Frequency Changes during Large Disturbances and their Impact on the Total System

Joint Grid Code and Distribution Code Workgroup Report

This proposal seeks to modify the Distribution Code

This document contains the findings of the Workgroup which formed on 26th October 2012 and concluded on 14th June 2013.

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The Workgroup recommends:

Changing RoCoF protection settings at new and existing distributed generators in stations of registered capacity of 5MW and above to 1Hzs^{-1} measured over 500ms

High Impact:

Owners of synchronous generators at stations of registered capacity of 5MW and above where, subject to a site specific risk assessment, mitigation measures may need to be implemented before protection setting changes can be applied.

Medium Impact:

Owners of non-synchronous generators at stations of registered capacity of 5MW and above.

Low Impact:

Name of parties impacted or None identified

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About this document

This document is a Workgroup Report which contains the discussions and recommendations of the GC0035: Frequency Changes during Large Disturbances and their Impact on the Total System Workgroup.

Document Control

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1.0	03 July 2013	National Grid	Final Workgroup Report

Any Questions?

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1 Executive Summary

Background

1.1 The electricity supply system in Great Britain is designed to operate as a single synchronised system. It is possible for a distributed generator, or a group of distributed generators, to supply their local distribution network and its customer demand in the event of a network fault that has disconnected that part of the network from the rest of the system.

1.2 Such an island would not be controlled to normal standards of quality of supply and is potentially unsafe to people in the proximity of the energised equipment. Historically smaller distributed generators have been required to have Loss of Mains protection which would shut the generator(s) down safely, and hence shut down the island, should an island be formed.

1.3 One of the techniques used to detect a Loss of Mains condition is to measure the Rate of Change of Frequency (RoCoF), which within an islanded system would be higher than experienced under normal system conditions. High Rates of Change of frequency can occur over the whole of the electricity supply system in the event of a large infeed (generation or import) or offtake (demand or export) loss. If these are high enough, RoCoF based Loss of Mains protection can operate. This protection operation would cause distributed generation to stop generating leading to a further disturbance and possible cascade effect. The current minimum recommended RoCoF setting is $0.125Hzs^{-1}$

1.4 If enough distributed generation were to cease generating (there is currently over 9GW of installed capacity), the result of this cascade effect would be the operation of Low Frequency Demand Disconnection (LFDD). A large number of electricity consumers would suffer an involuntary loss of electricity supply. National Grid has a statutory obligation to ensure that unacceptable frequency conditions do not occur under situations specified in the Security and Quality of Supply Standard (the NETS SQSS).

1.5 LFDD has only operated once since privatisation in 1990. This occurred on the 27th May 2008 after the loss of two large generators in rapid succession. There have been no occurrences of LFDD operation because of RoCoF to date.

1.6 National Grid has been working with the electricity supply industry to develop new frequency control services in response to the changing electricity generation and import mix. New "asynchronous" technologies offer many benefits but do not provide the natural damping or "inertia" of the more conventional "synchronous" type of generation. This means that under high import or windy conditions, frequency will change at a faster rate than it does today, meaning more rapid frequency control capability is likely to be required. The workgroup examining these requirements recommended that RoCoF settings should be reviewed for their future suitability.

1.7 National Grid monitors frequency on the electricity supply system continuously and analyses frequency deviations in detail when they occur. Large frequency deviations do not occur very often, but when they do they can provide new information on system behaviour. Recent frequency deviations have allowed National Grid to re-assess system behaviour and take a view of future performance. The conclusion of this assessment is that there is a need to take action to ensure the minimum protection setting of $0.125Hzs^{-1}$ will not be exceeded during light load periods for more than half the weekends and some weekdays in the year.

1.8 The action taken is either to pay for additional generators to run (these must be of a type which can limit the rate of change of frequency) or to limit the size of disturbance the system can be exposed to by reducing generator or interconnector output (or demand as the case may be). These actions come at an estimated cost of £20m pa with an upper value of £100m pa, rising into the future. In the future, fast acting control systems such as those described as Synthetic Inertia may provide an alternative solution but there is some uncertainty over whether this is feasible.

The Purpose of the Workgroup

1.9 A joint Distribution Code and Grid Code workgroup was therefore asked to examine:

- Whether there is still a need for RoCoF based Loss of Mains protection;
- The costs, benefits and risks of change to recommended RoCoF settings; and
- The need for a requirement to withstand a specified Rate of Change of Frequency.

1.10 The workgroup has developed a staged workplan and this report documents workgroup discussions and presents proposals for the first phase of work. The proposals in this report apply to the protection settings for existing and new distributed generators in stations of 5MW registered capacity and larger.

Workgroup Activities

1.11 The workgroup examined the potential rate of change of system frequency over the next decade and has concluded that rates of change in excess of $0.5Hzs^{-1}$ would occur for an event secured under the SQSS under a range of plausible operating conditions.

1.12 The workgroup reviewed recent frequency deviations and observed that because of their transient nature and the natural phase shifting effects of the impedances making up the total system the measured rate of change during a frequency deviation can vary across the system. Amongst other things, this means that actual rate of change measured by a protection relay may be higher than that predicted through the simulation of electricity supply behaviour.

1.13 Given the number and diversity of the stakeholders affected by the workgroup's possible recommendations, an open letter was published setting out the potential need for change, what the change could be and how the decision making process would work. Two stakeholder workshops were also held, one in Glasgow and one in London, to provide further information and to seek views.

1.14 The group commissioned an assessment of the risks to personnel as a consequence of changing RoCoF settings on Loss of Mains protection on existing generators within generation stations of 5MW registered capacity and above and came to the following conclusions for generators with RoCoF based Loss of Mains protection in stations of capacity 5MW and larger::

- There is a risk of desynchronised islands forming where synchronous generators are connected to the distribution networks;

- There is a negligible risk of desynchronised islands forming for all other types of generation;

- The probability of a desynchronised island forming is dependent on the match between the generation and the local load, and the generator's voltage control mode makes a significant difference to this;

- The risk to people from proximity to an islanded distribution network depends on how often a de-synchronised island is not detected under the specified RoCoF setting, how long it is sustained for and how much time a person could be in contact with network equipment. This risk is acceptably low for all settings examined;

- Each time an island forms there is a risk of "out of phase re-closure", where the control scheme which is designed to restore a loss of supply rapidly would switch automatically to reconnect the desynchronised island without checking that the electrical conditions were matched. This could damage generator equipment and place people at risk suggesting that a site specific risk assessment would be required for higher RoCoF settings on synchronous generators of this size.

Conclusions and Recommendations

1.15 The group concluded that the costs the could be avoided after making a protection setting change on existing and future distributed generators in stations of 5MW registered capacity and above were significantly larger than the costs of making a change to the RoCoF settings on Loss of Mains protection.

1.16 The workgroup considered the consequences of phasing protection setting changes as the system need increased but concluded that a single change to $1Hzs^{-1}$ was the most efficient and effective option. The workgroup noted that adopting a lower setting at $0.5Hzs^{-1}$ would be a smaller change and could have a smaller impact on the affected owners of synchronous generators who the group considered to be the most affected group of stakeholders.

1.17 The workgroup recommends that the minimum Rate of Change of Frequency setting specified for Loss of Mains protection on distributed generation within stations of registered capacity of 5MW and above should be changed to $1Hzs^{-1}$ measured over 500ms. The group believes it is necessary to specify a measurement period to minimise the impact of variability in measure frequency in the transient period after a disturbance. The change should be implemented by amending the Distribution Code and Engineering Recommendation G59.

1.18 The workgroup notes the risk assessment's conclusions in relation to synchronous generators and in particular in relation to the generation control mode. On sites where a RoCoF setting change would mean the risk to equipment and personnel is high, it is possible to reduce this risk through choice of control mode, adaptation of auto-reclose or the adoption of alternative

Loss of Mains techniques. The workgroup therefore recommends a specific risk assessment in respect of these sites, notes the costs to be incurred in completing this assessment, and that costs may be incurred if further action is required to mitigate the risks identified.

1.19 The workgroup recommends that its second phase of work is initiated as soon as possible to develop proposals for equipment rate of change of frequency withstand capability and for protection settings on distributed generators with station of less than 5MW registered capacity. In the absence of this work, the cost benefits of the first phase may not be realised.

2 Purpose & Scope of Workgroup

2.1 In September 2010, National Grid presented paper pp10/21 to the Grid Code Review Panel (GCRP) entitled "Future Frequency Response Services"[1]. This paper summarised the issues associated with meeting the requirements for frequency response arising from significant changes to the generation background.

2.2 In October 2010, the Frequency Response Workgroup discussed the establishment of a Frequency Response Technical Subgroup (FRTSG) which would develop recommendations to address the issues discussed in paper pp10/21 submitted to the GCRP.

2.3 In November 2010, the FRTSG was established to complement and extend the technical work initiated by Frequency Response Workgroup, and in particular investigate issues such as the ability of variable speed wind turbines to contribute to system inertia against a likely future generation background and quantify future frequency response and synthetic inertial requirements.

2.4 The FRTSG published their conclusions in November 2011[2] which outlined proposals to develop of frequency response which would act faster than the existing service definitions. The FRTSG recommended that further work was carried out to examine the effects of increasing rates of change of frequency and examine whether additional changes needed to be made to deal with these effectively. The simulations performed in the FRTSG report gave some indication to the potential change in the maximum rate of change of frequency settings which need to be considered in the context of the loss of mains protection deployed on distributed generation. As such the FRTSG report was highlighted to the Distribution Code Review Panel for further consideration.

Terms of Reference

2.5 At the November 2011 GCRP, National Grid presented pp11/623 which took account of the FRTSG recommendations and proposed that a workgroup was established was established to examine the expected behaviour of the Total System when subject to frequency changes during large disturbances, with particular focus on the rate of change of frequency. The purpose of the group was to assess whether the rates of change of frequency observed in the simulation work carried out in the FRTSG where plausible and would have an adverse impact on the resilience of the Total System.

2.6 The Terms of Reference for the workgroup were approved at the March 2012 GCRP and, a joint GCRP/DCRP workgroup was established subject to agreement at the DCRP.

2.7 At the March 2012 DCRP National Grid presented paper DCRP_12_01_03, the DCRP approved the establishment of the joint workgroup.

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[1] Future Frequency Response Services : http://www.nationalgrid.com/NR/rdonlyres/59119DD3-1A8D-4130-9FED-0A2E4B68C2D2/43089/pp_10_21FutureFrequencyResponseServices.pdf

[2] Frequency Response Technical Sub-Group Report: http://www.nationalgrid.com/NR/rdonlyres/2AFD4C05-E169-4636-BF02-EDC67F80F9C2/50090/FRTSGGroupReport_Final.pdf

[3] Draft Terms of Reference: http://www.nationalgrid.com/NR/rdonlyres/A948A721-F0A8-47E7-86E6-4406C62D3FA7/49869/pp11_62FCLDTSDraftToR.pdf

2.8 The Terms of Reference were updated in April 2013 and presented to the May 2013 GCRP. These revised terms of reference specified that the workgroup would also investigate and quantify the risks to DNO networks and Users of desensitising Rate of Change of Frequency (RoCoF) protection on distributed generation. They also proposed that the workgroup would present proposals in two stages, with the first stage applicable to generating stations of registered capacity of 5MW or greater.

2.9 A copy of the amended Terms of Reference can be found in Annex 1.

Timescales

2.10 It was agreed that this Workgroup would report back to the July 2013 GCRP. This report would present the findings from the first phase of work.

3 Why Change?

Background

3.1 A change in the infeed to or offtake from the electricity network will result in a change in system frequency. The rate at which frequency changes is dependant on the size of the imbalance between supply and demand, the energy stored within the system (in the form of rotating machines), any natural response to frequency and control action taken in response to frequency.

3.2 If the rate of change of frequency (or 'RoCoF') is high enough, protection intended to detect a 'Loss of Mains' and designed to prevent distributed generation running unsafely in an island mode, may operate. This may exacerbate the change in frequency by shutting down the affected distributed generation.

3.3 Where the initial change in system frequency is negative (as is the case where an infeed is lost) a loss of distributed generation with will increase the imbalance between demand and supply causing a further frequency fall. This further frequency fall could trigger involuntary demand control by operation of Low Frequency Demand Disconnection (LFDD)[4]. illustrates how this might occur for an infeed loss.

3.4 Where the initial change in system frequency is positive (as in the case of a loss in demand) a loss of distributed generation would have the effect of correcting system frequency initially. However, if the amount of distributed generation lost is large enough (greater than the demand loss and the effect of the frequency response in place to cater for an infeed loss) it is possible for LFDD to be triggered.

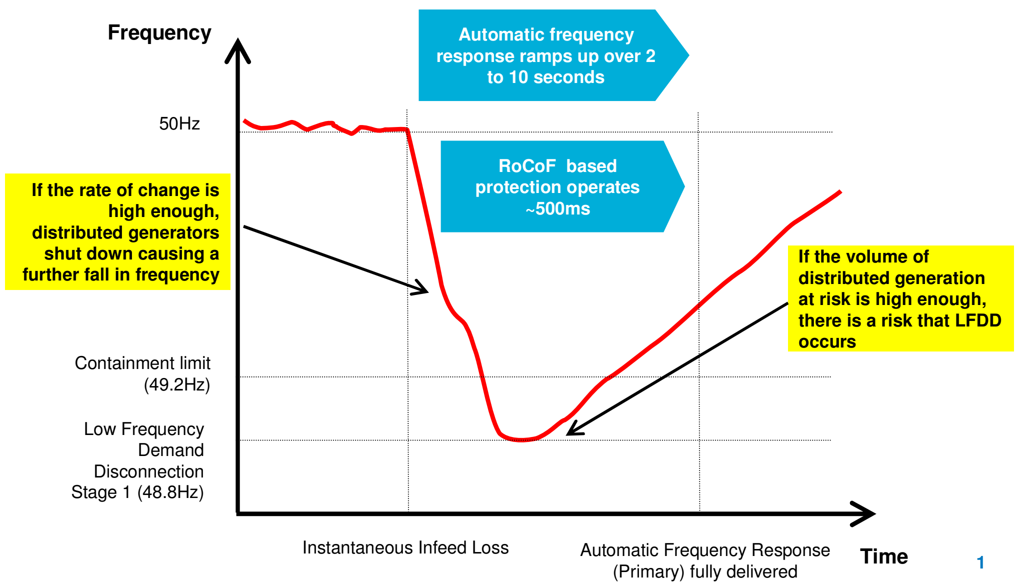

Figure 1: How LFDD would occur after an Infeed Loss and RoCoF trips

3.5 The requirement for Loss of Mains protection is set out in the Distribution Code and Engineering Recommendations G59 and G83 which are applicable to distributed generation. These documents provide guidance on settings.

[4] LFDD last operated in on the 27th May 2008 when a secured event was followed quickly by a second event.

Individual plant operators or installers make the final decision on the settings they use.

3.6 A further aspect to consider is generators' ability to continue generating after being after being subjected to a high rate of change of frequency. There is no obligation for generators within Great Britain to demonstrate the capability to withstand disturbances up to a specified rate of change of frequency. It is possible therefore that a high rate of change of frequency could cause generation failure or protection operation further exacerbating the frequency fall described above. However, generating equipment is known to be capable of withstanding rates of change of frequency significantly in excess of those that are likely to be experience in Great Britain under current operating conditions. Therefore, the electricity supply industry's attention has so far been focussed on protection settings rather than generator withstand capability.

National Grid's Obligation to Control Frequency

3.7 National Grid has a statutory obligation to ensure that frequency is controlled within prescribed limits and is obligated under its licence to operate the transmission system in accordance with the National Electricity Transmission System Security and Quality of Supply Standard (the SQSS). The SQSS stipulates the type of event that should be "secured" and for which acceptable frequency conditions must be maintained. Amongst the events which must be secured are the loss of a large infeed (eg a generator) or a large offtake. National Grid has a statutory obligation to ensure that unacceptable frequency conditions do not occur and therefore has an obligation to consider the "RoCoF Risk" (the risk of a secured event leading to LFDD as result of generation tripping because of a high rate of change of frequency).

3.8 The RoCoF risk is a widely known phenomenon, and has been managed actively across the electricity supply industry since the 1990s. Information on RoCoF related generator trips is exchanged by National Grid and DNOs reviewed annually by the Grid Code Review Panel. However, there have been no occurrences to date where Low Frequency Demand Disconnection has occurred due to RoCoF triggered protection operation.

3.9 New analysis techniques have been used by National Grid to evaluate recent significant frequency events. The analysis has been used to re-calibrate the parameters which feed into the process used by National Grid to set frequency control requirements. The results of this evaluation suggest that RoCoF risks will have a material impact sooner than was previously thought. Actions are now being to be taken to either change generation patterns or ensure further very fast acting automatic response is available.

Prevention

3.10 There are two actions which can currently be taken in order to prevent the RoCoF risk arising. The first of these is to change RoCoF based protection systems, to either disable them or set them at a sufficiently high value that they do not operate during a frequency deviation which is not the result of a power island being formed

3.11 Protection settings can only be changed if sufficient assurance can be provided over the safe operation of the distribution networks and user equipment. A significant amount of analysis is required before this action can be agreed and implemented. This is mainly to investigate the appropriate RoCoF limit which is high enough to prevent unwanted operation but still protects the DNO's network and its users against loss of mains. Such a change will to take a number of months to initiate, with a full programme potentially completed over an extended period due to the number of sites affected.

3.12 The other action which can be taken is to ensure that there is enough synchronous generation connected to the networks to slow down any change in frequency. Synchronous generation is directly coupled to the electricity network (a feature which is inherent to the technology) and therefore has the effect of damping out any disturbance and slowing down any change in system frequency. Induction machine based generators have a smaller damping effect and convertor based technologies have none at all. In practice this means that the action be taken is running conventional gas-fired, coal or nuclear generation, potentially in preference to output from wind or interconnectors. (if they do not have the capability to contribute to slowing down any change in frequency). The need for this action is being assessed as part of the normal short term planning and operating processes used in managing the electricity system across Great Britain.

3.13 It is conceivable that automatic action could be used to limit the rate of change of frequency. At the present time, there are no systems available of the required scale or speed and consistency of response (it would need to be a few hundreds of milliseconds from initiation) which could act automatically to limit the rate of change of frequency quickly enough to guarantee that protection relays do not operate. This would mean that technologies other than synchronous generators (wind and interconnectors for example) would be able to limit the rate of change of frequency. Presently available conventional frequency control services are not quick enough but capabilities such as "Synthetic Inertia" may be able to do this in the future if it can be delivered reliably in the timescales and volumes required.

Mitigation

3.14 The impact of high rate of change of frequency is that an initial large disturbance is may be followed by a further loss of distributed generator output. It is possible to limit the impact this has by ensuring that enough automatic action takes place to contain the subsequent frequency fall. Currently available frequency control services can help to do this if they are sufficiently fast acting in large enough quantities to cancel out the effect of the loss of distributed generator output.

3.15 However, if the amount of generation at risk is large enough, this action may not contain the frequency fall. At present, there is up to 10GW of generation capacity potentially at risk (this is the total capacity of distributed generation - see paragraph 4.32). Not all of this generation will be running at the times of concern and there is significant variation in protection setting, technique and performance which means that the actual capacity at risk is smaller.

3.16 At present, distributed generator output is not metered by National Grid in real time and its planned output is not indicated to network operators. This means that the volume of generation at risk to high rates of change of frequency has to be estimated. Also, there is no central record of relay settings and tests meaning that the likelihood and volume of generator protection operating for any specific rate of change needs to be estimated. Therefore, it is difficult to say with certainty how much automatic frequency control action is required to offset the loss of distributed generator output for a given rate of change of frequency.

Likelihood of Occurrence

3.17 The probability of a RoCoF event occurring is low. Large frequency deviations occur a few times per year and very few occur at the times when a RoCoF risk could be present. A large number of RoCoF relays would need to operate in these circumstances before Low Frequency Demand Disconnection would occur. This presumes that many relays would operate at the lowest recommended rate of change setting. However, the latest information available is that between 1GW and 3GW of generation is at risk of tripping at any point in time due to RoCoF. This volume of generation is substantially more than can be contained to a frequency which would prevent LFDD operating.

3.18 Many electricity consumers could be affected by such and event therefore National Grid takes action to meet its statutory obligations under certain conditions to prevent and prevent the RoCoF risk arising appropriately.

Why is this issue being raised now?

3.19 National Grid monitors system frequency continuously. Large frequency deviations due to instantaneous losses occur infrequently, but are the only reliable source of information on how the system will behave should such an event occur. They inform the steps to be taken to manage such an event in accordance with National Grid's statutory obligations.

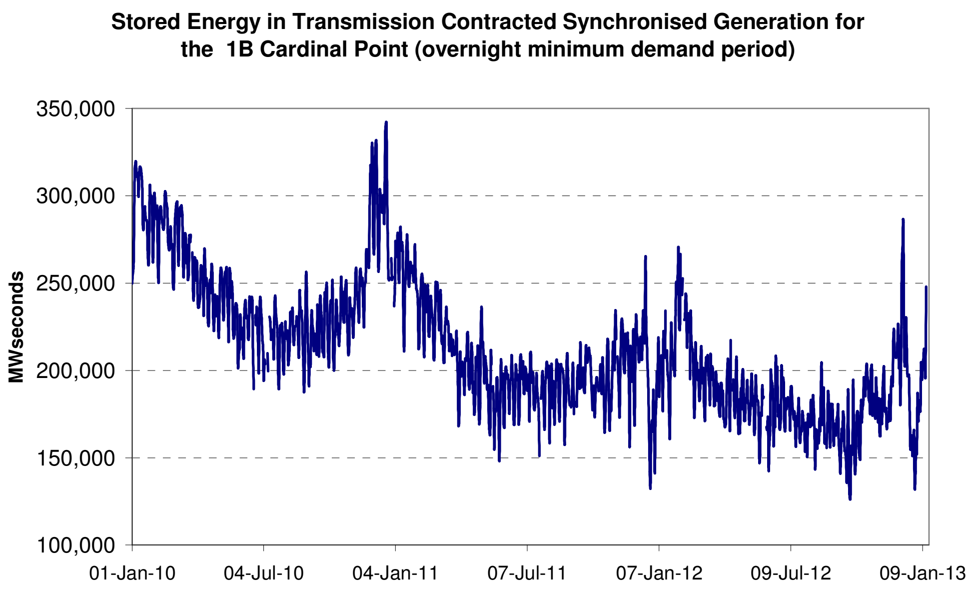

Figure 2: Recent trend in Inertia

3.20 Good plant models and operating information are available for large generators and networks therefore it is possible to simulate how these will behave in the event of a large frequency deviation. Figure 3 below is derived from the planned transmission connected generation operating conditions at the lowest overnight demand period every day over three years. The chart shows a clear trend in reducing inertia from large generation over the period. The reduction has occurred as synchronous generation has been displaced by asynchronous sources such as wind and interconnectors which has been necessary to meet emissions and renewable energy targets.

3.21 Less specific information is available for small and micro generation, and no specific information is available for industrial, commercial and domestic demand. The behaviour of these latter components can therefore only be deduced by looking at the behaviour of the system overall and removing the effect of the well understood components. For the purposes of looking at RoCoF risks, National Grid currently terms this the Residual Inertia. A value can be ascribed to Residual Inertia by looking at large frequency deviations and comparing an actual frequency trace with a simulated frequency trace which is based on known parameters (in this case, the known characteristics of transmission connected generation) as illustrated in Figure 3.

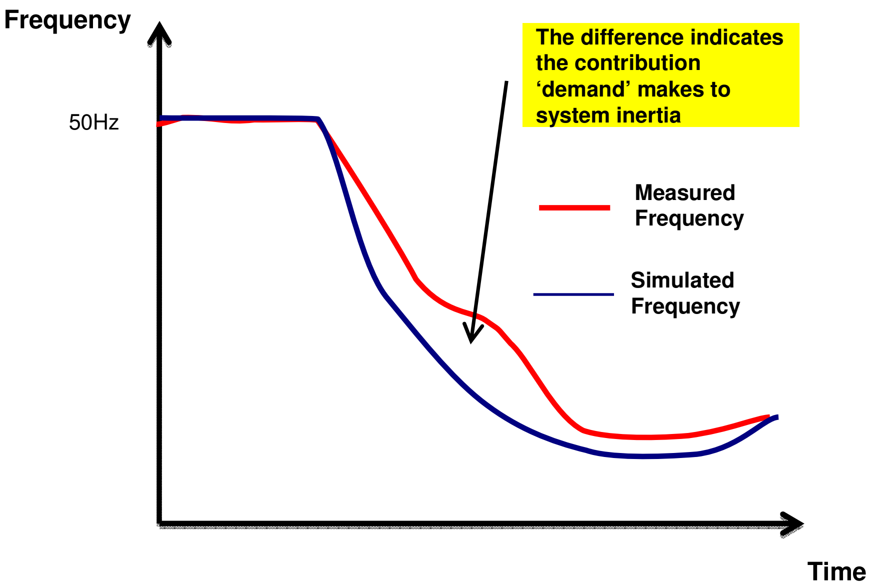

Figure 3: Evaluating Residual Inertia

3.22 It is conceivable that there is a downward trend in Residual Inertia. Electrical machines have become more efficient in recent years but in many cases the technology employed has the effect of supplying less inertia (the used of variable speed drives as opposed to induction machines for example). It should be noted that no clear trend or causal effect has been established at this time.

3.23 It is possible to predict a maximum rate of change using a combination of Residual Inertia and forecast generation operating patterns. Two tables are shown below which provide a view of RoCoF for different infeed loss risks.

3.24 The calculated figures are simulated system averages. Actual figures would vary dependent on the location of measurement and transient effects (further explanation is provided in paragraph 3.31) meaning that a margin needs to be applied to the figures illustrated.

3.25 The analysis is based on the Gone Green dataset used in the 2012 Electricity Ten Year Statement. The load and availability factors and scheduling assumptions used by the FRTSG were applied to the generation and demand schedule (eg 20GW demand scenarios reflect high wind conditions with 60% of installed wind capacity running).

3.26 Table 1 shows results from a “High Wind” condition. Table 2 is the same, but is intended to represent a “High Imports” condition, with an additional 2GW of asynchronous sources accommodated. The lowest demand level considered was 20GW. The lowest demand experienced this year so far is 19GW (as viewed from the transmission system) and it is likely that this will reduce over time. Further information on the assumed generation background is provided in Annex 4.

3.27 It should be noted that the rate of change is sensitive to generation mix and that there is considerable scope for variation as wind output and interconnector positions vary and synchronous generation is displaced. A number of sensitivities are not included in the analysis, including a growth in distributed generation from asynchronous sources and variation in damping within demand.

Year	**Demand**	**1320 MW loss**		**1800 MW loss**	
		100ms	**500ms**	**100ms**	**500ms**
2014	20 GW	-0.24	-0.24	-0.34	-0.33
	35 GW	-0.13	-0.13	-0.18	-0.17
2016	20 GW	-0.25	-0.24	-0.35	-0.34
	35 GW	-0.13	-0.13	-0.19	-0.18
2018	20 GW	-0.30	-0.29	-0.43	-0.42
	35 GW	-0.16	-0.16	-0.23	-0.22
2020	20 GW	-0.36	-0.35	-0.50	-0.49
	35 GW	-0.19	-0.19	-0.27	-0.26

Table 1: Predicted Average System RoCoF (High Wind Conditions)

Year	**Demand**	**1320 MW loss**		**1800 MW loss**	
		100ms	**500ms**	**100ms**	**500ms**
2014	20 GW	-0.26	-0.26	-0.36	-0.36
	35 GW	-0.14	-0.13	-0.19	-0.18
2016	20 GW	-0.27	-0.27	-0.38	-0.37
	35 GW	-0.14	-0.14	-0.20	-0.19
2018	20 GW	-0.33	-0.32	-0.47	-0.45
	35 GW	-0.17	-0.17	-0.24	-0.24
2020	20 GW	-0.42	-0.40	-0.57	-0.56
	35 GW	-0.21	-0.20	-0.29	-0.28

Table 2: Predicted Average System RoCoF (High Wind, High Imports)

3.28 Results are shown for the years up to 2020. It was not possible for the purposes of this analysis to derive feasible generation and demand balance solutions for scenarios beyond 2020 which satisfied frequency control requirements. Enhanced frequency control services, wider generator operating ranges and further demand side services are amongst the facilities that may be required to address this. Each of these options, if adopted, would have a different impact on the predicted maximum RoCoF value.

3.29 The predicted RoCoF values shown are all above the current minimum setting. Values approach and exceed 0.5Hzs-1 for infeed losses of 1,800MW under low demand conditions. Connections which constitute an infeed loss risk of 1,800MW are currently expected from 2017 onwards.

3.30 The predicted rates of change of frequency shown in and give a strong justification for a review of the corresponding aspects of Loss of Mains Protection. This is further strengthened by information derived from recent large frequency deviations.

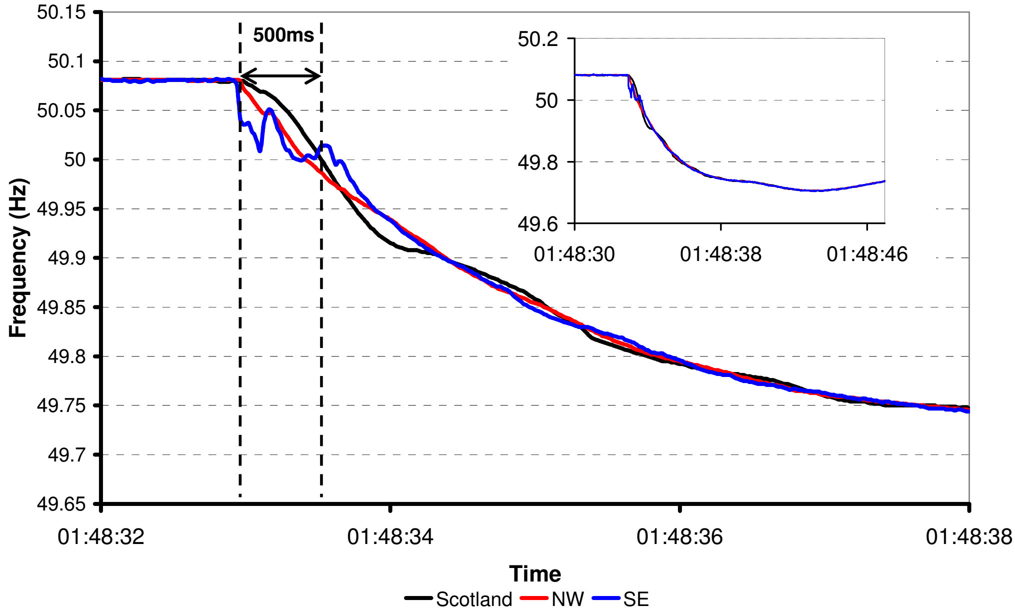

Figure 4: Frequency Measurements during a1,000MW Instantaneous Infeed Loss on 28th September 2012

3.31

3.32 Figure 1 from an interconnector trip on the 28th September 2012. The total infeed loss was 1,000MW, and the maximum observed rate of change of frequency over 500ms was 0.168Hzs-1, with significant differences in the measurements taken at different locations as a result of differing phase angles (the minimum was 0.116Hzs-1). There was also significant variation in rates of change in the first 500ms after the incident particularly for the measurements taken closest to the source of the disturbance. These two features mean firstly that there is some uncertainty over whether a RoCoF based protection relay will operate or not for a given average rate of change of frequency over the total system. Secondly, an automatic response mechanism intended to limit the rate of change of frequency (Synthetic Inertia for example) needs to be carefully designed to ensure it can respond appropriately.

