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DERlab

International White Book on DER Protection: Review and Testing Procedures

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Abstract:
This white book provides an insight into the issues surrounding the impact of increasing levels of DER on the generator and network protection and the resulting necessary improvements in protection testing practices. Particular focus is placed on ever increasing inverter-interfaced DER installations and the challenges of utility network integration. This white book should also serve as a starting point for specifying DER protection testing requirements and procedures.

A comprehensive review of international DER protection practices, standards and recommendations is presented. This is accompanied by the identification of the main performance challenges related to these protection schemes under varied network operational conditions and the nature of DER generator and interface technologies. Emphasis is placed on the importance of dynamic testing that can only be delivered through laboratory-based platforms such as real-time simulators, integrated substation automation infrastructure and flexible, inverter-equipped testing microgrids.

To this end, the combination of flexible network operation and new DER technologies underlines the importance of utilising the laboratory testing facilities available within the DERlab Network of Excellence. This not only informs the shaping of new protection testing and network integration practices by end users but also enables the process of de-risking new DER protection technologies.

In order to support the issues discussed in the white paper, a comparative case study between UK and German DER protection and scheme testing practices is presented. This also highlights the level of complexity associated with standardisation and approval mechanisms adopted by different countries.

International White Book on DER Protection: Review and Testing Procedures

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ABSTRACT

This white book provides an insight into the issues surrounding the impact of increasing levels of DER on the generator and network protection and the resulting necessary improvements in protection testing practices. Particular focus is placed on ever increasing inverter-interfaced DER installations and the challenges of utility network integration. This white book should also serve as a starting point for specifying DER protection testing requirements and procedures.

A comprehensive review of international DER protection practices, standards and recommendations is presented. This is accompanied by the identification of the main performance challenges related to these protection schemes under varied network operational conditions and the nature of DER generator and interface technologies.

Emphasis is placed on the importance of dynamic testing that can only be delivered through laboratory-based platforms such as real-time simulators, integrated substation automation infrastructure and flexible, inverter-equipped testing microgrids.

As DER technologies and operating conditions become more complex, novel DER and network protection schemes may be required. Barriers to their deployment are investigated while discussing integration strategies for new protection technologies through effective testing. Observations are also made where protection policy deficiencies exist to cater for such schemes.

To this end, the combination of flexible network operation and new DER technologies underlines the importance of utilising the laboratory testing facilities available within the DERlab Network of Excellence. This not only informs the shaping of new protection testing and network integration practices by end users but also enables the process of de-risking new DER protection technologies.

In order to support the issues discussed in the white paper, a comparative case study between UK and German DER protection and scheme testing practices is presented. This also highlights the level of complexity associated with standardisation and approval mechanisms adopted by different countries.

CONTENT

1 INTRODUCTION

Power system protection is a safety critical component of all electrical systems, and therefore, testing and validation have always been of vital importance. In a conventionally designed electrical system, the emphasis in terms of reliability has always been placed on the transmission system level protection, where very stringent and detailed type testing procedures and regulations have been developed over many years of engineering practice. Distribution system protection, due to the passive nature of the network, cost constraints and lesser impact on the stability and safety of the overall system, has always been designed in a simpler manner and the testing requirements were, therefore, less demanding. With the swiftly increasing penetration of various electrical energy sources at all distribution levels, conventional protection schemes and the procedures for their testing and validation are often insufficient. A number of limitations and issues of existing protection practice have been already identified in the technical literature. Some of these problems can be addressed with small alterations of existing practice, while others call for the development of new protection techniques or, at the very least, the use of existing transmission type protection schemes.

This white book aims to review the main DER related protection system issues and known solutions in future distribution systems with a diverse mixture of energy sources. In particular, testing procedures are emphasised as a way of ensuring sufficient protection system reliability and performance.

The document is organised as follows:

− Section 2 reviews the existing Distributed Energy Resources (DER) technologies in terms of their performance in general, and dynamic response to network faults in particular. A short review of typical DER connection and protection arrangements is also included.

− Section 3 outlines the main challenges to protection system (both network and DER related) and discusses a number of potential solutions. The need for carefully designed validation procedures is emphasised and a hardware-in-the-loop (HIL) based validation methodology is proposed.

− Section 4 is a comprehensive summary of existing procedures and testing methods of protective devices and schemes.

− Section 5 includes case study results based on real time simulation testing of a DER protection relay. For comparison purposes the tests were performed using German and UK recommended settings.

− Section 6 includes the main findings and recommendations for testing of DER protection.

2 IMPACT OF DER ON POWER AND PROTECTION SYSTEM PERFORMANCE

2.1 Scope

The level of penetration of DER, particularly Renewable Energy Sources (RES), is set to increase dramatically over the next 30 years [1]. DER is normally defined to be the generation which is connected to an MV/LV distribution system, targeted to meet the local customer demand. However, some power supply or storage systems connected to the transmission level, which are not controlled by the utility, can also be regarded as DER, e.g. wind farms in Scotland connected at 132kV, where the total power production substantially exceeds the demand of local customers [2]. Hence, the definition of DER in this paper captures a wide scale of both small and large power sources.

2.2 DER technology and practices

DER covers a broad range of technologies, including diesel generators, gas turbines, micro-turbines, CHP, fuel cells, small hydro plants, wind turbines, biomass generators and photovoltaic generators. In addition, DER also encompasses energy storage systems such as batteries and flywheels as they can be used to harness excess electricity produced by the most efficient generators during low load levels [3].

Although RES are the preferred class of DER that should be used in meeting the demand of EU energy policy, their implementation and penetration in existing power systems is limited by local environmental conditions and their intermittent nature. The utilisation of the wind resource is relatively low in countries such as Norway, France and the UK compared to Denmark, Germany, Spain, Portugal and Ireland. In Norway and France there is less concern about greenhouse gas emissions due to the high contribution of hydro power (Norway) and nuclear power (France), but there is a need for a greater diversity in the generation mix. The UK is very dependent on conventional thermal generation, especially from coal and gas [4], and there is a great emphasis on growing the contribution of DER in meeting the overall system demand. To meet the government's 2020 renewables target, large volumes of onshore and offshore wind generation are expected to be constructed, whilst, nuclear energy would also be considered in the long-term development [5]. Spain and Portugal have ambitious objectives for wind power growth. In Denmark and Germany, there is a tendency to develop off-shore wind farms due to the increasing difficulties in finding appropriate locations for on-shore installations [3].

2.3 Impact of DER installation

Understanding of the characteristics of different types of DER and their impact on the power system, including steady state and dynamic system performance, is essential to the design of effective DER protection and control arrangements. The main issues with respect to system operation and protection in light of DER installations are listed below:

- Conventional distribution systems are designed as radial systems with unidirectional power and fault current flows. The addition of DER results in bi-directional power flows and in fault current infeeds from "downstream" generation in some cases, which may require modified and/or additional protection provisions.

- Varied fault contributions from different types of DER make traditional overcurrent grading more challenging.

- Network voltage profile and regulation can be affected by DER.

- Inappropriate grounding arrangements may result especially during intentional islanding.

- Out of synch auto-reclosure due to frequency drifts caused by DER following initial disconnection from the main grid (e.g. resulting from fault clearance).

2.3.1 Power flow direction and voltage regulation

Most distribution systems operate in a radial configuration, which results in unidirectional power flows and this means that overcurrent protection or fuses can normally be used for correct fault detection and isolation. However, the installation of DERs may cause bi-directional power and fault current flows, which is uncertain due to their generating capacity, mode of interfacing to the system, operating mode, and load conditions. Graded overcurrent protection may therefore become ineffective in providing selective fault isolation. The problems that were only applicable to transmission systems are becoming more evident in distribution systems.

Conventional voltage regulation in distribution systems is normally achieved through Load-Tap-Change (LTC) transformers in the substations, and sometimes enhanced by switching capacitor banks [6]. This regulation method is based on the fact that power flow is always uni-directional from grid substations to the end of feeders. The presence of DER could have a significant impact on voltage profile, which depends on the DER technology, control method, location and level of power generated [7], [8]. When one DER suddenly connects or disconnects from the system, abrupt change of voltage profile (overvoltage or undervoltage) might cause undesirable tripping of network protection devices and/or other DER interface protection systems. Hence, when DER has a significant impact on maintaining system stability and security, i.e. wind parks connected to the transmission level, capability of Low Voltage Ride Through (LVRT) or Fault Ride Through (FRT) is mandatory [61]. These requirements have been specified in several grid codes including Irish Electrical Code [6] and the German Grid Code [63]. Furthermore, in the light of

significant increase of penetration of DER in the medium-voltage network, FRT capability becomes also required at this level according the German technical guidelines in [12].

2.3.2 Dynamic response of different types of DER

<u>Synchronous machine</u>

Most conventional thermal generators as well as CHP microgeneration driven by reciprocating engines utilise three-phase synchronous machines. Under steady state operation, a DC source is used for excitation. A synchronous generator always runs at a synchronous speed with a rotor angle corresponding to its electrical output power and mechanical input power. When multiple synchronous machines are connected in parallel, their rotational speeds and output frequency must be synchronised [9].

During a transient fault situation, although the electric power output is reduced, the field current supported by the excitation system persists, which maintains the voltage in the stator winding and in turn supplies a continuous fault current. This results in a sustained short-circuit current with a DC offset. As the short circuit current continues to flow in the system, the machine's winding equivalent impedance increases. This results in a faster fault current decay. Three reactance variables (subtransient, transient and synchronous) have been introduced by IEEE Std. 141-1993 to characterise this phenomenon [14]. According to [15], the decaying fault current characteristic depends on the fault position and rated power of the machine: close-up faults will have longer decay times than remote faults. Even small synchronous machines with limited fault current capability can produce up to three times full load output after a relatively short decay due to their excitation systems.

Should the grid fail to absorb sufficient amount of generator kinetic energy, gained from acceleration during the fault, the synchronous machine becomes unstable (i.e. loses synchronism with the rest of the system) after the disturbance is cleared. In this case, suitable protection should be provided to detect this instability and disconnect the DER from the utility network (e.g. pole slip protection). Alternatively, other methods of improving the transient stability of synchronous DER are used and can be found in [3].

