

Modification proposal:	Changes to the Distribution Code and Engineering Recommendation G59: Frequency Changes during Large Disturbances and their Impact on the Total System		
Decision:	The Authority ¹ directs that the proposed modification to the Distribution Code be made		
Target audience:	Parties to the Distribution Code and G59 Engineering Recommendation, and other interested parties		
Date of publication:	23 July 2014	Implementation Date:	1 August 2014

Background to the modification proposal

System inertia is a property of the electricity system. It can be described as the 'momentum' of the system and it helps to keep system frequency stable. System inertia is especially useful when a large infeed (a generator or importing interconnector) unexpectedly disconnects from the system – the system inertia resists the frequency from falling too quickly and gives the System Operator (SO) time to recover the situation.

System inertia primarily comes from synchronous generators. Due to the changing demand and generation mix and the increasing prevalence of non-synchronous generation, system inertia is decreasing and will continue to decrease. As system inertia decreases, the rate at which frequency falls – the Rate of Change of Frequency (ROCOF, measured in Hz/s) – following the loss of an infeed is likely to increase.²

One effect of this is that the increasing system ROCOF experienced after a large infeed loss could trigger ROCOF Loss of Mains (LOM) protection used by some Distributed Generation (DG)³, causing this DG to disconnect from the system. This disconnection of DG after a large infeed loss exacerbates the situation by causing the frequency to fall further, so risking low frequency demand disconnection (LFDD) and inhibiting efforts to recover frequency.

The SO, National Grid Electricity Transmission (NGET), manages the system so that the ROCOF post infeed loss is not sufficiently fast to trigger this secondary DG disconnection. The SO does this in two ways:

1. by reconfiguring the generating mix to increase system inertia – this can be as simple as constraining on synchronous generators, but as the requirement for reconfiguration increases it will mean non-synchronous wind generation is constrained off; and

¹ References to the 'Authority', 'Ofgem', 'we' and 'our' are used interchangeably in this document. The Authority refers to GEMA, the Gas and Electricity Markets Authority. The Office of Gas and Electricity Markets (Ofgem) supports GEMA in its day to day work. This decision is made by or on behalf of GEMA.

² Similarly the rate at which frequency rises following the loss of an offtake (demand or exporting interconnector) will increase.

³ LOM protection disconnects generators if their local network becomes islanded. ROCOF is a type of LOM protection. Transmission connected generators are not permitted to use ROCOF LOM protection.

2. by limiting the maximum instantaneous infeed loss risk (typically interconnectors) connected to the network – if an infeed suddenly and unexpectedly disconnects, the smaller the lost infeed then the slower the ROCOF.

In these ways, NGET manages the potential ROCOF so that it is less than 0.125Hz/s, the current target to prevent activation of ROCOF LOM protection. NGET predicts that the cost of taking such actions is likely to increase significantly in the coming years and that, eventually, they may be insufficient to manage the risk. These actions are paid for as Balancing Services, the costs of which are recovered from BSUoS parties through Balancing Services Use of System (BSUoS) charges (which, like other costs, are ultimately passed to consumers). Depending on how NGET performs relative to its SO Incentives targets, some of these costs may also be recovered directly from NGET.

The modification proposal

One solution to this situation is to 'desensitise' the settings of the ROCOF LOM protection on DG so that a higher ROCOF is needed to activate them. The Distribution Network Operator (DNO) licensees propose this solution in this modification.

The current prescribed setting for ROCOF LOM protection is $\geq 0.125\text{Hz/s}$. This is set out in the Distribution Code and in Engineering Recommendation G59. This modification proposes to change the setting for ROCOF LOM protection for generation sites with a registered capacity of 5MW or greater to -

- 1Hz/s for all new and existing non-synchronous generators. Existing non-synchronous generators would have until 1 July 2016⁴ to make the change. Non-synchronous generators commissioning on or after 1 July 2014 would be required to commission with the new setting.
- 0.5Hz/s for all existing synchronous generators and all synchronous generators commissioning before 1 July 2016. Existing synchronous generators would have until 1 July 2016⁵ to make the change.
- 1Hz/s for all synchronous generators commissioning on or after 1 July 2016.

To reduce spurious tripping, the modification proposes that the ROCOF must be measured to be continuously in excess of the required setting for 500ms before activating the trip relay.

