DC0079 Frequency Changes during Large Disturbances and their Impact on the Total System

What stage is this document at?

01	Proposal Form
02	Workgroup Report
03	Industry Consultation
04	Report to the Authority

The purpose of this document is to assist the Authority in it decision of whether to implement a proposed modification to the Distribution Code and EREC G59. The modification proposed in the Report was developed by Network Licensees after consideration of response to the consultation published on 13/06/2018

It is recommended that the Distribution Planning Code and EREC G59 should be changed to ensure that all existing embedded generators make changes to comply with the following:

a) That where rate of change of frequency (RoCoF) protection relays are used, as part of Loss of Mains protection, the applied setting should be $1Hzs^{-1}$ with a definite time delay of 500ms.
b) That vector shift protection technique should be removed where it is in use as Loss of Mains protection.
c) That existing Loss of Mains protection settings for type-tested generators need not be changed.
d) Any existing over-frequency setting relays still set at 50.5Hz should if possible be reset to 52.0Hz.

Given the retrospective nature of the proposed change, the workgroup recommends the creation of an implementation team, with the governance, resourcing and stakeholder representation necessary to assure efficient and effective implementation of the proposed changes.

High Impact:
All non-type-tested embedded generators with plant rated >16A per phase commissioned before 1 February 2018

Medium Impact:
None

Low Impact:
None

Contents

About this document

This document is the Report to the Authority for DC0079 which contains the responses to Industry Consultation and the network Licensees' recommendation. The purpose of this document is to assist the Authority in their decision whether to implement the proposed changes.

Document Control

Version	Date	Author	Change Reference
0.1		National Grid	Draft Industry consultation Report
0.2	08/05/18	National Grid	Includes implementation plan
0.3	02/07/18	National Grid	Final Draft
2.0	01/02/19	National Grid	Report to the Authority – for discussion at DCRP
3.0	13/02/19	National Grid	Draft Final Report to the Authority
4.0	25/02/19	National Grid	Final Report to the Authority

Any Questions?
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1 Executive Summary

1.1 This Report seeks that The Authority approves a change to the Loss of Main (LoM) protection requirements on all existing G59 generation of any size. This change, if approved, will require the removal of vector shift protection from existing G59 generation and replace it with RoCoF, where applicable. Where RoCoF relays are used, a setting of $1Hzs^{-1}$ with a definite time delay of 500ms should be applied.

1.2 Engineering Recommendation G59, which effectively forms part of the Distribution Code; requires embedded power stations to be fitted with LoM protection. This is to ensure that these power stations, following disconnection of all or part of the local distribution system to which they are connected from the rest of the distribution system, do not sustain an island with the local demand. The two most common forms of LoM protection are vector shift (VS) and rate of change of frequency (RoCoF).

1.3 The principles of RoCoF and VS protection have been extensively covered in GC0035[1] and the September 2017 DC0079[2] consultation documents. The same consultation documents also comprehensively covered the drivers to this change which are mainly, the general decline in system inertia, volatility of system frequency and inadvertent tripping of vector shift relays due to secured events on the transmission system.

1.4 The Authority has already approved the banning of vector shift protection and the change in RoCoF relay settings from $0.125Hzs^{-1}$ to $1Hzs^{-1}$ with a definite time delay of 500ms for all embedded generators commissioned on or after 1 February 2018[3] . The licensees, through this Report, are recommending that the same requirements be applied retrospectively to existing non-type-tested plant within the scope of EREC G59.

1.5 A separate consultation exercise covering on type-tested plant, concluded on 23 February 2018, with the intention of introducing an enhanced immunity type test. This was approved by the Authority on 4 May 2018, and therefore type-tested plant connecting to the distribution network on or after 1 July 2018, will be expected to remain connected for a RoCoF of up to 1Hzs-1 with a 500ms time delay or a vector shift of ±50º. This is a typical maximum value of the vector shift that embedded generators, in the vicinity of a transmission fault, are likely to be subjected to.

1.6 National Grid's outturn cost, as System Operator[4], of managing RoCoF constraint has been £30.3M, £30.7M and £59.2 for 2015/16, 2016/17 and 2017/18 respectively. The potential operational cost of managing vector shift is currently not reflected in the balancing services cost, if included this cost is likely to be higher. These costs are ultimately borne by the electricity consumer.

1.7 It is estimated that at least £600M will be spent in RoCoF related balancing costs from 2018 to 2024. Fig 1 shows the estimated annual RoCoF constraint costs. These figures are based on the more conservative, Steady State

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

2 https://www.nationalgrid.com/sites/default/files/documents/GC0079%20%20%20Industry%20Consultation%20Document.pdf

3 http://www.dcode.org.uk/assets/uploads/DC0079_Ofgem_Decision.pdf

4 National Grid is splitting into National Grid Electricity System Operator (NGESO) and National Grid Electricity Transmission. All references to National Grid in this paper refer to NGESO.

scenario of the 2017 National Grid Future Energy Scenarios (FES)[5]. The actual cost in 2018 exceeded £100m.

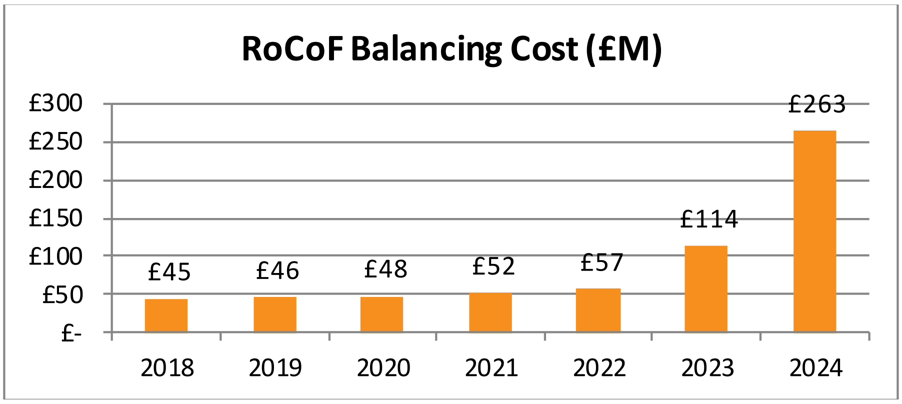

Fig 1 Annual Costs of Managing RoCoF

1.8 The annual cost estimates for the RoCoF constraint for the other three scenarios in the FES are expected to exceed the estimates shown in Fig 1.

1.9 To mitigate against these projected balancing costs, the workgroup proposes that loss of mains protection on existing non-type-tested embedded generators be changed to bring them in line with the requirements in EREC G59 for new embedded generators.

1.10 The workgroup also concluded that retrospective changes to existing G83 and G59 type-tested equipment is not required. Studies done by Strathclyde, summarised in the report entitled "Testing LV PV Inverters Stability during Voltage Magnitude and Vector Shift Disturbances[6] , concluded that the majority of inverters used by existing type-tested plant are able to meet the requirements for new type-tested generation. This conclusion would avoid the prospect of retrospective action for domestic PV generation and other small installations which use type-tested plant. Further details are covered in section 4.17 of this Report.

1.11 From the Week 24 submissions and feed in tariff data, the workgroup estimates that at least 50 000 sites are affected and will need to be assessed and, where required, made compliant with the proposed requirements. Table 1 shows a summary of all the G59 generators and the total estimated implementation costs.

Plant Category	No of Sites	Expected Cost	Low estimate	High estimate
P_g >5MW	677	2.2	0.5	4.2
1MW$\leq P_g$ < 5MW	1445	4.6	1	8.9
P_g <1MW	47890	24.1	19.5	83.8
Total	50012	30.9	21	96.9

Where Pg is generator registered capacity

Table 1: Implementation Costs

1.12 The workgroup estimated that the minimum cost of implementing these proposals could be within the range from £21M to £97M. This broad estimate is due to the scarcity of the information available for each site. The workgroup believed an estimate of £31M (Expected Costs) should be possible. However based on National Grid ESO's experience of incentivising the removal of

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[5] http://fes.nationalgrid.com/media/1253/final-fes-2017-updated-interactive-pdf-44-amended.pdf

[6] http://www.dcode.org.uk/current-areas-of-work/dc-0079.html

vector shift loss of mains protection in Spring and Summer 2019, coupled with the experience gained during GC0035 and some feedback from Distribution Network Operators (DNOs[7]), it is now thought that the upper figure of £97M is more appropriate.

