THE DISTRIBUTION CODE OF LICENSED DISTRIBUTION NETWORK OPERATORS OF GREAT BRITAIN

Stage 03: Industry Consultation

DCRP/18/08/PC

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

This document presents proposals to modify the Distribution Code and Engineering Recommendations G59 for Industry Consultation. Any interested party may make a response as set out in Section 7 of this document.

This document contains the findings of the workgroup up to 27/03/2018.

The workgroup recommends that the Distribution Planning Code and EREC G59 should be changed to ensure that all existing embedded generators make the necessary 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

Any Questions?

Contact:

David Spillett

+44 (0) 20 7706 5124

Proposer:

Graham Stein

National Grid

About this document

This is an industry Consultation document which contains a summary of the discussions and the recommendations of the DC0079 workgroup.

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

1 Executive Summary

1.1 This consultation seeks view on the revision of the Loss of Main (LoM) protection requirements on all existing G59 generation of any size. This will, if approved, 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 workgroup, through this consultation, is 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 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 ± 50 º. 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 The System Operator's outturn cost 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

[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

RoCoF constraint costs. These figures are based on the more conservative, Steady State scenario of the 2017 National Grid Future Energy Scenarios (FES)[4].

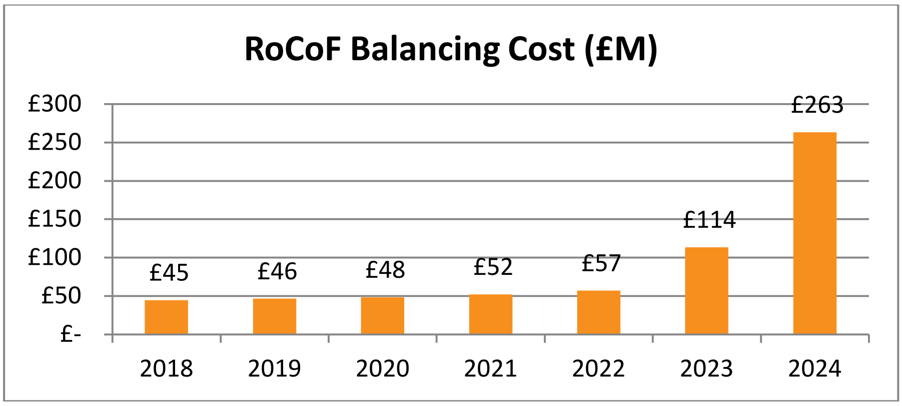


Fig 1 Annual Costs of Managing RoCoF

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[5] , 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 consultation.

1.11 From the Week 24 submissions and feed in tariff data, the workgroup estimates that at least 50 000 sites will need visiting in order to assess and, where required, to make them 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≤ 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 estimates that the cost of implementing these proposals could be within the range from £21M to £97M. This broad estimate is

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

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

due to the scarcity of the information available at each site. The workgroup believes an estimate of £31M (Expected Costs) is more realistic based on experience gained during GC0035 and some feedback from DNOs.

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, ie 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 The workgroup believes that the implementation programme should also engage with owners of type-tested plant. Such owners will not need to make changes to their plant, but the opportunity should be taken to ensure the DNOs hold complete and correct information on these customers' installations.

1.17 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 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 workgroup consultation:

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 42 meetings, the first on 14 June 2013 with the most recent meeting being on 27 March 2018.

3 Why Change?

Background

3.1 The reduction of system inertia, the causes, impacts, and mitigation measures have been extensively articulated in the GC0035[6] and GC0079[7] 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 $\pm 50^{\circ}$.

3.2 The System Operator'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 System Operator has spent over £39.2M in RoCoF related constraint costs.

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 consultation document.

---

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

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

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 – eg 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 (ie 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 consultation 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 for non-synchronous plant:

4.10.1 for existing embedded generation plant 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.

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, ie 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; ie 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[8] demonstrated that all type-tested inverters, within their sample tested,

4.19.1 Will trip in genuine islanding situations; and

4.19.2 Will remained 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:

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

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 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 consultation.

