ASSESSMENT OF ISLANDED OPERATION OF DISTRIBUTION NETWORKS AND MEASURES FOR PROTECTION

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Contractor Ecconnect

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1. Introduction

This report is prepared by Econnect Ltd and aims to consolidate the component tasks of ETSU Project K/EL/00235/00/00 in order to facilitate wide peer review.

The high level objective of the project is to develop a framework and recommendations for a detailed review of existing guidelines and practices related to islanded operation of distribution networks and loss of main protection.

The report is structured in a manner that establishes a logical pathway from the underlying technical issues of islanding embedded generators, via existing industry codes and practice, to an argued set of proposals for change.

The starting point for this journey is recognition that existing standards are not delivering consistent policy among Network Operators or consensus with their customers, the developers of Embedded Generation.

The report assumes a broad understanding of distribution networks but starts at a fundamental technical level in order to provide a strong foundation for developing firm proposals. This approach has been taken recognising that there is already a substantial but disjointed body of material written on the subject without any apparent piecing together of the interrelated issues.

2. Technical Background 2.1. What is islanding?

Islanding is the term used to describe a scenario involving a distribution network and one or more embedded generators (figure 1a).



Figure 1: Islanding of a distribution network section

In this scenario, a section of the network including the generator is disconnected from the main grid. During the period of disconnection, the embedded generator continues to operate with reasonably normal voltage and frequency and to export energy into the network "zone" to which it remains connected (figure 1b). The term 'islanding' denotes this independent operation of a network zone, in isolation from the main grid and energised by an embedded generator.

There are many possible zones of islanding involving one or more distribution feeders, substations and voltage levels (figure 2).



Figure 2: Possible zones of islanding

Each zone is associated with one or more points of disconnection. Figure 2 shows three zones of possible islanding and their corresponding disconnection point(s). This is not, by far, the full extent of possible zones, which are principally defined by network protection and disconnection facilities. Further zones are even created by remote devices such as pole mounted auto reclosers, drop-off fuses and sectionalisers.

The essential property of a sustained island is that the load and generation trapped within it are closely matched at the time of islanding or subsequently by automatic regulation. This means that the actual scope for islanding is limited by the penetration of embedded generation in the distribution network. The traditional grid with little or no embedded generation (figure 3) did not provide much scope for islanding.



Figure 3: Power flows in a traditional network

However, the growth of embedded generation in recent years (figure 4) has substantially increased the likelihood of sustained islanding and concerns associated with inadvertent island operation.



Figure 4: Power flows in a network with embedded generation

2.2. How does islanding happen?

Islanding has been defined as independent operation of a network zone, in isolation from the main grid and energised by an embedded generator or multiple generators. This section describes how this condition arises.



Figure 5: Steady-state grid connected system

Figure 5a illustrates a steady-state system comprising a radial feeder connected to an 11kV primary substation operating with a partially loaded synchronous embedded generator operated at unity power factor and a customer load. The feeder imports active and reactive power from the grid. It should be noted that embedded generators typically operate at unity power factor because of the voltage rise effects of exporting reactive power and the lack of commercial incentive to do so.

Figure 5b represents the same steady-state system by a power balance diagram. Power balance is a useful method of assessment of island systems because active and reactive power are always balanced in the complete system (electrical and mechanical). It should be noted that network losses (particularly reactive power losses on overhead line circuits) can be a significant factor in the overall power balance.

The balanced, steady-state system is then disturbed by an event that causes the disconnection of the feeder from the grid. The most common form of disconnection would typically arise from an earth fault on the feeder cable or overhead line which is detected by the feeder earth fault protection device and results in tripping of the feeder circuit breaker. Such an event is described in figure 6



Figure 6: Earth fault disconnection

The single phase earth fault shown in figure 6 may be transient or permanent. In either case the fault results in tripping of the source circuit breaker. The earth fault current is not sustained because the circuit breaker disconnects the fault from the network earth reference point, generally located at the star point of the primary substation transformer(s). In this scenario the islanded circuit could be sustained with one phase referenced to earth but without any fault current flowing. The earth fault has become the new "network earth reference".



c) Reactive power export from synchronous generator

Figure 7: Transient islanded system

The single line diagram of **Figure 7a** illustrates the same system as figure 5a but with the feeder disconnected from the grid. The power balance diagram, **Figure 7b**, demonstrates how the system responds immediately after disconnection from the grid. The island is initially deficient in active and reactive power. The deficiency of active power is balanced by the release of kinetic energy from rotating machinery connected to the system, and hence a reduction in system frequency. The deficiency of reactive power is mainly balanced by the export of reactive power from the embedded synchronous generator. Figure 7c illustrates the principle that reactive power flows from a node of higher voltage (generator field) to lower voltage (generator terminal).

The transient response period described above is prior to the regulating action of generator control systems. The effect of the control systems is dependent on the particular scheme and its settings which are widely variable between generator suppliers. Although the dominant grid connected, steady-state control scheme for synchronous generators is simply *power* and *power factor* control, its response to changing speed and voltage arising in an islanded circuit is commonly dominated by the

overriding effect of the speed governor (droop control) and voltage regulator (field forcing). These act to stabilise the system by respectively increasing the engine fuel intake (and hence electrical power output) and boosting generator field voltage (and hence reactive power output). If the range of generator power and excitation is sufficient then a new steady-state, islanded condition can be achieved in which power is balanced and frequency and voltage are stable at a level below nominal but within the operating range of the G59 protection devices.

An islanding event, such as described in this section, can be conveniently illustrated by a frequency and voltage versus time graph (figure 8). The characteristics of voltage and frequency shown in the graph do not represent a particular circuit but are reflective of the scenario described in the section.



Figure 8: Voltage and frequency response

There are factors other than the response of AVR and governor that can act to balance the power flow in an isolated system:

Active power balance:

- Motor speed change (and hence power reduction or increase);
- Voltage depression or boost resulting in reduced or increased resistive loading;
- Tripping of motors and sensitive equipment resulting in reduced load.

Reactive power balance:

- Voltage change resulting in reduced or increased <u>shunt</u> reactive demand (partly offset by an increase in <u>series</u> reactive demand);
- Longer term automatic response by equipment on any islanded transformers with automatic voltage control (AVC).

These factors emphasise the caution that should be applied in consideration of the probability that an island zone can be sustained.

2.3. What is the probability of islanding?

In cases where the minimum island zone load is much greater than the maximum corresponding generation it can be reasonably concluded that the probability of islanding is practically zero. However, this is becoming a less common case as the number of generation schemes increases. As the maximum generation approaches and exceeds the minimum zonal load the probability of stable islanding increases. Probability depends on three main factors:

- 1. Load/generation imbalance;
- 2. Network response;
- 3. Generator control and response;
- 4. Protection methods applied.

Factors 3 and 4 are covered in section 2.6. Factor 2 depends on the design of the network (mainly overhead lines, underground cables and distribution transformers). However, the most crucial factor is the imbalance of load and generation prior to islanding. If the circuit load and generation were constant then the imbalance would be easily defined. However, both load and generation are typically independently variable according to probability distributions derived from long-term operational patterns.