The primary function of LOM protection is to disconnect a generator if the network it is connected to becomes an 'island'⁶. Desensitising the ROCOF LOM protection setting increases the risk that, when an island network forms, generation connected to it does not disconnect and the island remains energised. This increases the risk to people near the island network and increases the risks of out-of-phase re-closure⁷. Out-of-phase re-closure can be especially damaging to synchronous generators. The risk to a specific synchronous generator is dependent on a number of factors. Therefore the licensees recommend that existing synchronous generators undertake a site specific risk assessment to quantify this increased risk, and help select appropriate mitigation

⁴ This date was proposed by the licensees to allow a two year implementation period after the introduction of this modification. When the proposed modification was submitted to us for approval, the licensees had assumed that this modification would be introduced on 1 July 2014. To ensure the proposed two year implementation period, as part of this decision we expect the dates in the proposed legal text to be updated.

⁵ See footnote 4.

⁶ An 'island' network is a section of network that has become disconnected from the wider system.

⁷ Out-of-phase re-closure is the event where a live electrical island is reconnected to the main system, and the phase angle and frequency of the waveform in the island is different to that of the main system.

measures, before implementing the change. The workgroup which developed this modification has developed risk assessment guidance.

The licensees predict this modification would result in Balancing Services savings of £33m by 2020/21, due to the avoided costs of managing the post infeed loss ROCOF to 0.125Hz/s.

This benefit must be assessed against the increased risk to people and generators. As part of our assessment of this modification, we have consulted with the Health and Safety Executive (HSE) on this matter. The benefit must also be assessed against the cost of implementation. The licensees state that there are 178 existing generation sites (132 synchronous, 46 non-synchronous) which would need to make changes to comply with this modification. The cost of a protection setting change for all generation sites is estimated as £10k per site. In addition to this cost, the licensees recommend all synchronous generation sites to undertake a site specific risk assessment, estimated at £25k per site. The licensees predict that 40% of these existing synchronous generation sites (53 sites) will also need to implement mitigation measures at an average cost of £100k per site. The licensees estimate the total implementation cost to be £11m.

Based on these costs and benefits, payback would be achieved by 2018/19.

A joint Grid Code Review Panel (GCRP) and Distribution Code Review Panel (DCRP) workgroup, which first met in October 2012, developed this modification. The workgroup consulted on their original proposal in August 2013 and, based on responses received, revised the modification proposal. This revised proposal was consulted on in March 2014, following which the relevant licensees submitted it to us for approval. The process also included four open workshops, an open letter to industry, and letters to all affected existing generators. Regular updates were provided to the GCRP and DCRP.

DCRP recommendation

At its meeting on 28 March 2014, the DCRP agreed to the submission to us of the final modification Report. The final modification Report⁸, the proposed legal text and supporting information were submitted to us on 9 May 2014.

Our decision

We have considered the issues raised by the modification proposal and in the final Report dated 9 May 2014. We have considered and taken into account the responses to both consultations on the modification proposal, included in the final Report. We have concluded that:

1. implementing the modification will better facilitate the achievement of the Objectives of the Distribution Code⁹; and
2. approving the modification is consistent with our principal objective and statutory duties¹⁰.

⁸ The final Report is available on NGET's website at: <http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/>

⁹ As set out in Standard Condition 21.4 of the Electricity Distribution Licence, see: <https://epr.ofgem.gov.uk//Content/Documents/Electricity%20Distribution%20Consolidated%20Standard%20Licence%20Conditions%20-%20Current%20Version.pdf>

¹⁰ The Authority's statutory duties are wider than matters which Distribution licensees must take into consideration and are detailed mainly in the Electricity Act 1989 as amended.

Reasons for our decision

We set out below our views on which of the Applicable Distribution Code Objectives are better facilitated by the modification, and our assessment of the modification against our principal objective and statutory duties. We agree with the licensees that the modification has no impact on Objective (c).

Objective (a): "permit the development, maintenance, and operation of an efficient, co-ordinated, and economical system for the distribution of electricity"

The licensees consider that the modification would reduce costs to electricity consumers by reducing Balancing Services costs incurred in managing the risk of DG LOM protection operation due to a high system ROCOF. They note that the reduction in Balancing Services costs is greater than the implementation costs of the proposal. They also state that the modification would reduce the risk that the ROCOF LOM protection is likely to operate due to a high system ROCOF.

While the first consultation did not ask respondents whether the original modification better facilitated this Objective, the majority of the 18 respondents agreed with the need for change and supported the proposal. Where detail was provided, these respondents thought that DG should be resilient to faster system ROCOF than currently and that it is desirable for all parties to have a stable and robust system. When asked as part of the second consultation whether the modification better facilitates this Objective, the majority (7 of the 11 responses) agreed, with one response disagreeing. Where detail was provided, the respondents in favour considered that it would reduce the risk of power cuts and increase network security.

