by the DSO to solve constraints could affect the system balance.

Appropriate methodologies and processes should be defined in order to ensure that market schedules are not in conflict with network operation or that transmission and distribution network operation are not in conflict with one another (e.g. TSO asking for a modification which would violate distribution system security standards). Enhanced monitoring and control strategies for distribution networks will need to be deployed (see section 2.4).

2.3.3. Voltage Control

As outlined earlier, voltage in the system needs to be maintained within a range defined by security standards. Voltage control is a system service managed by network operators in order to maintain voltage in their networks within limits and to minimise the reactive power flows and consequently, technical losses. While generation/load balance is carried out at system level by the TSO, voltage control of the distribution grid requires the involvement of the DSO.

The traditional approach to voltage control includes reinforcing the grid or installing preventative measures. Voltage control has been traditionally done by transformers (using on and off load tap changers moving reactive power) and capacitor banks that inject reactive power into the grid (see Figure 16). The DSO fixes a setpoint and prepares scenarios/ranges for different voltages within which the voltage must be maintained.

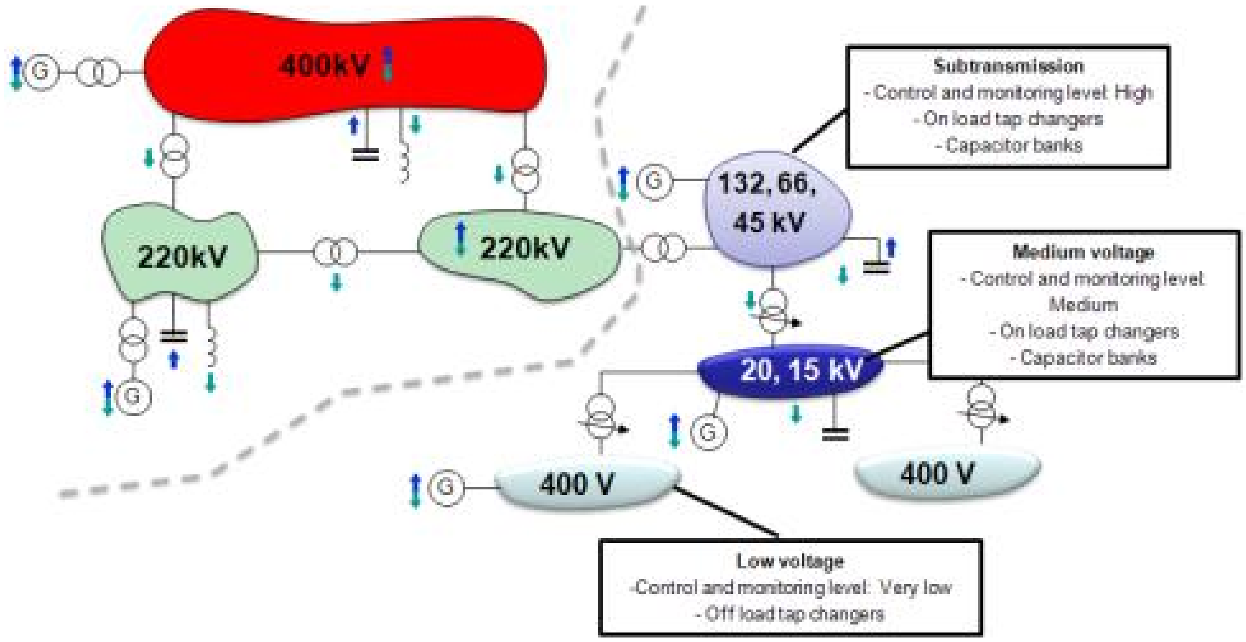


Figure 16 An illustrative example of a traditional approach to voltage control

HV	• Usually power transformers with on-load tap changers • Capacitors frequently used to control the voltage
MV	• No analogue values in secondary substations obtained in real time (typically analogue values only at MV feeders) • MV networks connected to HV through a power transformer with on-load tap changer Capacitors can be commonly found also in these substations to improve the power factor • Voltage setpoints specified at MV substation busbars
LV	• MV/LV transformers may be fixed ratio (i.e. have not tap changers) or have off-load tap changers, manually controlled. Taps selected to compensate the effect of MV voltage drops at LV levels (passive approach). • These tap-changers operate only a few times during transformers lifetime. • Sometimes capacitors are installed in consumer facilities to meet power factor regulations • New controllable MV/LV transformers are emerging but expensive

Table 3 Voltage control in current distribution networks

As the penetration of DG in networks increases, it is no longer possible to ensure sustained system security without some dynamic resources, including reactive power compensation and active voltage control. The DSO's role in ensuring not only that adequate network capacity is available for all connected customers (demand and load) under all conditions, but also in managing voltage and reactive power flows on distribution networks is becoming more complex.

Two technical considerations for voltage control in distribution networks include:

- With high DG penetration, active power becomes a significant driver for voltages changes in MV and LV networks (the kW-V effect is more significant than the kVAr-V effect). The lower the distribution voltage level, the higher this effect.
- In MV and LV networks, the active power effect may not be always neutralised by the reactive power injections/withdrawals available in the system. **To regulate voltage, DSO should be able to control reactive power and in some cases also active power.**

In high-voltage networks, DSOs will be able to maintain the voltage within the security standards if they have the means to manage reactive power flows.[20] Active power will not cause voltage deviation under normal operation. On the other hand, at medium and low voltage levels, active power changes due to DG feed-in cause voltage rises (especially in cables).[21] Distributed generation changes voltage triangle design and as a result, both scenarios with and without DG have to be considered. **Reactive power may help compensate the active power effect but may not be sufficient to neutralise it.**

As reactive power cannot be transported over long distances and as many regions with high DG penetration (thus voltage control challenges) have no conventional sources of reactive power, managing voltage on a local or sub-regional basis could be the most economically viable solution for the entire electricity system. For these purposes, the DSO should be able to sectionalise its networks, to actively interact with DG to request supply voltage control and reactive dispatch or to exploit active demand services over the distribution network to solve operational problems. Clear interface conditions and an agreed operational framework at the interface between TSO and DSO are also necessary (including parameters for TSO-DSO interface nodes).

[20] Through issuing suitable voltage set points and operating power factors to DG and operating network reactive power or voltage installed resources.

[21] The R/X ratio (ratio between the resistance and the reactance of overhead lines or cables) explains the relationship between active and reactive power and the voltage level. See Case study A in Annex 2.

Innovative approaches to voltage control should be explored. Experiences from several European countries show that compensation at the TSO-DSO connection point may not be flexible enough in case of emergency. The increasing DG penetration requires continuous adaption of the capacities at the connection points. Voltage control requires a system approach that would include minimising system losses, optimising network investments and coordinating the necessary operational windows and control actions between the individual TSO and DSO, with particular attention to cases of emergency.

Solutions on the network side and on the network users' side should be considered:

Network users' contribution

Generators could contribute to voltage based control. This is already the case in some countries and is being tested in others, as shown in case study B in Annex 2. The best generation technologies for voltage control are those that are able to absorb and deliver reactive power. These include modern wind turbines, small hydro and power electronics. Inverters originally supported neither active or reactive power but today address reactive power and have also elements for frequency support. For example DERs would react to voltage changes/disturbances or faults by altering real or reactive power based on pre-defined and dynamically configurable set-points (similarly to how frequency control operates at TSO level today).

Network contribution

There are cases where HV voltage control cannot be achieved in a manner which maintains both transmission and distribution security without additional reactive power resources on the network. Investments in new analytical, control and monitoring expertise and facilities in MV and LV (like power electronics, real time supervision) may be required. For example, satellite cables with large diameters could drastically reduce voltage rise within the grid.[22] Alternatively, voltage controlled MV/LV transformers can be installed in order to decouple the voltage rise within the MV and the LV networks caused by RES feed-in.[23] These innovative network techniques would need to be considered and allowed within regulation.