The example of figure 5A is used below to illustrate a simplified probabilistic approach for assessing load/generation imbalance. Probability distributions are assumed in figure 9 for the load and generation connected to the 11kV distribution feeder and the net load probability (or imbalance probability) is derived. The figures and their implications are explained in detail below:

Figure 9a shows the probability distribution and cumulative probability which is representative of a typical 11kV feeder load. The load varies from a summer minimum of just under 1MW to a winter maximum of over 4MW.

Figure 9b shows the probability distribution and cumulative probability for a high load factor generator such as a landfill gas generator. When the generator is operating its output is always in the range of 1.2MW up to its rated output of 1.6MW.

Figure 9c shows the net load (or imbalance) on the feeder. The shaded area represents the probability of having a load/generation imbalance of less than 150kW. In this case the probability that the imbalance lies between –150kW and +150kW is 0.2 per unit (20%). 150kW imbalance relates to a total load of about 1500kW and therefore the imbalance is 10% of the load. This implies that any protection technique which was unable to detect an imbalance of less than 10% would have only 80% dependability – clearly an unacceptable level.



Figure 9: Typical load and generation probability distributions

It should be noted that this assessment is highly simplified and will be significantly affected by load changes that are likely to occur during the islanding event (i.e. tripping of motors). However, some form of probabilistic method of assessment is essential if the dependability of loss of mains devices are to be critically reviewed.

2.4. Why is islanding a problem?

Although not inherently a problem (refer to section 2.5), islanding of distribution networks does present a number of problems that derive from the system not being designed to support it. The main transient or continuous hazards are tabulated below with their possible consequences.

Hazard	Regulation	Cause	Consequence				
			Dam- age	Dan- ger	Com- plaint	Description	
Uncleared earth faults	ESR ¹	Earth fault on unearthed network	1	4	1	Insulation damage and flash-over	
Uncleared phase faults	ESR E@WR ²	Fault level too low for protection	1	1	1	Sustained current, arcing and thermal damage	
Frequency above limits	ESR EN 50160 ³	System acceleration due to underload	1		1	Machine overspeed and motor overload	
Frequency below limits	ESR EN 50160	System deceleration due to overload	1		1	Motor underpower and equipment mal-operation	
Voltage above limits	ESR EN 50160	Phase unbalance or capacitive excitation	1	1	1	Insulation damage and flash- over	
Voltage below limits	ESR EN 50160	Phase unbalance or under- excitation	1		1	Motor stalling and equipment mal-operation	
Voltage unbalance	P29 ⁴ EN 50160	Load unbalance	1		1	Excess motor/generator unbalance currents	
Flicker above limits	P28 ⁵	Low fault level and high flicker emission			1	Equipment mal-operation and visible flicker	
Harmonics above limits	G5/4 ⁶	Low fault level and high harmonic emission	1		1	Equipment overheating and mal-operation	
Out of phase circuit breaker opening	E@WR BS 5311 ⁷	Rapid change of frequency during opening	1	1		Circuit breaker failure due to arc restriking	
Out of phase circuit breaker <i>closing</i>	<u>E@WR</u>	Automatic or inadvertent manual reclosure of CB	1	1	5	High synchronising inrush current with voltage and torque transients.	

Table 1: Hazards

In all cases it is the DNO that has the responsibility for the distribution network and is therefore liable for the possible consequences of contravening statutory obligations during inadvertent island operation. It is therefore the DNO that has the primary duty to protect the network and its customers from these hazards. This means that the DNO must ensure appropriate means are in place for safety or prevent extended islanded operation where such operation may contravene these obligations and put customers at risk.

2.5. How can islanding be harnessed?

As recognised by ER G75⁸, the deliberate operation of islands can bring benefit to customers. The benefits for customers connected to a public network are the same as those for a private customer that decides to operate parallel generation in its own premises, namely:

- Reduced customer minutes lost;
- Possible reduction in customer interruptions;

The technical hurdles to achieving safe and seamless operation of the island are also similar for public and private systems, namely:

- Speed of governor response;
- Range of operating power;
- Voltage and frequency control;
- Earthing or equivalent protection of the island network
- Re-synchronisation to grid.

Furthermore, the public distribution network must be operated within the DNO's licence obligations (including limits on voltage, frequency, flicker and harmonics).



(c) Relationship of demand and generation

Figure 10: Transition to island operation

Figure 10 illustrates a typical transition from grid connection to island operation. In the scenario given, the designated island exports active power to the grid and imports reactive power from the grid in the period before disconnection (figure 10a). A fault on the overhead line feeder causes the local network to be disconnected from the grid (figure 10b). Generator A, designated as providing frequency and voltage control, responds to control the island frequency and voltage. In order to achieve "seamless" transfer to island operation, generator A must firstly ride through the 33kV fault and secondly act to balance the active and reactive power in the islanded network. Figure 10c illustrates the range and speed of governor action required to respond to the large power imbalance immediately after grid disconnection. Furthermore, the generator automatic voltage regulation (AVR) must respond to support the local network reactive power demand. During this balancing period the voltage and frequency are unstable and may diverge beyond the interface (G59) protection limits. The possibility of a large imbalance is inevitable given the wide variation of typical load demand and the uneconomic prospect of private generation being controlled to follow local network demand.

If the preferred objective of seamless transfer is not achievable then the embedded generator will require a black-start capability and the ability to ramp-up its output from zero to rated capacity with full voltage and frequency control. This capability will involve substantial adaption of most standard embedded generators with resultant cost implications.

Addressing these technical issues will mean making significant changes to the design and control of existing MV networks and imposing onerous requirements on embedded generators. Feasibility will be driven by the existing security of supply, the penalties associated with outages and interruptions and any savings arising from displaced network reinforcement costs.

Deliberate island operation is covered in more detail in a separate report⁹. However, it is our present view that purposeful operation of islands will only be a marginal activity in the foreseeable future given the types of embedded generator involved and existing network design and practice.

2.6. How can islanding be prevented?

The technical and economic obstacles to re-designing distribution networks to support safe, sustained island operation are such that it is unlikely that this approach will be adopted widely in the foreseeable future. Reliable means are therefore required to prevent islanding.

The risk of islanding is related to the probability of grid disconnection and the dependability of the protection applied to disconnect the islanded generators if disconnection occurs. Before examining islanding protection, it is instructive to consider the importance of generator connection security in reducing the risk of islanding. Increasing the generator security means connecting at more reliable nodes in the network increasing the security of the existing network by operating closed ring or mesh networks. Protection technology is developing that will facilitate more economic application of these network configurations.

However, irrespective of the reliability of network there will be always be the possibility of islanding events. Reliable means are therefore required to detect loss of mains and trip the islanded generation within an appropriate time to prevent danger or risk of damage to the network, its customers plant, and/or the generation plant. The necessary features of any loss of mains protection are:

- Dependable operation for loss of mains events;
- Immunity from grid and local network disturbances;
- Immunity from normal generator power fluctuations;
- Immunity from interference (induced, conducted and radiated).

Given the crucial importance of the detection method in consideration of any protection strategy, the operation and co-ordination of all the main techniques are described and critically assessed in section 3.

