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CONTROL AND AUTOMATION SYSTEMS FOR ELECTRICITY DISTRIBUTION NETWORKS (EDN) OF THE FUTURE

CIGRE/CIRED JOINT WORKING GROUP

C6/B5.25/CIRED

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CONTROL AND AUTOMATION SYSTEMS FOR ELECTRICITY DISTRIBUTION NETWORKS (EDN) OF THE FUTURE

JWG C6/B5.25/CIRED

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EXECUTIVE SUMMARY

The CIGRE C6 Study Committee (Distribution Systems and Dispersed Generation) considers the different aspects of integration of distributed generation. In this context, the JWG C6/B5.25/CIRED has worked to map current functionalities and to identify future needs for the automation at the interface of transmission system operator (TSO) and distribution system operator (DSO) to empower the use of distributed generators (DERs) at system level.

The prevalence and continuing increase of renewables - especially on distribution level - is progressively changing the dynamic behaviour of both transmission and distribution networks. Therefore, there is a need to be able to better characterize this behaviour from the point of view of the TSO and for the DSO to start managing the present generation. Furthermore, since the distributed generation is generally interfaced with the network through static conversion systems, it has reduced the share of production from other conventional forms of generation, such as thermal generation. This causes a reduction of units providing system ancillary services, especially on TSO level. This reduction will aggravate in the future and therefore will require new TSO-DSO agreements to take advantage of the potential of distribution-level resources like DERs and Demand Side Response (DSR) to cover the deficit in these services.

The TSO has full responsibility for system security and coordination of ancillary service provision on transmission level. The DSO is responsible for continuity of service in distribution networks. This means that the TSO will continue to have the primary responsibility for coordination of balancing, frequency control and system recovery. The DSO will retain responsibility for management of distribution networks with greater emphasis on congestion and voltage control.

The definition of roles and responsibilities of all actors of at the TSO/DSO interface - not only for network operators, but also for electricity market participants - has highest priority for achieving improved coordination at the TSO-DSO interface. In this context, it is getting ever more important to improve observability on distribution level and to suitably share related relevant information among system operators and market participants. This necessity is underlined by the changes to be anticipated from emerging technologies such as electric vehicles and storage systems. Improved observability not only helps network operators to maintain a good level of service continuity but it also reduces errors in forecasting demand and limits the growth of reserves caused by the uncertainty of variable renewable energy.

In addition to improvement of observability, active power management of DER and DSR is increasingly important. It is required to solve the problems of congestion at both the transmission and distribution level, but also to maintain the frequency within the predetermined values to secure the overall system. The active power regulation of the TSO and DSO impacts all network levels, as just seen.

In the context of high penetration of variable renewables, technical and functional interoperability between distribution and transmission systems is particularly important for ensuring service quality and system reliability.

Improvement of observability, predictability and controllability at the TSO / DSO interface is essential for:

- improving the prediction of load and generation at the primary distribution level;
- improving the capacity of hosting to connect additional variable renewables (VR) while maintaining the reliability and quality of the system;
- increasing communication between automation systems of TSO and DSO.

At transmission level, there is a strong need for greater observability and knowledge of the distribution network and greater involvement of distributed energy resources in all processes related to the management of the electricity system, such as voltage regulation.

For these reasons, the JWG has worked to identify the level of automation that is available at present, and the most significant functionalities that DSOs must adopt to properly manage the TSO/DSO interface.

The survey carried out during this JWG has shown that DSOs throughout the world are conducting different tests to move from a "blind" exercise of the network to a more and more monitored and controlled one. For responding DSOs, the most promising functionalities are dynamic rating for feeders and transformers and distribution state estimation.

These functionalities represent the building blocks to provide sufficient flexibility and observability of the distribution network to provide network services to TSO.

Further there is a clear understanding that the TSO/DSO interface automation and functionalities are heavily affected by market and regulation in the different countries.

CONTENT

FIGURES AND ILLUSTRATIONS

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1. SCOPE OF THE DOCUMENT AND TERMINOLOGY

The CIGRE C6 Study Committee (Distribution Systems and Dispersed Generation) considers the different aspects of integration of distributed generation, such as distribution system operation and planning, demand management and active customer integration. In this context, the JWG CIGRE C6/B5.25/CIRED is set up to identify the control and automation systems for electricity distribution networks of the future. The increasing diffusion of not programmable energy sources, the forecasted forthcoming diffusion of distributed energy storage systems (ESS) and the active participation of demand will characterise the Electricity Distribution Networks (EDN) in the next years. EDN will have to provide secure and reliable power adequate to the digital age. Control and automation systems operate control and coordinate the behaviour of devices and systems that support operation of EDN. Centralised control functions and local control functions (e.g. governing active customers, distributed generators, microgrids and Virtual Power Plants) will have to coordinate their operation taking into account not only "internal inputs" coming from EDN monitoring and protection systems, but also "external inputs" coming from Electricity Transmission Networks (operated by the TSO) and the forthcoming "smart world" (i.e. smart cities including interactions with district heating, cooling and water supply systems, smart transports, smart industries, smart customers etc.). The processing of all such inputs coming from different sources will still be subordinated to the possibility for Distribution Companies to operate EDN under their ultimate responsibility.

In this context, the C6/B5.25/CIRED Working Group (WG) is specifically focused on:

1. Definition of Control and Automation Systems for EDN of the future: boundaries, constrains, possible architectures etc.
2. Survey on the current state of the art and expected requirements for the Control and Automation of EDN (a questionnaire has been sent to distribution companies)
3. Needs for interfacing EDN control and automation systems with control and automation systems of the transmission network and systems like EDM (Energy Data Management) and PFM (Portfolio Management) for exchanging market prices (dynamic tariffs for end-user) and balancing group information (schedules)
4. List of control and automation functions relevant for the EDN operation in the new scenario (e.g. coordinated control of distributed generators and ESS; interface with system protections including islanding management; voltage and frequency control by active and reactive power management; etc.)
5. Requirements for the architecture of control and automation systems for future EDN (e.g. hierarchical, centralised, distributed, local control; etc.)
6. Communication requirements for control and automation of future EDN (e.g. protocols and information systems for a seamless data exchange; security; privacy; etc.)
7. New technology for control and automation of future EDN (e.g. control of power electronics at all voltages; etc.)
8. Roadmap for the evolution towards EDN of the future (The 2030-2050 vision)

The Working Group originates from the work done by WG C6.11 (Development and Operation of Active Distribution Networks); WG C6.15 (Electric Energy Storage Systems); WG C6.20 (Integration of Electric Vehicles in Electric Power Systems); WG C6.21 (Smart Metering – state of the art, regulation, standards and future requirements), WG C6.22 (Microgrids), and WG C6.09 (Demand Side Management and Demand Response), WG B5.34 "The Impact of Renewable Energy Sources and Distributed Generation on Substation Protection and Automation and coordinate with ongoing B5.43 "Coordination of protection and control of future networks". International Standards and standardization roadmaps have also been considered.

2. SURVEY ON DSO AUTOMATION

In recent years, distribution utilities have started to evolve their passive distribution grids towards actively controlled networks, which can incorporate significant levels of distributed energy resources (DER) in an efficient and cost-effective manner. In some cases, these efforts have led some utilities to re-engineer their automation processes by adding the necessary procedures, methods and tools to support the development of active distribution networks.

Automation and control levels necessary to operate distribution networks with large penetration of Distributed Energy Resources (DERs), as seen from both TSO and DSO viewpoint, are the focus of this Working Group. The existing and expected information flow between TSO and DSO to enable new services and functionalities is also dealt with by the WG.

A survey was conducted to identify the development level of DSO automation and the necessary developments for improved **TSO and DSO integration**. Moreover, this report elaborates on the existing issues and barriers identified by respondents that constrain the development of active distribution network automation.

2.1 SURVEY DESIGN AND RESPONDENTS

A thorough survey was developed consisting of a total of 50 questions covering the following subject areas:

1) General Distribution Network Size Information
2) Control and Automation Systems at the MV (< 100 kV) Level
    a) MV Feeder Monitoring
    b) Monitoring and Control of DER connected at the MV level
    c) MV/LV Substation Monitoring
    d) Advanced Automation at the MV Level
    e) Fault Location Isolation and Service Restoration (FLISR)
3) Control and Automation Systems at the LV (< 1 kV) Level
    a) Monitoring and Control of LV Connected DER
    b) LV Feeder (or Secondary Network) Monitoring
    c) Automation at the LV Level
4) List of Control and Automation Functions
5) Communication Requirements
6) Data exchange between TSO and Markets
7) New Functionalities for Control and Automation of Future EDN
8) Other activities, regarding interaction with the TSO during distribution network operation

The survey starts from the standard level of network automation and common activities, and then expands into other activities relevant to distribution network monitoring and control.

A total of 36 survey responses (28 complete and 8 partial ones) have been received, representing many different energy companies across geographical regions of Oceania, North America, South America, Eastern Europe, and Western Europe. Additionally, the participants represent a wide range of varying DSO operating footprints and DER interconnection levels (see the respondents' statistics tabulated in TABLE 1).

TABLE 1. Summary Statistics of Survey Respondents

Percentage of respondents indicating operating high voltage (69 to 230 kV) systems	71%
Total annual consumption values per DSO as reported by survey respondents (annual GWh)	Min 15 Avg 27707 Max 517148 Total 914,336
Total length of all distribution lines per DSO as reported by survey respondents (total length in km)	Min 38 Avg 60,370 Max 743,298 Total 1,569,663
Total of installed distributed generation (MW) per DSO as reported by survey respondents	Min 0 Avg 4,690 Max 88,000 Total 164,100

A binary analysis was used to evaluate the questionnaire responses and to determine at what extent automation is used, at present, in the electrical industry. The survey results have been analysed by the task force and are intended to inform the other task forces for further analysis as well as to serve as a benchmark against which the transition towards active distribution systems [B1] may be assessed.

2.2 MAIN HIGHLIGHTS OF SURVEY RESULTS

The majority of the DSOs that responded to the survey report the use of SCADA. Furthermore, around 60% of the respondents reported the presence of a DMS (Distribution Management System) in operation in their network.

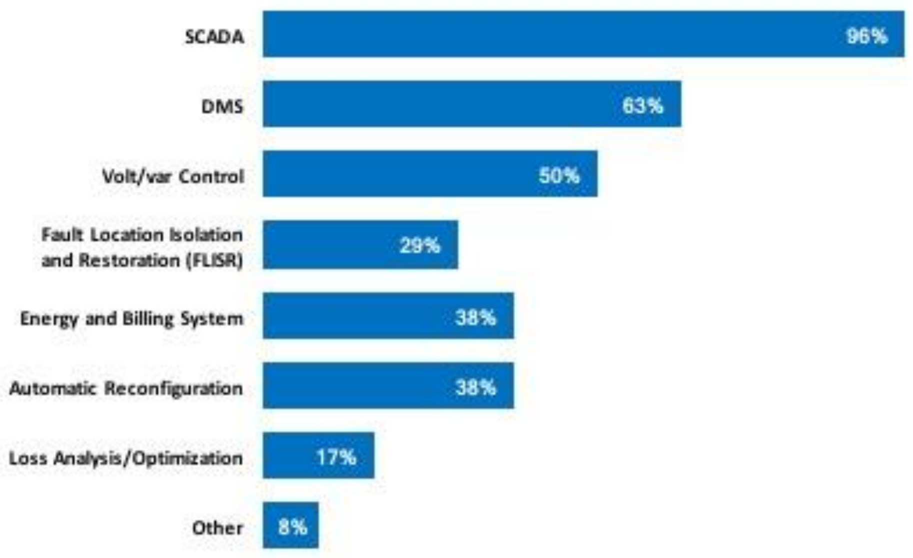


Figure 1 - Existing Reported Automation Functionalities

For the majority of DSO, current practice concerning the TSO–DSO interface is based on a manual interaction on demand. Results show that DSOs across the world are conducting different tests to move from a “blind” operation of the network to a more and more monitored and controlled one.

Advanced automation features that the DSOs reported as being currently implemented or planned are reported in Figure 2 – with nearly 50% or more of respondents indicating forecasting and dynamic ratings.

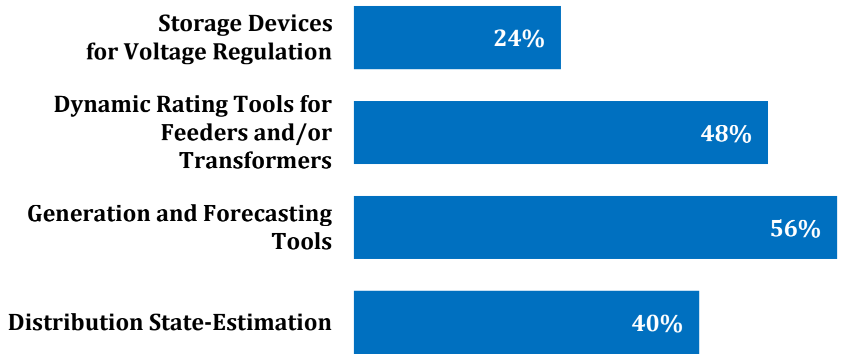


Figure 2 - Planned or Currently Implemented Advanced Automation Functionalities

2.3 SURVEY RESULTS

Each typical DSO monitoring and control activity was assessed through questions related to the development of Active Distribution Networks. Summary results for each topic are reported below and grouped by activity. The following key points are highlighted here:

- Almost all respondents indicated having SCADA systems (see Figure 1). Furthermore, around 60% of the respondents reported having Distribution Management System in operation in their network.
- For many DSOs, current interactions at the TSO–DSO interface are manual in nature (see Figure 16).
- Nearly 50% or more of respondents indicated dynamic ratings and forecasting, respectively, among the advanced automation features being currently implemented or planned (see Figure 2).
- Very little monitoring and control is currently employed at the LV portions of the system.

2.3.1 Control and Automation Systems at the MV (< 100 kV) Level

As expected, respondents indicated feeder monitoring, at the MV level, to be performed with a quite high sampling rate. In fact, over 70% of respondents indicated a sampling rate of one minute or less (see Figure 3). In contrast, DER connected at the MV level is monitored very differently across the responding utilities (see Figure 4). Even though none of the respondents provided a specific sizing criterion, there was a clear indication (nearly 80% of respondents) that monitoring and control of DER was a necessity at the MV level.