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 ie 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 50 000 sites will need to be visited 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 Table 4 below shows the workgroup estimated unit cost of implementing each activity. These costs were put together based on previous experience gained from GC0035 and feedback from DNOs and assume that there would be significant economies of scale associated with undertaking this work as a closely managed programme.

Nature of work	cost per site(£)
Site visit	200
Re-programme/reset/disable existing relay	200
Remove Vector Shift (non-synchronous plant except DFIG)	200
Replace VS relay or single function RoCoF relay	7700

Table 4 Unit cost

4.29 In an attempt to estimate the retrospective application costs the workgroup considered three cases namely the low estimate, WG estimate (central estimate) and the high estimate. Table 5 shows the nature of work and the associated estimated cost.

	Nature Of Work	Low Estimate		WG Estimate		High Estimate	
		Number of Sites	Cost (£)	Number of Sites	Cost(£)	Number of Sites	Cost(£)
1	Synch - reset RoCoF	355	71,074	477	95,379	260	52,070
2	Synch replace RoCoF	19	144,019	477	3,672,080	2,343	18,042,324
3	Synch reset VS to RoCoF	1,049	209,849	977	195,469	878	175,564
4	Synch replace VS with RoCoF	117	897,685	977	7,525,549	7,900	60,832,857
5	Asynch reset RoCoF	2,585	516,930	2,927	585,401	559	111,730
6	Asynch remove RoCoF	136	27,207	2,927	585,401	5,028	1,005,568
7	Asynch reset VS to RoCoF	41,176	8,235,255	20,625	4,124,951	3,304	660,876
8	Asynch remove VS	4,575	915,028	20,625	4,124,951	29,739	5,947,886

Table 5 No of Sites and estimated costs (excluding site visits)

4.29.1 The high estimate is characterised by a larger number of sites that require relay replacement either because relays cannot accept the new proposed RoCoF setting or are a single function vector shift relay. This estimate assumes that over 10 000 sites (line 2 and 4 in Table 5) will require relay change at the cost of £7 700 per site.

4.29.2 The WG estimate is what the workgroup believes is the best representation of the scope and cost of the work. This is based on the experience gained during GC0035 implementation and information from DNOs. This estimate assumes that approximately 1500 sites require relay replacement.

4.29.3 The low estimate, assumes that the majority of sites (over 80%) will have LoM protection provided by a relay with an appropriate range of settings. Under this case each relay would need to be reset to operate at a RoCoF of $1Hzs^{-1}$ with a time delay of 500ms at an estimated cost of £200 per site. This scenario has the least number of relays replacements (approximately 140 sites).

4.30 Table 6 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≤ 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 6 Retrospective Application Cost

Estimated Balancing Services Cost Savings DC0079

4.31 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).

4.32 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 the National Grid's Future Energy Scenarios.

4.33 Costs were estimated using the long-term market and constraints modelling tool BID3[9]. 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 [10](NOA).

4.34 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.

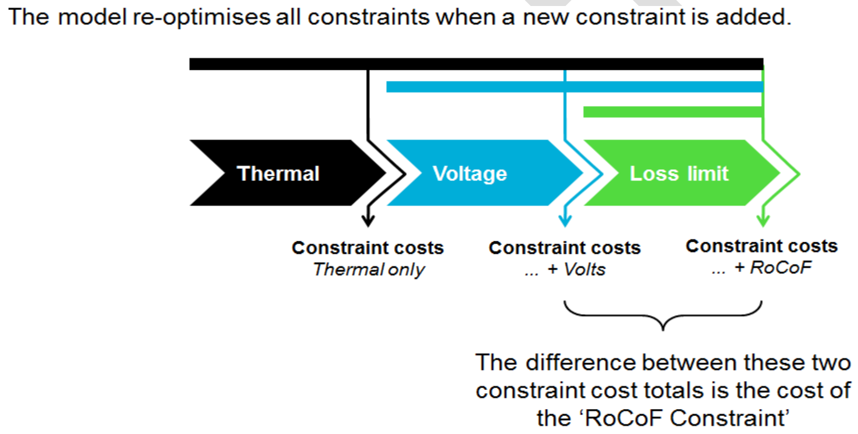


Fig 2 RoCoF Constraint Calculation Methodology

4.35 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).

