NIE Networks' Generator Interface Protection Amendment Project

Supporting Document

18th July 2017

Contents

1. EXECUTIVE SUMMARY

1.1 Purpose of Paper

This paper accompanies the Distribution-Code (D-Code) consultation on proposed amendments to generator interface protection settings. It provides a comprehensive overview of the need for amendments, the process in determining the implications of the amendments and NIE Networks' recommendations.

1.2 Need for Change

Studies have shown that in the future Northern Ireland power system, a Rate of Change of Frequency (RoCoF) up to 2Hz/s measured over 500ms could be experienced. In such a scenario the interface protection currently employed by Distributed Generators (DG) connected to the NIE Networks' distribution system will operate disconnecting a large quantum of generation from the system. In an already turbulent scenario this would further exacerbate system instability. Consequently NIE Networks has been asked by the Transmission System Operator (TSO) to examine the possibility of amending generator interface protection settings.

1.3 Research Findings

To overcome this concern NIE Networks commissioned Strathclyde University to identify interface protection settings that would remain stable during future power system events, based on actual and predicted worst case fault scenarios. However, in amending generator interface protection settings there will be an associated risk that the protection may not operate correctly to detect electrical islanding. Electrical islands present an increased risk of electrocution and out-of-phase re-closure between the main electricity system and the generator. Strathclyde University quantified the risks for the proposed interface protection settings, associated with Large Scale Generation[1] (LSG) and Small Scale Generation[2] (SSG), to be:

		LSG	SSG
Fatality	Risk/annum	1.36E-6	3.88E-5
	Occurrence (years)	735,294	25,773
Out-of-Phase Re-closure	Risk/annum	2.26E-3	6.18E-2
	Occurrence (years)	442	16

TABLE 1

Strathclyde University also identified that the transfer of DG employing Vector Shift (VS) protection to RoCoF protection will have a negligible impact on the risk figures for LSG and reduce the risk figures for SSG by c6.5%.

[1] Generation ≥ 5MW
[2] Generation ≥16A/phase & <5MW

1.4 Recommendations

Large Scale Generation

The risk of fatality associated with the proposed generator interface protection settings, for LSG, resides on the boundary[3] between the Health and Safety Executive's (HSE's)[4] "broadly acceptable" region and "tolerability" region. The HSE declare that any risks within the tolerability region are acceptable only if all necessary measures have been taken to achieve a level as low as reasonably practicable (ALARP). It is NIE Networks' view that with the prudent approach taken in the derivation of the risk figures, coupled with the requirement for NVD protection, measures have been taken to achieve a risk level as low as reasonably practicable, justifying the adoption of the proposed settings in Table 2 for LSG. The proposed settings will include the prohibition on the use of VS for LSG, as the Transmission System Operators' (TSOs) preferred Loss of Mains (LoM) detection methodology is RoCoF. For the avoidance of doubt these proposed protection settings shall be retrospectively applied to all LSG connected to the NI distribution system.

Protection Function	Existing Settings	Proposed Settings			
	Setting	Power Stations ≥16A/phase and <5MW		Power Stations ≥5MW	
		Setting	Time Delay	Setting	Time Delay
U/V stage 1[$]	0.9pu*	0.9pu*	0.5s	0.85pu*	3.0s
U/V stage 2[$]	N/A	N/A	N/A	0.6pu*	2.0s
O/V[$]	1.1pu*	1.1pu*	0.5s	1.1pu	0.5s
U/F	48Hz	48Hz	0.5s	48Hz	0.5s
O/F	50.5Hz	50.5Hz	0.5s	52Hz[5]	1.0s
LoM (RoCoF)	0.125 – 0 .4Hz/s	0.125 – 0 .4Hz/s	0s	1.5Hz/s	0.3s[∝]
LoM (Vector Shift)	6 – 12deg	N/A		N/A	

TABLE 2

* Base unit is defined as the nominal voltage at the connection point. This applies to phase-phase and phase-neutral voltages.

The consequences associated with out-of-phase re-closure for LSG, are dependent on specific circumstances, including generator location, technology and regime of operation; consequently, NIE Networks advise that each LSG perform their own risk assessment to satisfy themselves that they are content with the risk of out-of-phase re-closure and, if required, install additional protection to further reduce this risk.

[3] Boundary between the "tolerability" region and "broadly acceptable" region is 1E-06
[4] http://www.hse.gov.uk/comah/assessexplosives/step5.htm
[5] Staged up to 52Hz as per Over Frequency Shedding Schedule. Specific setting for generator will be stated in letter to generator.

There will be costs associated with the proposed settings change, which are estimated to be c£74000[6] for all LSG. It is anticipated that the benefits associated with making these changes will vastly outweigh the costs, with all-Ireland SEM production costs expected to be reduced by €13m/annum in 2020 if the new RoCoF standard has been adopted whilst generator curtailment is expected to be reduced by 4.4% in 2020. The Utility Regulator has declared that the costs associated with amending generator interface protection settings shall be borne by the individual generator.

<u>Small Scale Generation</u>

The risk of fatality associated with existing generator interface protection settings, for SSG, resides well within the Health and Safety Executive's (HSE's) "tolerability" region. Consequently, NIE Networks has taken the view that introducing additional risk, when the existing risk resides well within the "tolerability" region, cannot be justified and therefore changes to the interface protection settings for SSG cannot be justified. However, it is NIE Networks view that the use of VS protection for new SSG connectees should no longer be allowed and RoCoF should be used as outlined in Table 2. For the avoidance of doubt the proposed settings for SSG, outlined in Table 2, will not apply retrospectively.

1.5 Next Steps

NIE Networks will issue a public consultation on proposed D-Code amendments to incorporate the new generator interface protection settings. If approved by the Utility Regulator, NIE Networks will write to each LSG asking them to amend their generator interface protection settings. The settings outlined in Table 2 shall then be adopted by LSG and SSG connecting to the network on or after 1st October 2017. LSG connected to the network prior to 1st October 2017 will be required to adopt the proposed settings outlined in Table 2 before 31st December 2017. SSG connected to the network prior to 1st October 2017 will not be required to adopt the new settings outlined in Table 2.

6 Estimated in Q3 2017

2. INTRODUCTION

The Facilitation of Renewables (FOR) study, published in 2010, was a detailed technical study that considered levels of non-synchronous generation (wind and HVDC imports) up to 100% of system demand on the island of Ireland. The study has shown that during times of high wind generation following the loss of the single largest credible contingency[7], Rate of Change of Frequency (RoCoF) values of greater than 0.5 Hz/s could be experienced on the island of Ireland power system. If system separation between Northern Ireland and the Republic of Ireland were to occur RoCoF values in excess of 2 Hz/s could be experienced in Northern Ireland. Simulations show that for a voltage dip induced power imbalance in a system with significant volumes of wind generation, RoCoF values far in excess of 2Hz/s can occur.

Accordingly, the main outcome of the FOR study was that System Non-Synchronous Penetration (SNSP) of up to 75% of demand could be accommodated, but a series of mitigation measures would have to be carried out. One of these measures was the need to address the issue of RoCoF.

2.1 RoCoF Issue

In the event of the loss of the single largest credible contingency, RoCoF in Northern Ireland may reach 2Hz/s, measured over 500ms. In such a scenario the generator interface protection currently employed by Distributed Generators (DG) connected to the NIE Networks' distribution system will operate disconnecting a large quantum of generation from the system. In an already turbulent scenario this would further exacerbate system instability.

In order to overcome this concern, and thus enable higher SNSP levels to be experienced on the system, NIE Networks was tasked by the TSO with examining the current generator interface protection requirements employed by DG to ascertain if these could be relaxed. Consequently, NIE Networks employed Strathclyde University to establish the most appropriate generator interface protection settings for DG connected to the NIE Networks' distribution system. The following sections of this report outline the work carried out by Strathclyde University, the associated cost and benefits of amending generator interface protection settings and NIE Networks' position.

It should be noted that this paper considers solely the implications of amending generator interface protection settings on DG and no consideration is given to the capability of generating plant to withstand large system RoCoFs – information and progress on this piece of work can be found at the following location: http://www.nienetworks.co.uk/About-us/Distribution-code/DC-review-panel.

3. INTERFACE PROTECTION

Interface protection is the protection employed by DG at the point of connection to the electricity network to safeguard the electricity system from, amongst other things, electrical islanding. Electrical islanding occurs when part of the electricity system becomes disconnected from the main grid but remains energised due to the presence of connected DG: this phenomenon is shown in Figure 1. There are a number of substantial concerns associated with electrical islanding, which include but are not limited to:

- Increased risk of electrocution due to unearthed distribution system operation resulting from electrical islanding.

- Increased risk of out-of-phase re-closure of generation and the main grid, potentially causing catastrophic failure of generation and risk to human life.

[7] This refers to the loss of the largest infeed on the electricity system.