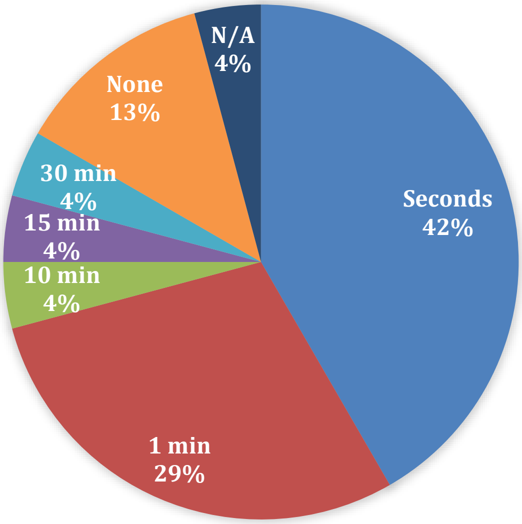


Figure 3 - Sampling Rate for MV Feeder Monitoring

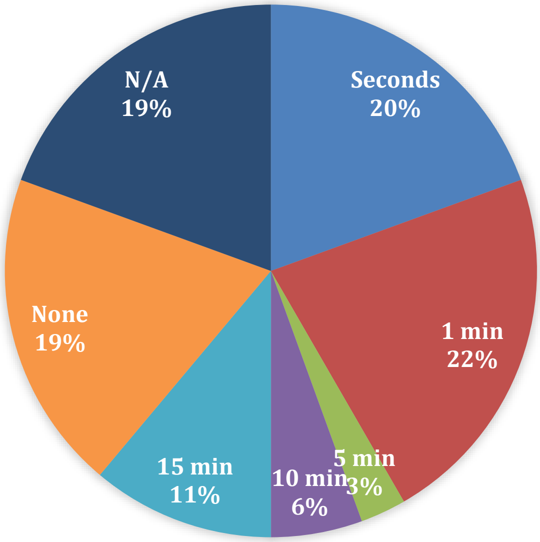
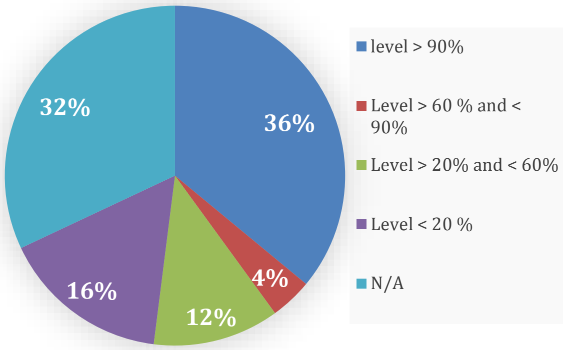
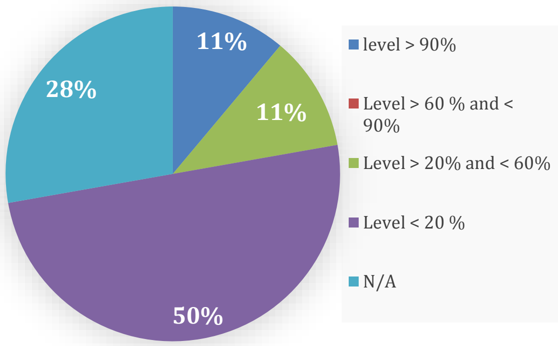


Figure 4 - Sample Rate for Monitoring of DER at MV level

As indicated in Figure 5, the reported level of network automation and MV/LV substation monitoring varied greatly between the participating utilities. More relevant to the high penetration of DER, only 40% of respondents indicated much of their network is currently automated, and less than 11% replied that they had monitoring in place at many of their MV/LV transformers. However, it is important to recognize that the degree and type of automation deployed may vary significantly among those respondents that report a large percentage of their network to be automated. Furthermore, where monitoring is deployed in the MV/LV substation, multiple system states tend to be monitored, with voltage and current being the most common (see Figure 6).





(a) (b)

Figure 5 - Level of Automation (a) and MV/LV Substation Monitoring (b) among Participants

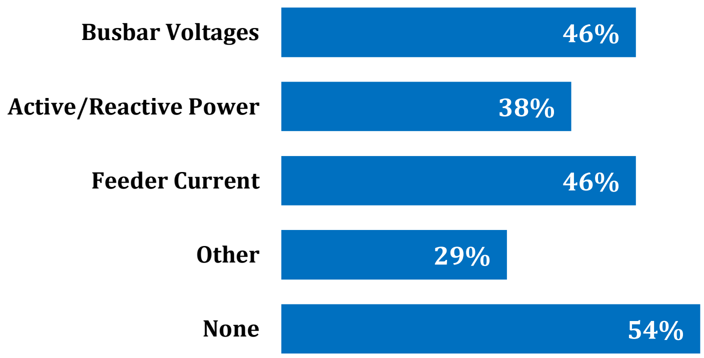


Figure 6 - Monitored System States at MV/LV Substations

Based on the survey results, network management systems are in operation at the MV level in all networks with different level of deployment, see Figure 7. The automation used is different, but most of respondents confirmed the use of reclosers and Load Tap Changers (LTC). Automated capacitor banks are much less common among the respondents and capacitor switch only used.

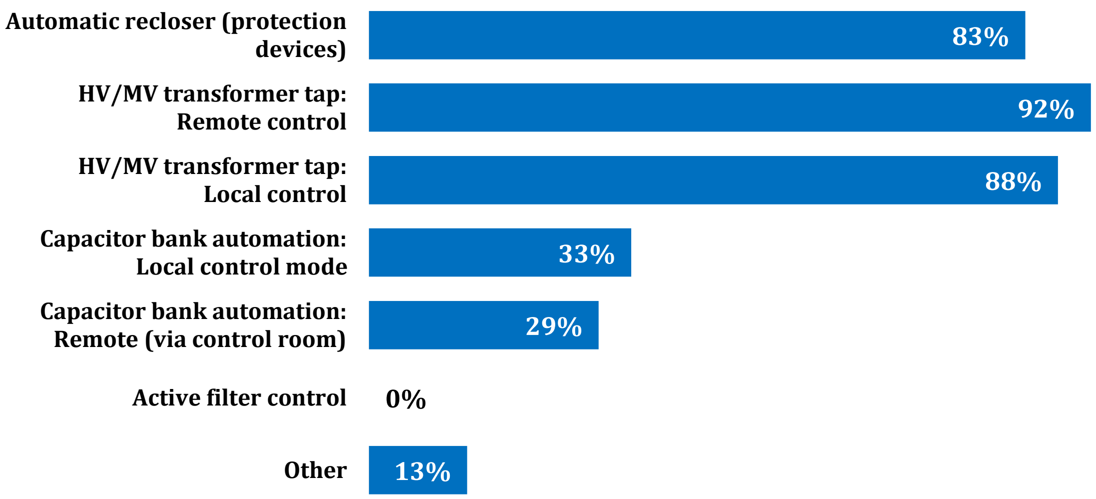


Figure 7 - Deployed Automation Types for Network Management

2.3.2 Control and Automation Systems at the LV Level (< 1 kV)

As expected, the level of automation in LV networks is comparably lower than in MV systems. The automation in terms of control and monitoring of installed LV DER is quite different among the utilities and there is a tentative indication that 30 – 100 kW may be a minimum basis for installation of DER control. However, there is not a clear consensus as only approximately 25% of the survey respondents currently monitor or control LV DER (see Figure 8). While not shown here, similar conclusion can be drawn for monitoring at the LV level as less than 40% of respondents declared they monitor LV feeders or include AMR in their operations.

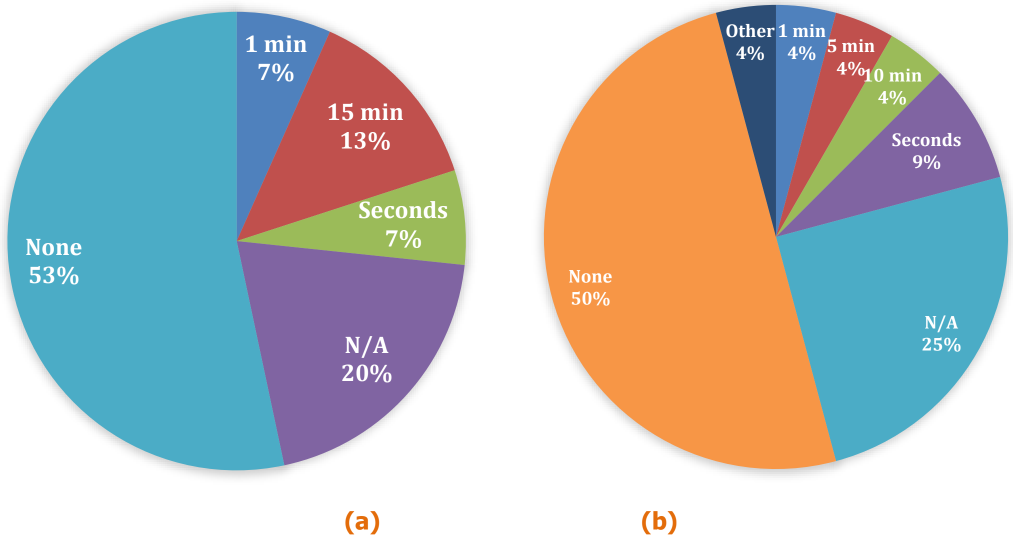


Figure 8 - Current Level of (a) Monitoring and (b) Control of DER deployed at the Low-Voltage Level

Based on the survey responses, a strong correlation between the level of DER penetration and the inclusion of AMR for operations purposes was not seen; respondents with both high and low DER penetration provided similar responses, see Figure 9. Here, "low" and "high" penetrations were defined as a value above or below 0.2 of the ratio between the annual energy consumption (GWh) and the installed DER (MW).

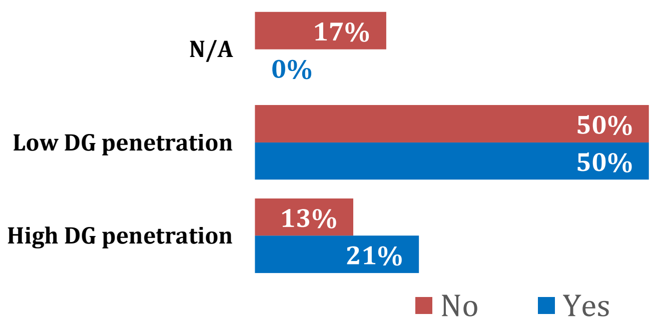


Figure 9 - Use of AMR for Operational Purposes

Application of advanced automation functions at LV levels is also quite low as reported in Figure 10.

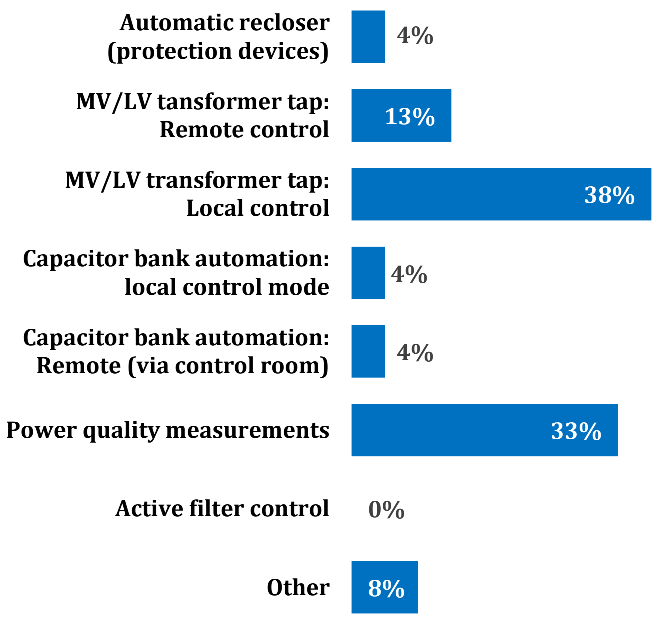


Figure 10 - Level of Advanced Automation at the LV Level

2.3.3 Control and Automation Functions

In response to the relevant DSO functionality questions, all respondents indicated the presence of SCADA systems, but only 60% responded that they have a Distribution Management System (DMS). Moreover, other advanced functionalities of network operation and optimization are present in less than 40% of the networks.

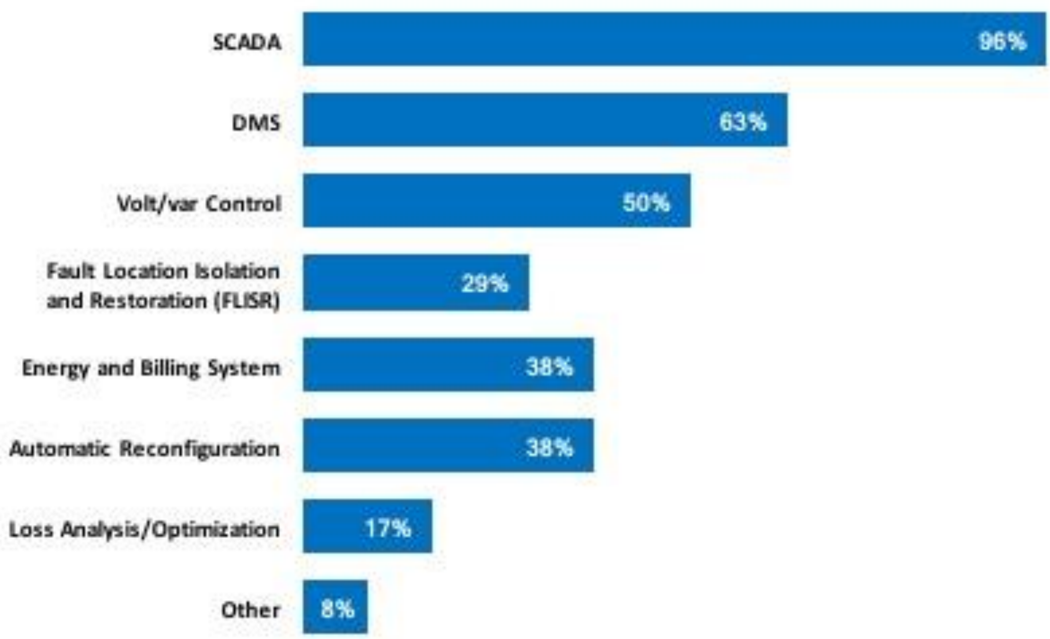


Figure 11 - List of functionalities for DSO

In contrast, fault isolation and restoration functions have not been widely adopted at this time, as depicted in Figure 12.

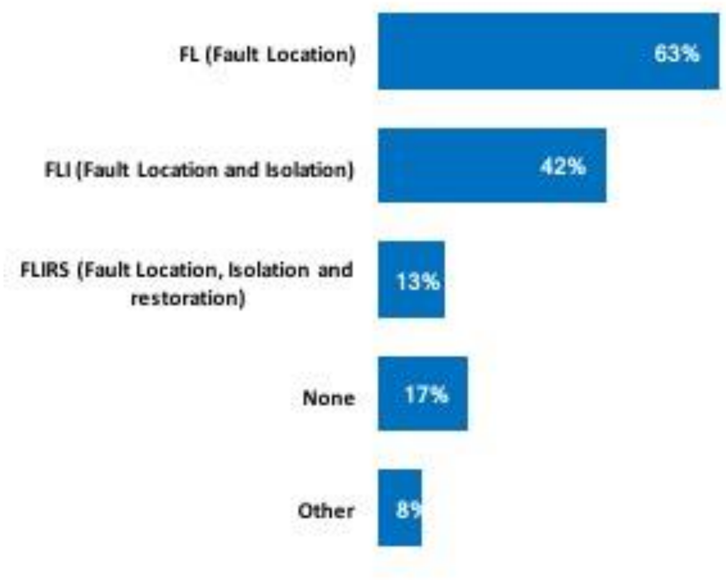


Figure 12 - Fault Location and Restoration Capabilities among Utilities

2.3.4 Communication systems

As shown in Figure 13, cellular and radio communication infrastructure dominate in both rural and urban areas; however, optical fibre is also commonly used in MV applications.

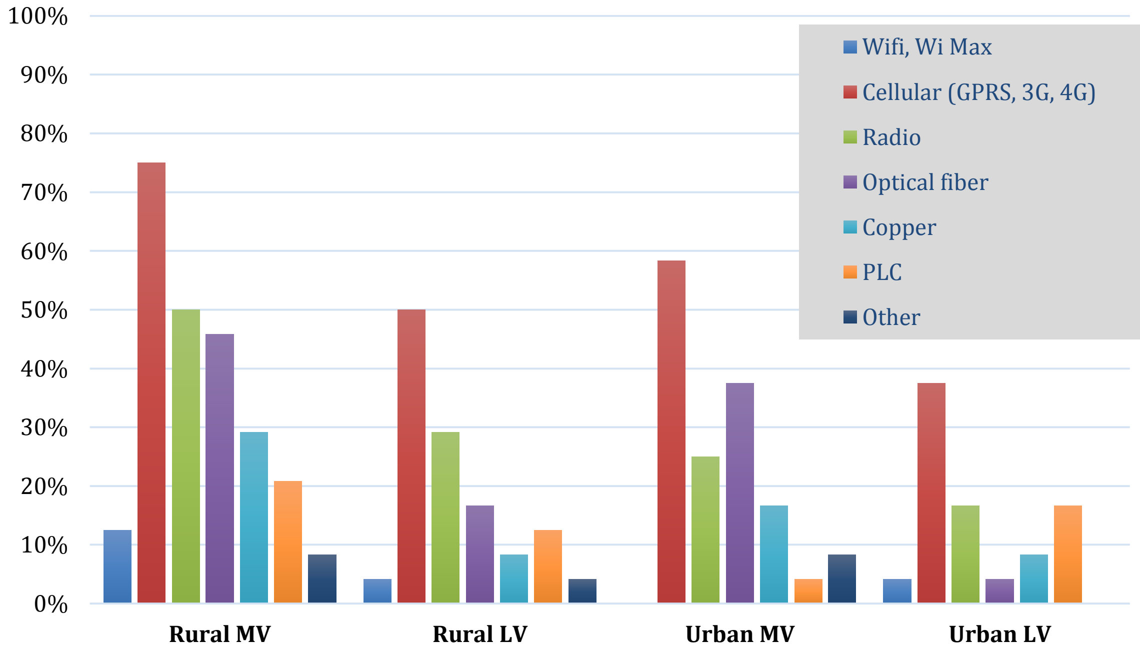


Figure 13 - Types and Levels of Communication Media Deployed

Survey results indicate there is a significant attention paid to security issues. Almost 70 % of respondents deploy data security measures, and quite a number use dedicated VPN (Virtual Private Network) and dedicated public APN (Access Point Name), as reported in Figure 14.