4 Workgroup Discussions

4.1 The first Workgroup meeting was held on 26th October 2012. The Workgroup met 7 times over the period between up to and 20th May 2013.

The Requirement for Loss of Mains Protection

4.2 The workgroup reviewed the background to and the current need for Loss of Mains protection described in paragraph 3.2 and concluded that Loss of Mains Protection was still required for the safety of people and protection of DNO and users' equipment.

4.3 The DNOs have statutory safety obligations stemming from the Energy Act 1983 and Electricity Safety, Quality and Continuity Regulations 2002.

4.4 Prior to the 1983 Act it was almost impossible to generate in parallel with the public supply. ER G59 was first written to deal explicitly with the issues perceived at that time and was published in 1985.

4.5 Loss of mains protection is designed to avoid problems for the following technical issues:

- Out of synchronism re-closure
- Inadvertent un earthed operation of an energised network
- Effective protection
- Control of Voltage and Frequency

Out of synchronism re-closure

4.6 DNOs employ auto-reclose systems at all voltages with typical dead times between 3s and 120s but can be as short as 1s in some areas. After the dead time, the circuit will be automatically re-energized (though it may trip again if the fault is still present on the system). If the generator has continued to generate, there the system and the generator would be out of phase to an extent which cannot be predicted. This would impose a disturbance on both the system and the generator, with the impact dependant on the difference in phase angle between the system and the generator For some generating plant this could cause severe damage and create a potentially dangerous situation. Generating plant which is not directly coupled to the system such as inverter based plant would not be subject tot the same level of disturbance.

Earthing

4.7 DNO High Voltage systems are only earthed at one point, at the source transformer station. If a generator supports an electrical island within a DNO network, in most cases this would not include the source transformers for that network. The island would then be unearthed. This is potentially unsafe as an earth fault on the HV system would be undetected and could give rise to danger to persons, it is also not allowed under ESQCR 2002. It is this risk that makes Neutral Voltage Displacement protection appropriate in some cases

Protection

4.8 DNOs protection against faults usually relies on high fault currents to operate protection. The source of the DNOs system has a low impedance. A generator supporting an island of the DNOs system will generally have a higher source impedance and may not provide sufficient current to operate the DNO's protection systems.

Control of Voltage and Frequency

4.9 A generator supplying an island of DNO's network will be controlling (or not) the voltage and frequency of the island – and the voltage and frequency provided to customers. If the generator has not been designed to maintain these within acceptable limits, customers' equipment might be damaged.

Summary of Requirement

4.10 For these reasons, power islands are not expected to be created unintentionally, and should not be allowed to form unintentionally. Under the current arrangements within Great Britain, having functioning loss of mains protection is the generator's responsibility.

4.11 Note that for system stability reasons the over and under voltage, and frequency protection settings in G59 and G83 are set well outside normal system operating ranges for voltage and frequency.

4.12 A variety of active and passive techniques can be applied to Loss of Mains protection. For example, reverse Power detection is an effective loss of mains protection. However if the generator wished to export, this approach cannot be used.

4.13 The use of dedicated inter-tripping circuits is also very effective but incurs a high capital and revenue cost and is not appropriate for smaller distributed generation.

4.14 Traditionally within Great Britain, two methods for the detection of loss of mains, based on frequency measurements have been considered suitable, though they both suffer from nuisance tripping during faults on associated networks. For all its difficulties, Rate of Change of Frequency (RoCoF) protection has been believed to be the best compromise, though Vector Shift (VS) protection can be very effective when used with non-synchronous generating units

International Experience

4.15 The workgroup reviewed the CIGRE report on 'The impact of Renewable Energy Sources and Distributed Generation on Substation Protection and Automation' prepared by WG B5.34 issued in 2010 provides a useful review on the international practice on anti-islanding. Below are some of the key points and comments:

4.16 There are a variety of methods (both active and passive) found in the technical literature but the results of the survey from the utility companies indicated in practice only a few are commonly used.

4.17 At (sub)transmission level (110kV and above) there is currently no requirement for a dedicated anti-islanding protection apart from Spain. At lower voltage levels 69kV and below the requirement for anti-islanding protection is more common and the methods found in practice can be summarised below:

- Voltage and/or frequency based protection is used in all countries. Where no other dedicated anti-islanding protection is installed the voltage and frequency protection with fast operation fulfils this function.

- ROCOF and Vector Shift (VS) are dedicated forms of passive anti-islanding protection for distribution system generator connections. Only six countries (i.e. UK, Australia, Austria, Belgium, Canada and Italy) were reported to use this form of protection.

- Inter-tripping is also a common practice which although relatively expensive provides the best performance for anti-islanding generator protection where it is practicable to monitor all potential points of separation. This is used in Spain, France, Norway, Germany and also by some utilities in Great Britain

4.18 Northern Ireland and Ireland are in the process of reviewing the suitability of RoCoF protection for the purpose of island protection and they have proposed grid code amendments to respectively require or increase RoCoF withstand capabilities of generators.

4.19 It is worth noting that active methods are still not widely utilised due to power quality and reliability concerns, however, some methods are accepted in the US with inverter based generation.

Types and Application of Loss of Mains Protection

4.20 In HV (sub)transmission networks where normally there are no embedded loads, intertrips or other anti-islanding relays should not be necessary. Synchrocheck would then be used to prevent a possible out-of- synchronism reclose.

4.21 In MV networks, where embedded loads are present, anti-islanding protection is necessary to prevent an islanding operation which broadly falls into two types:

- Voltage and/or frequency limit triggered or dedicated anti-islanding relays, such as RoCoF, or;

- Where the cost of communications links and additional relays can be justified, anti-islanding protection based on intertripping. Depending on the connection scheme, there are different solutions for the intertripping scheme:

    - Connection to a non-dedicated line: intertripping from the remote network licensee’s circuit breaker;

    - Tapped connection: intertripping from the remote network licensee’s circuit breakers;

- Connection to a non-dedicated substation: intertripping from the local/remote line circuit breakers.

4.22 The operation of the anti-islanding protection must be faster than the auto-reclosing delay in order prevent a possible out-of-synchronism coupling.

4.23 Some network licensees take a view that anti-islanding protection requirements could potentially be subject to a carefully performed risk assessment exercise. In cases where the chance of forming a stable island is negligible (e.g. when minimum local load is significantly larger than the generator capacity) there could be scope for the exclusion from the requirement of dedicated anti-islanding protection.

4.24 There is a correlation between the requirement for the maximum time of islanding detection (0.5 s in most cases) and the settings of the auto-reclose schemes. The requirement could be less stringent in parts of the distribution system with much longer auto-reclose settings.

4.25 There are a variety of approaches regarding the detection of an islanding condition in different countries ranging from the sensitive RoCoF method or highly reliable intertrip to the protection. Moreover, even within the same country, different utilities approach the issue differently. There may be a case for a higher degree of standardisation in anti-islanding protection requirements and laboratory tests.

4.26 For large size generators where it is practicable and economic to monitor potential points of separation, intertripping can be effective. There is no definitive solution for small and medium size distributed generation because of the unavailability for reliable communication links, cost and maintenance implications

Recent Experience in Northern Ireland and the Republic of Ireland

4.27 The workgroup examined the proposals under discussion in Ireland to change recommended rate of change settings for the purposes of Loss of Mains protection.

4.28 Recommendations have been developed as part of a package of changes. The workgroup's understanding is that there was a reasonable consensus amongst the affected parties in Ireland that a change to Loss of Mains protection rate of change settings to $1Hzs^{-1}$ was acceptable. Some issues were unresolved where it was proposed that all generators should be able to withstand a rate of change of frequency up to the same level. The workgroup understands that concerns focussed on existing generating plant as it was difficult and potentially costly to assess this type of plant's capability. [5]

[5] Recent publications with the Republic of Ireland are available on the Commission for Energy Regulation website: http://www.cer.ie/en/electricity-transmission-network-current--consultations.aspx?article=4318d070-3e7c-4e2d-8c91-51b61f9f4902

Reported events in Spain

4.29 The workgroup also spent some time reviewing the information that was available concerning incidents observed within the electricity distribution network in Spain.

4.30 It was reported that on at least one occasion, an islanding event had occurred where an isolated section of network fed solely by a large number of inverters driven by photovoltaics and had remained energised and continued operating for some time.

4.31 This was contrary to the group's initial expectations, as it was presumed that given the lack of explicit control mechanisms, sustained operation in this configuration was extremely unlikely. However, the group concluded that it was credible for an island to be sustained in this manner, particularly if the island had an initial excess of generation and that generating equipment could shut down under protection operation until a balance of supply and demand was reached. The group agreed that it was important to consider such scenarios fully when developing recommendations for smaller generating plant.

Information Gathering

4.32 The workgroup reviewed the information that was available concerning generation which had Loss of Mains protection fitted in accordance with ERG59 and ERG83.

4.33 For plant of capacity 5MW and larger, information had been gathered for under and over voltage and under and over frequency protection settings changes initiated in {year} as part of the {} exercise. A total of 4.3GW of generating capacity was captured by this list.

4.34 Data from the Feed in Tariff programme gave more information particularly at the micro-generation scale. The dominant component here was Solar PV at a capacity of 1.5GW and rising. The group noted that this type of generation was unlikely to make use of a separate Loss of Mains relay and would be protected using proprietary techniques built into the units control system. Where a rate of change was referenced, this would be $0.2Hzs^{-1}$ as a minimum. The group also noted that coincidence of periods of high solar output and times of low system inertia would be limited for the next 18 months at least.

4.35 Alternative information sources suggested that a further 3 to 4GW of generation capacity of 5MW and smaller was connected to the networks.

4.36 The information available for the Digest of United Kingdom Energy Statistics (DUKES) provides the most comprehensive view and is summarised the table below.

Embedded Generation	Capacity in 2010/11(MW)
Coal CHP	*176*
Fuel Oil CHP	*87*
Gas CHP	*2,914*
Renewable CHP	*260*
Other CHP	*917*

Embedded Generation	Capacity in 2010/11(MW)
Total CHP	***4,354***
Marine	***4***
Hydro E&W	*208*
Hydro Scotland	*334*
Total Hydro	***541***
Biomass	***2,140***
Wind E&W	*1,887*
Wind Scotland	*544*
Total Wind	***2,430***
Total	***9,469***

Table 3: Embedded Generation Capacity

4.37 The workgroup facilitated further information gathering on the Loss of Mains protection settings currently applied to embedded generation by drafting a structured questionnaire to embedded generators. Information had been requested by National Grid to aid its operational decision making process but was not readily available. The workgroup therefore produced a template letter and questionnaire for DNOs to address to appropriate users to help ensure that a consistent dataset was produced.

Stakeholder Engagement

4.38 The workgroup concluded early in its discussions that a broad range of parties could potentially be impacted by changes that the workgroup could ultimately recommend, and that there was a need to provide information to stakeholders on what changes could be made and how, prior to a formal consultation.

4.39 An open letter highlighting the potential for change, and how to get involved in the decision making process, was published on the 24th January 2013[6]. The letter informed of a number of matters under discussion including the range of frequency deviations to be withstood, the range of RoCoF to be withstood, how decisions would be made and how protection settings would be changed

4.40 Workgroup members also hosted stakeholder workshops on the 25th April 2013 in Glasgow and the 8th May 2013 in London. Questions raised are listed in Annex 3 along with outline responses.

Operational Actions

4.41 The workgroup was briefed on the actions that National Grid is taking on a regular basis in order to prevent high rates of change impacting adversely on electricity consumers. These are intended to ensure that system frequency would remain stable following an instantaneous large infeed or offtake loss in line with National Grid's statutory obligations.

4.42 The actions taken are a combination of re-configuring the generation pattern to increase system inertia (i.e. keeping additional synchronous generation running at periods of low demand) and limiting the size of the maximum instantaneous

[6] http://www.nationalgrid.com/NR/rdonlyres/B2E3861D-1281-4105-AD08-66E0D644FE3B/58626/OpenLetteronG83andG59protectionrequirementsv4.pdf

loss. It was noted that not all 'instantaneous' losses occurred quickly enough to trigger RoCoF based protection.

4.43 National Grid can re-configure the generation pattern and limit the maximum secured instantaneous loss risk by procuring Balancing Services. These can either take the form of energy trades ahead of real-time, or services instructed within the Balancing Mechanism (from 90 minutes to real-time). Where there is a need to procure a significant volume of services, or to buy a particular type or combination of services, it can be efficient for National Grid to buy services, or options on services in advance. The annual incremental cost of such services is now forecast at £10m per year with an upper range of £100m per year, which will rise into the future.

4.44 The workgroup was briefed on National Grid's intentions to procure services to manage RoCoF risks through a tender process for Summer 2013. The DRIVe[7] tender ("Downward Regulation, Inertia and Volts") would evaluate tenders to manage RoCoF, general frequency regulations and voltage control issues in an integrated tender and assessment process. The tender provided two potential benefits, the first being a more efficient way of buying the necessary services and the second being a means of establishing a value for inertia services to inform the development of new very fast acting frequency control services.

Work Phases

4.45 The workgroup concluded that there was a strong case to review recommended RoCoF settings for loss of mains protection and specify an associated withstand capability for generators and other affected equipment. In order to recommend a change, the group needed to establish how the safety of the distribution networks and the equipment connected to it could be affected. An increase in setting would mean that it was less likely an island condition would be detected leading to a higher possibility of unsafe islanded operation which would have to be quantified and assessed.

4.46 In formulating its workplan, the group reviewed the work carried out to examine Neutral Voltage Displacement (NVD) requirements for connection to distribution networks as the risk assessment performed for the NVD work had similar features to the risk assessment that the workgroup needed to perform (simulating network conditions and assessing how these impacted on individual risk for example). The group also considered the information that was available to it in terms of network design and behaviour, and generation type models. The group further reviewed experience in modelling and assessing multiple generator infeeds, and in particular inverter dominated scenarios as could be expected in areas of high photovoltaic generation penetration. The group then debated how best to balance the need to make changes which would reduce the risk of a significant volume of unwanted distributed generation shutdowns occurring as quickly and efficiently as possible with the time taken to assess any risks thoroughly.

4.47 The group concluded that the work was best tackled in two phases. The first phase would use well-established modelling and assessment techniques which the group had confidence represented a reasonable worst case. This work

[7] For the latest commentary on DRIVe at the June 2013 Operational Forum (podcast at 28:00): http://www.nationalgrid.com/uk/Electricity/Balancing/operationalforum/2013+Presentations/

would examine requirements for distributed generation plant which was 5MW or more in capacity (over 4GW of the generation capacity at risk). Smaller plant, and lower voltage networks with many infeeds would be examined in a second phase of work which the group would scope out in its first phase deliverables. This re-phasing was presented to and agreed by the Grid Code Review Panel and the Distribution Code Review Panel in May and June 2013 respectively in the form of a revised Terms of Reference.

Impact of a Change to RoCoF Protection Setting Requirements

4.48 The revision to the workgroup's terms of reference reduces the numbers of distributed generating stations impacted by any recommendation that the group makes relating to RoCoF settings in Loss of Mains protection in this working group report.

4.49 The network users affected by the change fall into the 5MW and above capacity category. There are some 300 individual existing generating sites (of all generation technologies) in this category. The workgroup estimates that less than 50% of these use RoCoF based protection. A change applied retrospectively would have to be implemented through a protection setting change, requiring competent engineering resource. The group estimated the cost at £1k (excluding loss of generation) per site although members articulated a range of views over what the maximum cost could be.

4.50 Any change in settings will change the risk of an unsafe island condition being undetected which may need to be mitigated. Therefore the group agreed that any change in settings needs to be assessed in terms of its impact to the safety of the distribution networks, its personnel and contractors and to the safety of users' equipment. The group commissioned the University of Strathclyde to perform this assessment.

Probability and Risk Assessment

4.51 The University of Strathclyde performed a probability and risk assessment under the supervision of the workgroup and using input and scenario data provided by workgroup members. The full report is provided as an Appendix to this report.

4.52 The assessment assesses and quantifies the probabilities and risks associated with proposed changes to RoCoF protection settings from the point of view of individuals' safety and equipment damage through out-of-phase auto-reclosing. This ascertains whether the risk of non-detection, under a range of possible proposed setting changes, is acceptable in light of the Health and Safety at Work act 1974 and other related utility policies and guidelines. To achieve this, experimental work was carried out to determine the potential islanding non-detection zone (NDZ) associated with different RoCoF settings.

4.53 The NDZ reflects the surplus/deficit power supplied by the DG prior to islanding and is expressed as a ratio of this power to the DG rating. The experimental work used a hardware-in-the-loop testing approach which incorporates a DG interface relay commonly used in the UK. The NDZ data has been utilised by the developed risk assessment methodology to determine the probability of islanding non- detection and consequently the associated risks. In addition to the NDZ data, the methodology makes use of annual load profiles and statistics relating to incidences of loss of primary substation supplies.

4.54 Conclusions from the risk assessment are discussed in the Impact & Assessment section of this report (Section 5). The full report is provided in conjunction with this document.

Plan for Further Work

4.55 The workgroup's Terms of Reference require the development of a plan to address further issues relating to RoCoF and Loss of Mains Protection. These require the group to develop proposals for consultation on any proposed changes drawing out the costs, benefits and risk of such a change to present to the January 2014 GCRP and DCRP. An outline plan is provided below.

1. *Research the characteristics (numbers/types etc) of embedded generation of less than 5MW registered capacity including likely RoCoF withstand capabilities;*

    a. Review DNO information and survey additional sources as necessary;

2. *Investigating the characteristics of popular/likely inverter technology deployed, particularly in relation to RoCoF withstand capability and island stability;*

    a. Survey manufacturers and installers and survey additional sources as necessary;
    b. Assess the requirement to test equipment to verify its characteristics;

3. *Development of RoCoF withstand criteria for use in GB (as will be required by RfG 8.1(b));*

    a. Workgroup members to develop a view of generation technologies' inherent withstand capability;
    b. Review the final proposals (post consultation) from the July 2014 recommendations in respect of protection settings and the Total System requirement;
    c. Identify and asses any gaps in withstand capability;
    d. Assess the costs, benefits and risks of setting withstand capability requirements for future generators;
    e. Assess the costs, benefits and risks of setting withstand capability requirements for existing generators;

4. *Assessing or modelling the interaction of multiple generators in a DNO power island;*

    a. Review existing approaches to multi-machine dynamic simulation;
    b. Develop new approaches if required;

5 *Investigating and quantifying the risks to DNO networks and Users of desensitising RoCoF based protection on embedded generators of rated capacity of less than 5MW;*

    a. Assess the costs, benefits and risks of requirements to de-sensitise RoCOF settings for future generators of registered capacity of less than 5MW;

5 *Analyse the merit of retrospective application of RoCoF criteria to existing embedded generation of less than 5MW (including comparison with similar programmes in Europe);*

a. Review international experience of large retrospective change programmes;

b. Assess the costs, benefits and risks of requirements to de-sensitise RoCoF settings for existing generators of registered capacity of less than 5MW;

6 *Consideration of issues relating to the continuing use of Vector Shift techniques;*

a. Review the likely exposure of distributed generation to vector shifts in excess of recommended settings during system disturbances.

5 Impact & Assessment

Probability and Risk Assessment Outcome

5.1 The group's probability and risk assessment examined the likelihood of an undetected island persisting for more than 3 seconds (as 3 seconds is the minimum auto-reclose time generally deployed currently). Eleven different settings options were applied and are listed in Table 4. Setting Options 9 and 10 are representative of the current minimum settings.

Setting Option	RoCoF (Hzs^{-1})	Measurement Period	Deadband Applied
1	0.5	0	No
2	0.5	0.5	No
3	1	0	No
4	1	0.5	No
5	0.5	0	Yes
6	0.5	0.5	Yes
7	1	0	Yes
8	1	0.5	Yes
9	0.12	0	No
10	0.13	0	No
11	0.2	0	No

Table 4: Setting Options

5.2 The assessment derived a probability of an undetected islanding situation being feasible by combining historic data on the loss of grid supply to a primary substation and the number of synchronous generators in the range of 5MW to 50MW[8], with RoCoF based Loss of Mains protection, and capable of sustaining an island of equivalent size. For the purposes of other generation technologies, it was assumed that they were not capable of sustaining an island using current control practice hence the probability of an island being sustained by wind generation alone, for example, was considered to be negligible.

5.3 This was then combined with an assessment of the load balance within any potential island based on measurements at sample sites and simulated generator behaviour in different voltage control modes (generators in this category would not operate in a frequency control mode although this may be considered desirable for future connections). The results were then fed into a G5/9 protection relay. If the relay did not operate within 3 seconds then an undetected island was deemed to exist.

5.4 It was established that the sampling frequency of the historic measurements had a significant impact on results therefore the final results were based on data-streams with 1 data item per second. It was also established that the generator control mode had a significant impact. Where the generator could control the voltage in an island, there was greater dependency on the RoCoF element of the protection as the over or under voltage setting was less likely to be breached within 3 seconds.

[8] The maximum size to which Loss of Mains protection can be applied under G59/2 by virtue of not being captured by the Grid Code

5.5 Once the probability of an undetected island occurring had been established, this could be used to derive an estimate of the risks to network and user personnel, and the public. The risk of harm to an individual from the distribution network was therefore estimated by combining the probability of an island being formed with the duration it would be sustained and the likelihood of a person being in a situation where they would come to harm (eg by electrocution). This was termed IR_e.

5.6 The highest calculated figure for IR_e was $2.37x0^{-9}$ for setting option 4 in P-V control mode which lies within the zone which is normally deemed acceptable (less than 10^{-6}). However, it should be noted that this is higher than the IR_e calculated for existing settings which was between $1.22x10^{-10}$ and $2.65x10^{-10}$ for the same conditions.

5.7 The annual rate of occurrence of out of phase of autoreclosure occurring after a desynchronised island formed was also estimated (N_{OA}). This was derived from the probability of an island being formed, under the assumption that auto-reclose schemes are in place in all locations and no facilities are in place to check for synchronism across the switches being closed (it was assumed that 20% of cases would be sufficiently in phase to have no impact).

5.8 The highest probability reported was $3.31x10^{-1}$ for the population of generators in power and voltage control mode under setting option 8 (a protection setting of $1.0Hzs^{-1}$, with a 0.5 second measuring period and a deadband applied). The probability was significantly lower for the generator population in power factor control mode at $4.56x10^{-4}$ ($2.98x10^{-1}$ in voltage control mode) for the group's favoured setting of $1.0Hzs^{-1}$, with a 0.5 second measuring period and no deadband applied (setting option 4). The probability for a similar setting with $0.5Hzs^{-1}$ applied was $8.26x10^{-5}$ (setting option 2).

Setting Option	N_{OA} (P-V control mode)	N_{OA} (P-pf control mode)
2	$2.98x10^{-1}$	$4.56x10^{-4}$
4	$1.42x10^{-1}$	$8.26x10^{-5}$

Table 5: Summary of Occurrence of Out-of-phase re-closure risks

5.9 An IR_{OA} figure could be derived by combining the risk of the networks being sufficiently out of phase for harm to be caused, and the likelihood of personnel being put in danger. No figures were calculated for the individual and equipment risk from such an event as limited information was available at the time of writing. However, interested parties can develop their own view based on the figures and methodology provided.

5.10 The risk assessment provides a view of risk for an average site. The risk at an individual site will vary depending on local conditions. The assessment allowed the group to identify the factors which would significantly increase the risk to a generator or person of an island being formed and sustained in an unsafe condition where RoCoF protection was deployed for Loss of Mains purposes:

- An increase in frequency control within the island;
- An increase in generator inertia;

- Generator operation in voltage control mode;
- Better matching of local demand to generation; and
- An increase in auto-reclose times.

5.11 The group also noted that an increase or decrease in the number of synchronous generators would increase or decrease the number of events expected to occur over the whole system.

5.12 The risk to an individual from the network (IR_e) would increase with the factors in paragraph 5.10 and with the time spent in proximity to the network and the likelihood of undertaking a dangerous activity.

5.13 The risk to generator equipment where RoCoF protection was deployed for loss of mains purposes would increase with the factors in paragraph 5.10 and decrease with:

- A decrease in time in operation;
- Use of intertripping;
- Installation of synchrocheck facilities on auto-reclose schemes;
- Divergence in local load and generation capacity;
- Reduction in auto-reclose times where synchrocheck facilities or similar where installed; and
- An increase in auto-reclose times were no synchrocheck facilities or similar were installed.

5.14 The risk to personnel from an out of phase re-closure (IR_{OA}) is dependent on all the factors listed in paragraph 5.13 and increases with time spent near, and the proximity to equipment as well as the nature of the equipment and its protection mechanisms.

5.15 Estimated future rates of change of frequency are summarised in paragraph 3.29. The Workgroup concluded from these that a change of RoCoF settings to $1Hzs^{-1}$ was the preferred way forward as this was the only practicable way of ensuring substantial Balancing Services costs would not be incurred into the future. The group's proposals are therefore based on setting option 4.

5.16 The group noted that a setting of $0.5Hzs^{-1}$ achieved the same effect in the short term but that it was likely the setting would have to be revisited in a few years. If this option were preferred, the group would recommend setting option 2. This lower setting carried a risk that generators would incur a cost in making a further protection setting change at a later date as system conditions change.

5.17 The group's preference was therefore to develop proposals for a change to $1Hzs^{-1}$ (setting option 4) which would give it the opportunity to seek views on the validity of the assumptions deployed in its assessment through a formal consultation.

Cost Benefit Analysis

5.18 The group has evaluated the costs and benefits of making a change to RoCoF protection settings in accordance with setting option 4. The recommended changes apply to distributed generators within stations of registered capacity of 5MW and above.

5.19 The direct cost of not making a change to RoCoF settings on existing Loss of Mains protection is the cost of procuring Balancing Services to limit the rate of change of frequency for a secure infeed or offtake to the total system. A further effect is an increase in greenhouse gases due to the use of fossil-fuelled generation to provide inertia and the displacement of low carbon sources.

5.20 The annual incremental cost of procuring services to operate within the current criteria of $0.125Hzs^{-1}$ (which must be viewed in the context of other Balancing Services costs) is now estimated at £10m per year with an upper value of £100m per year, rising into the future.

5.21 Costs will rise as larger infeed losses connect and as more wind and interconnector capacity connects to the system. The most significant increase will be when losses of greater than 660MW (a large number of generators of this size are connected to the system) cannot be accommodated which is a risk from 2015 onwards. Changing protection settings for generators at stations of 5MW and above means that these costs can be avoided. The further work the group has identified will need to be completed to fully deliver these benefits.

5.22 The direct cost of implementing proposals for existing plant include the costs of making a protection setting change. These are estimated at less than £10k per site distributed synchronous generator sites with RoCoF based protection (approximately half of the 183 synchronous generator sites). The workgroup recognises that this work is as yet unplanned and will result in some unexpected inconvenience. For new connections there is no incremental cost. The maximum cost of making a setting change is therefore estimated at £1m.

5.23 There are further costs in implementing the proposals in the risk of damage to generator equipment. The group believes that these costs are negligible provided appropriate assessment is undertaken and mitigation deployed. There will be a cost in the assessment work of in the order of £25k per site. Mitigation measures for existing sites could cost up to £100k per site. In the absence of any cost recovery mechanism, this cost would be borne by owners of the affected generating plant.

5.24 The group has concluded that the benefits of the proposed change outweigh the costs by a significant margin but notes that the benefits are contingent on the completion of further work.

Impact on the Grid Code and Distribution Code

5.25 The Workgroup recommends amendments to the following parts of the Distribution Code:

- Distribution Planning and Connection Code

5.26 The text required to give effect to the proposal is contained in Annex 2 of this document.

5.27 The appropriate text for G59 is contained in Annex 3 of this document

Impact on National Electricity Transmission System (NETS)

5.28 Reduce the volume of distributed generation at risk of shutting down because of the operation of loss of mains protection during a frequency deviation after a secured event.

Impact on Distribution Code Users

5.29 The proposed modification will require existing distributed generators at generating stations of a registered capacity of 5MW or greater with RoCoF based loss of mains protection to apply new settings. New generators of this type will apply new settings as part of their planned construction and commissioning of their new plant.

5.30 Owners of existing synchronous generators at generating stations of a registered capacity of 5MW or greater with RoCoF based loss of mains may need to assess their exposure to out-of-phase reclosure under new protection settings. Mitigating actions may be required as a result of this.

Impact on Grid Code Users

5.31 The proposed modification will affect Network Operators (DNOs).

Impact on Greenhouse Gas emissions

5.32 The proposed change will reduce emissions by reducing the number and duration of the occasions where additional fossil-fuelled plant has to run to provide additional inertia to the total system.

Assessment against Grid Code Objectives

5.33 The Workgroup considers that the proposed amendments would better facilitate the Grid Code objective:

(i) to permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity;

The proposal takes the first step required to remove a constraint on system RoCoF which means a minimum amount of synchronous generation has to remain connected to the system. In the absence of a change, Balancing Services cost will be incurred at an increasing rate as new users connect asynchronous generation and interconnection to the GB electricity networks. The costs incurred as a result of the proposed change are significantly less than the costs that can be avoided.

(ii) to facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity);

The proposal has a neutral impact on this objective.

(iii) subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole; and

The proposal takes the first step necessary to substantially reducing a risk of involuntary demand control due the operation of Loss of Mains protection on a large number of distributed generators.

(iv) to efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency.

The proposal has a neutral impact on this objective.

Assessment against Distribution Code Objectives

5.34 The Workgroup considers that the proposed amendments would better facilitate the Distribution Code objective:

(i) to permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity;

The proposal takes the first step required to remove a constraint on system RoCoF which means a minimum amount of synchronous generation has to remain connected to the system. In the absence of a change, Balancing Services cost will be incurred at an increasing rate as new users connect asynchronous generation and interconnection to the GB electricity networks. The costs incurred as a result of the proposed change are significantly less than the costs that can be avoided.

(ii) to facilitate competition in the generation and supply of electricity

The proposal has a neutral impact on this objective.

(iii) subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole; and

The proposal takes the first step necessary to substantially reducing a risk of involuntary demand control due the operation of Loss of Mains protection on a large number of distributed generators.

(iv) to efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency.

The proposal has a neutral impact on this objective.

Impact on core industry documents

5.35 The proposed modification does not affect any other core industry documents

Impact on other industry documents

5.36 The proposed modification does affect any other industry documents

Implementation

5.37 The Workgroup proposes that, should the proposals be taken forward, the proposed changes be implemented a the start of the calendar month following the Authority's decision.

6 Workgroup Recommendations

6.1 The workgroup recommends the following for distributed generators within stations of registered capacity of 5MW and above:

(a) that the minimum Rate of Change of Frequency settings specified for Loss of Mains protection on new distributed generation, with a completion date on or after the date of implementation of these proposals, should be changed to $1Hzs^{-1}$ measured over half a second, expressed as 0.5Hz over 0.5 seconds;

(b) that the protection setting described in (a) should be applied to generation with RoCoF protection and a completion date prior to the implementation of these proposals, and that the costs of not making such a change significantly outweigh the costs of making it.

6.2 The group's assessment indicates that the safety risk to network equipment and to personnel in proximity to network equipment (eg by electrocution) following implementation of the recommended change would lie within a range deemed acceptable by established practice.

6.3 The group's assessment indicates that the acceptability of the safety risk to synchronous generator equipment and to personnel in proximity to synchronous generator equipment following implementation of the recommended change is dependent on generator voltage control mode and local network conditions. The group recommends that site specific risk assessments should be undertaken prior to a protection setting change and notes that costs may be incurred in taking appropriate mitigating actions as a result of this assessment.

