

DG BEHAVIOUR AND PROTECTION SCHEMES IN CASE OF DISTURBANCES WITHIN THE CONCEPT OF DISTRIBUTION GRID AREA

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ABSTRACT

This paper describes the state of the art and future trends of adaptive protection systems, aimed at strengthening the penetration of Dispersed Generation (DG) units considering bidirectional power flows, while improving their operational behaviour within high network reliability and stability levels. Short-circuit currents, anti-islanding detection, voltage, current and frequency safe operation limits are addressed within the Distribution Grid Area concept.

INTRODUCTION

Protection relays perform an important task assuring the integrity and secure operation of distribution networks, under contingency circumstances avoiding negative impact on power assets and assuring human safety.

Traditionally, MV feeder protection relays are meant to be used in structured top-down networks, with radial topology, where power flows are unidirectional. Configuration settings are then assigned to each protection device, having in mind the different types of faults, the protection zone each relay is responsible for and the expected directionality.

Nowadays utilities face an increase of DG, impacting on what normally were unidirectional power flows. Protection schemes have been successfully defined and deployed together with substation automation, coping efficiently with transient disturbances always on a top-down perspective. This is becoming less applicable as the penetration of renewables is introducing time dependent bidirectional power flows, sometimes not predictable due to its intermittent nature. However, technology is able to tackle this situation, as long as proper infrastructures are available. Smart grids bring the adequate architecture, functionalities and communication interfaces between equipments capable of providing the necessary requirements for this issue.

This paper presents architecture concepts and coordination proposals for dealing with the DG dynamics, as well as with topology changes arising from self-healing or operational switching schemes.

PROTECTION SCHEMES

The design of distribution networks is commonly characterised by the extensive deployment of radial feeders. Even where topological changes are possible, for example in the case of a ring fed from two different substations, radial topology is usually maintained during system operation. Simple protection schemes have been deployed successfully for these network topologies,

both at substation and feeder side. However, this conventional approach did not consider challenges that DG introduce nowadays.

Protection relays deal with a multiple range of faults and disturbances. Each protection device must be able to observe and protect a specific zone of the grid, on a time-of-day basis, without compromising the coordination with other protective devices, namely reclosers installed along the feeder or fuses in MV/LV distribution substations. Its settings result from the predictability of top-down power flows, typically in feeders where loads are fed by the upstream substation.

Over-current protections for phase-to-phase and phase-to-ground faults are available. Directionality is usually not necessary for phase-to-phase faults, the coordination being typically achieved by different operation thresholds and trip time delays. Phase-ground faults present a harder challenge, being usually complemented with directional options fitted to the specific neutral connection present in the substation. These specific features guarantee protection scheme dependability and security, avoiding that a fault on a feeder affects its neighbouring feeders.

Other protection functions are also available for disturbances such as over-voltage, voltage sags, or frequency variations. Concerning DG, protection relays must also be in accordance with grid codes, for which special schemes are available such as rate of change of frequency (ROCOF) or vector shift protection.

DG DYNAMICS

Distribution networks were designed to be passive systems, not being able to receive high quantities of energy, namely generated from intermittent DG.

DG, as being more and more present in the distribution network, in the form of renewable sources, brings intermittent behaviour to the network operation. To some extent, it is possible to predict with an uncertainty level, a daily DG profile, e.g. solar or wind source. Yet, its real time behaviour might not be exactly what the operator was expecting creating mismatch problems in the real and reactive power balance between load and generation, as its intermittence impacts negatively on voltage and frequency variations.

From a substation perspective, feeder protections support the needed clearance of phase-to-phase and ground-faults, as well as under and overvoltage or under and over-frequency disturbances, considering that feeders are passive and there is no DG penetration, which is not the case under analysis. Currently, the penetration level of DG is considerably high,

influencing the power flows and their directionality across feeders and the substation, and, together with the dynamics of topological changes arising from operational decisions (improving network conditions, self-healing), impose a huge challenge for protection coordination and selectivity.