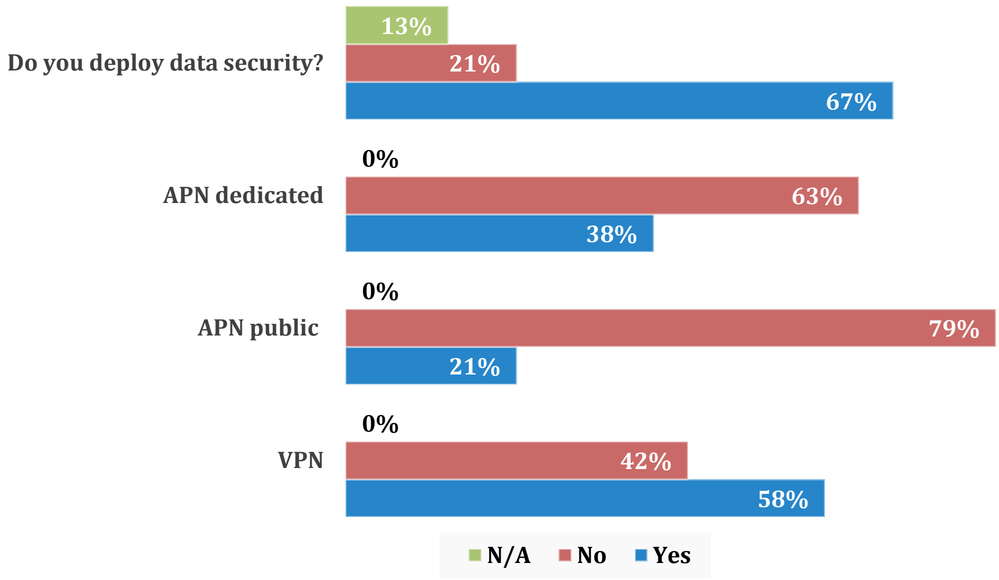


Figure 14 - Security Policy and VPN

Further, there is a significant use of a quite stable protocol (IEC 60870/101-104) and some DSOs (nearly 50 %) have started to implement IEC 61850. The use of not standard protocols is still present (30%).

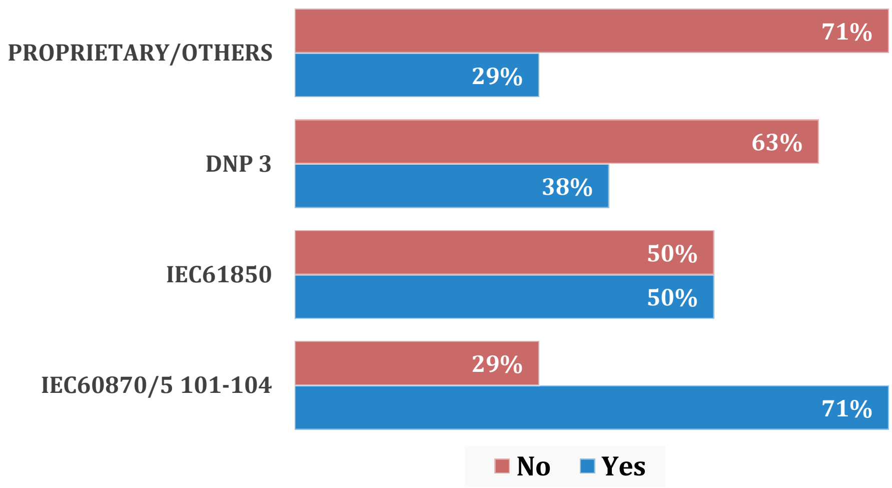
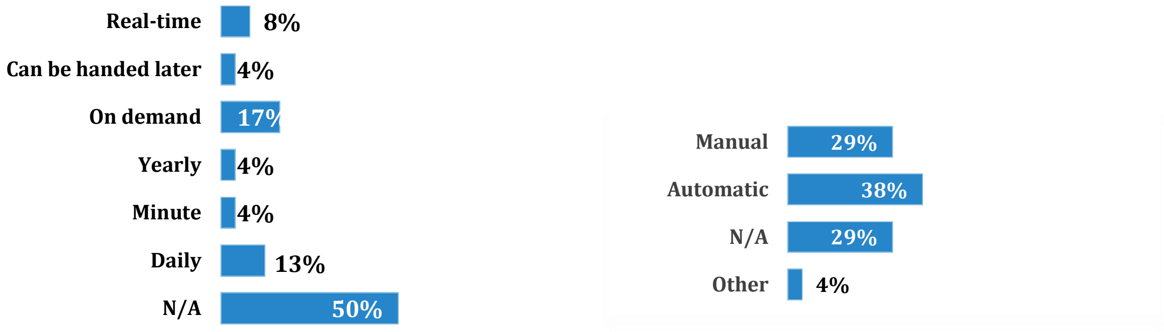


Figure 15 - Type of Communication Protocol Most Implemented

2.3.5 Information from TSO and Markets

Survey responses concerning frequency and level of communication between the DSO and TSO are plotted in Figure 16. As shown, the responses indicate that the current interactions between the DSO and the TSO (and/or market places) are significantly limited, unstructured in nature, and likely instigated in response to specific issues rather than on a regular basis. It is worth to notice that less than 30% of the respondents indicate regular scheduled or real-time communication, and nearly 20% of respondents replied that communication is on demand.



(a) (b)

Figure 16 - (a) Frequency of Communication and (b) Level of Communication with TSO

About half of the responding DSOs reported that they provide various services to the TSO. As depicted in Figure 17, these services mainly consist of load forecasting and voltage support. While the survey did not differentiate between short-term and long-term forecasting, 70% of those responding that an automatic communication between DSO and TSO is in place also responded that they provide forecasting services to the TSO.

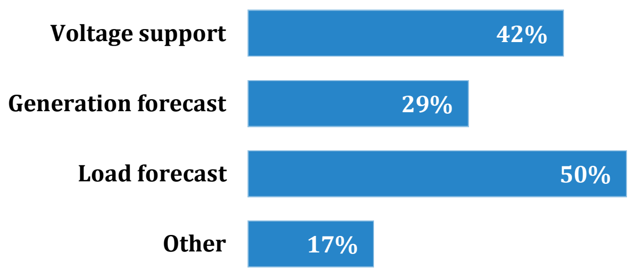


Figure 17 – DSO Provided Services to TSO

2.3.6 New Functionalities for Control and Automation of Future DSO

As depicted in Figure 18, the application of DSM programs within the participating DSOs is generally limited. Nearly 40% reported not having any program currently in place. Furthermore, many active DSM programs are based on Time-of-Use (TOU) tariffs and load control programs that are relatively easy to implement.

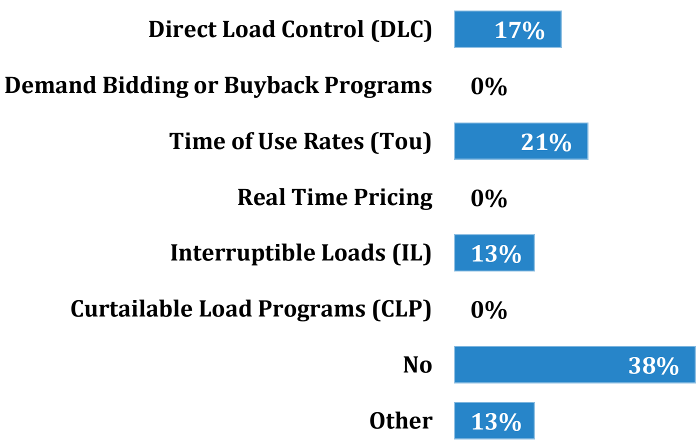


Figure 18 – Demand Side Management Programs

The majority of DSOs (67%) reported the willingness to include AMR in future network operations. When asked about the desired sampling rate, only 30% indicated a capability or a desire to provide data at least every 15 minutes or with better resolution (see Figure 19).

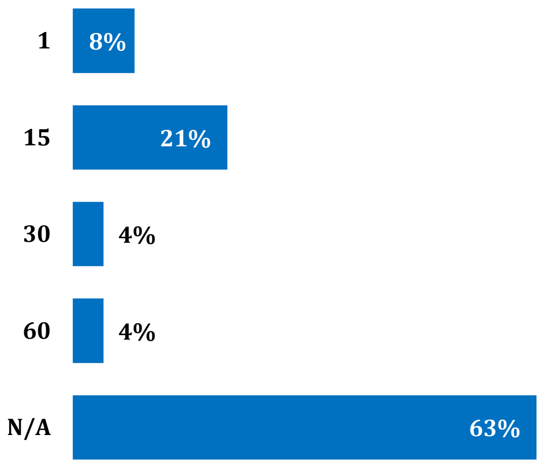


Figure 19 – Level of Information and Latency of AMR

Figure 20 reports the different functionalities that DSOs envisaged for their future network. Many DSOs are about to introduce new tools for a better use of the network (e.g. dynamic rating) and tools for generation and load forecasting. Both these functionality clusters have so far been typical of TSO applications.

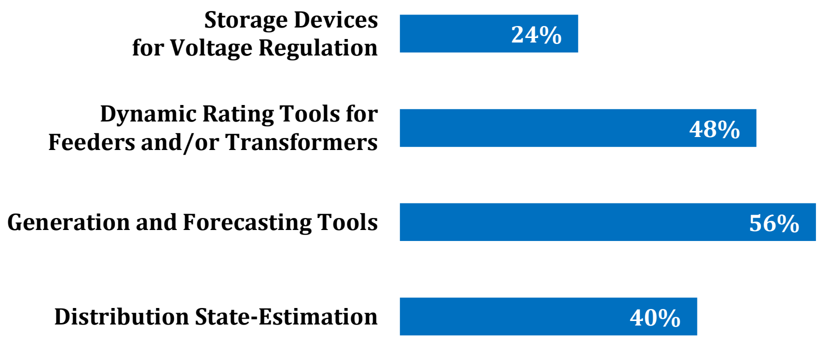


Figure 20 – New Functionalities Envisaged for DSO

To properly manage networks and congestions, several survey participants highlighted the necessity to have a clearer legal framework and the ability to better control DER, e.g., by changing reactive power. One DSO emphasized that DSM programs based on third parties (i.e. aggregators) will have an impact on the network without any contractual relationship between DSO and Aggregators.

2.4 CONCLUSIONS

Based on the survey results and analysis it is evident that DSOs throughout the world are conducting different tests to move from a "blind" exercise of the network to a more and more monitored and controlled one. For responding DSOs, the most promising functionalities are dynamic rating for feeders and transformers and distribution state estimation.

The scores in previous figures and in the full report can be used as references for utilities to determine the state and required developments of active control applied to the distribution networks. This information creates also the possibility to generate benchmarks on the development of active distribution network automation.

3. INTERFACING CONTROL AND AUTOMATION SYSTEMS OF DISTRIBUTION AND TRANSMISSION NETWORKS

This chapter describes and analyses the necessary interfacing control functionalities and exchange of information and services that DSO and TSO need to setup to better manage a power system with high penetration of variable renewables (VR). The description assumes that TSO and DSO belong to different entities even if in some countries there are examples of companies being vertically integrated.

3.1 CHALLENGES IN SYSTEM CONTROL DUE TO THE GROWING PENETRATION OF DISPERSED GENERATION

Significant increase in penetration of VR, penetration of highly power consuming loads such as EV and thermal loads like electrical boilers and heat pumps, and utilization of Smart Grid technologies make system control more challenging than in the past. Already now in some areas the consumers' demand in terms of energy is mostly supplied by VR, while in other areas and in some hours of the day the transmission and distribution network continue to assure services in a more conventional way. More challenges are expected for electrical system control strategies, and flexible-operating techniques of the distribution network can help significantly, with high shares of VR (that are already a reality in many countries).

As distribution systems are expected to have surplus of generation for a period of time with gradually increasing DER adoption, thanks to the improving degree of DER and load controls which are foreseen in the near future, distribution networks will be required to provide services to the system, like frequency and voltage control, historically provided by the big generation units connected to the transmission grid.

In this framework of high penetration of DER (especially VR), technical and functional interoperability between distribution and transmission systems must guarantee quality of service and system reliability.

- Through the implementation of "smart technologies" together with innovative system tools, VR generation (in particular, PV and wind) will be made more observable, predictable and controllable, improving:
- the load and generation forecast at primary distribution level,
- the hosting capacity to connect further VR maintaining quality and system reliability, and
- the communication between TSO and DSO automation systems.

At the transmission level, there is a strong need of greater but appropriate observability of the distribution network as well as a greater involvement of VR and DER in all the processes related to the management of the electrical system as a whole – such as voltage regulation and reactive power regulation, power flow and congestion management, load and consumption forecasting, defence planning, islanding, restoration, and asset exploitation.

These goals can be reached by means of a renewed, enforced and enhanced level of cooperation between TSO and DSOs that implies sharing of the needs and common procedures; definition of the information that must be exchanged; standardization of the information model; definition of new functionalities and implementation of systems and devices interoperating with each other.

There will be some new actions that must be considered and others, although already operating and managed in a centralized way, should be performed locally, by means of the TSO and DSO substation automation systems. New system architectures should be developed.

All the information provided by each DSO with the smart grid facilities must be collected by the TSO and integrated with the information coming from the TSO systems to offer a global and coordinated vision of the whole process, from the smallest VR generation plant, to the National Control Centre (without forgetting the VR directly connected to the HV grid), so that operators are in the condition to take the right decision at the right time.

DSOs will be requested to implement technologies, such as:

- advanced control systems for VR and heavy active loads such as HVAC systems,
- advanced substation monitoring,
- Distribution Management System including short term operational electricity distribution network planning with VR and flexibility actors; modern interfaces between DSO and TSO to facilitate the communication, and
- innovative forecasting tools.

The utilization of the technologies mentioned above will facilitate provision and management of ancillary services like voltage and frequency control. Furthermore, the more predictable the load profile at the DSO-TSO interface is, the easier and more effective the VR integration becomes.

3.2 NEED OF INTERFACING DISTRIBUTION AND TRANSMISSION SYSTEMS

The reasons for an interface between TSO and DSO are tied to issues that can be grouped into three main clusters:

1. Market Framework
   - All resources connected to transmission and distribution grids, such as generation, storage and active demand, should be able to participate in energy markets and offer services to the system (frequency response, voltage control, balancing, etc.). In particular, active demand should be treated as a resource because of the spreading of:
     i. Producers-Consumers (Prosumers)
     ii. Demand Side Response (DSR)
   - Generally, resources should be able to give their potential, independently of network voltage level at which they are connected. However, means must also be in place to deal with any local network issues attributable to the activation of the resource(s) - the effect of this principle on network losses should be investigated more closely. It is desirable to identify operation and market procedures that contribute to low-loss, efficient system operation.
   - Service provision could be facilitated by creating a common market with resources shared by TSOs and DSOs and aggregators.
   - The special role of reactive power ancillary services should be investigated more closely by research. Research is needed as well regarding recommendable interaction between market and DSO, when VR provide ancillary services to the TSO.
   - Multi-service provision by one VR to multiple parties needs carefully defined rules.