Combination of both solutions

A combination of both solutions may be used. Studies show that in some situations even a contribution by distributed generation will not be able to maintain the voltage within limits. Case study A in Annex 2 demonstrates that situations when the required reactive power exceeds the installed active power capacity may occur. Both to minimise any impact (active power generation) on DG and to ensure that TSO-DSO interface standards can be maintained for system stability, it may thus be necessary that additional reactive resources are installed on distribution networks. The contribution of the system operators or DG to these resources must be reflective of the particular network issue being addressed and the beneficiaries of the installation. It may also be necessary in future for DG which will displace reactive power resources to also contribute to the reactive power facilities on its hosting networks so as to maximise its potential to deliver active power.[24] This is already the case with larger (industrial) demand facilities that are required to meet strict power factor regulations. Where this solution is deemed the most cost-effective, generators should be required to comply with minimum connection & operational requirements necessary for managing distribution network stability. On the other hand, DG contribution to loss minimisation may be compensated on a commercial basis.

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[22] Werther, Becker, Schmiesing, Wehrmann: Voltage control in low voltage systems with controlled low voltage transformer (CLVT); CIRED Workshop - Lisbon 29-30 May 2012.

[23] Thies, Zdrallek, Schmiesing, Schneider: Future structure of rural medium-voltage grids for sustainable energy supply, CIRED Workshop - Lisbon 29-30 May 2012.

[24] Traditionally reactive power was supplied, rather than absorbed, by generation. As DG displaced conventional generation, reactive power resources are reduced.

Reduction of active power that might be technically necessary to manage the network voltage and avoid complete generation disconnection should be used only when other solutions have been exhausted. Congestion management would apply in this case, with emergency DG curtailment only if necessary.

Recommendations:

- **Active DSOs should be allowed to coordinate the offering of new system services. Such system services could be procured as ancillary services from DER or defined in grid codes (voltage and reactive power contribution).**
- **Flexibility platforms where flexibility is offered (either directly by larger DG/load or via aggregators which group a large number of DG and loads) to DSOs (but also to TSOs to provide balancing and redispatching in transmission grids) could play an important role for close to real-time flexibility in particular.**
- **DSOs should be included in the information exchange** about
    - planned location / connection / clustering of contracted customers (aggregators)
    - forecasts and schedules necessary for dealing with local grid constraints.

  Appropriate methodologies and tools for these purposes should be developed.
- **Voltage control requires a system approach considering transmission and distribution networks.** Coordination between DSO and TSO at the interface point should aim at reactive power optimisation and minimising system investments and losses.
- **DG contribution to voltage control, probably in combination with network solutions, is likely to play an important role in keeping distribution networks stable.** Where this solution proves to be the most cost-effective one, generators connected to the distribution network above a certain capacity should be required to have reactive power capabilities in line with those for transmission connected RES, adapted to the connection level and capacity. Where it goes beyond maintaining local system security as impacted by the generation connection, a market-based approach should be adopted for procuring additional amounts of reactive power such as DG contribution to minimise losses.

2.4. Technical Development: Towards Flexible Distribution Systems

With a rising share of DER, monitoring, control strategies and advanced protection systems in MV and LV distribution networks will have to develop to enable DSOs to:

- Determine and forecast grid capacity and bottlenecks;
- Supervise and control power flows and voltage in their networks;
- Enable the new operations at the distribution level (including non-discrimination and effective real-time grid capacity monitoring and management of injections/withdrawals);
- Enable market-based congestion management and voltage control in distribution networks;
- Enhance the distribution grid hosting capability.

This solution should not to be taken up in isolation from other options such as services from DERs to help manage the distribution system mentioned above. The route to the future energy system will incorporate both aspects. The most economically efficient solution will depend on the topology, load and generation profiles within a given distribution system. A two-level approach might be adopted: larger DG (with a defined installed capacity and level of connection) could be monitored and telecontrolled while other DER may not be dispatchable should be forecast and monitored by the DSO on an aggregated basis at the substation level.

Technology options for development of the abovementioned options are outlined in Table 4. For examples of implementation of different solutions see case studies C, D & E in Annex 2. In addition, new design ideas such as “satellite cables”[25] and dynamic line rating (DLR) are being tested. With DLR, real-time information, for example the temperature of the conductor or the wind speed, can be used to calculate a temporary rating of a line, thus allowing more power to flow. This technology increases the utilisation of the line and also allows more RES to be integrated than if static ratings were used. Smart meters will provide relevant monitoring functionalities, such as real-time local voltage and load data that will be of high importance in distribution network management processes and systems.

Function	Medium Voltage	Low Voltage
Monitoring	Current, voltage, fault passage indicators & other sensors	Centralization of information via secondary substations
Control	Remotely controllable reclosers, switches automated protection / fault sectionalisation – remote monitored fault detectors Voltage or power factor set points to DGs	Controllable MV/LV transformers[26] (with centralised or decentralised sensors)

Table 4 Technology options for distribution network development

3. Implications for Regulation and Market Design

The transition towards more active distribution networks requires the development of technology as well as requirements for both network operators and network users to contribute to system security. Appropriate commercial and regulatory frameworks need to be put in place.

As mentioned above, the new Energy Efficiency Directive provides a good baseline for setting up system services at distribution level that will allow for an energy efficient use of infrastructure. Its appropriate implementation is thus crucial.

In addition, regulation and a flexibility market model should be further developed to address the following issues:

- **Principles and methods for defining system states** within the so-called ‘traffic lights concept’: boundaries between the green, yellow (procurement of flexibility from markets) and red zones (emergency state with non-commercial services) described in chapter 2.3.1 should be defined depending on physical operating boundaries of a system, including methodologies of how they will be monitored, calculated and audited.

- **Key performance indicators and criteria for selecting most cost-effective solutions for different situations**: Inefficient investment deferral on one hand and oversized networks with long lead times for connections on the other hand should be avoided. Flexibility operators such as aggregators should not be incentivised to cause constraints that are not caused by reaction to market signals and subsequently remunerated for solving them. It is key that a system approach taking into account benefits to the society is adopted. Already existing methodologies should be used as a starting point.

[26] Werther, Becker, Schmiesing, Wehrmann: Voltage control in low voltage systems with controlled low voltage transformer (CLVT); CIRED Workshop - Lisbon 29-30 May 2012.

- **Regulations for steering the most cost-efficient solutions:** Regulatory mechanisms for steering when the investment deferral is more cost-effective than active distribution approach should be elaborated, for example in order to ensure that network development occurs when excursions to the yellow and red operating states become too frequent (what is 'frequent' is also to be defined).[27] Active system management will affect the amount and structure of operational expenditure and would replace some CAPEX with OPEX.[28] DSOs should be able to look at the business case for both the investment solution (CAPEX) and the service-based solution (OPEX), or a mixture of the two, and decide which is preferable. Adoption of a regulatory mechanism is necessary to integrate this approach in the grid fee calculation. DSOs need to be provided with adequate remuneration for the most adequate solution: investment or active system management tools including procurement of flexibility services from network users.

- **DG raises the need to review the suitability of the existing distribution network charging structures** (current network tariffs are largely volumetric). EURELECTRIC will present its proposals on this issue later this year.

- **New roles and relationships between different actors in the market:** In particular, the role of flexibility providers (to be taken up by aggregators/suppliers/ESCOs) and the relationship between these flexibility providers and network operators, suppliers, the BRP (balance responsible party) and the local customer/local producer should be addressed.

- **Interaction between the DSO and the market:** How will the DSO have visibility of what is happening on the market side that may impact on the DSO network and cause constraints in the short or long term? For example, a flexibility provider may have a contract to provide reserves to the TSO, but needs to use the distribution system to which its resources are connected to deliver this service. However, a bottleneck on the distribution system may prevent this delivery. These technical aspects of flexibility markets require further investigation.

- **Measurement/determination of "non-produced" and "non-consumed" energy is an important related issue:** unlike consumed and produced energy, saying how much a generator has "not produced" when he reduced his production on demand of e.g. an aggregator is rather difficult, and appropriate methodologies have to be developed and implemented. Knowledge of the initial schedule is important in this respect.

- **Revision of planning guidelines for distribution network development:** Revision of these rules should be reconsidered in order to account for ancillary services that the DSO can procure. Are deterministic security standards such as the N-1 criterion appropriate or should they move to being more probabilistic and based on reasonable risk of expected energy not served in order to maintain high reliability while minimising over-investment in redundant capacity?

- **Establishment of contingency assessment and outage management** (organisation and coordination of outages) rules for distribution networks and their users.