<u>Induction machine</u>

Though induction machines are more commonly used as motors in the power system, some DER units utilise this type of generator due to their simplicity of construction and ability of producing active power at varying rotor speeds. They are often used in wind turbines and some micro hydro generators. The prime mover drives the induction machine rotor above the synchronous speed, thus producing active power that is exported to the utility network.

Since induction machines do not use external DC sources for excitation, the field flux decays rapidly on the loss of external source of voltage following a fault condition. Consequently, under

symmetrical fault conditions, there is no steady state fault current and the current output rapidly decays to zero. Therefore, only a subtransient component exists for induction machines [16].

Power electronics interfaced machine

Power electronics can be used as an interface for a wide variety of energy sources. They convert the DC energy for connection to the AC system or decouple small rotating machines from the network and thus provide more flexibility in terms of machine rotational speed and efficiency of energy capture (e.g. wind). Other benefits of power electronic interfaces are their fast control of active and reactive power as well as voltage regulation, which can potentially enhance the operation of a weak remote network or support intentional islanding [17], [18]. The typical arrangements of using a power electronics interface for DER installations are presented in Figure 2-1. When interfacing with the DC power sources (fuel cells, batteries, etc.), a DC-AC inverter is used to regulate the AC output of DER into the grid. When used with a rotating machine, an AC-DC rectifier is added to rectify the uncontrolled AC power source. DC-DC converters are almost always found in photovoltaic battery charging systems to regulate and optimise the power input [17].

| Engine or Turbine | Synchronous or Induction Generator | AC-DC Rectifier | DC-AC Inverter | DER interface protection and metering |

| PV, Fuel cell, Storage system | | | DC-AC Inverter | DER interface protection and metering |
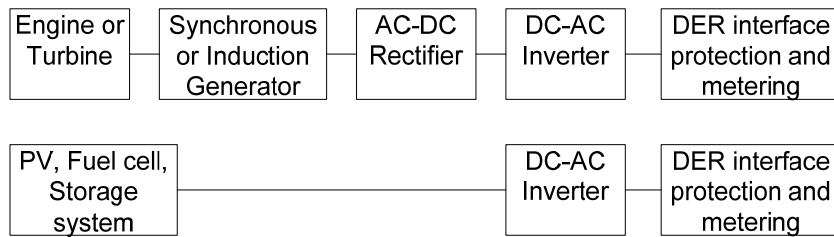
Figure 2-1: Basic connections of inverter based DER [17]

The fault behaviour and capability of the inverter is a function of the control design and the size of the power electronic components (which are usually influenced by cost). This area is currently not completely understood or standardised and there are only limited guidelines as to the minimum or recommended fault contribution of an inverter interfaced DER [19]. A number of publications demonstrate that the fault current from inverter based DER can be up to two or three times the inverter's full load current for one cycle or less. For example, [16] includes test results and discussion of fault characteristics of an inverter interfaced DER which shows that grid connected inverters can produce up to 2-4 times the rated current, but only for a very short period of 0.06 - 0.25 cycles. This is within the subtransient period for synchronous generators and such currents would have little impact on the operation of traditional overcurrent relays. Therefore during grid-connected mode there is no detectable impact on the existing protection strategies due to the limited fault current contribution. During intentional islanding mode, however, alternative schemes which are not based on the fault to load current ratio may be required [20]. Furthermore, there may be a problem with inverter's internal protection reacting too quickly and too sensitively to faults on the network; in some cases, a network fault could

lead to unnecessary tripping of many inverters and, in an islanded system, this could have severe consequences.

RES with crow-bar protection

One such example is a doubly-fed induction generator (DFIG). Its fault characteristic is a mixture of the response of an asynchronous machine and an inverter-interfaced DER. Crowbar protection is often to protect this generator against overcurrents caused by large system disturbances or faults. When a fault is detected, the rotor windings are short circuited using power electronic 'crowbar' switches to limit the rotor current by adding external rotor impedance until the fault is cleared.

2.3.3 DER connection arrangements

Connection schemes

DER connection arrangements vary greatly according to different voltage levels, rated power, utility system topology and the purpose of DER installation. Generally, different countries have different connection arrangements. According to [3], three connection schemes exist – connection to a dedicated/non dedicated line; tap connection to a loaded/non loaded line and direct connection to a dedicated/non dedicated substation. Typical connection arrangements are presented for MV and HV networks and practices in different countries are discussed in [3].

Interface connection

The power connection method has a major impact on the dynamic behaviour of the DER. Most utilities require a transformer for interconnecting DER to the utility network, however, there are also exceptions for direct DER connection. Generally, there are no universally accepted "best" arrangements for DER connections, and each type of connection has advantages and disadvantages with respect to both circuit design and protection coordination. These are summarised in Table 2-1. Furthermore, two methods which represent the most typical arrangements in DER installations will be discussed in detail.

HV Delta (Grid side) and LV grounded Wye (DER side)

In transmission systems and LV distribution systems, this connection is generally not preferred as there is a risk of high voltage potential on the utility side [3]. However, the ungrounded utility side has the advantage of minimal impact on the coordination of existing protection relays. This connection arrangement is implemented when:

- Installing a DER in the distribution system where multiple grounding is forbidden (e.g. in HV distribution system below 132kV in UK).
- Adding a DER to an existing transformer connection in an industrial system for export to the utility.

DER side (LV)	Grid side (HV)	Advantages	Disadvantages
Delta Gnd-Wye Delta	Delta Delta Wye	Zero sequence isolation between DER and Grid ensures no fault current infeed from utility side for DER winding faults. Provides no fault backfeed from DER side for grid fault.	High voltage potential during utility faults.
Delta	Gnd-Wye	Reduced voltage potential for grid faults. Zero sequence isolation between DER and Grid. Easy detection of faults at grid side. Fewer resonant conditions and ferroresonance.	Creates an unwanted grounding source for remote faults in utility network
Gnd-Wye	Gnd-Wye	No overvoltage for both grid faults and DER winding faults.	No isolation between Grid and DER, e.g. DER faults can be seen by the utility grid. No isolation for third harmonics.
Directly connected		Low cost	No isolation between Grid and DER. Missing effective grounding system during islanding. High potential during faults.

HV grounded Wye (Grid side) and LV Delta (DER side)

In transmission systems and LV distribution systems, this connection is recommended by most utilities and is widely used in practical installations, which is similar to the arrangements for large scale generating plants [3]. It offers a good grounding source for the utility grid, which supports high fault currents when a single-phase fault occurs (which is the most common fault type in reality). Thus faults can be easily detected by relays. When DER winding faults occur, there will be no additional fault current infeed from the utility side due to the zero sequence isolation between HV and LV windings. This connection also isolates third harmonics flowing into the grid, which have a negative impact on some sensitive machines.

This connection arrangement, however, introduces an additional zero sequence grounding source. Therefore, a remote grid ground fault can be seen by the interconnection transformer. If its ground impedance is low, then the selectivity and reach of protection relays might be affected. Moreover, during unbalanced operation, which happens frequently in low voltage distribution systems, the unbalanced load current will be divided by the utility grounding transformer and the interconnection transformer of DER. Thus, the load carrying capacity of the interconnection transformer is reduced during a serious unbalance.

Grounding arrangement

ER G59/2, UK engineering recommendation for the connection of DER, illustrates the grounding arrangements in detail [22]. Grounding arrangements depend on the operation mode of DER and voltage level of the utility grid it is connected to. For HV distribution systems below 132kV, multiple grounding sources are normally not permitted. For LV distribution systems, multiple grounding is the normal practice and DERs are mostly solidly grounded.

2.4 DER Protection

2.4.1 Example protection arrangements and settings (UK)

Protection arrangements for DER are highly dependent on the voltage level, the normal mode of DER operation, DER rated power and the nature of the network which the DER is connected to. To this end, ER G59/2, provides guidance on several DER connection cases and their protection. In this section, only two typical arrangements will be presented – one for LV connected DER that is designed for both islanded and grid-connected operation (Figure 2-2), the other is for HV connected DER that is also designed for the same operating modes (Figure 2-3). Other typical connection cases are included in ER G59/2 [22] and IEEE 1547-2003 [23].

According to current standards and grid codes it is the utility's responsibility to protect the network as opposed to the DER owner. Besides conventional overcurrent protection, neutral voltage displacement (NVD) protection is required as a back-up earth fault protection. When it comes to the DER and its interface protection, however, it is the DER owner's responsibility. In addition to standard generator protection, the DER owner must ensure that islanding detection is applied. Generally, loss of mains (LOM) protection application is mandatory for small DER [22].
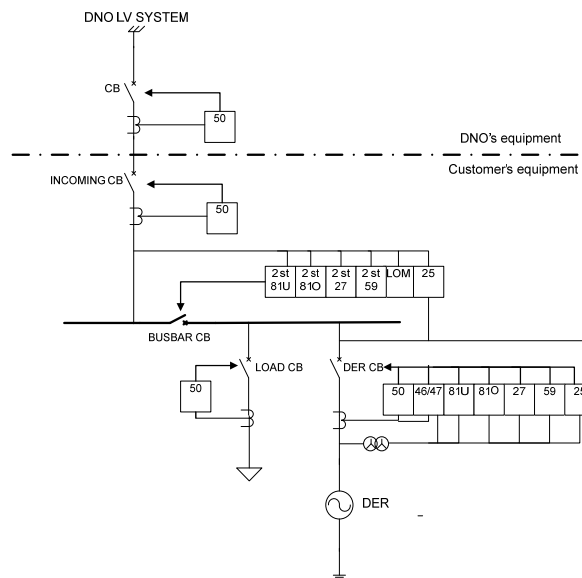

Figure 2-2: DER connected to LV system for islanded and grid-connected operation [22]
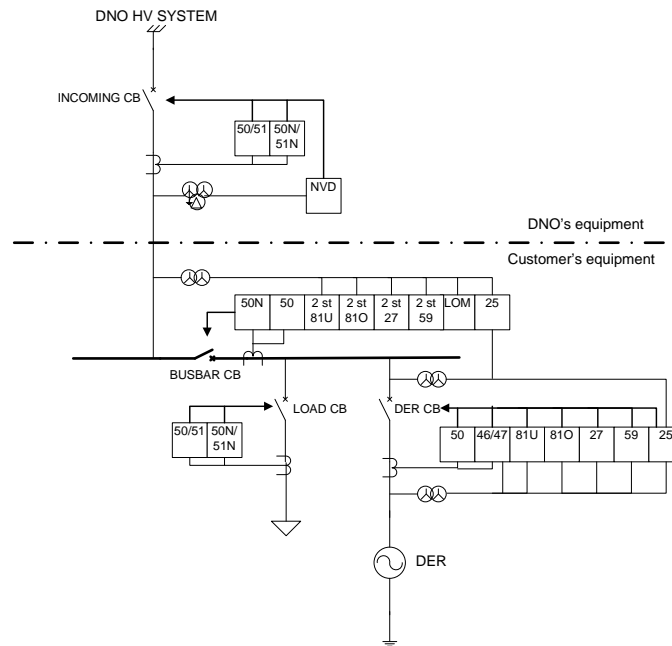
Figure 2-3: DER connected to HV system for both islanded and grid-connected operation [22]

As shown in Figure 2-2 and Figure 2-3, the utility only applies overcurrent protection (with NVD functions in the HV case), while the DER owner is responsible for most of the DER protection and its coordination with the utility protection. The minimum requirements and conditional requirements for interface protection at the utility and customer side are shown in Table 2-2.