2. Operational interaction
   - Because the grid is more and more active at distribution level, it is necessary for the DSO to have sufficient observability on distribution level.

- Sufficient observability, appropriate and relevant to their respective functions and roles, must be in place to serve all categories of actors such as DSO, aggregators and TSO.
- The utilization of system services for Transmission system purposes should be overseen collaboratively by both the TSO and DSO. In this scenario, the DSO should collect data from dispersed generation and provide them in appropriate manner. TSOs should be responsible for coordinating system control, defence plans and special protection schemes that could involve progressively more and more resources at the distribution level. However, they must do so in a manner that respects and makes provision for dealing with any network impact or congestion at Distribution level.

3. Planning interaction
    - Since the major changes will happen at the distribution level, an interchange of relevant information between DSOs and TSOs about the development of the grid is crucial and required. Indeed, the security of the system is more and more dependent on the distribution system and load and DER forecast for both short and long-term planning must be enhanced.

3.3 DESCRIPTION OF CHANGES AND SERVICES FOR SYSTEM CONTROL AND MANAGEMENT

In the next sections, different system services opportunities for DSOs are reported and discussed.

3.3.1 Local control of frequency and rules of disconnection

Frequency control is very important for electrical systems. With the shift of production at distribution level it is necessary to adopt common rules also for Distributed Generation - DER (and not only for generation on transmission level). Local control takes place in the DER itself, it does not require communication to be activated. It is also referred to as frequency containment reserve in the network code on electricity balancing (NC EB).

The main rule to guarantee the security of the system is to avoid disconnection of generators for frequency in the range between 47.5Hz $\leq f \leq$ 51.5Hz both for static and rotating generators. In fact, it is necessary to guarantee the DER remains connected during frequency transients when lack of power arises in a particular area. Specifically, the generator anti-islanding interface protection system should ideally, distinguish between local islanding events and global frequency events. Where this is not cost effective to implement, particularly for large numbers of small generators, settings should be raised sufficiently. The system should trip on frequency limits only for global frequency events.

Another measure to avoid disconnection of DER against grid events is to use the ability of the so – called voltage trough capability.

The general development towards increasingly high shares of DER in the total generation portfolio underlines the necessity for DER to adopt frequency regulation. For primary frequency control, as a first stage regulation, over-frequency should be adopted. DER should have the possibility to decrease the active power injected in the grid in response to a frequency rise with a certain droop as stated for example in the European Network Code Requirements for Generators.

Since most DERs are static, in case of re-connection after a frequency deviation, it is necessary to deliver power gradually.

In a second stage, this type of regulation could be adopted also at under-frequency. To work at under-frequency the DER should have an amount of power for up-regulation, which means they will operate below maximum operation condition for a period, even if the necessary wind or irradiation would allow a higher production.

3.3.2 Fault ride through and quasi stationary local voltage control

Since the production at the transmission level is decreasing, the voltage regulation from DER is very important for the electrical system, especially fault ride through (FRT) and primary voltage regulation. Fault ride through is already part of network connection codes in many MV systems. Regarding quasi-stationary reactive power/voltage control, in fact, currently DERs usually do not perform voltage control in most operated systems; in the future, however, it will be necessary that this kind of generation also performs voltage control. This is already practiced in some countries at MV level (e.g. in Germany based on BDEW MS-RL and in Italy with Grid Code and Annexes) as well as in HV systems (e.g., VDE-AR-N 4120).

Some possible ways to do quasi stationary reactive power/voltage control are:

1. Power factor control at the connection point (e.g., cosphi(P))
2. Voltage control on the connection point (e.g., Q(U))

However, any use of DER for these purposes should be agreed with the DSO and have due regard to the electrical distance or impedance from the DER location to the TSO-DSO interface. Where the DER is deeply embedded in the distribution system, it may make more sense to use it to contribute to the control of the local voltage, whereas if the DER is located electrically close to the TSO boundary, it may make sense for it to provide a form of Transmission support – again by agreement with the DSO and respecting distribution network limitations.

It is also imaginable that Demand Response would be integrated into local frequency and voltage control.

3.4 SECONDARY AND TERTIARY REGULATION (BALANCING)

3.4.1 Secondary and tertiary frequency regulation

Terminology used for referring to active power reserves differs. In Europe, terminology from the Network Code on Electricity Balancing (NC EB) is increasingly used. Secondary regulation there translates to automatic or manual frequency restoration reserve, while tertiary regulation is referred to as frequency replacement reserve. The terms are given in brackets in the following.

To balance load and generation, it could be possible to use aggregated DER instead of larger central power plants. DERs are usually coordinated and assembled by aggregators, or by so called virtual power plant (VPP) operators, who offer the aggregated power as product in the frequency control market. The request for frequency control action will always be issued by signals from the TSO – however, who sends the active power set points to the DER varies from country to country. Some examples of possible market-based distribution system DER dispatch may include:

1) The TSO controls HV and MV DER directly.
2) The DSO controls DER directly, considering the TSO requests and dispatch suggestions from the aggregator
3) The aggregator or VPP operator controls DER directly, while the responsible system operator has an additional control via the SCADA system that are used only when market mechanisms fail. The TSO mainly acts via market mechanisms e.g. with VPP operators.
4) TSO, DSO and the aggregators share a common ICT infrastructure for controlling the DER.

In addition to providing tertiary frequency regulation (replacement reserves), more and more generators and storages could provide also a band for frequency restoration reserve. In this way, manual or automatic frequency restoration reserve (secondary frequency control) can increasingly be provided by DER and DSM resources, after successful DSO prequalification.

Participation of DER in automatic frequency restoration reserve requires reliable, high-speed communication facilities between dispatcher and DER. If the DSO is to transmit active power set points to the DER via the SCADA system in the context of secondary regulation, this would require a high-speed inter control centre communication between TSO and DSO control centres. The same accounts for aggregators or VPP operators dispatching the DER per TSO needs. In case many DER participate in frequency regulation, it is practical for all parties to separate the DER frequency control from the regular TSO or DSO system operation even if eventually the same SCADA infrastructure is used. This then corresponds to option 4) in the above list.

Generally, it could be helpful for distribution system operation, if the DSO was aware of DERs' current frequency control status. This implies that the DSO should be in the information loop regarding the activation of control reserves in his system. Frequency regulation signals from the TSO could be transmitted to the DSO and the aggregators for activation of the reserve. Research is needed to identify the most efficient interaction schemes between DSO, TSO and market players for managing DER frequency control in congested DSO systems.

The possibility of utilizing DSO ICT infrastructure to allow the DSO to simultaneously perform the role of DSO and aggregator of DSO dispatched DER, needs to be carefully investigated for compatibility with the regulatory framework.

The same considerations that apply to DER participating in secondary and tertiary regulation (frequency restoration and frequency replacement reserve) also apply to demand response in this context.

3.4.2 Secondary and tertiary voltage control

The terms secondary and tertiary voltage control have been established and put into practice in France and Italy in the 1990ies [B22], [B23]. They apply the logic of secondary and tertiary frequency control analogously to the reactive power / voltage domain. While secondary and tertiary voltage control in the distribution system still seems somewhat distant, integration of the reactive power exchange at the TSO/DSO interface into a TSO secondary/tertiary voltage control scheme may be an option in some cases [B22]. This would further go into the direction of DSO systems behaving predictably and with similar services as generators from the TSO perspective.

3.4.3 Operational data

To control DER, observability via remote-measurements and remote signals is crucial. The DSO is responsible for ensuring agreed and relevant degrees of observability. The DSO in turn must transmit agreed and relevant signals, or aggregated information thereof to the TSO since they are very important for the security of the system.

For example[1], where the TSO operates EHV and HV systems, they would consider it very important to know the following data for every primary station:

Transformers:

[1] in general the boundary of TSO-DSO is specific of the country.

- Active power on medium voltage (MV) side
- Reactive power on medium voltage (MV) side

VR Static Production (Solar and Wind) MV/LV

- Equivalent active power production P per every transformer
- Equivalent reactive power production Q per every transformer

Rotating Production (Thermic and Hydro) MV/LV

- Equivalent active power production P per every transformer
- Equivalent reactive power production Q per every transformer

Load

- Absorbed active power
- Absorbed reactive power

Equivalent production means the sum of DER under every transformer. This kind of aggregation must be done by the DSO and data of this aggregation must be transmitted to TSO SCADA every 20'' in Italy. This sampling is the minimum to have a sufficient observability, according to [B24]. The ideal sampling could be 4''.

The aggregation implies the subdivision of DER into two groups, to consider the generation with and without inertia:

- Static generation (Solar and Wind Production)
- Rotating Generation (Thermal and Hydro)

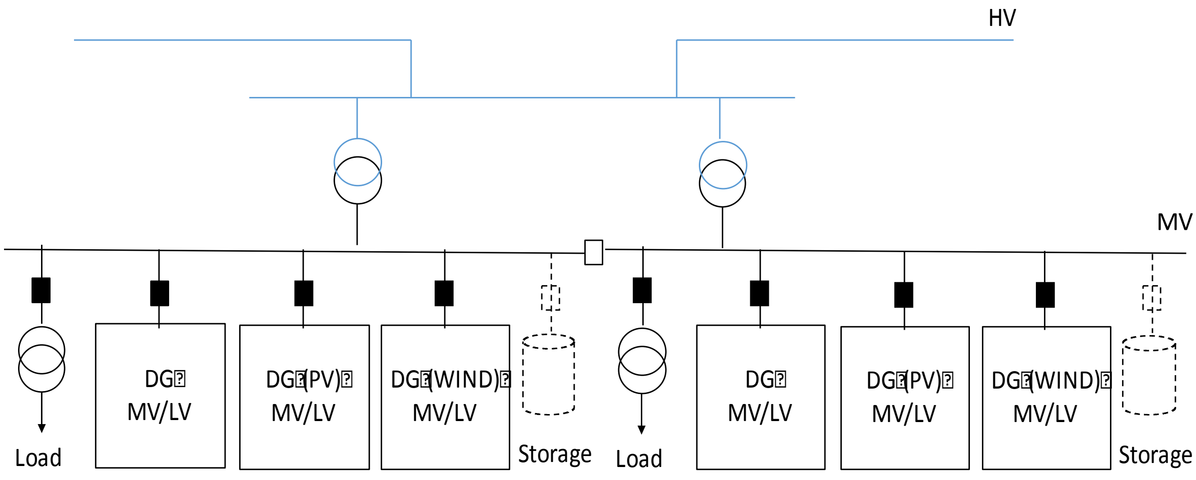


Figure 21 – Aggregation at HV/MV substation

For other cases, where the DSO operates the HV systems, arrangements must be agreed between the TSO and DSO.

3.4.4 Defence plan and special protection schemes

All actors involved in the operation of, or who connect to, the electrical system must contribute to the security of the system when there are events or outages that could compromise it. This concept is more stressed with the decrease of resources in transmission grids and the increase of resources in distribution grids. In this sense, where agreed with the DSO, it may be necessary in some locations, to extend special protection systems (SPS) also to resources at the distribution level by ensuring the communication between TSO and DSO with specific features to guarantee this service.

In particular, the tele-tripping could be implemented in two different ways:

1. Through a command delivered directly by the TSO or retransmitted by the DSO to the plant controller, who will put in practice the command to the protection device, or
2. Through a command delivered directly by the TSO or retransmitted by the DSO to protection device.

In both cases the command will be transmitted with a fast protocol (e.g. GOOSE).

Since commands are important for the security of system, they will be given by the TSO in a sufficient time to guarantee the stability of the system. Typically, the time between the request and the execution would be less than 400 ms (for instance in Italy). This command could be extended also to energy storage systems (e.g. batteries).

3.4.5 Load and DER forecasting

With the objective of a better load and generation forecast at system level, considering that the generation will be more and more present at distribution level, it will be necessary that DSO transmits the forecasts of measurements to the TSO. In fact, TSOs will remain responsible of forecasts on the electrical system but the quality of forecasts will be more tied to DSO forecast data. Forecasts of active power might be given to TSO with these features:

- Time window of 72 hours
- Sampling of 1 hour
- Generation divided into two types (rotating and static generation)
- Update every 3 hours

3.4.6 Common registry

In order to control the development of DER on the grid, it is important to share DER registry information on a common database between TSO and DSO.

For example, in Italy, which has a contribution of LV/MV DER of more than 40 % to system low load, the practice for data sharing is as follows:

- Wind production MV/LV: installed total active power at primary station level per transformer (update every 3-6 months).
- Solar production MV/LV: installed total active power at primary station level per transformer (update every 3-6 months).
- Thermal and Hydro production MV/LV: installed total active power at primary station per transformer and per energetic source.
- Energy storage production MV/LV: installed total active power at primary station level per transformer (update every 3-6 months).

4. CONTROL AND AUTOMATION FUNCTIONS RELEVANT FOR THE EDN, ISSUES NEEDS AND REQUIREMENTS FROM DSO PERSPECTIVE

In this section, the needs and requirements for automation are analysed with respect to the DSO perspective. Today's electricity supply systems must deal with several issues due to liberalization, increasing economic pressure, higher demand for increase of quality requirements from customer side, tighter environmental regulations, massive installation of renewable energy generation etc. These trends affect the distribution systems, which are responsible for the major part of the total system's cost and for the power quality.

The expansion of decentralised and intermittent renewable generation capacities is one of the biggest challenges that will impact the reliability and quality of power supply. Most of these new generators are being connected to distribution networks – a trend that will be increased in the coming years, especially in the LV network. Further, the electrification of the transport and heating/cooling sector will also increase the load at the distribution network grid, some loads being heavy energy consumers, for instance at households (Electrical vehicles and heat-pumps) compared to the existing loads. In this context, the issues that must be considered by the utilities managing future distribution networks include:

- Improving the observability of the MV and LV networks;
- Ensuring continuity of supply and low number and duration of outages;
- Ensuring good power quality despite heavy load and fluctuating power generation;
- Reduction of network losses;
- Increasing efficiency in operations including ensuring operations closer to the capacity limits;
- Increasing customer participation for demand response; and
- Improving forecast of load demand and power generation in the MV and LV network grid.

Distribution Automation (DA) can play an important role to deal with these challenges providing technical and commercial benefits to both users and network operators. To achieve all the goals above mentioned it is necessary to implement a set of features that will facilitate:

- Management of peak loads, reduce system losses and optimize power generation;
- Detection and recovering from equipment failures through real-time and near real-time monitoring, intelligent control, and dynamic network reconfiguration;
- Characterization, monitoring, and prediction equipment performance and operational lifetimes;
- Performance of voltage control in the MV and LV grid;
- Ensuring flexibility from costumers for active demand management; and
- Simplification of day-to-day network management and reduce demands on field personnel through automated remote monitoring and control systems.

4.1 DISTRIBUTION NETWORK MANAGEMENT

SCADA systems are globally accepted as a means of real-time monitoring and control of electric power systems and should have the following basic functionalities:

- Data acquisition;
- Alarms and events management;
- Schematic network and station diagrams; and

- Network and device tagging.

Presently there is an integration between SCADA and DMS/OMS systems to provide all needed functionalities in addition to the previous ones, and to enhance the management of the network, such as:

- Device and sequence control;
- Geographic maps;
- Work order handling service diary;
- Load flow calculations; and
- Tracing and dynamic line colouring.

The future will require a new set of SCADA/DMS applications to achieve the following benefits: improved system awareness, better asset utilization, improved contingency planning, improved load flow & where relevant, state estimation calculations, improved observation of overloaded equipment and voltage violations, improved crew efficiency, reduced CAIDI and SAIFI, improved operator efficiency during outages, increased reliability and lower systems losses.