2.7. Synchronous generator control

Section 2.2 introduced the typical control systems associated with synchronous embedded generators. Such control is commonly designed to support stable island operation with voltage and frequency control devices (AVRs and speed governors respectively). Voltage and frequency control are often retained even when the generator is connected to the grid. Conflict with the control of the grid is avoided by the generator control systems providing slacker control (steeper droop characteristic) so that the grid controls voltage and frequency for all normal conditions. However, when the grid is disconnected the generators respond by regulating voltage and frequency (section 2.2). This can mean that the island operates for extended periods within voltage and frequency limits giving rise to the possible hazards identified in section 2.4. Alternative control strategies could be applied specifically to de-stabilise an island network and substantially reduce the risk of sustained islanding:

Disable frequency control on connection to the grid

This approach, used by many generator sets, disables speed control on synchronisation of the generator to the grid using an auxiliary contact on the synchronising breaker.. In this scenario, the generator would control at a power set-point without any capability to govern the speed and hence frequency of an island network. Two possible disadvantages of this approach are: speed control would need to be reinstated (a signal from the site interface breaker) if site island operation were required and the generator would potentially be less stable and provide less support to the grid during local and national disturbances. The second of these has the most significance and would need to be examined in the context of generator and network security.

Disable quadrature boost control in grid connection mode

Nearly all synchronous generator switch from voltage control to power factor control on synchronisation to the grid. However, "secondary"

voltage control is generally retained which responds to voltage depression by overriding power factor control and boosting reactive power output. The feature is called quadrature boost or field forcing. Quadrature boost is used to support local voltage during motor starting or remote faults and therefore acts to improve local voltage stability. By the same measure, this feature also improves the stability of an undesirable island network. Consideration could be given to the disabling this device during grid connection in order to reduce the risk of islanding.

Apply "out of limits" set-points for the control systems.

This approach is similar to that applied to many grid-connected photovoltaic (PV) inverters. The principle is that the generator's speed and/or voltage control systems are set to a value outside the limits of grid operation. For example, if the speed set-point was 46.8Hz then the islanded generator would drive frequency below the protection limit and would trip-off using basic protection relays. The control aspects of this option are more complex, particularly when generators of mixed age and characteristics are connected to the same network, and would need some considerable development.

These proposed techniques for island prevention have the potential to provide a dependable and economic alternatives to both loss of mains devices and intertripping. It is considered that discussions with generator suppliers would be the first step in exploring the feasibility of these approaches.

2.8. Special considerations for wind turbines

The preceding sections have focussed on synchronous generators driven by a controlled source of power (such as gas, steam and diesel). It is appropriate to highlight the important differences in the characteristics of wind turbines. In relation to islanding, the most important differences are in voltage and frequency control.

Wind turbines generators are typically asynchronous machines with no inherent voltage control. Power factor correction capacitors are provided to supply the no-load reactive power demand of the generator and further switched capacitors may be provided to compensate for full load demand. The only means by which an asynchronous machine can support the voltage of an island network is by self-excitation. Voltage control in such a system is highly unstable and sustained operation within G59 voltage limits is extremely unlikely.

Wind turbines are driven by an unstored and variable energy source. Power control is provided by *pitch* or *stall* regulation in order to limit maximum power output and reduce power fluctuations. Most installed turbines are fixed speed machines in which the speed is fixed only by the grid frequency. However, many modern turbines are variable speed, in which the speed of the turbine is de-coupled from grid frequency and pitch controlled in order to allow the turbine to operate at optimum speed. Neither fixed nor variable speed machines are currently supplied with any form of frequency control. An islanded system supported by wind turbines will therefore have highly unstable frequency and sustained operation within G59 frequency limits is extremely unlikely.

3. Review of loss of mains techniques

3.1. Voltage and frequency detection

Figure 11 illustrates how voltage and frequency may respond to an islanding event and how the protection may discriminate islanding and other events.



Figure 11: Voltage and frequency detection and co-ordination

Figure 11a represents a scenario where the active and reactive power demand in the islanded network are greater than the generation supporting them. The frequency initially decreases at a rate proportional to the initial active power imbalance (see section 3.2 for further clarification) and the voltage dips in about a cycle to a level at which the reactive power balance is restored. After about 300 milliseconds the AVR responds to boost the voltage and the governor starts to respond to the frequency dip. This scenario results in a steady-state operating point being reached where the voltage is restored within normal limits but the frequency is still below the under-frequency set-point. The under-frequency relay element would therefore trip after normal time delay of 500 milliseconds as recommended by G59¹⁰.

Figure 11b represents a scenario where the active and reactive power demands in the islanded network are less than the generation supporting them. The frequency initially increases at a rate proportional to the initial active power imbalance and the voltage rises within about a cycle to a level at which the reactive power balance is restored. After about 400 milliseconds the governor starts to respond to the frequency rise by reducing output power. This scenario results in a steady-state operating

point being reached where the frequency is restored within normal limits but the voltage is still above the over-voltage set-point. The under-voltage relay element would therefore trip after normal time delay of 500 milliseconds.

The co-ordination charts in **figures 11c** and **d** indicate how the relay settings and characteristics influence its ability to discriminate between non-islanding and islanding events. As with all passive detection methods, full discrimination is not possible and optimisation is required. In particular:

- Frequency set-points must be outside the maximum divergence of grid frequency;
- Voltage pick-up must be outside the statutory and maximum voltage range at the point of detection (the relevant voltage range is greater than the "steady-state" range because it relates to an averaging period of less than one second rather than of minutes or hours);

The co-ordination charts in this report are indicative only. Although charting of co-ordination is a fundamental aspect of mainstream electrical protection, loss of mains protection would not appear to have had the same level of rigour applied. Rigorous charting of loss of main coordination could have an important role in any technical advancement of this topic.

3.2. Rate of change of frequency (RoCoF)

There are two main RoCoF techniques, one based on zero-crossing detection and the other based on Fourier analysis as described below:

Zero-crossing devices (such as the traditional WH Allen relay) measure and accumulate progressive changes in zero-crossing period over a predetermined number of cycles. These relays are not able to discriminate between rate of change of frequency and sudden vector shift (section 3.3). Although discrimination is improved by increasing the measurement period, this delay reduces the relay's ability to respond before the generator's speed governor.

Fourier devices (such as incorporated in equipment supplier Schneider's SEPAM range of protection relays) carry out a continuous Fourier transformation of the voltage waveform in order to derive its fundamental frequency. In the case of the SEPAM relay, practical immunity from vector shift is said to be achieved by setting the signal measurement period to about 80 milliseconds. Further time delays can be selected for the purpose of discrimination with non-islanding events.





b) RoCof detection - positive df/dt

Figure 12: RoCoF detection and co-ordination

Figure 12a represents a scenario similar to figure 11a except that the power imbalance is smaller resulting in a lower negative rate of change of frequency and a subsequent steady-state frequency inside the normal frequency protection limits of 50Hz +1%, -6%. The initial rate of change of frequency will generally be the greatest value. In this example the rate of change of frequency actually becomes greater than the setpoint for a brief period of time before decaying to zero.

Figure 12b represents a scenario similar to figure 12a except that the power imbalance is reversed with an excess of generated power in the islanded system.

Power imbalance and machine inertia are the principal determinants of rate of change of frequency in an unfaulted island system. The approximate relationship of these parameters is shown in table 3, based on an idealised model.