DG also contributes to short-circuit power variation, which subsequently affects fault current magnitude, and may shorten the reach of protection stages, increase fault clearance time (particularly for time inverse curves) or prevent protection trip at all.

On the other hand, protection relays play an important role dealing with voltage and frequency oscillation, thus preventing installations, including DG, to maintain their power injections under certain undesirable conditions.

Generation units islanded operation is not recommended even in the case where there is no fault, but a voltage or frequency load shedding has only occurred. The occurrence of islanding of a network section is undesirable due to the lower power quality characteristics and lower safety it brings, as well as to avoid having to deal with desynchronized (out of phase) reconnections, or to deal with fault clearing procedures that may fail.

This way, DG brings a new dynamic requirements to the protection issue, as coordination of passive methods for dealing with nuisance or unwanted tripping require a trade-off between reliability and events selectivity [1].

Nuisance tripping can be described as the inability of the protection associated with the DG to distinguish voltage/frequency variations due to islanding operation from other external events, such as upstream disturbances at HV level, faults in adjacent feeders or sudden load changes. This unwanted tripping (Figure 1) affects economically DG producers. As DG is supposed to sustain the network under voltage or frequency disturbances, unwanted tripping may trigger a chain reaction with further loss of generation, with the possibility of a complete collapse, not to mention the reduction of the lifetime of certain generation units, such as synchronous machines and gas turbines [2].

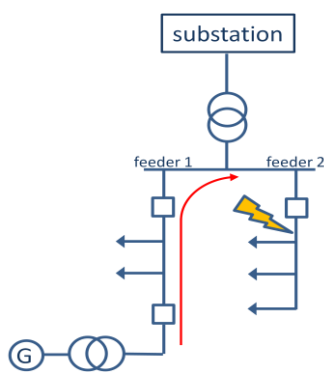


Figure 1 - Nuisance tripping due to an adjacent fault

Nuisance tripping relates closely to anti-islanding protections and the way they are coordinated.

BOOSTING DISTRIBUTED GENERATION

The increase of installed DG power plants from renewable energy sources and the enhanced control performance achieved by power electronics converters allow a new approach to the protection scheme adopted, namely by active regulation of active and reactive power supplied by renewable energy sources (RES).

Figure 2 shows a 1 MW PV power plant and the influence of the RES in the MV grid voltage, as well as the reactive power (provided by local algorithm in the power electronics converter) profile, dependent on the active power contribution.

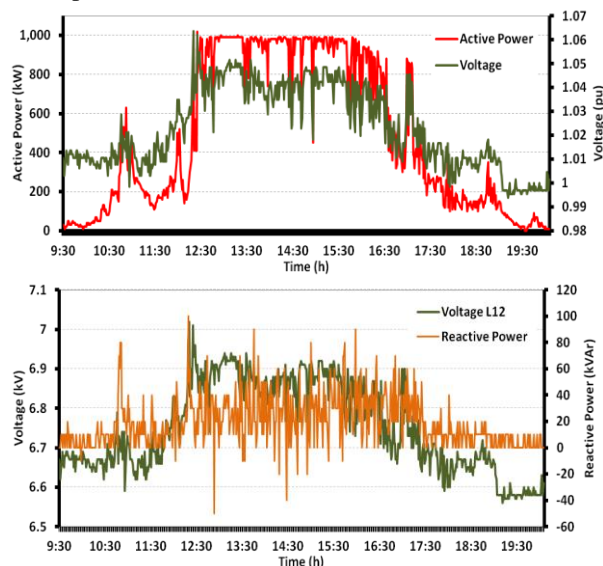


Figure 2 - Influence of a 1 MW PV plant in the MV grid

This DG unit is installed at Porto Santo, Madeira Island. It is a PV power plant with 2MW installed capacity but able to operate 2 groups independently of 1 MW. In this case, only 1 group was connected to the network since the connection of the total capacity would cause voltage rise problems, leading to overvoltage protections tripping. This is due to the low local demand and the characteristics of the network given that it is a physically islanded system.