To allow an even more powerful operation and planning of the network and to achieve optimal utilization of the assets and crews, new advanced functionalities will be needed, such as:

- Fault location, isolation and system restoration (FLISR) to rapidly isolate faulted sections and to restore service to the non-faulted sections;
- Optimal feeder reconfiguration, to optimize the location of normally open points and to find the better configuration of the network;
- State estimation, to deal with the complexity of the network due to increasing penetrations of variable, highly-dispersed resources and heavy loads, e.g. small-scale renewable energy, demand-responsive loads, electric vehicles, electric storages, and microgrids.
- Real-time simulation, to develop best practices and reach a better operation cost efficiency;
- Contingency analysis, to identify critical contingencies (voltage deviations, transformer and cable loading etc.) for the grid;
- Intelligent alarm processing, to provide a fast and deterministic analysis of events and to improve the operation efficiency of the network;
- Integrated Volt/ VAR control, to find the optimal control of capacitor banks and transformer regulator tap positions;
- Outage management, to analyse trouble reports and to support the supply restoration process; and
- Crew and resource management, to achieve an efficient response to trouble calls.

To improve system exploitation and efficiency, interfacing with other enterprise systems such as: customer information, automatic meter systems, mobile data systems and global position systems is recommended.

Today, normally the DSOs have no systems installed for acquiring data from smaller size DER. In some cases, the TSO receives information from DER in real time while DSOs do not have real-time access to this information. In many cases, there is no operational exchange between the TSO and the DSO.

In the future, a well-structured and organized information exchange, in real-time or near-real-time, between main players will be necessary to operate the distribution network. System services at the distribution level are a key in this respect. Such services include participation of decentralized generators in voltage and reactive power management, distribution network capacity management and congestion management, activation of flexibilities from active costumers and information exchange between TSOs, DSOs and aggregators for Distributed Energy Resources (DER) and active loads**.**

4.2 CONTROL AND AUTOMATION SYSTEMS

In the beginning control was just about equipment monitoring, protecting and operating the network. In response to the growing demand to improve reliability and efficiency of the power system, more automation is being implemented on distribution systems. Typically, the main Distribution Automation (DA) functions are:

- Monitoring and control of distribution equipment within substations and DA equipment on feeders;
- Automation of substations and DA equipment on feeders, such as reclosing, load shedding, automatic restoration, capacitor bank management, etc.;
- Monitoring of some DER systems.

More recently companies start using information provided by automatic meter reading equipment installed at customer sites.

The evolution of systems operation and control will be driven mainly by the changing nature of the generation and its location in the grid and the changing behaviour of the load due to market, energy efficiency programs and implementation of smart grids technology.

The management of the networks in the presence of variable generation and partly controllable loads requires advanced Network Operation and Energy Management capabilities to maintain the necessary level of availability, power quality and system security, to:

- Monitor and control voltage levels;
- Monitor and control active and reactive power flows;
- Monitor and improve power quality;
- Improve infrastructure optimization and capacity of the network;
- Manage faults and outages;
- Manage islanding;
- Increase resilience to generation-load variability;
- Balance generation-load;
- Reduce losses in the grid;
- Improve asset management; and
- Improve demand response approaches.

The network of the future will give rise to significant challenges for the protection and automation systems. Large networks of bulk power will require higher levels of reliability and flexibility from protection to avoid any risk of large incidents.

Distribution networks will require protection and automation systems able to deal with this new reality, and new algorithms and system architectures must be developed. To satisfy these requirements, the protection and automation systems should address the following new functions:

- New protection schemes like those used in transmission systems, based on distance and current differential protections to deal with new network topologies;
- Advanced protection algorithms to provide secure protections settings in increasingly complex networks – the protection functions should be adapted to the fault current through predetermined setting groups or dynamic setting calculations;
- Automated fault location, isolation and service restoration systems to improve distribution grid reliability by reduction of loss of power supply;

- Multi-level feeder reconfiguration, for minimizing energy losses, for equalizing voltages between feeders and substations and for balancing loads of substation transformers and distribution feeders;
- Optimal Volt/ VAR control to calculate the optimal settings of the voltage controller of the Load Tap Changers (LTCs), voltage regulators, DERs, power electronic devices, capacitor banks to optimize the operations;
- Where considered desirable, control of islanding operation to switch over to island operation in the event a of fault in some part of the network;
- Anti-islanding operation to avoid unsafe, unbalanced and poor-quality distribution electric islands; and
- Synchrophasor technology applications to monitor some key system variables and mainly to assure the system security during high power flow transfers.

In the future, Operation & Maintenance (O&M) support systems will become critical utility systems as utilities focus more and more on optimized operation. To reduce the global cost of ownership and exploiting assets as close as possible to their technical limits, O&M support systems are becoming a relevant if not critical requirement. By applying condition-based maintenance approaches and remote monitoring and management, utilities would be able to optimize O&M by:

- Limiting intrusive inspections;
- Reducing unnecessary maintenance;
- Preventing major failures and unplanned outages;
- Improving risk management;
- Reducing exposure to liability and insurance cost;
- Reducing redundancies;
- Reaching secure asset's life extension; and
- Optimizing workforce.

There are also other important subjects related with control and automation that should be addressed, such as:

- Precise time synchronization to achieve accurate control and precise global analysis of network response related to when, where and why any faults have occurred; and
- The adoption of a communication standard, such as IEC 61850, provides several benefits. It allows interoperability among the devices and enables a more scalable replicable design which can help drive down OPEX and CAPEX.

4.3 TELECOMMUNICATIONS AND CYBER-SECURITY

A remote communication network is necessary to retrieve data from remote systems to the SCADA. With assets distributed over a large geographical area, communication is linking part of the SCADA system and is essential to its operation. The remote applications have, due to different requirements, different types of telecom connectivity: metering, tele-protections, etc.

A telecommunication network intended to support new DA applications must meet following requirements:

- Capacity & latency needed to assure traffic demand, bandwidth and future needs;
- Support of standards, related with traffic types and network standards; and
- Security regarding confidentiality, integrity, and availability.

Substation communication networks are mission-critical infrastructures. Security mechanisms like port security, AAA (Authentication, Authorization and Accounting), VLANs (Virtual Local Area Network), firewalls, routers, gateways, and syslogs must be applied to increase resiliency against configuration and installation errors or even cyber-attack.

4.4 OBSERVABILITY OF TSO/DSO INTERFACES

The topic of observability may be treated from different perspectives. Each system operator has an observability of his own system, which is quite high for the TSO and frequently relatively low in case of DSO at MV and LV systems. Even if DSOs achieve full observability of their own system, the observability of the DSO system for the TSO will in many cases be limited to a subset of this information. This subset is defined based on the associated use-cases.

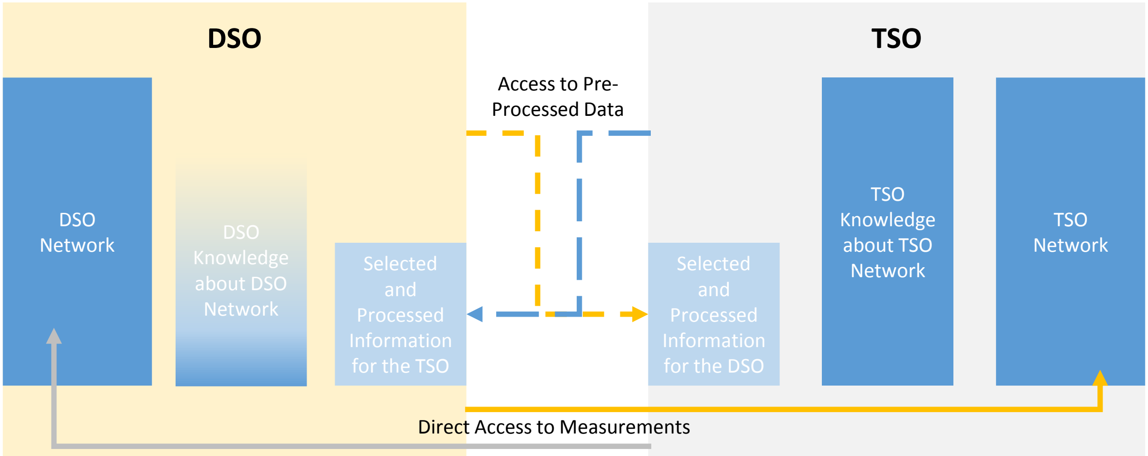


Figure 22 - High-Level View on TSO-DSO Information Exchange

The following types of information may be exchanged:

- Static network information
- Actual or estimated dynamic data (e.g., P, Q, V, circuit breaker statuses)
- Forecasts of dynamic data (e.g., P, Q, V, circuit breaker statuses)
- Outage schedules
- Smart meter data

The information may be deterministic or probabilistic in nature. There is a tendency to supplement deterministic information with probabilistic enhancements. An early example of DSO/TSO data exchange based on probabilistic criteria may be found in [B27].

Access to dynamic data may be subdivided into direct and indirect access. The choice is influenced by the sampling rate: the higher, the more relevant direct TSO access to the measurement. Some TSOs may thus be interested in obtaining pilot measurements from selected DERs in the distribution system. In case the distribution system contains phasor measurement units (PMUs), they would certainly fall into the category of direct access. Direct access of DSOs to measurements in the TSO network is frequently not allowed, or limited to measurements on the TSO side of TSO/DSO substations (e.g. voltage). In Germany, recent regulation was introduced that foresees star-communication from smart-meter gateways to the various interested parties, i.e. TSO, DSO, aggregators etc.

Indirect access to dynamic data refers to a view on pre-processed information. Usually, such pre-processed information will be of lower granularity, e.g., based on 15 minutes averaged values. An extreme case in this context is Italy, where the DSO is required to make available separate online estimates of load and generation every 20 seconds for each TSO/DSO interface point [B29].

Due to the large number of DSOs in Germany, the TSO will take on the role of pre-processing smart meter data for other market parties, e.g. balancing responsible parties.

Beyond the access type the reference point is a distinction criterion. The reference point is the location in the system that the dynamic data refers to. If no measurements or estimations from within the distribution system are available, the data exchange might be limited to providing a forecast of active/reactive power exchanges at the DSO/TSO interface. The TSO on the other hand could provide a forecast of expected voltage at the interface that considers the DSO forecasts.

Static network information and measurements may be combined to yield dynamically updated network equivalents, see e.g. [B38]. Exchange of such equivalents is of particular interest, when the DSO operates HV systems, or generally, when a galvanically coupled distribution system has several connections with the transmission system see e.g. [B28].

Increasing mutual network observability

The increasing penetration of renewable generation units and other distributed energy resources (DERs) including demand response units poses severe challenges for the control and operation of power systems. As the large-scale integration of these units occurs in the distribution networks, the TSO needs to acquire their active contribution in ancillary services for ensuring power system stability and security of supply [B9]. Consequently, it is very essential that the DERs participate in regulation and reserve markets to support the roles of the TSO. The distribution grids are characterized by huge number of feeders and nodes with limited metering points. Therefore, observability and knowledge of these distribution grids are very limited for the DSOs to ascertain the complex interactions of the increasing intermittent renewable and distributed generation units, and flexible loads. Additionally, the prosumers at the local grids to economically benefit from their small generating and flexible demand units by participating in electricity market needs better visibility and information exchange with the network operators and electricity market entities.

The DSOs role in the changing grid structure is to adapt the grids actively to address the grid integration challenges from DERs, supply and cyber security, and facilitate electricity market-based services while maintaining reliable operation of the grids. In this regard, DSOs need to utilise ICT, automation and smart metering infrastructure so that ample real-time and accurate information is available to TSOs to timely enable and utilise the grid services from the DERs [B9],[B10]. A strong interaction between TSO-DSO at different time frames is important for the sustainable and optimal utilisation of the grid resources and assets, thereby reducing system losses and ensuring secured and economic operation of the grid. The existing distribution management system has mostly measurements from HV/MV substations and big consumer loads/generation units, with which the overall picture of grid operating states cannot be determined.

Using smart metering and intelligent monitoring at each nodes of the network for the operation and control of the grid requires extensive communication infrastructure and huge data processing. This is extremely complex and expensive for the utilities. For implementing cost-effective solutions of accurate real-time representation of the grid and advanced grid management, a trade-off between the use of existing monitoring/control infrastructure and minimal possible instrumentation is essential. One of the viable solutions for the real-time optimal observability of the grid is to use superior algorithms in the form of a scalable Distribution State Estimator (DSE) [B11],[B12],[B36], using minimum amount of static and dynamic information of the grid assets giving robust and accurate results with low-computational burden [B31]. The DSE tools use grid topology as static data and pseudo and real measurements, and forecasted information as dynamic data for estimating the network conditions at all nodes. The DSE schedule inputs for control actions to optimally manage and operate active distribution grid assets and elements, and economically operate the distribution systems. The proposed scheme enables the network operators for the improvement of the hosting capacity of the distribution grid for distributed generation resources, deferment of grid reinforcements, and stable and secured operation of the power system. It is highly relevant for congestion management solutions to handle grid bottlenecks that can occur either on the transmission or distribution grids or both.

5. CONTROL AND AUTOMATION FUNCTIONS AT THE TSO AND DSO INTERFACES

The electric power system is undergoing a rapid transformation to both centralized and decentralized generation and controls – with a significant amount of all newly interconnected resources being integrated at the distribution network level. Most of these distributed resources are difficult to predict, observe and control [B7]. Nonetheless, these distributed resources could provide system services when coordinated and managed in an intelligent manner. Furthermore, demand response resources – such as electric vehicles, heat pumps, and distribution connected energy storage – could provide significant benefits in terms of system flexibility.

Closer interaction between TSOs and DSOs is essential to realizing the optimal and reliable utilization of distributed resources as well as secured and economic operation of the overall power system. This requires improved observability and controllability of the distribution grids through the establishment of automation and communication services between TSO and DSO. It is also important that the DSOs implement new communication and control solutions with the prosumers/flexible consumers as well as with the market players to carry out flexibility and congestion management and to deliver ancillary services to the grid [B8]. Additionally, the communication and data exchange will need to support and facilitate the necessary network planning functions.

An evaluation of the changing operational, market, and planning functions related to the TSO and DSO interface are provided below. Future control and automation functions for a demonstration project in Italy are also provided.

5.1 OPERATIONAL FUNCTIONS

5.1.1 Short-term Forecasting and Real-time Observability

Forecasting of distributed generation and consumption is expected to enhance distribution network observability [B16], [B17]. Forecasting tools using information gathered from advanced metering and monitoring interfaces will be able to predict network conditions, flows and resource availability; thereby providing close to real-time information concerning the state of the grid as well as resources.

Aggregated short-term forecasts of active and reactive power at well-defined interfaces may be helpful to the TSO. Additionally, information on new and planned DER connections, if not already known to the TSO, may be valuable. Beyond congestion management, maintenance management and look-ahead optimal power flow, the TSO-specific tasks of reserve management and generator re-dispatch may also benefit from these exchanges. In certain areas, a mutual exchange of relevant forecast schedules between TSO and DSO is recommended. Among these areas are planned outages, major network expansion and reconfiguration.

5.1.2 Network State Observability

Real-time information on DSO system load and generation that is considered significant, may also be used by the TSO as input for computing the system voltage stability margin and for strategically avoiding frequency transients [B38]. Conventionally, the stability margin is determined by TSOs from available SCADA/EMS data. However, additional and more precise information from DSOs may be useful in this process [B14], [B45], [B47]. Increasingly, stability margin estimation is based on PMU measurements [B15]. In the rare cases where DSOs have PMUs (e.g. in the context of system protection), sharing this data with the TSO may be particularly valuable.

5.1.3 Load Shedding

In critical system states, the DSO must implement generation or load shedding as requested by the TSO. Reducing implementation times of such emergency active power management and increasing the related degree of automation is vital for future power systems, especially for those with high degrees of distribution-level generation, see for example [B37].