			Excess island generation as % of total island load								
			1	2	4	6	8	10	12	14	
Lump inertia constant, H MWs / MVA	Representative machine type			Rate o	f chang	ge of fr	equen	cy (df/c	lt) Hz/s		
0.5	Gas engine (low-end)		0.5	1.0	2.0	3.0	4.0	5.0	6.0	7.0	
1.0	Gas engine (high-end)		0.25	0.50	1.00	1.50	2.00	2.50	3.0	3.5	
2.0	Small STG		0.13	0.25	0.50	0.75	1.00	1.25	1.50	1.75	
3.0	Medium STG		0.08	0.17	0.33	0.50	0.67	0.83	1.00	1.17	
4.0	Wind turbine		0.06	0.13	0.25	0.38	0.50	0.63	0.75	0.88	

Table 2: Rate of change of frequency for a range of inertia and powerimbalance

Formal charting of RoCoF co-ordination would highlight:

- RoCoF set-points in relation to the maximum grid rate of change of frequency as defined by NGC;
- RoCoF time delay in relation to clearance times for 33kV and 132kV system phase to phase faults;
- RoCoF settings in relation to the rate of change of frequency during post-fault generator power swings.

In summary, RoCoF relays, and Fourier devices in particular, can provide much greater sensitivity and speed of detection than the frequency relays described in section 3.1.

3.3. Voltage vector shift

Figure 12 illustrates how loss of mains gives rise to a voltage vector shift.





a) Equivalent circuit of a grid connected generator

c) Equivalent circuit of an islanded generator





Figure 13a shows the equivalent circuit diagram of the grid-connected generator with shunt impedance representing lumped load within the island zone. Network and generator site impedance within the island zone has been neglected for the purpose of simplification

Figure 13b shows the vector diagram relating to figure 13a illustrating the generator and grid power angles, \Box_g and \Box_s respectively.

Figure 13c shows the same equivalent circuit diagram after disconnection of the grid at point A.

Figure 13d shows the vector diagram relating to figure 13c illustrating the change in generator power angle, $\Delta \Box_g$, and the change in generator terminal voltage, V_t .

The vector shift in these illustrations arises from the change in generator power angle resulting from the instantaneous change in power flow in the island network and the generator internal impedance. It should be noted that this analysis, based on the textbook *Embedded Generation* by Nick Jenkins et al¹¹ is subject to some uncertainty because it neglects the sub-transient response of the generator with its time constant being greater than the half cycle measurement period of relay. It would be more appropriate to use the sub-transient or transient generator impedance together with a first order assessment of the change in generator current to derive the approximate voltage vector shift at the machine terminals.

Vector shift is quite insensitive to loss of mains changes (first order assessment indicates that a recommended setting of about 6-10° could require a power imbalance of more than 30% to cause operation). The relay was initially developed and as, is more appropriately considered as, a high-speed fault detection relay whose purpose is to detect the fault that initiates the disconnection rather than a true loss of mains relay.

The main aspects of the relay's characteristic are its:

- Sensitivity to the network faults that often initiate islanding;
- Susceptibility to network faults outside the island zone;
- Low sensitivity to rate of change of frequency;

In general the derivation and consideration of vector shift is complex and no textbooks or technical papers have been identified that adequately analyse the sensitivity of these relays under diverse islanding scenarios and the range of possible fault conditions. It is considered that more rigorous analysis should be undertaken if this method is to be used widely in the future as a primary loss of main device. Irrespective of any further analysis, it is a clear feature of this technique that it is dependent on a large instantaneous change in generator power output. It is therefore vulnerable to non-detection of loss of mains arising from non-fault grid disconnection and false detection for faults outside the island zone.

3.4. Reverse VAr detection

Reverse VAr protection had been used by one DNO to provide back-up loss of mains protection but is not widely applied. The principle is very simple, it measures VAr flow at the generation site point of supply and disconnects the generation with a definite time delay if VAr flow into the grid exceeds its set-point.



Figure 14 illustrates how reverse VAr is detected.

Figure 14: Reverse VAr detection

Figure 14a illustrates a single generator and lumped load on a grid connected radial 11kV feeder. The generator is operated at unity power factor and the load is inductive (imports VAr) as is predominantly the case for 11kV feeders. The VAr demand of the load is fully met by cable capacitance and import from the grid.

Figure 14b shows the power flows after disconnection of the grid. The VAr import from the grid is removed and must therefore be supplied from the

generator. The generator is able to export VAr due to the reduction in voltage at the generator terminals arising from the island VAr deficiency. The VAr export is reinforced after a short time by boosting of generator excitation by its AVR.

The problem of reverse VAr is illustrated by **figure 14c** where cable capacitance supplies the load VAr demand allowing the generator to continue at unity power factor in the islanded condition. This scenario is feasible where feeders have long cable runs and low load density and could also arise overrated or non-switched, customer power factor capacitors are installed. Application of overhead cables is being considered in rural networks. This will combine the issues of low load density and censity and circuit capacitance.

A further and more limiting problem with reverse VAr protection is its application where the island zone contains more than one generation site. The reason for this problem is that each generator in the island zone will have independent and differing AVR response characteristics. The response of each generator depends on its location in relation to the load and the other generators and the gradient of its voltage droop characteristic. Under certain conditions it is clearly possible that one or more generators in the island do not experience a voltage depression and hence do not export VAr into the island.

In light of the problem of parallel generation and the possibility of supporting VAr demand from other sources, it is considered that reverse VAr relays cannot be widely used for loss of mains protection.

3.5. Reverse power detection

This method has only limited applicable to connections where the site load is always greater than site generation. It is not covered further in this report.

3.6. Active devices

Research and development is being undertaken, particularly in mainland Europe regarding devices which continually measure network impedance and detect the sudden reduction in fault level arising from grid disconnection. Such devices are referred to by ERA in their survey of loss of mains devices¹². ER G77¹³, in relation to the connection of photovoltaic inverters, states:

The inverter should incorporate a recognised technique for providing loss of mains protection e.g. frequency shift or vector shift. Active techniques that distort the voltage waveform beyond the limits specified in section 4.1 or that inject current pulses into the DNO network are not approved.

Section 4.1 refers to BS EN 61000-3-2, Technical Report IEC 61000-3-4 and G5/3 (now G5/4).

Given the inherent limitations of passive detection devices, active devices may play an important role in the future. However, we are not aware of a proven technique that offers the potential for dependable operation with complete immunity from non-islanding events. For example, fault level detection is unlikely to fully discriminate loss of mains events from network or generator switching events.

3.7. Intertripping

Intertripping is conceptually different from all the other techniques described in this report in that it does not operate on the basis of the measurement of any electrical parameter. It detects the opening of contacts at the point of disconnection and transmits that signal to all generation sites that could support the respective island zone(s). The signal will normally be direct acting to provide a trip command without any local checking or qualification. Various requirements for an intertripping scheme are illustrated in figure 15.



a) Intertripping from pole mounted recloser



b) Intertripping from feeder circuit breaker



c) Intertripping from primary incoming circuit breaker



d) Intertripping from 33kV feeder circuit breaker

Figure 15: Intertripping schemes

Figures 15 a to d illustrate the fact that intertripping must be transmitted from every point of disconnection where the generator, in conjunction with other generators within the respective island zone, could possibly support the trapped load. Furthermore, most 11kV and 33kV networks will have multiple circuits requiring further interfaces and logic. The costs of intertripping schemes included in actual DNO connection offers have ranged from £15k to £100k, compared to about £1k for a loss of main relay.