4.36 The annual cost estimates for the RoCoF constraint for the other three Future Energy Scenarios are expected to exceed the estimates shown in Table 7

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

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

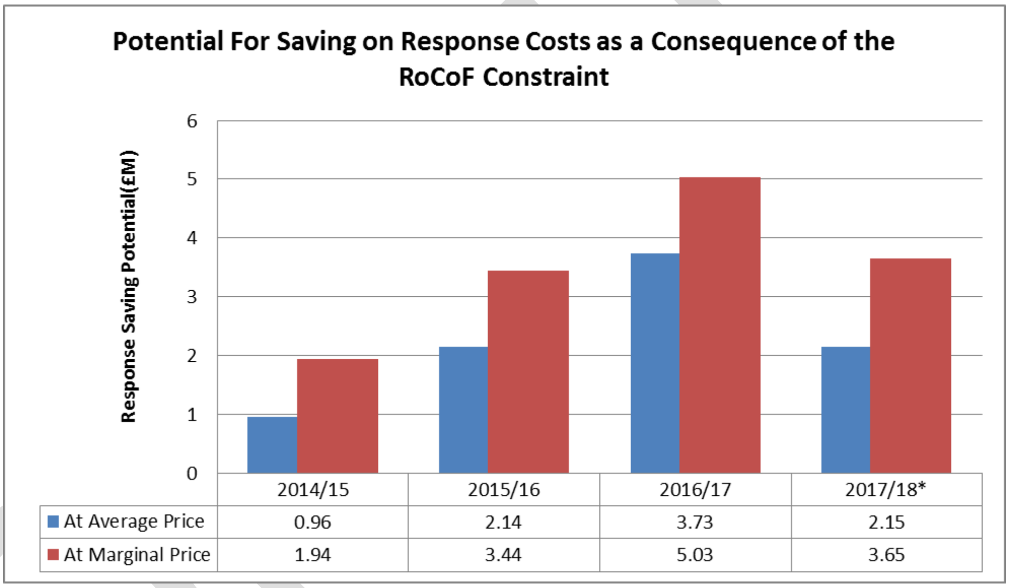
[10] https://www.nationalgrid.com/uk/publications/network-options-assessment-noa

Table 7 Estimated Constraint Cost: Steady State

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

4.37 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.

4.38 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.



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

Fig 3 Potential Savings in Response costs

4.39 The majority of 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.

4.40 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

4.41 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.

4.41.1 Net Present value calculations for the Low Estimate scenario where investment cost is £21M are shown in Table 8.

Year	2018	2019	2020	2021	2022	2023	2024
Remediation Cost	7.00	7.00	7.00				
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)	6.76	6.53	6.31	0.00	0.00	0.00	0.00
Present Value of Savings - Costs (annual)	**-6.76**	**-6.53**	**-6.31**	**38.67**	**40.79**	**78.55**	**175.91**
Cumulative net present value(Case 1)	**-6.76**	**-13.30**	**-19.61**	**19.05**	**59.85**	**138.40**	**314.31**
Savings (Discounted total)	333.92						
Costs (Discounted total)	19.61						
Net Present Value (total)	**314.31**						
Benefit: Cost ratio	**17.03**						

Table 8 NPV analysis for low implementation Estimate

4.41.2 Net Present value calculations for the workgroup estimate scenario where investment cost is £30.9M are shown in Table 9.

Year	2018	2019	2020	2021	2022	2023	2024
Remediation Cost	10.30	10.30	10.30				
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)	9.95	9.62	9.29	0.00	0.00	0.00	0.00
Present Value of Savings - Costs (annual)	**-9.95**	**-9.62**	**-9.29**	**38.67**	**40.79**	**78.55**	**175.91**
Cumulative net present value(Case 1)	**-9.95**	**-19.57**	**-28.86**	**9.81**	**50.60**	**129.15**	**305.06**
Savings (Discounted total)	333.92						
Costs (Discounted total)	28.86						
Net Present Value (total)	**305.06**						
Benefit: Cost ratio	**11.57**						

Table 9 NPV analysis for workgroup expected implementation estimate

4.41.3 Net Present value calculations for the high cost estimate scenario where investment cost is £96.9M are shown in Table 10.