Table 2-2: Minimum requirements for protection arrangements

	Utility equipment	**DER side equipment**
Minimum requirements	Instantaneous overcurrent (50/50N)	Under/over voltage (27, 59)
	Time overcurrent (51/51N)	Under/over frequency (81 U/O)
Conditional requirements	NVD relay	LOM/Anti-islanding relay
		Synch-check relay

Recommended settings

Under/over voltage relays

Under voltage usually occurs when there is a fault in the network. There are several instances when an under voltage is detected but should not cause disconnection of the generator, such as a fault outside the protective zone; a fault on adjacent lines or even remote lines; increased loading and power swings. To maintain stability and reliability of the power supply, and to reduce the

chances of nuisance DER tripping, a two-stage under voltage strategy is recommended for all LV and HV connected generation [22]. Conversely, to meet Fault-Ride-Through (FRT) capability requirements a single stage of delayed under voltage is applied in some cases.

Over voltage conditions are usually more hazardous compared to under voltage conditions. Hence, the time delay settings for over voltage relays are shorter. In addition, there is no similar risk of wide-scale blackout related to the overvoltage as there is in the case of under voltage. Thereby there are no similar "ride-through" rules that would require less sensitive operation.

Under/over frequency relays

A two-stage strategy is also recommended for under/over frequency protection.

LOM relays

There is a trade-off between sensitivity and stability when setting LOM protection. The recommendations for the application of LOM will be presented in Chapter 3.

Other relays

In addition to the protection functions discussed above, NVD protection, overcurrent protection, directional protection, earth fault protection, reverse power protection, check-synchronism, phase unbalanced protection, etc. should be installed according to grid code recommendations or in line with local DNO protection policy. The settings of these protection functions should be configured according to the recommendation made by the grid code and must take coordination with existing network protection into account [22].

2.4.2   Example protection arrangements and settings (Germany)

MV level

In the German interconnection requirements for the medium voltage (MV) level [12], an MV generating plant is considered to consist of different LV generating units. The generating plant can either be connected to a busbar of a transformer substation (case 1) or to the medium voltage network (case 2); there are different requirements for each case.

Case 1: Generating plants connected to the bus-bar of a transformer substation
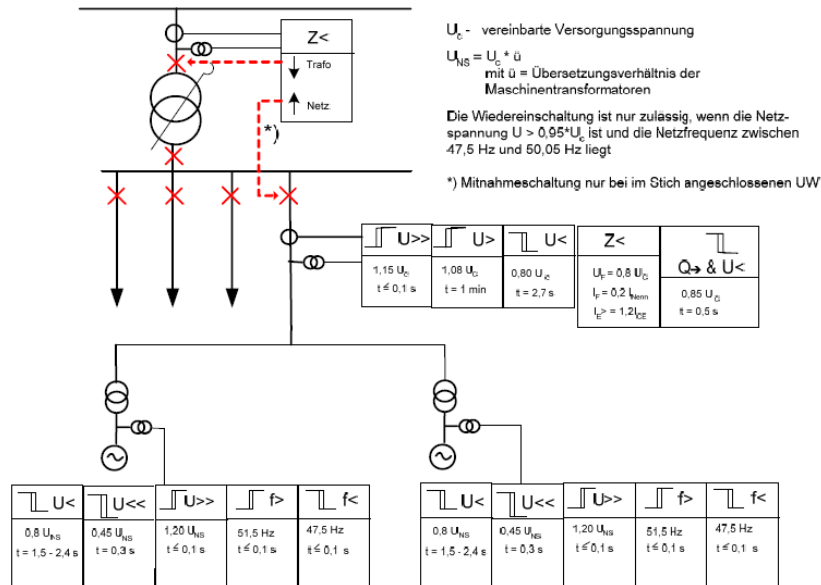
Figure 2-4: Protection applied for the connection of generating plant to the busbar of a transformer substation [12], Un = nominal voltage, Uc = voltage agreed on with the operator/customer

Table 2-3: Setting range and recommended settings for protective equipment at the network point of connection [12]

Function		Setting range	Recommended settings	
rise-in-voltage	U>>	$1.00 - 1.30\ U_n$	$1.15\ U_C$	≤ 100 ms
rise-in-voltage	U>	$1.00 - 1.30\ U_n$	$1.08\ U_C$	1 min
under-voltage	U<	$0.10 - 1.00\ U_n$	$0.80\ U_C$	2.7 s
reactive power / under-voltage	Q&U<	$0.70 - 1.00\ U_n$	$0.85\ U_C$	0.5 s

Table 2-4: Setting range and recommended settings for protective equipment at the generating unit [12]

Function		Setting range	Recommended settings	
rise-in-voltage	U>>	1.00 – 1.30 Un	1.20 Un	≤ 100 ms
under-voltage	U<	0.10 – 1.00 Un	0.80 Un	1.5 – 2.4 s
under-voltage	U<<	0.10 – 1.00 Un	0.45 Un	300 ms
rise-in-frequency	f>	50.0 – 52.0 Hz	51.5 Hz	≤ 100 ms
under-frequency	f<	47.5 – 50.0 Hz	47.5 Hz	≤ 100 ms

Case 2: Generating plants connected to the medium-voltage network (PCC somewhere in the network)

A figure on the protection arrangement for this case can be found in [12],

Table 2-5: Setting range and recommended settings for protective equipment at the generating unit [12]

Function		Setting range	Recommended settings	
rise-in-voltage	U>>	1.00 – 1.30 U_n	1.20 U_n	≤ 100 ms
under-voltage	U<	0.10 – 1.00 U_n	0.80 U_n	1.0 s
under-voltage	U<<	0.10 – 1.00 U_n	0.45 U_n	300 ms
rise-in-frequency	f>	50.0 – 52.0 Hz	51.5 Hz	≤ 100 ms
under-frequency	f<	47.5 – 50.0 Hz	47.5 Hz	≤ 100 ms

LV level

The German interconnection requirements for the low voltage (LV) level are currently under revision [24].

2.4.3   Brief review of practices in different countries

Although ER G59/2 provides a relatively generic set of recommendations for DER protection arrangements, it is only applicable in the UK and practices in different countries vary [22]. Some of these practices are summarised and compared in this section.

In the UK, the main recommendations for interconnection of DER to the grid are ER G59/2, ER G83/1 and ETR 113. The connection arrangements of DER vary with voltage level. At the 33kV level, DERs are generally connected to a single busbar of 132kV/33kV or 275kV/33kV substations. DERs are connected to mid-points of existing 33kV circuits only with the provision of a three-breaker switchboard at the connection point. ROCOF is generally used for LOM protection. At the 275/132kV level, large DERs are connected to the grid through one or two transformer stages [3]. The transformer is protected according to standard UK practice of biased differential and restricted ground fault with mechanical protection and overcurrent backup.

In Germany, two recommendations specify the requirements for DER connected to MV and LV systems [12], [24]. According to the interconnection requirements for the medium voltage (MV) level, an MV generating plant is considered to consist of different LV generating units. The generating plant can either be connected to a busbar in a transformer substation or to the medium voltage network. Both cases have different requirements. The German interconnection requirements for the LV level are currently under revision [24].

In Spain, connection arrangements for DERs are specified according to different voltage levels and system topologies. The settings of under/over voltage and under/over frequency relays are configured based on an "old law" [25]. Otherwise, the configuration of anti-islanding protection – mainly by transfer trip from utility breakers – is defined according to different system topologies and voltage levels. For connection of DER to a dedicated line automated reclosing is generally not necessary as no loss of customers is expected. In 66kV networks or below, line voltage check for blocking of the utility breaker closure is normally installed but there are no requirements for transfer trip function. In 132kV networks and above, communication aided distance protection scheme is utilised to coordinate with the remote line protection. It should be noted that teleprotection equipment can be also used to provide transfer trip functionality even though anti-islanding protection is not necessary in this case [3]. For connection to a radial non dedicated line, transfer trip from the utility circuit breakers is generally necessary to prevent an islanded operation [3]. For a tap connection to a two-ended line, for systems below 132 kV level, transfer trip is required for both ends of the line [3].

In France, connection arrangements for DER are even more detailed. Legal texts [26] and [27] define specific requirements for the connection of "installations" in transmission networks and distribution networks, including different types of decoupling protections for DER [28]. Regarding distribution level, protection functions are requested in case of tripping on islanding, ground and phase-phase faults (in 15kV, 20kV and 30kV system), inter-conductor fault (in 220V system), wrong coupling between DER and utility grid, grid fault (in 63kV and 90kV system, when DER generated power > 12MW). However, no specific LOM protection is defined [3].

In Denmark, most DERs are wind turbines and CHP units. One of the grid operators Eltra has set some requirements on protective equipment and settings at local CHP units. Anti-islanding protection is in the form of under voltage protection supplemented with a ROCOF function. There are also FRT requirements for wind turbines during faults in the transmission grid [3].

In Finland, the connection arrangements of DER at the transmission level (≥110 kV) are based on the Finnish grid code [29]. At the distribution level, however, with around 100 operators, the code is not unified. Many companies have defined or are currently defining – their own requirements. Recommendations in [30] published by the Finnish Electricity Association Sener have been applied in many cases as a guideline. Motiva Oy has also published recommendations for connecting small-scale generation [30]. Organization of Finnish Energy Industries has recently published a recommendation on connecting microgeneration to the public grid, which has been widely applied to the small-scale units in LV networks [31].