We consider that this modification would better facilitate Objective (a). It 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. We consider that system ROCOF is likely to continue to increase and therefore that increased resilience to this, where more economic options are not available, is beneficial.

We note that this modification will increase the risk of energised island networks on the distribution system, the risk of injury to people near distribution equipment and DG, and the risk of damage to synchronous DG. We therefore consulted with the HSE on this issue, in accordance with section 3C of the Electricity Act 1989. The HSE noted that the change appeared to be necessary due to the changing nature of electricity generation in GB, but stated that:

1. The effect of the setting change on individual generators would need to be assessed from the health and safety perspective. The HSE stated that this is the responsibility of the relevant duty holders.
2. It is important that the affected generators were made aware of the potential health and safety impact of the proposed settings changes.

The HSE has written to all DNO licensees asking them to write to all affected generators to convey the above two points.¹¹

¹¹ The letters, dated 23 July 2014, were sent from the HSE to the 20 DNO and IDNO licensees.

The Report submitted to us shows that the annual probability of out-of-phase re-closure will increase significantly. We understand that the generator control mode (P-V or P-pf) has an impact on this risk. We therefore expect DNOs to discuss this with generators as part of the risk assessment process.

We also expect DNOs to consider how implementation of the most cost efficient and effective forms of mitigation can be ensured, especially in the instance where the most cost efficient mitigation may be on the distribution networks (for example, installation of sync-check equipment or extension of auto-reclose times) rather than at generation sites. This will require DNOs, individually and collectively, to establish ways of engaging with these customers and using this engagement as a platform for identifying solutions. This will be a challenge but one to which we expect DNOs to respond. DNOs should be seeking to engage with stakeholders, and financial incentives, such as the stakeholder engagement element of the Broad Measure of Customer Service, provide the opportunity for reward where these activities lead to tangible benefits.

We consider that, while the licensees have correctly identified that this modification results in reduced Balancing Services costs, this is not relevant to our assessment against Objective (a). Balancing Services costs (which are ultimately passed onto consumers) are paid for predominantly by suppliers and transmission connected generators. Reductions in these costs (while beneficial to consumers) are unlikely to affect significantly the development, maintenance and operation of the distribution system.

Taking all these factors into consideration, overall we consider that the proposal better facilitates Objective (a).

Objective (b): "facilitate competition in the generation and supply of electricity"

The licensees consider that the modification limits the constraints that need to be applied to generators and facilitates access to the national electricity transmission system by reducing the volume of actions taken to managing the risk of LOM protection operation.

The consultations asked respondents to consider whether the original modification better facilitated Objective (b). Those who agreed felt that a stable and secure network promoted competition and that a reduction in constraints of generators and infeeds would benefit competition. Those who did not agree made the argument that the costs were only applied to specific groups of generators, and this proposal would force sites towards using a more expensive form of LOM protection, such as intertripping. This would increase the cost of developing these sites and could result in some sites not being developed.

We consider that the modification would better facilitate Objective (b). It will reduce constraints applied to large infeeds, associated balancing actions and facilitate the connection of more non-synchronous generation. We consider that reductions in constraints and balancing actions would improve competition by reducing the need for actions taken by the SO outside the market. We also consider that facilitating the integration of non-synchronous generation to bring more generation to market is likely to improve competition.

We recognise that existing $\geq 5\text{MW}$ DG which uses ROCOF LOM, and especially synchronous generators within that group, will incur a cost as a result of this modification. We consider that imposing a cost on only some market participants can have an adverse effect on competition. However we note that existing synchronous

generators, the group most at risk from higher implementation costs, would have a lower ROCOF requirement than other groups of generators (0.5Hz/s rather than 1.0Hz/s), based on responses to the first consultation. We welcome the consideration of generators' views when developing this modification. We agree that lower requirements for existing synchronous generators are appropriate. Furthermore, generators are entitled to make the case to us for derogation from any requirements of the Distribution Code. We assess derogations in accordance with our statutory duties and our published guidance¹².

We note concerns from respondents that this modification may force sites towards using a more expensive form of LOM protection, resulting in more expensive projects and possible cancellation of some projects. We consider that this modification is more likely to facilitate the connection of future generation by promoting a stable system which can economically accommodate more non-synchronous generation than might otherwise have been the case.

Taking all these factors into consideration, overall we consider that the proposal better facilitates Objective (b).