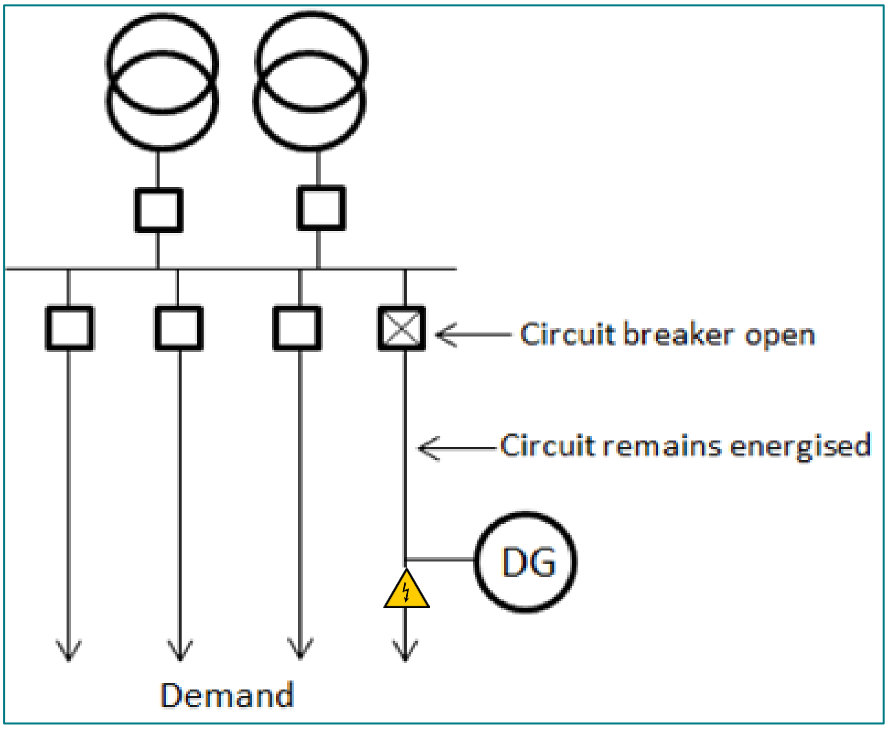


FIGURE 1

The current generator interface protection settings required by NIE Networks, commonly known as G59 protection, are shown in Table 3. Whenever an electrical island occurs, if there is a generation and demand imbalance on the island then the frequency and/or voltage magnitude on that island will fluctuate. The frequency, voltage and RoCoF or VS elements of the G59 relay work collectively to mitigate electrical islands, albeit the RoCoF or VS element will, in general, activate first. Furthermore, generation sites with ground mounted substations generally require Neutral Voltage Displacement (NVD) relays to be fitted as a further safeguard to ensure that islanding does not form as a consequence of earth faults.

Interface Protection Element	NIE Networks' Recommended Setting	Maximum allowable setting
Over Frequency	50.5 Hz	50.5 Hz
Under Frequency	48 Hz	48 Hz
Over Voltage	1.1pu	1.1pu
Under Voltage	0.9pu	0.9pu
RoCoF	0.125 Hz/s	0.4 Hz/s
Vector Shift	6º	12 º

TABLE 3

4. OPERATIONAL EXPERIENCE

Historically the interface protection employed by DG in Northern Ireland has been effective with no known electrical islands sustained on the system. However, the view within industry is that current interface protection settings will not be suitable for the future power system. This view has been corroborated through NIE Networks' operational experience as interface protection nuisance tripping is becoming more prevalent, as well as the findings from the 2013 snow storm and other experiences.

4.1 2013 Snow Storm

On 22/03/13 Northern Ireland was exposed to a severe snow storm which resulted in a significant number of faults on the distribution and transmission system. During three 15 minute blocks, 24 wind farms disconnected from the electricity system due to the activation of their interface protection, totalling a combined c316MW of lost generation from the system over a 15hr period and a total of 171MW in a single 15 minute period.

The post fault analysis concluded that the wind farms which disconnected from the system were only those with the VS element of their interface protection activated. The wind farms with RoCoF protection employed remained stable. Consequently, suspicions were raised as to the stability of VS and it was decided that the use of VS on the NIE Networks' distribution system should be investigated to determine appropriate settings.

5. ANALYSIS

In order to identify the most appropriate generator interface protection settings to ensure that DG will remain connected under large system contingencies whilst ensuring that electrical islands do not materialise under actual Loss of Mains (LoM) events, Strathclyde University were employed to undertake a comprehensive analysis. Strathclyde University had carried out similar analysis for the Great Britain (GB) electricity network and had developed a model for undertaking this analysis; consequently it was felt prudent to use Strathclyde and their industry approved methodology to undertake this work for the NIE Networks' distribution system.

5.1 Objectives

The main objectives of the research are shown below:

- Recommend the most appropriate generator interface protection settings to ensure system stability whilst maintaining the integrity of the protection to detect and operate for electrical islands and quantify the risks associated with the recommended settings.

- Perform a risk assessment for both LSG and SSG for the current and proposed interface protection settings.

- Perform analysis on the impact of NVD protection on the risks.

- Ensure that the proposed interface protection settings are future proofed against scenarios where load profiles have evolved and the performance of DG has changed.

5.2 Methodology

To achieve the objectives outlined in 5.1 the research was broken into the following sections:

- Work Package 1: Determine the levels of DG connected to the NIE Networks' distribution system and identify the generation mixes that could be formed.

- Work Package 2: Using modelled and actual "worst case" system events, propose interface protection settings to ensure that DG does not trip for these events.

- Work Package 3: Using network data specific to NIE Networks, determine the risk to human life and out-of-phase re-closure of LSG if the new settings were adopted.

- Work Package 4: Using network data specific to NIE Networks, determine the risk to human life and out-of-phase re-closure of SSG if the new settings were adopted.

- Annex to Work Package 3: Assessment of the impact on risks of NVD protection on LSG

- Annex to Work Package 4: Assessment of the impact on risks of NVD protection on SSG

5.3 Results

5.3.1 Work Package 1 & 2

Using a validated G59 relay model and verifying the results using an actual relay device (Micom P341), WP1 and WP2 attempted to identify what interface protection settings would be required to ensure stability for all system events. WP1 and WP2 examined the following elements of the interface protection:

- RoCoF

- Vector Shift

- Over-Frequency

- Under-Voltage

RoCoF

Fifteen significant events, under high SNSP conditions were modelled, with the “worst case” event shown in Appendix 1; the RoCoF settings required to ensure stability during these events were identified and shown in green in Figure 2. It can be seen that the existing, maximum setting of 0.4Hz/s with no inherent time delay would trip for this event. These settings were taken forward to be examined during WP3 and WP4. From Figure 2 It can also be seen that the delay setting used by the relay plays a significant role in ensuring the stability of the relay: with no inherent time delay a c4.8Hz/s setting would remain stable whilst with a 800ms time delay a 1Hz/s setting would remain stable.

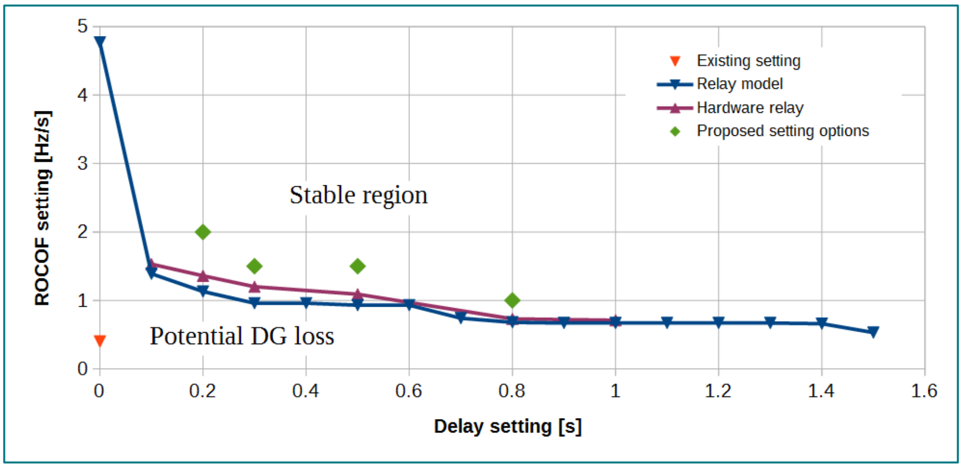


FIGURE 2

To provide an additional level of confidence regarding the ROCOF stability limits and proposed setting options, five available transmission system fault records were assessed in a similar way, using the ROCOF relay model, and further verified by hardware injection. It can be seen, in Figure 3, that there is a comfortable margin of stability between the proposed setting options and minimum required ROCOF settings to ensure stability for the available fault records.

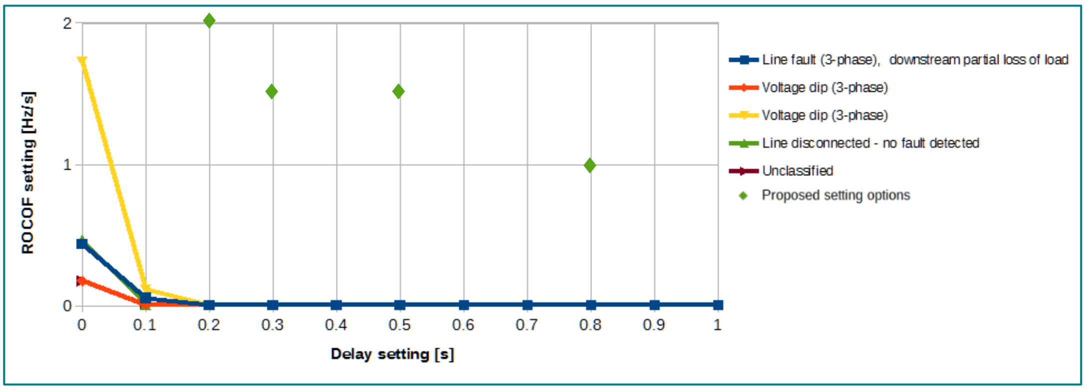


FIGURE 3

Vector Shift

When modelling the "worst case" system event under 75% SNSP conditions it was identified that the VS relay remained very stable. However, under further analysis it was concluded that whilst the modelling methodology, namely, using a Root Mean Square (RMS) model to generate frequency traces, is suitable for RoCoF relay analysis it does not represent voltage angle shifts that may occur during faults and other transients and therefore is not suitable for analysing VS relay stability. Consequently, it was concluded that in order to fully assess VS stability, actual fault records should be used.