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 10 NPV analysis for high implementation estimate

4.41.4 Table 11 is a summary of the cost benefit analysis

Description	Investmetn Cost (£M)	Discounted Benefits(£M)	Discounted Cost (£M)	Net Present Value (£M)	Cost Benefit Ratio
Low Estimate	21	334	20	314	17
WG Estimate	31	334	29	305	12
High Estimate	97	334	90	244	4

Table 11 Summary of the CBA

a) The net present value is greater that £300M for the workgroup estimate and greater than £200M for the high cost estimate case.

b) The ratio of the benefit to the cost is greater than one for all the cost estimates.

c) The breakeven points are shown Fig 4. For the low and workgroup cost estimates the breakeven point is within the year of project completion while that of the high estimate occurs between within two years of completion. So in general the payback period of this project is within two years of completion.

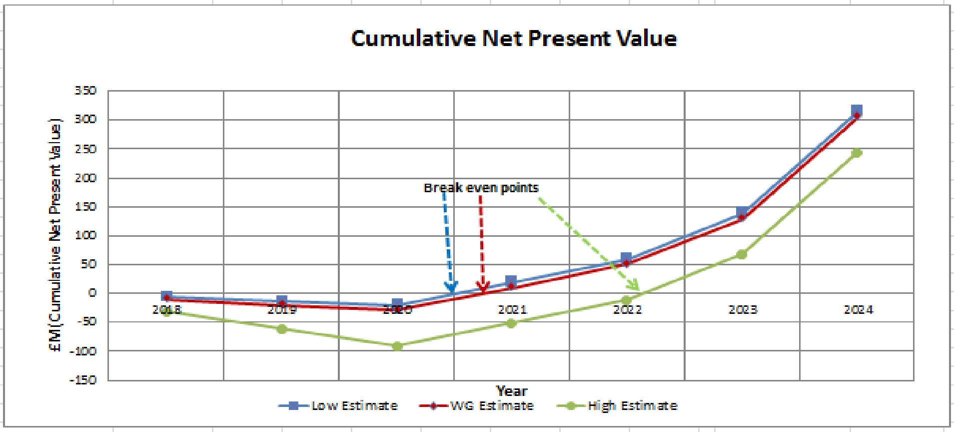


Fig 4 Cumulative Net Present Value

4.42 The workgroup concluded that the benefits of implementing these changes outweighed the expected implementation costs of £31M. The net present value is greater that £300M for the workgroup cost estimate.

The workgroup proposes that the project be implemented starting from 2018. This will ensure the escalating RoCoF constraint costs are curtailed, ultimately lower cost to the consumer.

4.43 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

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

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

4.44.2 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.

4.45 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.

4.46 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

4.47 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.

4.48 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''[11] the workgroup agreed with the conclusion that:

4.48.1 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.

4.48.2 The risk related to accidental electrocution for the LoM option where only EREC G59 frequency and voltage protection is used is estimated at 6.28×10^{-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.

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

5 Implementation

5.1 The workgroup recommendations will require Loss of Mains protection changes to be made at tens of thousands of Embedded Generation sites. In most cases this can be achieved with a settings change but further work may be required at many sites. A very high degree of compliance with the requirement is needed to achieve the benefits envisaged by the workgroup recommendations, as any embedded generators that do not make the necessary change will add to the effect frequency disturbances and prevent all the benefits of the change being delivered.

5.2 Known issues are:

- The embedded generators that need to change have little need to interact with network licensees or regulators
- All distribution licensees are affected implying a high level of co-ordination is required
- There is no clear existing means to fund the work
- A retrospective programme of this type and scale is unprecedented in Great Britain