In Norway, the connection arrangements of DER are based on IEEE standard 1547 [23] ROCOF is commonly used for anti-islanding.

In Portugal, connection schemes for different voltage levels and network topologies are specified by Directorate General for Energy Geology (DGEG) in 2007. However no dedicated LOM protection is required either [3]. More detailed information about protection practices in different countries can be found in Appendix D and E of [3].

3 CHALLENGES TO PROTECTION PERFORMANCE

3.1 Introduction

The increase in DER penetration has demonstrated detrimental effects on the performance of DER interconnection protection. The main performance issues of existing schemes, such as coordination with utility network protection, immunity to remote faults or adjacent disturbances, are described in this chapter along with an insight into the main proposed methods for tackling these challenges.

Special attention was paid to the response of inverter-interfaced DER (IIDER) during network disturbances and the impact these dynamics (that differ from conventional generator technologies) on the performance of generator interface protection. As such, this section focuses on the performance of anti-islanding protection and over-current/earth fault protection where the main protection challenges are being faced.

The effective use of laboratory facilities for testing DER interface protection has been discussed and emphasis was placed on testing under realistic operational scenarios. Furthermore, requirements for the validation of some of the recently proposed protection methods are described.

3.2 Coordination with utility network protection

The installation of DER has a great impact on the power flow through the system, which brings significant challenges to the current grading of conventional overcurrent protection and fuse saving. Hence, it raises the issue of coordination between DER interconnection protection and utility network protection.

3.2.1 Prevention of nuisance tripping of DER

Generally, nuisance tripping of DER can occur due to tripping on large fault current infeed from the DER—a sympathetic tripping on adjacent faults; or tripping on transient voltage sag—tripping on remote disturbances.

Suitable relay settings can avoid the issue of nuisance tripping on overcurrent. The time delay of the relay at DER should be set slower than those on the adjacent lines. Moreover, a directional component can be added to the relays on the lines connected to DER, which supports proper discrimination.

For spurious tripping due to voltage sag, the issue is more complicated. The reference [32] discusses two available methods. One is to use a delta-wye connection of the transformer at the common coupling point, with the delta winding on the utility side. This ensures that the phase-to-ground voltage of the DER side does not drop below 58%. The other method is to install an electronic sag corrector.

The first method is reasonably economic, however limited in its effectiveness. Operation at 0.58pu voltage is well outside the statutory limits, and further this method cannot solve the nuisance operation caused by other types of faults in adjacent lines. The second method seems expensive requiring the purchase and installation of a new piece of network equipment. An electronic sag corrector is able to maintain the voltage for only three cycles, which means that the fault on adjacent lines needs to be cleared in less than 60ms. As in some cases, it is closely related with the FRT issue.

3.2.2 Coordination issues related with the fault characteristics of DER

It is well know that synchronous and asynchronous based DER units have a great impact on the fault level of the whole system. As discussed above, these types of DER contribute a considerable amount of fault current during system fault. As a consequence, the sensitivity and reach of conventional overcurrent relays are reduced. When a fault occurs in the system, relays may fail to detect the fault. In some conditions, the utility system may also suffer increased power flows, leading to an overload or overvoltage condition or even a blackout. However, the solution of this issue is out of the scope of this paper.

Unlike the synchronous and induction based DER, the impact of IIDER on the conventional protection schemes is generally much less pronounced (that is during grid-connected operation), as each unit has a limited current output to the network. However, the opposite effect seems to be the issue. Based on the previous study of the fault characteristics of inverters [34], the inverters are quite sensitive to the system faults, and they will shut down within a very short period after the fault. This indicates a risk of nuisance tripping when using inverter connected DER, which is undesirable for future wide-spread deployment of them. Possible solutions to this issue may lie in two ways:

- Enhance the controllers of inverter based DER to increase its FRT capability
- To use more advanced FRT techniques based on an enhanced level of requirements. There should be a unified standard for the FRT requirements of inverter connected small scale DER.

IIDER sources are much more problematic in islanded mode of operation. Low fault current contribution from IIDER is one of the main challenges to application and coordination of conventional overcurrent protection in islanded networks that exhibit an increased number of these generators [34], [35]. Methods proposed to tackle some of the protection coordination issues that stem from this unique fault response are summarised in Table 3-1. In some prototypes of island operation with inverter units, this problem has been avoided by an extreme over dimensioning of the inverters. In wider use this does not seem viable. In addition to fault current issues, lacking inertia may become a problem where inverters are dominant. For instance the concept of virtual inertia is studied to tackle this problem.

Table 3-1: Techniques for overcurrent coordination of network protection

Coordination methods	Concept of operation	Limitations
Centralised based adaptive [36], [37]	Offline short circuit calculations are performed depending on the existing network conditions to calculate and coordinate protection settings	Requires extensive measurements from the primary system and reliability in the case of information loss is unclear. Also, a model of the network is necessary
Optimisation based [38], [39]	Linear programming and genetic algorithms are used to coordinate overcurrent relays using current setting and time multiplier setting respectively as constraints	Optimisation has only been applied to an individual overcurrent relay setting in each case (i.e. either TMS or current setting)
Multi-agent based adaptive [40], [41]	The use of several device and feeder agents to achieve set coordination goals	Requires communications between devices and assumes IEDs contain MAS enabling technologies

The methods discussed in Table 3-1 need access to communications infrastructure which is not widely available in distribution networks. Moreover, reliance on communications without having suitable fallback measures is a risky strategy. Key considerations for successfully deploying such schemes are the requirements driven scheme design and rigorous testing methodologies. Furthermore, the validation of the functionality of intelligent systems based techniques is rather difficult, and avoiding erroneous behaviour can be difficult to prove.

3.2.3   Reclosing coordination and fuse saving

Since the majority of faults in a power system are intermittent in nature, automatic reclosers are widely used in HV and MV power distribution systems to support the continuous power supply throughout the network. The installation of DER can disturb the normal reclosing performance of the utility in the following ways:

- The fault arc might not dissipate and fully clear before reclosing, since DER units will continue to energize the faulted line. This effect turns a potentially intermittent fault into a permanent fault and the utility equipment is likely to suffer from a shortened lifespan. Likewise, the DER unit (s) themselves can be damaged.
- The reclosing procedure causes a short period of islanding of the DER, which is likely to lead to an out-of-synchronism condition with the utility system. Circuit reclosure can be hindered by this.

To prevent this problem, one method is to extend the setting to 1-2 sec [42], which might not be feasible for the networks feeding sensitive customers. An alternative is to have faster tripping of DER on islanding detection. Nevertheless, there may be a conflict between the FRT capability of DER and the use of reclosers. Other options could be to add a synch check function or a "dead" voltage monitoring function before allowing reclosing. However these require the installation of voltage transformers at both sides of the automatic circuit recloser.

In an LV distribution system, the contribution from DER can disturb the fuse saving strategy [42]. It might be preferred to replace the fuses with circuit breakers, if a high penetration of DER is to be achieved.

3.3   Islanding protection

Engineering recommendations such as G59/2 [22] and standards such as IEEE 1547 [23] dictate that DER should be disconnected when a loss of mains connection (islanding) occurs. This is due to:

- Safety hazards to utility personnel during grid disconnection, with DER maintaining supply to the islanded network.
- Risk of out of phase reclosure between the islanded network and the grid due to DER supply frequency drift.
- Inability of DER to maintain power quality limits.

In most cases, loss of mains (LOM) condition can be easily detected by under/over frequency and/or under/over voltage and/or over current relays. It depends on the amount of load change seen by the DER and the time duration of the utility system failure. If the load increases above the capability of the DER, the simple methods listed above can be used to detect the LOM conditions. However, when load step change is small and remains within the capacity of DER, a dedicated LOM protection should be added.

LOM protection is achieved via a number of methods that are discussed in this section. The non-detection zone (NDZ) defines a limitation and performance measure for most commonly used methods due to low power import or export through the point of common coupling (PCC) [43]. At the same time severe network disturbances can result in spurious tripping of the most commonly used LOM protection techniques.

3.3.1   Existing methods

There are four commonly applied protection functions that are used for LOM protection. All of which are of a passive nature (i.e. do not actively introduce perturbations in the primary system):

- Under and over voltage protection (UV, OV).
- Under and over frequency protection (UF, OF).
- Rate of change of frequency (ROCOF).
- Voltage shift (VS).

The first two methods allow for straightforward detection of islanding due to the effect of load/generation mismatch on the voltage and frequency. However, when there is a smaller mismatch between those, the detection of loss of mains becomes more difficult. To this end ROCOF and VS aim to address this issue.

Sensitivity and stability performance tests of ROCOF and VS as reported in [44] have revealed great disparity in performance between LOM relays supplied by different manufacturers. Furthermore, careful attention must be paid to the type and size of generator when selecting a suitable LOM setting. This highlights the need for improved LOM detection methods specifically, and DER protection methods in general.

3.3.2 Improved islanding detection techniques

To mitigate some of the performance shortfalls of existing islanding protection practices, the methods proposed in literature have been mainly based on new passive methods, active methods or communications based methods. The first set summarised in Table 3-2 of techniques rely on the use of enhanced frequency measurements techniques for improved LOM detection and are usually incremental improvements of existing methods. While the second set relies on injecting primary quantities into the network which act to destabilise the LOM protection should an islanding event occur. These are summarised in Table 3-3. The final group of techniques utilise communications (usually predefined breaker status information or remote frequency measurements) to determine the onset of an islanding condition. The communication based LOM methods are summarised in Table 3-4.