Five large and distinct disturbance records of transmission faults were used to assess the stability of the VS relay with the results shown in Figure 4. These results clearly demonstrate that VS would activate at the current recommended setting of 6º and on some occasions relay operation can be expected with settings up to 12º.

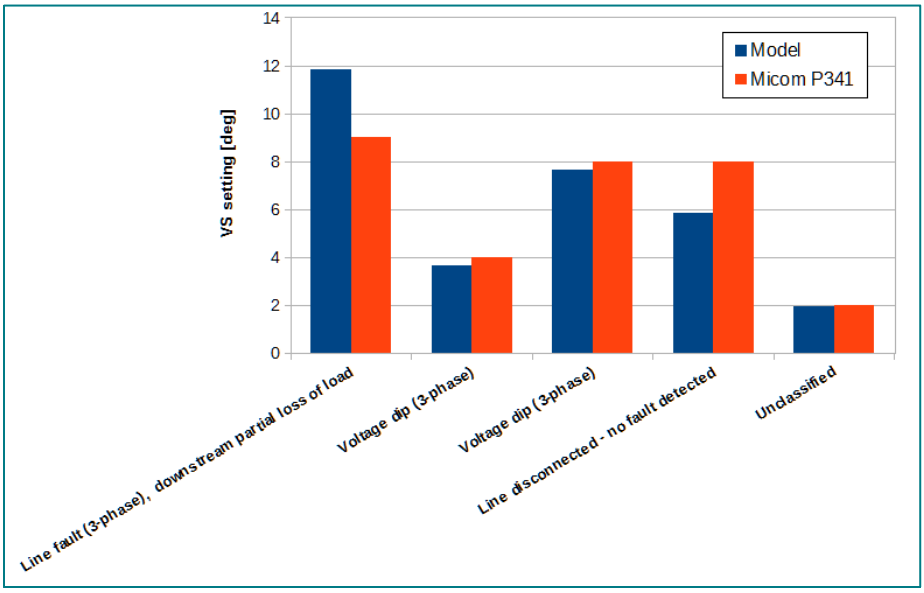


FIGURE 4

Over frequency

It was identified by the TSO that the current over frequency component of the interface protection, which has a setting of 50.5Hz, may not remain stable under large contingencies whilst the power system operates at higher SNSP levels. For the 15 modelled events Strathclyde University carried out analysis, shown in Figure 5, which demonstrated that the current over frequency setting would trip for 10 out of the 15 modelled events. It was demonstrated that a setting of 52Hz with a 1s time delay would remain stable for all of the events and as such this setting was used in WP3 and WP4.

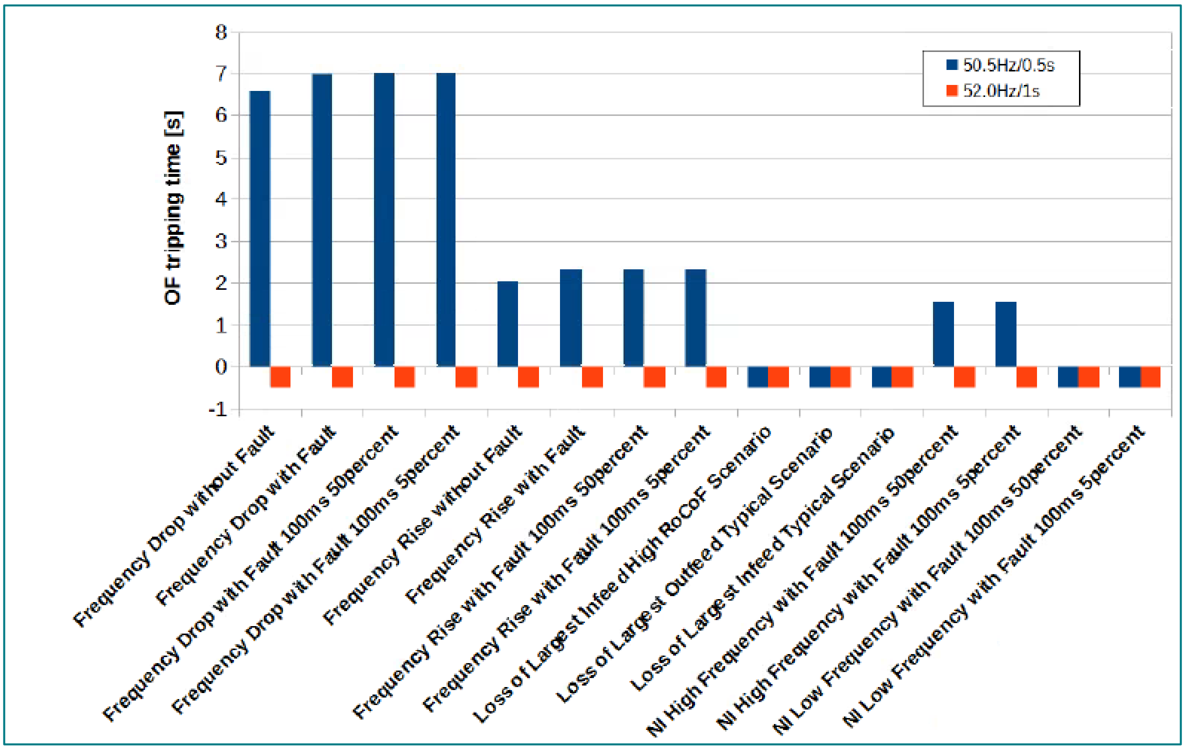


FIGURE 5

Under voltage

The NIE Networks' D-Code stipulates Low Voltage Ride Through (LVRT) requirements for both LSG and SSG which broadly align with the Requirements for Generators (RfG) ENTSO-e network code. However, the current DG under voltage interface protection settings will result in the disconnection of the generator from the system for under voltages less severe than the D-Code LVRT requirement. Taking this into consideration Strathclyde University determined that the under voltage settings required to ensure stability are:

- Stage 1: 0.85pu, 3s delay
- Stage 2: 0.6pu, 2s delay

5.3.2 Work Package 3 &4

The objective of Work Package 3 and 4 was to quantify the risks associated with implementing the proposed interface protection settings from Work Package 2 for LSG and SSG respectively. These risks are outlined in Table 4 – LSG Risks and Table 5 – SSG Risks for LSG and SSG respectively; the parameters used are described in Key 1. LoM option 1 is the current maximum RoCoF setting whilst LoM options 2 – 5 are the proposed RoCoF settings to ensure stability as determined by Work Package 2. LoM options 6 and 7 are the currently accepted VS settings, with VS setting 7 the proposed setting to ensure stability as determined by Work Package 2. LoM option 8 is the protection with VS and RoCoF disabled. For all of the LoM options the amended Under Voltage and Over Frequency settings, as described in section 5.3.1 have been used.

LOM Option	LOM Setting [Hz/s] or [°]	Time Delay [s]	Individual risk of electrocution			Risk of out-of-phase reclosure		
			$N_{LOM,E}$	IR_E	T_E [years]	$N_{LOM,AR}$	N_{OA}	T_{OA} [years]
1	0.4	0	3.84E-04	3.92E-09	2.55E+08	7.80E-06	6.24E-06	160,173.39
2	2.0	0.2	2.17E-02	3.43E-06	2.91E+05	6.85E-03	5.48E-03	182.51
3*	**1.5**	**0.3**	**2.16E-02**	**3.43E-06**	**2.92E+05**	**6.84E-03**	**5.48E-03**	**182.62**
4	1.5	0.5	2.61E-02	3.84E-06	2.60E+05	7.65E-03	6.12E-03	163.46
5	1.0	0.8	2.62E-02	3.86E-06	2.59E+05	7.70E-03	6.16E-03	162.40
6	6	-	2.14E-02	4.03E-06	2.48E+05	8.04E-03	6.44E-03	155.38
7*	**12**	-	**2.28E-02**	**4.16E-06**	**2.40E+05**	**8.29E-03**	**6.63E-03**	**150.74**
8	-	-	3.31E-02	5.39E-06	1.86E+05	1.07E-02	8.59E-03	116.45

TABLE 4 – LSG RISKS

LOM Option	LOM Setting [Hz/s] or [°]	Time Delay [s]	Individual risk of electrocution			Risk of out-of-phase reclosure		
			$N_{LOM,E}$	IR_E	T_E [years]	$N_{LOM,AR}$	N_{OA}	T_{OA} [years]
1	0.4	0	1.20E-01	1.42E-05	7.03E+04	2.83E-02	2.27E-02	44.10
2	2.0	0.2	1.45E-01	1.66E-05	6.03E+04	3.30E-02	2.64E-02	37.83
3*	**1.5**	**0.3**	**1.45E-01**	**1.66E-05**	**6.03E+04**	**3.30E-02**	**2.64E-02**	**37.83**
4	1.5	0.5	1.45E-01	1.66E-05	6.03E+04	3.30E-02	2.64E-02	37.83
5	1.0	0.8	1.43E-01	1.65E-05	6.07E+04	3.28E-02	2.63E-02	38.07
6	6	-	2.10E-01	2.39E-05	4.18E+04	4.77E-02	3.81E-02	26.22
7*	**12**	-	**2.10E-01**	**2.39E-05**	**4.18E+04**	**4.77E-02**	**3.81E-02**	**26.22**
8	-	-	3.54E-01	4.05E-05	2.47E+04	8.07E-02	6.46E-02	15.49

TABLE 5 – SSG RISKS

Parameters	Description
$N_{LOM,E}$	Annual rate of occurrence of undetected islanding incidents (with duration longer than T_{NDZmax}=0 s)
IR_E	Annual probability related to individual risk (injury or death of a person) from the energised parts of an undetected islanded network
T_E [years]	Expected average time between incidents (injury or death of a person) from the energised parts of an undetected islanded network [in years]
$N_{LOM,AR}$	Annual rate of occurrence of undetected islanding incidents (with duration longer than T_{NDZmax}=29.5 s)
N_{OA}	Annual rate of occurrence of any generator being subjected to out-of-phase auto-re-closure during the islanding condition not detected by LOM protection
T_{OA} [years]	Average time between the occurrences of out-of-phase auto-re-closure during the islanding condition not detected by LOM protection [in years]

KEY 1

5.3.2.1 Individual Risk of Electrocution

The individual risk of electrocution is the risk of electrocution resulting from an electrical island, most notably where an overhead line conductor has made contact with earth and remains energised due to the presence of connected downstream generation, forming an unearthed part of the distribution system.