1.13 The conclusion from the cost benefit analysis is that there is a strong case for implementing the recommendations proposed. Based on these estimates the payback period is within two years of project completion, i.e. by 2023.

1.14 This modification will result in lower Balancing Services costs, and so lower Balancing Use of System charges (BSUoS). As BSUoS charges, like other costs, are ultimately paid for by consumers, the workgroup believes that this modification will result in lower costs to consumers.

1.15 The workgroup notes the scale of the challenge in implementing its proposals. Many embedded generation owners and operators are affected and most of them have little, or zero, interaction with network licensees or regulators. The workgroup therefore recommends the creation of an implementation programme and associated team, with appropriate governance, resourcing and stakeholder representation. The programme would be tasked with ensuring that generators who needed to make a change to their equipment are provided with the support required to do so, and to provide assurance to National Grid that the system can be operated differently, and the promised savings made, as a result.

1.16 A key feature of the implementation plan is that the RoCoF risks and costs will be effectively controlled and mitigated once a critical number of sites have had the changes made. This critical number is thought to be only a few percent short of 100%, but will depend on the mix of sites having made the changes versus those not having done so. At this point, there will be no further cost benefit in pursuing changes to the remaining installations.

1.17 A minority of the WG and one respondent, recognizing this issue of diminishing returns towards the end of the project suggested that it might be that where the costs of making relay change to small synchronous sites (as opposed to disabling protection on equivalent asynchronous sites) outweighed the benefits it would be appropriate to retain the existing loss of mains protection on these synchronous sites.

1.18 The workgroup believes that the opportunity should also be taken to reset any existing overfrequency relays on generation <5MW from 50.5Hz to 52.0Hz. A programme of overfrequency relay resetting was undertaken between 2009 and 2011. Ideally all generation would have been included, but for practical reasons at the time, the exercise was limited to >5MW installations. These retrospective proposals for interface protection provide an opportunity to extend the 2009 programme to all generation, where it is practicable to make the change.

2 Purpose & Scope of the Workgroup

2.1 The Frequency Changes during Large Disturbances and their impact on the Total System workgroup was established by the Grid Code Review Panel (GCRP) and Distribution Code Review Panel (DCRP) in 2012.

2.2 The reasons and background for the formation of the workgroup are covered in Chapter 3 (Workgroup discussion) of the Phase 1, GC0035 report to the authority available on National Grid's website. Further to this, the same

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[7] The term Distribution Network Operators (DNOs) throughout this document is intended to cover both Distribution Network Operators (DNOs) and independent Distribution Network Operators (iDNOs)

workgroup was reconstituted under GC0079 and then DC0079 with the aim of assessing whether the recommendation of GC0035 should be extended the recommendations of GC0035 to embedded generation with a registered capacity less than 5MW.

2.3 The following are the workgroup objectives relevant to this Report:

2.3.1 To deliver proposals concerning RoCoF based protection for all embedded generators with a registered capacity of less than 5MW.

2.3.2 To investigate and recommend on the suitability of VS protection as an alternative to RoCoF, taking into account its possible unsuitability for transmission fault ride through requirements.

Terms of Reference

2.4 Terms of Reference can be found in Annex 1.

Timescales

2.5 The GC0079 workgroup held a sequence of 44 meetings, the first on 14 June 2013 with the most recent meeting being on 28 January 2019.

3 Why Change?

Background

3.1 The reduction of system inertia, the causes, impacts, and mitigation measures have been extensively articulated in the GC0035[8] and GC0079[9] reports to the Authority. This has resulted in:

a) The relaxation of RoCoF setting from 0.125 Hzs^{-1} to 1 Hzs^{-1} with a 500ms time delay for all embedded generation whose registered capacity is 5MW and above.

b) The requirement to set RoCoF to 1 Hzs^{-1} with a 500ms time delay for installations whose registered capacity is below 5MW and whose commissioning date is on or after 1 February 2018.

c) The banning of vector shift relay protection use as loss of mains protection for all embedded generation whose commissioning date is on or after 1 February 2018.

d) The proposal to amend the Distribution Planning Code to ensure that all type-tested generation commissioned on or after 1 July 2018 should demonstrate stability for appropriate RoCoF and vector shift disturbances. This proposal was approved by the Authority on 4 May 2018, and with effect from 1 July 2018 the new type-tested generation will be expected to remain connected for a RoCoF of up to 1Hzs^{-1} with a 500ms time delay or immune to a vector shift of ± 50º.

3.2 National Grid's outturn cost of managing RoCoF has been £30.3M, £30.7M and £59.2M for the period 2015/16, 2016/17 and 2017/18 respectively. Already in this financial year, the RoCoF constraint cost has exceeded £100m.

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

[9] http://www.dcode.org.uk/assets/uploads/Report_To_the_Authorityv3_1.pdf

3.3 It is estimated that at least £600M will be spent, over the next seven years, to manage RoCoF related system constraints. The methodology of calculating this is covered from section 4.7 of this Report.

4 Workgroup Discussions

4.1 This stage is a continuation of the work done under GC0035 and DC0079. In this final stage of DC0079, the workgroup discussion is mainly concerned with changing the LoM protection relay requirements on existing embedded generators commissioned before 1 February 2018 and cost and benefit case of this change.

Practical Considerations

4.2 In order to assess the scope of works required to apply the new protection settings on the existing embedded generation fleet, the workgroup discussed the practicalities of implementing this change.

4.3 A significantly large number of sites will have LoM protection provided by the control system of the power electronic converter. These sites are likely to be equipped with type-tested plant with a full convertor – e.g. domestic (roof-top) photovoltaic panels. Any modification to these plants is likely to require a significant change to the converter control system.

4.4 Some other sites will have LoM protection provided by a single function Vector Shift relay or by a RoCoF relay that cannot accept the required $1.0Hzs^{-1}$ and 500ms setting. Such a relay would need to be either

4.4.1 Replaced by a new relay that can be programmed to operate at a RoCoF of $1Hzs^{-1}$ with a time delay of 500ms; or

4.4.2 Subject to an appropriate risk assessment, either generic or on a case by cases basis, disabled.

4.5 The remaining sites will have their LoM protection provided by a relay with an appropriate range of settings. Such relay would need to be re-programmed to operate at a RoCoF of $1Hzs^{-1}$ with a time delay of 500ms.

Changing LoM Protection – Risk Assessment

4.6 The workgroup believes that it is always appropriate to maintain LoM protection for a synchronous machine (unless a site specific risk assessment can demonstrate that it is not warranted) and therefore has assumed that all synchronous machines will need to be retrofitted with RoCoF protection to the proposed requirements if the existing protection cannot be reconfigured.

4.7 In order to avoid the costs of replacing any relays that cannot be reprogrammed to provide LoM protection based on a RoCoF settings of $1Hzs^{-1}$ with a time delay of 500ms, the workgroup conducted a generic risk assessment to see whether relying solely on the over/under frequency and over/under voltage protection required by G59 (i.e. with no dedicated LoM protection), would increase the risk of islanding or not for non-synchronous plant.

4.8 The risk assessment was based on the analysis for embedded generation < 5MW conducted by the University of Strathclyde that was commissioned by National Grid to support the workgroup activities. This report is referenced in Annex 4 of this Report and the relevant results are summarised in Table 2.

4.9 Table 2 shows the Non-Detection Zone (NDZ), a measure of the ability of the embedded generating unit to detect an island, for different non- synchronous generation technologies. The lower the NDZ value the better the protection is at detecting an islanding condition. This was simulated under the following condition:

4.9.1 RoCoF relays set to operate at 1Hzs^{-1} with a time delay of 500ms with over/under frequency or over/under voltage relays absent;

4.9.2 Over/under frequency relays set to operate at the settings specified in EREC G59, no LoM relays;

Type of protection	Non Detection Zone (NDZ) (%)			
	Active Power		Reactive Power	
	Import	Export	Import	Export
DFIG				
RoCoF	1.98	2.38	7.2	5.04
Over/Under frequency	3.97	2.69	8.69	9.98
Other non- synchronous				
RoCoF	>50	>50	>50	>50
Over/Under frequency	0.65	0.87	0.28	0.43

Table 2 Non Detection Zone for Non-Synchronous plant

4.9.3 The values show that for doubly-fed-induction generation (DFIG), RoCoF relays are better in preventing islanding than over/under frequency relays. However, for other non-synchronous generation types, over/under frequency relays perform better than RoCoF relays.