[27] The intervention frequency on the customer side is registered – this parameter can be used as an indicator for the necessary grid reinforcement or extension.
[28] See EURELECTRIC report Regulation for Smart Grids, February 2011.

Key Conclusions

1. Secure and cost-effective integration of DER requires a rethink of how distribution grids are planned and operated

Distribution networks are currently coping with the rapid increases in decentralised RES feed-in that Europe is experiencing. Decentralised feed-in of RES has already started to outstrip local demand in some European regions. This growth can be quite rapid, as the increased feed-in often occurs in rural areas with little demand. **Building sources of production close to consumption does not reduce distribution network cost.** The network still has to be designed to supply maximum demand for situations when there is no DG production. **In addition, operation of such a system becomes more complex.** Once the share of decentralised RES passes a certain point, it overburdens the local distribution grid. **DSOs are therefore increasingly facing voltage problems and grid congestions.**

2. DSOs need tools that allow them to become real system operators

DSOs are responsible for developing their grids efficiently and providing quality of service for end customers. But in order to satisfy these responsibilities in the changing context of DER/DG, DSOs need adequate new tools. **System services at the distribution level are key in this respect.** Such services include the participation of decentralised generators in **voltage and reactive power management, distribution network capacity management and congestion management, and information exchange between TSOs, DSOs and DER.**

Distribution network capacity management involves taking services from DER into account in the planning stage to optimise investments and ensure that infrastructure is only extended when it is more cost-efficient than procuring services from DER. **To support congestion management, a 'traffic light' concept could be introduced to denote different system states.**

3. Optimising DER management through flexibility services should be explored

Traditional methods of grid expansion reinforce the network so that it may bear maximum feed-in from distributed generation. However, such maximum capacity is only required for a short period of time each year. While this approach will remain important, it may therefore not always be the most optimal and cost-effective solution – not least because new lines often face problems of public acceptance.

New solutions must be developed to enhance the hosting capacity of the distribution grid, minimising situations when DG feed-in has to be reduced or new connections have to be denied. Such solutions include **new network technologies and design concepts, the contribution of generation to system performance, and access to flexibility services provided by DG operators, storage and demand response.** Their flexibility could be procured on a competitive basis via flexibility platforms and be offered to DSOs, but also to TSOs as a way of managing redispatching issues in transmission grids. They should be used whenever it is most efficient.

4. One-size-does-not-fit-all: different distribution networks require different solutions

While best practice sharing is desirable, the most economically efficient solution will depend on the topology, demand and generation profiles within a given distribution system. The route to the future energy system will probably incorporate aspects of each of the abovementioned solutions. The regulatory framework should grant DSOs enough flexibility to determine the most appropriate solution for their network. Methods of prioritising and selecting the most cost-effective solutions should be further investigated.

5. Coordination among all relevant stakeholders is key

A system-wide approach to DG and network development is needed. For instance, all stakeholders must be involved in analysing **grid connection requests.** This will lower the costs of network development and connection while reducing connection waiting times for new users compared to business as usual.

Policy Recommendations

1. Properly implement existing legislation and adapt it to the new environment

The regulatory framework should enable the creation of new system services at distribution level, as a means of contributing to local grid stability and security of supply – a requirement of the new Energy Efficiency Directive (Art 15.1 of 2012/27/EC). **Such system services could be defined in grid codes (voltage and reactive power contribution) and/or procured as ancillary services from DER within a transparent and non-discriminatory regulatory framework.** While the role of EU-wide network codes is limited in this respect,[29] national grid codes and market arrangements backed up by European standardisation (in particular within the mandate M490 for smart grids) should set out *inter alia* appropriate connection requirements for these network users.

Full implementation of the so-called Second and Third Energy Packages is important to ensure fair, transparent and non-discriminatory network connection and access.

2. Take into account lessons learnt from smart grid demonstration projects

Europe already has experience of smart grid demonstration projects worth more than €5.5 billion.[30] The future large-scale deployment of smart grids should reflect **best practices from these projects and already implemented solutions. European network codes are currently being designed and will include requirements for distribution network users. They should take into account latest improvements on the ground and not close the door to the implementation of new, proven innovation in distribution networks. Standardisation plays a key role in facilitating these solutions.**

3. Tap into the potential of aggregation

Aggregators will act as possible middlemen for many small DG and load customers, offering the flexibility options they buy from their clients to TSOs and DSOs. **A market model should be developed to unlock the potential of such aggregation and new roles and relationships between new and existing actors should be defined.** This will enable demand, distributed generation and storage resources to participate in the markets for energy and ancillary services.

4. Equip DSOs with the tools they need to ensure quality of service and to facilitate the market

Establishment of system services at distribution level calls for adequate supporting tools that allow DSOs to operate their networks in a 'more active' way. Such tools should include access to technical data and further development of the ICT systems essential for operational control of the grid**.**

[29] Network codes shall be developed for cross-border network issues and market integration issues (Art. 8(7) of Regulation (EC) 714/2009).
[30] Smart Grid projects in Europe: lessons learned and current developments. Joint Research Centre, 2012.

It is the basic task of DSOs to guarantee security in their grids and to support the security of the system as a whole. They are also in the best position to plan and manage the new opportunities and risks related to the grid. **They should thus act as facilitators for flexibility platforms which will allow generators, suppliers and consumers** to offer network services either directly or via aggregators.

DSOs are also best suited to manage operational data of distribution network users and pass it to TSOs in an appropriate form and in the cost-effective manner if needed.

The flexibility market and European rules for system operation should not be designed in isolation. Technical and commercial data will become more interrelated. Operational rules have an impact on market rules. EU network codes that redefine operational and balancing rules will have implications for procurement of flexibility services from DG, decentralized storage and flexible loads and should therefore be designed to facilitate it.

5. Review connection and access regimes for distributed energy resources

A review of grid access regimes, including priority and guaranteed grid access for renewables[31] is becoming increasingly necessary. **Currently such rules prevent grid and market operators from implementing cost-effective solutions to avoid grid congestion. Instead, they trigger inefficient investments in grid extension based on rare situations.**

Variable network access contracts or alternatives involving close to real-time operation might be part of the solution. They would allow for limiting DG injection by the grid operator based on an agreement with the producer concerned, who would be remunerated, or at the initiative of the producer on the basis of market prices and/or local flexibility mechanisms.

Priority access rules for DER also should not prevent network operators from responding flexibly to emergency situations.

6. Design regulation to include network solutions beyond simple 'investment in copper'

DSO regulation should be adjusted to encourage the transformation of distribution networks into actively managed distribution systems wherever this is the most economical solution. Faced with new challenges posed by DER, **DSOs could design and operate their networks more efficiently if national regulation defines cost-efficiency more broadly.** The expected replacement of part of CAPEX by OPEX should be taken into account and DSOs should be provided with an adequate reward for CAPEX and improved evaluation of OPEX**.** DSOs should receive an adequate rate of return on their network investments without time delay.

In addition, the current approach to network development should be reconsidered: DSOs should be able to take into account DER and conventional assets when planning their networks (as required by Article 25.7 of Directive 2009/72/EC).

[31] Art. 16 of RES Directive 2009/28/EC.

Annex 1 – Example of a Positive CBA, the IMPROGRESS Project

The Improgress Project [32] compares the impact in overall system costs when implementing active network management tools, specifically advanced generation control and demand side management. Three real network scenarios were compared:

1. A rural area with wind power plants and CHP in the Netherlands (HV, MV and LV);
2. A residential area with PV penetration and micro CHP in Germany (MV and LV);
3. A semi-urban industrial and residential area with wind, PV, CHP and a high peak demand in Spain (HV, MV and LV).

A cost-benefit analysis was performed for these scenarios considering the 'classical' network and back-up plants investments avoided and the implementation of the control costs, which vary widely depending on the ICT techniques considered as most optimal in each case. In both cases, operation and maintenance costs are considered as well as losses. Redispatch and balancing costs are also taken into account. The active management options analyzed were demand side management and advanced generation control (via bilateral contracts between agents and DSOs or economic incentives (prices with some locational/temporal differentiation).

The advanced response resulted in a great impact on distribution costs due to the lowering of the maximum net generation and/or demand. Generation costs also dropped as less generation capacity as well as less peak generation was needed. External costs and balancing costs also decreased.