For both LSG and SSG it can be seen that LoM option 3 provides the lowest, or joint lowest, risk of electrocution for stable RoCoF protection[8] whilst a 12° VS setting is the lowest setting required to ensure system stability: these settings are therefore the proposed settings by Strathclyde University. For these settings the total risk of fatality associated with islanding is the summation of the risks associated with RoCoF and VS i.e. IR_E(LOM Option 3) + IR_E(LOM Option 7) e.g. LSG(Total IR_E) = 3.43E-06 + 4.16E-06 = 7.59E-06.

Large Scale Generation

The proposed settings result in an incremental increase in individual risk of electrocution associated with LSG, as a result of islanding, from 4.16E-6 per annum or 1 fatality every 240,000 years to 7.59E-6 per annum or 1 fatality every 132,000 years.

Small Scale Generation

The proposed settings result in an incremental increase in individual risk of electrocution associated with SSG, as a result of islanding, from 3.81E-5 per annum or 1 fatality every 26,000 years to 4.05E-5 per annum or 1 fatality every 25,000 years.

5.3.2.2 Risk of Out-of-Phase Re-closure

The individual risk of out-of-phase re-closure is the risk associated with the main electricity system reclosing onto a part of the electricity network which is energised by distributed generation operating on a different phase angle to the main electricity system.

This may or may not result in machine damage which could subsequently put individuals in close proximity at risk. The risk of machine damage and the associated risk to human life have not been quantified by Strathclyde University as these risks will depend on specific circumstances, including generator location, technology and regime of operation. However, it is anticipated that out-of-phase re-closure will only be of significant concern to

[8] Lowest risk compared to stable setting options 2 – 5.

synchronous generating units as other generating technologies may be able to withstand an out-of-phase re-closure.

Large Scale Generation

Adopting the recommended RoCoF and VS settings for LSG would result in an annual risk of out-of-phase re-closure between the main electricity network and a generator of 1.21E-2 per annum which equates to an out-of-phase re-closure once every 83 years.

Small Scale Generation

Adopting the recommended RoCoF and VS settings for SSG would result in an annual risk of out-of-phase re-closure between the main electricity network and a generator of 6.45E-2 per annum which equates to an out-of-phase re-closure once every 15.5 years.

5.3.3 Annexes

The risk levels considered in the Strathclyde University analysis will be further reduced by the presence of NVD, which is a requirement at many generator sites on the NIE Networks' distribution system. When a single phase-to-earth fault instigates islanding, the operation of the NVD protection limits the duration of the undetected island[9], and reduces the risk of out-of-phase re-closure, which takes place 30s after the fault. As single phase-to-earth faults form the majority of distribution system faults (especially on overhead lines), NVD protection is an effective way of reducing risks relating to undetected islanding.

Work Package 3 and Work Package 4 did not consider the impact of NVD protection; consequently, it was decided that annexes to Work Package 3 and Work Package 4 should be carried out to determine the mitigating impact of NVD on the risks associated with LSG and SSG respectively.

5.3.3.1 Annex to WP3

Table 6 shows the results from the Annex to WP3 where the total risk of electrocution from islanding of LSG with the proposed RoCoF and VS settings with NVD protection installed to be 1.36E-6 per annum or 1 fatality every 735,000 years and the corresponding risk of out-of-phase re-closure to be 2.16E-3 per annum or 1 out-of-phase re-closure every 463 years. This corresponds to a risk of electrocution and out-of-phase re-closure reduction of 82%.

[9] NVD protection for 33kV connected generation is set to 3s. NVD protection for 11kV connected generation is set to 10s.

LOM Option	LOM Setting [Hz/s] or [°]	Time Delay [s]	Individual risk of electrocution			Risk of out-of-phase reclosure		
			$N_{LOM,E}$	IR_E	T_E [years]	$N_{LOM,AR}$	N_{OA}	T_{OA} [years]
1	0.4	0	3.55E-04	6.96E-09	1.44E+08	1.38E-05	1.11E-05	90,267.77
2	2.0	0.2	1.17E-02	1.00E-06	9.99E+05	1.99E-03	1.59E-03	627.00
3•	**1.5**	**0.3**	**1.16E-02**	**9.97E-07**	**1.00E+06**	**1.99E-03**	**1.59E-03**	**629.37**
4	1.5	0.5	1.57E-02	1.36E-06	7.33E+05	2.72E-03	2.17E-03	459.98
5	1.0	0.8	1.66E-02	1.44E-06	6.94E+05	2.87E-03	2.30E-03	435.34
6	6	-	3.36E-03	3.60E-07	2.78E+06	7.17E-04	5.74E-04	1,742.38
7•	**12**	**-**	**3.36E-03**	**3.60E-07**	**2.78E+06**	**7.17E-04**	**5.74E-04**	**1,742.38**
8	-	-	2.00E-02	1.82E-06	5.50E+05	3.62E-03	2.90E-03	344.87

TABLE 6

It is anticipated that the groups which are particularly vulnerable to out-of-phase re-closures are those including synchronous generators, i.e. generation mixes 1, 5, 6, 11, 12, 13 and 15 in Table 7; the generator acronyms are expanded in Key 2. Those mixes contribute approximately 37.61% of all expected out-of-phase re-closures. Therefore, assuming hypothetically that other technologies are not affected, the risk of out-of-phase re-closure would be reduced to 2.16E-3*0.3761=8.13E-4.

Islanding Scenario	Generation Mix (*m*)	$N_{LOM,AR(m)}$	$N_{LOM,AR(m)[\%]}$
1	2 (IC 100%)	0.00000	0.0000
	3 (DFIG 100%)	0.00000	0.0000
	5 (SM 70%, IC 30%)	0.00023	11.6884
	6 (SM 30%, IC 70%)	0.00000	0.0000
	7 (IC 50%, DFIG 50%)	0.00000	0.0000
	8 (DFIG 70%, IM 30%)	0.00000	0.0000
	9 (DFIG 30%, IM 70%)	0.00038	19.3235
	11 (SM 20%, IC 40%, IM 40%)	0.00006	3.1003
	12 (SM 50%, DFIG 30%, IM 20%)	0.00006	3.0901
	13 (SM 30%, DFIG 50%, IM 20%)	0.00000	0.0000
	14 (IC 35%, DFIG 50%, IM 15%)	0.00000	0.0000
	15 (SM 15%, IC 30%, DFIG 30%, IM 25%)	0.00031	15.3730
2	1 (SM 100%)	0.00009	4.3566
	2 (IC 100%)	0.00000	0.0000
	3 (DFIG 100%)	0.00000	0.0000
	4 (IM 100%)	0.00000	0.0000
	10 (DFIG 50%, IM 50%)	0.00086	43.0682
	Total:	0.00199	100.00

TABLE 7

Acronym	Expanded Form
IC	Invertor Connected
IM	Induction Machine
DFIG	Doubly Fed Induction Generator
SM	Synchronous Machine

KEY 2

The annex also examined the impact on risk of electrocution and out-of-phase re-closure if all LSG employing VS are transferred to RoCoF protection, with NVD protection in service. The results shown in Table 8 demonstrate that the transfer from VS to RoCoF protection for LSG has a negligible impact on the associated risks i.e. IR_E (Table 8, LoM Option 3) = 1.36E-06 = IR_E(Table 7, LoM Option 3 + LoM Option 7) =1.36E-06.

LOM Option	LOM Setting [Hz/s] or [°]	Time Delay [s]	Individual risk of electrocution			Risk of out-of-phase reclosure		
			$N_{LOM,E}$	IR_E	T_E [years]	$N_{LOM,AR}$	N_{OA}	T_{OA} [years]
1	0.4	0	3.55E-04	6.96E-09	1.44E+08	1.38E-05	1.11E-05	90,267.82
2	2.0	0.2	1.51E-02	1.36E-06	7.35E+05	2.71E-03	2.17E-03	461.08
3*	**1.5**	**0.3**	**1.49E-02**	**1.36E-06**	**7.37E+05**	**2.70E-03**	**2.16E-03**	**462.36**
4	1.5	0.5	1.91E-02	1.72E-06	5.80E+05	3.43E-03	2.75E-03	363.91
5	1.0	0.8	1.99E-02	1.80E-06	5.55E+05	3.59E-03	2.87E-03	348.31

TABLE 8

5.3.3.2 Annex to WP4

Table 10 shows the results from the Annex to WP4 where the total risk of electrocution from islanding of SSG with the proposed RoCoF and VS settings with NVD protection installed, as per current NIE Networks' policy, to be 2.74E-5 and the corresponding risk of out-of-phase re-closure to be 4.36E-2. This corresponds to a risk of electrocution and out-of-phase re-closure reduction of c32%.

It is expected that synchronous machines will be most affected by out-of-phase re-closure; however, for SSG, synchronous machines are present in 100% of the generation mixes that form the out-of-phase re-closure risk. Therefore, it would not be reasonable to lower the estimated risk values.