6.4 The group has not developed a recommendation for a RoCoF withstand capability for generators, HVDC Convertors and other equipment and will bring proposals forward for this in its next phase of work in accordance with its Terms of Reference.

6.5 Consultation Issues:

The Workgroup recommends:

(a) Proposals for a change to RoCoF settings on loss of mains protection for existing and distributed generators within stations of registered capacity of 5MW and above to $1Hzs^{-1}$ measured over half a second are taken forward to consultation with views sought on:

(i) the findings of the group's probability and risk assessment relating to the risk to individuals and the risk to equipment;

(ii) the acceptability of an increase in islanding risk in the context of existing network related risks; and

(iii) the assessment and mitigation measures that would be appropriate for synchronous generators to take to reduce the risk of out-of-synchronism re-closures that could otherwise present a hazard; and

(iv) The costs and benefits that the group have considered in determining the value of proceeding with a change.

(b) Completion of information gathering for distributed generation at stations of registered capacity of 5MW and larger as described in paragraph 4.32 of this report;

(c) Implementation of protection setting changes within 18 months;

(d) Further, a site specific safety risk assessment in respect of distributed synchronous generators at stations of registered capacity of 5MW and larger prior to implementation of a protection setting change;

(e) To proceed with the workplan outlined in paragraph 4.55 of this report to develop proposals for all distributed generation of less than 5MW in capacity and to develop proposals for a RoCoF withstand capability.

Annex 1 - Terms of Reference

pp13/32
May 2013 GCRP

GC0035 Frequency Changes during Large Disturbances and their impact on the Total System.

TERMS OF REFERENCE

Governance

1. The Frequency Changes during Large Disturbances and their impact on the Total System Workgroup was established by Grid Code Review Panel (GCRP) at the May 2012 GCRP meeting.

2. The Workgroup shall formally report to the GCRP and the DCRP.

Membership

3. The Workgroup shall comprise a suitable and appropriate cross-section of experience and expertise from across the industry, which shall include:

Name	Role	Representing
Mike Kay	Chair	Electricity North West
Robyn Jenkins	Technical Secretary	National Grid
Graham Stein	Member	National Grid
William Hung	Member	National Grid
Geoff Ray	Member	National Grid
Campbell McDonald/Jane McArdle	Member	SSE (Generator)
Joe Duddy	Member	RES (Generator)
Paul Newton	Member	EON (Generator)
Joe Helm	Member	Northern Power Grid (DNO)
Martin Lee	Member	SSEPD (DNO)
John Knott	Member	SP Energy Networks (DNO)
Andrew Hood	Member	Western Power Distribution
Adam Dyśko	Technical Expert	University of Strathclyde
Julian Wayne	Authority Representative	Ofgem

Meeting Administration

4. The frequency of Workgroup meetings shall be defined as necessary by the Workgroup chair to meet the scope and objectives of the work being undertaken at that time.

5. National Grid will provide technical secretary resource to the Workgroup and handle administrative arrangements such as venue, agenda and minutes.

6. The Workgroup will have a dedicated section on the National Grid website to enable information such as minutes, papers and presentations to be available to a wider audience.

Scope

7. The Workgroup will:

- Review the expected behaviour of Total System when subject to frequency changes during large disturbances, with particular focus on the rate of change of frequency. Take into account the output of the Frequency Response Technical Sub-group and also recent experience of disturbances on the Total System.

- Take account of relevant international practice and the approach taken in European Code development.

- Research details of the RoCoF based protection settings applied to embedded generators of 5MW and greater rated capacity.

- Investigate and quantify the risks to DNO networks and Users of desensitising RoCoF protection on embedded generators above 5MW and greater rated capacity. Develop proposals for consultation on any proposed changes drawing out the costs, benefits and risks of such a change to present to the July GCRP and to DCRP members in July.

- Develop a work plan including timescales and resource requirements for the next stage of work, to include:

    - Development of RoCoF withstand criteria for use in GB (as will be required by the EU Network Code Requirements for all Generators (ref 8.1(b)));

    - Investigating and quantifying the risks to DNO networks and Users of desensitising RoCoF based protection on embedded generators of rated capacity of less than 5MW;

    - Investigating the characteristics of popular/likely inverter technology deployed, particularly in relation to RoCoF withstand capability and island stability;

    - Assessing or modelling the interaction of multiple generators in a DNO power island;

    - Researching the characteristics (numbers/types etc) of embedded generation of less than 5MW rated capacity including likely RoCoF withstand capabilities;

    - Analyse the merit of retrospective application of RoCoF criteria to existing embedded generation of less than 5MW (including comparison with similar programmes in Europe);

    - Consideration of issues relating to the continuing use of Vector Shift techniques; and

    - Develop proposals for consultation on any proposed changes drawing out the costs, benefits and risk of such a change to present to the January 2014 GCRP and DCRP.

Deliverables

8. The Workgroup will provide updates and a Workgroup Report to the Grid Code Review Panel and Distribution Code Review Panel which will:

- Detail the findings of the Workgroup;

- Draft, prioritise and recommend changes to the Grid Code, Distribution Code and associated documents in order to implement the findings of the Workgroup; and

- Highlight any consequential changes which are or may be required,

Timescales

9. Workgroup timescales are specified in the Scope section of this document.

10. If for any reason the Workgroup is in existence for more than one year, there is a responsibility for the Workgroup to produce a yearly update report, including but not limited to; current progress, reasons for any delays, next steps and likely conclusion dates.

Annex 2 - Proposed Legal Text

This section contains the proposed legal text to give effect to the Workgroup proposals.

Distribution Code

The proposed new text is in red.

DISTRIBUTION PLANNING AND CONNECTION CODE (DPC)

DPC7.4.3.4 The following summarizes the required **Protection** settings that will generally be applied:

Prot Function	Small Power Station				Medium Power Station	
	LV Connected		HV Connected			
	Setting	Time	Setting	Time	Setting	Time
U/V st 1	Vφ-n[†] - 13%	2.5s*	Vφ-φ[‡] -13%	2.5s*	Vφ-φ[‡]- 20%	2.5s*
U/V st 2	Vφ-n[†] - 20%	0.5s	Vφ-φ[‡] - 20%	0.5s		
O/V st 1	Vφ-n[†] + 10%	1.0s	Vφ-φ[‡] + 10%	1.0s	Vφ-φ[‡] + 10%	1.0s
O/V st 2	Vφ-n[†]+ 15%	0.5s	Vφ-φ[‡] + 13%	0.5s		
U/F st 1	47.5Hz	20s	47.5Hz	20s	47.5Hz	20s
U/F st 2	47Hz	0.5s	47Hz	0.5s	47Hz	0.5s
O/F st 1	51.5Hz	90s	51.5Hz	90s	52Hz	0.5s
O/F st 2	52 Hz	0.5s	52Hz	0.5s		
LoM (Vector Shift)	K1 x 6 degrees		K1 x 6 degrees[#]		Intertripping expected	
LoM(RoCoF) §	0.5Hz over 0.5s[¶]~~K2 x 0.125 Hz/s~~		0.5Hz over 0.5s[¶]~~K2 x 0.125 Hz/s~~[#]		Intertripping expected	

Notes:

φ-n; φ-φ denote RMS phase to neutral and phase-phase values respectively of the voltage at the **Connection Point**

†A value in the range 230-240V to suit the system

‡A value to suit the voltage of the connexion point

* Might need to be reduced if auto-reclose times are <3s

\# Intertripping may be considered as an alternative to the use of a Loss of Mains relay

K1 = 1.0 (for low impedance networks) or 1.66 – 2.0 (for high impedance networks)

~~K2 = 1.0 (for low impedance networks) or 1.6 (for high impedance networks)~~

§ Rate of change of frequency

¶ The desired protection requirement is 1Hzs^{-1}, but it is important that this is measured over a period of at least half of one second. The total tripping time will therefore be 0.5s plus circuit breaker operasting time. The total tripping time should not exceed 2.5s.

DPC7.4.3.5 Over and Under voltage **Protection** must operate independently for all phases in all cases.

DPC7.4.3.6 The settings in DPC7.4.3.4 apply to **Embedded Small Power Stations** and **Embedded Medium Power Stations**. In exceptional circumstances **Generators** have the option to agree alternative settings with the **DNO** if there are valid justifications in that the **Generating Plant** may become unstable or suffer damage with the settings specified in DPC7.4.3.4. The agreed settings should be recorded in the **Connection Agreement**.

DPC7.4.3.7 The underfrequency and overfrequency **Protection** settings set out in DPC7.4.3.4 also apply to **Generation Sets** in **Embedded Small Power Stations** already existing on or before 1 August 2010 with a **Registered Capacity** at or above 5 MW**,** except where single stage **Frequency Protection** relays are used, in which case the following settings apply.

Protection Function	Setting	Time
U/F	47.5Hz	0.5 s
O/F	51.5Hz	0.5 s

DPC7.4.3.8 The RoCoF **Protection** settings set out in DPC7.4.3.4 also apply to **Generation Sets** in **Embedded Small Power Stations** already existing on or before 1 August 2013 with a **Registered Capacity** at or above 5 MW.

DPC7.4.3.9 In exceptional circumstances **Generators** have the option to agree alternative settings with the **DNO** if there are valid justifications in that the **Generating Plant** may become unstable or suffer damage with the settings specified above. The agreed settings should be recorded in the **Connection Agreement**.

DPC7.4.3.~~8~~10 A loss of mains **Protection** of RoCoF or vector shift type will generally be appropriate for **Small Power Stations**, but this type of loss of mains **Protection** must not be installed for **Power Stations** >50MW. In those cases where the **DNO** requires loss of mains **Protection** this must be provided by a means not susceptible to spurious or nuisance tripping, eg intertripping.

DPC7.4.3.~~9~~11 Where short term paralleling in accordance with DPC7.1.4 is employed, the protection settings in the following table should be used in preference to those in DPC7.4.3.4.

	Infrequent Short Term Parallel Operation			
	LV Connected		**HV** Connected	
Prot Function	Setting	Time	Setting	Time
U/V	Vφ-n† - 6%	0.5s	Vφ-φ‡ -6%	0.5s
O/V	Vφ-n† + 10%	0.5s	Vφ-φ‡ + 6%	0.5s
U/F	49.5Hz	0.5s	49.5Hz	0.5s
O/F	50.5Hz	0.5s	50.5Hz	0.5s

†A value in the range 230-240V to suit the system..

‡A value to suit the voltage of the connexion point

Engineering Recommendation G59/2

The proposed new text is in red.

10.5.7.1 Settings for Long-Term Parallel Operation

Prot Function	Small Power Station				Medium Power Station	
	LV Protection(1)		HV Protection(1)			
	Setting	Time	Setting	Time	Setting	Time
U/V st 1	Vφ-n† -13% = 200.1V	2.5s*	Vφ-φ‡ -13%	2.5s*	Vφ-φ‡- 20%	2.5s*
U/V st 2	Vφ-n† - 20% =184.0V	0.5s	Vφ-φ‡ - 20%	0.5s		
O/V st 1	Vφ-n† + 14% =262.2V	1.0s	Vφ-φ‡ + 10%	1.0s	Vφ-φ‡ + 10%	1.0s
O/V st 2	Vφ-n†+ 19% =273.7V$	0.5s	Vφ-φ‡ + 13%	0.5s		
U/F st 1	47.5Hz	20s	47.5Hz	20s	47.5Hz	20s
U/F st 2	47Hz	0.5s	47Hz	0.5s	47Hz	0.5s
O/F st 1	51.5Hz	90s	51.5Hz	90s	52Hz	0.5s
O/F st 2	52 Hz	0.5s	52Hz	0.5s		
LoM (Vector Shift)	K1 x 6 degrees		K1 x 6 degrees#		Intertripping expected	
LoM (RoCoF)	~~K2 x 0.125 Hzs-1~~ 0.5Hz over 0.5s¶		~~K2 x 0.125 Hzs-1~~ 0.5Hz over 0.5s¶#		Intertripping expected	

(1) **HV** and **LV** Protection settings are to be applied according to the voltage at which the voltage related protection reference is measuring, eg:

- If the EREC G59 protection takes its voltage reference from an **LV** source then **LV** settings shall be applied. Except where a private none standard LV network exists, in this case the settings shall be calculated from **HV** settings values as indicated by section 10.5.16;
- If the EREC G59 protection takes its voltage reference from an **HV** source then **HV** settings shall be applied.

†A value of 230V shall be used in all cases for **Power Stations** connected to a **DNO LV Systems**

‡A value to suit the nominal voltage of the **HV System** connection point.

* Might need to be reduced if auto-reclose times are <3s. (see 10.5.13).

\# Intertripping may be considered as an alternative to the use of a LoM relay

$ For Grid surge voltages greater than 230V +19% which are present for periods of<0.5s the **Generating Unit** is permitted to reduce/cease exporting in order to protect the **Generating Unit**.

¶ The desired protection requirement is 1Hzs^{-1}, but it is important that this is measured over a period of at least half of one second. The total tripping time will therefore be 0.5s plus circuit breaker operasting time. The total tripping time should not exceed 2.5s.

(2) LOM constants

K1 = 1.0 (for low impedance networks) or 1.66 – 2.0 (for high impedance networks)

Annex 3 – Workshop Questions and Responses

Will a number of settings changes be required?

Licensees will always seek to minimize the number of times that customers are asked to make changes. The final requirements should be completed in line with the workgroup recommendations which will take into account the impact on customers.

Is there a cost benefit analysis needed to justify any changes?

The implications of any change of settings will need to be justified before the changes are accepted by the industry and ultimately by Ofgem.

The physical changes to settings on relays are not a material cost and no justification should be needed to undertake what should be just a routine operation. Changes that require capital modifications to equipment will always need some justification, although a de minimis of £10k exists for Transmission connected plant[9].

Would DNOs need to witness all of the tests?

Changes to protection relay settings do not necessarily need to be tested. Different DNOs will necessarily have slightly different policy approaches to reflect the different needs and risks of their networks.

In general a simple change of protection setting does not need extensive testing. DNOs should be given the opportunity to witness any tests necessary to commission or re-commission G59 protection.

Could there be a specified window in which to do all the tests/make all the changes, ensuring everyone is prepared?

It will generally be better for customers to determine the times to make changes to suit their own needs rather than looking for a common window. Historically licensees have not imposed deadlines for compliance with retrospective requirements, recognizing that it is generally more efficient to schedule the work in line with planned routine outages. However enforcement action could be considered if generators do not conform after a couple of outage seasons.

Would engineering assessments be required?

The level of assessment in relation to any individual generating plant is a matter for its owner. For simple protection requirement changes, this is not expected to be necessary. However if the setting change is seen as radical, then the owner might wish to make such an assessment.

If licensees specify new ride through or withstand requirements (possible in the future) then engineering assessments may be required

Will the recommendation be consulted on before the changes are implemented?

Yes, the Frequency Changes workgroup intends to consult on any proposed changes during Q3 2013.

---

[9] CUSC 11.3 definition of Material Alteration

Is this protection installed with the intention for it to change – is it expected that it would need to change?

All protection relays have variable settings to match the relay to the network characteristics. If those characteristics change, which is to be expected over the life of the installation, it is appropriate and expected to change settings.

Could there be a commercial arrangement with an aggregator to achieve the necessary security?

No. These are protection and capability requirements which apply to all relevant generators and cannot be delegated via a commercial agreement.

Does widening the RoCoF settings mean it could actually be decommissioned?

No. Even with wider tolerance settings RoCoF protection provides a useful loss of mains function for most generators in most conditions. The question about whether loss of mains is needed is a good question and will form part of future research and consideration.

At what point is it appropriate (and practicable) to re-think how power islands are treated?

Background thinking on this could form part of Phase 2 of the current Working Group's tasks. However there are many fundamentals that make power islands technically and legally very challenging. Licensees' opinion is that there is no short term possibility of intentionally running power islands within public distribution systems.

Where is the push for maintaining power islands coming from?

It is a possible elegant solution to the problems that now cause islanding within public distribution systems, and the loss of supplies that the current approach then causes. However it has its own considerable challenges. It remains a possible future option rather than a current project.

Could areas with net export sustain themselves?

Yes, but it requires significant engineering and other challenges to be viable.

If a group wants to be a power island, what is stopping them?

If it is on their own network there is nothing to stop them. A few big companies with extensive networks already do this. However it is not practicable for public networks with other customers connected to it. There is no legal and contractual framework to deal with the control and liability issues that could arise from such an arrangement.

Who has responsibility for equipment damaged as a result of voltage spikes in power islands?

This is one of the key issues facing the safe and legal operation of power islands. Ultimately the chain of responsibility might have to be tested in the courts following an unfortunate incident. It appears to be in the interests of all parties to avoid such an incident.

Do generators that supply power island have extra responsibilities?

See question above.

If a power island forms then how is it brought back onto the network, how would the generator reconnect?

This is one of the key technical and commercial challenges. Certain resynchronization points can be designed into the network, but under fault conditions there is no guarantee that the island would be formed at one of these points. The only safe option in many cases is to make the island dead and reconnect it. This is clearly undesirable.

Are RoCoF techniques viable in the long term?

This a good question and one that could form a later part of the working group's tasks.

Would Vector Shift be more vulnerable to local changes?

We believe that in general vector shift is more vulnerable to local faults. This could make it unattractive to generators if its use give rise to nuisance tripping

Would a technique, more robust that RoCoF, take longer to make a decision?

From a network only perspective, there is no detriment to a loss of mains relay taking appropriate time to properly discriminate for a true loss of mains event versus a transient condition. However from a generator perspective the longer this discrimination takes, the more chance there is that the DNO's network will auto reclose and create an out-of-synchronism condition for the generator.

Do the DNOs have records as part of the connection process?

Yes, but not necessarily of the G59 protection as that is the responsibility of the generator.

Could more seminars or workshops be done to educate people?

Yes

Is there a legal requirement for generators/manufacturers to cooperate and provide information?

There is a contractual requirement to co-operate and provide information as specified in the Distribution Code as part of the connexion process. There is a legal requirement (ESQCR 22(1)(d)) on generators to exchange necessary information with the network licensee before being connected.

How should interested parties who don't normally participate in workgroups be involved in the work?

This workshop is intended to facilitate this and further workshops are likely to be held during either or both the consultation and implementation stages of and change.

Could a leaflet/pamphlet be produced for circulation to industry (particularly Renewables UK members)?

All DNOs publish guides on DG connexion issues. They are based on a common guide: http://www.energynetworks.org/electricity/engineering/distributed-generation/distributed-generation.html

Is there a trade body for manufacturers?
Association of Manufacturers of Power Generating Systems (AMPS)

Are there any technical standards for manufacturers?
Could standards be developed? Generic, basic requirements would be an improvement.

G59 and G83 are functional standards. There are European standards in drafting
There are draft CENELEC standards

1. CLC/FprTS 50549-1 "Requirements for generating plants larger than 16A per phase to be connected in parallel with a low-voltage distribution network"; and
2. CLC/FprTS 50549-2 "Requirements for generating plants to be connected in parallel with a medium-voltage distribution network"

What needs to be considered if retrospective changes are required?

The need to keep a safe and secure system will drive the necessary changes. If these need to be retrospective, then an impact assessment will be undertaken.

How much of the 9GW of DG is PV?

See the Ofgem FIT register. There is now over 1.5GW of PV installed in Great Britain.

Are there mitigation measures in place for a staged approach?

The need to implement any mitigation measures will be captured in any proposals if these are necessary.

There are a lot of small inverters out there, Will a large number of small inverters add up to something that National Grid is interested in?

Yes

RoCoF is linked to largest loss but small generators are having to pay for it, is there a way to balance it out?

RoCoF protection is designed to detect local islanding and is required for integration with the local network. RoCoF protection needs to be resilient to the largest loss, and discriminate effectively between local and system wide events.

Could a market/ancillary service be developed for inertia?

National Grid is already considering this and has been seeking interia as part of its DRIVe tender exercise for summer 2013 which it expects to develop further.

Could widening settings lead to extra connection charges?

Connection charges will not be directly impacted by the change.

In G83/G59 have there been any changes to the witness tests?

Not specifically. G59 and G83 are being modified to allow much more use of type testing as a way of minimising or avoiding witness testing

Is Type Testing a possibility?

Yes – see above.

Is there likely to be a G83/3 and G59/4?

Yes. Future mitigation actions for frequency stability might drive future changes, and the incorporation of new European law (the EU Network Codes) will drive considerable change over the next few years.

Charging for these Engineering documents seems wrong, is the best place to put a requirement in a document that you have to buy?

Providing documents for free which have value and incur development costs is not possible under present arrangements. These documents take considerable resources to create and update. The income from them does not cover the costs. The balance of cost is ultimately paid by all electricity customers in Great Britain. Increasing the burden on all customers when the information is only required by a relatively small number of commercial entities is wrong. The charges are modest compared to similar documents such as British Standards, or the IET Wiring Regulations.

RfG requires Generators to be immune to auto-reclosure, to what extent does is make sense to hold out to see what the final RfG says?

RfG only requires Class C generators (GB generators >10MW) to withstand reclosures on meshed networks (Article 10(4))

Immunity to auto-reclose would potentially make LoM easier to implement, but it does not change the need to have LoM, and for the harmonization of RoCoF protection (and RoCoF withstand) with the needs of the system.

Annex 4 – Background for RoCoF forecast analysis

Generation Availability Factors

	20GW Scenario	35GW Scenario
Nuclear	60%	70%
Wind	60%	75%
Other	75%	80%

	GG Year 2014		GG Year 2016		GG Year 2018		GG Year 2020	
Demand (MW)	20,000	35,000	20,000	35,000	20,000	35,000	20,000	35,000
Pumping Load (MW) (H~4)	2,000	0	2,000	0	2,000	0	2,000	0
Synchronous Generation with H~4								
MVA	6,651	7,787	6,651	7,787	6,651	7,787	6,651	7,787
MW Output	5,654	6,619	5,654	6,619	5,654	6,619	5,654	6,619
Synchronous Generation with H~6								
MVA	18,668	29,833	17,155	27,647	11,636	20,454	7,119	14,443
MW Output	12,068	22,558	11,382	20,700	7,890	14,586	4,971	10,076
Asynchronous Generation H~0								
MW Output	4,259	5,823	4,945	7,681	8,436	13,795	11,355	18,304

	GG Year 2014		GG Year 2016		GG Year 2018		GG Year 2020	
Demand (MW)	20,000	35,000	20,000	35,000	20,000	35,000	20,000	35,000
Pumping Load (MW) (H~4)	2,000	0	2,000	0	2,000	0	2,000	0
Synchronous Generation with H~4								
MVA	6,651	7,787	6,651	7,787	6,651	7,787	6,651	7,787
MW Output	5,654	6,619	5,654	6,619	5,654	6,619	5,654	6,619
Synchronous Generation with H~6								
MVA	16,315	27,480	14,802	25,294	9,283	18,101	4,884	12,090
MW Output	10,468	20,558	9,582	18,700	6,090	12,586	3,151	8,076
Asynchronous Generation H~0								
MW Output	5,859	7,823	6,745	9,681	10,236	15,795	13,175	20,304

Technical Report

Assessment of Risks Resulting from the Adjustment of ROCOF Based Loss of Mains Protection Settings

Phase I

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June 2013

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Abbreviations and symbols

NDZ	- Non-Detection Zone
LOM	- Loss-Of-Mains
P_L, Q_L	- active and reactive power of the load
P_{DG}, Q_{DG}	- active and reactive power supplied by the distributed generator
$NDZP_a, NDZQ_a$	- accelerating NDZ (generator output is higher than the local load during LOM)
$NDZP_d, NDZQ_d$	- decelerating NDZ (generator output is lower than the local load during LOM)
T_{NDZmax}	- maximum permissible duration of undetected islanding operation
n_{NDZ}	- number of detected NDZ periods
T_{load_record}	- total length of recorded load profile
$T_{NDZ(k)}$	- length of k-th NDZ period.
P_2	- probability of non-detection zone for generator supplying power P_{DG}, Q_{DG}
P_3	- probability of non-detection zone duration being longer than T_{NDZmax}
$N_{LOG,1SS}$	- expected number of incidents of losing supply to a primary substation in 1 year
n_{LOG}	- number of Loss-Of-Grid incidents experienced during the period of T_{LOG} in a population of n_{PRIME} primary substations
$N_{LOM,1DG}$	- expected annual number of undetected islanding operations longer than the assumed maximum period T_{NDZmax} for a single DG
T_{NDZavr}	- overall average duration of the NDZ
T_{LOMavr}	- overall average duration of the undetected islanded condition
T_{ARmax}	- expected maximum time of auto-reclose scheme operation
n_{DG}	- number of all connected distributed generators in UK
p_{ROCOF}	- proportion of generators with ROCOF based LOM protection
LF	- generator load factor (understood as proportion of time the generator is connected to the network at rated output)
N_{LOM}	- expected national number of undetected islanding incidents in 1 year
T_{LOM}	- total aggregated time of undetected islanding conditions in 1 year
P_{LOM}	- overall probability of the occurrence of an undetected island within a period of 1 year
$P_{PER,E}$	- probability of a person in close proximity to an undetected energised islanded part of the system being killed
$P_{PER,G}$	- probability of a person in close proximity of the generator while in operation
IR	- probability related to individual risk
IR_E	- probability related to individual risk from the energised parts of an undetected islanded network
IR_{OA}	- probability related to individual risk from generator damage following an out-of-phase auto-reclosure
P_{AR}	- probability of out-of-phase auto-reclosing action following the disconnection of a circuit supplying a primary substation
N_{OA}	- annual rate of occurrence of any generator being subjected to out-of-phase auto-reclosure during the islanding condition not detected by LOM protection

Executive Summary

There are growing concerns relating to reduced inertia within power systems in the future and the impact this may have on the stable connection of distributed generation (DG). In particular, achieving a balance between sensitive and stable operation of ROCOF based loss of mains (LOM) protection for DG is becoming more difficult. Changing the recommended LOM settings to enhance the stability of DG interface protection can potentially increase the likelihood of islanding non-detection. Consequently, the risks associated with islanding non-detection may be increased.

The work reported in this document assesses and quantifies the risks associated with proposed changes to ROCOF protection settings from the point of view of individuals' safety and equipment damage through out-of-phase auto-reclosing. This ascertains whether the risk of non-detection, under the proposed setting changes, is acceptable in light of the Health and Safety at Work act 1974 and other related utility policies and guidelines. To achieve this, experimental work has been carried out to determine the potential islanding non-detection zone (NDZ) associated with different ROCOF settings. This work has considered synchronous DG connected using different control regimes.

The NDZ reflects the surplus/deficit power supplied by the DG prior to islanding and is expressed as a ratio of this power to the DG rating. The experimental work uses a hardware in the loop testing approach which incorporates a DG interface relay commonly used in the UK. The NDZ data has been utilised by the developed risk assessment methodology to determine the probability of islanding non-detection and consequently the associated risks. In addition to the NDZ data, the methodology makes use of annual load profiles and statistics relating to incidences of loss of primary substation supplies.

The report evaluates the potential impact of the proposed ROCOF setting adjustments on distributed generation with capacities of between 5MW and 50MW only (Phase I). Smaller scale generation (including PV) is expected to be evaluated in follow-on phases of this work.

It has been shown that the DG control mode has a significant impact on its ability to sustain an island and consequently the size of the NDZ. This is particularly evident when the generator is capable of providing reactive power to the islanded network with higher ROCOF settings. It has also been shown that there are significant increases in the probability of non-detection of islanding if the ROCOF settings are increased from prevailing recommended levels (as is being proposed). However, it is concluded that the calculated risk to individuals remain mostly within acceptable levels under the proposed setting changes when applied to generators within the 5-50MW range. The report does not attempt to quantify the consequences of the out-of-phase auto-reclosing, and therefore, the calculated annual rates of occurrence need further analysis to aid the decision process.

1 Introduction

This report describes the outcomes of work conducted at the University of Strathclyde to assess the risks associated with the adjustment of ROCOF based loss of mains (LOM) protection settings. This work has been commissioned by the joint working group of the UK Grid Code Review Panel (GCRP) and Distribution Code Review Panel (DCRP) which addresses the issue of system integrity under anticipated future low inertia conditions. Under such system scenarios, much higher maximum rates of change of frequency are expected. These ROCOF values are anticipated to be in excess of the existing protection settings recommendations included in G59/2 [1]. In order to prevent large amounts of distributed generation (DG) from spuriously tripping in reaction to non-LOM transients, the recommendation of increased ROCOF settings are presently being debated.

To inform this debate, the main objective of the work is to evaluate the risk to DNO networks and individuals (i.e. members of the public and/or personnel) associated with increasing the applied ROCOF protection settings (currently 0.125Hz/s) to 0.5Hz/s and 1Hz/s. This also takes into account the optional application of a ROCOF time delay of 500ms and a frequency dead-band setting of 49.5Hz to 50.5Hz (i.e. frequency range where operation of ROCOF is blocked).

The report contains two main sections corresponding to the work packages (WP) initially proposed prior to the commencement of the work:

- WP1 – Simulation based assessment of Non Detection Zone (NDZ): in this section, the NDZ is determined experimentally under varying ROCOF settings using hardware in the loop testing of a physical LOM protection relay with a real time simulation of the power network and distributed generator behaviour.
- WP2 – Calculation of probability of specific hazards at various ROCOF settings: in this section, a generic NDZ/risk characteristic is established based on the obtained NDZ values, available load profiles, and a few other assumptions.

1.1 Methodology

In order to meet the objectives outlined above, the work adopts the risk assessment methodology similar to the one previously applied by the researchers at Strathclyde to verify the requirement for NVD protection [2]. However, the underlying assumptions and risk tree used in this methodology are tailored to the specifics of this work. This methodology is illustrated in Figure 1.

A number of assumptions are made with regards to the network configuration including load representation, generation technology and its control. These are used to experimentally (through real time simulation) determine the extent of NDZ for different ROCOF setting options.

Furthermore, load profile data and annual fault statistics are utilised to estimate probabilities of islanding incidents and occurrences of balance conditions between local load and distributed generation output. Together, these are used to assess the risk of LOM non detection with the aid of the developed risk tree.

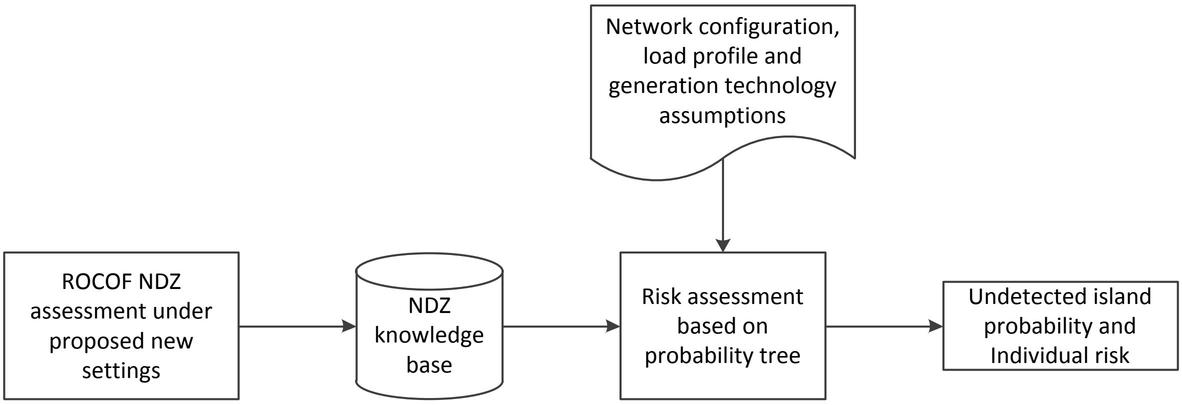

Figure 1. Risk assessment methodology

2 WP1 – Simulation based assessment of NDZ

2.1 WP1 overview

This section describes the main results and approach through which the NDZ has been experimentally determined for a range of ROCOF settings. A total of 11 test cases, corresponding to 11 setting options, have been performed on a 30MVA synchronous DG connected to a 33kV distribution network. Three spot tests have also been performed on a 3MVA synchronous DG connected to an 11kV network.