For example, the Spanish case led to a modification of peak demand scenarios, resulting in decrease of the simultaneity factor from 0.7 to 0.56 (the same demand requires less distribution capacity) and an increase in DG simultaneity factor from 0 to 0.5 in PV and from 0.3 to 0.6 in CHP (DSO can count on DG to meet its demand up to a certain stage).

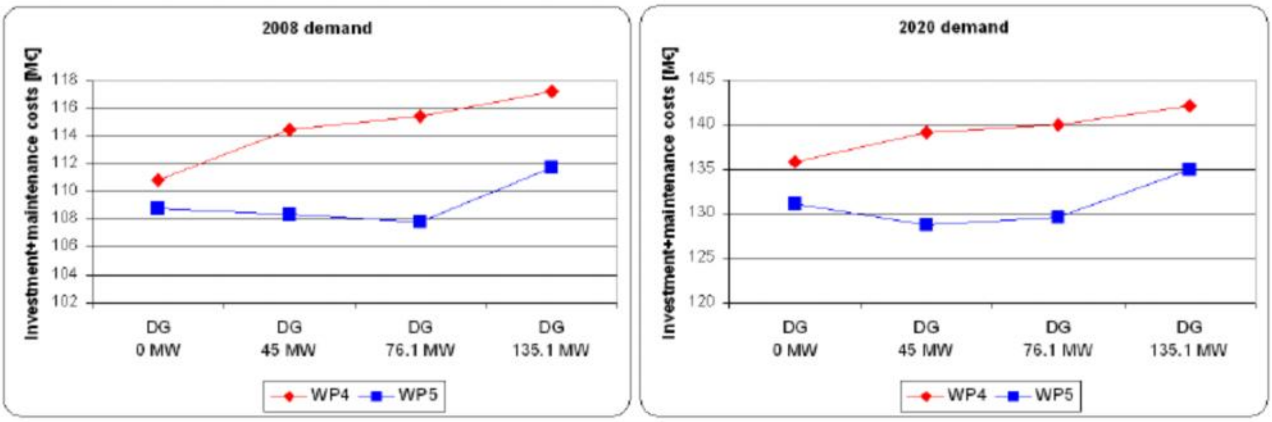


Figure 17 Comparison of BAU distribution Investments and maintenance costs (WP4) and costs when applying ANM solutions (WP5) for the Spanish network

The study concluded that investments in the abovementioned solutions were cost-effective on the overall account, even though a cost-benefit analysis should be made to evaluate on a region specific basis.

[32] Improvement of the Social Optimal Outcome of Market Integration of DG/RES in European Electricity Markets, for details see Deliverable 6 available at http://www.improgres.org/fileadmin/improgres/user/docs/D6.pdf

Annex 2 – Case Studies

A. Demonstration of active power effect in voltage control – Networks 2025 Project, Spain[33]

In Spanish medium and low voltage levels the R/X ratio (the ratio between the resistance and the reactance of overhead lines or cables) is quite significant, in the range of 1-4. For this reason voltage changes due to active power cannot be neglected. Figure 18 states that when the R/X ratio is very low (blue curves), active power changes are not affecting voltage levels. But when the R/X ratio increases (red curves), active power changes cause voltage rises.

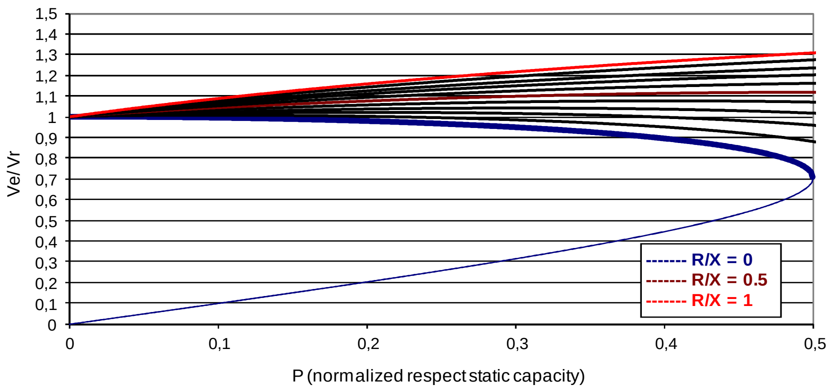


Figure 18 R/X ratio effect in voltage control

The key question is if by controlling reactive power injections or abortions by DG's/DSO's, the active power effect can be neutralized. Figure 19 shows the extra reactive power compensation required by DG technologies classified in voltage levels. The voltage control contribution by DG technologies is perfectly adapted in sub-transmission levels, where no extra reactive power compensation is needed. Nevertheless, in MV and LV networks voltage control requires extra high reactive power compensation from DG technologies, so that new investments might be assessed.

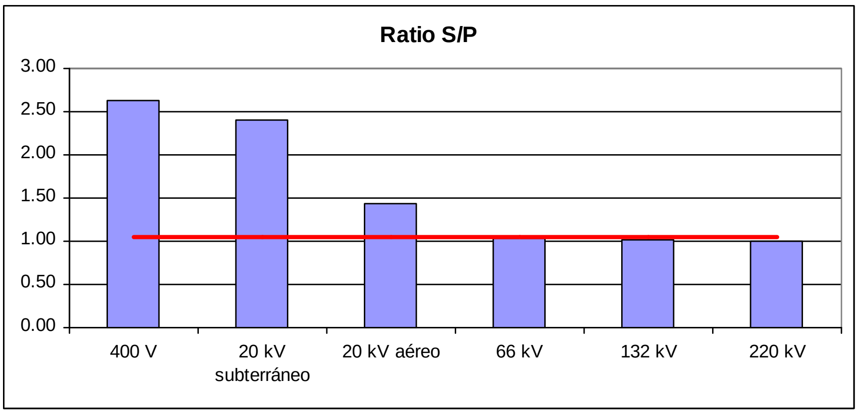


Figure 19 Extra reactive power contribution to maintain a voltage setpoint

These results demonstrate that DG contribution to voltage control may be limited in MV and LV levels. Table 5 shows that DG is ready to contribute to voltage control in distribution networks when the power factor control is needed. The power factor control is the DG ability to maintain the power factor at a specified setpoint at the DG connection point to the distribution network. The voltage set point control is the DG ability to maintain the voltage setpoint at the DG connection point to the distribution network.

[33] All the figures below are results of this project.

Voltage Level	DG technology	Power factor control	Voltage set point control
400 V	PV Micro CHP	✓	×
20 kV (Cable)	PV CHP Small wind power	✓	×
20 kV (OHL)	PV CHP Small wind power	✓	×/✓
66 kV	PV CHP Wind power	✓	✓
132 kV	CHP Wind power	✓	✓

Table 5 DG Contribution to voltage control by voltage level

Conclusions

- The **kW injection** increases the voltage level in distribution networks. The Spanish study case has demonstrated that under high DG penetration levels voltage could rise up to 10% in MV networks.
- The DG influence in voltage control is extremely dependent on the **DG location**. The further is the DG location from the source the higher is the voltage rise effect. This effect is also proportional to penetration level of DG.
- **DG modifies the triangle design in MV and LV** and there is not dynamic controllability at this voltage level. Voltage area grows and triangle design rotates (see Figure 20).
- Whenever it is possible, the **optimal approach** to voltage control with DG is the voltage setpoint approach.