Table 3-2: Passive methods for improved LOM protection

Passive Method	Concept of operation	Limitations
Accumulated phase angle drift [45]	An accumulation of phase difference between measured frequency and a historic based system frequency estimator is used to detect LOM	Extrapolation of system frequency based on historic samples depends on a number of system and DER parameters
Change of harmonic distortion [46]	Monitoring of total harmonic distortion (THD) levels before and after islanding is used as indicator for LOM	Sensitivity depends on load and inverter interface
Directional reactive power detection [47]	DER is setup as a continuous sink of VARs during grid connected condition so that a LOM event would result in a detectable reverse flow of VARs at the generator interface	DER must be setup to absorb VARs under normal operation. It is also not suitable where capacitor banks are present or the associated cable network has significant capacitance
Rate of change of voltage and power factor [48]	A combination of rate of change of voltage and change of power factor to detect LOM.	Hard to establish the limits as the tripping criteria change according to the system conditions and those are identified after extensive simulation scenarios

Table 3-3: Active methods for improved LOM protection

Active Methods	Concept of operation	Limitations
VAR export error detection [49]	DER is set to export a set level of reactive power which can only be maintained through grid connection	Slow operation since a time delay is necessary to prevent spurious tripping due to load fluctuations
Fault level monitoring [49]	Compares short circuit levels under grid-connected and islanded conditions using a small current injection across an inductor to produce a voltage signal indication of LOM	Assumes constant source impedance and requires power electronics for the current injection
Phase or frequency shift [47]	Positive feedback based introduction of phase shift is stabilised during grid connection but significant frequency change occurs during islanding	Operating characteristic contains stable zones even during islanded operation
Active frequency drift [47]	Introducing periods of zero current during the inverter output cycle results in detectable continuous shifting in voltage frequency during islanding	Sensitive to load power factor and can be ineffective under off-nominal frequency operation

Table 3-4: Communications based methods for improved LOM protection

Communication-based methods	Concept of operation	Limitations
COROCOF [50]	Localised effect of LOM on island frequency is used to for normal ROCOF operation while widespread frequency disturbances are detected by blocking relays placed at specific points.	Scheme stability is dependent on blocking relay placement
Centralised IEC 61850 [51]	Topological information is used to provide an extensible means of identifying LOM conditions without measuring analogue quantities	Faster GOOSE performance assumes IEC 61850 device compliance
Satellite based [52]	Comparison of locally measured frequency is compared to a master frequency measurement transmitted over satellite links.	Hardware investment required for signal reception and transmission. Also, the timing signal is locked into a single provider
Internet based [53]	Utilises internet infrastructure to enable communicating a reference system frequency or inter-trips to DER protection	The internet does not guarantee quality of service and the method assumes suitable internet connectivity at DER site

Although the techniques summarised above offer improved performance from both the DER and network perspectives, there are a number of challenges that need to be overcome. These techniques are non-standard approaches to established protection practice which introduces an element of risk to the network by introducing largely unproven technology. The use of active methods relies on destabilising the protection through active injection of primary quantities into the primary system which could have undesirable operational repercussions. For this reason, active methods are not used. Additional capital investment is also usually required to perform these functions.

3.4 Coordination with Fault ride-through (FRT)

According to the Distribution Code, any generators connected to distribution system, which contribute to the maintenance of system security, are required to have FRT capability [54]. The most typical example is the wind turbines, which at present are mostly designed to offer FRT capabilities. Nevertheless, for other types of DER, especially for units with low rated power, no FRT capabilities are required. Furthermore, until now, there is no consistent international standard for FRT regulation.

Typically, DER in the UK is required to ride-though solid three phase faults on the super-grid voltage lasting up to 140ms. The ride-though capability of DER for different voltage dips and durations for the UK are defined in [4] and this differs between on-shore and off-shore DER. Figure 3-1 shows an example FRT specification for an off-shore wind farm where V/Vn is the ratio of wind farm voltage to that of the nominal voltage (on the LV side).
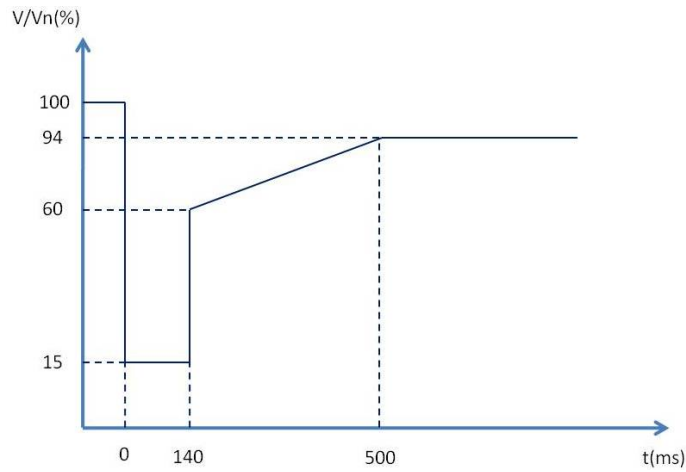

Figure 3-1: FRT requirement for an off-shore wind farm [44]

Crowbar protection is a standard application for DFIG based wind farms in order to protect the power electronics from high fault current by acting to short the rotor windings such that the machine operates as an induction generator. The introduction and removal of the crowbar is controlled through power electronics which results in fast reaction to faults. This rotor based strategy suffers from inability to support the system voltage through reactive power export as the machine absorbs reactive power during the ride-though period [54]

Another strategy entails the immediate interruption of stator current which effectively removes the generator from the grid. That is followed by a resynchronisation procedure based on the grid voltage level. This stator side technique offers the advantage of full current controllability during the ride-though period. However, more power electronics are required to achieve this compared to the crowbar method [55].

The use of FACTS is also an effective means of achieving fault ride-through by providing reactive power necessary to maintain the generator stability. Otherwise the generators are generally unable to provide this necessary reactive power especially during voltage dips. Increasing stability margins and limiting short circuit currents aid in maintaining generator stability [56]. It is important to note, however, that this requires a separate network investment and these devices are used for targeted transmission network support. In a similar manner energy storage systems can modulate the excess or deficit active or reactive power to better support the distributed generator during fault conditions.

Switching of a series resistor (series dynamic breaking resistor) can provide circuit damping along with the boosting of stator side voltage. However, this is not as flexible as using FACTS since its performance is limited by the power factor [56]. Superconducting fault current limiters can provide a similar function while dissipating the excess energy of the disturbance [57].

3.5   Validation challenges of improved DER protection techniques

De-risking of new DER protection techniques requires rigorous testing. Although desktop simulations are invaluable in evaluating the performance of these schemes under different primary system conditions and DER operational modes, technology maturity cannot be demonstrated. Neither can integration issues be overcome using such testing methods. Laboratory based testing offers a powerful means of bridging the gap between proof of concept and field deployment of some of these protection solutions. Laboratory based testing can still make use of model elements through a hardware-in-the-loop (HIL) setup [58]. Alternatively, miniature physical testing grids along with flexible inverter devices can be used. The utilisation of flexible inverters is emphasised as different generation technologies can be emulated for testing the DER protection. Figure 3-2 illustrates these different elements.
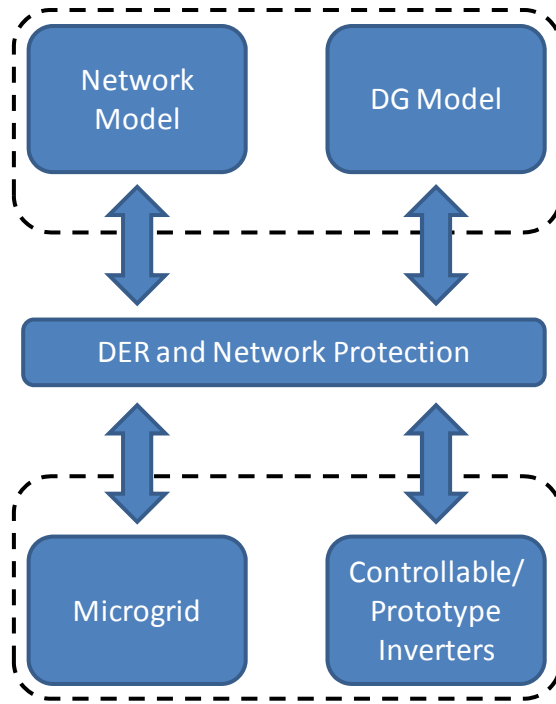
Figure 3-2: Model and physical elements for DER protection testing

Some of the improved approaches discussed earlier present new challenges to existing testing methodologies, especially those which are directly influenced by the primary system dynamics. So in addition to providing accurate DER models (or indeed physical inverters) for testing, it is important to consider network operational scenarios. These are becoming more influential in shaping DER protection performance. Hence exhaustive scenario based testing is becoming increasingly more important.

Active LOM protection methods as well as the use of FACTS and similar technologies to enable fault ride-though of DER can result in unique system dynamics that are not catered for in existing testing practices. Therefore, the scope of testing should be extended through the inclusion of these devices or suitable models in the testing arrangement.

The use of communications in LOM and network protection adds another dimension to the testing considerations. The reliability of the communications must be evaluated along with the impact on protection performance in the case of loss of communication.

4 DIFFERENT TYPES OF PROTECTION TESTING

4.1 Introduction

From the early beginning of power system protection there has been a need for testing of protection relays. The first generation of relays, which were electromechanical, were tested with heavy current test benches consisting of mains coupled sources, phase shifters, reactors and load units. These tests were limited to steady state accuracy tests.

When the technology and development of protection relays moved on from electromechanical relays to analogue relays also analogue test simulators became available. This generation of test sets consisted of low-level independent signal generators and signal amplifiers for amplification of the signals to levels required at the inputs of the analogue protection relays. With these analogue simulators the response of protection relays to different fault scenarios could be investigated.

With the introduction of numerical digital relays and also more sophisticated microprocessor-based test sets, open and closed loop (real time) digital simulators and open loop playback equipment have been introduced. Although the protection functions of digital and analogue relays are essentially very similar, the digital technology offers new possibilities and new problems due to the increasing complexity of relays and the trend towards communication based scheme logics as opposed to more traditional hardwired approaches.

Due to the increasing complexity and the great importance of some applications, type testing has become increasingly more important. This chapter describes different types of type testing, including both static and dynamic approaches.

4.2 Type testing classification

Type testing can be classified as certification or application conformance testing. Certification type testing is normally performed by a certification organization or by a testing company under the supervision of a certification organization, while application tests are performed by a manufacturer or a testing company on request for a specific end-user, for example a utility [59]. The way certification type tests are performed varies in each country, depending on the existing regulations. For more detailed review of certification standards, please, refer to chapter 4.