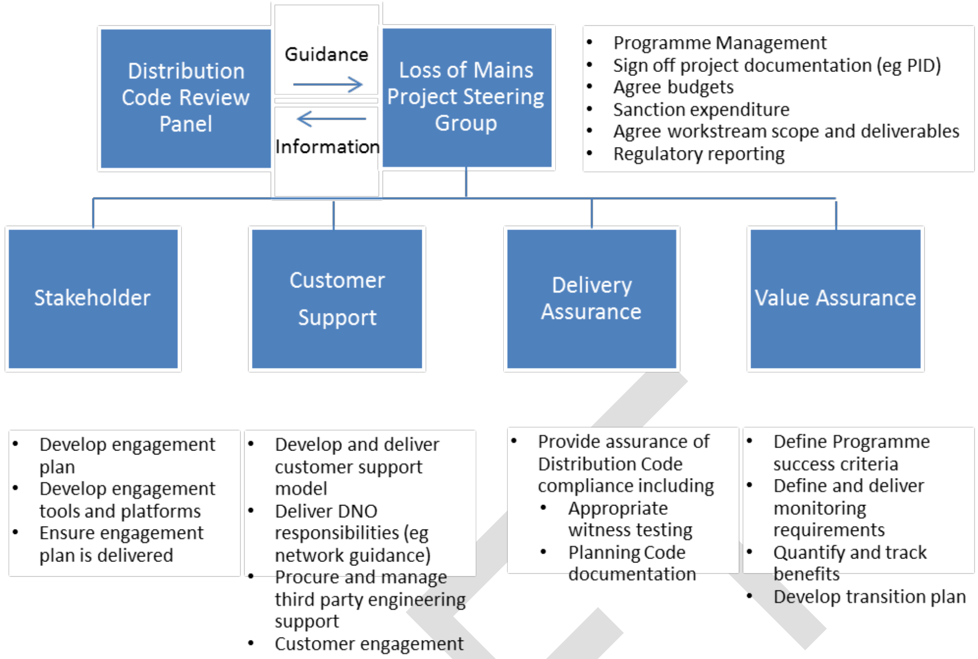
Outline Implementation Proposal

5.3 The network licensees propose to create a programme with responsibility for ensuring that necessary changes are made and the promised value is delivered. All network licensees will be represented and resource, best practice and experience shared in order to keep costs low and in line with the CBA presented in this document. The proposed approach to address the issues raised above is summarised in the following table:

Issue	Proposed Approach
Large Number of Users need to comply	• Proactive engagement - go out and find who needs to comply • Agree programme success criteria
Affected Users don't normally interact with licenses or regulators	• Proactive engagement – provide support and encouragement • Give affected User groups a meaningful role in the programme
Unprecedented Programme	• Set up governance necessary to allow decisions to be made as issues arise • Agree success criteria
Co-ordination Needed	• All affected parties involved

Table 12 Implementation approach

5.4 A multi-workstream programme is proposed, consisting of 4 workstreams reporting to a Steering Committee which would be responsible for delivery. The Steering Committee would work with the guidance from the Distribution Code Review Panel. Stakeholders will have a decision-making role on the steering committee, including affected stakeholders and other relevant stakeholders.



5.5 The core of the programme is a Customer Support workstream which would betasked with facilitating compliance. This workstream would:

- Identify and prioritise customers that need to comply
- Make contact and identify those that want help to do so
- Provide help for those that want it including
  - Assessing any network implications
  - Potentially assistance in physical changes on site (ie protection setting or equipment changes)
- Broader customer engagement in line with engagement plan
- Manage risks and liabilities and statutory compliance

5.6 Assurance of delivery and values realised will be provided by two separate workstreams, the first providing assurance that physical changes are made and the second providing assurance that the electricity networks will perform as expected as a result so that the anticipated benefits can be delivered.

Organisational Responsibilities

5.7 Programme governance will define the responsibilities of all programme members. The proposal also allows these to be aligned with organisational responsibilities.

What	Who	Link to Programme
Compliance with Distribution Code	Affected Network Users	Represented at • Steering Group • Customer Support Workstream • Delivery Assurance Workstream
Assurance of Compliance with Distribution Code	Distribution Licensees	Leading • Customer Support

What	Who	Link to Programme
		Workstream • Delivery Assurance Workstream
Assurance of Value	National Grid Electricity System Operator	Leading Value Assurance Workstream

Table 13 Organisational Responsibilities

5.8 There are a number of potential ways to implement the change programme, and any views and thoughts on the issues which should be taken into consideration are welcome in response to this consultation. Any proposals to make changes to put new obligations and/or funding into effect will require substantive input from the affected stakeholders in a process outside of Distribution Code governance.