5.2 MARKET SERVICES

5.2.1 Reactive Power Ancillary Services

Voltage and reactive power control becomes more complex with increasing penetration of distributed energy resources. As it is a local problem, voltage must be managed by the DSOs within the control area such that it won't create impact in the neighbouring distribution and the upper transmission grids. The TSO should be restrained from directly managing this control of reactive power from the local units as this could lead to further grid constraints that can impact the system as a whole [B18]. Apart from the dedicated reactive power supply units of the TSOs, the strategy to measure the available capacity of reactive power in the distribution grid and the ratio of the active and reactive power at the TSO-DSO interfacing nodes could be agreed between the two parties to support the former's secure operation of the power system with voltage control reserves [B19].

The TSO could utilize the reactive power reserves in the distribution grids by sending appropriate set-points of voltage, power factor or reactive power schedule to the probable interconnection points of the TSO-DSO. The DSOs can support the voltage control requirements/set-points of the TSO by suitably managing and controlling the tap settings of transformers and voltage regulators, flow of reactive power in the distribution grids, and also the reactive power capabilities of the distributed energy resources. This should be realized by agreement with the DSO and within the allowed current and voltage thresholds of the distribution grid. Further analyses of this topic may be found in [B20]-[B26].

5.2.2 Flexibility

In general, and where the appropriate means of study/assessment are in place, the advanced pre-qualification of flexibility by the DSO will permit TSOs and DSOs to enter into contractual agreements with power production units/prosumers to exploit the reserves and demand-side participation from generation and consumption units respectively and to address grid congestion and estimate system reserves, see [B33]. For some emerging faster products, such means of study/assessment may not be in place. This in turn allows both TSOs and DSOs to schedule operational set-points of grid assets, perform effective network reconfigurations, as well as reduce grid losses and bottlenecks. The advanced assessment of flexibility is especially relevant for the real-time operation of active network management.

5.2.3 Ancillary (Replacement) Reserves

TSO and DSO will need to find ways to facilitate participation of DER and third parties such as demand response within the framework of the Market structure. The ability to activate DER participation in the reserve market strongly depends on the Market schema and rules implemented in different countries and the role of the DSO (active or only "informed"). In section 6 an overview of the possible TSO/DSO and DER interactions is reported.

5.3 GENERAL ASPECTS AND TRENDS

As pointed out by [B38], the interests of TSO and DSO do not necessarily match. A thoughtful definition of performance standards and quality criteria is vital [B38]. To the benefit of the entire system, there should be a careful evaluation of the costs and benefits resulting from new TSO/DSO interaction requirements. When comparing international best practices and establishing standards, it is helpful have a use-case-based definition of requirements. Interoperability, scalability and ICT security of systems should be verified at all stages. A trend to shared data repositories between DSO and TSO is likely [B39]. Likewise, a trend towards co-simulation of interconnected domains is already being pursued and is expected to become increasingly important as the electric power system becomes increasingly more integrated. An example of TSO-DSO network co-simulation may be found in [B30], an example of Power-System-ICT-Co-Simulation in [B35].

Detailed process simulation of the TSO-DSO interactions – with the aim of improving performance, reliability and ICT-security – is increasingly in important field of research. In parallel with introducing TSO-DSO data exchange, the development of processes and architectures that focus on increasing efficiency and reducing the amount of data exchanged are needed, see [B32]. At all stages of design, interactions with the market and its participants should be considered in the architecture. New ancillary services markets at the distribution level may be a future extension to DSO/TSO interfaces [B40]. In this case, control centres will need to be upgraded with the new functionalities [B41]. For an overview of general guidelines on reinforcing the cooperation, see [B42], [B43].

5.4 NETWORK PLANNING

As is the case with operational function, short-term forecasts of active and reactive power at well-defined interfaces may be helpful to the TSO. Combining forecasting data with short and long-term prognosis tools, along with relevant information from the TSO, will provide DSOs the ability to more effectively plan the system operations to minimize losses, mitigate voltage issues, and coordinate maintenance. Furthermore, this capability will enable DSOs to more effectively optimise their network operations, utilise flexibilities from grid assets and relieve network congestions [B34]. Impacts of DER on long-term planning of HV networks are examined in the recent CIGRE Technical Brochure C1.29 on "Planning Criteria for Future Transmission Network in the Presence of a Greater Variability of Power Exchange with Distribution Systems" [B44].

6. ADVANCED DISTRIBUTION AUTOMATION AND EMERGING TSO/DSO FUNCTIONALITIES

The degree to which various advanced distribution automation and controls are expected to benefit the operational, market, and network planning functions previously discussed is provided in Table 2. It is assumed that HV is operated by the TSO and a favourable, efficient implementation of the TSO/DSO/market interface has been realized. As shown, short-term forecasting of demand and DER is expected to be the most beneficial of all identified TSO/DSO functions.

Improved situational awareness through the application of advanced monitoring (AMI, etc.) and state estimation at the distribution level will improve overall system visibility; however, the main benefit to the TSO/DSO interface will be through more accurate short-term forecasts of net active and reactive power at defined interfaces. Topology recognition, through SCADA systems and advanced distribution management systems (ADMS), can be used to improve distribution state estimations as well as provide information on the DER connected at specific interfaces during normal conditions and during reconfigured system states. Additionally, the enhanced system observability can potentially provide advanced assessment of flexibility is especially relevant for the real-time operation of active network management.

The ability to schedule or dispatch active power production of DER or demand-side participation, by the DSO or other parties, is necessary to achieve many of the operational and market functionalities previously discussed, but is expected to only have an indirect relationship with operational planning.

Dispatching the reactive capabilities of DER may enhance the DSO's ability to provide reactive power reserves to the TSO. However, this potential is highly dependent upon the specific distribution network and system constraints as well as resource capabilities. As mentioned previously, this should be achieved by the TSO sending appropriate set-points of voltage, power factor or reactive power schedule to the probable interconnection points of the TSO-DSO. If the TSO/DSO interconnection is on EHV/HV level, it may be recommendable to issue setpoints for HV network groups (galvanically connected HV network areas) consisting of several EHV/HV transformers.

Volt/VAr optimization (VVO) is already employed by many distribution networks to reduce consumption during emergencies or peak demand periods. As shown in Table 2, this capability can support the operational functions at the TSO/DSO interface as well as benefit the distribution system.

Many advanced distribution automation applications – such as contingency analysis and fault location, isolation, and service restoration (FLISR) – will improve overall system reliability, but are expected to only have an indirect or minor influence on the TSO/DSO functionalities. Automatic reconfiguration of distribution networks to optimize system performance and losses is also expected to have a minor influence on the TSO/DSO functionalities and can be easily accounted for within system forecasts.

TABLE 2. Advanced distribution automation & controls vs. emerging TSO/DSO functionalities

DISTRIBUTION AUTOMATION		OPERATIONAL FUNCTIONS	MARKET BASED FUNCTIONS	OPERATIONAL PLANNING
SITUATIONAL AWARENESS	DER Forecasting	●	●	●
	Load Forecasting	●	●	●
	Advanced Monitoring (AMI, etc.)	◒	◒	◒
	Distribution System State Estimation	●	◒	◒
	Topology Recognition	◒	◒	◒
SYSTEM ADJUSTMENT	Active Power Dispatch/Scheduling	●	●	○
	Reactive Power Dispatch/Scheduling	◒	○	○
	Volt/Var Optimization	●	○	○
PROTECTION & RELIABILITY	Automatic Reconfiguration	○	○	○
	Contingency Analysis	○	○	○
	Fault Location	○	○	○
	Fault Isolation and Service Restoration	○	○	○

● Highly Beneficial ◒ Somewhat Beneficial ○ Minimal Benefit

6.1 CLASSIFICATION OF POSSIBLE SCHEMES FOR ACCESS TO DER IN DSO SYSTEMS

The higher the DER penetration, the more important the involvement of distribution level DER in providing manual and in the future increasingly also automatic frequency restoration reserve. A variety of schemes are possible for ensuring suitable information flows between all relevant actors. Physical flow of information (sending of set-points) must be distinguished from contractual and informative enablers. Selected cases for implementing the physical connection are represented in Figure 23 and Figure 24.

The representations are schematic in nature, implementations in different countries will differ. Grey arrows refer to possible flows of information related to dispatching DER. Coloured arrows indicate a direct control and monitoring connection. The control direction of lightly coloured arrows is usually only utilized in the event of an emergency, e.g. for congestion management.

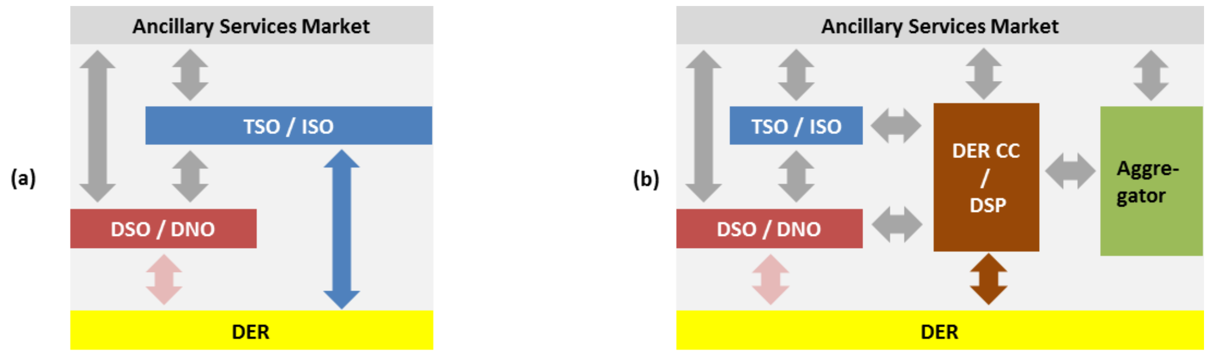


Figure 23 - Example schemes for physical access to DER in DSO systems

In case (a) the TSO has a direct communication connection to the larger DER in the DSO system. A typical sizing limit is 5 MW /Ireland, US, Italy/. If large amounts of distribution-level DER are to be managed, dedicated renewable control centres may be an option, see e.g. Spain [B45]. The smaller the amount of regulating reserve reached per communication connection, the more important are considerations of efficiency. To integrate generators and storages in the scale of up to 100 kW to several MW into the procurement of frequency restoration reserve in many cases aggregators are involved. Scheme (b) shows an option in which all direct control actions are carried out by a dedicated control centre for DER. Communication of actors can in principle occur directly, or via the ancillary services market platform. DSOs may or may not have an own connection for emergency measures. Scheme (c) is used e.g. in Germany. However, to date, there is less communication between the participants than sketched. Future schemes might add situation-dependent information flows. Scheme (d) is characterized by the DSO making available his communication infrastructure available to interested market participants, most notably aggregators. At the same time, he maintains the possibility of emergency override. While this design has the charm of using available, frequently high-speed, reliable infrastructure and thus may be quite efficient with respect to the utilized amount of communication infrastructure, it must be carefully investigated for compatibility with the respective regulatory framework. Also, not all DSOs are prepared to take on roles as sketched in (d).

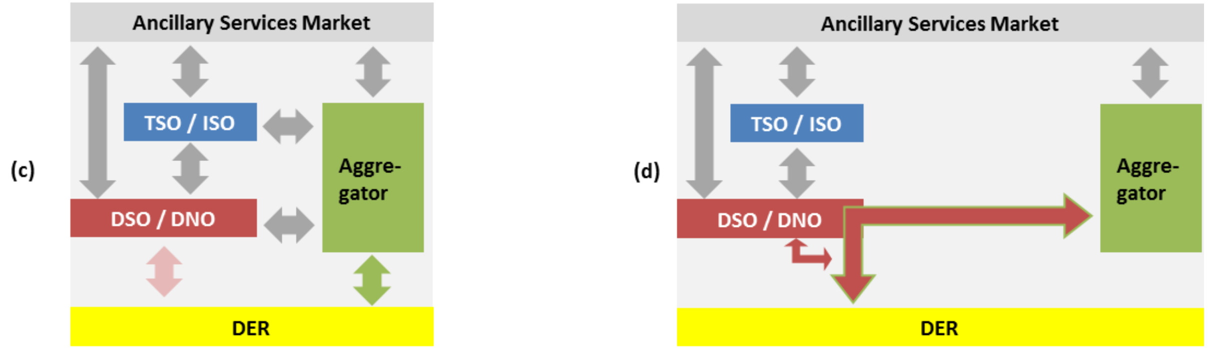


Figure 24 - Examples schemes for physical access to DER in DSO systems

Generally, there is a trend to involve even smaller units in reserve types requiring short activation times. If large amounts of these diverse small resources are available, a certain non-availability of the communication connections can be compensated for, as long as rescheduling can be carried out by the aggregator sufficiently fast. This is usually the idea behind concept (c).

Summarizing, in addition to providing tertiary frequency regulation, in the future more and more generators and storages could also provide a band for f/P control (secondary frequency regulation) so as to guarantee a band of power to restore the nominal value of frequency after a transient.

6.2 PARTICIPATION OF DER/DSO TO ANCILLARY SERVICE MARKETS [B51]

In order to guarantee a secure and reliable power supply at minimum cost also in case of high VR penetration in distribution systems, technical and market rules are being updated so that generation plants embedded in the electric system may actively contribute to system stability instead of jeopardizing its security and adequacy. The Italian Regulatory Authority for Electricity Gas and Water (AEEGSI) started analysing different options for the future regulatory framework and in 2017 launched a new model that will enable the participation of small generators and aggregated demand to Ancillary Service Markets (ASMs). This is the first step of a path that can lead to different possible market arrangements for energy services provided by DER as depicted in Figure 25.

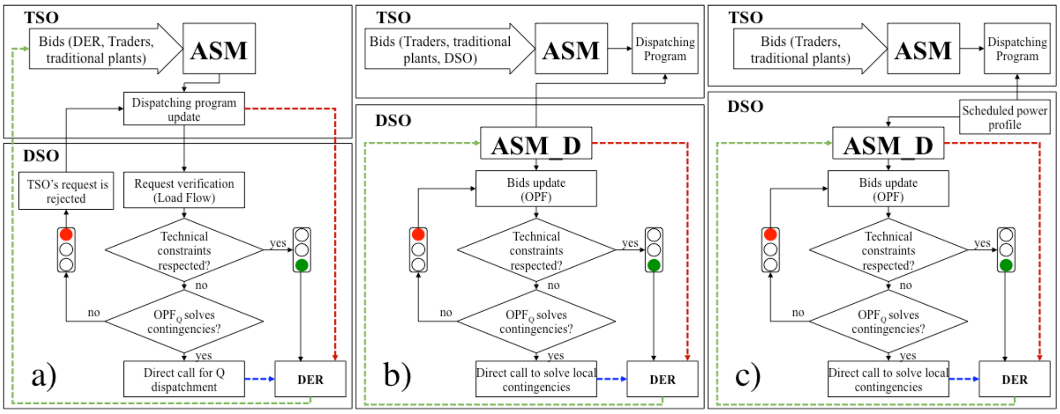


Figure 25 - Market models proposed by the Italian regulator. Currently model a) is going to be applied in 2018

Distribution networks are very site specific and their modelling is a complex exercise. Moreover, data on networks are not available for market players to avoid any possible market distortion. Distribution networks have been modelled with representative networks and simplified models. The underlying idea is that a real distribution network may be described as a combination of a limited number of "typical feeders". The network is described by combining the behaviour of such "typical feeders" that are characterized by topology, conductor types, loads and generation daily profiles, etc. – considering the peculiarities of the Italian Distribution System. Although the approach was developed for Italy, the same methodology can be applied in any other country.

Starting from the consumption and the production, each Power Station is represented as a generator capable to operate on 4-quadrant basis and to offer services in the bulk market per the specific regulation. Ramp-up time, capability curve, expected prices for upward and downward reserve, etc. are associated at the TSO/DSO interface. The expected prices and quantities are calculated by considering the profile of consumption (considering the shares of residential, agricultural, and industrial consumers), the distributed generation connected and the main features of the distribution network supplied. The example proposed refers to the island of Sardinia (Italy), where energy from renewables can be as big as 33% of demand and where at night wind generation is capable to feed almost all load and represent a significant case study with validity beyond the regional boundaries.