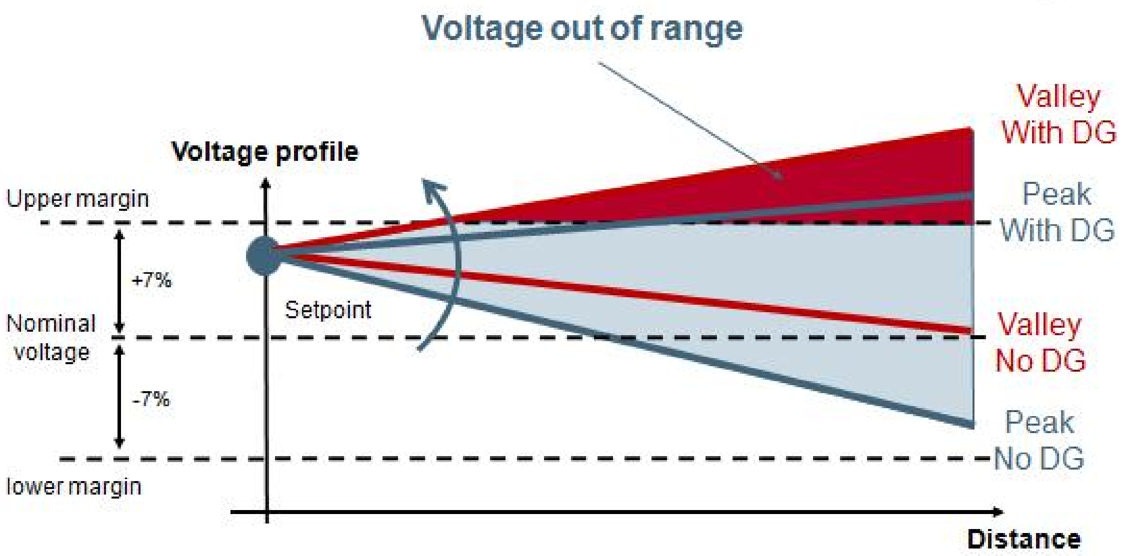


Figure 20 DG effect in the voltage triangle design

B. Active voltage management using wind generation voltage control and reactive capabilities – ESB Networks, Ireland

By 2020 Ireland will have the highest penetration of wind generation in Europe.[34] Already there is 1.8 GW installed and by the end of the current licensing, contracting and connection gate, there will be nearly 7 GW, well above Irish demand peak which is just in excess of 5 GW. Over half of this generation is connected to the distribution network, leading to challenges managing network voltages due to reverse power flows. The current policy to mitigate both thermal and voltage constraints is for full reinforcement of the network to meet all generation and loading conditions. Current operational policy, incorporated into reinforcement planning, is for all DG to operate at a constant power factor of 0.95 lagging unless otherwise specified. However this leads to reactive demands of the transmission network and may not make optimal use of available network capacity. Ultimately this static control may not always ensure voltage conditions are maintained, particularly in the absence of clearly predefined interface conditions at the TSO-DSO interface. Supplying the required reactive power required across the highly dispersed distribution network, with wind the highest wind resources in remote areas in the west of the country where there is little load, has lead the TSO to call for distributed sources of reactive power to be made available.[35]

A solution investigated by the DSO, ESB Networks, is for coordinated Volt / VAr control of clusters of wind farms on distribution networks, leveraging the decoupled active and reactive performance of modern DFIG wind turbines as are now deployed. This functional capability is as illustrated in Figure 21. The design principle is that the DSO issues voltage set points and operational sensitivity parameters ("droop" settings) to the wind farms, such that the wind farm controllers then regulate the voltage at network connection point (PCC) through varying their reactive power import or export.

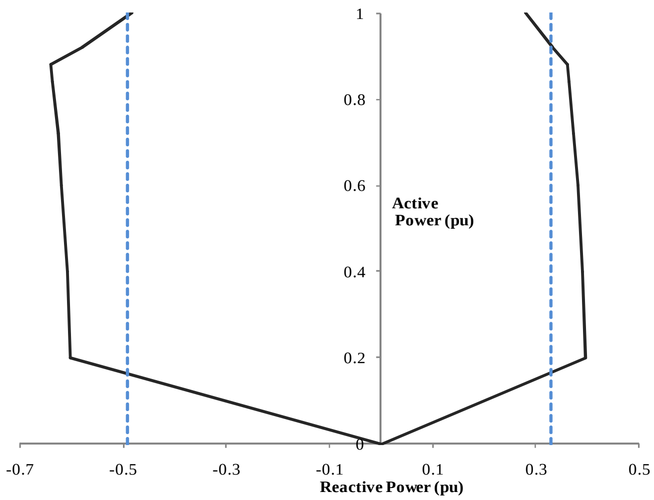


Figure 21 Wind farm active and reactive capabilities as demonstrated in ESB Networks Volt / VAr trials

The test network for these trials is as illustrated in Figure 22. To mitigate project risk, the initial field trials were on a 38 kW circuit dedicated to two wind farms, connected to a distribution substation on a dedicated transformer, isolated from the load of the substation. Initially each of the wind farms operated in constant voltage mode in isolation for a period of weeks, before the two wind farms operated in this dynamic control mode simultaneously.

The actions of the wind farm controllers, with reactive power varying to ensure that the PCC voltage is regulated were successful. During the field trials significant reactive capabilities were demonstrated. Voltage set points maintained and there was no hunting between the controllers and on-load tap changer at the substation transformer.

[34] Wind capacity according to NREAPs as a percentage of average minimum overnight summer demand plus interconnectivity in 2020 (Source: Pöyry).

[35] Eirgrid, SONI, *All Island TSO Facilitation of Renewables Studies*, June 2010.

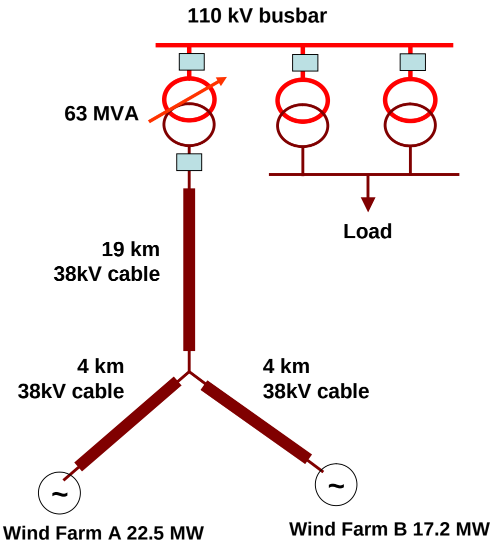


Figure 22 Test network for field demonstration of coordinated Volt / VAr Control

Analysis of the results illustrated that operating in this mode in itself can make additional capacity available on the existing networks without reinforcement, or that at times reactive power could be supplied to the transmission system or neighbouring networks if required. However, these pursuits may be mutually exclusive. Figure 23 illustrates the reactive power exported from the wind farms at a low active generation period and its unavailability when active generation is high as wind farms must operate at unity or lagging power factors for local voltage control.

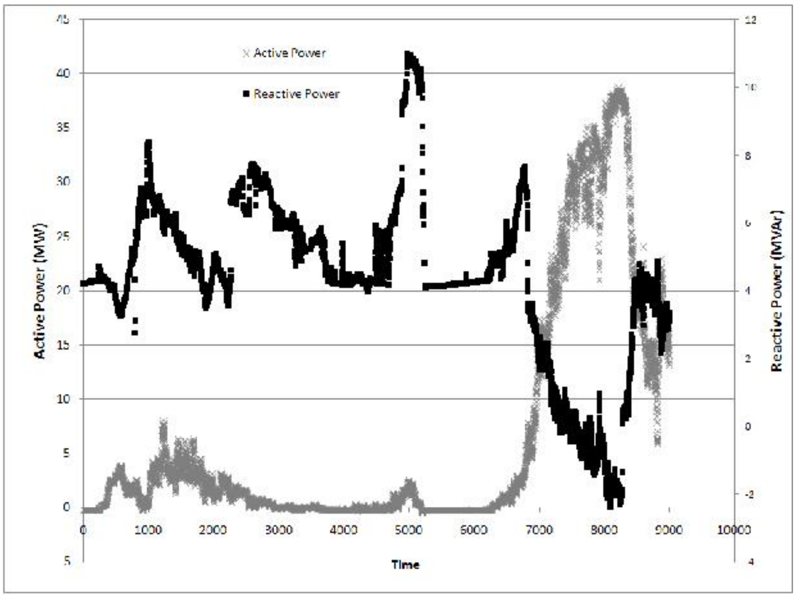


Figure 23 Active and reactive power where wind farms connect to substation - as active export increases, reactive power is imported to control PCC voltage