4.10 Based on these results, the workgroup recommends that:

4.10.1 for existing embedded synchronous generation plant and also asynchronous generation of the DFIG type, where it is necessary to do so, to apply a RoCoF setting of 1Hzs^{-1} and a delay of 500ms, LoM protection relays will have to be replaced; and

4.10.2 for existing embedded generation plant of other non-synchronous types, where it is necessary to replace a LoM relay to apply a RoCoF setting of 1Hzs^{-1} and a delay of 500ms, LoM protection relays can be disabled instead of being replaced.

4.10.3 A minority of WG members questioned whether in the case of very small synchronous machines it would be worth the benefit of making the changes if the costs of a relay change were required. The majority WG view was that synchronous machines should always be fitted with effective LoM protection, but noted that as far as the islanding risk is concerned retaining existing 0.125 Hzs^{-1} settings would achieve that.

Treatment of Non-synchronous machine above 5MW

4.11 The WG recognised that while the Strathclyde study was based on non-synchronous machines below 5MW, it is necessary to consider the case of non-synchronous machines above 5MW that might be fitted with VS.

4.12 It is expected that the existing control systems for asynchronous power generating modules will be similar on either side of the 5MW boundary and hence their behaviour under a loss of main conditions is likely to be the same.

4.13 Overall risk associated with non-detection of islanded operation is driven by four things: the topology of the network and likely islanding points, the machine(s) behaviour and load profile. Additionally, the overall risk is also driven by the number of generation installations.

4.14 The number of installations >5MW is known to be just short of 700, i.e. much smaller than the number of installations <5MW. Similarly, there is nothing technical that differentiates asynchronous machines either side of the 5MW boundary.

4.15 The WG noted that in the Strathclyde report there were some mixes of generation type that in the modelling showed that RoCoF protection had no benefit (although the frequency and voltage protection was effective). Therefore replacing VS with RoCoF in those cases would bring no benefit. Conversely RoCoF did bring discrimination benefits in other cases.

4.16 The WG therefore recommends that the approach for asynchronous machines above 5MW be the same as for those below 5MW; i.e. with the exception of DFIG, asynchronous machines above 5MW which currently use vector shift for LoM, and where the existing relay cannot be reprogrammed to the recommended RoCoF setting, vector shift protection should be disabled and G59 voltage and frequency protection should be used only.

Not Modifying the Control System for Type-Tested Plants – Risk Assessment

4.17 Type-tested generating units are generating units whose design has been tested by the Manufacturer, component manufacturer or supplier, or a third party, to ensure that the design meets the requirements of EREC G59 or EREC G83, as applicable, and for which the manufacturer has declared that all products supplied into the market will be constructed to the same standards, and with the same protection settings as the tested product.

4.18 The majority of type-tested embedded generating units are inverter based mostly photovoltaic, units. The LoM protection of these units is likely to be built into the logic of its converter design. Any changes to this logic would require the converter controller of a large number of plants, approaching 1 000 000 plants in GB, to be replaced.

4.19 Previous analysis by the University of Strathclyde[10] demonstrated that all type-tested inverters, within their sample tested,

4.19.1 Will trip in genuine islanding situations; and

4.19.2 Will remain stable during grid disturbances when the rate of change of frequency is up to $1Hzs^{-1}$, although some of the inverters may reduce their output during such events.

4.20 A further analysis by the University of Strathclyde (refer in section 4.8) was commissioned by National Grid to support these discussions. This analysis aimed to assess the consequences of subjecting the converter to a vector shift of up to ±60° at various loading levels and various levels of retained voltage. The results of this analysis are as follows:

4.20.1 All inverters tested (both single and three-phase) passed the vector shift immunity type test of ±50° at nominal voltage and loading. In case of three-phase inverters the same phase shift was applied simultaneously to all three voltages.

4.20.2 For a retained voltage below 80%, the results were less consistent as some of the inverters remained connected; some tripped and the others

[10] https://www.nationalgrid.com/sites/default/files/documents/8589936354-UoS%20Inverter%20Testing%20Final%20Report%20-%20December%202015.pdf

reduced their output. Another inconsistent behaviour was observed when three-phase inverters were subjected to unbalanced voltage resulting from typical transmission system unbalanced faults. One inverter remained stable while the other tripped on all unbalanced conditions (including for vector shift angles below ±50°).

4.21 Based on the Feed in Tariff report, there are more than 900 000 type-tested photovoltaic installations connected to the distribution system in GB with a total capacity of about 3.4GW. These correspond to the first three rows in Table 3.

Capacity Range	No of sites	% of total Sites	Installed Capacity [MW]	% Capacity
0 to ≤ 4 kW	853,574	94.3	2,459	20.0
4 to ≤ 10 kW	23,363	2.6	179	1.5
10 to ≤ 50 kW	24,043	2.7	720	5.9
50 kW to ≤ 5 MW	3,856	0.4	3,235	26.3
5 to ≤ 25 MW	406	0.0	4,286	34.9
> 25 MW	37	0.00	1,409	11.5
TOTAL	905,279	100	12,288	100

Table 3 Installed PV Capacities in Great Britain

4.22 This 3.4GW of generation is unlikely to be affected by system events that would result in a RoCoF level of up to $1Hzs^{-1}$. This has been inferred from the Strathclyde report documented in Section 4.19 of this Report.

4.23 Depending on the voltage levels and the pre-fault output of the converters, some of this capacity may trip or reduce their output following a transmission system event that results in some vector shift. However, the capacity at risk is thought to be very low due to the following reasons:

4.23.1 Vector shift events, compared to frequency excursions, are essentially local, although in some cases widespread i.e. only a fraction of the PV installations in GB will be affected by any particular transmission fault.

4.23.2 Due to diversity in the cloud cover, it is highly unlikely that the output of this PV generation will all be at full output at time of the transmission event.

4.23.3 The impact of the event would be a reduction in the aggregated output of the PV installation affected by the event, rather than a complete disconnection of such plants.

4.23.4 As the modification to the new type-testing requirements has been accepted by the industry and approved by The Authority, the risk will not increase.

4.24 Given the vast majority of the type-tested plant is PV, the workgroup proposes that type-tested plants that are currently connected to the system are not modified.

4.25 On findings relating to inverter ride through behaviour during faults, a separate expert group has been established with an objective of specifying fast fault current injection during faults and thus improve the overall voltage performance of the transmission and distribution system.

Costs of Retrospective Application

4.26 The workgroup estimates that there are 50 000 sites within the scope of this modification where it will be necessary to:

4.26.1 Either ascertain that no change is required or identify the scope of works required to be done;

4.26.2 Change the LoM protection settings of an existing relay such that it operates for a RoCoF of $1Hzs^{-1}$ with a delay of 500ms;

4.26.3 Disable the existing LoM relay; or

4.26.4 Change the existing LoM relay to a new relay that is set to operate for a RoCoF of $1Hzs^{-1}$ with a delay of 500ms.

4.27 This estimate is based on statistics from the Week 24 submissions and the Feed in Tariff report. This estimate also includes sites with generators whose registered capacity are 5MW and above. It is now necessary to ensure that none of these uses Vector Shift relays as means of LoM protection.

4.28 The total cost of implementing the changes retrospectively will be determined by the scope of works required at each site and the cost required to cover that scope. The more the sites that require significant works, e.g. replacement of a relay, are, the higher the overall the cost is; and the higher the cost of a site visit, re-programming of a relay, removal of a relay, or replacement of a relay is, the higher the overall cost will be.

4.29 Three estimates were used for the overall implementation cost. These reflect different scenarios with the number of sites requiring significant works, e.g. replacement of a relay, increasing from one scenario to another.

4.30 Table 4 shows the total cost estimates for the three different scenarios. These costs include **£10M** set aside for site visits under each scenario.

Plant Category	No of Sites	Expected Cost £m	Low estimate £m	High estimate £m
P_g >5MW	677	2.2	0.5	4.2
1MW$\leq P_g$ < 5MW	1445	4.6	1	8.9
P_g <1MW	47890	24.1	19.5	83.8
Total	50012	30.9	21	96.9

Where Pg is Generator registered capacity

Table 4 Retrospective Application Cost

4.31 Subsequent to the WG consideration of the costs of the change programme the network licensees have been considering in more detail the implementation of the programme (see Section 6) below. Their current thinking is that setting up a programme of dedicated resources will have considerable set up costs and crucially take significant mobilization and procurement time. Therefore, the network licensees are now proposing a payment programme similar to the one used in Summer 2018 to achieve a change to vector shift protection on selected generation sites will be appropriate. As such it is likely that the costs will be around the high estimate (i.e. £100M in round terms) in table 6 above.