Principal objective and other considerations

We have also considered this modification against our principal objective of protecting consumer interests. This modification will result in lower Balancing Services costs, and so lower BSUoS charges. As BSUoS charges, like other costs, are ultimately paid for by consumers, we consider that this modification will result in lower costs to consumers. We therefore consider that approving this modification is in accordance with our principal objective.

Reducing system inertia and increased non-synchronous generation is likely to continue for the foreseeable future. We consider that a modification which facilitates the stable integration of non-synchronous generation benefits consumers as it promotes supply side competition, helps achieve legally binding carbon reduction targets and reduces the likelihood of LFDD operation (which results in an involuntary loss of supply to large groups of consumers). We therefore consider that approving this modification is consistent with our principal objective.

A number of respondents recognised the challenge of reducing inertia, but queried whether changing ROCOF LOM protection settings was the best response, instead of other measures such as new ancillary service products. We recognise that there are other potential solutions to the challenges of reducing system inertia. We consider that, as a number of solutions are likely to be required to overcome these challenges, our approval of this modification would not preclude the development of other solutions. We also consider that it would be risky to rely on unproven solutions and that there is a cost of waiting to take action. The cost benefit analysis submitted to us in the Report shows that, even following approval of this modification, the Balancing Services costs of managing ROCOF will increase significantly over the coming years. Given its licence requirements to operate the system in an economic, efficient and coordinated manner, we expect the SO to continue to develop its understanding of the issue and potential solutions as a matter of urgency.

¹² <https://www.ofgem.gov.uk/ofgem-publications/52405/090119derogationsguidance.pdf>

We agree with consultation comments that it would have been desirable to undertake the work investigating withstand capability before changing ROCOF LOM protection settings for synchronous generators. However, recognising the views of respondents and that withstand capability will be considered under the next stage of work, we do not consider that this is sufficient reason to reject this modification.

Overall, we consider that this modification better facilitates the Applicable Distribution Code Objectives and that approving it is in accordance with our principal objective and statutory duties.

Modification implementation costs

This modification requires changes to DG as a solution to a whole system issue. The benefits from this modification are reduced Balancing Services costs, from which the generators affected by this modification will not benefit. We have considered the issue of who should bear the costs required to implement this modification. For the specific circumstances of this modification, we consider that it is appropriate for generators to bear their own costs of compliance. It should be noted that this does not set a precedent for future code modifications which result in benefits to other parties. With regard to any modification proposal to change the ROCOF LOM settings of generators smaller than 5MW, we will be scrutinising closely the costs and benefits to individual generators as well as the whole system cost benefit case.

Decision notice

In accordance with Standard Condition 21.10 of the Electricity Distribution Licence, we direct that modification proposal '*Frequency Changes during Large Disturbances and their Impact on the Total System*' be made.

We expect DNO licensees to write to all affected generators connected to their network, as requested by the HSE.

We approve the modification proposal and direct that it is implemented on 1 August 2014. To ensure the two year implementation period that was proposed by the licensees, we expect all relevant dates in the proposed legal text to be updated. Having considered the proposed legal text, we feel that to improve clarity a minor change, as suggested in Annex 1, should be made.

This document is notice of the reasons for this decision as required by section 49A of the Electricity Act 1989.

Andy Burgess

Associate Partner, Transmission and Distribution Policy

Signed on behalf of the Authority and authorised for that purpose

Annex 1

Annex 2 of Volume 1 of the final Report sets out the legal text proposed by the licensees to implement this modification. Pages 66-67 of Volume 1 of the final Report set out the proposed legal text, for Engineering Recommendation G59, describing the risk assessment guidance. As part of our decision to approve this modification proposal, we expect that the following text addition (in red) is made to this section of the proposed legal text.

- 13.11.4 When a **Generator** wishes to carry out a risk assessment the **DNO** will be able to provide an estimate of the **net (ie taking into account as appropriate other Generating Plant on that part of the network)** potential trapped load. This can be in the form of a yearly profile, and possibly in the form of a load duration curve. It is possible that an island may form at more than one automatic switching point on the **DNO's** network and the **DNO** will be able to provide a profile or estimate of a profile for each. This will enable a quick assessment to be made as to the whether the mismatch between load and generation is so gross as to obviate further study. It is for the **Generator** to determine what a gross mismatch is depending on the **Generating Unit's** response to a change in real or reactive power. The **Generator** should be aware that the trapped load on a network can change over time, due to the connection or disconnection of load and or **Generating Plant**, hence the trapped load assessment may need to be carried out periodically.