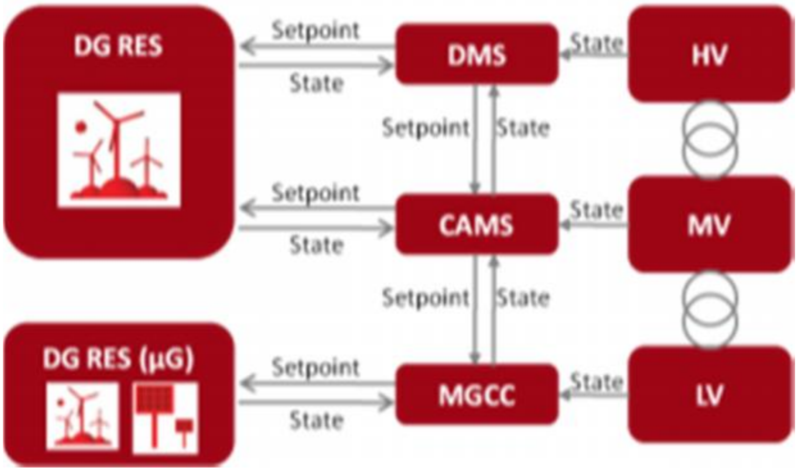
Technical trials continue. Going forward it will be vital to establish the role of wind farm reactive power and voltage control for network planning and operational purposes. Issues which require address are the relative merit of constant power factor, constant voltage or operator controlled active power implementations and the integration of any new operational framework into connection planning and DSO policy for wind integration. Additionally, establishing the operational framework between the TSO and DSO which best reflects their areas of control and responsibility and realising the operational resources required to deliver more active management of network voltage and reactive power with distributed wind generation is vital to the integration of these resources.

C. Technical Control Strategy for Active System Management – EDP Distribuicão, Portugal

A modern electric grid can be viewed as a large complex and distributed system which contains many subsystems. In a conventional electric grid, control strategies are accomplished by Distributed Management System (DMS - SCADA). However, with DMS, as a centralised control strategy, it is hard to achieve a platform-independent control for distributed generation and LV microgrids.

Therefore, besides DMS, EDP's approach introduces two new control levels:
i) Central Autonomous Management System (CAMS) and
ii) MicroGrid Control Centre (MGCC).

DMS, CAMS and MGCC systems communicate hierarchically to exchange information related to DG current state and to make the required adjustments/ tuning, based on a setpoint strategy.



DMS: Distributed Management System

The future DMS is crucial to coordinate energy flow between DSO and TSO grid. The biggest difference to the future DMS is the fact that it does not need to have direct access to the data relative to the (possibly numerous) microsources in every microgrid connected to the MV or LV network. The DMS is represented by DMS network elements that stand alone at the top level of the hierarchy. Its purpose is to guarantee system robustness by analysing data received from network elements positioned at the hierarchical level immediately below (CAMS – primary substation HV/MV). It also enforces the actions resulted from the analysis.

CAMS: Central Autonomous Management System

The CAMS answers to the DMS, under the responsibility of the DSO. Each primary substation HV/MV is a CAMS network element that is responsible for controlling and monitoring the running operations of each feeder from the primary substation and to report the overall status to the DMS and others CAMS network elements. At this level it's essential to have an overall schedule formed and the decision-making process includes the management of Distributed Generation (DG). CAMS is responsible for:

Critical but not so time-sensitive decisions;
Handle a large amount of data communication;
Coordinate with secondary substation level (MGCC) to achieve specific functions for a common goal;
Coordinate with DMS in order to control the amount of DG DER injected that can is necessary to maintain grid stability;

The decisions taken in CAMS level can give rise to a series of effects to sub-level (MGCC).

MGCC: Micro Grid Control Centre

MGCC controls and monitors all the microgrids (LV feeder) connected to a common secondary substation. A centralised control (MGCC) is a MGCC network element that is responsible for evaluating the data received from end-devices (such as smart meters). MGCC analyse the current status of microgrids and take actions in order to guarantee grid connection. Additionally, they report their overall status to the CAMS at the upper level.

There are two major smart meters type/ features for monitoring and controlling:

(i) DG smart meters: Collects information, as well as monitoring and controlling DG DER power levels and its connect/disconnect status;

(ii) Load smart meters: Aggregates all the resistive and inductive loads. It can also act over specific loads.

For example, a MGCC network element monitors the operation state of secondary substation and sends control instructions to open or close secondary substation breakers for switching between island-mode and grid-connected mode. The decisions taken in MGCC level need the most time-sensitive operations to achieve real time control of the microgrids and enhance the robustness of the power supply.

The study concludes that hierarchical control provides a flexible and cost effective way to efficiently control networks with multiple microgrids and high penetration levels of DG.

D. Protection and Automation Strategies in MV Networks – Enel Distribuzione, Italy

The objective of Isernia project (Molise region of Italy) is to test, on the field, an innovative model for the protection, automation and management of power generation in the distribution network. It aims at **efficient integration of renewable energy sources into the distribution network** (the geography and climate of Isernia offers the perfect setting to fully exploit solar, hydroelectric and biogas) while maintaining a reliable and safe management of the system under real operating conditions. The Isernia project has recently won a competition-based procedure launched by the Italian regulator (AEEG) granting incentives to innovative smart grids pilot projects. The **project offers a new approach to distributed generation management** which monitors the active involvement of both distributors and customers, recognized as prosumers (producer-consumers) of energy.

Monitoring occurs through a broadband connection, based on a Wi-Max communication protocol and a fibre optics communications infrastructure which depend on the remote management system implemented in the territory with the electronic meter.

The project will be developed around the primary cabin in Carpinone and will include the **installation of nearly 8.000 'Smart Info' devices for customers** connected to the low voltage grid. The devices will supply information about changes in the price of energy based on time slots, promoting efficient use and increasing active customer participation in the management of the system. The project also includes the **installation of a charging station to power a fleet of five electric vehicles, integrated with a photovoltaic plant** and a multi-functional storage system. The storage system may also be used for the management of medium voltage lines, or peak shavings and load profiling, and will be able to replace the charging system or receive energy directly from the photovoltaic plant.

- **Project period:** 3 years, from 2011 to 2014
- **Investment:** nearly 7 million euro.

E. Integration of RENEWABLES in MV and LV Networks – E.ON Bayern, Germany

As shown already in the beginning of this report Bavaria features an extensive amount of renewable energy generation, esp. small-scale PV. These renewable generators are mainly (ca. 80%) directly connected to the LV grid. In Figure 24 the vast amount of renewable installations in the E.ON Bayern grid is shown.