LOM Option	LOM Setting [Hz/s] or [°]	Time Delay [s]	Individual risk of electrocution			Risk of out-of-phase reclosure		
			$N_{LOM,E}$	IR_E	T_E [years]	$N_{LOM,AR}$	N_{OA}	T_{OA} [years]
1	0.4	0	1.03E-01	9.48E-06	1.06E+05	1.89E-02	1.51E-02	66.23
2	2.0	0.2	1.25E-01	1.12E-05	8.94E+04	2.23E-02	1.78E-02	56.09
3*	1.5	0.3	1.25E-01	1.12E-05	8.94E+04	2.23E-02	1.78E-02	56.09
4	1.5	0.5	1.25E-01	1.12E-05	8.94E+04	2.23E-02	1.78E-02	56.09
5	1.0	0.8	1.23E-01	1.11E-05	9.01E+04	2.21E-02	1.77E-02	56.52
6	6	-	1.81E-01	1.62E-05	6.19E+04	3.22E-02	2.58E-02	38.82
7*	12	-	1.81E-01	1.62E-05	6.19E+04	3.22E-02	2.58E-02	38.82
8	-	-	3.05E-01	2.74E-05	3.66E+04	5.45E-02	4.36E-02	22.94

TABLE 9

The annex also examined the impact on risk of electrocution and out-of-phase re-closure if all SSG employing VS are transferred to RoCoF protection. This demonstrated a further 6.5% reduction in the risk of electrocution and a 9.05% reduction in the risk of out-of-phase re-closure.

5.3.4 Future Proofing

Regarding risk levels in the future, there is no straightforward correlation between installed renewable generation capacity and the overall risk of undetected islanding. To address this issue the outcome of the study was based on a DG register which includes both already connected as well as contracted but not yet connected generation. The study indicated that in a network which has a relatively high DG penetration already, there might be little impact or even a reduction of the non-detection risk with additional DG connections. Furthermore, to safeguard the results against future system services markets and DG connection requirements, the generation models used in the assessment have fast-acting voltage and frequency controllers included which provide onerous conditions for the detection of electrical islands.

It is however acknowledged that areas on the distribution network with limited volumes of distributed generation will see an increased risk of islanding if future generators connect to that area and demand and generation balancing becomes more prevalent.

5.4 Comparison to Great Britain Risks

NIE Networks has been actively engaged with analogous work being undertaken in Great Britain (GB) through the GC0079[10] working group. As part of this working group Strathclyde University performed similar studies for the GB network as were carried out for the Northern Ireland network and as such comparisons can be made between the results. The results from the GB analysis for generators greater than 5MW are shown in Table 10 and the results for generators less than 5MW are shown in Table 11.

For LSG, comparisons can be made between the GB analysis for generation greater than 5MW, shown in Table 10 and the NI analysis for LSG shown in Table 8. However, Table 10 represents worst case analysis whilst Table 8 represents an average case; therefore, it is not appropriate to perform direct quantitative benchmarking. Instead a qualitative assessment should be performed.

[10] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0035-GC0079/

For SSG, comparisons can be made between the GB analysis for generation less than 5MW, shown in Table 11 and the NI analysis for SSG shown in Table 9. Both tables represent average cases and therefore more meaningful comparisons can be made.

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

Setting Option	ROCOF [Hz/s]	Time Delay [s]	N_{LOM}	P_{LOM}	IR_E	N_{OA}
1	0.13	0	1.66E-01	8.06E-08	8.06E-10	1.33E-01
2	0.2	0	3.29E-01	1.95E-07	1.95E-09	2.64E-01
3	0.5	0.5	2.96E+01	1.87E-05	1.87E-07	2.37E+01
4	1.0	0.5	5.66E+01	3.57E-05	3.57E-07	4.53E+01

TABLE 11

5.4.1 Individual risk of electrocution

It can be seen that $\mathbf{IR_E}$, for the GB recommended RoCoF setting[11] of 1Hz/s with a 500ms time delay is substantially lower than $\mathbf{IR_E}$ for the recommended RoCoF setting[12] for Northern Ireland for SSG and LSG: c3 orders of magnitude for LSG and c2 orders of magnitude for SSG. This is due to a number of different reasons which include but are not limited to:

- The Northern Ireland recommended RoCoF setting is 1.5Hz/s with a 300ms time delay, which would appear to be a less sensitive setting that the 1Hz/s with a 500ms time delay setting recommended for

[11] Setting option 4 and 8 in Table 10 for LSG and setting option 4 in Table 11 for SSG.
[12] Setting option 3 in Table 8 and Table 9 for LSG and SSG respectively.

the GB studies. Consequently, having less sensitive RoCoF settings will result in more undetected islands, by proportion, and consequently a larger $\mathbf{IR_E}$, by proportion.

- The D-Code and Grid-Code requirements in Northern Ireland place more stringent requirements on generators to provide fast acting voltage and frequency control compared to the GB D-Code and Grid-Code. These faster requirements have been reflected within the generator models used by Strathclyde University and therefore present more onerous implications in terms of islanding.

- Demand and generation balancing on the distribution system is more prevalent in Northern Ireland compared to GB due to the significant volumes of connected distributed generation as a percentage of system demand. Greater demand and generation balancing results in greater risk of islands forming.

- NIE Networks employ a dead time of 30s as standard practice before circuit breakers automatically reclose following a trip, whilst in the GB analysis a re-closure dead time of 3s has been assumed. Within the analysis it is assumed that electrical islands cannot be maintained after a re-closure has taken place. Consequently, in Northern Ireland electrical islanding can be maintained for a maximum period of 30s whilst in GB an electrical island can be maintained for a maximum period of 3s. Since electrical islands can be maintained for much greater time periods the risk of electrocution is also greater.

5.4.2 Risk of out-of-phase re-closure

With reference to the number of out-of-phase re-closures per annum ($\mathbf{N_{OA}}$) the Northern Ireland figure is substantially lower than the corresponding GB figure for their respective recommended RoCoF settings: c2 orders of magnitude for LSG; c3 orders of magnitude for SSG. Notwithstanding the differences outlined in section 5.4.1, this is principally due to the fact that NIE Networks' have employed a much larger circuit breaker auto re-closure dead time in their analysis when compared to GB. The consequence of the extended dead time is such that demand and generation balancing is required for 30s before there is a risk of out-of-phase re-closure: a scenario significantly less likely than having to maintain demand and generation balancing for 3s, as per GB.

6. COSTS & BENEFITS

The main drivers for amending generator interface protection settings are reduced Single Electricity Market (SEM) production costs, reduced generator curtailment and an increased percentage of Electricity from Renewable Energy Sources(RES-E) on the system. Following engagement with the TSO it was identified that the quantification of these benefits cannot be separated for SSG and LSG but rather represent a scenario were the system RoCoF standard has changed which will only occur after a critical mass of generator interface protection settings have been amended. Consequently, the following costs and benefits which are presented in this section are for all SSG and LSG connected on the network.

6.1 Who pays

Following a public consultation on charging arrangements for changes to generator protection settings[13] the Utility Regulator stated: "We are of the view that there is not sufficient rationale to impose the costs of generator code compliance on customers. Therefore we would expect that generators would make the necessary arrangements to amend their own protection settings and for them to fully comply with the relevant grid codes"[14].

[13] http://www.nienetworks.co.uk/documents/D-code/RoCoF-consultation-on-funding-mechanism.aspx
[14] Letter dated 15 March 2017. Jody O'Boyle to Rodney Ballentine.

On this basis the total costs associated with the amendment of generator interface protection settings shall be borne by each individual generator.

6.2 Benefits

6.2.1 Quantifiable

In 2014, EirGrid and SONI conducted a range of studies aimed at evaluating the benefits of the DS3 programme. In particular the study assessed the benefits of achieving enhanced system capabilities from system services over operating with current operational capabilities. The study aimed to compare both the production costs and system marginal price results from each case to derive the overall benefits from implementing the various elements of the DS3 project. These studies have been used as an input into the SEM committee decision paper on System Services (SEM-14-108). The detailed results from the TSOs' studies can be found on the SEM-C website.

One of the main findings in the report relates to the counterfactual case where RoCoF is implemented but system services are not included: Table 12. The results show a benefit of €13m in SEM production costs per annum in the base case (B) i.e. difference between RoCoF and current. The figure for the counterfactual RoCoF case provides an estimation of the benefit of implementing the RoCoF standard across the island. The case was approved by both regulators during the consultation period.

It can also be seen that an expected 4.4% reduction in wind curtailment levels will be realised in 2020 whilst an additional 1.5% towards the RES-E target of 40% by 2020 will be achieved.

These benefits represent a situation where the new RoCoF standard has been implemented and therefore represent a scenario where the interface protection settings have been amended for a critical mass of generators.

			Dispatch			
Scenario ID	Wind connected (GW)	Dispatch	SEM Production Cost (€m)	Wind Curtailment (%)	Wind (%)	RES (%)
A_50	3.5	50% (current)	€ 1,557	8.5%	23.1%	29.2%
A_60		60% (RoCoF)	€ 1,575	4.8%	24.0%	30.1%
A_70		70% (Partial)	€ 1,525	1.5%	24.9%	31.0%
A_75		75% (Full)	€ 1,516	0.7%	25.1%	31.2%
B_50	4.6	50% (current)	€ 1,445	15.6%	28.0%	35.3%
B_60		60% (RoCoF)	€ 1,432	11.2%	29.5%	36.8%
B_70		70% (Partial)	€ 1,344	2.8%	32.3%	39.7%
B_75		75% (Full)	€ 1,334	1.4%	32.7%	40.1%
C_50	5.7	50% (current)	€ 1,367	23.0%	31.7%	40.5%
C_60		60% (RoCoF)	€ 1,338	18.8%	33.5%	42.3%
C_70		70% (Partial)	€ 1,194	6.0%	38.7%	47.6%
C_75		75% (Full)	€ 1,176	3.5%	39.7%	48.7%

TABLE 12

6.2.2 Unquantifiable

Reduced Nuisance Tripping

NIE Networks is aware that under remote fault scenarios the interface protection of some generators operate, resulting in the disconnection of the generator from the electricity network. This phenomenon has been referred to as "nuisance tripping" by industry and results in a loss of revenue to the generator owner.