Accelerated VS change programme summer 2018

5.9 National Grid in collaboration with three DNOs initiated an accelerated VS change programme to mitigate risks for summer 2018. In time, these specific risks would have been addressed the proposals in this consultation, but an opportunity was identified and taken to resolve them earlier.

5.10 Analysis was carried out by National Grid with support from the DNOs to assess the risk due to VS tripping events in the period until the retrospective change is implemented. A risk was identified that the electricity system could become unstable because significant volumes of embedded generation shut down coincident with a transmission system fault.

5.11 This instability can be avoided by a combination of:

1) Maintaining a minimum level of system inertia. This would be achieved by synchronising generation using the Balancing Mechanism when necessary at an estimated cost of £40m per year;
2) Curtailing the output of the embedded generation at risk of shutting down, at an estimated cost of £3M per year; and/or
3) Enhancing the stability of the affected embedded generation relative to their obligated requirements at an estimated one off cost of £250k.

5.12 Option 3 was considered to be the most economic and efficient way of resolving the system concern.

5.13 Analysis also showed that due to the location of VS equipped plant and nature of the VS spread through the transmission system, the most effective way to address the risk is to seek changes at 800MW of embedded generation capacity in the following DNOs:

- WPD South West
- SSE: Southern Electric Power Distribution
- UKPN: Southern Power Networks
- And any downstream IDNOs in these networks

5.14 National Grid in collaboration with the three DNOs therefore initiated an accelerated VS change programme to mitigate risks for summer 2018. The invitation letters for participating in the change programme were published on 2 May 2018. A total of 811MW of generation capacity at 72 sites was selected to change VS type protection with a setting of RoCoF

1 Hzs^{-1} with 500ms delay. Generators who successfully implemented the change by 1 June 2018 will be compensated.

5.15 The payment rates were:

- £2,500 per generator where only a setting change was involved
- £4,000 where relay change was involved

Alignment of approaches

5.16 The actions used to address for Vector Shift risks in summer 2018 are different to those proposed under in this consultation, but are clearly related and are hence described here.

5.17 There are some differences in the need for action which mean there are differences in the proposed approaches:

a) There were immediate Vector Shift risks that needed to be, and could be, addressed. The benefits were delivered directly to BSUoS paying parties in short timescales meaning there was a clear case to address the problem using a Balancing Service. The full retrospective programme will take longer to implement and the benefit will be accrued once a very high level of compliance is achieved.

b) The immediate Vector Shift risks were addressed by improving a small number of embedded generators' resilience to transmission faults. The full retrospective change programme will facilitate compliance with requirements from a large group of stakeholders that has not been subject to such an exercise previously.

c) Vector Shift risks summer 2018 could be addressed through action by a subset of potential providers who are readily accessible and actively engaged with DNOs and National Grid. For the full retrospective LoM programme to be successful, it will need a very high volume of compliance with new requirements by parties who are not used to interacting with licensees and regulators.

d) The cost of addressing Vector Shift risks in Summer 2018 was in the order of £250k. The estimated cost of the full retrospective programme is £30m: the initiatives are significantly different in scale.

6 Impact & Assessment

Impact on the Distribution Code

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

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

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

Impact on National Electricity Transmission System (NETS)

6.2 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

6.3 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

6.4 The proposed modification will reduce the risk of embedded generators from tripping as a result of transmission related secured events.

Impact on Greenhouse Gas emissions

6.5 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

6.6 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

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

Impact on other industry documents

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

Implementation

6.9 The Workgroup proposes that, should the proposals be taken forward, the proposed changes be implemented

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

7 Workgroup Recommendations

7.1 This consultation recommends changes to EREC G59 and the Distribution Code to include the following:

7.1.1 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.

7.1.2 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.

7.2 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.

7.3 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, ie 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.

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

7.5 The workgroup believes that the programme should be completed within three years of the changes being approved by the Authority (provisionally complete therefore by October 2021).

7.6 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 System Operator will continue spending over £40M per annum in risk mitigation.

8 Consultation Responses

8.1 Views are invited upon the proposals outlined in this consultation, which should be received by **17/08/2018**.

8.2 Your formal responses may be emailed to dcode@energynetworks.org

8.3 The proposals set out in this consultation are intended to better meet the Distribution Code Objectives. To achieve this, they are intended to facilitate efficient and economic connection arrangements whilst ensuring there is no impact on the safety and security of the transmission system, and no discernible impact on the visual disturbance to electricity consumers.