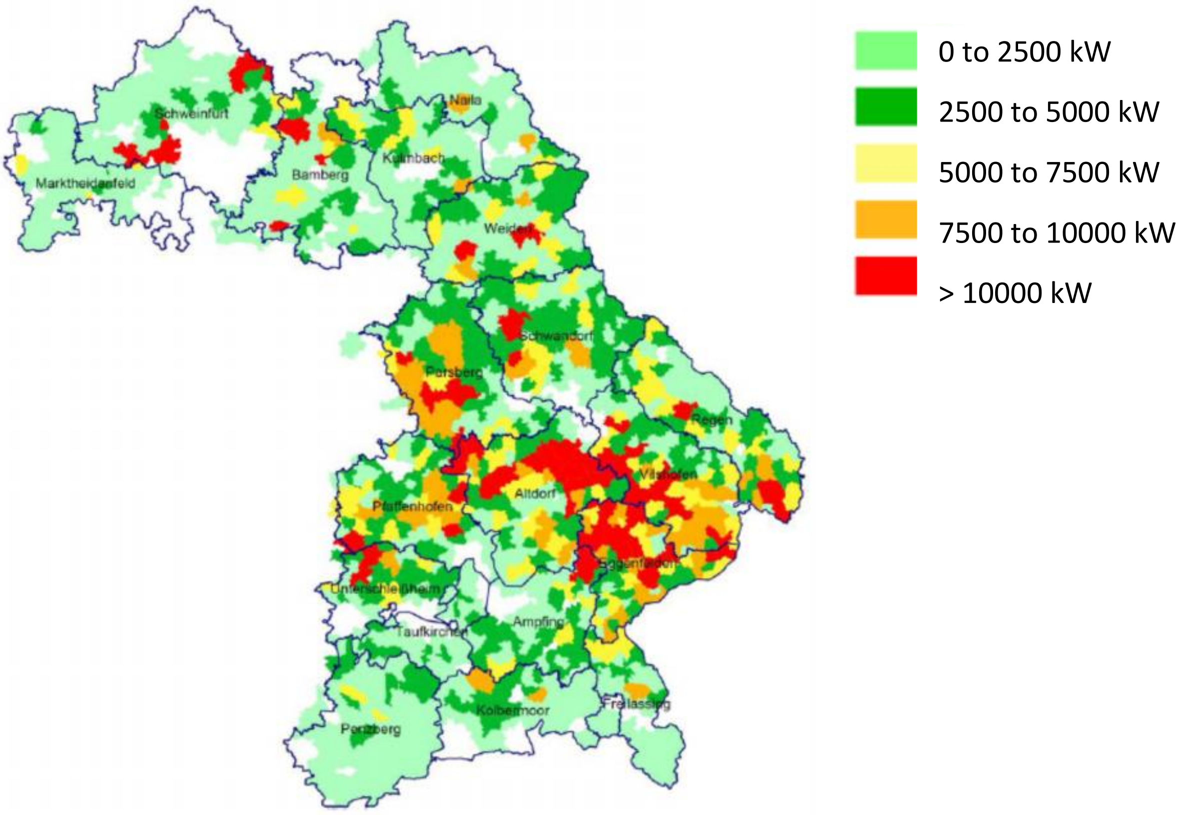


Figure 24 Hot spots areas in E.ON Bayern (installed RES capacity in EBY grid areas)

E.ON has selected one of the most affected networks areas in lower Bavaria with high amounts of PV installations to analyse the effects on the network, develop and test new grid solutions, the E.ON Bayern Smart Grid project. More than 100 power quality measurements were installed and more than 500 load profile meters were equipped with an additional power quality module. This setup was used to first of all create the basis for real-life analysis of PV integration, as currently all research activities in that field of technology are based on network simulations. Another project looks into what it means to have not only PV connected, but also heat pumps, e-vehicles, small-scale batteries etc. and how load curves are changing and what this means to currently existing network tariff system and planning standards.

New power grid technologies enhances grid utilisation

The new power grid technologies being developed, meaning controllable substation transformers, reactive power management (Power Factor – Voltage and Reactive Power – Voltage), inline voltage controllers, power quality measurements for LV networks and new load and generation profiles are enhancing the utilisation of the existing network and therefore reducing the grid reinforcement need. **Controllable substation transformers** (rONTs) help to minimise issues with voltage band violations. It is especially in rural networks with long radials and RES feed-in that higher than allowed voltage band violations can occur. In the past the generators connected to this radial would just shut-off due to too high voltages. The controllable substation transformer equipped with an on-load tap changer is now capable to stepwise increase the transformation ratio and thus lower the voltage along the radial. In case of lower generation or higher consumption the transformation ratio is automatically modulated and thus the voltage band stabilised. Within this Smart Grid project the use cases and control concepts for such transformers have been developed with special focus on autonomous single-type installations. A further project is looking at Integration of wind into grids investigating the differences between the integration of wind and of PV into the MV/LV networks (i.e. where do we need to have control over the voltage band and what is the coincidence factor for the different renewable sources).

Test of reactive power control service

Along this Smart Grid project E.ON investigated the use of **reactive power management** to lower the voltage lift in the LV network. A study analysing the reactive power – voltage control of inverters was performed, and E.ON is now analysing the results in real-life together with customers providing a reactive power control service with their PV installations. This real-life test is also taking into account any reciprocal effect on the rONTs. Currently the use of reactive power is limited to bi-lateral contracts as no market place for such provision exists. A further project is looking at reactive power management towards upstream grid operator (with the increasing feed-in of reactive power into the LV grid the limit between DSO and upstream grid operator is also experiencing more reactive power flow).

German feed-in-management regulation

Furthermore the recent adoption of the German renewable law allows the DSO to curtail generation as of certain capacity (CHP >100kW; PV >30kW) in case of congestions in the grid as a first step before grid enhancement. The generators are compensated with 95 % of lost income (loss for generators limited to 1 % of annual income).

Currently mainly voltage band violations caused by PV feed-in are occurring. With the implementation of sophisticated measures like rONTs and reactive power management it is foreseen that voltage band violations will be minimised, however overloads at substations will still occur. As the grid extension works are not as fast as the RES increase, intermediate measures are taken. One example is **feed-in management**. Here all customers with PV installations are by law asked to install remote control systems or generally curtail their production to 70% installed capacity. In case of PV the remote control is mainly executed by a traditional ripple control system at smaller installations or a telecontrol solution at larger generators. In case of a grid congestion the DSO will first curtail all non-renewable generation, then it is possible to curtail the renewable feed-in via e.g. a ripple control signal to small-scale generators in the vicinity of the congestion. Larger generators are controlled directly using telecontrol signals and the impact is directly measured via read-back signals.

Key conclusions

All of these technologies as well as the increased visibility of the LV network lead to new ways for detailed modelling of feed-in and load behaviour as basis for grid simulation and grid design, more feed-in of RES into not only the Bavarian networks, but throughout E.ON in Germany, refined specifications for generator capabilities (i. e. PV inverters) as well as requirements for internal data quality and the systems handling network connection data. A cost optimal solution is in most cases a mixture of traditional grid reinforcement measures together with intelligent power grid technologies like e. g. the rONT, and active management of the PV generation with reactive power control as well as active power feed-in management as a PV generator service to the DSO. Provision of these services shall be unbundling-compliant and may be provided via a smart market where the DSO is able to purchase such services.

Annex 3 – Survey Results

A. Automation and Control in MV & LV Distribution Networks

Proportion	0%	0-25 %	26-50 %	51-100%
Implementation level	0	Low	Medium	High

MV

Country	Company	Proportion of substations with monitoring and control to MV busbar		Proportion of MV networks with remote down line monitoring					Proportion of MV networks with remote down line control		Proportion of MV networks with automated protection / fault sectionalisation	
		2010	Projection for 2020	2010	Projection for 2020	All phases?	Time Granularity?	Real-time update or only reports to SCADA when set criteria breached?	2010	Projection for 2020	2010	Projection for 2020
Belgium	Synergrid	High	High	Low	N.A.	Yes	N.A.	Real time	Low	N.A.	Low	N.A.
France	ERDF	Very high	Very high	Very high	Very high	No	A few seconds	Real Time	Very high	Very high	Very high	Very high
Ireland	ESB Networks	Very high	100%	High	Very high	Not yet but becoming a priority	A few seconds	Real time update (subject to variation in excess of pre-set dead band)	Low / medium (approx. 20%)	Very high	Low / medium (approx. 20%)	High
Italy	Enel	High	High	High	High		On call and at every change of state.	Real time update	High	High	High	High
Portugal	EDP	High	High	Low	Medium	Yes	real time at primary substation level	Only reports to SCADA when set criteria breached	High	High	Low	High
Spain	Union Fenosa Distribution	High	High	Medium	High	Yes, in secondary substations, at LV	Less than one second on demand. Every hour, batch process	Not decided yet	Medium	Medium	Low	Medium
Sweden	Fortum	High	High	Low	Medium	Yes	On line	Only reports to SCADA when set criteria breached	Low	Medium	Low	Medium
UK	Electricity North West	High	High	Low	Low	Yes for newer installations	Sub one second on demand; 30 mins normally	To be decided. Currently continuous SCADA reporting	Low	Medium	Low	Medium

MV/LV Transformers

Country	Company	Tap changer in a standard model?	Do only some models have a tap changer? In what situation? (urban/rural deployment)	Proportion of MV/LV substations with remote monitoring		Proportion of MV/LV substations with remote control	
				2010	Projection for 2020	2010	Projection for 2020
Belgium	Synergrid	Yes but offload operation only	no	low		low	
France	ERDF	Very high (off load operation)	All MV/LV transformers have a tap changer (3 taps, 5 for some old models)	Low	High	Low	Medium
Ireland	ESB Networks	No	None that are currently deployed.	None (except for potential pilot project under development)	Depends on developing needs and cost benefit	None	Low unless clear necessity or cost benefit arises.
Portugal	EDP	Yes but off load operation only	All	Low	Medium	Low (< 10%)	Medium
Spain	Union Fenosa Distribution	Yes but off load operation only	All MV/LV transformers have tap changer (5 taps)	Low	Medium	Medium	Medium
Sweden	Fortum	Yes but off load operation only		Low	Medium	Low	Low
UK	Electricity North West	Yes but off load operation only	All distribution TXs have tapchanger. 33 kV/11 kV and higher voltages are on load and automatic	Low	Low	Low	Medium