A benefit of implementing the proposed interface protection amendments will be that interface protection will be less susceptible to "nuisance tripping" resulting in less interruptions to generator supplies. Statistics on generator "nuisance tripping" is not available and therefore this benefit cannot be readily quantified.

Carbon Benefits

Amending generator protection settings will allow for higher levels of SNSP, reducing wind energy curtailment by 4.4% in 2020. Because of the higher levels of SNSP and reduced renewable energy curtailment a reduction in carbon emissions will be realised.

6.3 Costs

NIE Networks anticipate that, upon request, all required generators will have the capability, and desire, to change the settings in their existing G59 relays to those proposed within this document. This scenario is referred to as the "Expected Scenario". However, it is possible that some relays may not be able to be amended to the recommended settings and therefore require a new relay to be fitted; to reflect this scenario a "Worst Case Scenario" contingency has been included which assumes that 50% of LSG and SSG require a new interface protection relay to be fitted. It is not the intention of this piece of work to amend G83[15] protection settings; therefore G83 generators have not been considered in this analysis. Following engagement with industry the unit costs for amending generator interface protection settings were determined and the total implementation costs were calculated; the results of which are shown in Table 13.

	Unit Cost		Quantity	"Expected Scenario" Costs	"Worst Case Scenario" Costs	Comments
	Settings Change Only	New Relay Required				
11.04kW – 200kW (G59 connected only)	£450	£1050	322	£144900	£241500	Assumed that generator will be LV connected. Assumed that NVD is not required.
200kW – 750kW (Export Capability)	£450	£2050	389	£175050	£486250	Assumed that generator will be LV connected. Assumed that NVD is required.

[15] Generation < 16A/Phase

200kW – 750kW (Non - Export Capability)	£450	£1050	83	£37350	£62250	Assumed that generator will be LV connected. Assumed that NVD is not required.
750kW – 5MW (Export Capability)	£950	£2550	28	£26600	£49000	Assumed that generator will be HV connected. Assumed that NVD is required. NIE Networks witness testing required.
750kW – 5MW (Non-Export Capability)	£950	£1550	43	£40850	£53750	Assumed that generator will be HV connected. Assumed that NVD is not required. NIE Networks witness testing required.
>5MW (Export Capability)	£2000	£13500	37	£74000	£286750	Assumed that generator will be 33kV connected. More expensive relay utilised. Assumed that NVD is required. NIE Networks witness testing required.
Totals			902	£498,750	£1,179,500	

TABLE 13[16][17]

From Table 13 it can be seen that the total implementation costs will be £498,750 for the "Expected Scenario". Carrying out the proposed interface protection amendments will benefit the customers on the island of Ireland significantly by reducing the SEM Production costs by €13m/annum, based on 2020 figures. Moreover, the

[16] Costs Accurate as per Q3 2016
[17] Costs are exclusive of NIE Networks' administration costs

interface protection amendments will enable higher levels of SNSP on the system, reducing generator curtailment and helping to meet the RES-E target of 40% by 2020. Additionally generators will be less susceptible to nuisance tripping. Considering both the quantifiable and non-quantifiable benefits it can be concluded that these benefits vastly outweigh the implementation costs and therefore provide financial justification for implementing the amendments.

7. NIE NETWORKS' POSITION

NIE Networks fully appreciate the financial benefits to the Northern Ireland customer by enforcing the proposed interface protection amendments to generation connected to the distribution network; a benefit which is envisaged will reduce SEM production costs by €13m/annum. This amendment however, does increase the existing risk of fatality due to electrical islanding and out-of-phase re-closure of generation.

7.1 Large Scale Generation

7.1.1 Risk of Electrocution

The combined risk of fatality associated with the recommended interface protection settings for LSG is 1.36E-6 per annum or 1 fatality every 7.35E5 years, placing the risk virtually on the border between the Health and Safety Executive's (HSE's) "Tolerability" region and the "Broadly Acceptable Region", shown in Figure 6 – LSG Risk of Electrocution. The HSE declare that any risks within the tolerability region are acceptable only if all necessary measures have been taken to achieve a level as low as reasonably practicable (ALARP). It is NIE Networks' view that with the prudent approach taken in the derivation of the risk figures, coupled with the requirement for NVD protection, measures have been taken to achieve a risk level as low as reasonably practicable, justifying the adoption of the proposed settings in Table 14 for LSG.

It was identified that if generators employing VS protection transferred to RoCoF protection the impact on risk would be negligible. Consequently, respecting the TSOs preference, it is NIE Networks view that VS protection shall no longer be allowed and RoCoF must be used. For the avoidance of doubt, this will apply retrospectively to all LSG.

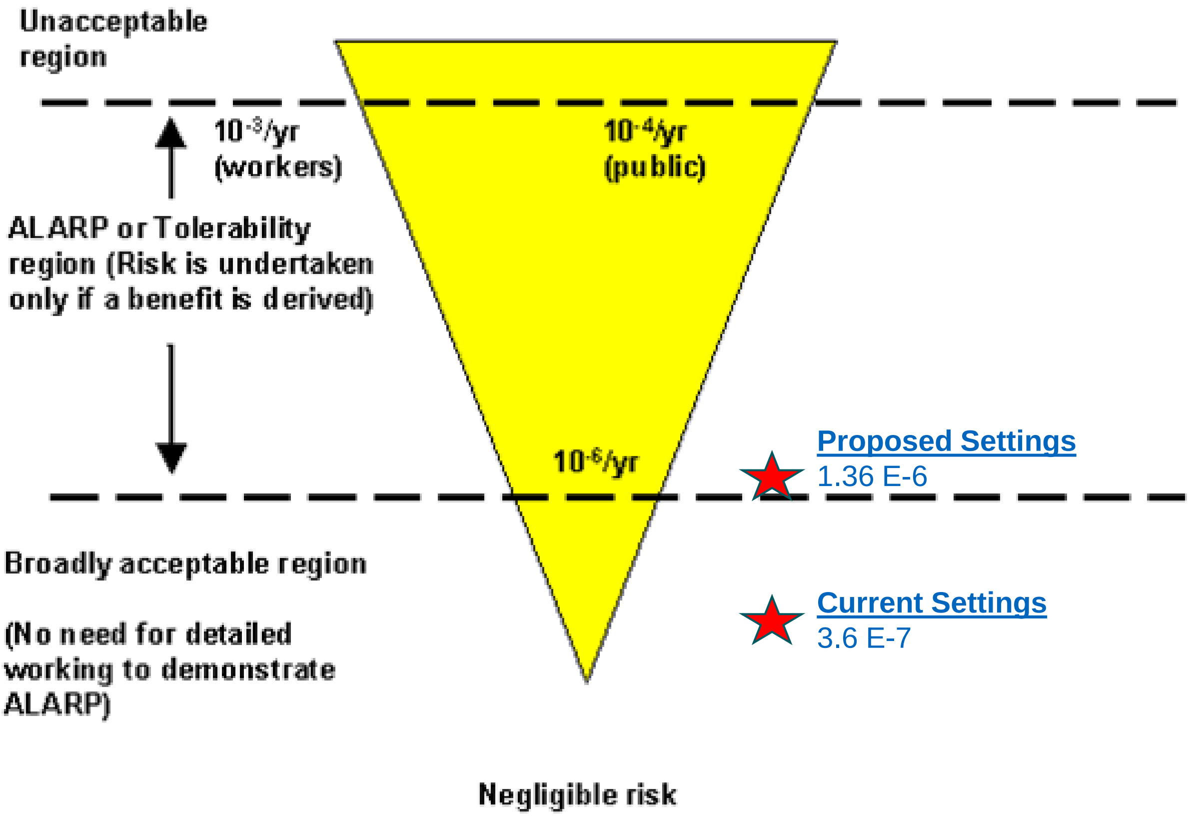


FIGURE 6[18] – LSG RISK OF ELECTROCUTION

7.1.2 Risk of Out-of Phase Re-closure

The combined risk of out-of-phase re-closure associated with the recommended settings for LSG is 2.16E-3 per annum or 1 out-of-phase re-closure every 463 years. However, the risks associated with damage to the generator caused by out-of-phase re-closure and the resultant potential for a fatality have not been quantified as they will be specific to the generator type, robustness and geographical location. It is however anticipated that out-of-phase re-closure will only be of concern to synchronous generators which reduces the risk figure to 8.13E-4 or 1 out-of-phase re-closure every 1,230 years. When compared to the risks calculated for GB the NI risk of out-of-phase re-closure is significantly smaller.

With this in mind, NIE Networks' position is that with the inclusion of NVD protection measures have been taken to achieve a risk level as low as reasonably practicable, justifying the adoption of the proposed settings in Table 14 for LSG. However, due to the site specific nature of out-of-phase re-closure risk NIE Networks advise that each generator should satisfy themselves that they are content with the risk of out-of-phase re-closure and, if required, install additional protection to further reduce this risk. NIE Networks will provide generators with the required data, chargeable to the generator, to facilitate them in conducting their own risk assessment, if required; guidance on performing a risk assessment is also available in the D-Code.