Estimated Balancing Services Cost Savings DC0079

4.32 If the RoCoF settings for existing generation are not to be updated, National Grid will have to continue to constrain generation and interconnectors such that if the largest secured loss on the system takes place, the system RoCoF remains below $0.125Hzs^{-1}$. This usually requires additional balancing actions to synchronise additional generation to the system to replace the generation or interconnector capacity that has been restricted and to constrain additional generation in order to ensure that the generation that has been synchronised to the system is operating above its minimum Stable Export Limit (SEL).

4.33 The annual cost estimates for this constraint from 2018 to 2024 were calculated for the Steady State scenario which is the most conservative scenario of National Grid's Future Energy Scenarios.

4.34 Costs were estimated using the long-term market and constraints modelling tool BID3[11]. This tool creates a generation and demand pattern based on historic data and forecasted changes in generation and demand capacity then alters the generation dispatch to ensure the power flows remain within the network limits that are considered while minimising the cost of constraining generation. This model is also used, in compliances with National Grid transmission licence obligation, for Network Options Assessment [12](NOA).

4.35 For the purpose of this analysis, the network limits that were modelled in BID3 are thermal constraints, voltage constraints, and the RoCoF constraint (largest loss limit). The BID3 analysis was first run with only thermal and voltage constraints activated. It was then re-run with thermal, voltage and RoCoF constraints activated. The cost of the RoCoF constraint is the difference between the total constraints costs of the two runs. This is illustrated by Fig 2.

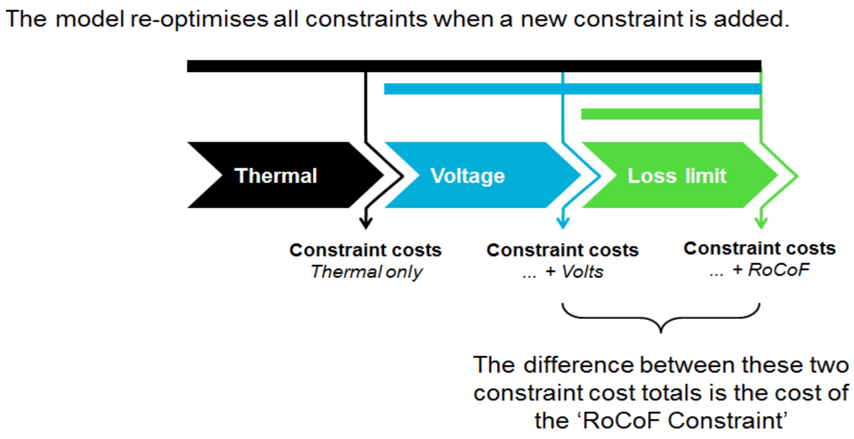


Fig 2 RoCoF Constraint Calculation Methodology

4.36 The annual cost estimates for the RoCoF constraint from 2018 to 2024 for the Steady State scenario are shown in Table 7. The table shows a gradual increase in RoCoF constraints cost up to 2022. This could be attributed to the continuing reduction in the system inertia. Years 2023 and 2024 show large step increases that reflect the connection of new generating units and/or power park modules and/or interconnectors with capacities that exceed the RoCoF constraint (largest loss limit).

4.37 The annual cost estimates for the RoCoF constraint for the other three Future Energy Scenarios are expected to exceed the estimates shown in Table 5

Year	2018	2019	2020	2021	2022	2023	2024	Total
Steady State[£M]	44.75	46.49	48.45	52.23	57.03	113.56	263.34	625.85

[11] https://www.nationalgrid.com/sites/default/files/documents/Long-term%20Market%20and%20Network%20Constraint%20Modelling.pdf

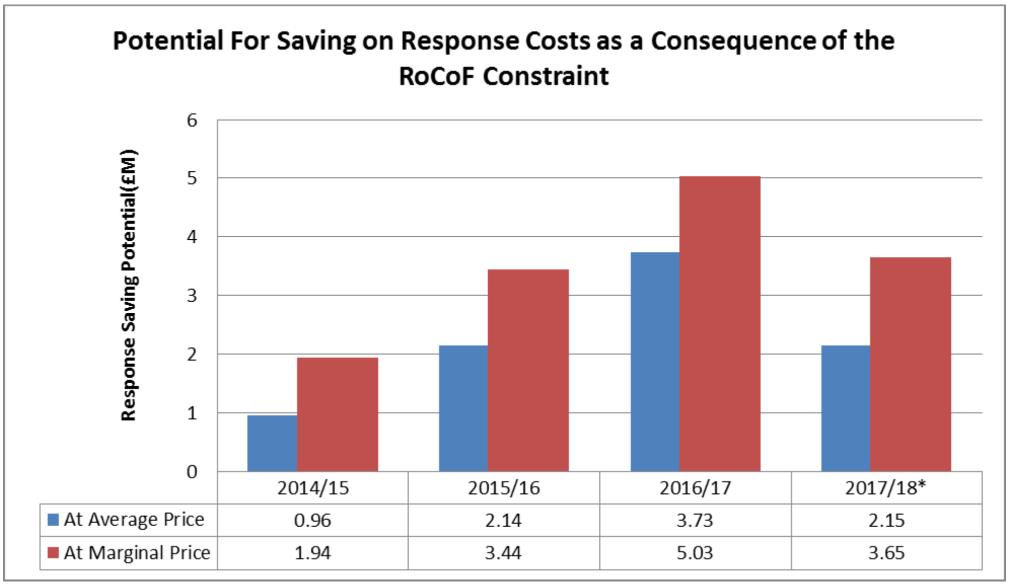
[12] https://www.nationalgrid.com/uk/publications/network-options-assessment-noa

Table 5 Estimated Constraint Cost: Steady State

Potential Frequency Response cost saving because of reduction of largest infeed loss by RoCoF

4.38 National Grid has to procure frequency response services (primary, secondary, and high) that are sufficient to ensure that the largest secured infeed, outfeed, or demand loss does not result in the system frequency violating the limits specified in the Grid Code and the NETS SQSS. In general, an increase in the largest loss would result in an additional Frequency Response requirement.

4.39 In order to manage RoCoF, National Grid has been constraining generation and interconnectors to reduce the size of the largest loss that would result from a secured event. This reduction in the largest loss has resulted in a reduction of the frequency response requirements and, consequently, a reduction in the cost of procuring these services. The estimated savings in frequency response costs for the current year and the previous three years are shown in Fig 3.



	2014/15	2015/16	2016/17	2017/18*
At Average Price	0.96	2.14	3.73	2.15
At Marginal Price	1.94	3.44	5.03	3.65

*2017/18 includes actual data for Q1 – Q3 and estimated data for Q4

Fig 3 Potential Savings in Response costs

4.40 The majority of the workgroup agreed that those potential response savings for future years should be taken into account in the CBA analysis. The workgroup also acknowledged that although there are significant uncertainties in calculating future response savings, it is reasonable to estimate the future savings based on the past data.

4.41 As can be seen from Fig 3 the past response saving is in the range of 5% to 15% of the total cost of managing RoCoF. To ensure the robustness of protection change case, the upper range of 15% has been assumed in the CBA.

Cost Benefit Analysis

4.42 The following assumptions have been made when calculating the net present value:

a) That project implementation will start in 2018 and will be implemented over three years with equal amounts of yearly investments.

b) The social discount rate of 3.5% has been assumed in accordance with the HM Treasury's The Green Book.

c) That benefit will accrue at the end of the project.

d) Costs associated with managing frequency response, if RoCoF were no longer an issue, are assumed to be of the order of 15% of the current cost on managing RoCoF.

4.43 Net Present value calculations for the high cost estimate scenario where investment cost is £96.9M are shown in Table 6.

Year	2018	2019	2020	2021	2022	2023	2024
Remediation Cost	32.23	32.23	32.23				
OPEX (base) (constraints)	44.70	46.50	48.50	52.20	57.00	113.60	263.30
Opex (case 1) (constraints)	44.70	46.50	48.50	7.83	8.55	17.04	39.50
Savings (base - case 1)	0.00	0.00	0.00	44.37	48.45	96.56	223.81
PV OPEX(Discounted Savings)	0.00	0.00	0.00	38.67	40.79	78.55	175.91
Remediation(Discounted Cost)	31.14	30.09	29.07	0.00	0.00	0.00	0.00
Present Value of Savings - Costs (annual)	**-31.14**	**-30.09**	**-29.07**	**38.67**	**40.79**	**78.55**	**175.91**
Cumulative net present value(Case 1)	**-31.14**	**-61.23**	**-90.31**	**-51.64**	**-10.85**	**67.71**	**243.61**
Savings (Discounted total)	333.92						
Costs (Discounted total)	90.31						
Net Present Value (total)	**243.61**						
Benefit: Cost ratio	**3.70**						

Table 6 NPV analysis for high implementation estimate

4.44 The breakeven point for this cost benefit analysis occurs in 2022, i.e. when the savings would be greater than the costs of implementation.

