THE NEW ROLE OF SUBSTATIONS IN DISTRIBUTION NETWORK MANAGEMENT

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ABSTRACT

This paper presents a novel architecture for electrical distribution networks based on a decentralized control system where a Substation Automation and Control System plays a key role. This new control element brings additional control and management functionalities that are crucial for future distribution networks with high levels of Dispersed Energy Resources in both interconnected and islanded operating modes. Several coordination and control issues are addressed with the aim of optimizing grid operation in interconnected mode and simulation results are shown for voltage and reactive power control.

INTRODUCTION

The addition of Dispersed Energy Resources (DER) to the Medium Voltage (MV) distribution network and the development of microgrids at the Low Voltage (LV) level are imposing serious challenges to the electrical power distribution systems.

Future distribution networks require new planning for novel, decentralized network architectures able to incorporate all these new grid elements, including the need for new design and planning tools that rely on heuristics, probabilistic approaches, multi-scenario analyses, etc. [1].

Complementarily, it is necessary to develop new active network technologies that enable a massive deployment and control of industrial and residential generation in combination with demand side participation.

In addition, with the implementation of market structures, new market players will emerge that require significant communication infrastructure improvements for data exchanges, as well as technical support services, in order to ensure system security, controllability and optimize network operation.

In order to address these concerns, the definition of a dedicated control architecture that must include an intermediate control level under the supervision of the traditional Distribution Management System (DMS) is required. This new element – Substation Automation and Control System (SACS) – will serve as interface between the central SCADA/DMS level and the LV level, in which the existence of a microgrid management system is assumed [2]. This brings a new level for network active control

attaching even more functionalities when in coordination with the SACS. When both MGCC and SACS are coordinated, new operation algorithms can be implemented. The inclusion of the SACS enables the implementation of a large set of functionalities, even with a reduced database, since most of the feeders associated with the substation are connected only to that substation even if they may be operated as open rings.

Under these conditions, the SACS only requires the network model associated with the feeders connected to the MV busbars, up-to-date topology information and a set of variables such as voltages, active and reactive powers to implement a set of functionalities that traditionally are performed by the central SCADA/DMS.

For instance, using fault detectors located along the feeders and using reclosers or switches, the SACS is able to perform locally fault location and isolation, network reconfiguration and service restoration, without the intervention of the central SCADA/DMS, and with reduced service restoration times.

DISTRIBUTED CONTROL SYSTEM

Control and Management Architecture

In this context, the HV/MV primary distribution substation emerges as a key control element, playing an important role in both management and control of the downstream distribution network. A generic scheme of the control architecture proposed here is shown in Figure 1.
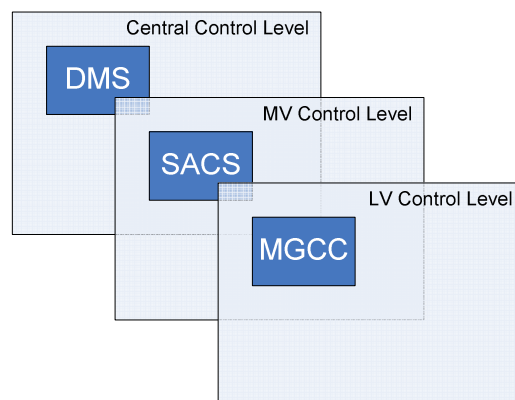

Figure 1 – Distribution Network Control and Management Architecture

The proposed network architecture uses three control levels:
- Central Control Level – at the top of the control hierarchy, the DMS is responsible for the supervision, control and management of the distribution system and serves as an interface between distribution and the transmission systems.
- Medium Voltage Control Level – an intermediate control level corresponding to the SACS to be housed in the HV/MV substations, which will accommodate some functionalities normally assigned to the DMS, as well as new ones, and will be responsible for interfacing the DMS with lower level controllers.
- Low Voltage Control Level – corresponding to the MicroGrid Central Controller (MGCC), to be housed in MV/LV distribution substations, which will be responsible for managing the microgrid, including the control of the microsources and responsive loads as well as managing storage systems.