The influence of power injection on the network voltage can be easily correlated. There is a considerable voltage rise when the generator is injecting energy to the grid. Even with local reactive control on the inverter, voltage profile exceeds 7kV (1.06pu) forcing the other PV group to remain disconnected.

An integrated design between DG control and the substation automation and protection system, allows the implementation of more reliable and adaptive controls in terms of fault level set up (short-circuit currents, anti-islanding detection, voltage, current and frequency safe operation limits), providing a more secure, predictive, available and reliable supply of RES power plants.

An integrated control architecture allows the minimization of problems while maximizing the energy

production of the RES and enabling the grid to better cope with transients phenomena (thru active control of reactive component), as well as adapting itself to the different grid code requirements.

PREVENTIVE ASSESSMENT

The behaviour of protections for passive feeders is affected by the upstream short-circuit power, as well as by any downstream reconfiguration that may result from operational switching or self-healing schemes, as a consequence of network topology changes.

When feeders have DG assets connected, they also influence the dynamic of the short-circuit power, affecting the coordination of protection relays. In particular cases, the anti-islanding protection schemes may fail due to uncoordinated settings between the ROCOF protection at the DG and feeder protections. DG plays also a role on changing the directionality of power flows, even contributing to unbalance transformer N+1 redundancy at substations, as security is normally designed on a top-down perspective [3].

The distribution network, with this entire DG dynamic, may be assessed preventively, in terms of demand, network topology and power flows, stability, voltage profiles, as well as contingency risk, the latter including weather forecast conditions. The authors propose the application of the Distribution Grid Area (DGA) concept [4]. A DGA is a network area defined according to utility criteria where an intelligent system sited at the primary substation plays the role of DGA master, hereafter called Smart Substation Controller (SSC) [5].

The SCC holds a data model of all downstream feeders, their tie points to other feeders, and their relation with adjacent substations, as well as of all DG assets present in the feeders. Also, a comprehensive and adequate communications infrastructure must be in place to ensure interfaces with the control centre, sensors, actuators, switches, telemetered data and protection devices deployed throughout the grid. The SSC has local intelligence capable of executing self-healing algorithms after a network disturbance.

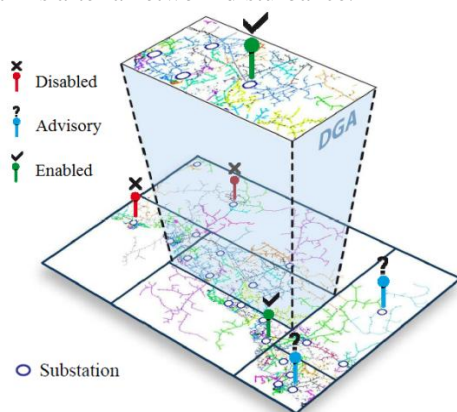


Figure 3 - Representation of several DGA and their status

Each DGA is a zone for fast and accurate protection schemes coordination, a task to be performed in real time. The centralized SCADA/DMS performs network assessment tasks over the whole network divided in several DGAs, sending to each one's SSC pertinent short-circuit power data, as well as assigning them with a tag for autonomous protection parameterization. The received data drives the overall dynamic adaptive protection setup coordination, which will be held at DGA level, carried out by its SSC. By receiving such tag, each DGA's SSC becomes aware about its role for protection coordination setup: disabled, enabled or advisory.

Disabled

The DGA's SSC is not authorized to perform any autonomous setting of adaptive protections, due to constraints imposed by the performed operational assessment carried out at SCADA/DMS level, e.g. a) entering into a high state alert for dealing with fault occurrences that may arise from weather conditions, b) maintenance tasks being carried out or programmed for some portion of the DGA's network, c) non-normal network configuration (cut, jumper). In these circumstances, only the SCADA/DMS may instruct the DGA's SSC to carry out specific upgrades on protection settings, for instance, shortening the Non Detective Zone of voltage and frequency relays.