4.45 The workgroup concluded that there is a strong case for the implementation of these changes with a net benefit exceeding £240m (based on the high implementation cost estimate). In reality, the net benefit is likely to be even higher than that level as the cost of managing the RoCoF constraint in 2018 only was twice the value used by the workgroup. It is therefore recommended to commence the implementation as soon as practicable in order to avoid the escalating costs of managing RoCoF constraints.

4.46 The workgroup recognised that there might be a need to understand future response/reserve requirements and cost implication with the reduction of system inertia and increase of largest infeed. However, the workgroup concluded that this is outside the scope of current DC0079. The workgroup therefore recommends that this issue be taken up as future works.

Vector Shift Benefit

4.47 This risk associated with continued use of VS relay could occur under the following network conditions:

4.47.1 When as a result of a transmission fault the total embedded generation capacity tripped exceeds the largest infeed loss.

4.47.2 When as a result of a transmission fault, a transmission connected generator and embedded generation are simultaneously disconnected with their combined capacity exceeding the largest infeed loss.

4.48 Without implementing the proposed VS protection change, the way to manage the risk in operational time scales could be either through embedded generation curtailment or though balancing mechanism actions. Between the two options available, curtailment is likely to be more efficient. Based on current analysis, curtailment option cost each year is estimated to be £3M for loss of embedded generation only and much more that £100M for a case where embedded generation is lost simultaneously with a transmission connected generator.

4.49 In the current CBA analysis, the total financial benefit for this retrofitting project only includes the RoCoF benefit. If the additional benefit (estimated between £3M-£100M) per annum VS management cost is included in the overall benefit, the payback period will be reduced significantly and this further demonstrates the strong case to implement the proposed recommendation.

Historical disparity of over-frequency settings

4.50 One further aspect that the WG discussed is the historical disparity of over-frequency settings. The original G59 had 50.5Hz as the over-frequency setting. This was changed for all new generators and for all generators over 5MW retrospectively in August 2010. As part of this exercise it is suggested that all over-frequency settings are set at the current requirement (which by the time the setting change will be done will be a single stage 52.0Hz setting). Where the change cannot be made, a record will be made of this. As this is a retrospective requirement an agreement will need to be made with the DNO to retain the old setting (as allowed for in section 10.5.11 in EREC G59) The records of the sites and their capacity with old settings will be useful to National Grid.

Risk Assessment summary

4.51 The risk associated with changing RoCoF settings and banning vector shift protection for embedded generators less than 5MW is documented in the GC0079 report to the Authority. Based in the Strathclyde report ''Assessment of Risks Resulting from the Adjustment of Vector Shift (VS) Based Loss of Mains Protection Settings Phase II''[13] the workgroup agreed with the conclusion that:

4.51.1 VS protection is generally very ineffective, especially for settings of 12° and above. Analysis concluded that when using these higher settings, in an attempt to reduce the risk of inadvertent tripping, generators are disconnected by EREC G59 protection (as opposed to VS) in the majority of islanding situations. This coupled with the absence of real life cases where out-of- phase auto-reclosure has been recorded in the network for the past 25 years led the workgroup to conclude that VS should not be used as LoM protection.

4.51.2 The risk related to accidental electrocution for the LoM option where only EREC G59 frequency and voltage protection is used is estimated at $6.28x\ 10^{-7}$ and therefore lies within what is termed as the "broadly acceptable" region of personal risk accepted as consistent with the Health and Safety at Work Act 1974.

4.51.3 A minority of the WG suggested that it could be appropriate to consider excluding small synchronous generation from making expensive relay changes, particularly if within the programme it could be shown that the costs outweighed the additional benefits that would be delivered from those affected small generation sites.

5 Consultation and Consultation Responses

13 https://www.nationalgrid.com/sites/default/files/documents/Appendix%202%20Strathclyde%20Report%202.pdf

5.1 The WG issued a consultation on the proposed changes to LoM requirements in EREC G59 from 13 July 2018 to 17 August 2018.

5.2 Seven responses were received from stakeholders. These are all included in Appendix 5, along with the DNOs' responses to stakeholders' comments. No respondent asked for their response to be confidential.

5.3 All responses were broadly supportive in general. One respondent did echo the concern also expressed in the WG that there could be a disproportionate cost to smaller synchronous generation owners that might not be warranted given the small contribution that such generation makes to the overall problem.

5.4 One respondent did express concerns about the changes on the health of older wind turbine generation equipment, but following further bilateral discussion and more research by the respondent, the respondent withdrew the concerns in November 2018.

5.5 Several respondents made the point that it was hard to comment fully on the implications of the proposals as the implementation and compliance arrangements were not clear at the time the consultation was undertaken. The WG did expect such a response, given that the implementation arrangements were still being developed by the network licensees.

5.6 The DNOs' response to stakeholders' comments, as per Appendix 5, were shared with the stakeholders in October 2018.

5.7 At the DCRP meeting on 7 February 2019 it was noticed that the consultation version of G59 had a couple of erroneous references in it to two stages of overfrequency protection, which elsewhere has been removed. This error has been corrected in sections 10.2.1, 10.5.5 and 13.3. The DCRP also suggested minor clarificatory wording in sections 2.10 and 10.5.7. These two minor changes have also been made in the version submitted to the Authority.

6 Implementation

6.1 Pending the approval of The Authority to this modification to the Distribution Code, to comply with the latest requirements, it will be necessary to revise the LoM protection settings for all the existing non-type tested distributed generation fleet to;

- Ensure that where rate of change of frequency (RoCoF) protection relays are used, as part of Loss of Mains protection, the applied setting should be $1Hzs^{-1}$ with a definite time delay of 500ms.
- Ensure that vector shift (VS) protection technique should be removed where it is in use as Loss of Mains protection.
- Remove LoM protection from all generation except synchronous and Double Fed Induction Generator (DFIG) where a suitable RoCoF setting cannot be made without additional investment.

6.2 The number of affected sites is in the order of 50 000 sites. Most these sites will require only a change of settings. Some sites will require additional works. A very high degree of compliance with the new requirements are needed to achieve the benefits envisaged by the workgroup recommendations.

6.3 In order to ensure timely compliance with the new requirements and to guarantee value delivery for the end consumer, it is proposed to set up a dedicated project team to provide the right level of transparency, stakeholder engagement, incentive to act and assistance as required, and where necessary eventually enforce compliance with Distribution Code obligations.

6.4 The project will deliver its output through a combination of up to three delivery programmes;

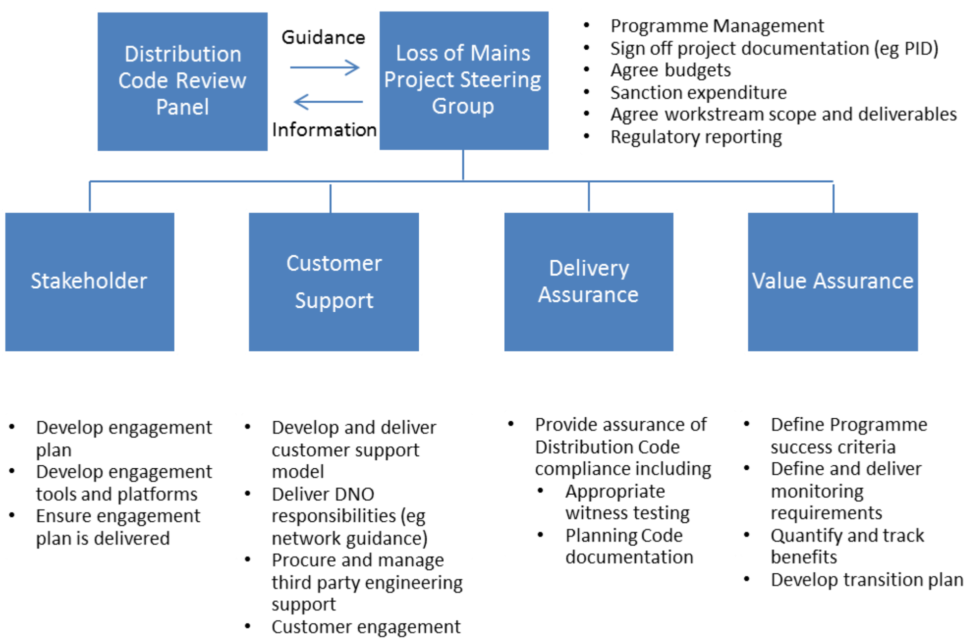
- A **Payment Programme** will incentivise a coordinated and rapid implementation by assisting in removing financial barriers that might prevent Generators from implementing the modification.
- Various forms of assistance will be made available via an **Assistance Programme** for Generators throughout the project, including providing Generators with a view of potential service providers able to administer the requisite protection changes.
- Finally, and if required, an **Enforcement Programme** will tackle the sites that consistently fail to respond to the support offered and do not make the changes.