The proposed control architecture will enable a coordinated management of both MV networks (including DER connected to this system) and microgrids at the LV level (through an MGCC installed at each MV/LV substation), together with an active load management approach.

The microgrid concept envisaged in this architecture has been developed within the framework of MicroGrids and More MicroGrids European research projects [3].

Although the control scheme is based on a hierarchical structure, it must use a decentralized approach, with a certain degree of autonomy of lower-level controllers. This is justified by the dimension of the distribution system, as it would be unpractical to overload the Central Control Level (*i.e.* the SCADA/DMS). This architecture follows the change in paradigm of electrical power systems that are moving away from conventional, fossil fuel-based centralized generation to a system with DER mostly based on renewable energy sources such as wind or solar.

The physical architecture of the distribution system is shown in Figure 2.

This type of architecture will enable the possibility to operate the distribution grid in two distinct modes:
- Normal operating mode, where the system is operated interconnected to the main distribution network;
- Emergency operating mode, where the system is operated in islanded mode, disconnected from the main power system.

Nowadays, a new set of control variables related to DER injections, active loads that can be managed, in conjunction with conventional devices (such as transformer taps, capacitor banks…) allow the improvement of operation performance and a better exploitation of the grid capabilities. The use of feeder automation equipments that can communicate with the SACS allows the inclusion of a set of functionalities at the substation level that, until now, could only be done at a central level by the central SCADA/DMS.

The SACS will require information from other Intelligent Electronic Devices (IED) located along the feeders and Distribution Transformer Controllers (DTC) sited at the MV/LV substations.

Those IED may be reclosers or switch controllers that enable control of those switching devices but also allow the remote monitoring of voltages, currents, frequency, active and reactive powers, and may also perform fault detection, a capability that is required to enable fault location and isolation.

In the MV/LV substations, DTCs allow the remote control of switching devices and the monitoring of variables associated with the MV and LV sides of the transformer.
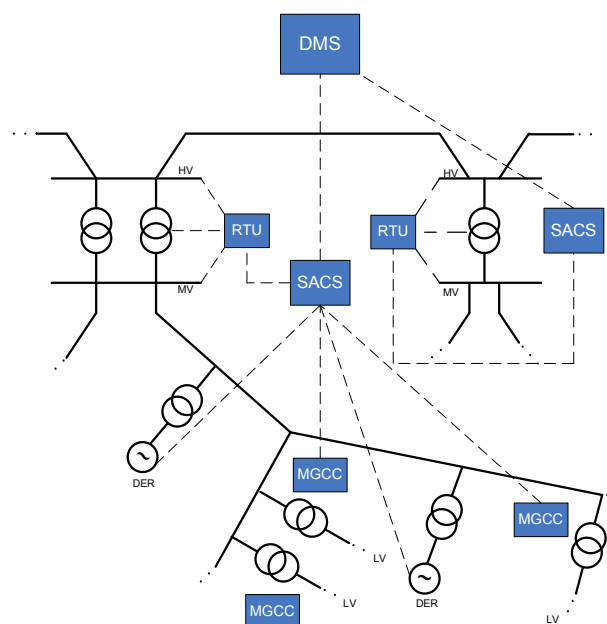

Figure 2 – Distribution Network Physical Architecture

Communication Requirements

In order to enable the functionalities indicated, the SACS must be able to communicate with the MV/LV substations and other devices such as reclosers and switches located along the feeders. A real time information system is necessary to feed the optimization algorithms with the needed updated input parameters.

Low bandwidth channels may affect the overall system performance so either broadband Power Line Carrier (PLC) or broadband wireless channels (such as GPRS/UMTS or WIMAX) are required.