Enabled

The DGA's SSC is fully granted with the right to perform any autonomous setting of adaptive protections, as a result of the mentioned operational assessment, (e.g. normal operating conditions, no problems expected from outage management or SCADA/DMS systems). While enabled, each DGA's SSC will take into consideration any short circuit-power data sent by the SCADA/DMS, while using its awareness of the downstream feeders and their inter-connection to other feeders. The available data will drive the execution of any new setting for the feeder protections and RES DG units protections as well.

Advisory

The DGA's SSC, upon detecting a situation candidate to carry out some new adaptive protection settings, will propose the corresponding actions, informing the control centre. Remotely, an authorized user will assess the group of protection setup proposed steps, by validating, contesting or changing them according to his/her own operational view and expertise.

The setting of protections, by the SSC at each DGA, can be performed in two ways: a) either by using pre-defined protection setting groups configured at the protection relay; b) by dynamically changing specific operational setting.

Pre-defined protection setting groups

This option is common, as manufacturers provide this kind of feature, available at protection relays. The typical range of setting groups may vary from 4 to 8, depending on the manufacturers. The protection relay has no ability to detect the most convenient pre-defined setting group, as this decision carries the responsibility of knowing the neighbourhood segments or even farther network conditions. But the protection relay can switch between more convenient setting groups as a response to a remote control sent by the DGA's SSC. As the SSC is as high processing power system and has a data model, its specific coordination application for protection setting determines which protection relays should change their setting groups. This task is performed by sending to each protection relay a remote control stating the new setting group number.

The authors rely on this approach to undertake dynamic configuration of protection settings, as this is feasible and simple. There is the limitation of the number of setting groups, available by manufacturers for their protection relays, but, at least for the most important cases, this flexibility may be enough as it is worthy.

Dynamically changed operational settings

For the cases where the mentioned limitation is really an issue, the protection relay must be sufficiently dynamic on its settings, thus allowing that a component hierarchically above would be able to change the protection settings according to a certain criterion, a role perfectly suited for the SSC. In this case, more flexible and accurate, relying on the SSC skills and ability to perform correct protection coordination, as it has been discussed in this paper, the limitations, if any, fall on the protection relay, which, in turn, should be equipped with such dynamic setting feature.

Constraints

The setting of protections by the SSC, as described before, faces a constraint. The role of the SSC, at DGA level, aims at managing all the protection selectivity settings for those protection relays participating actively in that specific DGA, for improving DG performance and reliability within the network area assigned to the DGA. As each DGA may have more than one substation, it means that the SSC may need to recommend changes on the protection settings of a protection relay from another substation, although belonging to the same DGA. The authors propose IEC 61850 as an improved inter-substation protocol/model driving this feature, as communication media seems not to be a constraint.

DGA role for performing DG controls

When integrated with the DG control system, the DGA's SSC can also calculate adaptive controls aiming at providing a more secure, predictive, available and

reliable supply of RES power plants. Sending set-points to the DG units controlling their output enables a more efficient and secure network operation within that area.

CONCLUSIONS

The authors proposed a model for improving the selectivity of protection relays, by performing dynamic tuning of their protection setting, aiming at enhance the role and performance of DG. Nuisance tripping will be minimized, limiting the impact of adjacent feeder faults. The role of the Smart Substation Controller (SSC) within the concept of the Distribution Grid Area (DGA), for managing the setting of protection relays was described, highlighting the different modes of autonomy assigned to the DGA and its role regarding the control centre. Furthermore, it was shown that the DG inverter controller can benefit from the network conditions awareness that the DGA's SSC can bring, as it can send set-points to the DGA inverter, in order to inject more reactive power, when needed, by compensating certain short term voltage dips.

The integration of DG control and the DGA's SSC has great potential to boost DG, as it may improve its reliability, while meeting grid code requirements.

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