Although the method is conceptually very direct, the signal must be transferred via a dependable medium, immune from interference, over distances of up to 50km (the normal limit of 11kV and 33kV circuits). The possible media for these tripping signals are illustrated in figure 16.



Figure 16: Intertripping media

Figure 16a shows a (BT) leased communication channel scheme. This is the most commonly used intertripping method applied to embedded generation. The reason for its widespread use is cost (see table 3), in particular where the scheme is applied to an existing distribution network with underground cabling. The communication medium is typically a private analogue channel on the BT network with an available bandwidth of 3-4kHz. The channel is continuously open and transmits variable frequency tones to signal a change in status at the sending end. Typically two distinct tones are used for one way protection intertripping applications to provide greater security and noise immunity. Interface units at each end provide high-speed encoding and decoding of the information contained in the tone changes to give a total tripping time of about 20 milliseconds.

Leased communication schemes must be guarded against the range of automatic testing schemes in use and also possible frequency changes attributable to the communication equipment..

Figure 16b shows a radio or microwave intertripping scheme. The principle of operation is similar to the BT leased line scheme except that the media is electro-magnetic radiation, the data format is typically digital and the transmission range is limited by atmospheric attenuation and line of sight.

Figure 16c shows a power line carrier intertripping scheme. The principle of operation is very similar to the BT leased line scheme except that the media is simply the distribution circuit supplying the generation site. The signal is typically applied, non-continuously, between a one phase and earth but multiple phase units are used. To provide directional transmission, blocking units (filters) are applied upstream of each transmitter. Currently, this method is mainly applied to long high voltage (132kV and above) overhead line circuits with attenuation being a possible limitation for use with underground cables. The potential advantages of this method are examined in section 3.8.

Figure 16d shows a hard wire intertripping scheme such used with fibre optic or copper cables. The bandwidth available to the user, with the optical fibre, is vastly greater than that required for intertripping. Normally standard VF signalling equipment would be used, multiplexed on the optical fibres with other signals (voice, data and control). Optical fibres, preferably without metallic sheathing, may be retrofitted to power lines and provide immunity to induced and contact voltages. Because of cost of fibres and the termination equipment this method is only likely to be cost effective where other communication requirements are present and remoteness of location make leased line or radio schemes impractical.

Copper signalling wires may be available in the form of pilot cables buried with power cables or strung under power lines. These may be used for conventional VF type signalling or for DC signals to operate surge proofed sensitive relays. Main issues to be considered are induced or contact voltages and the need for appropriate termination and insulation design.

The issues associated with each medium described are tabulated in table 3 below.

Fig-	Medium	Range	Dependability	Costs					
ure				Hardware (2 ends)	Media (per 10km)				
A	Leased land line	Unlimited	Regional variations Generally good	£6-10k	£17k ¹				
В	Radio	10 km (typ.) Line of sight	Possible atmospheric attenuation	£10k (ex. tower ³)	£3k ²				
В	Microwave	20km (typ.) Line of sight	Possible atmospheric attenuation	£10k (ex. tower ³)	?				
С	Power line carrier (PLC)	100km (overhead line)	Good on overhead line	£30-100k ⁶	Nil				
D	Fibre optic cable	20-50km without repeater	Very good	£10-15k	£90k ⁴				
D	Copper cable	10km without repeater	Good depending on screen & segregation	£6-10k	£50k ⁵				
1. Lease cost is based on typical case in UK. It includes connection costs of £1.5k and									
ca	capitalised charges of £1.5k/year capitalised over 20 years using a 10% discount rate.								
2. Radio media cost is based on a single licensed link costing £260/year capitalised as above.									
3. Cost of radio tower depends on what is required to obtain line of sight communication.									
4. Fibre optic cable media cost is based on installation on an existing overhead line.									

5. Copper cable media cost based on underground installation alongside new power cable.

6. The cost of PLC schemes is primarily dependent on voltage (high voltage = high cost)

Table 3: Intertripping media issues

An important factor to be considered for remote intertrip signals where the communication media is outside the control of the user is independence of mains supplies to ensure signals continue at times of disturbance and network full or partial shutdown.

Although smaller generation schemes are less likely to require intertripping from the 33kV circuits, the costs for intertripping a 500kW generation site are the same as for a 50MW site (assuming a similar order of dependability and security is acceptable irrespective of generator size). Concern over the costs are therefore focussed on the smaller generation schemes below 2MW where intertripping can be more than 50% of the total connection cost.

3.8. Intertripping and open ring feeders

Open ring 11kV feeders are probably the most common connection points for embedded generators considered in the scope of this report.



Figure 17: Inter-tripping and re-configuration of open ring circuits

Figure 17 illustrates the problem of using intertripping for generators connected to open ring circuits. When the open point is re-configured, the island zone is changed and the intertripping must be similarly re-configured to ensure that correct protection is achieved. This re-configuration would have to be manually implemented and may result in a further intertripping channel being required. The figure shows how power line carrier schemes have great potential to overcome this issue. They benefit from the simple fact that the signal is always communicated to the correct generators without any need for re-configuration. However, the feasibility of this technology for 11kV underground cable circuits is very much unproved and would need further research.

Where the associated network cables have pilot wire unit protection schemes, intertripping facilities may be used or easily provided. The intertrip signal may be DC or AC and may be blocked as appropriate by auxiliary contacts on each in circuit sectionalising or switching device.

3.9. Fault throwers

A further intertripping possibility, conceptually similar to the power line carrier scheme, would be the use of fault throwers. A fault thrower is a automatically operated switch which creates a short circuit from one phase to earth. "Fault throwing" is an accepted, reliable and a reasonably low cost option for intertripping a rural line with several generators.

The fault thrower could be used to trip islanded generators from the source end and would be interlocked with the circuit breaker initiating the island. It would apply a phase to earth fault which would be detected by neutral voltage displacement relays (section 3.10) and trip off all the islanded generation. The fault thrower acts as an earth reference only with the interlocking preventing substantial current flowing from the grid source. The device reset time would require co-ordinating with network protection and any auto-reclosing facility.

3.10. Neutral voltage displacement

Neutral voltage displacement (NVD) is not a form of a loss of mains protection. However, it is included in this section because it is used in conjunction with loss of mains devices to mitigate the risk associated with non-operation of loss of mains protection. It is a specific requirement of the ESR to ensure no danger is introduced by a network neutral becoming unearthed. The principle of NVD operation is demonstrated in figure 18.



Figure 18: Neutral voltage displacement

The circuit in figure 18 represents an 11kV feeder supplying a generation site via a source circuit breaker from a star-point earthed primary transformer. The generator transformer has a delta MV winding with no earthing point. The NVD relay is supplied from the open-delta secondary circuit of a 5 limb voltage transformer (or equivalent). The primary circuit is referenced to earth at its star-point via an earth electrode.

Most of the costs of NVD protection arise from making available a VT capable of providing the zero sequence or neutral displacement voltage reference. There is some where appropriate to develop low cost solutions based on capacitors or capacitor bushings.

Figures 18a and b show that the NVD relay does not distinguish between a healthy circuit which is grid-connected (a) or islanded (b). For case (b) the relay does not detect loss of mains because the islanded circuit is reasonably referenced to earth via the capacitance of each phase to earth.