2.2 Network modelling

The network model used for the test is based on a reduced section of 33kV and 11kV distribution network, based on a typical UK network. The test 33kV network is depicted in Figure 2, while the 11kV network is shown in Figure 3. These models were used previously to evaluate the performance of LOM protection and to recommend suitable settings in [1] but have been adapted for the use in this study. The potentially islanded section of network incorporating the DG is connected through a point of common coupling (PCC) to the main grid. An LOM condition is initiated by opening the PCC. The measured voltage (from which frequency is derived) at busbar 'A' is input to the relay under test. The network is modelled using a real-time digital simulator (RTDS) to allow credible testing of the physical LOM protection relay. Commercially available DG interface relay commonly used in UK practice has been utilised in this test. The network parameters are detailed in Appendix A.

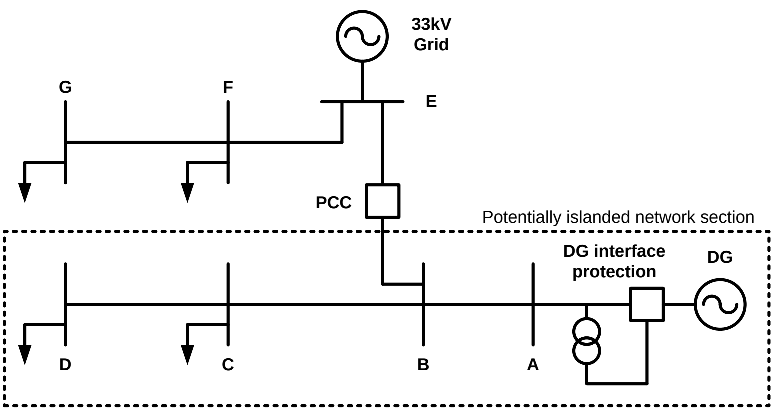

Figure 2. 33kV test network

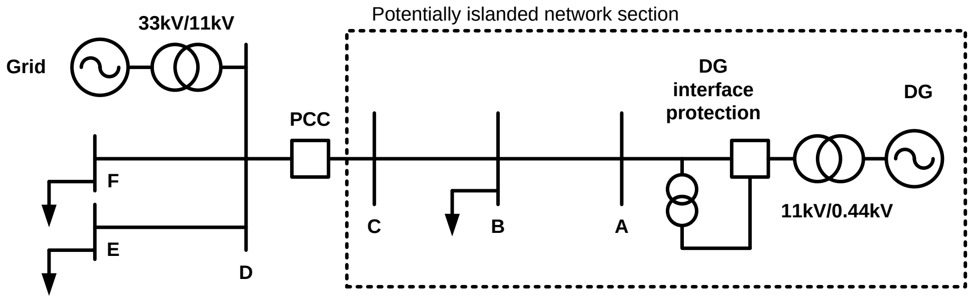

Figure 3. 11kV test network

The tests are carried out with two types of local load models: fixed power and fixed impedance; with a power factor of 0.98.

2.3 DG models and controls

For the first phase of testing, a synchronous machine based DG is modelled. The DG ratings used are 30MVA and 3MVA. The 3MVA generator is connected to the grid through a step up transformer. In this case, the interface transformer HV connection is not earthed [3]. Since no faults are applied in this work, the test results will not be affected by the absence of a transformer HV earthing point. Generator parameters are detailed in Appendix B. Two control modes are employed for:

- Fixed active power and voltage control (P-V control).
- Fixed active power control at unity power factor (P-pf control).

A standard IEEE governor/turbine model is used which is obtained from the RSCAD component library [4]. The block diagram for the governor control is depicted in Figure 4. The excitation control is achieved through combining voltage and reactive power control to either maintain a unity power factor or achieve fixed voltage control as shown in Figure 5 [5]. Controller parameters are detailed in Appendix C.

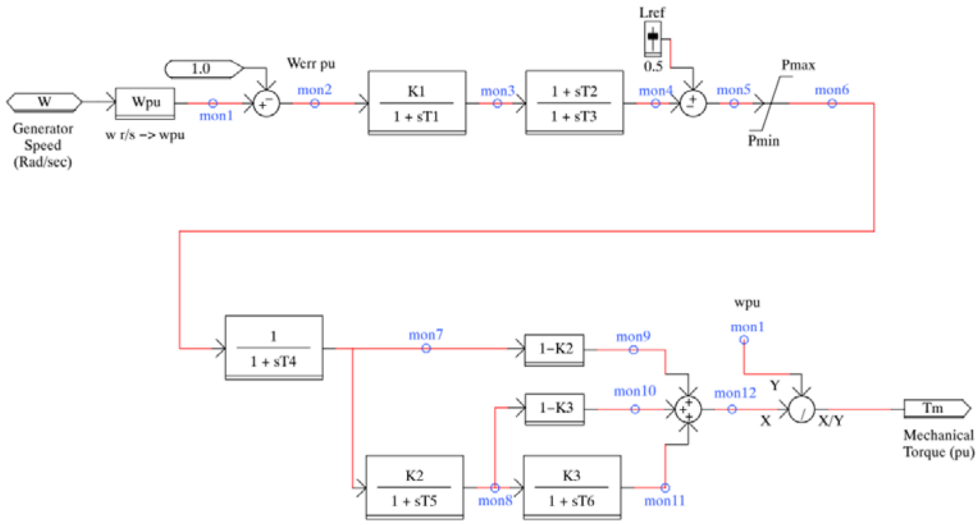

Figure 4. IEEE standard governor/turbine model [4]

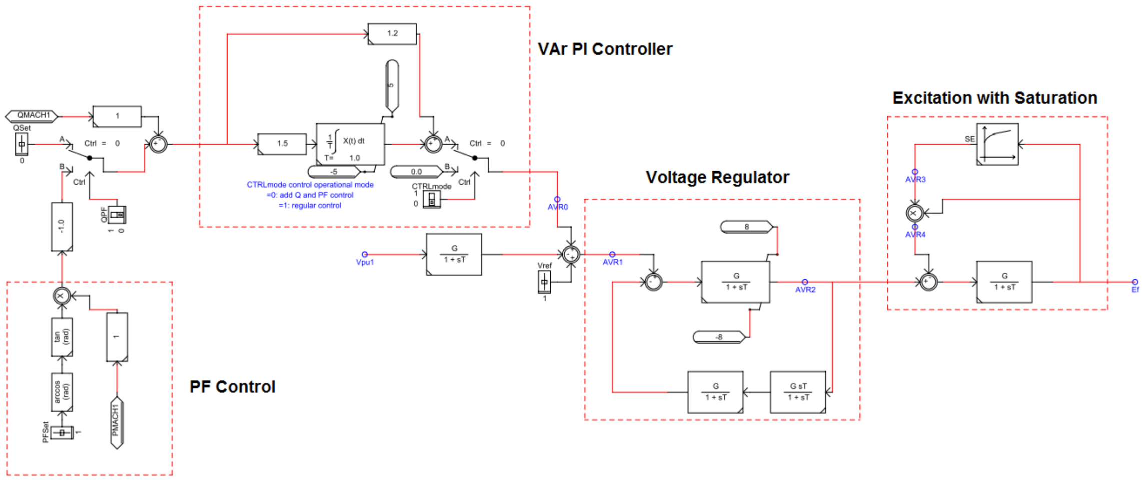

Figure 5. Combined reactive power and power factor control for generator excitation [5]

2.4 Experimental NDZ evaluation

The objective of this experimental evaluation is to determine the non-detection zone (NDZ) of the ROCOF protection relay as a percentage of DG MVA rating. The imbalance of active and reactive power through the PCC is adjusted independently to determine the NDZ for a range of ROCOF settings. Adjustments to the imbalance of power are achieved by changing the total local demand (i.e. load C and load D) while maintaining a constant pre-islanding DG output of 90% active power of its rating.

2.4.1 Hardware test setup

A commercial generator interface protection IED typically found in UK installations is used for testing. The following protection functions are enabled for all test cases:

- ROCOF.
- Under and over voltage (OV, UV), two stages.
- Under and over frequency (OF, UF), two stages.

The trip relay for each protection function is monitored separately to determine which functions (OV/UV/OF/UF/ROCOF) actually tripped for each test case and are recorded where appropriate. However, the assessment of NDZ focuses primarily on establishing ROCOF performance, but in cases where other elements have a narrower NDZ than the ROCOF element, then this is noted. The ROCOF settings used are summarised in Table 1. A frequency dead-band setting is used in some of the test cases. This inhibits ROCOF operation if the measured frequency lies within this band regardless of the measured rate of change of frequency. The voltage and frequency settings are summarised in Table 2.

The protection IED is tested using a hardware in the loop setup (HIL) as shown in Figure 6. Voltage measurements obtained from the RTDS are amplified to a nominal 110V before inputting into the relay. Disturbance records can be extracted from the IED if necessary (e.g. records of tripping out with the NDZ).

Table 1. ROCOF settings used for testing

Setting Options		Setting (Hz/s)	Delay (s)	Frequency dead-band (Hz)
proposed settings	1	0.5	0	0
	2	0.5	0.5	0
	3	1	0	0
	4	1	0.5	0
	5	0.5	0	49.5 – 50.5
	6	0.5	0.5	49.5 – 50.5
	7	1	0	49.5 – 50.5
	8	1	0.5	49.5 – 50.5
existing settings	9	0.12	0	0
	10	0.13	0	0
	11	0.2	0	0

Table 2. Voltage and frequency protection settings [1]

Protection functions	Settings	Delay (s)
UV stage 1	$V_{\phi\text{-}\phi}$-13%	2.5
UV stage 2	$V_{\phi\text{-}\phi}$-20%	0.5
OV stage 1	$V_{\phi\text{-}\phi}$+10%	1
OV stage 2	$V_{\phi\text{-}\phi}$+13%	0.5
UF stage 1	47.5Hz	20
UF stage 2	47Hz	0.5
OF stage 1	51.5Hz	90
OF stage 2	52Hz	0.5

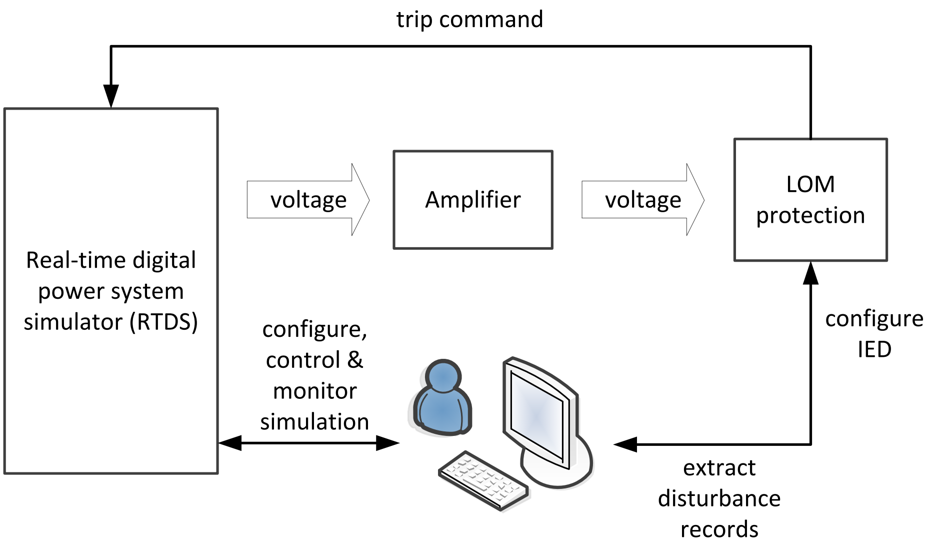

Figure 6. Hardware test setup for testing

2.4.2 Determining the NDZ

The NDZ is determined for both active and reactive power import and export across the PCC. The imbalance of one type of power is changed while holding the other type of power imbalance at 0% by adjusting the local demand (and generator reactive power output if necessary). The power imbalance is expressed as a percentage of the DG MVA rating. An automatic search routine developed specifically for this study is employed to iteratively change the power imbalances, inject the relay and monitor its trip response. With each incremental change in power imbalance across the PCC, the relay is injected with bus ‘A’ voltages to ascertain whether the level of imbalance lies within the NDZ. The reported values of NDZ are expressed according to (1):

$$NDZ_P = \frac{P_{pcc}}{S_{DG}} \times 100\%$$
$$NDZ_Q = \frac{Q_{pcc}}{S_{DG}} \times 100\% \tag{1}$$

P_{PCC} and Q_{PCC} are the real and reactive power imbalances across the PCC. S_{DG} is the DG MVA rating.

2.5 NDZ assessment results

The main results for the experimental NDZ assessment are included in this section.

Table 3 summarises the NDZ values for the 30MVA synchronous generator due to active power imbalance. The NDZ values are shown for power import (DG decelerates after LOM) and power export (DG accelerates after LOM) across the PCC prior to islanding. These correspond to generator deceleration and acceleration respectively post islanding. The results are depicted for all ROCOF setting options, load models and generator control modes described earlier.

It can be seen from Table 3 that the maximum NDZ is around 18% for setting option 8. This is the case for the majority of control and load configurations. This is expected as setting 8 has the highest pickup level (with a dead band applied) as well as a time delay. The results are consistent for all PV control mode test cases where higher setting thresholds result in larger NDZ boundaries. ROCOF protection exhibits high sensitivity to islanding events before which power was imported from the grid and the generator was operating in P-pf control mode.

The results in Table 3 are also depicted in Figure 7 for comparison. The results are shown in groups of four control mode/load type pairs for each setting option. An NDZ was also determined for voltage protection during P-pf operation for fixed impedance loads. The associated NDZ values are summarised in Table 4.

Table 3. 30MVA synchronous generator ROCOF NDZ results summary for active power imbalance

	ROCOF NDZ [%] (deceleration)				ROCOF NDZ [%] (acceleration)			
Control mode	PV		P/PF		PV		P/PF	
Setting Option	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load
1	5.94	6.9	0	0.17	-6.1	-7.11	-0.562	0
2	7.24	7.61	0	0.62	-7.16	-7.56	-7.73	-0.51
3	11.53	14.12	0	0.35	-12.35	-13.91	-13.76	-0.41
4	14.62	15.97	0	1.16	-14.55	-15.2	-16.67	-0.75
5	8.42	8.76	0	0.84	-8.44	-8.82	-9.89	-0.41
6	10.19	11.28	0	1.08	-10.56	-12.43	-12.19	-1.84
7	12.51	14.2	0	0.8	-13.13	-14.24	-15.66	-0.53
8	18.87	18.52	0	2.02	-17.65	-18.24	-18.75	-2.3
9	1.22	1.69	0	0	-1.31	-1.67	0	0
10	1.53	1.82	0	0	-1.55	-1.79	0	0
11	2.35	2.89	0	0	-2.37	-2.85	0	0

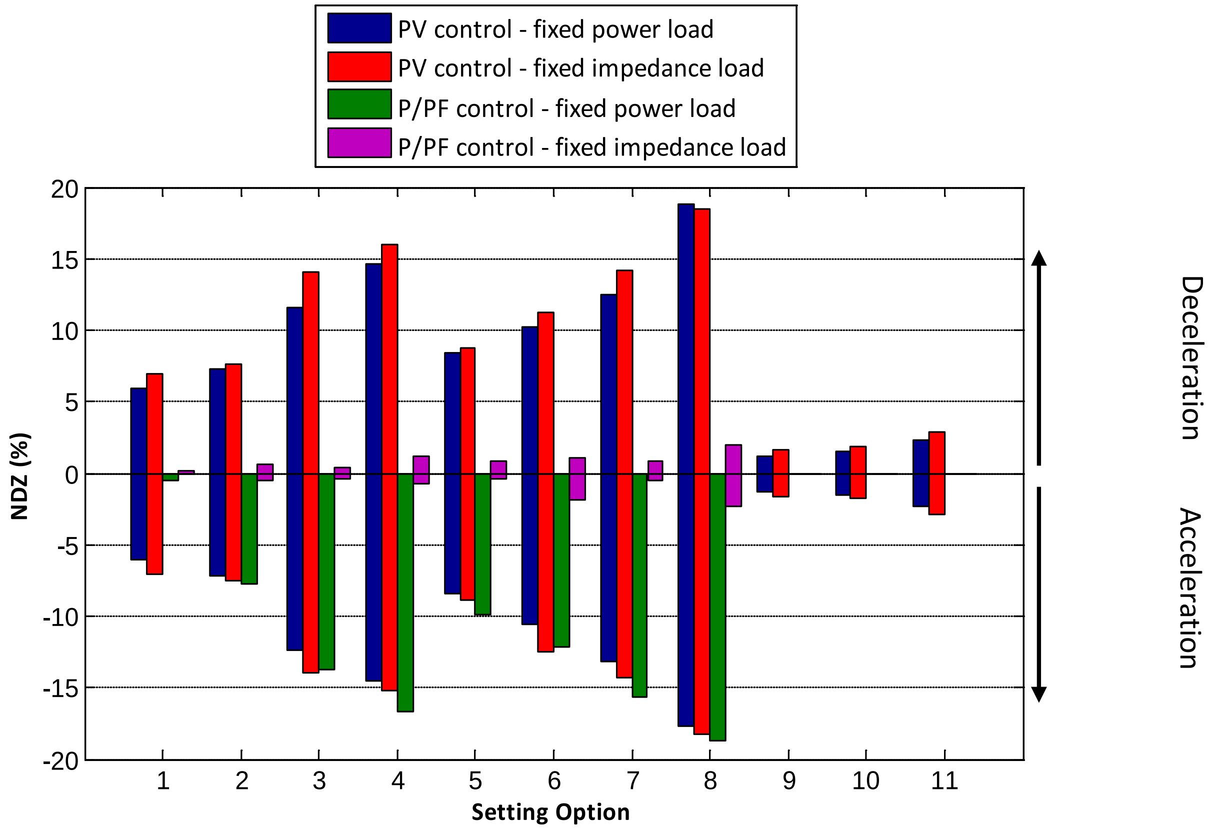

Figure 7. 30MVA synchronous generator ROCOF NDZ results for active power imbalance

Table 4. 30MVA synchronous generator voltage protection NDZ results summary for active power imbalance

	UV NDZ [%] (deceleration)		OV NDZ [%] (acceleration)	
Control mode	P/PF		P/PF	
Setting Option	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load
1	0	2.31	0	no trip
2	0	2.94	0	-2.62
3	0	2.15	0	-2.09
4	0	2.28	0	-1.87
5	0	3.94	0	-2.06
6	0	2.11	0	-1.64
7	0	2.06	0	-2.2
8	0	2.1	0	no trip
9	0	no trip	0	no trip
10	0	no trip	0	no trip
11	0	no trip	0	no trip

The NDZ values for the 30MVA synchronous generator due to reactive power imbalance are shown in Table 5 and also depicted in Figure 8. A similar behaviour of ROCOF protection to the previous case is exhibited. The NDZ boundaries, however, are much larger where a maximum NDZ of 100% can be observed for PV control mode. This is attributed to the loose coupling between reactive power and system frequency. Nevertheless, beyond a certain point the generator will not be able to support the network voltage which leads to instability. NDZ values for voltage protection are shown in Table 6.

Table 5. 30MVA synchronous generator ROCOF NDZ results summary for reactive power imbalance

	ROCOF NDZ [%] (deceleration)				ROCOF NDZ [%] (acceleration)			
Control mode	PV		P/PF		PV		P/PF	
Setting Option	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load
1	23.57	13.35	0	0	-17.6	-11.28	-19.76	-0.11
2	70.63	66.05	0	0.21	-88.91	-74.33	-20.02	-0.173
3	35.47	28.58	0	0.1	-38.87	-22.39	-27.05	0.167
4	87.67	88.48	0	0.38	-95.7	-99.92	-28.33	-0.44
5	54.22	52	0	0.38	-92.33	-42.17	-19.58	-0.174
6	84.15	85.38	0	0.48	-95.58	-81.27	-19.94	-0.64
7	61.08	60.7	0	0.11	-92.48	-48.03	-27.49	-0.25
8	99.97	99.99	0	0.52	-95.95	-100	-28.15	-0.64
9	4.8	2.64	0	0	-5.73	-2.9	0	0
10	4.1	3.23	0	0	-6.89	-3.6	0	0
11	6.99	4.6	0	0	-11.18	-4.67	0	0

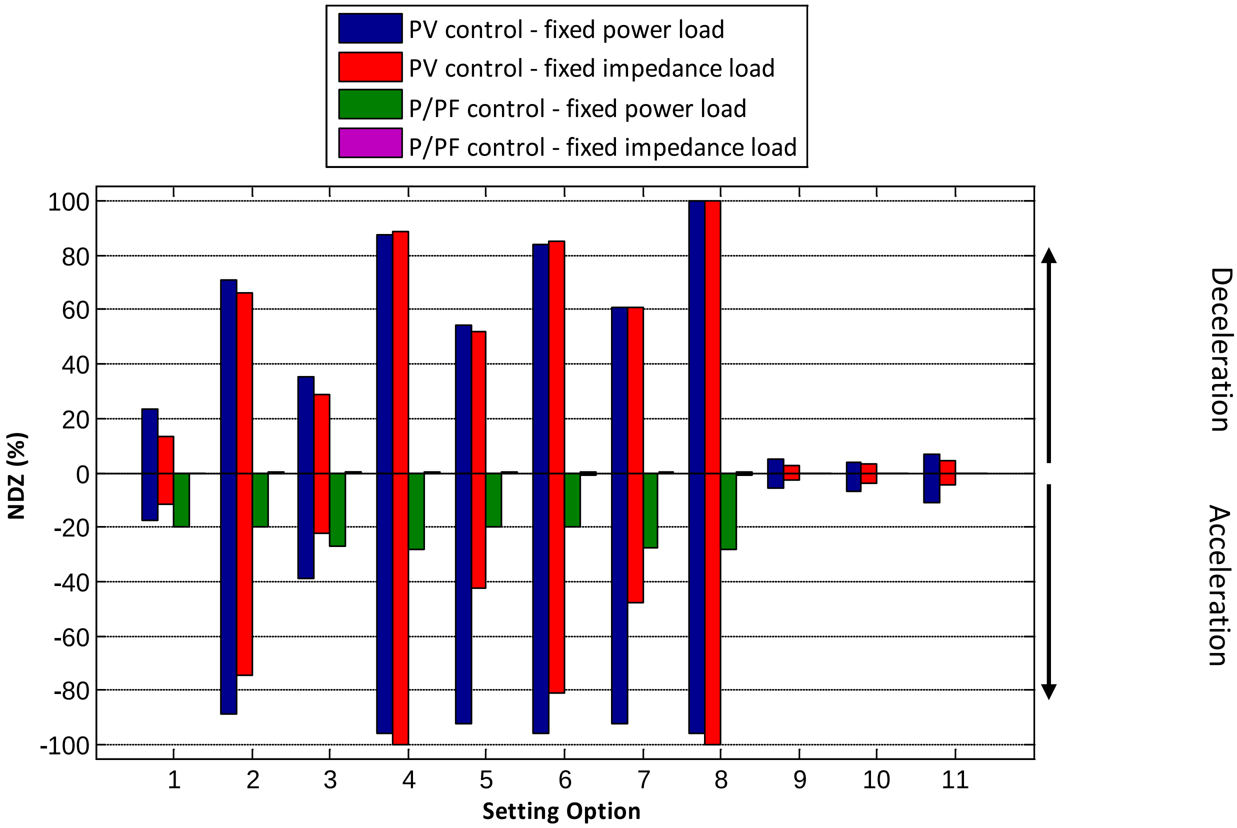

Figure 8. 30MVA synchronous generator ROCOF NDZ results for reactive power imbalance

Table 6. 30MVA synchronous generator voltage protection NDZ results summary for reactive power imbalance

	UV NDZ [%] (deceleration)		OV NDZ [%] (acceleration)	
Control mode	P/PF		P/PF	
Setting Option	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load
1	0	0.66	0	no trip
2	0	1.63	0	-0.59
3	0	0.86	0	-0.57
4	0	0.84	0	-0.56
5	0	0.54	0	-0.54
6	0	0.7	0	-0.67
7	0	0.94	0	-0.53
8	0	0.59	0	-0.71
9	0	no trip	0	no trip
10	0	no trip	0	no trip
11	0	no trip	0	no trip

The remainder of the results are for the 3MVA generator where spot tests have been made for three setting options (1, 6 and 10). Table 7 summarises the NDZ values for these tests for active power imbalance. These are also depicted in Figure 9. The smaller generator size, and consequently lower inertia, makes it inherently unstable against disturbances. This is evident in the generally smaller NDZ boundaries compared to the larger 30MVA generator.

Finally, the NDZ values for reactive power imbalance related to the 3MVA generator are summarised in Table 8 and depicted in Figure 10.

Table 7. 3MVA synchronous generator ROCOF NDZ results summary for active power imbalance

	ROCOF NDZ [%] (deceleration)				ROCOF NDZ [%] (acceleration)			
Control mode	PV		P/PF		PV		P/PF	
Setting Option	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load
1	3.28	3.31	0	1.98	-3.17	-2.76	-2.36	-2
6	8.17	9.62	0	2.34	-7.96	-8.97	-7.25	-1.64
10	0.74	0.6	0	0.47	-0.68	-0.8	-0.67	-0.22

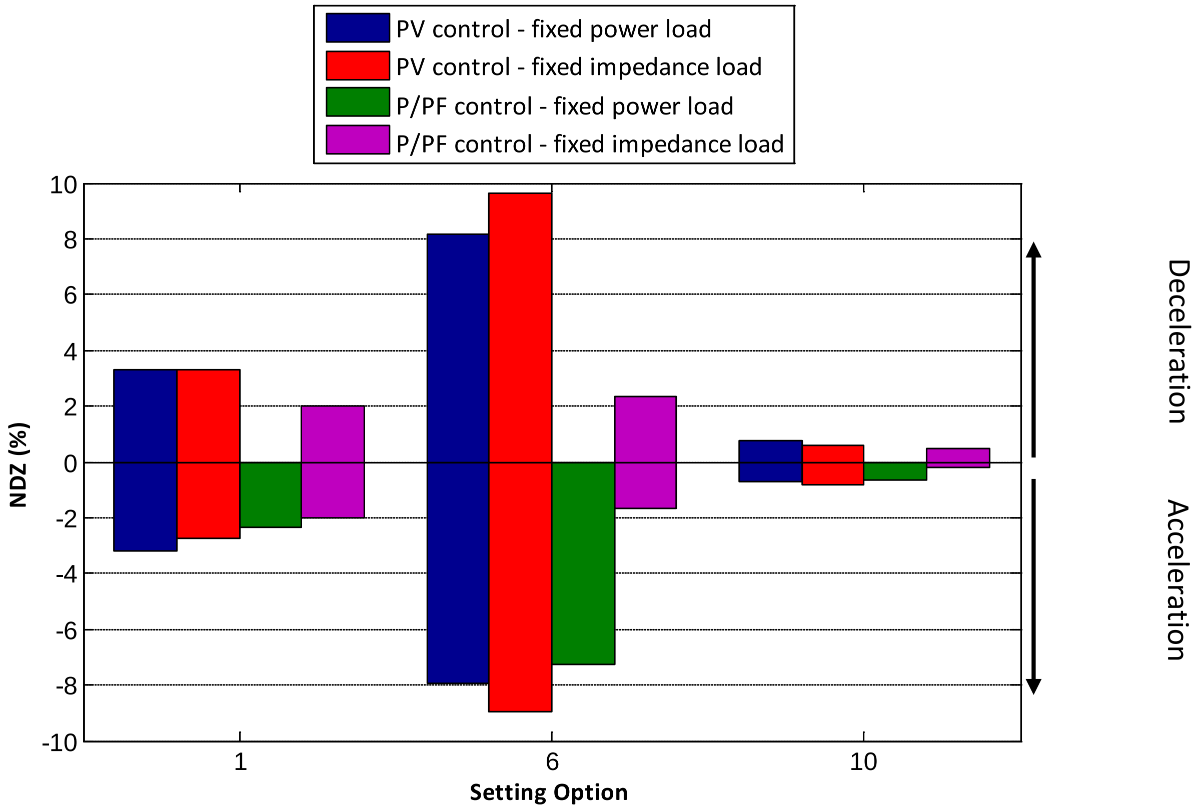

Figure 9. 3MVA synchronous generator ROCOF NDZ results for active power imbalance

Table 8. 3MVA synchronous generator ROCOF NDZ results summary for reactive power imbalance

	ROCOF NDZ [%] (deceleration)				ROCOF NDZ [%] (acceleration)			
Control mode	PV		P/PF		PV		P/PF	
Setting Option	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load	Fixed power load	Fixed impedance load
1	41.53	8.26	0	3.13	-49.13	-8.72	-49.63	-3.17
6	51.2	38.23	0	63.53	-62.9	-45.53	-49.78	-0.71
10	7.33	2.11	0	0	-8.63	-1.55	0	0

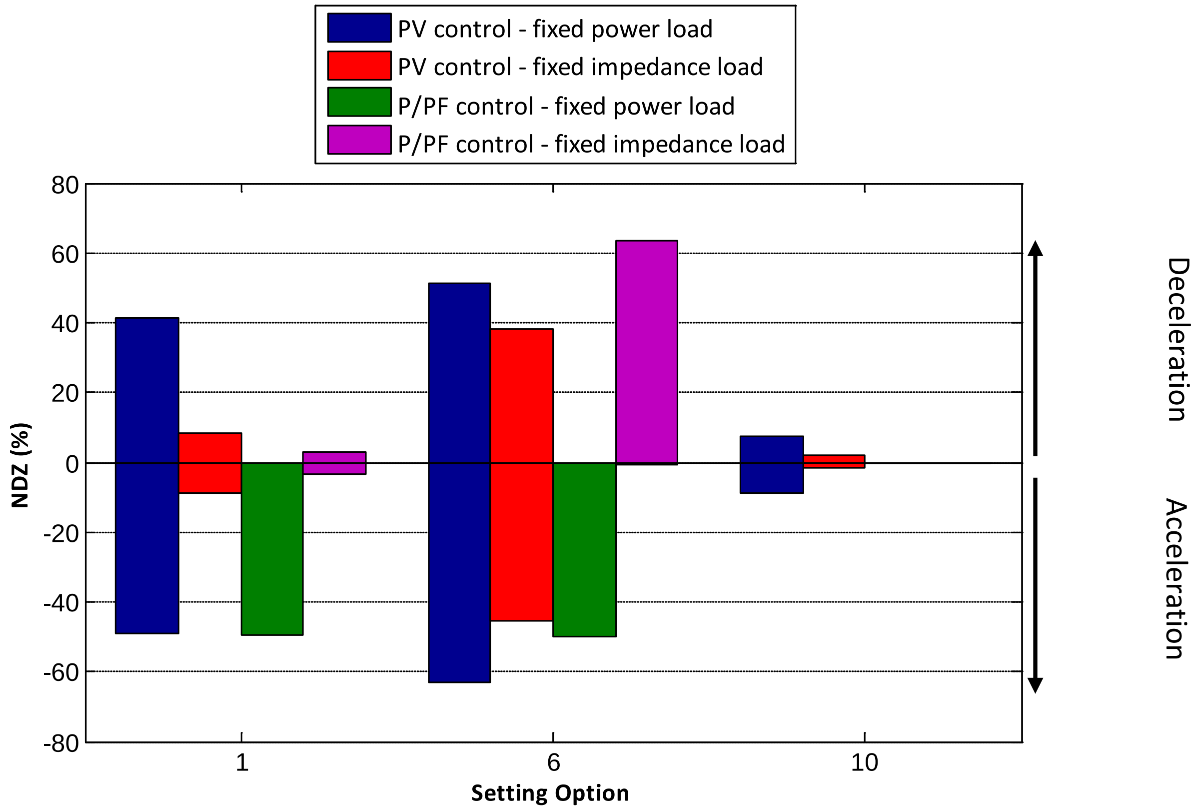

Figure 10. 3MVA synchronous generator ROCOF NDZ results for reactive power imbalance

3 WP2 – Risk level calculation at varying NDZ

3.1 Risk Calculation Methodology

The risk calculation methodology adopted in this work is similar to the method previously applied to verify the requirement for NVD protection [2]. This approach is based on a statistical analysis of the probability tree depicting perceived probability of specific hazards (including safety of people or damage to equipment). The methodology makes a number of assumptions regarding the type of utility network, type and size of the distributed generator and generator technology (refer to section 3.2 for details). It utilises the width of the Non Detection Zone (NDZ) established through laboratory testing and described earlier in in this document (WP1). Recorded typical utility load profiles and statistics of loss of supply to primary substations are also utilised to estimate probabilities of islanding incidents and load-generation matching. Assuming that the fault tree as presented in Figure 11 is used, the calculations, as described in the following sections of the document, are performed to assess:

a) personal safety hazard (the term Individual Risk IR is used in this report to denote the annual probability of death resulting from an undetected LOM condition), and
b) damage to generator occurring as a result of sustained undetected islanded operation of DG combined with likely out-of-phase auto-reclosure (the annual rate of occurrence of Out-of-phase Auto-reclosure N_{OA} is used in this report).