LV

Country	Company	Proportion of LV Monitoring or Control					
		2010	**Projection for 2020**	**Only on Circuits with Load and Generation?**	**What Communication Media is in Use? RTU, Fibre, Polling Radio, GPRS etc.**	**Are the networks controlled locally with decentralised intelligence (by use of local automation systems) or centrally by SCADA system?**	**Who owns communications RTU at DG site at each connection level (trans / dist / HV / MV / LV) – generator, TSO or DSO?**
Belgium	Synergrid	0 (negligible)	N.A.	N.A.	N.A.	N.A.	N.A.
France	ERDF	Low (only in test areas with smart meters)	High	No	PLC + GPRS	Neither at LV	HV : TSO MV : Generator LV : no RTU
Ireland	ESB Networks	R&D deployments only	Medium depending on framework for specific smart meter integration	No	At present GPRS, though trials of PLC, meshed radio and WiMax under way or completed.	Neither at LV	HV transmission TSO HV distribution – code defines this should be DSO MV – code defines this should be DSO LV – no RTU. Only monitoring is with meter (DSO owned)
Italy	Enel	High (if you include the smart meters) otherwise low	N.A.	No	GPRS, PLC	centrally	MV - DSO LV no RTU
Portugal	EDP	Low	Low for most of the grid. However, EDP is deploying smart grids initiatives with high monitoring capabilities	All kinds of circuits included in the geographical areas involved in smart grids initiatives	PLC + GPRS (and RF Mesh pilots)	Objective: Decentralised at secondary substation	HV: EDP; FlexNet (IP/ MPLS project with an telecom operator); MV and LV: GPRS from a public carries
Spain	Union Fenosa Distribution	Low	Low	No	At primary substations, fibre (52%), carrier (39%), VSAT (5%), radio (4%) At secondary substations, Carrier (72%), Carrier (3%), GSM (25%)	Centralised by SCADA systems	A combination. DNO owns some, and where not, use public 3G service
Sweden	Fortum	High	High		Primary Substation: RTU, fibre, satellite polling radio, copper cable Secondary Substation: Copper cable Smart Meters: 90 % GPRS; 10 % PLC Primary Substation: RTU, fibre, satellite polling radio, copper cable Secondary Substation: Copper cable Smart Meters: 90 % GPRS; 10 % PLC	Centrally by SCADA - primary substation, decentralised intelligence in Stockholm area	DSO
UK	Electricity North West	Low	Low	No	Mainly GPRS, 3G	Centrally by SCADA	Mixture. DNO owns some, and where not, use public 3G service

B. Curtailment of Distributed Generation

Country	Curtailment for DG RES connected to distribution*	Who is allowed to curtail?	As of which capacity?	Compensation of curtailment
Austria	Not allowed	Not defined	x	N.A.
Belgium	Yes for all plants in case of security issues. Currently no legislation on curtailment in case of congestion – but there are some pilot projects : when the producer accepted contractually to be curtailed (current alternative to a deny of contract)	Only DSO (or TSO if DG connected to transmission). If congestion at TSO network level, the TSO will send the order through the DSO via SCADA	Under discussion – legally possible as of 250 kW	Under discussion – currently no compensation
France	All plants in case of system security events (transmission level). Only some plants in case of congestion on the distribution grid.	Curtailment orders are always sent by DSO	> 1MW and case by case for plants < 1MW	No compensation for curtailment due to system security needs.
Germany	Yes, plants above certain size can be curtailed in normal operation, all plants in emergency at both transmission or distribution level	DSOs have the control for events of congestion on their grid, TSO for congestions on their grid	CHP > 100kW; PV > 30kW	Yes, compensation with 95 %of lost income in case of congestion in DSO grid
Ireland	Only in case of system security events (transmission level), not distribution	Only TSO is allowed to curtail the relevant DG RES (SCADA signal from TSO control centre to wind farm)	> 5MW	Yes as though delivering their full available capacity at the time (at market price at the time)
Italy	Only in case of system security events (transmission level), not distribution events	Only TSO is allowed to curtail the relevant DG RES	> 10MW	Wind Farms yes as though delivering the energy which has been curtailed, at market price (excluding incentives/certificates).
Portugal	Only in case of system security events at both transmission or distribution level; Micro generation: If voltage deviates more than 10% a protection at injection point actuates. Reconnection is done after some time if voltage level ay injection point is normal	DSO has control over protection settings (automatic curtailment in case of deviation from defined ranges)	x	Yes as though delivering their full available capacity at the time
Spain	Only in case of system security events at either transmission or distribution level	Only TSO is allowed to curtail the relevant DG RES; DSO to ask TSO in case of constraints in distribution grid	x	Constrained wind generators are paid 15% of the wholesale electricity price. There's no compensation for the curtailed generator. The curtailment should be justified.
Sweden	Only in case of system security events (transmission level), not distribution (?)	DSO has control over protection settings (automatic curtailment in case of need) DSO has control over protection settings (automatic curtailment in case of deviation from defined ranges)	x	No compensation for curtailment due to system needs.
UK	Only in case of system security events at both transmission or distribution level	TSO has commercial agreements with larger DG. DNO can curtail if in connection contract	TSO > 100MW	Yes if subject to TSO constraints, through the national balancing mechanism. No compensation for DNO constraints.

* Curtailment compensation scheme: Contract or agreement in place to compensate lost generation from RES, because of curtailments. This contract or agreement might refer both to the level of compensation received (how much) and the identification the parties involved (who receives the money and who pays).

Glossary

Ancillary services are commercial services procured by system operators (the TSOs and the DSOs) from network users. Ancillary services procurement is one of the tools that enable system operators to ensure the security of supply and quality of service of the electric system.

CLS – Controllable Load Systems are connected to the electricity grid and can be used as either energy source or drain in order to balance supply and demand. Therefore CLS can be disconnected and reconnected to the grid or their load can be increased or decreased. Preferably the CLS reacts automatically to price signals. Examples are electric vehicles (EV) and Renewable Energy Sources (RES) like photovoltaics or wind generators.

Demand Response includes the changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time. Demand response can also be defined as the incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardised. Demand response includes all intentional modifications to consumption patterns of electricity of end-use customers that are intended to alter the timing, level of instantaneous demand or the total electricity consumption.

Demand Side Management (DSM) is used with the aim to reduce energy consumption and improve overall electricity usage efficiency through the implementation of policies and methods that control electricity demand. DSM is usually a task of power companies to reduce or remove peak load, hence deferring the installation of new capacities and distribution facilities. The commonly used methods for demand-side management are: combination of high-efficiency generation units, peak-load shaving, load shifting, and operating practices facilitating efficient usage of electricity.

Distributed energy resources (DER) include distributed/decentralised generation (DG) and distributed energy storage (DS)[36].

Distributed/decentralised generation (DG) are generating plants connected to the distribution network, often with small to medium installed capacity, but important due to high numbers compared to the “size” of the distribution network. In addition to meeting on-site needs, DG exports the excess electricity to the market via the distribution network. It is often operated by smaller power producers or so-called prosumers.

DMS – Distribution Management System typically enables the DSO to supervise and control MV and LV networks. This allows the DSO to be able manage distributed renewable generation, to implement grid efficiency improvement measures, and to control the isolation and restoration of outages. With DMS, real-time information about the distribution grid and connected users is available. It is an important component for the DSO to guarantee distribution grid reliability.

Distribution system services are services provided by network operators to users connected to the system in order to ensure required power quality (and the stability of the distribution grid). They are paid by the grid users, in most cases via the tariffs.

Network access is the ability to make use of that physical connection in a non-discriminatory way.

Network connection is used in a technical context and relates to the physical connection to the system.

[36] Distributed energy storage is not only a resource but also an “off take/load”.

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ELECTRICITY FOR EUROPE

Union of the Electricity Industry - EURELECTRIC

Boulevard de l'Impératrice, 66 boîte 2
1000 Brussels
Belgium

T.: + 32 (0)2 515 10 00 - F.: + 32 (0)2 515 10 10
website: www.eurelectric.org
twitter.com/EURELECTRIC

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