Figure 18: (cont) Neutral voltage displacement

Figures 18c and d show that the NVD relay detects an earth fault irrespective of whether the circuit is grid-connected (c) or islanded (d), although it is more sensitive to the islanded earth fault. The relay must therefore be co-ordinated with earth fault protection throughout the 11kV network to prevent spurious operation for earth faults on other circuits. This is normally achieved by time discrimination with a time delay of about 3 seconds.

In conclusion, NVD protection is not designed to detect loss of mains but it does reliably and directly protect against the unsafe condition whereby one phase of the islanded system is referenced to earth causing an over-voltage condition on the other two phases.

3.11. Future possibilities

There will undoubtedly be other methods proposed as loss of mains devices. One recently published possibility involves the national broadcasting of grid frequency for comparison with local frequency. Receivers at generation sites around the country would allow comparison with measured local frequencies and divergence of a selected level would lead to local generator trip (as proposed and patented by Powergen Technology). However, this may give rise to a serious and widespread risk of common mode tripping.

4. Existing Codes and Practice

4.1. UK statutory framework and industry guidelines

The purpose of this section is to identify the UK regulations, codes, recommendations and guidelines that inform and direct the electricity industry on requirements for generator connections and in particular on islanding. Figure 19 shows the legislative and regulatory framework and how they govern the DNO and generator.



Figure 19: Legislative and Regulatory framework

Engineering Recommendations

Figure 20 shows the decision methodology established by current Engineering Recommendations, G59 and G75¹.



Figure 20: Recommendations on islanding

G59, relating specifically to generators not exceeding 5MW and connected at or below 20kV, is the main reference point for islanding protection for all embedded generators irrespective of size. This is because G75, covering all larger embedded generators, refers to G59 and contains no further guidance itself on protection methods. However, G75 influences any consideration of protection because of its spirit rather its detail. Whereas G59, and its guidance document ETR 113¹⁴, concentrate on securing the network without regard to the consequences of tripping generation off, the emphasis of G75 shifts towards the greater impact on security of National supplies and securing the larger generation. An example of this is the requirement in section 7.1/7.2 that all centrally dispatched generation (and other generating plant by agreement of the DNO and Generator) require firm connections with "at least two connections between the generating plant and a Major Busbar". Furthermore G75 provides cautious and guidance for deliberate islanding of embedded sanctioning generation. Evidence of this differing approach is apparent in clauses relating to securing generation capacity over a range of operating frequencies and voltages (sections 4.4 and 4.5). Although no explicit reference to loss of mains protection is made, it would be consistent to apply this same approach to security in consideration of relay immunity to false operation during network disturbances.

G59 was initially written by representatives of the Electricity Council Association and Area Electricity Boards who have been replaced by the Electricity Association (the trade association of Distribution Network Operators). The primary purpose was to safeguard the distribution network and its customers. This principle was established clearly from the outset:

"Under Regulation 27 [of the Electricity Act 1989] no PES is compelled to commence or continue a supply if the consumer's installation may be dangerous or cause undue interference with the PES system or the supply to other consumers."

Furthermore, G59 states that general protection arrangements will: "depend upon the particular Embedded Generator's installation and the requirements of the PES's local system. These individual requirements must be ascertained in discussions with the PES."

The scope is given to the PES (now DNO) to develop protection policies that diverge from the general spirit of G59 and its guidance document, ETR 113.

The whole subject of islanding protection derives from the requirement of section 6.4:

"In addition to any generating plant protection installed by the Embedded generator for his own purposes, the PES requires protective equipment to be provided by the Embedded Generator to achieve the following objectives:

(c) to disconnect the generator from the PES's system in the event of loss of one or more phases of the PES's supply to the installation;"

G59 proceeds, in section 6.4.1, to provide some definition of how these requirements must be met:

"To achieve the objectives [for HV connections] \dots the protection <u>must</u> include the detection of:

a) Over voltage

b) Under voltage

c) Over frequency

d) Under frequency

e) Loss of mains

Achieving objective (c) of Section 6.4.1 requires some form of Loss of Mains protection as indicated in the list above. This loss of mains protection will depend for its operation on the detection of some suitable parameter, for example, rate of change of current, phase angle change or unbalanced voltages.....

Other protection could be required and may include the detection of:

- a) Neutral Voltage Displacement
- b) Over Current

c) Earth Fault

. . . .

d) Reverse power

Further advice on the protection arrangements to meet the objectives of Section 6.4.1 are given in Engineering Technical Report 113..."

It is important to note the <u>requirement</u> for some form of loss of mains protection in the form of a relay detecting a suitable parameter. There is no reference in G59 to intertripping as a means of achieving objective (c) of section 6.4.1.

Other than the summary table 5.1 in G59 this is the full extent of industry recommendations for islanding protection of generation connected at high

voltage. Further criteria are given to determine whether loss of mains protection is required for low voltage connections as summarised in figure 20.

Engineering Technical Report No.113

As stated in G59, ETR 113 provides further advice on the protection arrangements to meet the objectives of Section 6.4.1. The document is titled "Notes of Guidance for the Protection of Embedded Generating Plant up to 5MW for Operation in Parallel with Public Electricity Suppliers' Distribution Systems". The most recent review of this document in 1993 was conducted by representatives of the PES, independent generators and the EA for the Distribution Code Review Panel. This included minor changes to G59.

Figure 21 gives an overview of the logical basis of ETR 113 and the subsequent text explains the main aspects of its assumptions and guidance.



Figure 21: ETR 113 guidance on islanding protection

The objective is again clearly established from the outset:

"This report is based on the needs of the UK electricity industry and the conditions under which it operates. It should not be assumed that the advice given would meet all the protection requirements of Generators' generating plant."

Since the primary objective of ETR 113 and G59 is to safeguard the network, it is interesting to note that the islanding protection devices are to be owned and operated by the generator. The generator is therefore given the responsibility for protection of the distribution network. This is a significant issue deserving further examination. It is accepted that DNO interface protection (cut-out fuse in a domestic installation) is required to protect the network from fault current flowing into or out of the customer's

installation. This is generally achieved in the form of inverse time overcurrent and earth fault devices. Furthermore, the DNO interface protection protects the customer's installation up to the customer protection device (the fuseboard in a domestic installation). The customer's protection device is responsible for protection of the remaining customer installation. The areas of responsibility relating to overcurrent protection are therefore well defined and understood. However, there is much confusion and disagreement over the role of and responsibility for G59 protection. This is a key area deserving focus and clarity in any future guidance document.

A crucial pre-condition for the document is defined in the introduction: "This document....considers the protection of PES systems....on the basis that the total output of embedded generating plant is a small proportion of the national demand (and) makes no significant contribution to system availability under conditions of major system disturbance. Any major changes in this assumption will force a review of the protection requirements...."

Given the substantial increase in capacity of embedded generation since the issue of ETR 113 in 1995 and the probable acceleration of this increase in the near future, this clause raises serious questions about the continuing validity of this document.

In essence, ETR 113 confirms G59's confidence concerning the effectiveness of loss of main protection starting with Section 3.4.5:

"With the use of under/over frequency and voltage protection and "loss of mains" protection it is most unlikely that embedded generating plant will remain in operation in islanded mode unless there is no load change as a result of, or after, isolation from the PES supply."