[18] http://www.hse.gov.uk/comah/assessexplosives/step5.htm

LSG must ensure that additional protection installed behind the connection point does not disconnect the generator prior to the interface protection operating for non-islanded events. For the avoidance of doubt, these new settings shall be implemented retrospectively by all LSG connected to the NIE Networks' distribution system and for new LSG connecting to the network.

Protection Function	Existing Settings	Proposed Settings			
	Setting	Power Stations >16A/phase and <5MW		Power Stations ≥5MW	
		Setting	Time Delay	Setting	Time Delay
U/V stage 1	0.9pu	0.9pu	0.5s	0.85pu	3.0s
U/V stage 2	N/A	N/A	N/A	0.6pu	2.0s
O/V	1.1pu	1.1pu	0.5s	1.1pu	0.5s
U/F	48Hz	48Hz	0.5s	48Hz	0.5s
O/F	50.5Hz	50.5Hz	0.5s	52Hz[19]	1.0s
LoM (RoCoF)	0.125 – 0 .4Hz/s	0.125 – 0 .4Hz/s	0s	1.5Hz/s	0.3s[∝]
LoM (Vector Shift)	6 – 12deg	N/A		N/A	

TABLE 14

7.2 Small Scale Generation

The risk of fatality associated with existing generator interface protection settings, for SSG, resides well within the Health and Safety Executive's (HSE's) "tolerability" region, as shown in Figure 7 – SSG Risk of Electrocution . Consequently, NIE Networks has taken the view that introducing additional risk, when the existing risk resides well within the "tolerability" region, cannot be justified and therefore changes to the interface protection settings for SSG cannot be justified. However, it has been identified that if SSG employing VS protection transferred to RoCoF protection the risk of electrocution would be reduced by c6.5%. Consequently, it is NIE Networks view that the use of VS protection for new SSG connectees should no longer be allowed. For the avoidance of doubt, this will not apply retrospectively. The interface protection settings outlined in Table 14 shall be adopted by new SSG connectees. SSG must also ensure that additional protection installed behind the connection point does not disconnect the generator prior to the interface protection operating for non-islanded events.

[19] Staged up to 52Hz as per Over Frequency Shedding Schedule. Specific setting for generator will be stated in letter.

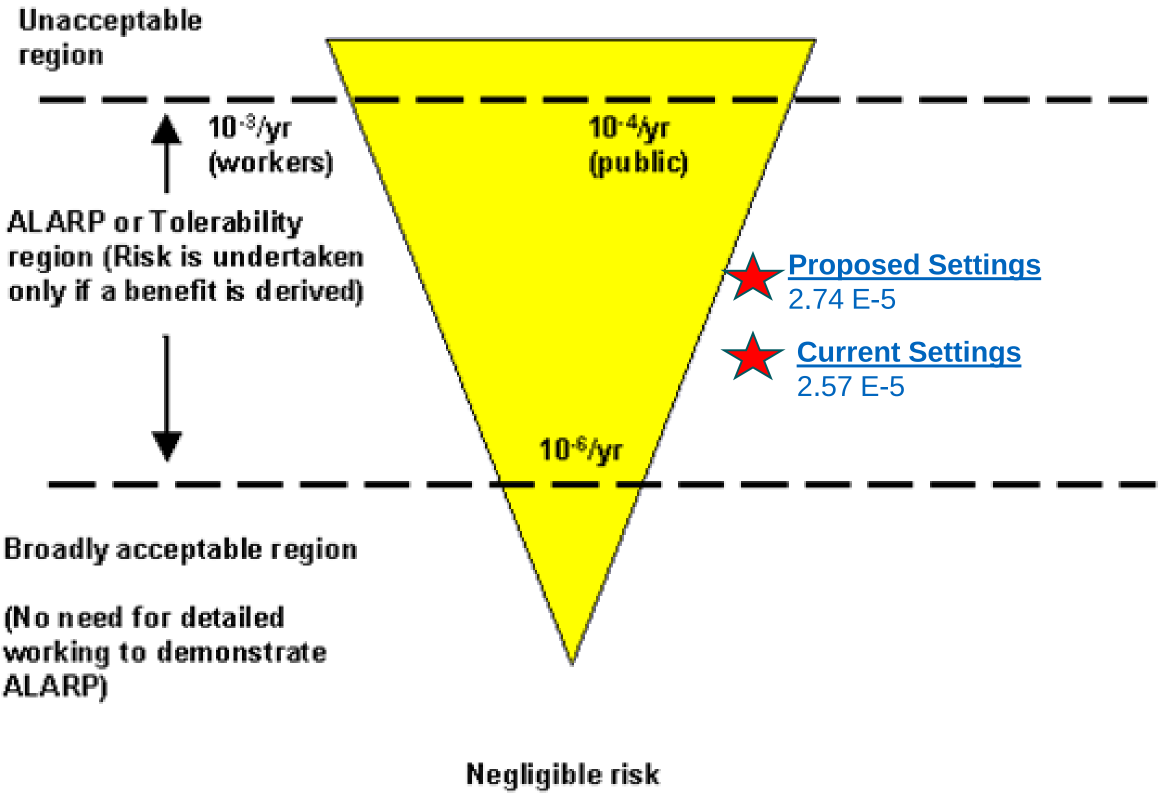


FIGURE 7 – SSG RISK OF ELECTROCUTION

7.3 Future Risk

Although an aspect of future proofing was included within the calculated risks it was identified that in some areas of the network where demand and generation balancing is not prevalent the future risk of islanding may increase. To safeguard against this, NIE Networks will reassess the risks in the early part of RP7 to determine if they have changed and will propose mitigation measures at that time. In the interim, NIE Networks will investigate measures to reduce the risk of electrocution and out-of-phase re-closure, with particular focus on SSG.

8. NETWORK CODE IMPLICATIONS

The three network codes implemented within NIE Networks which are relevant to generator interface protection are: Northern Ireland Distribution Code; Engineering Technical Recommendations G59/1/NI and Engineering Technical Recommendations 113.

8.1 Northern Ireland Distribution Code

CC 7.13 in the Northern Ireland Distribution Code gives guidance on the agreement of rate of change of frequency settings and gives provisions for agreeing new protection settings:

“In relation to any Generator which has agreed the settings with the DNO under these provisions, the DNO shall notify that Generator of any change of which it is aware in the expected rate-of-change-of-frequency on the Distribution System which may require new settings to be agreed.”

Following, industry best practice, NIE Networks will insert the interface protection settings into the D-Code, subject to a consultation process.

8.2 Engineering Recommendations G59/1/NI

Engineering Recommendation G59/1/NI details protection requirements for generation connected to the NI distribution system. Protection must disconnect the generator from NIE Networks' system in the case of a loss of one or more phases of NIE Networks' supply to that installation (6.4.1 (c)). To achieve this, HV connected generation protection must include the detection of:

- Over/Under Voltage
- Over/Under Frequency
- Loss of Mains

Rate of change of frequency, phase angle and unbalanced protection are given as suitable Loss of Mains detection techniques; however, no particular setting is prescribed in G59/1/NI for HV connected generation. G59/1/NI does however provide settings for under/over voltage and under/over frequency which will no longer be applicable. To avoid confusion the D-Code amendments will specify that the D-Code takes precedent over G59/1/NI. Currently the G59/1/NI document is under review and will be superseded by new codes which align to the ENTSO-e codes; the new interface protection settings will be included in the new document(s).

8.3 Engineering Technical Recommendation 113

ETR 113 provides guidance on the methods of meeting the protection requirements of Engineering Recommendation G59/1/NI and addresses other technical issues. Whilst providing guidance on interface protection arrangements ETR 113 does not specify interface protection settings and therefore no amendment to ETR 113 is required prior to performing interface protection settings changes.

9. NEXT STEPS

NIE Networks will consult on the inclusion of the proposed interface protection settings within D-Code. If approved by the UR, NIE Networks will write out to all LSG asking them to amend their interface protection settings to those outlined in Table 14 within the timeframes stipulated in the D-Code. Generators will be required to contact NIE Networks to arrange interface protection amendments, witness testing and supplementary data to perform risk assessments, if required.

10. CONCLUSION

In order to identify the most appropriate interface protection settings for LSG and SSG NIE Networks commissioned Strathclyde University to perform detailed analysis. Based on the specifics of the NIE Networks' distribution system, interface protection settings were identified that ensure stability for the system under worst case contingency events. However, it was identified that the adoption of these settings will introduce an increase in risk of electrocution and out-of-phase re-closure on the NIE Networks' distribution system.

10.1 LSG

The Strathclyde University reports identified that the risk of electrocution for LSG for the proposed interface protection settings will be 1.36E-6 per annum or 1 fatality every 7.35E5 years, placing the risk virtually on the border between the Health and Safety Executive's (HSE's) "Tolerability" region and the "Broadly Acceptable Region". It was also identified that if generators employing VS protection transferred to RoCoF protection the impact on risk would be negligible.