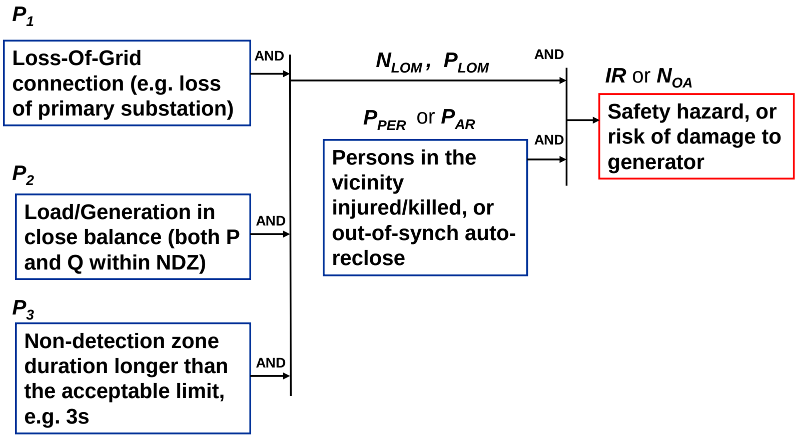

Figure 11. LOM Safety Hazard Probability Tree

3.1.1 Expected number of LOM occurrences in a single primary substation

For the purposes of this study (i.e. considering generator sizes between 5MW and 50MW) it was assumed that potential undetected islanding situations can only result from the loss of grid supply to primary substation. Other downstream faults involving isolation of individual 11kV circuits would typically not contain sufficient amount of islanded load to form balanced conditions with any of the generators considered in this report.

Accordingly, the expected number of incidents of losing supply to an individual primary substation during the period of one year can be estimated as follows:

$$N_{LOG,1SS} = \frac{n_{LOG}}{n_{PRIME} \cdot T_{LOG}} \tag{2}$$

where n_{LOG} is a number of loss of supply incidents experienced during the period of T_{LOG} in a population of n_{PRIME} primary substations.

3.1.2 Load/Generation balance within NDZ for a period longer than 3s (P_2 and P_3)

Probabilities P_2 and P_3 are calculated jointly by systematic analysis of the example primary substation recorded load profiles. This is performed iteratively in two nested loops. The inner loop (iteration i) progresses through the whole duration of the given load record, while the outer loop (iteration j) covers the range of generator outputs between 5MW and 50MW in 1MW increments. In each 1MW band (termed here as generator group j) there is a certain assumed number of DGs $n_{DG(j)}$. This number is based on the actual distribution of synchronous machine based DG ratings as derived from the UK DG survey [6] and presented later in section 3.2.3 of this report. It should be noted that generator output and generator rating are synonymous in the context of this calculation as constant 100% generator loading at near unity *pf* is assumed in the analysis.

Within the inner loop at each time step (iteration i), the instantaneous load values $P_{L(i)}$ and $Q_{L(i)}$ are compared with the assumed fixed output of the distributed generator from the outer loop ($P_{DG(j)}$ and $Q_{DG(j)}$) to check if the difference falls within the assumed NDZ. This condition is described by (3).

$$NDZP_a < P_{L(i)} - P_{DG(j)} < NDZP_d \wedge NDZQ_a < Q_{L(i)} - Q_{DG(j)} < NDZQ_d \qquad (3)$$

Where:

$P_{L(i)}, Q_{L(i)}$	- recorded samples of active and reactive load power
$P_{DG(j)}, Q_{DG(j)}$	- fixed active and reactive power of the generation group *j*
$NDZP_a, NDZQ_a$	- accelerating non detection zone (generator output is higher than the local load)
$NDZP_d, NDZQ_d$	- decelerating non detection zone (generator output is lower than the local load)

When consecutive samples conform to the conditions specified in equation (3), the time is accumulated until the local load exits the NDZ. After all NDZ instances (i.e. their durations) are recorded, the NDZ duration cumulative distribution function (CDF) is derived, an example of which is presented in Figure 12. As illustrated in the figure, the probability $P_{3(j)}$ that the NDZ is longer than T_{NDZmax} can easily be obtained from the CDF.

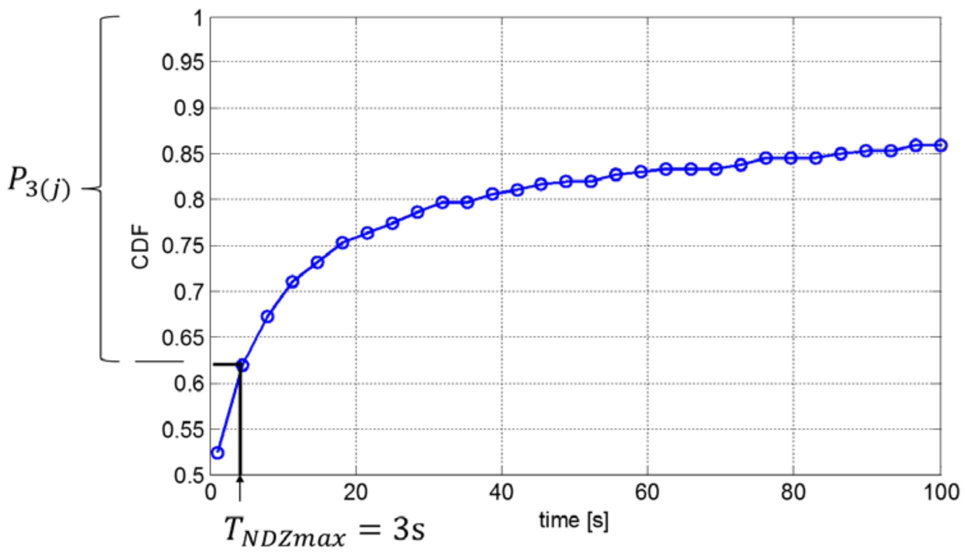

Figure 12. CDF of an example NDZ duration time

At the same time, the probability $P_{2(j)}$ of the load (both *P* and *Q*) being within the NDZ is also calculated as a sum of all recorded NDZ periods with respect to the total length of the recorded load profile (4).

$$P_{2(j)} = \sum_{k=1}^{n_{NDZ(j)}} \frac{T_{NDZ(j)(k)}}{T_{load\_record}} \tag{4}$$

Where:

$n_{NDZ(j)}$	- number of detected NDZ periods within generation group *j*
T_{load_record}	- total length of the recorded load profile
$T_{NDZ(j)(k)}$	- length of k-th NDZ period.

Finally, the joint probability $P_{23(j)}$ for each generation group j can be calculated as (5) which leads to the development of the probability characteristic as shown in Figure 13.

$$P_{23(j)} = \frac{n_{DG(j)}}{n_{DG}} P_{2(j)} \cdot P_{3(j)} \tag{5}$$

where:

$n_{DG(j)}$	- number of generators in group *j*
n_{DG}	- total number of generators included in the study

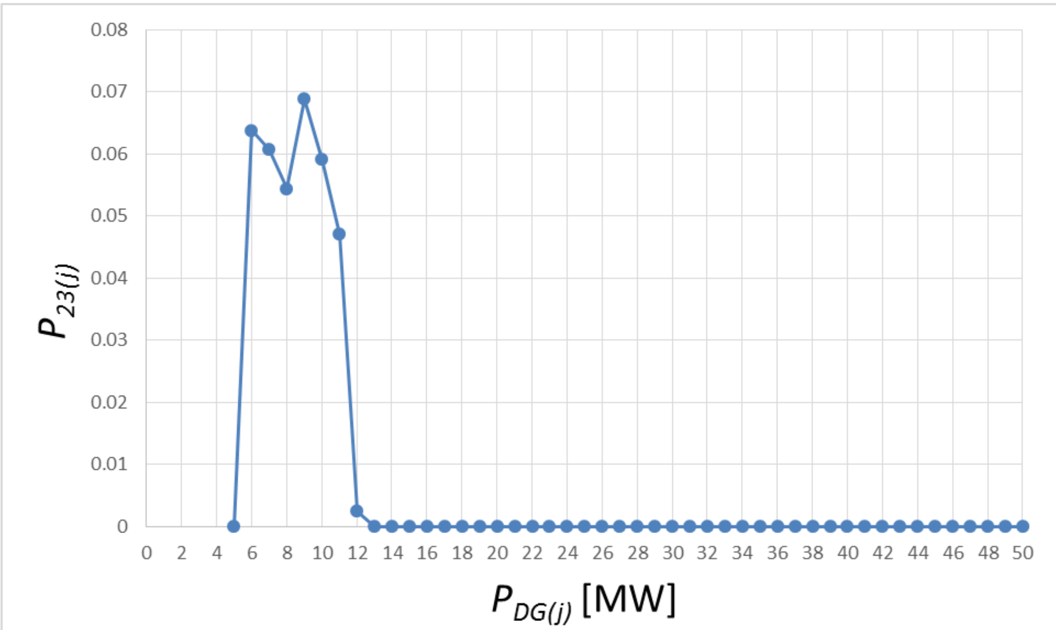

Figure 13. Non-detection zone probability at varying levels of generator output

Consequently, according to the principle of the marginal probability, the combined probability P_{23}, considering all generator sizes, is calculated using simple summation (6).

$$P_{23} = \sum_{j=1}^{n_{DGG}} P_{23(j)} \tag{6}$$

Where $n_{DGG} = 46$ is the number of generator groups.

The expected annual number of undetected islanding operations longer than the assumed maximum period T_{NDZmax} for a single DG can be calculated as (7).

$$N_{LOM,1DG} = N_{LOG,1SS} \cdot P_{23} \tag{7}$$

Additionally, the overall average duration of the NDZ (T_{NDZavr}) is calculated by adding all NDZ durations longer than T_{NDZmax} from all generator groups and dividing the sum by the total number of NDZ occurrences.

3.1.3 Calculation of national LOM probability figures and individual risk

Using the known total number of connected generators (n_{DG}) with an assumed proportion of ROCOF based LOM protection (p_{ROCOF}) and generator load factor (LF), the expected annual number of undetected islanding incidents (within mainland UK) can be estimated from:

$$N_{LOM} = N_{LOM,1DG} \cdot n_{DG} \cdot p_{ROCOF} \cdot LF \tag{8}$$

The expected cumulative time of undetected islanding conditions for all considered generators can be estimated using:

$$T_{LOM} = N_{LOM} \cdot (T_{LOMavr} - T_{NDZmax}) \tag{9}$$

where T_{LOMavr} is the average time that an undetected island can be sustained. This time is selected as the minimum value between T_{NDZavr} and assumed maximum operation time of the auto-reclosing scheme (T_{ARmax}). It is understood that sustained islanded operation following an auto-reclose operation is not possible.

Finally, the overall probability of an undetected islanded system at any given time and at specific assumed ROCOF settings is calculated as:

$$P_{LOM} = \frac{T_{LOM}}{T_a} \tag{10}$$

Where:

T_a – period of 1 year

For a single generator with ROCOF protection, the probability can be calculated as:

$$P_{LOM,1DG} = \frac{P_{LOM}}{n_{DG} \cdot p_{ROCOF}} \tag{11}$$

In order to ascertain whether the risk resulting from the proposed adjustment to the ROCOF settings is acceptable, the analysis and interpretation of the calculated N_{LOM} and P_{LOM} values is performed in two ways:

1. Firstly, the annual expected number of Out-of-phase Auto-reclosures (N_{OA}) during the islanding condition (undetected by LOM protection) is calculated as follows:

$$N_{OA} = N_{LOM} \cdot P_{AR} \tag{12}$$

where P_{AR} is the probability of out-of-phase auto-reclosing action following the disconnection of a circuit supplying a primary substation. Considering that in the vast majority of cases of losing supply to a primary substation auto-reclosing action would occur and also considering the fact that reclosure with small angle difference may be safe, the value of $P_{AR} = 0.8$ was assumed.

2. Secondly, the annual probability values are calculated related to perceived Individual Risk (*IR*). Two sources of *IR* are considered: (a) the risk of a fatality due to accidental contact with any elements of the energised undetected island (IR_E), and (b) risk of physical injury or death resulting from the generator destruction following an Out-of-phase Auto-reclosure (IR_{AR}). These two indices are calculated as follows:

$$IR_E = P_{LOM} \cdot P_{PER,E} \tag{13}$$

$$IR_{AR} = N_{OA} \cdot P_{PER,G} \tag{14}$$

where $P_{PER,E}$ is the probability of a person in close proximity to an undetected islanded part of the system being killed, and $P_{PER,G}$ is the probability of a person being in close proximity of the generator while in operation and suffering fatal injury as a result of the generator being destroyed by out-of-phase auto-reclosure. The resulting *IR* can be then compared with the general criteria for risk tolerability included in the Health and Safety at Work Act 1974 which adopts the risk management principle often referred to as the 'ALARP' or 'As Low as Reasonably Practicable'. The ALARP region applies for IR levels between 10^{-6} and 10^{-4}. Risks with probabilities below 10^{-6} can generally be deemed as tolerable. A similar approach has already been used in the risk assessment of NVD protection requirement [2] where the value of $P_{PER,E} = 10^{-2}$ was used. However, the probability $P_{PER,G}$ will depend on specific circumstances, generator location and regime of operation, and therefore it is beyond the scope of this report to quantify such probabilities.

The relative difference in the probability of undetected islanding condition under the existing recommended settings and the new proposed settings provides further guidance as to the acceptability of the proposed setting options.

3.2 Initial assumptions and available data

The following assumptions and initial values were made in this study:

- Generation range considered 5MW – 50MW;
- Generation output is constant and equal to the rated power of the machine, with the output assumed to be generated at a power factor of $pf = 0.99\ (lagging)$. This is based on the sample generation profile provided by ScottishPower Manweb (SPM) and included in section 3.2.2.
- On average the generator load factor is *LF*=2/3 (i.e. generator is in operation 16 hours a day).
- 50% of all connected generators are assumed to be equipped with ROCOF relays ($p_{ROCOF} = 0.5$). The remaining generators have other forms of LOM protection.
- Detailed distribution of DG sizes and numbers in the UK were obtained from [6] (also refer to section 3.2.3 of this document for more details). Only DGs based on synchronous machine were considered in risk calculations (in the study the total number of generators $n_{DG} = 183$ is assumed based on [6]).
- Eight different load scenarios recorded in typical primary substations in the UK were used as described in section 3.2.1.

- A period of $T_{NDZmax} = 3$s was assumed as the maximum permissible duration of undetected islanding condition (i.e. no auto-reclosing faster than T_{NDZmax} is expected to occur).
- A period of $T_{ARmax} = 20$s was assumed as the maximum expected time of operation of the auto-reclosing scheme (in other words, regardless of load/generation balance, undetected stable island will not continue to operate longer than T_{ARmax} due to the impact of out-of-phase reclosure).
- It is assumed that the generator does not continue to supply the system after an out-of-phase auto-reclosing operation.
- Potential undetected islanding situation can only result from the loss of grid supply to primary substation or supply point. The following primary substation incident records were available:
    a. ENW – in a population of 440 substations there were 96 loss of supply incidents during the period of 7 years,
    b. Northern Powergrid – in a population of 613 substations (including supply point sites) there were 258 loss of supply incidents during the period of 10 years.

  The combined figures were used to calculate expected annual number of LOM occurrences in a single substation according to equation (2) ($N_{LOG,1SS} = 0.0375$).

3.2.1 Available load profile data

In order to cover a wide range of possible loading scenarios and capacities, eight different active and reactive (*P* and *Q*) load profiles have been included in this study. These profiles were recorded by the utilities at various primary substations. This section includes a brief description of each record including a graphical illustration of the *P* and *Q* traces.

3.2.1.1 Load Case 1 (SSE)

This record (using data provided by SSE) has been obtained from a 33kV substation feeding a mix of residential and industrial loads. The trace is presented in Figure 14 and is a combination of six days sampled evenly over a period of one year (i.e. one day of data recorded every two months). The original sampling period was 5s, but for the purposes of NDZ risk calculation, it has been re-sampled with a 1s time step using linear interpolation between the existing measurement points. It must be noted that this specific recorder was configured to only record new data when changes of load were greater than 1% of substation transformer capacity. In practice, with two transformer substations sharing the load and with smaller capacity DG connected, this needs a 3 to 5 % change in load (on the DG rating base) to register a change. Therefore, short term small load fluctuations which could affect the NDZ risk calculation are not recorded.

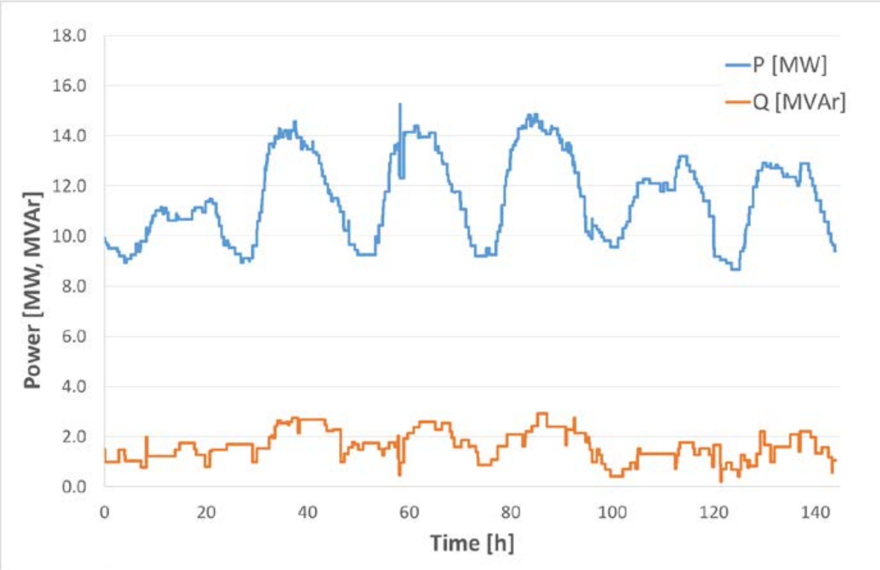

Figure 14. Load Case 1 (SSE) - mix of residential and industrial loads.

3.2.1.2 Load Case 2 (SPM)

This load trace is a summated combined load from three rural primary substations recorded simultaneously over a period of one day (Monday, 3 March 2013). As before, the original sampling period was 5s but this was subsequently resampled to obtain 1s resolution using linear interpolation between existing points.

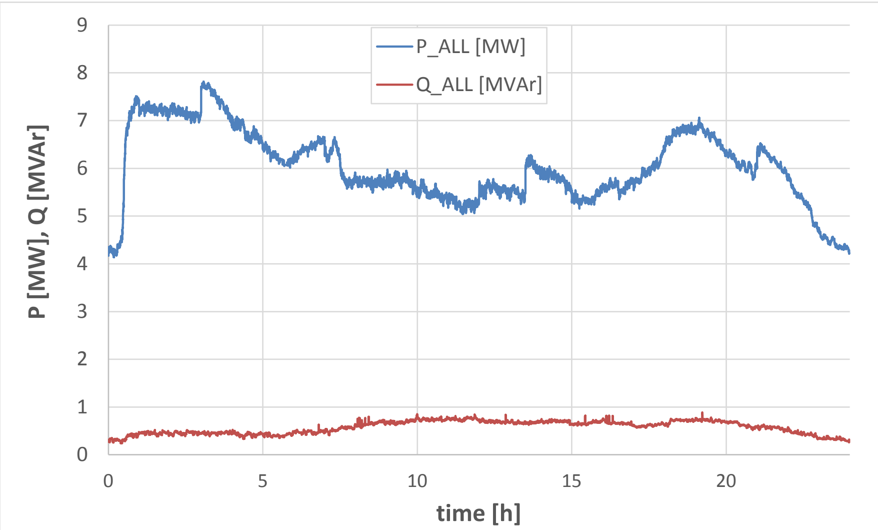

Figure 15. Load Case 2 (SPM) – combination of 3 rural substations

3.2.1.3 Load Case 3, 4, 5 and 6 (SPM)

Four different load profiles of varying peak demand (termed as Load Case 3, 4, 5, and 6 respectively) were formed using the SPM data recorded from an interconnected 33kV area with nine primary transformers. These load cases are illustrated in the following figures 16 to 19. The data was originally recorded with 30 minute time resolution over a period of 1 year but subsequently resampled with a 2 minute time step using linear interpolation.

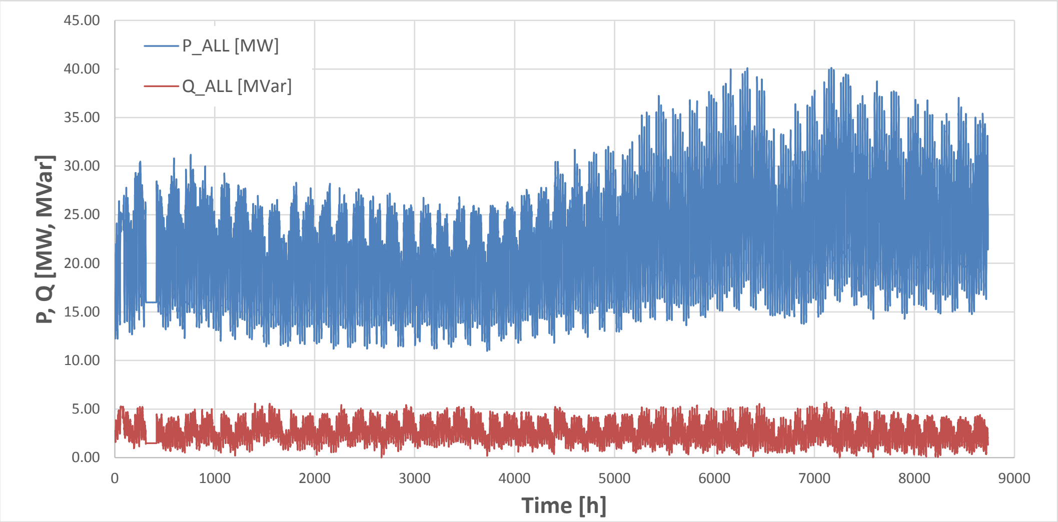

Figure 16. Load Case 3 (SPM) – combination of 9 interconnected primary transformers

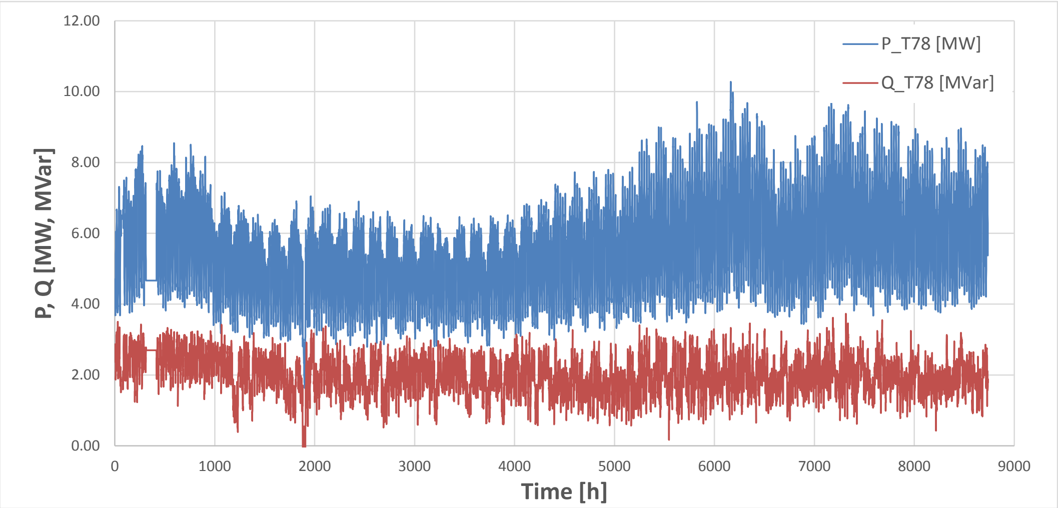

Figure 17. Load Case 4 (SPM) – combination of 3 rural substations

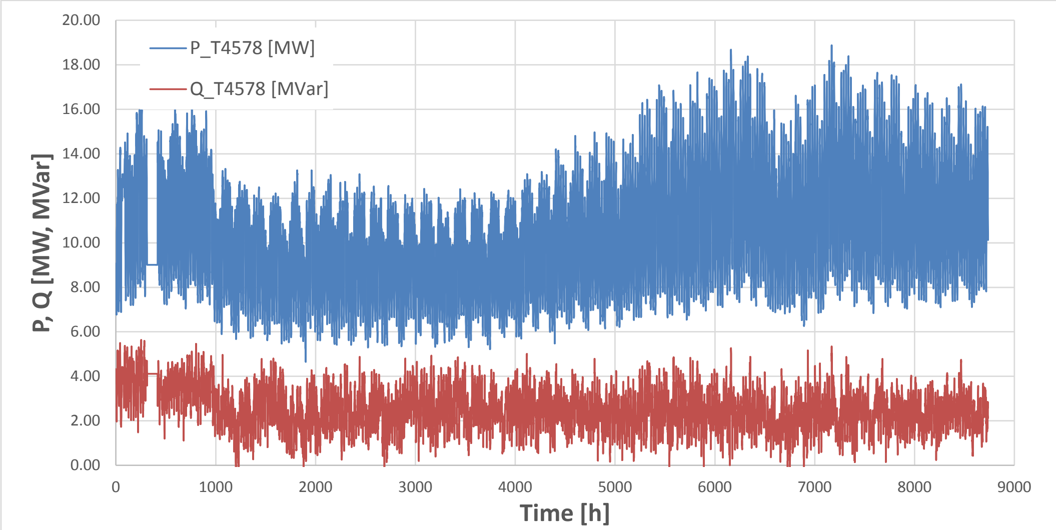

Figure 18. Load Case 5 (SPM) – combination of 3 rural substations

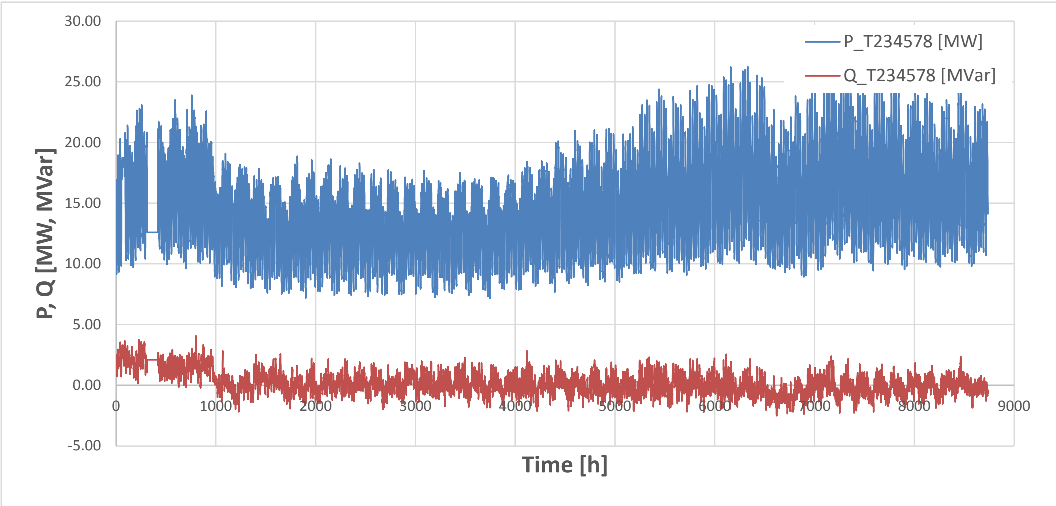

Figure 19. Load Case 6 (SPM) – combination of 3 rural substations

3.2.1.4 Load Case 7 and 8 (ENW)

These two records were obtained from the 6.6kV (2x11.5MVA) primary substations located in urban (Load Case 7) and suburban areas (Load Case 8). The data was originally recorded with 1s resolution over a period of four non-consecutive days (two weekdays and Saturday/Sunday) of the same week. For the risk calculation purposes and to preserve a balance between weekdays and weekend days, the remaining weekdays were created by repeating the available Wednesday and/or Thursday records.