However, it goes on to expand the definition of loss of mains protection to include under voltage and under frequency relays for small generating units where trapped load exceeds the unit's maximum output and, for larger generating units, the following are given as examples of other devices to detect loss of mains:

".....

- i. Reverse power relays (for non-export sites).
- ii. Reverse VAR relays.
- iii. Low power relays.
- iv. Intertripping.
- v. Loss of mains relay."

going on to state:

"Loss of mains protection.....is normally employed to detect this condition but can have limitations in application;"

These limitations are then discussed further in section 5.4 and amount to exceptional cases where no change in generator loading occurs due to the initiation of islanding. Even in this extreme case the suggestion in appendix 7 is that subsequent generator load changes will probably cause operation of the loss of mains devices.

Neutral voltage displacement (NVD) protection is discussed in section 3.10 of this document. NVD is recommended where there is a risk from an

undefinable period of islanding. This recommendation is founded on the ESR Regulation 26, Schedule 3, Part II, Section 2.2e)

"reasonable precautions to be taken to ensure the continuance of safe conditions if any neutral point connected with earth in any apparatus operated at high voltage becomes disconnected from earth."

It is stated that NVD will normally be required, suggesting that it is a reasonable precaution in addition to the protection afforded by loss of mains relays.

Finally, ETR113 section 3.4.5 offers a very interesting perspective on the function of loss of mains:

"Where the Embedded Generator is supplied by a ground mounted substation with auto reclosing circuit breakers, voltage interlocking or intertripping can be employed to prevent out-of-phase reclosure and meet the requirements of Section 6.4.1 of Engineering Recommendation G59/1."

The acceptance of voltage interlocking as a means of satisfying the PES islanding protection requirements would suggest that short term islanding is acceptable if the risk of out of phase reclosure is eliminated. Taken together with the requirement for NVD protection to address the loss of system earth reference, this implies that extended island operation of the network is acceptable if measures are taken to protect against earth fault and out of phase reclosure. The logical conclusion of this extract would be that no loss of mains protection is required if the risk of auto reclosure is eliminated. This approach is to found as mainstream policy of some network operators in Europe. However, it is only a viable approach on underground cable circuits where there is little benefit to supply reliability of using auto-reclose.

In conclusion, ETR 113 offers some interesting perspectives on islanding protection but is flawed by a founding assumption that is no longer valid and a lack of clarity in its advice on the acceptability of loss of mains relays as an adequate response to the risk of islanding.

4.2. DNO practice and opinion

In view of the fact that all DNO's are governed by the same requirements their approaches and policies are surprisingly diverse and summarised in table 4.

DNO	Written	Preferred prot'n		orot' ⁿ	Notes		
	policy	LOM	I/T	NVD			
Yorkshire Electricity	Yes ¹		1	1	RoCoF & vector shift not permitted for generators >1MW. I/T required when min load < 2 x total generation in island zone.		
Seeboard		1	1	1	Policy reinforced in 2000. I/T required when min load < 2 x total generation in island zone ²		
Northern Electric		1		-	Consider I/T (BT and pilot) to be unreliable over distances >10km ³		
Norweb		√		√			
Scottish and Southern		√		√			
Scottish Power		1		1			
Notes: 1. Extracted from Yorkshire Electricity Technical Standard No 1 Part D ¹⁵ .							

2. Policy communicated by S. Willis.

3. Stated by J. Morrel at meeting in 1999.

Table 4: Summary of DNO practice and opinion

Yorkshire Electricity are the only DNO known to have produced a policy document which sets out requirements extending beyond those of G59 and ETR 113. Prohibition of RoCoF and vector shift, in particular, is a response to its concern over both non-operation and spurious common mode operation of these relays. This view is based on ERA's survey of these devices and unidentified experience in the industry.

Seeboard's recent reinforcement of their policy on intertripping is based on increasing concern over the risk of islanding based on privately commissioned risk assessment and uncertainty over the dependability of loss of mains relays.

Many other DNO's refer to G59 in their insistence on loss of mains relays. In a few cases the view that voltage and frequency relays are an adequate form of loss of mains protection for asynchronous machines driven by wind turbine generators without voltage or speed control has been accepted (refer to section 2.8).

5. Problems arising from Current UK Practice 5.1. Inadequate assessment of network risk

G59 and ETR 113 do not make any attempt to list, categorise or quantify the network or generator risks. Furthermore, although some papers have been written which catalogue and discuss the hazards, no published material has been located which rigorously assesses network risk. Without such an assessment, informed and economic decisions cannot be taken.

5.2. Security of Total System

Current industry recommendations and guidance is based on an assumption that is no longer valid: "the total output of embedded generating plant is a small proportion of the national demand (and) makes no significant contribution to system availability under conditions of major system disturbance." Because of this assumption, islanding protection requirements pay little attention to the security of generation. The potential problem arising from this approach is that common mode tripping of embedded generation, particularly based on frequency or rate of change of frequency detection, could decrease the stability of total system or increase the requirement for secure spinning reserve.

Analysis of loss of mains techniques and information on the corresponding grid parameters is insufficient to allow good decision-making for the selection and setting of relays to achieve adequate immunity from unwanted operation.

5.3. Security of Local Distribution Network

The same assumption referred to in relation to the total system also applies to the local distribution network. In this case, all loss of mains techniques (except intertripping) can be susceptible to common mode tripping. Multiple tripping of embedded generation for a single fault or switching event could lead to severe disturbance and possible voltage instability, especially in industrial areas with high motor demand. This possibility also reduces any potential security benefits or deferred grid reinforcement that could arise from connecting embedded generation.

Analysis of loss of mains techniques and information on respective distribution network parameters is insufficient to allow good decisionmaking for the selection and setting of relays to achieve adequate immunity from unwanted operation.

5.4. NETA imbalance costs

Before NETA, the cost of unwanted tripping of embedded generation amounted simply to the cost of lost production. In the case of spurious loss of mains trips the restoration time is within minutes and therefore the costs have been of little significance to the generator except in the very unlikely event that they coincided with a TRIAD half-hour period. However, NETA imbalance penalties arising from these short outages will lead to a potentially significant cost to the generators in the future.

5.5. Ownership of protection

G59 requires that the generator has ownership and responsibility for the operation and maintenance of the islanding protection scheme. This position arose, in part, from the view that it would be cheaper for the generators to provide this protection themselves. However, some DNOs have expressed discomfort about depending on customer G59 equipment for protection of their network, and one, at least, has a policy of providing back-up protection at the metered circuit breaker in addition to the provision of loss of mains relays within the customer installation. This policy is justified by the view that they could not rely on the customer to correctly maintain and test the protection. However, the generator then has to pay for two protection devices or schemes.

However, there is also reluctance among DNO's to the proposition that the DNO that ownership of the islanding protection. Such a move may shift the responsibility for loss of customer supply to the DNO. With the introduction of NETA imbalance penalties this will become a more significant issue.

5.6. Dependability of loss of mains relays

Rigorous analysis of loss of mains techniques in relation to possible islanding scenarios is insufficient to allow adequate risk analysis and good decision-making for the selection and setting of relays to achieve adequate dependability of operation.