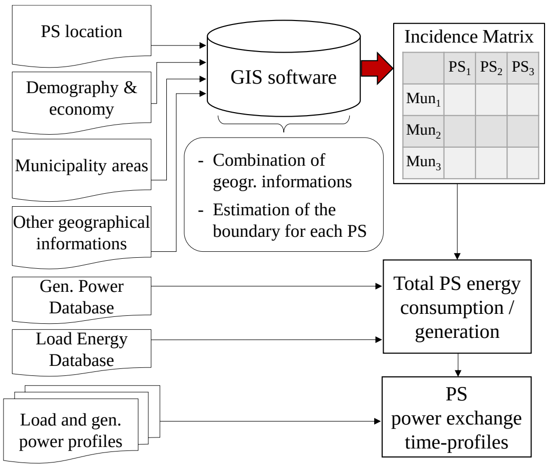


Figure 26 - Conceptual scheme to obtain the power exchange profiles for a given DN from different datasets.

VR (PV in the example) connected to the distribution networks are assumed capable to bid upward and downward services. VR limit power production to 90% of the instantaneous capability so that 10% is left for upward. Since the bidding strategy is profitable only if the Ancillary Service Market (ASM) allows a revenue increase with respect to day-ahead energy market, the final bid prices have been assumed greater than the energy selling price for upward reserve, and zero for downward reserve. Indeed, downward bids cannot have a negative value, while the upward offers must consider that a voluntary reduction of maximum power production represents an immediate economic loss for VR owners (i.e. loss of benefits and incentives) that should be recovered by a future income from actual supply of the service that is not sure and subject to market results.

CHP are the only distributed generators that in principle are programmable and controllable. However, in practical applications not all CHP generators are always fully controllable, mainly because of the thermal load to be served. Thus, only a small percentage (e.g., 5%) of CHP can participate to ASM. For upward/downward reserve the band is assumed equal to 20% of the instantaneous power. The bidding strategy is profitable only if the ASM participation grants revenue bigger than day-ahead energy market. The final bid prices for upward offers considers the fuel cost (and fuel saving for reduced boiler usage), while for downward offers the price is lower than the energy purchasing price. This assumption for the downward bids means that customers with 'shiftable' loads agree to purchase energy in advance by switching-on loads, originally scheduled for the day after, at a lower price that of the current energy price.

Industrial customers connected to the distribution network (25%) are active in ASM. Those industrial customers, by using energy management systems, can modify their consumption profile without compromising the production process by shifting their demand. For upward/downward reserve the bandwidth is assumed equal to 5% of the installed power.

Depending on the installed DERs (PV, WIND, CHP, Active Demand, Energy Storage, etc.) and on the regulatory framework considered, a given DN can offer flexibility at different prices in the market and, as a consequence, services at the DSO/TSO interface. The services offered and their prices can be estimated for each typical feeder supplied by a given PS in a given DER scenario as follows:

1. assess the theoretical limit conditions (maximum load and minimum production and vice versa) by considering the hypotheses of participation above defined for the installed DERs;
2. discretize into a sufficiently high number of points the upward and downward capacity of the equivalent power plant;
3. run LF calculations to check the status of the DN for each point defined in step 2 to find possible network congestions or the costs of congestions caused by services offered;

4. run OPF to estimate the reactive power required for relieving the contingencies for each point that does not comply with the technical constraints in step 3);
5. build three upward and three downward steps of the bid for the single typical feeder.

By repeating these steps for all the time intervals and for each DER scenario for the typical feeders, a database of bids in the ASM can be populated for each typical feeder. Therefore, once the network and DER scenario of a given PS is built by combining typical feeders to represent the true distribution network.

To quantify the potential impact, the cumulative energy (downward and upward offers) that the distribution network can offer is calculated for one year. Table 3 reports the bids for the scenario with PV (620 MW) participating in ASM. The scenario includes the flexibility of Active Demand (AD). Finally, the volumes of energy effectively traded in the ASM by the Italian TSO referred to the Sardinia zone for one year are included in Table 3.

TABLE 3. Upward and downward bids from distribution systems compared to traditional ASM offers

Scenario: PV participation	**ASM volume (2014) [TWh/year]**	**Average awarded price [€/MWh]**	**Volume offered by PV [TWh/year]**	**Average offered price by PV [€/MWh]**	**Potential PV awarded market**
Upward	2.123	128.4	0.074	91.9	3.49%
Downward	0.012	32.4	0.741	0.0	0.00%
Scenario: AD participation	**ASM volume (2014) [TWh/year]**	**Average awarded price [€/MWh]**	**Volume offered by AD [TWh/year]**	**Average offered price by AD [€/MWh]**	**Potential AD awarded market**
Upward	2.123	128.4	0.011	58.2	0.52%
Downward	0.012	32.4	0.011	47.3	92.00%

Despite the significant volume of downwards bids offered by PV plants, the corresponding yearly volumes would be not awarded. This is because PV plants have no fuel saving when performing downwards regulation. Therefore, their downward offers should be placed at a negative price (not admitted) or at zero prices. Such offers are no competition for downward reserves if compared with conventional power plants, where the energy not produced is purchased by the TSO at the downward price (zero, in the PV case).

In case of upwards bids, the volumes offered by PV plants (0.074 GWh/y) amount to around 3.5% of the upward volume in ASM, and are offered at an average price potentially competitive if compared to the average market price. Such result does not account for the hourly variation of the energy sold for the system services in the market and the bid prices.

By considering the participation of the active consumers, the cumulated volume offered is equal to 0.011 TWh/year. Both for upward and downward the bids might be competitive with average market prices. In case all AD bids would be accepted, total volume would cover 0.52% of the total upward volume in ASM, while, a significant portion of the total downward bids purchased in the real ASM might be covered by the AD flexibility (almost the 92% of the total). Indeed, for an Aggregator or a DSO the most convenient way to place a downward bid is to use flexibility and competitiveness of demand. To increase own consumption for downward bid, AD can be motivated and remunerated with a small discounted price on energy. In this example, the TSO would prefer these offers since they are more convenient than the downward bids from traditional fuel thermal generators again leaving space to distribution players in ASM.

6.3 DEMONSTRATION OF FUTURE DISTRIBUTION AUTOMATION IN ITALY

In the past time, the system of electricity has changed very quickly and fundamentally. In the last century, the common practice was to have only one system operator, responsible for the balancing between load and generation and the operation and expansion of the network. Normally the system had only big power plants with some hundreds of MW connected at each location in the system. Therefore, the communication between the units in the system was fast with a big effect on the system.

This situation changed at the beginning of this century especially in Europe. A decision was made between the network operator and power providers which allowed everybody to produce electricity and offer services to the market. Every user can choose his own supplier and producer. This fact facilitated connection of many small decentralized generation units to the existing network. These decentralized generation units have their network connection mainly at distribution level.

Several Smart Grid and Smart Cities projects have been completed or are under their way for completion in Italy [B52], [B53]. Amongst these projects, seven pilot projects are particularly relevant since they have been used by the Italian Regulatory Agency (AEEGSI) to set up the regulatory framework for promoting investments for Smart Grid. In [B53] details about the selection process and the main characteristics of the projects are described. There are reports for each Italian DSO involved with the main features tested on the field with real networks and the involvement of real customers and producers. AEEGSI directly financed the projects with the tariff paid by all system users; an input-based incentive in the form of an increase in the Weighted Average Cost of Capital (WACC) for the realization of the projects was used.

TABLE 4. Main Characteristics of the Italian Pilot projects

1. Function	A2A (1)	ASM Terni	A2A (2)	ACEA	ENEL	DEVAL	A.S.SE.M.
2. Bi-directional communication	X	X	X	X	X	X	X
3. DER monitoring and real-time data provision to TSO	X	X	X	X	X	X	X
4. Active demand	X	X	X	X	X	X	X
5. Advanced FLISR	X	X	X	X	X	X	X
6. Distribution Energy Storage				X	X		
7. EV re-charging infrastructure		X		X	X	X	
8. Demand response					X		

Despite Smart Grid pilot projects were subjected to input-based regulation mechanisms, the opportunity and the need to promote Smart Grid characterized by large-scale, fully interoperable and replicable solutions with an output-based regulation is clear [B53], [B64]. Indeed, the technology behind Smart Grid is nowadays enough mature to think about that, and metrics to assess the performance of Smart Grid based on cost-benefit analysis have been recently proposed [B53], [B64].

The ex-post analysis of the seven pilot projects is briefly summarised in Table 5. The functions can be grouped into three main clusters: monitoring, control, and protection.

3.

TABLE 5. Functionalities of the "Smart Distribution System"

Smart functionality	Main role	Communication with network users	M2M services
1. Observability	Distributor	Yes	Monitoring
2. Voltage regulation	Distributor and enabled active users	Yes	Control
3. Regulation of network users' active power	Distributor and enabled active users	No	Control
4. Remote tripping to prevent the phenomenon of "MV undesired" island"	Distributor and enabled active users	No	Protection
5. Advanced MV network operation	Distributor	Partially	Control and Protection
6. Utilization of energy storage systems	Distributor	Yes	Control

6.3.1 Monitoring

The proliferation of DER in the distribution system requires better observability, at least at the TSO/DSO interface, to allow TSO to assure security and adequacy in the new uncertain scenarios. AEEGSI defined 4 levels of observability, ranked according to complexity, costs and benefits (Table 6).

TABLE 6. Functionality "1. Observability of Power Flows and the State of Resources"

Levels	Description	Communication	Key role
1.a	Continuous forecast of distributed generation and load based on weather forecasts and/or historical data integrated with the control system of the PS and with a DMS	Between the PS and Distributor's Operational Centre (already existent) and between distributor and TSO (existent to be reinforced)	DSO, TSO
1.b	Correction of forecasts through the utilization of sensors installed into PS or located in secondary stations already remote controlled	Communication between PS and sensors (already existent) added to 1.a requirements	DSO, TSO
1.c	Correction of forecasts through the utilization of production data of sample plants already reached by satellite system managed by the Energy Services Operator (GSE)	Communication between DSO, TSO and GSE added to 1.b	DSO, TSO, GSE
1.d	Correction of forecasts through the utilization of production data sent by the DER	Direct communication between PS and active users added to 1.b or 1.c	DSO, TSO, GSE and active users

Increased observability functionalities allow reducing the quantities of balancing and ancillary services in the relevant market for tertiary regulation thanks to a better observability/foreseeability of distributed generation; reducing the curtailment of VR due to critical balancing issues and power congestions; enhancing distribution systems planning and operation.

6.3.2 Distribution Network control

The analysis of the functions implemented by the projects allowed identifying five levels of implementation of voltage regulation. Essentially, the first three levels improve the use of the on-load-tap-changer in the primary substation by using data from the field. The improvement of voltage regulation by including the measurements from the secondary substations requires a communication system between the DSO's control centre and the secondary substations scattered in the territory. Further improvements in voltage regulation are achieved with local regulators that modify the injection of reactive power (no communication with producers is necessary) or with the centralised control of reactive power production to optimise the voltage profiles along feeders (without any modification of the active power production). A communication system capable to reach all distributed energy resources involved in voltage regulation is necessary in this case. The application of voltage regulation and Volt/VAR regulation in the pilot projects proved that expenses for network renovation could be postponed and even avoided in some cases.

The control of active power generated/absorbed by users, unlike voltage regulation, is based on the availability of communication between the control centre (or the primary substation) and the users. This control function can be implemented for providing balancing and ancillary services that are useful both at system level (secondary and tertiary reserves and balancing, both up and down) and at local level (e.g., relief of power congestions and voltage issues). The benefits are related to the reduction of volumes and prices for the balancing and ancillary services market. Recent studies have proved that DER can significantly impact the service market and be competitive with traditional service providers as fuel power plants. Moreover, a reduction of VR curtailment is expected. Finally, the availability of active power control makes the resort to intentional islanding possible. This is especially interesting in critical areas where interruptions can be frequent and the recovery takes too much time.

6.3.3 Protection system

Two functions have been tested with the pilot projects to enhance FLISR and improve the quality of service. The remote tripping for the disconnection of a generator can be achieved in less than 200 ms but a communication link between distributor's plants and network users with very challenging latency levels is necessary. The use of low latency communication systems to implement a logical selectivity and thus improving FLISR in distribution systems is one of the most innovative functions used in the Italian pilot projects. Different communication media have been tested (e.g. fibre optical, LTE, ADSL, etc.). With the logical selectivity, it is possible to locate the faulted area without any intentional delay and to selectively disconnect only the generators in the faulted area. The innovative protection systems developed for the pilot projects allowed significantly improving SAIFI for all network users, including any DER that is currently disconnected as soon as a fault is detected in the network. The logical selectivity, besides avoiding/reducing capital expenses for networks, also enables the attainment of target levels of service quality in densely populated urban areas in which network investments are not easily realizable.

6.3.4 Functions related to distributed energy storage

The use of energy storage (batteries) was also tested in the pilot projects to smooth the power fluctuations at the TSO/DSO interface (functions relating to the control of active power); to control reactive power at the TSO/DSO interface (functions relating to the control of reactive power); to give back-up power during short interruptions; to black start a limited portion of a network; and to manage the charging stations of electric vehicles.

7. THE REGULATION AND NETWORK CODE FOR TSO/DSO INTERACTIONS

7.1 REGULATION IN EUROPE

TABLE 7 shows an overview of European network codes potentially relevant to TSO/DSO interaction. Usually the most immediately relevant documents are the operational codes and the connection code.

TABLE 7. Overview of EU network codes relevant to TSO/DSO interaction

Network Code	Short Form	Topic Area
Demand Connection Code	DCC	Connection Code
Capacity Allocation and Congestion Management Electricity Balancing Forward Capacity Allocation	CACM EB FCA	Market Code
System Operation Guideline Emergency and Restoration	SO ER	Operational Code

The degree to which the network codes affect TSO/DSO interaction shows a certain correlation with the amount of DER penetration in DSO systems, and the instantaneous distribution-level DER share in covering the system load. In general, the higher the instantaneous percentage of load covered by distribution-level resources, the higher the immediate impact on TSO/DSO interaction. Information exchange between TSO and DSO is addressed in network codes SO, ER and DCC. Few aspects may be found in NC EB as well. Regulations on reactive power exchange may be found in DCC and SO.

7.1.1 Regulation in Denmark

The smart grid strategy in Denmark is formulated based on the main challenges in the future electricity grids faced by the TSO in system balancing services with high amounts of wind power in the transmission system and by the DSOs in dealing with congestion and bottlenecks in their local distribution grids caused by the increasing penetration of distributed energy resources [B54]. The activation of flexible consumption and production is considered as one of the best solutions to meet these future challenges that demands and facilitates close synergy and interoperability between grid companies, system operator, consumers and electricity market players. The control of such flexibility services requires an increased level of automation, control and data management. Therefore, a future electricity market is recommended to deliver innovative and efficient flexibility products for supplying system balancing services for the transmission system, and congestion management and alternatives for grid reinforcement in the distribution grids [B55].

In Denmark, as a first step development of smart grid, a whole-sale market model was proposed as part of the energy agreement in 2012 [B55]. This market model is developed to create opportunities to trade flexible production and consumption of electricity and is planned to be implemented in two phases [B56]. The phase I of the scheme is to have a bilateral agreement for trading flexibility between the grid companies and electricity consumers - preferably larger customers who are willing to shift/reduce their consumption in an area where grid congestion normally occurs. The agreement is realized through electricity trading companies who devise and facilitate the payment from the grid companies to those customers providing the demand response services. This in turn avoids or defers investments for grid expansion by the grid utilities. The experience gained by the grid companies in phase I is expected to support the development of a fully-fledged smart grid flexibility market in Phase II where the trading companies, aggregators etc. play key roles in trading and controlling flexibility services and products.