NETWORK OPERATION CHALLENGES

Having a dispersed data acquisition and processing system, control capabilities and automation algorithms sited at the primary distribution substation is a big step towards network operation optimization. The HV/MV substation would monitor and control local IEDs, fault locators, switches and all devices installed along the feeders. Having real time information about voltages, currents, power flows and frequency and with the information provided by the MGCC,

local network operation could be optimized using reconfiguration, voltage VAr control, losses minimization specific applications that will increase network efficiency and will improve local reliability by decreasing restoration times. Moreover, assuming that a primary substation would have few microgrids attached to it, a wider vision over the MGCCs would allow a joint dispatch of several DERs making it possible to account with generation capacity and ancillary services for the LV and MV network. Such controls will need to communicate with the utility's SACS to provide the information needed to operate the network in an optimal way resulting in new control capabilities accessible to the Distribution Network Operator (DNO) exploiting distributed generation capabilities.

While nowadays Remote Terminal Units (RTUs) resident at this level just communicate upwards with SCADA systems centrally located, new intelligent SACS would enable the implementation of Demand Response processes interacting with microgeneration profiles.

Since DER would bring new challenges for distribution networks, with constantly changing parameters and various technologies present, voltage problems are likely to occur depending on the penetration levels, generation profiles, network type and topology [4]. The SACS would open the door for local control algorithms softening the amount of processes that today's central systems have and which is expected to increase with increase in DER penetration. In addition, all the expected issues with bi-directional power flows, fault level increase and losses optimization can be dealt with locally by distributing processing resources among primary substations and minimizing network operation costs.

Advanced Control Functionalities

As presented previously, two operating modes can be envisaged for the operation of the MV grid: normal mode and emergency mode.

In normal operating mode, several functionalities can be implemented which include local state estimation, voltage and reactive power control and self-healing capabilities for reducing interruption times such as fault location and isolation, network reconfiguration and service restoration. One of the most important functionalities in normal operating mode will be voltage and reactive power control that, due to the specific characteristics of distribution systems, will require a new management approach able to deal with simultaneous large-scale integration of DER directly connected to the MV network and microgeneration at the LV level.

On the other hand, an emergency mode can be considered by assuming the possibility of exploiting the MV grid in islanded mode, where DER are used for this purpose. Under this emergency mode, black start can also take place involving islanded operation and synchronization steps. In the islanded operating mode the substation and its associated MV and LV networks (including MV loads and generators, LV loads and generators at the microgrid level) will operate isolated from the main power grid. The interest in such capability also requires the development of an extended set of control functionalities to be implemented at the substation level. In this case, frequency control stands as the most important functionality that is expected to be installed at the substation level (namely when adopting a type of secondary control approach) to deal with local islanded scenarios and system synchronization.

Fault Location and Isolation, Network Reconfiguration and Service Restoration

Using the information of fault locators located along the feeders, the SACS is able to identify the feeder section where the fault occurred and, by operating both upstream and downstream switches, isolate that feeder section. After fault isolation, the feeder circuit breaker located at the HV/MV substation can again be closed, restoring the service to part of the loads.

Using pre-fault information about load levels, the SACS is also able to identify alternative paths, using other feeders of the same substation, and reconfigure the network in order to restore the service to loads that were left without supply after the fault isolation process.

The service restoration process may involve more than one substation. In this case a centrally coordinated action, at the central SCADA/DMS level may be required.

Voltage and Reactive Power Control

In this section, a new methodology for coordinated voltage support in distribution networks with large integration of DER and microgrids is described with some detail. This functionality can be implemented in the SACS for optimizing distribution network operation in interconnected mode, when dealing simultaneously with DER connected directly to the MV grid and microgeneration installed at the LV side.

Given the characteristics of the LV networks (namely a low X/R index), traditional control strategies using only reactive power control may not be sufficient in order to perform efficient voltage control since active / reactive power decoupling is not valid [5]. Therefore, in scenarios with high microgeneration penetration, generation shedding must also be employed.

The control algorithm proposed uses all traditional control approaches for voltage and reactive power control namely managing On-Load Tap Changing transformers, reactive power provided by DER sources and capacitor banks together with active power control at the microgrid level in extreme scenarios (using microgeneration shedding mechanisms).