Certification type tests are normally performed:

- At the end of development of a new protection relay
- After software upgrade of the protection relay
- After the addition of a new function
- After hardware upgrade of the protection relay

Certification type tests concern normalized tests under normalised procedures, the so-called conformance and performance tests, which aim at verifying the conformance of the protection relay against its specifications. These tests are generally related to international standards, such as IEC 60255 and ANSI C37.90. However compliance may also involve consideration of the requirements of IEC 61000, 60068 and 60529, while products intended for use in the EEC also have to comply with the requirements of Directives 89/336/EEC and 73/23/EEC [60]. Since type testing of a digital or numerical relay involves testing of software as well as hardware, the type testing process is very complicated and more involved than a static or electromechanical relay.

Functional conformance tests verify the functionality of the protection against the test standard specification. The functional conformance tests consist of applying the appropriate inputs to the relay under test and measuring the performance to determine if it meets the specification. They are usually carried out under controlled environmental conditions. The testing may be extensive, therefore to minimize the required time to perform these tests, dedicated test sets have been developed [61]. These types of tests are also called static type testing. Please, refer to subsection 4.2.1 for more information.

Technological conformance tests consider how the protection relay responds to external disturbances. To a great extent, these characteristics can be uncoupled from the type of relay and are valid for the whole family range. Practically, these tests cover:

- Electro Magnetic Compatibility (EMC) tests

- Product safety type tests

- Environmental type tests

EMC tests are carried out to determine the ability of relays to withstand the electrical environment in which they are installed. The substation environment is a very severe environment in terms of the electrical and electromagnetic interference that can arise. There are many sources of interference within a substation, some originating internally, others being conducted along the overhead lines or cables into the substation from external disturbances. The most common sources are: switching operations, system faults, lightning, flashovers [60].

Product safety type tests are carried out to demonstrate that the product is safe when used for its intended application. The essential requirements are that the relay is safe and will not cause an electric shock or fire hazard under normal conditions and in the presence of faults. A number of specific tests to prove this include: dielectric voltage withstand, insulation withstand for over voltages, overload and fault condition assessment, etc [60].

Environmental type test are conducted to prove that a relay can withstand the effects of the environment in which it is expected to work and they consist of temperature, humidity, enclosure protection and mechanical tests [60].

Application tests are carried out to demonstrate that a protection scheme is capable to protect a type of network under certain fault conditions. These tests are normally asked by the end-user, such as a utility:

- To study the behaviour of protection relays in a particular power network before new protection installation or change in the primary system

- In case of troubleshooting mal-operation

- To optimise settings in case of complicated networks

Application tests are based on the use of transients for testing protective relays in order to simulate the dynamic behaviour of the network during faults and test the protection system performance.

Generally, there are two ways of creating dynamic type tests:

- Using transients obtained from recorded or calculated waveforms. In this case, a test set can be used to playback a recorded waveform or to generate a calculated waveform that represents a transient of the network.

- Using transients calculated in real time. In this case, a real time digital simulator is used to simulate the network during normal and fault conditions.

4.2.1 Static type testing

Static type testing consists of applying inputs to a protection relay and measuring the performance to determine if it meets the specification or not.

Static type testing is normally extensive and it includes a high number of tests. For example, considering an overcurrent protection relay, some of the typical static type tests are: three phase pick-up and drop off accuracy, accuracy of DT timer, accuracy of IDMT curves, accuracy of reset timers, etc. All the tests are done over the complete range of settings.

One example of static type test technique is the ramping technique, which is used to determine limiting values, such as minimum pick-up or switching hysteresis (e.g. pick-up/drop-off ratio). The software controls the amplifier and commands it to generate ramps of amplitude, phase, or frequency for the current and voltage outputs and the response of the relay is recorded automatically.

This is normally done using a protection test set which generates series of waveforms and records the response of the protection device. Figure 4-1 shows the typical static type testing hardware environment.
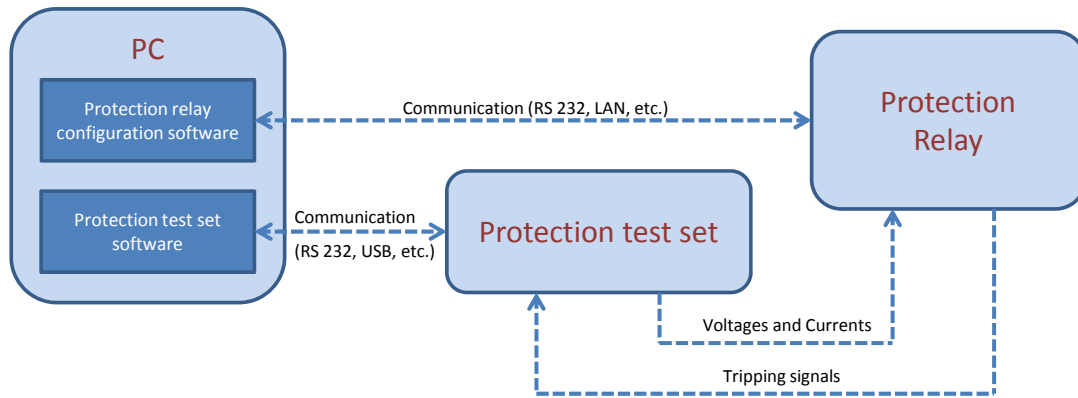
Figure 4-1: Static type testing hardware environment

The hardware normally involved in a static type testing is: a protection test set, a personal computer and the protection relay to be tested.

The personal computer is used for both configuring the protection relay using the relay's manufacture software configuration and to manage the protection testing using the protection test set software.

The protection test set generates voltages and currents and records the tripping signals received by the protection relay. If the protection relay is fully IEC61850 compliant, sample values substitute the analogue values and GOOSE messages are used instead of signalling via relay contacts.

4.2.2 Dynamic type testing

Dynamic type tests consist of simulating transients of a network model in real time to dynamically demonstrate the satisfactory performance of protection relays.

In the past, dynamic type tests were conducted by using physical scaled down models of electrical power systems, e.g. artificial transmission lines. However, these models had significant limitations in the current and voltage waveforms that could be generated and their use required a lot of time because testing automation was not possible.

With the evolution of microprocessors, a new generation of real time digital simulators based on distributed microprocessor hardware has been developed and it is now widely used to conduct closed-loop testing of physical devices, including protection relays and protection schemes.

Real time power system simulators are a combination of advanced computer hardware and comprehensive software. These simulators can solve the power system equations fast enough to continuously produce output conditions that realistically represent conditions in the real network. Therefore, the physical protection equipment can be connected in closed-loop regime with the power system model and can be subjected to virtually all possible faults and operating conditions including complex fault scenarios with multiple relays and communication channels [62].

Figure 4-2 shows the typical dynamic type testing hardware environment, where the real time digital simulator simulates the primary system and the protection scheme to be tested, which can be formed by one or more protection relays, receives voltages and currents amplified by slave analogue amplifiers.
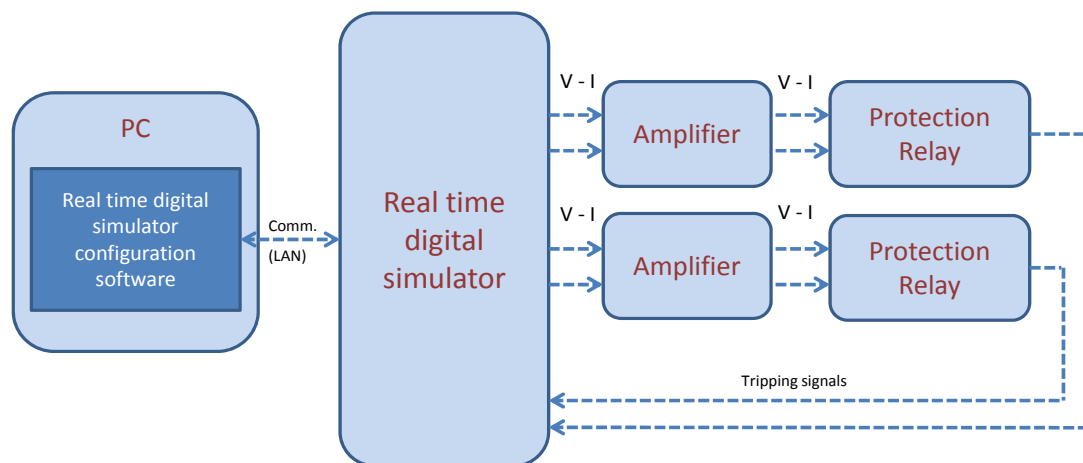

Figure 4-2: Dynamic type testing hardware environment

When the protection equipment is IEC 61850-9-2 sampled value compliant, voltages and currents are provided to the protection equipment through a dedicated interface able to send sampled values to the protection equipment instead of using the amplifiers.

The protection response to faults, such as trip and reclose signals, is then sent back to the simulator to operate the breakers modelled in the simulation. If the protection provides signals via conventional dry contacts, the signal will be received by the simulator using its digital input card, while if the protection equipment is IEC 61850 compliant the breaker commands can be imported into the simulation using a dedicated IEC 61850 interface card.

With the real time simulation and the protection equipment connected in a closed-loop regime the protection can be subjected to a myriad of faults and operating scenarios.

The faults and operating scenarios can be run manually or using automated batch files. The automated batch is often applied to protection system testing where faults are repeated again and again with small changes to the fault inception angle, fault type, fault location, etc. In this way the overall time of testing is significantly reduced.

4.3   Approaches to approvals and standardisation

4.3.1   Approaches to approval [Germany]

In Germany the registered non-profit association FGW (Federation of German Windpower and other Renewable Energies) has developed a technical guideline for approval of technical behaviour of wind turbines and other DER. In the third part of this technical guideline (FGW TR3, [63]) measurement methods and test procedures for the approval of the electrical behaviour of DER units according to the MV Distribution Code of BDEW [12] are described. This also comprises testing of protection devices. Based on the technical guidelines given by FGW a certification process has been established. Unit / plant certificates are a prerequisite for DER units' / plants' connection to the German power system. The technical guidelines given by FGW are ground-breaking for standards like e.g. IEC 61400-21[9] – new standards are being developed.

4.3.2   Approaches to approval [United Kingdom]

In the UK, the Energy Networks Association (ENA) co-operates with manufacturers in assessing protection relays and, if necessary, in witnessing type tests which include electrical, environmental, software, and dynamic validation. Equipment that meets the specified criteria is given an ENA Notice of Conformity Certificate through the appropriate Protection Assessment Panel (PAP) which is made up of representatives from the Distribution and Transmission Network Operators.