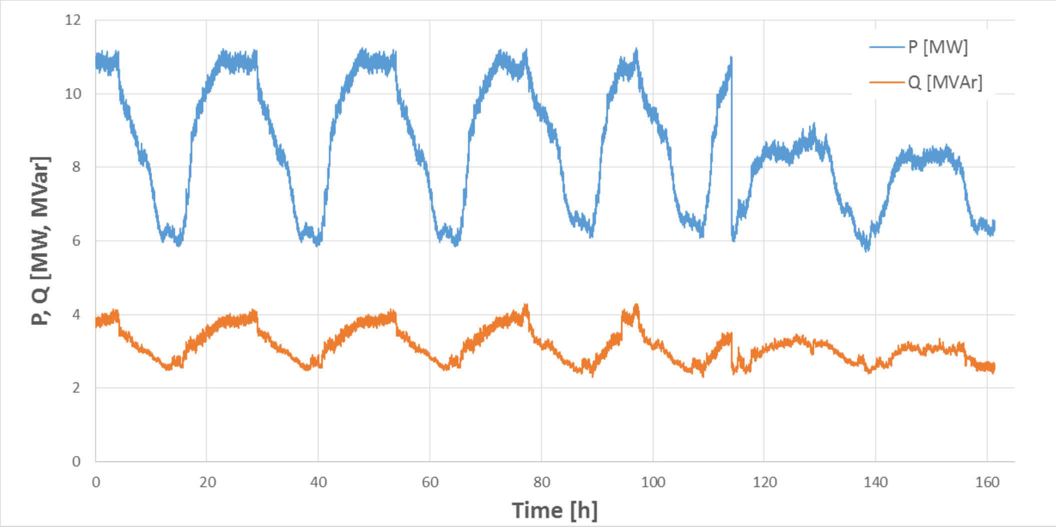

Figure 20. Load Case 7 (ENW) – urban substation

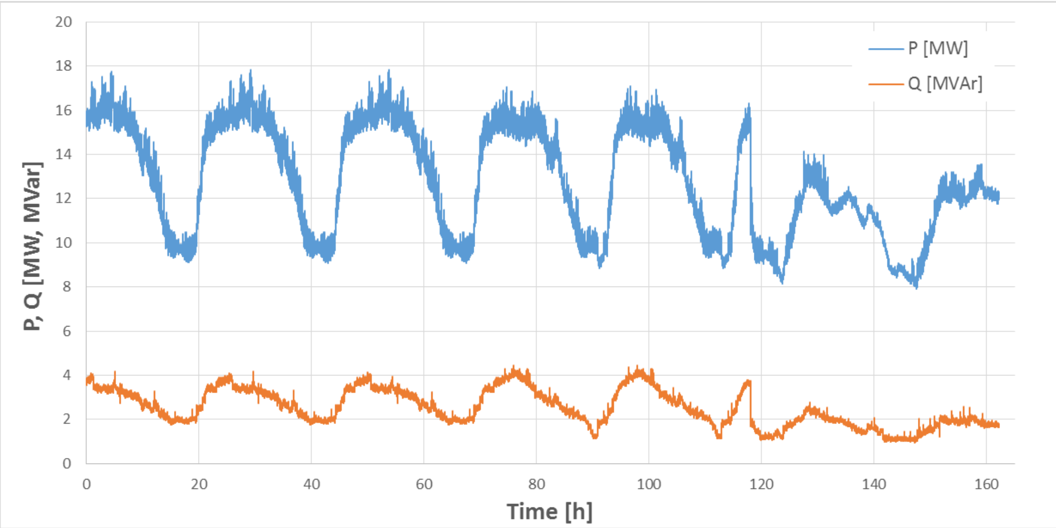

Figure 21. Load Case 8 (ENW) – suburban substation

3.2.2 Example DG profile

An example measured annual profile for of a 30MW DG was available as illustrated in Figure 22. It can be seen that the generator output is mostly constant and close to the installed capacity of the unit. The average power factor calculated from this data is 0.994 (lagging), i.e. the generator seems to be providing a very small amount of reactive power to the network (this should not be the case, and it could be that a measurement error is causing this to appear to be the case).

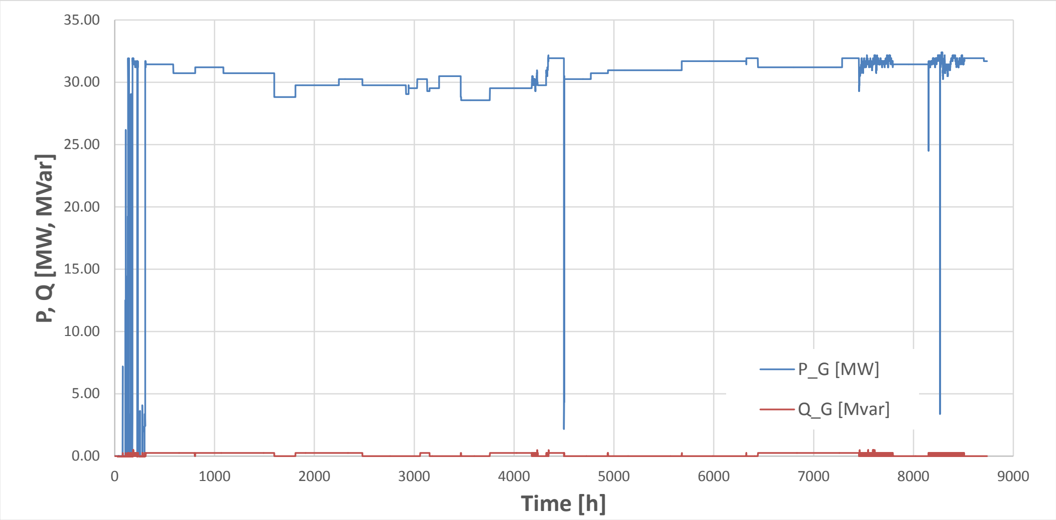

Figure 22. 30MW DG generation profile

3.2.3 UK generation between 5MW and 50MW.

Available records relating to UK-installed DG with capacities of 5 and 50MW [6] has been utilised to adequately represent the distribution of generator ratings. The histogram representing the distribution of synchronous machine based generation sizes is presented in Figure 23. The total capacity of this group of generators is currently 3236MW (74.3% of all DG in the UK falls within the 5-50MW range of ratings), with $n_{DG} = 183$ individual sites. These statistics are further used in marginal probability and overall risk calculations.

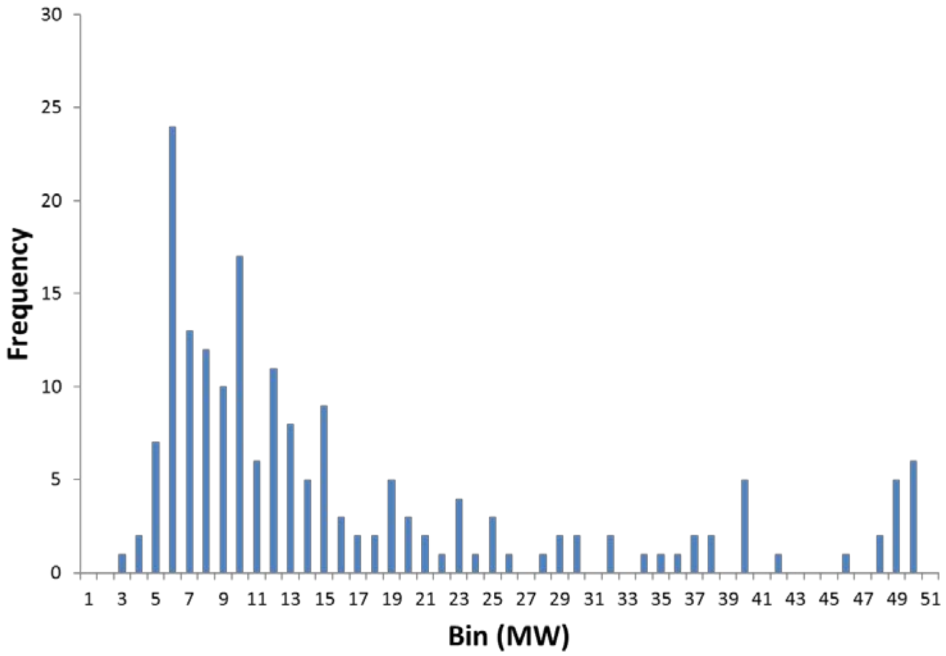

Figure 23. Histogram representing existing synchronous generator based DG in UK

3.3 Risk calculation results

The full numerical record of probability calculations performed on the eight available load profiles, considering eleven assumed setting options, two generator control types (P-V and P-pf), and two load models (fixed impedance and fixed power) is included in Appendix D. The results are initially presented considering ROCOF response only, and then also considering the overall response of DG interface protection including UV/OV and UF/OF modules (set according to G59/2 recommendation). Additionally, for ease of analysis, all results are also presented graphically in figures 25 to 32. It should be noted that in a number of cases the final probability was equal to zero. In order to represent this result on the graph using a logarithmic scale, a small value of 10^{-11} was used rather than zero. All other non-zero results were always higher than 10^{-11}, so this value can be used as an unambiguous indicator of a zero result.

It can be observed that scenarios with low 30min sampling resolution (load case 3, 4, 5, 6) result in probabilities which are approximately 2 orders of magnitude higher than those obtained from load cases 2, 7, 8 (sampled with 1s resolution). This issue is investigated further to verify if indeed the difference in the result originates from the low sampling rate or is due to some other factor(s).

Similarly, load case 1 also suffers from a similar effect due to the low measurement resolution of the data.

3.3.1 Sensitivity to sampling rate

In order to further verify the sensitivity of the results to sampling frequency, Load Case 8 was down sampled twice (to 5s and to 30min resolution respectively), and the probability of NDZ calculation was repeated with the result as shown in Figure 24. It can be seen that the same effect of increased probability by 2 orders of magnitude is manifested when both 1s and 30min data are used. Since the results presented in Figure 24 are all based on the same load profile, the only influencing factor is the sampling rate. Although an increase in the calculated probability is visible for case with 5s resolution data, the difference can be seen as acceptable.

Therefore, the final outcome, further discussion, conclusions and recommendations from this study are only based on the results obtained from load cases 2, 7 and 8 where data is sampled with 1s resolution.

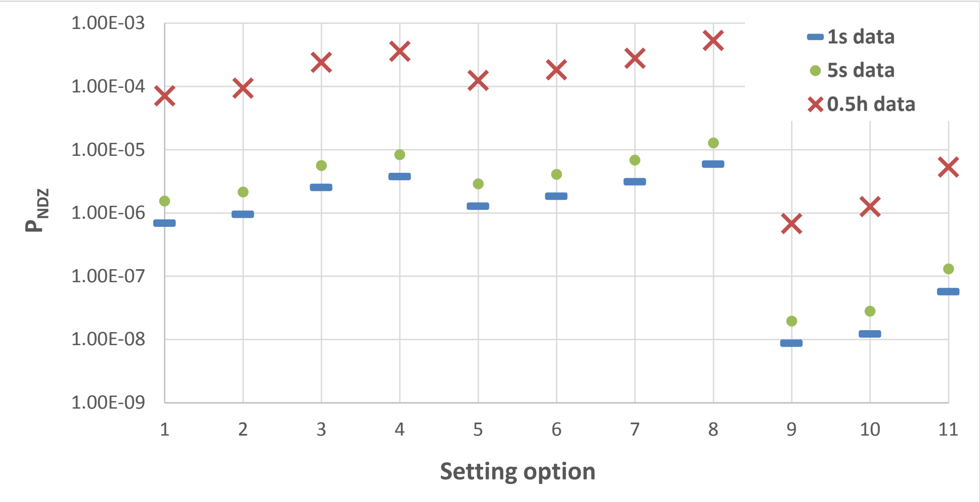

Figure 24. Impact of sampling frequency on NDZ probability calculation

3.3.2 Calculation of overall worst case based figures

Considering Load Cases 2, 7 and 8, the worst case probability figures N_{LOM} and P_{LOM} have been obtained (based on results in Appendix D) and both probability of Individual Risk (IR_E) and expected annual rate of occurrence of Out-of-phase Auto-reclosure (N_{OA}) calculated using the formulae (12) and (13). The results are presented in Table 9 and Table 10 for P-V and P-pf controlled generators respectively.

Table 9. Worst load profile based figures for P_{LOM}, IR_E and N_{OA} (generator in P-V control mode)

Setting Option	ROCOF [Hz/s]	Time Delay [s]	Dead Band applied	N_{LOM}	P_{LOM}	IR_E	N_{OA}
1	0.5	0	No	1.64E-01	1.04E-07	1.04E-09	1.31E-01
2	0.5	0.5	No	1.78E-01	1.13E-07	1.13E-09	1.42E-01
3	1	0	No	3.35E-01	2.13E-07	2.13E-09	2.68E-01
4	1	0.5	No	3.73E-01	2.37E-07	2.37E-09	2.98E-01
5	0.5	0	Yes	2.07E-01	1.31E-07	1.31E-09	1.65E-01
6	0.5	0.5	Yes	2.89E-01	1.83E-07	1.83E-09	2.31E-01
7	1	0	Yes	3.25E-01	2.06E-07	2.06E-09	2.60E-01
8	1	0.5	Yes	4.13E-01	2.62E-07	2.62E-09	3.31E-01
9	0.12	0	No	1.44E-02	9.14E-09	9.14E-11	1.15E-02
10	0.13	0	No	1.92E-02	1.22E-08	1.22E-10	1.53E-02
11	0.2	0	No	4.17E-02	2.65E-08	2.65E-10	3.34E-02

Table 10. Worst load profile based figures for P_{LOM}, IR_E and N_{OA} (generator in P-pf control mode)

Setting Option	ROCOF [Hz/s]	Time Delay [s]	Dead Band applied	N_{LOM}	P_{LOM}	IR_E	N_{OA}
1	0.5	0	No	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2	0.5	0.5	No	1.03E-04	1.43E-11	1.43E-13	8.26E-05
3	1	0	No	0.00E+00	0.00E+00	0.00E+00	0.00E+00
4	1	0.5	No	5.70E-04	1.57E-10	1.57E-12	4.56E-04
5	0.5	0	Yes	2.21E-04	4.00E-11	4.00E-13	1.77E-04
6	0.5	0.5	Yes	9.79E-04	3.92E-10	3.92E-12	7.83E-04
7	1	0	Yes	1.27E-04	1.97E-11	1.97E-13	1.01E-04
8	1	0.5	Yes	2.00E-03	1.03E-09	1.03E-11	1.60E-03
9	0.12	0	No	0.00E+00	0.00E+00	0.00E+00	0.00E+00
10	0.13	0	No	0.00E+00	0.00E+00	0.00E+00	0.00E+00
11	0.2	0	No	0.00E+00	0.00E+00	0.00E+00	0.00E+00

As a consequence of the assumed initial conditions and the scope of the study, the above figures represent the probabilities of the perceived hazards (*IR* and *OA*) under eleven different ROCOF protection setting options when applied to all existing synchronous generators in UK with ratings between 5MW and 50MW. It is important to bear in mind the following points when using these results to inform decision making processes:

- The presented probability figures are based on 183 existing connections, 50% assumed to have ROCOF based LOM protection and all assumed to be in operation for an average of 16 hours each day (*LF*=2/3). In the future, all probabilities will increase (or decrease) in proportion to the total number of separate DG connections using ROCOF.
- The results do not attempt to assess the change of ROCOF settings on other smaller generators (<5MW). Due to the large numbers of such connections and higher anticipated number of LOM incidents for these installations, the overall risk is expected to be consequently higher too.
- The study does not include the assessment of the impact of the change of protection practice to other forms of LOM protection (e.g. vector shift).
- Wherever exact data was not available, pessimistic assumptions were always made so that the final probability values will ideally never be lower than reality.
- The results are expressed as probabilities of specific events or occurrences happening within a period of one year. By inverting these values, the average expected time between such occurrences can be calculated.

4 Conclusions

When analysing the results the following observations can be made:

- The generator control strategy has a fundamental impact on its ability to sustain islanded operation.
- The probability of sustained islanded operation is highly unlikely with any protection settings, when the existing prevailing control strategy based on fixed real power output and unity *pf* is applied.
- There is a significant difference (between one and two orders of magnitude) in the probability of undetected islanded operation between the existing recommended ROCOF settings (setting options 9 to 11) and all considered new setting options 1 to 8.
- There are differences among the proposed setting options 1 to 8, but these are less pronounced than those between the existing G59/2 settings 9 to 11 and the setting options 1 to 8.
- When analysing the response of the relay with all G59/2 protection modules enabled, it can be observed that the NDZ is determined by the sensitive operation of the ROCOF module which sends a tripping signal before voltage or frequency protection operates (in the vast majority of cases). It is only in the case where the generator is in P-V control mode and the load is represented as fixed power, that the operation of the OV relay determines the NDZ width rather than ROCOF. This can be observed for example in load profiles 2 (Figure 26) and 8 (Figure 32).
- The Individual Risk (IR_E) resulting from the undetected energised islanded system (based on the worst case results) lies within the broadly acceptable region for all setting options according to the Health and Safety at Work Act 1974, i.e. the probability of a safety hazard is significantly less than 10^{-6} (at least 3 orders of magnitude).

- The rate of occurrence of out-of-phase auto-reclosing (N_{OA}) appears to be high and cannot be neglected, particularly for P-V controlled generators. Further assessment of the anticipated costs and individual risks associated with out-of-phase auto-recourse is required.
- The calculated probability levels for P-pf control regime (prevailing current operation mode) are 2 to 5 orders of magnitudes lower than corresponding values for the P-V controller generator.

5 References

[1] Electricity Networks Association, "ER G59/2: Recommendations for the Connection of Generating Plant to the Distribution Systems of Licensed Distribution Network Operators," 2010.

[2] Distribution Code Review Panel G59 NVD Working Group, “Embedded generation interface protection: Assessment of risks arising from relaxation in the application of neutral voltage displacement (NVD) interface protection.” Energy Networks Association, 31-Dec-2009.

[3] Electricity Networks Association, "ER G59/2: Recommendations for the Connection of Generating Plant to the Distribution Systems of Licensed Distribution Network Operators," 2010.

[4] RTDS Technologies, "RSCAD power system users manual," 2006.

[5] Adam Dyśko, Andrew MacKay, Graeme Burt, "Neutral Voltage Displacement Protection Requirement for DG," DTI Centre for Sustainable Electricity and Distributed Generation 2009.

[6] Distribution Code Review Panel, “Progress of Distributed Generators in changing frequency protection settings to comply with ER G59/2” – Ref. DCRP_12_02_04, June 2012

Appendix A: Network model data

33kV Distribution lines

	Resistance (Ω)	Inductance (mH)
Line A-B	0.167	6.55
Line B-C	0.167	6.55
Line C-D	0.167	6.55
Line E-F	1.155	7.1
Line F-G	1.155	7.1

11kV Distribution Lines

	Resistance (Ω)	Inductance (mH)
Line A-B	0.169	0.17
Line B-C	0.169	0.17
Line D-E	0.67	0.56
Line D-F	0.613	0.45

33kV/11kV transformer (grid interface transformer)

Rating (MVA)	15
Rated frequency (Hz)	50
Leakage inductance (PU)	0.15

0.44kV/11kV transformer (DG interface transformer)

Rating (MVA)	3
Rated frequency (Hz)	50
Leakage reactance (PU)	0.1

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Appendix B: Synchronous generator data

General parameters

	33kV connected generator	11kV connected generator
Rated MVA	30MVA	3MVA
Rated voltage	33kV	440V
Rated frequency	50Hz	50Hz

Generator reactances (PU):

	33kV connected generator	11kV connected generator
Xd	2.25	3.326
Xd’	0.38	0.22
Xd”	0.23	0.107
Xq	1.14	1.644
Xq’	0.38	1.644
Xq”	0.23	0.23

Time constants (s):

	33kV connected generator	11kV connected generator
Tdo’	8.5	12.5
Tdo”	0.06	0.05
Tqo’	3	1
Tqo”	0.13	0.05

Inertia H (s):

33kV connected generator	3
11kV connected generator	1.3

Appendix C: Generator controller data

Voltage regulator parameters:

	33kV connected generator	11kV connected generator
Gain	60	60
Time constant (s)	0.001	0.01
Limits	+/-8	+/-8

Excitation parameters:

Gain	1
Time constant (s)	1e-4
E1	7
SE1	0.05
E2	8
SE2	0.4

Reactive power PI controller:

P gain	1.2
I gain	1.5

Governor gains:

K1	14.3
K2	0.7
K3	1

Governor time constants (s):

T1	1
T2	1
T3	0.02
T4	0.673
T5	3
T6	0.45

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Appendix D. Full record of risk assessment results

D.1. Results based on ROCOF response only

Table 11. LOM risk assessment results assuming for P-V controlled generator

Load Case	Setting Option	Fixed power load				Fixed impedance load			
		T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}	T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}
1	1	141.18	2.64E-03	1.12E-09	1.02E-07	157.43	3.05E-03	1.29E-09	1.18E-07
	2	160.92	3.15E-03	1.33E-09	1.22E-07	180.16	3.50E-03	1.48E-09	1.36E-07
	3	285.16	5.37E-03	2.27E-09	2.08E-07	321.03	6.19E-03	2.62E-09	2.39E-07
	4	313.77	6.42E-03	2.71E-09	2.48E-07	329.11	6.84E-03	2.89E-09	2.65E-07
	5	184.90	3.94E-03	1.67E-09	1.52E-07	195.02	4.08E-03	1.73E-09	1.58E-07
	6	250.43	4.78E-03	2.02E-09	1.85E-07	280.97	5.34E-03	2.26E-09	2.06E-07
	7	296.79	5.72E-03	2.42E-09	2.21E-07	314.67	6.26E-03	2.65E-09	2.42E-07
	8	425.18	7.97E-03	3.37E-09	3.08E-07	424.16	8.06E-03	3.41E-09	3.12E-07
	9	34.75	3.33E-04	1.41E-10	1.29E-08	30.31	1.68E-04	7.09E-11	6.49E-09
	10	38.58	3.82E-04	1.61E-10	1.48E-08	44.67	3.50E-04	1.48E-10	1.35E-08
	11	61.11	8.80E-04	3.72E-10	3.41E-08	62.06	8.47E-04	3.58E-10	3.28E-08
2	1	3.34	2.36E-03	9.98E-10	9.13E-08	4.59	2.69E-03	1.14E-09	1.04E-07
	2	5.14	2.79E-03	1.18E-09	1.08E-07	5.28	2.92E-03	1.23E-09	1.13E-07
	3	8.88	4.80E-03	2.03E-09	1.86E-07	9.49	5.50E-03	2.32E-09	2.13E-07
	4	9.61	5.74E-03	2.43E-09	2.22E-07	12.35	6.12E-03	2.59E-09	2.37E-07
	5	5.30	3.32E-03	1.40E-09	1.28E-07	5.24	3.39E-03	1.43E-09	1.31E-07
	6	5.92	4.04E-03	1.71E-09	1.56E-07	8.92	4.74E-03	2.00E-09	1.83E-07
	7	8.48	5.18E-03	2.19E-09	2.01E-07	9.12	5.33E-03	2.25E-09	2.06E-07
	8	11.69	6.43E-03	2.72E-09	2.49E-07	11.95	6.78E-03	2.87E-09	2.62E-07
	9	0.82	2.36E-04	9.99E-11	9.14E-09	0.44	4.97E-05	2.10E-11	1.92E-09
	10	0.94	3.14E-04	1.33E-10	1.22E-08	0.69	1.26E-04	5.33E-11	4.88E-09
	11	1.19	6.84E-04	2.89E-10	2.65E-08	1.50	5.18E-04	2.19E-10	2.00E-08
3	1	112.89	1.31E-03	5.54E-10	5.07E-08	129.55	1.51E-03	6.38E-10	5.84E-08
	2	133.92	1.56E-03	6.60E-10	6.04E-08	140.78	1.64E-03	6.95E-10	6.36E-08
	3	224.15	2.59E-03	1.09E-09	1.00E-07	261.04	3.03E-03	1.28E-09	1.17E-07
	4	271.64	3.16E-03	1.34E-09	1.22E-07	290.00	3.38E-03	1.43E-09	1.31E-07
	5	157.60	1.83E-03	7.73E-10	7.07E-08	164.52	1.91E-03	8.06E-10	7.37E-08
	6	193.92	2.25E-03	9.50E-10	8.69E-08	222.73	2.57E-03	1.09E-09	9.93E-08
	7	239.88	2.78E-03	1.17E-09	1.07E-07	265.57	3.08E-03	1.30E-09	1.19E-07
	8	339.60	3.99E-03	1.68E-09	1.54E-07	342.98	4.01E-03	1.70E-09	1.55E-07
	9	24.75	2.05E-04	8.68E-11	7.95E-09	33.21	1.56E-04	6.59E-11	6.03E-09
	10	28.60	2.76E-04	1.17E-10	1.07E-08	35.79	2.05E-04	8.67E-11	7.93E-09
	11	43.56	5.06E-04	2.14E-10	1.96E-08	54.47	4.13E-04	1.75E-10	1.60E-08
4	1	115.12	1.40E-03	5.91E-10	5.41E-08	100.92	7.60E-04	3.21E-10	2.94E-08
	2	148.99	2.15E-03	9.07E-10	8.30E-08	156.21	2.25E-03	9.50E-10	8.70E-08
	3	224.16	3.43E-03	1.45E-09	1.33E-07	229.15	3.67E-03	1.55E-09	1.42E-07
	4	283.02	4.25E-03	1.80E-09	1.64E-07	300.03	4.51E-03	1.91E-09	1.75E-07
	5	171.19	2.48E-03	1.05E-09	9.60E-08	176.55	2.58E-03	1.09E-09	9.99E-08
	6	207.43	3.04E-03	1.28E-09	1.17E-07	234.86	3.49E-03	1.47E-09	1.35E-07
	7	250.68	3.75E-03	1.58E-09	1.45E-07	279.06	4.14E-03	1.75E-09	1.60E-07
	8	361.99	5.30E-03	2.24E-09	2.05E-07	365.25	5.40E-03	2.28E-09	2.09E-07
	9	23.40	2.50E-05	1.06E-11	9.66E-10	30.63	2.04E-05	8.62E-12	7.89E-10
	10	28.59	2.62E-05	1.11E-11	1.01E-09	37.08	2.66E-05	1.12E-11	1.03E-09
	11	42.46	8.32E-05	3.52E-11	3.22E-09	45.05	5.46E-05	2.31E-11	2.11E-09

Table 10. Continued…

Load Case	Setting Option	Fixed power load				Fixed impedance load			
		T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}	T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}
5	1	111.15	2.36E-03	9.99E-10	9.14E-08	113.05	1.98E-03	8.37E-10	7.66E-08
	2	138.78	3.06E-03	1.29E-09	1.18E-07	146.51	3.22E-03	1.36E-09	1.25E-07
	3	228.17	5.06E-03	2.14E-09	1.96E-07	260.76	5.81E-03	2.45E-09	2.25E-07
	4	280.88	6.23E-03	2.63E-09	2.41E-07	299.86	6.63E-03	2.80E-09	2.57E-07
	5	162.96	3.59E-03	1.52E-09	1.39E-07	170.03	3.74E-03	1.58E-09	1.45E-07
	6	200.57	4.42E-03	1.87E-09	1.71E-07	228.40	5.06E-03	2.14E-09	1.96E-07
	7	246.50	5.48E-03	2.32E-09	2.12E-07	273.76	6.08E-03	2.57E-09	2.35E-07
	8	347.68	7.75E-03	3.28E-09	3.00E-07	351.00	7.82E-03	3.31E-09	3.03E-07
	9	24.39	1.63E-04	6.90E-11	6.31E-09	28.14	1.27E-04	5.38E-11	4.92E-09
	10	29.27	1.91E-04	8.08E-11	7.40E-09	30.74	1.64E-04	6.92E-11	6.33E-09
	11	42.05	4.14E-04	1.75E-10	1.60E-08	46.18	3.45E-04	1.46E-10	1.33E-08
6	1	99.05	1.39E-03	5.89E-10	5.39E-08	87.60	6.54E-04	2.76E-10	2.53E-08
	2	135.29	2.42E-03	1.02E-09	9.36E-08	141.98	2.55E-03	1.08E-09	9.86E-08
	3	223.39	3.99E-03	1.69E-09	1.54E-07	230.30	4.18E-03	1.77E-09	1.62E-07
	4	272.13	4.86E-03	2.05E-09	1.88E-07	288.60	5.19E-03	2.20E-09	2.01E-07
	5	157.30	2.83E-03	1.20E-09	1.09E-07	164.35	2.95E-03	1.25E-09	1.14E-07
	6	193.56	3.47E-03	1.47E-09	1.34E-07	221.90	3.96E-03	1.67E-09	1.53E-07
	7	239.88	4.28E-03	1.81E-09	1.65E-07	265.29	4.74E-03	2.00E-09	1.83E-07
	8	340.04	6.08E-03	2.57E-09	2.35E-07	342.69	6.13E-03	2.59E-09	2.37E-07
	9	24.83	2.44E-05	1.03E-11	9.43E-10	32.43	9.14E-06	3.86E-12	3.53E-10
	10	29.28	4.44E-05	1.88E-11	1.72E-09	33.44	1.46E-05	6.19E-12	5.67E-10
	11	40.76	2.10E-04	8.89E-11	8.13E-09	43.68	3.96E-05	1.67E-11	1.53E-09
7	1	1.98	7.55E-04	3.19E-10	2.92E-08	0.00	0.00E+00	0.00E+00	0.00E+00
	2	2.75	1.71E-03	7.22E-10	6.61E-08	2.68	1.84E-03	7.77E-10	7.11E-08
	3	6.10	3.18E-03	1.35E-09	1.23E-07	6.51	2.92E-03	1.23E-09	1.13E-07
	4	8.19	3.47E-03	1.47E-09	1.34E-07	8.56	3.65E-03	1.54E-09	1.41E-07
	5	2.74	2.05E-03	8.69E-10	7.95E-08	2.69	2.22E-03	9.37E-10	8.57E-08
	6	4.04	2.80E-03	1.18E-09	1.08E-07	6.22	3.14E-03	1.33E-09	1.21E-07
	7	7.18	3.27E-03	1.38E-09	1.26E-07	7.80	3.47E-03	1.47E-09	1.34E-07
	8	5.46	4.36E-03	1.84E-09	1.69E-07	6.08	4.56E-03	1.93E-09	1.77E-07
	9	0.00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
8	1	1.85	1.32E-03	5.56E-10	5.09E-08	2.11	1.57E-03	6.63E-10	6.07E-08
	2	2.16	1.59E-03	6.70E-10	6.13E-08	2.22	1.67E-03	7.08E-10	6.48E-08
	3	3.57	2.48E-03	1.05E-09	9.60E-08	4.44	2.78E-03	1.17E-09	1.07E-07
	4	4.58	2.91E-03	1.23E-09	1.13E-07	4.78	3.07E-03	1.30E-09	1.19E-07
	5	2.55	1.81E-03	7.65E-10	7.00E-08	2.64	1.85E-03	7.81E-10	7.15E-08
	6	2.99	2.18E-03	9.23E-10	8.44E-08	3.59	2.45E-03	1.04E-09	9.49E-08
	7	4.10	2.65E-03	1.12E-09	1.03E-07	4.48	2.84E-03	1.20E-09	1.10E-07
	8	5.65	3.63E-03	1.53E-09	1.40E-07	5.58	3.64E-03	1.54E-09	1.41E-07
	9	0.36	1.05E-04	4.43E-11	4.05E-09	0.48	9.89E-05	4.18E-11	3.83E-09
	10	0.45	1.13E-04	4.79E-11	4.38E-09	0.53	1.22E-04	5.17E-11	4.73E-09
	11	0.59	3.99E-04	1.69E-10	1.54E-08	0.73	2.40E-04	1.01E-10	9.28E-09