6.5 It is anticipated that the Payment Programme will drive the most significant proportion of the required work, based on a successful experience of this type of programme in making the required Vector Shift changes during the early Summer of 2018.

6.6 The project will be administrated through two management phases;

- The Framework Setup phase that will run at the beginning of the project.
- The Continuous Review phase which will run through the entire project to monitor delivery, refocus priorities, develop new actions and mitigations if appropriate, and trigger project closure when appropriate.

6.7 The project will also require four specific workstreams to be established, with one workstream focusing on stakeholder engagement, another workstream coordinating customer support activities, a third workstream providing delivery assurance, and the fourth workstream providing value assurance. A project steering group will provide direction to the four workstreams and will report on delivery to the Distribution Code Review Panel and will give affected parties a meaningful influence over the project.



6.8 A procurement methodology will be published at the launch of the project and reviewed annually. This methodology will make clear how National Grid and the distribution network operators, will be procuring the expedited relay settings changes. This will include how National Grid intends to assess the value based on capacity, current type of loss of mains protection, load factor during effective periods and how soon the Generator can make the change. This will outline the procurement principles, assessment principles, the relationship between the generators, DNOs and National Grid, audit requirements and how to participate.

6.9 To facilitate the payment of generators National Grid will enter into a balancing services contract with the DNOs to provide a stability constraint management service, through coordinating the delivery of the requisite Generator protection changes. National Grid will agree the cost model with the DNOs up front, including the level of payment to generators.

6.10 As National Grid will be entering a balancing services contract with the DNO the Generator and DNO costs will be funded via Balancing System Use of System (BSUoS).

6.11 To provide assurance that the project is appropriately implemented National Grid will arrange for audits to be carried out during the process:

- **Procurement methodology:** National Grid will request independent feedback on the Procurement Methodology at the start of the process to ensure that National Grid are using appropriate best practice where possible in the timescales.

- **Confirmation of data:** National Grid will instruct an independent audit of a proportion of the sites to demonstrate that the changes have been delivered in line with the information that the DNOs have been provided. This will give the National Grid confidence that it can use the data provided to change its operational policy.

6.12 The project will be supported by a comprehensive Engagement Programme which will deliver general information and messaging about the project, facilitate targeting specific audiences, and provide monitoring and assurance on delivery to stakeholders.

6.13 General Engagement will run continuously over the duration of the project with an objective to ensure that stakeholders are fully aware of both the change to the Distribution Code and of this implementation project. The messages delivered about the changes to the Distribution Code will include the scope of change of requirements on LoM protection, the reasons behind this change, the works necessary for compliance, parties responsible to carry out these works, the timescales by which compliance will need to be achieved, and the consequences of non-compliance. The messages delivered about the project will include sufficient information about the project, assistance offered, payment offered, the process to apply for such payment, the criteria that would be used to assess whether payment will be offered or not, and the backstop enforcement options.

6.14 Targeted Engagement will comprise two elements. The first element is to be delivered by each DNOs individually to its own customers, i.e. through direct communication between the DNO and Generators. This element will be driven by the value assessment set out in the payment mechanism procurement methodology. The second element is to be delivered collectively by the Project through targeting specific stakeholder groups. Both elements will run in quarterly waves, with the targeting of sites following the general publicity for each wave. This will allow time for Generators to proactively engage with project and thus minimize cost of additional administration. The aim will be to maximise the value delivered by targeting specific stakeholder groups.

6.15 The costs incurred in this process will be significant and will be paid for through BSUoS. Therefore, it will be necessary to provide sufficient information throughout the project duration to allow

- BSUoS Payers;
- Ofgem; and

- all other stakeholders;

to track the costs and the benefits of the project.

6.16 Items to report will include costs incurred, projected future costs, projected impact on BSUoS charge, projections of future RoCoF constraints costs, and other performance measures monitoring the project progress.

6.17 The Payment Programme is intended to encourage the provision of information and the protection settings update by providing an offer of payment for generators who notify their ability to modify the protection settings within a specific time window. This financial support will be independent of how generators get the work done.

6.18 The Payment Programme will run in waves with expenditure in each wave capped to a declared amount. This will provide BSUoS payers confidence over the maximum exposure to costs, will manage the ramp up of workload for DNOs and will encourage early declaration of intent.

6.19 Within the time window specified for each wave, Generators will be required to submit application for payment. Once application is assessed and approved by network licensees, Generators should complete the necessary changes within the agreed timescale, cooperate the witness testing if required, then submit claims and supporting evidence of the initial LoM protection settings, the modified LoM protection settings, and the date at which these were modified DNOs will verify the evidence submitted and administer the payment if successful changes are made.

6.20 Once an application is approved, and prior to sending confirmation, the relevant DNO will apply agreed criteria to determine whether there will be a need to witness or check the implementation. The proportion of sites chosen for witness testing or checking will be specified at the start of the project and, if necessary, adapted in response to success rates.

6.21 Sites that do not require witnessed implementation may be required to allow a site visit to confirm the successful implementation. This will allow for an independent check to be made as part of an annual audit of the end to end process.

6.22 Continuous Review will take place in waves and will evaluate and report regularly in order to:

- Show the value of project performance against the success criteria agreed;
- provide visibility of progress, costs incurred, value delivered and potential future costs;
- identify particular problem groups of Generators or individual sites that may need specific consideration;
- assist the steering group in determining if it is appropriate or necessary to invoke the Assistance Programme or the Enforcement Programme;
- provide assurance of delivery by reporting on success rates.

This programme will also regularly review its assessment criteria and refocus the priorities for the next phase of the engagement programme and assistance as necessary.

6.23 A key feature of the implementation plan is that the RoCoF risks and costs will be effectively controlled and mitigated once a critical number of sites have had the changes made. This critical number is thought to be only a few percent short of 100%, but will depend on the mix of sites having made the changes versus those not having done so. At this point, there will be no further cost benefit in pursuing changes to the remaining installations.

6.24 The Value Assurance activity will determine when the point is reached beyond which pursuing further protection changes will be diminishing returns. This analysis also presents an opportunity for those small sites, particularly synchronous and possibly DFIG, who could be faced with protection change costs that would render their future operation uneconomic to fall into the category of sites that are not worth pursuing as the critical number has been reached where further costs bring no commensurate benefit in system operational savings.

6.25 Assistance will be offered to Generators in three forms:

- Lists of contractors who are willing to offer the service of updating the LoM protection at affected sites, to meet the new requirements, will be compiled and made available. Generators will be able to directly, and at their own risk, employ those contractors if they wish to use their services;
- Comprehensive guidance documents and clear process diagrams will be published to support Generators;
- Where necessary, Generators may ask the DNO for network data to assist with the risk assessment; and
- Where necessary, Generators will be able to seek guidance directly from the DNOs.

6.26 Further assistance may be made available for Generators who fail to or cannot engage with contractors. The extent to which this is provided will be determined in response to performance: a significant shortfall in planned protection changes will give a clear justification to considering an alternative approach.

6.27 The Enforcement Programme will target Generators who failed to respond to the Payment Programme and have not taken advantage of any assistance offered throughout the project. The aim of this programme is to achieve compliance through progressive engagement with the appropriate enforcement option being a last resort and probably subject to direction of the Authority.

6.28 This phase would only run, if necessary, towards the end of the project. It will have the potential of delivering the remaining value to be delivered by the project.

6.29 Each DNO would be responsible for delivering this programme for the relevant Generators connected to their networks.