This assessment is not compulsory but utilities normally require ENA Notice of Conformity Certificate, consequently manufactures voluntarily do the assessment process with ENA for every new protection relay type they want to introduce in the UK market.

The procedure relies initially on self-certification by the manufacturer with possible visits and witnessing of tests by specialists engineers on behalf of the UK Electricity Industry (EI).

The assessment includes the following areas:

- Quality of the manufacture
- Type tests to relevant standards
- Verification of conformance with standards and technical specifications
- Performance or functional tests to agreed criteria
- Site tests and/or field trials

5 TEST CASE STUDY

This section describes a case study on dynamic type testing of a DER interconnection protection relay. The testing was performed at the University of Strathclyde using a commercial protection relay and a real-time digital simulator (RTDS).

5.1 Methodology

The aim of this case study is to run a dynamic type testing of a DER interface protection relay, using network data of a section of a typical MV distribution network and recommended relay settings of both UK and German grid codes [12], [22]. Firstly, the considered network section is modelled in the power system simulation software RSCAD. The model includes the upstream network source, transformers, lines, transducers, circuit breakers, loads and a synchronous machine representing the DER unit for which the relay under examination will be configured. After compilation of the simulation the power system model is uploaded to the RTDS. Meanwhile the protection relay is prepared for testing by configuring the settings for the different protection functions under- and overvoltage, under- and overfrequency and ROCOF (Rate Of Change Of Frequency). Having saved different setting files according to both UK and German grid code recommendations, the relay is connected in a closed-loop arrangement to the RTDS. The test set-up used to perform the case study is shown in Figure 5-1.

Figure 5-1 Test set-up with real-time digital simulator (left), and protection relay with amplifier (right)

During the test different protection functions under examination are activated one by one, firstly with UK and secondly with German recommended settings. Different test scenarios are simulated by applying faults in different locations and by changing from interconnected to islanded operation mode respectively

5.2 System model and test scenarios

5.2.1 System model

The single line diagram for the network under examination is presented in Figure 5-2. In the system model, the upstream 33 kV network is represented by an infinite bus. The distribution network section comprises a 33 kV / 11 kV transformer (T1) and two 11 kV feeders. At the left hand side feeder (Feeder A) there is a variable load (load A) and an 11 kV / 0.4 kV transformer (T2) with a synchronous machine connected at the LV side. The machine rating and parameters are set according to the hardware lab unit (220 kVA) of Fraunhofer IWES. At the right hand side feeder (Feeder B) there is a variable load (load B). The synchronous machine at the end of feeder A is protected by the circuit breaker CB_{DG} which is controlled by the DER interconnection protection relay under test.
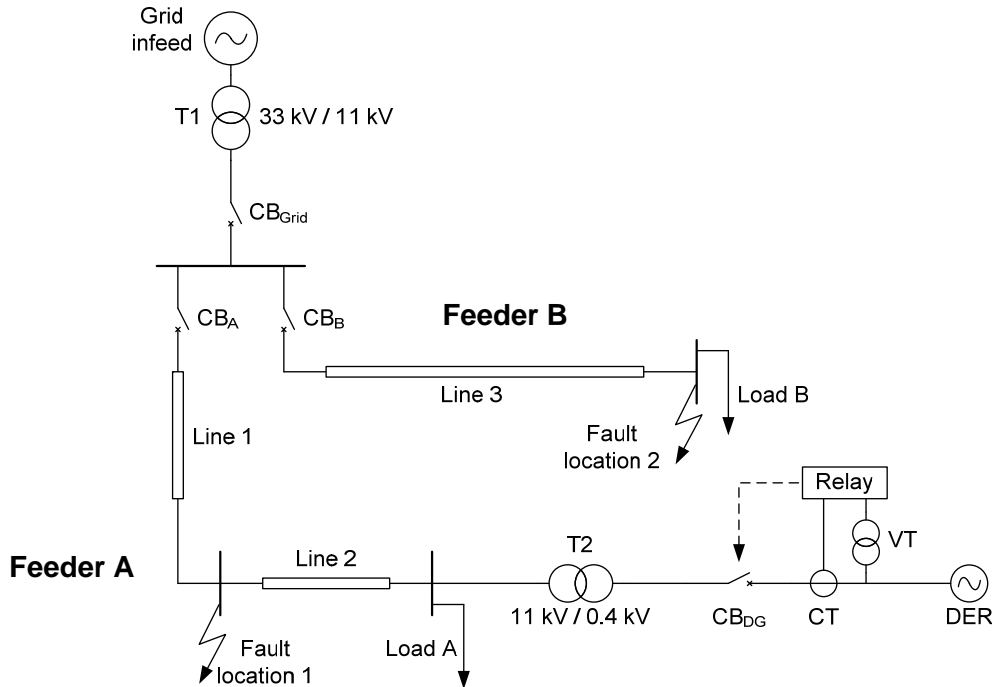

Figure 5-2: Network section considered in the case study

The model system data for network, transformer and generator is given in the Appendix. The graphical user interface for controlling the RTDS is shown in Figure 5-3.
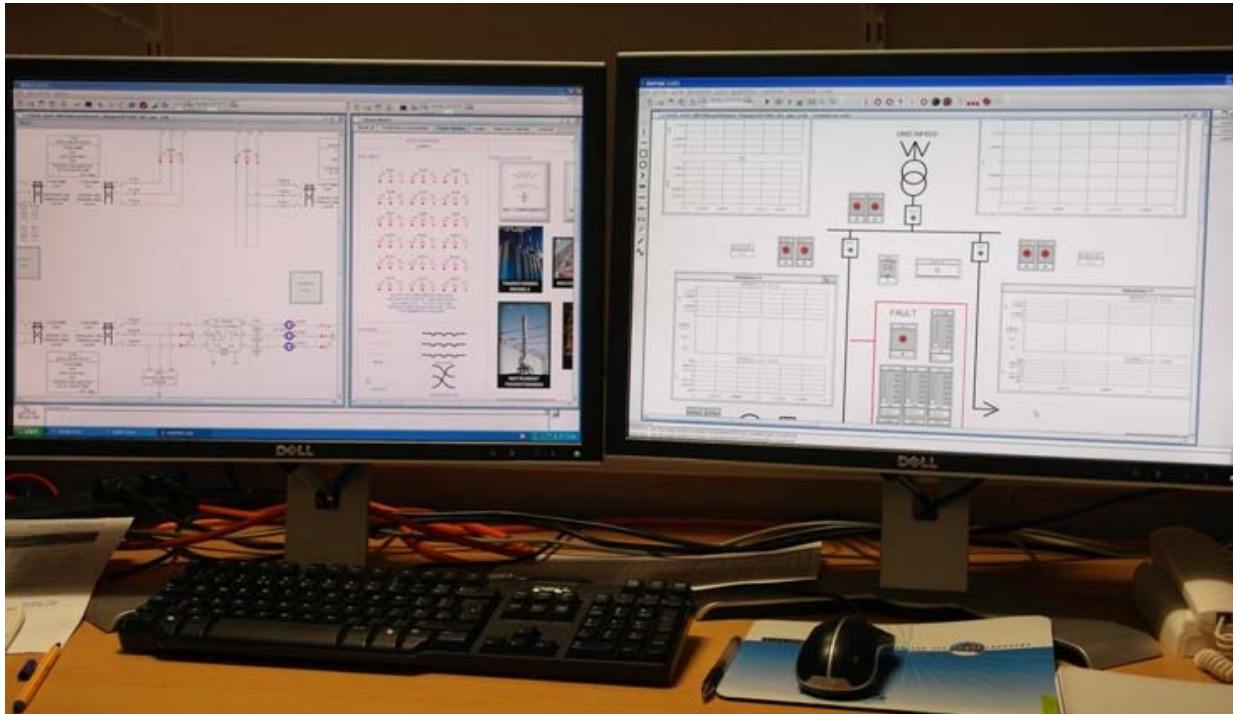
Figure 5-3: RSCAD / RTDS user interface for modelling (left screen) and simulation (right screen)

5.2.2 Test scenarios

A number of test scenarios have been developed to test the performance of the DER interconnection protection relay. The protection functions to be investigated are as follows:

- Under- and overvoltage protection (UV, OV).

- Under- and overfrequency protection (UF, OF).

- Rate of change of frequency (ROCOF).

The relay settings indicated in Table 5-1 are taken according to both UK [22] and German grid code recommendations [12]. The settings are implemented on the protection relay as two separate setting groups and saved to setting files. (Note: The maximum time delay which can be set on the relay under examination is 10s. Therefore, the two values in brackets given by the grid code recommendations cannot be realized).

Table 5-1: Relay settings applied for the case study, according to UK and German recommendations for DER unit interconnection protection, i.e. small power station HV (MV) connected

Protection function (with ANSI device number)		UK recommended settings		German recommended settings	
		Setting	Time	Setting	Time
Undervoltage 27, stage 1	U<	0.87 Un	2.5 s	0.80 Un	1.0 s
Undervoltage 27, stage 2	U<<	0.80 Un	500 ms	0.45 Un	300 ms
Overvoltage 59, stage 1	U>	1.10 Un	1.0 s	-	-
Overvoltage 59, stage 2	U>>	1.13 Un	500 ms	1.15 Un	100 ms
Underfrequency 81U, stage 1	f<	47.5 Hz	10 s (20 s)	-	-
Underfrequency 81U, stage 2	f<<	47 Hz	500 ms	47.5 Hz	100 ms
Overfrequency 81O, stage 1	f>	51.5 Hz	10 s (90 s)	-	-
Overfrequency 81O, stage 2	f>>	52 Hz	500 ms	51.5 Hz	100 ms
LOM / ROCOF		0.125 Hz/s [#]		-	-

[#] with 0.125 Hz/s for low impedance networks and 0.2 Hz/s for high impedance networks. → "A fault level of less than 10 % of the system design maximum fault level should be classed as high impedance."

By either applying faults in different locations or changing from interconnected to islanding operation mode different scenarios are created. These are as follows:

- Undervoltage protection testing by applying faults (phase A to ground) in islanded mode

- Overvoltage protection testing by load shedding in islanded mode

- Underfrequency protection testing by simulating genuine islanded situation (DER unit supplying a higher load than its output prior to LOM)

- Overfrequency protection testing by simulating genuine islanded situation (DER unit supplying a lower load than its output prior to LOM)

- ROCOF testing by intentional islanding (DER supplying both higher and lower load)

The relay settings for all tests are applied according to Table 5-1.