Table 12. LOM risk assessment results assuming for P-pf controlled generator

Load Case	Setting Option	Fixed power load				Fixed impedance load			
		T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}	T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}
1	1	1.50E+03	2.16E-05	9.13E-12	8.35E-10	0.00	0.00E+00	0.00E+00	0.00E+00
	2	4.26E+03	1.00E-03	4.25E-10	3.89E-08	14.91	3.77E-06	1.60E-12	1.46E-10
	3	6.58E+03	1.90E-03	8.02E-10	7.34E-08	0.00	0.00E+00	0.00E+00	0.00E+00
	4	7.44E+03	2.24E-03	9.49E-10	8.68E-08	23.99	1.48E-05	6.24E-12	5.71E-10
	5	4.89E+03	1.31E-03	5.56E-10	5.08E-08	24.93	1.19E-06	5.01E-13	4.59E-11
	6	5.68E+03	1.64E-03	6.93E-10	6.34E-08	20.57	2.35E-05	9.94E-12	9.09E-10
	7	6.75E+03	2.13E-03	9.00E-10	8.24E-08	14.91	3.30E-06	1.40E-12	1.28E-10
	8	8.05E+03	2.62E-03	1.11E-09	1.01E-07	30.46	3.44E-05	1.45E-11	1.33E-09
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
2	1	1.09E+01	4.36E-05	7.26E-12	6.64E-10	0.00	0.00E+00	0.00E+00	0.00E+00
	2	2.12E+02	1.67E-03	7.07E-10	6.47E-08	0.00	0.00E+00	0.00E+00	0.00E+00
	3	5.17E+02	3.12E-03	1.32E-09	1.21E-07	0.00	0.00E+00	0.00E+00	0.00E+00
	4	6.12E+02	3.59E-03	1.52E-09	1.39E-07	0.22	2.16E-07	4.57E-14	4.18E-12
	5	2.45E+02	2.34E-03	9.87E-10	9.03E-08	0.00	0.00E+00	0.00E+00	0.00E+00
	6	3.96E+02	2.96E-03	1.25E-09	1.14E-07	0.17	1.66E-07	2.46E-14	2.25E-12
	7	5.65E+02	3.49E-03	1.48E-09	1.35E-07	0.00	0.00E+00	0.00E+00	0.00E+00
	8	5.41E+02	4.05E-03	1.71E-09	1.57E-07	0.24	1.65E-06	3.88E-13	3.55E-11
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
3	1	3.06E+02	4.97E-05	2.10E-11	1.92E-09	2.36	1.64E-07	6.91E-14	6.33E-12
	2	3.88E+03	7.07E-04	2.99E-10	2.73E-08	7.59	3.68E-06	1.55E-12	1.42E-10
	3	7.00E+03	1.30E-03	5.48E-10	5.02E-08	0.00	0.00E+00	0.00E+00	0.00E+00
	4	8.61E+03	1.59E-03	6.74E-10	6.17E-08	13.41	1.31E-05	5.53E-12	5.06E-10
	5	4.98E+03	9.17E-04	3.88E-10	3.55E-08	9.43	5.77E-06	2.44E-12	2.23E-10
	6	6.20E+03	1.14E-03	4.83E-10	4.42E-08	19.78	2.72E-05	1.15E-11	1.05E-09
	7	8.05E+03	1.49E-03	6.30E-10	5.76E-08	8.07	4.38E-06	1.85E-12	1.69E-10
	8	9.80E+03	1.82E-03	7.70E-10	7.04E-08	24.17	4.21E-05	1.78E-11	1.63E-09
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
4	1	2.80E+02	6.44E-07	2.72E-13	2.49E-11	2.00	2.14E-08	9.03E-15	8.27E-13
	2	2.24E+03	1.50E-05	6.35E-12	5.81E-10	7.43	2.63E-07	1.11E-13	1.02E-11
	3	3.08E+03	4.46E-05	1.89E-11	1.73E-09	0.00	0.00E+00	0.00E+00	0.00E+00
	4	3.66E+03	6.65E-05	2.81E-11	2.57E-09	12.21	1.38E-06	5.83E-13	5.34E-11
	5	2.39E+03	2.31E-05	9.77E-12	8.94E-10	8.83	5.51E-07	2.33E-13	2.13E-11
	6	2.88E+03	3.53E-05	1.49E-11	1.36E-09	13.22	2.81E-06	1.19E-12	1.09E-10
	7	3.50E+03	6.03E-05	2.55E-11	2.33E-09	5.00	3.38E-07	1.43E-13	1.31E-11
	8	3.63E+03	7.99E-05	3.38E-11	3.09E-09	16.00	5.04E-06	2.13E-12	1.95E-10
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00

Table 11. Continued…

Load Case	Setting Option	Fixed power load				Fixed impedance load			
		T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}	T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}
5	1	4.03E+02	2.22E-05	9.38E-12	8.58E-10	2.00	9.94E-08	4.20E-14	3.85E-12
	2	3.30E+03	3.02E-04	1.28E-10	1.17E-08	3.98	2.15E-06	9.07E-13	8.30E-11
	3	4.87E+03	5.85E-04	2.47E-10	2.26E-08	0.00	0.00E+00	0.00E+00	0.00E+00
	4	5.43E+03	7.36E-04	3.11E-10	2.85E-08	7.66	8.45E-06	3.57E-12	3.27E-10
	5	3.92E+03	3.97E-04	1.68E-10	1.54E-08	5.39	3.68E-06	1.55E-12	1.42E-10
	6	4.45E+03	5.11E-04	2.16E-10	1.98E-08	11.62	1.97E-05	8.32E-12	7.62E-10
	7	5.26E+03	6.80E-04	2.88E-10	2.63E-08	4.14	2.42E-06	1.02E-12	9.37E-11
	8	5.86E+03	8.54E-04	3.61E-10	3.30E-08	13.59	3.10E-05	1.31E-11	1.20E-09
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
6	1	3.46E+02	7.58E-05	3.20E-11	2.93E-09	4.00	3.29E-09	1.39E-15	1.27E-13
	2	4.31E+03	1.04E-03	4.42E-10	4.04E-08	5.78	9.12E-08	3.86E-14	3.53E-12
	3	8.12E+03	2.24E-03	9.47E-10	8.67E-08	0.00	0.00E+00	0.00E+00	0.00E+00
	4	1.00E+04	2.75E-03	1.16E-09	1.07E-07	12.35	3.32E-07	1.40E-13	1.28E-11
	5	5.44E+03	1.31E-03	5.52E-10	5.05E-08	7.80	1.31E-07	5.56E-14	5.09E-12
	6	6.67E+03	1.65E-03	6.98E-10	6.39E-08	14.44	6.97E-07	2.95E-13	2.70E-11
	7	9.35E+03	2.57E-03	1.09E-09	9.94E-08	6.44	8.88E-08	3.75E-14	3.43E-12
	8	1.14E+04	3.10E-03	1.31E-09	1.20E-07	19.15	1.26E-06	5.33E-13	4.88E-11
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
7	1	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	2	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	3	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	4	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	6	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	7	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	8	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
8	1	6.29E+00	3.36E-06	2.33E-13	2.14E-11	0.00	0.00E+00	0.00E+00	0.00E+00
	2	5.12E+01	1.59E-04	6.72E-11	6.15E-09	0.12	1.69E-06	1.56E-13	1.43E-11
	3	7.47E+01	3.22E-04	1.36E-10	1.24E-08	0.00	0.00E+00	0.00E+00	0.00E+00
	4	9.47E+01	4.14E-04	1.75E-10	1.60E-08	0.19	9.34E-06	1.72E-12	1.57E-10
	5	6.78E+01	2.15E-04	9.11E-11	8.34E-09	0.15	3.62E-06	4.37E-13	4.00E-11
	6	6.76E+01	2.61E-04	1.10E-10	1.01E-08	0.26	1.72E-05	4.62E-12	4.23E-10
	7	9.17E+01	3.85E-04	1.63E-10	1.49E-08	0.13	2.08E-06	2.15E-13	1.97E-11
	8	9.74E+01	4.95E-04	2.09E-10	1.92E-08	0.32	3.28E-05	1.12E-11	1.03E-09
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00

D.2. Results based on combined ROCOF, UV/OV and UF/OF response

Table 13. LOM risk assessment results assuming for P-V controlled generator (no difference from ROCOF only results)

Load Case	Setting Option	Fixed power load				Fixed impedance load			
		T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}	T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}
1	1	141.18	2.64E-03	1.12E-09	1.02E-07	157.43	3.05E-03	1.29E-09	1.18E-07
	2	160.92	3.15E-03	1.33E-09	1.22E-07	180.16	3.50E-03	1.48E-09	1.36E-07
	3	285.16	5.37E-03	2.27E-09	2.08E-07	321.03	6.19E-03	2.62E-09	2.39E-07
	4	313.77	6.42E-03	2.71E-09	2.48E-07	329.11	6.84E-03	2.89E-09	2.65E-07
	5	184.90	3.94E-03	1.67E-09	1.52E-07	195.02	4.08E-03	1.73E-09	1.58E-07
	6	250.43	4.78E-03	2.02E-09	1.85E-07	280.97	5.34E-03	2.26E-09	2.06E-07
	7	296.79	5.72E-03	2.42E-09	2.21E-07	314.67	6.26E-03	2.65E-09	2.42E-07
	8	425.18	7.97E-03	3.37E-09	3.08E-07	424.16	8.06E-03	3.41E-09	3.12E-07
	9	34.75	3.33E-04	1.41E-10	1.29E-08	30.31	1.68E-04	7.09E-11	6.49E-09
	10	38.58	3.82E-04	1.61E-10	1.48E-08	44.67	3.50E-04	1.48E-10	1.35E-08
	11	61.11	8.80E-04	3.72E-10	3.41E-08	62.06	8.47E-04	3.58E-10	3.28E-08
2	1	3.34	2.36E-03	9.98E-10	9.13E-08	4.59	2.69E-03	1.14E-09	1.04E-07
	2	5.14	2.79E-03	1.18E-09	1.08E-07	5.28	2.92E-03	1.23E-09	1.13E-07
	3	8.88	4.80E-03	2.03E-09	1.86E-07	9.49	5.50E-03	2.32E-09	2.13E-07
	4	9.61	5.74E-03	2.43E-09	2.22E-07	12.35	6.12E-03	2.59E-09	2.37E-07
	5	5.30	3.32E-03	1.40E-09	1.28E-07	5.24	3.39E-03	1.43E-09	1.31E-07
	6	5.92	4.04E-03	1.71E-09	1.56E-07	8.92	4.74E-03	2.00E-09	1.83E-07
	7	8.48	5.18E-03	2.19E-09	2.01E-07	9.12	5.33E-03	2.25E-09	2.06E-07
	8	11.69	6.43E-03	2.72E-09	2.49E-07	11.95	6.78E-03	2.87E-09	2.62E-07
	9	0.82	2.36E-04	9.99E-11	9.14E-09	0.44	4.97E-05	2.10E-11	1.92E-09
	10	0.94	3.14E-04	1.33E-10	1.22E-08	0.69	1.26E-04	5.33E-11	4.88E-09
	11	1.19	6.84E-04	2.89E-10	2.65E-08	1.50	5.18E-04	2.19E-10	2.00E-08
3	1	112.89	1.31E-03	5.54E-10	5.07E-08	129.55	1.51E-03	6.38E-10	5.84E-08
	2	133.92	1.56E-03	6.60E-10	6.04E-08	140.78	1.64E-03	6.95E-10	6.36E-08
	3	224.15	2.59E-03	1.09E-09	1.00E-07	261.04	3.03E-03	1.28E-09	1.17E-07
	4	271.64	3.16E-03	1.34E-09	1.22E-07	290.00	3.38E-03	1.43E-09	1.31E-07
	5	157.60	1.83E-03	7.73E-10	7.07E-08	164.52	1.91E-03	8.06E-10	7.37E-08
	6	193.92	2.25E-03	9.50E-10	8.69E-08	222.73	2.57E-03	1.09E-09	9.93E-08
	7	239.88	2.78E-03	1.17E-09	1.07E-07	265.57	3.08E-03	1.30E-09	1.19E-07
	8	339.60	3.99E-03	1.68E-09	1.54E-07	342.98	4.01E-03	1.70E-09	1.55E-07
	9	24.75	2.05E-04	8.68E-11	7.95E-09	33.21	1.56E-04	6.59E-11	6.03E-09
	10	28.60	2.76E-04	1.17E-10	1.07E-08	35.79	2.05E-04	8.67E-11	7.93E-09
	11	43.56	5.06E-04	2.14E-10	1.96E-08	54.47	4.13E-04	1.75E-10	1.60E-08
4	1	115.12	1.40E-03	5.91E-10	5.41E-08	100.92	7.60E-04	3.21E-10	2.94E-08
	2	148.99	2.15E-03	9.07E-10	8.30E-08	156.21	2.25E-03	9.50E-10	8.70E-08
	3	224.16	3.43E-03	1.45E-09	1.33E-07	229.15	3.67E-03	1.55E-09	1.42E-07
	4	283.02	4.25E-03	1.80E-09	1.64E-07	300.03	4.51E-03	1.91E-09	1.75E-07
	5	171.19	2.48E-03	1.05E-09	9.60E-08	176.55	2.58E-03	1.09E-09	9.99E-08
	6	207.43	3.04E-03	1.28E-09	1.17E-07	234.86	3.49E-03	1.47E-09	1.35E-07
	7	250.68	3.75E-03	1.58E-09	1.45E-07	279.06	4.14E-03	1.75E-09	1.60E-07
	8	361.99	5.30E-03	2.24E-09	2.05E-07	365.25	5.40E-03	2.28E-09	2.09E-07
	9	23.40	2.50E-05	1.06E-11	9.66E-10	30.63	2.04E-05	8.62E-12	7.89E-10
	10	28.59	2.62E-05	1.11E-11	1.01E-09	37.08	2.66E-05	1.12E-11	1.03E-09
	11	42.46	8.32E-05	3.52E-11	3.22E-09	45.05	5.46E-05	2.31E-11	2.11E-09

Table 12. Continued…

Load Case	Setting Option	Fixed power load T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}	Fixed impedance load T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}
5	1	111.15	2.36E-03	9.99E-10	9.14E-08	113.05	1.98E-03	8.37E-10	7.66E-08
	2	138.78	3.06E-03	1.29E-09	1.18E-07	146.51	3.22E-03	1.36E-09	1.25E-07
	3	228.17	5.06E-03	2.14E-09	1.96E-07	260.76	5.81E-03	2.45E-09	2.25E-07
	4	280.88	6.23E-03	2.63E-09	2.41E-07	299.86	6.63E-03	2.80E-09	2.57E-07
	5	162.96	3.59E-03	1.52E-09	1.39E-07	170.03	3.74E-03	1.58E-09	1.45E-07
	6	200.57	4.42E-03	1.87E-09	1.71E-07	228.40	5.06E-03	2.14E-09	1.96E-07
	7	246.50	5.48E-03	2.32E-09	2.12E-07	273.76	6.08E-03	2.57E-09	2.35E-07
	8	347.68	7.75E-03	3.28E-09	3.00E-07	351.00	7.82E-03	3.31E-09	3.03E-07
	9	24.39	1.63E-04	6.90E-11	6.31E-09	28.14	1.27E-04	5.38E-11	4.92E-09
	10	29.27	1.91E-04	8.08E-11	7.40E-09	30.74	1.64E-04	6.92E-11	6.33E-09
	11	42.05	4.14E-04	1.75E-10	1.60E-08	46.18	3.45E-04	1.46E-10	1.33E-08
6	1	99.05	1.39E-03	5.89E-10	5.39E-08	87.60	6.54E-04	2.76E-10	2.53E-08
	2	135.29	2.42E-03	1.02E-09	9.36E-08	141.98	2.55E-03	1.08E-09	9.86E-08
	3	223.39	3.99E-03	1.69E-09	1.54E-07	230.30	4.18E-03	1.77E-09	1.62E-07
	4	272.13	4.86E-03	2.05E-09	1.88E-07	288.60	5.19E-03	2.20E-09	2.01E-07
	5	157.30	2.83E-03	1.20E-09	1.09E-07	164.35	2.95E-03	1.25E-09	1.14E-07
	6	193.56	3.47E-03	1.47E-09	1.34E-07	221.90	3.96E-03	1.67E-09	1.53E-07
	7	239.88	4.28E-03	1.81E-09	1.65E-07	265.29	4.74E-03	2.00E-09	1.83E-07
	8	340.04	6.08E-03	2.57E-09	2.35E-07	342.69	6.13E-03	2.59E-09	2.37E-07
	9	24.83	2.44E-05	1.03E-11	9.43E-10	32.43	9.14E-06	3.86E-12	3.53E-10
	10	29.28	4.44E-05	1.88E-11	1.72E-09	33.44	1.46E-05	6.19E-12	5.67E-10
	11	40.76	2.10E-04	8.89E-11	8.13E-09	43.68	3.96E-05	1.67E-11	1.53E-09
7	1	1.98	7.55E-04	3.19E-10	2.92E-08	0.00	0.00E+00	0.00E+00	0.00E+00
	2	2.75	1.71E-03	7.22E-10	6.61E-08	2.68	1.84E-03	7.77E-10	7.11E-08
	3	6.10	3.18E-03	1.35E-09	1.23E-07	6.51	2.92E-03	1.23E-09	1.13E-07
	4	8.19	3.47E-03	1.47E-09	1.34E-07	8.56	3.65E-03	1.54E-09	1.41E-07
	5	2.74	2.05E-03	8.69E-10	7.95E-08	2.69	2.22E-03	9.37E-10	8.57E-08
	6	4.04	2.80E-03	1.18E-09	1.08E-07	6.22	3.14E-03	1.33E-09	1.21E-07
	7	7.18	3.27E-03	1.38E-09	1.26E-07	7.80	3.47E-03	1.47E-09	1.34E-07
	8	5.46	4.36E-03	1.84E-09	1.69E-07	6.08	4.56E-03	1.93E-09	1.77E-07
	9	0.00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
8	1	1.85	1.32E-03	5.56E-10	5.09E-08	2.11	1.57E-03	6.63E-10	6.07E-08
	2	2.16	1.59E-03	6.70E-10	6.13E-08	2.22	1.67E-03	7.08E-10	6.48E-08
	3	3.57	2.48E-03	1.05E-09	9.60E-08	4.44	2.78E-03	1.17E-09	1.07E-07
	4	4.58	2.91E-03	1.23E-09	1.13E-07	4.78	3.07E-03	1.30E-09	1.19E-07
	5	2.55	1.81E-03	7.65E-10	7.00E-08	2.64	1.85E-03	7.81E-10	7.15E-08
	6	2.99	2.18E-03	9.23E-10	8.44E-08	3.59	2.45E-03	1.04E-09	9.49E-08
	7	4.10	2.65E-03	1.12E-09	1.03E-07	4.48	2.84E-03	1.20E-09	1.10E-07
	8	5.65	3.63E-03	1.53E-09	1.40E-07	5.58	3.64E-03	1.54E-09	1.41E-07
	9	0.36	1.05E-04	4.43E-11	4.05E-09	0.48	9.89E-05	4.18E-11	3.83E-09
	10	0.45	1.13E-04	4.79E-11	4.38E-09	0.53	1.22E-04	5.17E-11	4.73E-09
	11	0.59	3.99E-04	1.69E-10	1.54E-08	0.73	2.40E-04	1.01E-10	9.28E-09

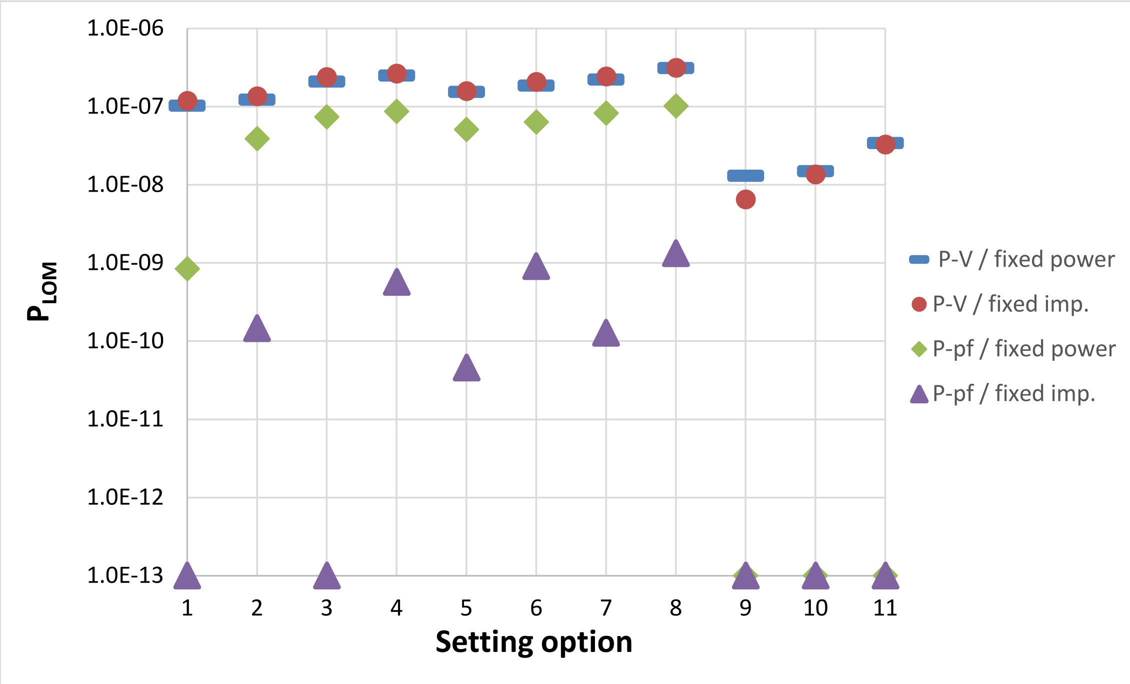
Table 14. LOM risk assessment results assuming for P-pf controlled generator (difference from ROCOF only results highlighted in bold)

Load Case	Setting Option	Fixed power load				Fixed impedance load			
		T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}	T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}
1	1	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	2	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	14.91	3.77E-06	1.60E-12	1.46E-10
	3	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	4	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	23.99	1.48E-05	6.24E-12	5.71E-10
	5	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	24.93	1.19E-06	5.01E-13	4.59E-11
	6	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	**20.56**	**2.35E-05**	**9.93E-12**	**9.09E-10**
	7	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	14.91	3.30E-06	1.40E-12	1.28E-10
	8	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	30.46	3.44E-05	1.45E-11	1.33E-09
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
2	1	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	2	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	3	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	4	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.22	2.16E-07	4.57E-14	4.18E-12
	5	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	6	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.17**	**1.66E-07**	**2.46E-14**	**2.25E-12**
	7	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	8	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.24	1.65E-06	3.88E-13	3.55E-11
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
3	1	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	2.36	1.64E-07	6.91E-14	6.33E-12
	2	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	7.59	3.68E-06	1.55E-12	1.42E-10
	3	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	4	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	13.41	1.31E-05	5.53E-12	5.06E-10
	5	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	9.43	5.77E-06	2.44E-12	2.23E-10
	6	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	**18.89**	**2.54E-05**	**1.07E-11**	**9.83E-10**
	7	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	8.07	4.38E-06	1.85E-12	1.69E-10
	8	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	24.17	4.21E-05	1.78E-11	1.63E-09
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
4	1	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	2.00	2.14E-08	9.03E-15	8.27E-13
	2	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	7.43	2.63E-07	1.11E-13	1.02E-11
	3	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	4	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	12.21	1.38E-06	5.83E-13	5.34E-11
	5	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	8.83	5.51E-07	2.33E-13	2.13E-11
	6	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	**13.39**	**2.64E-06**	**1.11E-12**	**1.02E-10**
	7	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	5.00	3.38E-07	1.43E-13	1.31E-11
	8	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	16.00	5.04E-06	2.13E-12	1.95E-10
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00

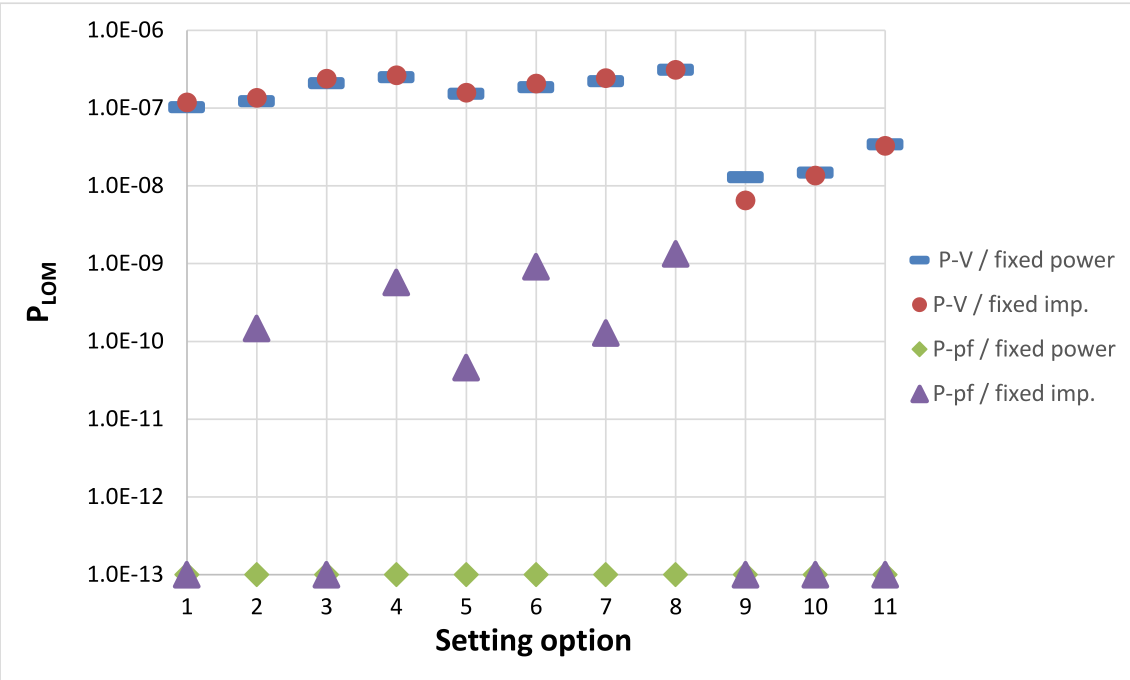
Table 13. Continued…

Load Case	Setting Option	Fixed power load				Fixed impedance load			
		T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}	T_{NDZavr} [min]	$N_{LOM,1DG}$	$P_{LOM,1DG}$	P_{LOM}
5	1	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	2.00	9.94E-08	4.20E-14	3.85E-12
	2	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	3.98	2.15E-06	9.07E-13	8.30E-11
	3	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	4	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	7.66	8.45E-06	3.57E-12	3.27E-10
	5	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	5.39	3.68E-06	1.55E-12	1.42E-10
	6	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	**11.41**	**1.85E-05**	**7.81E-12**	**7.15E-10**
	7	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	4.14	2.42E-06	1.02E-12	9.37E-11
	8	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	13.59	3.10E-05	1.31E-11	1.20E-09
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
6	1	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	4.00	3.29E-09	1.39E-15	1.27E-13
	2	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	5.78	9.12E-08	3.86E-14	3.53E-12
	3	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	4	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	12.35	3.32E-07	1.40E-13	1.28E-11
	5	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	7.80	1.31E-07	5.56E-14	5.09E-12
	6	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	**15.42**	**6.57E-07**	**2.78E-13**	**2.54E-11**
	7	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	6.44	8.88E-08	3.75E-14	3.43E-12
	8	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	19.15	1.26E-06	5.33E-13	4.88E-11
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
7	1	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	2	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	3	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	4	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	5	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	6	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	7	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	8	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
8	1	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	2	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.12	1.69E-06	1.56E-13	1.43E-11
	3	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.00	0.00E+00	0.00E+00	0.00E+00
	4	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.19	9.34E-06	1.72E-12	1.57E-10
	5	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.15	3.62E-06	4.37E-13	4.00E-11
	6	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.26**	**1.60E-05**	**4.28E-12**	**3.92E-10**
	7	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.13	2.08E-06	2.15E-13	1.97E-11
	8	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.00E+00**	0.32	3.28E-05	1.12E-11	1.03E-09
	9	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00
	11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00	0.00E+00	0.00E+00	0.00E+00