The coordinated voltage control problem is a non-linear optimization problem containing both continuous and discrete variables that can be formulated as follows:

$$\min \sum P_{loss} + \sum \mu G_{shed}$$

subject to:

$$V_i^{\min} \le V_i \le V_i^{\max}$$

$$S_{ik}^{\min} \le S_{ik} \le S_{ik}^{\max}$$

$$t_i^{\min} \le t_i \le t_i^{\max}$$

$$Q_i^{\min} \le Q_i \le Q_i^{\max}$$

where:

P_{loss} – Active power losses
μG_{shed} – Amount of microgeneration shed
V_i – Voltage at bus i
V_i^{min}, V_i^{max} – Minimum and maximum voltage at bus i
S_{ik} – Power flow in branch ik
S_{ik}^{min}, S_{ik}^{max} – Minimum and maximum power flows in branch ik
t_i – Transformer tap of or capacitor step position
t_i^{min}, t_i^{max} – Minimum and maximum tap

An optimization tool based on a meta-heuristic approach (Evolutionary Particle Swarm Optimization) was developed to address the coordinated voltage control problem at MV and LV level [6]. It uses an Artificial Neural Network to emulate the behaviour of the LV microgrid system.

Some of the main results obtained using MV and LV test-networks are presented next. The networks used are based on real typical Portuguese rural grids and have a radial structure. The MV network contains several DER units (mostly based on hydro and wind generation) and microgrids. The LV microgrid is assumed to contain a massive penetration of PV-based generation.
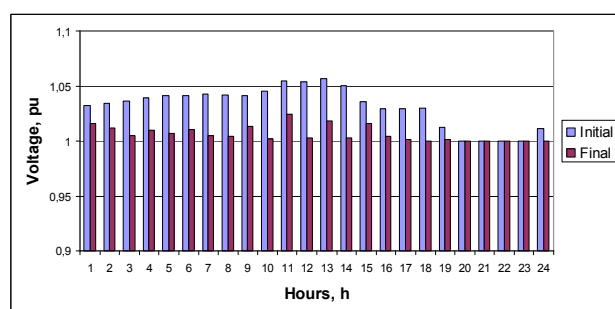

Figure 3 - Maximum Voltage Values inside a Microgrid

Figure 3 compares the base situation without the voltage control functionality (Initial) and the result obtained from the application of the control algorithm (Final) in the LV microgrid for each of the 24 hours of a typical day. It can be seen that the voltage values were out of an admissible range of ± 5% due to the massive penetration of PV-based microgeneration that generated power outside the peak demand hours but the algorithm succeeded in bringing voltage profiles back to admissible values.

Figure 4 shows that some microgeneration shedding was required (difference between Initial and Final values for microgeneration) in order to bring voltage profiles back

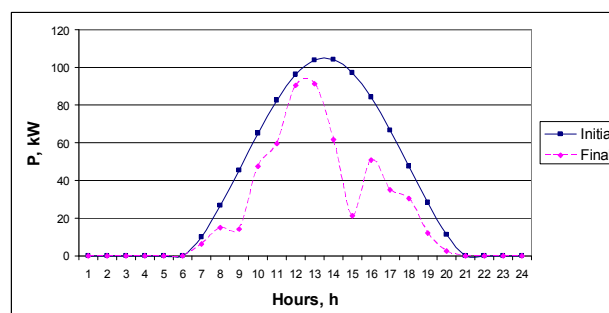within admissible limits (presented in Figure 3).

Figure 4 – Total Microgeneration inside a Microgrid

CONCLUSIONS

Distribution networks of the future require a coordinated, decentralized control approach in order to accommodate efficiently DER at the MV level, microgeneration and demand side participation at the LV level.

The proposed control approach addresses this issue by introducing a new system element – the SACS – located at the substation level to interface the LV control level with the DMS. This new system will allow the implementation of several functionalities essential for future distribution networks operating in normal or emergency mode. Such functionalities include fault location and isolation, network reconfiguration, service restoration and voltage / reactive power control. In particular, the voltage control algorithm presented has proven to be efficient in maintaining voltage profiles within admissible limits for the test networks used. In addition, the definition of communication requirements is essential in order to ensure good performance of the new control and management system.

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