6.30 Depending on how Generators respond to the project, there could be a situation when the cost of continuing the project exceeds the benefit delivered by it. Therefore, it will be necessary to reassess the situation on regular basis to ensure optimal cost and resource allocation. The assessment should evaluate:

- the overall costs of managing the LoM risk over future years taking into account credible operational conditions, and
- the costs of changing the relays at the remaining sites (as advised by DNOs)

Once the cost of continuing the protection modification project exceeds the costs of managing the LoM risk, the project should be closed as any further work will not deliver any additional value.

6.31 The membership of the Project Steering Group and the four project workstreams will include members of all network licensees and the relevant stakeholder groups representatives. The constitution and the leadership are expected to reflect the tasks appointed to each of the workstreams with the

Value Assurance expected workstream having more representation from the Electricity System Operator than from DNOs and with the Delivery Assurance and Customer Support workstreams expected to have significant representation from DNOs.

6.32 The Project Steering Group will be appointed by and will report to the Distribution Code Review Panel. Affected stakeholders, including affected generators and BSUoS payers will be represented. Representatives on each of the four project workstreams will be appointed by and will report to the Project Steering Group.

6.33 The Value Assurance Workstream will define the project success criteria and the key performance indices required to monitor them. It will monitor the implementation progress, and quantify and track the value delivered including specifying and performing the value assessment. It will also develop a transition plan to ensure all part of the system including the generators be ready for the higher RoCoF operation.

6.34 The Delivery Assurance Workstream will define the process, the documentation, and any tests or site visits required to ensure that the protection change at a specific site has been implemented in a satisfactory manner. It will also monitor the delivery on these requirements.

6.35 The Customer Support Workstream will sit at the heart of the project as it will develop and deliver the customer support model, deliver DNO actions required by the project, and procure and manage third party activities where such activities are necessary. It will respond to queries from Generators, process their claims, and pay them for the work done in line with the agreed payment criteria.

6.36 The Stakeholder Engagement Workstream will be responsible for Stakeholder Engagement activity planning and performance monitoring required to ensure the success of the protection change programme. It will develop the engagement plans including the activities, tools, and platforms required for their implementation. It will also oversee the delivery of these engagement plans.

Further details on the implementation plan are included in Annex 6 to this Report.

7 Impact & Assessment

Impact on the Distribution Code

7.1 The workgroup recommends amendments to the Distribution Planning and Connection Code and Engineering Recommendations G59

7.1.1 The appropriate text for the Distribution Planning and Connection Code is contained in Annex [2] of this document

7.1.2 The appropriate text for G59 is contained in Annex [3] of this document

Impact on National Electricity Transmission System (NETS)

7.2 This will result in limiting the total capacity of embedded generation that is at risk of being unnecessarily disconnected from the system by their LoM protection following an event on the transmission system.

Impact on Embedded power stations

7.3 The modification proposed will require that embedded generation connected to the system after the agreed implementation date and which is using RoCoF techniques for LoM must use a setting of $1Hzs^{-1}$ and time delay of 500ms. Vector shift protection technique should be removed where it is in use as Loss of Mains protection.

Impact on Grid Code Users

7.4 Implementation of the proposal reduces risk of inadvertent tripping of embedded Power Stations by their LoM relays. This will improve the security of supply on the Transmission System, and reduce the risk of significant system disturbances. It will also minimise the need to manage such risk via balancing actions which would reduce BSUoS charges on Users of the Transmission System.

Impact on Greenhouse Gas emissions

7.5 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 Distribution Code Objectives

7.6 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 distribution of electricity;

This modification will increase the stability and robustness of the electricity system. Having a stable and robust overall system is a prerequisite for an efficient, co-ordinated, and economical distribution system.

This modification will reduce the risk of RoCoF LOM protection inadvertently shutting down DG, benefitting the operation of the distribution and total system. RoCoF is likely to continue to increase and therefore that increased resilience to this, where more economic options are not available, is beneficial.

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

This modification will reduce constraints applied to large infeed, associated balancing actions, and facilitate the connection of more non-synchronous generation. The reductions in constraints and balancing actions would improve competition by reducing the need for actions taken by the SO outside the market. By facilitating the integration of non-synchronous generation to bring more generation to market is likely to improve competition

(iii) Efficiently discharge the obligations imposed upon DNOs by the Distribution Licence and comply with the Regulation (where Regulation has the meaning defined in the Distribution Licence) and any relevant legally binding decision of the European Commission and/or Agency for the Co-operation of Energy Regulators.

The proposal has a neutral impact on this objective.

(iv) Promote efficiency in the implementation and administration of the Distribution Code.

The proposal has a neutral impact on this objective.

Impact on core industry documents

7.7 The proposed modification does not affect any other core industry documents.

Impact on other industry documents

7.8 The proposed modification does not affect any other industry documents.

8 Working Group Recommendations

Implementation

8.1 The Workgroup proposes that, should the proposals be taken forward, the proposed changes be implemented on the 1st of May 2019.

8.2 That retrospective application for plant whose LoM is through relays should commence as soon as funding and implementation mechanism is in place.

9 Licensees' Recommendations

9.1 This Report recommends changes to EREC G59 and the Distribution Code to include the following:

9.1.1 VS protection technique should not be used as LoM protection. This change should apply for all existing non type-tested embedded power stations commissioned before 1 February 2018.

9.1.2 For plants employing RoCoF protection, all relays should be set at $1Hzs^{-1}$ with 500ms time delay. This change should apply for all existing embedded power stations commissioned before 1 February 2018.

9.2 On non-synchronous plant, other than DFIG, the workgroup recommends that in cases where RoCoF relay settings cannot be changed to $1Hzs^{-1}$ with a 500ms time delay, this protection should be disabled.

9.3 The requirements of 7.1 and 7.2 should be applied to all generation, including considering installations of >5MW that formed part of Phase 1 of this project, i.e. the GC0035 programme for installations >5MW that started in August 2014. That programme did not make any recommendations regarding vector shift: it is now necessary to remove vector shift from these installations where it exists, in accordance with 7.1 and 7.2 here.

9.4 The workgroup recommends that existing type-tested plant should be clearly identified, but not be retrofitted.

9.5 The workgroup believes that the programme should be completed within three years of the changes being approved by the Authority (provisionally complete therefore by May 2022).

9.6 The workgroup determined that there is a significant benefit from retrospective application of these requirements and hence recommends that work commences as early as possible otherwise the National Grid will continue spending over £40M per annum in risk mitigation.

Annex 1 – Terms of Reference

- The workgroup will investigate extending the first stage of work (Phase 1 underGC0035) to cover all distributed generation as Phase 2.
- The workgroup will undertake Phase 2 of the work. The context for Phase 2 includes the following considerations:

  a) There is a convergence of technical considerations when transmission system faults give rise to both voltage and frequency phenomena. GC0079 is concerned primarily with the frequency effects on the Total System, or on DNO power islands.

  b) It is recognised that National Grid will have to develop a formal operating standard in line with the European Codes defining the maximum RoCoF that the total system is secured against. This is an expected consequential requirement of implementing the EU Network Code currently titled “Network Code on Operational Security” in the GB frameworks.

  c) There are a number of factors that will prevent generating plant riding through frequency changes. These include both the physical capabilities of electrical and mechanical components, the capability of control systems, and the effects of protection.

  d) Generating equipment connected to distribution networks will generally have protection that fulfils two discrete functions. The first is to protect the generating equipment and ancillaries. The second is to provide the required network interface protection, i.e. as currently required by G59 or G83.

  e) The focus of Phase 2 is to address the risks of unwanted tripping initiated by the network interface protection, but includes considering mitigation of any additional frequency resilience risks arising from generating equipment protection and control.

  f) Phase 2 will investigate the suitability of VS shift protection as an alternative to RoCoF, taking into account its possible unsuitability for transmission fault ride through requirements.

- Phase 2 will therefore include the following activities:

  i) Monitoring the implementation of the protection changes recommended under phase 1.

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

  iii) Researching the characteristics of existing embedded generation of all sizes where the embedded generation is fitted with VS anti-islanding protection.

  iv) Investigate the likely effect of transmission faults on VS protection techniques, and determine the risk of wide spread DG tripping from VS protection being inappropriately sensitive to transmission faults.