With the roll-out of remotely-read smart meters at all consumer premises, the 2012 regulation has set-up direct access of electricity-retailers with consumers, hourly settlements and variable tariffs for the development of flexible electricity market. These steps are further supplemented by the introduction of a common data-hub in 2013 which functions as a harmonized data information model. It is a mandatory data exchange platform and a centralized storage for electricity data from smart meters where the information is shared between electricity stakeholders like TSO, DSOs, electricity traders, and consumers where electricity meter data are collected from all electricity consumers. This in turn provides an open and transparent link between the business/economic and physical (grid) layers where information (market and technical - both system and local) can be used for enhancing TSO-DSO interaction to utilize the grid flexibility for balancing the grid operation.

The development and operation of this centralized information exchange system is performed by Energinet.dk, the Danish TSO [B57]. The rules and rights with respect to information exchange are based on the Danish Electricity Supply Act [B58] and relevant regulations laid upon by the TSO [B59], [B60]. The DSOs are liable for the smart meters, its data and measurements which are transferred to the data-hub, whereas the information on consumers and balance settlements is submitted by the electricity-traders/suppliers and TSO respectively. The electricity players communicate and easily interact with each other through the data-hub for the use and development of the existing and new electricity grid and trading services. This also enables one-time settlements between players and facilitates several economic options for the electricity consumers. The TSO-DSO interface for system operation is limited to regulations like MVAr scheme [B61]. At primary distribution substation levels, there is a less use of automatic communication systems. The existing MVAr scheme provides guidelines to coordinate and utilize flexible reactive power resources for reactive power exchange at appropriate voltage levels in the transmission network and distribution networks to ensure operational flexibility and system security in terms of voltage regulation and dynamic stability. Also, some regulations exist for data exchanges between TSO-DSO at the physical boundaries of their control zones for system protection coordination and grid operational stability purposes. Further enlarging applications of the information exchange from the data-hub and flexibility utilization is expected to be part of prospective extensions of the electricity regulations for enhanced interactions between the Danish grid utilities and system operator to enable provisions and system tools for improved generation/load forecasting, grid controllability and grid observability, and extract appropriate system ancillary services from the distributed energy resources. There are further several grid codes for connection of power plants and wind turbines at different levels and sizes as well as recommendations/guidelines and technical specifications for systems conditions and system operation requirements, also setting up specification for data transfer and communication [B62], [B63]. When updating these, they should firmly reflect demands and possibilities related to new regulations and the expected flexibility utilization and new methods for providing ancillary services.

7.1.2 Regulation in Italy

To introduce output-based incentives it is necessary to identify metrics enabling an effective as well as a simple representation of the main benefits attainable through the investments to be promoted. The service quality indicators utilized in the incentivizing regulation (rewards/penalties) of service continuity display such a characteristic. The metrics to be adopted for the promotion of investments in smart distribution systems shall have to be subject to the following general criteria:

a. reliability: the indicators must not be influenced by variables outside the control of the subject on whom the incentives/penalties rest;

b. objectivity: indicators must be measured in an accurate, objective and fair manner, to reduce any possible dispute and litigation;
c. simplicity: indicators must be capable of bearing an immediate relation to the benefit linked with a specific investment;
d. controllability: indicators must be easily detectable through controls that do not necessitate excessive costs for the subjects or for the Authority, thanks also to executive guides on data collection and control and performance measures.

Besides the general criteria on metrics, an output-based regulation logic should not overlap other incentivizing regulations and valorisation of outputs based on a cost/benefit analysis. Following these ideas, the deliberation [B64] has been promulgated in December 2015 dealing with the Regulation for the time frame 2016-2019. It essentially recognises eligible for remuneration Smart Grid functions that aim at increasing the observability of the distribution networks and at improving voltage regulation in the MV network. These functions do not necessarily require low latency communication with users, thereby creating a basic infrastructure capable of ensuring broad interoperability. Regarding the observability of power flows and the state of network resources, the most critical areas with the highest penetration of renewable sources and/or the Primary Substations (PSs) in which the annual time portion with inverted power flow exceeds 5% are both eligible for incentives. Regarding voltage regulation in MV networks, the PSs in which the annual time portion with inverted power flow exceeds 5% and/or the most critical areas for accepting the connection of new DER are eligible for incentives. Two levels of observability are considered. Both levels require the capability of the DSO to send real-time measures of energy produced (Obs1) or measures of energy produced and estimates of both generation and consumption (Obs2); the frequency for sending the information is 20 seconds. To be eligible for rewards, the accuracy of estimates must be guaranteed on a monthly basis. Also, innovation in voltage regulation is rewarded. Again, two levels (Reg1 and Reg2) have been defined. Reg1 means improving the usage of OLTC in HV/MV transformers. In Reg1, the optimal set-point of the voltage in the busbar must be obtained by a combination of information about the real level of production and consumption and the configuration of the network. Reg2 enhances the voltage regulation by including the local voltage regulation of producers. Set-up and voltage regulation activation bands are sent to a certain number of selected producers so that the voltage profile of the line is improved. A register of improvements achieved with advanced voltage regulation must be prepared by the DSO.

The rewards are simply calculated; at the moment, only the rewards for Obs1 and Reg1 have been established whereas the rewards for the implementation of the most advanced Obs2 and Reg2 has not been monetarized yet.

7.2 REGULATION IN USA

While there has been substantial regulatory activity focused on the adoption of renewables across the United States, much of regulatory activities within the United States, related to reforming and modernizing the distribution system, have taken place in California and New York State. A brief overview of some of the aspects, related to distribution automation and data exchange between the DSO and TSO, is captured below.

7.2.1 California

The California Public Utility Commission (CPUC) issued an Order in 2014 to establish policies, procedures, and rules that directed California's investor-owned electric utilities to develop Distribution Resource Plan (DRP) proposals in accordance with the requirements of Public Utilities Code 769 [B65]. Added in Assembly Bill 327, Section 769 required a path forward for cost-effective integration of DER into distribution operations and planning that would yield net benefits to the taxpayer and more efficiently support integrated DER deployment to meet specified levels of DER integration.

The initial DRPs had to be submitted to the CPUC by July 1, 2015 are subsequently expected to be updated on a biennial basis. The filed DRP's and summary presentations can be accessed at [B66]. Topics covered in each DRP, as specified by [B67], include:

- Integration Capacity and Locational Value Analysis
- Demonstration and Deployment
- Data Access
- Tariffs and Contracts
- Safety Considerations
- Barriers to Deployment

Regarding this Brochure, the most relevant of these topics is Data Access. Even then, the focus of the topic has primarily been on planning horizon type data sets – such public availability of locational DER hosting capacity information. However, most of the DRPs did acknowledge that some types of requested real-time information is not currently or readily available. For instance, Southern California Edison's DRP states:

"For most of the data types identified in the Final Guidance, such as data related to forecasts, aggregated customer information, and distribution planning data, SCE does not update the data in real-time, nor would there be any value in collecting or providing such data in real-time." [B68]

Additionally, the DRPs acknowledged the need for collecting information from DER providers and sharing this information with the transmission system operators. While specific requirements for the data collection and sharing between the DSO and TSO were not addressed, the need for expanding and upgrading utility monitoring, communications, and data management systems to support increasing amounts of distribution automation and DER penetration were identified as barriers to deployment, see for example [B68].

Following the 2015 DRP filings, the CPUC identified three tracks to support the regulatory discussion and rulemaking; with Track 1 focused on methodological issues related to capacity and locational net benefit analysis, Track 2 demonstration and pilot projects, and Track 3 deals with policy issues including the types of grid services DER can provide [B69].

The California Independent System Operator (CAISO) provided comments to the CPUC Ruling on Track 3 Issues with specific focus on the consolidation and prioritization of the issues [B70]. Listed below are a few of CAISO's comments that indicate the current status of some issues and future needs from the TSO's viewpoint:

- Recommend instituting an additional issue area focused on "DER control and Operational Considerations in Planning" addressing which party has control and dispatch rights over the DER, prioritization of the different use-cases and obligations when dispatch rights are exercised, impact of multiple use-cases and rights to the distribution planning process, and how can the distribution utility best facilitate DER participation in the wholesale market.
- Recommend prioritizing forecasting of DER adoption along with coordinating ongoing forecasting and planning activities in the California Energy Commission's Integrated Energy Policy Report (IEPR), which is updated on a biennial basis and serves as a basis for resource and network planning at the bulk system level. CAISO, had previously noted the importance of the integration of forecasts in comments provided to [B71]. Specifically, it noted the need to be able to formally reconcile and introduce consistency in forecasts developed by different parties through different means, while considering top-down and bottoms-up drivers.

- In addition to long-term forecasting, short-term forecasting of DER was also recognized as an important future component. Nonetheless, CAISO indicated it its comments that is was not aware of any requirements for DER providers to provide real-time visibility to either transmission or distribution operators.
- The provided comments also recognized "The quality of services DER can provided to the ISO will depend critically on distribution system conditions: however, at this time there are no procedures for the distribution utility to (1) inform either the CAISO of the DER providers of how current conditions may affect the feasibility of DER responses to CAISO dispatches, or (2) coordinate DER participation in the ISO market with the distribution company" which affects the viability of DER as a Grid service provider.

7.2.2 New York State

In February 2015, the New York Public Service Commission issued an Order[2] instituting proceedings to launch its Reforming the Energy Vision (REV) initiative. This initiative aims to reorient both the electric industry and the ratemaking paradigm and intends to more fully integrate and utilize distributed energy resources (DER). Unlocking the potential economic and environmental benefits of this new paradigm, while also maintaining or improving system performance, requires robust models, holistic assessment techniques, increased system visibility, as well as new data exchanges practices and mechanisms.

The Order identifies future model distribution system utilities as a Distribution Service Provider (DSP) using the following definition:

"The DSP us an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third-party engagement that is aligned with the wholesale market and bulk power system [B72]."

Envisioned DSP functions are integrated system planning, grid operations, and market operations are:

- *Integrated System Planning* While the DSP retains responsibility for distribution planning and construction, the planning process will be required to be sufficiently transparent to allow customer and providers information upon which to base informed investments.
- *Grid Operations* DSP market commitment and performance data will be "incorporated into utility planning and operations to allow for an optimized, secure and more flexible power system, balancing supply and dynamically controlled demand-side resources including distribution level ancillary services [B72]." Operational functions identified include: real-time load monitoring and network monitoring, enhanced fault detection/location, automated feeder and line switching, and automated voltage and reactive power control.
- Market Operations, Structure and Products Expected services or products that the DSP can obtain in the near term are "grid services such as peak load modifications, non-bulk ancillary services, and load management to enable investment deferral and more secure system operations." Conversely, the DSP is expected to sell services to customer and third parties. Direct ownership of DER by utilities, however, is limited with the only real exception being energy storage.

[2] CASE 14-M-0101

Additionally, the order states, "the market must be transparent and provide DER providers and end-use consumers with the system need and price information as well as sufficient regulatory certainty so that all may invest and participate with confidence [B72]."

The REV initiative required each investor owned utility to file a Distributed System Implementation Plan (DSIP) as well as a Supplemental DSIP [B73] that would be a joint filing by the utilities addressing the tools, processes, and protocols that should be common across the State. The DSIP filings and other related documents can be found at [B74]. A few takeaways of note regarding issues discussed in this Brochure include:

- The existing levels of monitoring and automation deployed varied significantly between the utilities, but generally there is limited visibility – especially across the low voltage portions of the network.
- Monitoring and control is generally required for DER greater than 1 MW. However, many filings acknowledged the potential need to require monitoring and control for lower ratings. The ability of the utility to switch out the DER for crew safety was expressed as a strong need for this capability.
- All utilities expect to deploy more distribution management systems in the future, with volt-VAr optimization one of the main functionalities of interest.

The New York distribution utilities and the New York Independent System Operator (NYISO) have been coordinating on long-term demand forecasts in addition to energy efficiency, demand response, PV and other renewable. The coordination, however, will be expanded to maintain collaboration on forecasting approaches as well as near-term forecasting and situational awareness to determine the appropriate information exchanges.

8. CONCLUSIONS

The power grid is experiencing significant changes since an increasing number of variable renewable energy sources (VR) takes the place of more conventional forms of generation. This change is occurring together with increased production of energy in the distribution network. Simultaneously, consumers have started to become active participants in the electricity market, in the role of producer, consumer or both (prosumer). All these trends are constantly changing and therefore require interaction between TSO and DSO.

Consumers are at the heart of this change. The TSOs and DSOs should encourage this development by improving and reforming the way they interact and how they define their roles and their responsibilities.

To achieve these objectives, the network operators must make possible the access to all types of market (energy, system services, balancing) but always keeping sufficient reliability.

It is therefore increasingly important to take advantage of the opportunity to exploit and control the large and constantly rising numbers of energy resources placed at the distribution level (solar panels, wind turbines, energy storage systems) to offer services at system level.

The agreements for the operational management and planning between the TSOs and DSOs need to be reviewed and improved to support a market structure which would allow harvesting the potential improvements to the consumer.

The JWG has investigated the current level of automation at DSO level and provided technical guidelines of the future DSO automation requirements.

As identified in the survey, short-term forecasting of demand and DER is expected to be the most beneficial to all identified TSO/DSO functions.

Improved situational awareness through the application of advanced monitoring (AMI, etc.) and state estimation at the distribution level will improve overall system visibility; however, the main benefit to the TSO/DSO interface will be through more accurate short-term forecasts of net active and reactive power at defined interfaces. Topology recognition, through SCADA systems and advanced distribution management systems (ADMS), can be used to improve distribution state estimations as well as provide information on the DER connected to interfaces during normal conditions and during reconfigured system states. Additionally, the enhanced system observability can potentially provide advanced assessment of flexibility is especially relevant for the real-time operation of active network management.

The ability to schedule or dispatch active power production of DER or demand-side participation, by the DSO or other parties, is necessary to achieve many of the operational and market functionalities, but is expected to only have an indirect relationship with operational planning.

APPENDIX A. DEFINITIONS, ABREVIATIONS AND SYMBOLS

A.1. GENERAL TERMS

App Table 1. Definition of general terms used in this TB

Acronym	Definition
AAA	Authentication, Authorization and Accounting
ADS	Active Distribution System
AD	Active Demand
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
APN	Assess point name
ASM	Ancillary Service Market
AVC	Automatic Voltage Control
BaU	Business as Usual
CAIDI	Customer Average Interruption Duration Index
CapEx	Capital expenditure
CHP	Combined Heat and Power
DER	Distributed Energy Resource
DN	Distribution Network
EV	Electric Vehicles
DA	Distribution Automation
DLR	Dynamic Line Rating
DMS	Distribution Management System
DSI	Demand Side Integration
DSM	Demand Side Management
DSO	Distribution System Operator
EDN	Electric distribution network
ESS	Energy Storage System
FACTS	Flexible AC Transmission Systems
FAIDI	Feeder Average Interruption Duration Index
FAIFI	Feeder Average Interruption Frequency Index

FLIRS	Fault Location Isolation Restoration System
ICT	Information and Communication Technology
IED	Intelligent Electronic Device
IPP	Independent Power Producer
LCTA	Least Cost Technically Acceptable
LTC	Load Tap Changer
LVRT	Low Voltage Ride-Through
MO	Multi-objective
OLTC	On-Load Tap Changer
OpEx	Operational expenditure
PEV	Plug-in Electric Vehicle
PS	Primary Substation
PV	Photovoltaic
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
TotEx	Total Expenditure
TOU	Time of Use
TSO	Transmission System Operator
VLAN	Virtual local area network
VPN	Virtual private network
VPP	Virtual Power Plant
VR	Variable Renewable
VVO	Volt and VAR Optimization
WG	Working Group

APPENDIX B. LINKS AND REFERENCES

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[B69] Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge including Deconsolidation of Certain Proceedings and a Different Consolidation of other Proceedings, Application 15-07-008, filed Jan. 27, 2016. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9372

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