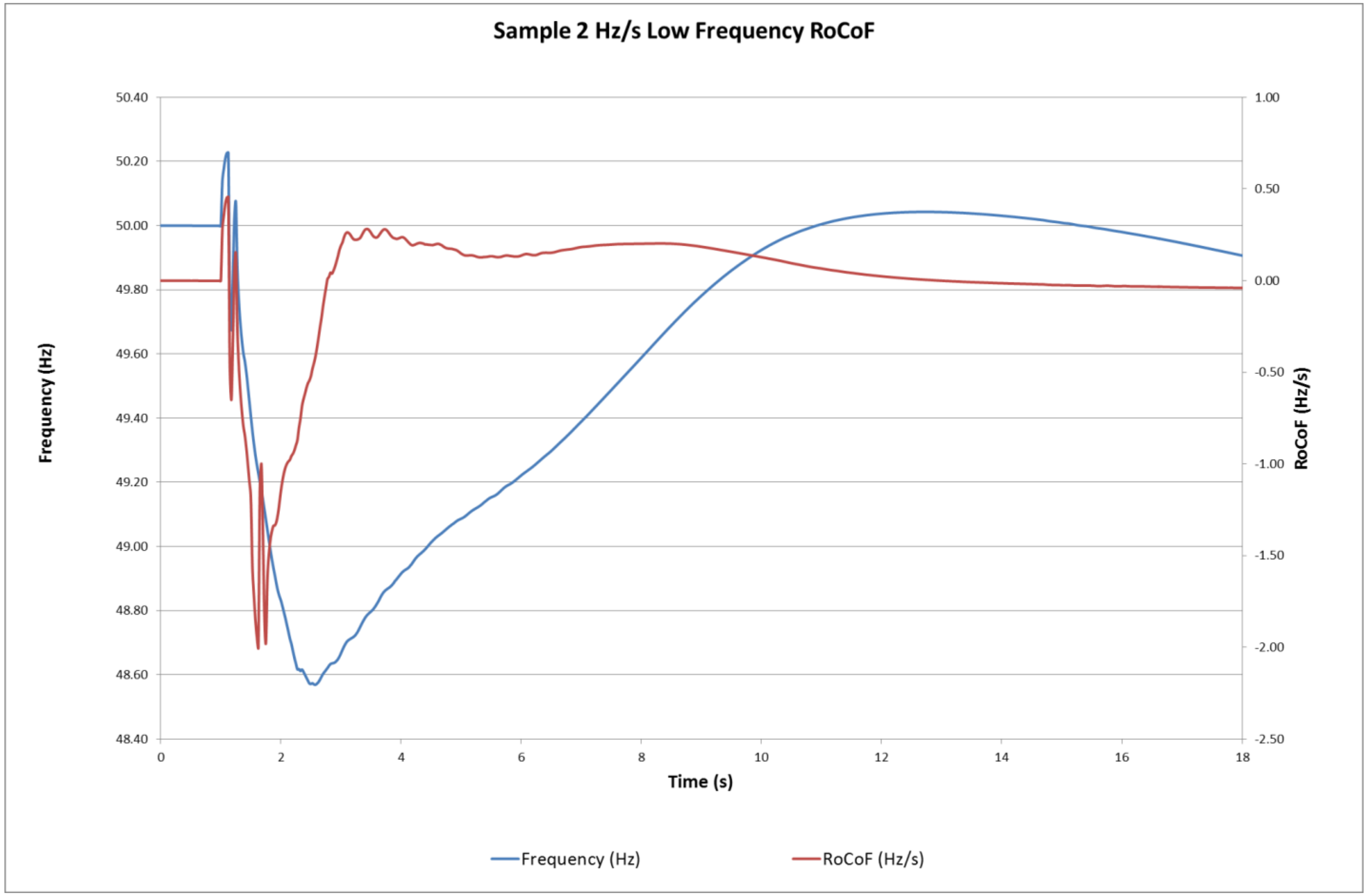
The combined risk of out-of-phase re-closure associated with the recommend settings for LSG is 2.16E-3 per annum or 1 out-of-phase re-closure every 463 years. However, the risks associated with damage to the generator caused by out-of-phase re-closure and the resultant potential for a fatality have not been quantified as they will be specific to the generator type, robustness and geographical location. It is however anticipated that out-of-phase re-closure will only be of concern to synchronous generators which reduces the risk figure to 8.13E-4. When compared to the risks calculated for GB the NI risk of out-of-phase re-closure is significantly lower.

It is NIE Networks' view that with the prudent approach taken in the derivation of the risk figures, coupled with the requirement for NVD protection, measures have been taken to achieve a risk level as low as reasonably practicable, justifying the adoption of the proposed settings in Table 14 for LSG. Moreover, VS protection shall no longer be allowed and RoCoF must be used. For the avoidance of doubt, this will apply retrospectively to all LSG. However, due to the site specific nature of the out-of-phase re-closure risk NIE Networks advise that each generator should satisfy themselves that they are content with the risk of out-of-phase re-closure and, if required, install additional protection to further reduce this risk. NIE Networks will provide generators with the required data, chargeable to the generator, to facilitate them in conducting their own risk assessment, if required.

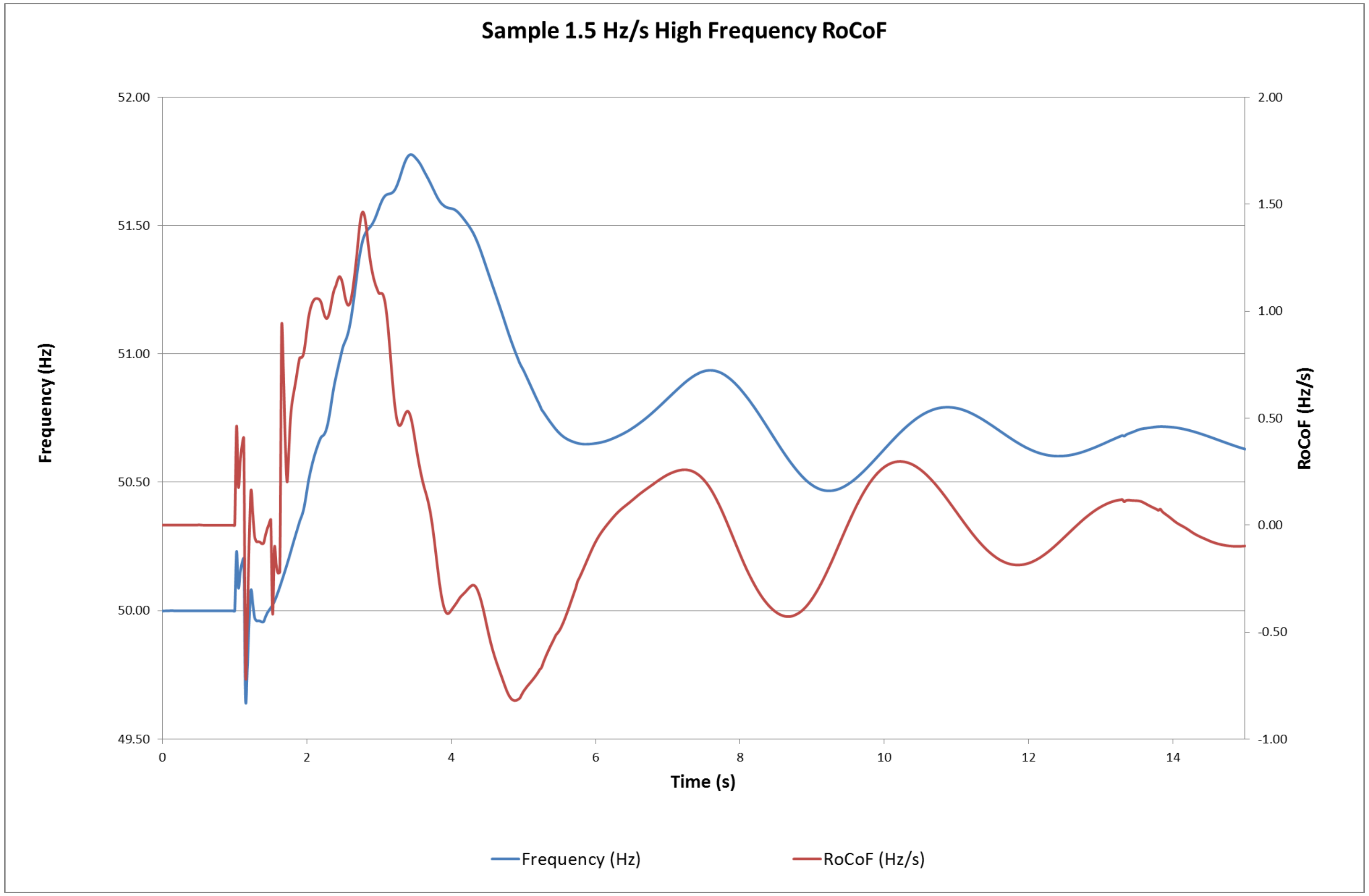
10.2 SSG

The risks associated with the adoption of the proposed Loss of Mains settings for SSG are significantly higher than those associated with the LSG. Strathclyde University have identified that with the inclusion of NVD protection, as per current policy, the risk of electrocution is reduced but still remains well within the HSE's "tolerability" region, as shown in Figure 7 – SSG . Consequently, it is NIE Networks view that the interface protection settings associated with SSG already connected to the network should not be amended. It was identified that if SSG employing VS protection transferred to RoCoF protection the risk of electrocution would be reduced by c6.5%. Therefore, the use of VS protection for new SSG connectees shall no longer be allowed. For the avoidance of doubt, this will not apply retrospectively. The interface protection settings outlined in Table 14 shall be adopted by new SSG connectees.

APPENDIX 1



Sample 2 Hz/s Low Frequency RoCoF
Frequency (Hz)
RoCoF (Hz/s)
Time (s)
50.40
50.20
50.00
49.80
49.60
49.40
49.20
49.00
48.80
48.60
48.40
1.00
0.50
0.00
-0.50
-1.00
-1.50
-2.00
-2.50
0
2
4
6
8
10
12
14
16
18
Frequency (Hz)
RoCoF (Hz/s)


Sample 1.5 Hz/s High Frequency RoCoF
52.00
51.50
51.00
50.50
50.00
49.50
Frequency (Hz)
2.00
1.50
1.00
0.50
0.00
-0.50
-1.00
RoCoF (Hz/s)
0
2
4
6
8
10
12
14
Time (s)
Frequency (Hz)
RoCoF (Hz/s)