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

  vi) Investigating the characteristics of popular/likely inverter technology deployed in relation to its behaviour in the presence of the voltage phenomena associated with transmission faults;

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

viii) 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;

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

x) Considering any other relevant issues in relation to the resilience of the total system in respect of the operating characteristics of small generation;

xi) Consider, if appropriate, revised VS protection settings, including any supporting risk assessment analysis;

xii) To the extent that revised settings are proposed, create detailed specifications for the application of those revised settings;

xiii) Consider any other adverse effect on total system operability that existing G59 and G83 requirements may present, given the changed context since G59 and G83 were originally introduced, and include any such issues and their mitigation in the drafting and consultation (for example the current and future implications of Black Start on the existing over and under frequency settings);

xiv) Developing proposals for consultation on any proposed changes to RoCoF and VS protection drawing out the costs, benefits, and risk of such changes to present to the GCRP and DCRP. Proposals should include a recommendation of where implementation costs should fall and the most appropriate workgroup for this issue to sit with;

xv) Initiating consideration by DNOs of the future management of out-of-phase reclose risk; and

xvi) Engaging with the Health and Safety Executive (HSE) and all affected parties considering the different stakeholders that will be affected by any proposed changes.

– Phase 2 will deliver proposals concerning RoCoF based protection on embedded generators of rated capacity of less than 5MW and concerning VS protection for all embedded generation.

Annex 2 – Distribution Code

The proposed modification would be implemented on 1 May 2019.

The draft of the new version (version number TBA) of the DCode submitted, has taken the current version 36 of the DCode and tracked changes to show the material changes to the DCode text and content. There are only a very small number of purely consequential changes to the Distribution Code, which are reproduced in isolation in the following pages of this Annex 2.

If other modification proposals are approved before the implementation of this modification proposal; and result in change to the current version 36 of the DCode, the tracked changes in this Annex will be applied to the version of the DCode that is current on the proposed implementation date.

Annex 3 – Legal Text for G59

Proposed changes to EREC G59 are documented in a file called **Annex 3 G59_3_4 assuming approved by Ofgem, modified for dc0079 retrospective - becoming G59_3_5** circulated together with this report.

DCRP/MP/18/01 proposes a minor modification to the current text of G59 Issue 3 Amendment 4. These changes in DCRP/MP/18/01 are judged to have no material impact on the changes proposed in this FMR but are expected to be implemented on 18 March 2019 ahead of the implementation of this modification proposal; DCRP/MP/18/02.

If the modifications as proposed in DCRP/MP/18/01 are approved by the authority and implemented before implementation date of this proposal on 1 May 2019, the modifications to G59 proposed in this report will be applied to the version of G59 that is current at the time of implementation (expected to be Issue 3 amendment 5).

Annex 4 – Disabling ROCOF on non-synchronous generation[14]

Risk analysis based on Non-detection Zone (NDZ)

If an existing non-synchronous installation has a relay that is not possible to reset to RoCoF with the required settings – one of the options is to disable it. This section provides a rationale for allowing such arrangement based on the Phase II risk assessment results reported in [1].

The question of disabling RoCoF (while preserving G59 voltage and frequency protection) can be best answered by analysing NDZ tables included in Appendix B of the report [1]. The NDZ tables for each individual technology (including predominant groupings) under all considered setting options are also included here for convenience

The four NDZ values (NDZ_{PI}, NDZ_{PE}, NDZ_{QI}, NDZ_{QE}) under RoCoF setting of 1 Hz/s with 0.5 s delay (the considered recommendation for RoCoF protection) need to be compared with the lesser of the two values given for UF/OF and UV/OV (G59 frequency and voltage protection only). If any of the four NDZ values corresponding to RoCoF are lower than those corresponding to G59 frequency and voltage protection only, an increase in risk of island non-detection can be expected after disabling RoCoF. Otherwise, the risk remains unchanged.

After analysing NDZ values for the three prevailing technologies (SG, DFIG and IC, also including a variety of generation mixes, 12 in total) it can be concluded that an increase of risk could be expected when disabling RoCoF protection for SG (**Table 1**) and DIFIG (**Table 3**) only. In each table the increase in terms of NDZ is indicated in red, i.e. NDZ value compared to the recommended RoCoF setting option of 1 Hz/s, 0.5 s delay.

Therefore, for non-synchronous generating technologies (with the exception of DFIG), the LoM protection can be disabled (providing both frequency and voltage G59 protection are in place) without increasing the risk of island non-detection.

DZ values as reported in Phase II risk assessment study

In the following tables the numbers in **green** indicate the existing NDZ values, the numbers in **blue** indicate the anticipated NDZ after disabling RoCoF protection, and the numbers in **red** indicate the corresponding NDZ increase.

Table 1. NDZ values for Generation Mix 1 (100% SG)

LOM Setting Option	NDZ_{PI} Import [%]	NDZ_{PE} Export [%]	NDZ_{QI} Import [%]	NDZ_{QE} Export [%]
ROCOF				
0.13 Hz/s	1.03	0.53	2.12	1.42
0.2 Hz/s	1.03	0.78	2.45	1.92
0.5 Hz/s, 0.5 s	3.05	1.58	7.36	14.56
1 Hz/s, 0.5 s	5.85	3.56	14.09	35.20
OF, UF, OV, UV				
UF/OF	6.92	3.14	12.16	23.67
UV/OV	>50	>50	>50	>50
NDZ increase ->	1.07	0	0	0

[14] https://www.nationalgrid.com/sites/default/files/documents/Appendix%202%20Strathclyde%20Report%202.pdf

Table 2. NDZ values for Generation Mix 2 (100% IC)

LOM Setting Option	NDZ_{PI} Import [%]	NDZ_{PE} Export [%]	NDZ_{QI} Import [%]	NDZ_{QE} Export [%]
ROCOF				
0.13 Hz/s	0	0	0	0
0.2 Hz/s	0	0	0	0
0.5 Hz/s, 0.5 s	>50	>50	>50	>50
1 Hz/s, 0.5 s	>50	>50	>50	>50
OF, UF, OV, UV				
UF/OF	**0.65**	**0.87**	**0.28**	**0.43**
UV/OV	16.49	17.13	8.32	4.35
NDZ increase ->	0	0	0	0

Table 3. NDZ values for Generation Mix 3 (100% DFIG)

LOM Setting Option	NDZ_{PI} Import [%]	NDZ_{PE} Export [%]	NDZ_{QI} Import [%]	NDZ_{QE} Export [%]
ROCOF				
0.13 Hz/s	0	0	0	0
0.2 Hz/s	0	0	0	0
0.5 Hz/s, 0.5 s	0.83	1.44	4.68	2.29
1 Hz/s, 0.5 s	**1.98**	**2.38**	**7.20**	**5.04**
OF, UF, OV, UV				
UF/OF	**3.97**	**2.69**	**8.69**	**9.98**
UV/OV	8.18	12.02	>50	17.92
NDZ increase ->	**1.99**	**0.31**	**1.49**	**4.94**

Table 4. NDZ values for Generation Mix 4 (75% SG + 25% PV)

LOM Setting Option	NDZ_{PI} Import [%]	NDZ_{PE} Export [%]	NDZ_{QI} Import [%]	NDZ_{QE} Export [%]
ROCOF				
0.13 Hz/s	0.92	0.32	1.27	1.73
0.2 Hz/s	0.92	0.32	1.99	1.9
0.5 Hz/s, 0.5 s	4.86	3.19	12.17	24.38
1 Hz/s, 0.5 s	6.78	5.32	15.96	>50%
OF, UF, OV, UV				
UF/OF	**5.37**	**2.49**	**8.65**	**17.45**
UV/OV	>50%	>50%	>50%	>50%
NDZ increase ->	0	0	0	0

Table 5. NDZ values for Generation Mix 5 (50% SG + 50% PV)

LOM Setting Option	NDZ_{PI} Import [%]	NDZ_{PE} Export [%]	NDZ_{QI} Import [%]	NDZ_{QE} Export [%]
ROCOF				
0.13 Hz/s	0	0	0	0
0.2 Hz/s	0	0	0	0
0.5 Hz/s, 0.5 s	4.55	4.30	12.75	45.61
1 Hz/s, 0.5 s	6.34	4.79	16.03	>50%
OF, UF, OV, UV				
UF/OF	**3.85**	**1.66**	**5.26**	**11.23**
UV/OV	>50%	>50%	>50%	>50%
NDZ increase ->	0	0	0	0

Annex 5 – Consultation Responses

Consultation responses received are documented in a file called **Annex 5 - DC0079 Consultation Responses** circulated together with this report.

Annex 6 – Detailed Implementation Plan

Proposed detailed implementation plan is documented in a file called **Annex 6 DC0079 Implementation Plan** circulated together with this report.