5.2.2.1 Undervoltage testing by applying faults (phase A to ground) in islanded mode

The undervoltage function is tested by intentional islanding of the network section with transformer T2 in YNyn connection. Load A is disconnected and load B set to 200 kW, 11 kVAr. To test protection sensitivity a phase-A-to-ground fault is applied at fault location 2 (refer to Figure 5-2) for a duration of 0.4 s and 0.6 s (UK) and 0.6 s and 1.2 s (Germany) respectively. The fault resistance is initially set to 1000 Ohm then gradually reduced in steps of 100 Ohm.

The single-phase fault applied within this test is a high resistive fault, which is in the power range of a large switchable load. For instance, a fault resistance of 1000 Ohm may be compared to a single-phase load of

$$\frac{\left(\frac{11\text{kV}}{\sqrt{3}}\right)^2}{1000\Omega} = 40.3 \text{ kW}.$$

5.2.2.2 Overvoltage testing by load shedding in islanded mode

The overvoltage function is tested in islanded operation mode of the network section, with transformer T2 in YNyn connection, load A set to 10 kW, 11 kvar and load B set to 200 kW, 11 kvar. CB_A is opened manually to create overvoltage conditions.

5.2.2.3 Underfrequency testing by islanding (DER unit supplying a high load)

The overfrequency function is tested in grid-connected operation mode of the network section, with transformer T2 in Dyn5 connection, load A set to 10 kW, 11 kvar and load B set to 400 kW, 11 kvar. CB_{Grid} is then opened to island the network section.

5.2.2.4 Overfrequency testing by islanding (DER unit supplying a low load)

The overfrequency function is tested in grid-connected operation mode of the network section, with transformer T2 in Dyn5 connection, load A set to 10 kW, 11 kvar and load B set to 10 kW, 1 kvar. CB_{Grid} is then opened to island the network section.

5.2.2.5 ROCOF testing by islanding (DER supplying high / low load)

The test is only done with UK settings as there are no specifications for ROCOF given in the German guidelines. A value of 0.125 Hz/s cannot be set in the relay. Therefore the test is done for both 0.1 Hz/s and 0.2 Hz/s. The same network switching actions performed in the underfrequency and overfrequency scenarios were used to test ROCOF.

5.3   Test results

5.3.1   Undervoltage testing by applying faults (phase A to ground) in islanded mode

With a fault resistance of 1000 Ohm no tripping occurs. With a fault resistance of 900 Ohm and less the relay trips for fault durations of 0.6 s (UK) and 1.2 s (Germany) respectively. This corresponds to the UK undervoltage setting stage 2 of $0.8\ V_n$ / 0.5 s and the German undervoltage setting stage 1 of $0.8\ V_n$ / 1.0 s.

Example simulated current and voltage waveforms are presented in Figure 5-3.

To make sure that the relay does not trip on overvoltage, due the voltage rise at the two healthy phases, the test is repeated with functions V> and V>> disabled. The relay still trips for 900 Ohms \ 0.6 s (UK settings).
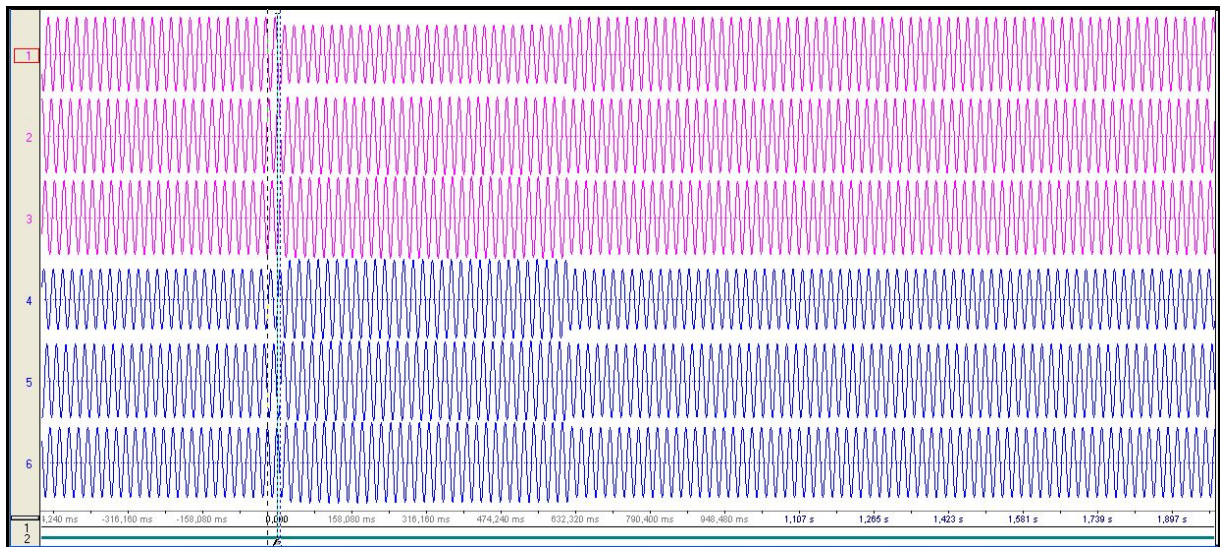

Figure 5-3: Voltages and currents at the DER for a fault with a resistance of 900 Ohm and a duration of 0.6 s (German settings)

5.3.2   Overvoltage testing by load shedding in islanded mode

Having opened circuit breaker CB_A the relay trips after 0.5 s (UK) and 0.1 s (Germany) respectively.

5.3.3   Underfrequency testing by islanding (DER unit supplying a high load)

By opening circuit breaker CB_{Grid} the network section is islanded and the generator suddenly has to supply a very high load. The load is much higher than the maximum power output of the generator and as a consequence frequency drops to 46.7 Hz which is below the setting value of

47.0 Hz (UK) and 47.5 Hz (Germany). After a set time delay of 500 ms (UK) and 100 ms (Germany) the relay trips on underfrequency.

If the same test is repeated with load A set to 200 kW, 11 kvAr, the frequency only goes down to 49.75 Hz and no tripping occurs as the maximum generator output roughly matches the load.

5.3.4 Overfrequency testing by islanding (DER unit supplying a low load)

By opening circuit breaker CB$_{\text{Grid}}$ the network section gets islanded and the generator suddenly produces a surplus of power, as feeding energy back to the grid is no longer possible. The load is much lower than the power output prior to islanding and as a consequence frequency rises to approximately 52.3 Hz which is above the setting value of 52.0 Hz (UK) and 51.5 Hz (Germany). After a set time delay of 500 ms (UK) and 100 ms (Germany) the relay trips on overfrequency.

5.3.5 ROCOF testing by simulating an islanding condition

For both scenarios (decrease and rise in frequency) the protection relay trips for 0.1 Hz/s as well as for 0.2 Hz/s.

5.4 Summary

The tests carried out show that the DER interconnection protection relay trips in accordance with the applied settings under both UK and German setting practice.

The RTDS based test scenarios described in this chapter are not intended to be an exhaustive set of relay testing procedures but have been included primarily as an illustrative example of the methodology and complexities involved in the testing of modern DER interface protection relays. It needs to be emphasized that realistic testing conditions (achieved here using RTDS but also possible using power hardware laboratory) should form an essential part of protection performance assessment. The level of testing attained using conventional static testing procedures is usually inadequate and can lead to unexpected behaviour in real power system conditions, e.g. spurious tripping of LOM protection resulting from fleared faults on adjacent circuits.

6   CONCLUSIONS

The protection white book has presented a review of the issues surrounding the impact of increasing levels of DER on the generator and network protection and the resulting necessary improvements in protection testing practices. Particular focus was placed on ever increasing inverter-interfaced DER installations and the challenges of utility network integration.

In terms of testing practices emphasis was made on the importance of dynamic testing that can only be delivered through laboratory-based platforms such as real-time simulators, integrated substation automation infrastructure and flexible, inverter-equipped testing microgrids. The combination of the emerging flexible network operation and new DER technologies underline the importance of utilising the laboratory testing facilities available within the DERlab Network of Excellence. This not only informs the shaping of new protection testing and network integration practices by end users but also enables the process of de-risking new DER protection technologies.

A comparative case study of interface protection based on the UK and German DER protection practice was also presented. This experimental work highlights further the difficulties associated with standardisation and approval mechanisms adopted by different countries and reinforces the need for better standardisation solutions in the near future.

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LIST OF FIGURES

APPENDIX: SYSTEM MODEL DATA

Network data

Source parameters

Short-circuit power $S_{SC}"_{max}$:	119.7 MVA
R/X ratio:	1.22

Line parameters

Type of line:	Overhead line
Rated voltage:	11 kV
Nominal frequency:	50 Hz
Resistance R' (pos. \ neg. sequence):	0.12 Ohm/km
Reactance X' (pos. \ neg. sequence):	0.16 Ohm/km
Resistance R' (zero sequence):	0.5 Ohm/km
Reactance X' (zero sequence):	1.1 Ohm/km
Length of line 1:	5 km
Length of line 2:	5 km
Length of line 3:	5 km

Transformer data

Transformer T1

Primary rated voltage:	33 kV
Secondary rated voltage:	11 kV
Connection group:	Dyn
Rated power:	24MVA
Nominal frequency:	50 Hz

Transformer T2

Primary rated voltage:	11 kV
Secondary rated voltage:	0.4 kV
Connection group:	YNyn0, Dyn5 (adjustable)
Rated power:	0.25MVA
Nominal frequency:	50 Hz

Generator data

Type of generator:		Synchronous machine
Nominal apparent power:		220 kVA
Nominal voltage:		0.4 kV
Power factor:		Unity
Synchronous reactances	x_d:	1.79 p.u.
	x_q:	1.71 p.u.
Transient reactance	x_d':	0.169 p.u.
Subtransient reactance	x_d":	0.135 p.u.

DERlab e.V. – European Distributed Energy Resources Laboratories

DERlab e.V. is the European association of independent laboratories working with the integration of distributed energy resources into power systems.The purpose of the Association is to achieve a more environmentally sustainable power generation by supporting the transition of energy supply systems towards more decentralised power generation.

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