5.7. Divergence of policy and approach

DNO policies and approaches are diverging and, in some cases, significantly more onerous than intended by G59 and ETR 113. The basis for this divergence is uncertainty over the dependability and immunity of loss of main relays and particular concern over grid security issues.

5.8. Disputes arising from the cost of protection

Divergent policies give rise to widely varying costs for protection schemes. Intertripping, in particular, is one to two orders of magnitude more expensive than loss of main relays. Connection quotations have been issued with intertripping costs amounting to about 50% of the connection cost of a 1MW generator. Moreover, a single 3MW generation project has incurred total intertripping costs of nearly £100,000.

Differing policies with little basis in industry recommendations give rise to disputes over connection quotations with ensuing project delays and costs.

5.9. Unclear definition of generator & network protection

G59 and ETR 113 do not adequately segregate the requirements for protection of the network and protection of generation plant. ETR 113 states that its guidance is based on the needs of the UK electricity industry and yet there is an implication in ETR 113 and G59 that loss of mains protection is specifically to protect the generator from out of phase reclosure. This lack of segregation makes it difficult to understand who bears the risk and therefore who takes makes the judgement on acceptability of risk.

6. Proposals for change

It is the overwhelming conclusion of this project and report that urgent change is required in the area of standards, guidelines and policy with regard to islanding and its protection in particular. The specific problems identified in section 5 can start to be addressed by more rigorous and peer reviewed analysis of protection methods and network risk and by re-writing of existing reference documents in light of the industry consensus based on its conclusions. The specific proposals in this section arise from and correspond to the problems itemised in section 5.

6.1. Inadequate assessment of network risk

a) Carry-out a rigorous quantitative assessment of the risk to the network and its customers of inadvertent island operation and the mitigation afforded by loss of mains and other protection schemes.

6.2. Security of total system

- a) Establish limiting values (confidence limits) for grid frequency and rate of change of frequency from measured data (as available) and modelled scenarios.
- b) Carry out rigorous analysis of the co-ordination between loss of mains detection (RoCoF and vector shift in particular) and the grid limits.
- c) Establish co-ordination charting as an effective tool to demonstrate and compare immunity from common mode tripping.
- d) Establish maximum levels for embedded generators that may be at risk of common mode tripping for system events.

6.3. Security of Local Distribution Network

- a) Survey protection methods and clearance times on distribution systems to establish a range of likely disturbances that may affect generation.
- b) Model a typical range of generator types and connections to identify where instability may be a limiting factor for security of generation.
- c) Carry out rigorous analysis of the co-ordination between loss of mains detection (RoCoF and vector shift in particular) and local disturbances.
- d) Establish co-ordination charting as an effective tool to demonstrate and compare immunity from common mode tripping.
- e) Establish the general requirements for generators to be accepted as contributing to local supply reinforcement and security.

6.4. NETA imbalance costs

- a) Use a range of examples to assess the likely costs of penalties arising from unwanted tripping of loss of mains protection.
- b) Assess the likely significance of these penalties in relation to selection of protection method (does it incentivise the use of intertripping?).

6.5. Ownership of protection

- a) Review the relative costs, benefits and contractual issues associated with transferring ownership of islanding protection to the DNO.
- b) Review the issues associated with change of location of islanding protection to DNO.

6.6. Dependability of loss of mains relays

- a) Analyse the theoretical application of RoCoF (zero-crossing and Fourier techniques separately) and vector shift relays to various islanding scenarios to assess and compare limits of dependable operation.
- b) Carry-out dynamic modelling of typical island scenarios to confirm limits of dependable operation.

6.7. Divergence of policy and approach

- a) Survey policies (written and unwritten) and obtain opinions of all UK DNOs in relation the islanding protection and associated network security issues.
- b) Develop an outline "Engineering Recommendation" relating specifically to islanding, superseding the islanding aspects of G59 and ETR 113.

6.8. Disputes arising from the cost of protection

- a) Examine the alternative options and costs for intertripping in the wider perspective of other future communication requirements for embedded generators (data and control).
- b) Establish the comparative performance of the lower cost intertripping schemes being used for embedded generators.
- c) Assess the incremental cost and benefits of applying intertripping relative to generation capacity with regard to improved connection security.

6.9. Unclear distinction of generator & network protection

- a) Separately assess risks of islanded operation from the perspective of the generator.
- b) Ensure that new "Engineering Recommendation" for islanding primarily addresses protection of the network and that, if any secondary guidance with respect to generator protection is included, it is clearly identified as such.

6.10. Miscellaneous

- a) Investigate the feasibility of a radically alternative approach to preventing islanding by ensuring uncontrolled or "out-of-limits" operation of the island zone as outlined in section 2.6.
- b) Review intertripping in the perspective of other possible communication requirements for embedded generators arising from the development of intelligent control systems and remote monitoring and metering requirements.
- c) Examine the scope for development of power line carrier or fault thrower type methods, as outlined in section 3.8, with particular reference to open ring feeders.
- d) Examine the benefits of moving from open ring to closed ring systems in terms of deployment of modern protection and reduced risk of islanding.

7. Summary and conclusions

Existing standards relating to islanding protection of embedded generators are not delivering consistent policy among Network Operators or consensus with their customers. Furthermore, the costs for connection of smaller generators are escalating on networks where there is a requirement for intertripping as the primary means of islanding protection.

The key recommendation, G59, and its guidance note, ETR113, were written and revised on the stated understanding that embedded generation was not a significant factor in the security of the local or total system. This founding basis is no longer valid and, on this point alone, there is a clear requirement to revise these documents. Furthermore, the documents do not, in any case, provide a sufficient foundation for consistent and risk-based decision-making on developing appropriate islanding protection schemes.

Assessment of islanding probability highlights the increasing risk of islanding on distribution network and the importance of the cumulative effect of multiple generators. This cumulative effect of smaller generators is not adequately addressed in existing documentation. Although it is technically feasible to harness this growing embedded generation to deliver network benefits by deliberately islanding sections of the distribution network, it is concluded that this will only be a marginal activity and should not detract from the need to develop appropriate recommendations on anti-islanding techniques.

An outline examination of the various loss of mains techniques highlights that they are all subject to possible common mode tripping with the potential for significant impact on the local and/or total system. Avoiding the potential for common mode tripping leads towards reduced dependability of their primary loss of mains function. A compromise setting is therefore required that provides an acceptably low risk of islanding and system disturbance.

The use of intertripping avoids the same compromise of dependability and immunity experienced by loss of mains relays. However, intertripping has the potential to be very complex and costly, especially when the generation is able to support several islanding zones. It is not clear, by any means, that this cost and complexity is justified by the risk of islanding and the inadequacy of cheaper alternatives.

The proposals made to initiate effective change can be summarised as follows:

1. Establish clear and common understanding of the risks both of nonoperation and spurious operation of anti-islanding schemes in order to develop a risk-based methodology for appropriate selection of protection solutions.

- 2. Clearly segregate the requirements for protection of the network and the generator and define the responsibility for and ownership of the protection selected.
- 3. Investigate alternative approaches to preventing islanding which have the potential to provide effective protection at reasonable cost.
- 4. Replace the islanding aspects of G59, G75 and ETR113 with a new Engineering Recommendation which specifically addresses islanding on the basis of the clarity, rigour and innovation established in its preparation.

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9. References

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