8.4 Responses are invited to the following questions:

(i) Do you believe that DC0079 better facilitates the appropriate Distribution Code objectives? If not, why do they fail to do so?

(ii) Do you support the proposal to remove vector shift protection technique as loss of main protection for existing distributed generators? If not, please clarify why.

(iii) Do you support the proposed change in RoCoF settings to $1Hzs^{-1}$ with a delay of 500ms for all non-type-tested distributed generators below 5MW? If not, please clarify why.

(iv) Do you agree that RoCoF protection should be disabled, in cases where settings cannot be changed, for all non-synchronous plant except for DFIG?

(v) Do you support the proposal that all DFIG machines should use RoCoF protection technique set at $1Hzs^{-1}$ with a 500ms time delay as loss of mains?

(vi) Do you agree that all synchronous generation >5MW, should have a RoCoF setting of $1Hzs^{-1}$ with a delay of 500ms retrospectively applied?

(vii) Do you agree that the same approach for asynchronous generation <5MW should be applied to that >5MW in that if the existing protection cannot be reset to RoCoF of $1Hzs^{-1}$ with a delay of 500ms, then it should just be disconnected/removed?

(viii) Do you agree with the workgroup's proposal that type-tested plant, currently connected to the system, should not be modified?

(ix) Do you agree that where practicable on existing relays, the overfrequency setting should be changed to the current requirements (and left as-set if the relay cannot accommodate it)?

(x) Do the proposed changes introduce any material risks for distributed generators? What are these risks? And have they been or will they be appropriately mitigated?

(xi) Do the proposed changes impose any additional material risks on the system operator, eg reduced stability margins, reduced reactive capability margins, or difficulty in managing transmission system voltages? If yes, please highlight these risks.

(xii) Do the proposed changes impose any additional material risks on distribution network operators, eg stability and security issues safety risks, or any additional investment that might be neither economic nor efficient? If yes, please highlight these risks.

(xiii) Do the proposed changes adequately protect the interests of all distribution network users? If not, why do they fail to do so?

(xiv) Are there further technical considerations to be taken into account? If yes, please highlight these technical considerations.

(xv) Is there any evidence that Users will be inappropriately or adversely affected by the changes proposed? If so, please provide details.

(xvi) Do the modifications proposed strike an appropriate balance between the needs of generators, DNOs, transmission licensees, and other interested parties? If not, why do they fail to do so?

(xvii) Do you agree with the proposed change implementation approach? If not, please explain why it is not appropriate and what other implementation options should be considered.

(xviii) Are there any specific additional actions you would recommend to engage small generators in the process to implement the proposed change?

(xix) What do you believe are the most important considerations in resourcing implementation of the proposals and in potentially developing new arrangements to do so?

(xx) Please provide any other comments you feel are relevant to the proposed change.

8.5 If you wish to submit a confidential response please note the following:

(i) Information provided in response to this consultation will be published on Distribution Code's website unless the response is clearly marked "Private and Confidential." We will contact you to establish the extent of the confidentiality. A response marked "Private and confidential" will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the

Distribution Code Review Panel and/or Grid Code Review Panel or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

(ii) Please note an automatic confidentiality disclaimer generated by your IT System will not in itself mean that your response is treated as if it had been marked “Private and Confidential.”

Annex 1 – Terms of Reference

i) The workgroup will investigate extending the first stage of work (Phase 1 underGC0035) to cover all distributed generation as Phase 2.

ii) 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.

iii) Phase 2 will therefore include the following activities:

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

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

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

   d) 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.

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

f) 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;

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

h) 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;

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

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

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

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

m) 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);

n) 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;

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

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

iv) 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

Proposed changes to Dcode are documented in a file called **Annex 2 DCode 31 draft (not approved) for RfG modified for DC0079 R** circulated together with this report.

Annex 3 –Legal Text for G59

Proposed changes to Dcode 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.

Annex: 4 Disabling ROCOF on non-synchronous generation[12]

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

12 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