D.3. Result figures

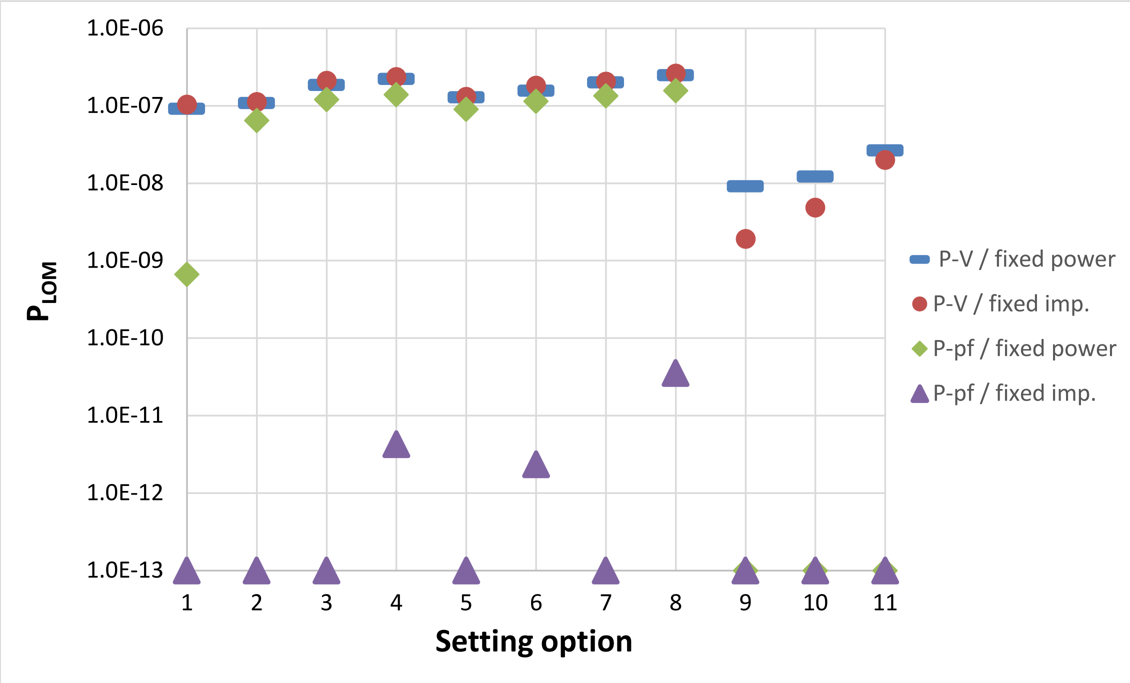


a) ROCOF enabled only

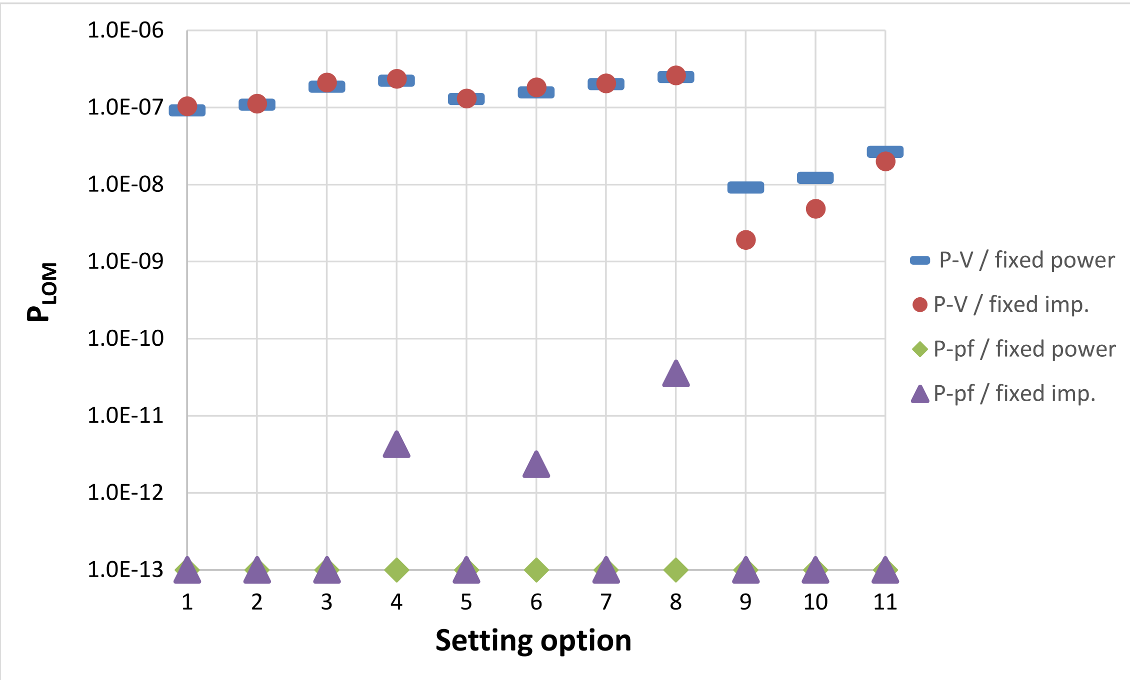


b) Full G59/2 interface protection enabled

Figure 25. Probability of undetected islanding operation – Load Case 1

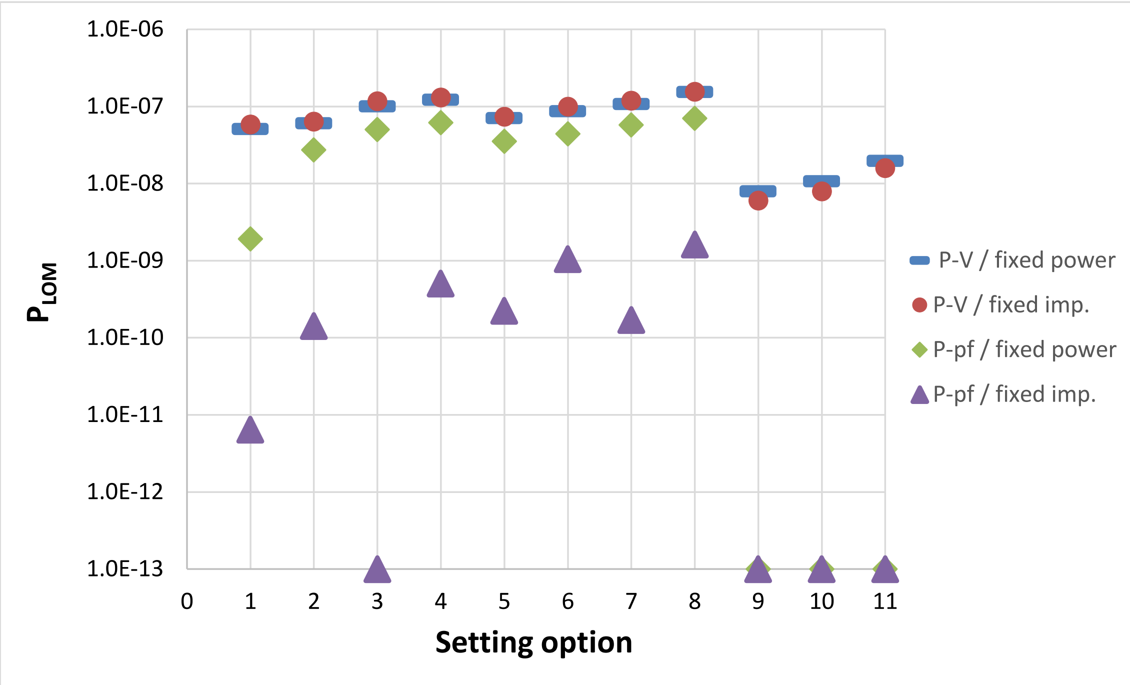


a) ROCOF enabled only

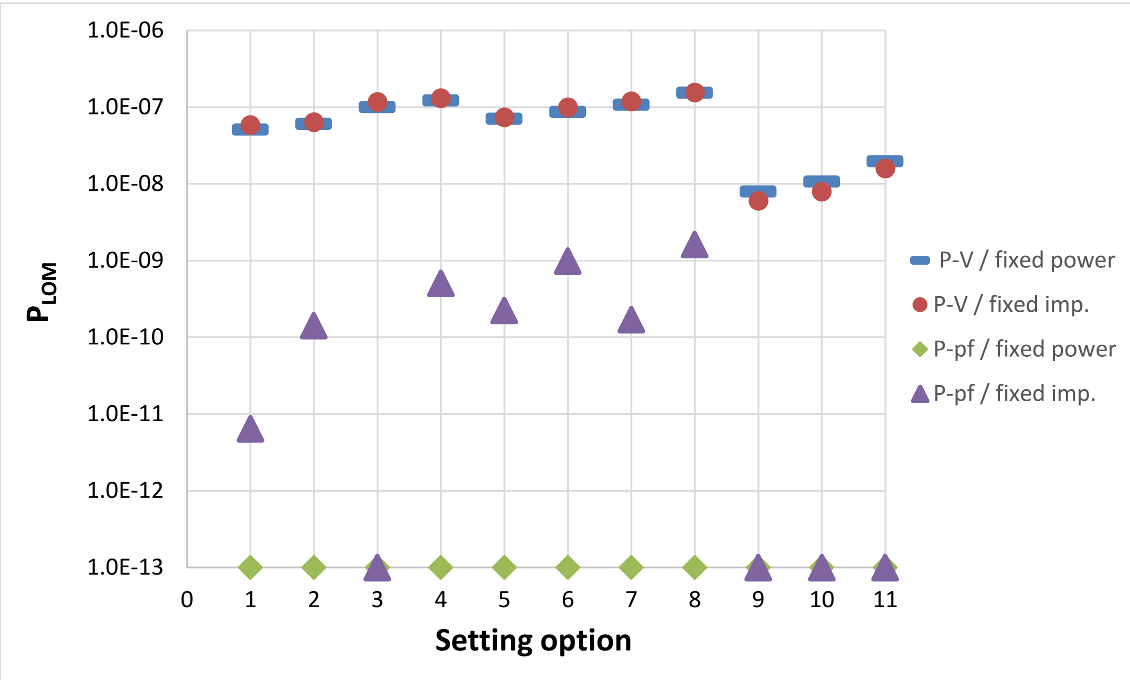


b) Full G59/2 interface protection enabled

Figure 26. Probability of undetected islanding operation – Load Case 2

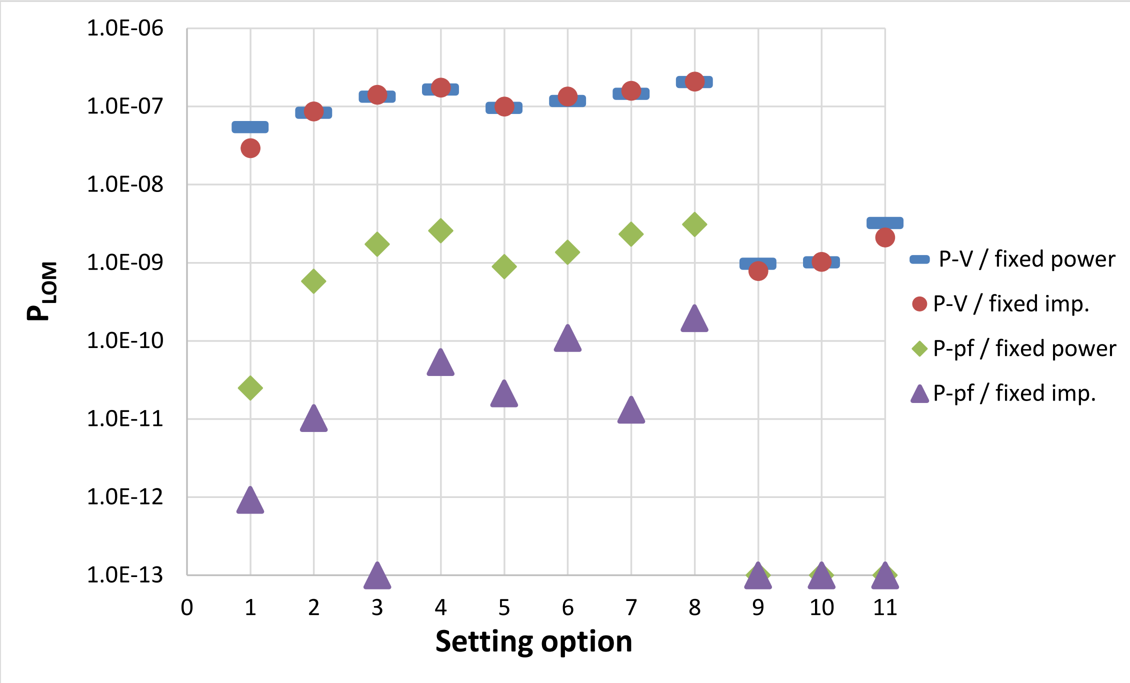


a) ROCOF enabled only

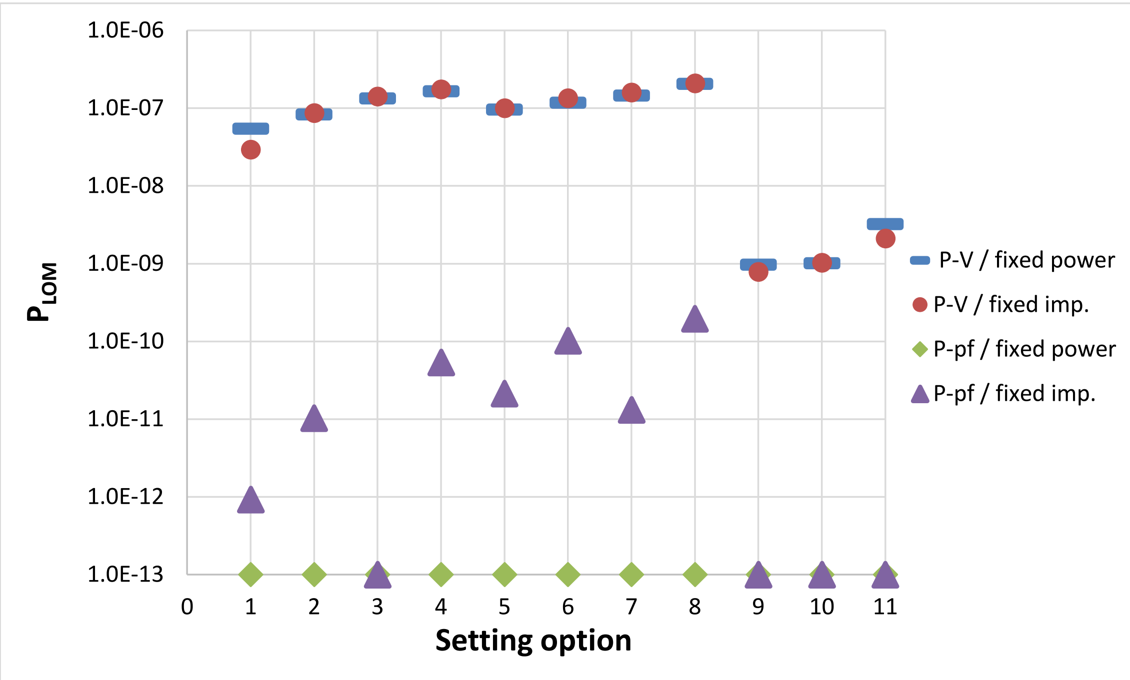


b) Full G59/2 interface protection enabled

Figure 27. Probability of undetected islanding operation – Load Case 3

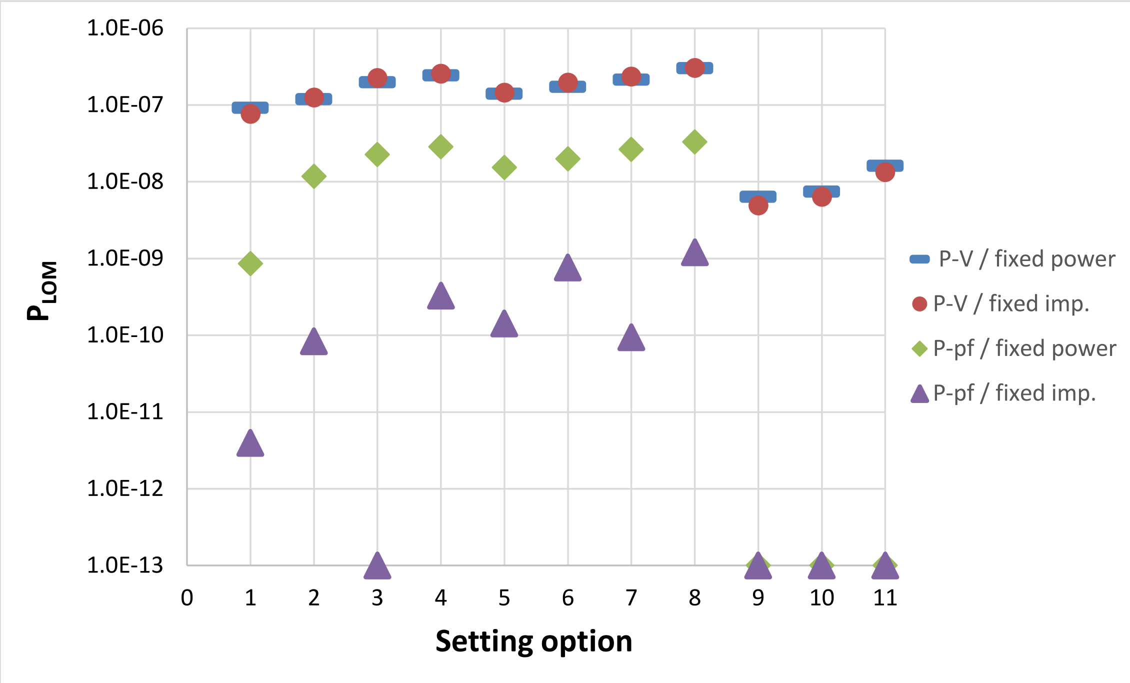


a) ROCOF enabled only

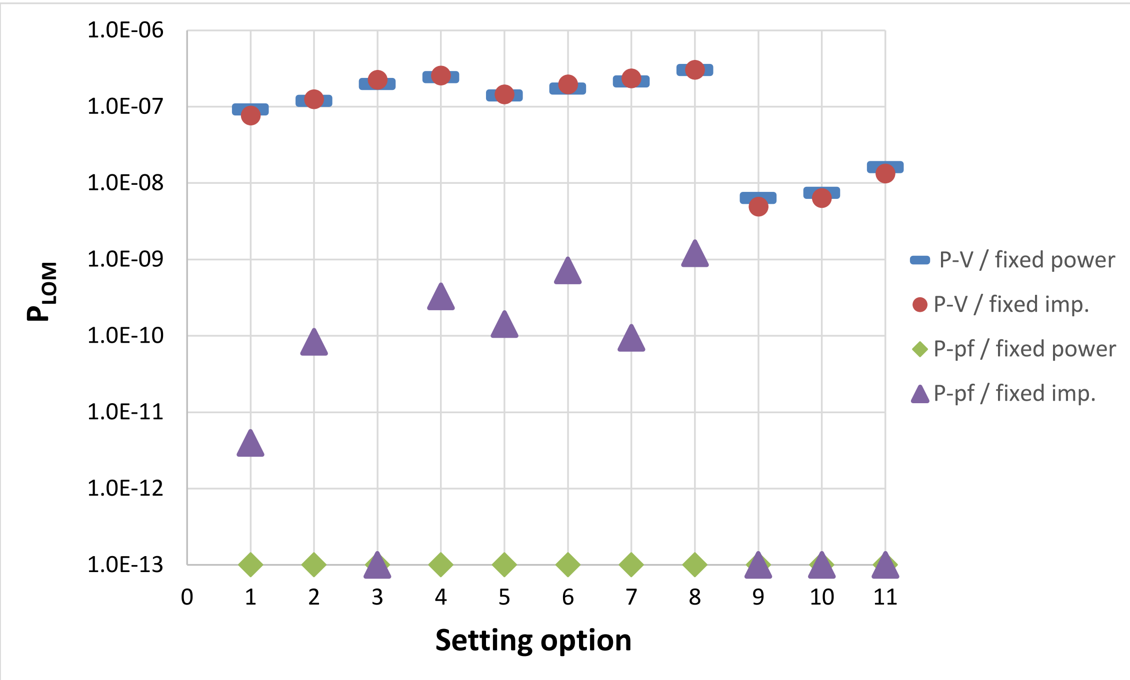


b) Full G59/2 interface protection enabled

Figure 28. Probability of undetected islanding operation – Load Case 4

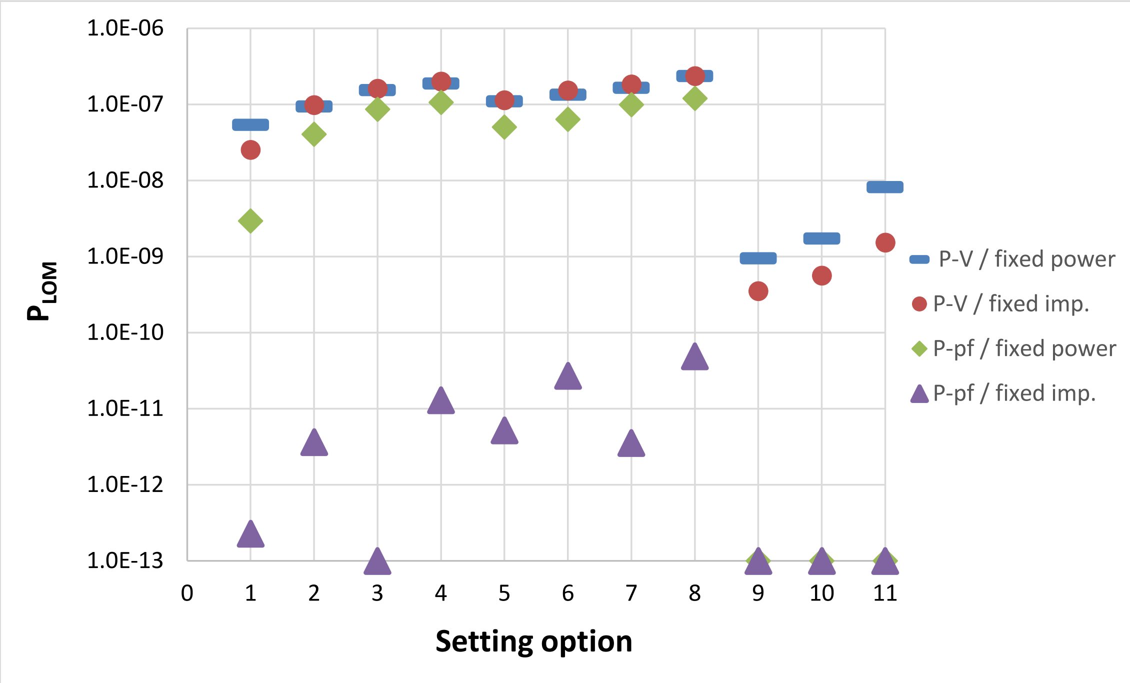


a) ROCOF enabled only

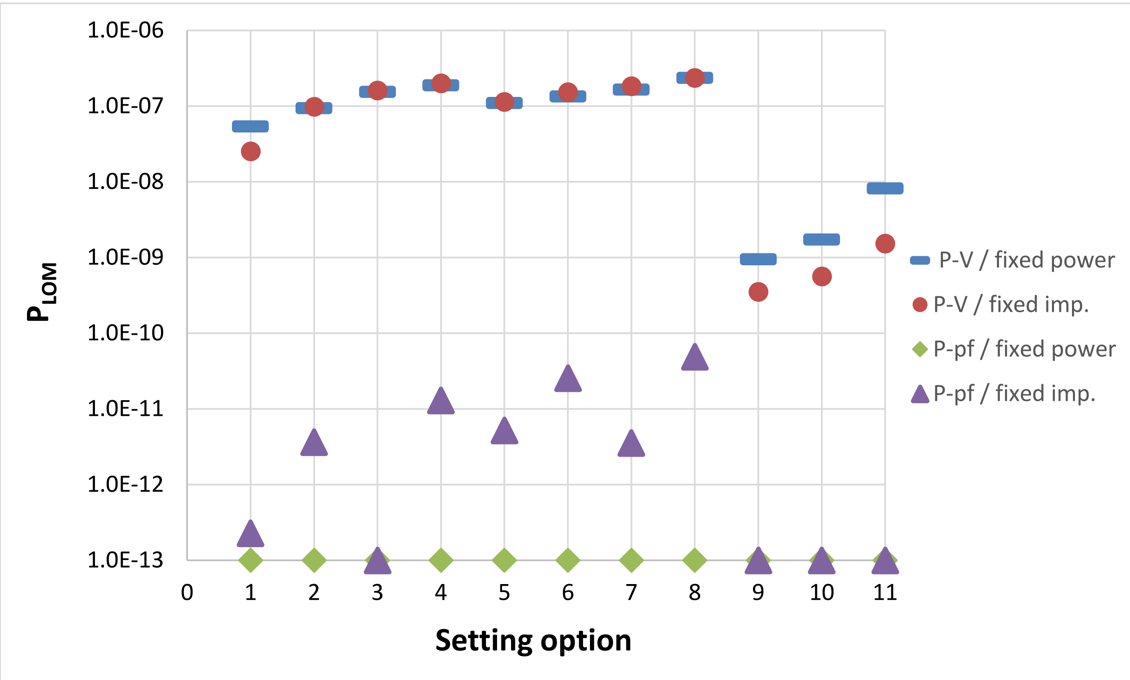


b) Full G59/2 interface protection enabled

Figure 29. Probability of undetected islanding operation – Load Case 5

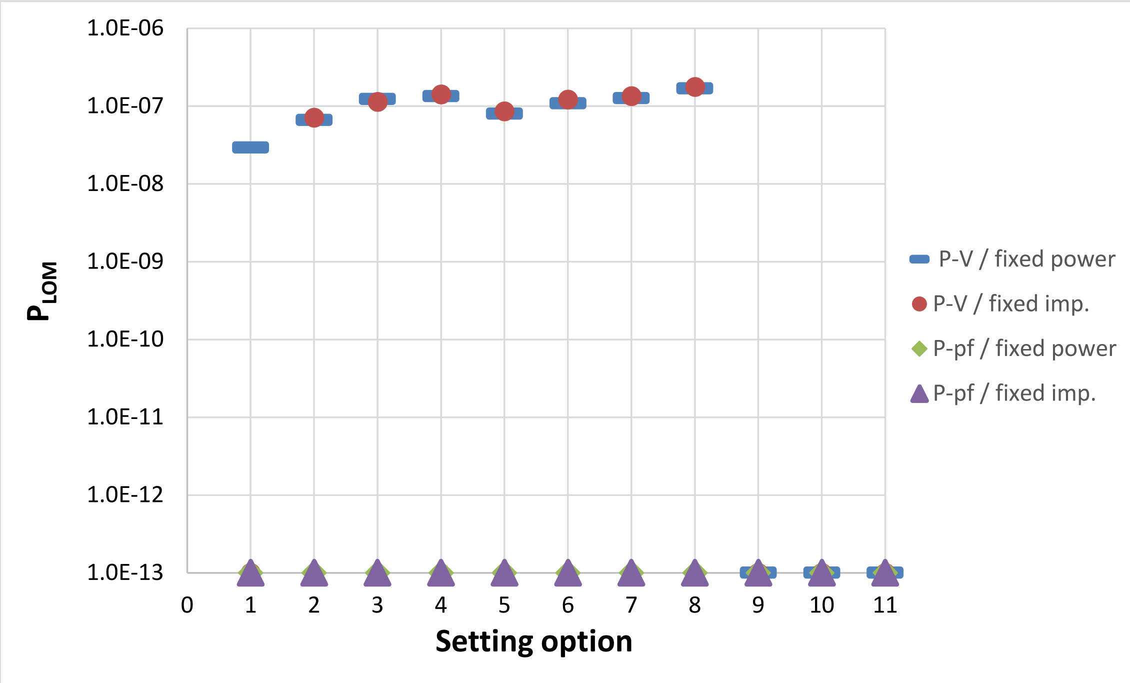


a) ROCOF enabled only

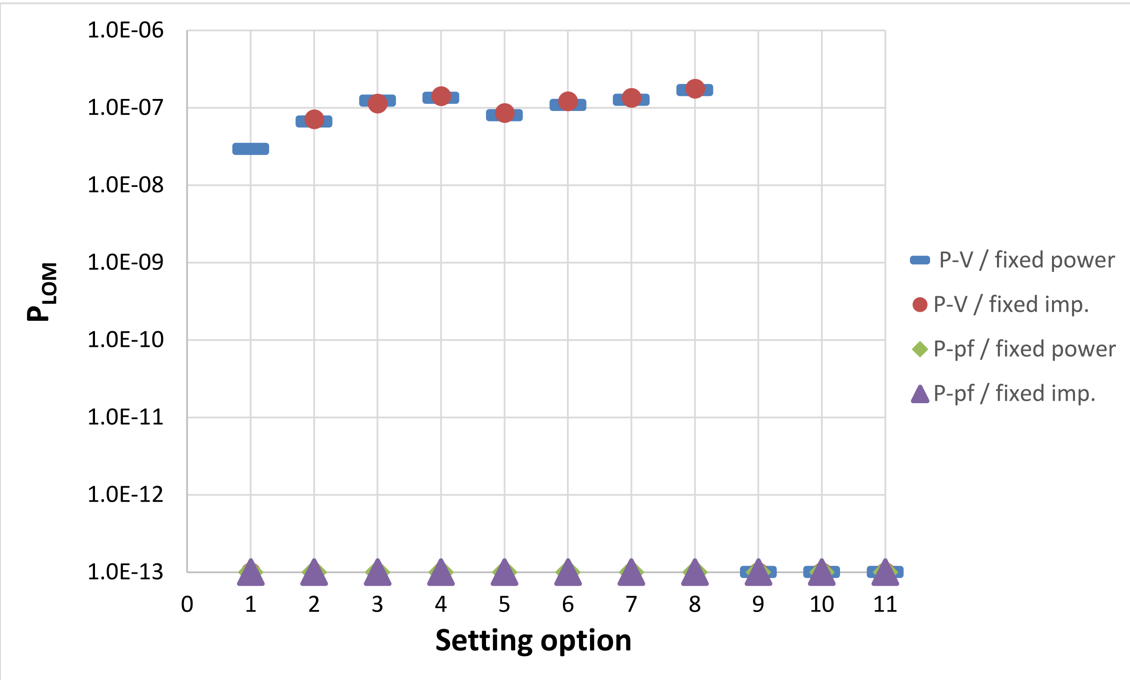


b) Full G59/2 interface protection enabled

Figure 30. Probability of undetected islanding operation – Load Case 6

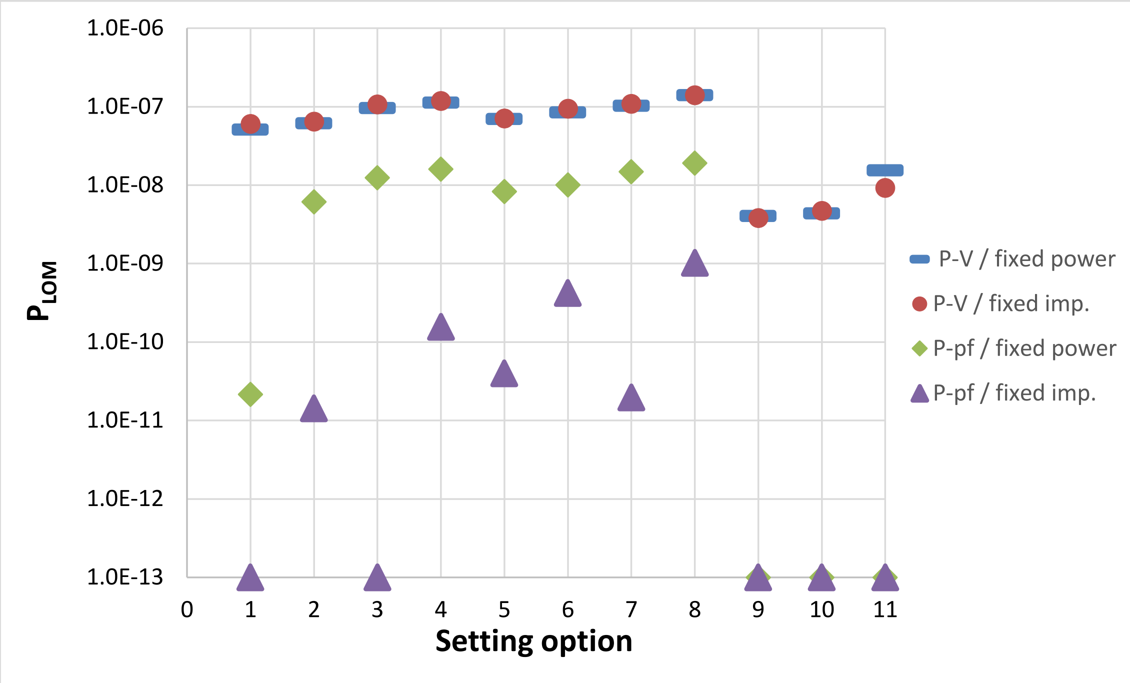


a) ROCOF enabled only

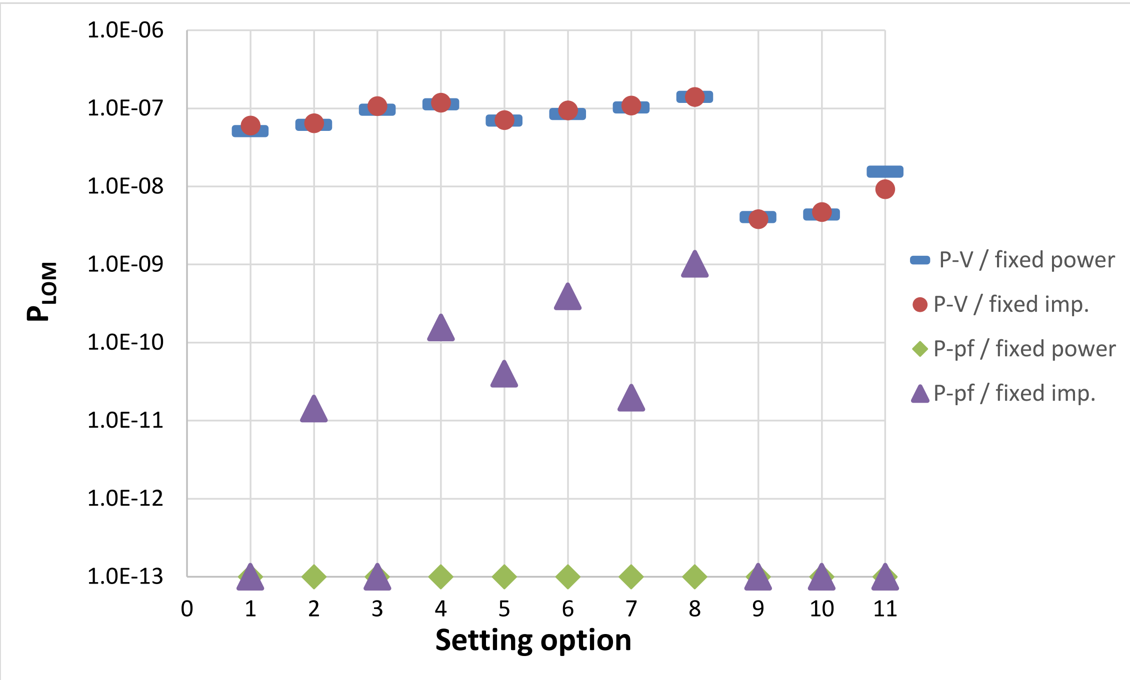


b) Full G59/2 interface protection enabled

Figure 31. Probability of undetected islanding operation – Load Case 7



a) ROCOF enabled only



b) Full G59/2 interface protection enabled

Figure 32. Probability of undetected islanding operation – Load Case 8